



COAL: AMERICA'S ENERGY FUTURE

VOLUME I

The National Coal Council

March 2006



**Coal will enable the United States
to meet the substantial increase in demand for energy;
ensure our continued economic preeminence in the world arena;
reduce our dependence on foreign oil and natural gas;
and improve the quality of life for all Americans.**

Coal: America's Energy Future

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The National Coal Council is a Federal Advisory Committee to the Secretary of Energy. The sole purpose of The National Coal Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to coal or to the coal industry.



The Secretary of Energy
Washington, DC 20585

April 7, 2005

Mr. Thomas Kraemer
Chairman, National Coal Council
1730 M Street, NW
Washington, DC. 20036

Dear Mr. Kraemer:

I am requesting the National Coal Council to conduct a study and prepare a report identifying the challenges and opportunities of more fully exploring our domestic coal resources to meet the Nation's future energy needs. Coal must be used to provide an adequate measure of energy security and reliability. It has been and will continue to be the major fuel of choice for electricity generation. However, environmental and other challenges remain.

I request that the National Coal Council complete an updated, thorough assessment of the domestic resource base for coal. I also request the preparation of a thorough assessment of the potential barriers to future coal production and use. In examining the potential barriers, solution pathways should be comprehensively evaluated, especially technology solution pathways, such as near zero emissions power generation technology and low impact coal mining technology.

The study should also investigate opportunities to use coal in new and innovative ways within sectors of the economy that traditionally have not used coal. Examples would include, but are not limited to, using coal to create liquid fuel products such as synthetic crude oil, using coal to produce the steam needed in the manufacturing of ethanol, and especially the gasification of coal for use in electricity production. All concepts considered should clearly and quantitatively address market introduction challenges and strategies for surmounting them. Environmental challenges and solution pathways must also be central to the analysis.

Each of these applications should be supported by examples and/or case studies. For instance, the coal-to-liquid fuels technology is being used by SASOL in the Republic of South Africa. Ethanol production has traditionally used natural gas to create the steam used in the production process. Recently some ethanol manufacturers have switched to coal due the price of natural gas. There may be opportunities for gasified coal to be used at these facilities to dramatically increase the amount of electricity available to the economy, while reducing pressure on natural gas.



I 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.

Please give my appreciation to the Council for assisting the Department in completing this important study. I look forward to receiving the report when it is completed.

Sincerely,

A handwritten signature in black ink, appearing to read "Sam Bodman", with a stylized, flowing script.

Samuel W. Bodman



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March 22, 2006

The Honorable Samuel W. Bodman
Secretary of Energy
U. S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585

Dear Mr. Secretary:

On behalf of the members of the National Coal Council, we are pleased to submit to you pursuant to your letter dated April 7, 2005, the report, "Coal: America's Energy Future." This study demonstrates a path to add 1.3 billion tons per year of U.S. coal production by 2025 to meet the nation's growing energy needs while improving the environment through deployment of cutting-edge clean coal technology. If the Department of Energy, with the help of other federal agencies, implements the recommendations in this report – and we think they should – more than 1 million new, high-paying energy manufacturing jobs will be created, U.S. energy costs will be reduced by 33 percent and the American people will realize an aggregate gain in Gross Domestic Product of more than \$3 trillion, which increases to \$4 trillion with enhanced oil recovery.

The study identifies ample amounts of U.S. coal reserves to support 100 gigawatts of new electricity generation, 2.6 million barrels per day of refined liquid products, 4 trillion cubic feet (TCF) per year of natural gas production for all applications, plus support for ethanol, enhanced recovery of oil and coalbed methane, and hydrogen production. Creating an additional energy supply of this magnitude, which is based on a doubling of U.S. coal production, will have a profoundly positive effect on our country and the world.

In the report, you will also see an in-depth discussion of the clean coal technologies available to increase our reliance on domestic coal to meet our future energy needs. The study takes a hard look at supply problems associated with imported oil and imported liquefied natural gas along with the explosive growth in energy demand in China and India.

The second Industrial Revolution being led by China in Southeast Asia will continue to strain the worldwide energy supply with a negative impact on the United States due to our economy's use and dependence on energy in all forms. Greater use of our domestic coal resources will enhance the health and wealth for the American people while removing competition for energy supply as a potential source of conflict between the United States and the developing world.

There are numerous projects in development around the country that would liquefy and gasify coal. Given current market prices and supply constraints for both oil and natural gas, we believe these projects will reach fruition. Yet the market risks associated with wide-scale development of Btu Conversion projects are very real. Without new initiatives at the federal level to lower the risk profile of these projects, needed development will be far less robust.

Doubling U.S. coal production as envisioned by this report will require the investment of hundreds of billions of dollars by the private sector. Proper tax, fiscal and regulatory process at the federal level will jump-start a new industry for widespread development of Btu Conversion projects that are necessary to meet the energy needs of the American people.

Substantial coal reserves are available in more than 25 states. In the energy future envisioned by this report, there will be widespread coal production, liquefaction and gasification in most of these states. As a result, the standard of living for all Americans will increase due to lower energy prices, a surge of industrial activity and creation of wealth.

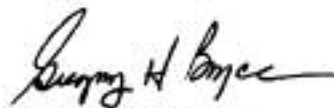
We believe the role of the federal government is to create conditions for more people to live longer, healthier and with a better quality of life. By instituting the policy recommendations in this report and allowing full development of our nation's vast coal resources, the United States will maintain and enhance its competitive position as the world's premier economy. Our country will also be a better place to live for all citizens as they work and prosper in a new energy manufacturing industry with environmental excellence.

Thank you for the opportunity to conduct this study. The Council stands ready to answer any questions you may have on the recommendations it contains.

Sincerely,



Thomas G. Kraemer
National Coal Council Chairman &
Coal Group Vice President
Burlington Northern Santa Fe Railway Co.



Gregory H. Boyce
National Coal Council Study Chair
President & Chief Executive Officer
Peabody Energy

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 United States 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
- 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 at no cost to the federal government.

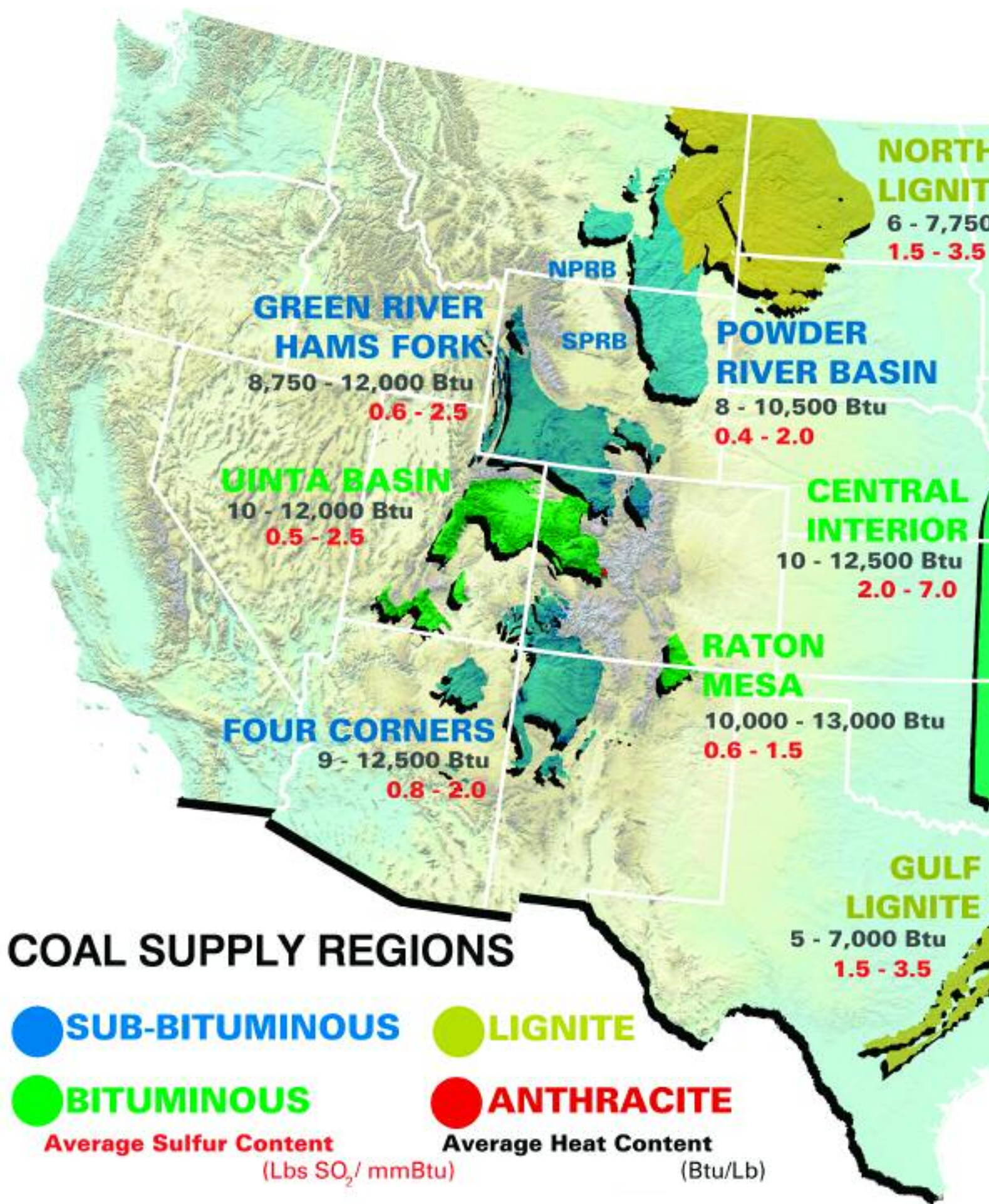
Coal: America's Energy Future

VOLUME I

Table of Contents

Executive Summary	1
Chapter One:	
Coal-to-Liquids to Produce 2.6 MMbbl/d	15
Chapter Two:	
Coal-to-Natural Gas to Produce 4.0 Tcf Per Year	33
Chapter Three:	
Coal-to-Clean Electricity	45
Chapter Four:	
Coal to Produce Ethanol	63
Chapter Five:	
Coal-to-Hydrogen.	73
Chapter Six:	
Enhanced Oil and Gas (Coalbed Methane) Recovery as Carbon Management Strategies	83
Chapter Seven:	
Delineate U.S. Coal Reserves and Transportation Constraints as Part of an Effort to Maximize U.S. Coal Production	95
Chapter Eight:	
Penn State Study, "Economic Benefits of Coal Conversion Investments"*	113
Appendix	
Abbreviations.	123

* Economic analysis conducted at Penn State University, 2006; see Volume II for analysis detail.



The Resource: 27% of the World's Coal is in the United States



Executive Summary

The National Coal Council thanks Secretary of Energy Samuel W. Bodman for his April 7, 2005 request for a “report identifying the challenges and opportunities of more fully exploring our domestic coal resources to meet the Nation’s future energy needs.”

The Secretary’s request is timely, as recent geopolitical events and hurricane devastation in the Gulf of Mexico have demonstrated that the precarious balance between energy supply and demand leaves our nation’s economy vulnerable to supply disruption and volatility in energy prices.

President George W. Bush made a number of points in his 2006 State of the Union address that make this study’s timing even more compelling:

“Keeping America competitive requires affordable energy. And here we have a serious problem.”

He went on to describe America’s addiction to oil and the need to break dependence on the Middle East for energy and later emphasized the Advanced Energy Initiative:

“... a 22-percent increase in clean-energy research at the Department of Energy, to push for breakthroughs in two vital areas. To change how we power our homes and offices, we will invest more in zero-emission coal-fired plants, revolutionary solar and wind technologies, and clean, safe nuclear energy.”

This report addresses the Secretary’s request in the context of the President’s focus, with eight findings and recommendations that would use technology to leverage our country’s extensive coal assets and reduce dependence on imported energy. Volume I outlines these findings and recommendations. Volume II provides technical data and case histories to support the findings and recommendations.

This National Coal Council report is based on the following fundamental premises regarding the evolving energy situation in the United States:

- **Energy demand will increase significantly over the next 25 years.** The Energy Information Administration (EIA) has projected that consumption will grow from 100 quadrillion British thermal units (Btu) in 2004 to



EXECUTIVE SUMMARY

127 quadrillion Btu in 2030, a rise of 27%. This 27 quadrillion increase is equivalent to the nation's total energy consumption increase from 1972 to 2004. But during those years, oil imports were available to meet **two-thirds** of new demand. Such an international supply cushion no longer exists. Thus, the great bulk of new energy supply for the next generation of Americans will come from coal in its many varied applications.

- **Coal is the only domestic fuel that has the flexibility and reserve base to meet this burgeoning demand.** Coal's annual production of over 1.1 billion tons can be more than **doubled** to 2.4 billion tons. This increase of 1.3 billion tons is possible because our coal reserves are vast. U.S. oil and natural gas (NG) production both peaked in the 1970s, but we have enough coal to last more than 100 years even at elevated levels of consumption. In 2004, the EIA estimated that the demonstrated reserve base (DRB) of the United States exceeded 496 billion short tons distributed across more than 25 states that have significant recoverable resources.

- **The emerging economies of the world, led by China, are moving rapidly to develop their coal resources (see Figure ES.1).** China will increase coal production from 1.7 billion tons per year (tpy) today to over 3.2 billion tpy by 2020. This additional coal will be used for electric generation, which will approach 1,000 gigawatts (GW) in total capacity, for coal liquefaction and for coal-to-syngas. Syngas production is already well under way in China, and liquefaction will follow shortly. Both are regarded as strategic imperatives by the Chinese government.
- **By maximizing the use of coal, we free the next generation from continued and increased dependence on foreign energy suppliers.** The EIA forecasts that from 2004 to 2030, petroleum imports will increase from 58% to 62% of supply, and NG imports will grow from 15% to 21%. In terms of domestic oil production, for example, the United States experienced a decline from 5.8 million barrels per day (MMbbl/d) in 2001 to 5.1 in 2005—an 11% decrease. During the same time period, NG production declined over 7%. Unless

Global Coal Use Soars 22%, or 1.1 Billion Tons, in 3 Years

Three-Year Percent Change in Global Energy Consumption

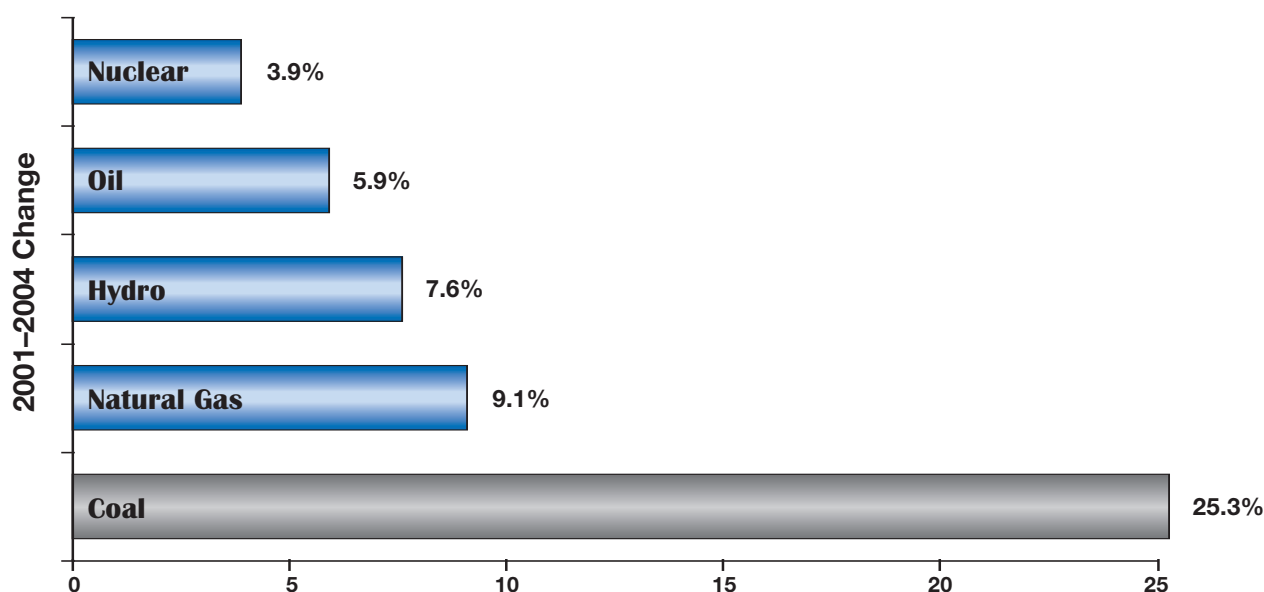


Figure ES.1 Source: BP Statistical Review of World Energy, 2003, 2004 & 2005

steps are taken to utilize more of our domestic energy resources, the United States will be forced to increasingly rely on the Middle East and other regions for both oil and NG.

- **Imported energy comes with a staggering cost.** At today's prices, oil and NG imports would reach as much as **\$2.5 trillion** over the 2010–2019 decade alone. Further, many of these imports would come from unstable and volatile regions of the world.
- **Clean coal technologies are commercially available to produce exceptionally clean, reliable and low-cost electricity;** to convert coal to NG and liquid fuels; to produce hydrogen; to increase enhanced oil recovery; to enhance coalbed methane recovery; and to fuel the production of ethanol in an environmentally acceptable manner. Government support of a portfolio of clean coal technology and environmental systems development will ensure that we continue to protect the environment while greatly expanding coal's long-time role as the cornerstone of low-cost, reliable energy in the United States.
- **Implementation of these technologies would generate unprecedented socioeconomic benefits** for the American people for decades to come. If the recommendations presented by The National Coal Council are implemented, an independent scholarly analysis conducted at Penn State University indicates that by 2025 energy prices would be reduced by 33%, more than **1.4 million new jobs per year** would be created, and the cumulative gain in Gross Domestic Product (GDP) would exceed **\$3 trillion** (see Volume II). If carbon dioxide from these



technologies is captured and used to enhance domestic oil production, these benefits would exceed \$4 trillion.

Overall, the **recommendations** presented here regarding the expanded role of coal will enable the United States to:

- meet the substantial increase in demand for energy over the next several decades for the benefit of the American people;
- ensure continued economic preeminence of the United States in the world arena;
- reduce the debilitating and even dangerous impact of our dependence on foreign energy; and
- improve the quality of life for all Americans.

Coal can do this.

EXECUTIVE SUMMARY

Before turning to the recommendations, it is useful to consider how an historical perspective from the energy crises of the 1970s sheds light on the current energy situation and demonstrates that recommendations for expanded use of coal have a strong foundation.

Before the 1973 oil embargo, oil was relatively inexpensive and utilized to generate almost 20% of electricity in the United States. When Middle Eastern oil-producing nations decided to use oil as a political weapon and embargoed oil shipments to the United States and other Western countries, prices greatly increased. Policy makers quickly recognized the dangers of dependence on foreign sources of energy.

In November 1973, President Nixon signed the Emergency Petroleum Allocation Act, implementing government regulation of energy supplies. Project Independence was created to free the United States from reliance on foreign oil by 1980, particularly for electricity generation. By 1978, perceived NG supply

problems led to the implementation of the Fuel Use Act, which virtually eliminated the construction of NG power plants until repealed in 1988.

Great strides were made in reducing America's dependence on foreign oil and NG for electricity production, and clean coal combustion played a key role in that process. Over 300 GW of coal combustion generation capacity was eventually brought to bear, supplemented by an additional 100 GW of nuclear (see Figure ES.2 for increases in coal generation).

The combined effect of new low-cost generating capacity from coal combustion and nuclear contributed to lower electricity prices. Electricity consumers in America benefited for decades. Coal is the backbone of U.S. power generation, providing more than 50% of electricity production while complying with ever-stringent environmental requirements. Nuclear power provides an additional 20%. Due to steady increases in electricity demand and high oil and NG prices,

Coal Use Grows While Emissions Decline

Coal Used for Electricity Has Tripled
Since 1970 While Emissions Have Been Significantly Improved

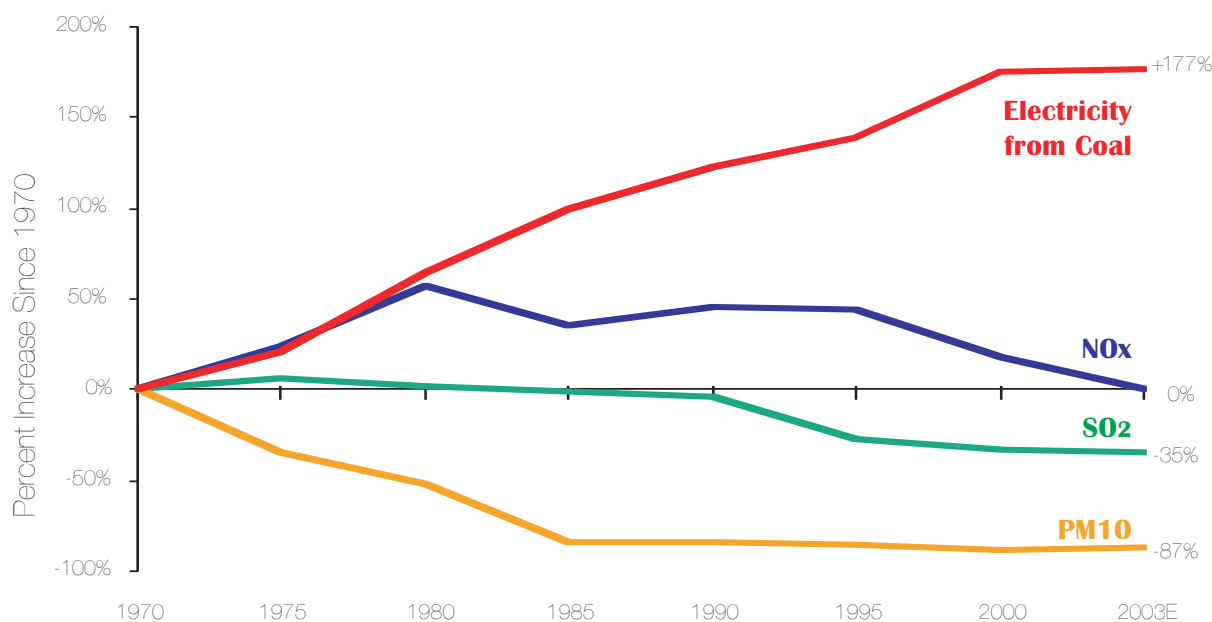


Figure ES.2 Source: EPA National Air Pollutant Emission Trends Dec 2004; EIA Annual Energy Review 2003 (September 2004)

U.S. Forecasts Largest Increase in Coal Generation in Decades

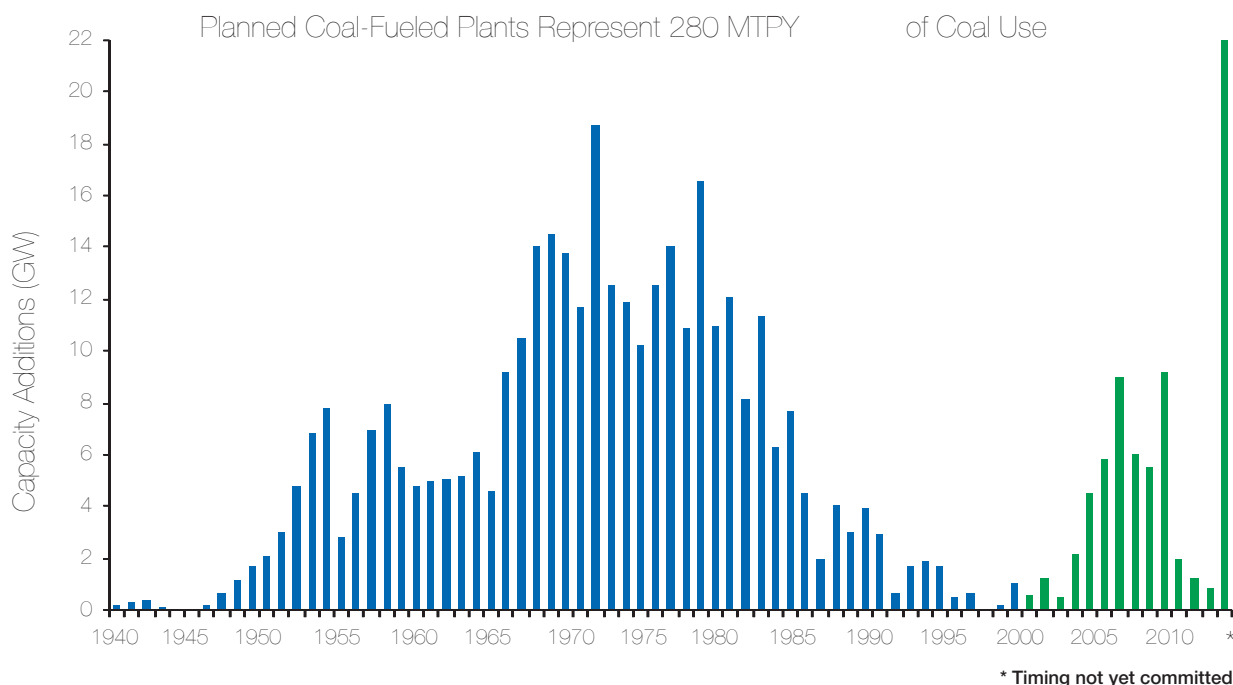


Figure ES.3 Source: DOE, National Energy Technology Laboratory, 2006

however, the coal and nuclear fleet is currently operating near full capacity as baseload generation. The time to add new coal generation capacity is now, and upwards of 90 GW are on the boards.

History offers an excellent example that growing coal use can also accompany improved emissions. Coal use for electricity generation has tripled since 1970, while criteria emissions have been reduced by one-third (see Figure ES.2).

Today, our problems are similar to the oil crisis of the 1970s, but also different. NG is faced with supply and deliverability issues, and is expensive in part due to a massive construction program of NG fueled electricity plants in the past six years and a depleting NG production base in the United States. The decline of NG domestic production (despite increased exploration and drilling) and the accompanying rise in NG prices have demonstrated

that the United States should expand its reliance on coal for future incremental electric demand (see Figure ES.3).

As noted by President Bush, America needs to develop new generation based on a portfolio of domestically available resources. Coal, as the nation's most abundant and energy resource, is the logical choice to provide the bulk of new generation.

Circumstances surrounding imported oil also differ from the 1970s. In that decade, for example, there was abundant but unused oil production capacity; it was political manipulation that

limited supply. Today, there is little or no unused capacity; market forces—supply and demand—are driving prices upward.

Today, oil produces only 3% of the nation's electricity, mainly in older units in the Northeast.



EXECUTIVE SUMMARY

On the other hand, America's thirst for oil has dramatically grown as a transportation fuel. The United States now imports 58% of its petroleum supply, as compared to 22% in 1970. A great deal of the imported oil we consume comes from either the same countries that embargoed oil in the 1970s or from countries that are hardly stable U.S. allies. The United States must break its addiction to foreign sources of oil. Fortunately, we have the domestic coal reserves and existing technologies to transform coal into transportation fuels to displace energy imports.

There is one additional critical difference in today's situation and that of the 1970s—the phenomenal recent and projected economic growth in Asia, especially China and India. Simply put, there is no precedent in human history for the magnitude of change that Asia and its rapid economic growth and industrialization will stimulate.

China's emerging energy needs are staggering. China's population today is 1.3 billion people. Notwithstanding the official one-child policy,

China's population will grow to at least 1.5 billion people by 2020, according to the Chinese themselves. China's auto industry produced 6.5 million vehicles in 2005, up from virtually nothing five years ago. At current growth rates of 13%–15%, China's automotive industry will easily surpass that of the United States by 2020.

In order to meet this massive demand, China plans to center its energy growth in the resource rich but less developed middle and western portions of the country. Annual coal production of 1.7 billion tpy will grow to over 3.2 billion tpy by 2020. Installed generating capacity will roughly double to 1000 GW during the same time frame. Within three years, 50 facilities will be in operation to convert hundreds of millions of tons of coal each year to syngas for industrial and agricultural applications and home heating. China has announced \$20 billion of investment in coal-to-liquid (CTL) facilities, and it regards Btu conversion as a strategic imperative.



In 2001, **China** used 4.9 million barrels of oil per day. In 2025, consumption is projected to exceed 14 million barrels per day, an increase of 189% that approaches the production capacity of Saudi Arabia. About 9.3 million barrels per day, or 65% of China's oil needs, will come from imports because Chinese production has peaked.

India also has global implications for energy supply and demand. India has a population of 1.1 billion that will approach 1.3 billion in 2025 and 1.7 billion by 2050. India consumes 2.2 million barrels of oil per day but produces only 0.8. By 2025, India is projected to import about 5 MMbbl/d. The country has extremely limited proven reserves—only 5.6 barrels per person—compared to 14 for China and over 70 for the United States. Although the world is focused on the rise of China, the entry of India into the modern age may be of even greater long-term significance. By 2030, the population of India will likely exceed that of China. In fact, the increased use

of petroleum has propelled India to the category of one of the world's fastest growing oil consumers with growth at 5.3% in 2005.

In addition, the dramatic growth in Asian economies could be replicated in the **Middle East** itself, which is home to 600 million people. Economic growth is now causing an increase in oil demand that is showing itself for the first time. This increased demand will put even greater pressure on the price and availability of oil for the rest of the world.

Liquefied Natural Gas (LNG) is expected to be an important component of incremental energy supply for our country. It would be imprudent, however, to simply assume that LNG will be available in abundant amounts at a reasonable price. Moreover, a large part of the source of future LNG supply will be from the same parts of the world where much of our imported oil originates (see Figure ES.4), with the same attendant problems.

Natural Gas Reserves in the World

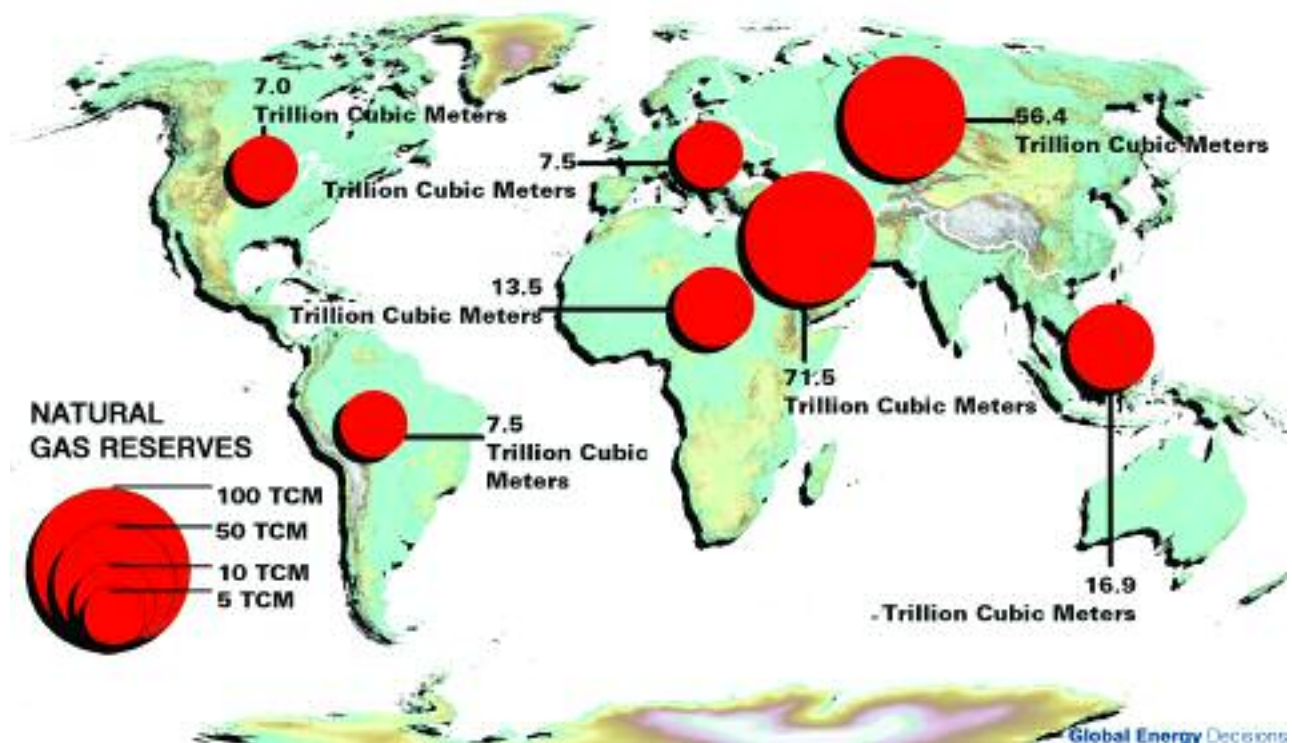


Figure ES.4

EXECUTIVE SUMMARY

Further, because LNG pricing could well be benchmarked on oil prices, U.S. residential and commercial consumers may be forced to pay a high price for energy fueled by LNG. The United States finds itself competing for LNG supply and is at a competitive disadvantage since the U.S. market is the



furthest from the source of incremental supply. In short, LNG represents a high-risk, high-cost and still uncertain answer to America’s energy needs, as well as increasing our country’s trade deficit.

Fortunately, there is a certain, secure and cost-effective way to change the United States energy model. As we did in the energy crises of the 1970s, the United States should increase its use of abundant domestic coal to significantly reduce dependence on foreign energy.

Coal can not only be used to generate electricity but also can be converted to the equivalent of oil and NG. Coal can fuel ethanol production and serve as the energy base of a hydrogen economy. Finally, carbon dioxide (CO₂), a byproduct of utilizing coal as a fuel, can be utilized for enhanced oil recovery as well as recovery of methane (NG) from coalbeds. And, should the nation choose a policy of CO₂ management, the technology to do so is being developed.

The **coal Btu conversion technologies** discussed here will use abundant domestic resources to enhance energy security and build economic prosperity. To attain this vision, the following capital expenditures over the next 20 years will be required, which in present-value terms is equivalent to \$350 billion:

Capital Expenditures for Coal Btu Conversion Technologies		
	Coal Use Per Year in Million Tons	Capital Expenditures in Billions (2005 Dollars)
Coal-to-liquids	475	\$211
Coal-to-gas	340	115
Coal-to-electricity	375	150
Coal-to-hydrogen	70	27
Coal for ethanol	40	12
TOTAL	1,300	\$515

Figure ES.5

Gains in Gross Domestic Product Resulting from More Robust Coal Use

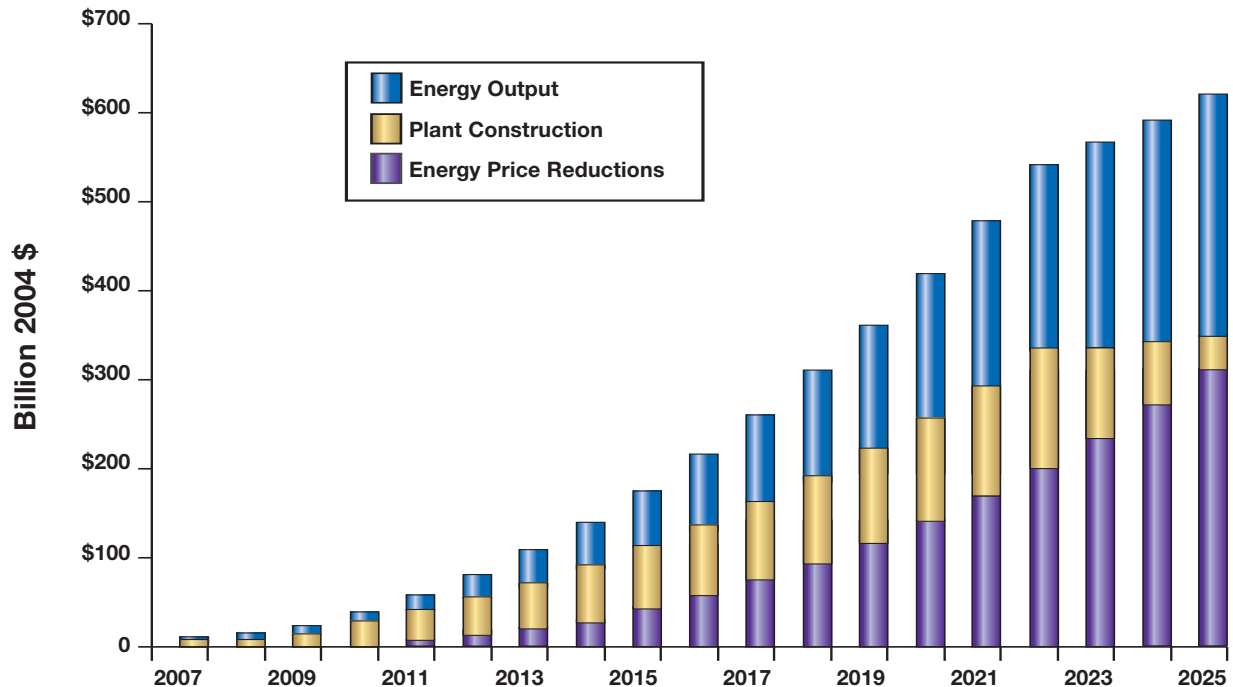


Figure ES.6 Source: Economic Analysis Conducted at Penn State University, 2006

While these capital expenditure requirements are significant, the social benefits from these investments are enormous. Research by independent scholars indicates such Btu conversion will generate profound socioeconomic benefits:

- After 20 years, coal Btu conversion would position U.S. energy markets with prices nearly 33% below those that would prevail without Btu conversion.
- Lower energy prices resulting from coal energy conversion and the stimulus from plant

construction and operation would result in GDP that is more than \$600 billion higher in 2025 and total employment 1.4 million greater than the EIA base case forecast (see Figure ES.6).

- The present discounted value of the cumulative gains in GDP from 2007 to 2025 is **\$3 trillion**. These gains increase to \$4 trillion if CO₂ from Btu conversion is used to enhance domestic oil production.





FINDINGS

The National Coal Council recommends that the United States Department of Energy (DOE) and other key government entities address eight National Priority Findings related to coal-fueled energy and Btu conversion technologies.

The eight chapters of this National Coal Council study will focus on these significant findings. Given the substantial future energy needs of the United States, these goals are presented as an integrated package rather than as a ranked set:

CHAPTER ONE

Coal-To-Liquids to Produce 2.6 MMbbl/d

FINDINGS: The United States continues to increase its dependence on foreign oil as domestic production declined by 11% from 2001 to 2005. Meanwhile, global demand is growing and concerns are mounting that world oil production is depleting reserves at rates faster than replacement reserves can be deployed. Application of coal-to-liquids technologies would move the United States toward greater energy security and relieve cost and supply pressures on transportation fuels by producing 2.6 MMbbl/d of liquids. These steps would enhance U.S. oil supply by 10% and utilize an additional **475 million tons** of coal per year.

CHAPTER TWO

Coal-To-Natural Gas to Produce 4.0 Tcf Per Year

FINDINGS: Conventional natural gas (NG) production in the United States is in significant decline, leading to supply and deliverability issues, higher prices and increasing dependence on foreign sources. These problems will become far more serious as domestic supplies continue to decline and NG demand increases. LNG presents the same economic cost and national security problems as imported oil. Using coal to produce NG and as replacement for NG in chemical processes would ease supply pressures by providing an alternative to at least 15% of America's annual NG consumption, or the equivalent of 4 trillion cubic feet (Tcf) per year. This additional supply would moderate NG prices and use an additional **340 million tons** of coal per year. The NG made available could be used for residential, commercial, industrial and any other application that uses NG. The amount is roughly equal to EIA's projection of LNG imports in 2025.

CHAPTER THREE

Coal-To-Clean Electricity

<

Coal to Produce Ethanol

FINDINGS: The United States is committed to expanding the use of ethanol to displace a significant amount of foreign oil as a transportation fuel. Currently, natural gas, diesel fuel and electricity are used to produce ethanol. But the ethanol industry is ready to embrace coal as a fuel source. Increasing the use of coal for heat and electricity in the production of ethanol would reduce costs and displace oil and NG by significant amounts while utilizing an additional **40 million** tons of coal per year, thereby freeing up NG for other uses and relieving price pressures.

Coal-To-Hydrogen

FINDINGS: The United States has identified the Freedom Fuel and FreedomCAR Initiatives as ways to transition the country to a hydrogen economy and use coal-fueled energy to power fuel cells. Development of a fleet of coal-to-hydrogen plants would mean that coal could satisfy at least 10% of the nation's transportation needs with FreedomCAR efficiencies. This application would use an additional **70 million tons** of coal per year.

Enhanced Oil and Gas (Coalbed Methane) Recovery as Carbon Management Strategies

FINDINGS: The United States has identified carbon capture and storage as a promising method of managing carbon after efficiency improvements. Major regional carbon storage projects and partnerships are underway around the country. One promising carbon management opportunity is enhanced oil recovery, which could potentially lead to production of an additional 2 to 3 million barrels of oil per day, assuming a technically recoverable reserve base of up to 89 billion barrels in 10 basins. Captured CO₂ can also be used to produce methane from coalbeds. This increase in domestic production would be an important step toward energy security and help to moderate price pressures on imported oil and natural gas. Other carbon capture and storage technologies should be developed to complement advanced coal utilization technologies.

Delineate U.S. Coal Reserves and Transportation Constraints as Part of an Effort to Maximize U.S. Coal Production

FINDINGS: The National Coal Council has conducted an in-depth survey of existing data and finds that the mining industry and U.S. transportation infrastructure can be expanded to accommodate growth in coal production by 1,300 million tons per

RECOMMENDATIONS

The findings of The National Coal Council clearly demonstrate that clean coal technologies stand ready to utilize an additional 1.3 billion tons of coal each year to enhance national security, meet the energy needs of the American people, stabilize energy prices and revitalize our industrial base.

The National Coal Council's recommendations are tantamount to the creation of an entirely new energy manufacturing industry in the United States, generating millions of jobs, resulting in a significantly improved balance of trade, and producing greater income, wealth, and environmental quality for all Americans. The initial expenditures to jumpstart this new energy manufacturing industry will require a significant investment of capital. The risk associated with such an undertaking will be perceived as substantial, given the historic volatility of oil prices, and more recently, the price of natural gas. The most significant contribution government can make to this endeavor is to lower the risk profile of investment. The National Coal Council recommends that capital funding policies be implemented to encourage the private sector to step forward on a massive scale. The specific fiscal, tax, financial, and regulatory recommendations presented here are all designed to encourage private sector commitments to seize this opportunity and secure America's energy future.

Many of the approaches recommended here build on existing law and recent federal enactments, including the American Jobs Creation Act of 2004 (AJCA2004); the Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU 2005); the Energy Policy Act of 2005 (EPA2005); and the President's Advanced Energy Initiative.

In order to remove potential barriers to expanded coal production and use, the DOE, acting in coordination with other federal agencies and states, should:

- **Accelerate research, development and demonstration of advanced technology by:**
 - Urging Congress to appropriate full funding for all clean coal programs authorized, including

FutureGen and the Clean Coal Power Initiative (CCPI), with the goal of developing at least 100 GW of clean coal power plants by 2025. Congress has recognized that a full portfolio of energy technologies is needed, including both coal gasification and combustion-based generation. The Department should take steps to ensure that U.S. energy policy achieves these goals.

- **Improve the ability of the industry to attract private capital for new facilities by:**
 - Providing for 100% expensing in the year of outlay for any coal-to-liquids (CTL) plant begun by 2020.
 - Providing for 100% expensing in the year of outlay for coal to gas (CTG) plants operated to displace NG usage in existing

characteristics to assure the broadest applicability in commercial use.

- Involving the Department of Defense in testing fuels to optimize plant and process design for the Air Force (jet fuel), Army (arctic diesel), and Navy (marine diesel) requirements.

- **Assure coal incentives for all alternative technologies by:**

- Providing for 100% expensing in the year of outlay for converting ethanol plants currently using natural gas to coal combined heat and power if the new plant is in service by 2010.

- **Minimize operating costs for new alternative fuel plants by:**

- Providing royalty (federal and state) relief for coal used to produce either liquids or gas.

- **Reduce permitting delays and regulatory uncertainty by:**

- Expediting permitting with a joint (federal and state) process, including Advanced Clean Coal power plants.
- Using, where appropriate, federal sites, including Base Realignment And Closure (BRAC) sites.
- Exempting initial CTL and CTG plants from New Source Review (NSR) and National Ambient Air Quality Standards (NAAQS) offset requirements.
- Where it has not been done, implementing the recommendations proposed by The National Coal Council in the 2004 report *Opportunities to Expedite the Construction of New Coal-Based Power Plants*.

- **Assure that enhanced oil recovery in new basins using CO₂ extracted from coal plants is an attractive investment by:**

- Increasing Section 43 investment tax credit to 50%.

- Creating an explicit exemption from the Alternative Minimum Tax (AMT) for new production from Enhanced Oil Recovery using CO₂.

- Providing federal and state royalty and severance tax relief for oil produced until capital payout (see EPLA 2005 § 354).

- **Provide incentives for upgrading the transportation infrastructure by:**

- Providing federal tax incentives to support taxpayers who invest in railroad infrastructure capacity.

- Urging Congress to appropriate funds for the upgrade of the inland waterway system, including barge access.

- **Ensure that all existing, identified U.S. economically recoverable reserves remain a part of the resource base by:**

- Seeking balance between precautionary protectionist policies and energy security.
- Supporting active enforcement of existing laws, including The Clean Water Act, the Endangered Species Act, the Surface Mining Control and Reclamation Act, and the Wilderness Act.
- Actively involving the DOE in addressing energy security in any policymaking that would “sterilize” significant coal reserves.
- Opposing overlapping and additional regulation that needlessly reduces access to the United States’ most abundant energy resource—coal. Recent examples would be the last-minute inclusion of the Kaiparowits Plateau in the Grand Staircase-Escalante National Monument designation and the Forest Service’s recently extended Roadless Forest Protection to July 16, 2007.

EXECUTIVE SUMMARY

- **Continuing to support the provisions of the Mine Safety and Health Act by:**
 - Ensuring a progressive approach to the important issue of enhancing mine safety and working to provide enhanced funding for mine safety research by the National Institute for Occupational Safety and Health (NIOSH).
- **Conduct a thorough and updated survey of U.S. coal reserves.**
 - The National Coal Council has conducted an in-depth analysis of coal mining and transportation infrastructure, but the resources of the federal government are required for a thorough analysis of our nation's vast reserves of coal.

Implementation of these recommendations is ambitious but achievable, and it must be done. The EIA projects that energy consumption will increase from 100 quadrillion Btu in 2004 to over 127 quadrillion in 2030. Coal is the only domestic energy resource that can meet the scale of such a massive increase. By pursuing the solution pathways recommended by The National Coal Council, the federal government can jumpstart coal's ability to secure America's energy future.

COAL-TO-LIQUIDS TO PRODUCE 2.6 MMbbl/d

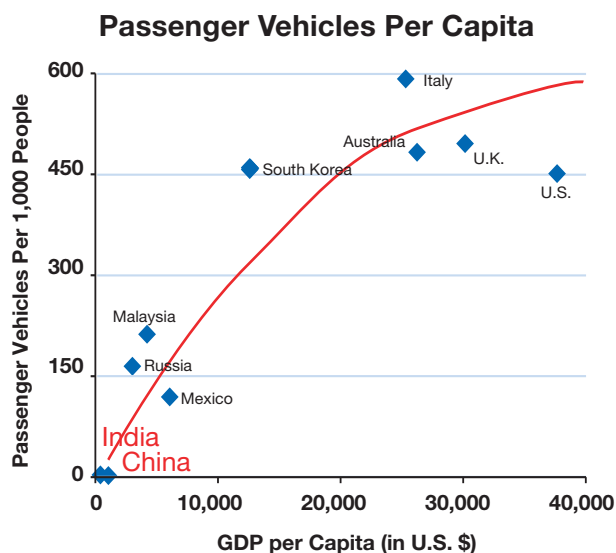


The United States continues to increase its dependence on foreign oil as domestic production declined by 11% from 2001 to 2005. Meanwhile, global demand is growing, and concerns are mounting that world oil production is depleting reserves at rates faster than replacement reserves can be deployed.

Application of coal-to-liquids technologies would move the United States toward greater energy security and relieve cost and supply pressures on transportation fuels by producing 2.6 MMbbl/d of liquids. These steps would enhance U.S. oil

supply by 10% and utilize an additional **475 million tons** of coal per year.

“Developing” Nations Driving Greatly Increased Energy Use



Source: United Nations' Human Development Report 2005, World Energy Outlook & ConocoPhillips

FINDINGS

The United States continues to increase its dependence on foreign oil as domestic production declined by 11% from 2001 to 2005. Meanwhile, global demand is growing, and concerns are mounting that world oil production is depleting reserves at rates faster than replacement reserves can be deployed. Application of coal-to-liquids technologies would move the United States toward greater energy security and relieve cost and supply pressures on transportation fuels by producing 2.6 MMbbl/d of liquids. These steps would enhance U.S. oil supply by 10% and utilize an additional **475 million** tons of coal per year.

Risks for the United States economy and to our national security could be substantially reduced by employing CTL technology to produce upwards of 2.6 MMbbl/d (million barrels per day) of liquids, including gasoline, diesel and jet fuel, requiring 475 million tons of coal per year. These additional supplies will be crucial in relieving upward price pressures on crude oil and petroleum products markets worldwide. In essence, the United States will emerge as a significant producer of manufactured liquid fuels.

Coal-To-Liquids is a Proven Technology

In July 2001, the U.S. Department of Energy reported results of its direct coal liquefaction development program. Following are excerpts from its Summary Report:

“The DOE direct liquefaction program produced a surprisingly mature technology. The intensive effort between 1976 and 1982 (Phase I), when 90% of the program funds were expended, resulted in a demonstration of the technical feasibility of the major process components. The Phase I processes, however, were deficient in terms of product yield and quality. This stimulated further research and development work between

1983 and 1999 (Phase II). The Phase II work was significantly less costly than earlier demonstration projects but resulted in substantial improvements in process performance and economics. It now is possible to produce liquids of high quality at high yields that approach the theoretical maximum. At the same time, the cost for a barrel of product dropped by 50% because of process optimization and increased yields. Economics and engineering studies conducted throughout Phase II have reduced the uncertainty, and therefore the risk associated with commercial deployment of the technology.

“The current technology is well defined in terms of cost and performance. It represents a technically available option for the production of liquid fuels. It can be used domestically in the

United States to limit our exposure to oil price increases in the international market or to offset supply reductions. It also can be used by other nations who choose to use domestic coal to meet their transportation fuel needs, thus reducing demands on conventional petroleum sources. It can be used with coal alone, or to

co-process a variety of lower value feedstocks. The results of the DOE program allow direct coal liquefaction to be accurately assessed in context to the costs and risks associated with other options for securing liquid fuel supplies should the need arise.”

DISCUSSION

Oil is the lifeblood of modern society. The specter of peak production, threats of supply disruption in countries such as Saudi Arabia and Nigeria, and rising demand from Asia and the Middle East all put the importance of oil in bold relief. Petroleum products are virtually omnipresent in American society and central to our quality of life:

- We use **21 MMbbl/d** of petroleum products, 58% of which comes from other countries.



- Oil accounts for 95% of all energy used for **transportation**. The efficient and rapid movement of people, food, goods and services relies upon a transportation system that was designed on cheap oil and remains dependent on readily available gasoline, diesel and jet fuel.
- Over 7.7 million households, primarily in the northeastern United States, **heat** their homes with distillate fuel oil.
- Refined petroleum products are the **basic building blocks** of materials that are embodied in thousands of manufactured products (e.g., plastics).
- Oil refining also produces asphalt and road oil and virtually all **lubricants** used in transportation and industry.
- Our **agricultural** system is utterly dependent upon oil to seed, grow, manufacture, preserve and ship food products to consumers. Fertilizers, pesticides,

herbicides, irrigation and farm equipment all depend on oil. It is estimated that the average food product is transported about 1,500 miles before it is consumed.

- **National security** depends on the timely movement of military personnel and equipment. Estimated Department of Defense use of petroleum is upwards of 400,000 barrels per day. Technological innovations have dramatically increased the efficiency of American air, naval, and land forces, but without liquid fuels these advances would be worthless.
- **Power generation** from oil is relatively small (3%) but may be crucial in times of high demand. Oil-based peaking units in New England, for example, may mean the difference in the ability to meet the load.

As Figure 1.1 indicates, petroleum accounts for about 40% of U.S. energy use, and that percentage

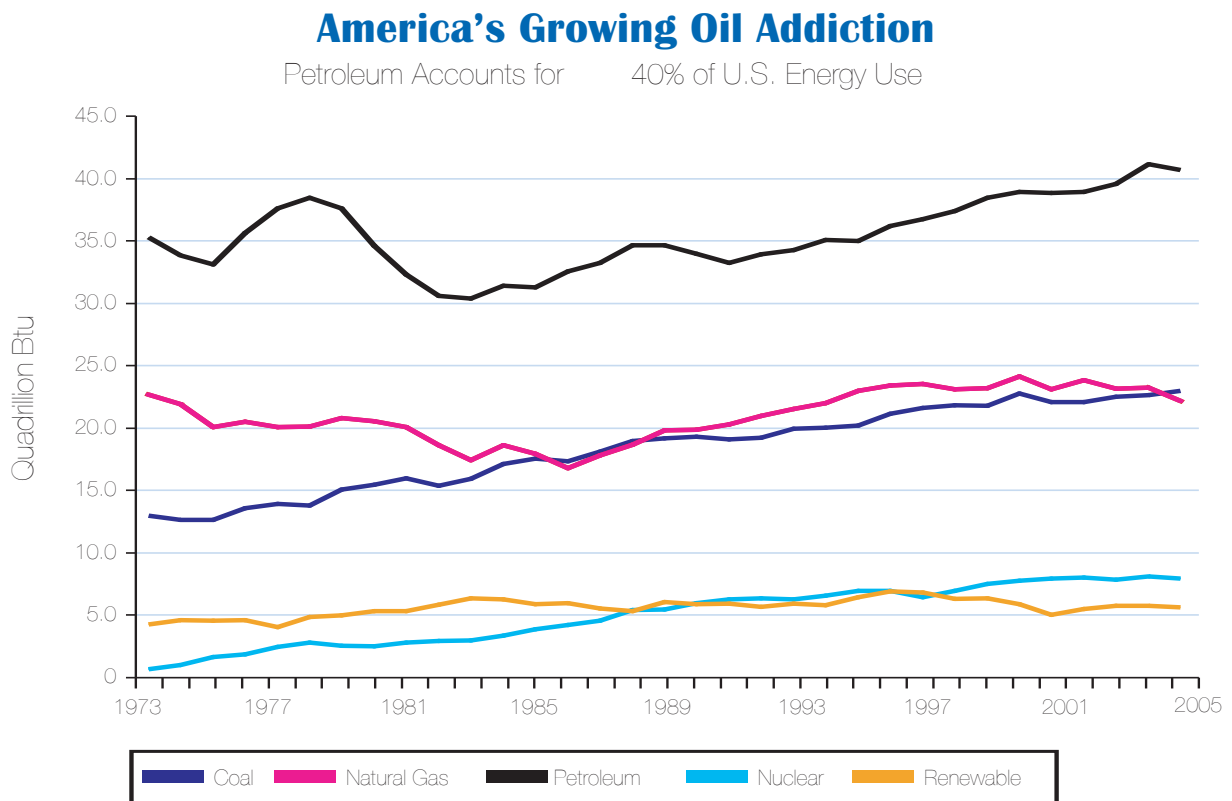


Figure 1.1 Source: EIA Feb 2006 Monthly Energy Review

COAL-TO-LIQUIDS TO PRODUCE 2.6 MMbbl/d

has grown consistently over the past two decades due to steady increases in fuel consumption. Even more importantly, the EIA projects that this 40% figure will persist in American society through 2030 as the nation maintains its dependence on oil.

Refined petroleum products such as gasoline, diesel and jet fuel are very attractive because they have high energy value per unit of volume. Society will continue to value these fuels because they are convenient in many applications.

The days of cheap and plentiful crude oil, which has been the primary feedstock for the manufacturing of these fuels, may be over. This situation attaches a tremendous importance to coal, which will likely become a significant source for producing liquid fuels.

Billions of people in less developed nations are industrializing in the same manner as did the United States and the other developed countries of the world. Use of oil in these societies is increasing rapidly, and crude oil producers around the globe are straining to satisfy these demands. As a result, real

crude oil prices have increased sharply. This demand-led recovery in real prices is unique because the oil industry has historically operated with significant excess production capacity. That excess no longer exists.

The supply challenges for oil are fundamental, arising from a confluence of potentially irreversible geological, political and economic factors that substantially increase the risk of relying on crude oil to meet future liquid fuel requirements.

To reduce the risk of dependence on foreign oil, a new emphasis should be placed upon coal to supplement our nation's liquid fuels supply portfolio. Refined petroleum products were once viewed as the exclusive domain of the oil industry. Now, however, they can be provided by well-developed technologies that convert the energy embodied in coal into liquids that are very close substitutes for oil. In fact, liquid fuels produced from coal via indirect liquefaction are generally superior to petroleum products because they have higher heat value and are considerably cleaner, with virtually no sulfur.

Real Oil Prices Highest Since Carter Administration

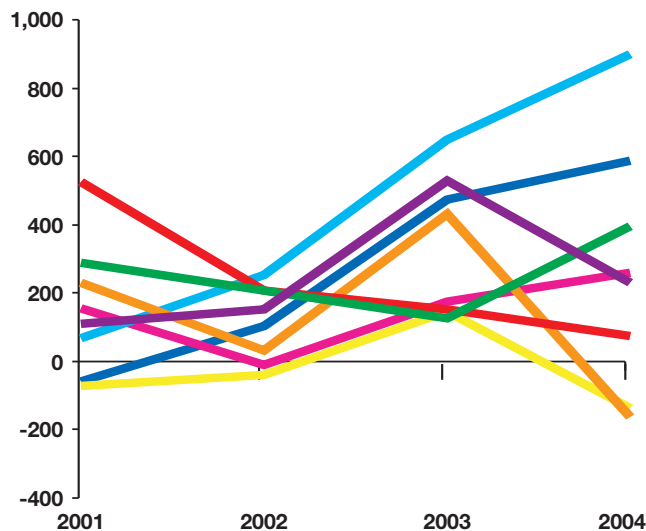
Prices Up 72% Since 2004



Figure 1.2 Source: Compiled from EIA Annual Data

Incremental Petroleum Demand

U.S., China Represent 50% of
Global Petroleum Demand



Region	2001	2002	2003	2004
North America	(60)	104	474	589
Western Europe	154	(11)	174	258
Pacific	(73)	(38)	145	(138)
China	69	253	650	899
Former Soviet Union	230	32	430	(164)
Eastern Europe	526	207	152	74
OPEC	288	207	127	395
Rest of World	111	153	549	230
TOTAL	1,245	908	2,701	2,144



Figure 1.3 Source: Energy Intelligence Group, 2006

These technologies, and the industries arising from them, will reinvigorate U.S. industry, make our country more secure, significantly reduce the trade deficit, contribute to lower and more stable fuel prices, and stimulate economic growth. For these reasons, coal should become part of our thinking, planning and investment in the provision of liquid fuels for society.

Oil Prices Have Increased 72% Since 2001

Inflation-adjusted world oil prices are at levels last seen in 1982, after the second great oil supply shock from 1979 to 1981. During that spike, prices peaked at the equivalent of nearly \$65 per barrel in today's dollars, as indicated in Figure 1.2. Except for the downturn in prices following the September 11 attacks and the subsequent reduction in air travel, oil prices have

steadily increased since 1998. Since 2001, real oil prices have increased 72%, with more than half the increase occurring during 2004. This sustained level of prices has not been seen since the 1970s.



Stronger economic growth, particularly in China and the United States, has substantially increased the demand for crude oil, putting upward pressure on prices. Figure 1.3 summarizes incremental demand for the past four years. Since 2002, world demand for petroleum products increased more than 4.8 million barrels per day, with more than half of the increase occurring in North America and China. The incremental additions to world petroleum consumption

during 2003 and 2004 are larger than any previous annual increase since 1986. Chinese petroleum

consumption alone increased 8.9% per year between 2001 and 2004.

Demand Growth Parallels Increasing Political Instability

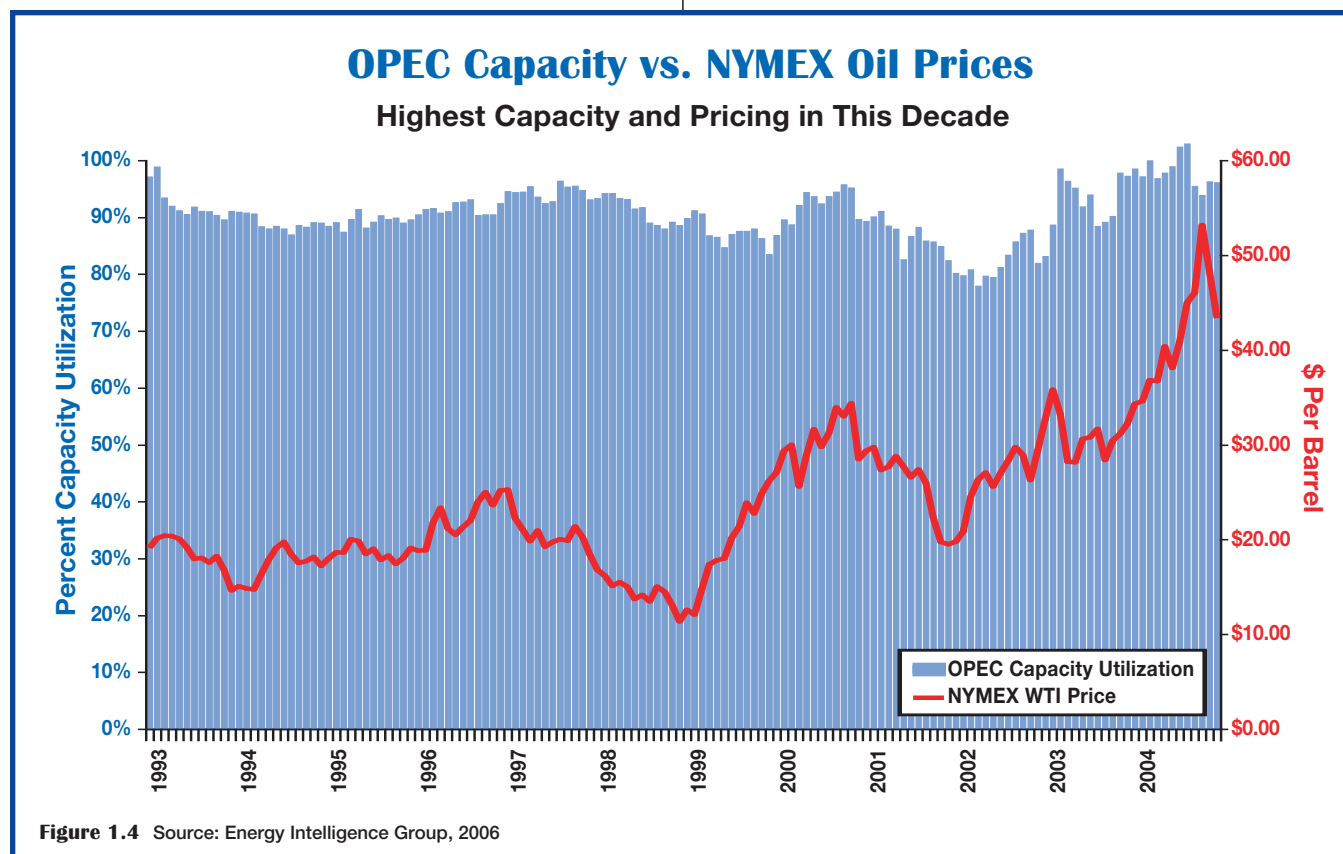
This demand growth is occurring along with increasing political instability and outright hostility to the United States in some producing regions. For example, Venezuelan unrest, armed attacks in Nigeria, sabotage of Iraqi oil exporting facilities, and a recent terrorist attack on Saudi export facilities all have contributed to higher and more volatile oil prices. The general strike in Venezuela virtually shut down that nation's oil industry in early 2003. To further exacerbate the situation, the Iraq war started shortly thereafter, causing a precipitous drop in Iraqi oil production. Nigerian production also declined as a result of an oil worker strike. Iran now openly flaunts its oil weapon as it moves to develop nuclear arms.

Meanwhile, significant domestic production declines have occurred over the past five years. From 2001–2005, oil production in the United States dropped from 5.8 MMbbl/d to 5.1 MMbbl/d—

an 11% decrease. Obvious declines occurred during the last hurricane season in the Gulf of Mexico (GOM), which produces more than 1.5 million barrels of crude per day.

Hurricane Ivan was somewhat unusual because it caused underwater mudslides. The slides caused significant damage to underwater pipelines connecting production platforms to shore. Repairs took a considerable length of time, which stretched a typical one-week production shortfall to well over a month, with production dropping 300 to 400 thousand barrels per day. While this shortfall may seem relatively small, it had significant impacts since it came at a time of increasing demand and Organization of the Petroleum Exporting Countries (OPEC) production restraint. During 2005, the hurricane season was even more devastating, with two major storms, Katrina and Rita, directly hitting the core of the GOM producing area.

As a result of two years of hurricanes in the Gulf of Mexico, by the end of 2005, more than 110 million barrels of oil had been shut in. A reasonable estimate





is that by the end of 2006, the United States will have lost production of more than 150 million barrels of oil. For the future, a number of forecasts suggest the United States may be in a more active cycle of hurricanes in the Atlantic and Gulf of Mexico. Continuing exploration efforts and new production of NG from the Gulf of Mexico can be expected, but not at the levels previously expected due to the increased risk profile of investment in the Gulf.

Crude oil supply shocks are nothing new. But the general pervasiveness of the current difficulties is both new and troubling. Even more alarming is the lack of excess production capacity in countries such as Saudi Arabia, declining production in mature fields such as the North Sea and China's Daqing field in Manchuria and relatively small incremental production from new fields. **Apart from West Africa and Central Asia, there are no new major producing areas ramping up production. With no new major production fields and steadily increasing demand, utilization of OPEC production capacity has increased sharply in**

recent years. Like many other industries nearing capacity constraints, prices must rise. As Figure 1.4 vividly illustrates, the oil industry is no exception. Also, as in other industries, higher prices likely will lead to additional production capacity, but this new capacity will take a number of years to develop.

Indeed, there are serious concerns about future crude oil production capacity. According to Cambridge Energy Research Associates (CERA) and the International Energy Agency (IEA), new production currently under development will add 16 million barrels per day of crude oil production capacity by 2010, which is a sizable increment to new supply. On the other hand, production declines in existing fields, while more difficult to estimate than new capacity expansion, are significant. The resulting capacity shortfall could total 4 to 5 million barrels per day. The consensus among oil company executives and analysts is that worldwide production decline rates average 5% per year.

As the world oil industry continues to operate at or near capacity, prices will exhibit greater volatility,

COAL-TO-LIQUIDS TO PRODUCE 2.6 MMbbl/d

and the market will be prone to periodic sharp price increases if demand increases unexpectedly or if supplies are cut off. Given the concentration of crude oil production in politically unstable regions around the world, recurring supply shocks must be assumed for planning purposes.

Planning for the Inevitable Peak in World Oil Production

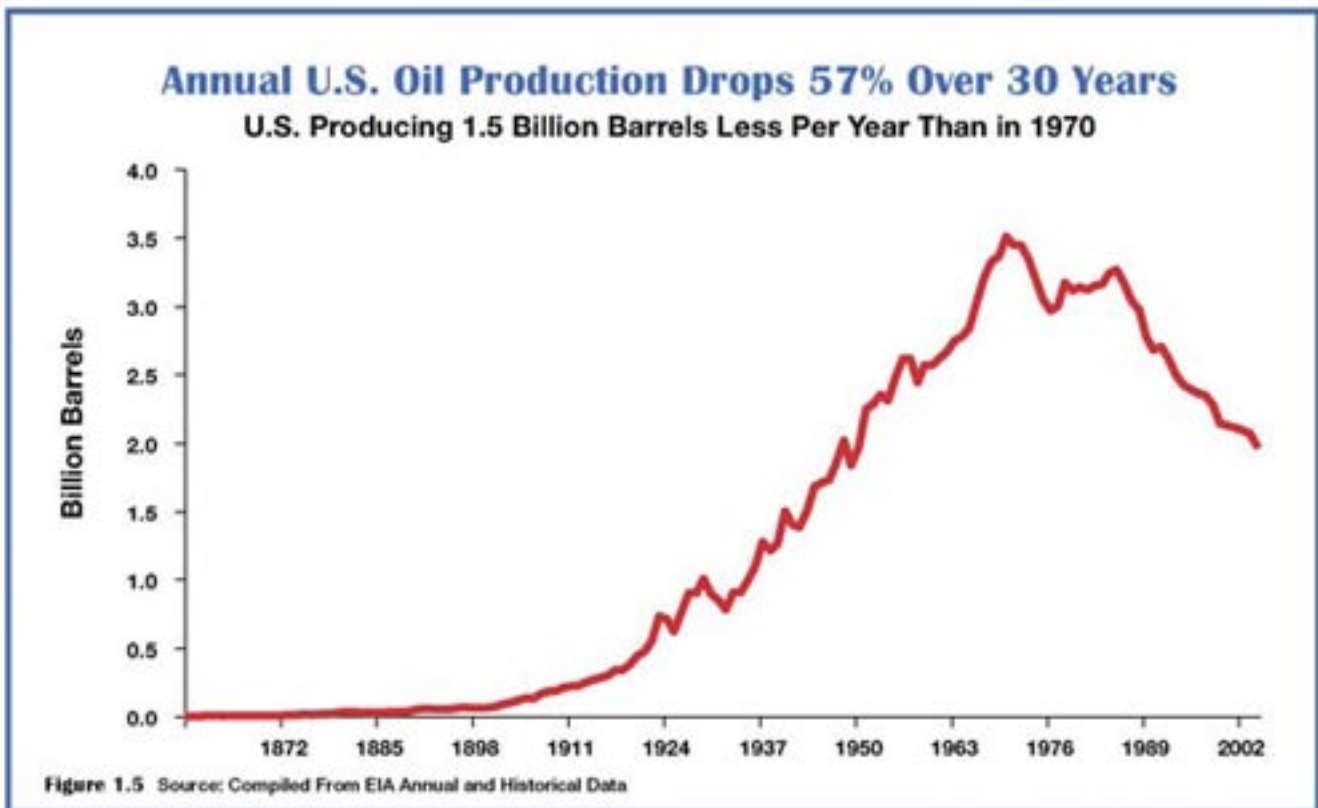
Prudent energy planning must also include the real prospect of a peak in world oil production. Past peaks in crude oil production have been observed in several regions around the world, including the United States. As shown in Figure 1.5, U.S. crude oil production peaked in 1971 at more than 3.5 billion barrels per year, which is equivalent to 9.6 million barrels per day. In 2004, U.S. crude oil production was 57% lower at 5.4 million barrels per day.

There are growing indications that a similar peak in world production is approaching. Crude oil production in the North Sea, especially the United Kingdom sector, is now in decline. While production in other regions, such as Central Asia and Russia, is increasing, there are serious concerns that these

additions will not offset production declines in mature producing areas. A peak in world conventional oil production is inevitable. The only unknown is when the peak will occur.

Oil and gas producers are in a continual race between bringing on new production from existing and new fields and declining output from existing wells undergoing the natural process of depletion. New production is achieved by developing and extending known reserves and exploring and developing new production fields in frontier areas. Observed production is the net result of depletion and new production additions.

Trends in world oil production are displayed below in Figure 1.6. World production has risen from about 30 million barrels per day in 1965 to more than 80 million barrels per day in 2004. From 1982 to 1999, including OPEC and non-OPEC, non-former Soviet Union regions each increased crude oil production about 10 million barrels per day. Production in the former Soviet Union during this period fell about 5 million barrels per day.



Trends in World Oil Production

OPEC and Soviet Union Provide 55% of Global Oil Supply

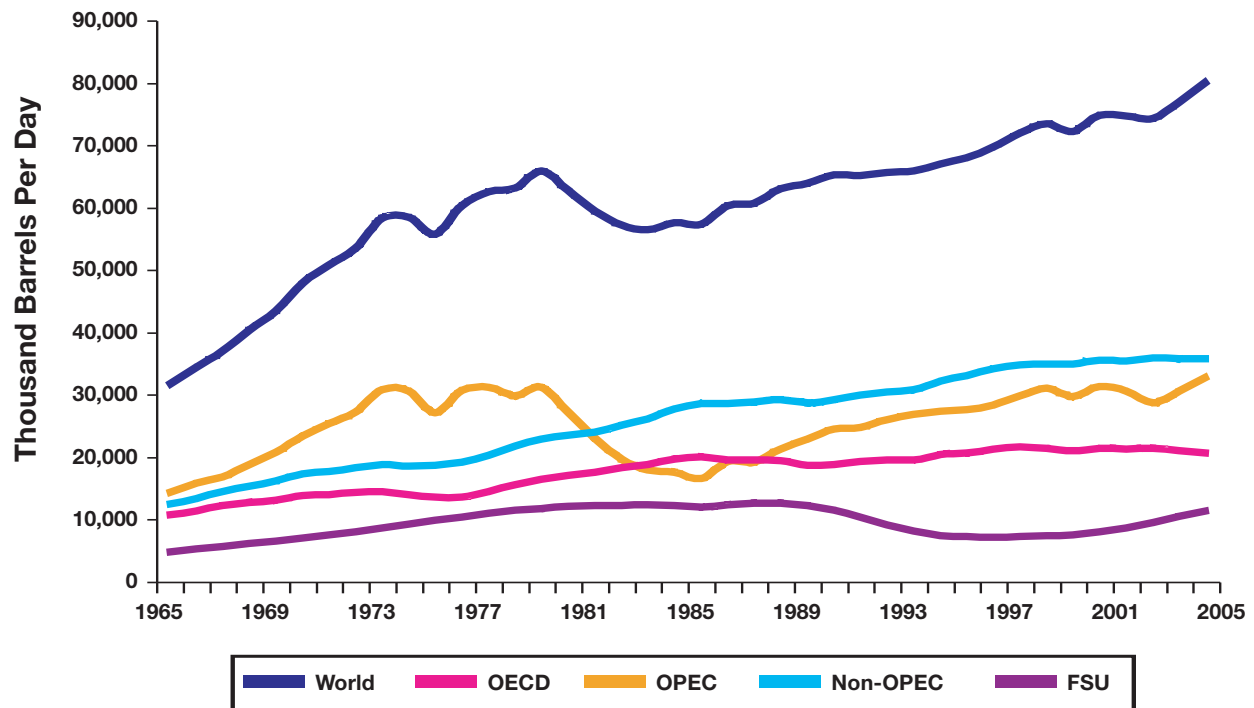


Figure 1.6 Source: Energy Intelligence Group, 2006

Since 1999, however, non-OPEC crude oil production has stagnated at roughly 35 million barrels per day while world oil production increased nearly 8 million barrels per day between 1999 and 2004. Non-OPEC crude oil production contributed only 12% of this increase, fewer than 1 million barrels per day. The former Soviet Union contributed nearly half the increase with OPEC supplying the remaining 40% of the increase. In short, **the world is becoming increasingly dependent upon OPEC and the former Soviet Union territories for crude oil.**

A growing group of scientists and economists are voicing concern over the possibility that world oil production capacity is peaking. Expanding decline rates, harder-to-find reserves, aging large oil fields, and increased capital costs for the same production

have resulted in global issues that mirror the U.S. production-related issues for oil beginning in the

1970s and NG in the 1990s. Concern ranges from published works by experts such as Matthew Simmons (*Twilight in the Desert*) and Kenneth Deffeyes (*Beyond Oil: The View from Hubbert's Peak*) to reports by the Department of Energy (Hirsch, Bezdek and Wendling's "Peaking of World Oil Production: Impacts, Mitigation and Risk Management").

With strong demand growth from China, India and other developing nations and a possible peak in oil production, **there could be a growing gap between oil consumption requirements and crude oil**

production capacity. Clearly, in such a world, prices would rise dramatically to reduce demand and stimulate supply from both conventional and non-



“Developing” Nations Driving Greatly Increased Energy Use

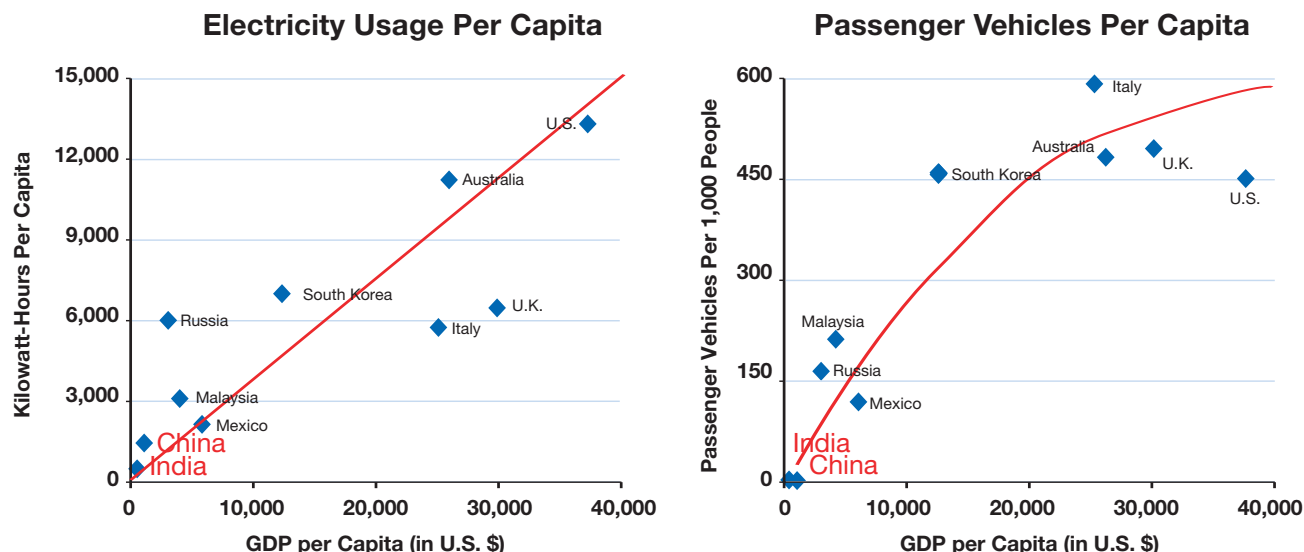


Figure 1.7 Source: United Nations' Human Development Report 2005, World Energy Outlook & ConocoPhillips

conventional oil supplies. Indeed, the IEA forecast predicts more than 10 million barrels per day from unconventional oil deposits by the year 2030.

EIA's International Energy Outlook for 2005 estimates that world demand for crude oil will grow from 78 million barrels per day in 2002 to over 119 million barrels per day in 2025. Much of the growth is expected from emerging Asian nations, where strong economic growth, urbanization and a rising middle class create significant oil demand growth (see Figure 1.7). Emerging Asia (including China and India) represents 45% of the total world increase in oil over the forecast period.

The projected increase would require an additional 41 million barrels per day relative to 2002 crude oil production of 80 million barrels per day. OPEC nations are expected to be the major source of production increases. Given demonstrated decline rates in mature oil fields and political turmoil in the Middle East, serious questions should be raised about whether the current oil supply infrastructure has the capability to increase production to fill this incremental demand. Moreover, such a large production increase may be inconsistent with OPEC's cartel pricing strategies.

As long as the world becomes increasingly reliant on oil and NG in politically unstable regions, the events of the past couple of years are quite likely to be repeated with increasing frequency in the years ahead. Hence, \$50 or \$60 per barrel oil may be only the beginning of long-term increases. The August 22, 2005 *Oil and Gas Journal* suggests that energy planners should consider alternative scenarios that involve significant oil supply shortfalls in the future:

“Although there is some potential for oil price declines in the short term, the beginnings of sustained high prices could be seen by 2009. With Saudi Arabia reported to have stated to U.S. energy officials (albeit unofficially) that there will be a likely 4.5 million barrel per day gap between what the world needs and what it can provide, traders are firmly focused on a future of \$100 oil.”

Global Competition from China for Oil

China is one of the world's most rapidly growing economies. When that description is applied to a nation with 1.3 billion people, policymakers must take notice. As Kevin B. Skislock of Laguna Research Partners has pointed out:

The Unprecedented Scale of Change in China

Social Structure	Characteristics and Change
Population	• 1.3 billion people • 280 million children under 14 years old • 761 million people in the labor force • 343 million males available for military service
Industrialization	• With less than 4% of global GDP, China uses 30% of the world's iron, 27% of steel and 40% of cement. China's demand for copper has depleted worldwide reserves. • China has 1.5 million industrial units, which employ over 122 million people. China has 82,000 mining corporations and 1.3 million manufacturers. • China is by far the largest industrializing nation in the world. Energy demand in industrializing countries grows faster than the economy as a whole due to disproportionate growth in energy intensive industries such as petrochemicals, heavy machinery and transportation.
Urbanization	• Over the period 1990–2003, the urban population of China increased from 302 million to 524 million, an increase of 74%. • About 10 million rural Chinese migrate to urban areas each year. • China has more than 100 cities with a population exceeding 1 million.
Modernization	• From 24 million private vehicles in 2003, China is projected to have 130 million by 2020 and plans to build 80,000 km of freeways. • According to the Chinese Academy of Social Sciences, about 50% of all urban households now meet the definition of middle class. • The rate of illiteracy in China reportedly dropped from 10.4% in 1990 to 2.4% in 2003. The proportion of university graduates increased 3.5 times over the same period.

Figure 1.8

“In a world frozen in denial over the impending depletion of crude oil reserves, the emergence of China’s 1,298,847,624 citizens as a vibrant global economic force is thrusting every net importer of crude oil into an urgent quest for energy security.”

China accounts for about 40% of all new world oil demand. In 2001, China consumed 4.9 MMbbl/d. **By 2025, China’s oil consumption is projected to exceed 14 million barrels per day—an increase of 187%—requiring new supplies of oil equivalent to the current annual production of Saudi Arabia.** By 2025 about 9.3 million barrels a day, or 65% of China’s oil needs, must come from imports since Chinese oil has peaked (i.e., production in the major Daqing field in Manchuria is in decline). Figure 1.8

summarizes the dramatic change taking place in China.

Further, China’s growth is not merely massive; it is a continuing phenomenon that will continue well beyond the 2025 forecasts of the EIA.

The importance of the latent demand for oil in China can be better understood with a comparison. Current U.S. oil consumption is about 27 barrels per person per year. Japan is 17, South Korea is 17, and China is 1.3. If China were merely to raise consumption to half that of South Korea, it would require more than 11 billion barrels of oil per year—more than the proven reserves of Brazil.

Recognizing its growing need for imported oil, China is scouring the world to secure future supply. China's tactics are creating concern in the United States for four key reasons:

- **Value neutrality** approach of Chinese foreign policy means they are prepared to deal for resources with countries under sanction by the United States: Iran, Sudan, North Korea.
- **Wellhead control** is an important component of China's strategy of access to oil resources. The United States generally procures its energy supply on open international markets.
- **Outbidding competition** by paying above-market prices enables state-controlled Chinese oil companies to outbid free market rivals.
- **New alliances** between China and other nations disregard their economic system or historical associations. China has breached the U.S. sphere of influence via a variety of energy agreements with Canada, Venezuela, Bolivia and Ecuador.



China's Energy Agreements Around the World

AFRICA

- Angola – China gave a \$2 billion infrastructure loan associated with oil production. Sinopec has purchased interest in offshore oil fields.
- Sudan – 7% of Chinese oil imports comes from Sudan. China National Petroleum Council (CNPC) is heavily invested in the southern oil fields, and China has built a pipeline and a refinery.
- Nigeria – China has offered Lagos \$7 billion for oil field investment in exchange for long-term supply agreements.

MIDDLE EAST

- Iran – 13% of Chinese oil imports come from Iran. Beijing has committed tens of billions of dollars to develop the Yadavaran oil field and to purchase 250 million tons of LNG over the next 30 years. China has sold ballistic missile components, as well as a variety of other weapons, to Iran.
- Saudi Arabia – Sinopec has agreed to develop NG and oil fields in the Rub Al Khali desert and to operate social welfare projects in the region.

CENTRAL ASIA

- Kazakhstan – China signed an agreement to help construct the crude oil pipeline from Atasu to the Chinese border (962 km). Russia has been asked to help fill the pipeline until Kazakhstan production is available. Kazakhstan has an estimated 35 billion barrels of reserves—more than twice the amount of the North Sea.

SOUTH AMERICA

- Venezuela – China and Venezuela are co-producing heavy oil fields in Orinoco Basin and are collaborating on the construction of pipelines and refineries.
- Brazil – CNPC and Petrobras have joint refining, pipeline and exploration projects. Brazil oil exports to China increased 180% in 2004 over 2003.
- Ecuador – Andes Petroleum Company, a joint venture of Chinese petroleum companies, purchased Encana's oil and pipeline interests, including all of the Tarapoa Block and all of the Shiripuno Block, as well as more than one-third of the 300-mile OCP pipeline.

NORTH AMERICA

- Canada – Petrochina, Sinopec and CNOOC all have invested in Alberta's oil sands development. The goal is to build a pipeline for 400,000 barrels per day to the Pacific coast from where the fuel would be tankered to China.

These are only representative examples of dozens of agreements China has made with energy-producing nations throughout the world.

India Also Will Become a Major Global Competitor for Oil

The world has been focused on the dramatic rise of China, but the entry of India into the modern age may have even greater long-term significance. For example, by 2030, the population of India will exceed that of China. India's oil needs already outstrip its meager reserves and are growing rapidly:

- India consumes 2.2 MMbbl/d but produces only 0.8. By 2025, India is projected to import about 5 million barrels per day.
- India has paltry proven reserves—only 5.6 barrels per person—compared to 14 for China and over 70 for the United States.
- India also is seeking to secure oil supply at the global level and has signed energy agreements with Syria, Iran, China, Russia and even Pakistan.

Other Emerging Asian Economies Represent Another Billion People—and More Global Competition for Oil

China and India are by far the largest of the emerging Asian economies. However, countries such as Indonesia, Thailand, Vietnam and Malaysia account

for almost 1 billion people. Further, these nations are growing even more rapidly than China and India. From 2000–2025, growth in population will be 12% for China, 32% for India, and 41% for the rest of emerging Asia.

These growing populations will mean significant increases in energy consumption. The EIA projects that while total world energy consumption will increase 57% by 2025, the corresponding increase in the emerging Asian economies will be 122%. Much of this increased demand will be for oil, where consumption is projected to rise by more than 128% by 2025.

Oil production in these countries will not keep up with demand because the reserves are simply not available. Virtually no Asian country has reserves greater than 15 barrels per capita, compared to a world average of 161. Given this reserve situation, the Asian Pacific Energy Research Center projects that by 2020, even those countries that have traditionally exported oil will be net importers (see Figure 1.9):

In short, by 2020 virtually every country in Asia will be importing oil. The EIA projects that by 2025 the

Imbalance Forecast in Asia Oil Supply & Demand

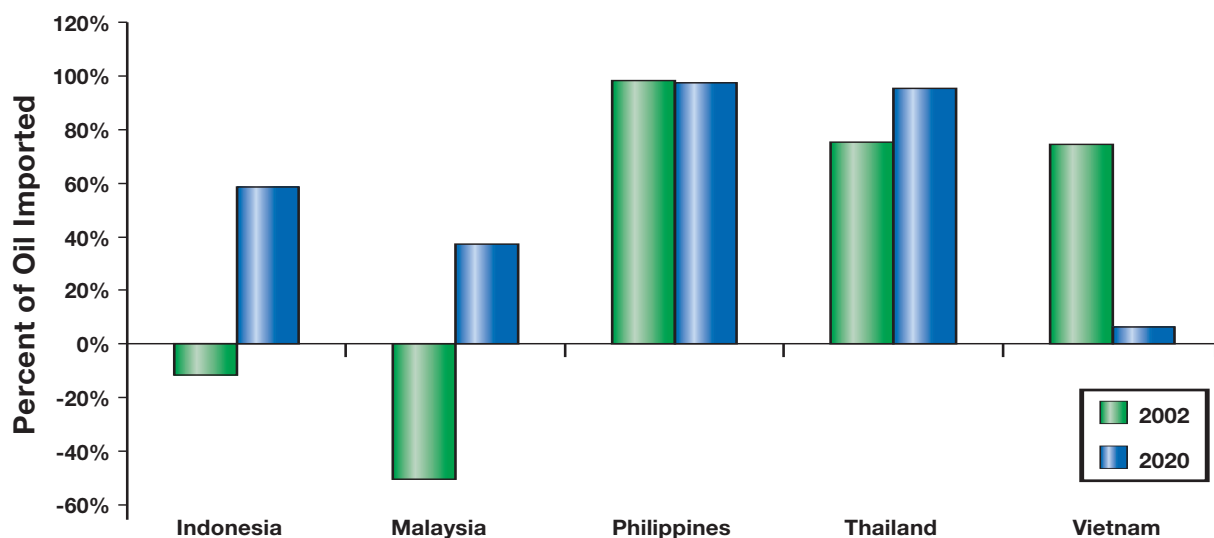


Figure 1.9 Source: Energy Intelligence Group

COAL-TO-LIQUIDS TO PRODUCE 2.6 MMbbl/d

Asian population will reach 4.3 billion and its oil consumption will total 40 million barrels per day. The fact that all of Asia was able to produce only 7.5 MMbbl/d in 2003 puts this developing demand in stark relief.

The global implications of the Asian economies' increasing demand for imported oil are profound. Like the oil embargo of 1973, Asian countries' competition for oil gives the United States a compelling reason to develop alternatives to imported oil. Fortunately, our country has that alternative in coal.

The United States has an historic opportunity to significantly ease demand and price pressures on global oil supplies by using existing and well-proven technologies to convert domestic coal assets into liquid fuels.

Coal-To-Liquids Technology

Coal-to-liquids (CTL) is the process of converting solid coal into liquid fuels and/or chemicals. Coal typically contains about 5% hydrogen, while

distillable liquid fuels typically contain 14% hydrogen. The hydrogen deficit can be made up in two different ways. In the direct route, hydrogen is forced into the coal under high pressure and temperature often in the presence of a catalyst. In the indirect route, coal is gasified with oxygen and steam to produce a synthesis gas containing hydrogen and carbon monoxide that is then passed over a catalyst to form hydrocarbons.

There are several additional ways to make transportation fuels from coal. Direct and indirect coal liquefaction can be integrated into a hybrid plant. Direct coal liquefaction can be combined with heavy oil upgrading in a coal and oil co-processing plant (see Figure 1.10). Finally, coal can be partially converted into liquid fuels by mild pyrolysis.

The aim of direct coal liquefaction is to break coal down into smaller component molecules, then to add hydrogen, creating lighter and more stable oil molecules. The process simultaneously removes sulfur, nitrogen and ash, resulting in a clean liquid fuel product.

Typical Direct Coal Liquefaction Process

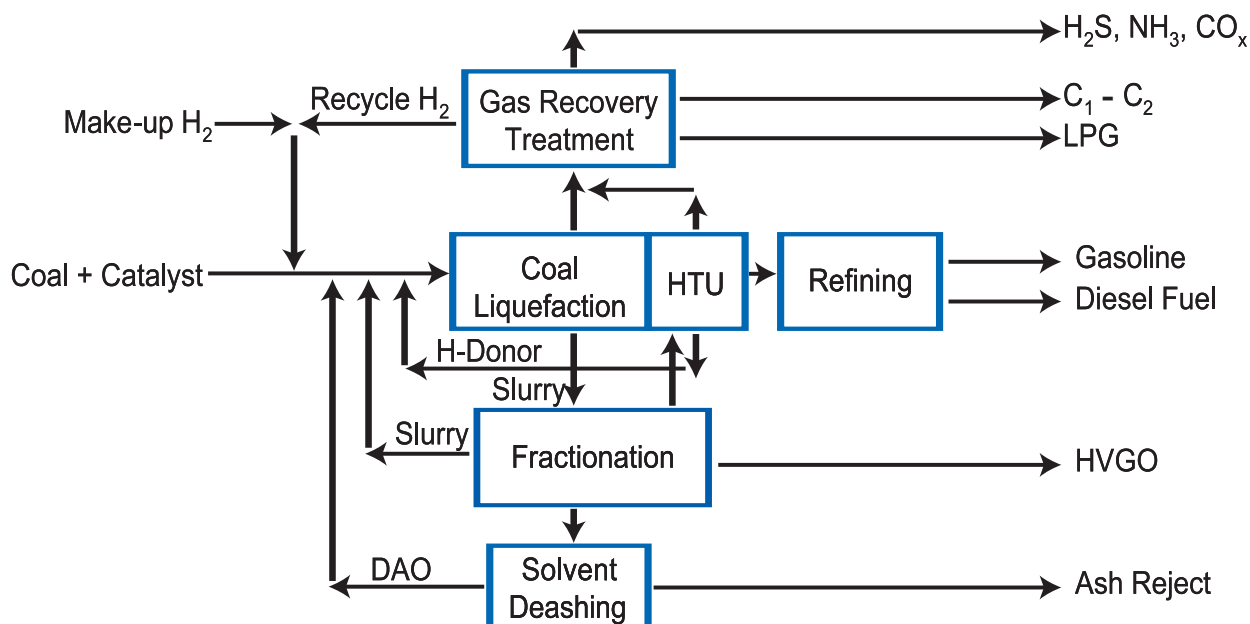


Figure 1.10 Source: NCC Working Group, September 2005

Typical Indirect Coal Liquefaction Process

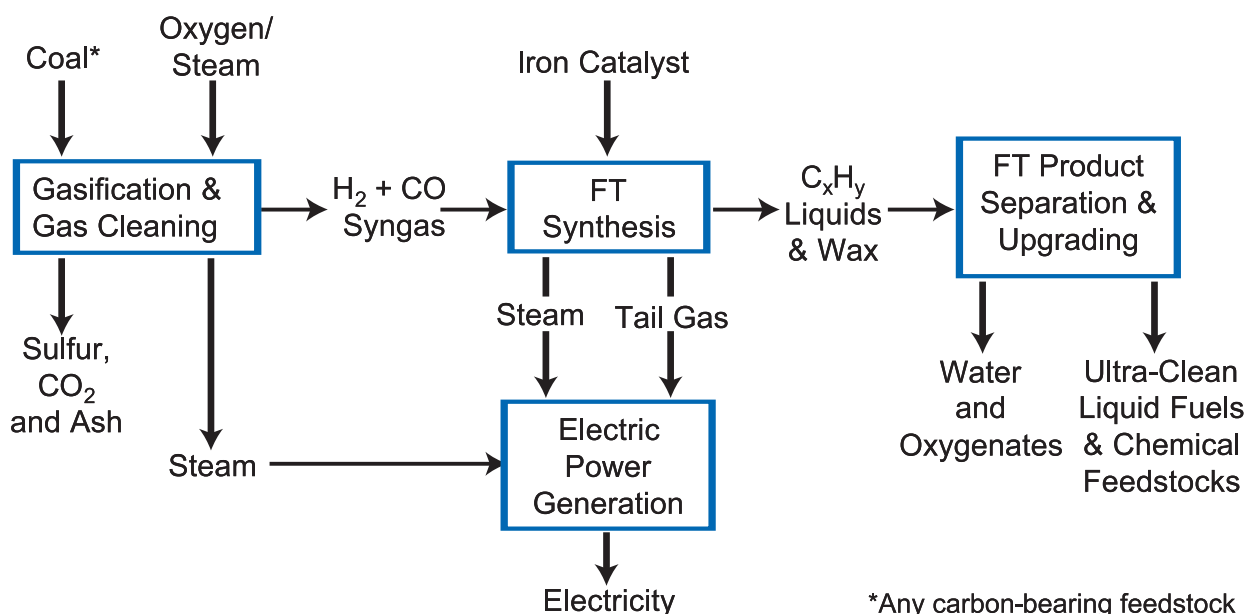


Figure 1.11 Source: NCC Working Group, September 2005

Direct coal liquefaction originated in Germany in 1913, based on work by Friedrich Bergius. It was used extensively by the Germans in World War II to produce aviation fuel. Since that time, tremendous advancements have been made in product yields, purity and ease of product upgrading.

In the direct coal liquefaction process, pulverized coal is slurried with a recycled oil and heated under high pressure to produce a synthetic crude oil that can be further refined into ultra-clean transportation fuels. The hydrogen required for this process can be produced by gasifying coal and residual carbon or reforming NG.

Following the petroleum price and supply disruptions in 1973, the U.S. government began a substantial program to fund the development of alternative fuels, particularly direct coal liquefaction. From 1976 to 2000, the U.S. government invested approximately \$3.6 billion (1999 dollars) on improving and scaling up direct coal liquefaction. Early direct liquefaction processes used single-stage reactor configurations. This was replaced by two-stage configurations to achieve higher efficiency of hydrogen utilization.

Pilot and demonstration facilities ranging up to 600 tons per day of coal (1,800 bb/d of fuel oil) were built and operated in the United States.

Indirect coal liquefaction involves first the gasification of coal to produce synthesis gas, followed by purification to remove CO₂ and other contaminants, and then conversion of the synthesis gas to liquid products using the Fischer-Tropsch (FT) synthesis process and associated product upgrading (see Figure 1.11). Indirect coal liquefaction can operate on virtually any coal feedstock as long as the proper gasification and gas cleaning technology are selected. Selection of the proper coal gasification technology is critical because it has perhaps the biggest impact on the overall project cost.

In the gasification process, coal is partially oxidized with oxygen and steam to form carbon monoxide and hydrogen syngas. The raw syngas is cooled and cleaned of carbon dioxide and other impurities. In the FT portion of the plant, the carbon monoxide and hydrogen are reassembled into long-chained hydrocarbon liquids and waxes



that are refined to produce high cetane (good diesel) and low octane (poor gasoline) fuels.

The Fischer-Tropsch synthesis technology, originally developed in Germany, was used by Hydrocarbons Research, Inc. (predecessor of Hydrocarbon Technologies, Inc.) to construct a 7,000 bbl/d gas-to-liquids plant in Brownsville, Texas, in 1949. Cathage Hydrocol operated the plant from 1950 to 1953 before shutting down due to declining oil prices.

During this same period (1950–53), Koelbel tested a 1.5-meter diameter slurry-phase FT reactor in Rheinpreussen, Germany. By the mid-1950s, all of the German FT plants were shut down due to the decline in world oil prices that followed discovery of abundant oil deposits in the Middle East.

While other countries were shutting down their FT plants, South Africa began commissioning its first indirect coal liquefaction plant. Sasol was established in 1950 with the objective to convert low-grade coal into petroleum chemicals and feedstocks. Sasol One was built in Sasolburg and produced its first liquid product in 1955. In 1969, the Natref crude oil refinery was commissioned. In 1980 and 1982, Sasol Two and Sasol Three, respectively, began production in Secunda.

Today, Sasol produces the equivalent of 150,000 bbl/d of fuels and petrochemicals from coal via the indirect liquefaction process. The process produces in excess of 40% of South Africa's liquid fuel requirements. Sasol manufactures more than 200 fuel and chemical products in Sasolburg and Secunda, South Africa, as well as several global locations. Sasol's total capital investment for indirect coal liquefaction from 1955 to 2000 exceeded \$6 billion.

The United States has several indirect coal liquefaction projects under consideration. Figure 1.12 is a list of those that have been discussed publicly.

The economics of direct and indirect coal liquefaction are virtually the same. If the same analysis were made with Wyoming Powder River Basin coal, the indirect route would be lower cost. If the economics were based on Appalachian coal, the direct route would have lower cost. Overall production costs could be lower in the West and higher in the eastern United States due to lower and higher coal prices, respectively, but both processes require significant amounts of water, which could be a constraint in the West.

One of the major differences between the two coal liquefaction technologies is that direct coal liquefaction makes high-octane gasoline and low-cetane diesel while indirect coal liquefaction produces high-cetane diesel and low-octane gasoline. One other difference is that direct coal liquefaction products are denser and therefore tend to have more Btus per gallon than indirect coal liquefaction products.

Hybrid coal liquefaction integrates direct and indirect coal liquefaction into a single plant. This concept takes advantage of the complementary characteristics of the two processes. Blending the products in an integrated plant allows production of premium quality gasoline and diesel with minimal refining.

The concept of a hybrid direct and indirect coal liquefaction plant has been discussed for many years. The U.S. Department of Energy commissioned MITRE Corporation to study the concept between 1990 and 1991. Initial studies indicated that production costs were slightly lower for a hybrid plant compared to stand-alone direct or indirect plants. No testing has been done on this concept to date.

CONCLUSION

Growing dependence on foreign oil represents an increasing burden for U.S. consumers and the economy while also creating national security concerns and international competition that could lead to conflict.

These problems can be alleviated by deploying existing U.S. coal-to-liquids technologies that have been proven effective. Implementation could produce 2.6 MMbbl/d of liquids and meet 10% of U.S. oil demand by 2025.

Further, there is substantial evidence that these technologies have beneficial environmental impacts. Rentech Corporation, for example, has indicated that CTL technologies produce fuel that is of higher quality and is environmentally cleaner than a standard petroleum product.

U.S. Indirect Coal Liquefaction Projects Under Consideration

State	Developers	Coal Type	Capacity (bpd)
AZ	Hopi Tribe, Headwaters	Bituminous	10,000-50,000
MT	State of Montana	Sub-bit./Lignite	10,000-150,000
ND	GRE, NACC, Falkirk, Headwaters	Lignite	10,000-50,000
WY	DKRW Energy	Bituminous	33,000
WY	Rentech	Sub-bituminous	10,000-50,000
IL	Rentech	Bituminous	2,000
PA	WMPI	Anthracite	5,000
WV	Mingo County	Bituminous	10,000

Figure 1.12 Source: Compiled from Company and Public Announcements

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COAL-TO-NATURAL GAS TO PRODUCE 4.0 Tcf Per Year

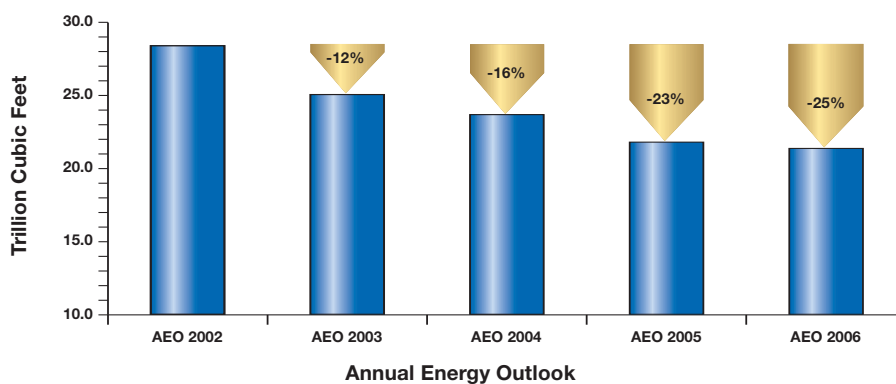


Conventional natural gas (NG) production in the United States is in significant decline, leading to supply and deliverability issues, higher prices and increasing dependence on foreign sources. These problems will become far more serious as domestic supplies continue to decline and NG demand increases. LNG presents the same economic cost and national security problems as imported oil. Using coal to produce NG and as a replacement for NG in chemical processes would ease supply pressures by providing an alternative to at least 15% of America's annual NG consumption, or the

equivalent of 4 trillion cubic feet (Tcf) per year. This additional supply would moderate NG prices and use an additional **340 million tons** of coal per year. The NG made available could be used for residential, commercial, industrial and any other

application that uses NG. The amount is roughly equal to EIA's projection of LNG imports in 2025.

**EIA Projected U.S. Natural Gas Production for 2020
Steadily Declined Since 2002 Projection**



Source: EIA AEO 2002-2006 Reference Case

FINDINGS

Conventional natural gas (NG) production in the United States is in significant decline, leading to supply and deliverability issues, higher prices and increasing dependence on foreign sources. These problems will become far more serious as domestic supplies continue to decline and NG demand increases. LNG presents the same economic cost and national security problems as imported oil. Using coal to produce NG and as replacement for NG in chemical processes would ease supply pressures by providing an alternative to at least 15% of America's annual NG consumption, or the equivalent of 4 trillion cubic feet (Tcf) per year. This additional supply would moderate NG prices and use an additional **340 million tons** of coal per year. The NG made available could be used for residential, commercial, industrial and any other application that uses NG. The amount is roughly equal to EIA's projection of LNG imports in 2025.

DISCUSSION

Natural gas is an important source of energy in the United States, consistently meeting more than one-fifth of the nation's energy demand—from 23% in 1985 to 24% in 2000 to a projected 21% in 2025. For many years, the strength of NG was that 90% of U.S. needs could be met through domestic production and the remainder was readily available from secure fields in Canada. Steady, stable production led to a consistent price.

But domestic NG resources are rapidly becoming insufficient to meet the energy needs of the American people and the U.S. economy. International NG supply is equally problematic, even assuming that unproven reserves do exist in sufficient size to meet growing international demand.

In 1980, the world consumed 53 Tcf of NG. By 2025, the consumption level will reach 156 Tcf,

a 194% increase. In the United States, consumption will rise from 22 Tcf in 2003 to almost 27 Tcf by 2025—essentially the equivalent of adding the combined 2004 production from the Gulf of Mexico and Louisiana to NG supply. Depletion of domestic fields and competition from other nations virtually ensure that the United States will not be able to meet its own demand unless decisive steps are taken to significantly expand supply.

In the past, policymakers, the financial community and the energy industry have looked to imported LNG to ease NG shortages. But this option is becoming increasingly uncertain with questions about availability, price volatility and reliability/stability of sources.

Btu conversion technologies can address potential shortages of both NG and LNG. Btu conversion of coal to NG will enable the United States to produce 4.0 Tcf of gas to meet at least 15% of the nation's needs for residential, commercial and industrial applications. Further, nationwide deployment of coal-to-gas technologies will eliminate the need to spend upwards of

\$300 billion per decade on imported LNG while simultaneously revitalizing America's industrial core and creating new businesses, jobs and income.

Coal gasification is the foundation of Btu conversion technology. Gasification is a proven, mature technology

that has been used for more than a century. Different methods of coal gasification allow flexibility in meeting technical, economic and environmental objectives.

Natural Gas Pricing Was Stable Until Recent Years

In 1981 the wellhead price of NG was \$1.98 per thousand cubic feet (Mcf). By 1998 the price had actually decreased to \$1.96 and, at that time, was projected to rise to only \$2.15 in 2005.



Natural Gas Prices See Two-Fold Increase Over 5 Years

Declining Production, Increased Demand
Lead to Higher Prices

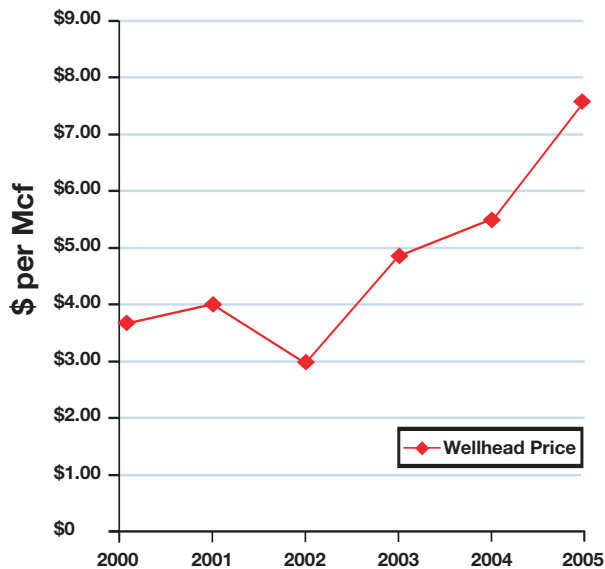


Figure 2.1 Source: EIA Annual Reports and Short-term Outlooks

When 2005 arrived, however, the NG situation had changed dramatically due to declining production and increasing demand. Wellhead prices have steadily increased (see Figure 2.1).

These higher prices have had a particularly adverse impact on the manufacturing sector, which is highly dependent on NG and where more than 3 million jobs have been lost since 2000.

Employment in industries such as chemical, foundries, glass, paper and fertilizer has been significantly reduced or, in some cases, virtually eliminated as facilities have closed or moved overseas, in some measure to areas with secure, long-term NG supplies. NG—once a strength of the U.S. energy portfolio—now has high volatility and increasing cost. In 2005 alone, NG prices for industrial consumers ranged from \$6.84 to \$11.92. This volatile situation makes it almost

impossible for many manufacturing firms to effectively plan energy costs, and undercuts their competitiveness in world markets.

As Roger Bezdek and Robert Wendling warned in *Public Utilities Fortnightly* in 2004:

“Reliance on low-cost NG has been an often-unrecognized factor in the U.S. manufacturing sector’s global competitiveness...This sector is bearing the brunt of the energy impacts of the NG crisis and is suffering...High NG prices are causing industrial electricity prices to increase, [and] the cost of NG as a feedstock and fuel is greatly increasing manufacturing costs.”

As cold weather approached in the fall of 2005, concern in the NG markets was so intense that it required a Henry Hub price of more than \$13 per Mcf to attain full winter storage. Near-term price declines following this rise were the result of an unusually mild winter.

Three Underlying Trends Have Changed the NG Situation

The demand for NG has been affected by three underlying trends. First, a steady stream of forecasts of NG supply and price were generally optimistic. Governmental agencies, industry associations and energy analysts projected that NG would be plentiful, stable and cheap far into the future. The consequences of these forecasts were substantial, as planners across the spectrum of construction and manufacturing industries made billions of dollars of investment decisions in turning to NG.

Second, demand increased based upon these optimistic forecasts as power plant construction and space heating steadily turned to NG as the preferred fuel. Consequently, demand for NG has steadily increased since 2000.

- **NG-heated homes** have accounted for 70% of new construction and, according to the American Gas Association, are increasing at a rate of more than 85,000 per month.



COAL-TO-NATURAL GAS TO PRODUCE 4.0 Tcf PER YEAR

- **NG power plants** totaling more than 200,000 MW have been added to electric generating capacity since 2000 and an additional 50,000 MW are projected by 2010. For example, in December 2005, Progress Energy began construction of a 500 MW NG unit at its Hines Energy Complex in Polk County, Florida. In January 2006, Progress announced planned construction of an additional 500 MW unit at Hines.
- **Organic demand** has increased through 2.3 million new U.S. residents each year, a growing economy, and the steady construction of NG consuming facilities ranging from swimming pools to new hospitals. The United States is a growing country. The current population is approaching 300 million and is projected to reach 350 million by 2030.

Third, the supply of NG from traditional major sources began to show signs of increasing strain and continues to do so. In 2004, the Gulf of Mexico produced 18% of our NG, Texas produced 23% and we imported over 16% from Canada. But this part of

our supply, which comprises nearly three-fifths of our total, is having substantial problems:

- **Gulf of Mexico** production dropped from 5,028 bcf in 2001 to 3,975 in 2004 and to only an estimated 3,100 in 2005—a 38% decline in just four years. Production in 2006 and subsequent years could be reduced even further given the long-term impacts of hurricanes in 2004 and 2005.
- **Texas** production also has fallen victim to depletion, and now about three times as many wells are required to produce less than two-thirds of the NG produced in the 1970s. In 1974, the 24,646 wells in Texas produced 8,171 bcf of NG. By 2004, there were 72,237 wells, but they produced only 5,067 bcf.
- **Canada** has its own production problems. An increase of over 6,000 wells (66%) since 2002 did not even serve to keep production flat. In 2002 there were 9,061 new wells drilled in Canada and production was 17.4 bcf/d. In 2004, it took 15,126 new wells to produce 17 bcf/d. Further, Canada's

Projections for Dry Natural Gas Production in North America



Figure 2.2 Source: EIA Annual Reports; AEO 2003 Reference Case

EIA Projected U.S. Natural Gas Production for 2020 Steadily Declined Since 2002 Projection

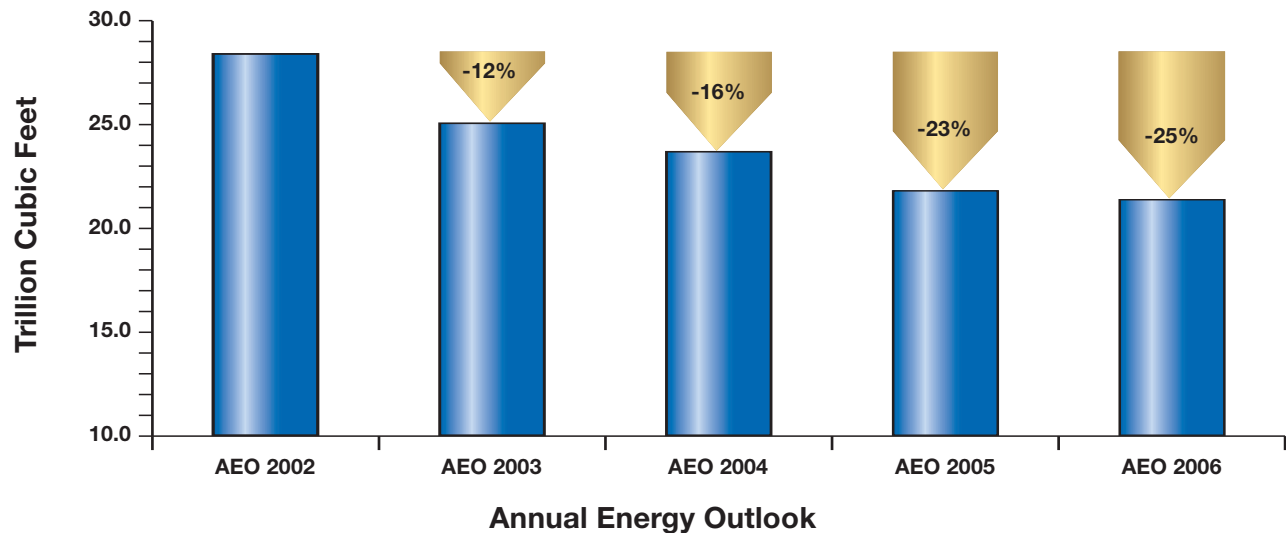


Figure 2.3 Source: EIA AEO 2002-2006 Reference Case

growing development of tar sands requires even more NG for the mining and refining process, leaving less available for export. Finally, the planned closure of coal-fired power plants in Ontario by 2009 has significant implications for the North American NG supply/demand ratio.

It is increasingly apparent that recent projections of NG production have generally underestimated these difficulties and consequently overestimated future supply, even in a short timeframe of only two years (see Figure 2.2).

As these data show, in the 2003 Annual Energy Outlook (AEO), the EIA projected that in 2005 NG production in the United States would reach 20.13 Tcf. Actual production was only 18.16. This 2 Tcf difference is more than three times the amount of all the LNG imported by the U.S. in 2005.

Hurricanes Pose Additional Problems

With Hurricanes Ivan, Katrina and Rita, the NG supply problem has become even more severe. At least 25 offshore drilling rigs and more than 175 platforms were lost or damaged. More than 200 pipelines were damaged and a number were totally destroyed. Onshore facilities were significantly

damaged and operations disrupted due to dislocation of workers. Some refineries and NG processing plants were offline into 2006. The Secretary of the Interior stated that it will “take many months” for full production to resume and that some marginal production has been lost forever.

But the hurricanes are only the most recent problems facing production. The EIA has increasingly recognized the deteriorating NG supply situation as a steady step backward in every AEO over the past five years. Figure 2.3 demonstrates the growing recognition that NG production in the U.S. will be under ever-growing stress.

LNG Is Necessary but Not Sufficient to Meet Our Needs

Given depletion rates in North American fields, the sources of NG supply must change significantly to meet demand growth of more than 4.6 Tcf in only two decades. It is also noteworthy that EIA has reduced its long-term estimate of NG demand by over 5 Tcf per year in just three years.

In terms of supply, the EIA projects an increase in NG production of 2.7 Tcf over the next two decades. A portion of this increased production would come

EIA Estimates 580% Increase in LNG to Meet Demands by 2025

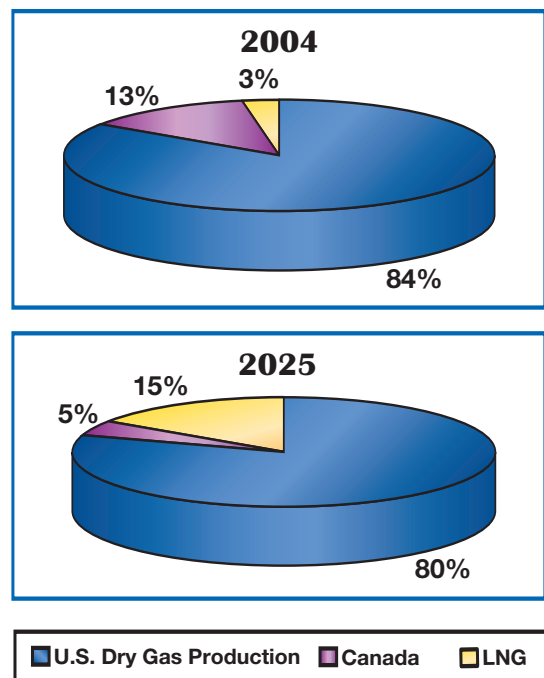


Figure 2.4 Source: EIA AEO 2006 Reference Case

from the Alaska NG pipeline and a portion from offshore NG development, largely from the Gulf of Mexico (GOM).

Assuming the NG pipeline is built, a 2012 in-service date is the earliest that significant new supplies can be expected. Further, in regard to offshore sources, *Oil and Gas Journal* has reported that the GOM hurricanes have shut in over 1.8 bcf/d as of February 2006 and it is estimated that over 1 bcf/d may be permanently lost. GOM decline rates have reached

35% and a substantial portion of the GOM rig fleet is being utilized for remedial and restoration work. Thus, the decline rate could well accelerate over the next several years.

Gulf of Mexico NG production in 2001 was 13.7 bcf/d, but in 2006 production may not reach 9 bcf/d. How far will production drop in future years with depletion rates of 35%, a reduced offshore drilling infrastructure and the prospect of more interruptions from hurricanes?

With Canadian imports projected from 13% of our supply to only 5%, it is widely assumed that LNG imports will fill the gap. EIA projections indicate that more than 75% of all new incremental demand must be met by a 580% increase in LNG imports — taking such imports to 4.1 Tcf (see Figure 2.4). To put such a large amount of LNG in perspective:

- 4.1 Tcf is greater than the entire 2004 NG production of the Gulf of Mexico (4.0).
- 4.1 Tcf is the Btu equivalent of importing more than 700 million barrels of oil (2 MMbbl/d).
- 4.1 Tcf at the 2005 (January–June) average LNG cost of \$6.46 per Mcf would cost the United States at least \$27 billion per year in addition to our current cost of more than \$200 billion for importing petroleum.

Optimism Surrounds the LNG Concept, but Significant Uncertainty Remains

Generally, the debate over LNG has been guided by safety issues and protests against receiving terminals with little focus on the availability or cost of assumed supply. Some of the following issues were raised by



Natural Gas Reserves in the World

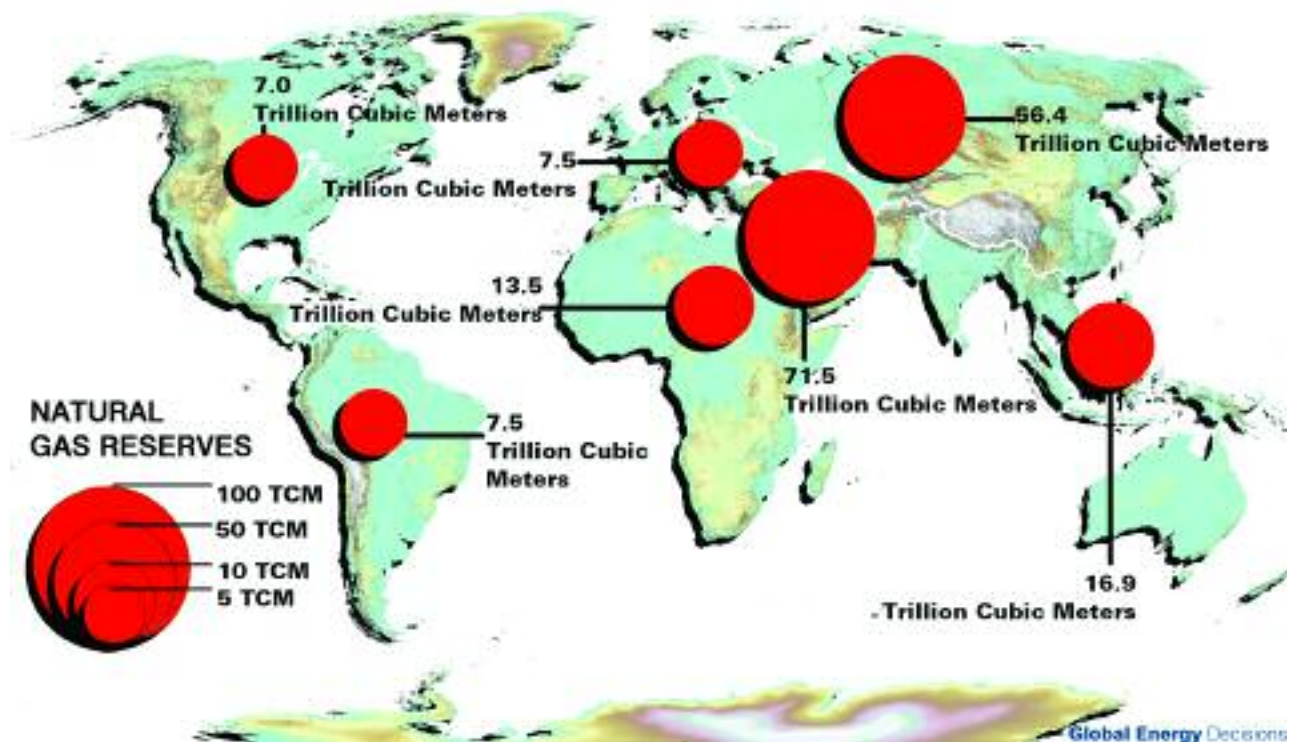


Figure 2.5

Andrew Weismann in 2005 testimony before the California Energy Commission. Much more empirical work is needed. It is clear, however, that efforts to import massive amounts of LNG will take time, cost money and could result in unforeseen consequences for all involved:

- **Oil prices** could fluctuate greatly, affecting LNG prices (especially in a peak oil scenario where the price of LNG is indexed to oil).
- Competition to LNG from **gas-to-liquids** could increase, particularly in isolated stranded gas fields where transportation becomes a limiting factor. This creates another demand for natural gas, which is conversion to high-value liquid fuels. Hence, the price of stranded gas will no longer be depressed by lack of access to pipeline networks but will instead be a function of petroleum product prices.
- The **availability** of LNG could require more time, given the capital investment required, siting issues, equipment constraints and time to build facilities at the producing end of the chain.
- The **reliability** of LNG-producing countries in a volatile global political climate (e.g., Iran) could become uncertain. The probability that a NG cartel will be formed and assumed lower prices may be a forlorn hope. There is risk that LNG producers may be subject to the same form of terrorism and military attacks as are the petroleum producers.
- **Energy security** issues could, and likely will, evolve as the United States becomes even more dependent on energy supply from foreign sources (see Figure 2.5), which can often be unstable. Not infrequently, optimistic projections of LNG ignore the dangerous nature of worldwide politics (e.g., NG dispute between Russia and the Ukraine in January 2006).
- **Price**—and the **volatility** of that price—could increase as the United States faces competition for

LNG Facilities Are Planned & Under Construction—World

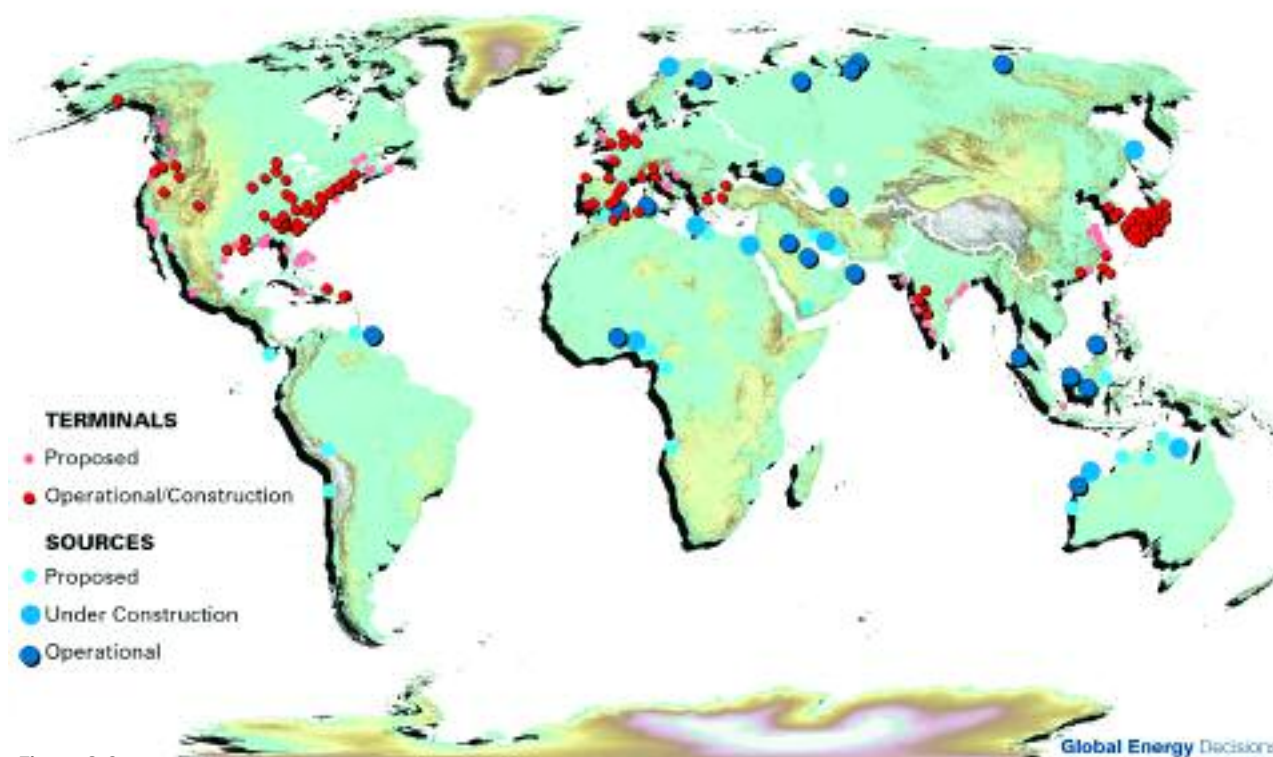


Figure 2.6

LNG from Europe, Japan and the rest of Asia (see Figure 2.6). Given the Ukraine's experience with reliability of NG from Russia, a number of European nations are looking to Nigeria and Qatar for LNG, putting them in direct competition with the United States. For instance, price spikes and a bidding war for cargoes prevailed in the last quarter of 2005, with some carriers waiting offshore to collect the highest bid.

LNG Facilities Are Planned and Under Construction throughout the World

- **Balance-of-trade** issues may develop as massive reliance on imported LNG will increase the trade deficit by as much as \$25–\$40 billion beyond the more than \$200 billion the United States is currently paying for petroleum.
- **Sudden swings in supply** may occur. Given the size of LNG projects and the role of LNG as the marginal supply, an unanticipated disruption in production could have an exaggerated impact on

the market, much like the current vulnerability of oil refineries (e.g., the 2003 fire at Tiga LNG plant in Malaysia).

- Institutionalized price could increase for U.S. consumers, businesses and agricultural operations as the United States is at an inherent economic disadvantage in **LNG transportation and regulatory induced cost**.

LNG is a promising source of new supply, but prudent planning suggests the parallel pursuit of other alternatives given the large number of unanswered questions that surround LNG.

Coal-To-NG Equivalents Can Relieve the Pressure on Other NG Supply

While the United States cannot rely on the hope that supplies of LNG from foreign countries will increase sufficiently and be reasonably priced to meet growing demand for NG, we can minimize that risk and reduce further outflow of capital by developing domestic

technologies that produce NG and NG equivalents from coal. One such technology is coal-to-NG, which could create 4 Tcf per year of NG equivalents by 2025. Such facilities would supply fuel for residential, commercial and industrial applications and ease supply pressures by providing more than 15% of America's projected NG demand. These coal-to-gas technologies are proven and available in the United States today and would consume upwards of 350 million tons of coal per year.

Coal Gasification Is More Than a Century-Old Technology

Coal gasification technology has been used for more than a century. During the nineteenth century and well into the twentieth century, coal-gas fueled street lamps and provided heating and lighting to homes and factories. During this era, coal was the dominant energy source. Solid coal was burned in fireplaces and furnaces, but the convenience of gaseous fuel distribution made the use of gasified coal products attractive.

Low-cost petroleum products and NG availability eventually eliminated the need to gasify coal except in extraordinary circumstances. For example, in Germany during the 1930s, scientists employed technologies developed years earlier that used coal-gas as a starting point for the synthesis of liquid fuels and military munitions. Eventually, during World War II, these technologies provided the bulk of liquid fuels for the German economy. In South Africa, an oil embargo imposed by the international community in response to apartheid policies forced the government to adopt coal-to-liquid fuel technologies that today provide 40% of that country's supply.

Such an extraordinary circumstance also created the Great Plains Synfuels Plant near Beulah, North Dakota, the only commercial-scale coal gasification plant in the United States that manufactures NG. The 1970s energy crisis spurred the development of the plant as part of the Federal Nonnuclear Energy Research and Development Act of 1974, which was designed to help the nation achieve energy independence. The \$2.1 billion plant began operating in 1984 and uses 18,506 thousand tons of lignite coal per day to produce a daily average of

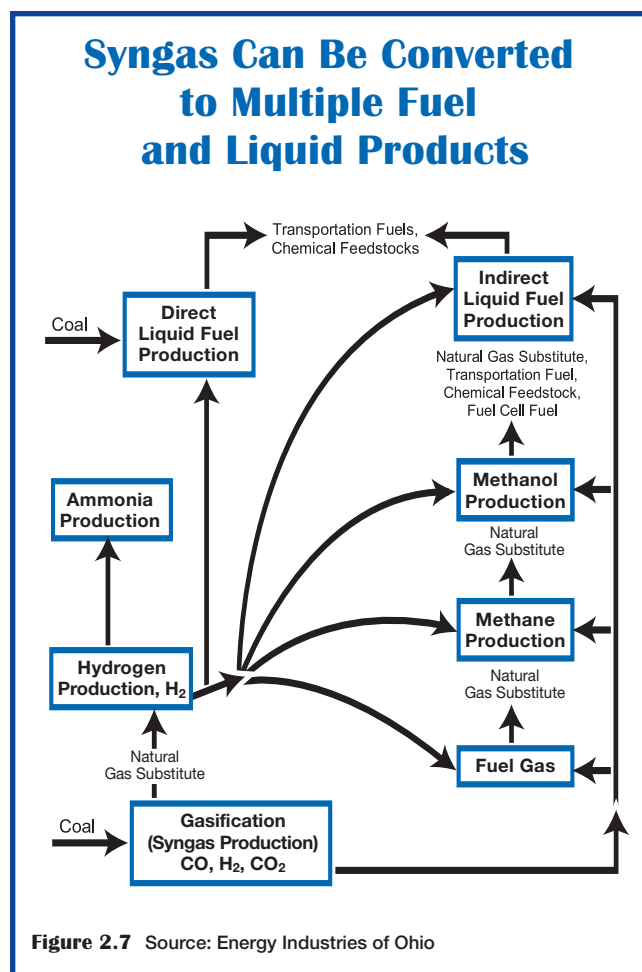


160 million cubic feet of NG. The plant's many byproducts include 1,200 tons/d of anhydrous ammonia. In fact, the plant recently began shipping CO₂ to Canada for enhanced oil recovery.

Coal Gasification Becomes Price-Competitive

Recently, crude oil and NG prices have reached levels that have revived the prospects of economically competitive uses for gasified coal. Indeed, coal gasification is booming worldwide.

According to the National Energy Technology Laboratory (NETL), in 2002 there were 128 operating gasification plants, with a total of 366 gasifiers producing the equivalent of approximately 1.28 Tcf/yr of NG (24 hours per day, 365 days per year). In addition, another 0.732 Tcf/yr of new gasification capacity is under development, with projected annual growth of 0.12 to 0.15 Tcf/yr.



The Coal Gasification Process

Pulverized coal, purified oxygen or air, and steam will react to produce a gas stream containing carbon monoxide, hydrogen, carbon dioxide and, when air is used, nitrogen. This stream is called “synthesis gas” or “syngas” because it can be used to synthesize a wide range of other chemical compounds. As the illustration above indicates (see Figure 2.7), syngas can be converted to a number of different products including hydrogen, ammonia, fuel gas for electricity generation, methane, methanol, and liquid fuels such as gasoline, diesel oil and jet fuel.

Following are some of the primary products of coal gasification and their uses:

- **Hydrogen** — can be used for fuel cells, ammonia production, coal-to-chemical operations and other industrial uses.

- **Fuel gas** — can replace NG in fueling baseload and peaking gas-turbine electric generators. With proper equipment modifications, fuel gas also can replace NG in a variety of residential, commercial, and industrial heating applications.

- **Anhydrous ammonia** — is an essential ingredient in the production of fertilizers, explosives, and industrial chemicals and is used as an industrial refrigerant. Currently, ammonia is produced from NG and the reduced domestic production of ammonia is the result of high NG prices.

- **Methane** — can be used as NG (typically NG is ~95% methane). The methanation reaction can also be used to produce higher Btu fuel gas.

- **Methanol** — is used in the production of biodiesel and can be burned in internal combustion engines similarly to ethanol (M85 is 85% methanol, 15% gasoline). Methanol also can be used in fuel cells and can replace NG in methane synthesis. Methanol is a critical ingredient in the production of a number of basic chemicals, including formaldehyde, acetic acid, methylamines, methyl methacrylate, dimethyl terphthalate, and MTBE. Again, the domestic production of methanol is nearly 100% NG-based and has been reduced significantly as NG prices have increased.

- **Coal-to-liquids** — is the production of liquid fuels.

Gasifier Types

There are a number of coal gasification processes that are either commercially available or under development with varying degrees of technical advantages and overall cost effectiveness. These gasifiers can be classified into one of three generic types, namely fixed-bed (or moving bed), fluidized bed, and entrained flow.

Experimental hybrid design gasifiers have been developed over the years and have had support from the DOE, but none has reached a commercial demonstration stage. One example of the hybrid gasifier designs is the M.W. Kellogg Transport Reactor Gasifier, which is an adaptation of the

MWK fluid catalytic cracking reactors. These gasifier types may be oxygen or air-blown and may have particular variations in operating conditions and gasifier geometry.

Various initial screening studies have shown that generic gasifier types can be used in an integrated coal gasification combined cycle power plant if a suitable cold or hot gas cleanup system is employed down stream of the coal gasifier to remove the contaminants harmful to combustion turbines. The primary technical factor in integrating the gas turbine and gasifiers is that the fuel gas must be capable of being fired at the high operating temperature of a modern gas turbine while producing an expander gas with sufficient mass flow to produce



the rated power from the turbine.

CONCLUSION

Declining supplies of domestic NG are leading to increased dependence on foreign sources. These sources are becoming increasingly expensive, less dependable and more of a national security concern.

Relying on imported LNG to address NG issues is problematic for the same reasons.

Using Btu conversion technologies to create a new NG supply or to replace the use of natural gas with a coal-derived gas stream could replace 15% of U.S. annual NG demand, moderating NG prices and using an additional 340 million tons of coal per year.

Gasification Process Developers

Process	Developer	Gasifier Type
BGL	British Gas/Lurgi	O ₂ /Fixed Bed
Lurgi	Lurgi	Air/O ₂ /Fixed Bed
CRSS	CRSS Capital	Air/Fixed Bed
KRW	MWK/Rust/WH	Air/O ₂ /Fluid Bed
U-Gas	IGT/Tampella	Air/O ₂ /Fluid Bed
HTW	Rheinbraun/Lurgi	Air/O ₂ /Fluid Bed
Shell	Shell Development	O ₂ /Entrained Flow
GE Gasification	GE Energy	O ₂ /Entrained Flow
E-Gas	ConocoPhillips	O ₂ /Entrained Flow
EPIC	EPIC	Air/O ₂ /Fixed Bed
Prenflo	GKT	O ₂ /Entrained Flow
MWK	MW Kellogg/Southern Co.	Air/Transport
IGC	IGC Assoc. (Japan)	Air/Entrained Flow
MHI	Mitsubishi	Air/ Entrained Flow
Future Energy	Future Energy Gmbh	O ₂ /Entrained Flow

Figure 2.8

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COAL-TO-CLEAN ELECTRICITY



The nation's focus on relatively expensive and price-volatile NG to meet incremental demand for electricity has not served the public interest. America must develop new coal-fueled generating capacity to avoid additional increases in NG demand that would further strain supplies and lead to much higher prices. Higher NG prices stress the economy, reduce productivity and cause severe economic problems for residential, commercial

and industrial consumers. Construction of 100 GW of coal-to-clean electricity plants by 2025 would mean that coal could satisfy more than 60% of the expected increase in electricity-generating capacity by using an additional **375 million tons** of coal per year. Increased coal-to-clean electricity capacity would relieve price

pressures on NG and allow it to be used in more cost-efficient and productive ways. Advanced combustion and IGCC-based technologies that focus on meeting near zero emissions goals at reasonable cost and high reliability are in development and/or commercial demonstration.

Over 51% of U.S. Electricity Is from Coal
Retail Cost Per kWh & Percent of Coal Generation



Source: EIA, March 2005

FINDINGS

The nation's focus on relatively expensive and price-volatile NG to meet incremental demand for electricity has not served the public interest. America must develop new coal-fueled generating capacity to avoid additional increases in NG demand that would further strain supplies and lead to much higher prices. Higher NG prices stress the economy, reduce productivity and cause severe economic problems for residential, commercial and industrial consumers. Construction of 100 GW of coal-to-clean electricity plants by 2025 would mean that coal would satisfy more than 60% of the expected increase in electricity-generating capacity by using an additional **375 million tons** of coal per year. Increased coal-to-clean electricity capacity would relieve price pressures on NG and allow it to be used in more cost-efficient and productive ways. Advanced combustion and IGCC-based technologies that focus on meeting near zero emissions goals at reasonable cost and high reliability are in development and/or commercial demonstration.

DISCUSSION

Demand for electricity in the United States has increased steadily over the past century, with annual growth in 28 of the past 30 years.

Further, electricity demand in the United States is expected to continue to grow steadily in the foreseeable future (see Figure 3.1). The EIA projects that growth of domestic demand from 2005 to 2010 alone will necessitate a generation increase of more than 310 billion kilowatt hours

Projected Electricity Generation in the U.S.

Expected to Increase 75% from 2005–2030

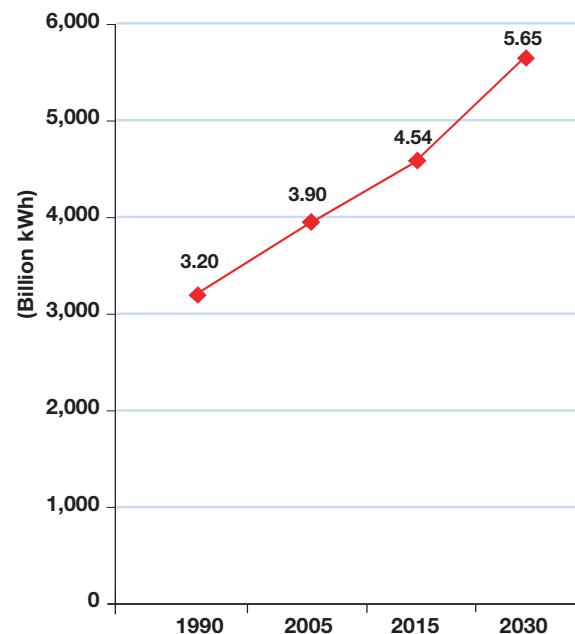


Figure 3.1 Source: EIA Annual Reports; AEO 2003 Reference Case

(kWh). Projections indicate that by 2030, 5,648 billion kWh of electricity generation will be required.

Currently, coal-based power plants produce more than 50% of the nation's electricity; nuclear, 21%; NG, 18%; oil, 3%; and hydro and other renewables comprise the balance.

NG plant capacity factors have been low recently due to a large number of NG plants coming on line in the past seven years and the current high cost of NG to run these plants. Hydro production varies widely on an annual basis, due to rainfall and regulatory decisions regarding issues such as fisheries management. Notably, coal and nuclear generation capacity factors have continued to rise, and little spare capacity exists within these fleets.

Over the past decade, power plant construction has overwhelmingly been based on NG as a feedstock (see Figure 3.2). A combination of overly optimistic





supply and price projections, modified environmental regulations, changing regulatory conditions, and simple convenience has led to an unprecedented build-out of the NG demand infrastructure through massive construction programs of NG.

In fact, since the 1990s virtually all new power plants have been NG or dual-fired—an historic departure

from the traditional fuel diversification strategy of electric utilities.

In just six years (2000–2005), the United States added more than 200,000 MW of NG generation to the electric power system, and more are being planned. Projections indicate that over the period 2006–2009, the United States will build an additional

Natural Gas Plant Start-Up Peaked in 2002

Percent of New Generation Still at 83% in 2005

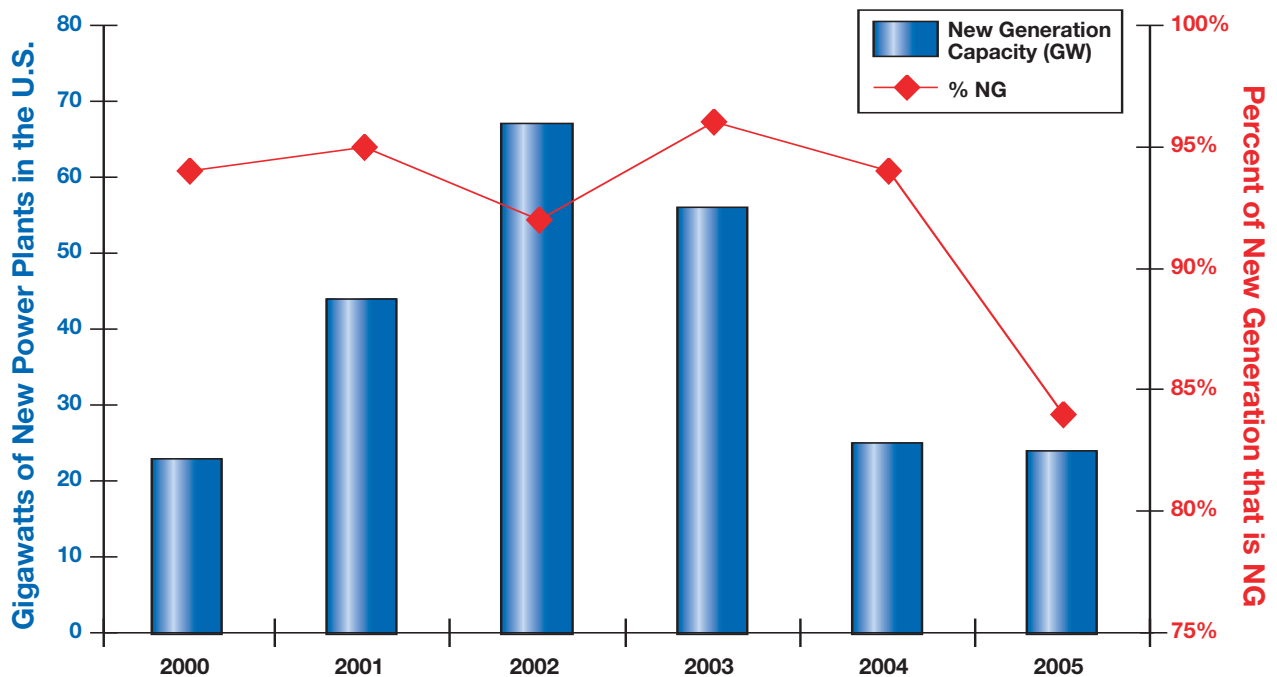


Figure 3.2 Source: EIA Annual Reports and New Generation Data

Natural Gas Costs Have Escalated Rapidly

At Wellhead and for Power Generators



Figure 3.3 Source: EIA Annual Reports and Short-term Outlooks

70,000 MW of power stations, of which 54,000 (77%) will use NG as the primary fuel.

The surge in NG demand to produce electricity has created domestic competition for supply between electric generators, households and industrial users, dramatically escalating prices, and adversely impacting consumers and businesses alike (see Figure 3.3).

Further, there is a direct correlation between electricity prices paid by consumers on a statewide basis and the level of dependence of that state on NG for electricity production (see Figure 3.4).

The Consequences of Over-Reliance on NG Power Plants

For the entire first decade of the 21st century, coal,

nuclear, hydroelectric, and all

other fuels combined will have

provided less than 10% of new

electric generation capacity,

dramatically highlighting the

nation's increasing dependence

on NG to produce electricity.

In 1990, only 13% of generation

was fueled by NG. The EIA

projects that by 2015 more than

22% will be NG. This focus on

NG-fueled power plants to meet

incremental demand for electricity

has had negative implications for

the American economy:

- NG plants are increasingly part of baseload generation, especially in such states as Texas,



California and Florida where NG now comprises more than 40% of electricity, even under normal conditions.

- Dramatic NG price increases can be directly attributed to meeting baseload demand with NG (see Figure 3.5). In 2000, the EIA projected that in 2005 electric power generators would be paying \$2.79 per million Btu for NG. The actual price in 2005 averaged more than \$7.28, a difference of more than 160%. NG power plants are increasingly competing with households, businesses and manufacturing facilities for supply.
- This domestic competition between various sectors of the economy is especially severe due to declining production of NG. Given the stress that electric power generation is placing on the NG supply system, it is not surprising that prices of more than \$13 were required to fill winter storage in 2005.

- This high cost of NG has resulted in tens of thousands of MW of capacity sitting idle because they are too expensive to operate even during periods of relatively high demand. Billions of dollars have been lost by investors who had assumed NG prices would be stable and economical.
- Reserve capacity in the United States is increasingly based on NG plants. This dependence upon NG for reserve margin greatly increases the vulnerability of the electric supply system to outages and supply shortfall.

Natural Gas Increasingly Setting Power Prices

Domestic NG resources are insufficient to meet the energy needs of the American people and the U.S. economy. The EIA has projected that U.S. demand for NG will rise from 22 Tcf in 2004 to 27 Tcf in 2025. As more fully discussed in the coal-to-NG

Over 51% of U.S. Electricity Is from Coal

Retail Cost Per kWh & Percent of Coal Generation

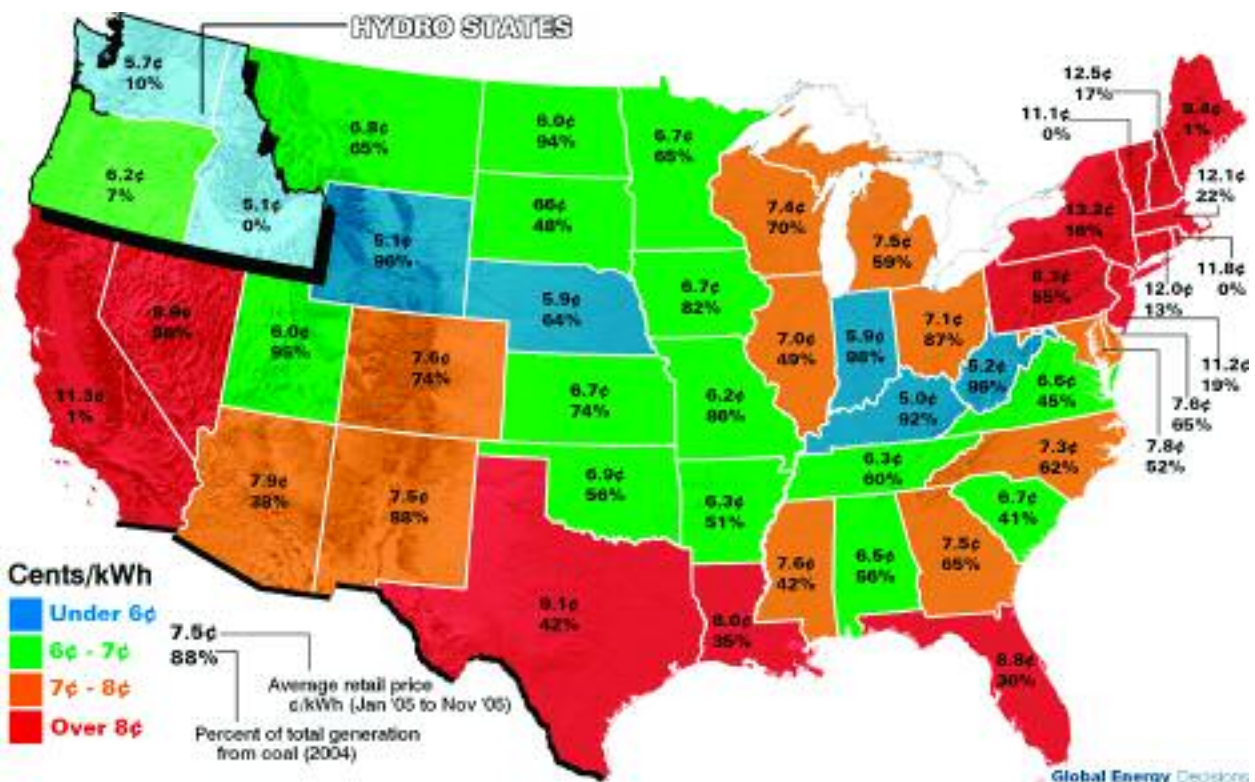
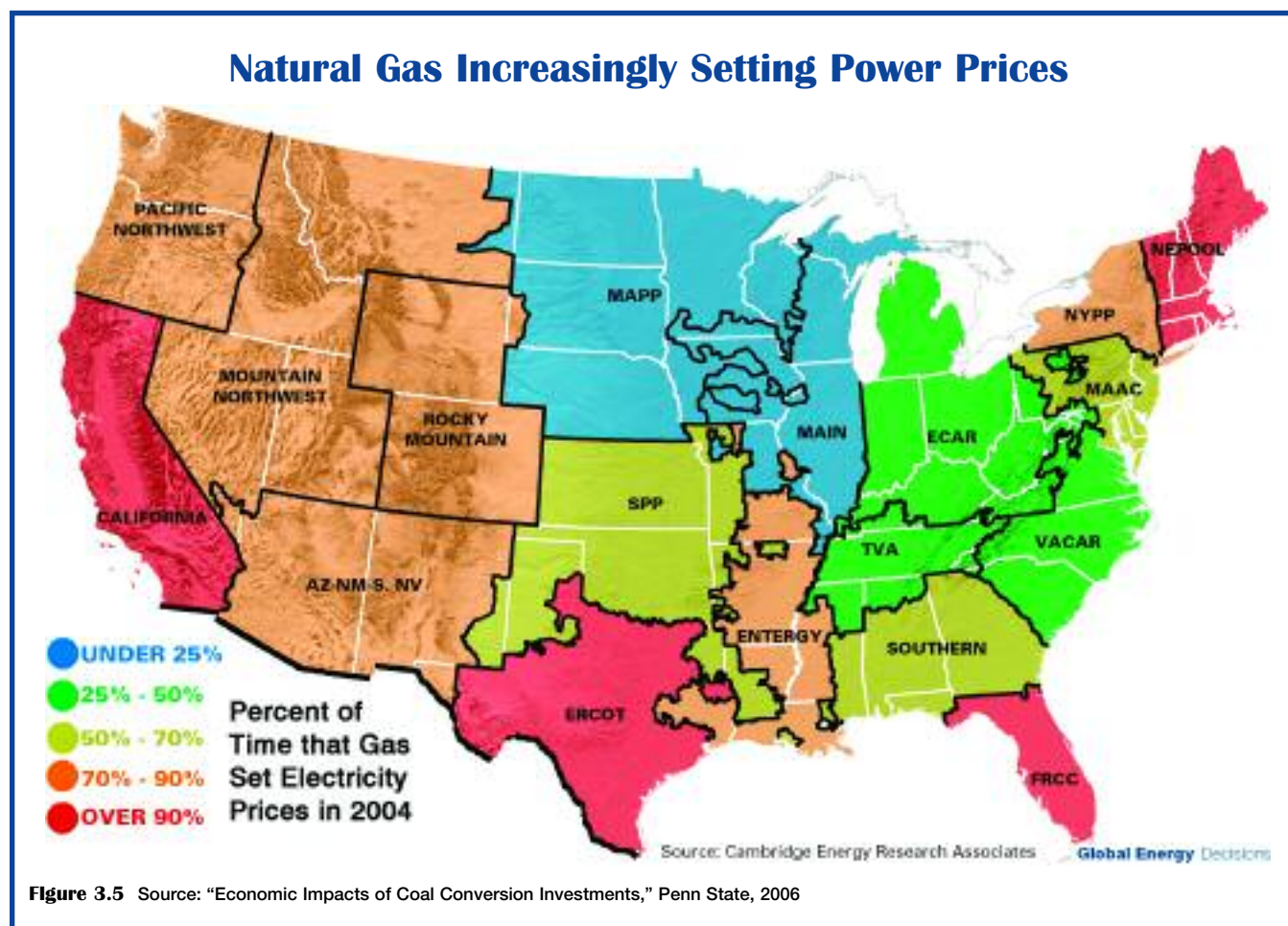


Figure 3.4 Source: EIA, March 2005



chapter, the United States does not have and cannot reasonably expect to obtain sufficient quantities of NG at any price to meet the needs of the existing NG generating fleet, let alone support additional NG-fired units (see Figure 3.6).

Coal Can and Must Produce More Electricity

The United States can reduce its dependence on expensive NG for electric generation by increasing its utilization of the existing coal-based generating fleet and adding at least 100 GW of new, state-of-the-art coal-based electricity plants, as well as the re-powering of existing natural gas combined cycle (NGCC) plants with coal gasifiers.

In fact, there is increasing evidence that producers are turning to coal to meet the next generation of demand for electricity. A recent National Energy Technology Laboratory (NETL) survey determined that there are 135 coal-fueled plants—representing \$108 billion in investment and 87 GW of capacity—

announced or in some stage of development. These proposals account for 33% of planned new generation capacity (see Figure 3.7).

Of these 135 proposed units, more than 110 are state-of-the-art combustion (pulverized coal or circulating fluidized bed) technology, and 19 are proposed to be integrated gasification combined cycle (IGCC). As recent experience has shown, there remain significant hurdles to building many of these proposed plants. This report illustrates that the significant advances in environmental protection by coal-based generating stations justify critically important federal and state government support for deployment of these power plants in a timely manner (see Figure 3.8).

Indeed, because of significant advances in emissions control technology and deployment, emissions from coal-based generation have declined significantly since 1970, even as coal used for electricity generation has more than tripled. This is true both

Imbalance Forecast in U.S. Gas Supply & Demand

Imports Unlikely to Close the Gap

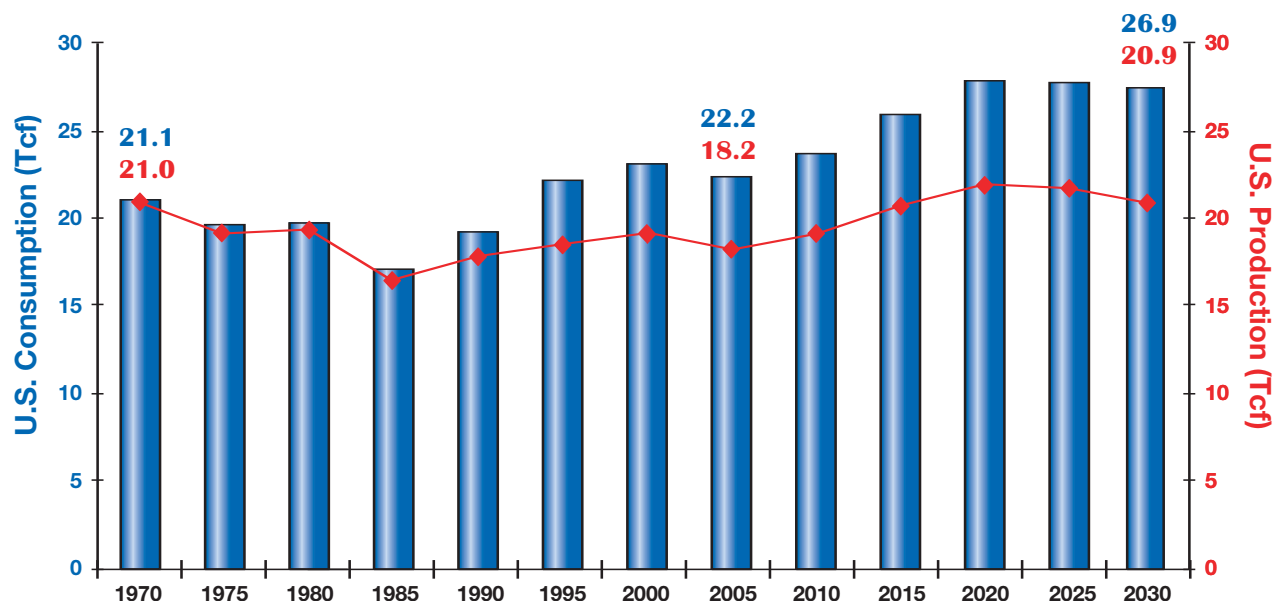


Figure 3.6 Source: EIA Annual Energy Review 2003, 1970–2000; AEO 2006 Reference Case 2005–2030

on an aggregate and per-unit basis and is a testament to the success of federal research and development and technology demonstration programs that supported development of clean coal generation and environmental technologies.

The Evolving Role of Coal Cleaning

Coal cleaning has been traditionally viewed as a method of removing rock from as-mined coal in order to reduce transportation and ash disposal costs. However, tightening environmental regulations in combination with increased knowledge about the role of coal quality in reducing power generation costs is leading to a new concept—the use of coal cleaning to produce a fuel tailored for a specific application.

Coal cleaning can change not only ash loading and sulfur emissions but also ash behavior in the boiler as indicated by changes in slagging and fouling indices. Proper manipulation of ash constituents during the cleaning process can often solve ash-related boiler problems, increasing boiler availability, efficiency and power output.

Resurgence in U.S. Coal-Based Electricity

135 New Coal-Fueled Plants Proposed Since 2000

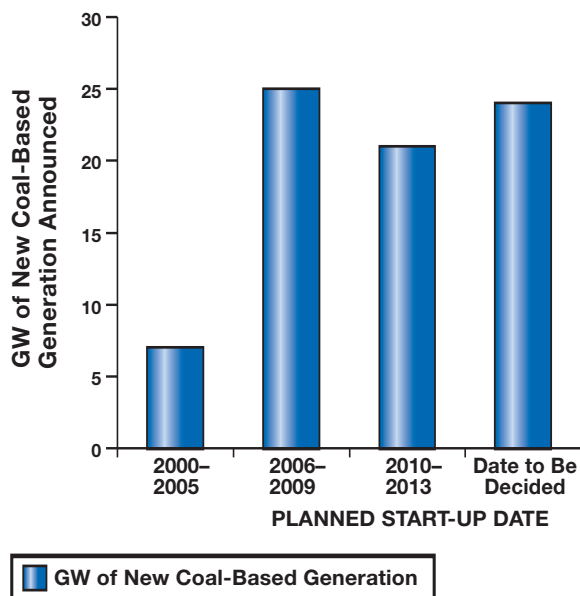


Figure 3.7 Source: NETL, January 2006

CAIR Accelerates 35 Years of Clean Air Progress

Nationwide SO₂ and NO_x Emissions from the Power Sector

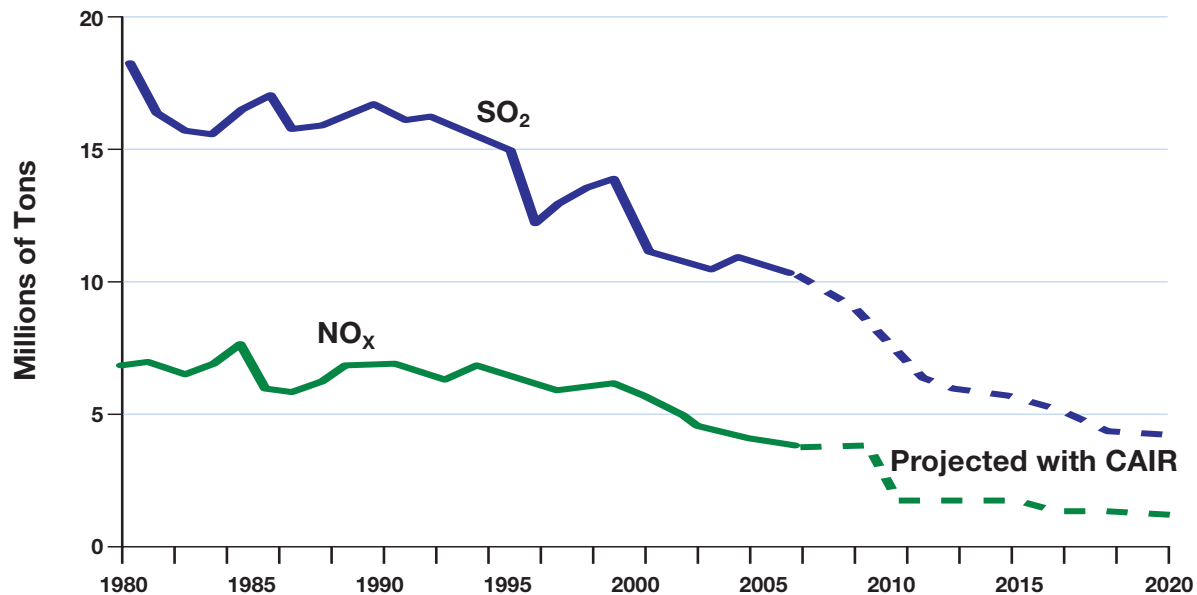


Figure 3.8 Source: EPA, 2006

Cleaning can also reduce boiler erosion by removing hard minerals, such as quartz. A study by the Electric Power Research Institute (GS-6517) found that cleaning a Texas lignite coal reduced boiler erosion by 50%, increasing boiler availability and reducing maintenance costs. The total economic benefit to the boiler was almost \$4 million per year, excluding the cost impact of improved unit availability.

In addition to reducing ash disposal costs and SO₂ emissions, coal cleaning can also economically reduce mercury emissions. In an EPRI study (TR-111852), it was found that a combination of conventional and advanced coal cleaning technologies could reduce mercury emissions by as much as 62% beyond the reductions typically achieved by coal cleaning. Costs were as low as \$15,000 per ton of mercury removed. Because the mercury removed by cleaning never enters a boiler,

concerns about the impacts of post-combustion mercury control on utility byproduct utilization and waste disposal are greatly reduced.

Clean Coal Technologies Exist Today

As a result of extensive R&D investments by electric utilities, equipment vendors and government agencies, there are a range of existing, commercial

clean coal technologies available today, categorized as advanced high efficiency combustion-based technologies and gasification-based technologies. Under development are technologies that will allow capture of carbon dioxide in both advanced combustion and gasification plants. Continued development of clean coal technologies is important for domestic implementation, and successful commercialization



will lead to exports to—and payments from—other countries. Even more important, adoption of clean

coal technologies on a global basis will lead to overall improvement in the global environment.

Advanced combustion-based technologies combust coal with air or oxygen. During combustion, the energy in the coal is used to generate steam, which is converted to electrical energy in a steam cycle. The exhaust gases from combustion processes are cleaned to remove contaminants using a combination of environmental controls. The environmental performance is enhanced by increased plant efficiency due to the application of advanced steam parameters (supercritical and ultrasupercritical cycles), resulting in lower emissions per megawatt hour (MWhr) of electricity. Today, over 50% of U.S. power generation is produced by coal combustion; as such, it has proven reliability, efficiency and low cost and is the backbone of inexpensive U.S. power generation.

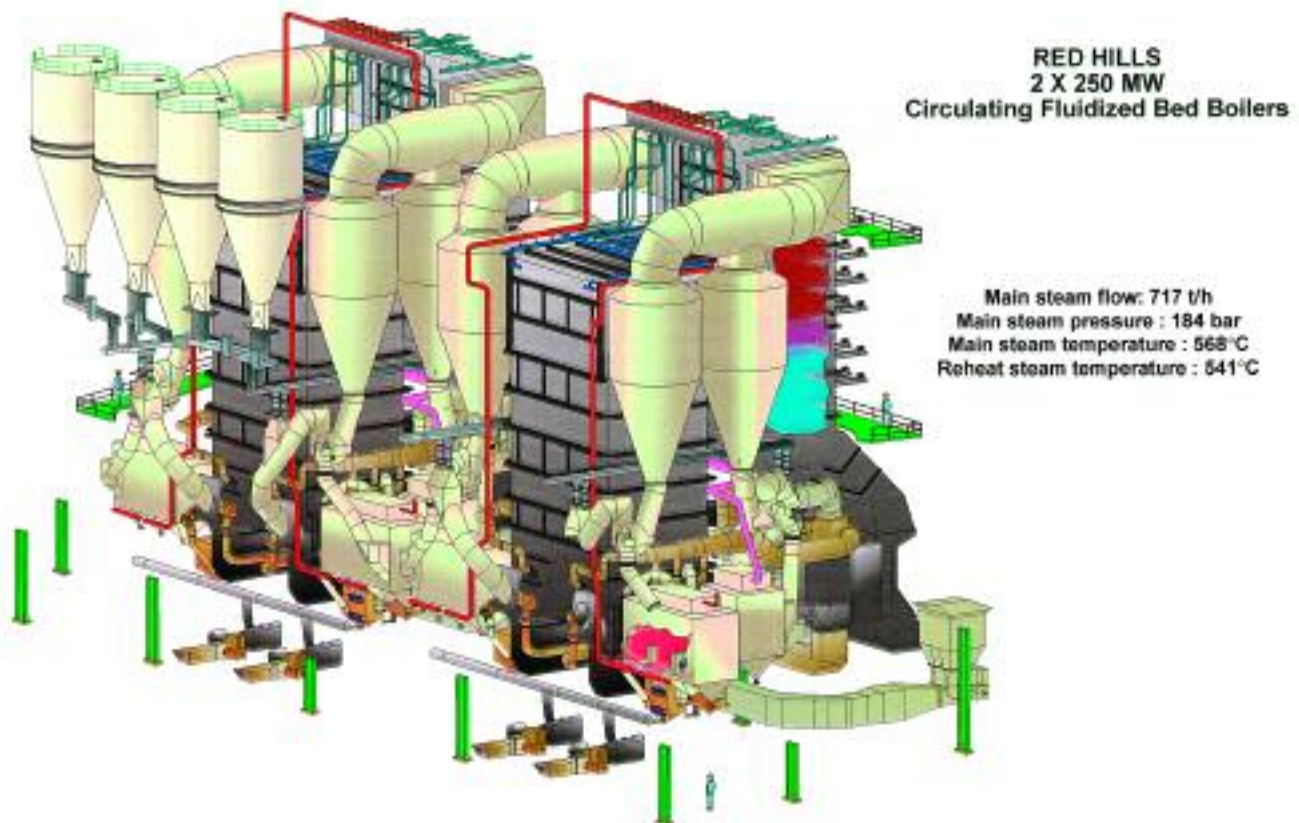
Gasification-based technologies use a partial combustion of coal, with air or oxygen, to produce a synthetic fuel gas. This gas is then cleaned to

remove contaminants before it is used as fuel in a combustion turbine or further processed into a feedstock for industrial production. As with combustion technologies, higher efficiency results in lower emissions/MWhr. Integrated gasification combined cycle (IGCC) has begun to be commercially offered following a handful of power demonstration units in the U.S. and Europe (the majority of gasifiers are operating in refineries producing feedstocks).

Variations on both technology categories are in different stages of development and commercialization. A portfolio of clean coal technologies exists today, and emerging and developing technologies are advancing rapidly:

Commercial today:

- Pulverized coal combustion (PC) and circulating fluidized bed (CFB), using subcritical or supercritical steam cycles, providing efficiencies in the range of 36–40% high heating value (HHV) with higher values related to supercritical cycles.



A Buildout of New Generation Has Begun

Planned Global Electricity Generation Capacity

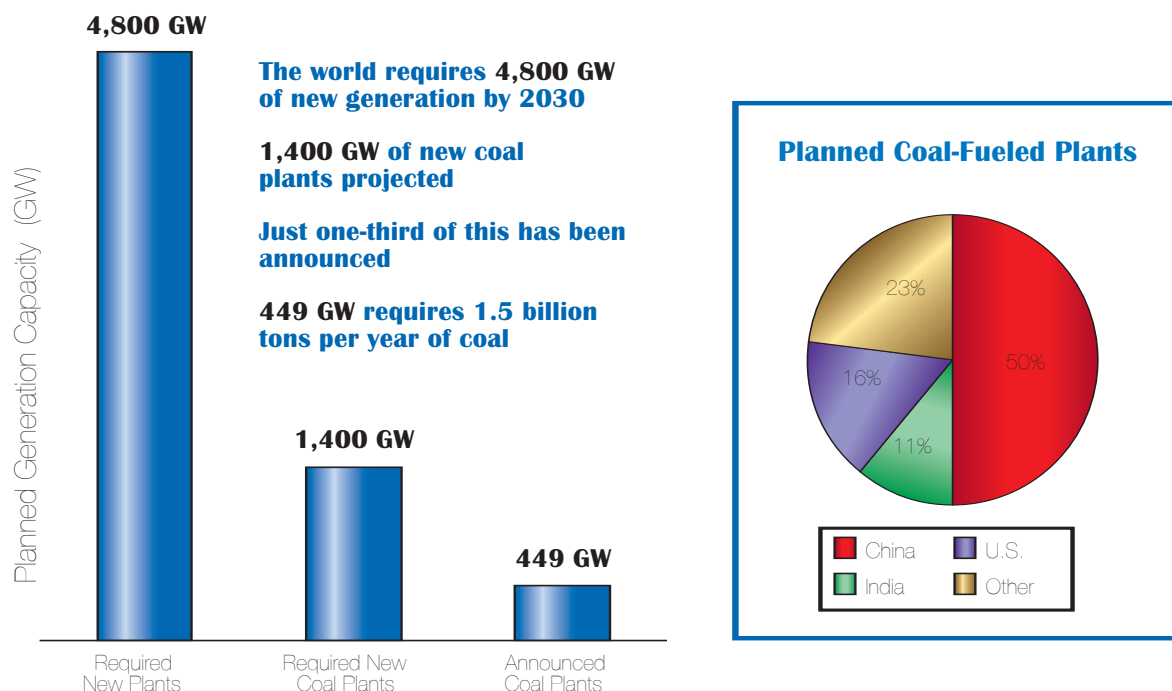


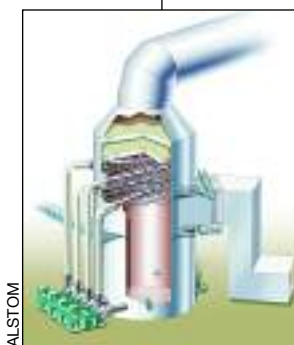
Figure 3.9 Source: International Energy Outlook & Platts Database

Emerging technologies at initial commercialization:

- Integrated gasification combined cycle (IGCC), with either air or oxygen blown gasification to produce syngas for use in combustion turbines, with plant efficiencies of 39–43% (HHV).
- PC/Supercritical (SC) steam plants of European and Japanese design, providing efficiencies of 40–42% (HHV).

Developing technologies:

- Advanced IGCC with hydrogen production and CO₂ capture (i.e., FutureGen).
- PC/SC steam plants, currently being researched by the U.S. DOE and the Ohio Coal Development Office, providing efficiencies of up to 48% or more (HHV).



- Advanced USC PC/CFB, with efficiency goals of approximately 50% (HHV) prior to CO₂ capture.
- Innovative post combustion capture technologies with reduced cost and power usage for PC/CFB technologies.

- Advanced PC/CFB with oxygen combustion to facilitate capture of CO₂ emissions.

Future technologies:

- Hybrid cycles (IGCC with fuel cell).
- Chemical looping combustion and gasification.
- Next generation PC/CFB Oxyfuel plants.

Attributes of these technologies are explained in further detail in Volume II, Section 1.

Facilitating Development of Advanced Clean Coal Power Plants

As noted previously, rising NG prices, coupled with electricity demand growth, have driven renewed interest in the development of new coal-based power capacity. This new capacity is vital to turning around the trend toward higher power prices due to higher NG prices and reducing the competition for NG supply to industry and residential users from the power industry. Action is needed to facilitate this new capacity.

First and foremost, we must begin to build new capacity now; new coal power plants are long-term construction projects, requiring three to four years to place into service after initial groundbreaking. Adding site evaluation, permitting, financing and other upfront project planning time means that plants under initial development today will not provide power to the grid until 2010–2012. Federal, state and local support is needed to coordinate permitting and approvals in a timely manner.

For the first round of new capacity, generators have chosen from proven designs for advanced clean coal combustion utilizing subcritical or supercritical PC or CFB, as well as higher temperature European/Japanese USC/PC designs. While their emissions depend on their efficiency, all of these plants, regardless of technology (PC/CFB/IGCC), are being designed to meet and, in fact, significantly exceed new source performance standards (NSPS), assuring that this new coal capacity will continue excellent progress toward the goal of near zero emissions while meeting system reliability and cost objectives.

Over the next decade, data from actual performance of the first commercial IGCCs for power generation should help improve operational flexibility and reliability, optimize designs, and achieve cost reduction goals. Similarly, the introduction of the first European/Japanese high temperature USC/PC designed in the U.S. (units are operating overseas) will expand understanding of the performance of boiler materials with the range of U.S. coals.

Proposed New Coal Plants

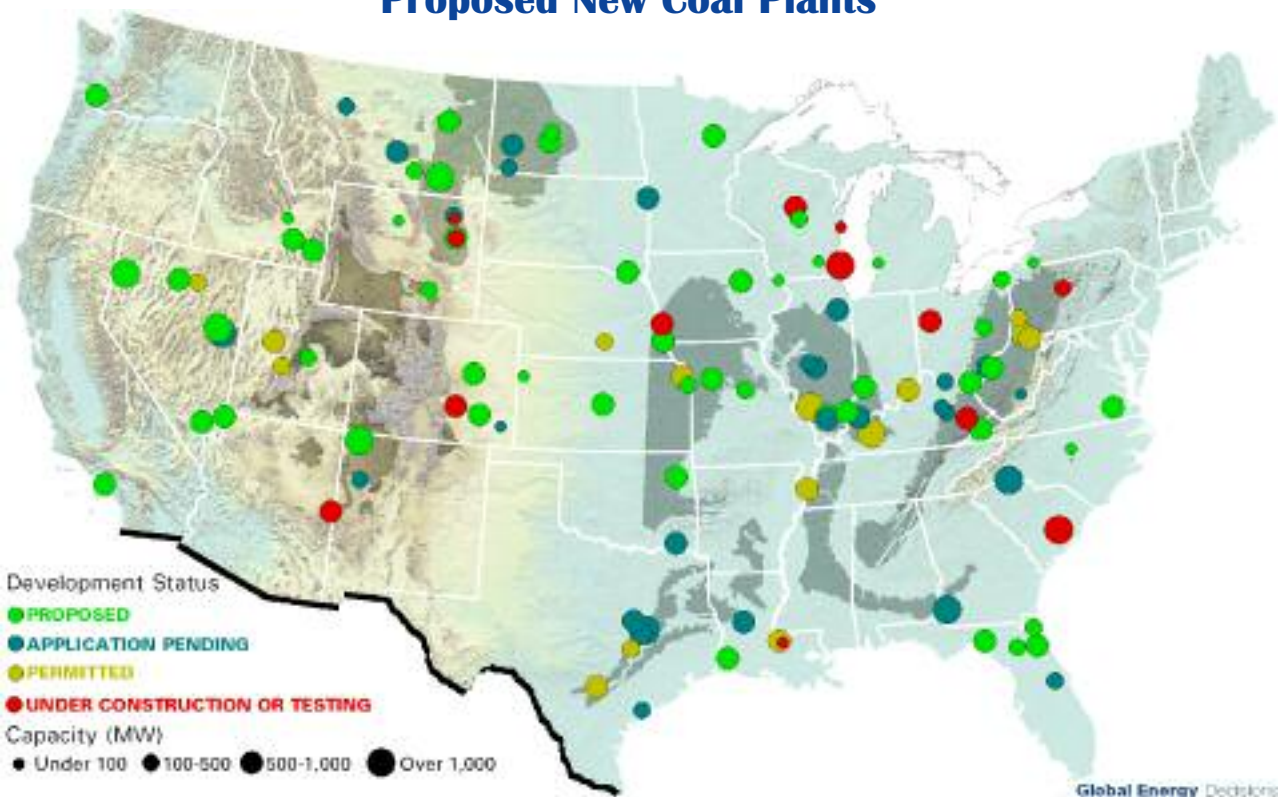


Figure 3.10



Within the next five years, the industry needs to introduce the next generation of advanced IGCC, and U.S.-designed USC/PC, bringing continued advancements in efficiency and environmental performance, including the capability for CO₂ capture (see next section for comments on carbon management).

The need for continued advancement of coal-based power technologies is compelling and the potential of all of the aforementioned technologies is well documented. What is needed is an aggressive series of technology commercialization followed by widespread commercial deployment, parallel development, and demonstration of the next advanced technologies, followed by another series of deployment and commercialization. However, meeting the goal of placing 100 GW of new coal power generation capacity into service by 2025 will require solid, committed and long-term cooperation and coordination of all industry players—including generators, regulatory agencies, government agencies, equipment suppliers, engineering and construction companies, and labor unions, as well as consumers, non-government organizations, and other stakeholders.

Regulatory and permitting agencies need to support a prudent and progressive approach to the introduction of each generation of new technology. This recommendation encompasses both ends of the spectrum. The EPA and environmental agencies, for instance, must recognize that only a portion of each new round of capacity additions can be first-of-a-kind projects in order to manage overall system risk. For example, new technologies in initial commercialization should not be deemed best available control technology (BACT) based on projected environmental performance; rather sufficient time must be allowed to prove or disprove performance, cost and reliability under actual grid conditions. Conversely, regulatory commissions need to work with utilities to find solutions to proceed with a reasonable number of first-of-kind projects, allowing sufficient risk coverage for the sponsoring utility.

Ultimately, the inherent nature of innovation is that some technologies will meet their potential and others will not; this uncertainty is a very strong argument for maintaining development of a balanced portfolio of coal-based power technologies to include the range of gasification and advanced combustion solutions. Additionally, some legislators and regulators appear to be taking a narrow view of

possible solutions and have implied that they may “legislate” IGCC as the single technology solution for coal-based power. The reality of coal-based power is that no single technology is optimal for all U.S. coals, plant locations, or applications. Generators need to have proven options from which to select a technology that provides them with a clean, cost-competitive and reliable solution for their unique site and situation. Narrowing these options, rather than setting the goals and letting technology providers compete with solutions, stifles innovation and increases the industry’s risk of not meeting reliability, economic and environmental goals. Given the magnitude and breadth of issues facing the power industry, it is most likely that all of these technologies will be needed to meet industry long-term needs.

Carbon Management

The National Coal Council supports the strategic vision of DOE’s Office of Fossil Energy to reduce carbon emissions by developing, commercializing and implementing a portfolio of technologies to support making fossil energy systems more efficient, and capturing and storing greenhouse gases.

Efficiency improvement

Efficiency improvement is by far the most predictable and lowest cost method to reduce all emissions, including CO₂. All coal generation technologies emit CO₂ in direct proportion to efficiency. Improving the plant thermal efficiency will reduce both CO₂ emissions as well as conventional emissions including SO₂, NO_x particulates, and heavy metals.

The thermal efficiency of new supercritical PCs and the projected efficiency of IGCCs under commercialization are both in the range of 39–43% on higher rank coals (on lower rank coals, IGCC may have a 1–3% lower efficiency and PCs 1–2% lower

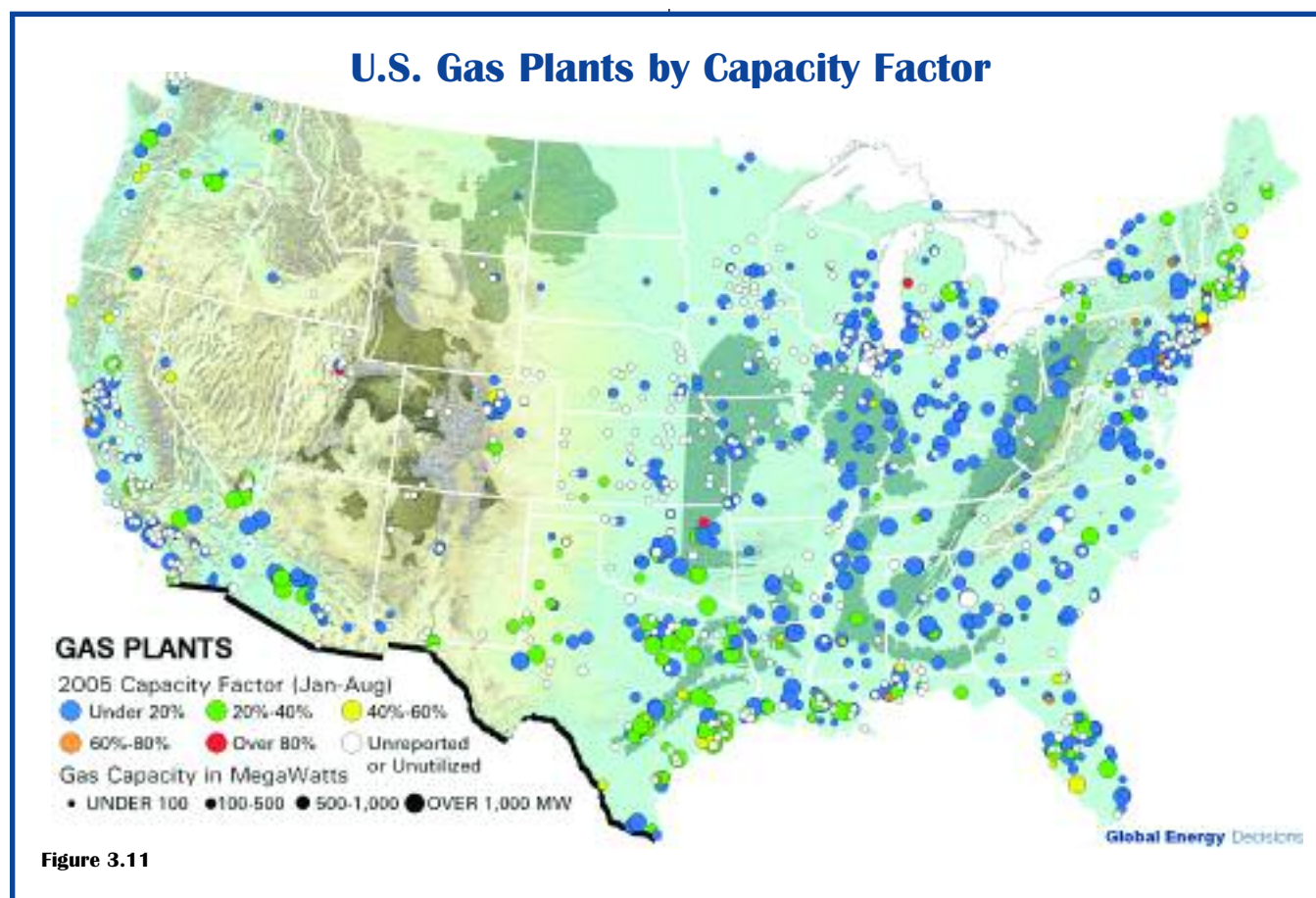


efficiencies). This represents an 8–10% efficiency improvement over new subcritical PCs and the two U.S.-operating IGCC units and more than a 20% improvement over the efficiency of the bulk of older operating coal generation. Emissions reductions would parallel the efficiency improvements from this new fleet of PC/CFB/IGCC.

U.S.-designed ultrasupercritical PC and advanced next-generation IGCC would increase efficiency to the 43–48% range, with CO₂ reductions of an additional 10–15%.

Efficiency improvements can be achieved for combustion technologies by operation at higher temperature and pressure steam conditions, utilizing advanced materials. The incremental investment costs for improved steam conditions for new combustion plants tend to be relatively low and the cost of electricity (COE) and emissions are reduced due to lower coal usage. The efficiency of IGCC can be increased by incorporating advanced heat recovery and improved plant component designs, including gas turbines.

Developing the materials and design concepts to achieve continued efficiency improvements in combustion and gasification technologies will require a highly coordinated effort between government, industry and suppliers. **Given the high payback of efficiency in both lower emissions and lower fuel costs, it is critical that DOE receive adequate**



funding for R&D and technology demonstration in these areas.

Carbon capture

To achieve CO₂ reductions beyond those accomplished by higher efficiency, CO₂ would need to be removed from the gas streams, concentrated, and compressed for transportation to the storage and sequestration location. Technical details are included in Volume II, Section 1.

Commercially available technologies can capture over 90% of the CO₂, but typically they are capital-intensive, impose an electric power output reduction, and cause energy efficiency penalties. The costs for carbon capture today for all coal technologies are substantial and would increase the cost of electricity significantly. The National Coal Council believes that a strong cooperative program between government and industry to drive technology innovation is critical to determine the viability of lower cost CO₂ capture for both combustion and gasification. This program

is a prudent measure to provide policymakers with solid scientific facts about costs and technology performance upon which to base future decision-making related to control of carbon emissions.

Due to higher concentrations of CO₂ and higher operating pressures of IGCC, the costs of CO₂ capture from an oxygen-fired IGCC would be lower than the capture costs for a supercritical pulverized coal (SCPC) using the mature monoethanolamine (MEA) capture processes commercial today. Because IGCC has a higher capital cost than PC, this advantage is counteracted somewhat in the overall levelized costs for each technology and the difference narrows for lower rank fuels. If CO₂ capture were required today, IGCC would provide the lowest leveled cost of electricity for bituminous fuels. For lower rank fuels, such as lignite, the levelized costs for SCPC with commercial amines and IGCC with CO₂ capture are competitive. Nevertheless, with today's capture technologies, CO₂ capture would be expensive in all cases.

However, as the DOE has stated:

“Opportunities for significant cost reduction (for carbon capture from combustion and gasification power plants) exist since very little R&D has been devoted to CO₂ capture and sequestration technologies. Several innovative schemes have been proposed that could significantly reduce CO₂ capture costs, compared to conventional processes.”

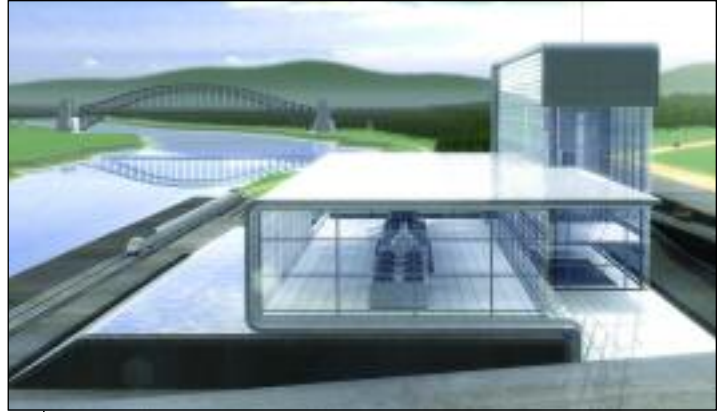
Examples of advanced technologies for post-combustion capture include advanced amines, ammonia scrubbing, and a variety of other promising solvents; these technologies are in the process of development, scale-up or demonstration. Oxygen fired PC and CFBC would allow for sequestration of the total flue gas without the need of CO₂ separation. The requirements of flue gas cleanup for this case are less stringent than those for gas turbine entry. Advanced CO₂ capture for IGCC includes improvements to the water-gas shift reaction and hydrogen separation. Preliminary studies and analyses by DOE, EPRI, the Canadian Clean Power Coalition and others indicate that advanced capture processes, applied to SPC or supercritical circulating fluidized bed (SCCFB), could result in competitive electricity costs between combustion technologies and gasification technologies with carbon capture. With the commercialization of these advanced capture processes, the selection of a coal power technology with carbon capture could be based on fuel, operational and site specifics, thus providing generation companies with a solid portfolio of proven and reliable options for near zero emissions power.

During the next decade, federal and state government and industry must work together to develop the protocols to support sequestration and storage.

During this time, support for innovations in capture technologies is equally important to reduce costs and power usage for both combustion and gasification technologies in order to minimize overall impacts on electricity costs for CO₂ capture.

Re-Powering with Coal

High NG prices have forced many electricity producers to shut down their natural gas combined



cycle plants for extended periods of time. Figure 3.11 illustrates that there are a large number of natural-gas-fired electricity generation plants (marked in blue) that have relatively low capacity factors. Converting some of these facilities to coal would allow the additional electricity production from coal, leading to lower electricity prices.

The decision to convert an NG plant to coal involves many financial, site suitability, environmental, performance and technical issues. The conversion itself involves the alteration of the combined cycle power equipment to utilize the lower-Btu fuel from coal. Construction of a gasification plant with oxygen-blown systems produces a higher Btu fuel but is more complex and expensive than an air-blown gasification system.

From an economic perspective, refueling allows lower operating costs by substituting lower-cost coal for high-cost NG but requires capital investment for the turbine modifications and the gasification plant. If the gasification facility is financed and constructed as a separate fuel-gas supply entity, the overall cost of the produced fuel-gas can be as low as 35–40% of current NG prices.

In general, the fuel switching should be considered only as a fuel change with some positive and only slightly negative emissions impacts. Fuel switching may require renegotiation of environmental permits and potentially reopening public discussion. Local public and infrastructure impact from coal transport also may be an issue. Clearly, for those locations where the natural gas combined cycle plant was established primarily for environmental reasons,

the difficulty of obtaining a permit to re-power may increase. It is important to note that for coal gasification plants, emissions are normally well within the ranges of NG and are certainly within Reasonably Available Control Technology limits—a benchmark in the permitting process.

A prime consideration in the conversion decision is the accessibility and availability of coal supply. The site must accommodate the logistics of coal delivery, off-loading, coal preparation, and storage of coal, re-agents, byproducts (or ash in the case of air-blown systems), and sulfur. In some cases, new environmental permits will be required. Public support for the use of coal at the site is another critical element.

When smaller natural gas combined cycle (and cogeneration) plants are considered, there are several hundred candidates for refueling. Not all of these plants can be converted due to limited access to coal

supply and necessary transportation. In the short term, there are many such plants within 50 miles of a coal mine and/or 50 miles of a large coal-fired power station. If the universe of possible natural gas combined cycle refueling plants is expanded to those with reasonable access to coal infrastructure, the short-term number of possible refueling sites can be expanded to well over 100. Longer term, if NG prices remain substantially above coal prices, as expected, firms will make the necessary infrastructure investments to convert even more natural gas combined cycle plants to coal.

FutureGen

The FutureGen Industrial Alliance is a coalition that is partnering with the U.S. Department of Energy to design, construct and operate the cleanest coal-fueled power plant in the world, using gasification generation technology with a target of zero emissions (see Figure 3.12). FutureGen will use advanced coal-based technologies to generate electricity to produce

The Path to Ultra-Low Emissions from Coal-Fueled Generation Plants

Emissions from U.S. Coal-Fueled Generation Plants

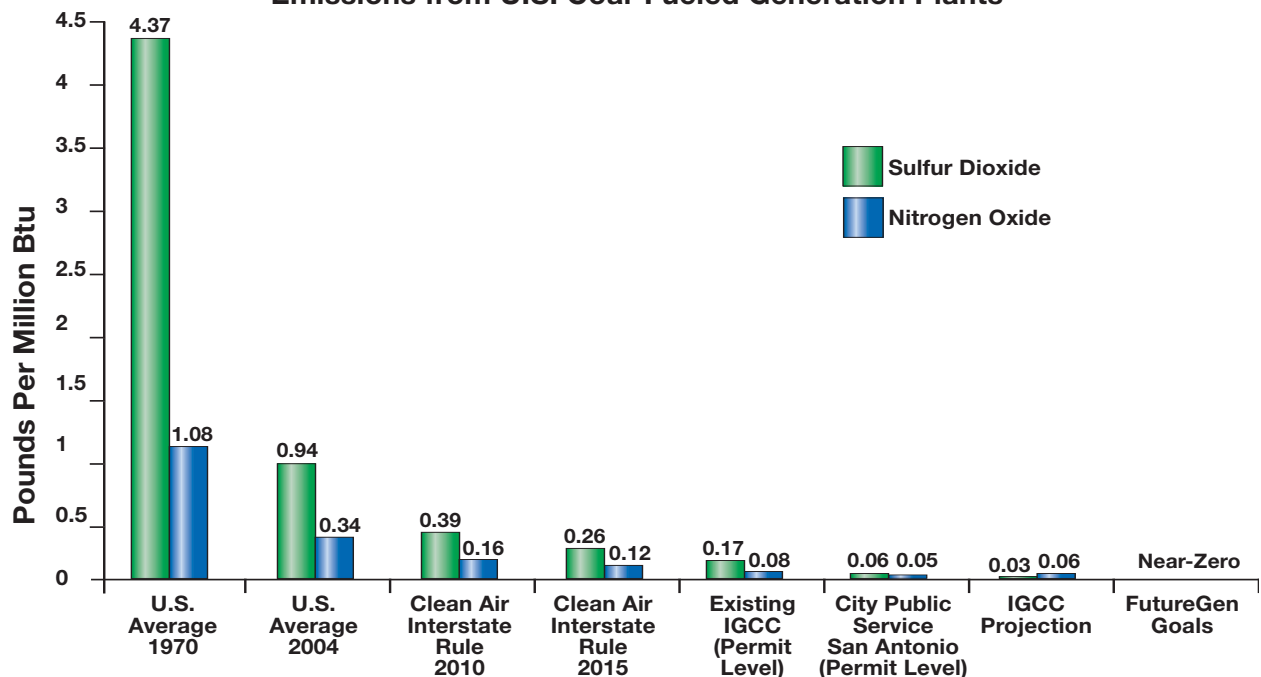


Figure 3.12 Source: EPA's Clean Air Markets Database; EIA Annual Energy Outlook 2004; GE Energy; SFA Pacific

hydrogen to power fuel cells for transportation and capture and permanently store the carbon dioxide that is produced in the process. In his 2006 State of the Union address, President Bush spotlighted this effort: “To change how we power our homes and offices, we will invest more in zero-emission coal-fired plants.”

The Alliance and the DOE are partnering in all development aspects of the \$1 billion project, including siting, technology selection, construction and operation. The Alliance and the DOE are pursuing an aggressive schedule that includes announcing a site selection process in 2006, beginning construction within three years and targeting plant operations in 2012.

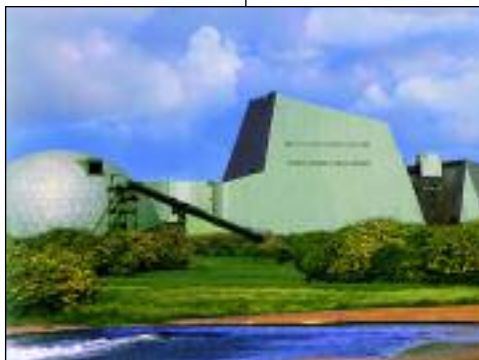
The Alliance is a non-profit corporation that represents a global coalition of the world’s largest coal and energy companies with operations on five continents. Members of the Alliance, who have voluntarily committed more than \$250 million to help fund project development, include the U.S. companies American Electric Power, BHP Billiton, CONSOL Energy Inc., Foundation Coal, Kennecott Energy, Peabody Energy, Southern Company, the British company Anglo-American, and the Chinese company China Huaneng Group. The U.S. government will invest about \$700 million in the project. Formation of the FutureGen Alliance was coordinated by Battelle, a non-profit research and development institution.

CONCLUSION

The United States is an electrical society, and electricity demand will continue to increase in the future even more than it has in the past. Increasingly, NG is being used for new plants and incremental growth. This trend has pushed up prices for NG, increasing the price of electricity and space heating for consumers as well as for industrial users. Projections show a significant gap between domestic supply of NG and demand in the coming decades. While it is widely assumed that imports will make up the difference, there are many real questions as to

whether sufficient quantities of LNG will be available at all or at an economical price.

By constructing 100 GW of new clean-coal electric generating plants utilizing a range of technologies to match diverse coals and site requirements, the United States can utilize its greatest domestic energy resource, reduce its dependence on NG for electricity production (thereby reducing supply/demand pressures on NG prices for homes and industry), and prevent growth in dependence on LNG imports from risky suppliers.



These new plants can be built with high efficiency designs, using state-of-the-art emissions controls to provide clean, economic and reliable electricity. The U.S. coal-based generating fleet has made great strides in improving its emissions profile and will continue to drive toward near zero emissions with subsequent advancements.

Both advanced combustion and gasification technologies will continue to improve. The speed of these improvements can be significantly increased by continued support of the federal government in basic R&D (such as advanced materials and innovative process designs) and in demonstration of technologies with Canadian Petroleum Products Institute (CPPI) and FutureGen. These advancements offer an improved U.S. environment and the ability to export those technologies to help improve the global environment and our balance of trade.

FutureGen, for example, is a significant step in advancing the ability of the United States to use its vast domestic resources of coal with near-zero emissions and will be an international example of environmental stewardship. We must, however, also maintain our efforts in other critical R&D and demonstration programs, including CCPI, to ensure a timely introduction of both gasification and advanced combustion technologies to the U.S. marketplace. The energy issues facing our nation are critical and they warrant a world-class response at the federal level.

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COAL TO PRODUCE ETHANOL

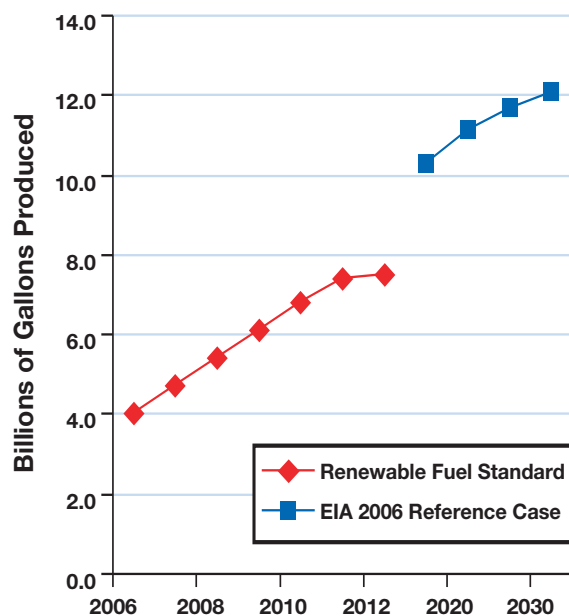


The United States is committed to expanding the use of ethanol to displace a significant amount of foreign oil as a transportation fuel. Currently, natural gas, diesel fuel and electricity are used to produce ethanol. But the ethanol industry is ready to embrace coal as a fuel source.

Increasing the use of coal for heat and electricity in the production of ethanol would reduce costs and displace oil and NG by significant amounts while utilizing an additional

40 million tons of coal per year, thereby freeing up NG for other uses and relieving price pressures.

Projected Future of Biofuels
Renewables Expected to Continue Growth



Source: EIA AEO 2006 Reference Case

FINDINGS

The United States is committed to expanding the use of ethanol to displace a significant amount of foreign oil as a transportation fuel. Currently, NG, diesel fuel and electricity are used to produce ethanol. But the ethanol industry is ready to embrace coal as a fuel source. Increasing the use of coal for heat and electricity in the production of ethanol would reduce costs and displace oil and NG by significant amounts while utilizing an additional **40 million tons** of coal per year, thereby freeing up NG for other uses and relieving price pressures.

DISCUSSION

The United States is committed to expanded use of ethanol to supplement transportation fuels. Four examples illustrate the institutional breadth of that commitment, including the 2006 State of the Union address, the Energy Policy Act of 2005, the American Jobs Creation Act of 2004, and the Governors' Ethanol Coalition of 2005.

State of the Union address solidifies the Bush Administration's position

In his 2006 State of the Union address, President Bush called for the accelerated development of ethanol production:

"We must also change how we power our automobiles... We'll also fund additional research in cutting-edge methods of producing ethanol, not just from corn, but from wood chips and stalks, or switch grass. Our goal is to make this new kind of ethanol practical and competitive within six years."

Energy Policy Act of 2005 doubles ethanol use

The Energy Policy Act of 2005 included a nationwide renewable fuels standard (RFS) that requires the production and use of 7.5 billion gallons of renewable fuels by 2012. This Act includes grant and loan guarantees for cellulose ethanol and for ethanol production from sugar. The RFS also includes 250 million gallons per year of cellulosic ethanol beginning in 2013. Figure 4.1 depicts the RFS mandate, the motor gasoline demand and the

potential demand for ethanol assuming a 10% blend of ethanol based on EIA projections (AEO2006) out to 2030.

American Jobs Creation Act ensures strong ethanol demand

The American Jobs Creation Act of 2004 included a number of provisions that will ensure strong demand for ethanol over the next several decades. For example, the Act created the Volumetric Ethanol Excise Tax Credit (VEETC) to ensure that Highway Trust Fund (HTF) revenues would not be adversely impacted by ethanol use. Further, VEETC makes ethanol blending flexible for petroleum companies and more accessible for growing markets such as E85, E diesel and fuel cells.

VEETC also extends the ethanol tax incentive at \$0.51 per gallon through 2010, creates a new biodiesel tax incentive, and improves the small ethanol producer tax credit to allow a farmer cooperative to pass the credit along to its farmer owners.

Projected Future of Biofuels Renewables Expected to Continue Growth

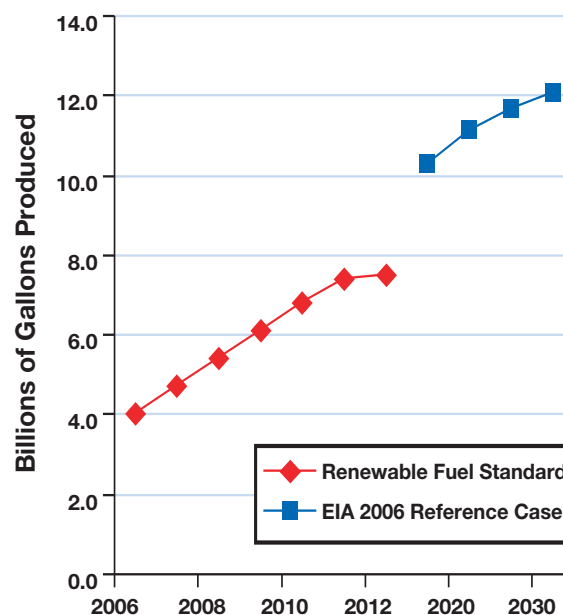


Figure 4.1 Source: EIA AEO 2006 Reference Case



Governors' Ethanol Coalition expands ethanol production

The Governors' Ethanol Coalition has called for significant expansion of ethanol production as a major step in improving national "energy, economic and environmental security." The Coalition has proposed that at least 5% of the nation's transportation fuel come from ethanol by 2010 and 10% as soon as possible after that. The Coalition recommended that (a) \$800 million be dedicated to research and development over the next decade, and (b) the federal government offer market-based production incentives to support large-scale operations resulting in production of 1 billion gallons of biomass-derived ethanol a year at a cost competitive with gasoline and diesel fuel.

It is clear from these examples that the increased production of ethanol has broad institutional support within the political structure of the United States, leading to a dynamic and growing industry.

Growth in the Industry

There has been record growth in the U.S. ethanol industry over the past several years. In 2004, 81 ethanol plants located in 20 states produced a record 3.41 billion gallons, a 21% increase from 2003 and a 109% increase since 2000.

Construction of 12 new ethanol plants was completed in 2004. These new facilities, combined with expansions at existing plants, increased annual production capacity by 500 million gallons to over 3.6 billion gallons. At the end of 2004, 16 plants and

two major expansions were under construction, representing an additional 750 million gallons of production capacity. In 2004, dry mill ethanol facilities accounted for 75% of U.S. ethanol production, and wet mills 25%.

In 2005 the total capacity reached over 4 billion gallons per year with 95 ethanol refineries nationwide. At year-end 2005, there were 29 new plants and nine expansions under way with a combined annual capacity of 1.5 billion gallons. Importantly, as

the industry expands, new refineries are being built outside the traditional Corn Belt, including California, North Carolina, Arizona, Texas and New Mexico.

Biodiesel production is expanding as a result of EPAct2005 also. Today, there are 38 biodiesel plants under construction and another four expanding that will add more than 320 million gallons of new capacity to that fledgling industry, which in 2005 produced only about 75 million gallons.

As is evident from Figure 4.2, more than 80% of the online production capacity is located in five

Ethanol Production Capacity Production Centralized in the Midwest

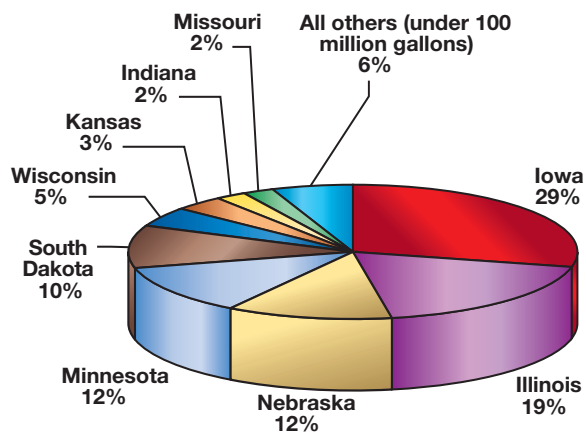


Figure 4.2 Source: Renewable Fuels Association, January 2006

COAL TO PRODUCE ETHANOL

states: Iowa, Illinois, Nebraska, Minnesota and South Dakota.

From the institutional support described earlier and the increasing amount of funds flowing to the industry, one can assume that growth will accelerate over the next several years. The Annual Energy Outlook 2006 states that the industry can grow to at least 12 billion gallons per year without having an impact on the price of corn for food.

Coal as the Fuel Source for Ethanol Production

Ethanol production requires significant amounts of energy. Ethanol facilities include both dry- and wet-milling operations. Dry mills are usually smaller than wet mills and are built primarily to produce ethanol. Wet mills are bio-refineries and produce a wide range of products such as ethanol, high fructose corn syrup (HFCS), starch, food and feed additives, and vitamins. Heat and electricity are the main types of energy used in both types of processing plants.

Figure 4.3 shows the energy required for each stage in the production of ethanol from corn. The energy demand is dominated by the ethanol conversion process (69%) and by the corn production process (26%), which includes all of the farm inputs.

Wet mills usually generate both electrical and thermal energy from burning natural gas or coal. In AEO2006 wet mills are assumed to have combined heat and

power plants that can burn coal or natural gas. Average fuel consumption is assumed to be 40,800 Btu of coal per gallon of ethanol and 10,200 Btu of natural gas per gallon.

Dry mills use natural gas and coal to produce steam and purchase electricity from a utility. AEO2006 assumes 36,900 Btu per gallon in 2006, declining to 35,000 Btu per gallon by 2020. Electricity use is 1.1 kWh (3700 Btu) per gallon. Process energy for existing dry mills is assumed to be half coal and half natural gas. New dry mills are assumed to use only natural gas.

Currently, the bulk of energy used to produce ethanol comes from NG and electricity. Coal, however, has the potential to significantly contribute to the process and deliver a wide array of benefits relative to NG:

- **Cost** — In 2004 the cost of NG to industrial users was \$6.10 per million Btu (MMBtu), while the cost of coal was \$1.74. Further, the EIA projects that in 2025 the industrial cost of NG will be \$5.99, but coal will only be \$1.86.
- **Stability** — Coal is our most price-consistent fossil fuel. NG is our most price-volatile and unpredictable fuel. In 2005 alone, NG ranged from \$5.75 to over \$15.00 per Mcf. No industry can confidently plan fuel costs and production in such a chaotic price environment. Coal will bring price predictability to the ethanol industry.

Energy Use per Gallon (Btu/Gallon) Without Co-Product Energy Credits, 2001

	Dry Mill	Wet Mill	Weighted Average	Percent of Total
Corn Production	18,875	18,551	18,713	26%
Corn Transport	2,138	2,101	2,120	3%
Ethanol Conversion	47,116	52,349	49,733	69%
Ethanol Distribution	1,487	1,487	1,487	2%
TOTAL ENERGY USED	69,616	74,488	72,053	100 %

Figure 4.3 Source: USDA 2004



- **Availability** — Coal is a home-grown fuel with substantial reserves and growing production. NG supply is dependent on ever-increasing imports and production is declining.
- **Reliability** — Coal gives ethanol producers the opportunity to sign long-term contracts. Few, if any, long term contracts for NG supply are available to small producers.
- **National Security** — As the Governors' Ethanol Coalition noted, increased ethanol production is an important step toward improved national security. Utilizing coal as a major fuel source for ethanol production eliminates the need to import NG for the process.
- **Socioeconomic Benefits** — Using domestic coal to produce ethanol will create jobs, spur new businesses and generate tax revenues for local communities.

- **Accelerated Ethanol Production** — The U.S. has ambitious plans to rapidly grow ethanol production, but the scale of this growth will depend upon the availability of an economical fuel source. Events over the past few years have painfully demonstrated that NG is not that fuel. By virtually any measure, coal should be the preferred fuel to produce ethanol.

Ethanol Production Turns to Coal as Fuel Source

Increasingly, ethanol producers are recognizing the benefits of coal. A number of facilities that will use coal are currently under construction. The following descriptions present the nature of these new facilities and why the firms involved have turned to coal to produce ethanol. Direct comments from local producers demonstrate the “real world” rationale for coal:

Illini Bioenergy (Logan County, Illinois)

- **Ethanol Production Capacity** — The plant as designed will produce 50 million gallons of ethanol each year, which will be marketed across Illinois and the U.S. as a clean-burning, high-octane transportation fuel additive.
- **Corn Usage** — The plant as designed will create demand for 18 million bushels of corn each year.
- **Distillers Grains** — As a co-product of ethanol production, the plant as designed will produce 168,000 tons of distillers dried grains with solubles (DDGS) annually, which will be marketed to livestock and poultry producers as a value-added nutritional supplement.
- **Energy Costs** — Coal integrated technology by ICM will result in reduced power costs compared to natural gas-powered facilities of similar size.

Central Illinois Energy (Canton, Illinois)

- **Costs** — The total projected cost of the Central Illinois Energy ethanol facility is approximately \$90 million. The construction of the plant accounts for \$49 million. Another \$28 million will be used to construct a waste coal co-generation facility, and



\$13 million will be used for site work, start-up costs and working capital.

- **Benefits to Farmers** — Central Illinois Energy will create a demand for corn in a market where prices have not kept up with inflation. To farmers who deliver their corn wet, it will mean a savings of approximately 40 cents per bushel. To the rest, it will afford the same price they would have received if they had transported their corn to the river.
- **Benefits to the Community** — The construction of Central Illinois Energy will bring a great deal of economic activity to the Canton area. Temporary workers will bring business to local hotels, restaurants and other establishments. Some local workers will find employment, and local companies could receive subcontracts associated with the project. Once the plant begins operating it will supply greater, more lasting benefits to the community. It will create approximately 45 full-time positions with an average salary around \$44,000 a year. The money generated will stay in

the community. And the ethanol plant will serve as a cornerstone for future businesses such as CO₂ production and provide opportunities for livestock enterprises to expand or move back into the Central Illinois area.

- **Remote Participation** — Farmers who are too far from Central Illinois Energy to deliver their own corn can still participate. They can sell their corn at a local elevator and use the money to buy corn close to the plant. That corn can then be delivered on their behalf. Central Illinois Energy will work with members and local elevators to ensure that the committed corn will be delivered to the plant.
- **Waste Coal Co-Generation Facility** — Central Illinois Energy will provide its own steam generation and electricity used by utilizing waste coal that is abundant in the area. By utilizing waste coal instead of natural gas, a significant savings in energy expense is realized. Energy expenses are the second largest expense in ethanol production. The cost of the corn used is the largest.

- **Carbon Dioxide (CO₂)** — Central Illinois Energy is currently in negotiations with three nationally known carbon dioxide processors. One of these processors will capture the carbon dioxide that is generated as a result of the fermentation process during ethanol production. By utilizing the CO₂, every part of the kernel of corn in the corn-to-ethanol process is being used.

Midwest Ethanol Producers (O'Neill, Nebraska)
Midwest Ethanol Producers (MEPI) is in the process of development and construction of a 50-million gallon per year ethanol plant to be located east of O'Neill at a cost of \$95 million.

By constructing a state-of-the-art economically and technically advanced plant, MEPI will be able to compete with the most successful producers in the market. **The use of coal to supply power to the facility, a new trend in the ethanol industry, is expected to reduce ethanol production energy costs by up to 60%:**

“Plant management can lock in coal contracts to help control and significantly lower energy costs. Natural gas prices fluctuate daily and have been near record highs in 2004. The investment in coal to obtain 1 million Btus is about one-third of the cost of 1 million Btus produced from natural gas. At current costs, the use of coal rather than natural gas will result in \$5 million in savings annually. This savings goes straight to the bottom line, accelerating the return on investment.

Coal-fired plants are equipped with modern technology to control emissions. They must comply with the same environmental standards as natural gas-powered plants and must meet the same strict permitting standards. By using coal, we are taking an energy source that is not used for transportation fuel purposes (coal) and transforming it into a clean-burning transportation fuel that helps America increase its fuel supply, lower its dependence on imported oil, and improve its air quality.

The use of coal as a primary energy source was influenced by the continued volatility and

escalation in the cost of natural gas (the primary energy source used in all other plants). Coal can be contracted at current prices (estimated to be \$1.75 per million Btus) for seven to ten years. Conversely, the average price of natural gas on the NYMEX for Jan. 1, 2006 – March 2010 is about \$7.25 per million Btus and the price can fluctuate daily.”

Missouri Ethanol LLC (Ladsonia, Missouri)
Midwest ethanol production will expand with the recent groundbreaking of the Missouri Ethanol, LLC plant in Ladsonia, Missouri. In addition, industry officials announced plans to build another facility in the southeastern region of the state.

Once completed, the two plants would more than double the amount of ethanol currently produced in the state. Missouri Ethanol will produce 45 million gallons of the fuel annually and will consume over 17 million bushels of corn from the region. The plant is expected to employ approximately 40 people with a payroll of \$1.8 million.

The state's corn industry group predicts that the plant will also improve the local corn industry and generate 134,000 tons of distiller's grain, which is a high-protein animal feed. Missouri Ethanol is expected to begin production in the fall of 2006.

In addition to the groundbreaking event in northeast Missouri, plans for Bootheel Agri-Energy were announced recently at the airport in Cape Girardeau, Missouri. The coal-fired ethanol plant could produce 100 million gallons of ethanol a year.

Since the first ethanol plant was built in Missouri, the cost of natural gas has increased more than 500%. The design of Bootheel Agri-Energy seeks to avoid skyrocketing natural gas costs by instead utilizing coal from local sources.

Great Rivers Energy and Headwaters Ethanol Project

North Dakota Governor John Hoeven announced that Headwaters Incorporated has completed a non-binding memorandum of understanding with Great River Energy to build a new state-of-the-art



Archer Daniels Midland (Columbus, Nebraska)

A 275 million-gallon expansion of an existing ethanol plant in Columbus, Nebraska has been announced by Archer Daniels Midland. The dry milling plant will use coal combined heat and power.

Coal as the Fuel Source for Future Ethanol Production

These examples from the producers actually implementing the ethanol production increases called for by the President,

Congress and multiple governors

\$65 million ethanol plant on land adjacent to Coal Creek Station near Underwood, North Dakota. The plant would begin operation the fall of 2006.

“The ethanol incentives that we have put in place—including marketing incentives, investment tax credits, and a counter-cyclical production incentive for new ethanol plants—are now beginning to produce real results,” says Hoeven. “This is the second venture announced in the state in the past week. Together, they mark the next chapter in a new era of energy development in North Dakota.” The ethanol plant would use waste steam from Coal Creek Station as part of the process to make ethanol.

The ethanol plant would produce 50 million gallons of ethanol per year and would require 18 million bushels of corn per year, with much of it coming locally and from southeast North Dakota. The plant would also produce enough dried or wet distillers grain for approximately 225,000 feeder cattle on an annual basis.

The economic impact of the plant would be significant, as it would require 200 jobs during construction, and approximately 30 jobs when operating. The economic impact of the plant would be about \$160 million on an annual basis.

are indicative of the promise of coal. The United States should base the bulk of future ethanol production on coal and convert the existing demands on imported natural gas to coal. This wholly domestic fuel can serve as the energy source for both heat and electricity as well as the feedstock for fertilizer. The targets for transforming production of ethanol by using coal-derived energy and fuels include:

- All new capacity should use coal combined heat and power (CHP);
- All existing facilities should be converted to coal CHP by 2015; and
- All farm inputs, including fertilizer, should be coal-derived by 2020.

The Renewable Fuels Association concludes that the RFS will displace more than 2 billion barrels of oil through 2012.

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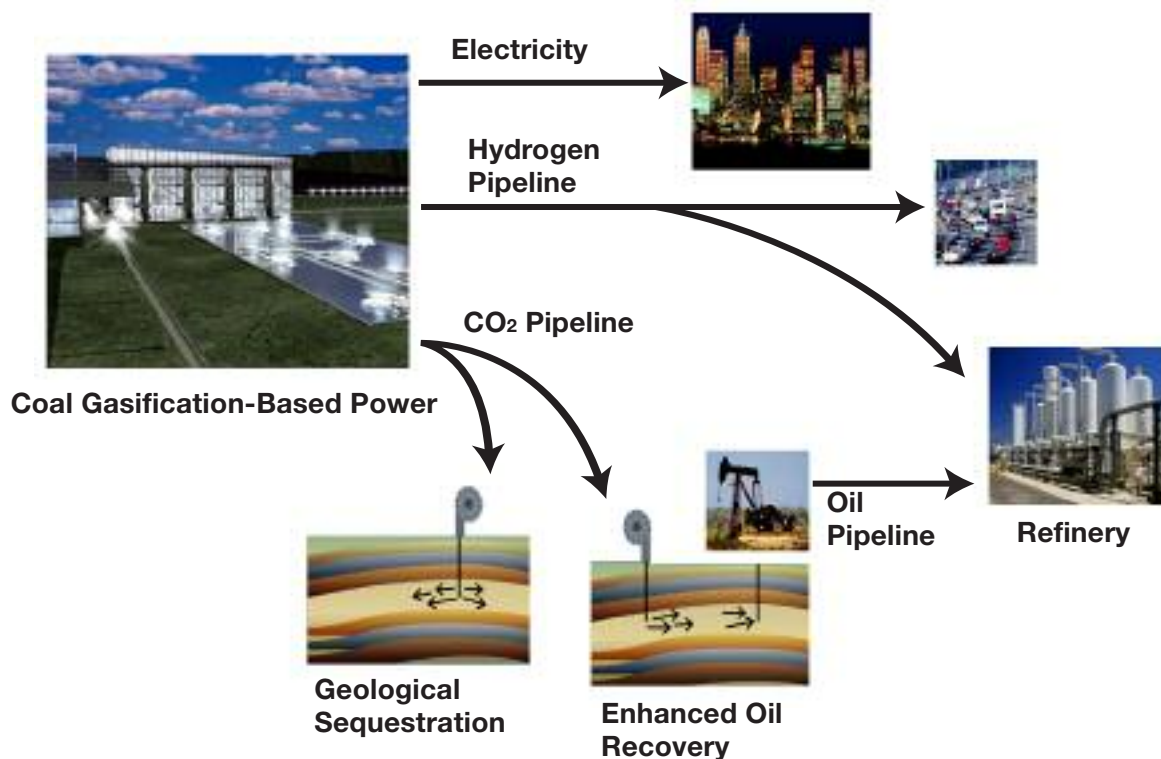
COAL-TO-HYDROGEN



The United States has identified the Freedom Fuel and FreedomCAR Initiatives as ways to transition the country to a hydrogen economy and use coal-fueled energy to power fuel cells. Development of a fleet of coal-to-hydrogen plants would mean that coal could satisfy at least 10% of the nation's transportation needs with FreedomCAR efficiencies. This application would use an additional **70 million tons** of coal per year.

FutureGen: Clean Coal & New Markets

\$700 Million U.S. Government & \$250 Million Industry Investment



Source: FutureGen Industrial Alliance

FINDINGS

The United States has identified the Freedom Fuel and FreedomCAR Initiatives as ways to transition the country to a hydrogen economy and use coal-fueled energy to power fuel cells.

Development of a fleet of coal-to-hydrogen plants would mean that coal could satisfy at least 10% of the nation's transportation needs with FreedomCAR efficiencies. This application would use an additional **70 million tons** of coal per year.

DISCUSSION

President George W. Bush's January 28, 2003 State of the Union address introduced the American people to the concept of a hydrogen economy. The President described a technology that would allow cars to run on hydrogen, a plentiful element found everywhere that produced no byproduct other than water. He pledged significant governmental financial support for expanded research and introduced the \$1.2 billion Freedom Fuel Initiative. Combined with the FreedomCAR (Cooperative Automotive Research) program, President Bush proposed \$1.7 billion over the next five years to develop hydrogen-powered fuel cells, hydrogen infrastructure and advanced automotive technologies.

By using fuel cell technologies, hydrogen can be used to power any electrical equipment, including electric motors, consumer electronics and electrical equipment in homes. Unlike electricity, hydrogen can be produced and stored if demand is not immediate. Nevertheless, significant technological, safety, logistical and cost issues must be solved before this vision can become a reality.

Unlike fossil fuels, hydrogen is not found as an element in its "natural" state. Hydrogen occurs naturally only in chemical compounds, predominantly water, and must be produced through chemical reactions. Hydrogen, like electricity, is a carrier of energy and, like electricity, is generally produced from a fuel. That production requires

energy, and current technology typically uses natural gas (NG) or other fossil fuels for economic reasons.

Once produced, hydrogen has the highest energy content per unit weight of any known fuel at ~61,200 Btu/lb. For example, a 15-gallon automobile gas tank carries ~92.25 pounds of fuel (using 6.15 lb/gal for gasoline). The amount of hydrogen with the same energy content would weigh only 29.77 pounds, taking gasoline at 19,745 Btu/lb and hydrogen at 61,175 Btu/lb. Hydrogen is also the lightest element. As a result, while the 15 gallons of gasoline occupy only about two cubic feet (at 70°F and 1 atmosphere pressure), 29.77 pounds of hydrogen occupies approximately 5,359 cubic feet at the same conditions. It is possible for 29.77 pounds of hydrogen to occupy two cubic feet, but in order to do



so, the hydrogen must be placed under approximately 39,000 lbs of pressure, which is an expensive process with the currently available technology.

Hydrogen's heat content is four to five times that of coal, yet **coal is the least expensive fuel to produce large quantities of hydrogen.** With continued research, development and commercialization of successful carbon capture and storage technologies,

coal will serve as the cornerstone of the hydrogen economy, characterized by energy independence and a reduction of air pollution and greenhouse gas emissions.

Current Hydrogen Production and Infrastructure

The United States produces and uses approximately 9 million tons per year of hydrogen, representing about 25% of global production and use. Most production (7.5 million tons) is utilized at the place of manufacture (“captive” hydrogen). The remaining 1.5 million tons are sold for commercial use (“merchant” hydrogen).

The hydrogen infrastructure consists of production, delivery, storage, conversion and end-use applications. Further development of this infrastructure faces real hurdles at every step in the chain. Major public and private research initiatives in the United States and abroad are under way to address the challenges.

Production

There are two proven methods for hydrogen generation. In locations where electricity is cheap and plentiful, hydrogen can be produced from the electrolysis of water. This approach is extremely rare in the commercial hydrogen market and is generally used only to produce high purity hydrogen.

The second method is the production of hydrogen from a carbon-containing fuel. Currently, the fuel of choice for 95% of domestic hydrogen production is natural gas; however, lower-priced coal could be used in the same basic process. The process involves two steps: steam reforming and water-gas shift.

- **Steam Reforming** — The fuel is reacted with water (steam) to generate a stream of carbon oxides and hydrogen. In the case of natural gas, this reaction takes place directly in the presence of a catalyst to produce carbon monoxide and hydrogen. When natural gas is used, this process is called steam methane reforming (SMR). When using other fuels (petroleum products and coke, biomass, coal, etc.), the fuel is first “gasified” (partially



burned with oxygen) in the presence of steam to produce a stream of carbon monoxide, carbon dioxide and hydrogen. The carbon dioxide is removed from this stream before further processing.

- **Water-Gas Shift** — Regardless of how the steam reforming step is accomplished, the final step is to take the resulting mixture of carbon monoxide and hydrogen and react it with additional steam over an appropriate catalyst to produce carbon dioxide and additional hydrogen.

Research on a biological path to hydrogen production is currently under way.

Approximately 20% of hydrogen is centrally produced for sale and distribution and is transported through pipelines or via cylinders and tube trailers. This merchant hydrogen production occurs primarily on location at 80 U.S. plants, which are operated by four companies. To date, only Texas, Louisiana,

How They Work: PEM Fuel Cells

There are several kinds of fuel cells, but Polymer Electrolyte Membrane (PEM) fuel cells—also called Proton Exchange Membrane fuel cells—are the type typically used in automobiles. A PEM fuel cell uses hydrogen fuel and oxygen from the air to produce electricity.

Hydrogen fuel is channeled through field flow plates to the anode on one side of the fuel cell, while oxygen from the air is channeled to the cathode on the other side of the cell.

At the anode, a platinum catalyst causes the hydrogen to split into positive hydrogen ions (protons) and negatively charged electrons.

The Polymer Electrolyte Membrane (PEM) allows only the positively charged ions to pass through it to the cathode. The negatively charged electrons must travel along an external circuit to the cathode, creating an electrical current.

At the cathode, the electrons and positively charged hydrogen ions combine with oxygen to form water, which flows out of the cell.

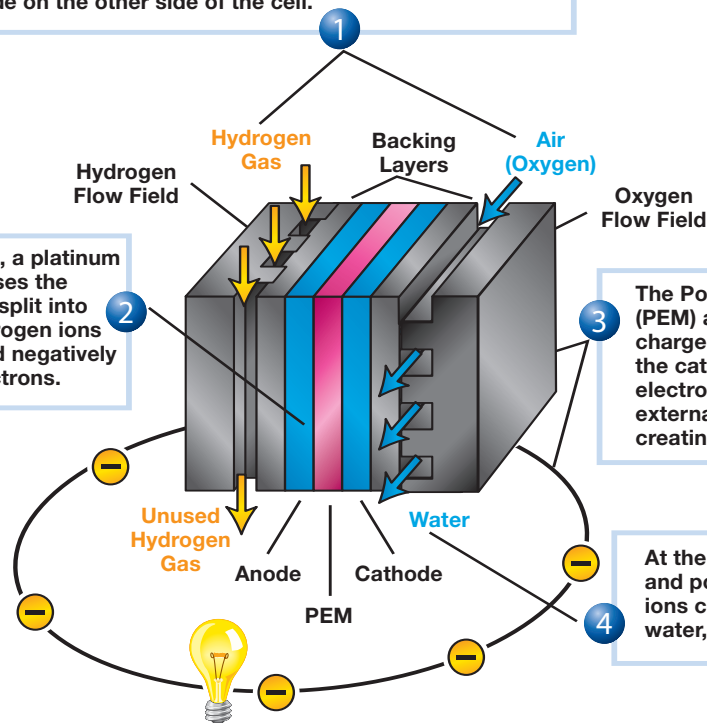


Figure 5.1 Source: DOE

California and Indiana have usable hydrogen pipelines. One drawback to using pipelines to convey hydrogen is a phenomenon called hydrogen embrittlement, which weakens the carbon steel pipes. In response to concerns about the possible deterioration of pipelines, industry leaders are currently developing alternate delivery options, including converting the hydrogen into compounds or chemical forms before transport.

In addition to pipelines, hydrogen is also distributed by means of cylinders and tube trailers, which travel by ground and waterway transportation. Trucks, railcars and barges carry containers of hydrogen, which is liquefied for long-distance distribution of up to 1,000 miles. Once on-site, the hydrogen is then usually vaporized for use. The liquid hydrogen

production capacity of 11 plants in North America is 283 tons per day.

A variety of technologies make it possible to store hydrogen as a gas, as a liquid, or in a chemical compound. The most mature method of hydrogen storage is to use tanks to hold the gas form, but because hydrogen is the lightest element, it has extremely low density and thus requires a larger storage space than many facilities are equipped to handle. The storage volume requirement can be mollified by compressing the hydrogen gas to higher pressures, or by mixing it with other compounds. When hydrogen has been liquefied, it is less voluminous and can be stored in cryogenic containers, but the process of liquefaction requires

enough electric power to equal one-third the energy value of the hydrogen.

It is possible to combust hydrogen in the same manner as gasoline or NG. Because water is the major by-product of hydrogen combustion, this process releases far fewer emissions than does fossil fuel combustion. In contrast to fossil fuel combustion, hydrogen combustion emits low levels of nitrogen oxides and no carbon dioxide. Both the National Aeronautics and Space Administration (NASA) and the Department of Defense use this technology for applications, including the space shuttle's main engines and unmanned rocket engines.

Fuel cells utilize the chemical energy of hydrogen to produce electricity and thermal energy (see Figure 5.1). Water is the only by-product they emit if they use hydrogen directly. Since electrochemical reactions generate energy more efficiently than combustion, **fuel cells can achieve higher efficiencies than internal combustion engines.** Current fuel cell efficiencies range from 40–50%, but higher efficiencies can be achieved in combination with heat and power applications. Because fuel cells are composed of positive and negative electrodes, they are similar to batteries. Batteries, however, store electricity, while a fuel cell actually produces electricity by reacting hydrogen with air across a membrane. Distinguishing characteristics of fuel cells include their electrolyte, operating temperature and the level of hydrogen purity required.

Traditional, proven uses for hydrogen include:

- production of ammonia for fertilizer (approximately 66% of U.S. consumption)
- petroleum refining (the breakdown of heavier crude oils and the removal of sulfur)
- hydrogenation of fats and oils (e.g., shortening)

- welding
- preventing oxidation in semiconductor manufacturing
- cooling turbines
- fuel (overwhelmingly used in the space program, including the space station's main engine and the onboard fuel cells that provide the space shuttle's electric power)

Hydrogen can be stored in its elemental form as a liquid, as a gas, or as a chemical compound, and it is converted into energy through fuel cells or by combustion in turbines and engines.

Research and development attention to the use of hydrogen in fuel cells is substantial, especially with regard to stationary, transportation and portable devices. Hydrogen fuel cells can be used for distributed generation, among other things. Phosphoric acid fuel cells are already operational, providing heat and power for buildings and industrial applications. These units include a reformer component that generates a hydrogen-rich gas from NG.

Fuel cell vehicles are being tested and developed for use in the transportation sector, a growing venue



for the application of this technology. In order to utilize hydrogen energy in vehicles, a compact power system and refueling stations are also needed. For this reason, municipally owned buses are the most common hydrogen-powered vehicle; their size enables them to carry large tanks of hydrogen, and the city usually structures the bus routes to refuel at a single location. American locales have used this technology for years; Chicago became the first U.S. city to use hydrogen fuel cells to power buses in its public transit system in March 1998, and today the state of California has seven such buses in operation through the California Fuel Cell Partnership.

Portable fuel cells can also be used to power small devices such as mobile telephones or personal computers. Larger power generators for recreation and other off-grid applications are under development.

These and other applications are currently being researched and demonstrated. However, significant hurdles exist in every element of the hydrogen infrastructure:

- **Lowering the Cost of Producing Hydrogen** — Currently, hydrogen is four times as expensive to produce as gasoline (when produced using NG at 2003 prices).
- **Delivery** — There is no established network in place to deliver hydrogen to the consumer and only limited options for commercial delivery.
- **Storage** — Hydrogen is a low-density gas, requiring unwieldy storage containers for even low-quantity uses. The durability of hydrogen storage systems has been questioned as adequate to meet automakers' safety requirements.
- **Fuel cell cost** — Expensive materials are part of the current generation of fuel cells. A fuel cell is 10 times more expensive than an internal combustion engine.
- **Durability** — Part of the fuel cell process causes internal parts to corrode.
- **Safety concerns** — Consumers have raised concerns about the potential flammability of the cells in cars, especially in a crash. Additional safety concerns center around hydrogen embrittlement of metals and the fact that hydrogen diffuses through most known materials.
- **Public acceptance** — Such radical changes to energy lifestyle will require adoption by the general public; widespread use of the now ubiquitous automobile took a long time.



Significant Benefits of the Hydrogen Economy

There are major research funds invested at the public and private level to bring about the reality of a hydrogen-based economy because of its significant benefits:

- Hydrogen use creates a decline in U.S. dependence on foreign energy.
- International adoption and implementation of hydrogen production and distribution would lessen the pressures of the current international bidding war for fossil fuels.
- Global air emissions such as SO₂, NO_x and mercury would be reduced with international implementation of hydrogen-based energy.
- Global Greenhouse Gas (GHG) emissions would be reduced, especially as emerging economies that are expected to be the largest contributors of CO₂ develop and adopt these technologies.

Path to Building a Hydrogen Economy Infrastructure

As noted, both current methods to produce hydrogen require energy. NG reforming (and similar processes using coal or other hydrocarbons) releases CO₂ in the hydrogen production process. Given the current prices of petroleum and NG, coal is the most economic fuel for the production of large quantities of hydrogen.

Generating hydrogen through electrolysis is only carbon-free when using electricity from a non-fuel source such as nuclear energy, or a renewable energy source such as wind. In France, the abundance of nuclear energy makes electrolysis the most cost-efficient method and is the predominant method of hydrogen production. In the United States, nuclear plants run at full capacity and are committed to generate electricity for the grid. New plants would be an option if the safety concerns of the public could be overcome. Renewables in the United States account for 9% of electricity, and 7% of that is hydro-based.

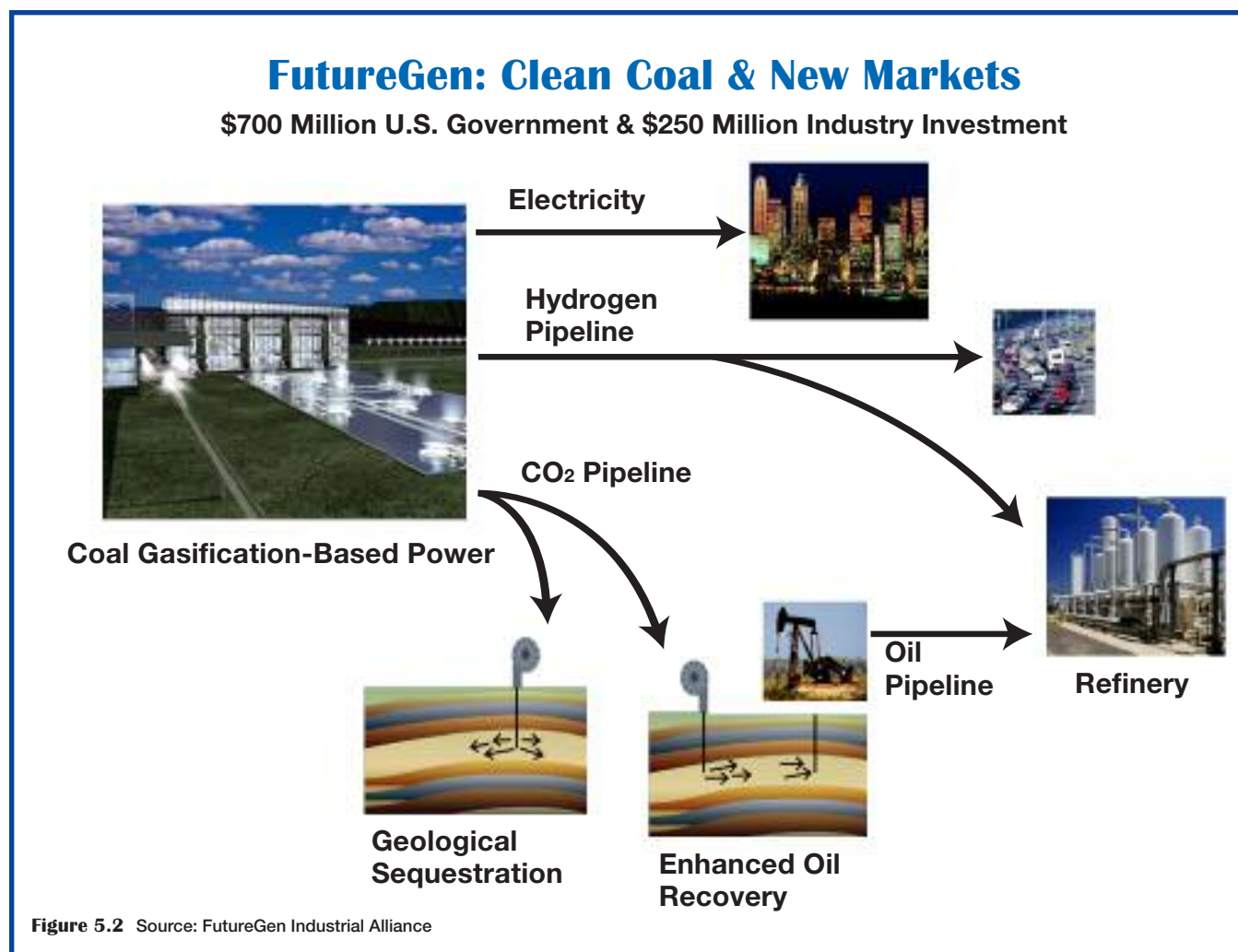
As a result, it seems reasonable that coal-based hydrogen production with CO₂ capture and storage is the most realistic option for large-scale hydrogen production (see Chapter Five Addendum).

While it may be possible for hydrogen to use existing infrastructure for energy distribution, specific upgrades and enhancements will be required in order to make this feasible. Although the technologies required to convert the NG infrastructure for the use of hydrogen are available, the current expense of that process is cost-prohibitive. Furthermore, without existing markets for the distributed use of hydrogen energy, there is no incentive to convert to hydrogen.

Upgrading the country's fueling stations in order to make hydrogen readily available presents a significant obstacle both technically and economically to the expanded use of hydrogen-fueled vehicles. For the emergence of a viable hydrogen-based transportation sector, automakers estimate that at least 30% of the country's fueling stations would have to be equipped to provide hydrogen. Private investment in this infrastructure is unlikely to precede long-term public policies in support of such an effort.

The scarcity of low-cost, lightweight storage options, especially in combination with the lack of commercially available and cost-competitive fuel cells, presents a great threat to the development of a hydrogen economy. To facilitate the evolution of the hydrogen economy, American consumers will need convenient access to hydrogen, and storage will pose a critical concern.





There is ongoing debate about the possible dangers of extensively expanding the manufacture and use of hydrogen due to its explosive nature. Safety issues related to hydrogen are being addressed as agreed-upon codes and standards are being drawn up at the national and international levels.

This century's technological developments, even in only the past decade, have provided exponential leaps of scientific capability. The creation of the World Wide Web, steadily declining cost of computer power, and the mapping of the human genome represent enormous progress in science. Similarly, the path to a hydrogen economy will take significant scientific breakthroughs in a number of areas that will require continuing research. With international interest in the utilization of hydrogen as fuel, the research community is now global in scope with real-time communication and collaboration possible

through the Internet. The possibilities for hydrogen use have never been better.

FutureGen

The FutureGen Industrial Alliance is in partnership with the U.S. Department of Energy to develop and site in the United States the cleanest coal-fueled power plant in the world, using coal gasification generation technology with a target of near-zero emissions, hydrogen production and carbon dioxide sequestration (see Figure 5.2).

FutureGen is planned to begin operation in about 2012 and testing will last for three to five years. If successful, it could run for 60 years and will no doubt be duplicated many times over, bringing the United States ever closer to a hydrogen economy.

At the FutureGen plant, hydrogen will be produced from the coal gasification process. The syngas produced, which will be about 33% hydrogen, will be separated so that the hydrogen goes to a purification unit. The carbon dioxide will be removed for storage, either underground or possibly pumped into oil fields for enhanced oil recovery.

FutureGen will establish that coal-to-hydrogen can produce electricity in a cost-effective, emission-free way and thus subsidize the production of pure hydrogen for other fuel uses.

More commercially available hydrogen also could benefit U.S. farmers and consumers in general. For instance, 65–90% of fertilizer is currently made with NG. Because NG prices have at least tripled in the past five years, many fertilizer factories in the United States have delayed production or closed. Farmers face increased costs from imported fertilizer, leading to higher food costs. More abundant hydrogen could reverse that trend and greatly benefit the U.S. economy.

CONCLUSION

In summary, the vision of a hydrogen economy promotes the benefits of U.S. energy independence and a cleaner environment. There is much work to be done, but America's greatest domestic energy resource—coal—can provide the source and cornerstone for large-scale hydrogen production.

The history of innovation proves that the scientific community can overcome the hurdles needed to reach the reality. Developing and proving the technology to produce electricity and hydrogen from coal with near-zero emissions and carbon capture and storage—FutureGen—is a major step forward in realizing the vision.

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CHAPTER FIVE ADDENDUM

The analysis contained in Chapter Five: Coal-to-Hydrogen regarding hydrogen production and use relied on a series of assumptions and calculations, which are explained in greater detail below.

Number of plants:

$$\frac{70\text{mty}}{1.1\text{ mty/plant}} = 64\text{ plants}$$

The 1.1 million tons of coal per plant is consistent with the hydrogen program plan at the U.S. Department of Energy in which 145 million tons of coal provide 20 million tons of hydrogen annually. Typical plants could consume 3,000 tons of coal per day, or 1.1 million tons per year. As a result, total hydrogen output implied by 70 million tons of coal should be:

$$(153\text{ million scf/day}) \times 365\text{ days} \times 64\text{ plants} = 3.574\text{ trillion scf H}_2/\text{yr}$$

The hydrogen production per plant is also from the DOE.

Hydrogen use per car:

$$\frac{185\text{ kg} \times 2.2\text{ lb/kg} \times 1\text{ metric H}_2}{3,500\text{ scf H}_2} = 73,260\text{ scf H}_2/\text{car}$$

If the total amount of hydrogen were used exclusively in transportation, the total number of cars using hydrogen would be:

$$\left[\frac{(3.574\text{ trillion scf H}_2)/\text{yr}}{73,260\text{ scf/car}} \right] / 1,000,000 = 48.8\text{ million cars}$$

ADDENDUM REFERENCES

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ENHANCED OIL AND GAS (COALBED METHANE) RECOVERY AS CARBON MANAGEMENT STRATEGIES

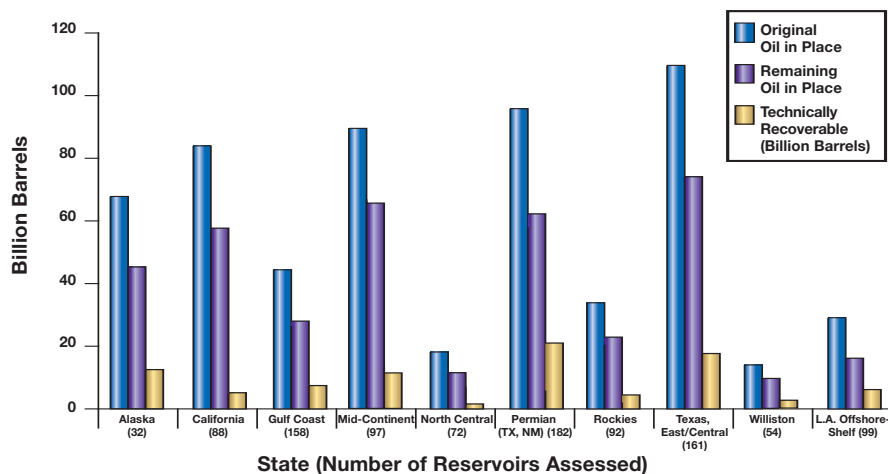


The United States has identified carbon capture and storage as a promising method of managing carbon after efficiency improvements.

Major regional carbon storage projects and partnerships are under way around the country. One promising carbon management opportunity is enhanced oil recovery, which could potentially lead to production of an additional 2 to 3 million barrels of oil per day, assuming a technically recoverable reserve base of up to 89 billion barrels in 10 basins. Captured CO₂ can also be used to produce methane from coalbeds. This increase in domestic production would be an important

step toward energy security and help to moderate price pressures on imported oil and natural gas. Other carbon capture and storage technologies should be developed to complement advanced coal utilization technologies.

Ten Areas Studied to Date
Enhanced Oil Recovery Could Tap Significant U.S. Reserves



Source: Advanced Resources International/DOE, 2005

FINDINGS

The United States has identified carbon capture and storage as a promising method of managing carbon after efficiency improvements. Major regional carbon storage projects and partnerships are under way around the country. One promising carbon management opportunity is enhanced oil recovery, which could potentially lead to production of an additional 2 to 3 million barrels of oil per day, assuming a technically recoverable reserve base of up to 89 billion barrels in 10 basins. Captured CO₂ can also be used to produce methane from coalbeds. This increase in domestic production would be an important step toward energy security and help to moderate price pressures on imported oil and natural gas. Other carbon capture and storage technologies should be developed to complement advanced coal utilization technologies.

DISCUSSION

Current technologies allow only part of the oil in a given reservoir to be recovered. The remaining oil is essentially “stranded” forever or at least until an economic technical solution is available. This stranded oil is especially important in the United States, where more than 390 billion barrels of oil remain unrecoverable with conventional production techniques.

Recognizing the value of this resource, the U.S. Department of Energy Office of Fossil Energy has supported important research on the topic by Advanced Resources International (ARI). The ARI studies demonstrate that one of the most promising modes of recovering remaining oil is by flooding the reservoir with large volumes of carbon dioxide, a process called Enhanced Oil Recovery (EOR). ARI found that EOR has the potential to recover up to 89 billion barrels of oil in 10 geographic regions that have historically produced oil: Alaska, California, the Gulf Coast, Mid-Continent (Oklahoma, Kansas), North Central (Illinois), Permian (Texas, New Mexico), the Rockies, Texas East/Central, Williston and the Louisiana Offshore Shelf. Their study examined 1,581 large reservoirs and found that 1,035 are favorable for CO₂-EOR. The recovery assumes state-of-the-art technology together with improved

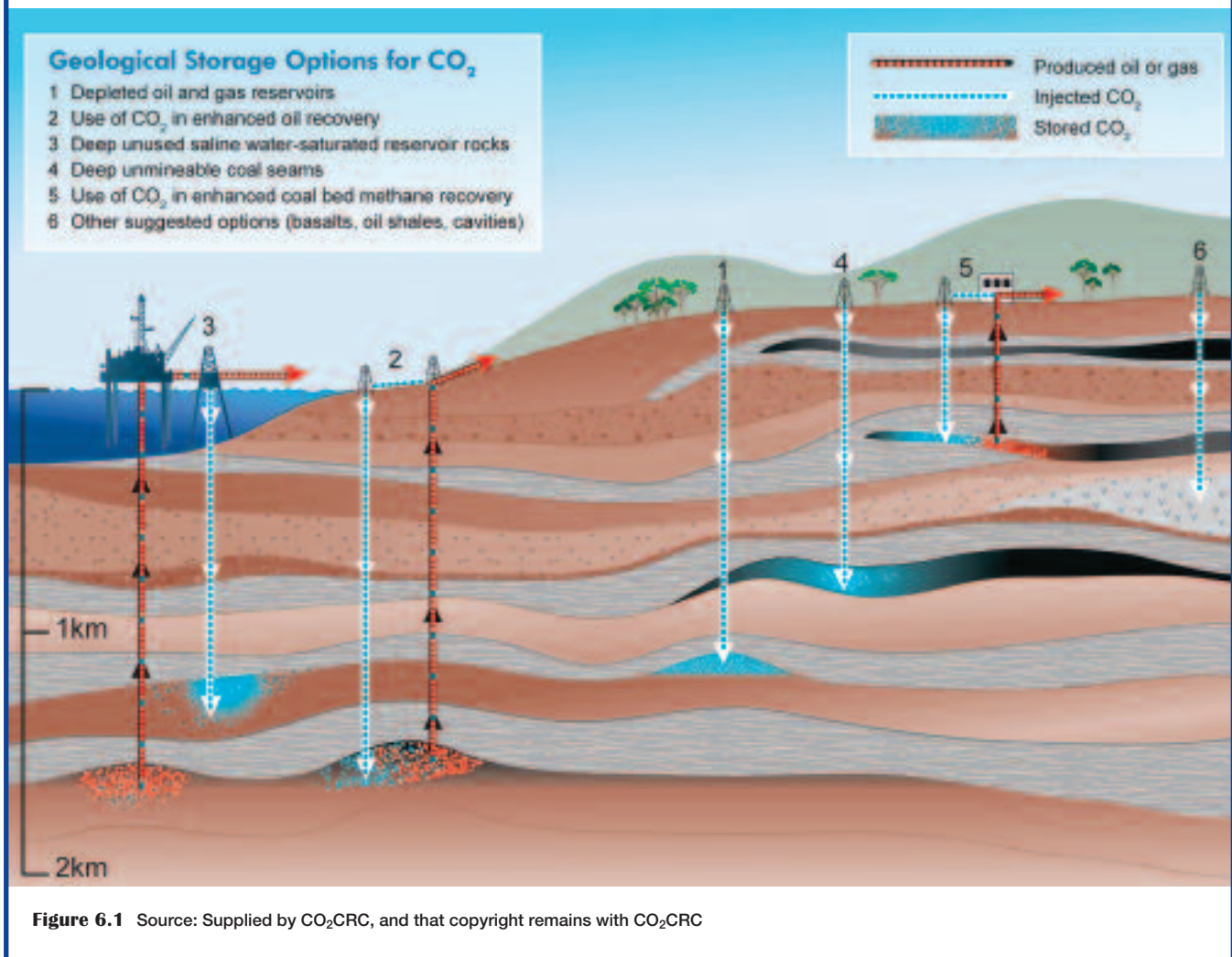
financial conditions (sustained high oil prices). The ultimate size of the “prize” is 88 billion to 129 billion barrels, which are technically recoverable, but which would require next-generation technology to get full extraction.

While EOR activities produced more than 200,000 barrels per day in 2004, it is clear that the potential is far greater. Until recently, the key limitations on expanded use of EOR have been the cost of CO₂ and the limited availability of CO₂ for use in the process. Increasingly, however, it is recognized that CO₂ from coal-fueled power plants is a largely untapped resource whose use would simultaneously reduce greenhouse emissions and enable the recovery of significant amounts of stranded oil. In addition, the CO₂ resulting from the fermentation of corn during the production of ethanol is also an available source for enhanced recovery. The general underground injection process is also applicable to coalbed methane recovery.

In a study of the potential of CO₂-EOR in the state of Illinois, ARI laid out a general logic applicable to many other regions:

- Current oil recovery practices leave behind a large resource of stranded oil. ARI estimated the amount of stranded oil in Illinois alone to be 5.7 billion barrels.
- A substantial amount of stranded oil is amenable to CO₂-EOR recovery. ARI estimated more than 700 million barrels of technical CO₂-EOR potential just in Illinois.
- Using current CO₂ technology and costs, none of this oil in Illinois is recoverable given the availability and cost of CO₂.
- CO₂ from coal-based power plants and other industrial sources could be used in CO₂-EOR in Illinois’ oil reservoir. In Illinois alone, more than 100 million tons of CO₂ emissions could be stored and utilized, significantly reducing greenhouse gas emissions into the atmosphere.

Options for Carbon Capture and Storage



Socioeconomic Benefits

In addition to the significant benefits from reducing greenhouse gas emissions, the DOE's Office of Fossil Energy has identified key social and economic benefits that would accrue to the nation through the recovery of 89 billion barrels of additional domestic oil recovery, at \$40 per barrel:

- A reduction in the nation's trade deficit of more than \$3.6 trillion through reduced oil imports.
- Enhanced national energy security from an additional 2 to 3 million barrels per day of domestic oil production by 2020.

- More than 200,000 high-paying domestic jobs from the direct and indirect economic effects of increased domestic oil production.
- More than \$800 billion of additional federal, state and local revenues from royalties, production and corporate income taxes.

CO₂ Capture and Storage

Carbon capture and storage (CCS) involves capturing the carbon dioxide to prevent the greenhouse gas from entering the atmosphere and storing it deep underground. Figure 6.1 shows major CCS options.

ENHANCED OIL AND GAS (COALBED METHANE) RECOVERY AS CARBON MANAGEMENT STRATEGIES

CCS is already a large, well-proven commercial industry in the United States. America is the world leader in CO₂ injection for enhanced oil recovery, as naturally occurring geologic carbon dioxide has been used for more than 30 years for injection and enhanced oil recovery. CO₂-EOR is also known as tertiary oil recovery, after pumping under field pressure (primary) and water floods (secondary) have removed as much oil as possible from a field.

Typical recovery efficiencies are: primary 15%, waterflood 30%, and CO₂ flood 15%. About 40% of the original oil in a field is non-recoverable. In a CO₂ flood, alternating amounts of CO₂ and water are injected into the reservoir to release oil trapped in the pores of the rock. Using multiple points of injection, the oil, water and CO₂ are flushed into an area beneath the existing well, making it easier to retrieve the oil. Water and CO₂ are separated and recycled.

The first CO₂ flood took place in 1972 in Scurry County, Texas. CO₂ floods have been used throughout the Permian Basin and also in limited

ways in Louisiana, Wyoming, Mississippi, Oklahoma, Colorado, New Mexico, Utah, Montana, Alaska and Pennsylvania. There is an extensive network of more than 2,000 miles of dedicated CO₂ pipelines from Colorado to the Permian Basin in Texas and New Mexico. The Permian Basin produced about 2.2 million barrels of oil per day (bbl/d) in 1973. Now it produces approximately 1 million bbl/d, which represents about 20% of the total U.S. oil production, excluding Alaska (see Figure 6.2). About 4 billion cubic feet per day (bcf/d) of natural gas is also produced.

About 16% of this oil production, or over 160,000 bbl/d, is attributable to more than 40 ongoing CO₂ flooding projects, which inject approximately 1.1 bcf/d of CO₂ to enhance oil recovery. This is the equivalent of 63,000 tons per day of CO₂, or about 22 million tons per year. Occidental Petroleum Corporation through its Oxy Permian unit is the largest oil producer in Texas and the world's largest CO₂ injection field operator. Kinder Morgan is the largest U.S. transporter and marketer of CO₂.

Carbon Dioxide Pipelines in the Permian Basin The Only Significant Pipeline Network in the U.S.

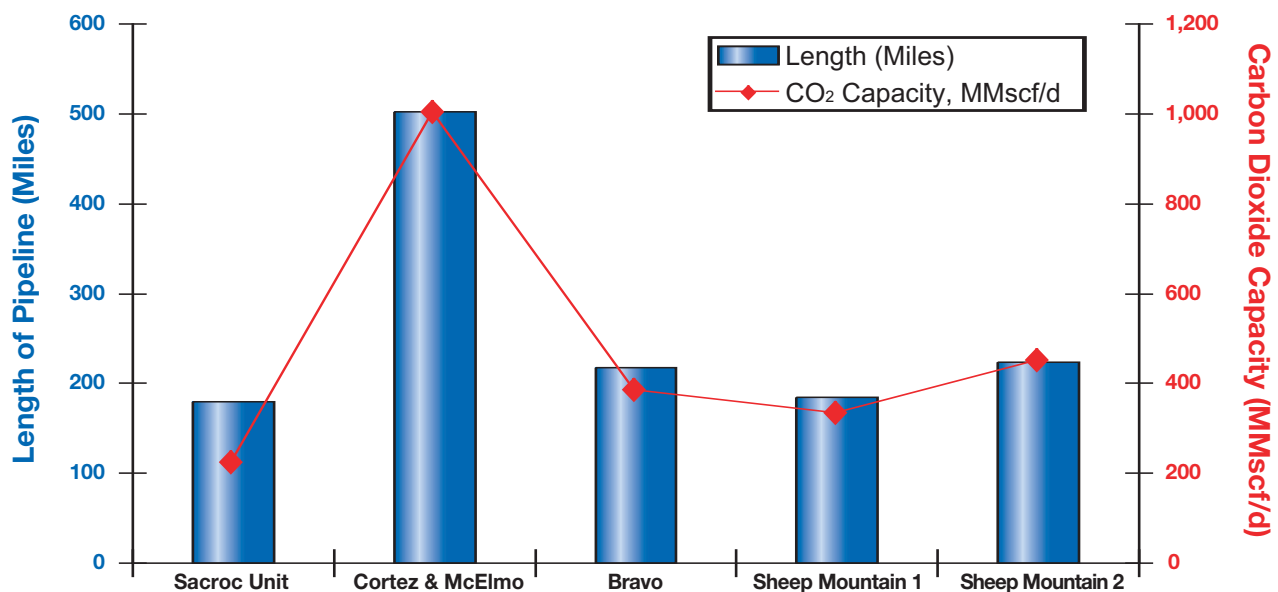


Figure 6.2

MMscf/d: Million Standard Cubic Feet Per Day

Carbon Dioxide Pipelines in Operation in North America

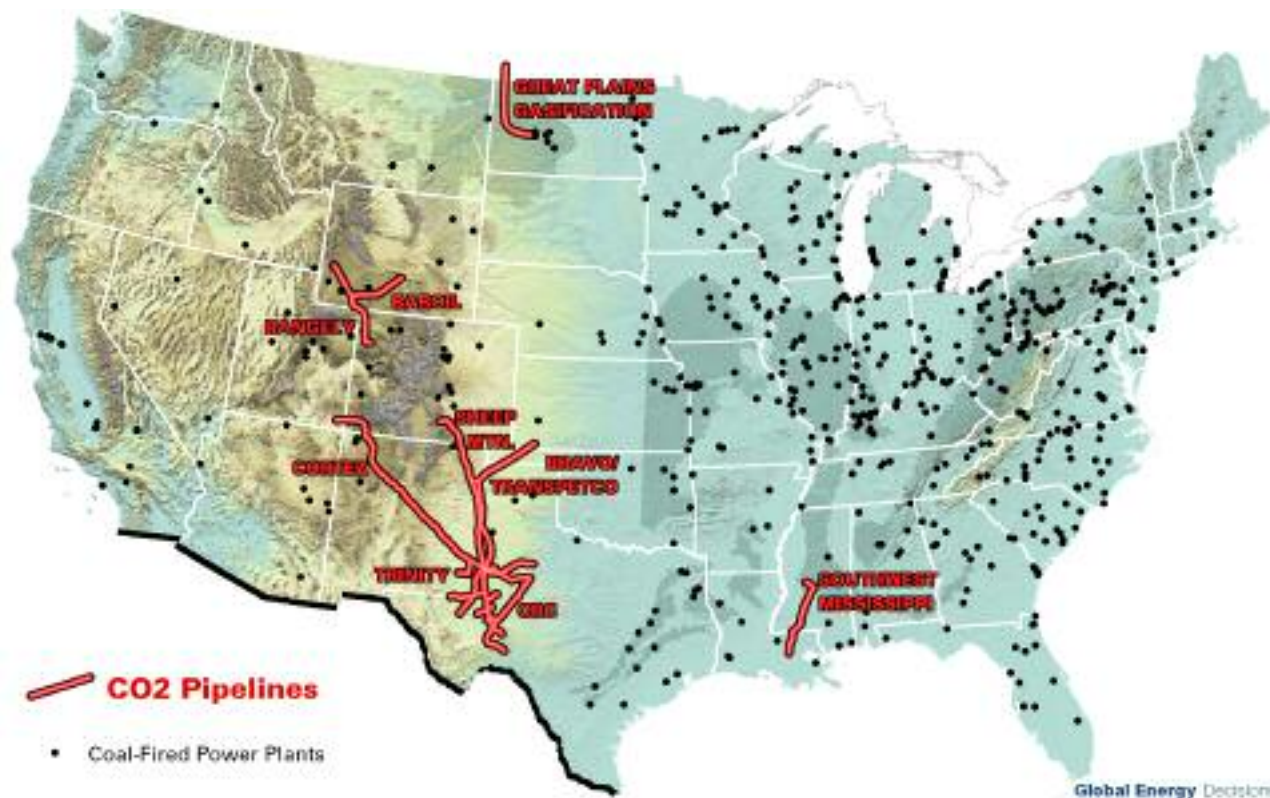


Figure 6.3

In the Permian Basin alone, it has been estimated that there could be 50 potentially economical CO₂ floodable reservoirs, representing incremental oil reserves of well over 1 billion barrels. This includes current oil fields that are utilizing water floods, which could become CO₂ floods in the future. However, the problem is that CO₂ is in somewhat short supply, so consideration to use CO₂ recovered from power plants for injection is now becoming an issue of growing interest. Figure 6.3 shows the major CO₂ pipelines that supply the Permian Basin.

In addition to the Permian Basin, there are other CO₂-EOR projects. Of particular interest is the Dakota Gasification Company lignite gasification plant in Beulah, North Dakota. Originally built during the 1970s energy crisis to produce substitute NG from lignite reserves, it uses Lurgi gasification technology, the same technology utilized by Sasol in South Africa to produce zero-sulfur diesel, naphtha and chemicals.

The Great Plains Synfuels Plant has the distinction of being the world's first large-scale coal gasification project to substitute NG and the first where CO₂ from coal gasification is removed and utilized specifically for a CO₂-EOR flood. The plant began operating in 1984 and today produces more than 54 billion standard cubic feet of NG annually. Coal consumption exceeds 6 million tons each year, and a number of other products are also produced, including ammonia fertilizers, phenol and naphtha.

A portion of the CO₂ produced by this plant (95 MMscfd) is compressed and sent through a 204-mile pipeline through North Dakota to the Weyburn oil field operated by EnCana Corporation in Saskatchewan, Canada. Injection began in September 2000, and the field recently passed a milestone of injecting 5 million tons of CO₂ while doubling the field's production rate to 20,000 bbl/d. The CO₂ from the Dakota plant had been vented for many years.

ENHANCED OIL AND GAS (COALBED METHANE) RECOVERY AS CARBON MANAGEMENT STRATEGIES

Thus, a waste product became a source of income for the project and a source of high-purity CO₂ for extended field life (20 years), oil production and revenue from the field. EnCana plans to produce an additional 130 million barrels of oil and sequester as much as 30 million tons of CO₂.

Andarko Petroleum Corporation has extended an existing CO₂ pipeline 125 miles to supply CO₂ to the existing 100-year-old Salt Creek oil field near Casper, from the LaBarge NG processing plant operated by ExxonMobil in western Wyoming. LaBarge also supplies CO₂ to several injection projects, including the Rangle field in Rio Blanco County, Colorado.

Salt Creek oil production is anticipated to increase from 5,000 bbl/d to perhaps 30,000 bbl/d, with an anticipated CO₂ sequestering of about 25 million tons. Andarko hopes to extract 115 million barrels of oil over 30 years. The Wyoming State Geological Survey recently estimated that there are about 50 oil

fields from which perhaps an additional 1.2 billion barrels could be produced using CO₂ injection.

Denbury owns CO₂ reserves in the Jackson Dome and a pipeline in Mississippi and plans to extend that pipeline into eastern Mississippi and southern Louisiana. EOR production is expected to reach 10,000 bbl/d in 2005 to 33,000 bbl/d in 2010. In Oklahoma, about 9,000 bbl/d of CO₂-EOR is produced, using CO₂ from existing ammonia plants.

A large geologic CO₂ discovery in Ridgeway, Arizona is awaiting exploitation, possibly for CO₂-EOR in the California oil fields.

EOR Requires Additional Supplies of Man-made CO₂

Increased CO₂ injection for enhanced oil recovery in the United States could provide critical support for domestic energy independence. The Gulf Coast Carbon Center has estimated that outside of the Permian basin area, CO₂ injection in Texas could

Ten Areas Studied to Date
Enhanced Oil Recovery Could Tap Significant U.S. Reserves

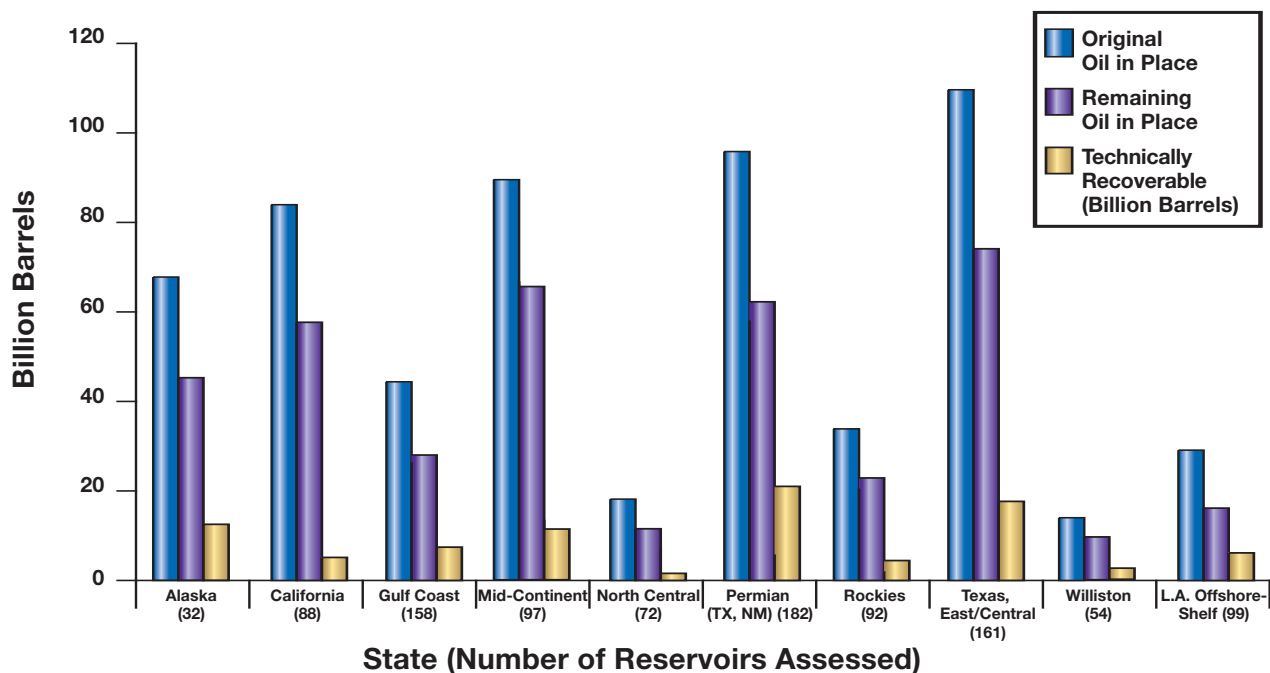


Figure 6.4 Source: Advanced Resources International/DOE, 2005

recover an additional 5.7 billion barrels of oil and lead to the storage of 0.7 billion tons of CO₂. DOE and ARI estimate that for the ten areas they have studied to date (see Figure 6.4), CO₂-EOR in the United States could potentially recover 89 billion barrels of additional oil.

Unfortunately, little of this oil is recoverable due to the current CO₂ supply shortage, as existing planned expansion will use up most of the available supply. In Texas, current oil leases are roughly 20% primary, 60% secondary (waterflood) and 20% tertiary (CO₂).

There is a real need for large quantities of additional sources of CO₂ from gas processing and chemical plants, power plants or coal gasification facilities, either for power, substitute NG or other chemicals such as ammonia. **CO₂ flooding has emerged as the lead process for storing CO₂ for the simple reason that valuable oil is produced.** This is especially true when approximate CO₂ flood costs (which are understandably highly site-specific) are about \$18 to \$25 per barrel, including the cost of the CO₂.

Incentives for additional man-made CO₂ supply projects are available through the incentives contained in the Energy Policy Act of 2005. These incentives will be required to create large-scale sources of man-made CO₂ that in turn will be used for EOR in the United States and Canada.

Although the United States is not a party to the Kyoto Protocol, there is interest in developing technologies to isolate carbon dioxide streams to address concerns over climate change. Creating significant additional supply of CO₂ for EOR to unlock and monetize the “CO₂ barrel” both eliminates CO₂ emissions to the atmosphere and addresses real domestic oil security issues.



CO₂ and CCS Demonstrations and Regional Partnerships Are Under Way

Following are examples of test projects and partnerships that will expand knowledge of CO₂ and CCS using different methodologies under different conditions.

Hall-Gurney Field, Kansas

DOE partners in this project are the University of Kansas, Murfin Drilling, U.S. Energy Partners and EPCO Carbon Dioxide Products. This is a unique miscible flood demonstration project, combining electricity cogeneration (15 MW gas-fired turbine), a 25 million gallon-per-year ethanol plant, production, and CO₂-EOR in the Hall-Gurney Field. A portion of the CO₂ produced by the ethanol plant is now trucked seven miles for injection into the depleted Hall-Gurney Field. If proven technically and economically sound, the target for CO₂ flooding is up to 250 to 600 million barrels of oil, from as many as 6,000 mature oil fields in Kansas.

Mountaineer Plant, West Virginia

American Electric Power's (AEP) Mountaineer coal-fired power plant is the site for a \$4.2 million carbon storage research project funded by the DOE and a consortium of public and private sector participants. Scientists from Battelle Memorial Institute lead this climate change mitigation research project, which

ENHANCED OIL AND GAS (COALBED METHANE) RECOVERY AS CARBON MANAGEMENT STRATEGIES

will also involve researchers from several other partnering organizations and universities. The study will determine whether the geology near AEP's Mountaineer Plant is suitable for injection of carbon dioxide deep into the earth, where it will be absorbed and permanently captured.

Frio Brine Project, Texas

DOE partners in this project are GEO-SEQ, a research consortium that includes the Lawrence Berkeley, Lawrence Livermore and Oak Ridge national laboratories and the Alberta Research Council (Canada); the U.S. National Energy Technology Lab (NETL); the U.S. Geological Survey; Sandia Technologies LLC; Texas American Resources; Schlumberger; BP; the Department of Petroleum Engineering at the University of Texas at Austin; Praxair Inc.; and the Australian Cooperative Research Centre for Greenhouse Gas Technologies. Funding is provided by NETL.

The project is starting the second phase of tests of carbon sequestration in a Frio Formation brine well more than 5,700 feet deep in Liberty County, Texas.

A research consortium called the Gulf Coast Carbon Center (GCCC) also was formed, funded by BP, ChevronTexaco, Kinder-Morgan, Praxair and the Jackson School of Geosciences. The GCCC estimates that the Gulf Coast region, which has the highest concentration of refineries and chemical plants in the United States, emits about 1 billion tons per year of CO₂, or about 4% of the world total.

Hamilton, Ohio

The Babcock and Wilcox Company (B&W) has undertaken Phase I of a project to convert a boiler in the City of Hamilton from air combustion to oxygen combustion, which would produce a concentrated carbon dioxide gas stream that could be captured and sequestered more easily. The B&W project, which is projected to cost approximately \$500K over 24 months, includes partners Air Liquide, the U.S. Department of Energy and the City of Hamilton.

Retrofitted Cyclone Boilers

The Babcock and Wilcox Company will conduct pilot-scale tests at 5 million Btu per hour for several coal types: lignite coal, sub-bituminous

Carbon Sequestration Regional Partnerships

Partnership	Partnership Lead	U.S. States; Canadian Provinces Represented
Midwest Regional Carbon Sequestration (CS) Partnership	Battelle Memorial Institute	IN, KY, MI, MD, OH, PA, WV
Midwest Geological Sequestration Consortium – Illinois Basin	University of Illinois, Illinois State Geological Survey	IL, IN, KY
Southeast Regional CS Partnership	Southern States Energy Board	AL, AR, FL, GA, LA, MS, NC, SC, TN, TX, VA
Southwest Regional Partnership for CS	New Mexico Institute of Mining & Technology	AZ, CO, KS, NV, NM, OK, TX, UT, WY
West Coast Regional CS Partnership	California Energy Commission	AK, AZ, CA, NV, OR, WA; British Columbia
Big Sky Regional CS Partnership	Montana State University	ID, MT, SD
Plains CO ₂ Reduction Partnership	University of North Dakota, Energy & Environmental Research Center	IA, MO, MN, ND, NE, MT, SD, WI, WY; Alberta, Manitoba, Saskatchewan

Figure 6.5 Source: DOE

coal, Powder River Basin pulverized coal, and Eastern bituminous coal. The Babcock and Wilcox Company will perform parametric testing in wall-fired and cyclone boiler configurations in order to optimize the oxycombustion process. The project is expected to demonstrate that a cost-effective approach for CO₂ capture and lower nitrogen oxide emissions can be achieved by retrofitting cyclone boilers with oxycombustion technology. The project will be conducted over a two-year period and is valued at \$3.5 million.

The DOE also is providing cost-sharing funding to seven regional partnerships to further develop carbon storage technologies as part of its strategy to reduce greenhouse gas intensity. This initiative directly supports President Bush's Global Climate Change Initiative (GCCCI) goal of reducing greenhouse gas intensity by 18% by 2012 and will help ensure that a suite of commercially ready sequestration technologies are available for the 2012 technology assessment mandated by the GCCCI. The University of Kansas will manage an information portal called the National Carbon Sequestration Database and Geographical Information System (NATCARB) to collect and manage the information generated by these regional partnerships.

From 2004 to 2008, these regional partnerships, which DOE sees as critical to its FutureGen plant design, are field-testing and validating carbon storage technologies best suited to the geology of their respective regions. This network of regional partnerships (Figure 6.5) is estimated by the DOE to include 240 organizations in 40 U.S. states, three Native American nations, and four Canadian provinces. The R&D program for these partnerships has two primary objectives:

- lowering the cost and energy penalty associated with CO₂ capture from large point sources
- improving understanding of the factors affecting CO₂ storage permanence, capacity and safety in geologic formation and terrestrial ecosystems



CCPC Plan Schedule

2000	Formation and planning
2001–2003	Phase I technology studies
2004	Results assessment and Phase II formation
2004–2006	Phase II optimization studies
2006	Status assessment & commitment to demonstration project
2007–2011	Design & construction
2012	Operation

Figure 6.6

These regional partnerships are clearly also investigating the use of CO₂ for enhanced oil recovery in their respective regions as a preferred option to costly storage.

Canadian Clean Power Coalition (CCPC) is a national association of Canadian coal and coal-fired electricity producers that represents more than 90% of Canada's coal-fired electricity generation.

Similar to FutureGen, CCPC is an industry/government partnership whose objective is to demonstrate that coal-fired electricity can effectively address all environmental issues projected in the future, including carbon dioxide. CCPC goals are to:

- Construct and operate a full-scale demonstration project to remove greenhouse gas and all other emissions of concern, including CO₂, from a coal-fired power plant by 2012.
- Provide flexible fuel capability — bituminous, sub-bituminous, lignite and petroleum coke (produced from oil upgraders in Alberta).
- Accomplish this at a competitive cost of power.

The CCPC plan schedule (see Figure 6.6) was designed to meet the objective for projects to go into operation in 2012.

ENHANCED OIL AND GAS (COALBED METHANE) RECOVERY AS CARBON MANAGEMENT STRATEGIES

Phase I technology studies have been completed. Phase II optimization studies are in process, with an aim to choose a technology and design in 2006 and to begin detailed design in 2007. Phase I funding was approximately Canadian \$5 million. Phase I compared gasification technology providers, and compared IGCC with CO shift and CO₂ extraction against conventional boilers with amine scrubbing for CO₂ control, and conventional boilers with OxyFuel (O₂ with recycled CO₂).

Phase I studies confirmed IGCC as the lowest-cost CO₂ removal technology with higher efficiency, ease of emission reduction and the lowest energy penalty to add CO₂ capture. CO₂ utilization and storage options studies were also completed, as well as studies of retrofitting CO₂ removal technology to existing conventional coal-fired boiler plants.

The Phase II engineering plan, now under way, will include a gasification technology evaluation to develop better technology for low rank western Canadian coals and evaluate amine scrubbing and OxyFuel combustion with advanced supercritical steam cycles.

The end result in 2006 of Phase II will be to refine capital and operating cost estimates, cost of power and cost of CO₂ removal and to evaluate business cases to support demonstration plant site selection.

In addition to Canada's program, it will be instructive to **view the FutureGen program as one of many global programs (see Figure 6.7)**. Research in any of these projects could lead to technology innovations that could be included in the final design of the site-specific FutureGen facility.

Global CSS Programs

1990	1990–2000	2000–2005	2005
Conceptual development CO ₂ -EOR projects in the USA (pre-1990)	Sleipner Project IEA greenhouse gas R&D program Canadian R&D program U.S. R&D program	EU & Norwegian R&D program CCPC Weyburn Project Australia R&D program Tiffany Project CO ₂ mitigation project CO ₂ capture program (CCP)	U.S. FutureGen U.S. CSS Regional Partnerships U.S. Mountaineer, WV Project; U.S. Frio Brine Project, Texas Commercial projects: in Salah, Gorgon, Snohvit Australian LETF CO ₂ CRC CSLF Babcock and Wilcox IPCC special report CCP2

Notes: CO₂CRC — Cooperative Research Centre for Greenhouse Gas Technologies;
CSLF — Carbon Sequestration Leadership Forum;
IPCC — Intergovernmental Panel on Climate Change;
CCP2 — CO₂ Capture project — Phase 2

Figure 6.7 Source: Compiled from Public Announcements



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DELINEATE U.S. COAL RESERVES AND TRANSPORTATION CONSTRAINTS AS PART OF AN EFFORT TO MAXIMIZE U.S. COAL PRODUCTION



The National Coal Council has conducted an in-depth survey of existing data

and finds that the mining industry and U.S. transportation infrastructure can be expanded to accommodate growth in coal production by over 1,300 million tons per year by 2025. Coal production at a significantly increased level can be conducted in a safe and environmentally friendly manner, meeting public concern over both mine safety and environmental impacts.



DELINEATE U.S. COAL RESERVES AND TRANSPORTATION CONSTRAINTS AS PART OF AN EFFORT TO MAXIMIZE U.S. COAL PRODUCTION

FINDINGS

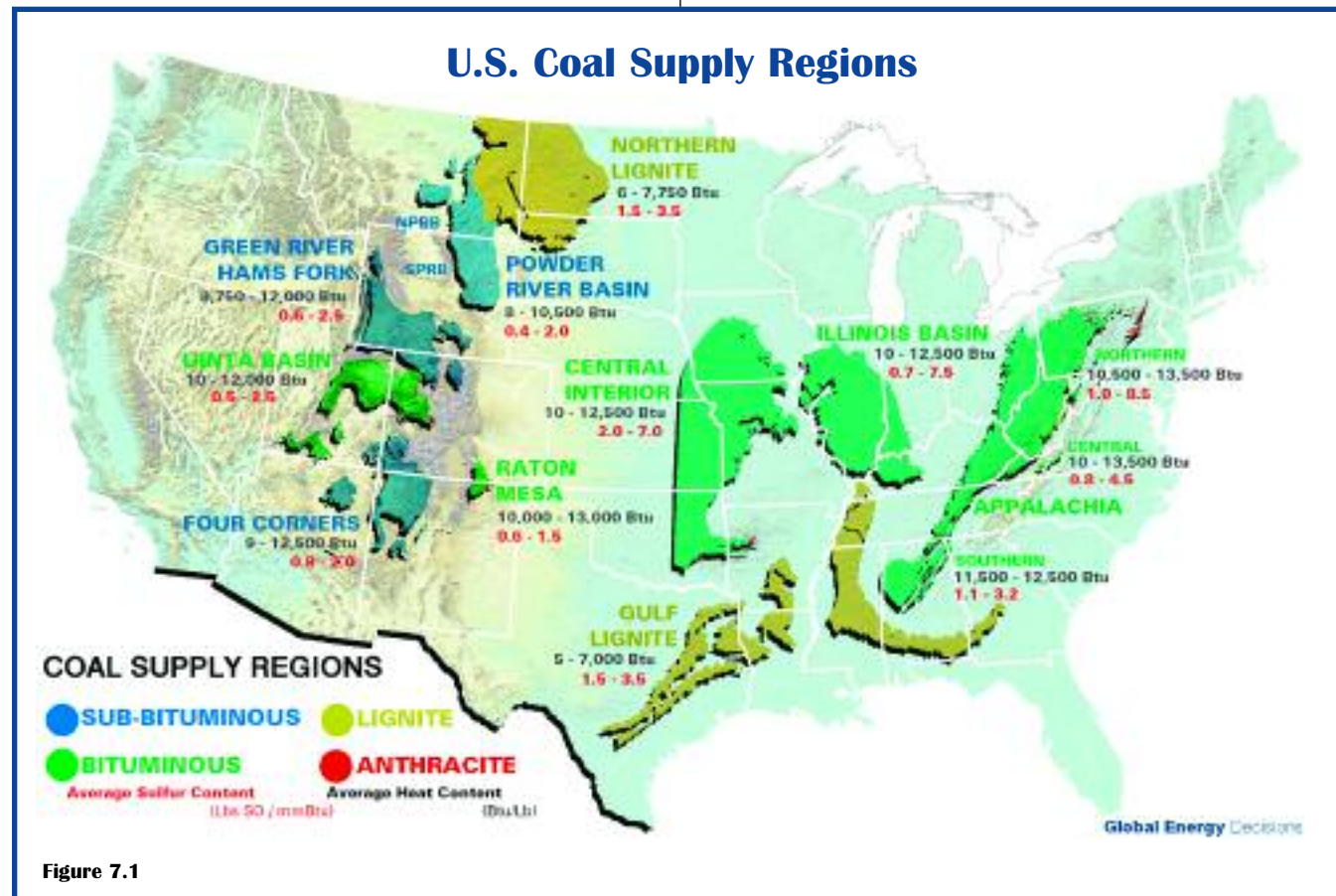
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DISCUSSION

The National Coal Council finds that it is in the national interest to create a new energy manufacturing industry by doubling coal production to meet the future energy needs of the American people. Public support for such an effort will be widespread once a full understanding of the nation's energy situation is attained in the context of the importance of stable energy supply and prices to the quality of life in America.

In addition, significant coal reserves can be found in over 25 states, and extensive coal mining, refining, gasification and electricity production at enhanced levels can be distributed across these states. The transportation infrastructure, of course, must be strengthened and supplemented. But the benefits will be widely dispersed—lower energy prices, millions of jobs in thousands of communities, and improved national security and economic well-being for all Americans.

At the same time, there undoubtedly will be concern over the environmental impact associated with the increased industrial activity surrounding a doubling of U.S. coal production and consumption. This chapter will show that the reserve base exists, along with a strict federal regulatory regime, which will ensure minimal environmental impact while enabling coal mining to proceed in the safest manner possible.



U.S. Coal Reserves by State and Type — 12/2004

Analysis to 1/2006

(Million Short Tons)

STATE	2004 U.S. Estimated Reserves at Active Mines	2004 U.S. Recoverable Reserves	2004 U.S. Estimated Demonstrated Reserve Base	2005 Production	12/31/05 Recoverable Reserves
East:					
Alabama	341	2,806	4,242	22.6	2,783
Georgia	—	2	4	—	2
Illinois	796	38,019	104,529	31.6	37,987
Indiana	398	4,080	9,534	33.6	4,046
Kentucky	1,129	15,004	30,225	114.4	14,890
Kentucky-East	823	5,960	10,671	89.9	5,870
Kentucky-West	306	9,044	19,554	26.7	9,017
Maryland	17	366	652	5.5	360
Michigan	—	59	128	59	—
Mississippi	W	—	—	3.7	W
North Carolina	—	5	11	5	—
Ohio	318	11,507	23,342	24.3	11,483
Pennsylvania	614	11,822	27,597	65.2	11,757
Penn-Bituminous	592	11,062	20,397	63.4	10,999
Penn-Anthracite	22	760	7,200	1.8	758
Tennessee	26	462	779	3.2	459
Virginia	250	1,022	1,740	28.3	994
West Virginia	1,518	18,104	33,220	151.0	151.0
TOTAL EAST	5,407	103,258	236,003	485.5	84,974
West:					
Alaska	W	3,291	6,112	1.5	3,290
Arizona*	—	—	3,330*	11.9	3,288
Arkansas	—	228	417	0.0	228
California	—	—	—	—	—
Colorado	415	9,798	16,293	39.9	9,758
Idaho	—	2	4	—	2
Iowa	—	1,127	2,189	—	1,127
Kansas	W	681	973	0.2	681
Louisiana	W	316	427	4.2	312
Missouri	—	3,847	5,990	0.6	3,846
Montana	1,140	74,989	119,280	37.8	74,951
New Mexico	1,304	6,934	12,172	28.0	6,906
North Dakota	1,191	6,935	9,090	29.4	6,906
Oklahoma	17	801	1,557	1.8	799
South Dakota	—	277	366	—	277
Texas	546	9,578	12,442	43.7	9,534
Utah	317	2,750	5,445	23.0	2,727
Washington	—	681	1,341	5.1	676
Wyoming	7,053	41,804	64,325	407.3	41,397
TOTAL WEST	11,983	164,039	261,723	634.4	163,405
GRAND TOTAL—U.S.	18,122 /1	267,297	497,726	1,119.9	248,379

W: Withheld Data — identifiable Private company resource

/1 Includes Withheld Data states

/2 Last 3 months of production estimated by EIA as of 2/28/2006

* Estimated coal resources on the Navajo and Hopi Reservations where there are several active mining operations; "Geologic Assessment of Coal in the Colorado Plateau," U.S. Geologic Survey Professional Paper 1625-B, 200, p. H27

Figure 7.2 EIA Coal Trade Outlook; EIA Coal Export and Import Outlook

DELINEATE U.S. COAL RESERVES AND TRANSPORTATION CONSTRAINTS AS PART OF AN EFFORT TO MAXIMIZE U.S. COAL PRODUCTION

Domestic Coal Resources Represent an Enormous Asset and U.S. Strength

The size of domestic U.S. coal resources, by all accounts, is vast. In 1999, the EIA estimated that the total resource was 3.97 trillion short tons. Of this total resource, the EIA estimated the demonstrated reserve base to be 498 billion short tons as of 2004.

The term “resources” in this case refers to coal deposit forms and amounts for which economic extraction is feasible. Demonstrated reserve base (DRB) is the portion of the resource that meets specified criteria related to current mining and production practices, including criteria for quality, depth, thickness and others.

The demonstrated reserve base of nearly 500 billion tons is widely distributed geographically (Figure 7.1): 102.9 billion tons in the Appalachian region; 158 billion tons in the Interior region; and 235.2 billion tons in the Western region. Eastern and western Kentucky are counted separately in both Appalachia and the Interior.

The demonstrated reserve base can also be classified by coal rank as follows: anthracite, 7.5 billion tons; bituminous, 263.6 billion tons; sub-bituminous, 181.5 billion tons; and lignite, 43.5 billion tons. The majority (336.2 billion tons) of the demonstrated reserve base is considered to be accessible via

underground mining methods, and the rest (159.9 billion tons) is considered to be accessible via surface mining methods (Figure 7.2).

The estimated total resource and even the demonstrated reserve base (DRB) are hundreds of times greater than the current U.S. production rate of about 1.1 billion tons per year. A portion of the demonstrated reserve base is accessible and economically recoverable by current mining methods under existing regulatory limits (see Figure 7.2). For example, the EIA estimated in 1999 that 17% of the DRB is inaccessible for mining (see later discussion) and that 34% of the accessible portion would be unrecovered or lost during mining, leaving 54% of the DRB as recoverable. This equates to 268 billion tons of recoverable coal using the recent DRB estimate. At current production rates, the recoverable portion of the demonstrated reserve base would last for about 240 years. Even if production were to double, the recoverable demonstrated reserve base estimated by EIA would last for more than a century.

The U.S. reserve base requires additional study. The foundation of the current DRB estimate is a one-time-only national assessment at the county/coalbed level reported in 1974 (BOM 1974) for reserves as of 1971 that was based upon then-current geologic knowledge and mining technology. The DRB has been updated numerous times (1989, 1993, 1996

and the previously referenced EIA reports), each time incorporating recent depletion and certain updated reserve data. However, the foundation of the current DRB remains the original 1974 study.

Also requiring additional study is the estimate of the recoverable portion of the DRB, which is estimated by the EIA to be 54%. The U.S. Geological Survey (USGS) has found, based on in-depth evaluations of selected coalbeds, that in the Appalachian Basin, an average of only 53% of the resource is available for mining (i.e., accessible within regulatory, land-use and technological constraints). There



Coal Mine Production in the U.S.

Surface Mining Is the Predominant Method

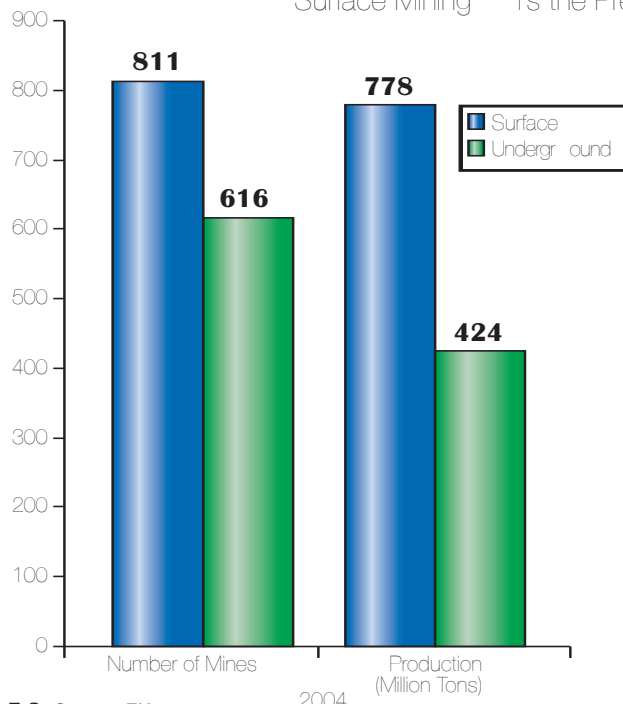
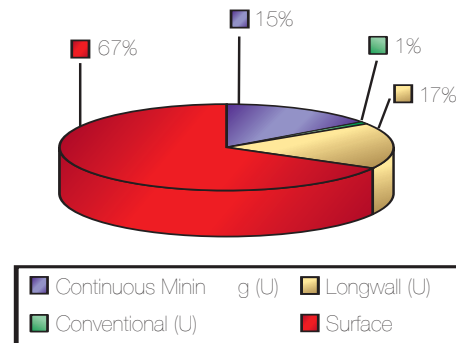


Figure 7.3 Source: EIA

Coal Production by Method 2004



is an average of only 32% of the original resource recoverable after mining and washing losses. The USGS also found similar percentages of availability and recoverability for coals in the Illinois Basin. The USGS also reports that only 54% of the original coal in the Powder River Basin is available for development; recoverabilities must be even less. The National Coal Council in 1987 speculated that the recoverability of the DRB could be as low as 35%, rather than the EIA's 54%, on the basis of recoverability rates reported by some analyses (see Richard Schmidt, 1979). The recoverability values reported by Schmidt and for selected Appalachian and Interior coalbeds by the USGS are both approximately 35%.

It is appropriate for the U.S. Department of Energy to perform or commission a new estimate of the DRB and its recoverable fraction. The USGS has historically conducted coal assessments of in-place resources, with nominal restrictions on what is considered in the assessment process. They take into consideration depth, thickness and quality (ash yield and sulfur content). While in-place

resources are important to understand and form a basis for further studies, policy decisions and land and resource management activities, it is also important to understand what portion of those resources are technically and economically recoverable.

The USGS has just revised the assessment method used in order to assess those resources that are technically and economically recoverable. The first basin assessed with this new approach will be the Powder River Basin, the single largest producing basin in the United States. USGS is now compiling and interpreting the geologic and engineering data for the Powder River Basin in order to conduct a reserve estimate of that basin in the near future.

Types of Coal Mining

Two major processes are commonly used in mining underground coal in the United States: longwall and continuous (Figure 7.3).

DELINEATE U.S. COAL RESERVES AND TRANSPORTATION CONSTRAINTS AS PART OF AN EFFORT TO MAXIMIZE U.S. COAL PRODUCTION

Longwall

Mining with the longwall process has helped revolutionize underground mine operation in the past 20 years. Over that period, longwall's share of total U.S. deep mine production has increased. The longwall process uses a rotating drum, which is dragged mechanically back and forth across a wide coal seam, often hundreds of feet long. The loosened coal falls onto a conveyor for removal from the mine. Longwall systems have their own hydraulic roof supports that advance with the machinery as mining proceeds. This system of mining has greatly increased coal mine productivity.

Continuous

This process accounts for the majority of underground mining. Continuous mining utilizes a special cutting machine that mechanizes the extraction procedure: the continuous miner. This machine tears the coal from a seam and automatically removes it from the area by conveyor. Remote-controlled continuous miners allow

an operator to direct the machine from a distance, increasing safety.

More than half the coal in the U.S. is produced by surface mining (see Figures 7.3 and 7.4). It is dramatically different from underground mining and is essentially an earth-moving operation. Surface mining is the removal of the covering layer of rock and soil called "overburden," the extraction of the coal, backfilling with earth and reclaiming or restoring the site to its approximate original vegetation and appearance. Draglines, a key element in this process, are large excavating machines used to remove overburden. The machines have a large bucket suspended from the end of a huge boom, which may be as long as 300 feet. The bucket, suspended from a cable, can scoop hundreds of tons of overburden as it is dragged across the excavation area. The dragline moves on huge pontoon-like feet and is one of the largest land-based machines in the world.

Coal Production by Mining Method
Surface Mining Increasing Source of U.S. Coal Supply

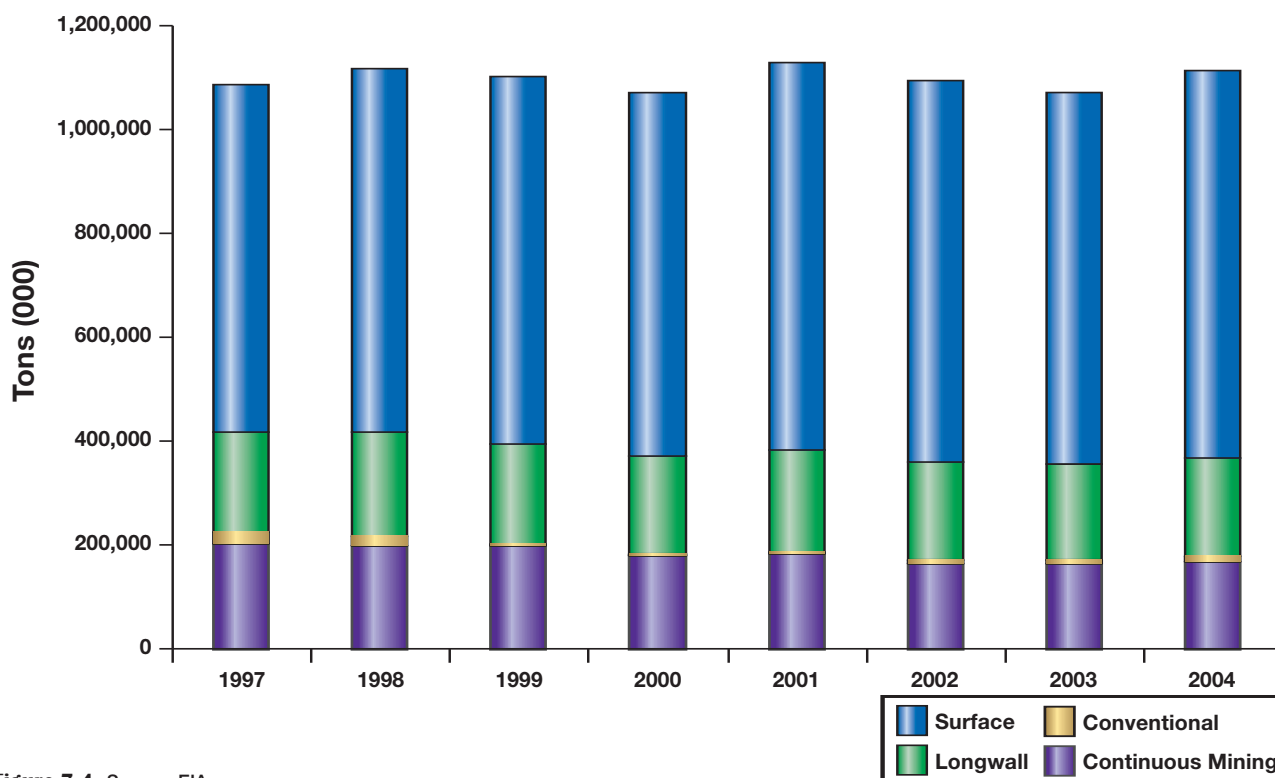


Figure 7.4 Source: EIA

Coal Mining Industry Continues to Increase Focus on Safety

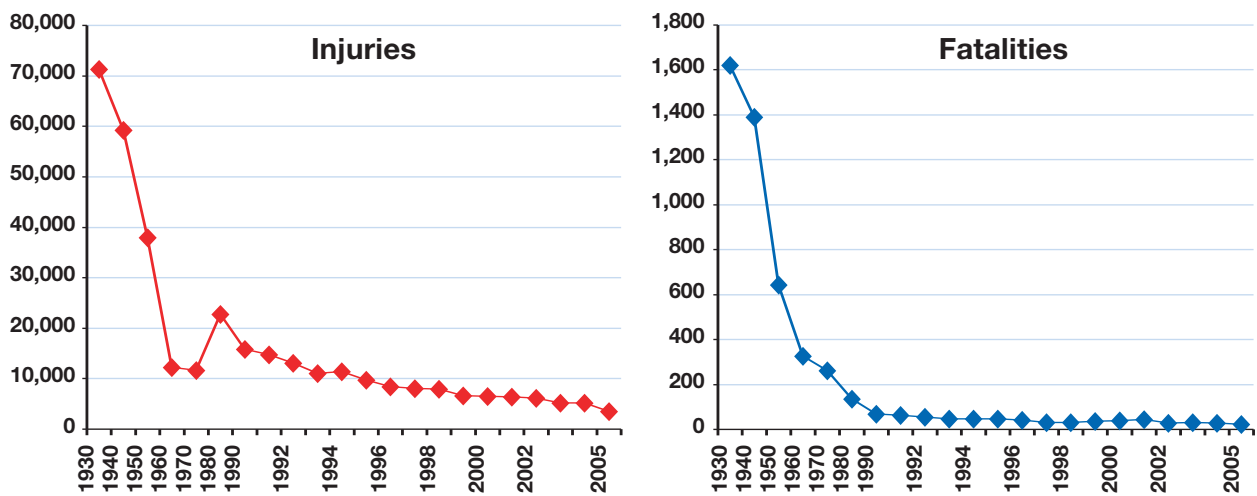


Figure 7.5 Source: MSHA

The U.S. coal industry is increasingly safe, both when compared with other industrial and service sectors and with previous coal industry performance (Figure 7.5). As the January 2006 tragedies in West Virginia remind everyone, no matter how favorable statistical safety trends may be, they still pale in the face of the human tragedy that results from any industrial accident. Coal mine safety requires constant vigilance and commitment to drive out all sources of accidents and injuries.

Legislative/Regulatory Considerations in Developing Coal Reserves

The advent of the environmental movement in the United States in the early 1970s brought with it laws to clean up and protect our air (Clean Air Act) and water resources (Federal Water Pollution Control Act). Within the next decade, additional laws were enacted that addressed hazardous wastes and fish and wildlife protection. In 1977, coal mining activities were significantly regulated through the

Surface Mining Control and Reclamation Act of 1977 (P.L. 95-87).

The federal Surface Mining Control and Reclamation Act (SMCRA) established a “nationwide program to protect society and the environment from the adverse effects of surface coal mining operations and surface impacts of underground coal mining operations [and] to promote the reclamation of mined areas left without adequate reclamation.”



SMCRA addressed virtually every environmental and land use issue associated with coal mining and established standards and protocols for coal operators. The federal regulations needed to implement SMCRA were developed by the newly formed Office of Surface Mining, Reclamation and Enforcement (OSMRE, now OSM). OSM’s regulations were more comprehensive than the statute, and they established new levels of both design and performance standards for coal mining operations. It established requirements for

DELINEATE U.S. COAL RESERVES AND TRANSPORTATION CONSTRAINTS AS PART OF AN EFFORT TO MAXIMIZE U.S. COAL PRODUCTION



designating lands as unsuitable for coal mining and standards for addressing surface subsidence from underground coal mining operations. The federal program also set up a mechanism to collect a fee to reclaim the unreclaimed sites from past coal mining activities.

States with coal reserves that wanted to regulate their coal industry developed their own state laws and regulations. The state programs had to be compatible with their federal counterparts. The state had the primary authority to regulate the coal industry within its borders, albeit with federal oversight from OSM.

A provision in **SMCRA (Section 522)** allowed any interested person to petition the state regulatory authority to designate a coal-bearing property as unsuitable for coal mining. If the regulatory authority found that mining would cause a significant and/or unavoidable impact to environmental resources or historic structures or that successful reclamation would not be feasible, the land could be declared off-limits to mining. There was no provision for compensation. This “designation of lands as unsuitable for coal mining” affected thousands of acres of coal throughout the coal-bearing regions of the country in the late 1980s and early 1990s.

Permits issued under SMCRA comply with all other applicable federal and state laws and regulations. Consequently, water discharges associated with a coal

mining operation are required to be permitted under federal or state programs governed by the Clean Water Act (formerly the Federal Water Pollution Control Act). These permits set specific effluent standards that the discharge must meet. Mining companies comply with these regulations.

Both **SMCRA and the Clean Water Act contain language that either directly or indirectly addresses the need to protect the water flow in perennial streams.** SMCRA establishes buffer zones for surface coal mining operations that require setback distances to be maintained. Underground mines, particularly those utilizing longwall mining systems, sometimes leave coal in place under certain conditions to avoid restricting stream flow. Large blocks of coal are left in place as the longwall system stops, is disassembled, reset at a new location, and restarted in order to protect streams.

Another provision of the Clean Water Act pertains to the dredge and fill permits issued by the Army Corps of Engineers. These permits allow for spoil, basically soil and rock, to be placed in valleys containing streams. These permits to create “valley fills” are essential to conduct a form of surface mining known as mountaintop mining. Over the past decade, this form of mining, which is conducted in central Appalachia (portions of Kentucky, Virginia and West Virginia) has come under increasing scrutiny as the mining operations have increased in size and number. SMCRA allows for mountaintop mining operations. The Corps of Engineers has established an extensive permitting process that allows placement of spoil material from the mountaintop mining operation into stream channels. The same permitting process for valley fills is also used for coal refuse disposal sites in Appalachia.

The impact of any mining operation on habitats containing threatened and endangered species (plants or animals) is also covered in SMCRA.

U.S. Fish and Wildlife Service and comparable state agencies review permit applications. If mining activities are likely to cause significant impact to these organisms, mining plans are revised to avoid impacts to their habitats. Where the risk to the

endangered species is deemed too great, the mining will not be allowed.

Another provision of the SMCRA-based regulations deals with **the potential for postmining discharges**. These are discharges from the mine (primarily underground mines) that occur after the mine is closed and the mine workings flood with groundwater. OSM has developed a policy, which has been adopted by most states, that prohibits permits from being issued for any new mine likely to have a postmining discharge. Currently permitted mines with postmining discharges were grandfathered under this policy and those mines are addressing the long-term funding for treating their discharges. Coal seams likely to develop postmining discharges after mining are evaluated. If they cannot be mined without postmining discharges, then they cannot be mined.

The balance between regulation and viable commercial progress is always difficult. Today's coal industry is committed to protecting the environment. It looks forward to working with state and federal agencies to comply with current

regulations and to provide input about regulations that experience suggests might need revision.

Transportation of Coal Is Varied and Cost-Efficient

Transportation has been crucial to coal growth and usage, and as a result the transportation industry has grown and improved its productivity.

Coal is now consumed in all regions of the United States. Electric generators consume about 90% of coal production, with coal exports, steel companies and industrial users representing the other primary coal markets. Each of these market sectors depends on timely coal delivery through an efficient transportation system encompassing railroads, trucks, barges and vessels and mine-mouth conveyor systems.

The major transportation modes carry significant amounts of coal. **Rail, truck and water delivery account for about 90% of coal shipments** to final U.S. destinations. In 2003, 680 million tons were delivered by rail, 115 million tons by truck and 114 million tons by water.

Coal for electric generation is now consumed in 46 of the 48 continental states with coal transported from the West, Interior and Appalachian supply regions. Of the more than 400 U.S. coal-burning power plants, approximately 58% are rail-served, 17% barge- and vessel-served, 10% truck-served, 12% served by multiple modes of transportation (primarily rail and barge), and 3% are mine-mouth plants with conveyor systems. All transportation modes have invested significant capital in infrastructure and equipment.

EIA projections for 2010 are for coal to be delivered for \$1.51/mm Btu, NG for \$7.19/mm Btu, and petroleum products for \$13.41/mm Btu.

Coal Is the Number One Commodity for Rail Transport

Coal is the largest single commodity transported by railroads. In 2004, coal accounted for 43% of tons originated by Class I railroads (the largest four in the United States; see Figure 7.6). No other commodity is as important to the rail industry as coal, and rail

Ten Largest Categories 2004 Class I Railroads

Million Tons Originated

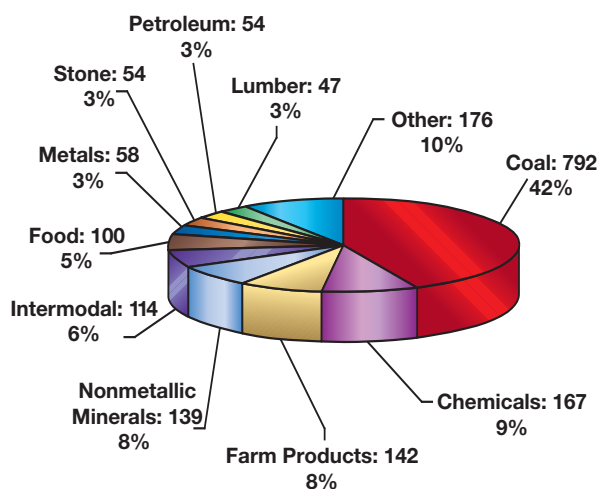


Figure 7.6 Source: American Association of Railroads

**DELINEATE U.S. COAL RESERVES AND TRANSPORTATION CONSTRAINTS
AS PART OF AN EFFORT TO MAXIMIZE U.S. COAL PRODUCTION**



railroads. This share has been growing and is expected to continue to increase as rail-served power plants, particularly in the East, have incremental electric generation capacity. From 1990, the year the Clean Air Act Amendments were enacted, through 2004, U.S. coal production grew from 1.029 billion tons to 1.111 billion tons, an 8% increase. During this same time period, coal tons originated by rail grew from 628 million tons to 792 million tons, a 26% increase.

transportation will continue to be the primary mode of coal transportation to the electric generating industry.

Today, railroads haul more coal for greater distances than ever before, and rail transportation of coal will grow as coal production increases. About two-thirds of U.S. coal production originates and terminates on

Coal represents 43% of the total tonnage transported by Class I railroads and accounts for 20% of total Class I rail revenue. Revenue per ton mile for rail coal transportation has declined by 24% in current dollars from 1990 through 2004 and 43% in inflation-adjusted terms (see Figure 7.7). **The present rail infrastructure and systems have transported increased coal volumes with declining**

Railroad Revenue Per Ton-Mile by Mileage Block: 1990–2004

Coal Haulage, Inflation-Adjusted 2004 Dollars

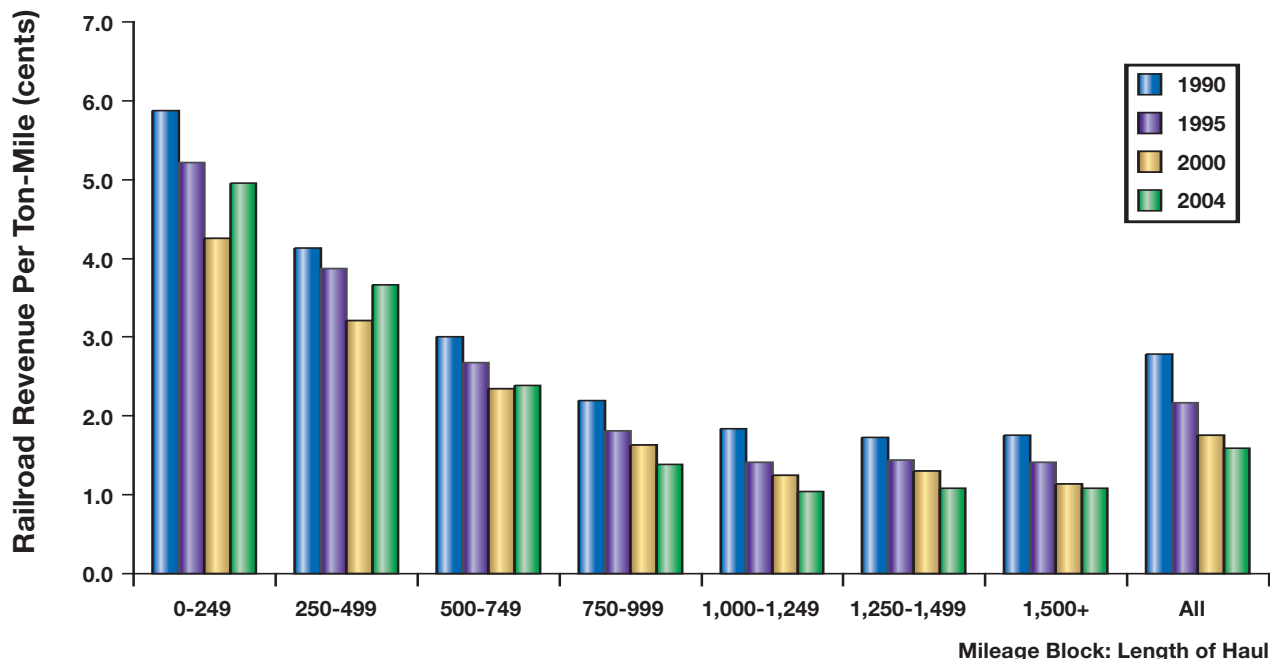


Figure 7.7 Source: American Association of Railroads

U.S. Electric Utility Delivered Cost of Fuel

Coal Is Stable While Gas & Oil Increase Significantly

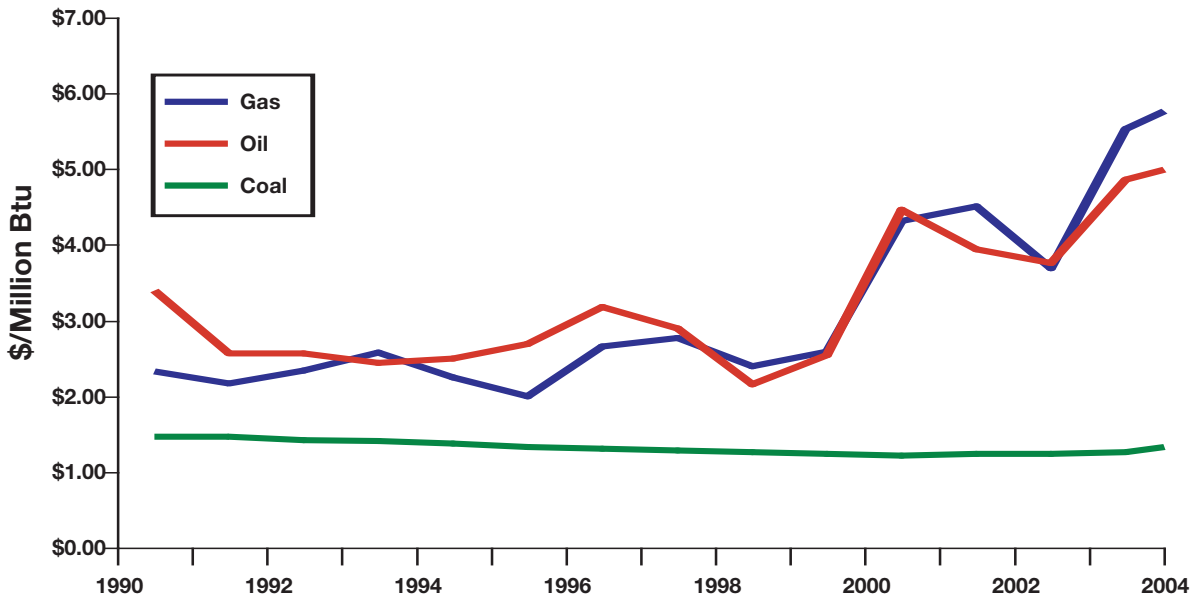


Figure 7.8 Source: EIA

rail rates. Though rates for coal transportation have begun to increase recently, **coal continues to be the fuel of economic choice on a delivered cost basis.**

The Staggers Rail Act of 1980 freed railroads from restrictive economic regulation and enabled them to compete in the marketplace. Over two and a half decades, railroads shed unproductive routes and achieved productivity improvements with resultant savings passed through to shippers in the form of lower freight rates. With capacity issues on many routes and an aging fleet of coal cars, railroads face unique challenges for capital investments to meet forecast increases in coal transportation demand.

Rails have invested billions of dollars in track structure and equipment as coal production and transportation requirements for all commodities have increased over the years. From 1994 through 2003, Class I railroads spent \$60 billion for capital expenditures. Recent rail capital programs highlight the accelerated reinvestment in rail infrastructure, much of which supports coal transportation.

With new capital investment to upgrade the rail infrastructure and increase productivity, delivered fuel costs to electric generators have been **essentially flat, in contrast to delivered prices for oil and NG that have seen price increases and volatility** (see Figure 7.8).

The Future: Transportation Modes Will Move More Coal Longer Distances

The EIA Annual Energy Outlook 2006 forecasts a 36% increase in coal production from 1.125 billion tons in 2004 to 1.530 billion tons in 2025.

While Appalachia production is projected to slightly decline, the Interior supply region is projected to have a 62% increase in production, totaling 90 million short tons (see Figure 7.9). The West is expected to have the greatest absolute growth, with an increase of 329 million short tons, or 57%. Most of this Western production is anticipated to be from the Powder River Basin (PRB). **This forecast continues the trend of growth and increased share of coal production coming from the PRB.** The Western forecast growth rate is 2.2% per year

Coal Production Is Spread Throughout Three Major Regions

Western U.S. Coal Production Predicted as Main Future Growth Source

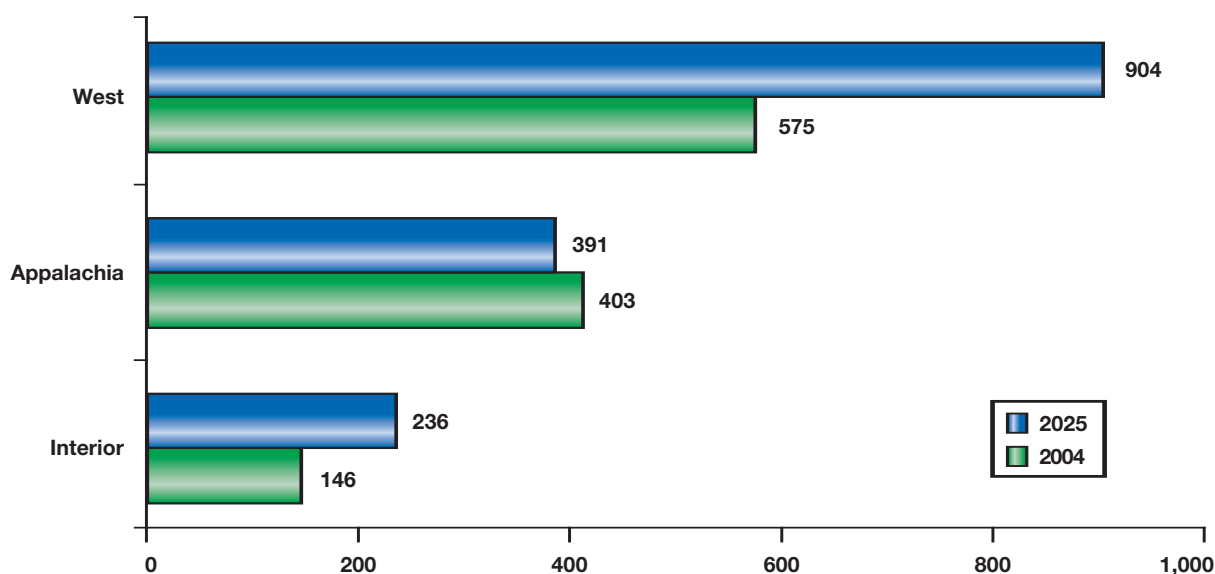


Figure 7.9 Source: EIA International Energy Outlook 2006

compared with the PRB growth rate of 5.4% from 1990 through 2004. In 1970, the year of the initial Clean Air Act, PRB production was less than 10 million tons. By 1990, the year the Clean Air Act amendments were enacted, production had increased to 200 million tons. PRB production then doubled to 420 million tons by 2004.

National coal supply and demand, based on available public reporting, illustrates **distinct differences in coal supply, transportation and economics**.

Northern, Central and Southern Appalachian coal supply is characterized by relatively high mine prices, higher Btu content and shorter transportation distances from mine to market. The Interior Illinois Basin is characterized by somewhat lower mine prices, lower Btus and shorter transportation distances to markets, while the Interior Gulf Coast lignites are generally mine mouth plants with low mine prices, very low Btu content, and no long-distance transportation requirements. Coal production in the West is dominated by the Powder River Basin with low mine prices, relatively low Btu content, and transportation requirements ranging from less than

100 miles to over 1,500 miles. Coal from the Central Rockies is characterized by higher mine prices, higher Btu value and short- and long-haul transportation requirements.

All transportation modes, and railroads in particular, will be called on in the future to transport coal longer distances to existing and new markets. Rail traffic density has increased dramatically over the last two decades as Class I railroads have shed excess track capacity (see Figure 7.10). Demand for rail transportation in 2004 and 2005 increased dramatically. As a result, rails are experiencing some short-term capacity challenges because of increased coal demand and volume increases for other commodities, particularly increases in intermodal traffic from both domestic and international origins.

Capital investments for locomotives, freight cars and track infrastructure will be needed to be put in place by individual rail systems to meet the growing demand for coal transportation forecast by the EIA. The capital-intensive rail industry annually already

spends significant amounts to maintain track and equipment on an ongoing basis. Additional capital for capacity expansion will be required for railroads to accommodate the anticipated volume increases.

Production projections for increased Western coal will require upgrades for loading facilities in the PRB, lane upgrades for increased tonnage moving from west to east via rail or rail-water transport, and increased delivery capability to new coal-fired plants that are being proposed throughout the United States.

Capacity also could be increased with two proposals for new rail construction in the West. The DM&E has been actively pursuing a track expansion project to upgrade its existing track and to build an extension into the Wyoming PRB. In addition, the proposed Tongue River Railroad is actively pursuing a rail construction project in the Montana PRB.



Environmental issues and energy legislation have a significant impact on U.S. coal production. Sulfur emission regulations have and will continue to affect these various coal supply regions as utilities without SO₂ scrubbers value low sulfur coal over other coal supply sources. SO₂ scrubber additions and changing emissions regulations can

rapidly alter the coal supply landscape and the resulting demand for transportation. This highlights the need for predictability of environmental regulations, as these regulations have a significant impact on coal markets and transportation requirements.

Eastern power plants are increasingly deciding to build new SO₂ scrubbers. This could force dramatic changes in coal markets as electric generators search for cheaper fuels for scrubbed plants that previously required low sulfur coals. Such shifts may

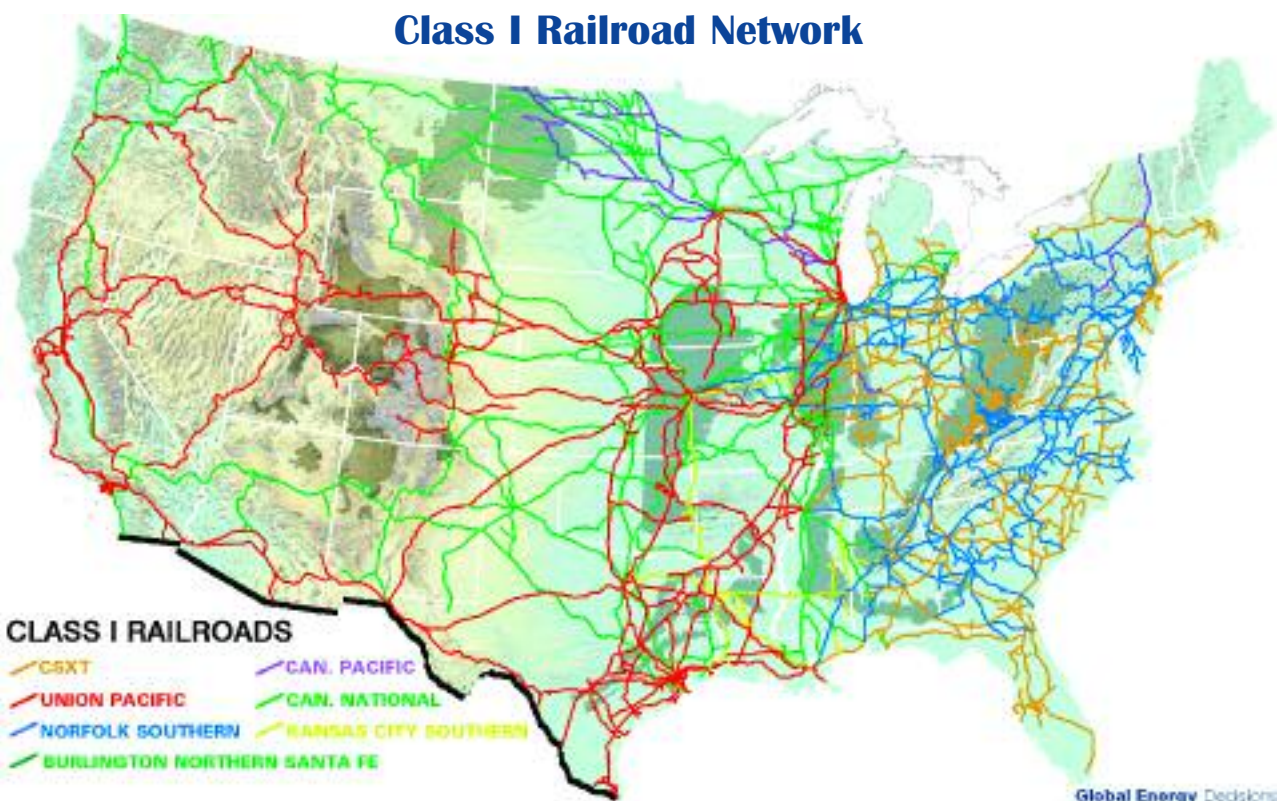


Figure 7.10

DELINEATE U.S. COAL RESERVES AND TRANSPORTATION CONSTRAINTS AS PART OF AN EFFORT TO MAXIMIZE U.S. COAL PRODUCTION

significantly alter the location of eastern rail capacity additions.

Railroads have been experiencing positive revenue growth and increased returns on investment but are still falling short of earning their cost of capital (see Figure 7.11). The gap between cost of capital and return on investment has been narrowing, but the need for adequate returns is required for additional ongoing capital investment.

Railroads are committed to operating in a deregulated market environment. Since the Staggers Act of 1980, railroads have increased productivity and expanded markets, and capital has flowed to the industry. For this progress to continue with capital additions for increased coal growth and transportation requirements, capital markets must be accessible to the rail industry, and operating in a deregulated environment is central to the success of the industry.

Railroads' performance and coal growth over the past three decades indicates the capability to move increased coal tonnage through the nation's rail

network. In the future, appropriate capital investments consistent with appropriate returns on investment will provide the capability for individual railroads to handle increased coal demand. Even with the forecasted dramatic coal growth and capital investments by the rail industry, delivered coal prices to electric generators will have a significant competitive advantage over delivered fuel costs for gas and oil in the years ahead. In 2005, both NG and oil prices exceeded \$10/mm Btu, in contrast to coal being delivered to electric generators in the range of \$1.50/mm Btu.

Barge Transportation: Inherent Cost Advantages—and Challenges

During 2004, about 150 million tons of coal were transported on the inland waterways for electric generation. On a national basis, water carriage accounts for 5% of freight costs while producing 15% of all ton miles. Escalating coal burns and longer hauls will place high demands on the U.S. transportation system. The barge industry plays a crucial and often unseen role within that system, moving cargoes at low cost and with minimal strain

Railroads Do Not Earn Their Cost of Capital

Additional Investment Will Be Required for Further Expansion

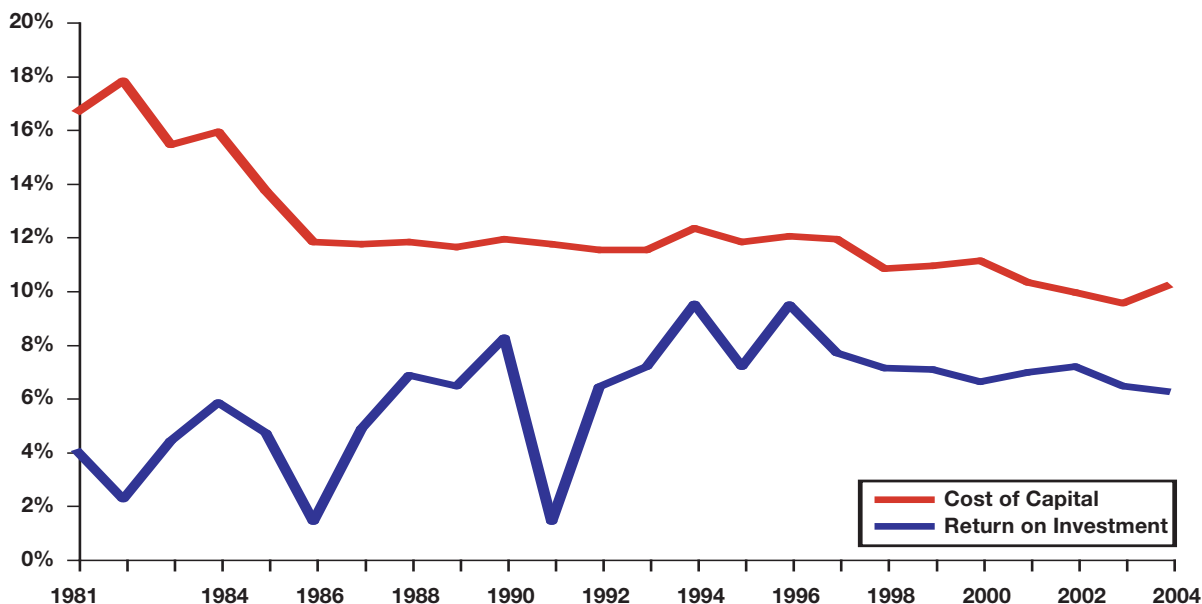


Figure 7.11 Source: STB and carrier reports to the STB

on the nation's infrastructure and environment, which is an important consideration for addressing these issues.

The current condition and age of the waterways' lock and dam infrastructure pose a major challenge to future demand growth. During recent years maintenance expenditures have changed little despite a number of unexpected and prolonged outages, creating a backlog of about \$600 million per recent U.S. Army Corps of Engineers (USACE) estimates of necessary Operations and Maintenance activity. Fortunately, such problems have not yet disrupted the production of electricity.

Although a handful of infrastructure projects have improved reliability and velocity, the USACE has been unable to address a host of urgent needs due to budget constraints. The barge industry pays a user tax into the Waterways Trust Fund to pay half the costs for such projects; however, budget pressures have limited expenditures even from this self-funding source of revenue.

The Waterways Trust Fund currently totals about \$370 million and annually receives more than \$90 million from user taxes. Spending required for timely infrastructure upgrades during the next 10 years as identified by the Inland Waterways Users Board totals about \$1.6 billion. The resulting economic boost, however, makes this a worthwhile, even compelling, investment.

About one-third of today's 17,000 hopper barges are expected to retire during the next five years, requiring \$2–3 billion of new assets. Although



market rates currently support such investment, shipyard capacity for new builds constrains near-term deliveries. The longer-term outlook for new construction is more favorable.

With adequate Congressional appropriations for the system's priority needs, the inland waterways can cost-effectively expand its capacity to move more cargo throughout much of the United States. Selective investment in the nation's waterways infrastructure and renewal of marine assets will facilitate the delivery of energy and other basic materials. Commercial barge operations enhance flexibility and reliability for a diverse group of shippers central to our nation's economic activity.

Transportation by Truck

Over-the-road truck transportation is a significant component of the U.S. coal industry. The U.S. Energy Information Agency indicates that more than 120 million tons of coal—or 8% of all U.S. coal—is trucked at some point in its transit from mine to electric generation, metallurgical coke and industrial coal consumers. Truck transportation is an integral part of the total coal logistics chain, both locally and nationally.

DELINEATE U.S. COAL RESERVES AND TRANSPORTATION CONSTRAINTS AS PART OF AN EFFORT TO MAXIMIZE U.S. COAL PRODUCTION

At the local level, trucks transport, at some point in its movement to the customer, an estimated 75% of the coal mined in Kentucky. *Kentucky Coal Facts* states that more than 1.8 billion ton-miles annually are incurred in the truck transportation of coal in Kentucky. Likewise, in Utah, almost 80% of the state's 21 million tons of coal production is transported by truck from remote mines to truck-to-rail loading facilities or directly to the customer. The West Virginia Office of Miners' Health Safety and Training reports that over 28 million tons of coal are initially transported by trucks from individual mines.

In general, truck coal haul lengths are less than 100 miles (one way). The EIA estimates that the average trucked coal distance is 32 miles (one way). Coal movements by truck tend to be over short distances, providing dedicated links between coal origins and the marketplace via truck-to-rail, truck-to-barge and truck-direct movements.

Almost one-third of all coal delivered to U.S. power generation plants is subject to at least one transloading somewhere along the transportation chain. For instance, Utah coal delivered to a Mississippi River power plant may include a 45-mile truck haul to a rail loading facility, a rail move of 1,400 miles to a barge loading terminal on the Mississippi River, and a 400-mile barge haul to the power plant. This multimodal movement represents a total distance of 1,845 miles. The EIA suggests that the multimodal distances are increasing with an average 1,088 miles. The coal, truck, rail and barge industries must recognize that truck transportation is an important component of the U.S. multimodal coal supply chain. More and more coal deliveries will be from longer distances and require more modal transfers. Transportation providers must continue to work together to provide integrated, efficient delivery systems so that customers receive best-value service.

Industrial coal customers have experienced higher rail rates, due in part to most industrial customers



not having rapid unit train unloading facilities. One option is for multiple industrial coal consumers, in proximity to one another, to consolidate coal deliveries into a common rail-to-truck transloading facility. The common rail-to-truck transload facility is developed to receive unit trains, store individual customers' coal and transport coal to each industrial plant on a just-in-time basis.

Each state regulates truck transportation through weight laws (bridge formulas) that define the Gross Vehicle Weight (GVW), which ultimately translates into payloads. GVW, depending on the state, generally ranges between 80,000 pounds (e.g., Pennsylvania) to 129,000 pounds (e.g., Utah) with a corresponding payload of 28 tons and 45 tons. The ability of the existing road system to handle larger and heavier loads is one of the major factors driving individual state weight laws.

Like other modes in the coal transportation chain, the trucking industry has made substantial gains in productivity, equipment design and overall capabilities. During the last few years, truck transportation equipment improvements have included lighter-weight tractors, more powerful and fuel-efficient engines, lower maintenance needs due to better component design and safer operation because of tighter suspensions and superior braking systems.

In the coming years, the trucking industry, as well as the mining industry, the railroads and the barge industry, will face many of the same challenges: finding and retaining experienced employees (drivers, maintenance, management, etc.), increasing diesel fuel costs as well as parts costs and availability (e.g., tires), and the long-term maintenance and expansion of the U.S. highway infrastructure. The U.S. coal truck transportation industry will continue to develop long-term solutions for these challenges.

Terminal Facilities Enhance Supply Chain Efficiency

Coal terminals are present on all major waterways, lakes and coastal ports in the United States and provide a strategic service in moving more than 250 million tons of coal from producer to consumer. As the middle link in the supply chain, coal terminals allow the connecting railroads, barge lines, trucking companies, vessel owners and utilities to become more efficient by using the terminals to receive, stockpile, blend and dispatch coal.

Examination of the coal terminal network is best evaluated on a regional basis.

Great Lakes Terminals have capacity for more PRB coal

Great Lakes loading terminals exist on Lakes Superior, Michigan and Erie. Features of the Great Lakes loading terminals include high stockpile capacity and unit train service due to the distance from the producing coalfields. Total lakes tonnage has remained relatively flat over the past five years at 41 million tons, but the distribution and type of coal have changed.

Sufficient capacity exists with terminals on Lake Superior and Michigan to process the projected increase in PRB production. In Canada, the Ontario government has made the decision to phase out all coal-based electric plants by 2009, freeing up additional capacity to move western coal to the Great Lakes region for domestic consumption.

Inland waterway terminals vary in ability to handle new capacity

Inland waterway terminals can be further broken into two primary regions, Northern/Central Appalachia Terminals and Western Coal Terminals.

In the East, there is a very high density of operations that provide a multitude of value-added services. Barriers to entry in this region are extremely low, with simple operations requiring little more than a fleeting area on the river, a few conveyors and simple mobile equipment. The eastern region is characterized by surplus capacity that can be easily pressed into service on short notice. With the anticipated reduction in Central Appalachian coal production, more eastern coal terminals capacity will become available.

In the western inland waterways along the Central Mississippi River, the Southern Ohio, the Tennessee and other tributary rivers, terminals range from small direct load operations to some of the largest terminals in the country. Smaller terminals tend to serve the local Illinois Basin mines. There are also a number of terminals that are poised to serve the west coal producing regions (Powder River Basin, Colorado and Utah) with eastern water movements. These terminals have the capacity to efficiently unload 135-car and longer trains and to efficiently blend and reload to barges.

Coastal terminals offer unused capacity, value-added services

The Gulf and East Coast terminals provide a multitude of coal options for consumers on or near deep-water ports. Coastal terminals can receive coal via barge or rail for distribution back to ocean-going barges or to vessels. U.S. coastwise terminals have seen a resurgence in throughput in the past two years with the increase in metallurgical grade coals moving

DELINEATE U.S. COAL RESERVES AND TRANSPORTATION CONSTRAINTS AS PART OF AN EFFORT TO MAXIMIZE U.S. COAL PRODUCTION

to the export market. This point is highlighted as near metallurgical grade coals have the ability to switch from utility consumption to metallurgical grade with only minor adjustments in the coal processing.

Recent events in New Orleans have shown the vulnerability of the coastal terminals to major storms. Two major terminals are located on the lower Mississippi River and serve as distribution hubs to the west-central Florida utilities and incurred significant damage. The effects of this storm demonstrate the vulnerability of the coal supply chain for a region or local utility. To overcome the loss incurred by this storm, several coastal terminals have stepped up to provide ongoing service.

Through support to the inland waterway infrastructure, terminal operators can continue providing the value-added services of ratable delivery, stockpile management, coal blending to specification and reliable supply chain management.

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PENN STATE STUDY, “ECONOMIC IMPACTS OF COAL CONVERSION INVESTMENTS”*



The National Coal Council finds that the United States could increase coal production by 1,300 million tons per year by 2025 for Btu conversion technologies and still have a supply that would last at least 100 years. Maximizing coal production could reduce dependence on imported energy, and the economic benefits for the United States would be enormous. An independent research analysis study conducted at Penn State University for this report shows that using upwards of 1,300 million tons of additional coal



for Btu conversion technologies would result in more than **\$600 billion** in increased annual economic growth and **1.4 million new jobs per year** by 2025. To achieve these gains, a capital investment in Btu conversion technologies of some \$500 billion will be required, or \$350 billion on a present value discounted basis. In return, a present value discounted benefit of cumulative

GDP gains of some **\$3 trillion** is expected. Such benefits will allow more Americans to live longer and better as they manufacture the energy needed to sustain a growing U.S. industrial economy.

* Economic analysis conducted at Penn State University, 2006; see Volume II for analysis detail.

PENN STATE STUDY, “ECONOMIC IMPACTS OF COAL CONVERSION INVESTMENTS”

FINDINGS

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DISCUSSION

As the country’s most significant energy asset, coal has delivered inexpensive electricity to American homes and businesses, supporting our high quality of life and our ability to compete in global markets.

With our vision, the U.S. coal industry will play an important role in the future of world energy markets. Coal will expand its dominant share in electric power generation and become a feedstock for gaseous and liquid fuels that will augment increasingly scarce supplies of conventional petroleum and natural gas (NG). This yields profound results for the U.S. economy:

- After 20 years, coal Btu conversion would position U.S. energy markets with prices nearly 33% below those that would prevail without such activities.
- Lower energy prices resulting from coal energy conversion and the stimulus from plant construction and operation would result in significant benefits. By the end of the forecast

period, gross domestic output would be more than \$600 billion greater and employment 1.4 million greater than the EIA base case forecast.

- The present discounted value of the cumulative gains in GDP from 2007 to 2025 is \$3 trillion.

Obviously, capital requirements for coal Btu conversion are significant, with a present discounted value of more than \$350 billion. Even over this relatively short timeframe, these costs and benefits demonstrate that society reaps a substantial rate of return from investments in coal energy conversion. Indeed, this rate of return is conservative because the Btu conversion plants would be operating and generating benefits well beyond the year 2025.

The principal force that drives these benefits is the capacity-constrained nature of the world energy complex. As Hurricanes Katrina and Rita demonstrated, even a relatively small reduction in the availability of crude oil, NG and petroleum refinery capacity can cause a dramatic increase in prices. With the likelihood that world oil and NG production capacity will peak, substantial geo-political risks associated with oil imports, and the voracious appetite for energy in developing countries, it is likely that world energy markets will continue to operate at or near production capacity limits for the foreseeable future. That is why significant incremental supplies — such as those from Btu coal energy conversion — would significantly reduce energy prices.

Even though the U.S. and other market economies are far more flexible in responding to energy price shocks than in the past, there remains a measurable relationship between energy prices, economic growth and employment. High energy prices reduce consumer discretionary income, consumer confidence and consumption. Business costs increase and profitability declines under the weight of higher energy prices. The coal energy conversion future envisioned in this report will ensure protection from these adverse impacts and foster the low inflation/high productivity economic environment the United States has enjoyed since the early 1990s.

In short, the vision for coal developed in this report should be considered an integral component of economic policies for ensuring long-term economic growth and full employment.

Under reasonable projections for world energy demand and somewhat more uncertain expectations for conventional oil and NG production over the next two decades, the world appears to be on a threshold of a historical transition to a growing reliance on more unconventional sources of energy. This transition will involve a shift from primary energy extraction to a greater reliance upon energy product manufacturing that will require significant infusions of capital, labor and technology.

Such a transition is similar to the historical development of many mineral resources in which high-grade deposits were depleted and replaced with large volumes of low-grade reserves that became economic with advances in technology. For example, high oil prices are once again renewing interest in developing oil shale and coal liquefaction. Similarly, expensive NG is stimulating interest in coal gasification.

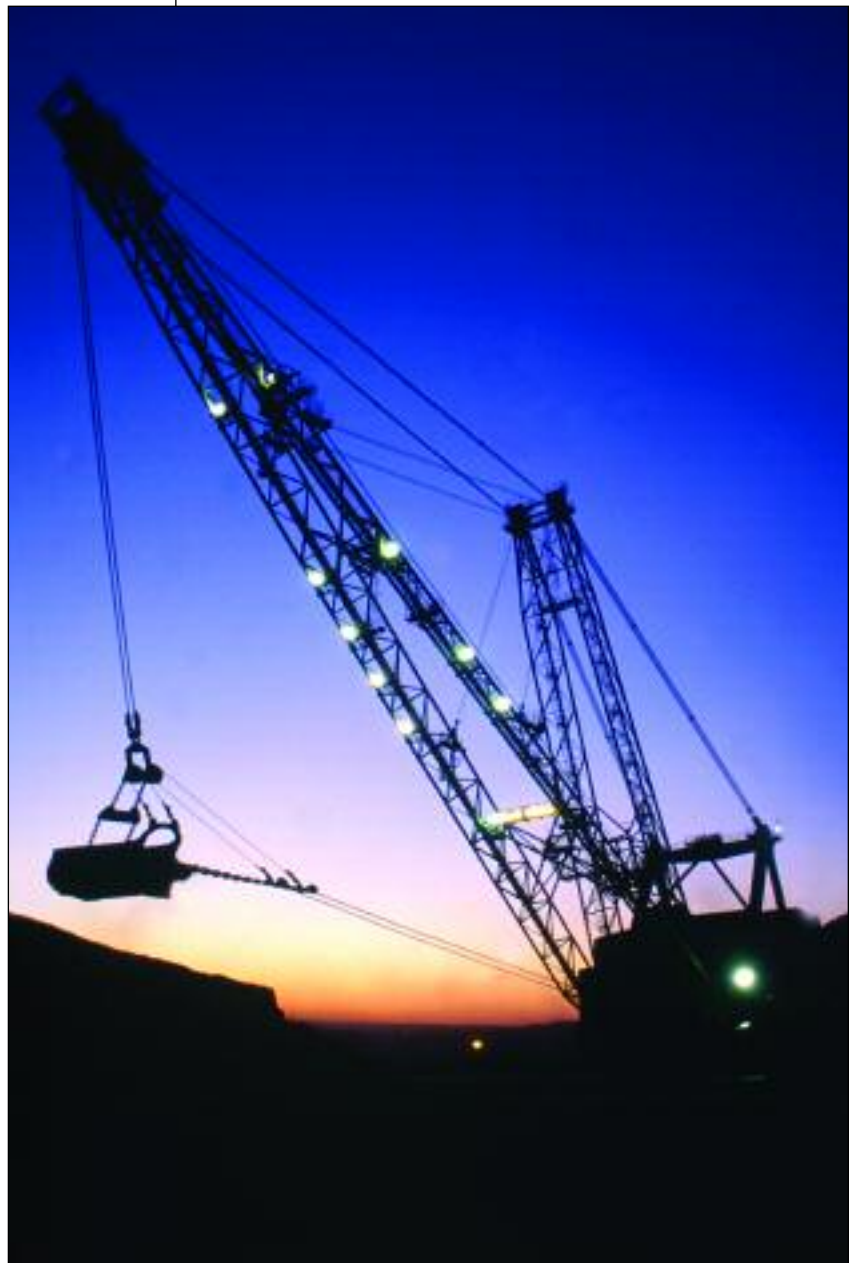
Clean-Coal Technologies Are Real Economic Competitors to Conventional and Unconventional Oil and NG

The U.S. government, in partnership with the coal industry and electric generation companies, has been developing these technologies to reduce and, in some cases, virtually eliminate the environmental residuals generated from using coal to produce electricity.

After more than 20 years of development, these technologies are now poised for full-scale commercial development. With superior environmental performance and competitive costs, these coal

technologies could displace significant quantities of imported oil and NG.

An import displacement could significantly reduce our energy trade deficit, which presently accounts for nearly half of our current trade account deficit. Also, additional energy supply in a capacity-constrained market would reduce the frequency of periods with high energy prices. In such a world, hurricanes would no longer imply sharply higher prices for gasoline and NG. Coal-based energy manufacturing would stimulate domestic production of coal and employment in rural coal-producing



PENN STATE STUDY, “ECONOMIC IMPACTS OF COAL CONVERSION INVESTMENTS”

regions in Appalachia, the Midwest and Rocky Mountain regions. The construction of coal gasification and liquefaction plants would stimulate a wide range of industries, including building trades, steel, concrete and industrial equipment. The operation of these facilities would create large numbers of high-wage, skilled manufacturing jobs and revitalize the manufacturing base of America.

Embarking upon such a path will involve challenges. Perhaps the most significant involves uncertainty. Building a coal-based energy industrial infrastructure will involve significant capital investment. While the timing of these investments is uncertain, there are already several coal energy conversion projects proposed and under development. Peabody Energy recently proposed a \$1 billion coal gasification plant in Illinois that would produce 35 billion cubic feet of pipeline-quality gas per year. In Pennsylvania, a coal-to-liquids plant is under construction that would use waste coal to produce ultra-clean diesel and jet fuel. As long as oil and NG prices remain above \$40 per barrel and \$6 per thousand cubic feet, respectively, additional coal energy conversion plants are economically attractive.

The Btu Conversion Scenario Through 2025

To quantify the benefits of the coal energy conversion vision, this study develops a plant construction scenario from now to the year 2025. Several assumptions are required.

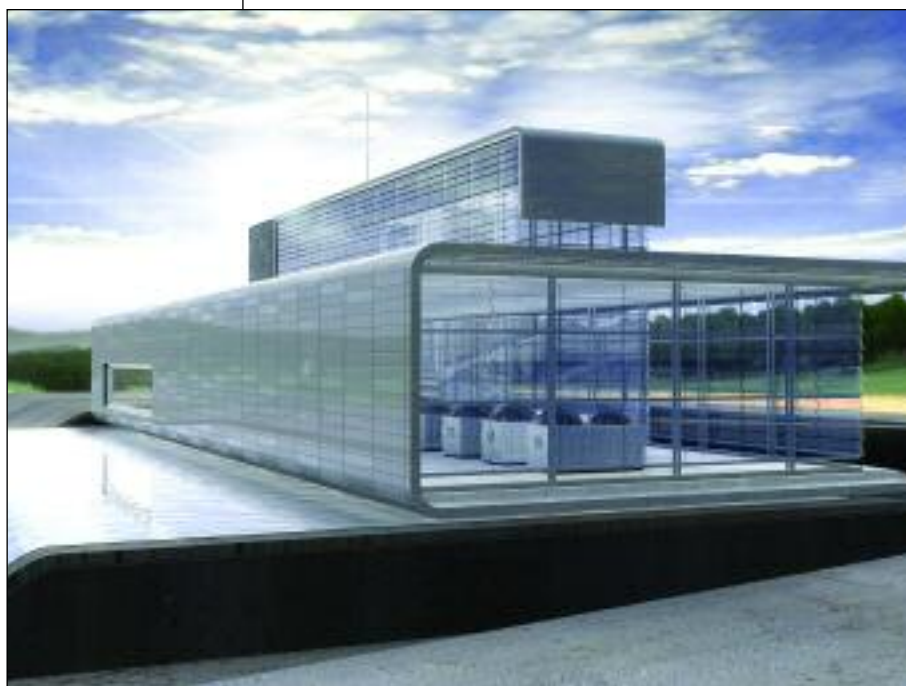
The first assumption is that two new plants will be started in 2007, which appears plausible given recent announcements of new IGCC power plants, coal-to-liquids plants and new coal-fired power plant construction. On average, these plants will take four years to build. Assuming each plant consumes 6 million tons of coal per year, an average of 1.5 new plants must be started each year to reach the goal of

1,300 million tons of additional coal for Btu conversion in the year 2025. The trajectory of new plant starts and incremental coal consumption per year is shown in Figure 8.1.

These plant starts include new conventional coal-fired power plants, coal-to-gas plants such as IGCC and methane-producing facilities, coal-to-liquids plants and plants producing hydrogen. The gradual escalation of new plant starts represents the phased acceleration of engineering construction capacity to build coal-energy manufacturing facilities.

Impact on Energy Markets — A Lower Equilibrium Price for Energy

Energy is used in many different forms, including electricity, petroleum products and NG. To simplify the following analysis, we consider the aggregate supply and demand for energy, which would include all final uses of energy and production activities to supply these uses. While the actual mix of conversion activities between liquid and gaseous products is uncertain, coal conversion will unambiguously increase the total supply of thermal energy units. Coal energy conversion would provide another path to produce final fuels, such as diesel fuel, methane, jet fuel or even gasoline. The amount of thermal



Study Shows Increasing Trajectory of New Plants and Additional Mining Will Have Profound Effect on U.S. Economy

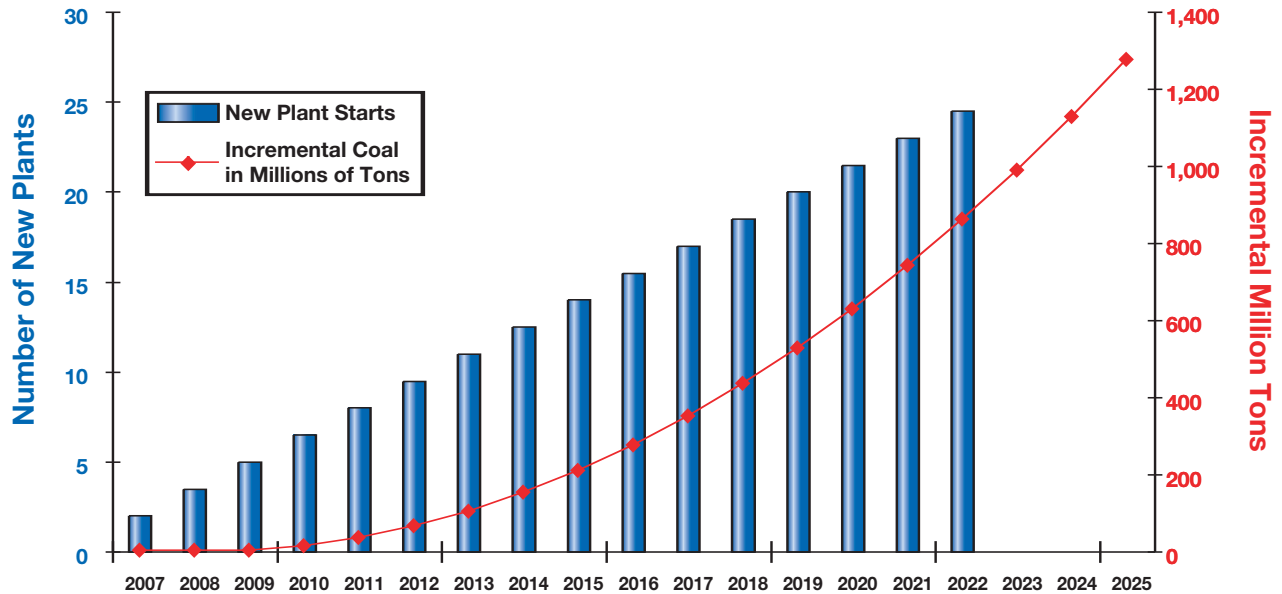


Figure 8.1 Source: Economic Analysis Conducted at Penn State University, 2006

energy units, or Btus, from coal devoted to these activities would be proportional to their useful energy in end uses after correcting for conversion efficiency. In essence, the greater amount of coal output envisioned in this study would increase the aggregate supply of Btus to the economy.

Based upon the laws of supply and demand, coal energy conversion increases the aggregate supply of energy and lowers equilibrium energy prices. For markets that are operating at capacity constraints, increased supply can dramatically reduce prices. Figure 8.2 illustrates this reduction in market equilibrium prices.

The vertical portion of the supply schedule represents a capacity constraint. The entry of coal conversion plants into the energy market shifts the supply schedule and lowers equilibrium

prices from P_0 to P_c . When the market is operating at capacity, the size of the price decline is a function of the increment in energy supply from coal conversion and the price elasticity of demand.

The price elasticity of demand is defined as the percentage change in quantity induced by a percentage change in price. Figure 8.2 shows the

percentage change in quantity that is given by the horizontal shift in the supply schedule. Based upon a survey of energy demand studies completed by Carol Dahl, Director of the Colorado School of Mines/Institut Français du Pétrole (CMS/IFP) Petroleum Economics and Management, a reasonable estimate of the

own price elasticity of demand for aggregate energy demand is -0.30. If the percentage increase in aggregate energy supply provided by coal conversion



PENN STATE STUDY, “ECONOMIC IMPACTS OF COAL CONVERSION INVESTMENTS”

Impacts of Coal Conversion on Energy Supply and Prices

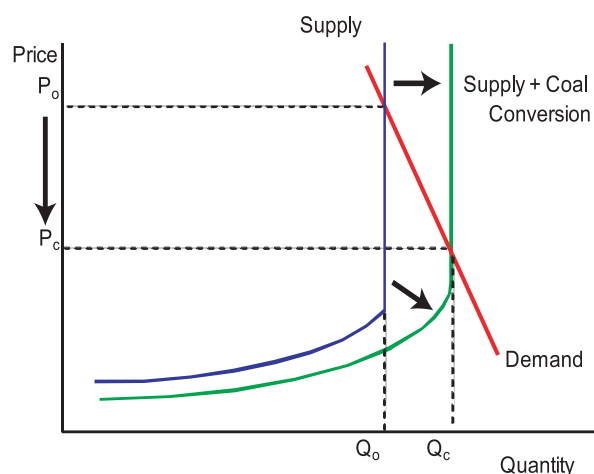


Figure 8.2 Source: Economic Analysis Conducted at Penn State University, 2006

is 10% and the price elasticity of demand is -0.30, then the percentage reduction in the energy price is 30%.

The buildup of additional energy from coal would reduce energy prices from where they would be without coal energy conversion. For example, energy prices would be 2% lower in 2012, two years after the first plants begin operating in 2010, and nearly 10% lower in 2017. If these incremental supplies continue to enter the market, energy prices would be 33.3% lower by the year 2025 (see Figure 8.3).

Again, this price reduction is substantial because the coal conversion plants would relax energy production capacity constraints. If energy industries were operating with excess capacity, which seems unlikely in the foreseeable future, the price reductions induced by coal conversion would be much smaller.

Another factor contributing to smaller price reductions is a larger absolute value for the energy price elasticity of demand, but this seems unlikely absent major technological change affecting energy consumption patterns and consumer behavior.

Local and Regional Impacts of Coal Energy Conversion

The coal energy conversion plants will likely be located near coal-producing regions to minimize transportation and other logistical costs. A wide swath of rural America from Appalachia through the Midwest, Great Plains and Rocky Mountains will directly benefit from the jobs and economic stimulus these plants will generate. Many communities in these regions have not shared the benefits of the high-tech boom of the 1990s. Instead, many of these communities have suffered from plant closings by companies that could not compete with cheap manufactured imports from Asia. The construction of coal energy conversion plants will revive these communities and help restore the social fabric frayed by years of falling employment, declining income and rising emigration.

The impacts of coal energy conversion plants on local and regional communities will likely be

very similar to the impacts generated during the construction and operation of conventional coal-fired power stations. For example, Professor Jim Musemeci of Southern Illinois University estimated in an economic analysis study that the 1,500-megawatt Prairie State electric generating facility in Washington County, Illinois, would inject more than \$2.8 billion into the state economy, generate more than \$200 million in new tax revenues for state and local governments, create more than 1,800 construction jobs per year during the building



of the mine and plant, and create 450 permanent mine and power plant jobs.

These gains are realized as the direct expenditures to build and operate these plants stimulate the demand for good and services in other sectors of the economy. For example, the construction of coal energy manufacturing plants would increase the demand for steel, concrete and other building materials. There would be subsequent rounds of spending, known as indirect impacts, as these sectors draw on their suppliers. Finally, there are induced impacts from the consumption spending by households from higher income levels generated by the direct and indirect economic impacts. For example, workers at coal energy conversion plants purchase local services, such as dining, entertainment and health care, which generate income in these sectors.

The vision for coal described in this study would create over 200 coal energy conversion plants scattered from Pennsylvania to Wyoming, each roughly the size of a 1500 MW power plant. Most of these plants will be in rural areas with relatively high

unemployment and limited resources for schools and other public services. With the income generated from coal energy conversion plants, these communities can restore these services and improve the quality of life not only for employees at the plants but also for their neighbors and families.

Three Continuing Benefits to the U.S. Economy

Coal energy conversion will affect the economy in three ways:

- First, the construction of plants will stimulate employment and increase the demand for building construction materials such as steel, concrete and other basic building materials.
- Second, once plants begin operation, the production of energy products will generate additional output, income and employment both directly and indirectly throughout the economy.
- Third, the macroeconomic stimulus from lower energy prices will boost consumer spending and investment and improve our trade balance.

Study Shows Average End-Use Energy Prices With and Without Increased Coal Utilization



Figure 8.3 Source: Economic Analysis Conducted at Penn State University, 2006

PENN STATE STUDY, “ECONOMIC IMPACTS OF COAL CONVERSION INVESTMENTS”

The changes in Gross Domestic Product (GDP) resulting from coal conversion are estimated based upon standard output and employment multipliers published in the economic literature. In this study, we use an output multiplier of 2.6 reported by D.J. Shields et al., which means that total output increases \$2.6 for every dollar spent on coal energy conversion plant construction and every dollar generated from the resulting energy output. The employment multiplier used to estimate the indirect and induced job gains from direct employment in construction and operation of energy conversions plants is 3.23, which is also drawn from the study by Shields.

The use of output and employment multipliers based upon input-output models of the economy assumes that relative prices are fixed. The findings above, however, clearly demonstrate that energy prices fall

from coal energy conversion. Accordingly, we need measures of how GDP and employment change with energy prices. For employment, we use the study by S.A. Brown and J.K. Hill that surveyed the major economic forecasting services and found the elasticity between national employment and oil prices is -0.0193. The elasticity of Gross Domestic Product and energy prices is -0.048, which is an average of the range reported by S.A. Brown and M.K. Yucel, based upon an Energy Modeling Forum study by B.G. Hickman.

The economic impacts of the coal energy conversion scenario considered here are significant. By the end of the forecast period, gross domestic output is more than \$600 billion greater and employment is more than 1.4 million higher than the base case (see Figure 8.4). The GDP gains occur from the

Impacts on Gross Domestic Product and Employment

Year	Changes in GDP Billions of 2004 Dollars				Changes in Employment (Annual Jobs Created)			
	Lower Energy Prices	Plant Cons.	Energy Output	Total GDP Gains	Lower Energy Prices	Plant Cons.	Energy Output	Total Jobs
2006	0	0	0	0	0	0	0	0
2007	0	2.3	0	2.3	0	6,296	0	6,296
2008	0	6.3	0	6.3	0	17,314	0	17,314
2009	0	12.0	0	12.0	0	33,054	0	33,054
2010	2.3	19.5	3.6	25.4	10,153	53,517	2,670	66,339
2011	6.5	26.3	9.8	42.6	27,766	72,405	7,343	107,514
2012	12.5	33.2	18.5	64.2	52,619	91,293	14,019	157,931
2013	20.7	40.1	29.6	90.4	85,005	110,181	22,698	217,884
2014	31.0	46.9	42.6	120.6	124,833	129,069	33,379	287,281
2015	43.7	53.8	57.8	155.3	171,876	147,958	46,063	365,897
2016	58.8	60.7	75.1	194.6	226,251	166,846	60,750	453,846
2017	76.6	67.5	94.1	238.2	288,964	185,734	77,439	552,137
2018	97.0	74.4	115.5	286.9	359,390	204,622	96,131	660,144
2019	119.9	81.3	137.7	338.9	437,068	223,511	116,826	777,405
2020	145.7	88.2	160.8	394.6	521,584	242,399	139,524	903,507
2021	174.5	95.0	184.2	453.7	613,753	261,287	164,225	1,039,264
2022	206.3	101.9	207.4	515.6	713,273	280,175	190,928	1,184,376
2023	241.4	79.0	230.4	550.8	820,519	217,214	219,634	1,257,368
2024	279.6	54.4	252.4	586.4	934,010	149,532	250,342	1,333,884
2025	322.0	28.0	273.0	623.1	1,056,719	77,127	283,054	1,416,900

Figure 8.4 Source: Economic Analysis Conducted at Penn State University, 2006

combination of lower energy prices and higher energy output. For instance, energy price reductions generate over \$320 billion in output while the induced output gains from the coal energy conversion plants are \$273 billion by the end of the forecast period. Employment gains arise primarily from the impacts of lower energy prices. In this case, service sector employment is stimulated by the higher level of discretionary income available to consumers made possible by the lower energy prices from the additional production from the coal energy conversion complex.

In short, the benefits of expanding coal production by almost 1,300 million tons per year by 2025 would touch every American for decades to come:

- energy prices nearly 33% lower after 20 years
- Gross Domestic Product more than \$600 billion higher and with 1.4 million more new jobs
- cumulative gains in Gross Domestic Product of \$3 trillion from 2007 to 2025

Further, if the carbon dioxide from coal energy conversion plants were utilized on a large scale, domestic oil production could increase by as much as 3 MMbbl/d. This additional oil would substantially contribute to even greater reductions in energy prices and a present value of cumulative gains in economic output of more than \$4 trillion.

Overall, the profound economic benefits identified here would translate into a higher quality of life for all Americans for generations into the future. The United States can be a significantly safer and more prosperous nation. Coal can provide this better future.



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