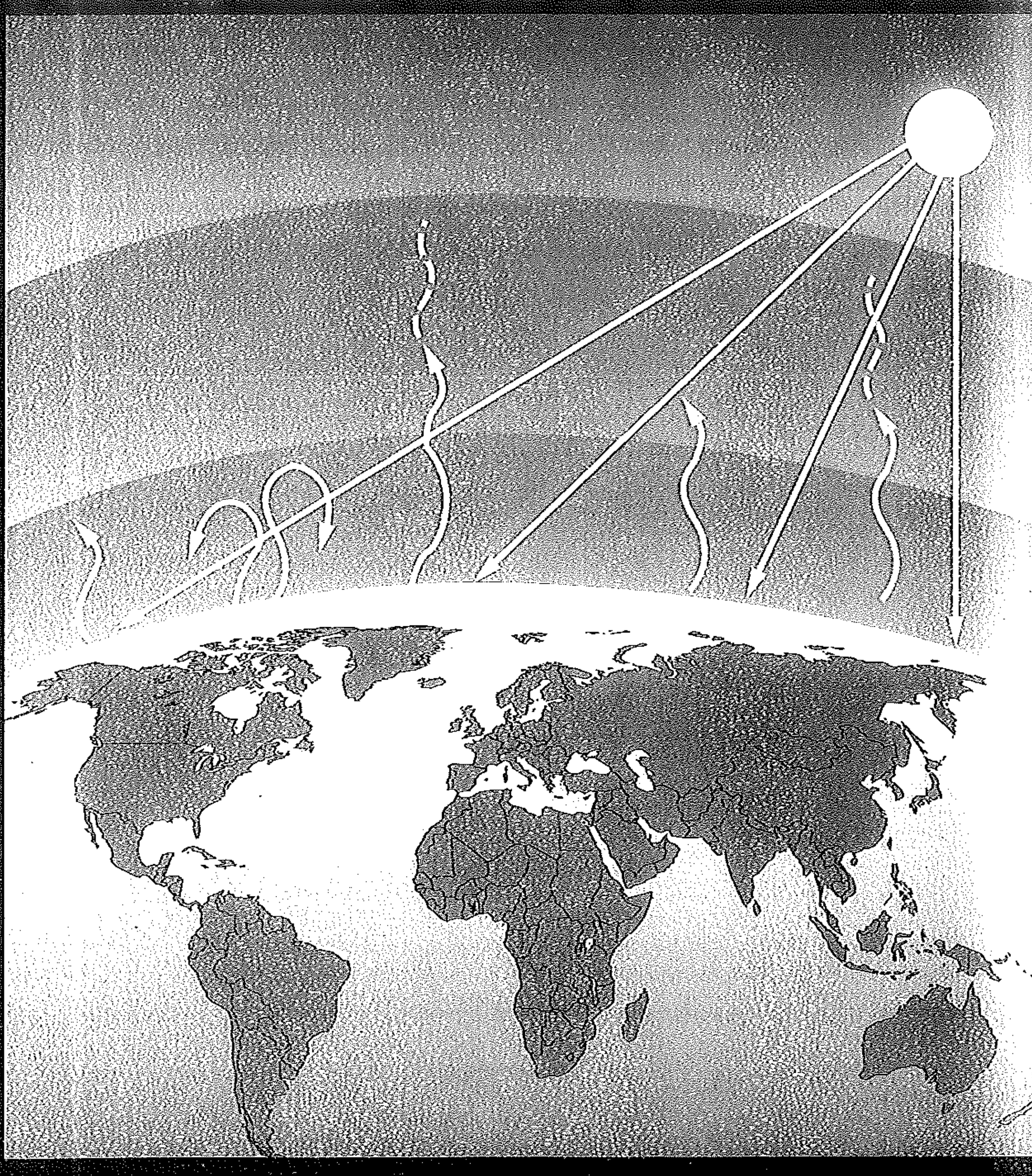
Coal's Role

in Achieving Economic Growth and Environmental Stability



November 1998

THE NATIONAL COAL COUNCIL

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E. Linn Draper, Jr., Chairman

Robert A. Beck, Executive Director

U.S. DEPARTMENT OF ENERGY

Bill Richardson, Secretary of Energy

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.

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COAL'S ROLE IN ACHIEVING ECONOMIC GROWTH AND ENVIRONMENTAL STABILITY:

An Interpretive Report on Recent Global Climate Change Studies with a Long Range and Strategic Perspective on Enabling Technologies

The National Coal Council
Chairman: Dr. E. Linn Draper, Jr.
Vice Chairman: Mr. Stephen F. Leer

Coal Technology Subcommittee
Co-Chairmen: Dr. Robert E. Nickell and Dr. George T. Preston

November 1998

Such advancements are needed as well so that the U.S. can optimize responses to the climate change issue. Many carbon sequestration technologies, especially those of the non-agriculture and non-forestry type, are in their infancy. Sequestration has the potential to reduce carbon in the atmosphere without suddenly abandoning our existing energy infrastructure. Additional and consistent development of these technologies is critical to resolving this difficult issue.

The Council anticipates working in partnership with you on implementing all of the recommendations contained in this report. The Department should participate technologically and financially in preserving fuel diversity and establishing and carrying out an aggressive research and development program for carbon sequestration.

The Council appreciates being asked to provide this report and stands ready to answer any questions you may have about it.

Sincerely,

E. Linn Draper, Jr., Ph.D.
Chairman

Enclosure

THE NATIONAL COAL COUNCIL, INC.
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November 19, 1998

The Honorable Bill Richardson
Secretary of Energy
United States Department of Energy
Room 7A-219
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Mr. Secretary:

On behalf of The National Coal Council I am pleased to submit the enclosed report Coal's Role in Achieving Economic Growth and Environmental Stability. This report was authorized on February 10, 1998 by your predecessor, Federico Pena in response to a request from the Council. This report was formally approved by The National Coal Council in November 1998.

In order to respond to the initial request, the Council formed a working group consisting of individuals with expertise in the relative subject areas. The group was co-chaired by two Council members, Dr. Robert E. Nickell and Dr. George T. Preston, and included members of the Council as well as additional recommended experts. All had excellent credentials for completing this task.

The focus of this report was sustaining the long-term economic growth and development of not only the U.S. but the rest of the world as well, while using coal and addressing the most pressing environmental issues of the day, global climate change.

Because of its domestic abundance and stable price, coal has been and will continue to be an essential energy component in sustaining this effort. However, no single fuel can or should dominate U.S. energy use or electricity production. The report supports preserving a diverse spectrum of fuel sources (coal, oil, natural gas, nuclear, biomass and other renewables) and energy conversion options (central station steam boilers, combustion turbines, distributed generation, and synergistic combinations of systems). Technology advancements in these areas are essential to continued efficiency improvements in energy conversion and use.

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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 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 (representing more than 30 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;
- environmental interests;
- state government, including governors, lieutenant governors, legislators, and public utility commissioners;
- consumer groups, including special women's organizations;
- consultants from scientific, technical, general business, and financial specialty areas;
- attorneys;
- state and regional special interest groups; and
- Native American tribes.

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

ABBREVIATIONS

Btu	British thermal units
Btu/kWh	British thermal units per kilowatt-hour
CCT	Clean coal technology
CDM	Clean development mechanism
CFBC	Circulating fluidized bed combustion
CO	Carbon monoxide
CO_2	Carbon dioxide
COP	Conference of the Parties
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FCCC	Framework Convention on Climate Change
FERC	Federal Energy Regulatory Commission
GCC	Gasification combined cycle
GDP	Gross domestic product
GEF	Global Environmental Facility
GHG	Greenhouse gases
GW	Gigawatts
H_2	Hydrogen
HAP's	Hazardous air pollutants
HHV	Higher heating value
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
JI	Joint implementation
kW	Kilowatt
kWh	Kilowatt-hour
lb/MBtu	Pounds of emissions per million Btu of heat input
LHV	Lower heating value
Mbtu	Million Btu
MIT	Massachusetts Institute of Technology
MT	Million metric tons
MW	Megawatts
MWH	Megawatt-hour
NCC	National Coal Council
NGCC	Natural gas combined cycle
NO_x	Nitrogen oxides
PV	Photovoltaics
SIP	State implementation plan
SNCR	Selective non-catalytic reduction

SO_2	Sulfur dioxide
R&D	Research and development
T	Ton
U.N.	United Nations
USAID	United States Agency for International Development

EXECUTIVE SUMMARY

The Executive Summary introduces the report, summarizes the major conclusions, and sets forth the National Coal Council's (NCC) recommendations to the Department of Energy. The scope of this study was to develop an interpretive report on recent global climate change studies with a long range and strategic perspective on enabling technologies.

INTRODUCTION

The Secretary of Energy authorized this study by the NCC to explore the role of coal in helping to continue U.S. economic growth while fostering global environmental stability.

The report is divided into four parts:

Part 1 – Coal's Position in the Economy – discusses current environmental and economic challenges facing coal, and the domestic and international environmental policies affecting the use of coal.

Part 2 – Enabling Technologies – reviews electric generation technologies and discusses efficiency improvements, knowledge gaps, and competition from other fuels and generation sources.

Part 3 – Five Labs Study – briefly reviews the recent Five Labs Study and its significance.

Part 4 – Alternate Carbon Emission Reduction Scenarios/Sequestration – describes reduction scenarios achievable using various fuel and technology options, and summarizes the status of some carbon sequestration technologies and their potential.

CONCLUSIONS

Coal's Role. Because of its abundance and stable price, coal has been and will continue to be an essential energy component for long-term sustainable economic development in the U.S. and around the world. However, in order to maintain the potential for continued economic growth while simultaneously protecting the environment from excessive accumulation of anthropogenic greenhouse gases (GHG) and other air emissions, a technology-based transition in coal utilization is necessary. This transition will be driven by more efficient generation of electricity, by the commercialization of technologies developed and demonstrated over the past two decades, and by the continuing electrification of the economy.

Fuel diversity. No single fuel can or should dominate U.S. energy use or electricity production. Preserving a diverse spectrum of fuel sources (coal, oil, gas, nuclear, biomass, and other renewables) and energy conversion options (central station steam boiler, combustion turbine, distributed generation, synergistic combination systems) is essential to the United States' competitiveness, economic health, societal growth, and world leadership role. Coal's low cost and reliable supply will be increasingly important in the selection of fuels and electric generation options.

Technology portfolio. Technology advancements are essential to optimizing U.S. responses to global climate change issues and commitments. Economic analyses do not identify a single preferred technology but rather demonstrate the advantages of the technology portfolio approach. These analyses also underscore the need to keep and enhance coal's role in the technology mix by optimizing electric generation in the existing fleet; gasifying coal with exit gas cleanup; co-firing coal with biomass; capturing CO_2 exit gas with sequestration; integrating methane capture, coal cleaning, CO_2 injection at the mine, and ash utilization; and sequestering carbon through land and forest management. Near-term investment in coal-based generation technology development provides long- and short-term payoffs. Such investments also improve the efficiency and reduce the cost of co-firing, integration, sequestration, and other later-developing technologies.

Carbon sequestration. Many non-agricultural, non-forest carbon sequestration technologies are still in their infancy. Sequestration has the potential to reduce atmospheric carbon loads without suddenly abandoning our existing energy infrastructure. However, only modest CO_2 reductions will be achieved in the near term from nascent sequestration technologies. Significant reductions related to their commercial application will be realized only as technologies mature over the next generation.

RECOMMENDATIONS

Coal's role. Near-term climate change responses should take into account the existing U.S. energy infrastructure in order to be economically feasible and practical.

The Department should continue and strengthen the development of sound, realistic assumptions for the relative roles of coal, nuclear, hydro and other renewables, and natural gas in energy production in near-, mid-, and long-term scenarios for the U.S.

Fuel diversity. The Department should continue to support U.S. and world coal usage and the enabling advanced clean coal technology improvements both in the near- and mid-term. This strategy will preserve a range of fuel options and thus protect against production upsets, interruptions, and price increases in other fuel sources.

Technology portfolio. The Department should maintain a vigorous clean coal utilization research and development program to continue to reduce the cost of clean electric generation. Successful partnerships with private industry to develop and implement coal technology advances on a timely schedule will depend on equitable structuring of costs, risks, and rewards. The Department should exploit its leadership role to support such arrangements.

Carbon sequestration. The Department should participate technically and financially in establishing and carrying out an aggressive research and development program for CO_2 capture, transport, sequestration, and trading.

A well thought out and carefully implemented global reductions trading program is crucial to developing the flexibility required to achieve emissions goals at acceptable economic impact. An international trading program should incorporate credit for early actions including reductions from forestation and agricultural practices.

Part 1
COAL'S POSITION IN THE ECONOMY

BACKGROUND

A February 1997 National Coal Council report, *Vision 2020: The Role of Coal in U.S. Energy Strategy*, assessed the effects of more stringent environmental rules and regulations on the cost and use of coal for generating electricity in the U.S. The study also took an initial look at how the coal market might respond to potential air regulations and international policies or treaties to limit greenhouse gas emissions. Since that report, there have been significant developments in both of these areas.

Air Regulations: The U.S. Environmental Protection Agency (EPA) has

1. promulgated new air quality standards for ozone and fine particulate;
2. called for significant reductions in oxides of nitrogen (NO_x) and sulfur dioxide (SO_2) emissions in 22 midwestern, eastern, and southern states along with the District of Columbia;
3. proposed stringent New Source Performance Standards for coal-fired units; and
4. proposed a new enforcement program specifically targeting emissions reductions of SO_2 and NO_x at older coal-fired electric utility units.

The cumulative effect of these regulations will be to significantly increase the cost of using coal, because of the addition of expensive emissions control equipment. In many cases, the costs to comply with these new regulations will make the units' electric generation non-competitive, forcing them to shut down. The impacts this will have on our nation's electric system reliability are not yet known.

International Policy: In December 1997, the U.S. participated in final negotiations for the Kyoto Protocol, an international treaty which would require industrialized countries to cut back on their GHG emissions. The U.S. agreed to reduce its GHG emissions to a level 7% below where they were in 1990 by the time period 2008-2012. In order to achieve this reduction, the U.S. will need to reduce its energy use by about one-third below U.S. Energy Information Administration (EIA) projections for the period of 1990-2012,. Many mechanisms for reducing energy consumption have been made and studied, most of which add to the price of fossil fuels (especially coal and gasoline) to encourage consumers to use less energy.

In view of these national and international events, it is important to re-examine the role of coal in meeting national and global economic objectives and environmental goals. By employing advanced technologies, coal can be used cleanly and efficiently. Through the widespread use of these technologies on new units, growth in CO_2 emissions can be minimized, especially in fast-developing countries such as China and India. At the same time, repowering at existing power plants using these technologies can be a major source of short-term reductions in CO_2. This report critically assesses these technologies and how they can help respond to existing and future GHG reduction programs and policies.

THE ROLE OF COAL IN THE U.S. AND THE WORLD

The Council's *Vision 2020* report emphasized how indispensable coal and coal-fired electricity are in the U.S. For example:

- A highly reliable supply of low-cost electricity has contributed significantly to the nation's current standard of living, low rate of inflation, and global competitiveness.
- Almost 90% of the coal used in the U.S. is to produce electricity.
- According to EIA, approximately 55% of our nation's electric utility generation is fueled by coal.
- Coal provides low-cost electricity, which provides our nation with the domestic, low-cost energy needed to grow and compete in the new global economy.
- Restrictions on coal use or increases in the cost of using coal will increase the cost of electricity and have a negative impact on jobs, gross domestic product (GDP), and the standard of living in the U.S.

The *Visions 2020* report also noted that developing countries are exploiting their vast coal reserves, much in the same way as the U.S. did at the turn of the century. According to the EIA's *International Energy Outlook 1998*, worldwide coal use is expected to double over the next 25 years. Developing countries will consume more than twice as much coal as the industrialized countries, and they will be responsible for about half of global GHG emissions during that period. China, presently the world's largest producer of iron, steel, and cement (large CO_2 producing activities), is expected to triple its use of coal during this timeframe to approximately 3 billion tons, which will exceed the U.S. anticipated output.

ELECTRIC UTILITY RESTRUCTURING

In 1995, the NCC noted the move toward restructuring of the electric utility industry. In its report, *The Implications for Coal Markets of Utility Deregulation and Restructuring*, the Council made a detailed assessment of how the utility industry would respond to restructuring and how changes in generation options and pricing could affect the use of coal. In its conclusions, the report noted:

- In the short term (two to five years), there may be a significant increase in coal demand, stemming from higher utilization of existing facilities with access to low-cost coal but offset by the closing of older non-competitive plants.

- Over the next five years, most of the increasing demand for electricity will be met by other fuels.

- In the mid term (five to 10 years for this analysis), and continuing into the longer term, there is a potential for coal use to grow if:

  - the price of alternate fuels, primarily natural gas, rises or is perceived as likely to rise substantially relative to the price of coal; and/or

  - new organizational partnering occurs among coal suppliers, transporters, and users is developed to reduce coal's cost relative to other fuels; and/or

  - the cost of existing or new coal technologies decline sharply and the time required to construct such projects shortens.

AGENCY POSITIONS AND PROTOCOLS

In early 1996, the United Nations Intergovernmental Panel on Climate Change (IPCC) released its second report, providing an update to the 1990 report *Climate Change: The IPCC Scientific Assessment*, addressing global climate change scientific issues. Two of its key conclusions were:

- the balance of evidence suggests that there is a discernible human influence on global climate; and

- our ability to quantify the human influence on global climate is currently limited because the expected signal is still emerging from the noise of natural variability and because there are significant uncertainties remaining.

The first of these conclusions marked the first time that the IPCC had noted a direct link between human activity and global climate change. The second key conclusion explained that the first point was by no means certain. This uncertainty was not well publicized.

The Conference of the Parties (COP) includes all the signatories to the U.N. Framework Convention on Climate Change (FCCC). This group has met three times since the original Convention was signed in Rio de Janeiro in 1992.

COP-1 was held in Berlin, Germany, during the spring of 1995. At the meeting, the Parties realized that the aim of the FCCC for industrialized countries to return their GHG emissions back to 1990 levels by the year 2000 would not be met. They created the Berlin Mandate, requiring industrialized nations, known as Annex I Parties, to negotiate mandatory targets and timetables for the post-2000 period.

Negotiations were completed at COP-3 in Kyoto during December 1997, resulting in the Kyoto Protocol. The Protocol includes the following major provisions:

- **Mandatory GHG reductions for Annex I Parties only, to be achieved by the time period 2008-2012.** The overall reduction for all of these Parties is about 5.2%. The U.S. agreed to reduce its emissions to 7% below 1990 levels by the prescribed time period. Developing countries have no reduction obligations either during this timeframe or in the future.

- **The concepts of flexibility mechanisms such as joint implementation (JI) and the clean development mechanism (CDM).** The JI program may give the U.S. and other industrialized countries a way to lower their compliance costs. With JI, a U.S. company could build a project in another Annex I country, and receive credit for the reductions. Similarly, the CDM would allow comparable projects in developing countries to receive a similar type of credit. The details of how these mechanisms might work were not included in the Protocol, and numerous disagreements about the details have surfaced.

U.S. POLICIES AND PROGRAMS

By agreeing to and signing the Kyoto Protocol, the U.S. Government accepted, for the first time, legally binding targets and timetables for reductions in GHG emissions. This was a major change in U.S. policy, going beyond the voluntary measures contained in the Administration's Climate Change Action Plan and the Climate Challenge, a voluntary emission reduction program between the electric utility industry and the U.S. Department of Energy. The Protocol must still be ratified by the U.S. Senate before it can be implemented. The Clinton Administration has not yet submitted it to the Senate.

According to the EIA's 1998 *Annual Energy Outlook*, U.S. carbon emissions from energy consumption were 1.346 billion tons in 1990 and are projected to be 1.803 billion tons in 2010. In order to comply with the Kyoto Protocol limitations, the U.S. must reduce its carbon emissions and its energy consumption by approximately 31%. Looking solely at the carbon emissions from the generation of electricity, a reduction of 33% would be necessary. This is a major task to be accomplished in a 10-year time frame.

Several technologies capable of sequestering large amounts of carbon exist. However, according to results of a workshop convened by DOE at the Massachusetts Institute of Technology in June

1998, these technologies are in their embryonic stages. Also, they are very costly at the present time, and should be the subject of an aggressive and well-funded research and development program involving both public and private participation.

PART 2
ENABLING TECHNOLOGIES

Over the past two years, "technology roadmap" strategic planning programs have been undertaken by (and mutually coordinated among) the Electric Power Research Institute (EPRI), DOE, the Coal Utilization Research Council, and NCC, as well as other public and private energy organizations. These efforts are evolving into a coherent framework for understanding the role of technology development and application to foster economic growth and achieve U.S. and world environmental goals.

The generalized steps for developing a "technology roadmap" are: 1) to define the desired outcomes (or destinations); 2) to specify technology barriers that stand in the way of reaching those destinations; and 3) to outline the R&D solutions that can develop enabling technologies.

It is clear that the availability of inexpensive, clean electric power will be essential to U.S. and global economic growth and environmental stability. Several of the major roadmap destinations are summarized below.

- **Increase the production efficiency, reduce the cost, and improve the environmental performance of coal-based generation.** Effective utilization of coal reserves will be a key element of a fuel diversity strategy. In addition, coal will be a feedstock in the next generation of chemical plants that will achieve ultra-high efficiencies by integrating electricity generation with chemical production.

- **Increase the efficiency and reduce the cost of gas turbine generation.** The gas turbine is an important enabling technology not only for the efficient use of natural gas for electricity generation, but also for coal gasification, pressurized fluid-bed systems, and a variety of hybrid designs.

- **Expand and accelerate the use of renewables.** Questions of capital cost, ability to integrate intermittent renewables with the grid, and total capacity potential must be resolved to take advantage of the low fuel cost and environmental benefits offered by renewable energy.

- **Revitalize U.S. nuclear power capability in an era of price competition and environmental concerns.** This will require decreased costs by standardizing design, construction, and operating practices; an integrated spent fuel management system; an effective, safety-focused regulatory framework; and resolution of policy and public perception issues about the use of nuclear energy.

- **Exploit distributed generation's potential to provide flexibility, independence from the grid, and extremely high efficiencies through cogeneration applications.**

The focus of this report is on the first-listed of these destinations. However, other enabling technologies are summarized to put coal's role in perspective as an essential element of a diversified energy portfolio. For example, reaching the gas combustion turbine destination - i.e. its performance targets - is inextricably meshed with coal's role in advanced power generation and as a chemical feedstock.

COAL-BASED CENTRAL STATIONS

Coal-fired power plants currently supply over half of all electricity generated in the U.S.; and, despite some switching to natural gas and startup of new gas turbine/combined-cycle plants, coal will continue to provide the bulk of U.S. power in the near term. Unless gas prices escalate significantly above current projections, a capital cost target of $800/kW is estimated by EPRI and others to be required in the U.S. for future coal-based units to compete with natural gas-fired combined cycles in the next two decades.

For the immediate future, subcritical pulverized-coal plants will be the major technology for growing markets. Supercritical plants will gradually increase their market share as domestic manufacturing capability of key components is developed and plant operators need higher efficiencies.

Circulating atmospheric pressurized fluidized bed combustion plants have been widely installed worldwide in sizes up to 250 MW. If designed for the purpose, these CFBC plants are able to handle poor-quality coal that is rejected by coal preparation plants.

The gasification of coal (or other liquid or solid fuels such as heavy residual oils, petroleum coke, biomass, etc.) with subsequent gas cleanup (using existing commercial processes) produces a clean gas from which most emission precursors have been removed. This gas is also a very suitable fuel for firing in high-efficiency gas turbines and fuel cells. The integration of the gasification with a combined cycle (IGCC) can be accomplished in a variety of configurations to achieve high plant efficiencies and very low emissions.

IGCC plants are currently being built in the U.S., Europe, and Asia based on the gasification of petroleum residuals, such as vacuum residual oils and petroleum coke. These plants are situated at refineries to supply the power and steam needs of the refinery, with sale of the surplus power to the local grid. In some plants, the gasification units also supply hydrogen for refining processes or syngas for chemical synthesis. These IGCC plants are often characterized as cogeneration, tri-generation, or coproduction units, and they provide extremely efficient utilization of a low-value fuel. They also are representative prototypes of the "powerplex" industrial parks that have been envisaged to require coal when natural gas is no longer cost effectively available for central power plant use. Such energy plants would probably produce the clean fuels (e.g., hydrogen or methanol) that would be required for small distributed generation units.

Efficiency and Cost Performance Targets

According to current DOE estimates, by 2020 in order to compete in a deregulated electric generation marketplace, coal-based central station power plants will need to be commercially available at 50% or higher efficiency (HHV basis), at $800/kW capital cost (1998 dollars), with the capability of meeting stringent environmental limits on criteria pollutants (99% SO_2 control, 0.05 lb/MBtu NO_x, 100% solid waste utilization) and trace substances. By 2050, coal-based central station plants will need to be available at 60-65% efficiency (HHV) and achieve required CO_2 reductions before or after combustion. Some plants will be "powerplex" units producing electricity, heat, clean fuels, hydrogen, and chemicals.

Implementation Timetables and Acceleration Potential

The new coal technology implementation timing steps described below are quite ambitious, but cannot be compromised if the above efficiency and cost-control targets are to be achieved. It should not be inferred from these timelines that the resources to meet them have been identified.

Knowledge gaps that must be closed by 2020 include:

- higher efficiency coal gasification and air separation units;
- hot gas particulate cleanup for gas turbine blade protection;
- advanced materials for higher steam conditions;
- gas combustion turbine advances integrated into IGCC designs; and
- incorporation of reheat into combustion turbine combined cycle plants.

Knowledge gaps that must be closed by 2050 (solutions implemented, not just shown at laboratory or prototype scale) include:

- feedstock flexibility for IGCC and powerplex plants;
- integration of IGCC designs with circulating PFBC and with fuel cell systems;
- identification or development of materials for high temperature reheat in combustion turbine combined cycle; and
- ceramic turbine blades.

GAS-BASED CENTRAL STATIONS & DISTRIBUTED GENERATION

The EIA's *Annual Energy Outlook* for 1998 predicts a modest rise in U.S. average natural gas prices from $2.50/MBtu in 1998 to $3.15/MBtu in 2020 (1998 dollars) and a natural gas-to-coal differential rising from $1.25/MBtu in 1998 to $2.20/MBtu in 2020. Around these averages, considerable uncertainty remains about the extent of recoverable natural gas reserves and the price levels needed to bring them to market. The development of new gas production techniques (e.g., methane hydrate recovery) and more definitive technology for estimating gas reserves, their availability, and price are important to reduce this uncertainty.

During the next 10 years, clean, inexpensive natural gas-fired turbine and combined-cycle plants will be brought on line in the U.S. and Western Europe to meet demand growth. These facilities will displace some of today's older fossil generation and high-cost nuclear plants. The large heavy-frame gas turbines of the F and FA classes currently being deployed have firing temperatures of 2300-2400` F (1260-1315` C) and combined-cycle efficiencies of 56-57% (LHV basis). Orders have already been placed for G-class turbines with firing temperatures of about 2600` F (1430` C), which will be in operation by 2000. The next generation H-class turbines also have firing temperatures of about 2600` F (1430` C) along with steam cooling of the first row of blades. H-class turbines are currently testing and are expected to have combined-cycle efficiencies of about 60%.

In addition to the need for large, efficient central-station units, there is a continuing need for improved mid-sized turbines suitable for fast-loading peaking and intermediate service. These flexible units, typically 20-100 MW, can use less advanced technology and can operate competitively at slightly lower efficiency. Smaller recuperated and intercooled turbines are available already, and larger machines such as the intercooled aeroderivative are emerging as promising intermediate and peaking units.

Technology development of small generating units based mainly on gas turbines and fuel cells will drive the implementation of distributed generation, as the historical primacy of central power stations is challenged by intense competition for customers under industry restructuring. In addition, some distributed generation technologies are well suited to developing countries that lack built-up electricity transmission/distribution and natural gas supply infrastructures.

Efficiency and Cost Performance Targets

Again according to current DOE estimates, by 2020, gas-based central station power plants must be commercially available at 70% efficiency (LHV bases; or ` 63% HHV basis). Flexible duty mid-sized units (20-100 MW) must be available at less than $200/kW capital cost (1998 dollars). Efficient, reliable, inexpensive simple cycle or cogeneration distributed generation units must be broadly available and implemented. By 2050, gas-fired central station plants must be available at 75% efficiency (LHV; ` 67% HHV) and achieve required CO_2 reductions - probably by hydrogen firing, oxygen firing with CO_2 recycle, or CO_2 removal from post-combustion exhaust gas.

Implementation Timetables and Acceleration Potential

The below-described timing for implementation of new gas-based generation technologies is quite ambitious but cannot be compromised if the above targets are to be achieved. It should not be inferred from the timelines that the resources to meet them have been identified.

Knowledge gaps that must be closed by 2020 include:

- reliability, availability, and maintainability of advanced turbine designs (to achieve efficiency targets) proven in central station baseload and cycling service;
- achieving very stringent NO_x emission limits at high temperatures and compression ratios;
- new materials to withstand higher firing conditions;
- integration of interstage cooling, heat recuperation, and humidified cycles into mid-sized units;
- ceramic blades and heat recuperation for microturbines (distributed generation);
- significantly higher fuel cell power densities than today; and
- hybrid fuel cell/combustion turbine cycles for small units.

Knowledge gaps that must be closed by 2050 (solutions implemented, not just shown at laboratory or prototype scale) include:

- hydrogen firing for CO_2 control;
- oxygen firing with CO_2 recycle; and
- ceramic blade materials and designs.

RENEWABLE ENERGY

Certain renewable energy technologies are suitable for extensive global deployment. Wind, due to its low cost, and photovoltaics (PV), due to its broad applicability and public acceptance, appear to be the dominant options. Biomass will also be important due to widespread resource availability and potential fuel cost reductions. Further, biomass - as a combustible fuel- will use many technologies originally developed for coal combustion. Despite some environmental problems, hydropower, today's most prevalent renewable, will continue to offer favorable costs. Solar thermal and "hot dry rock" geothermal are expected to make only minor inroads, as they are hampered by high R&D and market entry costs. Conventional hydrothermal geothermal technology faces resource availability limitations. Low-power-density (e.g., ocean thermal or tidal) or "exotic" renewable technologies (e.g., PV in orbit) also do not appear promising.

A caution is in order regarding economic comparisons. The busbar cost of electricity is a misleading figure for comparing renewables to fossil or nuclear power, or even in comparing renewables with one another. <u>In today's restructured competitive environment, electricity costs must be compared at the point of use.</u>

Efficiency and Cost Performance Targets

Again according to current DOE estimates, by 2020, renewable energy central station plants must be reliable and cost competitive - in commercially significant market niches - with currently "traditional" central station and distributed generation power technologies. By 2050, wind and biomass should be "first choice" wherever the energy resource is available, and PV units should be competitive at the point of use with fossil and nuclear central stations.

Implementation Timetables and Acceleration Potential

The below-described timing for implementation of renewable energy technologies is quite ambitious but cannot be compromised if the above targets are to be achieved. It should not be inferred from the timelines that the resources to met them have been identified.

Knowledge gaps that must be closed by 2020 include (costs in 1998 dollars):

- wind turbine capacity factors high enough to generate at $675/kW;
- biomass gasification costs less than $1500/kW; and
- PV cell and system manufacturing cost reductions to construct at less than $1100/kW.

NUCLEAR POWER

Nuclear power produces no combustion gases and thus inherently provides clean air advantages. However, the issue of developing permanent spent fuel disposal must be solved. Current average plant capacity factors in the U.S. are around 84%. These factors and low fuel cost can make new nuclear power plants a prime choice for baseload duty in large central-station plants if capital and operating costs can be reduced.

Efficiency and Cost Performance Targets

Again according to current DOE estimates, by 2020, nuclear power central stations must be commercially available with passive safety features. By 2050, a variety of nuclear power technologies must be commercially available to provide electricity and industrial heat.

Implementation Timetables and Acceleration Potential

Knowledge gaps that must be closed by 2020 include:

- competing passive safety designs evaluated and resolved;
- spent fuel management systems proven and accepted; and
- low-level radiation health questions resolved.

Knowledge gaps that must be closed by 2050 include:

- advanced high temperature reactor system; and
- advanced liquid metal reactor system.

PART 3
THE FIVE LABS STUDY

In September 1997, a DOE-commissioned Interlaboratory Working Group consisting of five U.S. Government national laboratories issued *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy-Efficient and Low-Carbon Technologies by 2010 and Beyond*, often referred to as the "Five Labs Report." Some analysts conclude that the Five Labs Report (and the "Five Labs Study" that is summarized here) support the feasibility of the U.S. complying with the Kyoto Protocol agreements at a low cost.

Salient features of the Five Lab scenarios are:

- A combination of rapid technology adoption and carbon permit fees (i.e., a tax on CO_2 emissions) could achieve the U.S.'s 1990 carbon emissions level by year 2010, amounting to approximately a 390 MT (million metric tons) per year of carbon reduction from the "business as usual" scenario for 2010.

- The Electric Utility Sector would contribute 136 MT/yr of the reduction by repowering coal plants with natural gas, retiring older coal plants, installing more wind power and biomass co-firing, increasing efficiency in still-running plants, extending the operation life of nuclear plants, and expanding hydroelectric power – all encouraged by a carbon permit fee of $50/T.

- The return to 1990 levels scenario also postulates reductions from business as usual of 62 MT/year in the Buildings Sector, 93 MT/year in the Industrial Sector, and 103 MT/year in the Transportation Sector.

These results have been summarized and critiqued in numerous references. For this report, key observations are:

- Several of the Five Lab report's main conclusions rest on assumptions that are not discussed in the energy sector scenario analyses.

- Some conclusions rest on assumptions that cannot be validated or that are subject to significant revision. For example, EIA's *Annual Energy Outlook* for 1998 projects that U.S. carbon emissions in 2010 will be 1803 MT (73 MT higher than EIA's 1997 projection for 2010 used as the business as usual scenario). This implies a that reduction of over 460 MT/year, not 390 MT/year, is necessary to return to 1990 levels.

The monetary benefit of climate change improvement was not estimated. Many of the cost impacts were not included. And some of the projected carbon reductions result not from carbon permit fees but from the coal plant retirement/conversion incentives of credits for other emission reductions.

For the purpose of proposing scenarios to stimulate thoughtful discussion, assumptions are appropriate, and a partial analysis of costs and benefits may be useful. However, if the assumptions cannot be shown true and important effects are omitted from the analysis -- as in the Five Lab study - then it does raise a serious caution about the report's usefulness as a basis for policymaking.

PART 4
ALTERNATE CARBON EMISSION REDUCTION SCENARIOS/SEQUESTRATION

ADDED FLEXIBILITY

The short-term deadline of 2008-2012 for compliance with the Kyoto Protocol and the lack of a flexible energy policy in the U.S. could force American electric energy suppliers to examine options to reduce emissions that are increasingly limited, increasingly costly, and probably not sustainable or flexible enough to achieve long-term emission targets. Therefore, finding diverse and creative solutions is necessary to meet the emissions challenge, including energy solutions that evolve from conservation, from technology, from financial instruments, and from both supply-side and demand-side of energy transactions.

In the following, an approach referred to as fuel diversity building block analysis is used to examine alternative greenhouse emission scenarios. These alternatives are needed in order to provide added flexibility relative to the timetable for meeting emission limits, permitting reasonable acceleration of development and deployment of advanced technologies, and cost-effective use of existing electric generating capacity. The alternatives also recognize that fuel uses have strategic implications that should be part of any national energy policy.

The goal is to avoid excessive dependence on any single fuel, especially imported fuels, while seeking a diversity of fuels and technologies that can accommodate economic growth while reducing overall emissions. Alternative cases using the same building block analysis suggest that a fuel diversity policy can support the use of several fuels for electric power while achieving emission goals in a more flexible and less wasteful way, as long as a more reasonable timetable for meeting those goals is adopted. But an examination of the fuel diversity building block electricity strategy and emission reduction requirements also emphasizes the need to consider accelerated technology development, including advanced clean coal technologies and carbon sequestration technologies.

The building block analysis of national fuel choices itself does not necessarily provide simple solutions. However, this approach identifies in a compelling way the questions that are most significant to the long-term course of electricity costs in an economy whose growth seems to directly track with electric energy consumption.

ASSUMPTIONS

The scope of the fuel diversity building block analysis is limited to U.S. electricity generation, and all fuel and electricity information applies only to the U.S. unless otherwise noted. All projections beyond the year 2015 are straight-line extensions of information available from the EIA. All projections other than those for the base case are "with Conservation." The base case itself should be considered the "business a usual" case; i.e., no CO_2 emission control requirements. The base case also uses the 1997 EIA assumption of a 1.48% annual electricity demand growth rate. For all of the other cases studied, the "with Conservation" assumption uses the EIA assumption of a 0.98% annual electricity demand growth rate; that is, end use conservation measures are employed. (The 1998 report by the EIA provides assumptions on electric power consumption growth of about 1.40% annually, but energy conservation efforts are assumed to reduce electricity demand growth by 0.25% annually from 1995 to 2030).

For the cases that involve assumptions with respect to nuclear energy generation, the capacity is either held at the current 100 gigawatts (GW) or, if not held constant as the result of license renewal, 39 GW is assumed to be retired by 2015 and 52 GW retired by 2020. Renewable generation is assumed to grow at EIA "extended" projections.

CARBON EMISSION REDUCTION CASE STUDIES

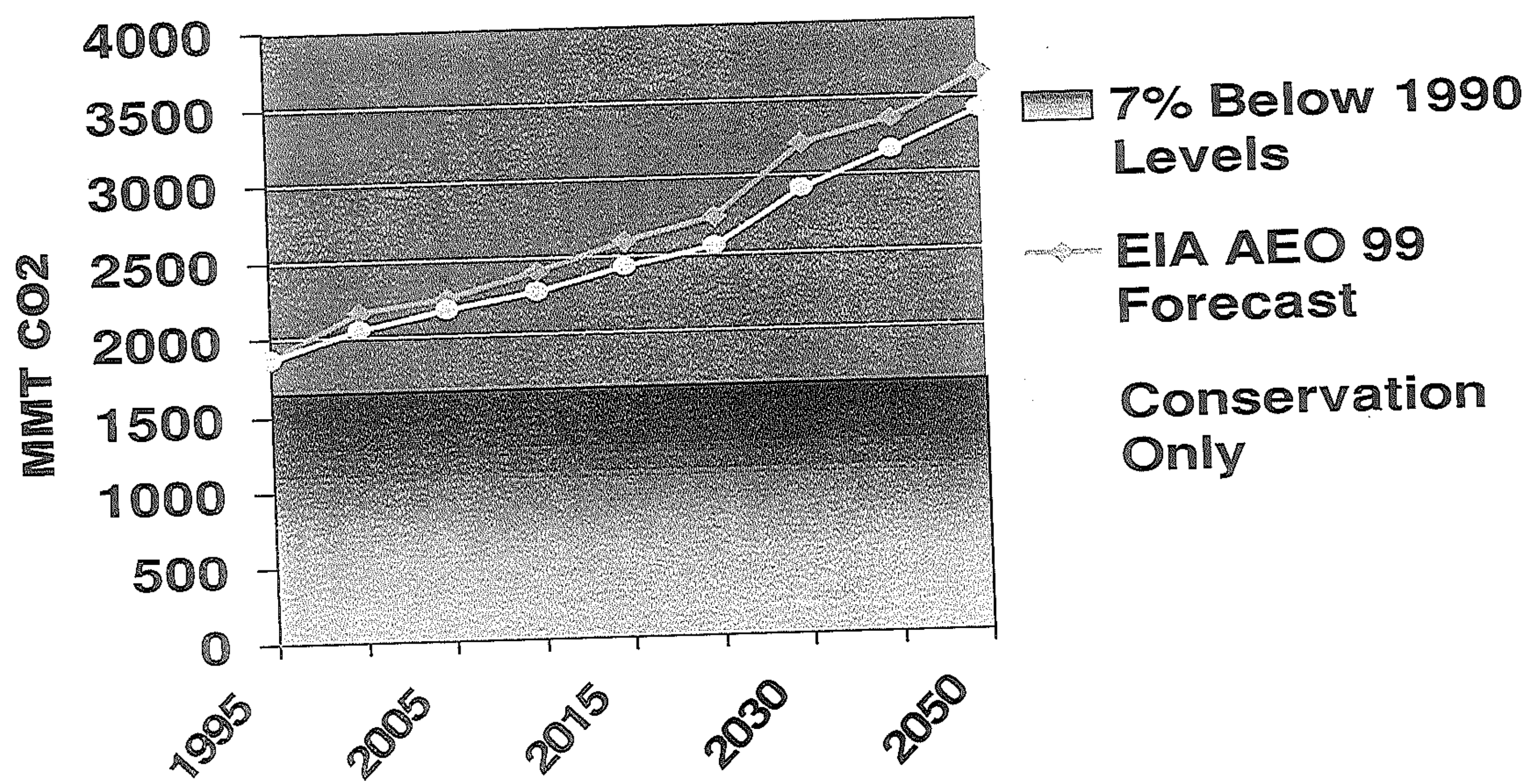
Base Case and Variations

The base case shows that, by 2010, total CO_2 emissions for electric power generation will reach 2,267 MT, 28% above the corresponding 1990 emission levels. Nuclear generation from this base case shows a decline from 100 GW of capacity to 89 GW. A variation on the base case with conservation enables this emission level to be reduced to 2,002 MT, still 13% above 1990 levels. Another variation on the base case, this time assuming that nuclear capacity remains at 100 GW, shows a reduction to 1193 MT, only 9% above 1990 levels. Finally, a variation on the base case with nuclear capacity at 100 GW, conservation, and with gas-fired generation dispatched preferentially versus coal-fired generation (gas-fired generation increasing from 23% to 31% of total generation, with coal-fired generation dropping from 46% to 37% of total generation). This variation brought the CO_2 emissions down to 1990 levels.

Projections for energy consumption using current trends show that enhanced conservation measures alone will not allow the U.S. to meet the Kyoto emissions target (see Chart 1: Case 1: Conservation). Enhanced energy conservation measures could reduce the growth in electricity assumption, and therefore emissions, by more than 50 MT/year by 2010. But that is still more than 250 MT above the Kyoto target level, even if an additional 250 MT in emission credits is available to help meet the prescribed target.

Extrapolation of the base case (plus the variations) into the future shows that reducing the emissions to 1990 levels by 2010 will:

Chart 1: Conservation Alone Won't Meet CO2 Goals



1. reduce the use of coal, a vital domestic fuel source, substantially and potentially to minimal levels by 2035;
2. increase the use of natural gas at a pace that may not be realistic from a capital structure standpoint alone;
3. result in dramatic increases in natural gas prices and demand that will drive the market price to burdensome levels, which will in turn drive the price of electricity to levels that U.S. industry will not accept;
4. create a very high imbalance of electric generation fuel sources, with natural gas at 70% of total U.S. electric generation by 2035; and
5. deplete domestic natural gas reserves (including 11.5% annual reserve growth) by 2020.

The base case extrapolation also indicates negative impacts to the U.S. economy, increased fuel imports and concomitant increased balance of trade deficits, and impacts to the nation's global competitiveness. A longer range approach is essential, since it will permit utilities to optimize the use of coal, to the benefit of the country; allow for a strategic balance of electric generation fuel sources; and promote effective research and development toward clean and efficient electric generation.

Technology Responses

In an effort to evaluate the longer range approach, the base case variations were extrapolated into the future, with the following technology change assumptions:

- By 2010, gas generation additions are assumed to be 95% combined cycle, with a heat rate of 6300 BTU/kWh, and 5% combustion turbines; also, 53 GW of inefficient coal-fired generation will be retired.
- By 2020, the overall gas-fired generation mix will have shifted to 95% combined cycle and 5% combustion turbines; any new gas-fired generation will be 100% combined cycle; 63 additional GW of inefficient coal-fired generation will be retired, leaving 189 GW of "existing coal generation;" any coal-fired generation that is added in this period will have a heat rate of 7250 BTU/kWh, with Case 2 adding 12 GW, Case 3 adding 50 GW, and Case 4 adding 51 GW.
- By 2035, all gas-fired generation will be combined cycle; also, hydrogen-based technologies will begin to arrive.

Of the four cases examined, **Case 1** will be referred to as the Natural Gas Substitution or Conservation Case, where any shortfall in electric generation caused by emission constraints that cannot be met by conservation is met by switching to natural gas. By the year 2010, this scenario leads to 46% gas-fired and 23% coal-fired generation, with nuclear holding at 19% and renewables taking a 10% share. By 2020, these percentages shift to 53% gas, 27% coal, 8% nuclear, and 10% renewables. By the year 2035, coal has moved back to 30%, with gas at 59%, nuclear down to zero, and renewables at 8%.

The **Case 1** analysis is based on assumptions of heat rates for various fuels for the years 1995-2020 from 1998 data, with reasonable projections based on those trends calculated for the years 2020-2030. This includes separately calculated efficiencies for existing natural gas combined cycle generating units, new units, existing coal-fired plants and clean coal technology units after 2010. In practice, however, it should be noted that policies on the environment, nuclear power, hydroelectric power, and energy technology seriously limit future options for designing these building blocks.

The swift conversion or mothballing of existing coal, nuclear, and hydroelectric generating units in favor of pursuing a generating strategy dominated by gas is possibly the only choice from today's energy technologies that could meet Kyoto's deadline for emissions reductions.

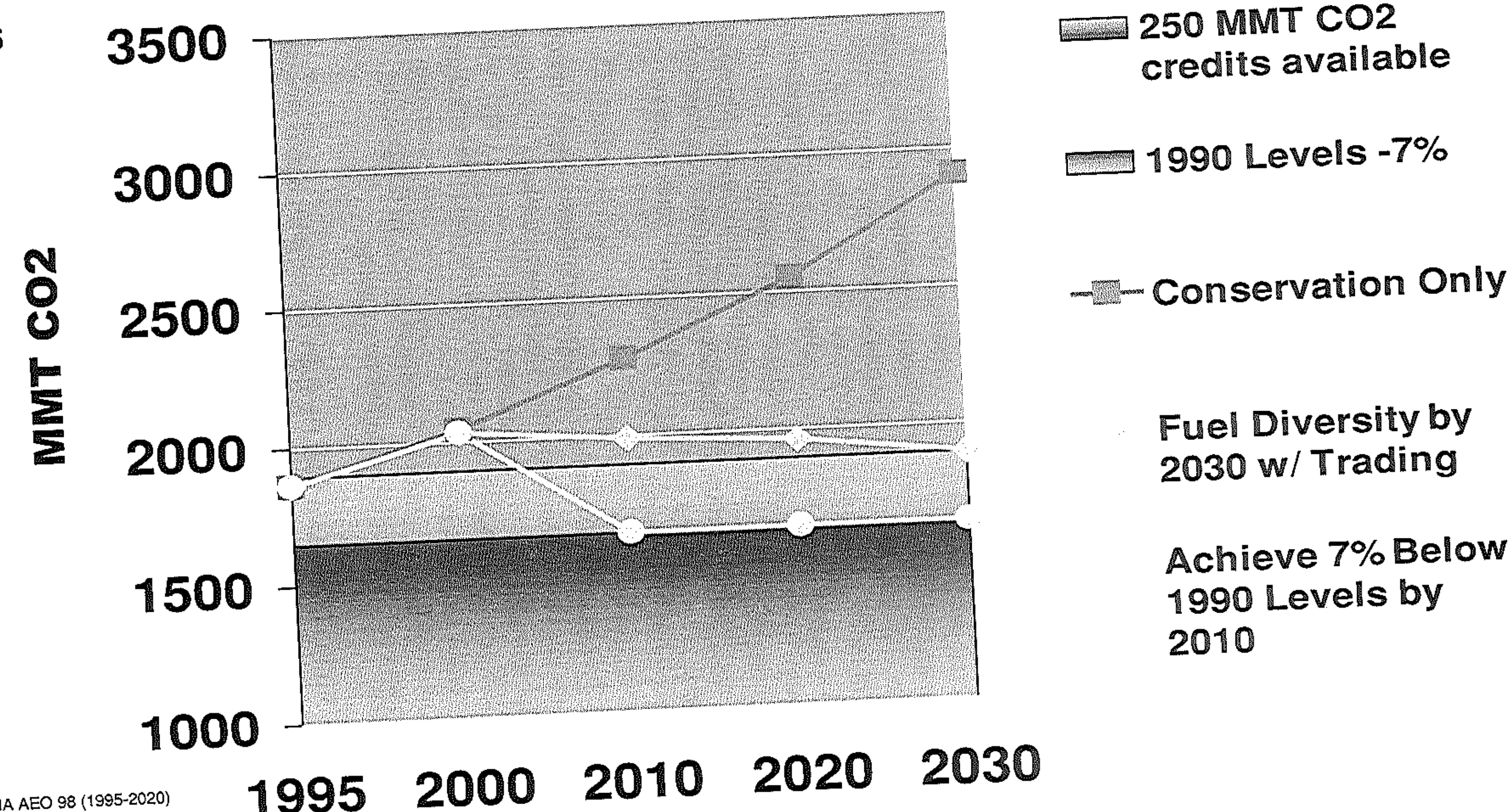
Case 1 (see Chart 2 - Heading Toward Fuel Restrictions) involves a rapid, extensive, and expensive substitution of natural gas generation for coal and nuclear power in order to satisfy electricity demand and still meet the 2010 Kyoto deadline. This implies a 17% cutback in total coal capacity by 2010 from 1995 levels, as well as a 19% decline in nuclear power. Natural gas powered generation in turn increases from 150 GW of capacity in 1995 to 402 GW by 2010. To maintain the Kyoto targeted emissions level through 2030, gas generation would have to increase to 705 GW, nearly five times current capacity for that fuel. This is, of course, a rapid and drastic shift in fuel sources for electricity (see Chart 3 - Natural Gas), ballooning gas from a 10% share of electricity generation in 1995 to a 40% share by 2010, the nominal Kyoto target date. The drawdown of existing and potential natural gas supplies is significant (see Chart 4 - Natural Gas Generating Growth) but largely unstudied at this point. Although this building block analysis does not predict the economic impact of this dramatic increase in gas utilization, it strongly suggests the need for a study of the potential for gas price increases as well as gas infrastructure and exploration economics.

Case 2 adopts a 2010 deadline for hitting the Kyoto target for emissions without substantial changes in existing energy trends. Coal-powered plants are retired or converted to gas, and nuclear units are retired as predicted by their current licenses, with some amount of relicensing. Case 2 is similar to Case 1, with the exception that some small amount of nuclear capacity (35 GW) remains in the mix by 2035, through either new generation or relicensing, and 12 GW of efficient coal-fired generation is added by 2020. In this case, by 2035, the generation mix is 51% gas, 33% coal, 5% nuclear, and 8% renewables.

Case 3 is the first of two Fuel Diversity Cases, with Kyoto emission targets achieved by 2030, instead of 2010. The diversity of fuels for electric power generation includes an increasing role for natural gas, a smaller role for coal, but a continued 20% of nuclear generation. For example, nuclear power is free of greenhouse gas emissions, but today faces a limited future in the U.S. Nuclear power plants today supply 21% of electricity generation, but the current trend toward accelerated phasedown of nuclear plants through early retirements means that nuclear power could fall to 1% of total electricity needs by 2030. Recent statements by some Clinton Administration officials, including Vice President Al Gore's comments during a recent visit to

Chart 2: Heading Towards Fuel Restrictions

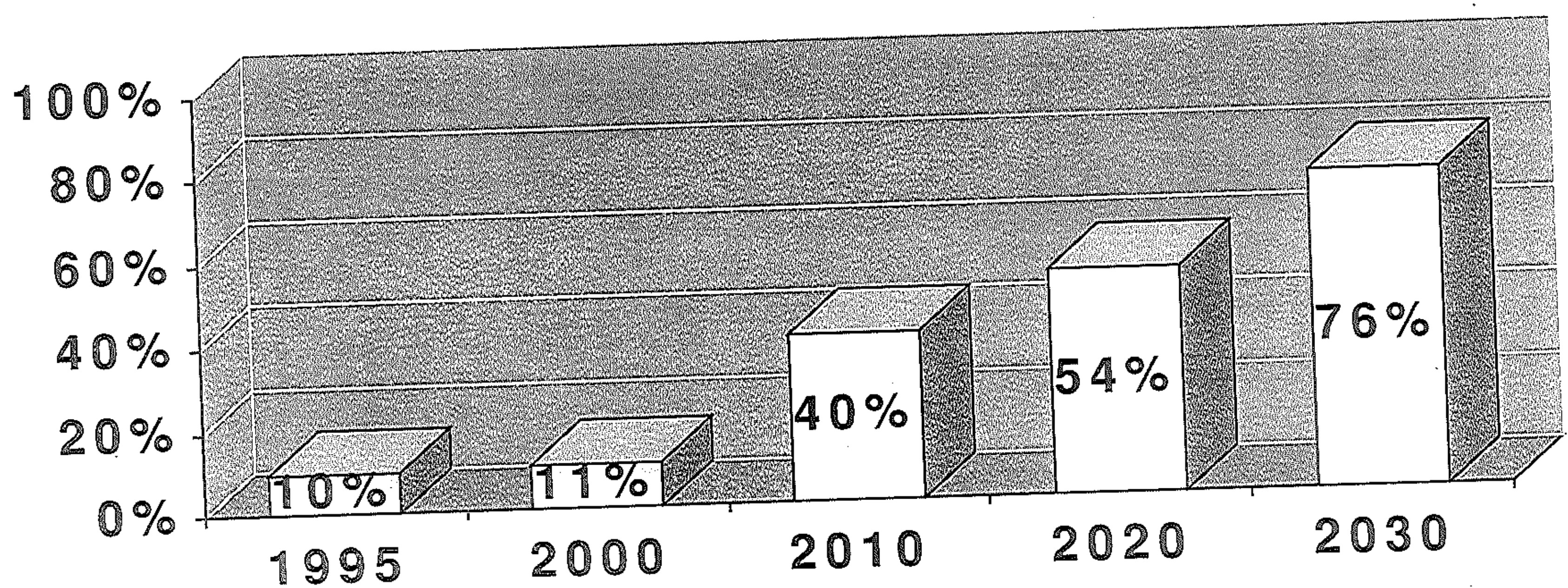
We can reduce CO2 by 2010, but only with early retirement of coal-fired plants



Source: EIA AEO 98 (1995-2020)
AEP Projection (2020)

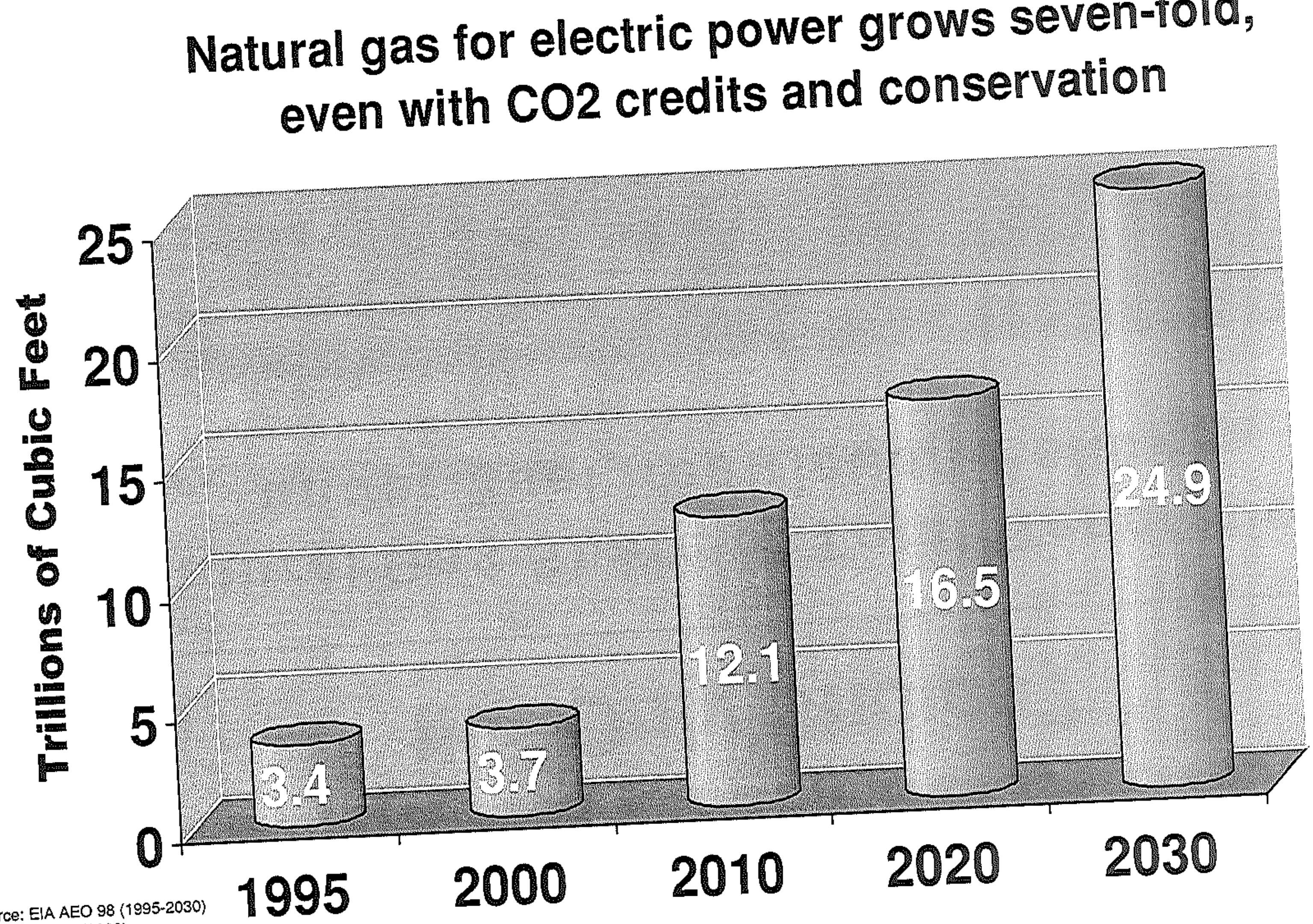
Chart 3: Natural Gas: Fuel of Choice or the *Only* Choice?

Natural Gas Share of Total Generation under Fuel Restriction Policy*



Source: EIA AEO 98 (1995-2020)
AEP Projection (2020)

Chart 4: Natural Gas Generating Growth



Source: EIA AEO 98 (1995-2030)
AEP Projection (2030)

Chernobyl, suggest a belated recognition that nuclear power may be essential to meeting emissions goals. At least two utility companies have applied for renewal of nuclear plant licenses. But today no new nuclear plant is under construction, no relicensing has occurred, and the Federal Government has failed to meet its contractual deadline for taking title to spent nuclear fuel from the nation's existing plants.

Case 3 puts the U.S. at Kyoto targets for emission levels by 2030, 20 years after the Kyoto deadline. That goal is ambitious, requiring substantial policy and technology developments to bolster the safety and economics of nuclear power, including nuclear relicensing and advanced reactor research, provisions for the commercialization of CCTs and the development of non-hydroelectric renewable resources for power generation.

Case 3 illustrates how comparable emission cuts can be achieved on a schedule that allows planning, development, commercialization, and installation time for the capital turnover necessary to a truly massive shift in the nation's fuel sources for electricity. Although this study evaluates domestic emission targets only, the technologies developed for coal, gas, nuclear, and renewable energy could all play a role in exporting energy technologies to other developed countries and to developing countries in which so much of the growth in global emissions is likely to occur.

Case 4 is the other Fuel Diversity Case, a relatively balanced mix of fuels compared to Case 1 and Case 2, with the capacity to support long-term controls of emissions through new coal technologies, use of natural gas, accelerated renewables development, nuclear power at a sustained level, and trading of emission credits.

The study also assumes that trends will continue in nuclear generating unit retirements, and that coal units will ultimately retire prematurely to give generating share to gas. By 2030, coal will have less than a 15% share of power generation, and nuclear will be less than 1%. Non-hydroelectric renewable sources – even with very optimistic projections – will supply only about 9% of the nation's power needs (see Chart 5 - Impact of Fuel Restrictions).

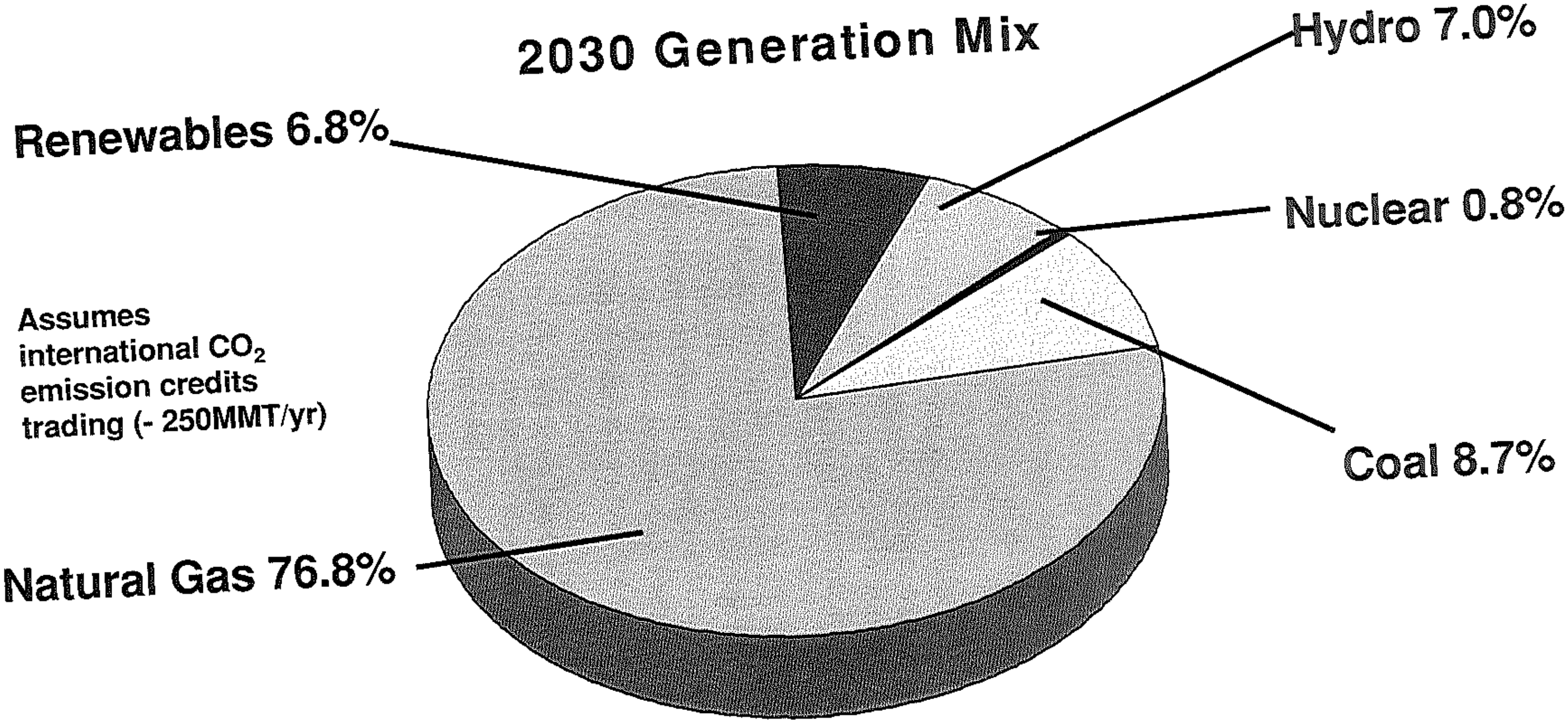
Highly accelerated growth rates are applied to the contributions of non-hydro renewables, with annual growth rates (years 2000-2020) as follows: wind, 2.9%; solar/PV, 18.3%; solar thermal, 2.7%; wood/other biomass, 1.8%; municipal solid waste, 1.8%; and geothermal, 0.6%. Meanwhile, hydro generation is assumed to decline 5% between 1995 and 2000, and then remain constant.

Energy conservation efforts are assumed to slow the growth of electricity use, relieving the need for expanding generation and fossil fuel consumption.

No meaningful participation in GHG emission controls is required from the developing countries, nor is there an overall plan to share emission control strategies between developed and developing nations. Nevertheless, developing countries' GHG emissions are projected to increase and exceed the reductions of the developed countries, negating the purported global environmental benefit of

Chart 5: Impact of Fuel Restrictions

By 2030, the effects of a Fuel Restrictions Policy could be dramatic, due to retired coal and nuclear plants



Assumes international CO_2 emission credits trading (- 250MMT/yr)

Source: AEP Projection

these reductions.

The emission reductions should be viable at least for the next 30 years, taking into account available and developing technologies as well as projected energy requirements during that timeframe.

Will the sudden conversion of capacity from coal to gas distort natural gas prices? Given these assumptions, several case studies of fuel choice building blocks were developed to illustrate significant policy options now available. The cases are not mutually exclusive, and they illustrate several combinations of fuel choices, potential flexibility on deadlines for hitting emissions targets and the role of trading and technology in easing the transition.

Case 4 neatly divides resources into three groups of fuels: two fossil and one nuclear/renewable. It projects that natural gas will become the source for about 36.5% of the nation's electricity by 2030, with coal's role falling to 30%. The other third of the fuel source pie would be a combination of renewables at 12.9% and nuclear, which would have to maintain a 20% share.

Beginning in 2010, approximately 250 MT of emissions credits can be purchased by the U.S. from other countries to make up for any shortfall in the domestic emission reduction effort.

The building block analysis assumes that all these strategies are theoretically available to energy policy makers and energy suppliers, and that - up to a point - we can combine and re-combine building blocks of fuel sources in order to reach emission reduction goals.

Emissions trading on an international basis may be able to ease the economic burdens of emissions reductions and make those reductions more economically efficient. Although many nations, including the U.S., have signed the Kyoto Protocol, few of the industrialized countries have even begun ratification proceedings, looking to the U.S. for leadership before they sketch out their own programs. The Kyoto document itself remains controversial in this country, but explorations on how to achieve its overall goals on a sound basis have begun in earnest.

Analysis of national fuel choices involved in supplying the nation's electricity needs can illustrate the potential for a dramatic conversion from coal power to gas technologies as the primary source of electricity generation within a timeframe unprecedented for the capital-intensive electric utility industry.

Clean development mechanism (CDM) strategies may involve creative partnerships between developing countries and energy companies. The international protocol provides no roadmap for the research and development necessary for energy technologies needed to assure long-term viability of the emissions reductions worldwide, and negotiators involved in the Kyoto process were not even equipped with a technology roadmap appropriate to the task.

It appears that the growth of GHG emissions, which has been progressing since the dawn of the

Industrial Revolution in the 19th Century, may be difficult and expensive to control in the relatively short-term timetable called for in the Kyoto Protocol.

SEQUESTRATION TECHNOLOGIES

A major strategy for significant control of GHG is carbon sequestration. Carbon sequestration can be defined as any method whereby carbon is removed from the atmosphere on a permanent basis. Several types of sequestration technologies are being studied, including:

- injection into oil and gas reservoirs and into very deep, unmineable coal seams;
- using saline aquifers of unmineable coal seams for disposal;
- forming CO_2 hydrates in deep ocean environments;
- injecting liquid CO_2 into the ocean; and
- many other options.

The introduction of new nuclear and renewable generating capacity will not be sufficient to meet the world's power demands for the majority of the 21st century, making the increased use of fossil fuels inevitable. Efficiency gains provide proportional reductions in CO_2 emissions per kWh generated. However, achieving greater reductions will require research and development on innovative fossil fuel processing and generating technologies incorporating CO_2 removal as well as accompanying work on sequestration of CO_2.

Several key projects have been proposed, both domestically and internationally, in an effort to prove the viability of CO_2 sequestration. One such project involves the potential partnership of several electric utility companies, the U.S. Fish and Wildlife Service and the scientific community. This project would reclaim thousands of low-lying abandoned acres of land which had previously been used for agricultural production. This land would be managed as hardwood forest. The forest has the potential to sequester hundreds of millions of tons of carbon over its growing lifetime and also has the added value of increasing habitat for numerous local species of wildlife. This double value of carbon sequestration and enhancement of species diversity is the result that the partners in this project are seeking as their goal.

Another project being advanced is more technological in nature. It begins with methane capture from a coal mine and the use of that methane in a combustion turbine to produce electricity. The coal from the mine would be washed and cleaned and then used in a boiler to produce electricity as well. The ash from the coal combustion would be collected and the usable carbon extracted from it for combustion in a second boiler. The remaining ash would be used as a feedstock for a high quality cement. Because the ash replaces cement, the production of which releases large amounts of CO_2 a double benefit is achieved. The CO_2 from these various combustion processes would be captured and injected into the worked out sections of the mine. This would serve two very valuable purposes; the CO_2 would be sequestered from the atmosphere and it would replace the methane in the geological structure thereby minimizing subsidence in the area.

These kinds of projects are attractive because of their multiple benefits. However, while the technological pieces of each are available, they have never been put into an organized system and additional research and development will be necessary to make them commercially feasible on a wide scale.

Additional research needs, summarized below, were charactered in a 1993 DOE/Massachusetts Institute of Technology report and updated in 1997. These include:

- Implementing CO_2 removal and sequestration will decrease power plant net efficiencies and significantly increase the cost of electricity throughout the U.S. To make responsible societal decisions, accurate and consistent economic and environmental analyses of all alternatives for atmospheric CO_2 mitigation are required.

- Although commercial CO_2 separation technology is available from non-power applications today, the most promising approach to economical power system CO_2 capture is the development of power generating technologies amenable to efficient CO_2 removal. A 1991 study by EPRI and the International Energy Agency (IEA) showed that CO_2 removal from coal syngas under pressure in an IGCC plant prior to combustion was substantially less energy-intensive and less expensive than post-combustion removal of CO_2 from the stack of a pulverized-coal plant (and likely any coal plant type) at atmospheric pressure. Subsequent IEA studies have yielded the same conclusion. Other innovative approaches have been proposed, including oxygen-fired combustion systems with CO_2 recycle (for natural-gas-fired combined-cycle plants, pulverized-coal plants, and pressurized fluidized-bed combustion plants).

- Both land and ocean disposal will require research to better understand environmental impacts. Even if the impacts prove to be minimal, the public may be reluctant to accept some disposal options.

- CO_2 disposal in depleted oil and gas reservoirs is feasible today, but the ability to dispose of large quantities of CO_2 is highly uncertain. Disposal into the deep ocean or in confined aquifers offers the potential for large-quantity disposal, but poses many unresolved technical, safety, liability, economics and environmental issues. The highest research priority should be to establish the feasibility of large-scale disposal options.

- Both land and ocean disposal will require research to better understand environmental impacts. Even if the impacts prove to be minimal, the public may be reluctant to accept some disposal options.

- Transportation of compressed, liquid CO_2 is conducted commercially in the southwestern U.S. However, cost, safety, liability, and institutional issues remain for large-scale deployment.

- Options for using captured CO_2 in an alternative fuel or as an industrial feedstock or agricultural growth enhancer - which may find strong interest in certain locales - are not yet promising for sequestering large amounts of CO_2, but further research is needed.

- Disposal of CO_2 into deep, unmineable coal beds poses many unanswered questions but may offer the advantage of displacing methane from the coal beds for enhanced coal seam gas recovery and use.

The total industrial use of CO_2 in the U.S. is less than 50 MT per year. Most of that industrial CO_2 is used for enhanced oil recovery, and comes from the CO_2 recovered from natural gas wells. While the total CO_2 emissions from power generation is estimated at 1.8 billion tons, sequestration of 50 MT would still be significant. Lowering the cost of recovery systems could open up this market even more.

A key electric generation technology available today is IGCC. At about 40% efficiency now (and over 50% with improved components), the installation of IGCC in lieu of a conventional pulverized coal generating unit provides a reduction in potential CO_2 emissions of about 15%. When retrofitting this technology on an older, less efficient plant, instantaneous reductions of 20% are possible. There are few technologies available that can achieve this magnitude of CO_2 emissions reductions.

IGCC provides an ideal source for pursuing CO_2 recovery for industrial use. In the oxygen-blown IGCC system, synthetic gas (syngas) is produced at a very high pressure, forming a concentrated stream of CO (carbon monoxide), H_2 (hydrogen) and CO_2. The CO_2 concentration in the gas stream from the gasifier is about 10%. Approximately half of the syngas is CO, which is burned to CO_2 in the combustion turbine, along with the H_2 produced in the gasifier. The acid gas removal system, which is utilized to remove the hydrogen sulfide formed from the sulfur in the coal, concentrates the CO_2 even more, to about 75-85%. This concentrated stream is then available for separation and recovery for industrial use. No other advanced power generation system provides the ability to produce such an ideal CO_2 stream for the purposes of recovery, as does IGCC. Recovery of this stream removes about 5% of the total CO_2 emissions from the IGCC unit. Further development of this technology in DOE's *Vision 21* will lead to greater efficiencies, lower CO_2 emissions, and CO_2 product streams more suited for lower cost recovery.

Overall, the reduction in CO_2 emissions from this combination of IGCC and CO_2 recovery can be very significant. First, the use (or retrofit) of IGCC provides for a 15-20% reduction in CO_2 emissions. Assuming that all of the CO_2 in the syngas stream is recovered, that reduces the CO_2 by another 5% for a total reduction of 20-25%.

Commercial deployment of such technologies will provide significant reductions in CO_2 emissions, both for existing and new power generation needs, here in the U.S. and abroad.

CREATIVITY

Any GHG control strategy can best take advantage of incentives and accelerated adoption if it includes some sort of emissions trading, incentives for adopting advanced technologies and the mechanisms for sharing that technology on a global basis.

Fuel switching involves going from standard coal plants to lower CO_2 emitting energy sources that include nuclear, renewables, natural gas, or advanced clean coal. Discussions following negotiation of the Kyoto Protocol have not outlined roles for advanced coal or nuclear power as strategies for emission reductions, putting an extraordinary burden on generation from other fuel sources. Given the intentions of developing nations, especially China, to expand the use of coal for electricity generation, it is daunting to realize that effective large scale and economic sequestration strategies for coal-powered electricity may still be many years away (although some smaller scale techniques may be economic and available soon).

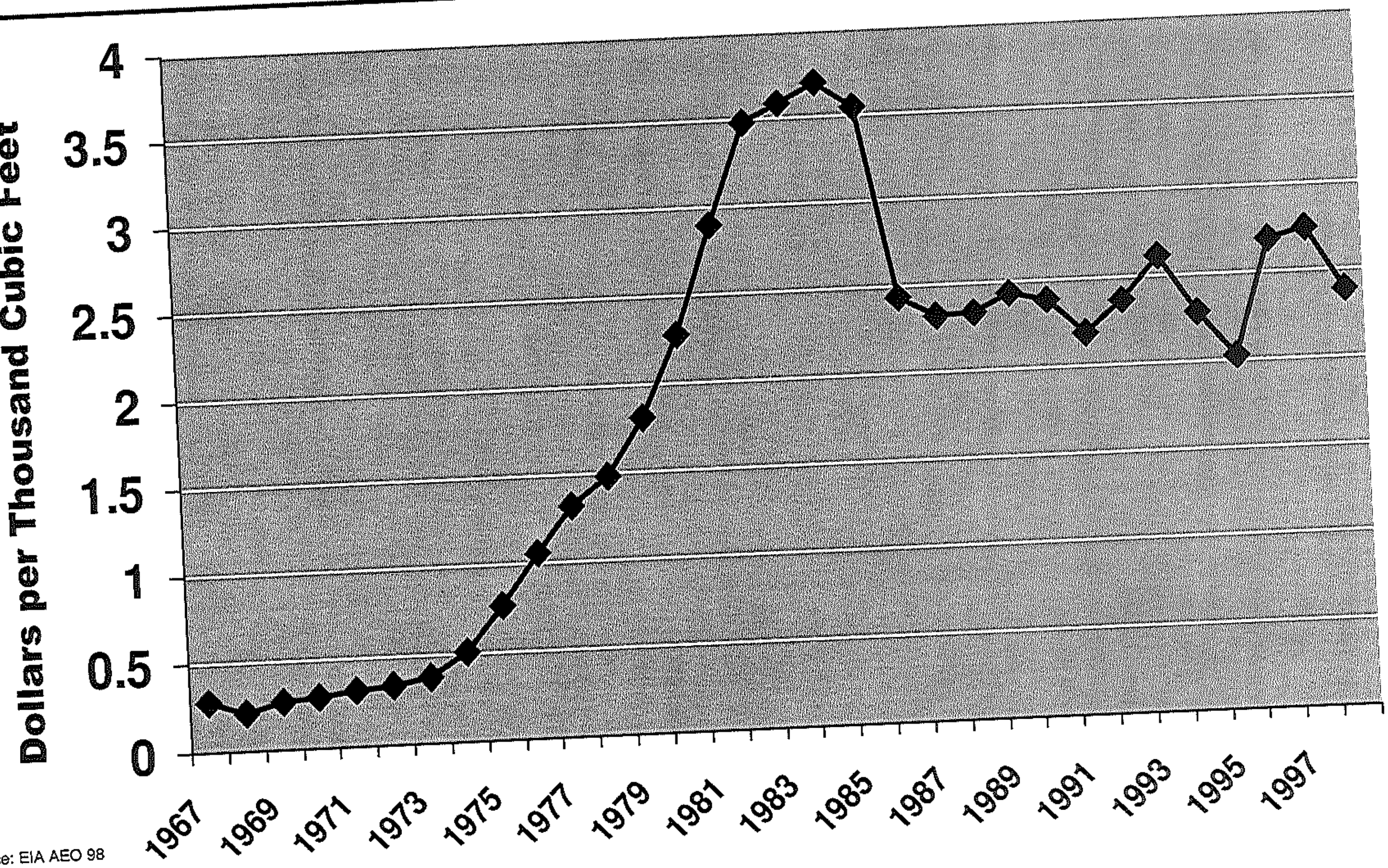
Ultimately most emissions reductions strategies now under discussion for the U.S. assume conversion of the nation's generating capacity to natural gas will be an essential strategy. Today, natural gas accounts for about 10% of electric power. Gas is a fossil fuel, but it burns in a way that limits CO_2 emissions to a fraction of those created for a given amount of electricity by coal power. Natural gas prices are at a fairly low level historically, and have been relatively stable in recent years. Nonetheless, at times of short supply, gas prices have been much higher and more volatile. (See Chart 6 - Natural Gas Prices, Inflation Adjusted, 1968-1998).

One possible source of growth in renewable power is non-hydro renewables, including wind, solar/PV, solar thermal, wood and other biomass combustion, municipal solid waste incineration, and geothermal power. Indeed, these non-hydro renewables are proposed to become a principle focus of federal research dollars. In 1997, non-hydro renewable sources supplied less than 0.25% of electric generation. The building block analysis, taking into account the most optimistic projections, assumes that non-hydro renewables can supply about 6% of the country's generation by 2030, so that along with hydropower, total renewable power would amount to about 13% by that year. (See Chart 7 - A Supporting Role for Renewables.)

Nonetheless, gas has capability - that is, unlike renewables, we can expand our use of gas by a large percentage factor that may be limited more by cost than available land or the intermediate term gas supply itself. Also, gas is storable and generally available on demand, unlike power from the sun and wind. So one key variable in the building block analysis is the extent to which the energy policy adopts natural gas conversions as a strategy for reducing emissions. As will be seen, that can vary from a co-equal supporting role with coal and nuclear power all the way up to total dominance in American energy markets during the next 30 years.

Despite the lack of a specific global energy strategy inherent in the treaty itself, the U.S. has at least five distinct energy options for emission reductions in this country that can be used in one combination or another. This diversity, and the wise use of it, will be key as the country decides its energy policy for the next century.

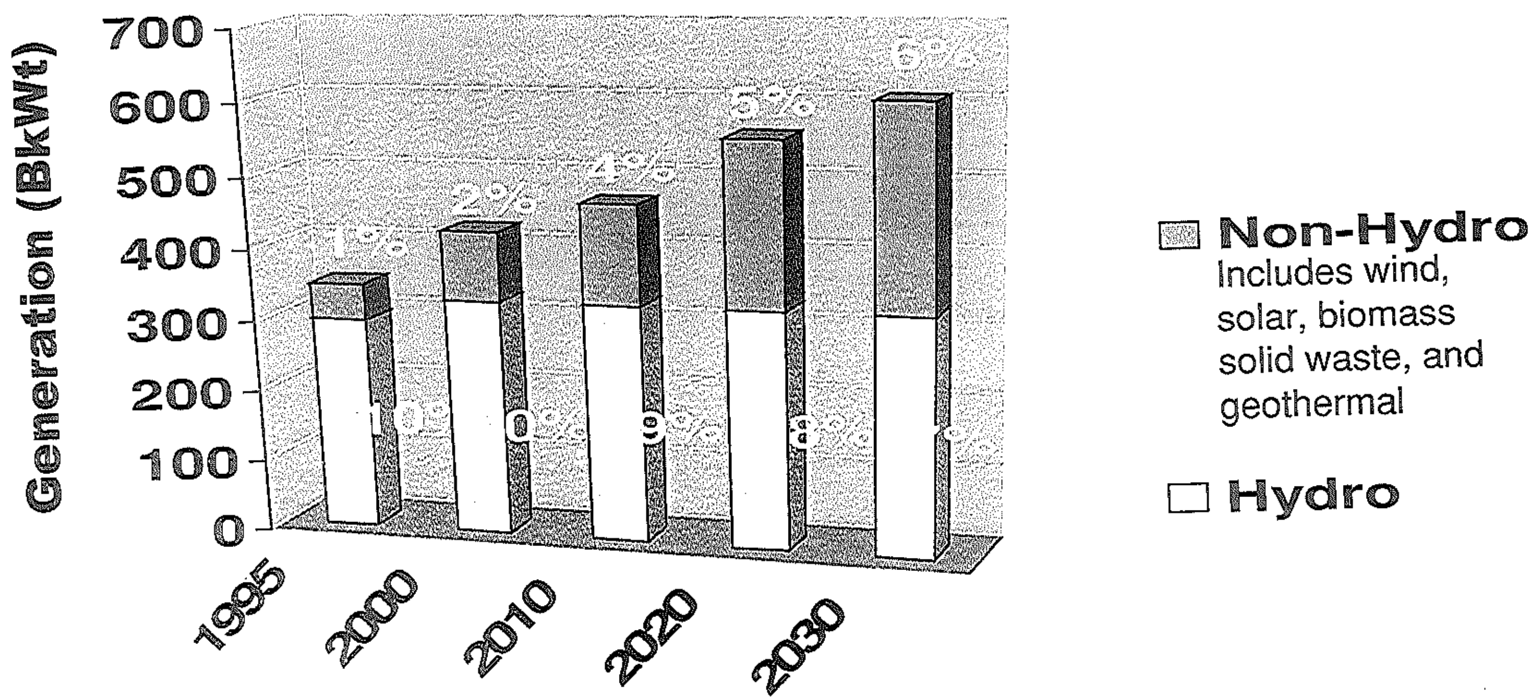
Chart 6: Natural Gas Prices to Electric Utilities, 1967-1998



Source: EIA AEO 98

Chart 7: A Supporting Role for Renewables

Renewables will not generate more than 13% of total generation by 2030, even with heroic projections for non-hydro renewables



Source: EIA AEO 98 (1995-2030)
AEP Projection (2030)

APPENDIX A

Description of the National Coal Council

Appendix A

Description of the National Coal Council

The National Coal Council was chartered in 1984 on the advice of the White House Conference on Coal. The Council became fully operational in 1985. Recognizing the critical role of coal to America and to the world's energy needs for the future, this industry advisory council was created with the conviction that such an assemblage would make a vital contribution to America's energy security. By providing information, the Council could help shape policies relative to the use of coal in an environmentally sound manner which, in turn, could lead to decreased independence on other less abundant, more costly, and less secure sources of energy.

The National Coal Council is chartered by the Secretary of Energy under the Federal Advisory Committee Act. Its sole purpose is to advise, inform, and make recommendations to the Secretary of Energy with respect to any matters relating to coal or the coal industry about which the Secretary requests its expertise. Members of the National Coal Council are appointed by the Secretary of Energy and represent all segments of coal interests and geographical regions. The National Coal Council is headed by a Chairman and a Vice-Chairman who are elected by the Council.

The Council is supported entirely by voluntary contributions from its members. It receives no funding from the Federal Government. In fact, by conducting studies at no cost to the Department, it saves the government money.

The National Coal Council does not engage in traditional trade association activities. It does not participate in lobbying efforts. The Council is a broad, objective advisory group whose approach is national in scope. The Secretary of Energy requests in writing the nature and scope of any requested study to be undertaken by the Council. The first major studies undertaken by the National Coal Council were presented to the Secretary of Energy in the summer of 1986, barely one year after its inception.

APPENDIX B

The National Coal Council Membership Roster

APPENDIX B

The National Coal Council Membership Roster

Mr. James R. Aldrich
State Director
The Nature Conservancy
Lexington, KY

Mr. Allen B. Alexander
President & CEO
Savage Industries, Inc.
Murray, UT

Dr. Sy Ali
Director
Advanced Industrial Programs
Allison Engine Company
Indianapolis, IN

Ms. Barbara F. Altizer
Executive Director
Virginia Coal Council
Cedar Bluff, VA

Mr. Girard F. Anderson
Chairman and CEO
TECO Energy
Tampa, FL

Mr. Henri-Claude Bailly
Chairman
Hagler Bailly, Inc.
Arlington, VA

Mr. Charles J. Baird
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Mr. L. G. Brackeen
Vice President
Houston Lighting & Power Company
Houston, TX

Mr. Donald P. Brown
President and CEO
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Ashland, KY

Mr. Robert L. Brubaker
Porter, Wright, Morris & Arthur
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Dr. Louis E. Buck, Jr.
New Orleans, LA

Mr. Robert A. Burns
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Mr. Frank Calandra
President
Jennmar Corporation
Pittsburgh, PA

Mr. Donald M. Carlton
President
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Austin, TX

Mr. William Carr
Cropwell, AL

Mr. William Cavanaugh, III
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Joseph P. Congleton, Esq.
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Mr. Ernesto Corte
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Mr. Richard F. Cronin
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Mr. James K. Davis
Sr. Vice President, Corp. Relations
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Mr. Forrest E. Hill
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Commissioner
Public Utilities Commission of Ohio
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Sargent & Lundy
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Mr. Steven F. Leer
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St. Louis, MO

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Mr. Peter B. Lilly
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Mr. Rene H. Males
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Strategic Decision, Inc.
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Mr. Emmanuel R. Merle
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Mr. C. O. Woody
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Juno Beach, FL

APPENDIX C

The National Coal Council Coal Policy Committee

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National Coal Council Coal Policy Committee

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Columbus, OH

Steven F. Leer, Vice Chairman
Arch Coal Inc.
St. Louis, MO

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Fairbanks, AK

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Richmond, VA

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Frank Calandra
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APPENDIX D

National Coal Council Coal Technology Subcommittee

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National Coal Council Technology Subcommittee

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Mr. Robert Kane
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APPENDIX E

Correspondence Between the National Coal Council and the Department of Energy

THE NATIONAL COAL COUNCIL, INC.
Post Office Box 17370, Arlington, Virginia 22216
(703) 527-1191

CLIFFORD R. MIERCORT
CHAIRMAN

October 2, 1997

The Honorable Federico F. Peña
Secretary of Energy
United States Department of Energy
1000 Independence Avenue SW, Room 7A257
Washington, DC 20585

Dear Mr. Secretary:

We regret very much that you were unable to attend our recently completed Full Council meeting in Tampa, Florida. It was an excellent meeting, and we very much missed having you with us. We sincerely hope that you will be able to join us at our next meeting in May in Washington, D.C.

At the Tampa meeting, the members concurred in a recommendation from our Coal Technology Subcommittee that we conduct a study, under our "Fast Track" procedure, as follows:

Title: "Coal's Role in Achieving Economic Growth & Environmental Stability"

Scope: An interpretive study of recent Global Climate Change studies with a strategic long range perspective on enabling technologies. (outline attached)

Accordingly, we respectfully request your approval to conduct this study and report the results to you. In addition, we ask that you appoint a government co-chair to assist the work group in its efforts.

Sincerely,

Clifford R. Miercort

Clifford R. Miercort

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cc: Dr. E. Linn Draper, Jr.
The Honorable Patricia Godley
Mr. Steven Leer
Mr. James F. McAvoy
Dr. Robert Nickell

An Advisory Committee to the Secretary of Energy

The Secretary of Energy
Washington, DC 20585

February 10, 1998

Mr. Clifford R. Miercort
Chairman
The National Coal Council, Inc.
P.O. Box 17370
Arlington, VA 22216

Dear Mr. Miercort:

Thank you for your letter of October 2, 1997, requesting approval for the National Coal Council to conduct the study entitled "Coal's Role in Achieving Economic Growth & Environmental Stability."

I am pleased to grant approval to the Council to conduct this study. The Government co-chairs for this effort will be Messrs. Robert Kane and Jerome Temchin. The issue proposed is especially timely in light of the current national discussion about the Administration's global climate change policy. It is important that coal remain a viable option for fueling the Nation's economy.

I was also pleased to hear that your November meeting was a success. I hope that my schedule allows me to address your next meeting in May 1998. I appreciate the efforts of the Council and look forward to seeing the results of this study. Timely advice from our stakeholders is a vital part of developing a balanced national energy policy.

Sincerely,

Federico Peña

12 May '98

APPENDIX F

Correspondence From Industry Experts

Strategic Decisions, Inc.
René H. Malès, President

1165 Hillsboro Mile, Unit 701 ♦ Hillsboro Beach, FL. 33062
Phone (954) 480-2709 ♦ Fax (954) 421-2446

November 12, 1998

Mr. Robert A. Beck
Executive Director
The National Coal Council, Inc.
PO Box 17370
Arlington, VA 22216

Dear Bob:

By your memo dated Nov. 4 you asked that we review the Draft of the latest study by the NCC and be ready to comment at our next meeting. As you know, I will not be able to be at the meeting, but I wanted to get a few comments to you and to Bill who will be there for me.

1. The organization of the report is not clear. Sections are not sequential and without pagination it is impossible to see how things fit together.

2. The report desperately needs a short executive summary to get across the excellent material contained.

3. The background section is well done, particularly the summary of environmental issues is clear, concise (considering the complexity of the subject) and focused on the major issues for energy policy.

4. Similarly, the technology section "II Enabling Technologies", is very well done and highlights in readable form the status of the various technologies and the issues affecting deployment or commercialization of each.

5. However, the section "E. Mobile Source Efficiency" is blank. I presume that someone is going to produce a contribution.

6. Similarly, section "V. A. Interpretation of Compelling Data" is blank as a section "D. No Regrets Policy" which appears in two places.

7. Section III describing the Five Lab Study and Its Significance is a good summary of the study but weak on the "significance" part.

8. Section "IV, Alternative Carbon Emission Reduction Scenarios is interesting and contains excellent material but I had difficulty in figuring out what conclusions I should draw from it. It would help the reader to bring the various ideas together in a summary or evaluation.

9. In the middle of the third paragraph on the first page, the report states "...the U.S. will actually need to reduce its energy use by about 1/3, to reach the 7% below 1990 level." I'm not sure what the writer had in mind, but I disagree with the statement. "Given the expected growth in energy" technology has to reduce CO2 emissions by one third to reach the proposed levels below emissions in 1990; a tall order in this time frame. Alternatively, energy efficiency in use will have to increase by X % to maintain the same economic output as projected under the base scenario or there will have to be a reduction in both economic growth and energy use to meet the CO2 emissions target.

This will be an excellent report when cleaned up. Sorry I can't be there to help.

Cordially,

Reni

cc William B. Schafer III

Subj: NCC Role of Coal Study Comments
Date: 98-11-16 21:10:23 EST
From: jgellici@ix.netcom.com (Janet Gellici)
To: rbeck82851@aol.com (Beck Bob)

November 16, 1998

TO: Bob Beck, Executive Director, National Coal Council
FROM: Janet Gellici, Executive Director, Western Coal Council
SUBJ: Comments re: "Role of Coal" Study – Draft 2

I now fully appreciate that turnaround time is a priority for the NCC ... I'd barely had time to open the envelope with the first draft and put it on my "to do" pile, than the second draft showed up! I'll jump on these more quickly in the future.

My comments are few; I thought the report was well written and I like the re-organization of the second draft ... the Executive Summary/Conclusions section up front is a good add. I believe the content accurately reflects the general views and concerns of the Western Coal Council membership; I feel my members would be supportive of the issues and conclusions presented.

1. Part 2 – Section B

I believe this section would be strengthened with the addition of information on the link between coal/electricity and economic vitality of the US economy. A summary of 3 or 4 key points or statistics on this would establish a foundation on which to more firmly base your conclusions. Although a general statement is included in Section A – Background [Part 2], I think it would help hammer home the point with the inclusion of a few stats. I believe RDI-Peabody would have some pertinent information to contribute here.

The inclusion of this information is even more important if you're considering dropping the bracketed gray text, which I would prefer to see retained.

2. Part 2 – Section C

In the paragraph that begins "Environmental groups have cautioned that ... ", the last two sentences don't read well. I think I understand what you're trying to say, but I'm not sure it's worded very effectively ... particularly "... as a possible way to use the environmental argument to adversely impact coal-fired generation."

3. Part 2 – Section G

I think the points addressed in this section are worth including, but agree that the current phrasing is perhaps too "volatile." I do believe the section could be re-worded to read more objectively.

4. Part 2 - General

I assume you'll be adding a section on Administrative Initiatives given the November 12th signing ... or perhaps a section on COP-4 developments.

5. Part 2 - General – Fuel Diversity Strategy

Part 2 does not establish fuel diversity as a national objective advocated by the Administration and Congress. The first time it arises is in Part 3 – Enabling Technologies. Part 5 – Alternative Carbon Emission Scenarios is certainly premised on the strategic and defensive benefits of a fuel diverse policy; this section would likely be strengthened if a link were established earlier on in the report between the Administration/Congress and these objectives.

6. Part 4

I think it reads fine as is; don't see how you could condense it any further.

7. Part 5 – Section F. Creativity

This entire section needs to be re-worked or re-organized ... it's very disjointed and in desperate need of some transitional phrasing ... reads as if it were cut and pasted in a very random fashion.

Also, is there more? I was left hanging with "... the U.S. has five distinct energy options ... used in one combination or another."

That's my comments to date, Bob. Hope they'll be of some help. I look forward to seeing you on Wednesday. I'll be arriving at the Four Seasons around 2:00 pm on Tuesday; please call me there if you need any clarification on the points I've raised prior to the meeting. I did manage to get a Van Gogh exhibit ticket ... 4:00 pm on Tuesday ... I'll let you know if it was worth what I paid for the ticket!

Regards,

Janet

------------------- Headers -------------------
Return-Path: <jgellici@ix.netcom.com>
Received: from rly-zb05.mx.aol.com (rly-zb05.mail.aol.com [172.31.41.5]) by air-zb02.mail.aol.com (v51.16) with SMTP; Mon, 16 Nov 1998 21:10:23 -0500
Received: from dfw-ix10.ix.netcom.com (dfw-ix10.ix.netcom.com [206.214.98.10])
by rly-zb05.mx.aol.com (8.8.8/8.8.5/AOL-4.0.0)
with ESMTP id VAA07744 for <rbeck82851@aol.com>;

Mon, 16 Nov 1998 21:10:23 -0500 (EST)
Received: (from smap@localhost)
by dfw-ix10.ix.netcom.com (8.8.4/8.8.4)
id UAA13868 for <rbeck82851@aol.com>; Mon, 16 Nov 1998 20:10:21 -0600 (CST)
Received: from den-co55-28.ix.netcom.com(206.214.71.28) by dfw-ix10.ix.netcom.com via smap (V1.3)
id rma013805; Mon Nov 16 20:10:12 1998
Message-ID: <3650DC08.AC1ED0CC@ix.netcom.com>
Date: Mon, 16 Nov 1998 19:14:33 -0700
From: Janet Gellici <jgellici@ix.netcom.com>
X-Mailer: Mozilla 4.04 [en] (Win95; I)
MIME-Version: 1.0
To: Beck Bob <rbeck82851@aol.com>
Subject: NCC Role of Coal Study Comments
Content-Type: text/plain; charset=iso-8859-1
Content-Transfer-Encoding: 8bit

American Electric Power
1 Riverside Plaza
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614 223 1000

AEP
AMERICAN
ELECTRIC
POWER

Ms. Pam Martin
National Coal Council
2000 15th Street N Ste 500
Arlington, VA 22201

January 14, 1999

Dear Ms. Martin:

Attached is the information we discussed, as well as some additional information I thought may be useful to you. If you find that you need anything further, please don't hesitate to contact me at (614) 223-1285.

Sincerely,

Manoj K. Guha/sdb

Manoj K. Guha
Manager - Special Projects
Power Generation Group

Manoj Guha

American Electric Power

The short-term deadline of 2010 for compliance with the Kyoto protocol and the lack of a flexible energy policy in the United States could force American electric energy suppliers to examine options to reduce CO_2 emissions that are increasingly limited, increasingly costly and probably not sustainable or flexible enough to achieve long-term emission targets.

An analysis of national fuel choices involved in supplying the nation's electricity needs can illustrate the potential for a dramatic conversion from coal power to gas technologies as the primary source of electricity generation within a time-frame unprecedented for the capital-intensive electric utility industry.

The swift conversion or mothballing of existing coal, nuclear and hydro generating units in favor of pursuing a generating strategy dominated by gas is possibly the only choice from today's energy technologies that could meet Kyoto's deadline for U.S. emissions reductions. The dimensions of this conversion to a gas-dominated generation mix raises four important questions:

- What will the cost of this conversion be?
- Who will pay it?
- Will the sudden conversion of capacity from coal to gas distort natural gas prices?
- Can the natural gas financial infrastructure and the physical infrastructure of exploration, transmission and distribution respond without significant distortions in the price of natural gas and electricity as well?

The building block analysis of national fuel choices itself does not provide automatic answers to these questions by any means. But the building block analysis suggests in a compelling way that these are questions significant to the long-term course of electricity costs in an economy whose growth seems to directly track with electric energy consumption.

Alternative cases using the same building block analysis suggest that a fuel diversity policy can support the use of several fuels for electric power -- including stepped-up growth for natural gas -- while achieving CO2 emission goals in a more flexible and less wasteful way, as long as a more reasonable timetable for meeting those goals is adopted. But an examination of the fuel diversity building-block electricity strategy and emission reduction requirements also points up the need to consider accelerated technology development, including advanced clean coal technologies.

* * *

Although many nations have signed the Kyoto protocol on carbon dioxide emissions, few of the industrialized countries have even begun ratification proceedings, looking to the United States for leadership before they sketch out their own programs. The Kyoto document itself remains controversial in this country, but explorations on how to achieve its overall goals on a sound basis has begun in earnest.

If control of CO_2 emissions becomes an agreed-upon strategy to prevent potential global warming, the challenge remains of trying to optimize C02 emission reduction strategies. Three key elements should be part of such a strategy:

- **Flexibility** - Finding diverse and creative solutions is necessary to meet the CO_2 emissions challenge, including energy solutions that evolve from conservation, from technology, from financial instruments, and from both supply-side and demand-side of energy transactions.

- Diversity - Avoiding overdependence on any single fuel and seeking a diversity of fuels and technologies which can accommodate economic growth while reducing overall emissions.

- Sustainability - The emission reductions should be viable at least for the next thirty years, taking into account available and developing technologies as well as projected energy requirements during that timeframe.

- Economic growth - Like other energy and environmental policies, the CO_2 emissions alternatives need to be screened both for economic realism -- whether likely available economic incentives and market behavior will support the strategy -- and for whether they will suport economic growth.

- Creativity - The strategy can best take advantage of incentives and accelerated adoption if it includes some sort of emissions trading, incentives for adopting advanced technologies and the mechanisms for sharing that technology on a global basis.

A full-fledged economic study of CO_2 control strategy costs is the logical follow-up to this building-block analysis. This analysis itself, however, is enough to suggest that current U.S. energy strategy and electric generating technology strategy have not been optimized to meet the emissions control challenges ahead.

It seems intuitively obvious that the growth of greenhouse gas emissions, which has been progressing since the dawn of the industrial revolution in the 19th century, may be difficult and expensive to control in the relatively short-term timetable called for in the Kyoto protocol. There are other serious limitations to the Kyoto approach, of course:

- No meaningful participation in greenhouse gas emission controls is required from the developing countries, nor is there an overall plan to share emission controls strategies between developed and developing nations.
- The international protocol provides no roadmap for the research and development necessary for energy technologies needed to assure long-term viability of the emissions reductions worldwide, and U.S. negotiators involved in the Kyoto process were not even equipped with a U.S. technology roadmap appropriate to the task.
- Emission trading rules and credits for actions that further reduce emissions on a collaborative international basis remain in dispute and of limited use to domestic energy suppliers.
- Given the intentions of developing nations, especially China, to expand the use of coal for electricity generation, it is daunting to realize that effective CO_2 sequestration strategies for coal-powered electricity may still be 30 years away.
- Discussions following negotiation of the Kyoto Treaty have not outlined roles for advanced coal or nuclear power as strategies for emission reductions, putting an extraordinary burden on generation from other fuel sources.

Despite the lack of a specific global energy strategy inherent in the treaty itself, the United States has five distinct energy options for emission reductions in this country that can be used in one combination or another:

- Fuel switching to lower CO_2 energy sources that include nuclear, renewables, natural gas, or advanced clean coal.
- CO_2 sequestration technologies [need a specific example here, perhaps]

- Joint implementation strategies involving creative partnerships between developing countries and U.S. energy companies
- Emissions trading on an international basis to ease economic burdens of emission reductions and make those recuctions more economically efficient
- Energy conservation efforts to slow the growth of electricity use, relieving the need for expanding generation and fossil fuel consumption

The building block analysis assumes that all these strategies are theoretically available to U.S. energy policy makers and energy suppliers, and that -- up to a point -- we can combine and re-combine building blocks of fuel sources in order to reach emission reduction goals.

In practice, however, it should be noted that U.S. policies on the environment, nuclear power, hydroelectric power and energy technology seriously limit future options in designing these building blocks.

For example, nuclear power is free of greenhouse gas emissions, but today faces a limited future in the United States. Nuclear power plants today supply 21 percent of U.S. electricity generation, but the current trend toward accelerated phasedown of nuclear plants through early retirements means that nuclear power could fall to 1 percent of total electricity needs by 2030. Recent statements by some Administration officials, including Vice President Gore's comments during a recent visit to Chernobyl, suggest a belated recognition that nuclear power may be essential to meeting CO_2 emissions goals. At least two utility companies have applied for renewal of nuclear plant licenses. But today no new nuclear plant is under construction, no relicensing has occurred, and the federal government has failed to meet its contractual deadline for taking title to spent nuclear fuel from the nation's existing plants.

Part of the building block analysis will have to take into account a major fork in the road for nuclear power (Chart 1. Fork in the Road for Nuclear Power). The default choice involved in reinforcing today' policies implies a continuation of the current trend toward early retirement of nuclear units. One alternative is to sustain nuclear's current share of electric power generation by providing for orderly renewal of nuclear plant licenses and development of a unified advanced reactor design for new units which could replace those which must retire.

Another portion of the building block analysis is the role of renewable energy sources in supplying future energy needs. Hydroelectric power, the nation's largest and most traditional renewable source of electricity, is likely to remain relatively static as a resource. Most of the rivers available for easy and economic hydro power have already been tapped, and the process of relicensing some hydroelectric power stations is now proving much more costly, lengthy and controversial than anticipated.

One possible source of growth in renewable power is non-hydro renewables, including wind, solar photovoltaic, solar thermal, wood and other biomass combustion, municipal solid waste and geothermal power. Indeed, these non-hydro renewables are proposed to become a principle focus of federal research dollars. In 1997, non-hydro renewable sources supplied less than 0.25 percent of U.S. electric generation. The building block analysis, taking into account the most optimistic projections, assumes that non-hydro renewables can supply about 6% of the country's generation by 2030, so that long with hydro power, total renewable power would amount to about 13% by that year. (Chart 2. A supporting role for renewables.)

This level of growth in non-hydro renewables is heroic in proportion to efforts today, and there are physical and economic limits to the extent non-hydro renewables can replace coal, gas and nuclear power. For example, to use biomass fuel in an effort to replace one 2,600-megawatt coal fired plant -- AEP has two comparable facilities with two 1,300-megawatt units -- would require the annual harvest of half of all Ohio's available forest and agricultural land. Also, some forms of renewable power have their environmental opponents: wind, for the potential mortality to birds from wind turbine blades; solar voltaic and photovoltaic for potential hazardous waste from spent cells; and municipal solid waste due to water table and land use objections.

Ultimately most CO2 emissions reductions strategies now under discussion for the United States assume conversion of the nation's generating capacity to natural gas will be an essential strategy. Today, natural gas accounts for about 10 percent of electric power. Gas is a fossil fuel but burns in a way that limits carbon dioxide emissions to a fraction of those created for a given amount of electricity by coal power. Natural gas prices are at a fairly low level historically, and have been relatively stable in recent years. But at times of short supply gas prices have been much higher and more volatile (Chart 3: Natural gas prices, inflation adjusted, 1968-1998.)

Nonetheless, gas has scalability -- that is, unlike renewables, we can expand our use of gas by a large percentage factor that may be limited more by cost than available land or the intermediate term gas supply itself. Also, gas is storable and generally available on demand, unlike power from the sun and wind. So one key variable in the building block analysis is the extent to which the U.S. energy policy adopts natural gas conversions as a strategy for reducing CO_2 emissions. As will be seen, that can vary from a co-equal supporting role with coal and nuclear power all the way up to total dominance in American energy markets during the next 30 years.

The assumptions common to each case in this building block fuel analysis for electric power are important to keep in mind (See Table of Assumptions):

- The domestic target for U.S. annual CO_2 emissions is 7 percent below 1990 levels by 2010, per the Kyoto protocol, so each building block fuel analysis seeks different combinations of fuel choices to reach that target.
- The 1998 report by the U.S. Energy Information Administration (EIA) provides assumptions on electric power consumption growth of about 1.49% annually, but energy conservation efforts are assumed to reduce U.S. electricity demand growth by 0.25 percent annually from 1995-2030.
- The analysis bases assumptions on a table of fuel and heat rates for various fuels for the years 1995-2020, also based on EIA's 1998 report, with reasonable projections based on those trends are calculated for the years 2020-2030. This includes separately calculated efficiencies for existing natural gas combined cycle (NGCC) generating units, new NGCC units, existing coal-fired plants and Clean Coal Technology (CCT) units after 2010.
- Beginning in 2010, approximately 250 million tons of CO_2 emissions credits can be purchased by the U.S. from other countries to make up for any shortfall in the domestic emission reduction effort.
- Highly accelerated growth rates are applied to the contributions of non-hydro renewables, with annual growth rates (years 2000-2020) as follows: wind, 2.9 percent; solar photovoltaic, 18.3 percent; solar thermal, 2.7 percent; wood/other biomass, 1.8 percent; municipal solid waste, 1.8 percent; and geothermal, 0.6 percent. Meanwhile, hydro generation is assumed to decline 5 percent between 1995 and 2000, and then remain constant.

Given these assumptions, several case studies of fuel choice building blocks were developed to illustrate significant policy options now available. The cases are not mutually exclusive, and they illustrate several combinations of fuel choices, potential flexibility on deadlines for hitting CO_2 emissions targets and the role of trading and technology in easing the transition.

Case 1 - **Conservation** - Enhanced conservation measures to reduce electricity demand without any change in currently projected fuel mixes.

Case 2 - **Fuel Restrictions** - U.S. adopts of a 2010 deadline for hitting the Kyoto target for CO_2 emissions without substantial changes in existing energy trends. Coal powered plants are retired or converted to gas, and nuclear units are retired as predicted by EIA.

Case 3 - **Fuel Diversity** - Kyoto CO2 emission targets are achieved by 2030, instead of 2010, and a diversity of fuels for electric power generation includes an increasing role for natural gas, a smaller role for coal, but a continued 20 percent of nuclear generation.

Projections for energy consumption along current trends shows that enhanced conservation measures alone will not allow the U.S. to meet the Kyoto CO_2 emissions target. (Chart 4: Case 1: Conservation). Enhanced energy conservation measures could reduce growth in electricity assumption and therefore CO_2 emissions by more than 150 million tons per year by 2010. But that is still more than 250 million tons of CO_2 above the Kyoto target level, even if an additional 250 million tons in CO_2 emission credits are available to help meet the prescribed target.

Case 2 - Fuel Restrictions (Chart 5) involves a rapid and extensive substitution of natural gas generation for coal and nuclear power in order to satisfy electricity demand and still meet the 2010 Kyoto deadline. This implies a 17% cutback in total coal capacity by 2010 from 1995 levels, as well as a 19% decline in nuclear power. Natural gas powered generation, in turn increases from 150 gigawatts of capacity in 1995 to 402 gigawatts by 2010. To maintain the Kyoto targeted emissions level through 2030, gas generation would have to increase to 705 gigawatts, nearly five times current capacity for that fuel. This is, of course, a rapid and drastic shift in U.S. fuel sources for electricity (Chart 6 - Gas Dominance), ballooning gas from a 10 percent share of electricity generation in 1995 to a 40 percent share by 2010, the nominal Kyoto target date. The drawdown of existing and potential natural gas supplies is significant (Chart 7 - Natural Gas Generating Growth) but largely unstudied at this point. Although this building block analysis does not predict the impact of this dramatic increase in gas utilization, it strongly suggests the need for a study of the potential for gas price increases as well as gas infrastructure and exploration economics.

The study also assumes that trends will continue in nuclear generating unit retirements, and that coal units will ultimately retire prematurely to give generating share to gas. By 2030, coal will have less than a 15 percent share of power generation, and nuclear will be less than 1 percent. Non-hydroelectric renewable sources, even with very optimistic projections, will supply only about 9 (???) percent of the nation's power needs (Chart 8 - Impact of Fuel Restrictions).

Case 3 involves Fuel Diversity, a relatively balanced mix of fuels compared to Case 2, with the capacity to support long-term controls of CO2 emissions through new coal technologies, use of natural gas, accelerated renewables development, nuclear power at a sustained level and trading of CO2 emission credits. Case 3 puts the United States at Kyoto targets for CO2 emission levels by 2030, 20 years after the Kyoto deadline. That goal is ambitious, requiring substantial policy and technology developments to bolster the safety and economics of nuclear power, including nuclear relicensing and advanced reactor research, provisions for the

Assumptions and Notes

All Cases

- **Growth of Electricity Demand (all cases assume energy conservation measures are in place)**

	1995-2000	2000-2010	2010-2020	2020-2030	2030-2040	2040-2050
Growth Rate	1.70%	1.25%	1.00%	1.00%	1.00%	1.00%

- **Annual Plant Heat Rate of New Plant additions as follows:**

	Existing	1995-2000	2000-2010	2010-2020	2020-2030	2030-2040	2040-2050
Natural Gas Combined Cycle (NGCC)	9,875	7,090	5,865	5,490	5,315	5,135	4,910
COAL	10,360						
Advanced Pulv. Coal-fired			8,750				
Clean Coal Technology I				8,530			
Clean Coal Technology II					7,580		
Clean Coal Technology III						6,820	6,820

Natural Gas Combined Cycle heat rates are based on lower heating value
Annual Plant Heat Rate for Coal-fired Plants is assumed to be 2% higher than Estimated Design Heat Rate
Generation cost of new coal technologies and NGCC are assumed to be competitive on a 20 year life cycle basis.

- **Renewables**

Actual hydro generation decreases 5% from 1995 to 2000, then remains the same
Non-hydro renewables increase as per the following table, in percent of total generation (2000 - 2030):

	1995	2000	2010	2020	2030
Cases 1-2b	1.40%	1.60%	1.60%	1.70%	1.80%
Case 3	1.40%	1.60%	3.70%	5.50%	6.00%

- **Carbon Sequestration ....** is not considered in any of the cases, however sequestration would result in lower carbon emissions by 2030-2050.

- **Emissions Trading......** it is assumed in many of the cases that 200 MMT of CO2 emission credit may be available during 2010-2030 from Russia and East European countries. It is assumed that 50 MMT credit will be achieved through joint implementation.

Case 1

- Nuclear generation is retired as licenses expire

Cases 2 through 2b

- Nuclear generation is retired as licenses expire
- Gas generation is added, coal generation retired, and CO2 credits are purchased to keep CO2 emissions at 7% below 1990 levels in Case 2. Case 2a is the same, except it ignores the possibility of CO2 credits, and remains at 7% below 1990 emission levels as long as possible. Case 2b maintains CO2 emissions at 2% below 1990 levels with gas generation and CO2 credits.

Case 3

- Nuclear generation licenses are extended and new nuclear technologies are added when necessary to keep Nuclear generation at approximately 20% of the total generation.
- In this case, no two generation fuels are allowed to take more than 2/3 of the total generation, to demonstrate the effect of a balanced generation mix on CO2 emissions. Advantages of this approach include:

  - In the long range, a comparable CO2 emissions strategy to Case 2
  - A balanced generation mix provides for a economically stable, sound national generation strategy
  - Commercialized new coal technologies are assumed economically competitive with NGCC, and will have a global impact on CO2 emissions as these new technologies are utilized in developing countries.
  - Elimination of extensive new gas generation infrastructure needs (pipelines,etc.) associated with case 2

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CASE II
RETIREMENTS AND ADDITION ASSUMPTIONS

	1995	2000	2010	2020	2030	2040	2050
CAPACITY, GW							
Conv. PCF (Pre-1995)	306	297	220	185	65	5	-
Conv. PCF (Post 2005)	-	-	34	34	34	34	-
CCT-1	-	-	-	-	-	-	-
CCT-2	-	-	-	-	-	-	-
CCT-3	-	-	-	-	-	-	-
total coal capacity	306	297	254	219	99	39	-
Existing NGCC	21	21	20	20	15	15	10
NGCC Adds I	-	24	24	24	24	24	24
NGCC Adds II	-	-	164	164	164	164	164
NGCC Adds III	-	-	-	108	108	108	108
NGCC Adds IV	-	-	-	-	163	163	163
NGCC Adds V	-	-	-	-	-	105	105
NGCC Adds VI	-	-	-	-	-	-	111
Combined Cycle	21	45	207	313	471	577	683
Existing CT	129	103	83	66	53	42	34
CT Adds I	-	42	42	42	42	42	42
CT Adds II	-	-	70	70	70	70	70
CT Adds III	-	-	-	38	38	38	38
CT Adds IV	-	-	-	-	31	31	31
CT Adds V	-	-	-	-	-	8	8
CT Adds VI	-	-	-	-	-	-	11
Comb. Turbine (1)	129	145	195	216	234	231	234
total ng capacity	150	190	402	529	705	808	916
Nuclear	99	96	80	49	2	-	-
	(1) Includes Gas-Fired Steam Generatior						
CAPACITY FACTOR							
Conv. PCF	62%	70%	40%	33%	32%	27%	-
Conv. PCF (Post 2005)	-	-	75%	75%	75%	65%	-
CCT-1	-	-	-	75%	75%	75%	-
CCT-2	-	-	-	-	75%	75%	-
CCT-3	-	-	-	-	-	75%	-
total coal cap factor	62%	70%	45%	39%	47%	60%	-
Existing NGCC	76%	74%	72%	70%	68%	66%	64%
NGCC Adds I	-	78%	78%	76%	76%	72%	72%
NGCC Adds II	-	-	80%	80%	78%	76%	76%
NGCC Adds III	-	-	-	80%	80%	78%	76%
NGCC Adds IV	-	-	-	-	80%	80%	78%
NGCC Adds V	-	-	-	-	-	80%	80%
NGCC Adds VI	-	-	-	-	-	-	80%
Combined Cycle	76%	76%	79%	79%	79%	78%	77%
Existing CT	16%	14%	14%	12%	10%	8%	6%
CT Adds I	-	20%	18%	18%	18%	18%	18%
CT Adds II	-	-	18%	18%	18%	18%	18%
CT Adds III	-	-	-	19%	19%	18%	18%
CT Adds IV	-	-	-	-	19%	18%	18%
CT Adds V	-	-	-	-	-	18%	18%
CT Adds VI	-	-	-	-	-	-	18%
Comb. Turbine (1)	16%	16%	16%	16%	16%	16%	16%
total ng cap factor	24%	30%	49%	53%	58%	60%	62%
Nuclear	78%	82%	85%	89%	89%	89%	89%

(1) Includes Natural Gas-Fired Steam Generatior

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CASE III
RETIREMENTS AND ADDITION ASSUMPTIONS

	1995	2000	2010	2020	2030	2040	2050
CAPACITY, GW							
Conv. PCF (Pre-1995)	306	297	240	190	150	110	50
Conv. PCF (Post 2005)	-	-	34	34	34	34	28
CCT-1	-	-	-	31	31	31	31
CCT-2	-	-	-	-	-	17	17
CCT-3	-	-	-	-	-	17	21
total coal capacity	306	297	274	255	215	209	147
Existing NGCC	21	21	20	20	15	15	10
NGCC Adds I	-	24	24	24	24	24	24
NGCC Adds II	-	-	128	128	128	128	128
NGCC Adds III	-	-	-	37	37	37	37
NGCC Adds IV	-	-	-	-	66	66	66
NGCC Adds V	-	-	-	-	-	66	66
NGCC Adds VI	-	-	-	-	-	-	84
Combined Cycle	21	45	171	209	269	336	415
Existing CT	129	103	83	66	53	42	34
CT Adds I	-	42	42	42	42	42	42
CT Adds II	-	-	70	70	70	70	70
CT Adds III	-	-	-	38	38	38	38
CT Adds IV	-	-	-	-	31	31	31
CT Adds V	-	-	-	-	-	8	8
CT Adds VI	-	-	-	-	-	-	11
Comb. Turbine (1)	129	145	195	216	234	231	234
total ng capacity	150	190	366	425	503	567	649
Nuclear	99	96	102	108	119	131	145
	(1) Includes Gas-Fired Steam Generatior						
CAPACITY FACTOR							
Conv. PCF	62%	70%	41%	36%	36%	23%	27%
Conv. PCF (Post 2005)	-	-	75%	75%	75%	65%	60%
CCT-1	-	-	-	75%	75%	75%	65%
CCT-2	-	-	-	-	75%	75%	75%
CCT-3	-	-	-	-	-	75%	75%
total coal cap factor	62%	70%	45%	46%	48%	46%	54%
Existing NGCC	76%	74%	72%	70%	68%	66%	64%
NGCC Adds I	-	78%	78%	76%	76%	72%	72%
NGCC Adds II	-	-	80%	80%	78%	76%	76%
NGCC Adds III	-	-	-	80%	80%	78%	76%
NGCC Adds IV	-	-	-	-	80%	80%	78%
NGCC Adds V	-	-	-	-	-	80%	80%
NGCC Adds VI	-	-	-	-	-	-	80%
Combined Cycle	76%	76%	79%	79%	78%	77%	77%
Existing CT	16%	14%	14%	12%	10%	8%	6%
CT Adds I	-	20%	18%	18%	18%	18%	18%
CT Adds II	-	-	18%	18%	18%	18%	18%
CT Adds III	-	-	-	19%	19%	18%	18%
CT Adds IV	-	-	-	-	19%	18%	18%
CT Adds V	-	-	-	-	-	18%	18%
CT Adds VI	-	-	-	-	-	-	18%
Comb. Turbine (1)	16%	16%	16%	16%	16%	16%	16%
total ng cap factor	24%	30%	46%	47%	49%	52%	55%
Nuclear	78%	82%	85%	89%	89%	89%	89%
	(1) Includes Natural Gas-Fired Steam Generatioi						

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CASE IV
RETIREMENTS AND ADDITION ASSUMPTIONS

	1995	2000	2010	2020	2030	2040	2050
CAPACITY, GW							
Conv. PCF (Pre-1995)	306	297	248	225	190	100	75
Conv. PCF (Post 2005)	-	-	34	34	34	34	34
CCT-1	-	-	-	32	32	32	32
CCT-2	-	-	-	-	12	24	24
CCT-3	-	-	-	-	-	56	56
total coal capacity	306	297	282	291	268	246	221
Existing NGCC	21	21	20	20	15	15	10
NGCC Adds I	-	24	24	24	24	24	24
NGCC Adds II	-	-	71	71	71	71	71
NGCC Adds III	-	-	-	36	36	36	36
NGCC Adds IV	-	-	-	-	60	60	60
NGCC Adds V	-	-	-	-	-	50	50
NGCC Adds VI	-	-	-	-	-	-	84
Combined Cycle	21	45	114	150	205	255	334
Existing CT	129	103	83	66	53	42	34
CT Adds I	-	42	42	42	42	42	42
CT Adds II	-	-	70	70	70	70	70
CT Adds III	-	-	-	38	38	38	38
CT Adds IV	-	-	-	-	31	31	31
CT Adds V	-	-	-	-	-	8	8
CT Adds VI.	-	-	-	-	-	-	11
Comb. Turbine (1)	129	145	195	216	234	231	234
total ng capacity	150	190	309	366	439	486	568
Nuclear	99	96	102	108	119	131	145

(1) Includes Gas-Fired Steam Generator

	1995	2000	2010	2020	2030	2040	2050
CAPACITY FACTOR							
Conv. PCF	62%	70%	58%	51%	50%	53%	51%
Conv. PCF (Post 2005)	-	-	75%	75%	75%	65%	65%
CCT-1	-	-	-	75%	75%	75%	65%
CCT-2	-	-	-	-	75%	75%	75%
CCT-3	-	-	-	-	-	75%	75%
total coal cap factor	62%	70%	60%	57%	57%	65%	64%
Existing NGCC	76%	74%	72%	70%	68%	66%	64%
NGCC Adds I	-	78%	78%	76%	76%	72%	72%
NGCC Adds II	-	-	80%	80%	78%	76%	76%
NGCC Adds III	-	-	-	80%	80%	76%	76%
NGCC Adds IV	-	-	-	-	80%	80%	78%
NGCC Adds V	-	-	-	-	-	80%	80%
NGCC Adds VI	-	-	-	-	-	-	80%
Combined Cycle	76%	76%	78%	78%	78%	77%	77%
Existing CT	16%	14%	14%	12%	10%	8%	6%
CT Adds I	-	20%	18%	18%	18%	18%	18%
CT Adds II	-	-	18%	18%	18%	18%	18%
CT Adds III	-	-	-	19%	19%	18%	18%
CT Adds IV	-	-	-	-	19%	18%	18%
CT Adds V	-	-	-	-	-	18%	18%
CT Adds VI	-	-	-	-	-	-	18%
Comb. Turbine (1)	16%	16%	16%	16%	16%	16%	16%
total ng cap factor	24%	30%	39%	42%	45%	48%	52%
Nuclear	78%	82%	85%	89%	89%	89%	89%

(1) Includes Natural Gas-Fired Steam Generator

CASE V
RETIREMENTS AND ADDITION ASSUMPTIONS

	1995	2000	2010	2020	2030	2040	2050
CAPACITY, GW							
Conv. PCF (Pre-1995)	306	297	275	235	180	102	75
Conv. PCF (Post 2005)	-	-	34	34	34	34	34
CCT-1	-	-	-	32	32	32	32
CCT-2	-	-	-	-	12	24	24
CCT-3	-	-	-	-	-	56	56
total coal capacity	306	297	309	301	258	248	221
Existing NGCC	21	21	20	20	15	15	10
NGCC Adds I	-	24	24	24	24	24	24
NGCC Adds II	-	-	55	55	55	55	55
NGCC Adds III	-	-	-	51	51	51	51
NGCC Adds IV	-	-	-	-	59	59	59
NGCC Adds V	-	-	-	-	-	50	50
NGCC Adds VI	-	-	-	-	-	-	84
Combined Cycle	21	45	99	149	204	254	333
Existing CT	129	103	83	66	53	42	34
CT Adds I	-	42	42	42	42	42	42
CT Adds II	-	-	70	70	70	70	70
CT Adds III	-	-	-	38	38	38	38
CT Adds IV	-	-	-	-	31	31	31
CT Adds V	-	-	-	-	-	8	8
CT Adds VI	-	-	-	-	-	-	11
Comb. Turbine (1)	129	145	195	216	234	231	234
total ng capacity	150	190	293	366	438	485	567
Nuclear	99	96	102	108	119	131	145

(1) Includes Gas-Fired Steam Generatior

	1995	2000	2010	2020	2030	2040	2050
CAPACITY FACTOR							
Conv. PCF	62%	70%	57%	49%	53%	52%	52%
Conv. PCF (Post 2005)	-	-	75%	75%	75%	65%	65%
CCT-1	-	-	-	75%	75%	75%	65%
CCT-2	-	-	-	-	75%	75%	75%
CCT-3	-	-	-	-	-	75%	75%
total coal cap factor	62%	70%	59%	55%	60%	64%	64%
Existing NGCC	76%	74%	72%	70%	68%	66%	64%
NGCC Adds I	-	78%	78%	76%	76%	72%	72%
NGCC Adds II	-	-	80%	80%	78%	76%	76%
NGCC Adds III	-	-	-	80%	80%	78%	76%
NGCC Adds IV	-	-	-	-	80%	80%	78%
NGCC Adds V	-	-	-	-	-	80%	80%
NGCC Adds VI	-	-	-	-	-	-	80%
Combined Cycle	76%	76%	78%	78%	78%	77%	77%
Existing CT	16%	14%	14%	12%	10%	8%	6%
CT Adds I	-	20%	18%	18%	18%	18%	18%
CT Adds II	-	-	18%	18%	18%	18%	18%
CT Adds III	-	-	-	19%	19%	18%	18%
CT Adds IV	-	-	-	-	19%	18%	18%
CT Adds V	-	-	-	-	-	18%	18%
CT Adds VI	-	-	-	-	-	-	18%
Comb. Turbine (1)	16%	16%	16%	16%	16%	16%	16%
total ng cap factor	24%	30%	37%	42%	45%	48%	52%
Nuclear	78%	82%	85%	89%	89%	89%	89%

(1) Includes Natural Gas-Fired Steam Generatior

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CASE VI
RETIREMENTS AND ADDITION ASSUMPTIONS

	1995	2000	2010	2020	2030	2040	2050
CAPACITY, GW							
Conv. PCF (Pre-1995)	306	297	275	232	200	100	75
Conv. PCF (Post 2005)	-	-	34	34	34	34	34
CCT-1	-	-	-	32	32	32	32
CCT-2	-	-	-	-	12	24	24
CCT-3	-	-	-	-	-	56	56
total coal capacity	306	297	309	298	278	246	221
Existing NGCC	21	21	20	20	15	15	10
NGCC Adds I	-	24	24	24	24	24	24
NGCC Adds II	-	-	50	50	50	50	50
NGCC Adds III	-	-	-	46	46	46	46
NGCC Adds IV	-	-	-	-	69	69	69
NGCC Adds V	-	-	-	-	-	50	50
NGCC Adds VI	-	-	-	-	-	-	84
Combined Cycle	21	45	93	139	203	253	333
Existing CT	129	103	83	66	53	42	34
CT Adds I	-	42	42	42	42	42	42
CT Adds II	-	-	70	70	70	70	70
CT Adds III	-	-	-	38	38	38	38
CT Adds IV	-	-	-	-	31	31	31
CT Adds V	-	-	-	-	-	8	8
CT Adds VI	-	-	-	-	-	-	11
Comb. Turbine (1)	129	145	195	216	234	231	234
total ng capacity	150	190	288	355	437	485	566
Nuclear	99	98	102	108	119	131	145

(1) Includes Gas-Fired Steam Generation

	1995	2000	2010	2020	2030	2040	2050
CAPACITY FACTOR							
Conv. PCF	62%	70%	59%	53%	48%	53%	52%
Conv. PCF (Post 2005)	-	-	75%	75%	75%	65%	65%
CCT-1	-	-	-	75%	75%	75%	65%
CCT-2	-	-	-	-	75%	75%	75%
CCT-3	-	-	-	-	-	75%	75%
total coal cap factor	62%	70%	60%	58%	56%	65%	64%
Existing NGCC	76%	74%	72%	70%	68%	66%	64%
NGCC Adds I	-	78%	78%	76%	76%	72%	72%
NGCC Adds II	-	-	80%	80%	78%	76%	76%
NGCC Adds III	-	-	-	80%	80%	78%	76%
NGCC Adds IV	-	-	-	-	80%	80%	78%
NGCC Adds V	-	-	-	-	-	80%	80%
NGCC Adds VI	-	-	-	-	-	-	80%
Combined Cycle	76%	76%	78%	78%	78%	77%	77%
Existing CT	16%	14%	14%	12%	10%	6%	6%
CT Adds I	-	20%	18%	18%	18%	18%	18%
CT Adds II	-	-	18%	18%	18%	18%	18%
CT Adds III	-	-	-	19%	19%	18%	18%
CT Adds IV	-	-	-	-	19%	18%	18%
CT Adds V	-	-	-	-	-	18%	18%
CT Adds VI	-	-	-	-	-	-	18%
Comb. Turbine (1)	16%	16%	16%	16%	16%	16%	16%
total ng cap factor	24%	30%	36%	40%	45%	48%	52%
Nuclear	76%	82%	85%	89%	89%	89%	89%

(1) Includes Natural Gas-Fired Steam Generation

George T. Preston

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Total _4_ pages

January 24, 1999

Robert A. Beck, National Coal Council
Telefax 703 527 1195

Re: **Climate Change Report**

Dear Bob:

I received the January 14 final draft that you sent out. The following pages are my revision of the entire Part 1 - Executive Summary of the report. I reviewed this version carefully to be sure that it contains all of the points on the one-page "Approval Summary" that the Council approved at the November 19, 1998 meeting. I omitted a few of the details that were in the Executive Summary that you sent out - where they were a bit off the main messages and (more importantly) were not in the summary that the Council approved.

You'll see that I used tag words for each Conclusion and each Recommendation to make it easy for the intended audience to relate the recommendations to the conclusions. As an alternative structure, the tag words would also make it easy to combine the conclusions and recommendations, i.e. follow the "Coal's role" conclusion immediately with the matching recommendation(s) and then go on to the "Fuel diversity" conclusion and recommendation, etc. I'll leave that to your and/or the editor's judgment.

I've e-mailed the text for my version of Part 1, to facilitate Pam's incorporating it in the report. I'll FedEx my marked-up draft with edits of Parts 2-5; you should receive it Tuesday afternoon.

One reason I've faxed the Executive Summary (next 3 pages) in addition to e-mailing it, is to show a consistent format with Parts 2 and 3.

Sincerely,

George Preston

c: Robin Jones

PART 1

EXECUTIVE SUMMARY

A. Introduction

The Secretary of Energy requested this report by the National Coal Council (NCC) on the role of coal in helping to continue U.S. economic growth while achieving global environmental stability. The report is divided into five parts:

Part 1: Executive Summary. Introduces the report, summarizes the major conclusions, and sets forth the recommendations of the NCC to the Department of Energy.

Part 2: Coal's Position in the Economy. Discusses current environmental and economic challenges facing coal, and the domestic and international environmental policies affecting the use of coal.

Part 3: Enabling Technologies. Reviews electric generation technologies and discusses efficiency improvements, knowledge gaps, and competition from other fuels and generation sources.

Part 4: Five Labs Study. Briefly reviews the recent Five Labs Study and its significance.

Part 5: Alternate Carbon Emission Reduction Scenarios/Sequestration. Describes reduction scenarios achievable using various fuel and technology options, and summarizes the status of some carbon sequestration technologies and their potential.

B. Conclusions

Coal's role. Because of its relative abundance and stable price, coal has been and will continue to be an essential energy component for long-term sustainable economic development both domestically and internationally. However, in order to maintain the potential for continued economic growth, while simultaneously protecting the environment from excessive accumulation of anthropogenic greenhouse gases (GHG) and other air emissions, a technology-based transition in coal utilization is necessary. This transition will be driven by more efficient generation of electricity, by the commercialization of technologies developed and demonstrated over the past two decades, and by the continuing electrification of the economy.

Fuel diversity. No single fuel can or should dominate U.S. energy use or electricity production. Preserving a diverse spectrum of fuel sources (coal, oil, gas, nuclear, biomass, other renewables) and energy conversion options (central station steam boiler, combustion turbine, distributed generation, synergistic combination systems) is essential to the United States' competitiveness, economic health, societal growth, and world leadership role. Coal's low cost and reliability of supply will be increasingly important in the selection of fuels and electric generation options.

Technology portfolio. Technology advancements are an essential element in optimizing U.S. responses to global climate change issues and commitments. Economic analyses do not identify a single preferred technology but rather demonstrate the payoffs of the technology portfolio approach. These analyses also underscore the need to keep and enhance coal's role in the technology mix through optimizing electric generation in the existing fleet; gasifying coal with exit gas cleanup; co-firing coal with biomass; capturing carbon dioxide exit gas with sequestration; integrating methane capture, coal cleaning, CO_2 injection and ash utilization at the mine; and sequestering carbon through land and forest management. Near-term investment in coal based generation technology development provides long-term as well as near-term payoffs, because such developments also improve the efficiency and reduce the cost of co-firing, integration, sequestration and other later-developing technologies.

Carbon sequestration. Many of the non-agricultural, non-forest carbon sequestration technologies that are known are still in their infancy. Sequestration is an approach with the potential to reduce atmospheric carbon loads without suddenly abandoning our existing energy infrastructure. However, it is unrealistic to plan for significant reduction impacts in the next 20 years from commercial application of sequestration technology.

C. Recommendations

Coal's role.

Near-term climate change responses should take into account the existing U.S. energy infrastructure in order to be economically feasible and implementable.

The Department should continue and strengthen the development of sound, realistic assumptions for the relative roles of coal, nuclear, hydro and other renewables, and natural gas in energy production in near-, mid-, and long-term scenarios for the U.S.

Fuel diversity. U.S. coal usage and the enabling advanced clean coal technology improvements should continue to be supported in the near and intermediate term to preserve a spectrum of fuel options and thus protect against production upsets, interruptions, and price increases in other fuel sources.

Technology portfolio. The Department should maintain a vigorous clean coal utilization research and development program to continue to reduce the cost of clean electric generation. Successfully developing and implementing coal technology advances in partnership with private industry on a time schedule that can make them effective will depend on equitable structuring of costs, risks, and rewards; and the Department should exploit its leadership role to support such arrangements.

Carbon sequestration.

The Department should participate technically and financially in establishing and carrying out an aggressive research and development program in carbon dioxide capture, transport, and sequestration.

A well thought out and carefully implemented global reductions trading program is essential to the flexibility required to achieve emissions goals at acceptable economic impact. An international trading program should incorporate credit for early actions including reductions from forestation and agricultural practices.

K Beck FYI
Handed to G Ruston
by Bob Kane (DOE-FE)
@ NCC working group
11/18/98

Fact Sheet
Carbon Sequestration

FY 1999 Congressional Request	FY 1999 House Mark	FY 1999 Senate Mark	Difference
$11,890K	$2,000K	$4,000k	$2,000K

Background:

Fossil Energy (FE) is committed to the development of technological options for energy production and use that foster a more productive and competitive economy, while improving environmental quality. The pursuit of cost-effective opportunities to reduce greenhouse gas emissions through carbon sequestration is consistent with this general mission.

FE's sequestration research is targeted to produce a suite of practical technologies for deployment in the 2015 timeframe, with significant expansion in scope and reduction in cost for sequestration in the following decade. Hence, although these technologies would not be appropriate for meeting obligations which may be incurred under the Kyoto Protocol, they are well suited to meet the potentially more difficult goals set forth in the Framework Convention on Climate Change (FCCC). (Following consent by the Senate, U.S. participation in the FCCC was ratified on October 15, 1992.)

The implications of the goal of the FCCC – to stabilize atmospheric concentrations of greenhouse gases at levels which prevent significant environmental damage – are that substantial reductions in greenhouse gas emissions will be required in the second half of the 21st century. Acceptable emission rates in that timeframe may be a small fraction of global emissions in 1990. Carbon sequestration is the only approach to meet such a goal while utilizing the current energy infrastructure.

FE has had a small program (about $1.5 million) underway in this area since FY 1993. The specific purpose of this program is to develop and demonstrate technically, economically, and ecologically sound methods to capture, reuse and dispose of CO2. This program is highly complimentary to the current FE R&D program.

Through this program, FE collaborates with 16 countries through the International Energy Agency's Greenhouse Gas Program. An industry/government research project on sequestration in deep, unmineable coal seams began in FY 1998 under this program.

In FY 1998, FE conducted a solicitation which resulted in the selection of 12 cutting edge research projects, which range from the use of CO2 absorbing algae to deep ocean greenhouse gas disposal.

In FY 1998 FE also began a formal working relationship with the Office of Energy Research, and has conducted workshops to solicit input from industry, academic, and other Federal stakeholders regarding research priorities. One of the products of the ER/FE partnership will be a carbon sequestration road map, requested by the Under secretary.

Issues:

The importance of <u>increased</u> carbon sequestration research has been underscored by the PCAST report. It specifically mentions collaboration with ER ,USGS, and with international efforts, notably those in Japan and Europe.

Senator Bennett of Utah has also sent a letter of support to FE regarding this program. In this letter he correctly categorizes FE's sequestration program as an "effort to evaluate and refine options should CO2 mitigation be determined necessary in the future."

With funding at the level of the House Mark, the FY99 program will look much like the FY98 program. As noted above, this program is characterized by leveraging of small amounts of U.S. funds in larger bilateral and multilateral sequestration research efforts. Independent U.S. efforts have been, and would continue to be constrained to small scale projects, such as the first phase of the Innovative Technology sequestration ($50,000 awards).

Funding at the Senate Mark level will allow somewhat greater participation in international efforts and a small expansion of independent (unilateral) research by the U.S. Funding of some, but not all, attractive technologies emerging from the Innovative Technology solicitation could be possible. It should be emphasized that continued funding at even the higher Senate Mark level will be inadequate to attain programmatic goals for sequestration. In particular:

Without additional funding, FE will not be able to carry out its domestic and international responsibilities in carbon sequestration as described above.

Additional funding is needed to explore more options which serve to reduce the technological development risks as well as the costs of sequestration, and thereby increase the probability of program success. Additional funding is also needed to investigate the potential environmental problems associated with sequestration, and how to avoid them.

FE's ability to continue sponsorship of the international project investigating sequestration in unmineable coal seams would be compromised.

Prepared by: Bob Kane (6-4753), Date: 8/26/98
Modified by Doug Carter (6-9684), Date: 9/4/98
C:\MyFiles\WordProc\seques2.wp

5 pp

Bob Beck –

Here are our final comments. Also, please check tone of other sections

Jerry [illegible]

and into very deep, unmineable coal seams

D. Sequestration Technologies

A major strategy for significant control of GHG is carbon sequestration. Carbon sequestration can be defined as any method whereby carbon is removed from the atmosphere on a permanent basis. Several types of sequestration technologies are being studied, including, but not limited to, injection into oil and gas reservoirs, using saline aquifers of unmineable coal seams for disposal, formation of CO_2 hydrates in deep ocean environments, and injecting liquid CO_2 into the ocean. There are many others.

The total industrial use of CO_2 in the United States is less than 50 million tons per year. Most of that industrial CO_2 is used for enhanced oil recovery, and comes from the CO_2 recovered from natural gas wells. While the total CO_2 emissions from power generation is estimated at 1.8 billion tons, sequestration of 50 million tons would still be a significant amount. Lowering the cost ~~of~~ recovery systems could open up this market even more.

today

now (and over 50% with improved compressors)

A key electric generation technology available today is Integrated Gasification Combined Cycle (IGCC). At about 40% efficiency, the installation of IGCC in lieu of a conventional pulverized coal generating unit, provides a reduction in potential CO_2 emissions of about 15%. When retrofitting this technology on an older, less efficient plant, instantaneous reductions of 20% are possible. There are few technologies available that can achieve this magnitude of CO_2 emissions reductions.

IGCC provides an ideal source for pursuing CO_2 recovery for industrial use. In the oxygen-blown IGCC system, the synthetic gas (syngas) is produced at a very high pressure, forming a concentrated stream of CO, H2, and CO_2. The CO_2 concentration in the gas stream from the gasifier is about 10%. About ½ of the syngas is CO, which is burned to CO_2 in the combustion turbine, along with the H2 produced in the gasifier. The acid gas removal system, which is utilized to remove the hydrogen sulfide formed from the sulfur in the coal, concentrates the CO_2 even more, to about 75-85%. This concentrated stream is then available for separation and recovery for industrial use. No other advanced power generation system provides the ability to produce such an ideal CO_2 stream for the purposes of recovery, as does IGCC. Recovery of this stream removes about 5% of the total CO_2 emissions from the IGCC unit. Further development of this technology in DOE's Vision 21 will lead to greater efficiencies, lower CO_2 emissions, and CO_2 product streams more suited for lower cost recovery.

Overall, the reduction in CO_2 emissions from this combination of IGCC and CO_2 recovery can be very significant. First, the use (or retrofit) of IGCC provides for a 15-20% reduction in CO_2 emissions. Assuming that all of the CO_2 in the syngas stream is recovered, that reduces the CO_2 by another 5%, for a total reduction of 20-25%.

Commercial deployment of these technologies will provide significant reductions in CO_2 emissions, both for existing and new power generation needs, here in the U.S. and abroad.

The introduction of new nuclear and renewable generating capacity will not be sufficient to meet the world's power demands for the majority of the 21st century, making the increased use of fossil fuels inevitable. Efficiency gains provide proportional reductions in CO_2 emissions per kWh generated, but achieving greater reductions will require research and development on innovative fossil-fuel processing and generating technologies incorporating CO_2 removal as well as accompanying work on sequestration of CO_2.

Several key projects have been proposed, both domestically and internationally, in an effort to prove the viability of CO_2 sequestration. One such project involves the potential partnership of several electric utility companies, the U.S. Fish and Wildlife Service and the scientific community. This project would reclaim thousands of low-lying abandoned acres of land which had previously been used for agricultural production. This land would be managed as hardwood forest. The forest has the potential to sequester hundreds of millions of tons of carbon over its growing lifetime and also has the added value of increasing habitat for numerous local species of wildlife. This double value of carbon sequestration and enhancement of ~~species diversity is the result that~~ the partners in this project ~~are seeking as their~~ goal.

Because the ash replaces cement, the production of which releases large amounts of CO_2, use of ash reduces CO_2 emissions.

Another project being advanced is more technological in nature. It begins with methane capture from a coal mine and the use of that methane in a combustion turbine to produce electricity. The coal from the mine would be washed and cleaned and then used in a boiler to produce electricity as well. The ash from the coal combustion would be collected and the usable carbon extracted from it for combustion in a second boiler. The remaining ash would be used as feedstock for a high quality cement. The CO_2 from these various combustion processes would be captured and injected into the worked out sections of the mine. This would serve two very valuable purposes: the CO_2 would be sequestered from the atmosphere and it would replace the methane in the geological structure thereby minimizing subsidence in the area.

These kinds of projects are attractive because of their multiple benefits. However, while the technological pieces of each are available, they have never been put into an organized system and additional research and development will be necessary to make them commercially feasible on a wide scale.

Additional research needs, summarized below, were characterized in a 1993 DOE/MIT report and updated in 1997. These include:

- Implementing CO_2 removal and sequestration will decrease power plant net efficiencies and significantly increase the cost of electricity throughout the United States. To make responsible societal decisions, accurate and consistent economic and environmental analyses of all alternatives for atmospheric CO_2 mitigation are required.

- Although commercial CO_2 separation technology is available from non-power applications today, the most promising approach to economical power system CO_2 capture is the development of power generating technologies amenable to efficient CO_2 removal. A 1991 study by EPRI and the International Energy Agency (IEA) showed that CO_2 removal from coal syngas under pressure in an IGCC plant prior to combustion was substantially less energy-intensive and less expensive than postcombustion removal of CO_2 from the stack of a pulverized-coal plant (and likely any coal plant type) at atmospheric pressure. Subsequent IEA studies have yielded the same conclusion. Other innovative approaches have been proposed, including oxygen-fired combustion systems with CO_2 recycle (for natural-gas-fired combined-cycle plants, pulverized coal plants, and pressurized fluidized-bed combustion plants).

- CO_2 disposal in depleted oil and gas reservoirs is feasible today, but the ability to dispose of large quantities of CO_2 is highly uncertain. Disposal into the ocean deep or in confined aquifers offers the potential for large-quantity disposal, but poses many unresolved technical, safety, liability, and environmental issues. The highest research priority should be to establish the feasibility of large-scale disposal options. (economics)

- Either land or ocean disposal will require research to better understand environmental impacts. Even if the impacts prove to be minimal, the public may be reluctant to accept some disposal options.

- Transportation of compressed, liquid CO_2 is conducted commercially in the southwestern United States. However, cost, safety, liability, and institutional issues remain for large-scale deployment.

- Options for using captured CO_2 in an alternative fuel or as an industrial feedstock or agricultural growth enhancer—which may find strong interest in certain locales—are not yet promising for sequestering large amounts of CO_2, but further research is needed.

- Disposal of CO_2 into deep coal beds poses many unanswered questions but may offer the advantage of displacing methane from the coal beds for enhanced coal seam gas recovery and use. unminable

E. Creativity

Any GHG control strategy can best take advantage of incentives and accelerated adoption if it includes some sort of emissions trading, incentives for adopting advanced technologies and the mechanisms for sharing that technology on a global basis.

emissions going standards from coal plants

CO_2 emitting

Fuel switching to lower energy sources that include nuclear, renewables, natural gas, or advanced clean coal. Discussions following negotiation of the Kyoto Treaty have not outlined roles for advanced coal or nuclear power as strategies for emission reductions, putting an extraordinary burden on generation from other fuel sources. Given the intentions of developing nations, especially China, to expand the use of coal for electricity generation, it is daunting to realize that effective sequestration strategies for coal-powered electricity may still be ~~30~~ many years away. large scale

and economic

(although some smaller small scale techniques may be economic and available soon)

Ultimately most emissions reductions strategies now under discussion for the United States assume conversion of the nation's generating capacity to natural gas will be an essential strategy. Today, natural gas accounts for about 10 percent of electric power. Gas is a fossil fuel but burns in a way that limits carbon dioxide emissions to a fraction of those created for a given amount of electricity by coal power. Natural gas prices are at a fairly low level historically, and have been relatively stable in recent years. But at times of short supply gas prices have been much higher and more volatile (Chart 6: Natural gas prices, inflation adjusted, 1968-1998.)

One possible source of growth in renewable power is non-hydro renewables, including wind, solar photovoltaic, solar thermal, wood and other biomass combustion, municipal solid waste and geothermal power. Indeed, these non-hydro renewables are proposed to become a principle focus of federal research dollars. In 1997, non-hydro renewable sources supplied less than 0.25 percent of electric generation. The building block analysis, taking into account the most optimistic projections, assumes that non-hydro renewables can supply about 6% of the country's generation by 2030, so that along with hydropower, total renewable power would amount to about 13% by that year. (Chart 7. A supporting role for renewables.)

Nonetheless, gas has capability -- that is, unlike renewables, we can expand our use of gas by a large percentage factor that may be limited more by cost than available land or the intermediate term gas supply itself. Also, gas is storable and generally available on demand, unlike power from the sun and wind. So one key variable in the building block analysis is the extent to which the energy policy adopts natural gas conversions as a strategy for reducing emissions. As will be seen, that can vary from a co-equal supporting role with coal and nuclear power all the way up to total dominance in American energy markets during the next 30 years.

Despite the at least lack of a specific global energy strategy inherent in the treaty itself, the United States has five distinct energy options for emission reductions in this country that can be used in one combination or another. This diversity, and the wise use of it, will be key as the country decides its energy policy for the next century.

APPENDIX G

Acknowledgments

APPENDIX G

Acknowledgments

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

Pamela A. Martin, The National Coal Council

Editorial Consultant: Ms. Julie Clendenin