Increasing Coal-Fired Generation Through 2010: Challenges & Opportunities

May 2002

THE NATIONAL COAL COUNCIL

Increasing Coal-Fired Generation Through 2010: Challenges and Opportunities

Chair: Mr. Steven F. Leer

Vice Chair: Mr. Wes M. Taylor

Study Work Group Co-Chairs:
Ms. Georgia Nelson & Mr. Richard Eimer

The National Coal Council
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Steven F. Leer, Chairman

Robert A. Beck, Executive Director

U.S. DEPARTMENT OF ENERGY

Spencer Abraham, U.S. 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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COVER LETTER TO SECRETARY ABRAHAM

May 7, 2002

The Honorable Spencer Abraham
Secretary of Energy
United Sates 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 entitled "Increasing Coal-Fired Generation Through 2010: Challenges and Opportunities." This report was authorized by your letter of September 21, 2001. It was prepared, deliberated and recommended by the Coal Policy Committee at its meeting on April 25, 2002, and formally approved by The National Coal Council at its meeting on May 7, 2002.

You requested that the Council conduct a study to determine what "advanced technologies" might be available for the generation of electricity from coal in the next five to seven years, and that the Council "quantify additional power that could be produced over this time frame at lower cost and with lower emissions" than the current commercial offerings. This study was to be a follow-up to the previous study prepared by the Council in May, 2001 entitled "Increasing Electricity Availability From Coal-Fired Generation in the Near Term."

The Council accepted this request and formed a study group of experts to conduct the work, at the direction of the Coal Policy Committee of the Council, which is chaired by Malcolm Thomas, Vice President of Kennecott Energy and a member of the Council. The study group was co-chaired by Richard Eimer, Senior Vice President of Dynegy Midwest Generation, and Georgia Nelson, President of Midwest Generation Company, respectively. Both co-chairs are members of the Council as well.

The original study produced in May, 2001, estimated that up to 40,000 MW of additional generation capacity could be added from coal-fired generation in the next three years. However, that estimate included the caveat that this new capacity would only be possible if the New Source Review (NSR) process and regulations were streamlined and reformed. The Council continues to support the May, 2001 report's findings and recommendations and urges your continued efforts in adopting them.

The enclosed report extends this three-year time horizon out to 2010. In the past 24 months, more than 22,000 MW of new coal-fired generation has been announced, planned or begun the permitting and licensing processes. Almost all of this capacity will use existing technology in its production.

In order to promote deployment of more advanced technologies and continue to reduce air emissions, the Council recommends that the Department of Energy:

? establish a program to facilitate the development of technologies for the use of coal along two pathways: combustion and gasification;

? promote and support the need for a broad portfolio of technology development to allow maximum fuel flexibility in the energy production sector of the country's economy;

- ? work together with other appropriate agencies of the Federal Government to establish a well-crafted, streamlined approach to emissions control from coal-fired electricity generation plants, within the structure of the Clean Air Act, which will improve regulatory stability over the next decade and facilitate increased investment in these advanced coal technologies;

- ? in addition to supporting and conducting research and development programs, establish incentives and/or government support to accelerate the development of advanced generation designs (and the materials needed to construct them) and to bring them to commercial viability; and

- ? support the application (by tax incentives or other means) of advanced mature coal utilization technologies that enhance the efficiency and reduce the emissions of electricity generation plants.

In addition, the Council is very interested in the long-term future of coal and the technologies which will continue to allow its use. In particular, the idea of coal refining into a variety of liquid and solid fuels for not only power generation, but for transportation, appears to be a promising approach to affordable, efficient energy security. We support the continued development of technologies such as this.

While the study group was preparing this report, on February 14, 2002, President Bush announced two major environmental initiatives: the "Clear Skies Initiative" (CSI) and the "Global Climate Change Initiative" (GCCI). This study does not address either of these initiatives in detail, and the Council is not in a position, nor do we have the expertise, to support or recommend specific emissions levels or targets.

However, the Council continues to support flexible, market-based mechanisms such as emissions trading, banking and averaging in order to reduce compliance costs. The Council also supports appropriate and reasonable compliance time schedules and credit for any early actions taken toward compliance. These tools are embodied in the CSI. The Council has historically supported voluntary approaches to controlling greenhouse gas emissions while increasing the efficiency of the electricity generation fleet, similar to those that are contained in the GCCI.

Mr. Secretary, the Council appreciates being asked to conduct this study and provide you with this report. We stand prepared to answer any questions you may have about it or to provide you with additional information.

Sincerely,

Steven F. Leer
Chairman

Enclosure

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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 United States 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;
? State government, including governors, lieutenant governors, legislators, and public utility commissioners;
? Consumer groups, including special women's organizations;
? Consultants from scientific, technical, general business, and financial specialty areas;
? Attorneys;
? State and regional special interest groups; and
? Native American tribes.

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

ABBREVIATIONS

AEO	Annual Energy Outlook
AQRVs	Air quality related values
B&W	Babcock & Wilcox
BACT	Best available control technology
Btu	British thermal units
Btu/kWh	British thermal units per kilowatt-hour
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CFB	Circulating fluidized bed
CO_2	Carbon dioxide
DOE	Department of Energy
ECAR	East Central Area Reliability Council
EEI	Edison Electric Institute
EIA	Energy Information Administration
EIO	Energy Industries of Ohio
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FGD	Flue gas desulfurization
FLAG	Federal Land Managers' Air Quality Related Values Work Group
FLMs	Federal land managers
GW	Gigawatts
HHV	Higher heating value
HRSG	Heating recovery steam generator
IGCC	Integrated gasification combined cycle
kW	Kilowatt
kWh	Kilowatt-hour
lb/MBtu	Pounds of emissions per million Btu of heat input
LAER	Lowest achievable emission rates
LHV	Lower heating value
LNB	Low NO_x burners
MACT	Maximum achievable central technology
MBtu	Million Btu
MDGC	Maximum demonstrated generating capacity
MW	Megawatts
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NCC	National Coal Council
NERC	North American Electric Reliability Council
NGCC	Natural gas combined cycle
NOVs	Notices of violation
NO_x	Nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operating and maintenance
OEM	Original equipment manufacturer
OCDO	Ohio Coal Development Office
OFA	Over fire air
PAC	Powdered activated carbon

PPM	Parts per million
PSI	Pounds per square inch
PSD	Prevention of significant deterioration
SCR	Selective catalytic reduction
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SO_3	Sulfite radical
USC	Ultrasupercritical cycle
tpy	Tons per year

Executive Summary

Purpose

By letter dated September 21, 2001, Secretary of Energy Spencer Abraham requested that the National Coal Council conduct a study to determine what "advanced technologies" might be available for the generation of electricity from coal in the next five to seven years. He requested that the Council "quantify additional power that could be produced over this time frame at lower cost and with lower emissions" than the current commercial offerings.

The Council accepted the Secretary's request and formed a study group of experts to conduct the work and draft a report. This study group extended the time frame of the investigation of available technologies out to the year 2010. Also, the group decided to include some discussion of environmental regulations and their effect on the implementation and deployment of these technologies. This environmental regulatory discussion is intertwined with the discussion of the various technologies.

The full text of the Secretary's letter of request can be found in Appendix E of this report. The list of participants of this study group can be found in Appendix D of this report.

Findings

The study group found the following:

? Various data sources that track generation capacity differ on the amount of coal-fired generation that is being planned, sited or permitted. However, in the past 24 months, these various sources indicate that between 22,000 MW and 65,000 MW of new coal-fired capacity has been announced. It is uncertain how much of this capacity will be built. The specific amount of additional capacity is dependent on site-specific, market-driven economic factors (natural gas price/availability, demand, siting and permitting costs, access to transmission, cost of capital, etc.).

? Coal-based power is strategically critical to the U.S. because it is a low-cost, domestic resource – providing economic stability and energy security to the overall economy. Today over 50% of the country's electricity is provided by coal and no energy source is currently available that can provide a significant alternative to this vast energy source. The continued use of coal, in a clean and environmentally acceptable manner, supports the stated national energy strategy of maintaining fuel diversity to secure economic and security objectives.

? Development and deployment of advanced technologies (ultra supercritical steam power plants, integrated gasification combined cycle power plants, gasification/combustion hybrids, etc.) requires incentives and/or special government support to accelerate their development and deployment during the next 10 years.

? Coal-based generators are subject to multiple, sometimes conflicting emissions regulations. New or revised emissions standards with varying implementation timetables add considerable uncertainty in coal-fired power plant investment by generation companies.

? Mercury control is the subject of considerable research and development and demonstration initiatives today and lessons learned should be factored into regulatory policies.

? Injection of powdered activated carbon (PAC) represents the most mature retrofit technology for reducing mercury emissions from coal-fired boilers. Full-scale testing at two plants has demonstrated that PAC injection may be capable of reducing mercury by 50-70% on units with electrostatic precipitators (90% of the existing fleet of coal-fired boilers) and up to 90% for units with fabric filters (10% of the existing fleet). These reductions vary depending on fuel type and plant configuration. To further mature this technology to a commercial stage, additional short-term field tests and long-term demonstrations must be conducted at a number of plants representing a range of plant designs, operating characteristics and fuel types.

? Effective application of a combination of technologies can control emissions of oxides of nitrogen (NO_x) up to 90%. Deployment of these technologies has achieved significant national reductions. To continue this downward trend, advanced economically feasible control technologies must be further developed.

? Technologies for controlling sulfur dioxide (SO_2) are relatively mature and commercially proven. Control of SO_2 emissions as high as 99% has been achieved at some plants, with 90-95% routine. Opportunities exist for further developments to reduce the cost of retrofit controls and to enhance the use of by-products.

? The topic of carbon dioxide (CO_2) capture and sequestration is now seeing a significant acceleration in research and development and innovative ideas. Continued support for research, development and demonstration is needed to develop a portfolio of potential solutions. In a May, 2000 report by the Council entitled "Research and Development Needs for the Sequestration of Carbon Dioxide as Part of a Carbon Management Strategy" specific recommendations regarding sequestration were provided. DOE is currently implementing most of these recommendations. The best near-term option is to deploy plants with greater efficiency and (in parallel) aggressively continue research and development to develop future solutions. This dual-track approach to carbon management is embodied in the Bush Administration's recently announced Global Climate Change Initiative and is the correct approach to the issue.

? Strategies like the Administration's recently announced Clear Skies Initiative which promote the combination of flexible, market-based mechanisms (such as emissions trading and banking) with reasonable reduction targets and time schedules, will facilitate the addition of the maximum amount of new coal-fired generation capacity mentioned above.

Recommendations

The National Coal Council recommends that the Secretary of Energy:

? Establish a program to facilitate the development of technologies for the use of coal along two pathways: combustion and gasification.
   - On the combustion pathway, development of advanced technologies for ultra supercritical boilers and controlling emissions of NO_x and mercury should be accelerated and expedited.
   - On the gasification pathway, technologies such as integrated gasification combined cycle (IGCC), CO_2 separation, etc., should be given increased support and funding.

? Promote and support the need for a broad portfolio of technology development to allow maximum fuel flexibility in the energy production sector of the country's economy.
   - This development would include continued improvement of current technologies, development of the next generation of combustion technologies, and accelerated development of technologies required for coal gasification.
   - National energy security would be enhanced through this portfolio approach because coal is domestic, economic and in abundant supply.

? Work together with the other appropriate agencies of the Federal government to establish a well-crafted, streamlined approach to emissions control from coal-fired electricity generation plants, within the structure of the Clean Air Act, which will improve regulatory stability over the next decade and facilitate increased investment in these types of generating plants. This approach should include, but not be limited to, the following:
   - Simplify the multiple and sometime-conflicting regulations currently in place.
   - Improve the diagnostic tools, such as air quality models, to better reflect actual operating conditions, meteorological and atmospheric conditions, and to eliminate overlapping conservativism inherent in these tools.
   - Stress the importance of the use of market-based mechanisms, such as emissions trading, banking and averaging, as ways to reduce regulatory compliance costs.

? In addition to supporting and conducting research and development programs, establish incentives and/or government support to accelerate the development of advanced generation designs (and the materials needed to operate them) and to bring them to commercial viability.

? Support the application (by tax incentives or other means) of advanced mature coal utilization technologies that enhance the efficiency of electricity generation plants.

Section 2:
TECHNOLOGIES AVAILABLE FOR INCREASING COAL-FIRED GENERATION BY 2010

I. Introduction

Over the past year, energy markets have been extremely volatile and unpredictable due to high prices of oil and natural gas, partial deregulation (or re-regulation), as well as concerns for energy shortages in certain regions. Although recent slowdown in economic growth has decreased the demand for oil, natural gas, and electricity, total energy consumption and electricity demand are still projected to increase at a rate of 1.8% per year during next 7 to 10 years (EIA AEO 2002).

Although coal's share of total electricity generation is expected to drop from the current 54% to 51% by 2010, generation from coal is projected to grow from 1,970 billion kWh in 2000 to over 2,260 billion kWh in 2010 (EIA AEO 2002, Table A8) with an average growth of 1.2% per year. This is roughly equivalent to 40 new 1,000 MW power plants and corresponds to coal consumption growing from approximately 965 million tons in 2000 to over 1,140 million tons in 2010.

Power plant operators may face new requirements to reduce emissions of SO_2 and NO_x beyond the levels called for by current regulations. They could also face additional requirements to reduce CO_2 and Hg emissions. Neither the magnitude of reductions, nor the timing for compliance, has been defined for these emissions. Because of these uncertainties, compliance planning is extremely difficult for power plant owners, as it takes four to six years to license, design and construct a new electric power plant. In comparison, retrofitting an existing plant with emission control equipment may take two to three years. Retrofitting may also affect reliability and availability of an existing plant.

New or revised emission standards with varying implementation timetables add considerable uncertainty to investment planning. An option that may look attractive today to meet one set of SO_2 and NO_x standards may not be as attractive if further reductions are required a few years later. Changes in emission limits may also inhibit fuel switching and emissions trading options, which have historically proven to be the preferred options. Depending on the eventual level of control required under proposed future regulations, there may be little flexibility to use market mechanisms with very low "caps" under a cap and trade policy. The optimal choice may also change if Hg and CO_2 emissions reductions are required in the future.

Thus, power plant owners are reluctant to make large capital investments that may prove unwise later. Understanding all of this, Congress and the President have proposed legislation that would require simultaneous reductions of multiple emissions, but would provide an element of regulatory stability following the implementation of the new limits. The Administration's position is described in the Clear Skies Initiative.

Through continued development of technologies, the U.S. will be able to continue utilization of its vast coal resources for electric power generation in an environmentally acceptable manner, while maintaining fuel diversity and promoting energy security. Coal thus becomes an important element of a portfolio of power generating options, that also includes gas, nuclear power, and renewable energy. It is important that we not only continue developing new technologies for coal utilization, but also develop legislation that will encourage the application of these technologies.

Coal also is a strong contributor to the overall security of the U.S. energy supply. Electricity is very difficult to store in significant quantities and so our system depends on generation being on call to meet the demand. Coal is normally stored at power plants and provides an inherent "buffer" in case of supply interruption. In recent years, most new generation has been natural gas-fueled, and while gas can be stored, it is typically not at the power plant, and so can be interrupted more easily by infrastructure problems or via terrorist acts. Increasingly, our natural gas use is based on imports to the U.S., while almost all coal is domestic. Therefore, continued use of coal supports the goal of reducing our nation's dependence on imported energy.

II. Role of Technology

A) Increased Efficiency of Existing Plants

Increasing the overall efficiency of existing coal-fired plants is the most cost-effective means for reducing the quantity of criteria pollutants (SO_2, NO_x and Hg), solid waste generation, and CO_2 emissions. The NCC's May, 2001 report, "Increasing Electricity Availability from Coal-Fired Generation in the Near Term," summarized the opportunity for increasing the availability and output of the current fleet while increasing efficiency. This report concluded that cost-effective modifications of existing plants could add 20,000 MW of new capacity and regain 10,000 MW of lost capacity. For example, one 600-MW coal-fired plant was able to add 25 MW of capacity through steam turbine upgrades alone. However, retrofitting emission control equipment generally requires additional auxiliary power, typically reducing output and lowering efficiency.

B) Environmental Drivers

Although the Clean Air Act Amendments (CAAA) of 1990 are well into Phase II reduction for SO_2 and NO_x, increasing pressures for continued emissions reductions have been coming from regulatory agencies, environmental organizations and the Congress. The EPA's Coal-Fired Power Plants Enforcement Initiative targets coal-fired units across the eastern and southeastern portion of the U.S., citing utilities for making modifications to their coal-fired plants without going through the New Source Review (NSR) program and installing the requisite emission controls. A few utilities have settled these actions with EPA, agreeing to install SO_2 and NO_x control equipment at significant cost. Others have chosen to defend their legal position in court, even after a recent ruling by the Department of Justice stating that the EPA had an adequate basis under existing NSR regulations to pursue these alleged violations. Broad applicability of NSR requirements could mean retrofitting existing plants with flue gas desulfurization (FGD) systems for SO_2 control and selective catalytic reduction (SCR) or other control technology for NO_x emissions. Furthermore, in some plants, even upgrades to the electrostatic precipitators (ESPs) may be necessary for increased particulate control.

While this initiative has targeted a specific group of plants/units, the NO_x SIP (State Implementation Plan) Call could result in thousands of megawatts of coal-fired plants being retrofitted with expensive SCR systems and/or may have to be retired if additional investment cannot be justified. In that case, they have to be replaced with new generating facilities.

Furthermore, with EPA's recent determination to regulate mercury emissions from coal-fired generation plants, the owners of these plants may have to make additional investment for retrofitting these plants with emission control equipment. Also, the solution to the climate change issue may require technologies that are CO_2-sequestration capable.

Another environmental issue which is now emerging with the planned development of new coal-fired power plants is the potential impact of these new units on Air Quality Related Values such as visibility and acid deposition in federally-protected Class I areas, including national parks and wilderness areas. The CAAA established these areas and gave federal land managers (FLMs) the opportunity for commenting in the permitting process on the potential for a proposed power plant to impact the air quality in their respective Class I areas. To guide the assessment of such potential impacts, the FLMs have established the Federal Land Managers' Air Quality Related Values Work Group (FLAG) process that must be followed in assessing the potential of new power plants on Class I areas up to 300 kilometers (186 miles) away.

The FLAG process is a very conservative air quality assessment approach that effectively limits the siting of new coal- and gas-fired units to some distance from the Class I area. In the western U.S., for example, given the clean air quality that generally prevails, the minimum siting distance determined by the FLAG process for new coal-fired power plants is approximately 160 kilometers (100 miles). This minimum siting distance limits the available sites for new coal-fired units to locations well away from Class I areas, even though many candidate sites may otherwise be well-suited for them. In the eleven western states, the available candidate siting areas for new coal-fired units are reduced to central Nevada, north central Utah, east central Wyoming, and extreme eastern Colorado. All other lands in the western U.S. are closed to consideration, since they are located too close to the Class I areas.

Numerous existing coal-fired power plants using older emission controls are currently operating in the U.S. without being identified as impacting air quality in Class I areas. Many of these plants are located within 100 miles of Class I areas. They would not likely pass the FLAG test, even though they are not currently causing an air pollution concern in a Class I area. While Class I areas need to be protected, the FLAG process is so conservative that it effectively prohibits plants where they would otherwise be acceptable. Hence, the process needs to be amended to provide a more realistic assessment of the true air quality impacts of the new plants on the Class I areas.

C) SO_2 Control – Status and Technology Opportunities.

New requirements being proposed may reduce SO_2 emissions beyond the levels called for in current regulations (CAAA). Phase II of the SO_2 reduction program – lowering allowable SO_2 emissions to an annual national cap of 8.95 million tpy – became effective January 1, 2000. Because SO_2 and NO_x emissions from electric power plants are alleged to contribute to the formation of regional haze, states could require that these emissions be reduced even further to improve visibility in some areas. New national ambient air quality standards for ground-level ozone and fine particulates (in the form of acid aerosols) may necessitate additional reductions of SO_2 and NO_x as early as 2007.

It should be noted, however, that technologies for controlling SO_2 emissions are relatively mature and commercially proven. By retrofitting FGD systems, modern plants can upgrade to >90% SO_2 removal at a marginal cost typically less than $250/ton. For new plants, the total cost of SO_2 removal, including the capital, fixed and variable O&M costs is approximately $500 to $700 per ton.

D) Nitrogen Oxides – Status and Technology Opportunities.

NO_x (a combination of NO and NO_2) emissions deserve special attention, because of their wide-ranging effects on the environment, including contribution to acid rain, reduction in visual range and production of tropospheric ozone. Fortunately, several existing and emerging technologies are available to reduce NO_x emissions.

Title IV of the CAAA requires NO_x control technology to be applied to all existing boilers in two phases, the first in 1995 and the second in 2000. Phase I called for NO_x emission standards from tangentially-fired and wall-fired boilers to be reduced to below 0.45 and 0.5 lb/MBTU, respectively. During the last decade, as a result of combustion process modification, NO_x emissions from coal-fired power plants fell from 6.7 million tons in 1990 to 6.1 million tons in 1995, and to about 4.6 million tons in 2000. Coal used in electricity generation increased by over 75% during the same time period. Combustion process modifications represent the first line of action in the reduction of NO_x emissions. Their application may also be cost-effective in combination with post-combustion flue gas treating technologies if deeper cuts in NO_x emissions are necessary.

✍ **Combustion NO_x Control:**

In coal combustion, NO_x is primarily formed by the oxidation of nitrogen compounds in the coal. To minimize oxidation of these nitrogen compounds, combustion-based NO_x control technologies deploy the following general techniques:

? sequential fuel-rich and fuel-lean combustion zones achieved by staged air and/or fuel supply to the combustion process;
? maintenance of high temperatures in fuel-rich flame zones; and
? reduced peak flame temperatures in fuel-lean flame regions.

Technologies capable of satisfying these requirements are:
? over fire air (OFA);
? low NO_x burners (LNBs); and
? gas (and/or coal) reburning.

Pulverized coal combustion conveniently lends itself to the staging of combustion air because only a fraction of the combustion air is normally used to inject the pulverized coal through the burner. The rest – highly preheated air – is injected as a separate air stream into the flame. Low NO_x combustion, however, requires more spatial separation between the fuel-rich and fuel-lean combustion zones to permit extended residence time in the fuel-rich flame for the NO_x reducing chemical reactions to occur. This can be achieved by OFA injected above the zone of fuel injection into the furnace. To date, approximately 39 GW of a total of 325 GW of coal-fired capacity in the U.S. have been fitted with OFA.

Application of LNBs can also significantly reduce emissions. There are a number of engineering designs that offer retrofits with no changes to boiler pressure parts and minimal or no changes to wind boxes of the boilers. LNBs, along with OFA, represent the most cost-effective NO_x reduction technology. Their application is rapidly increasing in the U.S. To date, over 35 GWe have been retrofitted with LNBs in the U.S.

In the NO_x reburning process, NO_x emissions are reduced by injecting a fuel (natural gas or coal) into the combustion products of the fully burned coal. The injected fuel represents 15% to 20% of the total heat input to the boiler. NO_x can be substantially reduced, depending on the boiler design. The reburning technology has been successfully applied on a few cyclone boilers, and also on wall- and tangentially-fired boilers. However, it is not a commercially successful process because it increases the marginal cost of electricity (due to the price of natural gas), and could be at a disadvantage when deployed in a deregulated business environment.

By effectively combining these combustion options, NO_x emission reductions are possible as follows:

? LNBs	30% to 50%
? LNB + OFA	35% to 60%
? Reburning (w/natural gas)	60% maximum

Some areas of concern in application of these technologies are:

? increased boiler metal wastage in regions of high temperature, fuel-rich combustion
? increased unburned carbon in fly ash
? slagging and fouling of boiler components

The reduction of NO_x emissions by combustion process modification has been applied to more than 188 GW of coal-fired generating capacity worldwide. It has been the primary compliance technology for Phase I of the CAAA. In the U.S., 39 GW capacity equipped with OFA and 35 GW with LNB have been operating for the last seven years.

✍ **Post-Combustion NO_x Control:**

Selective Catalytic Reduction (SCR)

In SCR, ammonia vapor is injected into the flue gas over a catalyst bed situated at the economizer outlet, where the flue gas temperature ranges from 600?F to 700?F. In the presence of the catalyst, ammonia chemically reacts with NO_x to form water vapor and molecular nitrogen. SCR can achieve up to 90% NO_x reduction, depending on the type of coal burned. The presence of ammonia in the fly ash can cause problems with its sale and/or disposal.

Catalyst performance is key to the performance of an SCR system. Recent improvements of catalysts resulted in increased NO_x emission reduction, lower SO_3 formation by the catalyst and increased resistance to catalyst degradation. It is estimated that the present day catalysts may be able to operate in some applications for more than four to five years before individual catalyst layers have to be replaced.

Currently more than 53 GW (IEA CR89) of coal-fired capacity worldwide is fitted with SCR. However, most of the experience with SCR systems is limited to low-sulfur (less than 1.5%) coal. Experience with high-sulfur coal is limited. Actual plant data shows that with high-sulfur (over 2%) coal, SO_3 formation can be a problem, with the attendant production of a “blue plume”.

Selective-Non Catalytic Reduction (SNCR)

SNCR has been successful in achieving NO_x emissions reduction in the range of 30% to 40%. In an SNCR application, ammonia (or urea) is injected into the flue gas stream in a temperature window of approximately 1,600? F – 2,000? F. The reagents react with NO_x to form N_2 and water. Since there is no need for a catalyst, capital cost ($/KW) is low but the reagent utilization quite high (requiring an

NH_3 to NO_x stoichrometric ratio of 1 to 2 compared to less than 1.05 in the SCR process). The performance of SNCR also heavily depends on the uniformity of reagent distribution over the furnace and/or convective duct cross sections, where the reagent is mixed with the flue gas.

To date, over 1,000 MW of coal-fired capacity in the U.S. have been retrofitted with a combination of combustion NO_x emissions reduction technology and post-combustion SNCR technology.

The costs of these technologies are as follows:

LNBs and OFA (maximum NO_x reduction: 60%)

- Capital cost: \$15/kW to \$30/kW
- Incremental cost-of-electricity: < 1 mill/kWh
- \$150 - \$330/ton NO_x removed

Natural Gas Reburning with Flue Gas Recirculation (maximum NO_x reduction: 60%)

- Capital cost: \$20/kW to \$30/kW
- Incremental cost-of-electricity: 2 -3 mills/kWh (at \$3.00/MBtu natural gas)
- \$375 - \$560/ton NO_x removed

Selective Catalytic Reduction (maximum NO_x reduction: >90%)

- Capital Cost: \$60/kW to \$140/kW
- Incremental cost-of-electricity: 2-5 mills/kWh
- \$570 - \$2,500/ton NO_x removed

Selective Non Catalytic Reduction (maximum NO_x reduction: 40%)

- Capital cost: \$10/kW to \$20/kW
- Incremental cost-of-electricity: 1-2 mills/kWh
- \$1,000 - \$2,500/ton NO_x removed

✍ Conclusion

Progress in NO_x control technologies has resulted in significant reductions of NO_x emissions from coal-fired plants. For NO_x emissions to continue this dramatic reduction trend, advanced control technologies must be developed to be effective and economical in the new electricity marketplace.

Combustion process modifications including combustion optimization, use of OFA, LNBs and other fuel/air staging techniques appear to be the most cost-effective reduction technologies for most types of boiler designs. SCR, when combined with combustion process modifications, can bring new, pulverized coal plant NO_x emissions to a level below that of any current emission reduction proposals. It should be noted, however, that when an existing coal-fired boiler is retrofitted with SCR combined with combustion process modifications, similar low-NO_x emissions may not be achieved due to various constraints such as a coal type, boiler and equipment configurations and condition of the plant and the site.

Since SNCR technology may increase the electricity dispatch cost by 10-15%, SNCR technology will only have limited penetration in the power industry.

E) Mercury Emission Control.

✍ Background

In 2000, the total mercury content of the coal received at power plants was approximately 75 tons. Because of fuel processing and other environmental control equipment, total mercury emissions were 45 tons -- approximately a 40% reduction relative to “as received” coal. (Approximately 30% of the mercury in eastern bituminous coal is typically removed by coal washing before shipping to the plant.)

Flue gas from bituminous coal generally contains 40% to 70% ionic mercury with the balance elemental mercury, whereas sub-bituminous coal (western coal, Powder River Basin coal) generally contains less than 25% ionic mercury and correspondingly, over 75% elemental mercury.

Chlorine in coal is often detrimental to boiler performance because of its corrosive nature. However, chlorine content in plays an important role in the reduction of mercury, because ionic mercury is oxidized during the operation of SCR and FGD. In general, the higher the chlorine content, the higher the mercury reduction, but it has not yet been confirmed for many different types of coal. This effect essentially disappears in less than 2,000 hours at plants burning Power River Basin (PRB) coal. Limited tests suggest that the use of FGD in combination with SCR may be able to capture 80% to 90% mercury from some high-chlorine bituminous coals, which tend to have a high percentage of ionic mercury. However, elemental mercury is not removed by FGD. Deactivation of the SCR’s mercury oxidation effect with time remains to be determined for bituminous coals.

In the case of sub-bituminous coals, a maximum mercury capture of 35% has been reported for units with ESPs. However, plants that burn sub-bituminous coals and have fabric filters report relatively high mercury removal levels of 60% to 99% (Grover, et al., 1999; Butz et al. 2000). Although the highest mercury removal levels are associated with high-unburned carbon levels, 60% mercury removal was achieved with an ash with less than 0.5% carbon. This is due to the excellent contact between the gas phase mercury and the carbon and reactive ash that is provided in a fabric filter.

In contrast to bituminous coals where a synergism or co-benefit between FGD and mercury control has been found, the opposite is true for sub-bituminous coals. This was first discovered in an analysis of data from the EPA’s 1999 mercury Information Collection Request (ICR). The data showed that mercury removal dropped when a spray dryer absorber was part of the air pollution control train (Kilgroe and Srivastava, 2001). The average mercury removal for ICR plants burning sub-bituminous coal with a fabric filter was 72%. However, for units burning sub-bituminous coal that had both a spray dryer absorber for SO_2 control and a fabric filter, the average mercury removal dropped to 25%. Further testing by the Electric Power Research Institute (EPRI) not only verified the drop in mercury removal downstream of the spray dryer absorber, but also showed that the injection of standard powdered activated carbon (PAC) was rendered ineffective. For these applications, iodated carbon was required, costing 10 to 20 times the standard cost for PAC.

Mercury control is the subject of considerable R&D and demonstration initiatives today. The U.S. government should support these initiatives and allow for lessons learned to be factored into regulatory policy.

✍ Legislative Actions to Limit Mercury Emissions

Currently, coal-based power plants are subject to multiple, often-conflicting air quality regulations under the CAAA. More than a dozen separate regulatory programs are being proposed leading to a "Multiple Emissions" approach to regulate power plant emissions.

Two major "Multiple Emissions Proposals" and their emissions levels are expressed in:

- ? Senator Jeffords' bill, S. 556; and
- ? the Bush Administration's Clear Skies Initiative.

While S. 556 includes CO_2 emissions reductions along with SO_2, NO_x and mercury emission reductions, the Clear Skies Initiative does not.

Mercury Emissions, tpy			
Actual 1999 Level	S. 556 (Level by 2007)	Clear Skies Initiative	
		2010	2018
45	4.5	26	15

✍ Current Technology Status

Based on very limited information on actual operating data, the EPA assumes much higher mercury co-benefits from FGD and SCR (or SNCR) than appears possible for a sustained period. EPA assumes that an FGD system plus SCR could achieve 95% mercury emissions reduction for all coal, with varying types of mercury content, irrespective of its chlorine content. Furthermore, EPA assumes that PAC injection is sufficient to meet stringent mercury emissions reduction requirements without a fabric filter. However, a fabric filter would be required to achieve 90% removal of mercury. In addition, EPA has assumed the application and benefits of water injection (spray cooling) to enhance capture by carbon (via the ash or injected) or through condensation of ionic mercury onto fly ash. As a result of these assumptions, EPA's costs of mercury control are underestimated.

Because mercury emission control technologies are relatively new and untested on a commercial scale, it will be extremely difficult to achieve the mercury emission levels required by S. 556 for 2007.

Complicating mercury emission controls is the need to dispose of mercury-containing wastes generated from the removal of mercury from flue gases. In addition, the activated carbon impacts the ability to sell coal combustion by-products. The use and presence of activated carbon may also complicate SCR operation and generate concerns that depleted catalyst be handled as special wastes. It may also complicate FGD system operation, with large quantities of FGD by-products requiring disposal in a landfill.

Any acceptable technology must be able to resolve these issues. With the current status of mercury removal technologies, it is unlikely that these issues will be able to be resolved by 2010.

✍ Cost/Economics

Sponsors of the various legislative proposals (e.g., S. 556) believe that the reductions are "cost-effective with currently available technologies." However, S. 556 could adversely impact reliability of electric power generation. Many plants may be forced to apply advanced but unproven technologies over a very short time period or shut down.

The Edison Electric Institute (EEI) estimates that 65% of coal-based capacity will have to add PAC injection – a technology yet to be fully tested in full-scale applications. It is also estimated that 58% of the coal-based capacity will have to add fabric filters to achieve the necessary mercury emission limit – a very expensive back-end technology.

Mercury control methods will be highly dependent on power plant design and operating characteristics and type of coal used. Since potential mercury emission reductions are unique to each unit, cost factors may vary considerably based on site-specific considerations.

✍ Conclusion

Based on several decades of power plant construction schedules, it appears that S. 556 would not allow sufficient time for the major construction activities associated with installing mercury emission control technologies, many of which are still in the early stages of development and/or deployment. Experience has proven that construction, operation and maintenance of new technologies will require more "down time" for existing plants, impacting the availability, reliability and cost of electric power. Due to regional electric transmission system constraints, it may be difficult – and in some areas impossible – to import the amount of electricity necessary to meet demand while coal-based power plants are retrofitted with new emission control equipment and/or replaced with natural gas-based generation

The short time allowed for compliance mandated under these proposals could result in human resource and material shortages, thus increasing compliance costs.

Many small, older units would likely be shut down due to the cost of or lack of space for emission control technology retrofits, though these units are currently critical to a reliable and diverse U.S. electricity supply and represent capacity that could otherwise contribute to the U.S. electric supply.

The U.S. economy relies on an affordable and reliable electricity supply that is built on a diverse fuel mix. Currently, coal-fired plants supply more electricity than all other sources combined. Analyses conducted by the electric utility industry and EIA show that if S. 556 reductions are enacted, many coal-fired power plants will be forced to shut down, resulting in substantial economic impacts. These analyses also show that neither the increased generation nor the necessary transmission infrastructure exists to meet the increased demand for natural gas-based generation that would result.

Electric utilities have made and will continue to make significant reductions in emissions. There are both environmental and energy policy benefits to taking a more integrated approach to regulation of power plant emissions with reasonable emission reduction targets and realistic time tables. A well-crafted, market-based, multi-emissions approach can improve regulatory certainty, thereby increasing investment in new, more efficient generation technologies.

III. New Generation Options

For new coal-based generation, the key drivers are increasing efficiency and reducing emissions, while simultaneously reducing capital and operating costs. Clean coal technologies, such as integrated gasification combined cycle (IGCC) and ultra-supercritical (USC) steam power plant designs, have the potential to achieve conversion efficiencies of >50% based on higher heating value (HHV), with a cost of electricity equivalent to comparable natural gas combined cycle generation.

Achieving this level of performance will require development of advanced technologies for power plant components, including air separation units, heat exchangers, filtration systems, alloys and ceramics for high temperature service, and new boiler and turbine designs. Technologies will also be needed to integrate these components into operating power plant systems.

A) Ultrasupercritical Steam Power Plants.

The DOE, U.S. boiler manufacturers, the Ohio Coal Development Office, the Energy Industries of Ohio (EIO), and EPRI are involved in research on advanced boiler materials. More attention is needed, however, to develop materials for the ultrasupercritical (USC) cycle design, including research on steam turbine materials. Although a limited number of USC plants have been operating in Europe, Japan and Russia, they have not accumulated sufficient operating experience to predict their long-term performance, and further advancement in steam conditions is also feasible.

The capital investment required for a USC plant is higher than that for a conventional subcritical or supercritical plant. This suggests that USC designs may initially be more attractive in scenarios characterized by high fuel prices and low cost of capital , which allows an economic return on high efficiency. Today, these conditions exist in Europe, Japan, Korea, and even China. In the U.S., low coal costs provide less economic incentive for high efficiency, but at a later date, higher efficiencies may become more important for domestic applications if CO_2 emission reductions are required. If avoided CO_2 has an economic value as a result of taxes or incentives, this would have the same impact as a higher fuel cost and therefore improved efficiency is economically attractive.

Power producers in the U.S. are driven by their ability to be the first to market with the most profitable product. They are also driven by low capital cost and high reliability, as the ability to deliver power to the grid is paramount to maximizing returns. In the near term (prior to 2007), supercritical and advanced supercritical cycles with steam conditions of up to 4,500 psi and temperatures up to 1,100ºF can play a major role in new power generation. Since USC steam conditions of >5,000 psi and temperatures approaching 1,400ºF require new materials for the boiler, steam turbine and associated piping which have yet to be developed, this technology will likely become commercialized after the period addressed in this report.

Several boiler OEMs have stated that commercial-guaranteed boilers operating at steam conditions up to 1,200ºF are available today. Increasing the temperature range to 1,300ºF to 1,400ºF will most likely yield commercial applications after 2010.

Various estimates for the amount of new coal-based capacity being planned for the U.S. over the next five to eight years are as follows:

- ? Energy Information Administration (EIA AEO 2002): 1,000 MW by 2005 and an additional 5,200 MW between 2005 and 2010;
- ? Babcock-Borsig (Boiler Manufacturer): 15,000 MW by 2008-2010; and
- ? Hitachi (Boiler Manufacturer): 2,500 MW under construction, 4,000 MW nearing construction approval, and an additional 18,000 MW in various stages of development.

During 2000-2001 when natural gas prices skyrocketed to $7.50 - $10.00/MBTU, more than 37,000 MW of new coal-fired plants were announced. With the recent decline in natural gas prices to below $3.00/MBTU, it is not certain how many of those coal plants will actually proceed with permitting and licensing.

Business conditions in the U.S. favor the construction of plants with less financial exposure and risk, and with well-proven technology to ensure financial and reliability goals. Therefore, these new plants will likely utilize conventional subcritical and supercritical technology. None of them plan to operate at steam conditions beyond 3750 psi/1,000?F/1,100?F. However, new European plants are being installed at higher conditions. Examples are the Niederausen plant – 1,012 MW, 4205 psi, 1,075?F/1,112?F and the Westfalen plant (under construction) with steam conditions of 4205 psi, 1,112?F/ 1,148?F, with 45% efficiency on a HHV basis.

Deployment of USC technology with steam conditions 4500 psi/1,200?F/1,200?F will require incentives and/or special federal government support or subsidies to accelerate the development of advanced designs and materials during the next seven to 10 years.

B) Limitation of Combustion-Based Coal Generation.

Combustion-based technologies may be ultimately limited by their viability to separate and remove CO_2 from the stack gases; however, many promising technology concepts are just emerging in response to recent attention to global climate change. These include oxy-fuel combustion with CO_2 recycle, chemical looping processes, and regenerative carbonate cycles.

With conventional combustion systems, the stack gases will have a maximum concentration of CO_2 in the range of 12% to 15%, and it is very expensive to separate CO_2 for sequestration at those concentration levels. Current commercial CO_2 amine-based CO_2 separation processes from the chemical processing industry applied to fossil power plants are very expensive mainly because of the amount of energy required to separate CO_2 from stack gases. It is estimated that the separation of CO_2 from a 500-MW coal-fired plant can require as much as one-third of the plant's output. Therefore, the cost-of-electricity would increase by over 50% -- clearly unacceptable to consumers. Therefore, if CO_2 capture and sequestration becomes essential, technology advances for combustion, such as oxy-fuel combustion with low-cost air separation or low-cost capture processes will be required.

Advanced materials for high steam temperatures will be required for use in the bottoming steam cycle of an Integrated Gasification Combined Cycle (IGCC) plant to achieve DOE's Vision 21 goal of 60% (HHV) efficiency for coal-based plants by 2015.

C) Integrated Gasification Combined Cycle (IGCC).

At present, there are over 130 gasification facilities in operation around the world using coal, oil, petroleum coke and other solid carbon-containing feed stocks. Of these, only four gasification plants are for electric power generation. The gasification of coal for producing "town gas" or for conversion to industrial chemicals has been commercially used since World War II. The concept of using coal gasification as an option for generating electric power was introduced in the 1980's with the successful demonstration of the 100-MW Cool Water Gasification Project in California.

Following the Cool Water Project, the DOE-sponsored Clean Coal Technology Program demonstrated commercial scale (250-MW +) IGCC technology, integrating the production of syngas from coal with the high efficiency combined cycle electric power generation for both re-powering and greenfield applications. Based on the technical success of these demonstration plants, IGCC technology seems to be a viable option for commercial deployment for electric power generation. The technology, however, has yet to become commercially (economically) attractive when compared to other power generation options such as Natural Gas Combined Cycle (NGCC) and other advanced coal combustion technologies, including advanced supercritical steam power plant technology.

D) Environmental Drivers.

IGCC technology may have an environmental edge in the area of mercury removal. Since coal gasification systems operate at a high pressure under reducing conditions (less oxygen than that required for complete combustion), the mercury in the gas stream is concentrated, making mercury removal comparatively less expensive than from a conventional coal-fired boiler. Recent data from reports prepared for DOE show that the cost per ton of mercury removal from an IGCC plant is about 10% of that from a conventional coal-fired plant. While considerable research and development is still needed to commercialize mercury removal technology for existing coal-fired plants, it is already in place for IGCC plants. It is reported that without any additional equipment installed, the Wabash River Gasification plant has over a 50% mercury removal rate. The coal gasification plant at Tennessee Eastman has been achieving greater than 90% mercury removal for the last 20 years with an additional carbon bed.

Due to the higher overall efficiency and more concentrated stream of CO_2 generated in an IGCC plant (where the reaction is normally carried out with oxygen rather than air); CO_2 separation in gasification plants is estimated to be less costly than in conventional, combustion-based plants. However, CO_2 capture and disposal for all fossil fuel-fired power plants remains a vexing technical and economic challenge for which no options today appear to be particularly attractive or proven.

IGCC also reduces SO_2 and NO_x emissions substantially and minimizes solid waste production when retrofitted to an existing coal-fired power plant.

E) Brownfield Applications of IGCC.

Repowering (or brownfield application) with IGCC may allow a utility to maintain and/or increase capacity while significantly improving environmental performance and producing low-cost electricity with low-price coal. Since IGCC technology takes advantage of the high efficiency of the combined cycle process, overall efficiency of a retrofitted plant may improve by 5% to 10%. The sulfur in coal can be recovered as elemental sulfur and/or sulfuric acid, both of which have some market value.

Repowering with IGCC may also eliminate the solid waste issues that will otherwise face if plants are retrofitted with FGD and SCR.

Near-term repowering with IGCC can allow the operator to gain the operating experience and knowledge necessary to introduce a new technology for the next generation of greenfield coal-based plants, while helping to address environmental issues. Anticipated technology advances, including advanced gas turbines, will reduce the capital costs of second generation IGCC. Repowering an existing coal-fired plant with IGCC will typically provide considerable opportunities for reducing costs by optimizing the reuse of existing steam cycle equipment, cooling tower and other infrastructure (i.e., buildings, coal handling systems, plant water systems, existing substation and transmission system components). It is estimated that repowering may reduce the overall capital cost by about 20%. In that case, IGCC may become competitive with NGCC if the ratio of natural gas to coal price is more than 3.0. However, initial capital investment requirements for the IGCC retrofitting is considerably higher than that for a NGCC plant.

With the majority of new and repowered units utilizing NGCC technology, environmental permitting agencies have become very familiar with the emissions characteristics and environmental performance of the technology. This is setting up an apparent regulatory barrier for repowered and/or new coal-based plants, including IGCC. Although no coal-fired facility can yet compete with NGCC with respect to SO_2, NO_x and particulate emissions, the benefits of repowering an existing coal plant with IGCC are significant. The Wabash River IGCC repowering project reduced emission rates are as follows:

Emissions in lb/MWh

	SO_2	NO_x	CO_2	VOCs
Original Pulverized Coal Power Plant	38.2	9.3	0.64	0.85
IGCC – Repowered Plant	1.07	0.75	0.55	0.09

Of particular interest is that repowering with IGCC has reduced SO_2 emissions by 5,500 tons per year and NO_x emissions by more than 1,200 tons/year compared to the original coal-fired power plant.

In a recent BACT determination for Tampa Electric's Polk Power Station, the Florida Department of Environmental Protection set NO_x BACT at 15 ppm through the use of combustion technology only. It may not be possible to use SCR technology for further NO_x reduction with IGCC because of the potential for catalyst poisoning (though sulfur removal rate is very high, even a small amount of H_2S may poison the catalyst).

F) Potential for New Generation (Greenfield Application) Using IGCC.

As mentioned earlier in this report, advanced supercritical and USC cycles will have increased efficiency of >40%. With the current status of IGCC technology, efficiency is 40%. From an efficiency comparison, first-generation IGCC technology may have no advantage over an advanced pulverized coal and Circulating Fluidized Bed (CFB) plant. These technologies will be enhanced by advances in steam cycle efficiency and steam turbine performance. IGCC technology will be able to take advantage of the ongoing increases in combustion turbine performance.

To overcome reliability and availability issues inherent in any new technology, the designer frequently uses a very conservative design for the first-generation plants. Therefore, the capital cost of the first-generation IGCC plants has likely been about 10% to 25% higher than what would be expected for second-generation plants. According to studies by GE, Texaco and EIA, a fully mature IGCC plant has the potential to have a capital cost that is competitive with an advanced supercritical pulverized coal plant.

GE notes that with the lessons learned from Tampa Electric's Polk Power Station and Wabash River Gasification Plant, considerable increases in performance and decreases in emissions can be achieved. The process and equipment enhancements will result in lower installed cost for subsequent future plants. GE estimates the next-generation installed cost of IGCC plant will be in the range of $1,050-$1,250/kW (EPC cost). Based on these projected costs and environmental performance, GE predicts 45,000-55,000 MW of IGCC penetration by 2015. This is likely to occur only with natural gas prices greater than $4.00/MBtu for a sustained period.

Global Energy Inc., which owns and operates the Wabash River Gasification Plant, is developing two new IGCC projects to be located in Kentucky and Ohio, near sources of coal and other opportunity fuels. At one of these plants, Global Energy plans to use the British Gas/Lurgi process, blending low-cost, pelletized coal and municipal solid waste as the feedstock. This project will be co-funded under the Clean Coal Technology Program. Also, Nordic Energy Corp. plans to install an IGCC unit in Ashtabula, Ohio.

In a recent study prepared for DOE, Mitretek Systems and Consol Energy investigated the potential for IGCC market penetration in the East Central Region of the North American Reliability Council (ECAR). The region includes Indiana, Kentucky, Ohio, West Virginia and parts of Michigan, Pennsylvania and Virginia. The region has the highest concentration of coal-fired plants and has considerable coal reserves. Mine-mouth IGCC plants could be developed in this region that will provide additional economic benefits due to low fuel cost. The study concluded that the first generation IGCC capital costs are not yet competitive with advanced supercritical technology. However, plants that would be developed over the next seven to 12 years would probably be able to take advantage of expected reductions in capital costs. For comparison purposes, the study looked at where these technologies are expected to be in the short term (within next 10 years).

Following are the EPC costs from this study for installation of these technologies in 2010:

? NGCC with "H" model gas turbine $ 460/kW
? Advanced Supercritical Pulverized Coal $1,025/kW
? Advanced Pressurized Fluidized Bed $1,000/kW
? Advanced Air-Blown IGCC $ 960/kW
? Oxygen-Blown IGCC $1,035/kW

If emission reductions are required for mercury, pulverized coal units will require additional capital costs. While mercury emission control system capitals may be low, operating costs can be substantial. Depending on the level of required emission reductions, there may be some co-benefit from SO_2 and particulate controls.

Compared to other coal-based power generation technologies, IGCC's comparable capital cost but superior environmental performance could result in 8-15% lower cost. One study concluded that IGCC's overall superiority may result in between 35 and 40 new IGCC plants (equivalent to 17,500-20,000 MW) during the next 10 to 15 years.

If a transmission system is available within five miles of mine mouth, new IGCC plants should be sited as close as possible to coal sources to minimize fuel costs. If mine-mouth coal price is $0.50/MBTU or less and natural gas price stays even at its current price of $3.00/MBTU, IGCC plant technology will be the economic choice.

Recent siting studies by utilities and IPPs in the western states have already concluded that mine-mouth IGCC is a viable option for the Powder River Basin coal in Wyoming and North Dakota (where lignite would be the feedstock).

G) Recommendation.

The next 10 years will be a transition period during which a variety of coal-based generation systems will compete against NGCC in the generation market. Recent capacity additions have focused on circulating fluidized bed (CFB) and pulverized coal (PC) technology, with some of the latter operating at supercritical steam conditions. The NCC expects this trend to continue for at least the next five years, but it's likely that IGCC and ultrasupercritical combustion plants will begin to gain market share. Looking beyond the next 10 years, the NCC sees an expanding role for IGCC in a market that will be shaped by a growing need to reduce carbon emissions.

At the end of 2001, there were approximately 325 GW of coal-fired generation facilities in the U.S., and 80% of this existing coal-based capacity will be 30 years old by 2007. The EPA's Coal-Fired Power Plants Enforcement Initiative Program targets coal-fired units that have not gone through the New Source Review Program and did not install emission control equipment. EPA has also recently determined to regulate mercury emissions from coal-fired plants.

Prior to these initiatives, a power generator's major goal was to increase efficiency of the existing coal fired plants and thereby reduce emissions of SO_2 and NO_x. This new initiative may force many plant owners to apply advanced, risky technologies over a very short time period that will create more uncertainties.

It is recommended that a well-crafted, multi-emissions approach be developed to improve regulatory certainty, foster increased investment in new generation, increase operational flexibility to reduce compliance costs, maintain fuel diversity to avoid price spikes, and sustain reliable generation.

With adequate time and flexibility, the electric power industry will continue to reduce emissions, provide affordable and reliable electricity, and meet the goals of balanced energy and environmental policies.

Both repowering (or brownfield application) and greenfield supercritical steam plant and IGCC plant options should be aggressively pursued. However, as discussed in the next section, the public sector should assume part of the responsibility for helping to mitigate the risk of first-of-a-kind technology

Section 3:
TRANSITIONING TO AN ADVANCED COAL GENERATION FUTURE

Implementing the technologies described in Section 2 of the report will require transitions both in the technology itself and in the policies and regulations that will govern the generation business of the future. The need for orderly transitions derives from the desire to minimize technical and financial risk on the parts of the generating companies and the financial institutions that will invest in new power plants.

That it is possible to think in terms of new coal-based generation within the next seven to 10 years reflects a remarkable turnaround that has occurred in the U.S. over the last few years. Coal-fired power plants, once thought to be facing a rapid demise, are now broadly perceived as one element of a strategy to use indigenous resources for the future energy security of the country.

Transitioning to this future will require concerted efforts in four inter-dependent areas:

? developing <u>public/private partnerships</u> to fund technology development and demonstrations;
? creating <u>tax and other incentives</u> to encourage investment in technology development and implementation;
? designing <u>a technology rollout strategy</u> to implement new technologies, while reducing the associated technology and financial risks; and
? managing an <u>institutional transition</u> to address public policy, regulatory, and environmental/ecological issues.

Funding Technology Development Through Public/Private Partnerships.

To assure the future of coal-based generation, it will be necessary to increase efficiency and reduce emissions while decreasing capital and operating costs. Clean coal technologies, such as USC and IGCC power plants, have the potential for conversion efficiencies of >50% (HHV). Deployment of these technologies will depend on lower fuel costs to help offset the higher capital cost of these options. Current estimates suggest that these technology advances have the potential to make new clean coal generation competitive with equivalent NGCC plants on a cost of electricity basis in the 2010 to 2020 time frame. In certain niche areas or cases, IGCC may be able to take advantage of low-cost and opportunity fuels, as well as its superior environmental performance, to compete in the next seven to 10 years.

As another example, the technologies under development in the DOE's Vision 21 have the potential for far more efficient and complete utilization of coal's total resource value, but not until 2020, well after the 10-year time horizon of this report.

However, timely advances in coal technology cannot be achieved without a significant increase in research, development and deployment funding that will permit commercial viability within the next 10 years. This is problematic in the current economic and regulatory environment because power plant operators are under extreme pressure to reduce costs and are unwilling to invest in new technologies. Moreover, investing now in an advanced power plant technology requires patience, because the investment will not earn a return until some time after successful commercialization.

All of these issues suggest that traditional forms of private-sector funding for new technologies are not viable in today's electricity generation business environment. Public/private consortia are emerging as a mechanism to provide the needed resources. They allow for front-loading the R&D processes, as well as the early stages of pilot and full-scale tests. DOE funding of research for the advanced coal program follows this precept, in that the DOE cost share is higher for high-risk technology development and lower for commercialization activities. This approach has been a success in prior programs, such as the Clean Coal Technology Program, and is working well to sustain interest in the current Vision 21 program.

Although these programs encourage private sector participation in the technology development process, the current funding levels are not adequate to develop and commercialize the technologies that the U.S. will need to deploy a new fleet of advanced coal-based generation systems.

Additional R&D is necessary for the following specific technologies and high priority issues:

? high-pressure solid feed systems;
? fuel cell development and testing;
? slip stream testing of fuel cells;
? high-temperature metallic heat exchangers (for service at 1,800°F);
? gasifiers for high-ash, high-moisture coals;
? enhanced trace element monitoring; and
? char combustion and gasification.

The FY2003 Federal Budget Request for gasification is approximately $40 million, barely enough to fund portions of the Vision 21 component development effort. The combustion program, which now focuses on pressurized fluidized bed systems, should be broadened to include all advanced combustion systems, and the program scope should be increased to include hot gas filtration, combustion/gasification hybrids, and component testing under anticipated operating conditions. It is expected that scope expansion could be accomplished through an industry consortium organized around a research program emphasizing precompetitive research topics. This approach has recently been employed by a public/private consortium of boiler manufacturers, the DOE, OCDO, EIO and EPRI, which is pursuing development of advanced alloys for service in USC boilers.

Investment Incentives.

Cost sharing can be an effective means for reducing the costs associated with bringing a new technology to the market. However, government action should not be limited to research funding. There is a clear role for government in supporting the deployment of new technologies. Government should help industry speed the deployment of clean coal technology to improve fuel diversity and reduce emissions. Without a strong advanced coal program, there will be dramatic reductions in the use of coal over the next 30 years and a huge increase in natural gas consumption for electricity generation. This prospect threatens the energy security and perhaps the economic well being of the U.S. One answer is a national strategy that encourages the balanced use of all our energy resources -- coal, gas, nuclear and renewable energy sources.

With respect to coal-based technologies, incentives are needed to address the issues associated with building new plants due to uncertainties about future emission control requirements.

It is possible to define a tax and incentive package aimed at boosting the maximum generation efficiency of coal-fired power plants from the 37% achievable today to 50% or higher. Achieving these goals would produce significant environmental benefits

Three types of incentive package have been proposed to encourage early commercialization of advanced coal technologies. These are:

? an investment tax credit tied to the project owner's equity;
? a variable production tax credit tied to energy production and energy efficiency over the first 10 years of operation, with higher benefits to early implementation of high efficiency technologies; and
? a "risk pool" to cover repairs or modifications necessary to achieve the required performance during startup and the first three years of operation.

A legislative package incorporating these features was proposed as part of the energy bill recently debated in Congress. It is estimated that over a 23-year period from 1999 to 2021, the package would cost the government $1.5 billion. Of that amount, the investment tax credit would be $203 million while the production tax credit would account for $1.02 billion. The risk pool would be $276 million. By comparison, the entire Clean Coal Technology program is $7 billion.

Technology Rollout Strategy.

Investors and operators are reluctant to be the owners of "Serial No. 1." This suggests the need for a strategy of rolling out technologies in a series. The first units in a series would have modest improvements in performance, with minimal additional financial risk. In addition, the initial technology advances would be familiar to the operators, minimizing re-training. This suggests that pulverized coal plants with improvements in steam conditions might be preferred for near-term investments in advanced technologies. In comparison, a plant to make hydrogen from synthesis gas produced by a slagging gasifier might be a better choice for an organization with prior experience in some or all of the unit processes implied in a sophisticated hydrogen production operation.

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