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Coal-Related Greenhouse Gas Management Issues

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THE NATIONAL COAL COUNCIL

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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 National Coal Council is forbidden by law from engaging in lobbying or other such activities. The National Coal Council receives no funds or financial assistance from the Federal Government. It relies solely on the voluntary contributions of members to support its activities.

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

- Large and small coal producers;
- Coal users such as electric utilities and industrial users;
- Rail, waterways, and trucking industries as well as port authorities;
- Academia;
- Research organizations;
- Industrial equipment manufacturers;
- State government, including governors, lieutenant governors, legislators, and public utility commissioners;
- Consumer groups, including special women's organizations;
- Consultants from scientific, technical, general business, and financial specialty areas;
- Attorneys;
- State and regional special interest groups; and
- Native American tribes.

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

ABBREVIATIONS

AEO	Annual Energy Outlook
AFBC	Atmospheric fluidized bed combustion
AMM	Abandoned mine methane
API	American Petroleum Institute
BACT	Best available control technology
Bcf	Billion cubic feet
Btu	British thermal units
Btu/kWh	British thermal units per kilowatt-hour
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CBM	Coalbed methane
CCS	CO_2 capture and storage
CCT	Clean Coal Technology
CDM	Clean Development Mechanism
CFB	Circulating fluidized bed
CMM	Coal mine methane
CO	Carbon monoxide
CO_2	Carbon dioxide
COE	Cost of electricity
DOE	Department of Energy
DSM	Demand side management
EEI	Edison Electric Institute
EIA	Energy Information Administration
EIIP	Emission Inventory Improvement Program
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FBC	Fluidized bed combustor
FE	Fossil energy
FGD	Flue gas desulfurization
FY	Fiscal year
GCCI	Global Climate Change Initiative
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatts
GWP	Global warming potential
H_2	Hydrogen
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
JI	Joint implementation
kW	Kilowatt
kWh	Kilowatt-hour
lb/MBtu	Pounds of emissions per million Btu of heat input
lb/MWh	Pounds of emissions per megawatt-hour generated
LHV	Lower heating value
LNB	Low NO_x burners
MBtu	Million Btu
MMTCE	Million metric tons carbon

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

SECTION 1: EXECUTIVE SUMMARY

Purpose

By letter dated September 24, 2002 (see Appendix F), U.S. Secretary of Energy Spencer Abraham requested that the National Coal Council prepare a study of how increased energy efficiency and carbon sequestration can be utilized as part of a greenhouse gas (GHG) management program. The Secretary asked the Council to use as a starting point for this report its previous report, entitled "Research and Development Needs for the Sequestration of Carbon Dioxide as Part of a Carbon Management Strategy" as it was submitted to then-Secretary of Energy Bill Richardson in May 2000.

Secretary Abraham specifically asked that the Council evaluate the effectiveness and economics of sequestering carbon. He asked that the Council highlight the public-private partnerships already established between the U.S. Department of Energy and industry that currently address the issues of increasing electricity generation efficiency and carbon sequestration. Secretary Abraham also requested that the Council recommend ways that additional such partnerships could be established. Lastly, he asked the Council for its perspective on how voluntary approaches to reduce greenhouse gas emissions could best be achieved.

The Secretary expressed his hope that this report "will serve as a carbon management blueprint for industry and act as a catalyst to promote additional public-private partnerships to support voluntary reduction of greenhouse gases and carbon sequestration."

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

Introduction

This report updates and expands on the findings and recommendations concerning greenhouse gas management by coal-related industries made by the NCC to the Secretary of Energy in May 2000. It should be read in conjunction with that earlier report, which provides a good overview of the political, environmental and economic factors framing the greenhouse gas issue, and a detailed discussion of various carbon sequestration options. In this report, we have built on the findings of the earlier report, incorporating new information gathered over the last three years and analyzing in more detail the opportunities, needs and impediments to the development and deployment of technology to reduce greenhouse gas emissions from coal-based industries.

Findings

Status of Current Programs for Voluntary Action

There has been widespread participation across a range of industries in voluntary programs to reduce greenhouse gas emissions. As described below, the number of participants and reported projects in the Voluntary Reporting of Greenhouse Gases Program ("1605b Reporting") has grown steadily since the program's inception a decade ago, and a wide variety of emissions reduction and sequestration projects have been reported.

In February 2003, the Bush Administration's Climate VISION program drew responses from essentially all of the major energy-intensive industrial sectors, which put forward specific action plans to meet the goal of reducing greenhouse gas emissions intensity by 18% in the next decade. The various public-private partnership programs, such as Climate Wise, the Landfill and Coalbed Methane Outreach, and the Green Lights programs, have drawn formal commitments to reduce future emissions from 85 entities.

This significant response of U.S. businesses to calls for voluntary action demonstrates that they view global climate change as an important issue. Companies are taking steps to identify not only the risks and challenges associated with the evolving climate change arena, but also the business opportunities that could be developed. To do this, however, companies must first have an understanding of the extent and nature of their GHG emissions. In that regard, all of the voluntary action programs should benefit from the current work underway in the Department of Energy to provide improved guidelines for reporting GHG emissions and reductions under the 1605b program. It is important that changes to the 1605b program are consistent with accounting and reporting principles supported by U.S. industry, and, to the extent possible, harmonized with international accounting and reporting protocols.

To some extent, greenhouse gas reductions through voluntary actions have been inhibited by certain regulatory impediments. That is, environmental regulations can be a disincentive for businesses to take actions to sequester or control greenhouse gas emissions. Two examples are cited in this report: reclamation requirements that inhibit more productive forestation practices on mined lands, and the implementation of New Source Review procedures that discourage power plant operators from making efficiency improvements.

Partnerships for Greenhouse Gas Management

The federal government has established or announced several programs to address the technical, environmental and societal challenges to widespread adoption of GHG management technologies by private industry, both domestically and internationally. Three of these programs, highlighted in this report, are the Regional Partnerships for Carbon Sequestration, the Climate VISION Program (see above), and the Carbon Sequestration Leadership Forum.

The Regional Partnerships program recognizes that opportunities for and impediments to large-scale carbon sequestration are likely to have a great deal of regional specificity. There will be differences in technical, economic and regulatory requirements depending on the type of sequestration sink and its location. The Regional Partnerships will address these issues through assessment projects during Phase I and field testing of promising options in Phase II.

Efforts also are under way to coordinate research and voluntary action on greenhouse gas management internationally. Since its climate change policy was announced, the Bush Administration has announced a number of bilateral international partnerships and other initiatives for international cooperation focused on collaborative efforts meant to address climate-related issues. Examples of opportunities for cooperation that may result in significant GHG reductions include, but are not limited to, CCT and CO_2 capture and storage technology development, expanded use of cogeneration and renewable sources of energy, as well as concrete ways of reducing GHG emissions through sustainable agriculture and forestry management practices.

On February 27, 2003, the Departments of State and Energy announced the formation of the Carbon Sequestration Leadership Forum, a ministerial-level international organizational focusing on enhancing international opportunities to address GHG management. The partnership will promote coordinated research and development with international partners and private industry, including data gathering, information exchange, and collaborative projects.

Efficiency in Electricity Generation

Efficiency improvement in electricity generation is a very important near-term option for reducing greenhouse gas emissions from coal-based power plants. Increased efficiency has several benefits. First, it can decrease the cost of electricity generation by reducing fuel consumption. Second, it can provide additional generating capacity at relatively low cost, without the need to site and build new plants. Third, it will, in most cases, reduce emissions of the criteria pollutants and the production of solid waste in proportion to the efficiency increase. Finally, it will decrease emissions of CO_2 in the same proportion.

In this report, we considered efficiency improvements that can be applied to the existing generating fleet, and those that can be achieved by the commercial deployment of advanced clean coal technologies in new facilities.

With respect to the existing fleet, 75% of existing plants are candidates for retrofit of technologies to increase boiler or steam turbine efficiency, and 25% could be retrofitted with a CCT. If these improvements all were implemented it would result in an overall efficiency increase of approximately 8%, with a proportional decrease in CO_2 emissions. In terms of emission reductions, this would be the equivalent of replacing or repowering 24 GW of existing coal-based generating capacity with “zero-emission” technology, with a corresponding CO_2 emission reduction of approximately 200 million tons annually.

As a result of the DOE-industry sponsored CCT Program, a number of new coal-based power generating systems of increased efficiency are now commercially available. Others will be available for demonstration and deployment after 2010. Four specific technologies are discussed in this report, either because of their readiness for application or significant promise of performance in the near future (with further development):

- Pulverized coal (PC) combustion with supercritical (SC) and ultra-supercritical (USC) steam;
- Pressurized Fluidized Bed (PFBC) Combined Cycle with Topping Combustor (PFBCwTC);
- Integrated Gasification Combined Cycle (IGCC); and
- Hybrid Gasification/Fuel Cell/GT/Steam (DOE’s Vision 21Cycle)

These technologies offer 45% cycle efficiency (LHV), leading to a potential for a 25% CO_2 emissions reduction, compared to installed capacity. United States and international R&D efforts are in progress to develop advanced materials for USC plants with the prospect of an efficiency increase up to 50% (LHV). Such plants are expected to be available for initial deployment by 2010.

At present, capital costs, operating costs and the cost of electricity are lower for PC-SC steam than for the combined cycles. However, PFBCwTC and, especially, IGCC could become more competitive if CO_2 sequestration were required, because of the lower potential cost for CO_2 capture with these advanced systems.

Vision 21 Cycle aims at "zero emissions" and >60% cycle efficiency. Development of this advanced power generation system is worthy of governmental and industrial support. It is the best prospect for extending coal use while meeting more stringent environmental limitations.

CO_2 Capture Technology

Analysis of the pathways to atmospheric CO_2 stabilization suggests that carbon capture and storage (i.e., sequestration) could ultimately account for more than 40% of global CO_2 emission reductions. However, this will require an extraordinary acceleration of current research programs, because there are no suitably developed technologies for capturing CO_2 at large sources, including coal-fired power plants, or for storing CO_2 in geologic or oceanic sinks. Capturing CO_2, in particular, poses large challenges in the areas of cost and energy consumption, and is generally considered to be a major economic impediment to the large-scale adoption of sequestration technology.

For conventional combustion-based plants, the partial pressure of CO_2 in the flue gas is only 2-3 psia. Of the five major types of processes being studied, the most developed is chemical absorption, which is commercial in the chemical and natural gas processing industries, although at a smaller scale than that required for power plants. A few power plant demonstrations using amine-based CO_2 removal systems are under way worldwide on relatively small generating units.

The chief drawbacks are large and expensive contacting and pumping equipment and the large amount of energy needed to desorb captured CO_2 and regenerate the sorbent. The total impact on a new supercritical unit would raise the cost of electricity (COE) by >60% and reduce net electrical output by about 30%. The impact of a retrofit to an existing subcritical unit would be even greater. Nonetheless, gaining experience operating pilot and full-scale systems at power plants is crucial to overall commercialization efforts, and these processes offer a solid basis for such testing as well as opportunities for cost and performance improvement.

Removing CO_2 from integrated gasification combined cycle (IGCC) plants is relatively easier. Gasifiers can be operated in a "steam shifted" mode to produce synthesis gas with a CO_2 partial pressure exceeding 150 psia. Of the five major types of process being explored, the most developed is physical absorption. According to a recent DOE-EPRI study for a 90% CO_2 reduction requirement at new power plants, an IGCC unit with CO_2 capture could have a COE 25% lower than that of a PC unit using monoethanol amine (MEA), assuming IGCC power block cost reduction goals are met. In absolute terms, however, the cost adders and energy penalties for IGCC CO_2 removal are high, and warrant further R&D.

Given the magnitude of the problem, research is needed on a wide range of new concepts, such as CO_2 clathrate (hydrate) separation, which offer promise for lower-cost CO_2 and H_2S removal. Given the time before wide-scale sequestration is likely to be practiced, there is an opportunity to explore a wide range of potential capture options, applicable to both gasification and combustion systems, in the hope that breakthrough technology can be identified to reduce the onerous costs and energy penalties of current approaches.

Carbon Sequestration

After CO_2 has been separated and captured from flue gas or syngas, it must either be stored or put to use. Several concepts for storage have been evaluated; however, options for carbon sequestration vary depending on the locations of storage sites and types of storage/ sequestration technologies used. The choice of sequestration option may also depend on the technology that generates the CO_2. For example, for combustion systems, it may be desirable to sequester CO_2 that contains other flue gas components, such as the acid gases. The capacity, effectiveness, and potential health and environmental impacts of various types of CO_2 storage systems and the potential impacts of inadvertent releases are key areas of scientific uncertainty. Leading approaches to CO_2 storage described in this report include:

- Geologic Sequestration
- Terrestrial Sequestration
- Ocean Sequestration
- Novel Sequestration Systems
- Novel Integrated Systems
- Utilization

Funding provided by the DOE and the private sector for carbon capture and sequestration research has increased considerably since the first National Coal Council report on this subject in May 2000. In FY 2000, the DOE carbon sequestration budget was around $8 million. By FY 2003, this had been increased to $42 million. As of October 2002, the DOE/FE portfolio included 104 projects, with a total value of $162 million. Significantly, the non-federal cost share ($66 million) represents 40% of the total, indicating willingness on the part of private industry to invest in this research, despite the uncertain need for and timing of its eventual application.

Demonstration of Capture and Sequestration Technology

One common need for all potential sequestration technologies is large-scale demonstration that is long enough to prove their technical and economic feasibility and to ensure that their CO_2 remains permanently in storage. Given the number of possible sinks and likely regional differences in the characteristics of these sinks, there is a need for a several of these large-scale, long-duration demonstrations.

As with any major new technology with enormous financial, environmental, and energy security ramifications, CO_2 sequestration technologies cannot be considered commercially ready until successfully proven at full-scale, under “real-world” conditions, for a period of time adequate to assure expectations of prolonged safety and reliability. Any demonstration needs to convince prospective public- and private-sector investors that the costs and risks are sufficiently understood and acceptable so as to enlist the commitment of manufacturers and service providers, financiers and insurers, state and local authorities, and the public. These demonstrations also must provide adequate scientific information on which to base future regulatory requirements related to the deployment of sequestration technology.

Given the diverse make-up of the coal-based generating fleet, the wide variation in the types and properties of regionally economical fuels for power production, and the tremendous range of terrestrial ecosystems and subsurface geological features found across the U.S., effective national deployment of carbon sequestration measures will require the development and commercialization of a portfolio of CO_2 capture and storage technologies.

In this regard, we note the Department's current call for proposals to create regional partnerships in the U.S. to identify sequestration options pertinent to specific geographic areas of the country, and to conduct feasibility and field studies of promising sequestration options. One outcome of this program should be a much clearer picture of the number of demonstrations that are necessary to qualify sinks of sufficient size to support large-scale sequestration (if it is required in the future).

To begin to populate a commercial sequestration technology portfolio over the medium-term (8-15 years), development and/or refinement of the most defined promising options and demonstration at pilot scale must begin immediately. Commercial success at full scale will require the effective integration of technologies for capturing CO_2 at power plants, safely transporting it to storage sites, and assuring that placed CO_2 will remain sequestered from the atmosphere for centuries. Therefore, addressing integration issues in conjunction with the pilot-scale demonstrations will accelerate their resolution at full scale.

Carbon Sequestration and the "Hydrogen Economy"

Just as coal plays a major role in the production of electricity, it has the potential to do the same for hydrogen. The added costs for CO_2 capture and storage will be significantly lower for hydrogen production than for electricity production. To the extent that gasification is the preferred route of producing hydrogen from coal, implementing gasification technologies will position coal to take advantage of this potential new market should a hydrogen economy evolve.

The recently announced Presidential FutureGen Sequestration and Hydrogen Research Initiative could well serve as a major platform for developing CO_2 sequestration in conjunction with coal gasification. This unique facility is envisioned to provide R&D capability to allow testing of novel equipment under realistic conditions and may carry a significant share of U.S. R&D activities. However, it will still be necessary to have multiple demonstrations or combinations of pilot and demonstration projects to cover differing gasification designs, or designs not based on gasification technology, with differing coals and differing regional types of sequestration.

Non-CO_2 Greenhouse Gases from Coal Production and Use

Carbon dioxide from coal combustion is the principal greenhouse gas emission associated with coal. However, two additional gases, methane and nitrous oxide, also are emitted during coal production and use. They may represent targets of opportunity for near-term reductions in greenhouse gas emissions.

Coal mine methane (CMM) is one of several major sources of anthropogenic methane, accounting for about 10% of anthropogenic methane emissions in the U.S. CMM is responsible for about 1% of the total GWP of U.S. anthropogenic emissions of all GHGs. The U.S. coal industry has made substantial progress in recovering and using CMM though drainage systems. Of the 134 Bcf of CMM liberated from underground mines in 2000, 36 Bcf was recovered and used. This recovery represents an almost three-fold increase from the 13.8 Bcf recovered in 1990.

Currently, the recovery of CMM is driven by two factors: the resulting improvement in mining conditions and the value of the gas. Most of the recovered CMM is used as pipeline-quality gas, although smaller quantities are used at qualities not meeting pipeline specifications and some is used as combustion air. Technologies under development -- including ultra-lean-burn turbines and methane concentration systems -- could expand the options available for recovery and use. Future GHG reduction requirements, in conjunction with advanced recovery technologies, could easily result in increased recovery or utilization of CMM.

N_2O has a GWP 296 times that of CO_2. Because of its long lifetime (about 120 years) it can reach the upper atmosphere, depleting the concentration of stratospheric ozone, an important filter of UV radiation. N_2O is emitted from fluidized bed coal combustion; global emissions from FBC units are 0.2 Mt/year, representing approximately 2% of total known sources. N_2O emissions from PC units are much lower. Typical N_2O emissions from FBC units are in the range of 40-70 ppm (at 3% O_2). This is significant because at 60 ppm, the N_2O emission from the FBC is equivalent to 1.8% CO_2, an increase of about 15% in CO_2 emissions for an FBC boiler. Several techniques have been proposed to control N_2O emissions from FBC boilers, but additional research is necessary to develop economically and commercially attractive systems.

<u>Assessing the Cost of Greenhouse Gas Management</u>

The cost of technological options to reduce, capture, and sequester CO_2 depends on a large number of factors. Different cost studies typically employ different assumptions that often are not fully communicated or well understood by their audience. Different assumptions can significantly influence cost results, and lead to large uncertainties that are frequently not reported. For technologies at pre-commercial stages of development, costs are especially uncertain. To the extent that cost estimates often are a factor in decisions about technology development or deployment, the basis for those estimates, and their uncertainties, needs to be better characterized in ongoing work.

Future GHG emission constraints would affect the price and availability of electricity — two factors that could have a profound impact on the U.S. economy. Because coal is abundant domestically, and its price is low and stable relative to other fossil fuels, the predominance of coal-based power plants has helped keep U.S. electricity affordable, reliable, and secure.
If stringent CO_2 reduction requirements are imposed, the cost of electricity and the balance in the fuel mix could change dramatically. CO_2 removal technologies would be unprecedented in their cost and energy consumption, compared to the emission controls for SO_2, NOx, and particulates adopted over the last 30 years. In the absence of commercially available CO_2 capture and sequestration technologies, substantial near-term (less than 10-12 years) CO_2 emission reduction requirements would likely force many coal-fired plants to be retired prematurely. This would likely lead to a further surge in the construction of new NGCC plants. Such a shift would place tremendous pressure on the gas production and pipeline industries to keep up with demand, and would tend to tie electricity prices ever more tightly to the price of natural gas, a fuel with a much more volatile price history than coal. While the historic price differential of gas to coal is

about 2:1, recent trends and availability projections may make that gap even greater in the future. Under this scenario, higher natural gas price prices would result in great impacts on the cost of electricity and on the economy in general.

Deployment of Greenhouse Gas Emission Reduction Technology

Implementing the technologies described in this report will require transitions both in the technology itself and in the policies and regulations that will govern the electricity generation business of the future. The need for orderly transitions is necessary due to 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.

It is likely that existing coal-fired plants will continue to provide the majority of our nation's electricity for decades to come, unless political decisions are made which force their retirement for economic reasons. Ultimately, economic and technical factors will make it necessary to build new power plants to replace retiring capacity and to meet load growth. As indicated in this report, significant reductions in CO_2 emissions can be achieved in the near term by increasing the efficiency of the existing generating fleet. Moreover, replacement or repowering of the existing units with new, more advanced CCTs can further increase fleet efficiency and reduce CO_2 emissions. Finally, new plants can be designed to facilitate CO_2 capture and sequestration, if this becomes necessary and technologically and economically feasible.

Three important components of federal policy in this regard are support of research and development, cost-sharing by the federal government in the first-of-a-kind demonstration of new technology, and tax incentives to encourage replicate deployment of demonstrated technologies. The latter is particularly important for encouraging investment in capital-intensive technologies such as central-station coal-fired power plants. The argument is that some number of these new technologies must be built to move the technology along a "learning curve" that reduces technical risk and cost to the point that plants can attract conventional commercial financing. This concept is embodied in the National Environmental and Energy Technology (NEET) legislation, which has been introduced in both the House and the Senate.

Timely advances in coal technology cannot be achieved without a significant increase in RD&D 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. 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 may not be feasible in today's electricity generation business environment. Public-private consortia are emerging as a mechanism to provide the needed resources for technology development. 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 CCT Program, and it is working well to sustain interest in the current Vision 21 program. It is anticipated that it will be successful in the FutureGen program as well.

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.

Recommendations

Implementing Greenhouse Gas Management Technology

- The Department should continue to promote public-private partnerships, both domestically and internationally, to identify opportunities, incentives and regulatory impediments affecting voluntary actions to reduce GHG emissions, and to conduct research and technical assessments of carbon management technologies and opportunities.

- The Department should expedite revisions (as detailed in this report) to the National Energy Policy Act 1605b reporting guidelines for GHG emissions in a way that ensures they are sufficiently flexible to encourage voluntary action, and consistent with similar guidelines being developed by other public- and private-sector organizations.

- The Department should provide objective technical and economic information to inform public policy decisions and private investment decisions regarding GHG technologies. The Department also should work with other government agencies and the private sector to help develop and implement economic and other incentives (including removal of regulatory impediments) to accelerate the deployment of highly efficient advanced coal-based power technologies and other means of GHG emissions reduction. Early deployment of these advanced technologies is critical to reducing the cost of commercial application.

- The Department, working with other agencies as appropriate, should identify and assist in exploiting near-term opportunities for reductions of non-CO_2 GHGs associated with coal production and use, including emissions of methane and N_2O, and enhanced carbon management on mining lands.

- The Department should expand its cooperation with the Departments of State and Commerce in the areas of international research, development and demonstration for carbon management technologies as it has begun to do with the FutureGen Project. This cooperation should be conducted in concert with the domestic programs underway at DOE, in recognition of the global nature of GHG issues.

Developing Greenhouse Gas Management Technology

- The Department should continue to work closely with the private sector to improve and refine the technology “roadmap" for advanced coal-based power generation technology and carbon capture, transport and sequestration technology with particular attention to defining the time and cost necessary to achieve the roadmap's technical and economic goals.

- The Department should conduct and support R&D to improve the efficiency of coal-based power generation for both new and existing (or repowered) units as the most cost-effective and commercially available near-term means for reducing GHG and other emissions. This R&D includes:

- o Materials for ultrasupercritical steam units capable of up to 50% LHV (47.5% HHV) cycle efficiency;
- o Improvements in IGCC technology (syngas cleanup and gas turbine development) to enhance availability and reliability;
- o Novel combustion processes capable of lower-cost CO_2 capture; and
- o Development of the Vision 21 Fuel Cell Gas Turbine Hybrid to enable demonstration by 2010.

- The Department should expedite research on a wide range of CO_2 capture options applicable to either gasification or combustion technologies, to improve energy efficiency and reduce the cost of capture, and to explore promising novel technologies now in the laboratory or conceptual stage of development.

- The Department should continue and expand the core R&D and demonstration programs as described in the report. In addition, the Department should further develop the FutureGen project (including its associated goals for hydrogen and fuels production) as a research platform leading to technology demonstrations, while recognizing that the core R&D program is necessary to support not only FutureGen but a wider range of important coal technology.

- The Department should develop a set of guidelines regarding the key assumptions that should be reported when estimating the costs of CO_2 reduction technologies (including carbon capture and sequestration systems). These guidelines should include methods to characterize uncertainty in the reported results.

Demonstrating Greenhouse Gas Management Technology

- The Department should conduct a sufficient number of large-scale, long-term field tests of promising sequestration options to ensure that sinks of sufficient size and integrity are available to store the large volumes of CO_2 that would need to be sequestered if reductions were required. The tests are necessary to fully understand the technical, economic and environmental consequences of sequestration within the context of regional characteristics. The Department should begin them as soon as possible, because of the long time duration needed for adequate evaluation.

- The Department should support multiple, large-scale, integrated demonstrations combining the most promising generation, capture and sequestration technologies based on the development of the unit components and design studies of the integrated systems.

SECTION 2:
EXISTING VOLUNTARY PROGRAMS AND PUBLIC-PRIVATE PARTNERSHIPS FOR GREENHOUSE GAS MANAGEMENT

2.1 Summary

This section outlines the recent voluntary actions by industry to reduce, avoid, sequester and control GHGs. The main emphasis will be on actions taken by coal producers and consumers, but other examples of voluntary actions by other entities are also presented. U.S. industry has been able to produce significant reductions in GHG emissions through a range of voluntary programs initiated in partnership with DOE. The success of these programs (and the lessons learned from them) have formed the bases for follow-on voluntary programs which will continue to provide GHG emission reductions in the future.

The main source for this information is the U.S. Energy Information Administration's (EIA) report, "Voluntary Reporting of Greenhouse Gases 2001." Values presented in this section are as reported by participants in this program for 2001.

2.2 Energy Policy Act of 1992 - Section 1605(b) Program

The Voluntary Reporting of Greenhouse Gases Program, established by Section 1605(b) of the Energy Policy Act of 1992, records the results of voluntary measures to reduce, avoid, or sequester GHG emissions. Since its inception in 1994, this program has received reports of over 2,000 projects to reduce or sequester GHG emissions. Reports have been filed from entities representing 38 different industry segments, as distinguished by the SIC codes of the reporting organizations. As exemplified by the projects highlighted in this report, voluntary GHG reductions since 1994 have been achieved by a wide variety of actions, including increased energy efficiency, enhanced resource recovery, waste minimization and changes in land use practices to increase terrestrial sequestration. The number of reporting entities has more than doubled since the program began, while the number of reported projects has almost tripled.

A total of 228 U.S. companies in 25 different industries or services reported to the EIA that they had undertaken 1,705 projects to reduce or sequester GHG emission reductions. The projects reported a total of 60.5 million metric tons carbon equivalent (MMTCE) or 244.5 million tons of CO_2 ($MTCO_2$) of direct reductions, 19.4 MMTCE (78 $MTCO_2$) of indirect reductions, 2.2 MMTCE (8.8 $MTCO_2$) of reductions from carbon sequestration, and 4.1 MMTCE (16.5 $MTCO_2$) of unspecified reductions.

Of the 109 organizations reporting at the entity level, 104 calculated their entity-wide GHG emissions. These entities reported direct GHG emissions of 246 MMTCE (993 $MTCO_2$), equal to about 15% of total U.S. GHG emissions. Also reported by these organizations were 40 MMTCE (162 $MTCO_2$) of indirect emissions, equal to 2% of total U.S. GHG emissions. Also, 107 entity-level reporters tallied emission reductions, including 46 MMTCE (186 $MTCO_2$) of direct emissions reductions, 7.7 (31 $MTCO_2$) of indirect emission reductions, and 1.9 MMTCE (7.7 $MTCO_2$) of emission reductions resulting from carbon sequestration projects.

In the early years of the program, reporting was dominated by electric utilities. In the first reporting year, the 95 submissions from electricity producers represented 88% of the 108 reports received. Since then, the program has seen an influx of new participants from outside the electric utility sector, representing a diverse set of other industries. Several mergers and acquisitions involving reporters to the program have accompanied the ongoing restructuring of the electric utility industry. Many of these merged entities have submitted single, consolidated reports, thus reducing the number of reports received from electricity producers. As a result, only 45% of the organizations reporting to the program for data year 2001 were from the electric utility industry.

Most projects involve actions within the U.S. Some are conducted in foreign countries, designed to test various concepts of joint implementation (JI) with other nations. Fifty-eight of the 89 foreign projects represent shares in two forestry programs in Belize and Malaysia sponsored by the electric utility industry.

The principal objective of the majority of the projects reported was to reduce CO_2 emissions. Most of these projects reduced CO_2 either by reducing fossil fuel consumption or by switching to less carbon-intensive sources of energy. Many also achieved small reductions in emissions of other gases. A total of 900 projects involved either efficiency improvements and switching to less carbon-intensive sources in the electricity industry or energy end-use measures affecting stationary or mobile combustion sources. Projects that primarily reduced CO_2 emissions also included the 87 “other” emissions reduction projects -- most of which involved either the reuse of fly ash as a cement substitute in concrete or the recycling of waste materials.

Projects that primarily affected CO_2 emissions accounted for reported direct reductions of 51 MMTCE (206 $MTCO_2$), representing 76% of the total direct reductions reported. In addition, indirect reductions totaling 8.5 MMTCE (34 $MTCO_2$) were also reported for the projects that reduced CO_2 emissions.

A variety of efforts to reduce emissions of gases with high global warming potentials (GWPs) were also reported. In this group, 293 of the reported projects (17%) reduced methane and nitrous oxide emissions from waste management systems, animal husbandry operations, oil and gas systems, or coal mines. The direct emission reductions for these projects totaled 7.9 MMTCE (32 $MTCO_2$), representing 13% of the total direct reductions reported. Indirect reductions reported for projects that reduced methane and nitrous oxide emissions totaled 11 MMTCE (44 $MTCO_2$). The 47 projects reported on the short form reduced emissions from unspecified sources by a reported 1.1 MMTCE (4.4 $MTCO_2$).

<u>Coal Mining</u>
CONSOL Coal Group reported its reductions as an entity-level reporter, without defining specific projects that were responsible for directly reducing the emissions. CONSOL was one out of the 48 companies that reported only entity-level information. 109 of the 228 companies reported entity-level information, while 61 of all the participants in the program reported both entity-level information and project-level information.

CONSOL Coal Group reported the largest individual entity-level direct emissions reduction at 5.2 MMTCE (21 $MTCO_2$), accounting for 11% of the total reported CO_2 equivalent direct reductions. These reductions are the combined effect of changes in mining operation, the initiation of coal bed methane (CBM) gas sales projects, and the internal use of CBM as a fuel.

There were 16 projects reported to specifically reduce methane emissions from coal mines, with total direct emission reductions of 538,285 metric tons (3.15 MMTCE) and indirect reductions of 96 metric tons methane (550 metric tons carbon equivalent).

Jim Walter Resources, Inc., reduced methane emissions by 242,570 metric tons (1.4 MMTCE) , mostly due to the capture and sale of gob gas to an interstate pipeline. These gob wells are drilled in advance of the longwall mining in order to assist in the removal of methane from the active mine operations. The company also practices degasification through horizontal boreholes on all their deep mines.

Two other companies contributing to the methane reductions at coal mines were U.S. Steel Mining Company, reporting direct methane reductions of 106,771 metric tons methane (0.6 MMTCE) from its two projects and El Paso Production Company, reporting direct reductions of 79,914 metric tons (0.45 MMTCE) from its project in White Oak Creek coalbed in Alabama.

None of the coal mining companies reported any sequestration projects that involved afforestation or reforestation. Mining companies are required under Subchapter B 30 CFR Surface Mining Law Regulations, to re-vegetate all post-mining areas. Under Part 715, the code requires that "a diverse, effective, and permanent vegetative cover of species native to the area of disturbed land or species that will support the planned post-mining uses of the land approved according to Sec. 715.13." If the land use category is changed, i.e., from a rangeland, cropland, hayland, or pasture to a forest land, it would have to be approved by the regulatory authority, after consultation with the landowner provided it meets the criteria outlined in Sec. 30 CFR 715.13 (d). If introduced species were to be substituted for native species, the regulatory authority would have to approve it after the appropriate field trials demonstrated the species had equal or superior utility.

While there are opportunities for mining companies to be involved with afforestation projects, regulations have not allowed companies to transform a rangeland into a forest.

<u>Electric Utilities</u>
Eighty-four electric power providers reported 391 projects that reduced emissions a total of 45.6 MMTCE (184 $MTCO_2$) through direct and indirect sources. Electric power projects are reported in two categories:

(1) carbon content reduction; and
(2) increased energy efficiency in generation, transmission, and distribution.

Carbon content reduction projects include availability improvements, fuel switching and increases in lower emitting capacity. Increased efficiency through generation, transmission, and distribution projects includes such activities as heat rate improvements, cogeneration and waste heat recovery, high-efficiency transformers, and reductions in line losses associated with electricity transmission and distributions. A total of 188 projects reporting 4.6 MMTCE (18.5 $MTCO_2$) were for increased energy efficiency and 225 projects representing 42 MMTCE (169 $MTCO_2$) were reported under carbon content reductions. About three-quarters of the reported electric power projects were related to nuclear power.

Of the 188 projects related to energy efficiency, 117 projects were defined as improvements in generating efficiency. Heat rate improvements at coal-fired power plants are a commonly reported means of increasing efficiency and reducing CO_2 emissions. There are numerous opportunities for improving efficiency at existing power plants. The reductions reported were 2.5 MMTCE (10.2 $MTCO_2$) – 5.56% of the total emissions reported by power companies.

FirstEnergy Corporation reported heat rate efficiency improvements on the Ohio Edison System that were accomplished through:

(1) shutdown of less efficient coal-fired boilers;
(2) installation of enhanced boiler controls; and
(3) turbine modifications.

This project reported a reduction of 8.6 trillion Btu in consumption of bituminous coal, resulting in direct reductions of 0.22 MMTCE (0.89 MT CO_2) emissions.

American Electric Power (AEP) reported 71 projects that reduced emissions. Two of these were related to emission reductions from heat rate improvement projects at their coal-fired power plants accomplished through operational changes, equipment changes, and improved load optimization. The emission reductions reported were 0.35 MMTCE (1.4 MT CO_2).

Southern Company reported one project out of 34 on heat rate improvement on coal-fired capacity. From 1990 to 1994, Southern Company improved their average net heat rate by better operation and maintenance of plant equipment. Examples include enhanced boiler heat recovery in economizer and air preheater systems, component replacement for efficiency gain (fans, heat exchangers, pumps), heat rejection upgrades, and improved turbine performance monitoring/maintenance. For 1995-2000, the average coal-fired heat rate increased, mostly due to emission control projects required by the 1990 Clean Air Act Amendments. With the number of selective catalytic reduction (SCR) systems coming on-line and installation of flue gas desulfurization (FGD) systems, further improvements in heat rates will no longer be achievable.

Tennessee Valley Authority has reported a total of 7.4 MMTCE (30 MT CO_2) direct and indirect emission reductions, with 25 projects defined.

<u>Coal Ash</u>

Thirty-seven projects were reported that reused coal ash. This accounted for indirect reductions of 1.46 MMTCE (5.9 MT CO_2) that represented over 7 million metric tons of coal ash reused.

FirstEnergy recovered 177,800 tons of fly ash to be used in the production of Portland cement, which was an indirect reduction of 0.42 MMTCE (0.14 $MTCO_2$). Fly ash substitution for Portland cement saves CO_2 emissions by displacing Portland cement that would otherwise need to be produced. CO_2 emissions saved in the Portland cement manufacturing process results from the direct combustion of fossil fuels plus from the calcination of limestone that will be avoided.

AEP sold fly ash for use in ready-mix concrete, pozzolan, and concrete block. They recycled 741,827 tons of fly ash for an indirect reduction of 0.17 MMTCE (0.58 $MTCO_2$). This was the second largest quantity of coal ash reuse. (TXU recorded the largest.)

Energy End Use

Reported reductions for the 329 energy end-use projects reported on the long form included 5.2 MMTCE (21 $MTCO_2$) from direct sources and 2.2 MMTCE (8.8 $MTCO_2$) from indirect sources. Energy end-use reductions were reported for stationary-source applications, such as building shell improvements, lighting and lighting control, appliance improvement or replacement, and heating, ventilation and air conditioning improvements. Much smaller reductions were reported for the 53 transportation projects reported on the long form, including 0.12 MMTCE (0.049 $MTCO_2$) from direct sources and 0.024 MMTCE (0.097 $MTCO_2$) from indirect sources.

Carbon Sequestration

Almost all of the 369 carbon sequestration projects reported to EIA increased the amount of carbon stored in sinks through various forestry measures, including afforestation, reforestation, urban forestry, forest preservation, and modified forest management techniques. EIA recorded that 45 of the 51 reporters involved in forestry or natural resources programs that sequestered carbon or reduced emissions in 2001 were electric utilities.

These activities accounted for 25% of the projects reported on the long form; 243 of the reported carbon sequestration projects presented 27 electric utilities' shares in nine projects conducted by the UtiliTree Carbon Company. The sequestration reported for carbon sequestration projects on the long form totaled 2.2 MMTCE (8.8 $MTCO_2$). Direct emission reductions totaling 0.0003 MMTCE (0.0012 $MTCO_2$) were also reported for a few carbon sequestration projects in which changes in forest management practices reduced fuel consumption. A further 14 carbon sequestration projects reported on the short form sequestered or avoided emissions of 0.0025 MMTCE (0.01 $MTCO_2$).

AEP accounted for the largest number of projects (14% of the 251 afforestation and reforestation projects). AEP reported 34 afforestation projects on land owned by its operating companies, which sequestered a reported 0.04 MMTCE (0.16 $MTCO_2$). Three of the projects were initiated in 2001.

AEP reported 11 projects that involved the utility's annual additions to its modified forest management efforts conducted in upland central hardwood stands. The stands are selectively harvested, removing over-mature, mature, cull, and diseased trees. Other steps are undertaken, as necessary, to improve growing space relationships and maximize the growth rates of the stands. The combined additional sequestration reported by AEP for these projects in 2001 was 0.004 MMTCE (0.017 $MTCO_2$).

FirstEnergy is involved in an urban forestry project since 1992. Under the tree source project, 17,900 trees were planted in 2001. The company provided ornamental trees, free of charge, to its Ohio customers for residential planting.

Methane Emissions

Emission reductions for the 246 methane abatement projects reported on the long form included 7.9 MMTCE (29 $MTCO_2$) from direct sources and 11 MMTCE (44 $MTCO_2$) from indirect sources. The three most frequently reported sources of methane reductions were municipal waste landfills (198 projects), natural gas systems (19 projects), and coal mines (16 projects). In addition to reducing methane emissions, projects that involved the recovery and use of methane for energy also reduced CO_2 emissions by displacing fossil fuels – such as oil and coal – that have higher carbon contents and thus produce more CO_2 when burned.

Future Commitments

Eighty-five entities reported formal commitments to reduce future emissions, to take action to reduce emissions in the future, or to provide financial support for activities related to GHG reductions. More than one-third (34%) of these entities are electricity generators participating in the Climate Challenge Program. Fifty-six other entities also reported commitments. Other voluntary programs represented among the commitments reported included Climate Wise, the Voluntary Aluminum Industrial Program, the U.S. Initiative on Joint Implementation, the Green Lights Program, the Landfill Methane Outreach Program, the Coalbed Methane Outreach Program, Motor Challenge, and the Sulfur Hexafluoride Emissions Reduction Partnership for Electric Power Systems.

There are three forms of future commitments in the Voluntary Reporting Program:

1) entity commitments;
2) financial commitments; and
3) project commitments.

Entity and project commitments parallel the entity and project aspects of emissions reporting. An entity commitment is a commitment to reduce the emissions of an entire organization. A project commitment is a commitment to take a particular action that will have the effect of reducing the reporter's emissions through a specific project. A financial commitment is a pledge to spend a particular sum of money on activities related to emission reductions, without a specific promise about the emissions consequences of the expenditure.

Twenty-five firms made 32 specific promises to reduce, avoid, or sequester future emissions at the entity level. Some of these entity-level commitments were to reduce emissions below a specific baseline, others to limit the growth of emission per unit of output, and others to limit emissions by a specific mount relative to a baseline emissions growth trend. In their reports, companies committed to reducing future entity-level emissions by a total of 25.7 MMTCE (104 $MTCO_2$) – 44% of entity-level emission reduction commitments were for the year 2000, with an additional 31% falling within the 2001 to 2005 time horizon.

Twenty-nine companies reported on commitments to undertake 182 individual emission reductions projects. Some of the commitments were linked to future results from projects already under way and forming part of the reporters' submissions. Others were for projects not yet begun. Reporters indicated that the projects were expected to reduce future emissions by 41 MMTCE (166 $MTCO_2$), most of which (24.5 MMTCE or 99 $MTCO_2$ or 60%) would be reductions of methane emissions.

Twenty-one firms made 39 separate financial commitments. The total amount of funds promised was $51 million, of which $7 million was reported to have been spent in 2001.

The Business Roundtable Climate RESOLVE Program

The Business Roundtable is an association of chief executive officers of leading corporations with a combined workforce of more than 10 million employees in the U.S. and over $3.7 trillion in revenues. In February 2003, the BRT announced the Climate RESOLVE (**R**esponsible **E**nvironmental **S**teps, **O**pportunities to **L**ead by **V**oluntary **E**fforts) program at a U.S. Department of Energy event in conjunction with the Department of Agriculture, Environmental Protection Agency and Department of Transportation. The event highlighted cooperative public and private programs to address climate change. The Climate RESOLVE program encourages BRT members to report their greenhouse gas management efforts to the Department of Energy. BRT will regularly report on progress towards the 100% participation goal.

In addition to its call for voluntary action, the Business Roundtable will give its member companies support and tools to effectively manage GHG emissions. The BRT will assist companies through workshops, one-on-one consulting support, an implementation workbook and examples of cost-effective options to reduce, avoid, offset and sequester GHG emissions.

The BRT has stated their belief that the development and deployment of breakthrough technologies will provide the most effective long-term response to concerns about global climate change. In the meantime, BRT member CEOs have pledged to apply best management practices to make American companies among the most greenhouse-gas efficient in the world.

2.3 Improvements in Reporting Protocols

2.3.1 Corporate GHG Accounting and Reporting

Global climate change is viewed as one of the important issues of the 21st century. The momentum for responding is increasing as governments are adopting aggressive actions, including potential ratification of the Kyoto Protocol in 2003, and establishing national, statewide, and regional emissions reporting initiatives or trading schemes. There also is increasing pressure on businesses in the developed world to demonstrate that they are taking responsibility to quantify and manage their GHG emissions, particularly for carbon intensive industries.

Proactive companies are taking steps to identify not only the risks and challenges associated with the evolving climate change arena, but also the business opportunities that could be developed. To do this, however, companies must first have an understanding of the extent and nature of their GHG emissions.

2.3.2 Hierarchy of Existing GHG Accounting and Reporting Initiatives

A range of programs currently exist for reporting, registering, and trading GHG emissions and emissions reductions. While these programs differ from each other, one thing they have in common is the need for guidance on how GHG emissions are accounted for and reported. The approaches taken by these programs often differ widely, however, even among programs with similar purposes.

The programs referenced within this chapter can be grouped into four categories:

1. U.S. Government-Sponsored Programs at the Federal and State Level
    a. DOE's Voluntary Reporting of Greenhouse Gases Program - 1605(b) Program
    b. EPA's Climate Leaders Program
    c. The California Climate Action Registry
    d. The New Hampshire Voluntary GHG Reductions Registry
    e. The New Jersey Open Market Emissions Trading Program
    f. The Wisconsin Voluntary Emission Reduction Registry

2. Programs Offered by Non-Governmental Organizations
    a. The Climate Neutral Network
    b. The Climate Trust
    c. Environmental Defense Fund's Partnership for Climate Action
    d. Environmental Resources Trust's GHG Registry
    e. World Wildlife Fund's Climate Savers Program

3. International Initiatives
    a. The UNFCCC (e.g., National Registries & Flexible Mechanisms)
    b. The World Bank's Prototype Carbon Fund
    c. The World Resources Institute (WRI)/World Business Council for Sustainable Development (WBCSD) Greenhouse Gas Protocol Initiative
    d. The American Petroleum Institute's (API) Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry
    e. The Chicago Climate Exchange

4. Existing Programs in Specific Foreign Countries or Regions
    a. The Australian Greenhouse Challenge
    b. Denmark's National GHG Trading Scheme
    c. EurElectric Group's GHG Emissions Trading Simulations
    d. The European Union's Emissions Trading Directive
    e. The Netherlands' ERUPT (JI) and CERUPT (CDM) Tenders
    f. The United Kingdom's National Emissions Trading Scheme

Within these categories, the programs have a range of purposes. Typically they exist to promote public recognition of efforts to reduce emissions, to provide protection for emissions baselines (e.g., ensure that voluntary actions are taken into account if and when a mandatory regime is adopted), or to promote emissions trading. In some cases, the programs serve more than one purpose.

2.3.3 Initiatives With Heavy Industry Participation

While there is no universally accepted international business standard for estimating GHG emissions, three efforts have enjoyed heavy participation from the private sector:

1. DOE's Voluntary Reporting of Greenhouse Gases Program – 1605(b)

2. API Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry, (API, 2001)

3. WRI/WBCSD *The Greenhouse Gas Protocol* and associated Stationary Combustion Tool (WRI/WBCSD, 2001)

The DOE Program

The DOE's Voluntary Reporting of Greenhouse Gases Program, created under Section 1605(b) of the Energy Policy Act of 1992, allows any company, organization or individual to establish a public record of emissions, reductions, or sequestration achievements in a national database. Reporters can gain recognition for environmental stewardship, demonstrate support for voluntary approaches to achieving environmental policy goals, support information exchange, and inform the public debate over GHG emissions.

During 2002, the President directed the Secretary of Energy, working with the Secretaries of Commerce and Agriculture and the Administrator of the EPA, to propose improvements to the current 1605(b) program to "enhance measurement accuracy, reliability and verifiability, working with and taking into account emerging domestic and international approaches." The President also requested recommendations "to ensure that businesses and individuals that register reductions are not penalized under a future climate policy, and to give transferable credits to companies that can show real emissions reductions."

The API Compendium

The API Compendium project reviewed numerous GHG protocols and methodology documents in an effort to compare and contrast different greenhouse emission estimation techniques and develop a document of internationally recognized best practices. Protocols from participating petroleum companies and publicly available guidance documents and inventory protocols were included in this detailed review. Internationally recognized sources reviewed under the API project include:

- EPA's AP-42 (EPA, 1995 including supplements A through F);
- Intergovernmental Panel on Climate Change (IPCC, 1996);
- Emission Inventory Improvement Program (EIIP, 1999);
- Energy Information Administration (EIA, 1996; EIA, 2001); and
- WRI/WBCSD (WRI/WBCSD, 2001)

API is currently reaching out to other protocol development organizations (governmental and non-governmental) to gain broad peer-review of its efforts, with the ultimate goal of achieving harmonization of estimation methods and improved global comparability of emission estimates. Although the focus of the Compendium is on oil and gas industry operations, methodologies presented for combustion sources and energy generation are directly applicable to electric utility operations.

The GHG Protocol Initiative

The WRI/WBCSD GHG Protocol Initiative is an international undertaking to promote the use of standardized methods for estimating and reporting GHG emissions. Proposed principles and standards are provided for developing a corporate GHG inventory and for performance reporting. A separate spreadsheet tool is available for estimating emissions from stationary combustion sources and energy generation. The WRI/WBCSD GHG Protocol is widely cited and recognized as the accepted approach for developing GHG inventories.

Module I of the WRI/WBCSD GHG Protocol addressing entity-wide reporting has been completed. Module II on project-based reporting was launched in 2002 and is not expected to be completed until the end of 2003. WRI is seeking feedback on reporting efforts using Module I guidelines.

The EPA Climate Leaders program is using a reporting protocol based on a modified version of the WRI/WBCSD GHG Protocol. It held a workshop October 2002 to discuss feedback on the reporting protocol and GHG reduction-setting methodology. Climate Leaders has also "released for comment"[1] its first draft GHG Protocol document, the Stationary Combustion Module. During 2003, EPA will seek comments on the draft Climate Leaders GHG Inventory Protocol documents. The protocol will be released in stages as individual modules are completed. After gathering feedback on all of the inventory protocol modules, EPA will integrate comments, finalize the modules, and publish the protocol, updating it as needed.

2.3.4 Accounting and Reporting Recommendations

Consistency in Accounting and Reporting Metrics

The U.S. government, through the DOE, should make every effort to ensure that:

- Changes to the 1605(b) program are consistent with the accounting and reporting principles supported by U.S. industry (e.g., API and GHG Protocol Initiative); and
- Wherever possible, be consistent with international accounting and reporting best practices in an effort to reduce the accounting and reporting burden of U.S. multi-national corporations.

Nature of Reporting

Reporting should:

- Stay flexible, including retention of the flexibility to report either entity-wide emissions or project-specific reductions only;
- Accommodate multiple purposes for reporting, including (but not limited to) recording emissions and achievements, informing public debate, participating in educational exchange, as well as providing transferable credits, baseline protection and credit for past actions; and
- Allow the reporter to specify those projects and reductions for which transferable credits, baseline protection, and/or credit for past action is being sought versus those reported activities for which it is not being sought.

[1] This is not public comment via the Federal Register.

Reference Cases

1. Multiple options should be available for setting reference cases.[2]
2. Modified reference cases[3] should remain an option (including those developed from emission rates).

Project-Based "Reductions"

1. Accounting and reporting guidelines should:
   - Continue to allow project "reductions" to be reported separately from the reporting of entity-wide emissions. If entity-wide emissions are reported, the ability to report project-level reductions should not depend on the entity-wide emissions showing a reduction.
   - Continue to allow reporting of off-site sequestration projects, including abandoned mine land reclamation programs.
   - Include projects that avoid emissions and provide an indirect emissions benefit by reducing energy consumption (including energy efficiency and DSM).
   - Continue to allow reductions from international projects, including those approved by governments under activities implemented jointly (under the UNFCCC) and CDM and JI flexible mechanisms (under the Kyoto Protocol).

2. Reporters should distinguish between projects where they have <u>direct</u> control (*e.g.*., electricity generators' heat rate improvement programs, enhanced CBM recovery, etc.) versus those activities where others may affect the level of direct reductions (*e.g*., electric utilities' DSM programs).

Entity-Wide Reporting

1. Entities should continue to have the flexibility to choose their reporting boundaries and otherwise define the scope of their reports in a way that is consistent with a specific industry's best practices.

2. Indirect emissions should continue to be a separate, optional category for reporting.

3. If an entity *opts* to assign a portion of its direct emissions from their operations to purchasers of their products, they should also report that portion assigned to their customers as an indirect emissions reduction (e.g., credit) against their direct emissions, in order to accurately account for all of their emissions. Any reporting in this manner should be <u>in addition</u> to the reporting of all direct emissions of GHGs from their operations.

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[2] "Reference case" is the term used in the 1605(b) guidelines for a project baseline, or what the emissions would have been in the absence of the project.

[3] "Modified reference cases" are references cases that recognize that, even in the absence of the project, future emission levels would differ from historic levels.

4. Reporting entities should be urged (but not required) to report other categories of direct emissions if they believe that the emissions from any of the other categories (*e.g.*, fleet vehicles, methane, N_2O) are greater than a *de minimis* amount established for that industry.

5. Quantification of reductions based on *entity-wide* emissions should meet the same standards for "leakage" (and other relevant criteria) that are applied for quantification of reductions from *projects*.

Verification

1. Third-party verification should be optional (e.g., it may be desirable for some projects in order to create fungible/tradable emission reduction credits).

2. In those cases where reporters have elected to have third-party verification of projects, it would be helpful to have some uniform standards for such verification.

Confidentiality

1. Trade secret and commercial or financial information that is privileged or confidential should continue to be protected under the Freedom of Information Act, Section 1605(b)(3) or other applicable law. Any other approach would discourage participation in a voluntary program.

SECTION 3: EVALUATION OF RESEARCH AND DEVELOPMENT NEEDS FOR GREENHOUSE GAS MANAGEMENT

Introduction

Approximately one-third of all CO_2 emissions due to human activity arise from the combustion of fossil fuels used to generate electricity, with each power plant capable of emitting several million tons of CO_2 each year. This contributes to the build-up of GHGs in the atmosphere. Policy proposals to limit emissions of CO_2 and other GHGs are being considered at the international, national, regional, and local levels.

International efforts to limit GHG emissions are based primarily on the United Nations Framework Convention on Climate Change (UNFCCC), which seeks "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." Although a target concentration has not been specified, actions to reduce emissions of CO_2 and five other major GHGs are proceeding through policy instruments, such as the emission reduction targets set for developed countries under the 1997 Kyoto Protocol.

The U.S. has not agreed to the GHG reduction targets set forth under the Kyoto Protocol, but the Bush Administration has proposed a Global Climate Change Initiative (GCCI) to voluntarily reduce the carbon intensity of the U.S., as measured by CO_2 emitted per unit of GDP, over the next 10 years. The GCCI has set forth the goal of significantly reducing the GHG intensity of the U.S. economy over the next 10 years, while maintaining the economic growth needed to finance investment in new, clean energy technologies. This will require increased R&D investments with a heightened emphasis on carbon sequestration and reductions in non-CO_2 GHG emissions, such as methane and N_2O.

Because more than 85% of the CO_2 emitted by the power sector originates from coal, achieving the GCCI-targeted 18% reduction in GHG intensity over the next decade within the power sector will be a challenge. By focusing on GHG intensity as the metric of choice, the government must promote vital R&D while minimizing the economic impact of GHG emission reduction on the U.S. This goal could be accomplished through a synergistic, three-pronged approach, consisting of:

- Increasing the efficiency of the energy system;
- Increasing the use of low-carbon fuels; and
- Developing technologies to capture and store CO_2 from fossil fuels used for energy.

A portfolio of new advanced technologies that would increase energy system efficiency holds great potential to reduce GHG emissions. In addition, the development of carbon capture and sequestration technologies will play a critical role if the U.S. is to successfully manage its GHG emissions.

Plotting and Following the Technology Roadmap

If GHG management on the scale envisioned in various futurist scenarios is required, it will be a massive technical and economic undertaking. On the other hand, if the international community's will to utilize its abundant fossil fuel resources is not to be denied, the undertaking will require the development and deployment of new technology at an unprecedented pace and scale. To achieve this, particularly in an international context, will take a clear vision of what is needed and what must be done to accomplish it. Therefore, it is imperative that there be broad consensus embodied in national energy policy that outlines the overall goals, time frame and costs for achieving them in a comprehensive technology roadmap. The roadmap must include both a range of options for achieving the goals and a framework for allocating resources to meet the goals with the greatest economic and temporal efficiency.

Recently, there has been a substantial effort in the technical community to achieve agreement on a common road map for coal utilization technology directed at the production of electricity and fuels. This road map has been drawn from individual roadmaps of the DOE, the Coal Utilization Research Council, and EPRI, and includes greenhouse gas management as a specific objective. It is important that the roadmapping effort continue to assist DOE, private industry and the public to update and focus performance objectives, technology options and economic resources.

3.1 Energy Efficiency Improvements

3.1.1 Summary

Enhancing generation efficiency can be the most cost-effective approach for reducing CO_2 emissions and simultaneously improving the utilization of coal, a critical domestic energy resource. With higher efficiency, less coal is used to produce the same power output, resulting in reduced emissions of pollutants and GHGs. The application of highly efficient, clean power generating systems is essential for coal to maintain its position as the most important energy source for power generation.

As a result of the DOE-industry sponsored CCT Program, a number of coal-based power generating systems of increased efficiency are now commercially available. Others will be available for demonstration and deployment after 2010. Four specific technologies are discussed in this section, because of their readiness for application or significant promise of performance in the near future, with further development:

- Pulverized coal (PC) combustion with supercritical (SC) and ultra-supercritical (USC) steam;
- Pressurized fluidized bed (PFBC) combined cycle with topping combustor (PFBCwTC);
- Integrated gasification combined cycle (IGCC); and
- Hybrid gasification/fuel cell/GT/steam (DOE's Vision 21Cycle).

These technologies offer 45% cycle efficiency (LHV), with a potential 25% CO_2 emissions reduction compared to currently installed capacity. U.S. and international R&D efforts are in progress to develop further materials for USC plants with prospects of efficiency increases up to 50% (LHV). Such plants are expected to be available by 2010.

Capital costs, operating costs, and the cost of electricity are lower for PC-SC steam than for the combined cycles. However, PFBCwTC and, especially, IGCC could become more competitive when it becomes commercially viable to add CO_2 capture equipment.

Vision 21 Cycle aims at "zero emissions" and >60% cycle efficiency. Development of this advanced power generation system is worthy of governmental and industrial support. It is the best prospect for extending coal use while meeting more stringent environmental limitations.

3.1.2 Coal-Based Generation Technologies for New Plants

The efficiency of the existing coal-based power plant fleet in the U.S. is about 35% (LHV). Advanced coal-based power generation technologies are able to generate electricity at significantly increased efficiency (>45%, LHV). Several of these technologies have been developed over the last 15 years through successful government-industry cooperation under DOE's CCT Program, and are now commercially available.

Higher efficiency is the key to the reduction of all emissions, since higher efficiency means less fuel is burned and fewer pollutants are emitted. This includes GHGs such as CO_2. Until CO_2 capture and removal from flue gas becomes a commercially available technology, efficiency increases will remain the most practical and cost-effective method for mitigating CO_2 emissions.

SC and USC Technology

PC-SC boilers have been in use since the 1930s. With improvements in materials and efficiency, this system has become the choice of new PC plants worldwide. Efficiency improvements have been achieved by using higher temperatures. In subcritical steam cycles, the maximum practical efficiency is just under 40% (LHV). The efficiency of a PC steam plant can be increased in small steps to beyond 45% (LHV) using SC steam parameters as shown in Figure 1 (Schilling [1]). The diagram illustrates reduction in waste heat loss, improved combustion to reduce excess air, and reduction in stack temperature.

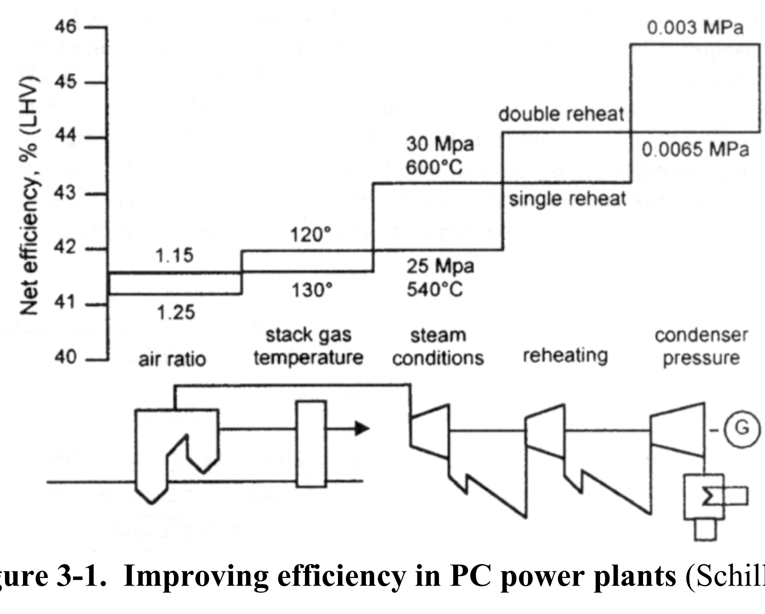


Figure 3-1. Improving efficiency in PC power plants (Schilling [1])

SC steam parameters of 3750 psi/1000 °F single or double reheat with efficiencies that can reach 42% (LHV) represent a mature, commercially available technology for U.S. power plants.

In several papers [2-8], the EPRI reviewed the history and performance of SC units in the U.S. and in the former Soviet Union, where most of the SC plants have been operated since the 1930s. SC plants also have a long history in the U.S. The original Eddystone Unit 1 with the most advanced steam parameters of 4800 psi/1150 °F was constructed in1960 and is still in operation. There are 157 PC-SC power plants in the U.S. These plants show significant efficiency advantages of up to three percentage points, without increased outages, over subcritical units.

Further improvement in efficiency achieved by USC parameters is dependent on the availability of new, high-temperature alloys for superheaters, reheaters, and steam turbines. The state of development and new USC plant commissioning internationally are shown in Table 3-1. USC steam plants in service or under construction in Europe and in Japan during the last five years are listed in Table 3-2. Today, steam parameters of 4500 psi and 1110°F can be realized, resulting in efficiencies >45% (LHV) for bituminous PC power plants. There are over five years of experience with these plants in service, with excellent availability.[2] This improved efficiency represents a significant 25% reduction in CO_2 emissions, compared to the emissions from existing coal-fired capacity.

EPRI is the technical lead organization in a program of materials development [2] aimed at steam temperatures in excess of 1300°F and enabling further efficiency gains up to 50% (LHV). The program is undertaken by DOE at its National Energy Technology Laboratory (NETL) and the Ohio Coal Development Office, with U.S. boiler manufacturers as participants and major contractors. Specific technical issues being addressed include maintaining efficiency at partial load, and the effect of load changes on the lifetime of boiler and turbine components.

International efforts, such as the USC Materials Consortium in the U.S., and AD700 in the European Union aim for further improvement of USC power generation with steam parameters of 5440 psi and 1292/1328 °F and efficiencies of 50% (LHV). Such plants are expected to be available within a decade. Application of SC steam cycle parameters is also planned for FBC systems in order to improve efficiency.

Table 3-1. International materials development. (Blum and Hald) [2]

Japan	USA	Europe
Development and Plant Operation: EPDC	Development: EPRI	Development: Cost
1981-2000	EPRI Projects: 1978-2003	Cost 501/522: 1983-2003
Turbine and boiler -Materials development -Component manufacture -Pilot plant operation (50 MW) -Target: 300 bar, 630 °C/ 630 °C	-Basic studies, turbine and boiler -Thick-walled pipe steels (USA, J, EU -Standardization achieved -Trial components in service	Turbine and boiler -Interaction with VGB, Brite-Euram, Marcko, ECCC, etc. -All major power plant components -Target: 300 bar, 620 °C/ 650 °C
Power Plant Orders		Power Plant Orders
-1000 MW, 241 bar, 593°C, 593°C, comm 97 -1050 MW, 250 bar, 600°C, 610°C, comm 01 - 600 MW, 250 bar, 600°C, 610°C, comm 02		-400 MW, 285 bar, 580°C, 580°C, comm 97 -530 MW, 300 bar, 580°C, 600°C, comm 01 -975 MW, 260 bar, 565°C, 600°C, comm 02
NIMS Materials Development	DOE Vision 21	Thermie AD700
1997-2007	2002-2007	1998-2013
-Ferritic Steel for 650°C	Materials development and qualification Target: 350 bar, 760°C (870°C)	-Materials development and qualification -Component design and demonstration plant demo Target: 400-1000 MW, 350 bar, 700°C, 720°C

Table 3-2. USC plants in service or under construction in Europe and Japan.
(Blum and Hald 2002) [2]

Power Station	Cap. MW	Steam Parameters	Fuel	Year of Com.	Eff. %	Boiler/Steam Line Materials	Turbine Materials
Matsuura 2	1000	255 bar/598°C/596°C	PC	1997		Super304H/P91	TMK1
Skaerbaek 3	400	290 bar/580°C/580°C/580°C	NG	1997	49	TP347FG/P91	COST 501 F
Haramachi 2	1000	259 bar/604°C/602°C	PC	1998		Super304H/P91	HR1100
Nordjylland 3	400	290 bar/580°C/580°C/580°C	PC	1998	47	TP347FG/P91	COST 501 F
Nanaoota 2	700	255 bar/597°C/595°C	PC	1998		TP347FG/P91	Toshiba 12Cr
Misumi 1	1000	259 bar/604°C/602°C	PC	1998		Super304H/HR3C/P91	TMK2/TMK1
Lippendorf	934	267 bar/554°C/583°C	Lignite	1999	42.3	1.4910/P91	COST 501 E
Boxberg	915	267 bar/555°C/578°C	Lignite	2000	41.7	1.4910/P91	COST 501 E
Tsuruga 2	700	255 bar/597°C/595°C	PC	2000		Super304H/HR3C/P122	Toshiba 12 Cr
Tachibanawan 2	1050	264 bar/605°C/613°C	PC	2001		Super304H/P122/P92	TMK2/TMK1
Avedore 2	400	300 bar/580°C/600°C	NG	2001	49.7	TP347FG/P92	COST 501E
Niederaussen	975	265 bar/565°C/600°C	Lignite	2002	>43	TP347FG/E911	COST 501E
Isogo 1	600	280 bar/605°C/613°C	PC	2002		Super304H/P122	COST 501E

Materials Guide
Superheater:
TP347FG:Fine Grain 18 Cr10NiMoNb Super304H: 18Cr9Ni3Cu HR3C:25Cr20Ni 1.4910: 18Cr12Ni2 1/2Mo

Steam Lines and Headers:
P91: 9CrMoVNb P92: 9Cr1/2Mo2WVNb E911: 9CrMoWVNb P122: 11Cr1/2Mo2WCuVNb

Turbine Rotors
COST 501 F: 12CrMoVNbN101 COST 501 E: 12CrMoWVNbN1011 HR1100: 111Cr1.2Mo0.4WVNbN
TMK1: 10Cr1.5Mo0.2VNbN TMK2: 10Cr0.3Mo2W0.2VNbN Toshiba: 11Cr1Mo1WVNbN

PFBC

PFBC has all the advantages of atmospheric fluidized bed combustion (AFBC), including sulfur capture in the bed, low-NOx emissions, and the capability to use low-quality fuels, plus the enhanced efficiency of combined-cycle operation. While the low temperature of the fluidized bed is advantageous for avoiding "thermal NO" formation, it has the disadvantage of nitrous oxide (N_2O) emission and an inability to take advantage of the higher inlet temperature range of modern gas turbines.

PFBCwTC responds to the need for a higher gas turbine inlet temperature. In this cycle (Figure 3-2), a coal-water slurry is injected into a pressurized carbonizer where it undergoes mild gasification to produce a low heating value syngas and char. The char is burned in a PFBC boiler with high excess air, and the 1600 °F combustion products are cleaned of particulate and alkalis, and then enter the gas turbine. Sulfur is captured in the PFBC boiler and in the fluidized bed carbonizer by adding dolomite. The syngas is injected into the topping combustor, where it is burned to raise the temperature of the PFBC exhaust gas at the inlet to the gas turbine to 2280 °F. This temperature rise increases the cycle efficiency to about 47% (LHV). N_2O emissions are eliminated because the N_2O decomposes at the elevated temperature in the topping combustor.[10]

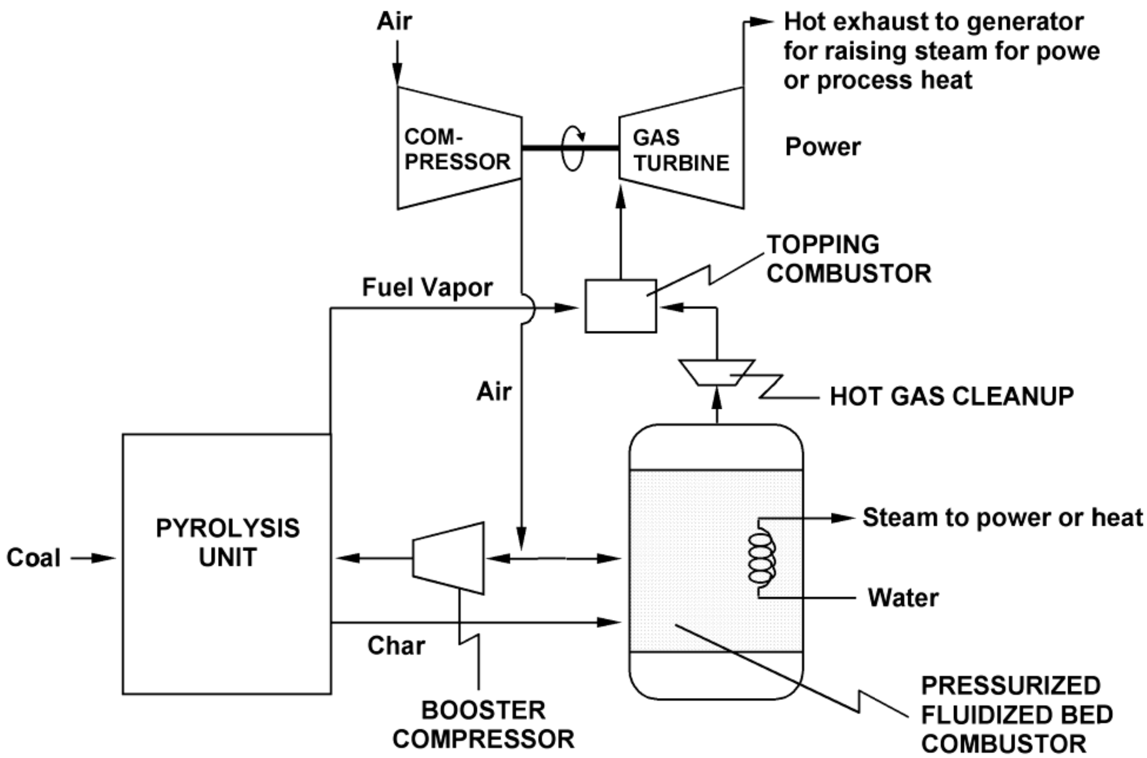


Figure 3-2. Pressurized Fluidized Bed with Topping Combustor.

Further improvements in efficiency can be obtained by the application of advanced gas turbine technology and, on the steam side, by SC steam parameters with high-temperature double reheat. Commercial realization has been hampered by slow progress on hot gas filter development, expense of turbines for this application, and complex plant integration. The future of PFBC is uncertain.

IGCC

IGCC involves the total gasification of coal with oxygen and steam to produce a high heating value syngas. The syngas is cleaned of particulate, alkalis, ammonia, and sulfur compounds and the syngas is burned in a gas turbine with low-NOx combustors. IGCC also produces steam for a steam power cycle. Main features of IGCC are shown in Figure 3-3.

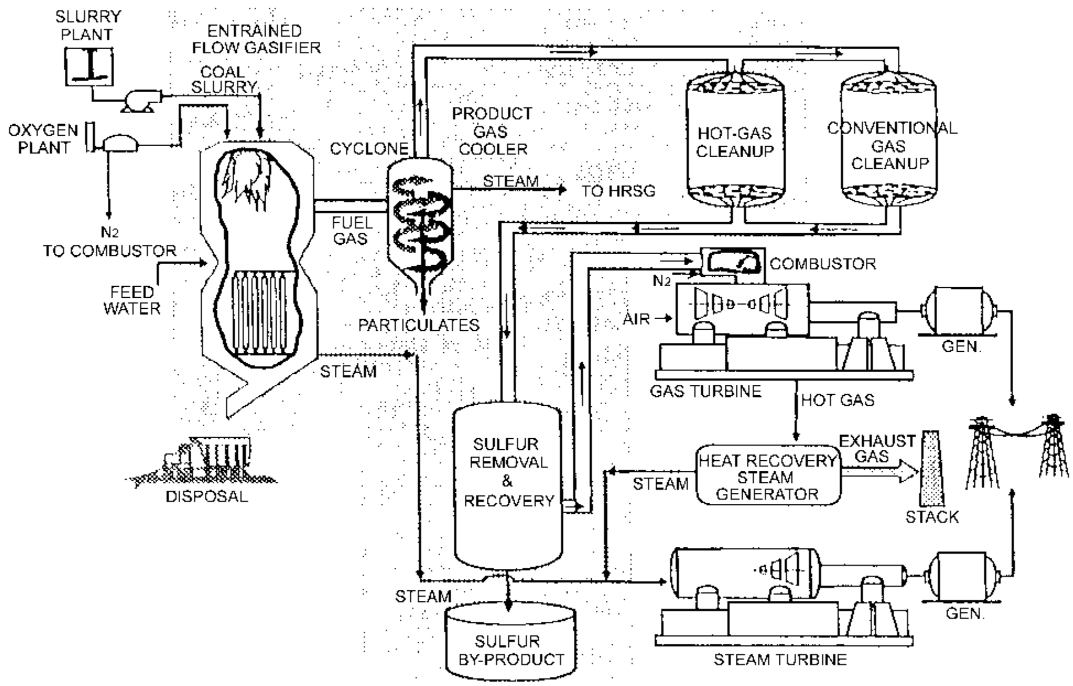


Figure 3-3. Integrated Gasification Combined Cycle (IGCC).

IGCC is the cleanest advanced coal technology, and has been successfully demonstrated at full commercial scale over the past 7-8 years, although long-term reliability and availability concerns remain. The future of IGCC depends on further reductions in capital and operating costs and increases in overall efficiency. The capital cost is presently high, mainly for the oxygen-blown gasifier, which requires an air separation plant for producing oxygen. There is a need for more complete integration of the various subsystems, such as the gasifier air separation plant, syngas coolers and cleanup, gas turbine, and steam plant.

Existing IGCC demonstration plants in the U.S. have efficiencies just below 40% (LHV). Two European IGCC demonstration plants (Buggenum in the Netherlands and the Puertollano plant in Spain, both of which began operation in 1993) have higher design efficiencies of 43% and 45% (LHV), respectively. The higher cycle efficiencies are mainly due to improved gas turbine and steam plant efficiencies and better sub-system integration. Current work being done by the gas turbine manufacturers on IGCC is aimed at utilizing ultra-high efficiency H-Class gas turbines designed and developed in a DOE-funded program. The goal is to achieve an efficiency greater than 45% (LHV) and to reduce the cost. A recent estimate indicates that a 500 MW IGCC plant would cost approximately $1,300/kW in 2002 dollars. [12] At that price, IGCC plants are not economically competitive with other advanced coal-based systems. Further considerations may, in the future, tilt the balance in favor of IGCC applications, including the facts that:

- IGCC lends itself to the efficient capture and removal of CO_2 from the high pressure syngas; and
- Mercury emissions can be controlled at relatively low cost.

DOE's Vision 21 Cycle

One of the most promising advanced coal-based cycles with "zero emissions" is DOE's Vision 21 Cycle[13] (one example is presented in Figure 3-4). In this cycle, syngas produced in an oxygen-blown gasifier is cleaned to remove contaminants harmful to the gas turbine. CO_2 is also captured. The clean syngas is composed mainly of H_2 and CO. The H_2, along with compressed air, is used to generate electricity in a solid oxide fuel cell, and the CO is burned in a combustion turbine that drives the air compressor. The efficiency could reach 60% (LHV) in this "zero emission" scheme. Several advanced concepts, including Integrated Gasification Fuel Cell, might meet these ambitious goals. In this concept, high-pressure compressor exhaust is introduced into the fuel cell. The fuel cell exhaust is used in a gas turbine to produce additional power without the addition of fuel in the gas turbine. The gas turbine exhaust can then be used in the steam turbine to produce additional power. DOE estimates that 63% efficiency (LHV) is achievable by 2010[13], when it should be ready for demonstration. The combination of high efficiency and CO_2 capture will result in significant reductions in CO_2 compared to existing coal-fired technologies.

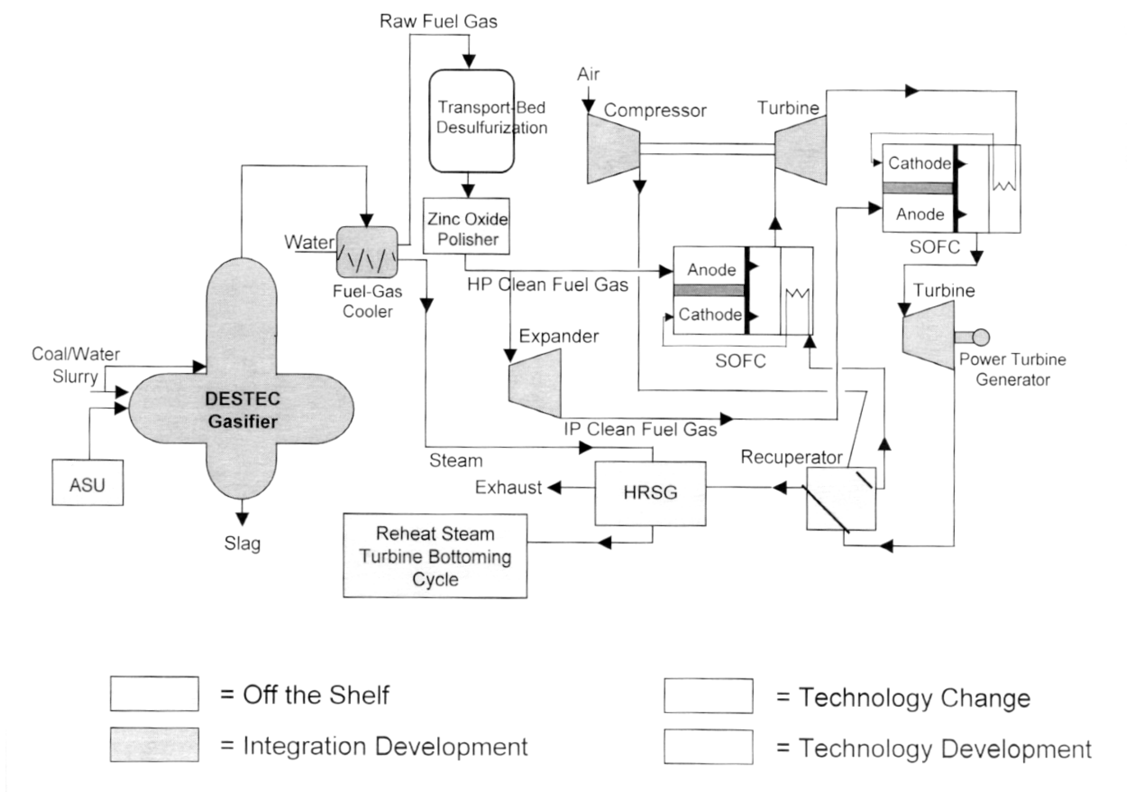


Figure 3-4. Gasification/Fuel Cell/Gas Turbine/Steam Turbine Cycle (DOE Vision 21). [11]

Comparison of CCTs

Advanced power generation schemes vary in efficiency, capability for CO_2 capture, commercial availability, and cost. Potential efficiencies of PC, PFBC, and IGCC as a function of gas turbine inlet temperature are illustrated in Figure 3-5. [14][15]). As the gas turbine inlet temperature rises, so does the combined cycle efficiency.

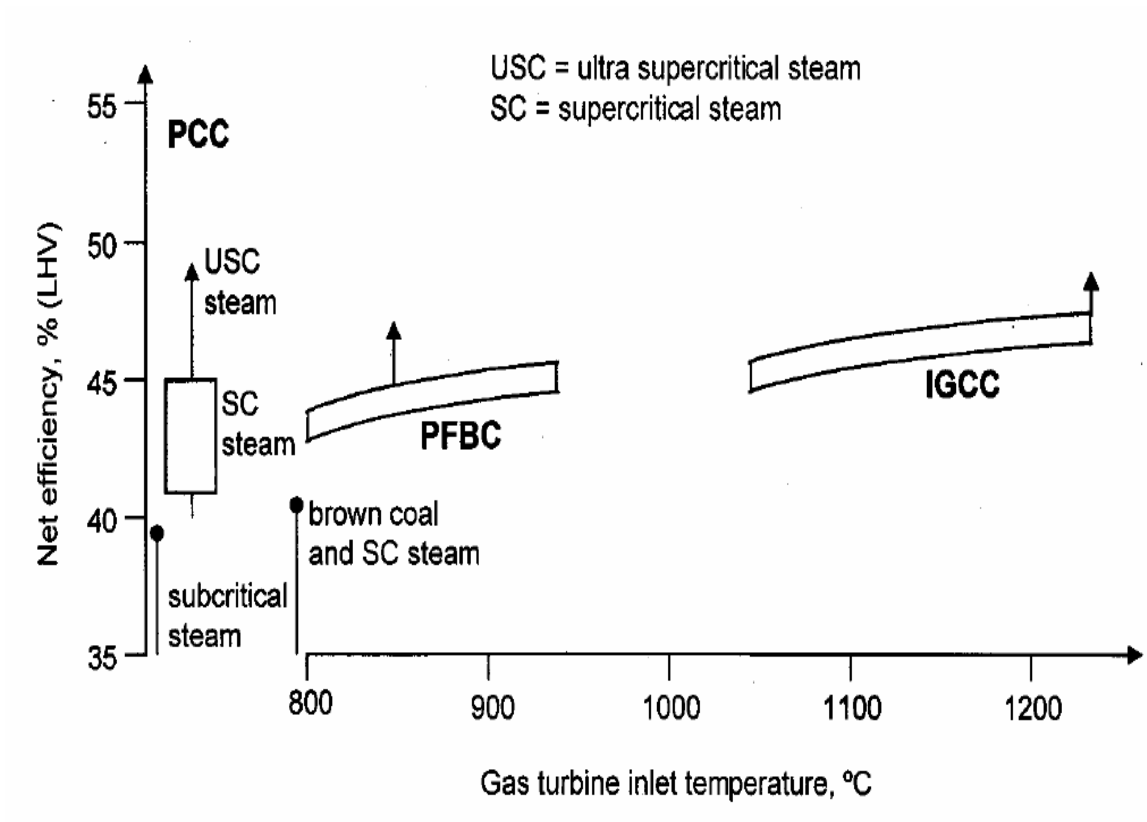


Figure 3-5. Effect of gas turbine inlet temperature on combined cycle efficiency.

Options for coal-based generation, efficiency, and CO_2 emissions are presented in Figure 3-6. The diagram shows the significant effect of the cycle efficiency upon CO_2 emissions. SOx, NOx, and PM are also proportionately reduced with increasing efficiency as illustrated by a comparison of emissions and by-products of different 600 MW plants in Figure 3-7.[16] The excellent environmental performance of IGCC is also illustrated.

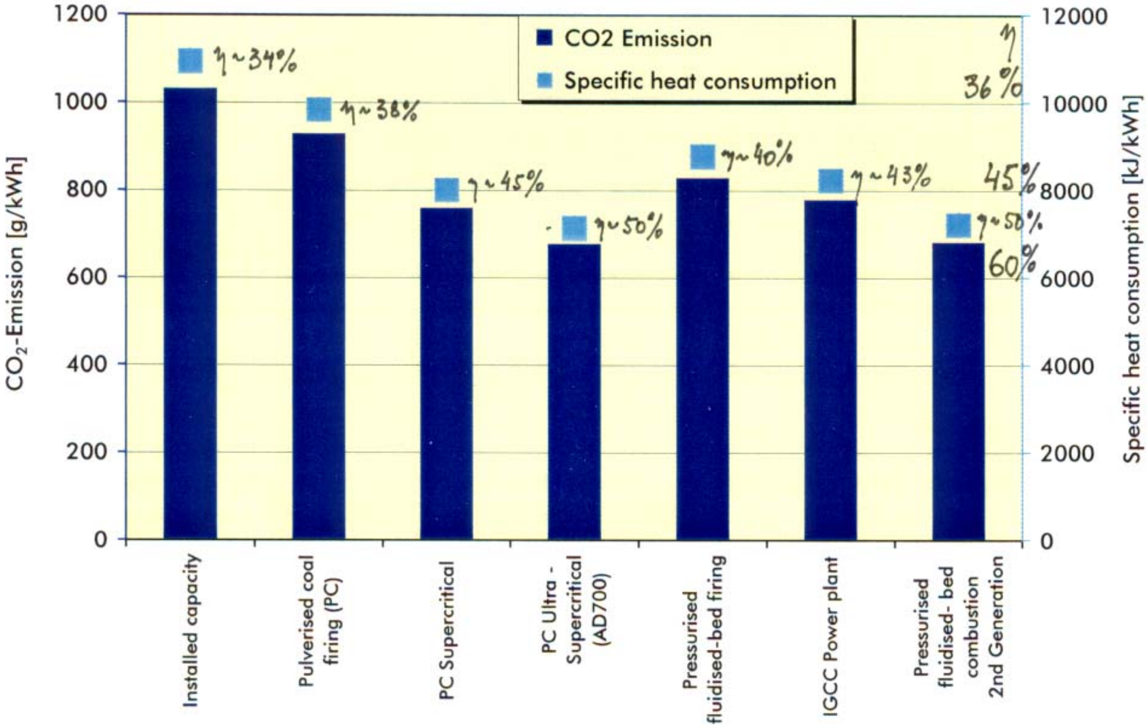


Figure 3-6. Efficiency of and CO_2 Emissions from Advanced Power Plants. (Stamatelopoulos et al. 2002) [16]
(1000g/kWh=2.205 lb/kWh and 8000 kJ/kWh=7584 Btu/kWh)

Coal/ Natural gas	Limestone		CO_2	SO_2	NO_2	Ash	Gypsum	Rejected heat (Cooling water)
[g/kWh]			[g/kWh]	[mg/kWh]		[g/kWh]		[MJ/kWh]
320	12	Pulverized-Coal-Fired Steam Power Plant η = 45%	770	560 *	560 *	32	19	4.0
300	22 **	Combined Cycle Power Plant with Pressurized Fluidized Bed Combustion η = 48%	730	525 *	525 *	Ash / Gypsum / Limestone Mix 56 **		3.2
285		Integrated Coal-Gasification C.C. Power Plant η = 50%	700	140	275	Slag 29	Sulfur 4	3.0

Figure 3-7. Comparison of emissions and byproducts for different 600 MW power plants. (after Haupt et al. 1998) [17]

The costs of the PFBCwTC and of IGCC relative to that of PC-SC units have been assessed by a team at Electricité de France)[18]. Table 3-3 shows that, at the time of their calculations, the cost of electricity (COE) produced by an IGCC plant or a PFBCwTC plant was estimated to be 16% and 7% higher, respectively, than that produced by PC-SC. The higher cost of IGCC, however, might be weighed against its superior environmental performance and its potential for CO_2 capture. In the meantime, PC-SC remains the cost-effective advanced coal-based power technology option.

Table 3-3. Advanced Power Generating Plant Costs as % of PC-SC costs. (after Delot et al. EDF 1996) [18]

Technology	PC/SC	PFBCwTC	IGCC
Space requirement (acres)	2.2	1-1.7	7
Net Efficiency (% LHV)	45	47	44.5
Capital cost (%)	100	106	118
O&M costs (%)	100	145	155
Relative COE (%)	100	107	116

Two recent EPRI Reports [19, 20] provide further support for IGCC with CO_2 removal. It is estimated [19] that, given a coal price of $1.24/MBtu, the breakeven point with natural gas combined cycle (NGCC) for the lowest COE occurs at a natural gas price of $4.00/MBtu. Above that gas price, IGCC with CO_2 removal will have lower COE than NGCC with CO_2 removal, and will produce electricity for 20% lower cost than PC-SC plants with CO_2 removal.

3.1.3 Technologies for Existing Plants

<u>Increasing the Efficiency of Existing Power Generation Equipment</u>

In order for coal to continue its role in supplying more than one-half of all electricity generated in the U.S., it will be necessary to develop advanced coal-based technologies which will be able to generate electricity at significantly higher efficiency than existing plants. A wide range of technologies, including boiler and steam turbine enhancements, are available for retrofitting existing units.

Technologies for retrofit include:

- Improved materials for steam-generation and superheater tubing;
- Steam turbine modernization improvements and upgrades;
- Control system improvements, i.e. neural networks;
- General plant efficiency improvements; and
- Consolidation of multiple, smaller inefficient units to larger, more efficient units.

Recent examples of the success of such retrofits include turbine upgrades (more aerodynamic steam paths) that were made on two 400-MW rated units to obtain an additional 25 MW per unit (a 6% increase in efficiency). No additional steam was required from the boiler. Another utility plans to replace existing turbine blades with a new, more durable blading configuration to increase the efficiency of two turbines by 4.5% each. Neural networks, which interface with existing control systems and provide real-time combustion optimization, have been shown to increase efficiency by up to 0.5%, still a notable increase. Overall, 5% efficiency increases could be readily accomplished across the fleet of existing units, at low cost.

Repowering With More Efficient Technologies
DOE's CCT Technology Program has demonstrated advanced coal-based technologies which can be used to repower existing units to become significantly more efficient. A prime example of this is repowering with 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). Repowering (or brownfield application) with IGCC results in a significant increase in efficiency. Since less fuel is used for the same amount of generation, emissions per MWh are reduced proportionally. This includes SO_2, NOx, and CO_2.

Two of the IGCC projects constructed as part of the CCT Technology Program have efficiencies of approximately 38% (HHV). With lessons learned from these facilities, as well as continued enhancements to the gasification and combined cycle portions of this technology, present IGCC technology can provide an efficiency of approximately 41% (HHV) when retrofitted to existing plants. For existing units, an improvement of 6 percentage points, from 35% to 41%, is actually a 17% increase, with emissions of CO_2 being reduced proportionally. One very good example of the size of potential CO_2 emission reductions is Global Energy's Wabash River Plant in Indiana, where an existing coal-fired power plant was repowered with IGCC. Repowering the plant resulted in a reduction in emissions of CO_2 from 0.64 lbs/MWh to 0.55 lbs/MWh, a 14% decrease.

Potential Reductions in CO_2 Emissions from Existing Plants
Given the size of efficiency increases that are currently available from either retrofitting individual technologies or repowering existing plants, significant reductions in CO_2 can be realized on the existing fleet of coal-fired capacity. The National Coal Council's 2001 report noted that 75% of existing plants could easily retrofit one or more technologies to enhance boiler and/or steam turbine efficiency. The report also noted that 25% of the existing units could be repowered with a CCT. Assuming a 5% increase in efficiency on 75% of existing plants (from efficiency enhancements), and a 17% increase on the other 25% (from repowering with existing IGCC technology), an overall 8% increase in efficiency of today's coal-fired generating plants could be accomplished. This would result in a proportional 8% decrease in emissions, including CO_2.

3.2 CO_2 Capture Technology

3.2.1 Summary

Processes for removing CO_2 from flue gas or syngas can be classified in terms of the subject gas stream's pressure and the partial pressure of CO_2 within the gas stream. Typically, low-pressure processes are applied to combustion sources and high pressure to IGCC sources of CO_2.

Low total and CO_2 partial pressure gas streams are predominantly flue gases from power plants, refinery off gases, and industrial boiler flue gases. High total and CO_2 partial pressure gas streams are less common, with the primary example being syngas from IGCC plants. Technologies used for capture of CO_2 and other gases, used in other industries, may be able to be applied to coal-based power plants for CO_2. Much work remains to be done to determine how to integrate these technologies into both combustion-based and IGCC plants. Even with sufficient R&D to make these technologies commercially available, capital and O&M costs will be significant, as will impacts on power plant efficiency.

3.2.2 Technology for Coal Combustion Applications

Conventional processes for CO_2 separation/removal from multi-component gaseous streams at atmospheric pressure include:

- chemical absorption;
- physical absorption;
- adsorption;
- gas permeation (i.e., selective membranes); and
- cryogenic cooling or cryogenic-supported absorption.

Chemical absorption is the most common of these, most frequently using organic chemical absorbents such as monoethanol amine (MEA), di-ethanol amine (DEA), methyl di-ethanol amine (DMEA), tert-ethanol amine (TEA), and 2 amino-2-methyl-1-propanol (AMP). Alkaline compounds such as sodium hydroxide, potassium carbonate, and sodium carbonate are also used.

The CO_2 that is absorbed is then removed by either raising the temperature or lowering the pressure of the amine solution to desorb CO_2. The liberated CO_2 stream usually contains small amounts of H_2S and other acidic gases, and may require further cleanup before compression and transportation to an end user or to a sequestration site.

The chief drawbacks of amine-based processes are their limited absorption and the significant amount of energy necessary to release the captured CO_2. Typically, one pound of low-pressure steam is required to liberate one pound of absorbed CO_2. Thus, the absorber and stripper towers are large and require very large amounts of heat to regenerate the amines. Amine-based systems also require large pumps to circulate liquid absorbents and heat exchangers to manage the heat released in the process, as well as large compressors that raise the flue gas pressure to 15-30 psi to compensate for the pressure drop in the absorber tower.

Physical absorbents, such as methanol, dimethyl ether of polyethylene glycol (Selexol), and other organic sorbents, dissolve CO_2 without chemical reaction. These fluids are most often used in IGCC plants where CO_2 pressure is high, and are candidates for treating flue gases from coal combustion sources. CO_2 liberation and solvent regeneration are accomplished by pressure swings or temperature swings. High cost is the primary drawback of physical absorbent technologies for PC units.

Adsorption-based CO_2 removal processes are based on the significant intermolecular force between gases and the surface of certain solid materials, such as activated carbon. The adsorbents are usually arranged as packed beds of spherical particles. Either pressure or temperature swings are employed to capture and release CO_2 in a cyclic adsorption/desorption sequence.

Adsorption processes are used commercially for CO_2 removal from industrial steam-based natural gas reformers. While they are relatively simple, the CO_2 loading and selectivity of available adsorbents is low. Since flue gas is at atmospheric pressure, some compression is necessary, particularly with pressure swing desorption. Very high CO_2 purity is obtained, but overall costs are high. Activated carbon or carbon molecular sieves would be the likely adsorbents used for CO_2 removal from PC units.

Gas separation membranes operate on the principle that porous structures permit the preferential permeation of certain gas stream components. The primary design and operational parameters for membranes are selectivity and permeability. Permeability is the major limiting factor for membranes used to remove CO_2 from flue gas, which means very large surface areas are necessary and, thus, costs are high. In order to provide an adequate driving force, the flue gas must be compressed to at least 50 psi. A two-stage separation system may be required to effectively remove CO_2 from flue gas, at about twice the cost of amine-based systems.

Gas absorption membranes consist of microporous solid membranes in contact with an aqueous absorbent. In a common arrangement, called membrane-assisted absorption, CO_2 diffuses through the membrane and is then absorbed by MEA. The equipment for this process tends to be more compact than that for conventional membrane systems. Since the captured CO_2 is in the liquid phase, it can be cost-effectively pumped to high pressure for discharge from the plant or to a sequestration site. Membrane-assisted absorption costs are comparable to that for conventional MEA absorption. Further R&D might identify a more optimal membrane/absorber coupling, improving the economics.

Cryogenic separation of flue gas constituents involves compressing and cooling the flue gas in stages to induce phase changes in CO_2 and other gases. Although cryogenic processes can lead to high levels of CO_2 recovery, the processes are very energy intensive. The cost of cryogenic CO_2 removal may not be significantly higher than for amine absorption processes.

3.2.3 Technology for Gasification Applications

Removing concentrated CO_2 from IGCC syngas, which is usually at pressures from 300-1,000 psi, allows a broader range of process options than does removal from atmospheric-pressure flue gas. As a consequence, the costs per ton of CO_2 removed from IGCC power plants are lower than for PC plants (primarily due to the higher concentration in IGCC syngas than in PC plant flue gas). Cost reductions and performance improvements for “high pressure” CO_2 removal systems are still necessary to approach the goals of DOE’s Vision 21 and the recently announced FutureGen program.

Because virtually all CO_2 control options for IGCC plants involve removal prior to syngas combustion, effective overall plant CO_2 reductions require operation of the gasifier in a "steam shifted" mode to produce less CO (which would oxidize to CO_2 in the gas turbine combustor) and more H_2 and CO_2. Although "shifting" leads to reduced power output, higher CO_2 partial pressures substantially improve CO_2 separation process performance.

CO_2 removal process candidates for IGCC plants are:

- selective physical absorption using an organic fluid such as methanol, with desorption by low-pressure steam;
- physical adsorption on activated carbon, with CO_2 regeneration by pressure swing;
- selective polyamide or ceramic membranes for CO_2 separation;
- cryogenic distillation; and
- CO_2 hydrate separation.

The most analyzed and practiced high-pressure CO_2 separation processes involve ***physical absorption*** with Selexol, Rectisol (low-temperature methanol), propylene carbonate, or other organic working fluids. CO_2 is liberated and the solvent regenerated at relatively low pressures (15-30 psi). Because the gas stream to be treated does not require compression, and because extensive heating is not required to regenerate the solvent, physical absorption processes for gasification power plants are much less energy-intensive than low-pressure processes for PC plants. However, even this lower rate of parasitic energy demand is still costly.

Adsorption processes for removing CO_2 from gasifier synthesis gas are functionally similar to those for treating flue gas. The adsorption/desorption processes are cyclic, with the most common desorption approach being pressure swing. The two main concerns being investigated by researchers are: (a) the selectivity of adsorbents to capture only CO_2, and (b) low-surface adsorbing capacity for CO_2, requiring large, costly contact areas.

Gas separation membranes have been widely explored for CO_2 capture from high-pressure synthesis gas as well as from flue gas. Membrane separation of CO_2 from light hydrocarbons has been very successful in the oil and gas industry because of its simplicity of operation, absence of moving parts, and modular construction. The main disadvantages are the limitations in CO_2 flow through the membrane and the large CO_2 pressure drop necessary to effect separation. A new class of high-temperature, high-pressure "ion transport membranes" is being developed, which may enhance the performance of membrane processes. Most of the effort associated with this research is, at present, focused on O_2 separation from air, but it may also be a promising research field for CO_2 separation.

Cryogenic separation of gas mixtures involves cooling in stages to induce selected phase changes in constituents, including CO_2. For syngas, however, water vapor in the gas stream could lead to formation of solid CO_2 hydrates and ice, which with solid CO_2 can cause major plugging problems. Because cryogenic processes are inherently energy intensive, their use for CO_2 removal in IGCC plants will constitute a major parasitic load.

CO_2 hydrate separation processes are designed to produce CO_2 clathrates in high-pressure, multi-component gaseous streams to selectively remove CO_2 and H_2S. In the SIMTECHE process, syngas (generated by a gasifier operating in a shift mode) is cooled to about 35°F and contacted with a nucleated water stream to form a CO_2/H_2S hydrate slurry. The remaining gas, containing primarily H_2 (and also N_2 if using an air-blown gasifier), is separated from the hydrate slurry in a gas/liquid separator. The CO_2/H_2S hydrate slurry can be decomposed in a "flash reactor." Performance and economic analyses suggest that this process may be substantially less energy intensive and less costly than established processes for extracting CO_2 from shifted synthesis gas and compressing it for transportation. New organic salt "promoters" have been identified, which could enable very high CO_2 separation rates. These compounds are highly soluble in water and could permit CO_2 hydrate formation at temperatures as high as 75-85°F and with low CO_2 partial pressures. Operation under these conditions should reduce both parasitic power losses and cost.

3.3 Non-CO_2 GHG Emission Reductions

3.3.1 Methane

Methane is the second most important non-water GHG, with a Global Warming Potential (GWP) 21 times as great as that of CO_2 on a mass basis, assuming a 100-year time horizon. Coal mine methane (CMM) is one of several major sources of anthropogenic methane, accounting for about 10% of anthropogenic methane emissions in the U.S. CMM is responsible for about 1% of the total GWP of all U.S. anthropogenic GHG emissions.

The total volume of CMM liberated from active mines in the U.S. in 2000 was 187 billion cubic feet. Underground mining activities alone liberated 134 Bcf of CMM (72% of U.S. total CMM). A substantial part of the CMM liberated from underground mining is recovered for use rather than being emitted. Other sources of liberated CMM include surface mines and post-mining activities (e.g., coal storage, processing, and transportation). Methane from abandoned coal mines is called abandoned mine methane (AMM), and for current purposes is considered separately from CMM. During 2000, 11.5 Bcf of AMM was liberated, with a fraction of that recovered for use. Coal bed methane (CBM) that is produced strictly for sale into natural gas pipelines (i.e., not in association with coal mining activities) is not addressed in this discussion. Table 3-4 summarizes the amounts of CMM and AMM liberated, recovered, and emitted in the U.S. in 2000.

Table 3-4. Relevant Data of U.S. CMM and AMM for 2000.

Category	Quantity, Bcf
Active Mines (CMM)	
CMM liberated	187
CMM emitted	151
CMM recovered	36
Underground mine CMM liberated	134
Underground mine CMM drained	45
Underground mine CMM drained and recovered	36
Underground mine CMM drained and emitted	9
Underground mine ventilation air methane	89
Underground mine CMM emitted	98
Abandoned Mines (AMM)	
AMM Liberated	11.5
AMM Recovered	2.5
AMM Emitted	9
Total Active Plus Abandoned Mines	
CMM + AMM liberated	198.5
CMM + AMM recovered	38.5
CMM + AMM emitted	160
Note: *This table does not consider CBM obtained solely for injection into natural gas pipelines or CBM not produced in association with coal mining.*	

Types of CMM

Methane is liberated from underground coal mines either in advance of mining, during mining activities, or after mining has occurred. The liberated methane exits the mine through drainage (degasification) systems or mine ventilation systems. In the case of abandoned underground mines, the liberated methane exits through vents or drainage systems.

When liberated in advance of mining, methane is drained through vertical boreholes drilled into the coal seam much as in conventional natural gas production. This type of CMM recovery often occurs years ahead of the mining activity. CMM that is drained in advance of mining is also considered to be coalbed methane, or CBM. This methane is often of very high quality, and acceptable for injection into natural gas pipelines. Horizontal boreholes are sometimes used for degasification in advance of, but near the time of, mining. This process often produces high-quality gas that can be recovered. However, its recovery is frequently impractical and much of this gas is emitted through boreholes to the surface or with the ventilation air.

After coal is extracted in a longwall type of underground mine, the methane can be released into the mine to mix with the ventilation air or it can be drained through vertical wells. This CMM can be of pipeline quality; however, it is often contaminated with air and must be processed prior to being injected into the pipeline.

Ventilation air is another source of methane emissions from underground coal mines. Air is drawn through underground mines, to provide a breathable atmosphere and to dilute the liberated methane to concentrations usually below 1% for safety reasons. The ventilation air mixes with liberated methane and the mixture is exhausted into the atmosphere.

Recovery of CMM and AMM for Use

The U.S. coal industry has made substantial progress in recovering and using CMM though drainage systems. Of the 134 Bcf of CMM liberated from underground mines in 2000, 45 Bcf was liberated through drainage systems. The remainder, 89 Bcf, was emitted as ventilation air. U.S. industry recovered 36 Bcf (or 80%) of the CMM liberated through drainage systems in 2000. This recovery represents an almost three-fold increase from the 13.8 Bcf recovered in 1990. The unrecovered CMM from drainage systems (9 Bcf per year) is generally low- to medium-quality gob gas or stranded gas.

During 2000, the methane liberated from underground mines but not recovered included 9 Bcf of low-quality or stranded drained gas and 89 Bcf of ventilation-air methane (VAM). VAM is the single largest source of unrecovered CMM. Although VAM is a potential fuel resource, essentially 100% of it is emitted because its capture and use is difficult due to its low methane concentration (typically 0.3% to 1.5%). This concentration is too low for use in even the most lean-burning of available combustion systems that require methane concentrations of 2% or more. The utilization of VAM currently is limited to a few isolated cases in which it can be used as combustion air in fossil-fuel-fired power plants located at the ventilation fan.

An estimated 2.5 Bcf (22%) of the 11.5 Bcf of liberated AMM was recovered for use in 2000. The total CMM plus AMM recovered in 2000 (38.5 Bcf) represents a resource of approximately 0.4 quadrillion Btu of fuel energy, and the avoided emissions are equivalent in GWP to the emission of approximately 17 $MTCO_2$ (see Table 3-5 for equivalencies). This amount of energy is much greater than the fuel plus electricity consumption of the entire U.S. coal mining industry, which was only about 0.1 quadrillion Btu in 1997. In the event that it becomes desirable to reduce coal-mining GHG emissions, it will be important to maintain and expand the recovery of CMM and AMM.

Table 3-5. Selected Equivalencies.

1 Bcf of methane	~ 21,085 short tons of methane
	~19,128 metric tonnes of methane
	~ 1.010 X 10^{12} Btu (HHV)
	~ 442,785 short tons of CO_2 GWP equivalent
	~ 120,760 short tons of carbon GWP equivalent
	~ 401,688 metric tonnes of CO_2 GWP equivalent
	~ 109,551 metric tonnes of carbon GWP equivalent

Currently, the recovery of CMM is driven by two factors: the resulting improvement in mining conditions and the value of the gas. Most of the recovered CMM is used as pipeline-quality gas, but smaller quantities are used at qualities not meeting pipeline specifications and some is used as combustion air. Technologies under development, including ultra-lean-burn turbines and methane concentration systems could expand the options available for CMM recovery and use. Future GHG reduction requirements, in conjunction with advanced recovery technologies, could easily result in increased recovery of CMM. Further development and demonstration of additional recovery and use options for CMM and AMM is recommended.

Table 3-6. 1997 Energy and Fuel Consumption by U.S. Coal Mining Industry.

Fuel or Energy	Lignite & Bituminous Surface Mines[d]	Bituminous Underground Mines[d]	Anthracite Mines[d]	Total Coal Mines	Fuel energy, Btu/unit[e] (gross)	Energy consumption 1E+09 Btu (gross)	Energy consumption quads (gross)
Electricity purchased, MWh	4203672	7061319	89914	11354905	3.4121E+06	38745	
Distillate fuel, 1000 Bbl	7420.4	655.9	97.2	8173.5	5.8270E+09	47627	
Residual fuel, 1000 Bbl	721.8	144.8	35.8	902.4	6.1880E+09	5584	
Gas, bcf	0.7	0.5	D	1.2	1.0350E+12	1242	
Gasoline, million gal	29.4	4	0.3	33.7	1.2480E+11	4206	
Coal, 1000 ton [a]	31.5	221.4	D	252.9	2.4000E+10	6070	
Coal, 1000 ton [b]	D	D	0	0	2.4000E+10	0	
Total						103473	0.1035

Coal energy production in U.S. in 1997, quads[c]	23.211
Energy used to produce U.S. coal in 1997, quads[f]	0.1035
Parasitic energy consumption in 1997 for U.S. coal industry, %	0.446

D = not disclosed

(a) produced and used in same plant

(b) purchased

(c) source: U.S. Energy Information Administration, Annual Energy Review 2002.

(d) source: U.S. Economic Census, Mining Sector, EC97N-2121A, B, C, 1999.

(e) assumes electricity is 100% efficient, values for gross Btu/unit of fuels are author's estimate.

Conversion of CMM

Because the combustion of a given mass of methane to CO_2 and water reduces its GWP by 87%, it is possible to greatly reduce the GWP of the unrecovered CMM emissions by combustion (or more precisely, oxidation) even if the fuel value of the methane is not realized. For example, CMM of sufficient concentration could be combusted in a flare. This technique is being demonstrated at a coal mine in Australia. Alternatively, CMM of low concentration, such as VAM, could be oxidized in thermal or catalytic oxidation systems. Small-scale thermal oxidation systems have been operated on VAM in both Australia and Great Britain, and there are plans to demonstrate a small commercial-scale system in a coal mine in Pennsylvania as part of a public-private initiative by the DOE.

The 98 Bcf of CMM emitted in 2000 represents the equivalent GWP of 43 $MTCO_2$. Recovery and use (or oxidation) of these methane emissions may be an attractive means of reducing GHG emissions at relatively low cost. Further development and demonstration of CMM destruction and utilization options is recommended.

Projected Costs for Further Abatement of CMM Emissions

The EPA performed a marginal abatement cost analysis for CMM and AMM. That study projects that in the year 2005 and in the absence of carbon credits, it will be possible to economically capture and use 33% of the CMM plus AMM liberated from U.S. coal mines (66.6 Bcf out of 203.5 Bcf liberated in that year). This compares with the 19% actually captured and used in the year 2000. The percentages of the total liberated CMM plus AMM that could be reduced at various levels of carbon credits are shown in Table 3-7. For example, at carbon credit values of $9.09/ton and $18.20/ton ($2.48/ton and $4.96/ton of CO_2), EPA projects that it will be possible to economically increase the amount captured and used to 39% and 48%, respectively.

Table 3-7. Marginal Abatement Costs for CMM and AMM, Projected for the Year 2005

Credit Value $/ton carbon	$/ton CO_2	% reduction
0	0	33
9.09	2.48	39
18.20	4.96	48
27.27	7.44	55
45.45	12.40	60
90.90	24.80	64
181.81	49.59	65

In the table, "% reduction" refers to the percentage of the total CMM plus AMM liberated (projected to be 203.5 Bcf in 2005) that could be captured and used at the corresponding credit value. Values have been converted to standard tons of C and CO_2.

Source: U.S. Environmental Protection Agency, "Addendum to the U.S. Methane Emissions 1990-2020: 2001 Update for Inventories, Projections, and Opportunities for Reductions", downloaded from www.epa.gov/ghginfo/pdfs/final_addendum2.pdf, last modified February 20, 2002.

3.3.2 N_2O Emissions

Background

N_2O is a highly effective GHG, with a GWP 296 times that of CO_2. Because of its long lifetime (about 120 years) it can reach the upper atmosphere, depleting the concentration of stratospheric ozone, an important filter of UV radiation. Estimates of N_2O emissions from coal combustion globally are 0.2 Mt/year, approximately 2% of total known sources.

The origin of the small amount of N_2O emitted from coal combustion is the fuel nitrogen, released both during devolatilization and char combustion.[1,2] Maximum N_2O formation occurs at about 1350°F. As the temperature rises, N_2O is increasingly reduced to NO. As a result, only a negligible amount of N_2O (0.5-2.0 ppm in the flue gas) is emitted from high temperature (>2300°F) PC combustion.

N_2O Emissions From FBC

In optimum FBC operation, there is a conflict between the lower temperature favoring sulfur capture and the higher temperature required to reduce N_2O emissions. Typical N_2O emissions in the range of 40-70 ppm (at 3% O_2) result from operation at 1472-1562°F, the optimum temperature range for sulfur capture. At higher temperatures, $CaSO_4$, the product of sulfur capture, gradually decomposes and SO_2 is released.

An inventory of N_2O emissions from FBC is shown in Table 3-8.[4] It is noted that 60 ppm N_2O emission is equivalent to 1.8% CO_2, an increase of about 15% in CO_2 emission for an FBC boiler.

Table 3-8. N_2O Emissions from FBC (from IEA Coal Research [4])

Unit Size, MWe Hard Coal	N_2O Emissions, ppmv		O_2, %	Reference
	Mean	Range		
160	40	20-60	3-4	Brown and Muzio, 1991
110	70	40-100	3-4	Brown and Muzio, 1991
70	60	20-100	6	Bonn and others, 1993
50	70	40-100	6	Kimura, 1992
40	50	40-60	3-4	Boemer and others, 1993
24	52.5	45-60	1.5-2	Boemer and others, 1993
21	50.5		6	Vitovec and Hackl, 1992
21	69		3	EER, 1991
16	68	53-83	6	Sage, 1992
14	77.5		6	Vitovec and Hackl, 1992
13	45	20-70	6	Sage, 1992
11	28		6	Sage, 1992
6.7	70		6	Svensson and others, 1993
0.7	88	25-150	6	Hulgaard and Johansen, 1992

More research is needed to understand how fuel type, boiler operating conditions, post-combustion flue gas treatment, and pressure affect N_2O emissions. Qualitative effects of FBC operating parameters upon N_2O emissions are illustrated in Table 3-9.

Table 3-9. Effect of FBC operating parameters on N_2O emissions. (after Takeshita et al.[4])

Parameter increases	N_2O emissions
Temperature	↓↓
Excess air	↑
Air staging	↓
Boiler load	↓
Limestone feed	–
Coal rank	↑
Fuel N content	↑
$SNCR-NH_3$	↑
SNCR-Urea	↑↑
SCR	–
↑↑ emission strongly increases	
↑ emission increases	
↓↓ emission strongly decreases	
↓ emission decreases	
– no effect observed	

Possibilities for N_2O Control

Several techniques have been proposed to control N_2O emissions from FBC boilers. There have been several proposals that involve adjusting the combustion process to lower the N_2O emissions.[11,12] Since temperature is the strongest factor for N_2O reduction, many of these involve various staging techniques to achieve a higher temperature at the top or downstream of the combustion zone. This may be achieved by staging the air or by introducing additional fuel. For example, the temperature of the particle-free gas at the exit from the process cyclone can be raised by after-burning, but this may require about 10% natural gas to produce an effect of about 50% reduction.[5] Similar reductions achieved by afterburning with 10% ethane or propane injection were reported from laboratory studies.[13,14] Proprietary strategies to increase FBC combustion temperatures above the stability temperature of calcium sulfate have also been developed, and it has been proposed that various catalysts, structural or powdered, may be used in or following the combustion zone to reduce the N_2O emissions.[15] Further R&D is needed to find economically attractive solutions.

PFBC emits N_2O at somewhat lower levels, but N_2O can be strongly reduced at the elevated temperature in the topping combustor of the PFBCwTC cycle.[6]

Published N_2O Emission Factors

Published emission factors represent an average emission rate from a typical emission source and, therefore, on average are applicable to other similar emission sources. However, emission rates may vary with equipment size, efficiency, and vintage, as well as maintenance and operational practices. Applicability of an emission factor to a specific emission source requires an understanding of the conditions associated with developing the emission factor or a measurement of potential bias -- information that may not be readily available.

Ideally, data quality is assessed through statistical analysis of accuracy and precision. EPA's AP-42 provides quality ratings for each of their emission factors. These are shown in Table 3-10 for the N_2O emission sources. A rating of "A" represents excellent quality data, meaning the factor is based on a large data set with a random pool of facilities in the population. Rating "B" represents above average quality, and "C" is average. A rating of "D" represents a factor with below-average quality, mainly resulting from limited data points or not having a random sample of the industry. A rating of "E" represents a poor quality factor, with a high degree of variability within the source category population.

Table 3-10. Comparison of Coal N_2O Emission Factors.

Combustion Technology	Equipment Configuration	IPCC Table 1-15, Volume 3 g N_2O/GJ (LHV)	IPCC Table 1-15, Volume 3 Converted to g N_2O/ GJ (HHV)	AP-42 Converted to g N_2O/ GJ (HHV)	AP-42 Reference Table, Year, and Quality Rating	% Difference (AP-42 vs. IPCC)
PC Bituminous	Dry Bottom, wall fired	1.6	1.5	0.5	Table 1.1-19, 9/98, E	206.2%
	Dry Bottom, tangentially fired	0.5	0.5	1.3		64.1%
	Wet Bottom	1.6	1.5	1.3		14.8%
Bituminous Spreader Stokers	With and without re-injection	1.6	1.5	0.7		129.7%
Bituminous FBC	Circulating Bed	96	91.2	57.9	Table 1.1-19, 9/98, B	57.5%
	Bubbling Bed	96	91.2	57.9		57.5%
Bituminous Cyclone Furnace		1.6	1.5	1.5	Table 1.1-19, 9/98, E	2.1%
Lignite AFBC		42	39.9	41.4	Table 1.7-4, 9/98, E	-3.6%

Early studies (prior to 1988) reported substantial levels of N_2O emissions from PC units, with levels proportional to NOx emissions. However, it was later determined that the high levels of N_2O measured were an artifact of the sampling procedure. Since 1988, measurement programs have utilized corrected sampling techniques and have measured much lower N_2O emission rates. The data cited in Table 3-8 for FBC are free from the sampling artifact, and current AP-42 emission factors in Table 3-10 also reflect these more recent results. N_2O emission values in Table 3-10 for PC and cyclone furnaces are small, their rating is poor (E), and the number of measurements is limited. In contrast, measurement data for FBC are of much higher value, and their ratings are also higher (B). When converted from to ppm (at 3% O_2), data for FBC give good agreement with those in Table 3-8.

The API GHG Emissions Workgroup, which developed the API Compendium, has begun a study of N_2O emission factors for stationary combustion sources. This study will compile additional N_2O emission measurements from an earlier API program, review literature for more recent studies, and gather data from participating petroleum companies.

The information will be evaluated to assess the quality and applicability of the emissions factors and to determine the relative contribution of N_2O emissions for different facility types. An assessment of emission factor quality or access to information from which to analyze emission factor quality is generally not available from published sources. It would benefit industry if DOE, in cooperation with EPA, were to improve AP-42 by increasing the number of N_2O emissions measurements for the different coal types and combustion technology combinations.

3.4 Carbon Sequestration

After carbon is removed from a flue or fuel gas stream, it must be "sequestered" or stored to avoid its emission into the atmosphere. While carbon capture technology is in commercial use in a number of industries, carbon sequestration technology is, except for a few relatively small-scale examples, unproven. The DOE Carbon Sequestration Program is developing a suite of technologies that have the potential to reduce GHG emissions from power generation. These systems could make a substantial contribution to efforts to meet GHG intensity goals. The availability of these systems as commercially proven technologies would be an important component of the decision-making process for any future actions taken to reduce GHG emissions.

Goals of the Carbon Sequestration Program

The NETL has summarized its vision and goals as follows (values converted to \$/ton CO_2 and standard tons):

Vision: Possess the scientific understanding of carbon sequestration options and provide cost-effective, environmentally sound technology options that ultimately lead to a reduction in GHG intensity and stabilization of overall atmospheric concentrations of CO_2.

Overarching Goals:

- By 2006, develop instrumentation and measurement protocols for direct sequestration in geologic formations and for indirect sequestration in forests and soils that enable the implementation of wide-scale carbon accounting and trading schemes.
- By 2008, begin demonstration of large-scale carbon storage options (>1 $MTCO_2$/year) for value-added (enhanced oil recovery, enhanced CBM recovery, enhanced gas recovery) and non-value-added (depleted oil/gas reservoirs and saline aquifers) applications.
- By 2008, develop (to the point of commercial deployment) systems for advanced indirect sequestration of GHGs that protect human and ecosystem health and cost no more than \$2.48 per ton of CO_2 sequestered, net of any value-added benefits.
- By 2010, develop instrumentation and protocols to accurately measure, monitor, and verify both carbon storage and the protection of human and ecosystem health for carbon sequestration in terrestrial ecosystems and geologic reservoirs. Such protocols should represent no more than 10% of the total sequestration system cost.
- By 2012, develop (to the point of commercial deployment) systems for direct capture and sequestration of GHG emissions from fossil fuel conversion processes that protect human and ecosystem health and result in less than a 10% increase in the cost of energy services, net of any value-added benefits.
- By 2015, develop (to the point of commercial deployment) systems for direct capture and sequestration of GHG emissions and criteria pollutant emissions from fossil fuel conversion

processes that result in near-zero emissions and approach a no net cost increase for energy services, net of any value-added benefits.

- Enable sequestration deployments to contribute to the President's GCCI goal of an 18% reduction in the GHG intensity of the U.S. economy by 2012.
- Provide a portfolio of commercial-ready sequestration systems and one to three breakthrough technologies that have progressed to the pilot test stage for the 2012 assessment under the GCCI.

Sequestration Technology

Several concepts for storage have been evaluated; however, technological and economic feasibility (and public acceptance) of carbon sequestration options vary depending on the locations of disposal sites and types of disposal/storage/sequestration technologies used. The capacity, effectiveness, and health and environmental impacts of various types of CO_2 disposal systems and the impacts of inadvertent releases are key areas of scientific uncertainty. Leading approaches to CO_2 storage presently include:

- Injection into deep saline aquifers or coal seams;
- Stimulation of oil and gas production;
- Disposal in depleted oil and gas reservoirs;
- Terrestrial sequestration (e.g., forestation, improved land-use practices);
- Growth of plants or algae for use as bio-fuels;
- Ocean sequestration; and
- Use as a feedstock for the manufacture of chemical products.

Potential Capacity of Sequestration Sinks

One of the most frequently asked questions related to carbon sequestration is that of storage capacity. While the conventional wisdom is that this capacity is quite large (i.e., 1000s of GtC[4] worldwide), the actual capacity is quite uncertain. This is because one first must estimate the total amount of void space available underground (or under water). Next, an estimate of what fraction of void space would be appropriate for CO_2 storage is required. For the first estimate (total void space), data are sparse. While many wells have been drilled, they have only revealed data on a small fraction of the underground. The second estimate (usable fraction) relies both on data about underground reservoirs (which data are sparse), as well as an understanding of how CO_2 would behave in these reservoirs. Despite these difficulties, estimates have been made, but there is no consensus on the numbers. It does seem safe to assume that the geologic storage capacity in the U.S. is over 100 GtC and could potentially be over 1,000 GtC. Several of the published estimates for the U.S. and the world are given below.

[4] 1 GtC = one billion (10^9) metric tons carbon. Note that 1 GtC = 3.67 $GtCO_2$. Also, current world anthropogenic carbon emissions are less than 7 GtC.

Table 3-11. The Worldwide Capacity of Potential CO_2 Storage Reservoirs.

Ocean and land-based sites together contain an enormous capacity for storage of CO_2[a]. The world's oceans have by far the largest capacity for carbon storage.	
Sequestration option	**Worldwide capacity**[b]
Ocean	1,000 – 10,000+ GtC
Deep saline formations	100–10,000 GtC
Depleted oil and gas reservoirs	100 – 1,000 GtC
Coal seams	10–1,000 GtC
Terrestrial	10 - 100 GtC
Utilization	currently <0.1 GtC/yr

[a] Worldwide total anthropogenic carbon emissions are ~7 GtC per year (1 GtC = 1 billion metric tons of carbon equivalent).
[b] Orders of magnitude estimates.

Source: Herzog, H.J. and D. Golomb, "Carbon Capture and Storage from Fossil Fuel Use," contribution to Encyclopedia of Energy, to be published (2004).

Table 3-12. Worldwide Potential for CO_2 Sequestration.

Human activity	6 GtC/yr
Forest & Soils	> 100 GtC
Geologic	300-3200 GtC
Oceans	1400-20,000,000 GtC
Deep saline aquifers	10,000 – 200,000 GtC

Source: U.S. DOE Fossil Energy website (http://www.fe.doe.gov/coal_power/sequestration/); Bruant et.al., "Safe Storage of CO_2 in Deep Saline Aquifers," ES&T, pp. 241A-245A, June 1, 2002; IPCC Workshop on Carbon Capture and Storage, Regina, Canada, 18-21 Nov 2002. See http://www.climatepolicy.info/ipcc/ipcc-ccs-2002/index.html.

Table 3-13. U.S. Potential for CO_2 Sequestration.

Deep saline aquifers	**1-130 GtC**
Natural gas reservoirs	**25 GtC**
Active gas	**0.3 GtC/yr**
Enhanced coalbed methane	**10 GtC**

Source: U.S. DOE, "Carbon Sequestration Research and Development," Rpt # DOE/SC/FE-1 (1999). page 5-5

Table 3-14. U.S. potential for sequestration.

Depleted gas fields	690 GtC
Depleted oil fields/CO2-EOR	120 GtC
Deep saline aquifers	400-10,000 GtC
Unmineable coal seams	400 GtC

Source: IPCC Workshop on Carbon Capture and Storage, Regina, Canada, 18-21 Nov 2002. See http://www.climatepolicy.info/ipcc/ipcc-ccs-2002/index.html

These studies have shown that there is substantial potential for CO_2 storage in natural reservoirs, such as deep saline aquifers or in the deep ocean. While some have estimated that the storage/disposal process may be considerably less costly than the CO_2 capture process, large-scale carbon sequestration has yet to be demonstrated and significant uncertainty remains about the economic costs and environmental impacts of the site-specific applications described above. Such issues indicate a need for further research; collaborative programs are being developed to examine many of these topics.

Certain underground geologic formations exhibit structure, porosity, and other properties that render them suitable as potential CO_2 storage sites. These structures are ones that already have stored crude oil, natural gas, brine, and CO_2 over millions of years.

CO_2 injection is practiced at numerous sites worldwide for enhanced oil and natural gas recovery (EOR and EGR, respectively). However, in the current applications of CO_2 injection for EOR and EGR, processes have not been optimized for underground CO_2 disposal, and the long-term stability of the stored CO_2 remains unknown. Furthermore, political and siting issues must be addressed before any major quantity of CO_2 can be stored underground in this manner.

Long-term storage of CO_2 in geologic formations has the potential to be feasible in the near-term. Many power plants and other large point sources of CO_2 emissions are located near geologic formations that may be amenable to CO_2 storage. Saline formations do not contain oil and gas resources and thus do not offer the value-added benefits of enhanced hydrocarbon production. However, the potential CO_2 storage capacity of domestic saline formations is enormous; estimates are on the order of several hundred years of CO_2 emissions.

The primary goal of research in this area is to better understand the behavior of CO_2 when it is stored in geologic formations in order to ensure secure and environmentally acceptable storage of CO_2. The fastest and surest means of obtaining the necessary information is to conduct field tests in which a relatively small amount of CO_2 is injected into a formation, with its fate and transport under close monitoring. The DOE program includes several such field tests, which ultimately should provide industry with tools and techniques to measure the movement of CO_2 in underground formations. These tests will provide field protocols that preserve the integrity of geologic formations.

Research and Development Requirements for CO_2 storage

1. Geologic Sequestration

Unmineable coal seams

- Coal seams that are unmineable for economic or technical reasons (e.g., depth or reserve characteristics) are potential CO_2 storage sinks.
- Existing recovery technologies should be used to evaluate the feasibility of storing CO_2 in unmineable coal seams for commercial-scale field demonstrations.
- The knowledge gained to verify and validate gas storage mechanisms in coal seams can be used to develop a screening model to assess CO_2 storage potential.

CBM production

- Carbon dioxide injection may be used to stimulate methane production from coal seams, improving the economic attractiveness of this sequestration option.
- A broad-based geologic screening model should be developed to quantify the CO_2 storage potential in CBM regions and apply the model to identify additional sites with high CO_2 storage potential.

Depleted oil reservoirs

- Research is needed to investigate down-hole injection of CO_2 into depleted oil reservoirs and conduct computer simulations, laboratory tests, field measurements, and monitoring efforts to understand the geomechanical, geochemical, and hydrogeologic processes involved in CO_2 storage.
- These observations could be used to calibrate, modify, and validate modeling and simulation needs.

Carbon storage in geologic formations

- Geologic sinks, such as deep saline reservoirs, represent some of the largest potential sequestration sinks.
- The capacity and availability of these potential sinks needs to be quantified.
- Research is needed to investigate safe and cost-effective methods for geologic sequestration of CO_2.
- Research is needed on the siting, selection, and longevity of optimal sequestration sites to lowering the cost of geologic storage.
- Monitoring techniques need to be identified and demonstrated which are cost-effective for tracking the potential for CO_2 migration in storage.

2. Terrestrial Approaches

Carbon sequestration in terrestrial ecosystems is either the net removal of CO_2 from the atmosphere or the prevention of CO_2 net emissions from the terrestrial ecosystems into the atmosphere. The terrestrial biosphere is estimated to sequester large amounts of carbon (approximately 2 billion metric ton of carbon per year). There are two fundamental approaches to sequestering carbon in terrestrial ecosystems:

(1) Protection of ecosystems that store carbon; and
(2) Management of ecosystems to increase carbon sequestration.

Research is under way to evaluate these approaches for the following ecosystems, which offer significant opportunity for carbon sequestration:

- Forest lands, including below-ground carbon and long-term management and utilization of standing stocks, understory, ground cover, and litter.
- Agricultural lands, including crop lands, grasslands, and rangelands, with emphasis on increasing long-lived soil carbon.
- Biomass croplands related to biofuels.
- Deserts and degraded lands in both below-and above-ground systems.
- Boreal wetlands and peatlands including management of soil carbon pools and conversion to forest or grassland.

3. Ocean storage

The oceans are the ultimate natural sink for CO_2 and may have potential for long-term CO_2 storage, but the environmental impacts of ocean sequestration are not adequately understood and the acceptability of empirical tests is problematic, given environmental sensitivity to marine systems. If ocean sequestration is to be accepted by the public, certain key questions must be answered.

- How well can the performance of storage be predicted?
- What will be the environmental impacts?
- Can such systems be successfully engineered?
- How can legal and jurisdictional obstacles be overcome?
- What will be the public acceptance of this idea?

4. Utilization of CO_2

Captured CO_2 could also be used for commercial purposes, such as a feedstock from which to derive chemicals. If economically feasible, such applications would offer the co-benefits of sequestering this GHG and replacing the use of other, manufactured feedstocks. CO_2 already is used for a wide range of applications in the food and petroleum industries, although in most cases the gas is not permanently stored in final products but is released to the atmosphere at a later date. The income generated from the sale of CO_2 would help to offset the cost of capturing and cleaning the gas. Significant costs would be incurred in producing chemical products and such processes generally require the input of energy, resulting in the emission of additional CO_2 if this energy is generated from fossil fuels.

The utilization of CO_2 to make chemicals is only effective as a mitigation option if, overall, less CO_2 enters the atmosphere than would otherwise have been the case. Also, the direct use of CO_2 to grow algae in order to make bio-fuels might be feasible, but only under certain conditions and in specific locations. A similar conclusion has been reached about the growth of crops to produce liquid fuels, which currently remains only an option for discussion.

Status of Carbon Capture and Sequestration Research

Funding provided by the DOE and the private sector for carbon capture sequestration research has increased considerably since the first National Coal Council report on this subject in May 2000. In FY 2002, the DOE carbon sequestration budget was around $8 million. By FY 2003, this had been increased to $42 million. As of October, 2002, the DOE/FE portfolio included 104 projects, with a total value of $162 million, with about 40% directed to carbon capture, and 60% to sequestration. Of this total, DOE funds $96 million. Significantly and importantly, the non-federal cost share ($66 million) represents 40% of the total, demonstrating a willingness on the part of private industry to invest in research partnerships to develop capture and sequestration technology, despite the uncertain need for and timing of its eventual application. Four of these research partnerships are described below.

Dakota Gasification Project (Weyburn).
The Weyburn Carbon Dioxide Sequestration Project is a $27-million research project intended to expand the knowledge of the capacity, transport, fate, and storage integrity of CO_2 injected into geological formations located in southeastern Saskatchewan, near the U.S. border with North Dakota. DOE will support this project by funding $4 million over a three-year period. The knowledge obtained from this project will enable DOE to inform public policy makers, energy industries, and the general public by providing reliable information and analysis of the geological sequestration of CO_2.

Sequestration of Carbon Dioxide in an Unmineable Appalachian Coal Seam.
Unmineable coal seams offer large, permanent storage potential for geologic sequestration of CO_2. These coal seams also represent an opportunity to sequester CO_2 while enhancing the production of coalbed methane as a value added product. CONSOL Energy is performing a seven-year R&D project to evaluate the effectiveness and economics of carbon sequestration in an unmineable coal seam in tandem with enhanced coalbed methane production. This project is a Cooperative Agreement at a total cost of $9.2 million with a 24% industry cost share.

Research and Commercial-Scale Field Demonstration for CO_2 Sequestration and Coalbed Methane Production.
In 2001, DOE awarded a $5.9 million, 70% cost-shared cooperative agreement with Advanced Resources International, BP Amoco, and Shell Oil for demonstrating existing and evolving recovery technology to evaluate the viability of storing CO_2 in deep, unmineable coal seams in the San Juan Basin in northwest New Mexico and southwestern Colorado. The knowledge gained with this demonstration effort will be used to verify and validate gas storage mechanisms in deep coal reservoirs, and to develop a screening model to assess CO_2 sequestration potential in coalbeds in the U.S.

The DOE has established a website listing all DOE-supported capture and sequestration projects (as of October 2002) and providing links to similar sites containing information on carbon sequestration research throughout the federal government and internationally. Current DOE projects are listed in Table 1 in Appendix A of this document. These project span a wide range of topics relevant to carbon capture and sequestration, including:

Separation and Capture
- Pre-combustion decarbonization
- Oxygen-fired combustion
- Post-combustion capture
- Advanced integrated capture systems
- Crosscutting science

Geologic Sequestration
- Monitoring, verification and remediation
- Health, safety and environmental risk assessment
- Knowledge base and technology for storage reservoirs

Terrestrial Sequestration
- Productivity enhancement
- Ecosystem dynamics
- Monitoring and verification

Ocean Sequestration
- Ecosystem dynamics
- Measurement and prediction
- Direct injection
- Ocean fertilization

Novel Sequestration Systems
- Biogeochemical processes
- Mineral conversion
- Novel integrated systems

3.5. GHG Management and the "Hydrogen Economy"

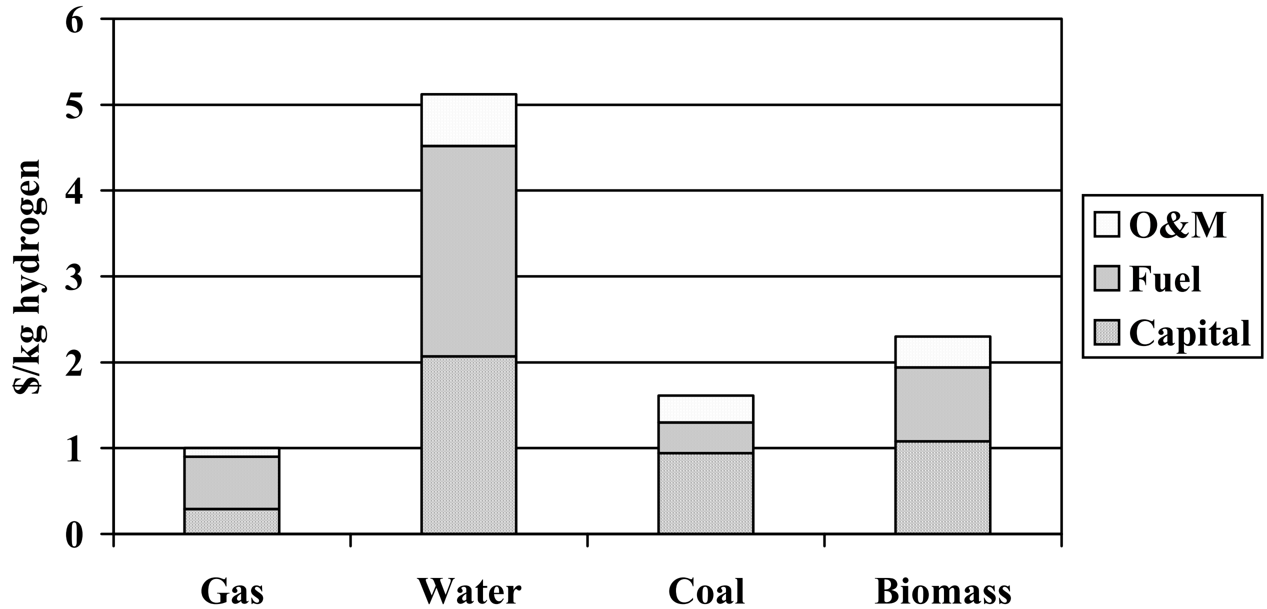
Hydrogen is called by many "the fuel of the future." However, it is important to realize that hydrogen is *not* a primary energy source like coal, oil, natural gas, wind, solar, biomass, hydro, nuclear, etc. Instead, like electricity, it is an energy carrier. As a result, hydrogen must be produced from the same array of primary energy sources that we use to produce electricity. Therefore, hydrogen is not in direct competition with coal as a fuel, but presents an opportunity to develop a new market for coal as a major feedstock for hydrogen production.

Figure 3-8 shows costs for the production of hydrogen from four possible sources: gas, coal, biomass, and water (via electrolysis).[5] This case assumes a central plant design of 165 ton/day of hydrogen with compression of the product to 1,100 psi, suitable for pipeline transportation. Costs of transmission and distribution are not included in this figure. Hydrogen is produced from natural gas by steam reforming, from coal and biomass by gasification, and from water by

[5] Data from Simbeck and Chang, Hydrogen Supply: Cost Estimate for Hydrogen Pathways – Scoping Analysis, NREL/SR-540-32525 (July 2002).

electrolysis (electricity is from the grid). Gas prices used were \$3.50 per MBtu and coal prices were \$1.10 per MBtu.

Figure 3-8. Hydrogen Production Costs



At relatively low natural gas prices, the lowest-cost hydrogen is produced from a natural gas feedstock, as is the case today in much of the commercial marketplace. However, the break-even price is very sensitive to natural gas cost. Other studies indicate an even lower break-even price for hydrogen from coal (at a gas price of \$3.15-\$4.00/MMBtu for gas, compared to \$1.00/MMBtu for coal). At the time of this report, the forward curve for gas did not go below \$4.00/MMBtu for any time that is currently traded. Therefore, if gas prices remain high or rise in the future (or gasification technology becomes less costly), coal is or would become the lowest cost feedstock. This is one of several similarities that can be drawn between hydrogen production and electricity production. It should also be noted that producing hydrogen from electrolysis is very expensive when compared to other options.

The cost and energy penalties for CO_2 capture from hydrogen production via gas, coal, or biomass are relatively small. This is because to produce hydrogen from hydrocarbon feedstocks, the capability to remove CO_2 is an integral part of the process. On the other hand, for CO_2-free hydrogen production from electrolysis, one must use CO_2-free sources of electricity. Since these are significantly more expensive than the current fuel mix, one can expect that hydrogen costs will grow significantly from those indicated in Figure 3-8. In the case of producing CO_2-free hydrogen, the advantage for using coal or gas will be even greater than the differential shown in Figure 3-8.

Just as coal plays a major role in the production of electricity, it has the potential to do the same for hydrogen. The added costs for CO_2 capture and storage will be significantly lower for hydrogen production than for electricity production. Since gasification is the preferred route of producing hydrogen from coal, implementing gasification technologies will position coal to take advantage of this potential new market should a hydrogen economy evolve.

3.6 International R&D Partnerships

3.6.1 Bush Administration Climate Change Policy

President Bush's climate plan announced on February 14, 2002, consists of long-term and short- to medium-term components. One component is a stated goal to "promote new and expanded international policies to complement the domestic program." The President's plan specifically cites the following examples of international cooperation:

- Investing $25 Million in Climate Observation Systems in Developing Countries. In response to the National Academy of Sciences' recommendation for better observation systems, the President has allocated $25 million and challenged other developed nations to match the U.S. commitment.
- Tripling Funding for "Debt-for-Nature" Forest Conservation Programs. Building upon recent Tropical Forest Conservation Act (TFCA) agreements with Belize, El Salvador, and Bangladesh, the President's FY '03 budget request of $40 million to fund "debt for nature" agreements with developing countries nearly triples funding for this successful program. Under TFCA, developing countries agree to protect their tropical forests from logging, avoiding emissions and preserving the substantial carbon sequestration ability therein. The President also announced a new agreement with the Government of Thailand that will preserve important mangrove forests in Northeastern Thailand in exchange for debt relief worth $11.4 million.
- Fully Funding the Global Environmental Facility (GEF). The Administration's FY '03 budget request of $178 million for the GEF is more than $77 million above this year's funding and includes a substantial $70 million payment for arrears incurred during the prior administration. The GEF is the primary international institution for transferring energy and sequestration technologies to the developing world under the UNFCCC.
- Dedicating Significant Funds to the U.S. Agency for International Development (USAID). The President's FY '03 budget requests $155 million in funding for USAID climate change programs. USAID serves as a critical vehicle for transferring American energy and sequestration technologies to developing countries to promote sustainable development and minimize their GHG emissions growth.
- Pursue Joint Research with Japan. The U.S. and Japan continue their High-Level Consultations on climate change issues. Later this month, a team of U.S. experts will meet with their Japanese counterparts to discuss specific projects within the various areas of climate science and technology, and to identify the highest priorities for collaborative research.

- Pursue Joint Research with Italy. Following up on a pledge of President Bush and Prime Minister Berlusconi to undertake joint research on climate change, the U.S. and Italy convened a Joint Climate Change Research Meeting in January, 2002. The delegations for the two countries identified more than 20 joint climate change research activities for immediate implementation, including global and regional modeling.

- Pursue Joint Research with Central America. The U.S. and Central American Heads of Government signed the Central American-United States of America Joint Accord (CONCAUSA) on December 10, 1994. The original agreement covered cooperation under action plans in four major areas: conservation of biodiversity, sound use of energy, environmental legislation, and sustainable economic development. On June 7, 2001, the U.S. and its Central American partners signed an expanded and renewed CONCAUSA Declaration, adding disaster relief and climate change as new areas for cooperation. The new CONCAUSA Declaration calls for intensified cooperative efforts to address climate change through scientific research, estimating and monitoring GHGs, investing in forestry conservation, enhancing energy efficiency, and utilizing new environmental technologies.

3.6.2 Bilateral Partnerships

Since its climate change policy was announced, the Bush Administration has also announced a number of bilateral partnerships (*see* Table 3-15) focused on collaborative efforts meant to address climate-related issues. Examples of opportunities for cooperation that may result in significant GHG reductions include, but are not limited to, CCT and CO_2 capture and storage technology development, expanded use of cogeneration and renewable sources of energy, as well as concrete ways of reducing GHG emissions through sustainable agriculture and forestry management practices.

Recommendation

Current efforts at forming bilateral partnerships are important steps in addressing the policy issue of global climate change. However, absent in most of the agreements is a particular emphasis on identifying opportunities to pursue collaborative CCT and CO_2 capture and storage technology development projects. In recognition of its vast U.S. coal reserves, the DOE has been one of the world's major funders of carbon sequestration RD&D. It is of vital importance that the U.S. now engage other nations in funding new CCT RD&D and pursue policies advocating upgrades or replacement of older coal-fired power stations around the globe with newer, more efficient technologies.

The DOE, acting as a principal agent of the U.S. within the bilateral partnerships, should perform the role of information clearinghouse on the partnerships' various efforts to develop CCT and CO_2 capture and storage technology development projects. Such a role could be accomplished by enhancing the existing materials on the agency's website (http://www.fe.doe.gov/international).

TABLE 3-15		
Date	**County**	**Partnership Agreement Details**
July 19, 2001	Italy	Pledge joint research in several critical areas, including: − atmospheric studies related to climate − low-carbon technologies − global and regional climate modeling − carbon cycle research
Feb. 27, 2002	Australia	Focus will be on such issues as: − emissions measurement and accounting − climate change science − stationary energy technology − engagement with business to create economically efficient climate change solutions − agriculture and land management − collaboration with developing countries to build capacity to deal with climate change
Feb. 28, 2002	Japan	The Partnership's priority research areas include: − improvement of climate models making use of the "Earth Simulator" and research on earth processes for modeling − impact and adaptation/mitigation policy assessment employing emission-climate-impact integrated models − observations and international data exchange/quality control − research on greenhouse gas (GHG) sinks including LULUCF (land use, land-use change and forestry) − research on polar regions − development of mitigation and prevention technologies such as separation, recovery, sequestration and utilization of carbon and GHGs − research and development of renewable and alternative energy technologies, resources, and products, as well as energy efficiency measures and technologies
Mar. 7, 2002	Canada	Both countries have agreed to pursue increased bilateral cooperation that will focus on such issues as: − climate change science and research − technology development − carbon sequestration − emissions measurement and accounting − capacity building in developing countries − carbon sinks − targeted measures to spur the uptake of cleaner technology and market-based approaches
May 6, 2002	India	The two sides announced their intention to enhance ongoing collaborative projects in: − clean and renewable sources of energy − energy efficiency − energy conservation

Date	Country	Partnership Agreement Details
Oct. 24, 2002	New Zealand	Themes for potential enhanced cooperation might include: – climate change science and monitoring in the Pacific; – assistance to developing countries, particularly Pacific Island states – climate change research in Antarctica – cooperation in the development of emission unit registries – GHG accounting in forestry and agriculture – technology development aimed at carbon reduction technologies
Jan. 16, 2003	China	The U.S. and China identified 10 areas for cooperative research and analysis: – non-CO_2 gases – economic/environmental modeling – integrated assessment of potential consequences of climate change – adaptation strategies – hydrogen and fuel cell technology – carbon capture and sequestration – observation/measurement – institutional partnerships – energy/environment project follow-up to the World Summit on Sustainable Development (WSSD) – existing clean energy protocols/annexes
Jan. 17, 2003	Russia	– Discuss and exchange information related to climate change policy and related scientific, technological, socioeconomic, and legal issues of mutual concern and interest. – Explore possible common approaches to addressing climate change issues before the United Nations Framework Convention on Climate Change, the Intergovernmental Panel on Climate Change, and other relevant international arenas. – Identify and encourage needed climate change science and technology research that is or could be performed individually or jointly by U.S. and Russian departments, agencies, ministries, and scientific institutions. – Benefit from and complement other established bilateral activities between the two countries.

SECTION 4:
ACHIEVING GREENHOUSE GAS EMISSION REDUCTIONS – CHALLENGES AND COSTS

4.1 Assessing the Costs of CO_2 Capture and Sequestration

Although there is some consensus in the literature on the approximate cost of currently available CO_2 capture and storage (CCS) technologies, published cost estimates still vary widely (by as much as a factor of two). Cost estimates for many advanced technologies currently under study or development offer an even broader range of values. In some studies, CO_2 abatement costs are reported not for a specific technology, but on a sector-wide or nationwide basis (e.g., for the electric power industry, or the U.S. economy as represented by the GDP).

In this section of the report, we discuss some of the factors that underlie these differences and cloud a simple answer to what many believe is the simple question: How much does it cost to capture and sequester CO_2 emissions from power plants?

4.1.1 Defining the System Boundary

The first requirement of any economic assessment is to clearly define the "system" for which CO_2 emissions and cost are being characterized. The most common assumption in economic studies of carbon sequestration is a single power plant that captures CO_2 and transports it to an off-site storage area such as a geologic formation. The CO_2 emissions not captured are released from the power plant stack along with other emissions.

Other system boundaries that are used in reporting CO_2 abatement costs for a single facility include the power plant only, without CO_2 transport and storage. Alternatively, costs sometimes include CO_2 emissions over the complete fuel cycle that encompasses the mining, cleaning, and transportation of coal used for power generation, as well as any emissions from by-product use or disposal. Emissions of other GHGs are included in some analyses.

Still larger systems might include all power plants in a utility company's system, all plants in a regional or national grid, or a national economy where power plant emissions are but one element of the overall energy system being modeled. In each of these cases it is possible to derive a mitigation cost for CO_2, but the results are not directly comparable because they reflect different system boundaries and considerations.

4.1.2 Defining the Technology of Interest

Costs will vary with the choice of CCS technology and the choice of the power system that generates CO_2 in the first place. In studies of a single plant or technology, such definitions are usually clear. But where larger systems are being analyzed (as in regional or national studies), some of these choices may be unclear. The context for reported cost results is then unclear as well.

4.1.3 Defining the Technology Time Frame

Another factor that is often unclear in economic evaluations is the nature or basis of the assumed time frame for technology costs, particularly for "advanced" technologies that are not yet commercial. Such cost estimates frequently reflect assumptions about the "n^{th} plant" to be built sometime in the future when the technology is mature. Such estimates reflect the expected benefits of technological learning. The choice of time frame and assumed rate of cost improvements can make a big difference in CCS cost estimates.

4.1.4 Different Measures of Cost

Several different measures of cost are used to characterize CCS systems. Because many of these have the same units (e.g., \$/ton CO_2), there is great potential for misuse or misunderstanding.

One of the most widely used measures in studies of individual technologies is the "cost of CO_2 avoided." This is defined as:

$$\text{Cost of } CO_2 \text{ Avoided} = \frac{(COE)_{capture} - (COE)_{ref}}{(CO_2/kWh)_{ref} - (CO_2/kWh)_{capture}}$$

This value reflects the average cost (\$/ton CO_2) of reducing atmospheric CO_2 emissions by one unit of mass (nominally 1 ton), while still providing one unit of electricity to consumers (nominally 1 kWh). Thus, the choice of both the capture plant and the reference plant without CO_2 capture and storage plays a key role in determining the CO_2 avoidance cost. Usually, the reference plant is assumed to be a single unit the same type and size as the plant with CO_2 capture. If there are significant economies of scale in power plant construction costs, differences in power plant size also can affect the cost of CO_2 avoided.

A measure having the same units as avoided cost can be defined as the difference in net present value of projects with and without CCS, divided by the difference in their CO_2 mass emissions. Unless the two projects produce the same net power output, the resulting cost per ton is not the cost of CO_2 avoided; rather, we call it the "cost of CO_2 abated." Numerically, this value can be quite different from the cost of CO_2 avoided for the same two facilities.

The marginal or average cost of CO_2 abatement for a *collection of plants* (as in a utility system, regional grid, or national analysis) also can be expressed in terms of \$ per ton of CO_2 reduced. These results depend on a host of assumptions about the technologies and fuels included in the analysis (including fuel price projections). Results from such studies have a different meaning than those from studies of a single plant or technology.

Arguably, the impact of CO_2 abatement on the COE is most relevant for economic, technical and policy analyses. For a single plant or technology, the COE can be calculated as:

$$\boldsymbol{COE = [(TCR)(FCF) + (FOM)]/[(CF)(8760)(kW)] + VOM + (HR)(FC)}$$

TCR = total capital requirement ($),
FCF = fixed charge factor(fraction/yr),
FOM = fixed operating costs ($/yr),
VOM = variable operating costs ($/kWh),
FC = fuel cost ($/kJ),
CF = capacity factor (fraction),
8760 = hrs/yr
kW = net plant power (kW).

Thus, many factors affect the COE (and hence, the cost of CO_2 avoided as well). Cost studies can differ widely in their assumptions about these factors. For example, assumptions about the plant capacity factor have a large impact on the calculated COE.

For a variety of reasons, cost studies often do not report all of the key assumptions that affect the cost of CO_2 control. For example, the total capital requirement includes the cost of purchasing and installing all plant equipment, plus a number of "indirect" costs that typically are estimated as percentages of total plant cost.[10] Assumptions about such factors (such as contingency costs) can have a pronounced effect on cost results. Further, some CO_2 cost studies exclude certain items (like interest during construction and other "owner's costs") when reporting total capital cost and COE. Thus, the use of terms like "total plant cost" doesn't always mean what it seems. Unless such assumptions are transparent, results can easily be misunderstood.

Finally, for studies involving multiple plants (often using different fuels and technologies), aggregate cost results, such as a change in the average COE, reflect a much larger set of assumptions than cost estimates for a single plant. Macroeconomic studies of a national economy, in which energy costs are but one element of a complex modeling framework, offer cost measures such as the change in GDP from the imposition of a carbon constraint. These reflect myriad assumptions about the structure of the economy and the values of specific model parameters. Such results are far more difficult to understand fully, in terms of the influence of particular assumptions on reported results.

4.2 Economics of CO_2 Capture and Sequestration

4.2.1 Impacts of GHG Reduction Requirements on Existing Coal-Based Plants

Future GHG emission constraints would affect the price and availability of electricity — two factors that could have a profound impact on the U.S. economy. Because coal is abundant domestically and its price is low and stable relative to other fossil fuels, the predominance of coal-based power plants has helped keep U.S. electricity affordable, reliable, and secure.

If stringent CO_2 reduction requirements are imposed, the cost of electricity and the balance in the fuel mix could change dramatically. CO_2 removal technologies would be unprecedented in their cost and energy consumption, compared to the emission controls for SO_2, NOx, and particulates adopted over the last 30 years. In the absence of commercially available CO_2 capture and sequestration technologies, near-term (<10-12 years) CO_2 emission reduction requirements would likely force many coal-fired plants to be retired prematurely. This would likely lead to a further surge in the construction of new NGCC plants. Such a shift would place tremendous to tie electricity prices ever more tightly to the price of natural gas, a fuel with a much more volatile price history than coal. While the historic price differential of gas to coal is about 2:1, recent trends and availability projections may make that gap even greater in the future. Under this scenario, higher natural gas price prices would result in great impacts on the cost of electricity, and on the economy in general.

4.2.2 Technical Challenges of CO_2 Removal and Sequestration at Coal-Based Plants

The key challenges for CO_2 removal are energy use and cost. The key challenge of long-term storage or sequestration is the fate of the CO_2 (how well it will stay sequestered). The leading candidates for demonstrations to gain experience with CO_2 removal at coal-based plants are solvent absorption/stripping processes that are commercially used in other industries. Only modest work has been completed to date on adapting these technologies for use in existing power plants. Serious technical and economic challenges remain both within the CO_2 removal step itself and in pre-process cleanup of the gas stream to remove trace constituents that would contaminate the solvents.

In PC plants with today's commercial technology, CO_2 would be removed from flue gas in an absorber vessel using a solvent such as MEA. The CO_2 would next be stripped from the solvent via heat in a separate vessel, and the solvent returned to the absorber column. The heating requirements reduce the net power plant output. Because flue gas is at atmospheric pressure, and is composed primarily of nitrogen from the combustion air, the partial pressure of CO_2 (the key parameter determining the necessary solvent quantity, equipment size, and regeneration energy) is low. This results in large and costly CO_2 removal equipment. For example, the MEA process will increase the wholesale COE for a new, high-efficiency PC-SC plant by approximately 60% and consume about 29% of the plant's energy output.

IGCC plants offer the opportunity for CO_2 removal at a lower incremental cost and with a lower energy penalty because the removal step can be performed on high-pressure/high CO_2 concentration syngas prior to its combustion in the gas turbine. The partial pressure of CO_2 is higher if the gasifier is oxygen-blown (rather that air-blown), and the synthesis gas is "shifted" to convert CO to CO_2. A physical solvent absorption/stripping method, such as the Selexol process, appears most promising for bulk CO_2 removal. A DOE-EPRI study suggested that coal-based IGCC systems might be the most economical option for new generating capacity *if* CO_2 removal is required and *if* goals for reducing IGCC cost and improving availability are met.

and Natural Gas

In 2000, DOE and EPRI conducted a comprehensive engineering economics study (subsequently updated in 2002[6]) to look at new plant economics and design for CO_2 removal. This study developed engineering and cost estimates to:
(1) predict the cost and performance impacts of MEA absorption/stripping applied to conventionally designed PC plants and NGCC plants, and those of the Selexol process applied to IGCC plants; and
(2) identify which coal plant options would most effectively compete with NGCC plants if 90% CO_2 removal were required.

The plant designs evaluated in the study were intended to represent the next generation of commercially available power systems: PC plants with SC and USC steam conditions, IGCC plants with H-Class gas turbines, and NGCC plants with F-Class and H-Class gas turbines.

Key results from this study include (values converted to tons of CO_2):

- The levelized cost per metric ton of CO_2 removed was \$17.73 for IGCC units, \$38.55 for USC PC units, and \$54.91 for NGCC units with H-Class turbines.
- If 90% CO_2 removal were required for new fossil fuel power plants, and the constant dollar cost of coal remains at approximately its current rate of \$1.26/MBtu, then NGCC plants appear to offer the lowest levelized COE up to a natural gas price of \$3.64/MBtu. If the constant dollar cost of natural gas were higher, then IGCC plants would have the lowest COE.
- For 90% CO_2 removal, IGCC plants appear to have a COE up to \$18/MWh (~ 25%) lower than PC plants.

4.2.4 Strategies for an Economically Feasible Transition to a CO_2-Restricted Environment

There are approximately 305 GW of coal-fired generating capacity in the U.S. Eighty percent of this existing capacity will be at least 30 years old by 2007. The capital costs and efficiency penalties for retrofitting this fleet with current CO_2 removal technology would be considerably higher than the values discussed above for new plants. However, the existing plants are likely to continue operation for decades, and thus will represent the greatest source of coal-related CO_2 emissions for the foreseeable future. Therefore, the development of cost-effective CO_2 removal technology for retrofit application to existing plants, while a great technical challenge, is a worthwhile research target.

Retrofits would be costly because of the usual retrofit considerations, such as space constraints and site access difficulties, and because of difficulties in installing the equipment required for

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[6] *Evaluation of Innovative Fossil Fuel power plants with CO_2 Removal* US DOE and EPRI Report December 2000, EPRI report number 1000316. *Updated Cost and Performance Estimates for Fossil Fuel Power Plants with CO_2 Removal* US DOE and EPRI, Palo Alto CA., U.S. Department of Energy, Office of Fossil Energy Washington, D.C.

absorption/stripping amines or cause corrosion problems. The cost of retrofitting CO_2 removal systems based on current technology would be prohibitive for most coal-based power plants, and many might be replaced with NGCC, despite concerns about natural gas price volatility and fuel diversity.

A recent study by EPRI[7] provided costs to remove CO_2 and upgrade existing emission controls at existing plants. The cost is estimated to be much higher than for new plants. The capital cost for a variety of emission control schemes, including retrofitting CO_2 scrubbers, or retrofitting O_2 combustion and recycle, all exceeded $1,000/kW, doubling or tripling the COE.

Given the significant cost and performance issues for retrofitting existing CO_2 control technologies on existing coal-based plants, which provide the basis for low-cost electricity in the U.S., it may be appropriate to allocate R&D dollars toward the development of more cost-effective removal options for both new and existing plants. Such an effort should include not only a means to better adapt existing solvent-based techniques to coal-based power plants, but also to explore promising novel technologies now in the laboratory or conceptual stage of development.

Because CO_2 removal methods appear much more energy-efficient and cost-effective when applied to IGCC plants, R&D to improve the cost and reliability of the power block portions of IGCC plants will be a crucial complement to work on CO_2 removal systems. Because the nature and timing of CO_2 reduction requirements are uncertain, the development of "phased" IGCC plant designs, in which plants are built to accommodate later installation of CO_2 removal technology, could help avoid retrofit burdens.

IGCC may only become broadly competitive with PC and NGCC plants under a CO_2-restricted scenario. Therefore, vendors currently do not have an adequate economic incentive to invest R&D dollars in IGCC advancement. Similarly, power companies are not likely to pay the premium to install today's IGCC designs in the absence of clear regulatory direction on the CO_2 issue. Therefore, accelerating the development of low-cost, low-CO_2-emitting CCTs, such as IGCC, will require substantial cooperation and funding from both public and private sources.

4.3 <u>The Need for Large-Scale Demonstrations</u>

4.3.1 R&D Timeframe

As with any major new technology with enormous financial, environmental, and energy security ramifications, CO_2 sequestration technologies cannot be considered commercially ready until they are successfully proven at full-scale, under "real-world" conditions, for a period of time adequate to assure expectations of prolonged safety and reliability. Any demonstration needs to convince prospective public-sector and private-sector investors that the costs and risks are sufficiently understood and acceptable so as to enlist the commitment of manufacturers and service providers, financiers and insurers, state and local authorities, as well as the public.

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[7] *Options for Removing Multiple Pollutants Including CO_2 at Existing Coal-Fired Power Plants*, EPRI, Palo Alto

Given the diverse make-up of the coal-based generating fleet, the wide variation in the types and properties of regionally economical fuels for power production, and the tremendous range of terrestrial ecosystems and subsurface geological features found across the U.S., effective national deployment of carbon sequestration measures will require the development and commercialization of a ***portfolio*** of CO_2 capture and disposal technologies.

To begin to populate a commercial sequestration technology portfolio over the medium term (i.e., 8-15 years), development and/or refinement of the most defined promising options and pilot-scale demonstrations must begin immediately. Commercial success at full scale will require the effective integration of technologies for capturing CO_2 at power plants, safely transporting it to disposal sites, and assuring that placed CO_2 will remain sequestered from the atmosphere for centuries. Therefore, addressing integration issues in conjunction with the pilot-scale demonstrations will accelerate their resolution at full scale.

4.3.2 CO_2-Capture Technologies

Because a requirement for CO_2 emissions reductions much greater than those attainable through efficiency improvement could occur before any substantial turnover in the capital stock of U.S. power plants, capture technology RD&D should concentrate on systems suitable for retrofit to today's PC units and for incorporation in coal repowering projects. Successful development of such retrofit and repowering technology would not only satisfy domestic needs, but also position the U.S. to be a technology exporter because PC plants are the predominant type of generating unit throughout the world.

Another priority for CO_2-capture technology RD&D should be the development of systems for IGCC plants. As a major DOE-EPRI evaluation of potential capture technologies found, the incremental cost and energy penalty for CO_2 removal from IGCC syngas is much lower for PC flue gas. IGCC plants can also accommodate low-grade fuels and offer the potential for co-production of steam and clean transportation fuels, making them attractive for new coal capacity, assuming that goals for cost reduction and availability improvement can be met.

Because the costs and energy penalties for the most-developed CO_2-capture technologies (i.e., those that are commercial in other, albeit smaller, industrial applications) appear high, two parallel research paths are recommended for the near term (within the next 5-7 years):

- Refine, to the extent practical in a short period, the processes that are commercial in other industries and are adaptable to large coal-fired power plants. Then begin demonstration testing at "flexible" pilot-scale facilities. These pilot-scale facilities would accommodate equipment configurations to allow testing of multiple processes, including those that are not yet ready at the commencement of initial tests, thereby avoiding the expense and time delay of having to build a separate pilot plant for each candidate process. This approach will advance capabilities in technology assessment, help researchers gain experience in running pilot CO_2-capture tests, and produce CO_2 gas streams with trace constituents representative of "real-world" power plants, which is vital for sequestration demonstrations.

promise lower cost, the production of easier-to-place solid products, and greater public acceptance. Emphasizing more "fundamental" research is important because breakthroughs in cost and energy use for commercially available chemical and physical processes are not expected.

4.3.3 PC Plants

The commercial technology most cited as potentially applicable to capturing CO_2 from the large volumes of flue gas produced by PC power plants is MEA absorption/ stripping. DOE and EPRI have estimated that the MEA process will increase the wholesale COE for a new, high-efficiency SC-PC plant by about 60% and consume about 29% of the plant's energy output. The cost and energy penalties for most existing PC plants, which have lower-efficiency subcritical steam conditions, will be considerably higher.

There are opportunities for improvement. Pilot-scale demonstrations of MEA scrubbing at power plants would allow researchers to experiment with designs that use less energy and, therefore, reduce the COE increase. Parametric testing could correlate MEA scrubbing performance as a function of fuel type, gas temperature, concentration of minor or trace flue gas constituents, such as SO_2, and other factors. Multiple pilot units will be required to span the full range of conditions present in the U.S. generating fleet.

Since the use of MEA-based systems will lead to significant reductions in efficiency for coal-based power plants, continuing to work solely with this technology will likely not provide the performance or economics needed for low-cost GHG emission reductions. Since these systems require significant amounts of energy, more fuel resources will be utilized in the long run in order to overcome the lost power output. Development of other processes that utilize a new generation of solid and liquid sorbents with low regeneration energy may provide the needed answers. One alternative is the use of high temperature CaO-$CaCO_3$ cycles that operate above the thermodynamic power cycle and potentially do not reduce efficiency.

Pilot-scale testing also provides insight into the scalability of equipment to full scale. By leveraging the "best-of-breed" process conditions and equipment designs from a series of pilot-scale demos, large-scale demonstrations can be conducted at lower risk of material and other "nuisance" failures, thereby helping to assure cost-effective development of information suitable for commercialization decisions.

4.3.4 IGCC Plants

The commercial technologies that appear most promising for removing CO_2 from IGCC syngas are derived from acid-gas cleanup methods used in the oil and gas industry, such as the Selexol process. Selexol, in particular, also has been used in conventional IGCC units (i.e., those without CO_2 capture) for removing H_2S and COS from syngas to prevent corrosion in downstream heat exchangers and the combustion turbine.

CO_2 emissions, they require that the gasifier be operated in a "shift" mode to produce syngas with more H_2 and CO_2 and less CO. Selexol and other candidate processes for CO_2 capture from IGCC power systems exact a smaller loss in the plant's energy output, relative to MEA processing of PC plant flue gas, because the volume of syngas to be treated is approximately 1/200th of that involved in treating post-combustion flue gas

According to a DOE-EPRI study, the total incremental cost of CO_2 removal from an IGCC plant could be only about 40% of that from a PC plant. The overall relative competitiveness of IGCC plants and PC plants with CO_2 removal is unclear, and depends on future relative capital costs, fuel costs, availability rates, and non-fuel O&M costs. Under one scenario examined by DOE and EPRI, an IGCC plant's COE could be as much 25% lower than that of a PC plant. Given such projections, developing and commercializing CO_2-capture technologies for IGCC plants would be vital to improving the economics of clean coal power systems.

As with PC plants, multiple IGCC demonstrations would be necessary given the substantial differences in the major types of gasifier designs and in the properties of regionally economical IGCC fuels.

4.3.5 Novel CO_2-Capture Technologies

Current candidate technologies for CO_2 capture from PC and IGCC units will remain relatively energy intensive and expensive. Over the near- to mid-term, it will be crucial to accelerate development and pilot-scale testing of novel CO_2 removal processes. Today, numerous novel processes have shown promise on the basis of conceptual evaluations and/or laboratory tests, but need refinement and subsequent testing at bench and pilot scale to assess their true potential and scalability. Such processes involve myriad physical, chemical, and biological principles. Examples include membrane separation, biomimetic reproduction of the enzyme used by mollusks to repair damaged shells (which then is used as gas scrubbing medium), chemical looping, mineralization, microbe/genetic engineering, oxyfuel combustion, and more.

4.3.6 CO_2-Sequestration Technologies

Because carbon sequestration requires the safe storage of CO_2 or other carbonaceous compounds and associated trace substances for indefinite periods, determining the capacity, effectiveness, and health and environmental impacts of CO_2 disposal options may require demonstrations lasting a decade or more (to assure confidence in the environmental integrity of storage sites and methods). It is highly desirable to begin such demonstration projects as soon as possible using CO_2 gas streams as "realistic" as possible in terms of the trace constituents produced by CO_2-capture process applied to coal-fired power plants.

Public acceptance of carbon sequestration demonstrations, let alone full-scale applications, can be expected to vary depending on the location(s) of storage sites and the types of storage technology used. In general, public acceptance is likely to be highest for terrestrial solutions (e.g., tree planting) and for geologic solutions involving pre-existing formations—such as depleted oil and gas wells.

In the intermediate and long-term, geologic solutions offer significant potential for CO_2 storage capacity. Terrestrial options, such as forests, require long-range planning and may take 25-50 years to reach full capacity but they may have collateral benefit (habitat creation, enhanced agricultural practices, ecological restoration, etc.) which mean that they should be implemented early. Currently, the injection of CO_2 into geological formations is practiced at numerous sites worldwide for EOR and EGR.

Small-scale demonstrations of geologic CO_2 disposal options could establish a benchmark for trace leakage and help gauge risks for rapid release. Over the medium term, larger-scale demonstrations of geologic solutions as well as pilot-scale demonstrations of the potentially more complex oceanic disposal will be necessary to ensure sufficient CO_2 disposal capacity to support significant CO_2 emissions reductions via sequestration.

R&D should also evaluate novel sequestration options that produce stable, solid products, ideally with a market value to help offset processing costs. DOE's Albany Research Center is already experimenting with CO_2-rich "bricks."

4.3.6 The Value of Integrated Demonstrations

Integrated demonstrations, in which power plant CO_2 capture, transport, and disposal components are combined, are critical to improving the industry's understanding of the real-world feasibility of carbon sequestration in terms of costs, health and environmental impacts, risks, legal and liability issues, and public acceptability.

Early insights in this regard could prove highly valuable in terms of informing today's decisions on technology selection and siting for new power plants that would make them more or less amenable to subsequent CO_2-capture technology retrofits.

Large-scale integrated demonstrations also give power plant owners, technology developers, financiers and insurers, and policymakers greater confidence that successful demonstration results portend collective movement of all the necessary market actors toward true, self-sustaining commercialization of carbon sequestration technology.

4.3.7 Challenges

Key challenges include securing funding for multiple large-scale demonstrations and, especially for CO_2 disposal, obtaining permits from local governments. Addressing the funding issue will require strong public-private partnerships. In some cases, the power industry may work closely with other industrial sectors, such as where valuable products could be co-produced and sold in the process of disposing of CO_2 (e.g., EOR, EGR, or CBM production). Local permitting agency concerns may be addressed through education programs designed to accurately present potential risks and benefits of carbon sequestration. Leveraging small-scale demonstrations to gather data prior to large-scale storage projects will help researchers quantify these risks.

The recently announced Presidential FutureGen Sequestration and Hydrogen Research Initiative could well serve as a major platform for developing CO_2 sequestration in conjunction with coal gasification. This initiative will speed the development of hydrogen production based on coal and of CO_2 sequestration technologies applicable to coal gasification. This program also matches the recommendation of the National Research Council's Review of Vision 21 in which they recommended..."The Vision 21 program should continue to sharpen its focus. It should focus on the development of cost-competitive, coal-fueled systems for electricity production on a large scale (200-500 MW) using gasification-based technologies that produce sequestration - ready CO_2 and near-zero emissions of conventional pollutants." This program also should meet specific gasification development and sequestration goals developed in joint industry-government roadmapping documents such as those developed in conjunction with DOE/ EPRI and CURC (refer to http://www.coal.org/rdmap.htm).

This unique facility is envisioned to provide R&D capability to allow testing of novel equipment under realistic conditions and may carry a significant share of U.S. R&D activities. It will still be necessary to have multiple demonstrations or combinations of pilot and demonstration projects to cover differing gasification designs, or designs not based on gasification technology, with differing coals, and differing regional types of sequestration.

4.4 Future Programs for Voluntary Actions

4.4.1 Summary

The federal government has established or is establishing several programs to address the technical, environmental and societal challenges to widespread adoption of GHG management technologies by private industry. Three of these programs are highlighted in this report: Regional Partnerships for Carbon Sequestration; the Climate VISION Program, and the Carbon Sequestration Leadership Forum.

Under the ***Regional Partnerships*** program, DOE has called for proposals to identify the opportunities and impediments to carbon sequestration, recognizing the distinct differences likely for different geographic regions. These projects, conducted over the next two years, are intended to lead to larger scale field tests of promising sequestration options on a regional basis.

In February, 2002, the President announced the goal of reducing GHG intensity by 18% over the next decade, and called on private industry to work in partnership with the government to meet this goal. In February, 2003, DOE responded by announcing agreements with the major industrial sectors[8] to participate in its ***Climate VISION*** program, creating voluntary public-private partnerships administered by the DOE, to pursue cost-effective initiatives that will reduce the projected growth in America's GHG emissions.

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[8] Oil and Gas Production, Transportation and Refining, Electricity Generation, Coal Production and Mining, The Portland Cement Association (PCA) , The American Iron and Steel Institute (AISI), The Semiconductor Industry Association (SIA), Magnesium Coalition and the International Magnesium Association, The American Chemistry Council (ACC), The Aluminum Association, The Association of American Railroads (AAR), The Alliance of

On February 27, 2003, the Departments of State and Energy announced the formation of the ***Carbon Sequestration Leadership Forum***, a ministerial-level international organizational focus on development of carbon capture and storage technologies as a means to stabilizing atmospheric GHG concentrations. The partnership will promote coordinated research and development with international partners and private industry, including data gathering, information exchange, and collaborative projects.

4.4.2 Regional Partnerships for Carbon Sequestration

Among the many elements of its GHG management program, the DOE has issued a solicitation[9] to establish "regional partnerships" to facilitate the development and use of technology for the capture, transport, and storage of CO_2 from anthropogenic sources throughout the U.S. This concept recognizes that patterns of fossil fuel use, and the nature and location of potential sequestration sinks differ widely throughout the U.S. As a result, distinctly different regional approaches may be required if the country as a whole is going to address the issue of CO_2 in a cost effective manner. In addition to the technological factors affecting the regional sequestration option, social, legal and regulatory issues (including permitting requirements and public acceptance) need to be addressed on a regional and local basis.

DOE envisions these issues being addressed by a number of regional partnerships, which would include fuel producers, energy producers, consumers, industrial entities, the academic and research community (academia and environmental advocacy organizations), and state agencies.

The regions will be defined by the participants in a partnership based on commonality of technical, economic, and political interests. The specific objectives set out by DOE for Phase I of the regional partnership program include:

- Defining the geographical boundary of the region;
- Characterizing the region for its sources, potential sinks, and key infrastructure requirements, such as CO_2 transportation mechanisms;
- Developing action plans which identify and address critical issues for wide-scale use of the most attractive regional sequestration approaches;
- Defining mechanisms to ensure public awareness and acceptance of carbon sequestration; and
- Analyzing the results of the foregoing steps to identify the most attractive options in a regional context on the basis of economic, environmental, and social criteria to select prime candidates for future large-scale demonstrations.

Under Phase II of the program, participants would conduct small-scale field tests to demonstrate the validity of the sequestration options identified in the assessment and analysis phase of this program.

[9] DE-PS26-03NT41713 "Regional Carbon Sequestration Partnerships – Phase I". The due date for proposals was

million to each for initial Phase I planning. As much as $7 million could be provided to partnerships for the field verification tests and further regulatory and infrastructure assessment expected to be conducted in Phase II.

4.4.3 Industrial Commitments to Voluntary Emissions Reductions Under the Climate VISION Program

On February 14, 2002, President Bush committed to reducing America's GHG intensity (the ratio of emissions to economic output) by 18% in the next decade. On February 12, 2003, the DOE announced the Administration's Climate VISION (Voluntary Innovative Sector Initiatives: Opportunities Now) Program, a voluntary, public-private partnership to pursue cost-effective initiatives that will reduce the projected growth in America's GHG gas emissions. Climate VISION will be administered through the DOE's policy and international program. The industry sectors which announced their participation and their stated goals are described below.

Oil and Gas Production, Transportation and Refining
The API proposed to increase the energy efficiency of members' U.S. refinery operations by 10% from 2002 to 2012 through reduced gas flaring and other energy efficiency improvements, expanded combined heat and power facilities, increased by-product utilization, and reduced CO_2 venting. API members will develop GHG management plans to identify and pursue opportunities to further reduce emissions.

Electricity Generation
EEI and six other power sector groups[10] formed the Electric Power Industry Climate Initiative (EPICI) to reduce the sector's carbon intensity. The EPICI will pledge to reduce the power sector's carbon impact in this decade by the equivalent of 3-5% through increased natural gas and CCT, increased nuclear generation, offsets, and expanded investment in wind and biomass projects.

Coal Production and Mining
The National Mining Association (NMA) committed to achieving a 10% increase in the efficiency of those systems that can be further optimized with processes and techniques developed by DOE and made available through the pending NMA-DOE Allied Partnership. The commitment includes steps to recover additional CMM, expansion of land reclamation, carbon sequestration efforts, and coal and mining research.

The Portland Cement Association (PCA)
PCA has committed to reduce CO_2 emissions by 10% per ton of cement from a 1990 baseline by 2020 through enhancements to the production process, the product itself, and how the product is applied.

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[10] National Rural Electric Cooperative Association, the Nuclear Energy Institute, the American Public Power Association, the Large Public Power Council, the Electric Power Supply Association, and the Tennessee Valley Authority.

Thirty-three member firms, representing nearly three-quarters of the nation's steel-producing capacity, have committed to achieving a 10% increase in sector-wide average energy efficiency by 2012 from 1998 levels.

The Semiconductor Industry Association (SIA)
SIA committed to reduce a suite of the most potent GHG emissions (HFC, PFC and SF6 "perfluorocompounds") by 10% from 1995 levels by the end of 2010. EPA estimates that this will reduce emissions by over 13.5 MMTCE in the year 2010, or the equivalent of eliminating GHG emissions from 9.6 million cars.

Magnesium Coalition and the International Magnesium Association
Magnesium Coalition and the International Magnesium Association companies have committed to eliminate sulfur hexafluoride (SF6) emissions from their magnesium operations by 2010, which will have a climate benefit equivalent to eliminating 1.4 MMTCE in GHG emissions.

The American Chemistry Council (ACC)
The ACC, whose members operate 90% of the chemical industry production in the U.S., has agreed to an overall GHG intensity reduction target of 18% by 2012 from 1990 levels through increased production efficiencies, promoting coal gasification technology, increasing bio-based processes, and by developing products which increase energy efficiency in other sectors

The Aluminum Association
The Aluminum Association is committed to reducing sector-wide GHG emissions. Through one of the first voluntary partnerships with EPA in 1995, the Voluntary Aluminum Industry Partnership (VAIP) reduced perfluorocarbon (PFC) emissions in 2000 by over 45% compared to 1990 levels.

The Association of American Railroads (AAR)
The AAR has committed to reducing the transportation-related GHG intensity of their Class 1 railroads by 18% in the next decade.

The Alliance of Automobile Manufacturers (AAM)
AAM has agreed to reduce GHG emissions from its members' manufacturing facilities by at least 10% by 2012, based on U.S. vehicle production from a 2002 baseline by installing energy efficient lighting, converting facilities' coal and oil power sources to cleaner natural gas, and upgrading ventilation systems.

The American Forest and Paper Association (AF&PA)
AF&PA members expect to reduce their GHG intensity by 12% by 2012 relative to emissions levels in 2000 through the Sustainable Forestry Initiative program, recycling, avoiding landfill methane emissions, and increasing carbon storage.

On February 27, 2003, the Departments of State and Energy announced the formation of the ***Carbon Sequestration Leadership Forum***, a ministerial-level international organization focusing on enhancing international opportunities related to GHG management. The partnership will promote coordinated research and development with international partners and private industry, including data gathering, information exchange, and collaborative projects.

An inaugural meeting, scheduled for June, 2003, will involve presentations by government, the private sector, and non-governmental organizations on the status of sequestration research and the technical, economic, and public policy challenges that must be addressed. A Ministerial Roundtable will be held to discuss the Forum and each country's goals in participating.

The Carbon Sequestration Leadership Forum does not change any of the existing bilateral agreements that the U.S. has with many countries. Instead, it is intended to focus the efforts of the international community specifically on carbon sequestration as one option in an overall GHG mitigation strategy.

In that regard, it is worth noting that, at its meeting on February 19-21, 2003, the IPCC[11] gave formal approval to the writing of a Special Report on CO_2 Capture and Storage as a climate change mitigation option. The report will be written under the auspices of Working Group III (WGIII) on Mitigation. The Energy Research Centre of the Netherlands (ECN) operates the Technical Support Unit for WGIII. The Special Report will take two years to complete, with delivery planned for the first half of 2005. A workshop to prepare a scoping paper for this report met November 18-21, 2002, in Regina, Canada (workshop proceedings available at http://www.climatepolicy.info/ipcc). According to that scoping paper, reasons to proceed with this report include:

- CO_2 capture and storage is an emerging technology option with a very high mitigation potential. It has been suggested that about half the world cumulative emissions to 2050 may be stored at costs comparable to other mitigation options.
- The keen interest in this subject is demonstrated by plans considered by several leading industrial countries to invest in this emerging technology in the coming years.
- There is a growing interest in the scientific and technical community in the subject of CO_2 capture and storage, demonstrated by the growing availability of the literature.
- Policymakers have a growing need for a reliable synthesis of the available scientific literature in order to facilitate the decision making process on the plans for CO_2 capture and storage as a climate change mitigation option.

[11] The IPCC has been established by WMO and UNEP to assess scientific, technical and socio- economic

4.5.1 Incentives for New and Existing Facilities

Background

It is likely that existing coal-fired plants will continue to provide the bulk of our nation's electricity for decades to come, unless political decisions are made which force their retirement for economic reasons. Ultimately, economic and technical factors will make it necessary to build new power plants to replace retiring capacity and to meet load growth. As indicated in this report, significant reductions in CO_2 emissions can be achieved in the near term by increasing the efficiency of the existing generating fleet. Moreover, replacement of the existing units with new, more advanced CCTs can further increase fleet efficiency, and reduce CO_2 emissions. Finally, new plants can be designed to facilitate CO_2 capture and sequestration, if this becomes necessary, and technologically and economically feasible. Therefore, three principal elements of a strategy to reduce CO_2 emissions, while continuing to utilize our domestic coal resources are to increase efficiency on the existing generating fleet, replace existing capacity or add new capacity with more highly efficient advanced technologies, and prepare for possibility that carbon capture and sequestration may be necessary in the future.

An analysis of the previously reported actions under Section 1605(b) of the Energy Policy Act demonstrates that private companies are willing to take voluntary actions to reduce GHG emissions if technological and financial risks and rewards are acceptable. However, the goal of advancing new technology can be accelerated if incentives are available to offset the incremental risk taken on in early full-scale demonstrations and deployment of the most advanced technologies. These incentives can take the form of financial instruments intended to reduce the financial risk engendered by the technical uncertainty inherent in the demonstration or early use of new technology.

Two important components of federal policy in this regard are cost-sharing by the federal government in the first-of-a-kind demonstration of new technology, and tax incentives to encourage replicate deployment of demonstrated technologies. The latter is particularly important for encouraging investment in capital intensive technologies such as central-station coal-fired power plants. The argument is that some number of these new technologies needs to be built to move along the technology along a "learning curve" that reduces the technical risk and cost to the point that plants can attract conventional commercial financing.

This concept is embodied in the National Environmental and Energy Technology (NEET) legislation which has been introduced in both the House and the Senate.

Under NEET, tax incentives are provided for the installation of CCT that increases thermal efficiency and reduces emissions at coal-fired power plants. The bill includes provisions for existing and new plants. For existing facilities, the bill provides a production tax credit of \$0.0034/kWh for retrofitting or repowering of units to meet the energy efficiency and emission requirements qualifying it as CCT as defined in the bill.

For new units, NEET provides a 10% investment tax credit, and production tax credits of varying amounts, depending on the year in which the unit goes into operation and the efficiency (heat incentive increases as the efficiency of the unit increases.

4.5.2 Addressing regulatory issues

In some instances, environmental regulations can have the effect of impeding actions that would otherwise result in the reduction or sequestration of greenhouse gases. Two examples are cited here: reclamation requirements affecting carbon sequestration on mined lands; and interpretation of New Source Review regulations affecting the ability of power plants to make efficiency improvements.

1. Statutory and regulatory impediments to terrestrial sequestration at mining sites.
Opportunities exist for more CO_2 to be sequestered at surface coal mining reclamation sites by changing the laws, interpretations of laws, and local practices of mine reclamation to allow for more effective approaches to reforestation. Practices and laws governing post-mining land use, approximate original contour requirements, topsoil requirements, and revegetation requirements need to be addressed in order to promote increased forestation.

Post Mining Land Use. The Surface Mining Control and Reclamation Act (SMCRA) established that all areas disturbed during mining be restored in a timely manner to: (1) conditions that are capable of supporting the uses which they were capable of supporting before any mining; or (2) higher and better uses under certain criteria and procedures.

If land was not forested before mining, some jurisdictions have ruled that reforestation is not a higher and better use of the land. In particular, this is the case in the Midwest where pre-mine lands are designated as prime farmland. With the significant potential for CO_2 sequestration on mining lands through reforestation, State and Federal regulatory agencies should allow reforestation as a higher beneficial post-mining land use. This would require no change in regulation, just a change in classification.

Approximate Original Contour Requirements. Mining laws require that the land surface be returned to the approximate original contour (AOC) that existed prior to mining or an approved postmining topography (PMT) for thin overburden mines. The action of heavy equipment required to transport, backfill, and grade the material needed to create a narrowly defined AOC/PMT results in a highly compacted soil surface.

Highly compacted soils decrease tree survivability and do not allow for rapid and large tree growth. Reclamation regulations or enforcement practices should be changed to allow more flexibility in this area. This would reduce the intensity of grading, thus enabling an environment for proper tree growth and survivability, as well as enhancing CO_2 sequestration.

Topsoil Requirements. Topsoil removal, segregation, storage, and replacement are required in many jurisdictions. Some jurisdictions also require that topsoil be replaced at a uniform thickness.

In many areas of the country, larger and faster tree growth can be demonstrated by using mixed reclaimed surfaces, even though varying depths are found in the premining environment. Using thicker topsoil in valleys and thinner on peaks would help foster a more diverse vegetation cover. Flexibility in topsoil requirements would help to increase reforestation and the re-establishment of shrubs, also enhancing CO_2 sequestration.

Revegetation Requirements. SMCRA requires that mine permit holders establish a diverse, effective, and permanent vegetative cover of species native to the area to support the planned post-mining uses of the land. While this provision allows for non-native species of plants to be used, local regulation has not always allowed for this to happen. In order to maximize CO_2 uptake, non-native vegetation may need to be allowed.

2. ***New Source Review.***
A wide range of technologies are available for improving efficiency at coal-fired power plants. These include improvements in materials, upgrades of boiler pressure parts, burner improvements, and new designs for steam turbine blades. Such efficiency increases, as previously noted, would result in fewer GHG emissions per unit of fuel burned. As the Council noted in its May, 2001, report, "Increasing Electricity Availability from Coal-Fired Generation in the Near Term," the change in enforcement procedures by EPA (reinterpreting as violations of the Clean Air Act what had previously been considered routine maintenance at power plants) has had a direct and chilling effect on all maintenance and efficiency improvements at existing power plants.

At issue is whether or not these changes would in fact result in increased emissions of various pollutants, and if the utilities in question should have submitted permit applications prior to doing the maintenance or making the efficiency upgrades. EPA contends that certain methods of calculating future emissions could show increases, which would require that emission control systems would need to be retrofitted, at great cost and with significant project delay, negating any achievable increases in efficiency.

Over the past several years, EPA has continued to pursue the legal action, while at the same time proposing potential "fixes" to the new source review definitions, calculation methods, and enforcement. With some of the companies "settling" their cases, other cases being handled in venues in various states, and EPA continuing to re-propose various regulatory "fixes," it is likely that various outcomes will occur, making it even more difficult for utilities to determine how to proceed on what would otherwise have been the "right" thing to do, with improvements in efficiency being stalled. As the Council noted previously, legislative action to make the appropriate corrections on a nationwide basis may be the best option to promote efficiency improvements that would led to lower emissions of GHGs from coal-fired power plants.

4.5.3 Transition Issues for Coal Generation

Implementing the technologies described in the previous sections of this 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 is necessary due to the desire to minimize technical and financial risk on the parts of the generating companies and the

Coal-fired power plants, once thought to be facing a rapid demise, now are 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 interdependent areas:

- Developing public/private partnerships to fund technology development and demonstrations;
- Creating tax and other incentives to encourage investment in technology development and implementation;
- Designing a technology rollout strategy to implement new technologies while reducing the associated technology and financial risks; and
- Managing an institutional transition to address public policy, regulatory, and environmental/ ecological issues.

4.5.4 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. CCTs, such as USC and IGCC power plants, have the potential for conversion efficiencies of >50% (LHV). 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, and of its superior environmental performance, to compete in the next seven to 10 years.

Timely advances in coal technology cannot be achieved without a significant increase in RD&D 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. 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 may not be feasible in today's electricity generation business environment. Public-private consortia are emerging as a mechanism to provide the needed resources for technology development. 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 CCT Program, and is working well to sustain interest in the current Vision 21 program. It is anticipated that it will be successful in the FutureGen program as well.

Although these programs encourage private sector participation in the technology development process, the current funding levels are not adequate to develop and commercialize the 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 1800°F);
- Gasifiers for high-ash, high-moisture coals;
- Enhanced trace element monitoring; and
- Char combustion and gasification.

4.5.4 Investment Incentives

Government action should not be limited to research funding. There is a clear role for government in supporting the deployment of CCT to improve fuel diversity and reduce emissions. Without a strong advanced technology development 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 emissions control requirements.

It is possible to define a tax and incentive package aimed at boosting the maximum generation efficiency of coal-based power plants to 50% or higher (LHV). Achieving these goals would produce significant environmental benefits.

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

- 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.

4.5.5 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 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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APPENDIX A
SELECTED TABLES & FIGURES

Project Title	Performer Type	Performer	Project Start Date	Project End Date	Total Estimated Cost	DOE Share
Ocean Carbon Sequestration	Gov't Agency	Department of Navy - Naval Sea Systems Command	07/07/1999	03/30/2003	$576,094	$576,094
Terrestrial Sequestration of CO_2	Gov't Agency	USDA - Forest Service - Southern Research Station	09/07/1999	09/29/2004	$75,000	$25,000
Carbon Capture and Water Emissions Treatment System (CCWESTRS) at Fossil-Fueled Electric Generators	Gov't Agency	Tennessee Valley Authority	09/17/2000	09/29/2003	$1,289,007	$729,007
Chemical Fixation of CO_2 in Coal Combustion Products and Recycling Through Algal Biosystems	Gov't Agency	Tennessee Valley Authority	09/17/2000	09/29/2002	$755,291	$604,233
Economic Evaluation of CO_2 Sequestration Technologies	Gov't Agency	Tennessee Valley Authority	09/17/2000	07/30/2002	$1,321,113	$1,056,890
CO_2 Capture by Absorption with Potassium Carbonate	State Univ.	University of Texas at Austin	03/31/2002	03/31/2005	$728,007	$461,849
Laboratory Investigations in Support of CO_2-Limestone Sequestration in the Ocean	State Univ.	University of Massachusetts	03/31/2002	03/31/2004	$267,840	$206,290
Calcium Carbonate Prod. by Coccolithophorid Algae in Long-Term CO_2 Sequestration	State Univ.	California State University San Marcos	04/30/2001	04/25/2004	$306,846	$212,371
Atomic Level Modeling of CO_2 Disposal as a Carbonate Mineral	State Univ.	Arizona State University	06/11/1998	07/30/2002	$369,225	$199,697
P-H Neutral Concrete for Attached Microalgae & Enhanced CO_2	State Univ.	Louisiana State University	07/14/1998	05/14/1999	$50,373	$50,373
Optimal Geological Environments for CO_2 Disposal in Saline Reservoirs	State Univ.	University of Texas at Austin, Bureau of Economic Geology	07/23/1998	07/14/2004	$404,434	$404,434
Reactive, Multi-phase Behavior of CO_2 in Saline Aquifers Beneath the Colorado Plateau	State Univ.	University of Utah - OSP	08/08/2000	08/12/2003	$428,049	$342,412
Separation of Hydrogen and CO_2 Using a Novel Membrane Reactor	State Univ.	North Carolina A&T State University	08/18/1999	08/30/2002	$199,963	$199,963
High Temperature CO_2 Semi-Permeable Dense Ceramic Membranes	State Univ.	University of Cincinnati	08/24/2000	08/30/2002	$57,195	$49,999
An Innovative Concept for CO_2-Based Tri-generation of Fuels, Chemicals, and Electricity Using Flue Gas in Vision 21 Plants	State Univ.	Pennsylvania State University - University Park	08/29/2000	11/29/2001	$50,000	$50,000
Oxygen-Enriched Coal Combustion with CO_2 Recycle and Recovery	State Univ.	University of Utah - OSP	08/30/2000	05/29/2002	$49,719	$49,719

Project Title	Performer Type	Performer	Project Start Date	Project End Date	Total Estimated Cost	DOE Share
Preliminary Characterization of CO_2 Separation and Storage Properties of Coal Gas Reservoirs	State Univ.	University of Arizona	09/11/2001	09/10/2002	$49,997	$49,997
Development of Superior Sorbents for Separation of CO_2 From Flue Gas at a Wide Temperature Range During Coal Combustion	State Univ.	University of Cincinnati	09/17/2001	09/16/2002	$57,650	$50,000
Enhancement of Terrestrial C Sinks Through Reclamation of Abandoned Mine Lands in the Appalachians	State Univ.	Stephen F. Austin State University	09/19/2000	09/18/2003	$839,504	$628,169
Understanding Olivine CO_2 Mineral Sequestration Reaction Mechanisms at the Atomic Level: Optimizing Reaction Process Design	State Univ.	Arizona State University	09/19/2001	09/18/2002	$77,113	$49,170
Enhancing the Atomic Level Understanding of CO_2 Mineral Sequestration Mechanisms via Advanced Computational Modeling	State Univ.	University of Arizona	09/19/2001	09/18/2004	$262,545	$195,717
Active Carbonation: A Novel Concept to Develop an Integrated CO_2 Sequestration Module for Vision 21 Plants	State Univ.	Pennsylvania State University - University Park	09/23/2001	09/22/2002	$55,000	$50,000
CO_2 Sequestration and Recycle by Photosynthesis	State Univ.	University of Akron	09/23/2001	09/22/2004	$266,620	$199,965
Novel Nanocomposite Membrane Structures for Hydrogen Separation	State Univ.	University of Texas at Austin	09/26/2001	09/25/2004	$200,000	$200,000
Maximizing Storage Rate and Capacity and Insuring the Environmental Integrity of CO_2	State Univ.	Texas Tech University	09/27/2000	09/30/2003	$2,618,393	$2,081,348
Enhanced Practical Photosynthetic CO_2 Mitigation	State Univ.	Ohio University	09/27/2000	09/30/2003	$1,369,495	$1,075,022
Unminable Coalbeds & Enhancing Methane Production Sequestering CO_2	State Univ.	Oklahoma State University	09/28/1998	03/14/2003	$876,175	$820,649
CO_2 Sequestering Using Microalgal Systems	State Univ.	University of North Dakota Energy and Environmental Research Center	09/30/1998	03/30/2003	$0	$0
Geologic Screening Criteria for Sequestration of CO_2 in Coal: Quantifying Potential of the Black Warrior Coalbed Methane Fairway, Alabama	State Agency	Geological Survey of Alabama	09/28/2000	10/04/2003	$1,398,068	$789,565
CO_2 Removal from Natural Gas	Small Business -	Carbozyme,Inc.	08/26/2001	05/25/2002	$100,000	$100,000

Project Title	Performer Type	Performer	Project Start Date	Project End Date	Total Estimated Cost	DOE Share
Obtaining EPA Permits for CO_2 Ocean Sequestration Experiment in Hawaii	Small Business	Pacific International Center for High Technology Research	05/31/2002	10/29/2002	$60,495	$60,495
A Zeolite Membrane for Separation of Hydrogen from Process Streams	Small Business	TDA Research, Inc.	06/14/1998	03/13/1999	$100,000	$100,000
A Novel CO_2 Separation System	Small Business	TDA Research, Inc.	07/09/1998	12/30/2003	$549,999	$549,999
Sequestration of CO_2 Using Coal Seams	Small Business	Northwest Fuel Development Inc.	07/14/1998	05/14/1999	$56,752	$56,752
Natural Analogs for Geologic Sequestration	Small Business	Advanced Resources International	07/29/2001	07/30/2004	$1,736,390	$1,123,390
Organization of 2003 National Carbon Sequestration Conference	Small Business	Exchange Monitor Publications, Inc.	07/31/2002	07/31/2002	$245,120	$100,000
Oil Reservoir Characterization and CO_2 Injection Monitoring in the Permian Basin with Cross-Well Electromagnetic Imaging	Small Business	ElectroMagnetic Instruments, Inc.	09/10/2000	08/30/2003	$1,150,630	$767,821
Geologic Sequestration of CO_2 in Deep, Unmineable Coalbeds: An Integrated Research and Commer	Small Business	Advanced Resources International	09/27/2000	03/31/2004	$5,543,246	$1,387,224
Recovery & Sequestration of CO_2 from Stationary Comb. Systems by Photosynthesis of Microalgae	Small Business	Physical Sciences, Inc.	09/28/2000	09/30/2003	$2,361,111	$1,682,028
Support for the International CO_2 Ocean Sequestration Field Experiment	Small Business	Pacific International Center for High Technology Research	09/28/2001	09/29/2002	$93,613	$44,613
Weyburn CO_2 Sequestration Project	Non-US	Natural Resources Canada-CANMET	05/31/2002	12/29/2002	$27,000,000	$4,000,000
CANMET CO_2 Consortium-O2/ CO_2 Recycle Combustion	Non-US	Natural Resources Canada-CANMET	09/29/1999	09/29/2002	$765,000	$35,000
An Integrated Modeling Framework for Carbon Management Technologies	Private Univ.	Carnegie Mellon University	08/13/2000	09/29/2003	$896,466	$717,172
International Collaboration on CO_2 Sequestration	Private Univ.	Massachusetts Institute of Technology	08/23/1998	10/22/2002	$950,000	$950,000
CO_2 Sequestration in Coalbed Methane Reservoirs	Private Univ.	University of Southern California	09/19/2001	09/18/2002	$50,000	$50,000
Development of Mesoporous Membrane Materials for CO_2 Separation	Private Univ.	Drexel University	08/30/2000	12/30/2002	$53,458	$50,000
Photoreductive Sequestration of CO_2 to Form C1 Products and Fuel	Nonprofit	SRI International Corporation	03/19/2002	03/18/2003	$124,967	$99,974

Project Title	Performer Type	Performer	Project Start Date	Project End Date	Total Estimated Cost	DOE Share
Development of Synthetic Soil Materials for the Reclamation of Abandoned Mine Sites	Nonprofit	Western Research Institute	04/09/1998	06/29/2003	$279,434	$139,717
Recovery of CO_2 in Advanced Fossil Energy	Nonprofit	Research Triangle Institute	07/14/1998	02/27/2002	$550,000	$550,000
CO_2 Capture From Flue Gas Using Dry Regenerable Sorbents	Nonprofit	Research Triangle Institute	08/30/2000	08/30/2003	$1,050,889	$812,285
The Potential of Reclaimed Lands to Sequester Carbon and Mitigate the Greenhouse Effect	Nonprofit	Western Research Institute	11/14/1999	09/29/2002	$0	$0
Application and Development of Appropriate Tools and Technologies for Cost-effective Carbon Sequestration	Nonprofit	The Nature Conservancy (TNC)	07/10/2001	07/09/2004	$2,023,597	$1,618,878
Feasibility of Large-Scale CO_2 Ocean Sequestration	Nonprofit	Monterey Bay Aquarium Research Institute	09/17/2000	09/29/2003	$1,106,409	$812,695
The University of Kansas Center for Research	Nonprofit	University of Kansas Center for Research	09/26/2000	12/20/2003	$3,307,515	$2,436,690
Zero Emissions Power Plants Using SOFCs and Oxygen Transport Membranes	Large Business	Siemens Westinghouse Power Corp. - Pittsburgh	05/31/2000	11/29/2002	$3,084,061	$2,311,108
CO_2 Capture Project	Large Business	BP Corporation North America Inc	07/10/2001	11/10/2004	$9,994,165	$4,995,000
R&D Entitled, "Large Scale CO_2 Transportation and Deep Ocean Sequestration"	Large Business	McDermott Technology, Inc. (MTI-OH)	07/14/1998	12/30/2001	$619,732	$619,732
The Removal and Recovery of CO_2 from Syngas and Acid Gas Streams in an IGCC Power Plant	Large Business	Tampa Electric Company	08/23/1998	04/23/1999	$112,950	$50,000
Evaluation of Oxygen Enriched Combustion Technology for Enhanced CO_2 Recovery	Large Business	McDermott Technology, Inc, (MTI-Lynchburg)	09/01/1999	08/30/2002	$99,985	$99,985
CO_2 Capture from Industrial Process Gases	Large Business	Air Products and Chemicals, Inc.	09/17/1998	05/17/1999	$70,143	$50,000
Fuel-Flexible Gasification-Combustion Technology for Production of H2 and Sequestration-Ready CO_2	Large Business	GE Energy and Environmental Research Corporation	09/18/2000	09/29/2003	$3,378,920	$2,500,000
Sequestration of CO_2 Gas in Coal Seams	Large Business	CONSOL Inc.	09/20/2001	12/30/2008	$9,269,333	$6,959,601
Advanced Oxyfuel Boilers and Process Heaters for Cost Effective CO_2 Capture and Sequestration	Large Business	Praxair, Inc.	09/23/2001	12/30/2005	$5,836,482	$4,085,537
Greenhouse Gas Emissions Control by Oxygen Firing in Circulating Fluidized Bed Boilers	Large Business	ALSTOM Power, Inc., US Power Plant Laboratories	09/26/2001	10/26/2004	$1,996,486	$1,597,189
CO_2 Hydrate Process for Gas Separation from a Shifted Synthesis Gas Stream	Large Business	Bechtel National Inc.	09/29/1999	12/30/2005	$9,076,621	$9,076,621
Land Application Uses of Dry FGD By-Products	For-profit Organization	Dravo Lime Company	07/22/1991	07/21/1999	$4,302,804	$1,341,125

Project Title	Performer Type	Performer	Project Start Date	Project End Date	Total Estimated Cost	DOE Share
CO_2 Selective Ceramic Membrane for Water-Gas-Shift Reaction with Simultaneous Recovery of CO_2	For-profit Organization	Media and Process Technology Inc.	08/30/2000	08/30/2003	$900,000	$720,000
Novel Composite Membrane and Process for Natural Gas Upgrading	For-profit Organization	Innovative Membrane Systems, Inc.	09/28/1999	06/29/2002	$512,248	$392,373
Evaluation of Multiple Product Power Cycles	Natl Lab	Argonne National Laboratory (ANL)	02/08/2000	09/29/2002	$400,000	$400,000
Zero Emissions Steam Technology Research Facility Study	Natl Lab	Lawrence Livermore National Laboratory (LLNL)	02/09/2001	03/24/2002	$2,400,000	$1,200,000
Developing an Atomic Level Understanding to Enhance CO_2 Mineral Sequestration Reaction	Natl Lab	Argonne National Laboratory (ANL)	02/15/2001	02/14/2002	$357,000	$357,000
Nonaqueous Biocatalysis Applied to Coal Utilization	Natl Lab	Idaho National Engineering and Environmental Laboratory (INEEL)	03/08/1998	09/29/2002	$130,000	$130,000
Whitings as a Potential Mechanism for Controlling Atmospheric CO_2	Natl Lab	Idaho National Engineering and Environmental Laboratory (INEEL)	03/08/1999	09/29/2002	$1,600,000	$1,600,000
Vortex Tube Design and Demo for the Removal of CO_2 from Natural Gas and Flue Gas	Natl Lab	Idaho National Engineering and Environmental Laboratory (INEEL)	04/14/2000	09/29/2002	$925,000	$625,000
CO_2 Separation Using a Thermally Optimized Membrane	Natl Lab	Los Alamos National Laboratory (LANL)	04/14/2000	04/13/2003	$1,215,360	$1,215,360
Continue Evaluation of Feasibility of CO_2 Disposal in a Deep Saline Aquifer in	Natl Lab	Battelle Columbus Laboratories	04/29/1998	02/27/1999	$99,995	$99,995
Natural Gas Vehicle Fuel from Landfill Gas	Natl Lab	Brookhaven National Laboratory (BNL)	04/30/2000	09/29/2003	$50,000	$50,000
Sequestration of CO_2 in a Depleted Oil Reservoir - LANL	Natl Lab	Los Alamos National Laboratory (LANL)	04/30/2000	09/29/2002	$1,053,000	$1,053,000
Geological Sequestration of CO_2: GEO-SEQ / ORNL	Natl Lab	Oak Ridge National Laboratory (ORNL)	04/30/2000	09/29/2002	$1,540,000	$1,540,000
Sequestration of CO_2 in a Depleted Oil Reservoir	Natl Lab	Sandia National Laboratories (SNL) - NM	04/30/2000	04/30/2003	$2,295,095	$2,295,095
GEO-SEQ Project	Natl Lab	Lawrence Berkeley National Laboratory (LBNL)	04/30/2000	09/29/2002	$14,550,000	$2,750,000
Geological Sequestration of CO_2: GEO-SEQ	Natl Lab	Lawrence Livermore National Laboratory (LLNL)	04/30/2000	09/29/2002	$1,500,000	$1,500,000
CO_2 Separation Using Thermally Optimized Membranes-Nanocomposite Development	Natl Lab	Idaho National Engineering and Environmental Laboratory (INEEL)	05/14/2000	05/13/2003	$185,000	$185,000
Evaluation of CO_2 Capture, Utilization, and Disposal Options	Natl Lab	Argonne National Laboratory (ANL)	05/21/1992	04/29/1997	$815,000	$815,000

Project Title	Performer Type	Performer	Project Start Date	Project End Date	Total Estimated Cost	DOE Share
Experimental Evaluation of Chemical Sequestration of CO_2 in Deep Saline Formations	Natl Lab	Battelle Columbus Laboratories	07/09/1998	09/29/2004	$596,649	$596,649
Enhancement of CO_2 Emissions Conversion Efficiency by Structured Microorganisms	Natl Lab	Idaho National Engineering and Environmental Laboratory (INEEL)	07/31/1999	09/29/2002	$327,000	$327,000
Biomineralization for Carbon Sequestration	Natl Lab	Oak Ridge National Laboratory (ORNL)	07/31/1999	09/29/2002	$1,000,000	$1,000,000
Enhanced Practical Photosynthesis Carbon Sequestration	Natl Lab	Oak Ridge National Laboratory (ORNL)	07/31/1999	09/29/2002	$172,000	$172,000
Modification/Development of Carbon Fiber Composite Molecular Sieve for Removal of CO_2	Natl Lab	Oak Ridge National Laboratory (ORNL)	07/31/2001	12/30/2002	$344,000	$172,000
CO_2 Hydrate Process for Gas Separation from a Shifted Synthesis Gas Stream	Natl Lab	Los Alamos National Laboratory (LANL)	08/14/1999	01/29/2005	$5,230,000	$5,230,000
Renewable Hydrogen Production for Fossil Fuel Processing	Natl Lab	Oak Ridge National Laboratory (ORNL)	09/01/1998	09/29/1999	$22,000	$22,000
CO_2 Sequestration by Mineral Carbonation Using a Continuous Flow Reactor	Natl Lab	Albany Research Center (ALRC)	09/29/2001	09/29/2003	$1,300,000	$1,300,000
Evaluation of CO_2 Capture/Utilization/Disposal Options	Natl Lab	Argonne National Laboratory (ANL)	09/30/1997	09/29/2002	$544,000	$544,000
Mineral Carbonation - Preliminary Feasibility Study	Natl Lab	Albany Research Center (ALRC)	09/30/1997	11/29/2001	$2,145,700	$945,700
Development of Hydrogen Separation and Purification Membranes	Natl Lab	Sandia National Laboratories (SNL) - CA	09/30/1998	09/29/2002	$594,000	$594,000
Exploratory Measurements of Hydrate and Gas Compositions	Natl Lab	Lawrence Livermore National Laboratory (LLNL)	09/30/1998	09/29/2002	$500,000	$500,000
Screening of Marine Microalgae for Maximum CO_2 Biofixation Potential	Natl Lab	Pacific Northwest National Laboratory (PNNL)	09/30/2000	09/29/2002	$200,000	$200,000
Advanced Plant Growth	Natl Lab	Los Alamos National Laboratory (LANL)	09/30/2000	11/29/2001	$880,000	$880,000
Ecosystem Dynamics	Natl Lab	Los Alamos National Laboratory (LANL)	09/30/2000	11/29/2001	$1,705,000	$1,145,000
Enhancing Carbon Sequestration & Reclamation of Degraded Lands with Fossil Fuel Combustion Byproducts	Natl Lab	Oak Ridge National Laboratory (ORNL)	12/31/1999	12/30/2001	$1,067,000	$1,067,000
Full-Scale Bioreactor Landfill	County Agcy	Yolo County	08/01/2001	07/31/2004	$1,748,103	$563,000
Fossil Fuel Derivatives with Reduced Carbon	tbp	Applied Sciences, Inc.	09/30/1998	09/29/1999	$99,845	$99,845
Total					$161,998,484	$95,624,581

Appendix B
DESCRIPTION OF THE NATIONAL COAL COUNCIL

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

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

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

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

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

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Appendix F
CORRESPONDENCE BETWEEN THE U.S. DEPARTMENT OF ENERGY & THE NATIONAL COAL COUNCIL

The Secretary of Energy
Washington, DC 20585

September 24, 2002

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

Dear Mr. Taylor:

The National Coal Council (NCC) has provided valuable advice and guidance on a continuing basis on general policy matters related to coal.

In a previous report entitled "*Research and Development Needs for the Sequestration of Carbon Dioxide as Part of a Carbon Management Strategy,*" the NCC recommended: "...the U.S. Government...in partnership with the entire coal industry, implement an even fuller and more aggressive carbon management program with a major component being research and development of cost-effective CO^2 sequestration technologies." Additionally, recent NCC studies have demonstrated the importance of increased energy efficiency from coal-fired power plants in reducing greenhouse gas emissions.

This Administration has implemented a three-pronged strategy to address climate change: increased energy efficiency, use of lower and no-carbon fuels, and carbon sequestration. Given the President's strong endorsement of voluntary greenhouse gas reductions, the major commitments that various industry groups and individual companies have made to promote the President's goals, and technological improvements in coal-fired generation and sequestration technology, I request that the NCC now prepare an update to this report. For example, several companies have partnered with the Department of Energy to evaluate the effectiveness and economics of sequestering carbon. These and other public-private partnerships should be highlighted in this report, as well as future partnership opportunities. Also, your perspective on how voluntary approaches to reduce greenhouse gas emissions could be best achieved would also be very valuable.

We believe that your membership represents a broad spectrum of senior level industry, State, and public interest organizations and is well positioned to carry out this request.

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We also believe that the updated report will serve as a carbon management blueprint for industry and act as a catalyst to promote additional public-private partnerships to support voluntary reduction of greenhouse gases and carbon sequestration.

I am designating Mr. Robert G. Card, Under Secretary for Energy, Science and Environment, and Mr. Carl Michael Smith, Assistant Secretary for Fossil Energy, to represent me in the conduct of this important study. I offer my gratitude to the Council for its efforts to assist the Department in defining the scope of this study request. We look forward to receiving this report when completed.

Sincerely,

Spencer Abraham

Spencer Abraham

Appendix G
CORRESPONDENCE
FROM INDUSTRY EXPERTS

Comments on R&D Needs for Coal Related Global GHG Management (re Draft NCC Report)
Alex Green, University of Florida, aesgreen@ufl.edu

Essential Comment: Some attention was given to natural processes in the Terrestrial Sequestering section of the May 2000 and in this NCC report. However, the writer believes that the forestry-agriculture component of coal related GHG management deserves more R&D emphasis via two thrusts and possible combinations of these thrusts:

T1) Co-utilization of some CO_2 neutral biomass with coal in electrical generation.

T2) Increasing natural carbon dioxide sequestering by restoring soil organic carbon in agriculturally depleted areas, by fostering the growth of trees and by constructing long lived wooden or carbon structures

Background: Nature over billions of years developed photosynthesis and plants that extract CO_2 from the atmosphere and convert it to biomass via reactions such as

$$5CO_2 + 5H_2O + \text{solar energy} \rightarrow C_5H_{10}O_5 + 5\,O_2$$

The use of biomass for energy, human-kinds oldest technology, simply completes a CO_2 neutral cycle:

$$C_5H_{10}O_5 + 5O_2 \rightarrow 5CO_2 + 5H_2O + \text{heat energy}$$

Nature, has also developed natural biological and physical processes (coalification) that transform biomass successively into peat, lignite, sub-bituminous bituminous and anthracite coal. Somewhat similar natural de-oxygenating processes changed some types of plant matter into oil and natural gas. The several hundred million year deposits of coal, oil and natural gas since the Carboniferous age became a vast storehouse of underground solar energy. However, since the industrial revolution human withdrawals from this bank have been at very high rates and oil and natural gas deposits will probably be depleted in few decade. However, since coal, widely distributed on the globe, should last two or three centuries, it is prudent, to use this resource in eco-friendly ways.

IC on CDF (T1): An International Conference (IC) on Co-utilization of Domestic Fuels (CDF) was held at the University of Florida on February 5 and 6, 2003. The main purpose of the CDF conference was to examine various CDF technologies and their energy, environmental and economic benefits. Particular attention was given to co-use of coal with biomass (wood, agricultural residues, municipal solid waste, bio-solids, etc.) in eco-friendly thermo-chemical reactors for electrical generation, waste disposal and for production of gaseous fuels, liquid fuels and chemicals.

The CDF conference participants included 8 senior academics from abroad 12 from the USA, 32 utility persons or persons from engineering firms supporting utilities, 10 from government agencies or organizations advising government agencies (including NCC's Bob Beck and Irene Smith, a CDF expert from UK), one Sierra Club representative, and 3 experts from a forestry conference then assembled in Gainesville. Table 1 gives the list of conference sponsors.

To set the stage for discussions at the CDF conference three books [1-3], two recent reports [4,5] and a compact disc [6] of a Florida report on renewables in electrical generation were distributed at registration. The CDF conference proceeding are available in CD form and selected papers will be published in a special issue of IJPES.[7]

Global Aspects: The GHG emissions problem is a global one and proposed solutions must be examined from a global perspective with serious consideration of the policies of other countries on GHG emissions. . Figure 1 shows the global fuel shares in % (see www.iea.org). Since it is important to be mindful of the location of the decimal place note that over the globe, renewables (non-GHG energy sources) are at the same order of magnitude as oil, coal, natural gas and nuclear. Among the renewables, combustible renewable and waste (CRW) are at 11% and hydro at 2.3% whereas solar is only at 0.04% and wind at 0.03 %..

Table 1 lists the total primary energy supply (TPES) for various regions of the world or country groupings. The TPES in the 2nd column are in Mtoe (Mtoe=one million tons of oil equivalent = $42*10^{15}$ joules = 0.040 quads = 40.10^{12} BTU) The Organization for Economic Co-operation and Development (OECD) countries are here subdivided into OECD-Pac (Pacific for Japan, Korea, Australia and New Zealand), OECD-Europe, and OECD-NA (North America for USA, Canada and Mexico). Column 2 gives the regions TPES. Column 3 gives the percentage of the TPES that is combustible renewable and waste (CRW). Column 4 gives the percentage of the other renewable components (hydro-electric, geothermal, wind, solar and tide/wave/ocean).

The large CRW levels for Africa, Asia, China, and Latin America in Table 1 reflect large residential consumption of biomass for home cooking and heating. In view of population growth in these geographic areas the ability of annual biomass resources to keep up with these residential needs is a matter of concern. In these regions CDF technologies might be developed in which coal or natural gas is used in small percentages to enhance the efficiency of biomass utilization. On the other hand in developed regions where CRWs are now in low percentages a proven CO_2 management strategy would be to rebuild the use of biomass to a larger percentage of TPES.

The extra row at the bottom of Table 2 gives specific data for the USA. The USA with 4.6% of the global population accounts for about 24% of the global energy consumption and some 24% of global CO_2 emissions. Developing and fostering practical CDF systems in the USA to facilitate greater use of CO_2 neutral biomass energy could help the USA's balance its military leadership by environmental leadership.

The USA has considered returning to the use of wood and other forms of biomass since the oil crises of 1973. Residential use of wood increased strongly nationwide and biomass generating capacity gradually built up to 6 Gigawatts by 1990. California with favorable legislation led the way, however, by 1995 half of the California biomass power industry shut down. Today biomass is regaining attention both as a GHG management and for energy security. A number of states are mandating or otherwise encouraging the use of renewables in the electric generating mix. In most geographic locations biomass stands out as the only renewable that can significantly be expanded in the next decade or two via CDF technologies.

Table 3 illustrates representative solid fuel properties that resulted from the "coalification" process. Columns 2-4 give representative ultimate analyses in weight % corrected to apply for dry, ash, sulfur and nitrogen free feedstock. The 5th and 6th columns give total volatiles (V_T) and fixed carbon (FC) also in wt%.. The 7th column gives heating value (HVs in MJ/Kg). The 8th and 9th columns give energy density, (E/vol, in MJ/liter) and estimated relative char reactivities. Biomass has advantages of high volatility and char reactivities that make conversions from solids to more useful gaseous or liquid fuels relatively easy. On the other hand coals have advantages of global abundance, high HVs, high energy densities and other features that fosters low costs. Technologies for co-utilizing biomass with coal enable the useful properties of one fuel to assist the thermal processing of the other.

Since 1992 the European Union has actively pursued co-utilization of coal and biomass [8-10], (see additional references in [4]) as a means of bringing more advanced technologies to bear on the use of biomass, and as a CO_2 mitigation measure. The costs and availability of biomass in various parts of the globe have been studied extensively in this context [11]. A recent European Union White Paper [12] projects the growth of biomass use from 3.1% of their total energy in 1995 to 8.5% in 2010. By taking advantage of regions with abundant sunshine and rain the USA could easily match or exceed this goal. To some experts our emphasis on R&D towards zero emission technologies or hydrogen as the solution of our emission problems is distracting the USA from pursuit of doable near term measures that can benefit the environment and the economy and restore USA's environmental leadership. .

Terrestrial CO2 Sequestering (T2): As summarized on page 11 of the May 2000 NCC report and on page 16 of this report and in the literature [13] GHG management can be fostered by restoring forests, soil organic carbon (SOC) and the use of long lived wood or carbon structures. The possibility of restoring SOC with mildly oxidized low rank coal is an R&D area that seems worth pursuing [14]. Going from lignite back to peat and other modest manipulations of nature's coalification processes does not seem as remote as zero-emissions. Research on optimum combinations of T1 and T2 is sorely needed. In R&D projects, in contrast to demonstration projects, we appear to be overlooking the possibility of modest improvements upon nature's ways in favor of "all or nothing" moon -shots type methods. Getting plant people together with the coal people to examine and possibly improve upon of nature's ways is probably the fastest way of bringing more renewables into our energy mix and also enhancing carbon sequestration.

Table 4 list why "the farmers and the miners should be friends" a theme that has been almost as hard to sell as getting the farmers and the cow-men to be friends after the Oklahoma land-rush.

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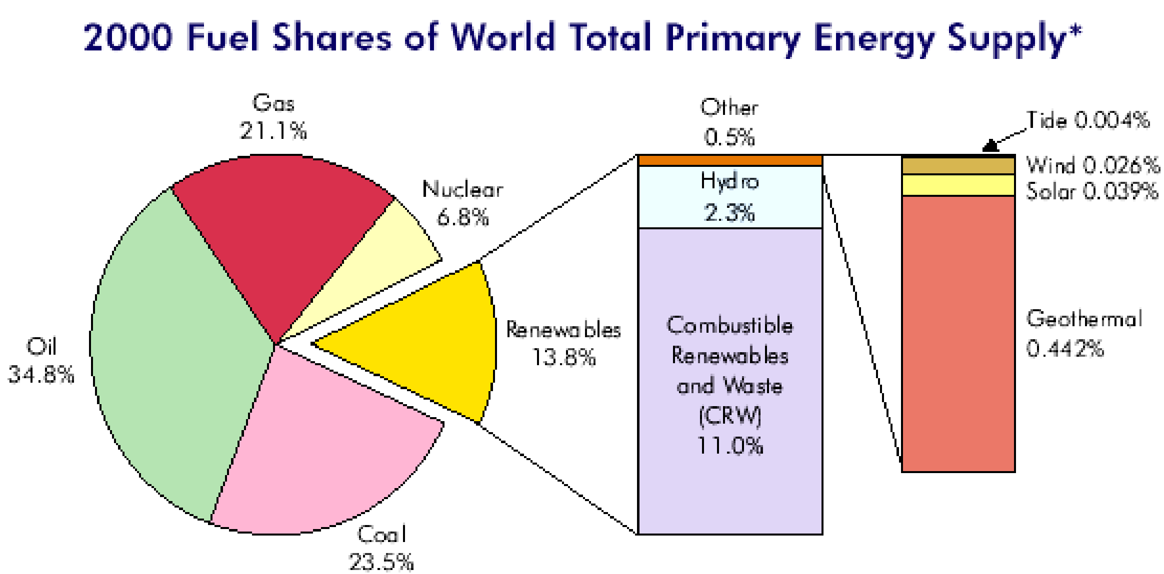

Table 1: List of Sponsors

1) United States Department of Energy
2) Mick A. Naulin Foundation
3) College of Engineering, University of Florida
4) Division of Sponsored Research, University of Florida
5) School of Forest Resources and Conservation,
6) Public Utility Research Center, University of Florida
7) Florida Agricultural Experiment Station
8) National Rural Electric Cooperative Association
9) Triangle Consulting Group
10) Science and Technology Corporation
11) Green Liquids and Gas Technologies
12) Fuel and Combustion Technology Division, ASME
13) Coal, Biomass and Alternative Fuels Committee, IGTI
14) Florida Department of Agriculture & Consumer Services, Division of Forestry
15) International Association of Science and Technology for Development

Table 2: Total Primary Energy and Renewable Indicators

Region	**TPES (Mtoe)**	**CRW (%)**	**Other (%)**
Africa	508	49.6	1.3
Latin America	456	17.1	10.8
Asia	1123	31.5	2.5
China	1158	18.5	1.7
Former USSR	921	1.2	2.1
Middle East	380	0.3	0.5
Non-OECD-Eu	95	5.3	4.6
OECD Europe	1765	3.9	3.1
OECD Pacific	847	1.7	2.2
OECD NA	2705	3.6	2.8
Total	**9957**	**11.0**	**2.8**

USA	2300	3.4	1.6

Table 3. Solid fuel properties along coalification path

Rank	Ultimate Analysis			Proximate Analysis			Other properties	
Name	C	H	O	VT	FC	HV	E/vol	React
Cellulose	44	6	50	88	12	10	9	1600
Wood	49	7	44	81	19	18	11	500
Peat	60	6	34	69	31	23	18	150
Lignite	70	5	25	58	42	27	27	50
Sub Bitum	75	5	20	51	49	30	36	16
Bitum	85	5	10	33	67	33	49	5
Anthracite	94	3	3	7	93	34	58	1.5

Table 4: Why "the farmers and the miners should be friends"

I. <u>What can Biomass do for Coal</u>

<u>A)</u> Co-firing Biomass with Coal
1) Lower CO_2, SO_2 and NOx emissions
2) Foster renovation and ecofriendly use of coal facilities
3) Foster IGCC, IG-cogen, CHP and chemical factories.

B)Co-gasifying Biomass with Coal
1) Facilitate conversion to useful gases and liquids
2) Provide important environmental roles for coal
3) Facilitate capture of toxics (mercury, arsenic…)

C) CO_2 Sequestration, Nature's Way
1) Federal, state land reforestation, new parks
2) Interstate highway plantings
3) Urban forestation (elms)
4) Wood buildings and long lived carbon products
5) Restore agriculturally depleted lands

D) Phytoremediation
1) Restoration of mined lands
2) Foster phyto-mining
3) Remediate toxic sites

II. <u>What can Coal do for Biomass?</u>

A. Make Opportunity fuels competitive
1) Lower capital cost of co-utilization (co-firing)
2) Foster use with turbine generators (co-gasifying)

B. Provide economic agricultural alternatives
1) Energy crops
2) Use of agricultural residues
3) Disposition of problem plant matter
4) Overcome biomass-use problems

<u>III. What can friends do for the Globe?</u>

A. Foster greening of planet earth
1) Lower CO_2, pollution and toxic emission problems
2) Foster advanced environmental technologies
3) Foster phyto-remediation, phyto-mining

B. Facilitate economic recovery
1) Develop a biomass market and supply infrastructure
2) Foster biomass to liquid fuels and chemicals
3) General development of fuel co-utilization

From the Musical Oklahoma

The farmer and the miner should be friends
Oh the farmer and the miner should be friends
One likes to plant a tree, the other likes to set coal free
but that's no reason they caint be friends

Energy folks should stick together
Energy folks should all be pals
Miners dance with farmers daughters
Farmers dance with miners gals
Repeat

Appendix H
ACKNOWLEDGEMENTS

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Julie Clendenin, ***Editor***

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