COAL: ENERGY FOR THE FUTURE

J. P. Longwell,* E. S. Rubin† and J. Wilson‡

*Department of Chemical Engineering, MIT, Cambridge, MA 02139-4307, U.S.A.
†Center for Environmental Studies, Carnegie-Mellon University, Pittsburgh, PA 15213, U.S.A.
‡National Research Council, Washington, DC 20418, U.S.A.

Received 2 August 1995

Abstract—Coal is by far the largest fossil fuel resource in the U.S. with known reserves adequate to meet expected demand without major increases in production cost well beyond the year 2010. In contrast, domestic natural gas, its principal fossil fuel competitor for power generation, is a more limited resource and increases in production cost and decreased availability are projected to occur after the year 2000, thus weakening its ability to compete with coal for power generation in the U.S. Renewable and nuclear energy sources are not expected to displace coal to a major extent during the 1995–2040 time period considered here. For manufacture of liquids and gaseous fuels, coal is predicted to be less competitive with other resources (petroleum, oil shale and bitumen) in the 2021–2040 time period. Increasingly strict requirements for environmental management of coal-generated waste streams are also anticipated with a growing incentive to reduce CO₂ production through increased efficiency. This planning model imposes demanding requirements for conversion of coal to electricity and to clean gaseous and liquid fuels and, thus, for a strategic program of research, development and commercialization to most efficiently utilize coal resources in the 21st century. This review is based on an assessment of DOE programs for production of, development, demonstration and commercialization programs for the time period 1995–2040. This assessment was conducted under the auspices of the National Research Council, in response to a request from the Acting Assistant Secretary for Fossil Energy. For the above time period, electric power generation is expected to dominate the use of coal, although a growing production of merchant medium Btu gas and liquid transportation fuels is anticipated during the period 2021–2040. The current DOE coal program emphasizes activities through 2010 and is focused almost exclusively on power generation technologies with small programs on other uses. Funding for many of the latter programs has been reduced significantly in recent years. The present study, with its longer time horizon, proposes an increasing emphasis on clean fuels research and on advanced research that addresses the barriers to higher efficiency in both power generation and fuels production to reduce CO₂ emissions. Improvements will also be needed in control of air pollutants and the discharge of solid wastes. The power generation program addresses both near term goals that do not offer significantly higher efficiency, and also more ambitious goals based on combined cycles utilizing high performance gas turbines or fuel cells to potentially provide a 10–15 point increase in efficiency. These increases in efficiency will require extensive R&D to overcome technological barriers. For fuel cells, high cost appears to be the major problem. For the gas turbine systems, production of a hot gas stream of sufficient purity to allow use of the very high efficiency gas turbines being developed for use with natural gas presents the major challenge. Critical components include: high temperature filters for PFBC systems; high temperature air/furnace heat exchanger for indirect fired systems; hot gas cleanup system for PFBC and for gasification-based systems; high temperature turbine blades compatible with trace impurities that may escape the high temperature gas cleanup system; and high thermal efficiency gasification. Solution of these challenging problems will require a continued program of advanced research and component development. The choice of winners from the large array of technologies will also require augmented use of systems studies and development of realistic commercialization strategies. As natural gas prices rise, production of cleaned coal-based medium Btu gas for use in existing natural gas fueled-combined cycles and for industrial heat becomes economic and could relieve the pressure on the supply of natural gas for other uses. Conversion of this coal-based medium Btu gas to methane (SNG) might follow towards the end of the 2021–2040 time period. For this use, high efficiency oxygen blown-coal gas cleanup gasification is needed. At present, however, the DOE gasification program is concentrated on air blown processes specifically aimed at integration with power generation. Production of medium Btu (synthesis gas) will allow concurrent production of hydrogen or Fischer–Tropsch liquids. The use of simplified once through processes with production of electric power from unconverted feed and low value products (such as methane) could bring costs of premium liquid fuels to a level competitive with 25–30 $/bbl imported crude oil (DOE financing basis). Current projections indicated that the price of imported crude oil could be in this range in the 2021–2050 time frame. Direct liquefaction costs, with continued R&D, are believed to be approximately the same as indirect liquefaction, but with 5–10% higher efficiency and correspondingly less production of CO₂. Given the long-term nature of opportunities, a potential role in supporting technology development aimed at cost reduction and efficiency improvement for these potentially important uses of coal.

*To whom correspondence should be addressed.
CONTENTS

Part I: Strategic Planning for Coal
1. Introduction and Scope of the Study
   1.1. Coal research and development
       1.1.1. Private sector activities
       1.1.2. International activities
   1.2. Organization of the report
2. Overview of U.S. Department of Energy Programs and Planning
   2.1. Major trends in the DOE coal program
   2.2. The DOE coal program structure and budget
       2.2.1. Fossil energy research and development
   2.3. CCT program
       2.3.1. Clean Coal Technologies Research, Development, and Demonstration Program Plan
3. Trends and Issues for Future Coal Use
   3.1. Overview of coal markets
   3.2. Markets for export of coal utilization technology
   3.3. Changes in structure of the electric utility industry
       3.3.1. Introduction of new technology
       3.3.2. The availability of coproducts
   3.4. Projected electricity requirements
   3.5. Energy sources for power generation
       3.5.1. Coal
       3.5.2. Natural gas
       3.5.3. Liquefied natural gas
       3.5.4. Oil
       3.5.5. Nuclear power
       3.5.6. Renewable energy
   3.6. Coal use for liquid and gaseous fuels
       3.6.1. Resource base for petroleum and bitumen
   3.7. Other uses of coal
   3.8. Environmental issues for coal use
   3.9. Summary
4. The Strategic Planning Framework
   4.1. Baseline strategic planning scenarios
   4.2. Alternative scenarios
       4.2.1. Near term
       4.2.2. Mid and long term
   4.3. Scenario implications for RDD&C planning
   4.4. Additional criteria to set national coal RDD&C priorities

Part II: Overview of Current DOE Coal Programs
5. Coal Preparation, Coal–Liquid Mixtures, and Coalbed Methane Recovery
   5.1. Coal preparation
       5.1.1. Description of technology
       5.1.2. State of the art
       5.1.3. Current programs
       5.1.4. Technical issues, risks, and opportunities
       5.1.5. Summary
   5.2. Coal–liquid mixtures
       5.2.1. Background
       5.2.2. State of the art
       5.2.3. Current programs
       5.2.4. Summary
   5.3. Coalbed methane recovery
       5.3.1. Background
       5.3.2. State of the art
       5.3.3. Current programs
       5.3.4. Issues, risks, and opportunities
       5.3.5. Summary
6. Clean Fuels and Speciality Products from Coal
   6.1. Gasification of Coal
       6.1.1. Background
       6.1.2. State of the art
       6.1.3. Gasification technology and IGCC performance
       6.1.4. Technical issues and opportunities
       6.1.5. Current programs
   6.2. Products from coal-derived gas
       6.2.1. Hydrogen production
       6.2.2. Synthetic natural gas production
       6.2.3. Liquid products from synthesis gas
at a steady state; bbl, barrel; Bituminous coal, type of coal most commonly used for electric power generation, with a heating value of 10,500–15,000 Btu per pound, carbon content of 45–86%, and moisture content of less than 20%; Btu British thermal unit; CAAAs, Clean Air Act amendments; CCT, clean coal technology; CCTC, clean coal technology coalition; CI, combustion engineering; CH₄, methane; CI, chlorine; CO, carbon monoxide; CO₂, carbon dioxide; COM, coal-oil mixture; CWM, coal-water mixture; CWS, coal-water slurry; DOE, U.S. Department of Energy; DRB, demonstrated reserve base; DSM, demand-side management—DSM programs are instituted by utilities, such as rebates to customers for installation of energy-efficient appliances or reduced rates for nonpeak-load use of electricity, to encourage customers to reduce electricity consumption overall or at certain periods; ECU, European currency unit; EFCC, externally fired combined-cycle; EIA, Energy Information Administration; EMF, electromagnetic fields; EPA, U.S. Environmental Protection Agency; EPACT, Energy Policy Act of 1992; EPR1, Electric Power Research Institute; ESP, electrostatic precipitator; EU, European Union; FBC, fluidized bed combustion; FE, fossil energy; FGD, flue gas desulfurization; F-T, Fischer–Tropsch process—catalytic conversion of synthesis gas into a range of hydrocarbons; GDP, gross domestic product; Greenhouse gases, cases, such as water vapor, carbon dioxide, tropospheric ozone, nitrous oxide, and methane, that are transparent to solar radiation but opaque to long-wavelength radiation—their action is similar to that of glass in a greenhouse; GRI, Gas Research Institute; GW, gigawatt (10⁹ watts); GWh, gigawatt-hour; H₂, hydrogen; Hg, mercury; HHV, higher heating value; HIPS, high-performance power system; IFC, indirectly fired cycle; IGCC, integrated gasification combined-cycle—IGCC power generation systems replace the traditional coal combustor with a gasifier and gas turbine; IGFC, integrated gasification fuel cell; KRW, Kellogg–Rust–Westinghouse; kW, kilowatt; kWh, kilowatt-hour; LEBS, low-emission boiler system; LHV, lower heating value; Life extension, life extension is achieved by maintaining or improving the operating status of an electric power plant within acceptable levels of availability and efficiency, beyond the originally anticipated retirement date; Lignite, type of coal with a heating value of 4,000–8,300 Btu per pound, a carbon content of 25–35%, and moisture content up to 45%; LNG, liquefied natural gas; Mcf, thousand cubic feet; MCFC, molten carbonate fuel cell; METC, Morgantown Energy Technology Center; MHD, magnetohydrodynamics; Mild gasification, see pyrolysis; MMBo, million (10⁶) Btu; MW, megawatt (10⁶ watts); MWe, megawatt electric; MWh, megawatt thermal; NCA, National Coal Association; NCC, National Coal Council; NH₃, ammonia; NO₂, nitrogen dioxide; NOₓ, oxides of nitrogen—a mix of nitric oxide (NO) and nitrogen dioxide (NO₂); NSPS, new source performance standards; NUG, non-uniform generator; O₃, ozone; OECD, Organization for Economic Cooperation and Development; OPEC, Organization of Petroleum Exporting Countries; PAF, phosphoric acid fuel cell; PC, pulverized coal; Peak load, peak load (usually in reference to electrical load) is the maximum load during a specified period of time; PETC, Pittsburgh Energy Technology Center; PFBC, pressurized fluidized-bed combustion; ppm, parts per million; psi (or psig), pounds per square inch (psig indicates gauge pressure, that is, pressure above atmospheric pressure); PURPA, Public Utility Regulatory Policy Act of 1979; Pyrolysis, thermal decomposition of a chemical compound or mixture of chemical compounds; quadrillion (10¹⁵) Btu; Rank, variety of coal—the higher the rank of coal, the greater its carbon content and heating value; RDD&C, research, development, demonstration, and commercialization; Repowering, repowering is achieved by investments made in a plant to substantially increase its generating capability, to change generating fuels, or to install a more efficient generating technology at the plant site; ROₐ, particulate matter; Sasol, South African Coal, Oil, and Gas Corporation—coal conversion plant in operation at Sasolburg—coal is gasified by the Lurgi process and then converted to liquid hydrocarbons through the Fischer–Tropsch process; SCCWS, super clean cold water slurry; SCR, selective catalytic reduction—post-combustion NOₓ control with the use of catalysts; SNG, synthetic natural gas; SNOₓ, combined SO₂ and NOₓ, catalytic advanced flue gas cleanup; SOFC, solid oxide fuel cell; SOₓ, sulfur oxide; SO₂, sulfur dioxide; Synthesis gas, mixture of carbon monoxide and hydrogen and other liquid and gaseous products; Subbituminous coal, coal with a heating value of 8,300–11,500 Btu per pound, a carbon content of 35–45%, and a moisture content of 20–30%; Synthetic Fuels Corporation, organization established by the Energy Security Act of 1980 to facilitate the development of domestic nonconventional energy resources; Tef, trillion (10¹²) cubic feet; UF₆, uranium hexafluoride; UNDE ERC, University of North Dakota Energy and Environmental Research Center; VOC, volatile organic compounds.

PART I: STRATEGIC PLANNING FOR COAL

1. INTRODUCTION AND SCOPE OF THE STUDY

This article is based on a study carried out for the U.S. Department of Energy (DOE) by the National Research Council (NRC)* Committee on Strategic Assessment of the DOE Coal Program. The committee was asked to recommend, in broad strategic terms, the emphasis and priorities that DOE ought to consider in updating its coal program and in responding to the Energy Policy Act of 1993 (EPACT). EPACT represents the culmination of several years of energy policy deliberations, prompted largely by the Bush Administration’s 1991 National Energy Strategy proposals. EPACT provides congressional guidance on a wide range of energy-related issues and enumerates many coal-related activities.

The fossil fuels coal, petroleum, and natural gas have been central in supplying reliable, low-cost energy in the United States for more than a century. Today they account for almost 90% of the nation’s primary energy consumption. The domestic coal resource base is the most extensive, representing over 94% of proven U.S. fossil energy reserves. While the United States imports significant amounts of oil and gas, coal, in contrast, is a net export commodity for the U.S. economy.

Coal’s continued viability as a domestic energy source will be strongly linked to its environmental acceptability and cost relative to those of competing sources. Research, development, demonstration, and commercialization (RDD&C) programs will therefore be critical in ensuring that coal technologies
meet or exceed requirements for acceptable use and that they are available for timely deployment. The present study suggests the directions of coal RDD&C strategies and priorities for the United States.

1.1. Coal Research and Development

Over the years, R&D has been conducted in the United States on all stages of the coal fuel cycle, from mining to end use, in both private and public sectors. Coal R&D has also been undertaken overseas and has been pursued cooperatively between the United States and other countries. The pace of domestic R&D has been uneven, depending on economic circumstances, perceived U.S. vulnerability to energy interruptions, and the reality of such energy problems as the 1973 oil embargo by the Organization of Petroleum Exporting Countries (OPEC). The following brief discussion of private sector and international activities provides some general background for the committee's assessment. Specific private and international programs, such as the development of Fischer–Tropsch (F–T) processes and of gasification technology, are addressed in later technical discussions of the DOE program.

1.1.1. Private sector activities

R&D by the private sector has been affected by the ebb and flow of government support for coal-related R&D, although much R&D has been carried out independent of government support, driven mainly by perceived economic opportunities. Prior to the 1973 OPEC oil embargo, the private sector was involved in technical developments relating to coal mining, electric power generation, and, to a lesser degree, coal liquefaction. The subsequent energy uncertainties of the 1970s resulted in rapid price rises for petroleum and natural gas. With some forecasts projecting high petroleum prices for the longer term, the private sector envisioned opportunities to produce liquid fuels or synthetic natural gas from resources other than gas or petroleum. Programs were undertaken on technologies to exploit coal, oil shale, tar sands, biomass, and other nonconventional domestic resources, but these programs have now largely been abandoned.

Coal gasification technologies have been pursued extensively by private industry. Gasification is a critical step in converting coal to liquid fuels, or synthetic natural gas, and/or any number of chemicals, including methanol, petrochemicals, and ammonia. Commercial coal gasification plants in the United States include the Great Plains Gasification Plant, the Dow gasification cogeneration plant, and the Tennessee Eastern syngas-to-chemicals plant.

Coal technologies to produce electric power have been pursued extensively by both the private sector and DOE. The Electric Power Research Institute (EPRI), which is funded by the utility industry, is developing advanced electricity generation technologies powered by coal, with a current annual coal R&D budget of approximately $150 million, excluding cosponsors' funds. In addition, the private sector will contribute approximately two-thirds of the total $6.9 billion budgeted for the DOE's Clean Coal Technology.

1.1.2. International activities

In countries of the Organization for Economic Cooperation and Development (OECD), the most important consideration for future coal use is environmental. R&D programs within the OECD emphasize the development of cost-effective clean coal technologies to limit sulfur dioxide (SO₂), oxides of nitrogen (NOₓ), and CO₂ emissions from power plants. A number of OECD countries, including the United States, are also pursuing R&D individually to compete for the large anticipated markets for clean coal technologies in China, India, and other non-OECD nations. Outside the United States, the major effort to develop clean coal technologies is within the European Union (EU). Japan's New Energy and Industrial Technology Development Organization (NEDO) is funding a clean coal technology program, and there are limited clean coal technology developments in Australia, but these activities are not of the magnitude of the U.S. effort to develop and commercialize clean coal technologies.

EU coal programs are aimed at ensuring the availability and use of technologies for clean, cost-effective exploitation of coal, which provides nearly 40% of EU power generation requirements. The EU Energy Demonstration program (1978–1989) provided financial support to pilot and demonstration projects in liquefaction, gasification, and combustion of solid fuels. EU grants totaling 302 million ECUs made up about 40% of the program costs (ECUs = European Currency Units; at present 1 ECU = U.S.$1.15). The EU THERMIE PROGRAM (1990–1994) was aimed at promoting greater use of European energy technologies and at developing new clean processes, notably for the combustion and conversion of solid fuels. EU funding for this program was about 150 million ECUs annually, with additional funding coming from industry participants and governments of EU member nations. Clean coal technologies supported by THERMIE include transport fuels from coal, NOₓ emission controls, atmospheric fluidized-bed combustion (AFBC), pressurized fluidized-bed combustion, gasification, and an integrated gasification combined cycle (IGCC) plant.

1.2. Organization of the Report

The remaining sections in Part I of this article elaborate on issues and findings central to the com-
Fig. 1. History of funding for coal R&D under DOE's Office of Fossil Energy R&D budget. (Data shown in Fig. 1 for FY 1976 through FY 1994 represent congressional appropriations for coal-related FE R&D in current dollars. The values shown do not include any adjustments, such as supplemental, rescissions, reprogrammings, etc., that took place after enactment of the appropriations bill. The FY 1995 number shown is the congressional budget request in current dollars. Budget data for FY 1976 through FY 1994 by specific program area are given in Appendix A.) Sources: DOE budget archives.

2. OVERVIEW OF U.S. DEPARTMENT OF ENERGY PROGRAMS AND PLANNING

2.1. Major Trends in the DOE Coal Program

Trends in federal funding for coal-related R&D since DOE's inception are illustrated in Fig. 1. The 1973 oil embargo and subsequent energy supply uncertainties of the 1970s led to a greater federal role in energy technology development, with increased effort directed at more secure energy supplies, as through greater reliance on plentiful domestic coal. Efforts were focused especially on developing more efficient, cost-effective, and environmentally acceptable coal technologies. The 1980 Energy Security Act established the Synthetic Fuels Corporation to develop the domestic nonconventional energy resources, such as liquid fuels from coal and oil shale. This increased federal interest was reflected in the rapid growth of DOE's Office of Fossil Energy (FE) coal R&D budget in the late 1970s, as Fig. 1 shows.

The intense interest in and funding of federal energy R&D during the 1970s was replaced in the Reagan administration by an emphasis on decontrolling energy markets, relying more on the free market and the private sector. There were significant reductions in federally sponsored fossil energy R&D, cancellations of synthetic fuels demonstration plants, and the eventual phaseout of the Synthetic Fuels Corporation. The marked drop in coal R&D funding from FY 1981 to FY 1982 was largely attributable to very significant reductions in funding for coal liquefaction and surface coal gasification activities. A sharp decline in the world petroleum price in 1986 substantially decreased the economic attractiveness...
of coal-derived petroleum substitutes and the perceived need for R&D in this direction.

However, sustained interest in coal-based power generation technologies led to congressional funding of DOE’s CCT program, starting in FY 1986. This program has constituted a major effort outside the traditional coal R&D projects undertaken by DOE and its predecessor organizations, and CCT funding is therefore not included in Fig. 1. The CCT program has emphasized the need for demonstration and commercial deployment of environmentally responsive, economically competitive technologies and is based on cost sharing between the private sector and DOE, with the former contributing at least 50% of total demonstration cost.

During the Bush administration, the National Energy Strategy report was published, providing an overall administration strategy for energy policy. A fundamental tenet of this strategy was to continue reliance on market forces wherever possible by removing any barriers to efficient market operation. Emphasis was placed on improving energy efficiency and increasing production of domestic oil and natural gas. Coal was recognized as an important domestic source of energy, with emphasis on the development of economically viable technologies achieving specified levels of environmental performance relating to acid rain precursors and greenhouse gas emissions. Thus, in the area of electric power generation, advanced systems characterized by high efficiency, very low pollutant emissions, and competitive economics became the focus of DOE’s coal program. Another recognized need was for R&D to reduce the costs, investment risks, and environmental impacts of producing liquid fuels from coal.

An important initiative of the Clinton administration has been the Climate Change Action Plan. This plan lays out the goals of returning U.S. greenhouse gas emissions to their 1990 levels by the year 2000 and positioning the United States to compete better in the global market. A main thrust of this initiative is to reduce energy demand throughout the U.S. economy by actions that align market forces with the goal of reducing greenhouse gas emissions. Thus, the Clinton administration has promoted increased use of natural gas (which emits less CO₂ per unit of energy than coal or oil), improved energy efficiency, and renewable energy technologies that can release no net CO₂ to the environment. As discussed below, decreased coal R&D funding has accompanied these new emphases.

2.2. The DOE Coal Program Structure and Budget

DOE’s coal-related activities currently fall under two main budget categories: FE R&D and the CCT program. The first category also includes R&D programs in petroleum and natural gas, which are not considered in the present report, except when directly relevant to the coal program (e.g. cross-cutting R&D in advanced turbines and fuel cells). The CCT program was initiated in 1986 and is scheduled to run through 2004, with the specific goal of demonstrating the commercial potential of advanced power generation technologies. The CCT program is thus more transient than FE R&D, which has been in existence since the inception of DOE and forms the continuing basis of DOE’s coal program.

2.2.1. Fossil energy research and development

Annual funding for FE R&D for FY 1992 through the FY 1995 budget request has remained relatively constant, at something over $400 million. However, the oil and natural gas program budgets have increased at the expense of the coal program (Fig. 2).* Fossil fuel prices have declined during the past several years, especially for gas and oil. The low current and projected price of natural gas has resulted in an emphasis on technologies for gas utilization, with the potential to use coal-derived gas. Recent years have seen the completion of R&D on power plant emissions control to prevent acid deposition, and the initiation of new activities to achieve lower emissions of conventional air pollutants and higher power cycle efficiencies. These activities reflect a change in emphasis within the coal portion of the FE R&D program, with a decline in proof-of-concept activities and an increase in funding for demonstration programs. The current program addresses both R&D and technology demonstration.

Table I shows trends in expenditures for the three main budget categories of the FE R&D coal program: Advanced Clean Fuels, Advanced Clean/Efficient Power Systems, and Advanced Research and Technology Development (AR&TD). A major change in the FY 1994 budget was the shifting of the fuel cell program from the coal component of the FE R&D budget to the gas component. The total FE R&D coal program budget has declined by about 25% (almost 30% in real terms) since FY 1992, not including the transfer of the fuel cell activity. DOE’s FY 1995 request would bring the FE coal R&D program budget (in constant dollars) just over half what it was three years ago. However, the budget request is not necessarily a good indication of the final budget, since Congress historically has added funds that DOE did not request.

Both the Advanced Clean Fuels and Advanced Clean/Efficient Power Systems components of the coal program experienced funding reductions of about 30% (in current dollars) between FY 1992 and

*The fuel cell activity was transferred from the coal program to the natural gas program in FY 1994. However, for comparison purposes, fuel cell funding has been included in the natural gas budget rather than the coal budget illustrated in Fig. 2.

†Excluding the fuel cell activity.
FY 1994. A significant part of the decrease in the second program area reflects completion of the magnetohydrodynamics program. High-efficiency IGCC is the only area in the Advanced Clean/Efficient Power Systems program that has seen funding increases each year from FY 1992 through FY 1994.

2.3. CCT Program

In the CCT program the most promising of the advanced coal-based technologies are being moved into the marketplace through demonstration. The demonstrations are at a scale large enough to generate the data needed to judge the commercial potential of the systems developed. Congress originally funded the CCT program with almost $400 million, to be spread over FY 1986 through FY 1988. In March 1987, in response to the Joint Canadian and U.S. Special Envoy recommendations concerning acid rain, President Reagan expanded the CCT program’s funding by $2.35 billion. Congress established that this funding would be offered in five solicitations for cost-shared projects (CCT-Round 1 through CCT-Round V), in which industry would provide at least 50% of the cost of design, construction, and operation of the demonstration project. A unique feature of the CCT program is that each project must commit to repaying the government’s share of the project’s funding from the proceeds of successful commercialization of the technology.

Table 2 shows currently authorized CCT funding, by solicitation round and fiscal year. The CCT program has been authorized and appropriated $2.75 billion altogether, representing 45 active demonstration projects and a total public and private investment of $6.9 billion. The FY 1995 budget request seeks to have previously authorized funding for the CCT program extended to cover solicitation rounds IV and V.

Section 1332 of EPACT calls for solicitations for CCT projects in developing countries or countries with economies in transition from a nonmarket to a market economy. The FY 1995 budget request seeks funding for international ‘showcase’ demonstration projects in Eastern Europe and China. However, it remains unclear whether this will receive congressional approval.

2.3.1. Clean Coal Technologies Research, Development, and Demonstration Program Plan

An important source of information on DOE’s strategic planning for coal is its Clean Coal Technologies Research, Development, and Demonstration (RD&D) Program Plan. This planning document should be distinguished from the similarly named but programmatically distinct CCT program.

Activities described in the RD&D Program Plan are aimed at enabling the use of plentiful U.S. domestic coal resources while meeting environmental requirements. This plan focuses on near-term planning; it does not address requirements for coal utilization beyond 2010. (Thus, the planning horizon corresponds to the near-term period and first five years of the mid-term period defined by the committee.) This plan proposes activities that span the full cycle of technology development, from basic research through demonstration and commercialization. Private industry has an important role to play in all stages, with the degree of industry cost sharing expected to increase as a technology moves toward commercialization. In the CCT program the most promising advanced coal technologies are being moved into the market through demonstration at a scale that permits their commercial potential to be assessed; as noted earlier, industry partners must contribute at least 50% of the demonstration costs.

The advanced power systems program described in the RD&D Program Plan supports the development of several coal combustion and coal gasification options, which are expected to become commercial at different times. The aim is to enable future coal-fired plants to produce lower cost electricity with
Table 1. Fossil energy coal R&D program budget (millions of current dollars appropriated)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Advanced Clean Fuels</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal preparation</td>
<td>15.1</td>
<td>9.9</td>
<td>11.3</td>
<td>5.5</td>
</tr>
<tr>
<td>Direct liquefaction</td>
<td>19.4</td>
<td>15.7</td>
<td>11.4</td>
<td>5.6</td>
</tr>
<tr>
<td>Indirect liquefaction</td>
<td>13.7</td>
<td>16.2</td>
<td>9.1</td>
<td>7.6</td>
</tr>
<tr>
<td>Advanced and environmental technology</td>
<td>7.1</td>
<td>5.9</td>
<td>5.2</td>
<td>0.8</td>
</tr>
<tr>
<td>Systems for coproducts</td>
<td>4.3</td>
<td>1.5</td>
<td>3.9</td>
<td>0.6</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td>59.6</td>
<td>49.2</td>
<td>40.9</td>
<td>20.1</td>
</tr>
<tr>
<td>Advanced Clean/Efficient Power Systems</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Advanced pulverized coal-fired power plant</td>
<td>8.2</td>
<td>9.1</td>
<td>9.1</td>
<td>7.6</td>
</tr>
<tr>
<td>Indirect-fired cycle</td>
<td>24.6</td>
<td>12.1</td>
<td>14.4</td>
<td>11.9</td>
</tr>
<tr>
<td>High-efficiency IGCC*</td>
<td>18.0</td>
<td>19.5</td>
<td>27.2</td>
<td>28.1</td>
</tr>
<tr>
<td>High-efficiency PFBC†</td>
<td>18.6</td>
<td>18.5</td>
<td>24.1</td>
<td>20.4</td>
</tr>
<tr>
<td>Advanced research and environmental technology</td>
<td>26.8</td>
<td>21.7</td>
<td>17.8</td>
<td>13.4</td>
</tr>
<tr>
<td>Magnetohydrodynamics</td>
<td>39.9</td>
<td>29.9</td>
<td>4.8</td>
<td></td>
</tr>
<tr>
<td>Fuel cells‡</td>
<td>51.0</td>
<td>51.1</td>
<td>187.1</td>
<td>161.9</td>
</tr>
<tr>
<td><strong>Subtotal</strong> [136.1]§</td>
<td>[110.8]§</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Advanced Research and Technology Development</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal utilization science</td>
<td>4.0</td>
<td>1.9</td>
<td>3.1</td>
<td>3.1</td>
</tr>
<tr>
<td>Materials and components</td>
<td>9.2</td>
<td>8.9</td>
<td>10.7</td>
<td>7.8</td>
</tr>
<tr>
<td>Technology cross-cut</td>
<td>10.8</td>
<td>9.6</td>
<td>9.3</td>
<td>9.4</td>
</tr>
<tr>
<td>University/national laboratory coal research</td>
<td>5.9</td>
<td>5.9</td>
<td>5.9</td>
<td>6.0</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td>29.9</td>
<td>26.3</td>
<td>29.0</td>
<td>26.3</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>276.6</td>
<td>237.4</td>
<td>167.3</td>
<td>127.8</td>
</tr>
</tbody>
</table>

*Integrated gasification combined-cycle.
†Pressurized fluidized-bed combustion.
‡The fuel cell activity was transferred from the coal program to the natural gas program in FY 1994. Fuel cell budgets are $51.8 million for FY 1994 and $67.8 million for FY 1995 (request).
§Excluding fuel cells.
Sources: DOE. 7, 8

Table 2. Authorized funding for the CCT program (millions of current dollars)

<table>
<thead>
<tr>
<th>Solicitation round</th>
<th>FY 1996</th>
<th>FY 1993</th>
<th>FY 1996</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>CYT-I</td>
<td>398</td>
<td></td>
<td></td>
<td>398</td>
</tr>
<tr>
<td>CYT-II</td>
<td>575</td>
<td></td>
<td></td>
<td>575</td>
</tr>
<tr>
<td>CYT-III</td>
<td>575</td>
<td></td>
<td></td>
<td>575</td>
</tr>
<tr>
<td>CYT-IV</td>
<td>450</td>
<td>100</td>
<td>50</td>
<td>600</td>
</tr>
<tr>
<td>CYT-V</td>
<td>225</td>
<td>275</td>
<td>100</td>
<td>600</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>2223</td>
<td>375</td>
<td>150</td>
<td>0</td>
</tr>
</tbody>
</table>

Source: DOE. 10

Table 3. Strategic objectives of DOE's advanced power systems program

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Efficiency* (%)</td>
<td>42</td>
<td>47</td>
<td>55</td>
<td>60</td>
<td></td>
</tr>
<tr>
<td>Emission†</td>
<td>1/3</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost of energy</td>
<td>10-20% lower than currently available pulverized coal technology</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Based on fuel heating value (see Glossary). A DOE presentation to the committee also noted CO₂ reduction objectives of 32, 34, 42, and 47% for each of the four periods, respectively, based on energy efficiency improvements. 11 All these values are calculated assuming a base plant efficiency of 32%.
†Current federal New Source Performance Standards (NSPS) apply to emissions of sulfur dioxide, oxides of nitrogen, and particulates from coal-based steam generators.
Source: DOE. 3

from coal, emphasizing liquid transportation fuels. There is no work on production of synthetic natural gas (SNG), except for some activities under coal gasification. DOE's strategic objective for the advanced fuel systems program is to demonstrate by 2010 'advanced concepts for production of coal-based transportation fuels, chemicals and other products' that can compete with petroleum products, when petroleum prices are $25/bbl or greater in 1991 dollars, 2 equivalent to $26/bbl in 1992 dollars.

Different bases may be used for estimating production costs for liquid transportation fuels from coal. The electric utility industry with its relatively predictable selling prices for electricity and stable production costs can attract capital at a lower rate than, for example, the oil industry where future product and feedstock prices are much less certain. Major investments are frequently split between a component with relatively assured, but lower return, and a higher return component that will incur a larger risk. In the utility industry a substantially larger component of low-risk borrowed money is more common than in the petroleum industry, where 100% equity financing
has been more commonly practiced. Hence, the term 'utility financing' is frequently used to describe more highly leveraged investments (e.g. 6–65% debt and 35–40% equity) whereas 'petroleum financing' describes the smaller component of borrowed money generally employed in that industry. Utility financing has been used throughout the present report for consistency with DOE's approach (see Glossary for further details), although there is no general consensus on the most appropriate financing basis for estimating equivalent crude costs.

A number of technologies are relevant to both advanced power and advanced fuel systems. Four corresponding 'cross-cutting' technology programs are described in the RD&D Program Plan: coal preparation; alternative fuels utilization; flue gas cleanup; and waste management. Progress in these areas can improve the efficiency, environmental performance, or life-cycle costs of many of the advanced power and fuel systems under development. Specific objectives are defined for each of the cross-cutting technology programs. Three main program areas are defined: advanced power systems; advanced fuel systems; and cross-cutting technology programs. In the broadest terms these three program areas correspond to the three main budget categories of the FE coal R&D program. However, the advanced power systems and advanced fuel systems areas in the RD&D Program Plan also include support of some CCT activities. (DOE's planning objectives for advanced power and fuels systems are evaluated later by the committee in the context of its own strategic planning framework; see Section 10.) These R&D areas are discussed in subsequent sections.

3. TRENDS AND ISSUES FOR FUTURE COAL USE

This section reviews factors likely to influence coal use, especially U.S. domestic coal use, over the periods of interest to this study, namely, near-term (1995–2005), mid-term (2006–2020), and long-term (2021–2040) planning horizons.

3.1. Overview of Coal Markets

Coal is a major international commodity used primarily for generating electricity and producing coke for steelmaking. The first use is increasing steadily; the latter use is constant—slightly declining.

Coal-exporting countries can be divided into two classes. For the first group, including the United States, South Africa, Poland, and parts of the former Soviet Union, coal exports are a fraction of a substantial domestic market. Other countries mine primarily for export. The leading country in this class is Australia, with Colombia and Venezuela also increasing coal exports rapidly. China is a special case: it is the world's largest coal producer, but almost all of its coal is consumed domestically. However, with investment in transportation networks and some automation, China could quickly become a major force in international coal markets. Japan is the world's largest coal importer, while the fastest import growth is occurring in the rapidly developing Pacific Rim countries, especially Taiwan and South Korea.

Over the past 10 years, many changes have occurred in the U.S. coal industry. Although more coal is still produced in states east of the Mississippi River, coal production in the west has increased dramatically; in 1988 Wyoming surpassed Kentucky as the largest producing state. This shift in coal production initially was a result of changes in environmental regulation that favor low-sulfur Western coal. Subsequent factors have been the competitive cost of western coal and a lower cost for its rail transport to markets traditionally served by eastern coal.

Transportation costs are more generally a critical determinant of the competitiveness of coal from different sources. On the Gulf and Atlantic coasts of the United States, South American coals are very competitive with U.S. coals on a delivered price basis. For example, Colombian coal currently is $3–6/ metric ton cheaper than U.S. coals. About 10% of the coal used in the United States during the first decade of the next century will likely be imported.

Another change in the industry has been the continued decrease in the price paid for coal at the mine. For mines producing 10,000 tons/year or more, the average price at the mine decreased in 1992 for the 10th straight year, to $21.03/ton. This trend of decreasing coal prices is expected to persist for the near term, keeping coal a relatively low cost energy source for the United States.

Coal exports contribute significantly to the U.S. balance of payments. Of the total 1992 U.S. coal production of 998 million tons, 103 million tons were exported, primarily to Europe (57%), Asia (20%), and North America (15%). Coking coal exports amounted to $2.7 billion and steam coal to $1.5 billion. Most U.S. exports are metallurgical coals, purchased because of their high product quality and consistency, which are important parameters in making coke. However, coke production worldwide is decreasing, as environmental regulations and newer technology change the way steel is produced and as other materials are substituted for steel. Despite increasing international markets for steam coal, this sector of the U.S. export market is expected to remain flat or decrease, because U.S. coal is not

*Unless otherwise noted, all 'tons' referred to in the text are short tons (i.e. 2000 lb or 0.91 metric tons).
competitive on a delivered-price basis with South American and South African coals in Europe and the Middle East, nor with Australian and Indonesian coals in Asia.

3.2. Markets for Export of Coal Utilization Technology

The most important international markets for coal utilization technologies are for electricity generation. Two major market components have been identified, namely, the construction of new generating capacity and the retrofit and rehabilitation of existing plants. More than half of the new capacity market will be in China, where projected capacity additions are approximately three times those of South Asia, the second largest market. China's need for new capacity through 2010 is more than four times that of all the industrialized countries combined. The world retrofit market, which is driven largely by environmental considerations, is about 25% larger in total size than the market for new capacity. About 45% of the retrofit market lies in developing countries, notably China. Significant markets also exist in Eastern Europe and the former Soviet Union.

The demands for new and retrofit capacity represent potentially large export markets for U.S. technology. Many of the advanced power generation and environmental control technologies being developed under DOE's CCT program might achieve the two principal market requirements: high efficiency and minimal environmental impacts. It is very difficult, however, to project the extent of U.S. participation in these international markets. Determining factors will include the effectiveness of foreign competition, the rate of industrialization in the less developed countries, the economic balance between coal costs and the capital costs of new technology, and the environmental constraints within the purchasing countries.

Environmental constraints will have some of the greatest impacts on international sales of coal-related technology. These environmental constraints will depend on the degree of industrialization and urbanization. Urbanization is accompanied by environmental problems so acute that even developing countries strained for capital resources cannot ignore them. In Turkey, for example, which is seeing a massive population shift from rural to urban areas, in major cities there is a shift from indigenous coal to imported natural gas as a home heating fuel, and scrubbers for sulfur dioxide removal are being retrofitted on power plants that use high-sulfur, usually low-rank, local coal. In China coal gasification is being used to ameliorate some critical instances of pollution. The motivation to reduce coal-related pollution may be domestically driven or may be a response to environmental requirements imposed by aid donors and international financial institutions. The World Bank now considers environmental impacts as a primary factor in evaluating proposed projects.

3.3. Changes in Structure of the Electric Utility Industry

The electric utility industry has been subject to extensive price and entry regulation virtually from its beginning almost a century ago. Like other formerly heavily regulated industries, such as transportation, telecommunications, and natural gas, the electric utility industry has seen notable changes of regulatory structure and practice in recent years.

The Public Utility Regulatory Policy Act of 1979 (PURPA) and subsequent regulation and legislation, at both state and federal levels, have permitted non-utility generators (NUGs) to sell power to the transmission grid. PURPA provided the first opportunity since the development of the modern regulatory system for entry into the utility franchise by requiring electric utilities to purchase power offered by cogenerators, small power producers, and other qualifying facilities when the price of purchased power was below the utility's own avoided cost. Independent power producers (IPPs) were excluded from the provisions of PURPA, but later changes, such as enactment of EPACT that allows utilities and non-PURPA generators to compete on a wider scale in the wholesale power market, permitted and even encouraged electric utilities to acquire additional capacity and power from NUGs without regard to PURPA's qualification requirements. Increasingly, access to the transmission and distribution network is being proposed for a variety of currently captive customers. Although there are many problems to be resolved, deregulation of the electric utility industry is expected to continue, to probably intensify, and to become one of the dominant strategic concerns of electric utility managers.

For this paper the question at issue is how the industry's deregulation should shape DOE's coal program. The principal areas of concern appear to be the power generation industry's ability to develop and adopt promising new technology and the availability of electricity produced jointly with other products, as in cogeneration of power and steam.

3.3.1. Introduction of new technology

The electric utility industry's former regulatory structure provided a highly favorable environment for introducing new technology: the return of prudently incurred costs was allowed, reducing commercialization risks. The efficiency of conventional coal-fired power plants increased markedly from the
early 1900s until the 1960s without the benefit of significant federal R&D funding. Beginning in the 1960s, the industry commercialized nuclear power based on federally funded R&D. Since the early 1970s the industry has also funded significant R&D through the EPRI, with most members’ contributions incorporated into the rate structures approved by regulatory commissions.

As regulatory structures loosen and competition intensifies, new entrants and less-protected utilities may be unwilling or unable to accept the risks of commercialization or to fund industrywide R&D. In this regard the power generation industry differs markedly from the pharmaceutical and telecommunications industries, for example, largely because of the nature of its product. The influence of increasing competition in the electric utility industry can already be observed in the reliance on NUgs for additional increments of capacity and in the shift of EPRI’s focus toward activities of more short-term benefit to its members. A recent report from the National Regulatory Research Institute notes that the technical and financial risks inherent in adopting innovative generation technologies may bias technology choices in favor of conventional options. As a result of these trends, the future development and implementation of advanced power generation technologies will likely become increasingly dependent on federal funding of R&D and on federal participation in commercializing new technology, at least in the near term.

3.3.2. The availability of coproducts

Under traditional regulation, electric utility companies specialized in, and had a monopoly on, the production and distribution of electricity in a given region. Sizeable economies of scale were realized under this arrangement, but it did not encourage the capture of economies that result from coproducing electricity and other products, such as steam. Electric utilities did provide steam to some customers but generally only in the centers of large and usually older cities because of the economics of distributing steam. In most cases customers who needed steam for industrial processes produced their own. They might also generate electricity, but for a variety of reasons, including regulation, they could not sell excess electricity to the local electric utility.

The recent changes in the electric utility industry sketched above have created the opportunity to realize economies where electricity, or the fuels to generate electricity, are the by-product of some other industrial process. These processes typically operate at a smaller scale than the conventional electric utility generating unit, and this feature has meshed well with smaller-capacity additions demanded by recent slower electricity growth. The joint production of electricity and steam has been the main beneficiary of these changes to date. Coproduct systems are discussed further in Section 6. The gas turbine combined-cycle systems now being installed that use natural gas as a fuel also offer opportunities to use clean coal-based gases, either as an integral part of the power generation system or obtained as a fuel from a separate supplier.

3.4. Projected Electricity Requirements

Table 4 gives growth rates observed and projected by the Energy Information Administration (EIA) for U.S. electricity demand from 1960 to 2010. According to recent EIA projections, electricity demand will grow 1.0–1.5%/year to 2010, while the gross domestic product over the same period will grow 1.8–2.4% annually, for 'low' and 'high' economic growth cases. The decrease in electricity demand growth relative to growth in the gross domestic product through 2010 is expected to result primarily from energy efficiency improvements associated with demand-side management and compliance with the directives of EPACT. The industrial sector is the fastest-growing demand sector in the EIA projections.

Alternative estimates from Data Resources, Inc. (DRI)/McGraw-Hill suggest that the trend in electric demand growth will average 2.0%/year from 1993 to 2010, during which time there will be a 2.3% annual increase in the gross domestic product. These projections assume a smaller impact of demand-side management on electricity demand than the EIA projections.

EIA projections of new capacity needs to meet new demands and to offset plant retirements are summarized in Fig. 3. These new capacity requirements are in addition to the augmentation of existing resources through electricity imports and through plant life extension and repowering (see below). Between 1990 and 2010, utilities are expected to install 110 GW of new capacity in the EIA reference case but retire 60 GW, for a net capacity increase of 50 GW. In response to legislative changes aimed at making electricity production more competitive, NUGs and cogenerators are expected to add an additional

<table>
<thead>
<tr>
<th>Period</th>
<th>Gross domestic product growth (%)</th>
<th>Electricity demand growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1960–1970</td>
<td>3.8</td>
<td>7.3</td>
</tr>
<tr>
<td>1970–1980</td>
<td>2.8</td>
<td>4.2</td>
</tr>
<tr>
<td>1980–1990</td>
<td>2.6</td>
<td>2.6</td>
</tr>
<tr>
<td>1990–2010</td>
<td>1.8–2.4</td>
<td>1.0–1.5</td>
</tr>
</tbody>
</table>

*Italics indicate projected values.
Source: EIA.17
73 GW, accounting for a large share (40%) of total new capacity additions of 183 GW over the forecast period. Figure 3 shows that new capacity will be needed particularly between 2000 and 2010, during which time repowering and other options will be insufficient to meet increased demand. The surplus capacity of the 1980s still persists in some areas, and it will probably not be completely employed in many areas until the turn of the century. Thus, projected capacity additions lag projected increases in demand. Despite these different assumptions, coal is projected to be a major energy source for power generation in 2010.

The additional generating capacity does not necessarily require the construction of new plants. Repowering, broadly defined to include any activity that stabilizes or reverses the age-induced deterioration of generating units, can result in improved efficiency and increased generating capacity at less than replacement cost. According to some projections, an emphasis on repowering—including performance optimization, component replacement, component refurbishment, life extension, and/or unit upgrading—is likely over the next decade. This forecast trend is consistent with the low number of scheduled power plant retirements reported to the North American Reliability Council for the period through 2003. Although a large number of the fossil-fuel-fired steam plants operating today are nearing the end of their nominal life (40-45 years), utilities appear to be planning to continue using them for the foreseeable future.

The choice of technologies to meet additional
Table 6. Various coal consumption forecasts, 2000 and 2010 (in millions of tons)

<table>
<thead>
<tr>
<th>Year/forecast</th>
<th>EIA AEO94</th>
<th>DRI</th>
<th>GRI</th>
<th>WEFA</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production</td>
<td>1081</td>
<td>1090</td>
<td>1091</td>
<td>1060</td>
</tr>
<tr>
<td>Consumption</td>
<td>958</td>
<td>961</td>
<td>973</td>
<td>958</td>
</tr>
<tr>
<td>Power generation</td>
<td>847</td>
<td>844</td>
<td>863</td>
<td>847</td>
</tr>
<tr>
<td>2010</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Production</td>
<td>1223</td>
<td>1379</td>
<td>1333</td>
<td>1278</td>
</tr>
<tr>
<td>Consumption</td>
<td>1079</td>
<td>1237</td>
<td>1182</td>
<td>1165</td>
</tr>
<tr>
<td>Power generation</td>
<td>950</td>
<td>1004</td>
<td>1077</td>
<td>1053</td>
</tr>
</tbody>
</table>

Notes:
DRI, Data Resources, Inc./McGraw Hill.
GRI, Gas Research Institute.
WEFA, Wharton Economic Forecasting Association.
The WEFA Group.
Source: EIA.17

generating capacity requirements depends on both peakload and baseload needs. Peakload is the maximum load during a specified period of time, whereas baseload is the minimum amount of power required during a specified period at a steady state. According to EIA projections,17 there will be a need through 2010 for flexible generating technologies, such as gas-fired or oil-and-gas-fired combined-cycle and combustion turbine systems, designed primarily to meet peak and intermediate load requirements but able to meet baseload requirements as needed. Peakload requirements are anticipated to increase from 589 GW in 1994 to 804 GW in 2010.22

3.5. Energy Sources for Power Generation

This section addresses the major competing sources of energy for electric power generation over the time periods of interest for this study.

3.5.1. Coal

The coal base of the world is large, some 1,145 billion tons. The top two producing countries are China and the United States. The U.S. demonstrated reserve base (DRB) of coal is now estimated to be 474 billion tons.25 The DRB is the amount of coal that can potentially be mined by surface or underground methods. The amount of coal that can be extracted economically using available technology, taking into consideration the laws, regulations, economics, and usages that affect coal production, is the recoverable portion of the DRB.26 With a current U.S. production of approximately 1 billion tons/year resource limitations are not expected to be important within the time horizon considered in this study.

All projections for U.S. coal consumption indicate that coal will continue to be a major source of fuel for electricity generation up to and beyond 2010. A range of forecasts is shown in Table 6. Estimates of coal's share of the power generation market in 2010 range from 45–58%, slightly lower on average than the current value of 56%. New coal-steam units are expected to account for 25% (42 GW) of all new capacity additions through 2010, with approximately three-fourths of the new coal-fired capacity coming online after 2000.17 This 42 GW of new coal capacity is equivalent to 140 new power plants in the 300-MW size range.

3.5.2. Natural gas

In recent years natural gas has become the fuel of choice for new power generation capacity additions because of its currently low price and lower capital investment requirements. While domestic gas resources are adequate to support this trend in the near-term, depletion of domestic gas resources will likely result in reduced availability and higher prices within the time period considered in this study.

Estimates of the remaining technically recoverable domestic natural gas resource provide some perspective on the future use of natural gas for power generation. A comparison of such estimates has been prepared by the Potential Gas Agency at the Colorado School of Mines.27 Assuming current technology and unspecified prices in the lower 48 states, and varying assumptions on access to potential gas fields, the estimates ranged from a low of 650 trillion cubic feet (Tcf), the value used in formulating the 1991 National Energy Strategy, to the Gas Research Institute (GRI) 1993 estimate of 1,100 Tcf. The National Petroleum Council estimate of 870 Tcf falls between these extremes. Table 7 gives National Petroleum Council estimates of the effect of wellhead price on the recoverable resource (in this case Alaska was included). Table 7 also shows the estimated effect of advances in technology expected by the year 2010 and illustrates the pronounced effect of increased wellhead prices on resource recovery. Cumulative production through 1992 was approximately 800 Tcf. This is about equal to the remaining resource even for a wellhead price of $3.75/10^6 Btu.28 The Canadian gas resource is about half the U.S. resource but a smaller fraction has been produced. It is projected by GRI (1995)29 to supply about 11% of total U.S. natural gas consumption in the year 2010.

Dividing the total amount of gas by the current annual consumption provides a rough measure of the time before depletion, assuming constant consumption (see Table 7). The actual time will depend on consumption rate, which is expected to rise for the next decade and then decrease as finding and production costs increase with progressive resource
Table 7. National petroleum council estimate of remaining recoverable domestic natural gas*†

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Unspecified</td>
<td>1065 (Tcf)</td>
<td>1295 (Tcf)</td>
</tr>
<tr>
<td>$3.74</td>
<td>600 (Tcf)</td>
<td>825 (Tcf)</td>
</tr>
<tr>
<td>$2.67</td>
<td>400 (Tcf)</td>
<td>600 (Tcf)</td>
</tr>
</tbody>
</table>

*These amounts include production in Alaska, which, at higher prices, might be delivered to the lower 48 states and which, for the unspecified price and advanced technology case, was estimated to be 15% of the total resource.
†Total U.S. natural gas production up to 1990 was approximately 700 Tcf.
‡The EIA projects a wellhead price rise to $3.50/million Btu by 2010. The price to a utility is greater than the wellhead price and may vary by region. In 1992 the average wellhead price was $1.75/thousand cubic feet (Mcf), whereas the delivered price to electric utilities was $2.36/Mcf.
§Improvements in imaging of underground structure, in fracturing to improve production rate, and in other production-related technologies that are believed to be reasonable extrapolations of the current state of the art.
¶U.S. consumption in 1992 was 18 Tcf.
Source: Potential Gas Committee.

3.5.3. Liquefied natural gas

In considering the outlook for natural gas in the United States, attention must also be given to liquefied natural gas (LNG). Small amounts of LNG are presently imported into the United States. More importantly, there are huge, low-cost reserves of natural gas in the Pacific Basin and Middle East that, when liquefied, can be transported across oceans. Thus, the cost at which LNG can be imported operates as a limit on the domestic price of natural gas and on the price that would be paid for gas produced from domestic coal.

The process through which natural gas is liquefied, transported at cryogenic temperatures, and regasified is unique and costly and was economic only when domestic gas prices were higher than present. Several LNG facilities were built on the East and Gulf coasts of the United States during the 1970s. However, LNG projects in the United States were abandoned once the domestic natural gas price decreased as a result of deregulation, and new proposals by potential exporters have not succeeded. An advantage of LNG for power generation is that it can be stored and used to meet peaking requirements without the need to construct larger pipelines.

In view of these considerations, LNG will not figure as an economic source of energy for power generation until natural gas prices rise to approximately $5/10^6 Btu. In the United States, coal gasification and other options should be economic at lower prices.
Table 8. U.S. Natural gas supply and disposition, 1992–2010 (quads)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EIA</td>
<td>18.51</td>
<td>19.63</td>
<td>20.87</td>
<td>20.89</td>
<td>0.7</td>
</tr>
<tr>
<td>GRI</td>
<td>18.10</td>
<td>20.00</td>
<td>21.20</td>
<td>22.40</td>
<td>1.2</td>
</tr>
<tr>
<td>Net imports</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EIA</td>
<td>2.49</td>
<td>2.95</td>
<td>3.32</td>
<td>3.86</td>
<td>2.5</td>
</tr>
<tr>
<td>GRI</td>
<td>2.10</td>
<td>3.10</td>
<td>3.70</td>
<td>3.80</td>
<td>3.3</td>
</tr>
<tr>
<td>Total supply</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EIA</td>
<td>21.00</td>
<td>22.58</td>
<td>24.19</td>
<td>24.75</td>
<td>0.9</td>
</tr>
<tr>
<td>GRI</td>
<td>20.20</td>
<td>23.20</td>
<td>24.90</td>
<td>26.20</td>
<td>1.5</td>
</tr>
<tr>
<td>Total consumption</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EIA</td>
<td>20.15</td>
<td>22.67</td>
<td>24.31</td>
<td>24.89</td>
<td>1.2</td>
</tr>
<tr>
<td>GRI</td>
<td>20.30</td>
<td>23.10</td>
<td>NA</td>
<td>26.10</td>
<td>1.4</td>
</tr>
<tr>
<td>Power generation</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EIA</td>
<td>2.86</td>
<td>4.36</td>
<td>5.24</td>
<td>5.10</td>
<td>3.3</td>
</tr>
<tr>
<td>GRI</td>
<td>2.88</td>
<td>3.91</td>
<td>NA</td>
<td>4.32</td>
<td>2.3</td>
</tr>
</tbody>
</table>

NA, not available.
Sources: EIA,17 GRI.30

Table 9. Projected natural gas prices for electric utilities (dollars/million Btu)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>EIA</td>
<td>2.28</td>
<td>3.03</td>
<td>3.88</td>
<td>4.43</td>
<td>3.8</td>
</tr>
<tr>
<td>GRI</td>
<td>2.47</td>
<td>3.15</td>
<td>NA</td>
<td>3.78</td>
<td>2.4</td>
</tr>
</tbody>
</table>

NA, not available.
Sources: EIA,17 GRI.30

3.5.4. Oil

If crude oil prices were to fall to $12/bbl or less, coal might find a competitor for power generation in low-sulfur residual or distillate fuel. Distillate can be used in combined-cycle power generation systems as a substitute for natural gas, LNG, or coal-derived gas. The use of cheaper residual fuel is not currently feasible in turbines, but at a low enough price (less than $1.50/10^6 Btu, or approximately $9.50/bbl) it could displace coal in some existing boilers, as it has in the past.

3.5.5. Nuclear power

Nuclear power accounted for 21% of U.S. electric power generation in 1993 and 14% of total U.S. generating capacity. However, no new commercial orders for U.S. nuclear power plants are anticipated until well after 2000. Nonetheless, recognizing the future attractiveness of electricity from nuclear fusion, in part because of the potential for simpler, more economical nuclear plants, U.S. suppliers, nuclear utilities, the federal government, and EPRI are supporting the development of advanced light-water reactor designs (both evolutionary 1,300-MW units and mid-size 650-MW units), to be available for order by the mid-1990s. Modular high-temperature gas reactor and advanced liquid metal reactor designs are under development. Although these designs may be available as early as 2005, their adoption is uncertain. While concern over greenhouse gas emissions could increase the attractiveness of nuclear power plants relative to coal, the economic and environmental issues associated with plant operation and waste disposal are assumed to impede any significant growth of nuclear capacity in the near to mid term. In the committee's base scenario, significant deployment of new nuclear power plants is unlikely until after 2020.

Considering installed and anticipated nuclear power plants in the United States and worldwide, there is no prospect of a uranium shortage before 2020. However, a significant expansion of nuclear power thereafter could challenge accessible uranium supplies. If supply constraints forced up uranium prices after 2020, the continued use of nuclear-based electricity would require technology development on fast breeder reactors and fusion reactors.

3.5.6. Renewable energy

Most electricity from renewable resources in the United States comes from hydroelectric power, which in 1993 accounted for about 10% of installed generating capacity and 9% of electricity generation. Other renewable sources accounted for 0.3% of electricity generation in 1993: geothermal, biomass wastes from municipal solid waste), modest but growing amounts from wind turbine 'farms', and distributed high-value, high-cost, solar photovoltaic power.

Cost reductions in renewables have resulted from persistent R&D, field experience, and manufacturing automation made possible through federal and private investments. EPRI has projected cost ranges for
wind, photovoltaic, and biomass, assuming favorable locations (Table 10). These data indicate likely increases in cost over the next 15 years, together with changes in the relative economics of different renewable sources. Although wind and biomass may be attractive for specific applications in favorable locations, it is clear that renewables could not meet energy demands across the economy as a whole.\textsuperscript{31}

Many utilities look at renewable technologies as a strategically valuable set of contingency options if prices rise substantially or fossil fuel use is curtailed. For example, policy actions to tax emissions would make renewables more competitive. While renewable energy sources are expected to gain a larger share of the U.S. power generation market (16\% by 2010, according to EIA\textsuperscript{17}), they are not expected to become dominant sources of bulk power generation during the periods addressed in this study.

3.6. Coal Use for Liquid and Gaseous Fuels

While electric power generation is expected to be the principal use for coal in the near- to mid-term periods, liquid and gaseous fuels derived from coal have the potential to compete with natural gas- and petroleum-based fuels in the mid and long term.

3.6.1. Resource base for petroleum and bitumen\textsuperscript{*}

Liquid hydrocarbon resources can be classified on the basis of viscosity as conventional petroleum, heavy oil, and tar (or bitumen).\textsuperscript{†} Because of its low viscosity, petroleum tends to accumulate in large pools with natural gas and is relatively cheap to produce, with high resource recovery. In general, it contains less sulfur than the heavier hydrocarbons and can be refined to specification fuels more easily and cheaply than heavy oils and tars. While large resources of heavy oils and tars have been found,

---

\textsuperscript{*} The resource for natural gas was discussed above in the context of fuels for power generation.

\textsuperscript{†} Defining viscosities are as follows: conventional petroleum, less than 100 centipoise (cp); heavy oil, 100–10,000 cp; tar or bitumen, greater than 10,000 cp.

---

Table 10. Comparative costs of electricity from wind, photovoltaic, and biomass sources (cents/kWh)

<table>
<thead>
<tr>
<th>Source</th>
<th>1990</th>
<th>2000</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>8-10</td>
<td>4</td>
<td>3-4</td>
</tr>
<tr>
<td>Photovoltaic</td>
<td>37-53</td>
<td>11-32</td>
<td>9-16</td>
</tr>
<tr>
<td>Biomass</td>
<td>5-9</td>
<td>5-6</td>
<td>4-5</td>
</tr>
</tbody>
</table>

Source: Preston.\textsuperscript{31}

Table 11. World and U.S. petroleum resources

<table>
<thead>
<tr>
<th>Source</th>
<th>1992 resource consumption (billion bbl)*</th>
<th>Total resource (billion bbl)</th>
<th>Resource/1992 consumption (years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>World</td>
<td>20.4</td>
<td>17001</td>
<td>83</td>
</tr>
<tr>
<td>United States†</td>
<td>3.1</td>
<td>99-204§</td>
<td>32-66</td>
</tr>
</tbody>
</table>

* Data from EIA.\textsuperscript{17}

† Total U.S. petroleum consumption in 1992 was 6.2 billion bbl, with about 50\% accounted for by oil imports.\textsuperscript{17} If total consumption were used for the last column, the resource/consumption value for the United States would decrease to 16-33 years.

‡ See Riva.\textsuperscript{32}

§ Low number based on current technology and price of $20/bbl; high number based on advanced technology and price of $27/bbl.\textsuperscript{23}

current production is restricted by the higher production and refining costs. Estimates of world and U.S. petroleum resources are shown in Table 11.

Petroleum finding and production costs for major producers are currently well below the international price, which includes profit taken by producing countries and by private investors, and is the result of an extremely complex combination of economic and political factors. As low-cost resources are depleted and production costs rise, the trading cost can be expected to rise.

In addition to conventional petroleum, there are substantial resources of heavy oil and bitumen.\textsuperscript{32}† The total world resource for heavy oil is estimated to be 600 billion bbl (equal to 35\% of the conventional petroleum resource). About 50\% of the heavy oil resource occurs in Venezuela and about 30\% in the Middle East. The total resource for tar sands bitumen is approximately 3,500 billion bbl, but only 5-10\% of this amount is currently considered to be economically recoverable. Here Canada is dominant, with 75\% of the world total. Both heavy oil and bitumens require more costly production and refining than conventional petroleum and are not competitive with petroleum at current prices.

To compete with coal for power generation, heavy oils and bitumen would require pollution control similar to that required for coal, because of their high sulfur and metals content. To compete with coal at approximately $1.4/million Btu,\textsuperscript{§} the deliv-

\textsuperscript{†} Heavy oil is defined as crude oil with an American Petroleum Institute gravity between 10° and 20° and viscosity between 100 and 10,000 cp (American Petroleum Institute gravities are expressed in degrees and the specific gravity of water is defined as 10°). Bitumen is more viscous and dense and is produced by mining.

\textsuperscript{§} Based on projected ninemonth price in 2010 of $30.9/ton\textsuperscript{11} and Btu content of approximately 21 million Btu/ton.
Table 12. Projections for domestic coal consumption by end use, 1990–2010 (million short tons)*

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential and</td>
<td>7</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>5</td>
</tr>
<tr>
<td>commercial</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Industrial</td>
<td>76</td>
<td>74</td>
<td>87</td>
<td>94</td>
<td>101</td>
</tr>
<tr>
<td>Coke plants</td>
<td>39</td>
<td>32</td>
<td>28</td>
<td>24</td>
<td>21</td>
</tr>
<tr>
<td>Electricity generation</td>
<td>774</td>
<td>780</td>
<td>837</td>
<td>862</td>
<td>950</td>
</tr>
</tbody>
</table>

*Data for 1990 and 1992 are actual rather than projected values.
Source: EIA.18

The measured price of tars would need to be about $9/bbl or less. The above considerations support the assumption that unrefined tars and heavy oils will not displace a significant amount of coal for power generation in the foreseeable future.

3.7. Other Uses of Coal

Coal still has some uses as a fuel outside the utility sector. Industry burns coal as a boiler fuel to raise steam. Limited use is also seen commercially in a variety of smaller boiler designs and some U.S. households continue to burn coal for space heating.17 The primary use of coal not combusted directly is the production of metallurgical coke, which is both the fuel and the source of the reducing agent (carbon monoxide) in smelting various ores. The most important application of metallurgical coke is for reduction of iron ores in blast furnaces. EIA projections (reference case) of domestic coal consumption for these applications through 2010 are shown in Table 12. Data on coal use for electricity generation are included for comparison.

The only anticipated growth in demand (except for electricity generation) is industrial steam, due largely to growth in coal use for cogeneration in the chemical and food processing industries. The utilization of coke in the iron and steel industry is steadily diminishing for several reasons. First, improvements in blast furnace technology have significantly reduced the amount of coke required to produce a ton of iron. Second, there has been a major shift away from the use of blast furnaces toward the use of electric furnaces that use scrap steel. This change has reduced the demand for freshly produced pig iron or steel, reducing the need for coke. Third, the domestic iron and steel industry has suffered from competition with imported steel products, further reducing the domestic use of coke. No major upturn in the demand for metallurgical coke is foreseen for the periods of interest to this study.

The conversion of coal to metallurgical coke yields by-product hydrocarbon mixtures commonly known as coal tar. The value of coal tar as a source of chemicals or synthesis material for other products began to be recognized in the 1870s. For about 75 years, until the end of World War II, virtually the entire organic chemical industry was based on the utilization of coal tar. However, in the past half-century the organic chemical industry has shifted to the use of petroleum and natural gas, although coal tar is still a useful source of certain specialty chemicals, such as aromatic hydrocarbons with multiple fused aromatic rings, and coal tar pitch has some niche applications that cannot be satisfied by petroleum-derived pitch. When imported petroleum increases in cost, coal could once again become a source of chemical products, though any large market for chemicals based on coal is not likely to develop until it becomes economic to produce gaseous and liquid fuels from coal.

Coals have a variety of other specialized uses, most of them low-volume applications. For example, anthracites can be used as filter material for tertiary water treatment processes. Lignites have some ion-exchange behavior and can be used in some cases as inexpensive ion-exchange ‘resins’. These applications include wastewater treatment (e.g. the removal of chromium from electroplating wastes) and the concentration of ions, such as gold, in hydrometallurgy. Lignites can also be converted into so-called humic acids, which are useful soil amendments and can be nitrated to form fertilizers. There is also interest in converting coals, particularly those of high carbon content, into carbon-based materials, such as graphites. Most of the R&D on these niche applications is taking place outside the United States. At the present time, no significant domestic markets for these applications are anticipated during the period addressed in this study.

3.8. Environmental Issues for Coal Use

Environmental concerns will have a major effect on future coal use for power generation in the industrialized countries.26 In the United States, coal-fired power plants are already subject to a range of emission controls that will likely become increasingly stringent and wide ranging over the periods addressed by this study. Current and possible regulations governing emissions from coal-fired power plants are summarized below, along with comments on the current status of control technologies. Emissions control technologies are discussed in more detail in Section 7.

National ambient air quality standards for particulate matter, sulfur dioxide (SO₂), nitrogen dioxide (NO₂), and photochemical ozone were promulgated under the 1970 Clean Air Act to protect human
health and welfare throughout the country. The primary drivers of technology innovation to control air quality over the past two decades have been pollutant-specific emission standards for new and existing air pollution sources, together with the ambient air quality standards, promulgated by federal and state governments.

In contrast to ambient air quality standards, aimed at protecting human health, acid deposition regulations guard against cultural and ecological damage to aquatic systems, forests, visibility, and materials. Anticipation of acid rain controls was the main factor motivating SO$_2$ and nitrogen oxides (NO$_x$, a mix of NO and NO$_2$) control technology development during the 1980s. The acid deposition provisions of the 1990 Clean Air Act amendments (CAAAAs) established for the first time an absolute cap on total U.S. SO$_2$ emissions, with provisions for emissions trading to achieve the required overall reduction in utility emissions most cost effectively. A reduction in NO$_x$ emissions was also mandated, although no cap on total emissions was established.

Significant progress has been made over the past decade in the capability of commercial systems to reduce SO$_2$, NO$_x$, and particulate emissions from pulverized coal-fired power plants. Emissions trends for a new pulverized coal power plant burning medium-sulfur coal are shown in Fig. 4. Air pollution control devices today achieve emission levels well below federal new source performance standards (NSPS). The most efficient wet scrubbers reduce SO$_2$ emissions to about one-fourth to one-sixth of NSPS requirements (98% control). The most efficient commercial systems yield particulate emissions of about one-half to one-quarter of NSPS levels (99.9% control). U.S. technology for power plant NO$_x$ control has focused on combustion modification methods that currently reduce emissions to about one-half to two-thirds of NSPS levels (50–60% control). In Japan and Germany, post-combustion controls achieving up to 80% NO$_x$ reduction (about one-third to one-sixth NSPS levels) are in widespread use on low-sulfur coal plants. These controls have

---

*Photochemical ozone is formed from emissions of volatile organic compounds (VOCs) and nitrogen oxides (NO$_x$) via a complex series of chemical reactions fueled by sunlight. While the emphasis in the past has been control of VOCs, improved understanding of photochemical smog formation now indicates that NO$_x$ controls must be a more significant component of ozone reduction strategies.*

---

Fig. 4. Trend in emission rates of criteria air pollutants from a new pulverized coal power plant. Percentage reductions are relative to an uncontrolled power plant based on a dry-bottom tangentially-fired boiler firing bituminous coal of 10,000 Btu/lb heating value and containing 2.5% sulfur, 12% ash, and 10,000 Btu/lb. Percentages on the bars are % reductions relative to uncontrolled emissions of that component. (NSPS = new source performance standards; FGD = flue-gas desulfurization (wet magnesium-enhanced lime); FF = fabric filter (baghouse); ESP = electrostatic precipitator; LNB = low NO$_x$ burner; SCR = selective catalytic reduction.)
not yet been deployed in the United States, but such systems are now being demonstrated at U.S. plants as part of DOE’s CCT program, and several are offered commercially. Post-combustion NO\textsubscript{X} controls that employ selective catalytic reduction have been installed on several gas-fired power plants, including combustion turbines, to meet state and local air quality requirements. Over the next 10 years, new requirements for NO\textsubscript{X} reductions at existing and new coal-based power plants are likely, in order to achieve national ambient air quality standards for tropospheric ozone. Also possible are new standards for fine particulates. Future NO\textsubscript{X} controls would likely exceed the modest reductions (10\% of 1980 levels) already required for acid deposition control.

Title III of the 1990 CAAAs lists 189 substances as ‘air toxics,’ subject to maximum-achievable control technology when emitted at rates of 10–25 tons/year from designated industrial and other sources. Emissions of these hazardous air pollutants from fossil-fueled power plants were exempted from the CAAAs provisions pending further study by the U.S. Environmental Protection Agency (EPA). Air toxics of primary concern to utilities are the 10–20 trace substances commonly found in coal, including arsenic, mercury, selenium, nickel, cadmium, and other heavy metals. The basis for regulating emissions of these species from electric utilities would be an EPA finding of an unacceptable health risk or an ecological risk to one or more regions of the country named in the 1990 CAAAs. Independent of EPA action, however, individual states may impose regulations or guidelines on emissions of hazardous air pollutants.

Current worldwide concern over potential global warming may pose the greatest long-term threat to expanded coal use, primarily because of the emissions of the ‘greenhouse gas’ carbon dioxide (CO\textsubscript{2}) from coal combustion. Over the mid to long term, CO\textsubscript{2} emission reductions may be critical to address these concerns, although policy measures could force such reductions sooner. At the present time there is significant scientific uncertainty regarding timing, magnitude, and consequences of increased greenhouse gas emissions. Inevitably, such uncertainty is reflected in varying views about the need for CO\textsubscript{2} emissions controls. However, the preponderance of scientific opinion—as reflected, for example, by a recent NRC study—suggests that the threats are of sufficient concern to warrant some initial actions. Together with some 150 other nations, the United States is already committed to a program of CO\textsubscript{2} reduction by virtue of being a signatory to international agreements stemming from the 1992 United Nations Conference on the Environment. Such reductions are currently voluntary, although the Clinton administration is aggressively and successfully pursuing utility participation. The EPACT also involves utilities in programs to establish baseline CO\textsubscript{2} emissions.

The most cost-effective method of reducing CO\textsubscript{2} emissions from power generation and other coal-based systems is to improve the systems’ overall efficiency. DOE’s strategic objectives for its Advanced Power Systems Program are consistent with this approach (see Section 7). Technology exists to remove CO\textsubscript{2} from combustion gases and other coal-based gas streams, but the costs of doing so are high, and no proven methods yet exist for disposing of the collected CO\textsubscript{2}. Beyond the 2040 planning horizon considered in the present study, other technologies might become available. For example, very high temperature nuclear reactors might be used as an energy source in fossil fuel conversion processes, such as steam gasification of coal, to reduce their greenhouse gas emissions.

Methane from coal mining is also of concern as a greenhouse gas. It has been estimated that in the United States approximately 3.6 million metric tons of coalbed methane is released each year in this process. A large percentage of this total is from underground mining. About 30\% of concentrated methane from wells in the coal seam is now collected and used. The ventilation air exhaust, which typically contains less than 1\% methane, is not generally collected and makes up over 70\% of the total methane released to the atmosphere from coal mining. Estimates indicate that the greenhouse effect of the methane released from underground coal mining represents up to 8 or 9\% of the greenhouse effect of the CO\textsubscript{2} released in burning the mined coal. For a 40% thermal efficiency power plant, the additional greenhouse effect of methane released from coal mining is equivalent to decreasing the plant’s efficiency by up to about 2\%. Control of coal mine methane emissions, therefore, has less potential for reducing greenhouse gases than achieving higher plant efficiency through the use of advanced technology. However, methane emissions from coal mining are independent of coal use in combustion equipment; current understanding of global warming issues suggests that they are of sufficient magnitude to justify development of appropriate technology for their control.

*Methane from U.S. underground mining comes from mine ventilation air (2.29 million metric tons/year), coal seam degasification (1.00 million metric tons/year), and postmining emissions (0.24 million metric tons/year).
†In 1992, 384 million metric tons of coal were produced by underground mining in the United States, with a net release of 3.22 million metric tons of methane. Combustion of the same coal liberated approximately 800 million metric tons of CO\textsubscript{2}. On a weight basis, the direct and indirect effects of methane have been estimated to be 21 times more powerful than CO\textsubscript{2} as a greenhouse gas. The greenhouse effect of the methane released from mining compared to the effect of CO\textsubscript{2} from combustion is therefore 21 \times 3.22 \times 100/800 = 8.5\%. More recent studies by the Intergovernmental Panel on Climate Change no longer quantify the indirect effects of methane; rather, only the direct effects are included in the Global Warming Potential. This gives an index of 11 rather than 21 for a 100-year averaging time.
Emissions of nitrous oxide (N₂O), another greenhouse gas, also arise from coal combustion. Because N₂O is formed primarily at relatively low temperature and pressure, the largest emissions rates are associated with atmospheric fluidized-bed combustion systems. Overall, N₂O emissions from coal combustion worldwide are estimated to contribute less than 1% of total global warming emissions. The primary sources of N₂O from human activities are fertilizers and agricultural wastes.36

Coal-fired electric power plants and fuel conversion processes are subject to state and federal regulations to protect the quality of surface waters, ground water, and drinking water. The principal environmental concerns are thermal discharges to waterways (discharges prohibited for new plants) and various chemical emissions, including heavy metals, organics, suspended solids, and other aqueous constituents found in power plant waste streams. In recent years there has been increasing attention to the control of hazardous or toxic trace chemical species and a general tightening of effluent emission standards at existing and new facilities.39 High-volume wastes, such as flyash from coal-fired power plants, have been declared 'nonhazardous', with only some low-volume wastes such as boiler cleaning sludges falling under the 'hazardous' category. The latter require more rigorous treatment and involve much higher disposal costs to avoid surface or ground water contamination. Nonetheless, to control the release of suspended solids and other chemical constituents of high- and low-volume wastes, water treatment systems similar to those found in other industrial processes are an integral requirement for modern power plants.

The large volumes of solid waste that must be disposed of, particularly ash from coal, represent a growing problem because of concern over contamination of ground water and surface waters and the decreased availability of landfill sites for waste disposal. Ash solubility and its effects on ground water can be greatly reduced by processes that fuse ash, resulting in products that can be used as construction materials, such as gravel substitutes. While research on the conversion of solid wastes to higher-value products has shown that by-product and re-use options are technically feasible, such conversion methods currently are not able to absorb the large quantities of material produced and often are not economical in today's markets. Another disposal option, especially applicable to western open-face mines where coal is transported by rail, is returning waste to the coal mine.

To an increasing extent, federal NSPS levels for power plants no longer set the benchmark for environmental control performance. Rather, state and local determinations of 'lowest-achievable emission rates' now set the critical requirements in many cases. A related trend is the adoption by some state public utility commissions of 'externality adders', economic costs added to the nominal cost of power generation that reflect the environmental damages due to emissions that escape control. Increasingly, state public utility commissions are requiring externality costs to be included in comparing different investment options and associated environmental impacts and risks. The effect is to put further downward pressure on all emissions from coal-based power systems.

3.9. Summary

The principal findings from the preceding review, summarized here, form the basis for the strategic planning scenarios presented in Section 4.

Coal supplies are expected to be abundant for the periods considered in this study. The steady decline in domestic coal prices over the past 10 years is a trend expected to continue in the near term. In the mid to long term (2006–2040), coal production costs are expected to be stable. Given the continuing availability of low-cost domestic coal, and the evolutionary rather than revolutionary nature of changes in energy consumption patterns in the United States, coal will likely continue to satisfy a significant part of growing U.S. energy demands over the next several decades.

Electricity demand is projected to grow as the U.S. economy grows. Estimates of new capacity requirements over the next 15 years differ widely, but there appear to be significant markets for retrofit and repowering options, as well as for new capacity construction. Changes in regulatory structure and practice in the electric utility industry since 1979 have contributed to a trend toward more widely distributed, smaller-scale power generation facilities that have relatively low risk and low capital costs. In addition, increased competition is reducing the willingness of the utility industry to develop and deploy advanced power generation technologies that are perceived as having higher risk.

In the near term, natural gas-fired systems will likely be the primary source of new capacity additions, driven by demands for peak and intermediate power, low gas prices, and low capital costs relative to coal. However, coal is expected to remain the largest single energy source for power generation, and resource limitations for domestic natural gas are expected to result in price increases and, combined with a substantial need for new baseload generating capacity between 2006 and 2040, are anticipated to result in a resurgence of coal-based power generation facilities in the mid-term period. In the longer term, growth of nuclear energy using advanced reactor designs is possible, and such energy could begin displacing coal after 2020. Renewable energy sources are expected to play a growing role in U.S. electric power generation, but they are not anticipated to become a large source of bulk electricity within the periods covered by this study.

Environmental concerns will probably be the most
significant influence on future coal use in the United States, and requirements to reduce the environmental and health risks of waste streams from coal technology are expected to grow more stringent. In the near- to mid-term periods, control of SO$_2$, NO$_x$, and fine particulate air pollutants, solid wastes, and possibly air toxics, will continue to determine the acceptability of coal-based systems, with state and local environmental requirements posing the most restrictive demands on power plant emissions. Among these, concern over global warming could present the greatest long-term threat to coal use because of the CO$_2$ emissions from coal combustion. Reducing CO$_2$ emissions over the mid- to long-term periods may be critical to maintaining coal’s viability as an energy source. The most cost-effective method of reducing CO$_2$ emissions from power generation and other coal-based systems is to improve their overall efficiency.

Expansion of coal-based power generation is anticipated in the developing nations, notably China, and major international markets exist for coal utilization technologies. In the near term, capital investment requirements are expected to be a controlling consideration in most foreign markets. Foreign requirements to minimize conventional pollutant and greenhouse gas emissions will lag those imposed in the United States, but their introduction is expected to have a large impact on international sales of coal-based technologies, especially in the mid- to long-term periods.

World petroleum resources are sufficiently large, and production costs sufficiently low, that prices for imported oil will continue to be governed primarily by political and institutional factors. Oil prices are expected to increase over time. However, international political events and disruptions could produce high price volatility in any time period. When time-averaged imported oil prices exceed $25–30/bbl, use of heavy oil and tar from North and South America becomes competitive with conventional petroleum. If production of gaseous and liquid fuels from coal can compete in this price range, a major market for coal beyond power generation could develop. Coal-derived gaseous and liquid fuels could also be used in chemicals production.

4. THE STRATEGIC PLANNING FRAMEWORK

DOE’s coal program planning horizon has generally extended only to 2010, with the objective of developing technologies that will be deployed and yield benefits in subsequent years. However, as the discussions in Section 3 indicated, coal will undoubtedly be a major source of energy well past the year 2010, with production of coal-derived liquid and gaseous fuels becoming a major potential consumer of coal after 2020. A longer planning horizon, therefore, is needed to develop a national RDD&C program relevant to this broadening spectrum of expected coal uses.

Three planning periods were identified to assess the DOE coal program: near term, 1995–2005; mid term, 2006–2020; and long term, 2021–2040. Scenarios were developed for each of these three planning periods, reflecting likely U.S. energy demands, resource and environmental constraints, and coal use outside the United States.

4.1. Baseline Strategic Planning Scenarios

Based on the preceding discussions strategic planning scenarios were developed and are summarized in Table 13. These scenarios describe a demanding, but not unreasonable, set of circumstances against which the requirements for coal RDD&C are assessed. While circumstances less demanding can be envisioned, it was felt that a major role of DOE is to provide technological insurance for a credibly demanding future. For example, requirements to reduce CO$_2$ emissions are sufficiently probable to provide a strong driving force for the very ambitious DOE efficiency goals for power generation. Further, the coal program should be sufficiently robust and flexible to accommodate evolving needs.

4.2. Alternative Scenarios

Given the inherent uncertainty of predictions, the committee also developed and considered several variations on the baseline scenarios. Less demanding scenarios would postpone the need for advanced coal utilization technology, while more demanding scenarios would accelerate the need.

4.2.1. Near term

Less demanding scenarios would result if natural gas and oil prices remained low or if concerns about the environment diminished. If no natural gas shortages were anticipated, for example, there would be less need for new or improved technologies for coal-based power generation. If oil supplies remained plentiful and prices low, there would be little incentive to develop technologies to produce liquid fuels from coal. Less severe environmental constraints would also reduce the need to develop clean coal technologies for both domestic and international markets. In particular, if no new regulations were enacted to control air toxics or other air pollutants, and if concerns about CO$_2$ emissions diminished, there would be fewer pressures to develop advanced environmental control technologies or maximally efficient coal-based plants.

On the other hand, the demand for new coal-based plants would be accelerated if there were unexpected shortages of electricity or natural gas. This scenario would create more demanding RDD&C requirements for advanced coal utilization technologies. Disruptions in the supply of imported oil could increase
Table 13. Baseline scenarios to assess coal RDD&C needs

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric power generation (domestic)</td>
<td>Demand for new baseload electric power generation stations will be low.</td>
<td>Substantial need exists for new generating capacity.</td>
<td>Due to higher prices for natural gas, advanced coal-based technologies are used increasingly.</td>
</tr>
<tr>
<td></td>
<td>Sufficient natural gas will be available to meet limited needs for new capacity.</td>
<td>Concerns about future natural gas supply and price result in new demand for coal-based capacity.</td>
<td>Power generation using natural gas and 1970s and 1980s nuclear technologies decreases.</td>
</tr>
<tr>
<td></td>
<td>Natural gas prices may rise but not enough to justify investment in new coal plants.</td>
<td>Economic incentives for efficiency improvements increase.</td>
<td>Renewables are a significant but not predominant source of electric power.</td>
</tr>
<tr>
<td></td>
<td>Growing concerns about future environmental restrictions, stimulate planning for cleaner, more efficient, coal-based technologies.</td>
<td>Continued trend toward decentralization and risk aversion for new power generation technologies.</td>
<td>Construction of advanced nuclear power plants begins during this period, providing new competition for coal-based systems.</td>
</tr>
<tr>
<td></td>
<td>Growing trend toward smaller, more decentralized power generation systems in response to utility deregulation and increased competition; emphasis on reliable, low-risk technologies.</td>
<td>New capacity needs are met by existing technology, but interest grows in more advanced and lower-cost systems for environmental controls.</td>
<td>Markets develop for advanced coal-based power generation systems to provide new capacity.</td>
</tr>
<tr>
<td>Foreign markets (power generation systems)</td>
<td>Existing Clean Air Act requirements met by modifying existing coal plants using current or near-term control technologies.</td>
<td>Air pollution control and solid waste disposal requirements become more severe.</td>
<td>Maximum-efficiency coal-based systems are required to minimize CO₂ emissions; attention is given to establishing CO₂ removal and disposal options.</td>
</tr>
<tr>
<td>Environmental constraints</td>
<td>By the end of the period, more stringent regulations on fine particulates, NOₓ, and air toxics may be in place. Concerns may be growing about CO₂ emissions.</td>
<td>New CO₂ emissions penalties provide new incentives to install high-efficiency, coal-based generating systems and to continue R&amp;D on CO₂ removal and disposal options.</td>
<td>Pressure continues to reduce all emissions to an absolute minimum and to re-use or recover solid wastes as by-products; advanced emissions control systems are required for coal-based plants.</td>
</tr>
<tr>
<td>Clean fuels from coal</td>
<td>State and local requirements for facility siting and operation continue to push use of state-of-the-art environmental controls.</td>
<td>State and local requirements for facility siting and operation continue to push use of state-of-the-art environmental controls.</td>
<td>State and local requirements for facility siting and operation continue to push use of state-of-the-art environmental controls.</td>
</tr>
<tr>
<td></td>
<td>Oil and natural gas prices rise but not enough to justify investment in processes to manufacture liquid fuels or merchant fuel gas from coal.</td>
<td>Oil and natural gas prices rise but not enough to justify investment in processes to manufacture liquid fuels or merchant fuel gas from coal.</td>
<td>Oil and natural gas prices rise but not enough to justify investment in processes to manufacture liquid fuels or merchant fuel gas from coal.</td>
</tr>
</tbody>
</table>

Oil prices significantly, resulting in new emphasis on domestic energy security and coal liquefaction technology. A more demanding short-term scenario could also result from increased domestic or international concern about the environmental impacts of coal-based facilities. Concern about the effects of global warming could lead to penalties for CO₂ emissions, encouraging faster development and use of very high efficiency coal-based systems and greater R&D on CO₂ removal and disposal options.
4.2.2. Mid and long term

Over the mid and long term, less demanding scenarios would result from the continued availability of domestic natural gas or gas imports (including liquefied natural gas) or a decrease in electricity demand growth. In these cases there would be less demand for new coal-based generating capacity. Imported oil and bitumen prices below $30/bbl would reduce incentives to manufacture liquid fuels from coal. However, interim technology advances (e.g. in coproduct systems) might allow coal-derived fuels to be produced competitively at an equivalent crude oil price of $25/bbl or less. If, contrary to expectations, environmental constraints on coal use for power generation do not become more severe over the mid to long term, there will be less need for associated clean coal technologies, such as advanced environmental controls and high-efficiency systems.

More demanding mid- to long-term scenarios, on the other hand, could result from unexpectedly high growth in electricity demand, such that new coal-based capacity would be needed earlier than expected. High natural gas prices could also accelerate the need for such new capacity and perhaps also encourage a new synthetic natural gas industry. Disruptions in international oil and tar markets and related price increases could boost the demand for coal liquefaction. Increased coal RDD&C might also be needed if there is earlier or more widespread enactment of new environmental restrictions on power plant solid wastes, air emissions, or liquid discharges. Finally, heightened concern over global warming could push the drive for high-efficiency technology, CO₂ sequestration methods, and the use of nuclear energy to reduce greenhouse gas emissions.

4.3. Scenario Implications for RDD&C Planning

The baseline planning scenarios suggest that DOE's coal program should anticipate national needs in several areas:

- Growing U.S. markets for advanced coal-based generating technologies, probably beginning about a decade from now and with sustained longer-term demand for these technologies.
- More effective and less costly environmental control systems to meet the increasingly stringent demands of federal, state, and local regulatory agencies for both new and existing power plants.
- High-efficiency power generation systems to address growing concerns about greenhouse gas emissions, resource depletion, and other environmental impacts.
- Reliable, smaller-scale technologies, compatible with the emerging trends to more decentralized power generation and more competitive business accompanying utility deregulation.
- Future domestic markets for coal-derived fuels likely emerging in the mid to long term.
- Growing international markets for low-cost environmental control technologies and coal-based electric power systems, for both retrofit and new plant applications.

The alternative scenarios suggest that the timing of projected changes may vary but that the principal requirements will remain much the same. Regardless of timing, then, there is likely to be a demand for low-cost, clean, efficient, coal-based power generation technologies and for high-efficiency gasification for power generation and production of clean gaseous and liquid fuels. However, shifts in the timing of requirements, such as those described under the alternative scenarios above, would necessitate changes in DOE's coal program priorities.

4.4. Additional Criteria to Set National Coal RDD&C Priorities

While the scenarios above provide valuable information to establish overall goals for the DOE coal program, further criteria are needed to set more specific program objectives and priorities. In the most general terms, these goals are: to promote national economic well-being through lower energy costs, creation of U.S. jobs, and improved balance of payments based on technology manufacture and export; to protect and enhance environmental quality by minimizing emissions from coal-based facilities, as well as the impacts of these facilities' solid, liquid, and gaseous wastes; and to enhance national security by reducing dependence on foreign energy sources. Following from these general goals (which were also reflected in the scenarios above) additional criteria were developed to aid in evaluating the strategic importance of individual DOE programs for the three planning periods defined.

*General criteria*—(a) Are the timing and goals of the program consistent with the scenarios and objectives developed by the committee and with other EPACT and DOE goals and objectives? (b) What is the potential for technological success?

*Economic criteria*—(a) What potential does the technology have to reduce the costs of electric power, gaseous or liquid fuels, or other by-products for both new facilities and existing plants? (b) Does a market exist for the technology and how large is it? What export potential does a technology have? (c) What potential does the technology have to increase the international competitiveness of U.S. firms? (d) What potential is there to accelerate application of the technology?

*Environmental criteria*—(a) What potential does the technology have to economically control, reduce, or eliminate environmentally important wastes, notably criteria air pollutants (NOₓ, SO₂, fine particulates), air toxics (inorganic and organic), greenhouse gas emissions (CO₂, methane), solid wastes (hazardous and nonhazardous), and liquid wastes (organic...
and inorganic) from coal-based facilities for power generation and fuels production? (b) What is the technology's applicability to new and existing plants in both the United States and other countries?

The DOE role—(a) Is there a role for DOE given the existence of other domestic industrial programs, other U.S. government programs, foreign programs, and the projected market for the technology? (b) What is the recommended role for DOE?

The need for DOE participation requires special consideration because both domestic and foreign groups may be actively carrying out related programs. However, the national goal of improving the U.S. economy by creating more U.S. jobs and improving the balance of payments calls for a competitive and well-rounded U.S. program. With proper planning and setting of priorities, DOE programs can have several important roles:

- Accelerating the commercial application of improved technologies through cost sharing and other arrangements.
- Promoting the development and demonstration of new systems.
- Developing a technical basis for improved systems and components, including performing and supporting advanced research aimed at enhanced cost and efficiency.
- Identifying major opportunities to improve cost and performance through systematic modeling of systems and components.

The relative importance and practical application of the above considerations necessarily depend on the individual program and the subject addressed, as will be seen in subsequent discussions. To prepare for work across all timeframes, DOE activities now need to focus not only on near-term demonstration and commercialization but also on longer-term R&D for the mid term and beyond, and on basic R&D for the long term.

PART II: OVERVIEW OF CURRENT DOE COAL PROGRAMS

5. COAL PREPARATION, COAL- LIQUID MIXTURES, AND COALBED METHANE RECOVERY

5.1. Coal Preparation

5.1.1. Description of Technology

Coal preparation—or cleaning—is the removal of mineral matter from as-mined coal to produce clean coal, a quality-controlled product with a composition that adheres to specifications based primarily on environmental and combustion performance. Its primary purpose is to increase the quality and heating value (Btu/lb) of coal by lowering the level of sulfur and mineral constituents (ash). In most Eastern bituminous coals, roughly half to two-thirds of the sulfur occurs in a form that can be liberated by crushing and separated by mechanical processing. Western coals typically contain much lower levels of sulfur, have lower heating values and are not readily amenable to physical cleaning methods for sulfur reduction. All coals contain mineral matter that can also be removed through physical cleaning. Coal preparation as currently practiced in the coal industry involves four generic steps: characterization, liberation, separation, and disposition.

During characterization, the composition of the different-size raw coal particles is identified. The composition of the raw coal and the required clean coal specifications dictate the type of equipment that must be used to remove the mineral matter. Crushing liberates mineral matter. Complete liberation can only be approached by reducing the mined coal to very fine sizes, since particles containing both coal and mineral matter, called middlings, are also produced during crushing. Separation involves partitioning of the individual particles into their appropriate size groupings—coarse, intermediate, and fine fractions—and separating the mineral matter particles from the coal particles within each size fraction. Separation techniques for larger-size raw coal particles generally depend on the relative density difference between the organic coal and inorganic mineral matter particles. Separation techniques for fine raw coal particles utilize the difference in the surface properties of the particles in water. Disposition is the dewatering and storage of the cleaned coal and the disposal of the mineral matter.

5.1.2. State of the art

Coal preparation technologies are widely practiced by the coal industry. Recent R&D efforts\(^6\)\(^-\)\(^8\) have been aimed at developing processes that will further reduce both the sulfur and ash contents of coals. Coal cleaning techniques for the fine fractions also are now commercial. Many of these same techniques have been utilized to produce the very clean coals required for coal-liquid mixtures (see below). Sustained investigations into chemical and biological coal preparation techniques that remove organic as well as inorganic sulfur have not, however, produced any systems with a strong potential for commercialization, largely because of their high costs.

5.1.3. Current programs

DOE currently performs or funds the majority of coal preparation R&D in the United States. This activity falls primarily within the Advanced Clean Fuels Research Program. The FY 1994 program budget of $11.3 million included $4.6 million for work on technologies for producing premium fuels and removal of air toxic precursors; $2.25 million for continued testing of high-efficiency processes; and $4.1 million for continuation of in-house bench-scale and characterization research at PETC related to advanced physical and chemical cleaning concepts.\(^7\)
In addition to the direct funding of the coal preparation program, the AR&TD (advanced research and technology development) component of the DOE budget supports a number of closely allied programs of a more basic nature, such as the $1.9 million program on the bioprocessing of coal for sulfur and nitrogen removal, which is part of DOE's Advanced Manufacturing Technology program. This program recently shifted its emphasis to the removal of SO$_2$ and NO$_x$ from combustion gases, rather than from coal.

For FY 1995, DOE has proposed a 52% reduction in funding for coal preparation, to a total of $5.5 million. The main thrusts of the program include continued research on advanced physical coal cleaning methods to produce premium coal fuels very low in ash, sulfur and air toxics precursors at the proof-of-concept scale of technology development ($2.6 million), and continued in-house research on bench-scale development of advanced cleaning concepts ($2.0 million) and related studies ($0.8 million). The AR&TD program on bioprocessing of coal would continue at its present level ($1.9 million), with emphasis on involvement with small and emerging companies.

5.1.4. Technical issues, risks, and opportunities

Current physical coal cleaning techniques cannot reduce the sulfur content of coal to the levels needed to comply with most environmental regulations. Although the inorganic sulfur component of coal can be removed with other mineral matter, the organic sulfur is chemically bonded to the coal and is not amenable to physical separation. Biological and chemical methods for sulfur removal so far have not been promising for commercial-scale application. Because coal is an abundant and relatively low cost fuel, the added cost of advanced preparation technology, combined with the cost of coal that is lost with separation process wastes, makes it extremely difficult for advanced cleaning methods to be economically competitive for applications involving direct coal use. The most promising applications for advanced beneficiation methods lie in the production of premium fuels that replace oil or gas (e.g. coal-liquid mixtures, discussed below). However, current and projected prices for oil and gas make it unlikely that significant markets for coal-based alternative fuels will emerge before the mid-term period. In the near term, however, coal preparation might prove a desirable technique for selective treatment of coal to meet possible future hazardous air pollutant regulations by reducing trace element concentrations prior to combustion.

The utility industry is interested in promoting technical and economic improvements in coal beneficiation methods as an indirect means of reducing fuel-related costs. Lower-sulfur fuels provide better cost–benefit solutions for older boilers than scrubbers. Burning upgraded coal reduces the cost of maintaining boiler systems and increases combustion efficiency. SO$_2$ reduction in the flue gas reduces scrubber costs where flue gas desulfurization (FGD) is needed. Achieving maximum energy recovery requires improved liberation, improved separation efficiency, total cleaning, and process control. Size reduction and thermal drying account for about 75% of the capital costs and 50% of the operating costs for processing coal. The challenge for coal cleaning is to deliver coal at a price that is economically competitive with other sources of coal of comparable quality. Thus, the markets for cleaned coals are highly dependent on site-specific factors.

There is an emerging global market for this segment of the U.S. coal industry, particularly in India, Poland, and China, which have large reserves of relatively low quality coal. Improved U.S. coal preparation technology would make the United States more competitive in the international coal technology market. Improving the technology, in some cases, requires more development. For example, commercial preparation is not currently economically optimized. There is a need for testing and verifying new technologies, performing unit operations analysis, developing instrumentation for process control, including computerized on-line analysers, and improving dewatering for both fine high-rank coals as well as low rank coals. However, the R&D and demonstration planning should use market-based decision tools and have extensive industrial participation.

5.1.5. Summary

DOE has contributed to the development of the fine coal cleaning technology that is now commercially available. Applied research to improve current commercial preparation processes may help such technology compete more effectively, especially in international markets. Advanced power and fuel systems are being designed for fuel flexibility and high-efficiency sulfur removal and may be unlikely to require coals that have been subjected to coal preparation beyond current commercial practice.

Reduction of trace element concentrations in coal representing air toxic precursors may offer an R&D opportunity for meeting future, as yet undefined, hazardous air pollutant emission standards. Work in this area is addressed in the DOE's proposed program for FY 1995.

5.2. Coal–Liquid Mixtures

5.2.1. Background

Coal–liquid mixtures consist of finely ground coal suspended in a liquid, such as oil or water, together with small amounts of chemical additives to improve stability and other physical properties. The primary
purpose of coal–liquid mixtures is to make solid coal behave as an essentially liquid fuel that can be transported, stored, and burned in a manner similar to heavy fuel oil. The most mature coal–liquid mixture technologies are those using coal–oil and coal–water mixtures (CWM). Several of these technologies have already been offered commercially. Since coal–liquid mixtures are intended as a substitute for oil, their market penetration is heavily dependent on oil prices.

5.2.2. State of the art

Areas for further performance improvements in COMs depend on advanced coal beneficiation to further reduce sulfur and ash content and improved additives or other means of increasing the weight percentage of coal in the mixture. CWSs also are a potential alternative to premium fuels (oil and gas) being used in industrial and utility boilers and were offered commercially in the early 1980s. Cost studies suggest that slurries could be prepared and used economically with oil prices around $25–30/bbl, given a production facility of sufficient scale and the infrastructure required to handle the fuel. Such studies also indicate that slurries are economical if the differential in cost between heavy oil and slurry is $1.50/10^8 Btu. Present oil price forecasts, however, make it unlikely that coal-based substitutes will be competitive in the near to mid term. Nevertheless, one Pennsylvania utility (Penelec) is currently investigating cofiring its pulverized coal utility boilers with a CWS to provide 20–40% of fuel needs. This technology would allow the utility to purchase and utilize fine upgraded coal while reducing NOx emissions with no boiler derating.

5.2.3. Current programs

Much of the current work on coal–liquid mixtures is being funded, at least in part, by DOE. Activities range from fundamental research on mixture preparation and properties, through bench-scale preparation and combustion, to commercial-scale demonstrations. The emphasis in all these programs is on CWSs rather than COMs.

Fundamental research on CWSs is being conducted at Adelphi University, Carnegie Mellon University, and Texas A&M University under the Coal Utilization Science program of DOE’s AR&TD activity. Topics under investigation include the combustion system atomization processes, modeling, and measurement of viscosity and surface properties. The Pennsylvania State University is conducting a super-clean CWS program with support from DOE and the commonwealth of Pennsylvania to determine the capability of firing such slurries in an industrial boiler designed for firing heavy fuel oils, with no adverse impact on boiler rating, maintenance, reliability, and availability. DOE, through the University of North Dakota Energy and Environmental Research Center, is also supporting the conversion program at the Pennsylvania State University for the U.S. Department of Defense, with the objective of developing commercial CWS technology. The program will provide a military base with a commercially engineered CWS conversion system for firing its oil/gas-fired boilers.

Demonstration projects using CWS include a CCT (Clean Coal Technology) Round V program to demonstrate clean coal diesel technology. The diesel system will use a CWS produced from Ohio coal by a two-stage coal cleaning and slurring process. Another CCT program is demonstrating the combustion of injected coal in the tuyeres of two blast furnaces at Bethlehem Steel. Blast furnace coal injection technology, where granulated or pulverized coal is injected into a blast furnace in place of natural gas (or oil) as a fuel supplement or reductant to lower the coke rate and hot metal cost, may incorporate CWS technology in the future. A University of North Dakota project on power generation from an Alaskan coal–water fuel has demonstrated the preliminary process economics of a concentrated low-rank coal–water fuel. The second phase of the program is aimed at developing a low-cost indigenous replacement for the imported diesel fuel used in many native villages of the Alaskan interior.

While a specific breakdown of DOE funding for coal–liquid mixture R&D is not provided in the FY 1995 budget request, the overall funding for the AR&TD Coal Utilization Science program is projected to decrease from $3.1 million in FY 1994 to $2.2 million in FY 1995. Part of this decrease is due to a reallocation of some projects to other coal program budget lines. A more detailed discussion of DOE’s advanced research budgets appears in Section 9.

5.2.4. Summary

COM and CWS technologies are either commercially available or on the verge of commercialization. Aside from some niche market opportunities, the private sector currently has little current interest in adopting these technologies. However, if oil or gas prices increase significantly above current or projected near-term levels, COMs are available for commercial application. At that time, there may be a need for programs that assist the private sector in taking CWS technology to the marketplace.

5.3. Coalbed Methane Recovery

5.3.1. Background

The coal formation process occurs when organic debris is converted to coal and various by-products, including water and methane (CH₄) gas. The latter
may be found in the coal itself or trapped in the strata surrounding the coal. For every ton of coal formed, as much as 5000 cubic feet of 'coalbed methane' may be generated in situ.51 Coalbed methane liberated into mine workings by underground coal mining can be a serious safety hazard, since methane is highly explosive in volume concentrations of 5–15%. Thus, underground mines in the United States are required to maintain methane concentrations below 1% of the concentration of the air in the mine.52

Methane has attracted recent attention as a greenhouse gas that may contribute to global warming (see Section 3). The Clinton administration's Climate Change Action Plan9 identifies coal mines as one of the primary sources of methane emissions in the United States and requires the EPA (U.S. Environmental Protection Agency) and DOE to launch a coalbed methane outreach program to raise awareness of the potential for cost-effective emissions reductions with key coal companies and state agencies. In addition, the Climate Change Action Plan requires DOE to expand its research, development, and demonstration (RD&D) efforts to broaden the range of cost-effective technologies and practices for recovering methane associated with mining.

5.3.2. State of the art

While all coal seams contain some methane, the highest levels of coalbed methane in the United States occur in seams in Virginia, West Virginia, Utah, and Colorado. To mine these gassy seams, mining companies have developed a number of techniques to eliminate or reduce the amount of methane liberated during mining. The primary technique is to design the mine ventilation system with enough capacity to keep the concentration at acceptable levels well below the lower explosive limit—generally less than 1% methane by volume. Other methods involve vertical drilling into the coal seam to vent methane before and after mining and drilling horizontally into the seam and venting the gas to the surface. There are instances where mining companies collect high-concentration methane and, after limited cleaning, sell the gas to a commercial pipeline. The economics of collection and sale to a user or distributor can either be based on a direct payback basis or justified by a reduction in mine ventilation costs.

5.3.3. Current programs

Section 1306 of EPACT requires DOE to study barriers to coalbed methane recovery, to assess environmental and safety aspects of flaring coalbed methane liberated from coal mines, and to disseminate information on state-of-the-art coalbed methane recovery techniques to the public. DOE is further required to establish a coalbed methane recovery demonstration and commercial application program, with emphasis on gas enrichment technology. DOE requested $300,000 in the FY 1994 budget for coalbed methane activities, but that funding was not approved. The administration's FY 1995 budget request includes coalbed methane recovery activities in the natural gas portion of the Fossil Energy program. As required by the Climate Change Action Plan (see above), EPA recently launched an outreach program to encourage coal companies to install methane recovery equipment at mines across the United States. The goal of this program is to reduce methane emissions from coal mines by at least 500,000 metric tons (25 billion cubic feet) by 2000.53 DOE has developed a plan to expand RD&D for methane recovery from coal mining: DOE and industry will cofund projects on a 50% cost-sharing basis. This activity will be coordinated with the EPA outreach program.

5.3.4. Issues, risks, and opportunities

Technology for the recovery of coalbed methane from gas streams with high methane concentrations is commercially available and practiced by the gas and mining industries where conditions justify the investment. However, the collection and sale of methane are not widespread in the coal mining industry because of a number of technical and commercial issues. These include ambiguities in mineral rights concerning gas ownership, trade-offs between the selling price of methane and tax credits to encourage investments, the dependence of methane recovery on gas concentration and porosity of the coal or strata, the quantity and quality of gas to be vented, and constraints on the underground mining technique used (e.g. room and pillar versus longwall).

Technology for the use or control of coalbed methane emissions in very dilute gas streams (methane concentration less than 1.0%) is not currently available. Low-quality mine gases must be upgraded or enriched for sale to a distribution system. In view of the importance of methane as a greenhouse gas (see Section 3), opportunities exist to encourage the utilization of dilute methane streams emitted from coal mines by developing relevant technologies.

Possible research areas include new techniques for methane separation and the combustion of very dilute methane streams. Separations of methane from dilute ventilation air by conventional methods is expensive and energy intensive. Research aimed at finding new materials for selective adsorption or selective diffusion through membranes is of interest (see Section 9). Ventilation air streams are too dilute to burn in conventional combustion equipment without use of additional fuel, which would generate additional greenhouse gases. Catalytic combustion systems offer some promise, and advances made for other applications are of interest (see, for example, Ref. 54).
5.3.5. Summary

Coalbed methane recovery is a commercially available technology that is being practiced where concentrations are sufficiently high and where merited by the return on investment or benefits to mining.

Technologies for the capture and use of dilute coalbed methane streams are not sufficiently mature for commercial implementation. Given the increased emphasis on reducing emissions of greenhouse gases, including methane from coal mining, there are potential research opportunities directed toward the recovery of coalbed methane from very dilute gas streams.

6. CLEAN FUELS AND SPECIALITY PRODUCTS FROM COAL

Coal is currently a major source of fuel for power generation, industrial heat, and, on a smaller scale, manufacture of coke and by-product coal tar. In the mid to long term, anticipated increases in the cost of natural gas and petroleum relative to coal are expected to increase the incentive for expanded efforts to convert coal to ash-free, low-sulfur transportation fuels and, ultimately, gaseous fuels for domestic use (see Section 3). As natural gas prices increase, substitution of gas from coal in natural gas-fired power generation plants may become economic. Advanced combined-cycle and fuel cell power generation technologies will also require the conversion of coal to clean gaseous fuels. In addition to the above major uses, economical use of clean gaseous and liquid products from coal can provide a source of feedstock for chemicals production.

However, when petroleum and gas prices fell and it became clear that domestic resources were adequate to provide low-cost natural gas at least through the year 2000, the incentive for the construction of facilities for SNG production was eliminated, leaving relatively few surviving commercial coal gasification systems. These were primarily aimed at manufacture of high-value products, such as methanol, ammonia, and chemicals. Today’s emphasis on increased power generation efficiency, and the availability of high-performance gas turbines and fuel cells, have created a strong incentive for development of high-efficiency gasification systems specifically designed to provide fuel for power generation. These systems can differ from systems optimized to produce highly purified synthesis gas for catalytic conversion to chemicals and clean fuels in that dilution by methane and nitrogen is acceptable and a higher level of impurities can be tolerated.

6.1. State of the art

The status of gasification processes of current interest that are either commercially available or have reached the stage of major pilot plant development is shown in Table 14.

Gasification processes can be divided into three major classes: entrained-flow, fluidized-bed, and moving fixed-bed. All involve operating pressures up to several hundred psi. For entrained-flow systems, powdered coal is generally first gasified with a mixture of steam and oxygen (or air) in a zone where the main part of the molten slag is collected. The high-temperature products require quenching or cooling prior to cleanup, with resulting loss of thermal efficiency. Entrained-flow gasification systems produce little methane, are relatively compact, and, because of the high operating temperature (1040–1540°F [1900–2800°F]), involve short reaction times. Entrained solid gasifiers are insensitive to most coal properties as long as the coal can be pulverized to about 80% below 200 mesh (44 μm) size. Entrained-flow systems, most notably the Texaco units, have found commercial application during the past decade for production of synthesis gas for chemical syntheses. The Texaco, Shell, and Dextec processes are commercial technologies developed primarily in the United States. As a result of the required high reaction temperature and resulting high oxygen consumption, this class of gasifier has inherently lower thermal efficiency than fluidized-bed and moving fixed-bed gasifiers. The gas produced is relatively free of tars, hydrocarbons heavier than methane, and nitrogen compounds. Because of their proven performance, entrained-flow gasifiers have been chosen for IGCC demonstrations both in the United States and overseas. Such demonstrations primarily address systems integration issues rather than gasifier development.

Fluidized-bed gasification systems operate at
Table 14. Status of gasification processes

<table>
<thead>
<tr>
<th>Developer*</th>
<th>Status</th>
<th>Gasifier exit temperature °C (°F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Texaco (U.S.), CCT</td>
<td>Commercial</td>
<td>1260–1480 (2300–2700)</td>
</tr>
<tr>
<td>Shell (Europe/U.S.)</td>
<td>Commercial</td>
<td>1370–1540 (2500–2800)</td>
</tr>
<tr>
<td>Destec (U.S.), CCT</td>
<td>Commercial</td>
<td>1040 (1900)</td>
</tr>
<tr>
<td>Preñilo (Europe)</td>
<td>Commercial/demonstration</td>
<td>1370–1540 (2500–2800)</td>
</tr>
<tr>
<td>Koppers Totzek (Europe), Atmospheric ABB Combustion Engineering (Europe/ U.S.), CCT</td>
<td>Commercial</td>
<td>1480 (2700)</td>
</tr>
<tr>
<td>IGC (Japan)</td>
<td>Development</td>
<td>1040 (1900)</td>
</tr>
<tr>
<td>HYCOL (Japan)</td>
<td>Development</td>
<td>1260 (2300)</td>
</tr>
<tr>
<td>VEW (Germany)</td>
<td>Development</td>
<td>1480–1620 (2700–2950)</td>
</tr>
<tr>
<td>Fluidized-bed processes</td>
<td></td>
<td></td>
</tr>
<tr>
<td>KRW (Europe/U.S.), CCT</td>
<td>Demonstration (development)</td>
<td>1010–1040 (1850–1900)</td>
</tr>
<tr>
<td>High-Temperature Winkler/Lurgi (Europe)</td>
<td>Demonstration (development)</td>
<td>950 (1750)</td>
</tr>
<tr>
<td>Exxon Catalytic (U.S.)</td>
<td>Demonstration (development)</td>
<td>760 (1400)</td>
</tr>
<tr>
<td>Tampella/U-Gas (Finland/U.S.), CCT</td>
<td>Development (currently inactive)</td>
<td>980–1040 (1800–1900)</td>
</tr>
<tr>
<td>MCTI Pulse Combustor/Gasifier, CCT</td>
<td>Demonstration (development)</td>
<td>1090–1260 (2000–2300)</td>
</tr>
<tr>
<td>Moving fixed bed processes</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lurgi (dry ash) (Europe)</td>
<td>Commercial†</td>
<td></td>
</tr>
<tr>
<td>British Gas Lurgi (slagging), CCT</td>
<td>Commercial</td>
<td></td>
</tr>
<tr>
<td>British Gas Lurgi (high pressure, 1,000 psi)</td>
<td>Demonstration</td>
<td></td>
</tr>
<tr>
<td>DOE-Sirrine Advanced Moving Bed (U.S.)</td>
<td>Research/development</td>
<td>850 (1560)</td>
</tr>
</tbody>
</table>

* CCT is technology demonstrated in DOE’s Clean Coal Technology program (see Table 17).
† Over 100 units in operation.
Sources: COGARN, DOE.

760–1040°C (1400–1900°F), depending on the reactivity of the feed coal and ash softening temperature, and have the potential for higher efficiency. Because the temperatures on exiting the gasifier are well matched to the requirements for hot gas cleanup systems, fluidized-bed gasifiers offer overall efficiency advantages relative to higher-temperature entrained-flow systems that require gas cooling prior to cleanup. Relative to moving bed gasifiers, fluidized-bed units offer higher coal throughput rates, which reduce the unit size and cost. Thus, fluidized-bed gasifiers offer an attractive method for producing a wide array of products from coal-derived gas. While no high-pressure systems are classified as commercial technologies, it should be noted that the atmospheric version (Winkler) has been in commercial use for over 65 years. Demonstration programs are underway in Europe and the United States. As discussed later in the section on technical issues and opportunities, the low-temperature Exxon Catalytic Process, with modifications, may offer the potential for high efficiency, although this program is currently inactive. The lower-temperature, higher-pressure versions of fluidized-bed gasification processes produce methane as well as synthesis gas, which requires less oxygen and increases the efficiency. Due to the low temperatures, the residues (ashes) from fluidized-bed gasifiers are possibly less inert and may require more attention to their disposal in an environmentally secure repository. A special ash agglomeration section, as in the Tampella/U-Gas and KRW gasifiers, can reduce this problem.

In the moving fixed-bed gasification process, approximately 2 x 1-inch-sized coal moves down the reactor countercurrently to the gas flow. The countercurrent flow leads to higher efficiency. However, moving bed systems are more costly and more complex than stationary bed systems due to the equipment needed to maintain the flow of solids. Historically, the moving fixed-bed process is the most widely used gasification system. High temperatures above the oxidizing gas inlet decrease as the gases exchange heat and react with the incoming coal and exit temperatures are low. Some pyrolysis products (methane, light hydrocarbons, and tar) escape oxidation, and subsequent removal of the tar is required. The commercial Lurgi process yields an unfused ash chinker; however, a slagging version has been developed in cooperation with British Gas. A high-pressure version (6.9 MPa [1000 psi]) with higher methane yields has been piloted. Use of in-bed limestone for sulfur capture is proposed, but hot gas desulfurization is also being considered. Because of the relatively long residence times and limitation on reactor diameter, moving fixed-bed units have lower coal throughput than is achieved with fluidized-bed units. Commercial moving bed gasifiers have capacities in the 800–1000 tons/day range.
Table 15. Effect of gasifier design on IGCC efficiency

<table>
<thead>
<tr>
<th>Case number</th>
<th>1</th>
<th>1a</th>
<th>2</th>
<th>2a</th>
<th>3</th>
<th>3a</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasifier*</td>
<td>KRW fluidized-bed air-blown in situ</td>
<td>KRW fluidized-bed air-blown in situ</td>
<td>KRW fluidized-bed air-blown hot gas</td>
<td>KRW fluidized-bed oxygen-blown hot gas</td>
<td>CE entrained-flow air-blown cold gas</td>
<td>CE entrained-flow air-blown hot gas</td>
</tr>
<tr>
<td>Oxidant</td>
<td>cold gas</td>
<td>hot gas</td>
<td>cold gas</td>
<td>hot gas</td>
<td>cold gas</td>
<td>hot gas</td>
</tr>
<tr>
<td>Gas cleanup†</td>
<td>81.3</td>
<td>86.4</td>
<td>85.9</td>
<td>84.6</td>
<td>79.0</td>
<td>84.5</td>
</tr>
<tr>
<td>Carbon-to-gas efficiency‡</td>
<td>80.5</td>
<td>85.5</td>
<td>81.8</td>
<td>80.5</td>
<td>77.4</td>
<td>82.8</td>
</tr>
<tr>
<td>Coal-to-gas efficiency‡</td>
<td>44.9</td>
<td>46.7</td>
<td>46.0</td>
<td>45.0</td>
<td>43.4</td>
<td>45.4</td>
</tr>
<tr>
<td>Carbon-to-electricity efficiency‡</td>
<td>44.5</td>
<td>46.2</td>
<td>43.8</td>
<td>42.8</td>
<td>42.5</td>
<td>44.5</td>
</tr>
</tbody>
</table>

*KRW, Kellogg-Rust-Westinghouse; CE, Combustion Engineering.
†In situ (Cases 1 and 1a) refers to the KRW gasifier for sulfur removal. Cold gas cleanup is at 315°C (600°F) for the KRW system (Case 1) and 230°C (450°F) for the CE system (Case 3). Hot gas cleanup is at 565°C (1050°F) for all systems and assumes use of candle filters for particulate removal and the General Electric barium tinate system for sulfur removal.
‡All efficiencies are given as percentages on a higher heating value basis (see Glossary). The carbon-to-gas efficiency refers to the production of clean fuel gas, excluding carbon losses. The coal-to-gas efficiency includes all losses. Carbon conversion efficiencies for the KRW system are 99.9% for the in situ sulfur removal (Cases 1 and 1a), 95.2% without in situ removal (Cases 2 and 2a), and 98.0% for the CE system (Cases 3 and 3a).
Source: Gilbert/Commonwealth, Inc. 57

The Shell, Destec, and Texaco high-temperature entrained-flow gasifiers have a single-train capacity resulting from the small coal particle size and high operating temperature, of up to 2000 tons/day of coal corresponding to about 265 MW of electricity. The high-temperature Winkler circulating fluidized-bed system planned for the European KoBra demonstration after the year 2000 has a planned capacity of about 300 MW using brown coal. To date, Lurgi fixed-bed units have a lower capacity than do entrained-flow units. This difference in capacity is subject to change with further development.

6.1.3. Gasification technology and IGCC performance

The first-generation U.S. IGCC systems are scheduled for demonstration in the ongoing CCT program (see Sections 7 and 8) using the Destec and Texaco entrained-flow gasifiers with design power generation efficiencies of 38 and 40%, respectively. Demonstration of the Shell gasifier as part of an IGCC system is under way in the Netherlands, and a Prefo system demonstration is under way in Spain. Another IGCC demonstration project based on the moving-bed British Gas/Lurgi slagging gasifier is included in DOE's CCT program but has not yet been contracted for. Also in the CCT program, a 100-MW IGCC system with a KRW fluidized-bed gasifier has been designed with an efficiency of 40.7%. Since all these systems make use of state-of-the-art 1300°C (2350°F) gas turbines, increases in efficiency to the 45% level projected for second-generation systems depend on the use of hot gas cleanup systems plus improvements in gasifier performance and optimized systems integration.

In addition to the method of contacting coal and oxidant (entrained-flow, fluidized-bed, or moving-fixed-bed), important gasification choices include the use of air or oxygen, and hot or cold gas cleanup. Table 15 presents results of a study of the effects of these variables on efficiency using Illinois No. 6 coal in two gasifiers still in the development stage, namely, the KRW fluidized-bed system and the Asea Brown Boveri (ABB)/Combustion Engineering (CE) air-blown entrained-flow system, both using a General Electric MS7001 (1300°C [2350°F]) turbine. 57 Both are scheduled for demonstration in the DOE CCT program.

The performance estimates in Table 15 show an overall thermal energy loss of approximately 15–20% in the gasification and gas cleanup steps. This results in a penalty of about 5–10 percentage points in electrical generating efficiency. Other findings from this study are as follows:

- When hot gas cleanup is used, changing from

*The KRW air-blown in situ desulfurization version of the KRW process is scheduled for demonstration under CCT-IV at the Sierra Pacific Power Company. For this process, using western coal, the ash is sintered and removed as agglomerate. The ABB/CE process is scheduled for demonstration at City Water, Light and Power in Springfield, Illinois, with CCT cost-sharing. The first stage of the entrained-flow system operates at 1480–1650°C (2700–3000°F) and produces a molten slag. The second-stage gas leaves at 1070°C (1960°F) and is then cooled to allow hot-gas cleanup (540–590°C [1000–1100°F]) with the General Electric zinc tinate/zinc ferrite sulfur removal and candle filtration.
air to oxygen results in an efficiency reduction of approximately one percentage point (Cases 2 and 2a). This stems primarily from the energy requirements of oxygen production.

- For the air-blown systems, use of hot gas cleanup rather than cold gas cleanup results in an energy savings of 5% and a corresponding electrical efficiency gain of approximately two percentage points (Cases 1 and 1a, plus 3 and 3a). The efficiency advantage for hot gas cleanup is expected to be lower for oxygen-blown systems because of their lower mass flow rates and sensible heat loads.

- The most efficient system in this comparison is the air-blown fluidized-bed gasifier with hot gas cleanup plus in-bed sulfur removal (Case 1a). A gain of over three percentage points in net generating efficiency (HHV) is indicated compared to the oxygen-blown entrained-flow gasifier with cold gas cleanup (Case 3) of the type currently under demonstration. However, carbon dioxide emissions increase by 4.5% due to the calcination of limestone in the gasifier.

The efficiency penalty for coal gasification can be attributed to losses involved in cooling the gasification product, the temperature cycling required by the gas cleanup system, the pressure drops incurred by all gas cleanup systems, and by flow through the gasification reactor. Continued R&D can likely reduce these losses, as discussed below.

6.1.4. Technical issues and opportunities

Improvements in the integration of coal gasification with advanced power generation systems are of greatest current interest. In the mid- to long-term periods (2006–2040), the production of hydrogen, clean low- and medium-Btu gaseous fuels for industrial and utility use, and synthesis of liquid fuels and chemicals are expected to be major potential applications for coal gasification. For both power generation and fuels production, greenhouse gas concerns are expected to greatly increase the emphasis on improved efficiency. Thus, new and improved gasification processes with higher thermal efficiency will be required.

The inherent problem of coal gasification is the high-temperature required to achieve a practical rate of reaction of coal with steam. The temperature varies—depending on the reactivity of the coal and the choice of gasifier—from about 800–1650°C (1500–3000°F) for uncatalyzed gasification. If the raw exit gases are cooled to the low temperature conventionally required for removal of hydrogen sulfide (H₂S) and other contaminants, losses in useful heat are incurred despite use of bottoming cycles and transfer of heat to other process streams.

These losses can be minimized by reducing cyclic heating and cooling of the gas. Several approaches are possible. Hot cleanup of the gasification product to minimize or eliminate cooling is currently limited to the temperature range of 650–760°C (1200–1400°F) and is primarily applicable to integrated gasification gas turbine or fuel cell systems for power generation. In these applications it has the potential for savings of one–three efficiency points relative to cold gas cleanup and is a major part of the DOE coal R&D program (see Section 7). Lowering the gasification temperature reduces these losses, but it also increases the direct formation of methane. The lowering of gasification temperature by increasing the reactivity of the coal (char) is achievable by use of catalysts; this has been studied extensively and piloted by Exxon. Acceptable reaction rates were obtained at temperatures down to 625–650°C (1160–1200°F). This approach remains a promising opportunity for cost reduction.

While methane is an undesirable product for hydrogen or syngas manufacture, its direct formation is advantageous for both SNG manufacture and power generation, since the volumetric heating value of the fuel gas is higher and cleanup and compression energy requirements are reduced. The direct formation of methane during gasification, or by prior pyrolysis, reduces oxygen and steam requirements and reduces the volume and heat capacity of the fuel gases. Use of oxygen instead of air further reduces the heat capacity and volume of the gas mixture. The use of oxygen, rather than air, for production of SNG, hydrogen, and synthesis gas-based liquid fuels and chemicals also eliminates dilution from atmospheric nitrogen; most gasification systems have been developed for oxygen use.

The manufacture of oxygen requires energy for air compression to drive the separation process and also represents a major capital expense. For gas turbine generation, therefore, air-blown systems appear attractive. However, the larger volume of gas will increase both temperature cycling and pressure drop losses. Oxygen-blown systems produce about half the gas volume of an air-blown system but consume energy for oxygen manufacture. The cold gas cleanup losses (approximately 1%) can also be reduced by tailoring cold gas cleanup to match the emissions requirements for power generation, which are considerably less demanding than for catalytic synthesis of SNG or liquids. For fuel cell systems, to avoid electrolyte degradation, a high level of cleanup might be economically desirable.

For use in clean fuel manufacture, air-blown systems that result in about 50% nitrogen dilution are impractical. Dilution by methane, while undesirable for stand-alone syngas plants, presents less of a problem in plants when electricity or steam generation can make good use of the waste gas from liquids and hydrogen manufacture. Oxygen-blown systems are, therefore, needed for these applications. As previously discussed (Table 15), the loss in power generation efficiency for oxygen-blown versus air-blown systems is about 1% for the KRW fluidized-bed system provided that hot gas cleanup is successful,
Table 16. Gasifier systems being demonstrated for power generation under the CCT program

<table>
<thead>
<tr>
<th>Gasification technology</th>
<th>Name, location</th>
<th>Oxygen or air-blown</th>
<th>Hot or cold gas cleanup</th>
<th>Total project cost* (millions of current $)</th>
<th>DOE cost share (millions of current $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Entrained-flow</td>
<td>Texaco, Polk Power Station, Tampa Electric Co. Destec, Wabash River Station, PSI Energy, Inc. ABB Combustion Engineering, Lakeside Station, City Water, Light and Power</td>
<td>Oxygen</td>
<td>Cold plus 10% hot Cold</td>
<td>241.5</td>
<td>120.7</td>
</tr>
<tr>
<td>Fluidized-bed</td>
<td>KRW, Tracy Station, Sierra Pacific Power (Pinon Pine) MCTI Pulse Combustor, Caballo Rojo Mine Tampella U-Gas, Toms Creek Mine, Va.</td>
<td>Air</td>
<td>Hot</td>
<td>270.7</td>
<td>129.4</td>
</tr>
<tr>
<td>Moving fixed-bed</td>
<td>British Gas Lurgi, slagging, Camden IGCC, Duke Energy Corp.</td>
<td>Oxygen</td>
<td>Cold</td>
<td>780.0</td>
<td>195.0</td>
</tr>
</tbody>
</table>

*Total value of projects is $2,192.1 million.
†Total DOE cost share is $991.8 million (40%).
Source: DOE.16

and this small difference can likely be reduced by further research and optimization. With this small difference, the incentive for development of specialized air-blown systems is not clear.

No single gasification process is likely to be optimal for all applications; the wide range of coal properties will, in itself, affect the choice. An overriding need is for mechanical simplicity. Solid reaction systems are notoriously difficult to extrapolate, making development of any system to commercial scale a costly operation (about $0.5 billion for each process). Thus, careful selection of R&D and demonstration programs to be pursued is extremely important. For maximum efficiency, the following general guidelines are offered: minimum gasification temperature to reduce temperature cycling and oxygen consumption and to maximize methane production. Production of fused ash to minimize solid waste removal/disposal problems also is an important goal. The use of catalysts to allow lower-temperature operations appears attractive to achieve significant improvements in efficiency and to minimize the production of tars. The cost of using catalysts would be a disadvantage.

6.1.5. Current programs

DOE's participation in R&D and demonstration of gasification technologies falls into three categories: CCT programs,* development programs, and advanced research programs related to gasification.

The last two fall within the scope of the coal R&D program in DOE's Office of Fossil Energy.

The CCT programs summarized in Table 16 all involve gasification for power generation. The gasifiers, while constituting a fraction of the total program cost, are an essential feature of each demonstration. The gasification systems being demonstrated represent technologies of commercial interest to companies within the United States, including affiliates of overseas companies. Overall, the program should provide a basis for commercialization of IGCC power generation plants, as well as a framework for future advances in gasification efficiency and cost reductions for power generation.

Of the seven programs, five plan to use the currently experimental hot gas cleanup—one on a 10% slipstream. Use of cold gas cleanup reduces efficiency by approximately two percentage points (see Table 15). Four of the programs will use air as the oxidant with an efficiency advantage of approximately 1% over the use of oxygen. These advantages are specific to dedicated power generation systems and would not be applicable to the supply of hydrogen or syngas for coproduction of liquid fuels.

Recent DOE budgets for surface coal gasification are shown in Table 17. The major expense is for construction of facilities for development of an Advanced Hybrid Gasification System. This facility is designed for development of an air-blown moving fixed-bed system with hot gas cleanup. The proprietary CRS Sirrine Engineers, Inc., PyGas™ staged gasifier has been selected for development with 20% industry cost share.58 Given the committee's concern regarding optimization of gasification systems and
the central role of the PyGas™ staged gasifier in the DOE program, the proposed technology is discussed below in some detail.

Coal, air, and steam are contacted in a cocurrent flow duct where the temperature rises to 815–980°C (1500–1800°F) and pyrolysis of the coal occurs. The hot pyrolyzed coal (char) falls to the top of a countercurrent fixed-bed gasification section, and dry ash is withdrawn at the bottom. Remaining tars are cracked in a tar cracking zone where the temperature is increased by addition of air. The pyrolyzed gases join the hot gas leaving the countercurrent section to produce a 112 Btu/dry standard cubic foot gas stream. The product gas temperature is expected to be around 815°C (1500°F). In Phase I of the project, limestone will be included to capture sulfur in the bed. The spent lime, which exceeds the amount of coal ash, must be treated to oxidize the calcium sulfide before disposal. Use of hot gas cleanup is proposed for a later phase of the program. This system appears to have potential for efficient integration with hot gas cleanup in a power generation system. However, because it is air-blown it would not be a good choice for coproduction of clean gaseous or liquid fuels.

In addition to the programs given in Table 17, there is a program for developing the Wilsonville facility centered around hot gas cleanup. In January 1992 the hot gas particulate removal test facility at Wilsonville, Alabama, was expanded to include system development and integration studies for advanced power systems and was renamed the Wilsonville Power Systems Development Facility. The facility could ultimately be reworked for gasifier research. The proposed FY 1995 budget for this facility is $12.9 million.

The two gasification research programs suffered a 58% reduction in funding in FY 1994, with a further reduction proposed in the FY 1995 budget request. These small programs ($0.8 million) are not sufficient to take advantage of the opportunities identified for further improvements in efficiency of gasification systems. Some additional discussion of advanced research opportunities for gasification can be found in Section 9.

6.2. Products from Coal-Derived Gas

The raw gaseous products from coal gasification include hydrogen (H₂), carbon monoxide (CO), carbon dioxide (CO₂), water (H₂O), ammonia (NH₃), hydrogen sulfide (H₂S), nitrogen (N₂), methane (CH₄), and, for the lower-temperature processes, higher hydrocarbons and tar. For conversion to ‘clean’ gas suitable for combustion in simple equipment or for further processing to other clean fuels or chemicals, the mixture is scrubbed to consist primarily of H₂, CO, CH₄, and N₂. This type of ‘synthesis gas’ (syngas) mixture is currently of industrial importance for production of commodity chemicals and, to a growing extent, production of fuels. Natural gas is currently the dominant feedstock for production of syngas, with a large, continuing industrial and international R&D activity in this field. In this section the following major product categories are discussed: hydrogen, synthetic natural gas, methanol and other oxygenated products from synthesis gas, and products from F-T (Fischer–Tropsch) synthesis. The costs presented are based on the standard utility financing used by DOE. Costs would be $6–10/bbl higher for liquid feed production from coal if conventional petroleum industry financing were assumed (see Glossary).

6.2.1. Hydrogen production

Major uses for hydrogen include ammonia manufacture for fertilizers and the refining of petroleum liquids with low hydrogen and high sulfur content. Hydrogen is also required to convert fossil resources into transportation fuels, since the hydrogen-to-carbon ratio for liquid transportation fuels is approximately two, compared to less than one for coal and slightly greater than one for petroleum tars.

The standard technique for hydrogen manufacture from natural gas or by coal gasification is to employ the water/gas shift reaction:

\[ \text{CO} + \text{H}_2\text{O} \rightarrow \text{CO}_2 + \text{H}_2. \]
Production of hydrogen is favored by low temperatures, but satisfactory reaction rates currently require a temperature of 300–700°C (570–1290°F). In addition, a high level of acid gas (H₂S, CO₂, hydrogen chloride [HCl]) removal is needed to maintain catalyst reactivity. Hydrogen can also be separated from synthesis gas by cryogenic distillation. Another alternative for hydrogen production is to develop processes for the production of SNG, methanol, or liquid fuels that accomplish the shift of H₂/CO mixtures in situ, thereby avoiding energy losses incurred by heating and cooling, the shift reaction, and subsequent removal of CO and CO₂ from the product stream. Pressure swing methods for hydrogen separation are advantageous principally for small- and medium-scale applications.

If pure hydrogen could be obtained economically as a coproduct from the coal-derived fuel gas supplied for electric power generation, it might be used for high-efficiency fuel cell operation, hydrogenation of by-product coal pyrolysis liquid, direct coal liquefaction, or sold for the many conventional applications of hydrogen. New materials to allow efficient, low-cost separation of hydrogen from coal-derived gas by selective membrane diffusion offer performance enhancements, as discussed further in Section 9.

**6.2.2. Synthetic natural gas production**

SNG is produced from gasified coal by a set of reactions of CO, CO₂, H₂, and H₂O over a catalyst to form methane. While the stoichiometry of the reaction is

\[
\text{CO + 3H}_2 \rightleftharpoons \text{CH}_4 + \text{H}_2\text{O}
\]

in the presence of catalysts, the interchange between the feed components can be rapid and controlled by thermodynamic equilibrium, such that the feed H₂:CO ratio can be much lower than the stoichiometric 3:1 ratio. While the above methane synthesis reaction is highly exothermic, the gasification reactions to form synthesis gas are about equally endothermic, and the balancing of these reactions to minimize thermal losses from heating and cooling is essential for achievement of high efficiency. A large number of catalysts and systems have been studied with the goal of minimizing cost. An extensive discussion of SNG technology can be found in a report from the DOE Coal Gasification Research Needs Working Group.

The one commercial SNG facility in the United States, the Great Plains plant in North Dakota, was built in the late 1970s by a consortium of natural gas companies in anticipation of constraints on natural gas supply and associated price rises. Despite the low cost of coal today and technically satisfactory operation, the plant is only profitable because contractual product prices are higher than the market price and a large portion of the capital costs is borne by the federal government. SNG is also produced in South Africa, and China plans to build a $220 million plant in Henan province to produce 40 Mcf/day of SNG, with over 20% of the coal gas destined for use as petrochemical feedstock.

The Great Plains plant uses 14 Lurgi dry bottom gasifiers followed by cold gas cleanup to reduce sulfur content to less than 1.0 ppm. The H₂:CO ratio produced is around 2.0, while for the higher-temperature British Gas Lurgi slagging gasifier the ratio is 0.46, with ratios for other gasification systems falling between these limits. Advanced catalytic systems for directly converting the low H₂:CO ratio gas from coal gasification have been an active R&D area. Goals include improvement in sulfur tolerance by appropriate choice of catalyst and operating conditions, better reactor temperature control, and avoidance of carbon formation favored by low-hydrogen-content fuel gas. It has been estimated that when commercialized these advanced technologies, together with limited work on improvements in the removal of acid gases, will reduce SNG costs by 25% for stand-alone plants using western coal.

For the year 2010, EIA (Energy Information Administration) projects a wellhead price for natural gas of $3.50/Mcf, and continued increases in price may be expected past this date as a result of resource limitations. Substitution of coal-generated low- and medium-Btu gas for natural gas for power generation and industrial use could make additional supplies of natural gas available for domestic and commercial consumers. Thus, the need for major dedicated SNG manufacture could well be delayed beyond the year 2021.

Currently there are no DOE programs budgeted specifically for SNG production. However, since the major cost and energy consumption are incurred by the gasification step, opportunities for improvement are similar to those for oxygen-blown advanced IGCC and fuel cell systems. A program aimed at improving gasification thermal efficiency could be applied to both uses, providing an additional incentive for an integrated gasification program.

**6.2.3. Liquid products from synthesis gas**

By careful choice of catalyst and conditions, synthesis gas can be reacted to produce higher hydro-

---

*Methane is also produced noncatalytically in low-temperature gasification by thermal equilibration. The Exxon fluidized-bed catalytic gasification process makes use of this reaction with cryogenic separation of the methane produced (15–20 volume % of gas at 630°C [1200°F]) and recycle of unconverted feed. Methane can also be produced from coal pyrolysis, and lower-temperature processes can provide up to 20% methane by volume in the gasifier product. High-temperature entrained-flow processes produce little methane.*
carbons and oxygenates such as methanol. These products are useful for commodity chemicals, are of increasing interest for use as transportation fuels, and have been considered for production of storable supplementary fuel for IGCC electric power plants.60,61

The reaction between carbon monoxide and hydrogen to produce paraffinic oxygenates or hydrocarbons is extremely exothermic.62 The heat evolved is approximately 20% of the heat of combustion of the product and, because of the narrow temperature range over which the catalysts provide satisfactory selectivity to the desired product, control of reaction temperature is a major engineering challenge. The difference between the several catalytic processes in use or under development is largely related to differences in approach to temperature control and choice of catalyst.

6.2.3. Methanol. Methanol has been a major commodity for many years, with principal uses in the chemical industry and as a solvent. It can also be used as a motor fuel and, with the requirement for inclusion of oxygenates in gasoline, its use for preparing oxygenated components by reaction with olefins has grown rapidly. Its direct use as a gasoline blending agent is limited by its relatively low solubility in gasoline and its tendency to be extracted by any water present in the gasoline distribution system. Its use as the primary fuel component offers good performance but is limited by cost in competition with imported petroleum, a potential problem with formaldehyde emissions, and the difficulties of establishing an adequate distribution system and availability of automotive systems designed to use this fuel. Other limitations of methanol are its high toxicity, potential reaction with elastomers used in the automobile fuel system, the fact that it burns with an invisible flame, the potential for ground water pollution, and a limited driving range because of the low energy content per unit volume.

Methanol is made by the catalytic conversion of syngas at about 250°C (480°F) and a pressure of 60–100 atm. Both coal and natural gas can be used as syngas sources. The current commercial processes use a fixed-bed catalytic reactor in a gas recycle loop. There are a wide range of mechanical designs used to control the heat released from the reaction. Lurgi and Imperial Chemical Industries technologies currently dominate, but other designs are offered by Mitsubishi, Linde, and Toyo corporations. New developments in methanol technology include use of a liquid-phase slurry reactor for methanol synthesis and fluidized-bed methanol synthesis being developed by Mitsubishi Gas Chemical. Liquid-phase slurry reactors offer improved control of temperature and are of considerable interest for both methanol and F–T hydrocarbon production. A DOE-owned liquid-phase slurry reactor plant at LaPorte, Texas, has been operated with industry cost sharing for a number of years. A DOE-supported demonstration plant is now being built by Eastman Chemical at Kingsport, Tennessee. In the fluidized-bed design a fine catalyst is fluidized by syngas. Better contact between syngas and catalyst gives a higher methanol concentration exiting the reactor, which reduces the quantity of recycle gas, the recycle compressor size, and the heat exchange area in the synthesis loop.

A study on production technologies for liquid transportation fuels38 provides some perspective on costs of methanol production using both coal and natural gas as syngas sources. Natural gas at current prices is by far the lowest-cost feed, but at a delivered natural gas price of greater than $4–5/Mcf, coal gasification was judged to be competitive.

6.2.3.2. Methanol-derived fuels. There has been extensive industrial R&D, in the United States and overseas, on processes to convert methanol to gasoline, olefins, and diesel fuel.38 Major participants include Mobil Research and Development Corporation, Union Rheinische Braunkohlen Krafstoff AG, Uhde Gmbh, Haldor Topsoe, Mitsubishi, and Lurgi. Technologies for the conversion of methanol to gasoline have been demonstrated at scales of 1–100 bbl/day, and the Mobile process operates commercially in New Zealand producing 14,500 bbl/day of gasoline from syngas derived from natural gas rather than coal. Conversion of methanol to olefins has been demonstrated in Germany at a 100 bbl/day scale; high-quality gasoline is also produced. At present, however, new plants for hydrocarbon fuel production from natural gas use the F–T synthesis, indicating no current major advantages for prior synthesis of methanol.

Production costs for imported methanol manufactured from overseas natural gas at $1.00/Mcf have been estimated38 at $29/bbl equivalent crude oil cost (for gasoline equivalent). This cost is approximately competitive with methanol production from coal using advanced technology and coproduction with electric power.63 Even when domestic natural gas prices rise to a level where dedicated production from coal could compete economically, natural gas is expected to remain the lowest-cost syngas source for methanol production due to the large overseas supply of very low cost natural gas. However, as discussed later in the section on coal refineries and coproduction systems, coproduction with gasification combined-cycle power generation might be competitive with imported methanol.

While there is extensive industry activity on methanol synthesis starting with natural gas and using synthesis gas with the stoichiometric $H_2:CO$ ratio of 2.0 and low or very low sulfur content, there is relatively little activity on development of once-through processes using low $H_2:CO$ ratios and sulfur concentrations achievable with hot gas desulfurization. Such a process could be more efficient and advantageously integrated with coproduction of electricity.
Table 18. F-T process development and commercial activities

<table>
<thead>
<tr>
<th>Participants</th>
<th>F-T Process</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sasol</td>
<td>Lurgi/Sasol Arge fixed-bed process; wax product from coal feed</td>
<td>Commercial operation at Sasol I for 40 years</td>
</tr>
<tr>
<td>Sasol</td>
<td>Sasol Synthol circulating fluid bed; light olefins and olefinic naphtha from coal feed</td>
<td>Commercial operation</td>
</tr>
<tr>
<td>Sasol</td>
<td>Slurry-phase process using coal feed; 30-44% paraffins, 50-64% olefins, 7% oxygenates</td>
<td>Commercialized in 1993 after 10-year development program. Plant capacity is 2500 bbls/day</td>
</tr>
<tr>
<td>Shell Oil Company</td>
<td>Shell middle distillate fixed-bed synthesis using gas feed</td>
<td>Bituflu plant in Malaysia became operational in 1993; capacity is 12,000 bbl/day</td>
</tr>
<tr>
<td>Mobil R&amp;D Corporation/DOE Exxon</td>
<td>Slurry F-T reactor with gas feed using ZSM-5 catalyst</td>
<td>Major development in late 1980s</td>
</tr>
<tr>
<td>Exxon</td>
<td>Slurry hydrocarbon synthesis with gas feed and product hydrosomerization</td>
<td>Program completed in 1993 demonstrated processes at a scale of 200 bbl/day; ready for large-scale commercialization</td>
</tr>
<tr>
<td>Statoil DOE plus industrial partners*</td>
<td>Gas to middle distillate slurry process Slurry-phase F-T technology using coal feed</td>
<td>Pilot plant stage Demonstrated at LaPorte facility in 1992</td>
</tr>
</tbody>
</table>

* Air Products, Exxon, Shell, and Statoil.

6.2.4. F-T synthesis

The F-T process reacts and polymerizes synthesis gas to produce a wide range of products: light hydrocarbon gases, paraffinic waxes, and oxygenates. Further processing of these products is necessary to upgrade the waxy diesel fraction, the low-octane-number gasoline fraction, and the large amount of oxygenates in the product water. A premium diesel fuel can be manufactured from the higher-molecular-weight hydrocarbons and the wax. The gasoline boiling range fraction has low octane number and requires more substantial upgrading to produce useful motor fuel. The distillation of high-molecular-weight products can be adjusted by choice of catalyst and operating conditions; wax produced as an intermediate is hydrotreated to produce a high cetane product. Greatest current interest is in the production of highmolecular-weight material for diesel and jet fuels, for which the low sulfur and high hydrogen content (compared to petroleum fractions) commands a premium price.

As with methanol, there is active industrial interest in the use of low-cost overseas natural gas to manufacture F-T synthesis products. The largest commercial activity with coal feed is by the South African Coal, Oil, and Gas Corporation (Sasol) in South Africa. Most of the R&D in the United States on F-T processes has been conducted by Exxon. Important research areas are in catalyst development and optimization of processing conditions. Highlights of F-T development and commercialization activities are summarized in Table 18. For production of both methanol and hydrocarbons, the slurry process has been a focus of DOE research since it can accept the low-hydrogen/carbon monoxide synthesis gas produced from coal without the additional step of shifting the ratio required by the traditional fixed-bed systems. Success of this DOE approach has been demonstrated in a large-scale pilot plant at LaPorte, Texas, with joint DOE/industry funding.

While there is an active international R&D program on F-T for use in remote natural gas locations, improved catalysts and process conditions for once-through processes with electricity as a coproduct may offer research opportunities specific to coal.

The results of DOE-sponsored design and systems studies on the cost of coal liquids production for stand-alone indirect liquefaction plants and for coproduction of coal liquids with gasification-based power generation are discussed below (see Section 6.4, Coal Refineries and Coproduct Systems).

6.3. Products from Direct Liquefaction and Pyrolysis of Coal

6.3.1. Direct liquefaction

6.3.1.1. Background. In direct liquefaction, hydrogen is added to coal in a solvent slurry at elevated temperatures and pressures. The process was invented by Friedrich Bergius in 1913 and was commercialized in Germany and England in time to provide liquid fuels during World War II. The first U.S.

*Direct liquefaction is generally believed to be 5-10% more efficient than indirect liquefaction because of lower consumption of gasified coal.
testing of direct liquefaction processes followed World War II. Efforts in the area declined when inexpensive petroleum from the Middle East became available in the early 1950s. Interest revived when the Arab oil embargo of 1973 caused high oil prices, resulting in increased federal funding for such research. A variety of process concepts were examined on a small scale (10–20 tons/day), and three—Solvent Refined Coal, Exxon Donor Solvent, and H-Coal—were tested on a large scale (200–300 tons/day) in the late 1970s and early 1980s. The DOE provided much of the funding for these successful demonstrations, but none of the processes proved economical when oil prices fell in the early 1980s. Overseas, Veba Oil and others built and operated a large-scale pilot plant at Bottrop, Germany, in the late 1970s and early 1980s. The facility is currently being used to hydrogenate chlorinated wastes. This facility was funded primarily by the German government. Demonstration of the liquid solvent extraction process developed by the British Coal Corporation is continuing at the Point of Ayr Plant in Wales with both industrial and government support. In the late 1980s the Japanese operated a 50-ton/day liquefaction plant in Australia.

6.3.1.2. State of the art. Products of direct coal liquefaction can be refined to meet all current specifications for transportation fuels derived from petroleum. Major products are likely to be gasoline, propane, butane, and diesel fuel. Production of high-quality distillate fuels requires additional hydrogen to decrease smoking tendency and to increase cetane number for use in diesels.

High octane is achieved by the high aromatic content of the liquids. At one time, this was considered to be an advantage; however, the CAAAs (Clean Air Act amendments) of 1990 place sharp limits on the aromatic content of motor fuels in the United States. Fortunately, the benzene content of gasoline made from coal is extremely low; the concentration of other aromatics can be reduced by hydrogenation to produce naphthenes at a modest increase in cost. This increases the volume of the products, decreases the octane number, and increases process hydrogen consumption.

The projected cost for direct coal liquefaction has dropped by over 50% since the early 1980s. Recent improvements in economics cannot be attributed to any single breakthrough but rather to the accumulation of improvements over several years of operation, notably the following:
- A more effective and reliable process was developed to remove solids from the liquid product by controlled precipitation, replacing a filtration process.
- A second catalytic reactor was added to improve control over the chemistry of liquefaction. This reactor was first installed downstream of the solids removal and distillation systems; moving the reactor upstream further improved operation.
- Some of the recycled liquid used to slurry the feed coal was bypassed around the solids removal unit, increasing the efficiency of the unit.
- Improved catalysts were added to both the first and second reactors.

This series of modifications led to higher liquid yields, improved conversion of nondistillable liquids, less rejection of energy along with discarded coal minerals, and increased throughput relative to early two-stage systems. The success of this evolution shows that steady R&D can achieve major technological advances over time. The current U.S. direct liquefaction technology appears to be the best for U.S. coals, but work continues overseas with emphasis on other coals. All of the foreign projects have had the bulk of their financing contributed by government.

6.3.1.3. Current programs. U.S. research into direct coal liquefaction continued after the big pilot plants were abandoned in the 1980s, but both industrial and DOE activities have steadily decreased with time. Small test units capable of continuous operation for sustained periods of time were available at Hydrocarbon Research, Inc., Exxon, Lummus-Crest, the University of Kentucky, and Amoco Corporation, but today are either shut down or only in limited use. The Advanced Coal Liquefaction R&D Facility in Wilsonville, Alabama, operated full-time through 1991. Hydrocarbon Research, Inc. started up a smaller facility in the second half of 1992 under DOE sponsorship. The unit operates approximately half-time, but funding beyond 1994 is uncertain. Research at West Virginia University on the production of coal-derived precursors using solvent extraction techniques as carbon product feedstocks has been supported by DOE. However, DOE funding for advanced research in direct liquefaction has decreased in recent years (see Section 9).

6.3.1.4. Technical issues, risks, and opportunities. A 1989 assessment of research needs conducted by DOE’s Office of Program Analysis outlined a comprehensive program aimed at bringing down the cost of direct liquefaction. Industry participants in the aforementioned study stressed the need for federal funding of a large-scale pilot plant capable of processing 150 tons/day or more of coal, but such a unit was never funded. In addition, funding of intermediate-size flow units of the size of the Hydrocarbon Research, Inc. facility was recommended to test changes in process configuration at reasonable cost. Smaller pilot plants are needed to evaluate catalysts, explore operating conditions, and provide low-cost testing of new ideas.

A design and system analysis study, based on runs at the DOE Wilsonville plant, was carried out by a Bechtel-Amoco team under contract to PETC. Using Illinois No. 6 coal (bituminous), the equivalent

\*This study assumed nth plant costs with 3%/year price inflation over the plant life, 25% owner equity with 15% return, and 8% interest charges for the 75% loan.
crude price was approximately $33/bbl, compared to estimates of $44/bbl prepared for an earlier study.\textsuperscript{38} This cost reduction results from the incorporation of more recent results from the DOE Wilsonville plant, improved gasification, and from inclusion of 3% inflation in the DOE-sponsored estimates. The earlier estimates assumed 10% return and did not include inflation. If inflation were eliminated from the current DOE-sponsored calculations, the equivalent crude cost would be increased by approximately $5/bbl. An extension of the Bechtel-Amoco study will be based on lower-cost Wyoming coal and is expected to reduce the equivalent crude costs to slightly less than $30/bbl. On the basis of achievements to date, there is now optimism at DOE and among some industry groups that the $25/bbl target (in 1991 dollars) set by DOE\textsuperscript{2} may be attainable by sustained R&D and continued optimization studies.

The 1989 assessment\textsuperscript{47} also recommended a broad range of fundamental and exploratory research, based on the recognition that possible improvements to the current technology may be limited but that advances in conversion chemistry may bring down the cost of liquid fuels produced from coal to be competitive with petroleum products. Possible approaches to conversion chemistry that might achieve costs below the current $25/bbl goal include low-pressure reaction (2.17 MPa [300 psig] or less), direct use of gasifier product, use of low-cost subbituminous coal or lignite, removal of oxygen in coal as carbon dioxide, and elimination of product hydrocarbon gases (increased selectivity).

Integration of direct coal liquefaction with an existing petroleum refinery could take advantage of existing facilities and ease the transition between petroleum and coal feedstock. DOE sponsored work on simultaneous processing ('coprocessing') of coal with heavy petroleum fractions in an ebullated-bed hydroprocessing reactor. One CCT program submission utilizing this technique was selected for funding but was unable to find the private sector funding needed to proceed.

6.3.2. Coal pyrolysis

Pyrolysis of coal dates back to the 18th century, using temperatures below 700°C (1290°F) in fixed or moving fixed-bed reactors. The primary product was a low-volatile smokeless domestic solid fuel, although the value of the liquid products was also soon recognized. During the 1920s and 1930s there was a great deal of R&D in low-temperature processes, but interest dwindled in the mid-1940s when gas and oil became readily available at low prices. With the oil embargo and increased oil prices of the early 1970s, interest renewed in coal pyrolysis, but in more recent times interest has again declined along with petroleum prices.\textsuperscript{69} Pyrolysis kinetics are reasonably well understood and have been modeled extensively.\textsuperscript{70} Both yield and liquid fuel properties depend on pyrolysis conditions. Pyrolysis under mild temperatures (500–700°C [930–1290°F]) and pressures (up to 50 psig) with rapid heat-up can produce high liquid yields without adding hydrogen. However, a significant part of the feed coal remains as char with market value comparable to or somewhat less than that of the feed coal. Coal pyrolysis offers some promise of lower liquid costs if the char can be upgraded to higher-value speciality products, such as form coke, smokeless fuel, activated carbon, or electrode carbon, or if the liquid yield can be significantly increased by using low-cost reactants (steam and carbon dioxide) or catalysts. Pyrolysis liquids have a low hydrogen-to-carbon ratio, generally less than 1, in contrast to petroleum tar and bitumens (around 1.4) and high-quality petroleum products (approximately 2.0). They also contain substantial amounts of oxygen, compared to tar, and thus require more extensive hydrogen addition to produce specification fuels. Their tendency to polymerize on standing can cause operational problems, which also must be addressed.

Little heat is required to produce pyrolysis liquids from coal, however, and production as a side stream to coal gasification or fluidized-bed combustion is efficient. Pyrolysis reactors generally operate at modest pressures and temperatures compared to other coal conversion systems and offer high throughput. Both of these features lead to low capital cost. The cost of pyrolysis liquids could thus be low and might be competitive with bitumen or for integration with oil refinery hydroconversion operations where their solubility characteristics could improve the operability of hydrocarbon units. They could also be combined with direct coal liquefaction. When made from low-sulfur coal, pyrolysis liquids have limited potential as a substitute without refining for petroleum fuel oil, and an ongoing CCT program (ENCOAL Mild Coal Gasification project) is aimed at this market. Pyrolysis liquids have traditionally been a source of coal tar chemicals, and the DOE Mild Gasification program is aimed, in part, at this market (see below).

The budget for the DOE Advanced Clean Fuels Program within the FE coal R&D activity underwent a 30% reduction between FY 1993 and FY 1994, and a further 45% reduction is proposed for FY 1995 (see Table 1). These budget decisions reflect a diminished commitment to the use of coal for production of clean liquid fuels by either indirect or direct liquefaction. Of particular note is the proposed reduction of 84% in FY 1995 funding for Advanced Research and Environmental Technology; programs in this area are expected to lead to improvements in efficiency and cost reductions for liquid fuel production (see Section 9).
6.4. Coal Refineries and Coproduct Systems

A coal refinery or coproduct system is defined as a system consisting of one or more individual processes integrated in such a way as to allow coal to be processed into two or more products supplying at least two different markets. The concept resulted from the realization that coal must be processed in nontraditional ways to meet the needs of potential expanded markets. A key feature of the coal refinery concept is the production of more than one product form, for example, steam and electricity or fuel gas and electricity. The concept can be generalized to include cogeneration of steam and electricity, production of fuel gas for both industrial heat and electricity generation, production of syngas for manufacture of chemicals and/or fuels, capture and use of pyrolysis tars for chemicals and fuels manufacture, and production of specialty coals.

6.4.1. Cogeneration

Cogeneration was initially practiced in energy-intensive industrial plants to meet internal needs for steam and electricity. Steam and electricity coproduct systems are now a major commercial activity. With few exceptions cogeneration facilities are designed to use natural gas because of the lower investment compared to a plant that uses coal. As natural gas prices rise to a level that renders the higher investment in coal facilities economically advantageous, advanced cogeneration systems, where the first step is gasification, could also supply coal liquids, fuel gas, and syngas made from coal. Currently, there appears to be ample opportunity for a variety of coproducts produced by the primary coal gasification process. Steam and electricity would continue to be major products.

It seems reasonable to expect that the time for introduction of cogeneration systems based on coal would approximately correspond to the time when the projected cost and/or availability of natural gas would justify investment in new coal-based, power-generating facilities, perhaps during the mid-term period (2006–2020). This time might well arrive before manufacture of synthetic natural gas is required to meet domestic demand. The large world resources of petroleum and bitumen, combined with low prices, are expected to defer manufacture of liquid transportation fuels from coal until the price range is $25–30/bbl, although security considerations could call for an earlier date. The first major opportunity for coproducts would then arise from the predicted mid-term need for new high-performance coal-based, power generation systems. These high-performance systems will probably involve coal gasification offering the possibility of coproducts from the gasifier (syngas, fuel gas, and pyrolysis tar). The production of coproducts, in conjunction with SNG manufacture, was of major commercial and DOE interest until the 1980s, when low oil and gas prices and ample supplies eliminated the near-term economic incentive for synthetic fuels processes. The expected growth in coal-based power generation appears to offer a more robust opportunity for fuel and chemical coproducts than the traditional single product or dedicated plant approach.

The business environment and regulatory changes that have encouraged cogeneration could provide a framework for extension to the use of coal as a source of energy and a resulting greater variety of coproduct streams. Recent industrial concerns regarding efficient production of major products and conservation of capital are resulting in steam and power being supplied by external companies that build and operate facilities for supply of steam and electricity to both local manufacturing plants and utilities. In some cases these companies are subsidiaries of a utility. Such companies might supply fuel gas and syngas to chemical and petrochemical companies. Nonetheless, the complexity of the potential business relationships and the need for a flexible approach should not be underestimated.

With today's emphasis on increased generation efficiency and the availability of high-performance gas turbines and fuel cells, an incentive for development of high-efficiency gasification systems specifically designed to provide fuel for power generation has been established. As discussed earlier, these systems can differ from systems optimized to produce highly purified synthesis gas for conversion to chemicals and clean fuels in that dilution by methane and nitrogen is acceptable; a higher level of impurities can also be tolerated.

6.4.2. Indirect liquefaction

DOE-sponsored design and systems studies by the Mitre Corporation and Bechtel have provided information on cost for both present-day stand-alone indirect liquefaction plants and coproduction of coal liquids with gasification-based electrical power generation. For the stand-alone F-T synthesis, the Mitre study found an equivalent crude price of $35/bbl. Coproduction with electricity reduced the equivalent crude cost by $5–6/bbl to approximately $30/bbl. The savings for coproduction were attributed to a combination of better heat integration and the economies involved in once-through operation.

The study by Bechtel estimated a difference in equivalent crude cost of coal liquids produced by stand-alone and coproduction methods of approximately $7/bbl. For coproduction, the gasoline boiling

---

* Prior to the formation of DOE in 1977, programs were conducted under the auspices of the Energy Research and Development Administration.
† See Section 2 and the Glossary for discussion of financing options.
range fraction was sent to the turbines, thus reducing total liquid production but also avoiding the costs of upgrading the low-octane-number naphtha produced by this process. While the required selling price was similar to that for the Mitre study, the assumed refined product values were higher, with a larger assumed premium for the diesel fuel. This assumption, together with other cost differences, makes comparison of the two studies difficult. The Bechtel study estimates an equivalent crude price for coproduction of somewhat less than $25/bbl. The cost estimates from the Bechtel and Mitre studies differ significantly from those found in a previous National Research Council study, where the estimated equivalent crude price was greater than $40/bbl for the stand-alone plant. The difference results from a combination of the inclusion of inflation in the DOE-sponsored studies, higher product values, improved gasification technology, and use of the slurry reactor.

World oil prices in 2010 are projected to be in the range of $18–34/bbl. For the EIA reference case, the projected oil price in 2010 is $28/bbl, indicating that, on the basis of the estimated costs discussed above, indirect liquefaction could be of commercial interest within the mid-term timeframe (2005–2020). However, it is important to note that the estimated costs from the Mitre and Bechtel studies are for the "nth" plant and are below pioneer plant costs. As in the case of advanced power generation technologies, early market entry would likely require some federal cost sharing (see Section 8).

6.4.3. Direct liquefaction

Coproduction of coal liquids and electric power based on IGCC systems offers additional opportunities for cost reduction in the production of hydrogen, which could be used for direct liquefaction. No estimates of the magnitude of possible benefits are available for direct liquefaction; however, they would probably be somewhat less than those predicted for the F–T process because of lower synthesis gas consumption.

6.4.4. Current programs

The U.S. Congress, in EPACT, directed DOE to examine the potential of coal refineries, evaluate their potential for meeting new markets, outline R&D needs for potential commercialization, and prepare a report on the subject for congressional consideration (see Appendix A). DOE activities related to this directive have included continuation of the program sponsored by DOE’s Morgantown Energy Technology Center aimed at commercialization of the mild gasification process, which is based on pyrolysis and is directed toward producing specialty cokes and tars for production of chemicals. No further funding for the program has been requested for FY 1995. In addition, the ENCOAL mild coal gasification project is being funded by DOE on a 50:50 cost-share basis with ENCOAL Corporation under Round III of the CCT program. The two year operational test period began in July 1992, and solid process-derived fuel and coal-derived liquids have been produced. DOE has also issued the mandated report to Congress.

DOE coal R&D funding for systems for coproducts is divided into two categories: the mild gasification program and conceptual studies of coproduction of electricity and coal liquids. The former activity at the Illinois Mild Gasification Facility is cost shared with Kerr/McGee. It received $1.5 million in FY 1993 and $3.9 million in FY 1994; no funding was requested for FY 1995. A similar process is addressed in the ENCOAL CCT project, thereby reducing the incentive for major continuation of funding under the coal R&D program. A conceptual study of electricity and coal liquids production—as proposed in the FY 1995 congressional budget request—could extend the existing preliminary studies. In FY 1995, $0.6 million was requested for this study; there was no funding for this activity in FY 1993 and FY 1994.

6.5. Summary

6.5.1. Coal gasification technology

1. Technology for the manufacture of clean gas is unique to coal-based systems; technology development is not addressed in DOE Fossil Energy programs other than those relating to coal (FE coal R&D and CCT).

2. The expected major future use of coal gasification in power generation has stimulated industrial R&D for gasification systems tailored to high-efficiency power generation requirements. Seven systems are scheduled for demonstration in the CCT program. However, further improvements in gasifier performance are required to achieve DOE's 45% efficiency goal for second-generation IGCC systems.

3. Use of coal gasification for supply of clean gaseous and liquid fuels, in addition to uses for power generation, provides an incentive to develop improved processes for this set of interacting needs. Fluidized-bed systems, with possible use of catalysts, offer an attractive method for providing the entire array of products from coal because of their temperature characteristics and compatibility with hot gas cleanup systems.

4. There are systems integration and research opportunities for further improvement in combined gasification/gas cleanup efficiency.

5. The air-blown fixed-bed gasifier scheduled for development at the DOE Gasification Product Improvement Facility may be competitive for use in a hot gas cleanup combined-cycle power generation system. If cold gas cleanup is used, the overall
advantage over current commercial systems is not
clear.
6. Despite opportunities for technology improve-
ment, the proposed FY 1995 budget indicates reduc-
tions in funding for gasifier development, systems
studies, and research.

6.5.2. Gaseous products

1. Manufacture of low- and medium-Btu gas is
expected to play a major role in high-efficiency power
generation systems, as a source of syngas and hydro-
gen for manufacture of coal-based liquid fuels, and
for production of industrial chemicals.

2. Improvements in gasification efficiency and re-
ductions in capital cost offer major R&D opportu-
nities.

3. While domestic natural gas is currently favored
as fuel and as a source of hydrogen and synthesis
gas, projected increases in price and decreased avail-
ability will increasingly favor use of coal-based gases.
Displacement of natural gas by coal-based low- and
medium-Btu gas can extend the supply of low-cost
natural gas for domestic and commercial consumers
and postpone the need for synthetic natural gas
facilities.

4. Minimum CO\textsubscript{2} production, as well as cost, will
be important factors in the choice of processes to
manufacture gaseous products from coal.

5. Efficient separation of gaseous products and
gas cleanup processes offer opportunities for
improvement.

6.5.3. Liquid fuels from coal

1. Advances in coal gasification and liquefaction
technology have reduced estimated costs to approxi-
mately $33/bbl equivalent crude oil cost for mature
(i.e. not pioneer) single-product plants using direct
liquefaction with Illinois No. 6 coal.

2. Experience with sustained R&D indicates that
DOE's goal of $25/bbl (1991 dollars) for coal-based
liquids may be attainable with continued research
and systems studies.

3. Industrial programs have been drastically
reduced.

4. The DOE budget for FY 1995 proposes a dras-
tic reduction in liquefaction activities.

6.5.4. Coal refineries and coproduct systems

1. The concept of coal refineries or coproduct
systems, defined as the production of more than one
commercial product from coal, offers opportunities
for optimization and significant cost reduction of coal
conversion systems relative to single-product plants.

2. Coproduction with electricity has the potential
to reduce indirect coal liquefaction costs by $6/bbl
or more, indicating that pioneer production of liquids
may become economically attractive in the timeframe
projected for widespread construction of advanced
gasification power generation facilities.

3. Opportunities for coproducts could determine
the choice of gasification technology. Systems studies
are needed to identify the major research, develop-
ment, and commercialization opportunities.

4. The first major opportunities for implementa-
tion of coal refineries will likely involve electric power
as the major product. Indirect liquefaction could
well be the first application of coproduction with
electricity.

5. The large reduction in FY 1995 funding for
DOE coal R&D programs relating to coproduct
systems is caused by discontinuation of the mild
gasification activity. DOE has proposed $0.6 million
for conceptual studies of coproduction of liquids and
electricity.

7. ELECTRIC POWER GENERATION

A major part of the DOE effort in the Office of
FE is directed toward development of coal-fired elec-
tric power generation systems. The DOE program
sponsors coal technology development from basic
research through engineering, proof-of-concept test-
ing, and commercial-scale demonstration. These ef-
forts include R&D on components that are engi-
neered and designed to operate in an integrated
fashion in advanced power generation systems. For
example, IGCC electric power systems include com-
ponents such as advanced coal gasifiers, high-tem-
perature gas cleanup systems, and advanced gas
turbines.

This section focuses on the main coal-based electric
power systems under development in DOE and indus-
try programs—namely, pulverized coal-based sys-
tems, fluidized-bed combustion systems, and inte-
grated gasification-based systems. Other concepts,
including magnetohydrodynamics and direct coal-
fi red heat engines, also are discussed. In each case
the main emphasis is on identifying technical issues,
risks, and opportunities likely to influence future
development activities by DOE and other organiza-
tions. Two key components of many of these sys-
tems—combustion turbines and emission control
technologies—are then discussed separately. Com-
plementing the R&D directed toward improvements
in coal-based electric power systems, the DOE has en-
gaged in extensive technology demonstration through
its CCT program (see Sections 2 and 8). Relevant
CCT demonstration activities are also addressed in
this section.

DOE's programs in coal-based power generation
focus on advanced technologies that can enable utili-
ties to meet future environmental requirements while
containing electricity costs. Thus, advanced power
systems must not only produce significantly lower
emissions than current coal-fired plants but also must
compete economically with other future options.
Higher efficiencies in the new technologies will contribute not only to lower fuel costs but also to improved environmental performance for a given power output. DOE’s research goals for advanced power systems performance and cost were shown earlier in Table 3. Later parts of this section include discussions and assessments of goals for individual power generation technologies. Budget data are taken from the FY 1994 and FY 1995 congressional budget requests.775

7.1. Pulverized Coal Systems

7.1.1. Background

Pulverized coal-fired electric power generation involves reducing coal size to a powder and conveying it with combustion air into a boiler where it is burned. The heat released evaporates water flowing in tube in the boiler walls to form high-pressure, high-temperature steam, which is used to drive a turbine connected to an electric generator. The steam is then condensed back to a liquid and returned to the boiler to repeat the cycle (called the Rankine cycle). A wide range of coals may be combusted in pulverized coal boilers; however, units designed to burn a variety of coals are more costly than units using a more uniform fuel. Coal cleaning is widely practiced, usually at the mine, to reduce the coal ash and sulfur content and to raise its heating value, thus providing a more uniform fuel supply (see Section 5). Pulverized coal combustion has been practiced for many decades, and there is an extensive literature on boiler and system designs.

7.1.2. State of the art

The overall efficiency of a pulverized coal power generation cycle is affected by many factors, including the thermodynamic cycle design, steam conditions (temperature and pressure), coal grind, combustion air:fuel ratio, fuel mixing, air leakage into the system, cooling (condenser) water temperature, and parasitic energy loads for auxiliary equipment such as grinding mills, pumps, fans, and environmental control systems. The net thermal efficiency (conversion of fuel energy to electricity leaving the plant) of U.S. coal-fired generating plants operating today averages 33%.74 However, newer state-of-the-art plants with full environmental controls have efficiencies of 38–42%, the higher values corresponding to new supercritical steam units operating in Europe. Supercritical steam units operate at much higher temperature and pressure conditions than subcritical steam units, thus achieving higher overall efficiency. U.S. experience with early supercritical units installed in the 1960s and 1970s was generally unfavorable because of lack of operator experience and reliability and maintenance problems. Most U.S. coal plants today employ subcritical steam conditions, which give lower efficiency (typically 36–37%). Some early supercritical units, however, are still operating satisfactorily. The most efficient supercritical steam unit operating in the United States is the Marshall 4 unit of Duke Power, which was installed in 1970 with a design efficiency of 40% and today operates at a 38% efficiency without a FGD (flue gas desulfurization) unit.75 Typical capital costs of modern U.S. subcritical pulverized coal plants equipped with an FGD system range from about $1100–1500/kW, with typical electricity costs of about 40–55 mills/kWh.*

7.1.3. Current programs

The DOE program to improve pulverized coal-based power generation systems builds on several aspects of current pulverized coal power generation technology that are commercial or near-commercial, including:

- Staged air and other combustion modification techniques for NOx control.
- Selective noncatalytic NOx reduction using ammonia or amines.
- Advanced (supercritical) steam conditions to 590°C (1100°F), 31 MPa (4500 psia).
- Combined power generation and space heating (hot water).
- Combined power generation and process steam (cogeneration).
- Coal-water slurry combustion with up to 70% coal by weight.
- Expansion turbine electricity generation using steam, hot combustion gases, or heated air.

As shown in Table 19, there are three major components of the DOE RD&D program on pulverized coal-based power generation systems: the APC (advanced pulverized coal) systems activity incorporating the LEBS (low-emission boiler system) program and the coal-fired cogeneration program; the IFC (indirectly fired cycle) system activity comprising the externally fired combined-cycle (EFCC) and HIPPS (high-performance power system) programs; and the direct coal-fired heat engines systems activity, incorporating two distinct but related power generation systems—direct coal-fired gas turbines and direct coal-fired diesels. The major technology goals for these programs are summarized in Table 19. The FY 1994 budgets for these activities were $9.1 million for advanced pulverized coal and $14.4 million for IFCs.

7.1.3.1. Advanced pulverized coal. The LEBS program is focused on improvement in currently available pulverized coal systems through integration with

---

*Personal communication from C. McGowin, Electric Power Research Institute, to E. S. Rubin, Vice Chair, Committee on Strategic Assessment of DOE’s Coal Program, May 1994.
advanced combustion and emissions control technology and state-of-the-art supercritical steam generators. Three power system design teams are currently engaged in cost-shared systems analyses and preliminary design studies. Current designs include use of boiler combustion modification and advanced flue gas treatment systems (e.g., combined SO₂/NOₓ removal) to achieve cost-effective emissions control. Selection of final designs for further development is scheduled for early 1995, with engineering development and subsystem testing to be completed in 1996. Proof-of-concept facility construction and operation are scheduled to lead to commercial readiness during the year 2000.²⁶

The related APC coal-fired cogeneration program is aimed at combined electricity and process steam generation in plants of 100 MW electric (MWe) or smaller (i.e., medium industrial and institutional markets). The program addresses constraints imposed on the use of coal in urban areas—including environmental constraints—and the market for process steam.

7.1.3.2. Indirectly fired cycle. IFC systems are advanced coal-based combined-cycle systems intended to compete with oil and gas-fired generation using conventional generation technology familiar to the utility industry. The EFCC variant necessitates the development of an advanced high-temperature ceramic heat exchanger to transfer the heat from coal combustion to an air stream that is the working fluid for a gas turbine. Thus, the turbine is not directly exposed to corrosive and abrasive coal combustion products. The ceramic heat exchanger tubes will allow clean filtered air from the gas turbine compressor to be heated to the turbine inlet temperature, eliminating the need for complex fuel preparation from pulverized coal.²⁷ EFCC will demonstrate the combined cycle including steam generation from the gas turbine and combustion exhaust gases, using current postcombustion emission controls (e.g., FGD plus fabric filter). Subsequent development of HIPPS will incorporate a new high-temperature advanced furnace—also requiring development—that integrates combustion, heat exchange, and emission controls. Although there is no consensus that DOE's goal for NOₓ emissions (Table 19) can be met by application of advanced state-of-the-art staged combustor technologies, some optimism has been expressed.* A major incentive is to avoid the additional cost of flue gas treatment (e.g., selective catalytic reduction) to meet the emissions goal.

7.1.3.3. Direct coal-fired heat engines. DOE's direct coal-fired heat engines program is directed toward commercialization by the private sector of two types of coal-fired engines—a direct-fired gas turbine and a direct-fired diesel engine. The program is aimed at burning coal-water slurry fuels in a combustion turbine by using a sufficiently clean fuel or modifying the turbine. The program is intended to develop modified diesel engines to burn coal-water slurry fuels. Both programs were completed in 1993 and are not part of ongoing DOE activities.

7.1.4. Technical issues, risks, and opportunities

Central station power generation technology using pulverized coal is commercially mature and widely implemented in industrialized countries around the world. The large base of existing capacity and expertise provides a strong incentive to seek environmental, efficiency, and cost improvements by enhancing pulverized coal technology.

DOE's program goals for the LEBS system offer thermal and environmental performance goals comparable to the capabilities of state-of-the-art pulverized coal technology today (see Section 3), while EFCC and HIPPS offer a potential for significantly higher efficiencies. However, numerous technical challenges must be overcome if the program's environmental and efficiency goals for EFCC and HIPPS are to be met simultaneously with the cost goals, especially for the higher-efficiency systems. Some of the major technical challenges, well recognized by DOE, include development of key system components, notably a specialized ceramic heat exchanger for EFCC, a high-temperature advanced furnace for HIPPS, and reliable low-emission slagging combustor technology.

An example of the technical challenges facing DOE is illustrated by the heat exchanger requirements for the EFCC system. Experimental studies in the 1940s on open-cycle, indirectly fired gas turbines using metallic heat exchangers did not allow sufficiently high turbine inlet temperatures for economic power production.²⁸ The use of ceramic materials may permit higher operating temperatures and resulting system efficiencies, but significant materials technology development is still required to achieve the performance targets projected in Table 19. The exit air temperature from current ceramic heat exchangers is limited by materials constraints (see Chapter 9) to approximately 1100°C (2000°F), significantly below the inlet temperatures of 1290°C (2350°F) for state-of-the-art turbines, or 1370–1425°C (2500–2600°F) for advanced turbines. If development of a high-temperature, high-pressure ceramic heat exchanger proves not to be feasible either technically or economically, a compromise solution may be considered where natural gas is used to reach a high turbine inlet temperature. In one scoping design study²⁹ the heat supplied from natural gas was of the order of 30–40% of the heat supplied by coal for a ceramic.
Table 19. DOE's program goals for pulverized coal systems

<table>
<thead>
<tr>
<th>Technology goals</th>
<th>Advanced pulverized coal</th>
<th>Direct coal-fired heat engines</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low emission boiler system</td>
<td>Coal-fired cogeneration</td>
</tr>
<tr>
<td>Net efficiency, %</td>
<td>42</td>
<td>70 (total system)</td>
</tr>
<tr>
<td>Emissions, fraction of SO₂</td>
<td>1/3</td>
<td>Meet local regulations</td>
</tr>
<tr>
<td>New Source Performance Standards (NSPS) NO₂</td>
<td>1/3</td>
<td>Meet local regulations</td>
</tr>
<tr>
<td>Particulates</td>
<td>1/2</td>
<td>Meet</td>
</tr>
<tr>
<td>Air toxics emissions relative to 1990 Clean Air Act</td>
<td></td>
<td></td>
</tr>
<tr>
<td>amendments</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Solid wastes</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capital cost, $/kW</td>
<td>Saleable</td>
<td>Benign</td>
</tr>
<tr>
<td>Electricity cost compared to current pulverized coal</td>
<td>1400</td>
<td>NA</td>
</tr>
<tr>
<td>Commercial completion milestones</td>
<td>Lower</td>
<td>5 MW</td>
</tr>
<tr>
<td>Commercial demonstration by 2000</td>
<td>Commercial demonstration</td>
<td>demonstration in 2001</td>
</tr>
<tr>
<td></td>
<td>by 2000</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Development status</td>
<td>Preliminary commercial</td>
<td>System design completed in</td>
</tr>
<tr>
<td></td>
<td>design in 1994</td>
<td>1994</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

NA, not available.
Source: DOE.²
heat exchanger limited to an operating temperature of 1100°C (2000°F) or less.

In addition to these specific technical challenges, the DOE program emphasizes a 'unified approach', 'synergies', and integration of components and subsystems to achieve target efficiencies and reduce the cost of the commercialized technology. To achieve these opportunities, substantial development and demonstration of integrated systems still remains.

7.1.5. Summary

Pulverized coal combustion systems are an established and mature technology for power generation, with comparatively limited opportunity for further performance enhancements based on a simple Rankine steam cycle relative to advanced combined-cycle systems. Thus, the market niche for the LEBS system is not clear. Environmental performance is comparable to state-of-the-art commercial systems available today, and the efficiency of the LEBS system is comparable to today's supercritical steam units. Potentially lower costs through system integration, however, could be of interest for near-term power generation markets.

The indirectly fired combined-cycle systems have the potential for significantly higher efficiency. However, this higher efficiency depends on providing gas heated to 1260–1425°C (2300–2600°F), while heat exchanger materials are currently limited to 1100°C (2000°F). Increasing this temperature is a major materials challenge. The fallback strategy of depending on natural gas for increasing the gas temperature could provide an interim system.

7.2. Fluidized-Bed Combustion

7.2.1. Background

Fluidized-bed combustion (FBC) technology consists of forming a bed of finely sized ash, limestone (for sulfur removal), and coal particles in a furnace and forcing combustion air up through the mixture, causing it to become suspended or fluidized. The height of bed material suspended above the bottom of the furnace is a function of the velocity of the combustion air entering below the bed. Atmospheric 'bubbling-bed' FBC technology has a fixed height of bed material and operates at or near atmospheric pressure in the furnace. In atmospheric circulating FBC technology, the combustion air enters below the bed at a velocity high enough to carry the bed material out of the top of the furnace, where it is caught in a high-temperature cyclone and recycled back into the furnace. This recycling activity improves combustion and reagent utilization. In all AFBC (atmospheric fluidized-bed combustion) designs, coal and limestone are continually fed into the furnace and spent bed material, consisting of

ash, calcium sulfate, and unreacted or calcined limestone, is withdrawn at the rate required to maintain the proper amount of bed material for fluidization.

The amount of coal fed into the bed is approximately 2–3% of the total weight of the bed material. The fluidization of the bed and the relatively small amount of coal present in the bed at any one time cause good heat transfer throughout the bed material, and the resulting bed temperature is relatively low, about 800–900°C (1470–1650°F). The fluidization and relatively low bed temperature enhance the capture of SO₂ emitted during combustion and retard the formation of NOₓ. The features of in-bed capture of NOₓ and relatively low NOₓ emissions, plus the fluid bed's capacity to combust a range of different fuels, are the main attractions of FBC as a power generation technology. Under some operating conditions, AFBC units also may produce higher levels of organic compounds, some of which may be potential air toxics. Current studies also indicate that AFBC units emit higher levels of N₂O—a greenhouse gas—than other combustion systems.

AFBC technology has been in commercial use worldwide for well over 50 years, primarily in the petrochemical industry and in small industrial steam generators that are a 10th to a 100th the size of commercial power plant generators. In the United States, development of AFBC technology began in 1965, when DOE contracted for development of a low-cost, industrial-sized AFBC unit. AFBC development in the U.S. power generation sector began in the early 1980s, with support from the private sector, including EPRI (Electric Power Research Institute), and DOE. A 20-MW bubbling bed AFBC unit was constructed and operated by the Tennessee Valley Authority and EPRI beginning in 1980 and concluded in 1987. During this same period, four AFBC demonstration projects ranging in size from 80–160 MW were implemented as either retrofits or repowering of an existing unit. As a result of these demonstrations and similar installations abroad, AFBC technology became commercial by the end of the 1980s for industrial steam generation, cogeneration, and utility-scale applications.

The next generation of FBC technology operates at pressures typically 10–15 times higher than atmospheric pressure. Operation in this manner allows the pressurized gas stream from a pressurized fluidized-bed combustion (PFBC) unit to be cleaned and fed to a gas turbine. The exhaust gas from the turbine is then passed through a heat recovery boiler to produce steam. The steam from the PFBC unit and that from the heat recovery boiler are then fed to a steam turbine. This combined-cycle mode of operation significantly increases PFBC system efficiency over the AFBC systems. If the PFBC unit exhaust gas can be cleaned sufficiently without reducing its temperature (i.e. by using hot gas cleanup systems), additional cycle efficiency can be achieved.
Table 20. DOE’s program goals for pressurized fluidized bed combustion systems

<table>
<thead>
<tr>
<th>Technology goals</th>
<th>First-generation</th>
<th>Second-generation</th>
<th>Improved second-generation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net efficiency, %</td>
<td>40</td>
<td>45</td>
<td>≥ 50</td>
</tr>
<tr>
<td>Emissions, fraction of NSPS</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SO₂</td>
<td>1/4</td>
<td>1/5</td>
<td>1/10</td>
</tr>
<tr>
<td>NOₓ</td>
<td>1/3</td>
<td>1/5</td>
<td>1/10</td>
</tr>
<tr>
<td>Particulates</td>
<td>Not specified</td>
<td>Not specified</td>
<td>Not specified</td>
</tr>
<tr>
<td>Air toxics emissions relative to 1990 Clean Air Act</td>
<td>Meet</td>
<td>Meet</td>
<td>Meet</td>
</tr>
<tr>
<td>amendments</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Solid wastes</td>
<td>Not specified</td>
<td>Not specified</td>
<td>Not specified</td>
</tr>
<tr>
<td>Capital cost, $/kW</td>
<td>1300</td>
<td>1100</td>
<td>1000</td>
</tr>
<tr>
<td>Electricity cost compared to current pulverized coal</td>
<td>10% lower</td>
<td>20% lower</td>
<td>25% lower</td>
</tr>
<tr>
<td>Commercial completion milestones</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Development status</td>
<td>70-80-MW demonstion projects ongoing</td>
<td>Systems development, integration, and testing ongoing</td>
<td>Development initiated</td>
</tr>
</tbody>
</table>

Source: DOE.²

Development of PFBC has been under way since 1969, when the British Coal Utilization Research Association began operating a PFBC test unit at Leatherhead, U.K. A significant portion of the test work conducted there over the next 15 years was supported by EPA, DOE, and the U.S. private sector. In the early 1980s a number of other PFBC test and pilot facilities were constructed in the United States and Europe. The United States, the United Kingdom, and the Federal Republic of Germany under the auspices of the International Energy Agency constructed an 85-MW thermal (MWT) PFBC unit that was placed in service in 1980. Early cooperation between the American Electric Power Service Company and ASEA STAL (now ASEA Brown Boveri, with its subsidiary ABB Carbon) led, in 1982, to the construction of a 15-MWt PFBC component test facility now located in Finspong, Sweden.⁵¹

7.2.2. State of the art

AFBC technology has achieved commercial acceptance, while PFBC technology is currently undergoing commercial demonstration. As of mid-1993, 622 AFBC units (293 bubbling bed and 276 circulating bed) were operating worldwide, with an average steam capacity of 235,000 lb/hr. About 43% of the steam capacity and 35% of the total number of units were sold in North America, mainly in the United States. EPRI has estimated that 75% of the U.S. capacity is circulating FBC technology. Independent power producers, rather than investor-owned utilities, have pushed the development of AFBC in the United States. The present generation of AFBC technologies has no difficulty meeting the current NSPS for steam electric power plants or industrial sources.

PFBC technology is in the early stages of commercialization. Four PFBC units of less than 80 MW, two in Sweden, one in Spain, and one in the United States, have been placed in operation in the past four years. A fifth 71-MW unit is in initial operation in Japan. The DOE CCT program is sponsoring an 80-MW circulating PFBC project expected to be in commercial operation in mid-1997.⁵²

In addition, the CCT program has selected a 95-MW second-generation PFBC project for funding. This advanced PFBC system will involve partial gasification of the coal, with the resulting fuel gas going to a topping combustor along with cleaned gases from a circulating unit that will receive char from the gasifier. Electricity is generated from the topping combustor and from a steam cycle coupled to the PFBC unit. An advanced system for hot gas cleanup will also be used in the demonstration. A fully integrated second-generation PFBC system is also scheduled to be tested at the 8-MWe level at the Power Systems Development Facility under construction in Wilsonville, Alabama, sponsored by DOE, Southern Company Services, and EPRI. This PFBC testing will evaluate the integration of all of the components in the PFBC system, with emphasis on the integration of hot gas cleanup ceramic filters and gas turbines.²

7.2.3. Current programs

DOE funding for AFBC technology development ended in FY 1992. The current PFBC program is aimed at developing second-generation systems for
electric power generation with performance goals as summarized in Table 20. The FY 1994 Office of Fossil Energy budget for PFBC was $24.1 million.

7.2.4. Technical issues, risks, and opportunities

AFBC systems, either in the bubbling bed or circulating bed configuration, constitute a commercially mature technology, and DOE has contributed in a major way to its success. To further enhance its commercial application, manufacturers need to refine the technology to achieve lower capital costs compared with modern pulverized coal (PC) plants, improved environmental performance, and improved operating efficiency. However, the time period for competitive application of this technology in the U.S. electric power production sector is now and in the immediate future. The availability and cost of natural gas, along with competition from modern PC plants, will dictate whether AFBC continues to be a technology of choice for environmental compliance and new capacity additions by independent power producers. Because most new coal plants currently are being constructed outside the United States, the greatest opportunity for this technology is in developing countries.

PFBC technology is just beginning to be commercially demonstrated and offers significant design, performance, environmental compliance, and cost advantages over AFBC technologies. As noted earlier, a second generation of PFBC technology offering additional performance (efficiency) benefits is entering the pilot and demonstration phase. These systems employ a coal pyrolyzer to produce a fuel gas that is burned in the turbine topping cycle. Since only a portion of the coal is gasified, this design has the potential for higher efficiencies than IGCC systems, where all of the coal is gasified. Maude estimates that the efficiency advantage may be approximately four percentage points. Because PFBC operates at a higher pressure and increased efficiency compared with AFBC, the same power output can be achieved with a unit that requires less land area (i.e., smaller 'footprint' of equipment). The steam flows for PFBC units are also compatible with steam turbines at existing power plants. Thus, the technology is especially attractive for repowering existing units at existing power plant sites, avoiding the need and difficulty of developing new sites. The higher cost of equipment operating at higher pressures and temperatures is partially offset by the reduced equipment size and higher efficiency. Efficiencies of the order of 39–42% can be achieved with newer PFBC designs, compared with 34% efficiency for AFBC. EPRI estimates the capital cost of a 340-MW bubbling bed supercritical PFBC boiler (42% efficiency) at $1318/kW (in 1992 dollars), with a total levelized cost of 37 mills/kWh (80% capacity factor, eastern bituminous coal).

Substantially higher efficiencies (from 45 to greater than 48%) are expected from second-generation PFBC systems. It is questionable whether the advanced PFBC systems can achieve DOE's goal of 20–25% reduction in electricity cost as well as capital cost reductions relative to current PC plants. In general, the higher degree of complexity of advanced systems makes it likely that capital costs will tend to increase rather than decrease, although the resultant efficiency gains will have a positive effect in lowering the cost of electricity. At present, however, there remains considerable uncertainty as to the future costs of advanced power systems.

One of the key performance and cost uncertainties for advanced PFBC systems is the development of hot gas cleanup technology. Reliable hot gas particulate cleanup plus advanced (1370°C [2500°F] or higher) turbine systems will be required for PFBC technology to achieve DOE's projected performance potential of more than 50% efficiency while meeting environmental compliance requirements. At the present time these technologies are under development. The status of hot gas cleanup technology and advanced turbine systems (ATS) is discussed later in this section.

Related issues concern the development of adequate SO₂ and NOₓ controls and their associated costs. Current DOE flow sheets for advanced PFBC systems are beginning to incorporate the possible need for selective or nonselective catalytic reduction systems for NOₓ control in addition to the combustion controls inherent in FBC systems. Added NOₓ controls would increase the base cost of the plant. Also of concern is the reagent requirement for sulfur removal and the resulting solid waste generation. As elaborated later in this section (see Part 7.7, Emission Control Technologies), increasingly stringent requirements for SO₂ removal are becoming more difficult or more costly to achieve with fluidized-bed systems, which also generate larger quantities of solid waste than new PC plants with FGD. An increase in solid waste generation is inconsistent with DOE's goals for advanced power systems, which seek sizeable reductions in solid waste. Thus, there is a need to demonstrate efficient environmental designs and to address potential by-product markets for spent reagent in order to reduce solid waste impacts.

7.2.5. Summary

AFBC systems are a mature commercial technology, and, as such, DOE is no longer pursuing additional R&D on this technology. Significant performance improvements are expected for PFBC systems, which are now beginning to be commercialized. The DOE performance goals for the PFBC program appear to be reasonable for the first- and second-generation systems. The capital cost goals for all generations appear to be optimistic, especially as the number of components and complexity of the system are increased for the second-generation and improved second-generation systems. A major uncer-
tainty still facing PFBC systems is the reliability and cost of hot gas particulate controls. Reduction of solid wastes, economical high SO₂ removal efficiencies, and generation of supercritical steam in a fluidized bed are other issues to be addressed.

7.3. Integrated Gasification Combined-Cycle Systems

7.3.1. Background

Coal gasification is a method of producing a combustible gaseous fuel from almost any type of coal. The current status of gasification technology and opportunities for efficiency enhancement have been discussed in Section 6. Gasification is a key step for advanced conversion of coal to electricity using IGCC systems. An IGCC power plant is a gasification facility coupled to a gas-fired combined-cycle unit. Based on current environmental control capabilities, IGCC offers a coal-based power technology with low emissions, high thermal efficiency, and the potential for phased construction—that is, building simple-cycle natural-gas-fired combustion turbines first, then converting to combined-cycle, and finally adding coal gasification as gas prices increase or gas availability deteriorates. Future advances in gasification-based power production are linked to increases in gas turbine firing temperature, hot gas cleanup of the fuel gas, coproduction of both chemicals and electricity, improved gasifier designs, and integration of gasification with advanced cycles and fuel cells.

7.3.2. State of the art

Components of IGCC technology have been under development for some time, and several competing coal gasification processes now have successful commercial-scale operating records (see Section 6). These include the Texaco, Shell, and Destec (formerly Dow) entrained-flow processes and the Lurgi moving-bed process. Other gasification processes have been successfully tested at pilot scale and are ready for scale-up to commercial size, including the Prenflo entrained-flow, the British Gas/Lurgi moving-bed, and the KRW and the high-temperature Winkler fluidized-bed processes.

The IGCC concept was first successfully demonstrated at the 100-MW scale at Southern California Edison's Cool Water Station in Daggett from 1984 to 1989 using the Texaco entrained-flow coal gasification process. Destec is currently operating a 160-MW IGCC plant in Plaquemine, Louisiana, using a two-stage, entrained-flow coal gasification process. In the Netherlands, SEP (the joint authority for electricity production) has begun operation of a 250-MW IGCC plant based on the Shell entrained-flow coal gasification process. Each of these plants employs gas turbines with firing temperatures of about 1100°C (2000°F).

Table 21. IGCC power plant performance and economics based on shell gasification technology and eastern bituminous coal (all costs in constant 1992 dollars)

<table>
<thead>
<tr>
<th>Plant parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal size, MW</td>
<td>500</td>
</tr>
<tr>
<td>Thermal efficiency (HHV basis)</td>
<td>42%</td>
</tr>
<tr>
<td>% Fuel to power</td>
<td></td>
</tr>
<tr>
<td>Net heat rate, Btu/kWh</td>
<td>8900</td>
</tr>
<tr>
<td>Total capital cost, $/kW</td>
<td>1613</td>
</tr>
<tr>
<td>Levelized cost of electricity,* mills/kWh</td>
<td>41</td>
</tr>
</tbody>
</table>

*Assuming a capacity factor of 80% and a levelized coal price of $1.30/10⁶ Btu.
Source: EPRI.**

Table 21 summarizes the performance and economics for a hypothetical 500-MW first-generation IGCC plant employing a state-of-the-art, oxygen-blown, entrained-flow gasification process to provide fuel gas to advanced combustion turbines. The IGCC plant is fueled with an eastern bituminous coal, is highly integrated, and employs cold gas cleanup. The cost for current systems is significantly higher than the DOE goals for advanced systems shown later in Table 22.

7.3.3. Technical issues, risks, and opportunities

First-generation IGCC plants have already demonstrated outstanding operability and environmental performance at commercial scale. The key issue for these technologies is the impact of high capital cost on economic competitiveness. Section 6 discussed technical issues and opportunities related to coal gasifiers. Reductions in the capital costs of IGCC systems can be accomplished through simplification and optimization of the process, economies of scale, and/or through thermal efficiency gains. Future improvements to the economics of IGCC, therefore, are linked mainly to development of advanced gas turbines with firing temperatures over 1370°C (2500°F), and secondarily to development of reliable hot gas cleanup schemes. Both of these subjects are discussed later in this section. As noted in Section 6, energy losses in gasification and gas cleanup amount to about 15–20% of the total coal energy input, resulting in a loss of 5–10 percentage points in power generation efficiency. Thus, improved gasifier designs with lower energy losses also can contribute to overall efficiency improvements. Current systems studies suggest that the integration of gasification with advanced cycles, such as the humidified air turbine, and compressed air storage with humidification, also has the potential to reduce capital costs and provide competitive intermediate-load capacity.85–87 The highest-efficiency system proposed by DOE and based on gasification is an integrated gasification advanced-cycle (IGAC) system based on a humidified gas turbine.8
### Table 22. DOE's program goals for integrated gasification-based systems

<table>
<thead>
<tr>
<th>Technology goals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Second-generation integrated gasification combined-cycle*</td>
</tr>
<tr>
<td>Integrated gasification advanced-cycle</td>
</tr>
<tr>
<td>Integrated gasification fuel cell</td>
</tr>
<tr>
<td>Net efficiency, %</td>
</tr>
<tr>
<td>45 (by 2000)</td>
</tr>
<tr>
<td>Emissions, fraction of NSPS</td>
</tr>
<tr>
<td>SO₂</td>
</tr>
<tr>
<td>1/10</td>
</tr>
<tr>
<td>NOₓ</td>
</tr>
<tr>
<td>1/10</td>
</tr>
<tr>
<td>Particulates</td>
</tr>
<tr>
<td>Not specified</td>
</tr>
<tr>
<td>Air toxics emissions relative to 1990 Clean Air Act amendments</td>
</tr>
<tr>
<td>Meet</td>
</tr>
<tr>
<td>Solid wastes</td>
</tr>
<tr>
<td>Not specified</td>
</tr>
<tr>
<td>Capital cost, $/kW</td>
</tr>
<tr>
<td>1200</td>
</tr>
<tr>
<td>Electricity cost compared to current pulverized coal</td>
</tr>
<tr>
<td>20% lower</td>
</tr>
<tr>
<td>Commercial completion milestones</td>
</tr>
<tr>
<td>Demonstration 2001</td>
</tr>
<tr>
<td>Development status</td>
</tr>
<tr>
<td>Under development</td>
</tr>
<tr>
<td>Development initiated</td>
</tr>
<tr>
<td>Current activities focusing on natural gas-fired systems</td>
</tr>
</tbody>
</table>

*First-generation integrated gasification combined-cycle power systems are presently at the commercialization stage and are being demonstrated with design improvements in the CCT program.

Source: DOE.

### Table 23. Major European IGCC projects in progress

<table>
<thead>
<tr>
<th>Project</th>
<th>Technology</th>
<th>Efficiency (%)</th>
<th>MW (net)</th>
<th>Startup</th>
</tr>
</thead>
<tbody>
<tr>
<td>SEP, Buggenum, Netherlands</td>
<td>Shell entrained Oxygen-blown Cold gas cleanup Siemens V94.2 gas turbine</td>
<td>41</td>
<td>253</td>
<td>January 1994</td>
</tr>
<tr>
<td>ELCOGAS, Puertollano, Spain</td>
<td>PRENLRO entrained Oxygen-blown Cold gas cleanup Siemens V94.3 gas turbine</td>
<td>43</td>
<td>300</td>
<td>Mid-1996</td>
</tr>
<tr>
<td>RWE, KoBra, Hurth, Germany</td>
<td>HT Winkler fluid bed Air-blown Cold gas cleanup Siemens V94.3 gas turbine</td>
<td>43</td>
<td>312</td>
<td>Post-2000</td>
</tr>
</tbody>
</table>

Source: Wolk and Holt.

#### 7.3.4. Current programs

DOE's program goals for IGCC systems are summarized in Table 22. The FY 1994 Fossil Energy coal program authorization for IGCC was $27.2 million. The DOE CCT program also includes several gasification-based power projects, which represent the state of the art and encompass both entrained-flow and fluidized-bed gasification systems. Table 16 summarized the status of these CCT projects. The completion of the CCT programs in about five or six years will provide the data and experience for subsequent commercial IGCC plants to be employed beyond the year 2000. Table 23 summarizes the major European IGCC projects in progress. Except for the Buggenum project (Table 23), all the combustion turbines are 1300°C class (2350°F). Other IGCC projects are also planned for Asia.

#### 7.3.5. Summary

IGCC offers a coal-based power technology with low emissions, the potential for higher thermal efficiency, and the capability for phased construction. First-generation IGCC plants have already demonstrated outstanding operability and environmental performance at commercial scale. The key issue for these technologies is the high capital cost and its impact on economic competitiveness.
Gasification is an enabling technology that allows the use of very high efficiency energy conversion devices—such as high-temperature gas turbines and fuel cells—for power production in combined-cycle systems. Reductions in capital costs can be accomplished through process simplifications, economies of scale, and thermal efficiency improvements. With completion of the DOE CCT programs and the major European demonstration projects in the next five to six years, areas for continued improvements to the gasification technologies and IGCC process can be identified to reduce the capital cost and enhance the economic competitiveness.

7.4. Integrated Gasification Fuel Cell Systems

7.4.1. Background

Fuel cells are electrochemical energy conversion devices that convert the chemical energy in a fuel and oxidant directly to electricity without direct combustion. They can be thought of as ‘gas batteries’ where the electrochemically active materials are gases that can be ducted to the electrodes from outside the battery case. The reaction products are also gases and can be removed similarly. A fuel cell can be ‘discharged’ continuously to produce electricity as long as the reactants are supplied and the products removed.

The fuel cell has many of the same features as a battery. The power production takes place at a constant temperature; hence, it is not constrained to the theoretical upper limit for heat engines (known as the Carnot cycle efficiency). Thus, fuel cells potentially can be much more efficient than combustion-based systems. Environmentally, the electrochemical reactions do not involve direct combustion, so thermal NO\textsubscript{x} production is negligible. Reactants are consumed exactly in proportion to the electric energy output, so the efficiency remains high even when the level of power production is reduced.

In practice, fuel cell system efficiencies remain limited by energy losses and inefficiencies inherent in most engineered systems. Continued R&D is aimed at reducing these losses to improve overall efficiency. An attraction of fuel cell systems is that natural gas or coal-derived fuel gas both make suitable fuels for running a fuel cell system. Interest in fuel cells as an energy conversion system stems primarily from the fact that they offer the highest efficiency and lowest emissions of any known fossil-fueled power generation technology.

7.4.2. State of the art

Fuel cells first came to public attention in the 1960s because of their importance in the manned space program. Today, commercially available fuel cell systems are based on phosphoric acid fuel cell (PAFC) technology and are configured for small-scale commercial and residential cogeneration applications. These systems use natural gas or other light hydrocarbons as fuel. They typically yield 36% net electrical efficiency and over 70% total efficiency if all thermal energy is used (e.g. for space heating). This type of fuel cell operates at approximately 200°C (400°F), too low a temperature for the thermal energy to be efficiently converted to useful work in a bottoming cycle. ONSI Corporation has delivered nearly 60 of the 200-kW PAFC cogeneration systems. Plant reliability and availability based on experience to date have been outstanding.

Molten carbonate fuel cells (MCFC) using a molten alkali-metal carbonate electrolyte operate at approximately 650°C (1200°F), a temperature where rejected heat can be used efficiently in a bottoming cycle and where conventional materials still can be used for the balance of plant equipment. This type of fuel cell power plant is just entering the demonstration phase of development. Power plants from several U.S. and Japanese manufacturers ranging in size from 200 kW–2 MW are planned to be in operation in 1995. These plants are expected to enter the utility market as 1–5-MW units, natural gas fueled, with electrical generation efficiency greater than 50% (without a bottoming cycle) by the year 2000. In larger sizes, with steam or gas bottoming cycles, efficiency will be 60% or higher when using natural gas fuel.

The solid oxide fuel cell (SOFC), of which the basic building block is an oxide-ion conducting ceramic electrolyte, operates at an even higher temperature (980°C [1800°F]). The potential for future cost reduction makes SOFCs attractive. The most successful system to date is the Westinghouse tubular design that has been operated in units of up to 20 kW for over 6000 hours. The key fabrication issue is the use of chemical vapor deposition to fabricate these tubular components, which is expensive. A great deal of current research is focusing on simpler planar systems that show promise for less expensive fabrication techniques. The largest planar unit under test at this time is 1 kW. It is anticipated that the scale will be increased to 10 kW within one year.

Fuel cells integrate readily with coal gasifiers. Such IGFC systems are potentially the most efficient and least polluting method to generate electricity from coal. Characteristics of the three types of fuel cells integrated with coal gasifiers are given in Table 24. EPR1 estimates that integrated gasification molten carbonate fuel cells based on current state-of-the-art entrained-flow gasification will have a full-load efficiency around 50%. Because of energy losses of about 15–20% inherent in gasification (see Section 6), major advances in gasification technology will be required to meet the DOE IGFC efficiency goal of 60% or greater. The total capital requirement is approximately $1900/kW, and the cost of electricity is not
yet competitive with other gasification-based power systems. The capital cost must be reduced by approximately 20% to make the systems competitive. This is generally considered feasible, with technological advances already planned for the fuel cell and gas cleaning subsystems within the plant.

7.4.3. Technical issues, risks, and opportunities

IGFC will not materialize for utility-scale electricity generation until the fuel cells are first used commercially as small-scale distributed generators on natural gas. This in turn requires demonstration that engineering development issues are resolved and that the fuel cells themselves have the reliability and durability necessary for utility service. Since demonstration projects are costly, there is the risk that commercial firms could fail because of insufficient funds to complete the necessary demonstrations of their technology.

Molten carbonate systems offer the most attractive near-term opportunities for utility applications. For the long term, there is some risk that the MCFC manufactured cost will not decrease to the levels needed for widespread use in distributed generation and in coal-based IGFC systems. Independent studies of MCFC manufacturing methods, however, show that stack costs similar to combustion turbines (i.e. $250/kW) are possible in production quantities of 300–400 MW per year. Manufacturing costs now are about 10 times higher—partly because manufacturing facilities are still about 100 times smaller. Studies indicate that the balance of plant costs will exceed the stack costs in commercial fuel cell power plants. A systematic market-entry program is the key to overcoming the high-cost, low-volume hurdle of new technologies.

For applications with coal, contamination of the fuel cell by trace coal constituents is the primary area of concern. Substances such as chlorides, sulfides, arsenic, alkali metals, zinc, cadmium, lead, and mercury vapors are capable of poisoning fuel cells and reducing their performance. At present, there is little information on the acceptable levels of these contaminants. High-temperature purification systems that can reduce some trace contaminants to very low levels are under development.

7.4.4. Current programs

DOE's program goals for IGFC systems are presented in Table 22. The FY 1994 budget authorization for fuel cells R&D—which is now in the natural gas program—was $31.8 million. DOE is supporting technology and demonstrations of MCFC by two manufacturers at approximately $30 million/year, with EPRI and GRI collaborating at approximately $5 million/year each. One application is a 2-MW plant for the Santa Clara, California, municipal electric utility grid; the other is a 250-kW pilot plant at Unocal's research center. Both demonstrations are expected to begin operation in the first half of 1995.

EPRI also has been sponsoring testing of a 20-kW MCFC stack on a coal-gas slipstream at the 160-MW Destec IGCC plant in Plaquemine, Louisiana, since late 1993. To date, this test has shown no indication that coal-derived gas presents any difficulty in use. However, long-term data remain to be collected.

DOE is supporting SOFC R&D at approximately $18 million/year, with EPRI and GRI each contributing approximately $1 million/year. For the tubular SOFC, the effort is focused on scale-up and demonstration. For the planar SOFC, the emphasis is on fundamental materials and manufacturing issues at a number of industrial, specialty research, and academic organizations. No prototype or commercial-scale plants are envisioned for three-four years for the planar SOFC. Many cost and manufacturing issues remain to be resolved in this time period.

While both the MCFC and SOFC systems ultimately will operate on gasified coal, at this time there are no commercial-scale or demonstration projects of coal-based IGFC.
7.4.5. Summary

The current U.S. fuel cell program is focused on the use of natural gas, although IGFC systems running on coal-derived fuel gas are envisioned by DOE as a logical follow-on. Such systems offer the highest efficiency and lowest emissions of coal-based technologies, but their cost currently is high. The initial demonstration of MCFC projects by two manufacturers is under way at the 250-kW and 2-MW scales using natural gas. However, it is not likely that these demonstrations will be capable of resolving all technical issues.

At a reasonable rate of growth in demand for fuel cells, manufacturing costs for MCFC stacks could drop an order of magnitude to the $250/kW range. A systematic market entry program is the key to overcoming the high-cost, low-volume hurdle. Therefore, planned DOE support of balance of plant cost reduction development is the logical next step in fuel cell technology development, since these costs are larger than the fuel cell stack costs.

Future development of coal-based IGFC systems will depend on the success of current gas-based technology and on the resolution of key technical issues, particularly the types and levels of contaminants in coal-derived fuel gas that must be controlled.

7.5. Magnetohydrodynamic Power Generation

7.5.1. Background

MHD (Magnetohydrodynamic) power generation is a method for converting thermal energy directly to electric power. The MHD generator is based on the concept of using a flowing ionized gas or liquid metal heated by fossil and/or nuclear fuel as the moving conductor in an electric generator. By using this very high temperature (typically 2300°C [4170°F]) working fluid directly, the MHD generator serves as a topping cycle that achieves high overall efficiency (60% or more) when combined with additional power generation from a steam cycle fueled by the hot exhaust gas.

The simplest MHD generator is based on a linear geometry—the hot combustion gas flows through a linear duct or channel. A magnetic field provided by high-strength electromagnets at right angles to the gas flow induces an electric field at right angles to both the gas flow and magnetic fields. A 'seed' material such as sodium or potassium is added to the combustion gas to improve its electrical conductivity. If electrodes are then placed on either side of the channel and connected through an external electrical load or resistance, current will flow through the gas, electrodes, and external load, providing power. In addition to MHD systems based on the flow of high-temperature seeded combustion gases, other proposed schemes for MHD power generation employ flows of liquid metals, combinations of liquid metals with gas bubbles, and alkali-seeded noble gases (or pure nitrogen or hydrogen) that ionize at much lower temperatures than do combustion gases.44

7.5.2. State of the art

Most of the development work on MHD power generation has been on open-cycle combustion gas systems. These projects received significant funding in the United States (from DOE) and in the former U.S.S.R. Both projects have now been closed down. In the U.S.S.R., a 25-MW natural gas-fired system (U-25) provided electricity to the Moscow power grid for several years. The DOE concentrated on smaller-scale coal-fired systems, which included tests of over 2000 hours on the lower-temperature heat recovery systems. The proof-of-concept high-temperature combustion and MHD generator sections were run for only about 400 hours. While most of the test performance goals were reached, the long-term high-temperature component durability required for utility applications is still in question. A proposal to DOE's CCT program to scale up to a combined MHD-steam plant of about 75 MW with an efficiency of approximately 31% was not selected for funding. Work on a tall-loop liquid metal MHD cycle has been concentrated in Israel, where test loops have been built to prove out the concept. These systems have the potential of 45% efficiency, but funding for further development is uncertain.

7.5.3. Technical issues, risks, and opportunities

The open-cycle combustion gas systems as tested would extrapolate to a 500-MW coal-fired MHD plant meeting the federal NSPS for SO_2 and NO_x with an efficiency of up to 45%. This efficiency potential would drop considerably for smaller power plants. A claimed potential efficiency of 60% could only be met with the development of a high-temperature heat exchanger to preheat the combustion air to over 1370°C (2500°F), but little development work has been done on this exchanger. Furthermore, economic operation would depend on low-cost seed recovery, but only preliminary work has been accomplished in this area. The durability of the high-temperature MHD channel has not yet been demonstrated, and an integrated plant has not operated at any scale. Relative to other advanced technologies now under development, MHD systems pose much greater technological challenges because of the aggressive thermal environment and system complexity. At the same time, the thermal efficiency advantage of MHD systems has been eroded by more recent developments in other coal-based systems employing advanced gas turbines, fuel cells, and gasifiers.

7.5.4. Current programs

DOE funding of the MHD proof-of-concept
facility ended in FY 1993. FY 1994 funding and that requested for FY 1995 are only for site restoration, and no large-scale follow-on work is planned.

7.5.5. Summary

While a number of important technical goals were met by the DOE MHD program, significant issues were left unresolved, notably operational reliability. No U.S. funding is planned to resolve these remaining issues, since other advanced power systems now offer comparable or superior performance with higher reliability, lower projected cost, lower emissions, and a much lower level of technical risk.

7.6. Combustion Turbines

7.6.1. Background

The combustion turbine is the key power generation component in most advanced coal-based systems. The turbine system consists of a compressor to take combustion air from atmospheric pressure to a pressure of 8–16 atm; a combustor burning a fossil fuel (natural gas, light refined petroleum fractions, or coal-derived fuel gas) to produce hot combustion gases; and an expansion turbine to extract work as the high-temperature, high-pressure gas is reduced to ambient conditions. This system is referred to as the Brayton cycle. About two-thirds of the shaft work of the expansion turbine drives the compressor, and the remainder drives a generator to produce electricity. The net power output depends strongly on the turbine inlet temperature, which is limited primarily by materials considerations. Combustion turbines can be designed to burn any of the above-mentioned fuels (provided they are adequately free of contaminants) and to switch from one fuel to another in service.

Two types of combustion turbines are used for electric power generation, namely, heavy-frame and aeroderivative turbines, the latter derived from jet engine technology. Historically, major evolutionary improvements in aircraft jet engine technology have been adapted to heavy-frame utility combustion turbines. In addition, utilities have used aeroderivative combustion turbines for smaller-capacity generation applications. Thus, forecasting the evolution of combustion turbines for power generation is a relatively straightforward matter of assessing current jet airplane engine technology.

7.6.2. State of the art

Current commercial gas turbine systems offered by U.S. and foreign manufacturers achieve firing temperatures up to 1300°C (2350°F), with unit sizes up to about 250 MW. Natural gas and light petroleum liquids are the fuels currently employed for power generation, typically for peak or intermediate loads. The simplest, lowest-cost-per-kilowatt, fossil power plant for peaking duty is the simple Brayton cycle combustion turbine described above. Both aeroderivative and heavy-frame turbines are used in this way. Aeroderivative turbines are more efficient in simple-cycle operation because jet aircraft engines are intended to extract maximum energy from the hot combustion gases during the turboexpansion.

A combined-cycle combustion turbine plant, in which a Brayton cycle gas turbine is combined with a Rankine cycle steam generator using the waste heat in the exhaust from the turboexpander, is the most efficient system for a fossil power plant commercially available today. Because relatively little useful energy remains in the expander exhaust of an aeroderivative combustion turbine, the heavy-frame machine has the higher efficiency in combined-cycle operation. Table 25 compares the capacities and thermal-to-electric energy efficiency typical of 1300°C-class (2350°F-class), heavy-frame, and aeroderivative combustion turbines burning natural gas being sold now or expected for delivery in the mid-1990s.

If the feed gas has been cleaned to a level that will meet air quality standards, oxides of nitrogen (NOx) are the only emission concern for combustion turbine power generation. Gas turbine manufacturers have developed dry (no water or steam injection) premixed lean-burn low-NOx combustors for commercially available gas turbines to achieve NOx levels of 7–25 ppm in the exhaust. As noted earlier (Section 3), such levels are required to comply with various state and local regulations, which are far more stringent than the federal NSPS of 75 ppm for gas turbines. Some of the first-generation dry low-NOx systems, however, are not so effective if operating at low load. Steam injection is another approach used to lower NOx and simultaneously augment power output by putting more mass through the turboexpander.

Continued evolution of gas turbines is projected with firing temperatures up to 1430°C (2600°F). These machines will require further cooling advancements, NOx reduction improvements, and probably ceramic nozzles and blades in the hottest sections of the hot gas path. The major combustion turbine

<table>
<thead>
<tr>
<th>Turbine-type</th>
<th>Simple-cycle</th>
<th>Combined-cycle</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heavy-frame</td>
<td>140–160 MW</td>
<td>200–250 MW</td>
</tr>
<tr>
<td></td>
<td>34% efficiency</td>
<td>50% efficiency</td>
</tr>
<tr>
<td>Aeroderivative</td>
<td>25–45 MW</td>
<td>35–55 MW</td>
</tr>
<tr>
<td></td>
<td>36% efficiencyId</td>
<td>47% efficiency</td>
</tr>
</tbody>
</table>

Source: Preston.96
manufacturers are forecasting commercial availability of such machines (using natural gas) in the 1998–2000 timeframe.

7.6.3. Technical issues, risks, and opportunities

Ongoing and future technology improvements can further increase economic application of combustion turbines and broaden the attractiveness of coal utilization in advanced power systems. At this time, however, most of the technical issues and opportunities in gas turbine development remain focused on the use of natural gas. Cleaner fuels and combustion air to keep out corrosive agents, materials to resist corrosion at higher turbine operating temperatures, more sophisticated blade cooling methods (closed-circuit steam cooling, partial cooling of the last-stage blades), and designs for reduced maintenance all will increase reliability over current combustion turbine models and are expected to push combined-cycle efficiencies on natural gas to 53% (HHV) or higher by the end of the decade and to 57% no later than 2010.

Advancements in hot section cooling designs, construction materials, coatings for oxidation and corrosion resistance, and thermal barrier coatings (see Section 9) will be the key to increasing combustion turbine firing temperatures and thus further increasing the efficiency of combustion turbines and associated coal-based power generation cycles. Single-crystal alloys—already used in aircraft engines—could advance last-stage turbine blade design and thus improve combined-cycle efficiency. A major uncertainty for coal-based applications is the level of fuel gas cleanup needed to protect such advanced turbine designs.

Other technical issues facing application of combustion turbines in advanced coal-based power generation include:

- Corrosion and/or deposition on turbine blades.
- Integration of coal gasification with novel combustion turbine thermodynamic cycles.
- Potential for catalytic combustion (low NOx) technology using coal syngas.

Many of these issues are being addressed in the ongoing programs described below. For example, recently reported work at General Electric Company, sponsored by EPRI and DOE, has confirmed that the combustion of coal gas with heating values below 100 Btu/scf is stable with very low CO emissions if the volumetric ratio of hydrogen to carbon monoxide exceeds unity. NOx emissions are also significantly below current standards. Control of NOx emissions from advanced turbines achieving higher firing temperature (and thus producing higher thermal NOx in air-blown systems) will require further study to determine whether future standards can be met by combustion controls alone or if additional requirements for postcombustion controls will be required.

DOE programs have investigated the corrosion potential of alkali metals on gas turbine blades in both PFBC and IGCC systems. In lower-temperature systems below about 870°C (1600°F), little damage has been observed. At higher temperatures, there has been some experimental evidence that fine mineral matter components carried along in the gas phase interact with vapor-phase alkalis to form innocuous solids that do not attack the turbine blades. If the problem turns out to be more severe, blade coating has been identified as the most promising approach for current designs. For higher-temperature advanced turbines (e.g. 1430°C [2600°F]), requirements for contaminated removal from coal-derived fuel gas are not yet established.

Issues of system integration for coal-based power plants also remain to be addressed. At the present time, the concept of phased construction is widely viewed as a flexible strategy that can be a cost-effective way to transition the modest capital investment in a combustion turbine from peaking application to midload and eventually to baseload. However, there are significant technological and regulatory hurdles to overcome in such a conversion, which must be addressed. For example, a combustion turbine optimized for simple- or combined-cycle gas firing is not optimal for coal-based IGCC operation. Overall, converting to gasified coal lowers the net power plant efficiency by 5–10 percentage points—depending on gasifier and cleanup system design—relative to natural gas, primarily due to losses upstream of the turbine.

Finally, turbine design modifications may be needed to take full advantage of integration issues that are unique to coal-based systems. For example, conceptually, integration of coal gasification with gas turbines that have been modified for operation on compressed humidified air from a storage reservoir have the potential to reduce gasification power plant costs by 20%. Another advantage to this cycle is that low-level waste heat energy can be reinjected into the cycle through the evaporation of hot water to humidify the high-pressure air. Expensive development efforts, however, will be required to modify existing aeroderivative turbines for this cycle. Systems studies are needed to identify the most promising options, as well as associated risks.

7.6.4. Current programs

DOE's ATS program—housed in the natural gas program of the Office of Fossil Energy—is a major effort to develop and design high-efficiency combined-cycle combustion turbines. The FY 1994 authorization for this program was $21.9 million; the FY 1995 DOE request has more than doubled to $44.9 million. The research is aimed at potential barrier issues, focusing on two primary areas: higher
firing temperatures, mainly from improved cooling concepts and materials, and high-efficiency cycles, aimed at steam cooling, interstage compression cooling, and chemical recuperation. The program aims to provide technology ready for commercial baseload application by 2000 that will be applicable to coal and biomass systems as well as natural gas. DOE is also involved in other cooperative programs with industry, notably the Collaborative Advanced Gas Turbine program involving DOE, EPRI, GRI, and turbine manufacturers.

Increases in the firing temperatures of advanced gas turbines will occur as a result of competitive pressures among manufacturers with a very significant acceleration resulting from the DOE ATS program. The availability of those machines will significantly improve IGCC plant efficiencies, as discussed earlier in this section. The higher-temperature turbines will also utilize higher pressure ratios and be significantly larger. As a result, single-train IGCC plants will have outputs of 350–400 MW, which will lower specific plant costs through improved economies of scale.

As noted above, the General Electric Company has successfully tested combustion in a General Electric model 7F combustion turbine of a simulated coal-based syngas diluted with H₂O, CO₂, and/or N₂ to HHV (higher heating values) as low as 100 Btu/lbf. These heating values (which are nearly 10 times less than that of natural gas) are comparable to values from the low-Btu fuel gas produced by advanced air-blown coal gasifiers.

7.6.5. Summary

Combustion turbine technology will continue to advance rapidly, driven by aircraft technology improvements but also by power generation application needs. Continued combustion turbine technology improvements and advanced cycles development on natural gas also will benefit the economics of future coal-based systems such as IGCC, PFBC, and IFC designs.

With respect to coal-based applications, key issues and uncertainties include fuel gas cleanup requirements for advanced turbine designs and the design and integration of turbine systems that can optimally accommodate evolution from natural gas to coal gas firing. NOₓ emission control requirements and approaches for higher-temperature advanced turbines also remain to be resolved.

7.7. Emission Control Technologies

7.7.1. Background

The development of environmental control technologies for electric power generation has primarily focused on the control of air emissions resulting from the combustion of fossil fuels. For coal-fired steam-electric generation, the emphasis has been on the control of particulate matter, sulfur dioxide (SO₂) (and nitrogen oxide (NOₓ) emissions—the three ‘criteria’ air pollutants subject to federal NSPS (see Section 3).

Particulate emissions in coal-based systems arise primarily from coal ash entrained in the flue gas stream (flyash) and from chemical reagents added to control other pollutants, especially SO₂. Control methods may employ inertial separation, wet scrubbing, electrostatic precipitation, or filtration to separate particles from the gas stream. The electrostatic precipitator (ESP) is the most widely used technology in conventional pulverized coal combustion systems. The particle-laden flue gas passes through an ionizing field, which imparts an electric charge to the particles, allowing them to be collected on an oppositely charged surface. Alternately, a fabric filtration system may be employed to collect particles by passing the flue gas through a fabric filter (baghouse) collector, which operates much like a high-efficiency vacuum cleaner. Current IGCC systems remove particulates by condensing or quenching the raw fuel gas with water (wet scrubbing). First-generation PFBC designs often employ cyclone (inertial) separators in conjunction with an ESP or fabric filter. Advanced IGCC and PFBC systems employ solid (typically ceramic) barrier filters that operate at high temperature and pressure, in contrast to conventional low-temperature devices at atmospheric pressure.

Sulfur dioxide is a component of flue gas resulting from the oxidation of sulfur in the coal during combustion. Sulfur dioxide can be controlled by reducing the sulfur content of coal prior to combustion, by reacting the SO₂ with a reagent (typically calcium-based) either during or after combustion, or by a combination of both approaches. Postcombustion removal of SO₂ using wet or dry FGD (flue gas desulfurization) systems is the most common technology for conventional power plants. For PFBC systems, the SO₂ reacts with a sorbent injected directly into the fluid bed. This approach is also being examined as an option for IGCC systems employing fluidized-bed gasifiers. Gasification-based power systems convert sulfur to hydrogen sulfide (H₂S) rather than SO₂. Current IGCC systems employ cold gas cleanup to remove H₂S via commercial low-temperature absorption systems. Advanced IGCC systems are being designed to remove H₂S using an absorption-regeneration system at high temperatures to improve system efficiency. Any H₂S remaining in the gas stream is oxidized to produce SO₂ emissions when the fuel gas is burned to generate electricity.

Nitrogen oxide emissions are formed from high-temperature reactions involving the oxygen and nitrogen present in coal and combustion air. Formation of NOₓ can be reduced by various measures that control the temperature-time profile of combustion reactions. Postcombustion control of NOₓ is typically
accomplished by the injection of ammonia-based substances, with or without catalysts, that reduce NO\textsubscript{x} to nitrogen gas. In gasification-based systems, nitrogen in the fuel gas stream typically occurs as ammonia, which is converted to NO\textsubscript{x} upon combustion in the gas turbine. Cold gas cleanup systems remove most of the ammonia prior to combustion, thus lowering potential NO\textsubscript{x} emissions, while current hot gas systems do not. In the latter case, postcombustion controls could be required to meet applicable emissions standards.

Most current methods of air pollution control generate some type of solid waste that must be disposed of or reused. At a minimum, the wastes include the mineral (ash) originally found in the coal. Other wastes arise from technologies to control SO\textsubscript{2} emissions. Technologies and processes do exist to replace or eliminate many of these wastes through reuse or by-product production, but most of these options are not economical in the United States at the present time. Hence, their use is not widespread. In the future, however, waste minimization is expected to become increasingly important in response to new economic and environmental pressures.

7.7.2. State of the art

Recent trends in particulate, SO\textsubscript{2} and NO\textsubscript{x} emission reductions achievable with current technology for pulverized coal-fired power plants were addressed in Section 3 (see Fig. 4). Particulate control technologies were the first to be developed, and their evolution has been undertaken primarily by the private sector with limited government support. Current ESPs and fabric filters achieve emission levels of one-third to one-sixth NSPS levels at costs of about $50–75/kWh and about 2–4 mills/kWh in total electricity cost.\textsuperscript{97} FGD technologies came into use in the United States in the 1970s and were developed throughout the 1980s with limited research and pilot plant efforts by EPA and DOE. Wet limestone systems, the most prevalent now in use, are being designed today for up to 95% annual average SO\textsubscript{2} removal, with about 97-98% removal using organic acid additives, in contrast to 90% removal a decade ago. Wet scrubbers using magnesium-enhanced lime systems are the most efficient FGD units now deployed, achieving over 98% SO\textsubscript{2} removal.\textsuperscript{98} For the typical plant shown earlier in Fig. 4a, this corresponds to an emission rate of 0.1 lb SO\textsubscript{2}/million Btu, or one-sixth of the NSPS level. On low-sulfur coals, lime spray dryer systems, originally deployed as a 70% removal technology, today are designed for over 90% SO\textsubscript{2} removal in the United States and over 95% in Europe.

The cost of FGD systems also has decreased significantly as a result of process improvements and design simplifications over the past decade. Typical capital costs for application with a new power plant now range from about $100–200/kW, with total levelized costs of about 5–10 mills/kWh.\textsuperscript{99} Capital costs for retrofit systems are typically higher than those cited above. For example, the capital cost of most FGD systems announced for Phase I compliance with the 1990 CAAAAs (Clean Air Act amendments) range from $220–260/kW.\textsuperscript{100}

For NO\textsubscript{x} control, advanced low-NO\textsubscript{x} burner designs and other combustion modifications now available or nearing commercialization are able to achieve emission reductions of 30% or more below the NSPS level for new PC-fired power plants.\textsuperscript{101} Costs are relatively low, at roughly $7–15/kW.\textsuperscript{89} Retrofit situations pose greater difficulties for coal plants due to the wide variety of boiler types and plant vintage. To date, NO\textsubscript{x} reductions from existing coal-fired units have not yet been widely undertaken or required to meet the ambient NO\textsubscript{x} standard.

Postcombustion NO\textsubscript{x} removal systems employing selective catalytic reduction (SCR) technology are now in widespread use on coal plants in Japan and Germany, with about 30 GW of installed capacity.\textsuperscript{102} Current SCR technology achieves up to 90% NO\textsubscript{x} removal in low- and medium-sulfur coal applications overseas.\textsuperscript{103} Such systems have not yet been deployed in the United States, although demonstration of SCR with U.S. coals currently is in progress as part of DOE’s CCT program. A commercial order also has been placed for SCR on a 285-MW coal-fired plant operated by an independent power producer.\textsuperscript{103}

The cost of SCR remains high relative to combustion controls, although a decade of experience and the emergence of industry competition have lowered the cost significantly. Capital costs today are roughly $50–80/kW, with total levelized costs of about 2–6 mills/kWh for hot-side systems on new coal-fired plants.\textsuperscript{104} SCR costs are dominated by the cost of the catalyst and frequency of catalyst replacement. Substantial cost reductions have been achieved in both areas in recent years. Retrofit costs for SCR can be significantly higher depending on the level of difficulty, the size and age of the plant, and other factors. For gas turbine systems, SCR already is required on some U.S. plants to meet local air quality standards. NO\textsubscript{x} emission levels of 9 ppm or less are being achieved.\textsuperscript{105} Gas turbine designers also are employing a variety of combustion-based control measures in efforts to avoid the need for tail-end SCR.

The DOE CCT program has resulted in significant joint federal and private sector funding for the further development and demonstration of advanced emission control technologies. As elaborated in Section 8, this program includes the commercial demonstration of 19 emission control systems, with five completed, 11 in operation, and three in design and construction. Table 26 shows the control levels projected to be achieved by the emission control systems in the CCT program and indicates whether the technologies can be utilized for new facilities or as retrofits on an existing facility.
In addition to the emission control systems above, advanced systems employing hot gas cleanup and in-bed desulfurization are being developed. For PFBC systems, the current state of the art for sulfur removal employs a circulating PFBC designed to achieve SO₂ removal efficiencies of 95% or more. Scale-up and demonstration of this capability are planned under Round V of the CCT program. The goal is to achieve SO₂ reductions comparable to modern FGD systems at reagent stoichiometries low enough to permit economical operation with minimum solid waste. At the present time, relatively high reagent use is often required to achieve high SO₂ removal efficiencies. The spent and unreacted sorbent roughly doubles the total solid waste for coal-fired plants.

Hot gas desulfurization systems that achieve over 99% sulfur removal from gasifier fuel gas streams also are scheduled for demonstrations in conjunction with several IGCC CCT projects. To date, hot gas (480-700°C [900-1300°F]) desulfurization systems employing regenerable metal oxides such as zinc ferrite and zinc titanate have not achieved the durability required for a cost-effective process. Continued work on improved sorbents and reactor designs is in progress. System studies for IGCC systems using advanced fluidized-bed gasifiers also suggest that the optimal SO₂ removal system may be a combination of hot gas desulfurization and in-bed desulfurization in the gasifier using limestone.

Hot gas particulate removal from PFBC and IGCC gas systems also is under development. These devices can be viewed as an integral component of the power generation system rather than as an environmental control technology, since they serve the critical function of removing particles and alkaline materials from the fuel gas to protect the gas turbine from erosion and corrosion. For current and advanced turbine designs, the cleanup requirements needed to protect the turbine from particle-induced damage exceed the current requirements for environmental protection. The most promising systems to date have employed barrier filters designed to achieve emissions of less than 2 ppm by weight of particles greater than 5 μm in diameter. The major problem,

<table>
<thead>
<tr>
<th>Project</th>
<th>Removal efficiency (%)</th>
<th>New</th>
<th>Retrofit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sulfur dioxide removal</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas suspension absorption</td>
<td>90+</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Confined zone dispersion</td>
<td>50</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Furnace sorbent injection with humidification (LIFAC)</td>
<td>85</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Advanced flue gas desulfurization</td>
<td>95+</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>CT-121 flue gas desulfurization system</td>
<td>98+</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>NOₓ removal</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cyclone fired coal reburn</td>
<td>—</td>
<td>55</td>
<td></td>
</tr>
<tr>
<td>Low-NOₓ cell burner</td>
<td>—</td>
<td>50+</td>
<td></td>
</tr>
<tr>
<td>Low-NOₓ burner-gas reburn</td>
<td>—</td>
<td>70</td>
<td>X</td>
</tr>
<tr>
<td>Advanced combustion—wall fired</td>
<td>—</td>
<td>50</td>
<td>X</td>
</tr>
<tr>
<td>Advanced combustion—tangentially fired</td>
<td>—</td>
<td>48</td>
<td>X</td>
</tr>
<tr>
<td>Selective catalytic reduction</td>
<td>—</td>
<td>80</td>
<td>X</td>
</tr>
<tr>
<td>Micronized coal reburn</td>
<td>—</td>
<td>60</td>
<td>X</td>
</tr>
<tr>
<td>Combined SO₂/NOₓ</td>
<td>—</td>
<td>96</td>
<td>94</td>
</tr>
<tr>
<td>SNO₂ catalytic advanced flue gas cleanup</td>
<td>—</td>
<td>70</td>
<td>50</td>
</tr>
<tr>
<td>Limestone injection multistage burner</td>
<td>—</td>
<td>85</td>
<td>90</td>
</tr>
<tr>
<td>SNRB combined SO₂ and NOₓ control</td>
<td>—</td>
<td>50</td>
<td>70</td>
</tr>
<tr>
<td>Low-NOₓ burners and gas reburn</td>
<td>—</td>
<td>97</td>
<td>70</td>
</tr>
<tr>
<td>NOₓ/NO dry regenerable flue gas cleanup</td>
<td>—</td>
<td>95</td>
<td>30</td>
</tr>
<tr>
<td>S-H-U* wet FGD</td>
<td>—</td>
<td>70+</td>
<td>80+</td>
</tr>
</tbody>
</table>

*Saarberg Holter Umwelt.

Source: DOE. 82
however, has been longevity. Current candle filter
designs have operated no more than several hundred
hours at the required temperatures (760–870°C
[1400–1600°F]) before breaking, whereas lifetimes of
the order of 16,000 hours are needed for eco-
nomical PFBC systems.2106 Improved designs, as
well as testing in the reducing gas environment of
IGCC systems, are planned as part of the CCT
demonstration projects.

With respect to solid waste emissions, many state-
of-the-art air pollution control systems offer im-
proved prospects for waste reduction through the
production of salable by-products, especially with
regard to sulfur emissions control. Modern FGD
systems produce gypsum, which can be upgraded to
commercial quality and sold (which is common prac-
tice in Europe and Japan). Several advanced flue gas
cleanup systems being demonstrated in the CCT
program produce by-product sulfur or sulfuric acid,
as do the hot and cold gas cleanup systems employed
with coal gasifiers. Only advanced PFBC systems
increase rather than decrease the total solid wastes
generated from coal use. In all cases the economic
viability of by-product recovery systems depends on
site-specific factors and markets. In the United States
today, waste disposal in landfills is still more attrac-
tive for many electric utilities.

7.7.3. Technical issues, risks, and opportunities

Existing control technologies for the criteria air
pollutants (SO₂, NOₓ, and particulates) associated
with PC-fired power plants are capable of meeting
current or anticipated emission reduction require-
ments in the near term (i.e. prior to 2005). The same
is true of cold gas cleanup control technologies for
gasification-based systems. Cost reduction and mini-
mization of solid waste remain important goals to
improve the viability of these coal-based systems.
For the medium term (post-2005), additional perform-
ance improvements may also be required, especially
for NOₓ controls.

Control technologies applicable to advanced com-
bustion and gasification technologies need further
development. In particular, hot gas cleanup systems
for SO₂ and particulate removal, which are critical
to several of the advanced high-efficiency technol-
ogies—especially PFBC—have yet to achieve
the performance, reliability, or durability needed for
commercial applications. In IGCC systems, hot gas
cleanup does not presently control nitrogen emissions
(in the form of gaseous ammonia), which increases
downstream costs and complexity for NOₓ controls
in the gas turbine/heat recovery system. Research to
address these issues is in progress.

With respect to solid waste minimization, one of
the key needs is to improve the sorbent utilization
for sulfur removal in advanced fluidized-bed combus-
tors and gasifiers. Current PFBC systems produce
the largest volume of solid waste per unit of sulfur
removed. The presence of unreacted lime (as well as
sulfides in the case of gasifiers) adds to the difficulty
and cost of waste disposal. Pilot plant data for
circulating PFBC designs show improved sorbent
utilization relative to bubbling bed designs, but more
work is needed to achieve commercially acceptable
systems. More intensive research on re-use of spent
sorbent is also needed if DOE’s goal for solid waste
reduction is to be achieved.

Control technologies for noncriteria pollutants
also need to be addressed. To deal with the emerging
issue of air toxics (see Section 3), trace substance
emissions and fate must be characterized for current
and advanced technologies. It is anticipated that
existing high-efficiency particulate control technolo-
gies will be adequate to deal with most heavy metal
emissions from coal combustion, but specific regula-
tions have yet to be established. Similarly, the extent
to which vapor-phase emissions such as mercury,
chlorides, and selenium will have to be controlled is
not yet clear; technologies to control these emissions
may well be needed in the near future. Should that
be the case, an additional risk of hot gas cleanup
systems is their uncertain capability to control emis-
sions of air toxics, since they presently do not remove
vapor-phase species. Additional controls for air toxics
may impose additional economic costs.

The ability of control technology to reduce or
eliminate emissions of potential air toxics is currently
under study by DOE, EPRl, and others. The most
prevalent data are for conventional cold-side ESPs,
which show high removal efficiencies for most heavy
metals but much lower removal rates for volatile
species such as mercury.2107 Wet FGD systems in
conjunction with an upstream particulate collector
appear to offer the greatest removal rates of volatile
species and other potential air toxics such as chlor-
ides. However, there is large uncertainty in the data,
with relatively little information currently available
for wet scrubbers operating in the United States.
Experiments with carbon-based additives show an
enhanced ability to remove mercury in some cases,
particularly with high chloride coals. Research on
novel control methods for air toxics is being pursued
by EPRl, DOE, and others.

As noted in Section 3, a major concern for all
carbon-based technologies is the potential require-
ment to control carbon dioxide (CO₂) emissions. The most
economical means is to improve the efficiency of
energy conversion and utilization so that less CO₂ is
emitted per unit of useful energy delivered. For coal-
fired power plants, average U.S. energy losses are
about 2% in coal preparation, 67% in power genera-
tion, and 8% in transmission and distribution,74 yield-
ing an overall efficiency of about 30% for fuel to
delivered electricity. Within the limits of thermody-
namic cycles, the greatest opportunity for energy
efficiency improvements thus lies in the power gen-
eration process. As noted previously, the most efficient
PC-fired plants commercially available today have
efficiencies in the range of 38–42%. Thus, advanced technologies achieving 50–60% efficiency offer the potential to reduce CO₂ emissions up to a third relative to current new plants.

The potential for CO₂ capture and disposal has also received preliminary study. The consensus is that the technological means of scrubbing CO₂ from flue gases already exists today but that the feasibility of CO₂ disposal in deep wells, oceans, or other final storage sites remains a critical issue to be resolved. From a cost viewpoint, CO₂ removal today is very expensive. Estimates for a 90% CO₂ reduction suggest roughly a doubling of electricity generation costs and about a 35% energy penalty for removing and transporting CO₂ to a hypothetical disposal site. Somewhat lower energy penalties are estimated for advanced combustion and gasification cycles. The development of viable CO₂ removal and disposal processes remains a long-term challenge to control technology development.

7.7.4. Current DOE programs

The Control Technology program in the Office of Fossil Energy is divided into four program components: Flue Gas Cleanup, Gas Stream Cleanup, Waste Management, and Advanced Research. As noted in Section 2, DOE has established incremental emission control goals for its Advanced Power Systems program (Table 3) that must be supported by the Control Technology program. The FY 1994 authorized budget for this activity was $13.25 million for flue gas cleanup, $19.29 million for gas stream cleanup, $2.41 million for waste management, and $1.16 million for advanced research.

As noted previously, commercial technology developed by the private sector with DOE participation already can achieve the DOE emission goals for 2000 and 2005 for conventional coal combustion systems. With the anticipated increase in demand for baseload generating capacity beyond 2005 and the expected tightening of future emission control requirements, the DOE program emphasis on developing improved control technologies for highly efficient, ‘superclean’ power systems appears to be well placed.

The Flue Gas Cleanup program has a goal of reducing SO₂, NOₓ, and particulate emissions to 1/10th current NSPS levels without high-volume waste generation. Further goals are to control air toxics and CO₂ emissions and to develop saleable by-products from the control systems. Development of advanced FGD systems and combined SO₂/NOₓ removal systems are also part of this program area. The other major component is the Gas Stream Cleanup program. It has a similar focus of removing contaminants from gasifier or combustor streams prior to their entry into advanced power systems such as the PFBC, IGCC, and IGFC systems. Activities focus on the development of high-temperature, pressurized contaminant control systems.

DOE also has a Waste Management program focused on waste products formed by advanced power generation technologies. The goal of that program is to ensure that solid waste from advanced fossil energy technologies is not a roadblock to commercialization of those technologies. More specifically, the objectives are to achieve a 50% utilization of solid waste from advanced fossil energy technologies and commercial markets by 2010, to establish use for mine remediation of alkaline by-products such as produced by fluidized-bed combustors and gasifiers with limestone added for sulfur removal, and to provide commercial acceptance of products manufactured from advanced pulverized coal by-products.

Many examples of successful waste product recycling, such as the use of flyash, exist. The best uses for the future are generally considered to be in construction, agriculture, mine reclamation, and soil stabilization. The present cost of these options and the enormous quantities of waste relative to by-product demand are the principal roadblocks to increased commercialization.

The final component of the Control Technologies Program is Advanced Research. The emphasis in this part of the program is on fundamental hot gas cleanup methods such as ceramic filter and membrane research.

7.7.5. Summary

Current commercial technologies for SO₂, NOₓ, and particulate control for pulverized coal plants have improved substantially over the past decade and now can meet or exceed DOE's air pollutant emission targets for 2000 and 2005. Cost reduction is the primary need and the main potential benefit of current CCT demonstration projects.

The most difficult near-term R&D challenges are in development of the hot gas particulate and sulfur cleanup systems to be employed with advanced power generation systems (IGCC, PFBC, IGFC). In particular, the technical problems of achieving reliable and sustained operation have yet to be overcome. Solutions to these problems are central to the achievement of cost-effective, high-efficiency power generation systems. Especially critical is the need for a high-temperature, high-pressure particulate removal system for advanced PFBC.

Other DOE programs are beginning or continuing to address the emerging issues of hazardous air pollutants (air toxics), greenhouse gas emissions (especially CO₂), and solid waste minimization. All of these are important issues that will require increased R&D attention in the future.

8. TECHNOLOGY DEMONSTRATION AND COMMERCIALIZATION

EPACT specifically directs DOE to conduct demonstration and commercialization programs on coal-
based technologies (see Appendix A). DOE's CCT program constitutes the major effort in this area, although relevant activities are also being conducted under the Office of FE's R&D program for coal. The CCT program constitutes a major government-funded effort and provides some useful insights into the role of DOE in facilitating the transition of advanced coal-based technologies from demonstration into the commercial sector. Under the Clinton administration, there is a strong emphasis on accelerating the commercial deployment of new technologies and on developing markets for U.S. technologies both domestically and overseas.

8.1. Commercialization Issues

The steps required to commercialize any new technology differ greatly, but the fact that coal is a solid substance introduces a significant technical risk into the technology scale-up process. The difficulty of extrapolating the processing of solids from laboratory through pilot scale to commercial scale is widely recognized. Piloting even at a 1000 ton/day scale cannot completely ensure the same results at 10,000 ton/day. This differs from processing gases or liquids, where extrapolation from laboratory to full commercial scale in a single step is now commonly practiced, based on an in-depth understanding of the chemical engineering parameters governing such operations. For example, a 14,000 bbl/day commercial Mobil fixed-bed methanol-to-gasoline plant was designed and built based on a 4 bbl/day laboratory unit. \textsuperscript{111} The difficulty of scale-up when processing solids, such as coal, increases with increasing complexity of the process. Systems that require multiple sequential or tightly integrated solids reactors are at a distinct disadvantage; simplicity is at a premium for solids processing, and this extends to the many auxiliary steps required for the demonstration of a complete coal-fired power generation system. Thus, in scaling-up coal technologies, notably for power generation, there is a need for prudent stepwise increases in capacity from laboratory to pilot plant to demonstration scale. The complexity of power generation systems implies that commercialization is particularly expensive.

The objective of the DOE demonstration and commercialization effort is to enhance the process whereby a developing technology is demonstrated at the commercial scale such that it is regarded as commercially available by the ultimate user. In most instances this requires the mitigation or elimination of the additional technological and economic risks that the user associates with the adoption of a new as compared to a proven technology. In the power generation area, the investor-owned utility cannot generally assume the risk for a new technology, faced with a possible loss of return on investment from the rate-making authority if the technology does not perform as expected and requires modification.

It is an accepted principle for advancing new technology to commercial maturity that the first-of-a-kind commercial plant is significantly higher in cost to build than subsequent plants and does not provide adequate information on all operating, maintenance, and cost issues. A new technology is not considered mature and commercially demonstrated until two-five applications of the technology have been installed, as illustrated by the generic capital cost learning curve shown in Fig. 5. The issue for DOE is how to enhance the installation of additional applications of early demonstrations.

8.2. Clean Coal Technology Program

The CCT program is a technology development effort jointly funded by government and industry in which advanced coal-based technologies are being demonstrated at a scale large enough for the marketplace to judge their commercial potential. A unique feature of the program is that industry plays a major role in defining the demonstration project and in ensuring eventual commercialization. It is intended that once the program is complete the private sector should be able to make use of the technologies developed in the commercial arena without further government support. The industrial partner in each CCT project is required to contribute at least 50% of the total cost, indicating the extent of their commitment to develop a technology with a real commercial potential. The patent rights for inventions developed during the demonstration program are normally granted to the industrial participant, thereby preserving the incentives for subsequent commercialization. Five competitive solicitation cycles (CCT Rounds I through V) have been conducted, resulting in 45 active demonstration projects encompassing total public and private investments of $6.9 billion, of which DOE is providing $2.4 billion (34%), and private and other sources are providing $4.5 billion (66%). Currently authorized funding by solicitation round for the CCT program is given in Section 1. From CCT Round III onward, industrial program participants have been required to commercialize technologies in the United States on a best-effort, nondiscriminatory basis, although they cannot be forced to license technologies to their competitors. A summary of CCT activities is provided in Table 27. Additional information on demonstration projects in the CCT program is provided in Appendix F.

8.3. Advanced Power Systems Demonstration Projects

DOE's technology goals for the Advanced Power System demonstration projects were given earlier
in Section 7 (Tables 19, 20, and 22). Many of the technologies being demonstrated in the CCT program are the same as those being targeted in the FE R&D program. As a result, a number of the CCT demonstrations are also being considered demonstrations under the FE R&D program, notably, first- and second-generation PFBC, first- and second-generation IGCC, IGFC, and mild gasification technology demonstrations. Of the 45 active CCT demonstration projects, 18 are scheduled for completion, 11 will be in operation, and the remaining 16 were in design and construction by the end of FY 1994.

8.3.1. Advanced emission control systems

Of the 45 active CCT demonstration projects, 19 involve advanced emission control systems technologies aimed at the cleanup of SO$_2$, NO$_x$, and particulates (see Section 7, Table 26). The 19 projects require an obligation of $672 million (approximately 15% of the program funding), of which the private sector has contributed approximately 58%. The demonstrations apply to 3250 MW of generating capacity (units from 5-605 MW in size). These activities are expected to have a relatively short-term payoff and result in commercially available technologies for compliance with the acid rain precursor provisions of the Clean Air Act. The technologies being developed also offer significant export potential.

8.3.2. Integrated gasification combined cycle

A key component for new power generation systems in the near- to mid-term periods (through 2020) will likely be the gas turbine. The fundamental thermodynamic advantage of a heat engine with a 1260°C (2300°F) (and rising) inlet temperature over the typical steam turbine with a 540°C (1,000°F) inlet is very great and the main reason thermal efficiencies in excess of 50% are possible.

In the foreseeable future, gas turbine capacity is anticipated to be in the range of 100–300 MW, including a combined steam generation cycle. This will require gasification systems that use between 1000 and 3000 tons/day of coal. The series of new gasification systems being demonstrated under the CCT program can be expected to achieve these levels, although most still fall in the lower end of the range. IGCC units being demonstrated under the CCT program (see Table 16) have capacities of 65–480 MW (total capacity of 1343 MW), and all are scheduled for completion between 1995 and 2000. Thermal efficiencies are predicted to reach 45%, with SO$_2$, NO$_x$, and particulate emissions well below New Source Performance Standards (NSPS) levels. A discussion of the gasification technologies being demonstrated under the CCT program is given in Section 6.

8.3.3. Pressurized fluidized-bed combustion

Another new technology being demonstrated is PFBC. Two first-generation PFBC demonstrations, sized at 70 and 80 MW, are part of the CCT program, as is a 95-MW second-generation PFBC demonstration unit. PFBC technology has the potential to achieve 50% thermal efficiencies but only if hot gas cleanup systems can be improved and used in conjunction with advanced turbines (see Section 7). PFBC has a very compact footprint that makes it a viable technology for repowering existing generating units.

8.3.4. Direct-fired systems

The technology for direct firing of coal in a gas turbine or diesel engine has been developed through the proof-of-concept phase under the FE R&D program. In addition, a dual stationary coal-fired diesel engine with a combined rating of 14 MW will be demonstrated in Round V of the program. This activity is not scheduled to receive any further funding under the FE R&D program.
8.3.5. Indirectly-fired systems

The FE R&D program has supported this technology through two programs: EFCC (externally fired combined-cycle) and HIPPS. A demonstration of EFCC technology at the 47-MW level is planned for Round V of the CCT program. Continuation of development work on HIPPS is proposed for FY 1995, with a goal of achieving 47% thermal efficiency.7 If the HIPPS technology is to advance to the demonstration phase, the components that will be demonstrated in the CCT EFCC project must prove to be commercially viable. Thus, demonstration of HIPPS technology must await the outcome and economic evaluations of the EFCC demonstration.

8.3.6. Advanced pulverized coal systems

As noted in Section 7, the FE R&D program is supporting the development of the low-emission boiler system with the goal of demonstrating a 42% efficient system with emissions from one-half to one-third of the NSPS by the year 2000. For FY 1995, the FE R&D program has requested $7.6 million to continue engineering development and subsystem testing of this technology.

8.3.7. Fuel cells

Development and demonstration of fuel cell technology have been transferred from the coal component of the FE R&D program to the gas component, on the basis that technology demonstration and commercialization will likely be accelerated using gas rather than coal. An IGCC demonstration selected in CCT Round V will utilize a portion of the clean coal gas to fuel a 2.5-MW molten carbonate fuel cell.

8.4. Future Directions

8.4.1. Additional CCT solicitations

Section 1321 of EPACT requires DOE to conduct additional solicitations for the development of cost-effective, higher-efficiency, low-emission coal utilization technologies for commercialization by 2010. Recommendations for the future of the CCT program have been made by two groups, the CCTC and the NCC.

The CCTC, representing the coal, utility, manufacturing, design, and construction industries and states,
advocates the demonstration of clean coal technologies and has made recommendations to DOE regarding the future of the CCT program. The CCTC seeks to ensure that technologies demonstrated in whole or in part through the existing CCT program are also commercially deployed and thereby made ready for 'commercial application' as required by Section 1301 of EPACT. The CCTC's specific position regarding Sections 1301 c(3) and c(4) is as follows:

- While continuing to support the completion of the projects already selected in the current CCT program, the program would be modified to address commercial deployment by reducing the financial risks associated with the use of the technologies.
- The program would operate basically as it does now but would cost share only certain cost differentials when compared to a conventional technology. The DOE's cost share of the 'risk gap' would be significantly less than the current 50%. Specifically, DOE support for commercial demonstration plants would be determined using a risk-based formula to make a given CCT cost competitive with conventional technologies.

With regard to Section 1301 c(5), the CCTC would keep the same program elements and management structure in place, with a revised focus on cost sharing the financial risk. The proposed risk-based formula for determining cost sharing would address both capital cost risk and operating cost risk. As these risks decrease in subsequent demonstrations, so would the cost-shared DOE support, resulting in eventual commercial acceptance with no cost sharing. Timing of this future program must build on the first-of-a-kind projects and result in commercial acceptance to meet repowering and new capacity requirements from 2005 onward.

The NCC, a federal advisory committee to the Secretary of Energy, has, at the request of the Secretary, made recommendations regarding the future direction of the CCT program. The NCC has recommended that no more solicitations be issued under the current CCT program. The NCC further recommends that the Secretary foster the establishment of a new federal-level CCT incentive program to stimulate initial and sustainable commercial deployment of CCT. The recommended CCT incentive program would provide approximately $1.1 billion of capital incentives and $0.3 billion in operating incentives over the 15-year period 1995–2010. The incentives would offset 10–15% of the capital risk and help offset operating risks associated with first-of-a-kind and early commercial units. The incentive would be based on a percentage of the capital and operating cost risk differential between the CCT and conventional technology. For example, if the risk differential between a 400-MW IGCC project and conventional pulverized coal with FGD plant is $360 million, the federal incentive for the project would be $54 million or 15% of the differential.

8.4.2. International CCT Initiative

Section 1332 of EPACT (Innovative Clean Coal Technology Transfer Program) proposes the development of a joint DOE/Agency for International Development clean coal technology program to encourage exports of U.S. technologies that allow more efficient, cost-effective, and environmentally acceptable use of coal resources. FY 1995 funding has been requested to implement an international initiative for 'showcase' demonstration projects in clean coal technologies in China and Eastern Europe. Specifically, DOE has proposed that China receive approximately $50 million for an IGCC demonstration plant, and $25 million in support is proposed for power plant refurbishment in Eastern Europe. DOE expects these funds to be available from projects that were selected in the first five rounds of the CCT program but have or will in the future drop out of the program.

The first priority for the existing CCT program, mandated by Congress in Section 1301 of EPACT, is to conduct a research, development, and demonstration program that will result in CCT technologies that are ready for commercial use by 2010. Thus, in the view of the committee, the impact on the existing CCT program of using CCT program funds to support technology demonstrations in a foreign country requires careful examination. Funding of CCT technology in foreign countries in lieu of domestic demonstrations runs a risk of delivering little if any technology advancement, export opportunities, or lasting U.S. jobs. It is entirely possible that demonstrations will provide a basis for a foreign country to copy the technology and provide subsequent installations itself.

A further question raised by the committee concerns the suitability of IGCC technology to meet China's major increases in demand for electricity and significant environmental problems. Commercially available pulverized coal plants with modern flue gas cleanup technology may be more cost effective and beneficial (see Section 3). Supporting funding for commercially available technology, including retrofit technologies for environmental control, could come from the traditional sources of overseas aid, without impacting the existing CCT program or the FE R&D program budget.

8.5. Advanced Fuel Systems Demonstration Projects

As noted in Section 2, the objective of the Advanced Fuel Systems program is to develop systems that can produce coal-derived transportation fuels, chemicals, and other products at costs competitive with oil-derived products. At the present time, the prices of coal-derived liquid fuels are significantly greater than those derived from petroleum or natural gas. Oil prices are not expected to rise sufficiently in the near future to change this situation. As a result, there is currently minimal private sector
support for developing and demonstrating technologies for the conversion of coal to fuels at a commercial scale. One exception is in mild gasification technology. The FE R&D program has sponsored a process development unit for mild gasification (the Illinois Mild Gasification Facility) that is supported by 20% private sector investment. In addition, the CCT ENCOAL Mild Coal Gasification project aims to demonstrate the production of both a solid and a liquid fuel from coal. This approach has been attempted many times in the past and has not been successful, principally because 50–70% of the feed coal remains as a low-volatiles-content char that must be used as a fuel or feedstock. Pyrolysis as a source of liquid fuels has been commercially practiced only under wartime conditions in Germany between 1935 and 1945 based on the Lurgi sweep gas carbonization process. Current efforts have focused on using the char as a boiler fuel or in the production of form coke. The characteristics of the char and the resulting price paid for it have prevented this approach from being economical. DOE has no further plans to use the Illinois Mild Gasification Facility following completion of ongoing development activities. No additional funding for the facility has been requested for FY 1995.

A stand-alone facility for producing finished liquid fuels from coal must necessarily be large to achieve economies of scale and will thus be very expensive. As discussed in Section 6, recent systems studies have projected equivalent crude prices of $30–35/bbl for stand-alone production of high-quality gasoline and distillate fuels. This cost, combined with the uncertainty in crude oil prices over the operating life of the liquefaction plant, are strong disincentives for demonstration and commercialization projects. However, coproduct systems combining F–T (Fischer–Tropsch) synthesis of coal liquids and electric power generation have the potential to reduce the equivalent crude cost of coal liquids by approximately $5–7/bbl (see Section 6).*51,72

The above results, together with oil price projections for 2010,24 indicate that demonstration and early deployment of liquefaction technology in coproduct systems may become economically attractive within the mid term (2006–2020), that is, in approximately the same timeframe as installation of advanced IGCC power generation facilities. Nevertheless, the price projections from the studies assume 'mth plant' costs. As for advanced power generation technologies, first-of-a-kind or pioneer plant demonstrations are likely to be significantly more expensive than fully commercial systems. Thus, the committee anticipates that some federal cost sharing of early demonstration plants, similar to that in the CCT program, will be necessary to stimulate industry participation, and ultimate adoption, of coproduct systems to produce coal liquids and electric power.

8.6. Summary

1. Demonstration of advanced coal-based technologies at a commercial scale, as in the FE R&D and CCT programs, is an important step in the development of commercially available technologies. The demonstrations being supported by the FE R&D and CCT programs appear, for the most part, to be well directed toward advancing power generation technologies that have the potential to meet relevant goals for thermal efficiency, environmental control, and reduced costs.

2. The program components and management of the current CCT program have demonstrated the ability to conduct a successful demonstration program, as evidenced by the involvement and financial support of the private sector.

3. The commercial acceptance of new power generation technologies will be impeded by the remaining financial risk associated with second- and third-of-a-kind demonstration projects.

9. ADVANCED RESEARCH PROGRAMS

The present section provides a brief overview of the organization and budgets for the DOE's Office of FE advanced research programs relating to coal. The DOE and committee perspectives on the role of advanced research for coal-based technologies are then presented. The section concludes with a brief discussion of opportunities for advanced research in three areas: combustion and gasification, coal conversion and catalysis, and materials. It is not the intention of the committee to provide a comprehensive list of research opportunities for coal-based technologies but rather to highlight key areas. The specific research opportunities discussed were identified as the basis of review and analysis of current DOE programs (Sections 5 through 7), and particular importance was accorded activities unique to coal technologies. In each case the proposed research is directed toward meeting, and ultimately exceeding, DOE's targets for advanced coal-based power systems and the production of clean fuels from coal.

9.1. Program Organization and Budgets

The advanced research programs within the DOE FE coal R&D program consist of a set of cross-cutting programs within the AR&D (Advanced Research and Technology Development) budget category and a set of technology-specific programs falling under the general category of Advanced Research

*In the studies cited the economic return on electric power production was assumed to be constant. All savings were applied to the liquid products.
Table 28. Trends in advanced research budgets (millions of current dollars)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>AR&amp;TD (research)</td>
<td>21.1</td>
<td>20.2</td>
<td>21.2</td>
<td>22.9</td>
<td>23.0</td>
<td>20.4</td>
<td>22.6</td>
</tr>
<tr>
<td>AR&amp;ET (fuels)</td>
<td>6.1</td>
<td>6.9</td>
<td>6.8</td>
<td>8.1</td>
<td>7.1</td>
<td>7.4</td>
<td>5.2</td>
</tr>
<tr>
<td>AR&amp;ET (power systems)</td>
<td>8.1</td>
<td>7.4</td>
<td>7.1</td>
<td>8.2</td>
<td>7.3</td>
<td>2.9</td>
<td>2.1</td>
</tr>
<tr>
<td>Total*</td>
<td>35.3</td>
<td>34.5</td>
<td>35.1</td>
<td>39.2</td>
<td>37.4</td>
<td>30.7</td>
<td>29.9</td>
</tr>
<tr>
<td>(41.1)</td>
<td>(38.5)</td>
<td>(37.5)</td>
<td>(40.3)</td>
<td>(37.4)</td>
<td>(29.9)</td>
<td>(28.4)</td>
<td>(20.7)</td>
</tr>
</tbody>
</table>

*Figures in parentheses represent total budget in constant 1992 dollars.

Source: Personal communication from David Beecy, U.S. DOE, to Jill Wilson, National Research Council, July 20, 1994.

Table 29. Advanced research budgets for FY 1994 and FY 1995 (millions of current dollars)

<table>
<thead>
<tr>
<th>Area</th>
<th>FY 1994 (enacted)</th>
<th>FY 1995 (requested)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AR&amp;TD</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal utilization science</td>
<td>3.1</td>
<td>3.1</td>
</tr>
<tr>
<td>Materials</td>
<td>8.9</td>
<td>6.9</td>
</tr>
<tr>
<td>Components</td>
<td>1.7</td>
<td>0.9</td>
</tr>
<tr>
<td>Bioprocessing of coal</td>
<td>1.9</td>
<td>1.9</td>
</tr>
<tr>
<td>University and national laboratory coal research plus university coal research</td>
<td>5.0</td>
<td>5.0</td>
</tr>
<tr>
<td>HBCUs,* education and training</td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>Instrumentation and diagnostics</td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>Subtotal (AR&amp;TD)</td>
<td>22.6</td>
<td>19.8</td>
</tr>
<tr>
<td>AR&amp;ET</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Advanced clean fuels research</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal liquefaction</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Advanced clean/efficient power systems</td>
<td>5.2</td>
<td>0.8</td>
</tr>
<tr>
<td>Combustion systems</td>
<td>0.5</td>
<td>0.4</td>
</tr>
<tr>
<td>Control technology and coal preparation</td>
<td>1.1</td>
<td>1.0</td>
</tr>
<tr>
<td>Surface coal gasification</td>
<td>0.5</td>
<td>0.4</td>
</tr>
<tr>
<td>Subtotal (AR&amp;ET)</td>
<td>7.3</td>
<td>2.6</td>
</tr>
<tr>
<td>TOTAL</td>
<td>29.9</td>
<td>22.4</td>
</tr>
</tbody>
</table>

*Historically black colleges and universities.

Source: DOE.

and Energy Technology (AR&ET), formerly known as Advanced Research. The AR&ET technology-specific programs fall within the Advanced Clean Fuels and Advanced Clean/Efficient Power Systems budget categories (see Table 1). This program organization responds to a directive from Congress stating that, for ease of budget presentation and receiving testimony, advanced research directly related to a specific coal area should be presented both in the budget and in testimony as part of the total program for that specific technology area, rather than as part of the AR&TD budget category.

The AR&TD program includes both research and nonresearch portions. The technology cross-cut activities within AR&TD (see Section 2) include all nonresearch areas, namely, environmental activities, technical and economic analyses, international program support, and coal technology export, as well as two advanced research areas, specifically, instrumentation and diagnosis, and bioprocessing of coal. For the purposes of the present discussion, the nonresearch portion of the AR&TD program will not be considered, and corresponding budget data are not included in Tables 28 and 29.

Table 28 presents the funding history of advanced research programs on coal since 1988. The 1995 budget request represents the DOE and administration proposal to Congress. When these budget numbers are expressed in constant dollars, it can be seen that there was a decrease of approximately 30% in the advanced research budget between FY 1988 and FY 1994, with an additional decrease of approximately 25% from the FY 1994 level proposed for FY 1995.

A more detailed comparison between the FY 1994 enacted appropriation and the 1995 congressional request is shown in Table 29, which also shows in more detail the advanced research activities funded
under AR&TD and AR&ET. Major budget reductions are proposed in FY 1995 for the programs in materials (25%), components (50%), and, most notably, coal liquefaction (85%). It is proposed that the FY 1994 budget of $5.2 million for coal liquefaction be reduced to $0.8 million in FY 1995.

9.2. The Role of Advanced Research

9.2.1. DOE perspective

A perspective on the mission, vision, and goals of the FE advanced research activities is provided in a recent document from DOE. The role of advanced research within the FE program is to stimulate, nurture, and advance critical enabling science and technologies for fossil energy systems. A series of advanced research goals, strategies, and success indicators have been selected to support relevant DOE business lines and the core Office of FE business lines of clean fuel systems and clean/efficient power systems (see Section 2) and to directly reflect customer and stakeholder expectations. The goals are as follows:

1. Provide the core competencies in the critical enabling science and technologies that enable the Office of FE business lines to succeed in their missions.
2. Through feasibility testing, identify and nurture innovative concepts for advancing the technology and removing barriers to achieving the Office of FE's business line goals.
3. Provide the fundamental data, information, materials, and tools required by the U.S. fossil energy industry to bring advanced fossil energy systems to commercial fruition.
4. Improve the environmental performance of fossil energy systems by performing research that significantly increases system efficiencies, provides advanced environmental control systems, and shifts from waste management to pollution prevention/waste minimization.

9.2.2. The committee's perspective

Based on its analysis of likely future trends in coal use and ongoing DOE coal programs, the committee observed that the use of coal for power generation is confronting an increasingly demanding set of requirements. Following many years of gradual improvement of pulverized-coal-steam turbine baseload power systems, with limited add-ons for emissions control, there is a need for greatly enhanced technology for emission control, for improved efficiency, and for improvements in the overall economics of power generation. Similarly, during the time periods considered in this study it is probable that liquid and gaseous fuels manufactured from coal will be needed. Improvements in the cost and efficiency of manufacturing processes will depend on further advances in the chemistry and engineering related to coal use.

In light of the continuing needs for advances beyond the 2010 targets defined for the power systems and fuels programs (Section 2) and the goals defined in DOE's Strategic Plan, the committee identified a critical role for DOE advanced research programs on coal. Such programs have the potential to exploit the extensive opportunities for improved coal technology while compensating for the decline in industrial and non-DOE government support for long-range research on coal. The optimum role for DOE differs from one advanced research area to another but is largely determined by technology needs and their degree of specificity to coal-based systems and by complementary research activities in industry and government organizations outside DOE. The following discussions of some major research areas address opportunities for DOE advanced research programs to contribute to the development of coal technologies. The research areas discussed are combustion and gasification, coal conversion and catalysis, and materials.

9.3. Combustion and Gasification

Research on oxidation of fuels to provide useful energy with acceptable emissions is the subject of a large international activity. Much current work relates to gas-phase reactions and to soot formation and oxidation (see, for example, The Combustion Institute). However, coal combustion research falls outside these areas because of the large amount of char formed by the pyrolysis step and because of the ash content of coal. Problems directly related to coal—such as emissions, waste products, and char oxidation efficiency—are receiving far less attention than problems relating to other fuels. Much of the recent advanced research on coal-related combustion issues, notably the interaction with coal ash and the final stages of oxidation, has been conducted in the United States, principally under DOE and, to a lesser extent, National Science Foundation sponsorship. The committee noted that, in the absence of research needs and funding from other sources, DOE support is important to achieve progress in quantitative understanding of coal-related combustion and gasification issues and to identify innovative concepts for further investigation.

While still a promising area for research, gas-phase chemistry of NOx formation and destruction and of the oxidation of carbon monoxide (CO) and hydrocarbons, has advanced to the point where simplified gas kinetic models can be used in conjunction with primitive turbulence modeling as a semiquantitative design and development tool for low-emission furnaces and gas turbine combustors. However, in the case of coal, the early release of gas-phase hydrogen cyanide introduces NOx production pathways not yet
quantitatively explored. Moreover, promising research opportunities still exist, including implementation of more sophisticated models. In contrast, the understanding and quantitative treatment of carbon kinetics, taking into account catalytic and physical interactions with ash and graphitization of carbon as the oxidation process proceeds, is at a relatively primitive stage. Since future innovations in coal gasifier and combustor design will depend, to a considerable extent, on quantitative understanding of the interaction between pyrolysis, carbon oxidation, and emissions, the committee noted that DOE's advanced research program for coal needs to address this issue.

The final stage of carbon oxidation is of special interest because of the observed reduction of reactivity at high conversion rates. The long reaction times and high temperatures required for high carbon conversion will increase thermal NOx formation in the presence of excess air. The interactions involved are complex, and improved quantitative understanding of the evolution of carbon reactivity and its interaction with the physical and catalytic properties of the coal ash is needed for choice of optimum levels of carbon oxidation.

Two major advanced research opportunities were identified by the committee as a basis for improving high-performance gasification systems. In low-temperature and countercurrent fixed-bed gasification processes, escape of fuel nitrogen as ammonia can occur, resulting in the formation of additional NOx on combustion if not removed. Quantitative treatment of this problem is needed for improvement of these processes. For low-temperature gasification processes where high carbon conversion is needed, catalysis of carbon gasification by ash constituents, such as calcium, or by added catalysts remains a promising area related to future advances in gasification efficiency.

9.4. Coal Conversion and Catalysts

The complexity of coal structure and chemistry has important implications for conversion technologies and catalysis. Coals are inhomogeneous on the macroscopic, microscopic and molecular levels. They are insoluble, opaque, macromolecular systems composed of a mixture of organic and inorganic constituents. While knowledge of coal's physical and chemical structures remains rudimentary, knowledge and understanding of coal reactivity are even more limited. Most of the available tools for determining chemical structure are designed to work with systems of pure compounds and either do not work when applied to coals or become much more complex in their application. The efficacy of solid catalysts when used with solid coals decreases very significantly compared to their effectiveness in fluid systems. Opportunities exist to develop entirely new catalysts that will contact coals and effect desired reactions. The committee identified a role for DOE in supporting advanced research on coal conversion and catalysis to ensure the cleanest and most efficient utilization of coal, consistent with the goals of the advanced fuels and power systems programs, and to compensate for the absence of significant industrial research in this field.

In reviewing current DOE coal advanced research programs, the committee particularly noted the decline in efforts devoted to coal liquefaction technology. Given the likely growth in importance of coal liquids in the mid and long term, as described in the committee's strategic planning scenarios (see Section 4), the committee identified coal liquefaction as an important area for advanced research within the DOE coal program. Industrial transformations of fossil fuels are catalytic, and the creation of new and improved catalysts and better reactors to use those catalysts has been a central thrust of fuel chemistry for almost a century. The use of catalytic chemistry with coals presents unique and difficult problems. Since coal is a solid, it cannot move around into contact with a catalyst surface. Thus, the use of immobile solid catalysts typical of oil and gas processing is not possible with coal. It is necessary either to render the coal fluid, to use catalysts of extraordinarily high dispersion, or to use catalysts that are themselves mobile fluids. All three approaches have been used with some success, and there has been a fairly continuous improvement in catalysts used. Further enhancements can be anticipated based on a mix of applied and fundamental studies on topics such as highly dispersed catalysts, diffusion in coals and coal-catalyst contacting, and effective mobile catalysts. Both lower-temperature catalysts and more selective chemistries have the potential to reduce costs.

Research opportunities can be conveniently divided into two major categories: improvements in current processing chemistry and technology, and liquefaction processes based on new chemistries. Possible improvements in chemistry and technology (see also Section 6) include:

- Low-pressure reaction at 2.17 MPa (300 psig) or less.
- Use of low-cost subbituminous coal or lignite, especially deposits having high hydrogen-to-carbon ratios.
- Removal of coal oxygen as carbon dioxide.
- Complete conversion to liquids with boiling points below 540°C (1000°F).
- Improved selectivity to minimize production of hydrogen, water, and hydrocarbon gases.
- Coproduction of high-value chemical and other nonfuel products.
- Direct use of gas from IGCC systems equipped with hot gas cleanup for F-T synthesis and to produce hydrogen for direct liquefaction.

For direct liquefaction, existing processes require cold gas cleanup, shifting to convert carbon monoxide
and water to hydrogen and CO₂, and scrubbing to remove CO₂. There would be significant energy and capital cost savings if the hot gasesfier gas could be used without cooling and further processing. Water/gas shift activity in the catalyst system used would be desirable; however, currently available catalysts are not sufficiently sulfur resistant. The use of hot gasifier product for F-T synthesis would require new catalysts capable of carrying out the reaction in the presence of the sulfur concentrations and traces of heavy metals remaining after hot gas cleanup. More active or selective sulfur-tolerant catalysts could markedly improve both direct liquefaction and the upgrading of coal liquids.

Alternative process chemistries of potential interest include: coprocessing based on alkylation or transalkylation chemistry rather than hydrogenation; oxidative depolymerization to oxygenate fuels; and new depolymerization chemistry followed by fixed-bed catalytic upgrading.

The DOE AR&T&D budget for bioprocessing of coal was $1.9 million in FY 1994, and the same funding has been proposed for FY 1995. The main thrusts of the bioprocessing program in recent years have been to explore and apply recent advances in biotechnology to convert coal to liquid fuels and to improve the environmental acceptability of advanced power systems. Activities have included characterization of the metabolic features of bacteria found to remove organic sulfur, mineral matter, and metals from coal and investigation of mechanisms for bioconversion of coal. Most experts in the field now agree that biotechnology is best suited for the manufacture of high-value-added products and is least well suited for the production of very large amounts of low-value-added materials, as in the case of coal processing. Thus, current and proposed future DOE coal program efforts in biotechnology will focus on cleanup of sulfur- and nitrogen-containing compounds in combustion gases, rather than on coal desulfurization and demineralization. The committee notes that, although there are possible opportunities for biological cleanup of flue gas (NOₓ and SO₂ removal), significant technological difficulties remain because of the relatively long processing times and large volumes of gas to be treated.

9.5. Materials

9.5.1. General comments

R&D aimed at developing high-performance materials designed to operate in hostile environments is a very large and active area of endeavor worldwide. Given the limited resources of DOE's coal advanced research program in materials, the committee identified a need for this program to focus on key materials development issues for coal-based technologies while leveraging more generic materials developments from other programs.

The preceding review of DOE's coal R&D programs, given in Sections 5 through 7, has been used by the committee as a basis for identifying opportunities in materials research specific to coal-based technologies. Three areas have been selected for emphasis and are discussed below: advanced gas turbines; high-temperature, high-pressure heat exchangers; and inorganic membranes. The present discussion is not intended to provide an exhaustive list of materials research opportunities relevant to the coal program but rather to highlight key materials-based enabling technologies critical to the success of DOE programs in advanced clean fuels and advanced power systems.

9.5.2. Advanced gas turbines

Many of the advanced coal-based power generation technologies currently being developed incorporate gas turbines (e.g., IGCC, advanced PFBC, direct coal-fired gas turbines, and IFC [indirectly fired cycles]). Thus, gas turbines constitute a key component in advanced coal-based power generation technologies.

The ATS (advanced turbine systems) program, funded under the natural gas component of the FE R&D program budget, aims to develop advanced land-based turbines for natural gas systems but adaptable to coal- or biomass-derived fuels. The systems efficiency target using natural gas is greater than 60% based on lower heating value (approximately 55% HHV equivalent). Many generic materials issues,* such as increased temperature capability and extended operating lifetime, are being addressed in the ATS program by DOE and industry participants, and related developments for natural-gas-fired turbines should be broadly applicable to turbines using coal-derived fuels. The committee recommends that activities in the FE coal R&D program focus on materials issues specific to the use of coal-derived fuels in advanced turbines.

All attempts to-date to direct fire gas turbines with coal have resulted in significant ash deposition and corrosion of hot gas path components as a result of the aggressive chemical nature of the products of coal combustion. The development of turbine materials capable of surviving the hostile environment of direct coal-fired systems represents a major challenge. In the case of gasification-based systems, the environmental constraints imposed on the turbine materials are less demanding than in the case of direct coal firing but more severe than in a natural-gas-fired system. Coal gasification produces a raw syngas consisting mainly of carbon monoxide and hydrogen but with substantial quantities of CO₂ and water;

*See NRC [17] for an assessment of materials needs for large land-based gas turbines.
Coal: Energy for the future

minor quantities of hydrogen sulfide, ammonia, and hydrogen chloride; and a few parts per million of alkali metals.\textsuperscript{117} While unprocessed natural gas can contain large amounts of hydrogen sulfide, pipeline natural gas contains no hydrogen sulfide and a sulfur weight fraction of only 0.000007.\textsuperscript{118}

The major issue associated with the use of coal-derived gas in advanced turbines is the effect of contaminants, notably sulfur and alkali metals, on turbine performance (operating temperature and lifetime). Possible penalties in the overall efficiency of gasification-based systems can be anticipated based on the need to operate at lower temperatures to reduce the corrosive effects of contaminants in the coal-derived gas. Corrosion is also likely to severely reduce the lifetime of the turbine components. The ability of hot gas cleanup systems to reduce contaminants to levels acceptable for high-temperature advanced turbines has not yet been demonstrated. Reverting to cold gas cleanup would involve an efficiency penalty of one to three percentage points.

From a materials perspective, the critical issue for coal gas-fired systems is the extent to which corrosion-resistant turbine blade materials and coatings can increase the environmental tolerance of advanced turbines, thereby reducing (or eliminating) the need for gas cleanup and possible associated efficiency penalties. Allowable levels of contaminants depend on engine design and turbine pressures and temperatures, but the corrosion problem is likely to be the most severe for the first-stage blades that are exposed to the highest temperatures and the full concentration of impurities in the gas stream.\textsuperscript{119}

Given the increased likelihood of environmental attack, evaluation of candidate material systems for coal-fueled turbine systems is necessary, with an accompanying search for better materials. The superalloys currently used for turbine blades are generally protected from high-temperature oxidation and corrosion attack by a variety of coatings. Formation on the coating surface of reaction products—specifically, adherent alumina or chromia scales—retards subsequent reaction between the coating and the environment. A recent review of high-temperature coatings for combustion turbine blades\textsuperscript{119} addresses coating requirements for protection from different types of environmental attack. Since fuel type is probably the most important variable influencing the choice of a coating, the use of gas derived from coal gasification is likely to have a significant impact on the choice of turbine blade coatings. The complex chemical reactions that occur at high temperatures, and the susceptibility of these reactions to small chemical changes in the coating and gaseous environment, suggest that significant effort will be necessary to develop and evaluate coatings for turbines used in coal gasification-based power systems. There are a large number of commercial coatings available, and a number of different application methods that influence the coating behavior, but there is no one coating that is resistant to all types of high-temperature attack. It has been suggested that in systems using coal-derived fuel, coatings on advanced superalloys and the alloys themselves will need to form chromia rather than alumina scales for increased corrosion resistance.\textsuperscript{120} In the case of the substrate (blade) materials, this constraint may limit the availability of suitable high-strength alloys.

Recently, the use of thermal barrier coatings (TBCs) has proven extremely useful in extending the temperature capabilities of existing superalloys. TBCs are ceramic coatings applied over metal substrates to insulate them from high temperatures. They consist of a layer of stabilized zirconium oxide that is 0.12–0.38 mm (0.005–0.015 inches) thick applied over a bond coat composed of an oxidation-resistant metal coating. Although TBCs themselves are expected to be only minimally corroded by the more aggressive environment in coal-fueled turbines, both the substrate and the bond coat may be adversely affected.

The development of alternative turbine materials with higher-temperature capability than existing superalloys—notably monolithic ceramics and ceramic matrix composites—is being addressed in the ATS program. The potential improvements in high-temperature corrosion resistance of ceramic materials compared to state-of-the-art superalloys is of interest for turbines using coal-derived fuels.

9.5.3. Heat exchangers

In terms of materials behavior, the critical requirements for the ceramic heat exchanger for EFCC power generation systems (see Section 7) are:

- To maximize operating temperatures for the proposed duty cycle, notably combinations of high temperature and pressure.
- To resist fouling and alkali corrosion, with emphasis on the latter for low-rank coals.
- To avoid catastrophic failure.

Although advanced ceramics offer excellent high-temperature properties, such as high strength, corrosion and erosion resistance, and refractoriness, they are subject to brittle fracture due to critical flaws. High-velocity fragments from a failed ceramic tube have the potential to initiate rapid sequential failure of the array of ceramic tubes in the heat exchanger. The current proprietary tube design permits 'graceful' rather than catastrophic failure.

Advanced structural ceramics with increased temperature capability and improved toughness are under development in a number of government/industry programs, including the ATS program (see above), the Integrated High-Performance Turbine Energy Technology program, including the U.S. Air Force, Navy, Army, Advanced Research Projects Agency, and the National Aeronautics and Space...
Administration (NASA), and the NASA Enabling Propulsion Materials program. Materials developed in these and other programs for high-temperature gas turbine applications may offer the higher operating temperatures and improved brittle fracture characteristics required for the ceramic heat exchanger in EFCC power generation systems. Since the proposed ceramic heat exchanger involves no moving parts, it is significantly less susceptible to deterioration from ash deposition or corrosion than are rotating components in the gas path of a turbine. However, the ash deposition and corrosion problems encountered using pulverized coal and the high-pressure cycles encountered in EFCC applications are unlikely to be addressed in materials development programs that are not targeted at coal-based technologies. In the view of the committee, the DOE coal materials program should focus on such issues specific to coal-based systems.

Current materials development and testing of the ceramic heat exchanger for EFCC systems is being conducted by Hague International. Activities are focusing on pressure and environmental testing. Over 2 million hours of successful operation of low-pressure ceramic heat exchanger units in corrosive high-temperature industrial environments has already been demonstrated. A series of tests is planned to demonstrate that a complete ceramic heat exchanger can contain pressures up to 1.21 MPa (175 psia), endure at least 100 hours of operation under static and dynamic loadings, and meet thermal performance requirements. During these tests, the combustor will be fired with natural gas for operational simplicity. Subsequent testing with a coal-fired combustor will verify the ability of the slag screen to protect the ceramic heat exchanger from coal ash.

Ceramic materials demonstrate superior corrosion resistance compared to conventional metals and superalloys but can be severely degraded by alkali metals in coal combustion products. In particular, nonoxide ceramics such as silicon carbide (SiC) corrode in an oxidizing environment. The corrosion process is affected by the material processing technique, grain size, and impurity content. Hague International has conducted a series of corrosion tests on 46-cm (18-inch) long, 2.5-cm (1-inch) diameter tubular coupons of candidate heat exchanger materials, notably, an alumina matrix composite, reaction-bonded SiC, mullite (orthorhombic aluminum silicate, \( \text{Al}_2\text{Si}_2\text{O}_5 \)), and monolithic alumina (\( \text{Al}_2\text{O}_3 \)). Preliminary results indicate that mullite shows the highest temperature capability and good corrosion resistance. After 300 hours at 1090°C (2000°F) with brief excursions to 1480°C (2700°F), little corrosion was observed.

Despite performance enhancements in advanced ceramics, a temperature limit of approximately 1090°C (2000°F) currently exists for ceramic heat exchanger materials. A report published in the late 1980s noted that federal government support has been necessary to accelerate development of the ceramic materials and system technology for heat exchangers, despite projected economic and performance advantages. Material manufacturers and end users have considered the technical risks too high to invest their own funds in systems development and implementation.

### 9.5.4. Membranes

Membranes play a key role in the production of fossil-fuel-based products that meet composition standards for engine and combustor performance and provide environmental compliance through the removal of pollutant molecules. Possible applications of membranes to coal-based systems include the separation of hydrogen from coal gas streams and of impurities such as hydrogen sulfide (H\(_2\)S), ammonia (NH\(_3\)), SO\(_2\), NO\(_x\), and trace metal compounds from coal conversion (e.g., gasification) and combustion (flue gas) streams. Such separations can account for a major fraction of the investment and operating cost for coal-based systems. A particularly important application for advanced clean/efficient power systems is the cleanup of coal gasification streams to drive advanced turbines. As discussed above, the ability of hot gas cleanup systems to reduce the contaminants to levels acceptable for high-temperature advanced turbines remains to be demonstrated. Another possible application of membranes is for the separation of methane from very dilute coalbed methane streams (see Section 5).

Low-temperature polymer membrane technology is fairly well developed and is useful for liquid-liquid, liquid-gas, and gas-gas separations. However, polymer membranes are limited to relatively low temperatures (less than 250°C [480°F]) and are subject to chemical and abrasive attack, particularly in the aggressive environments encountered in coal-based systems. Inorganic (ceramic) membranes have the potential to operate at the high temperatures required for advanced power generation systems (e.g., 815°C [1500°F] for removal of hot gas particulates from advanced PFBC and IGCC systems) and to provide significantly enhanced corrosion and erosion resistance compared to polymer membranes. Other expected advantages of advanced inorganic membranes include high permeability (1000–10,000 times organic membrane permeability) and high selectivity.

In materials terms, refractory behavior and resistance to environmental attack depend on a suitable choice of ceramic material and associated fabrication process. Possible problems can be anticipated in coal-based systems due to reaction of candidate ceramic membrane materials—such as alumina, zirconia, and silica—with gas stream components, notably SO\(_2\) and alkali metals, at temperatures in the range of 540–1090°C (1000–2000°F). The presence of steam is likely to accelerate the degradation process.
Requirements for high separation efficiency impose further materials constraints in terms of pore size distribution and mean pore size in the membrane. A high degree of control during membrane fabrication is necessary to achieve the desired microstructural features. Ceramic membranes consist of a porous support a few millimeters thick, a porous intermediate layer 10–100μm thick with pore diameters in the range of 0.05–0.5μm,* and the separation layer with a thickness of 1–5μm.126 Generally, the separation layer must have pore diameters less than 10 nm for effective separation of gaseous components by diffusion;127 in some cases a mean pore size of 2.5 nm may be necessary.†

Current commercially available membranes do not meet all performance requirements for cleanup of coal-gas and flue gas streams, although several manufacturers produce inorganic membranes for micro- and ultrafiltration applications, and some of these have pore diameters less than 10 nm and are capable of separating gaseous components. However, extensive membrane technology has been developed over the past 40 years for nuclear gaseous diffusion applications, and alumina and zirconia membranes have been used for the separation of uranium hexafluoride (UF₆) isotopes for the nuclear industry since 1950.127 Current DOE programs to develop ceramic membranes for coal-based applications are attempting to leverage this existing knowledge base. Investigators at the Oak Ridge Gaseous Diffusion Plant have produced alumina (ceramic) membranes with pore radii as small as 70 nm. Membrane separation tests have demonstrated a capability to separate hydrogen from gas mixtures.124

Membrane material research opportunities specific to coal-based systems involve primarily the development of inorganic membranes for separation of coal-derived products and impurities at elevated temperature and in corrosive environments. Improvements can be anticipated in the selectivity and separation efficiency based on enhanced understanding of the relationship between pore structure and the physical chemistry of molecular separations.32 Opportunities also exist for the development of membranes with improved resistance to the environments characteristic of coal-based systems, such that operating lifetimes can be extended. Given the likely increase in concerns over greenhouse gas emissions, the investigation and demonstration of cost-effective separation of methane from very dilute coalbed methane streams using membrane techniques also merit some attention.

9.6. Summary

Future innovations in coal gasifier and combustor design will depend largely on an improved quantitative understanding of the interactions between coal ash, carbon oxidation, and emissions. The committee identified this topic as being of importance for DOE’s coal-related advanced research activities, given its relevance to improved coal-based systems for power generation and fuel production.

Advanced research on coal liquefaction has the potential to achieve significant cost savings, either through improvements in current processing chemistry and technology or through processes based on new chemistries. There is currently very little industrial research on coal liquefaction; most activities are funded by DOE.

The operating environment in a coal-gas-fired turbine is more corrosive than that in a natural-gas-fired turbine, due primarily to the presence of sulfur and alkali metals. Evaluation of existing and emerging turbine material systems is needed to determine their suitability for advanced coal gasification-based power generation systems. This evaluation will require appropriate test rigs and methods for accelerated long-term testing in corrosive environments. Subsequent materials development will likely be necessary to optimize substrate and coating materials. The need for improved corrosion-resistant turbine materials is dependent on the ability of hot gas cleanup systems to reduce contaminant levels in coal-derived gas to acceptable levels for advanced gas turbines. The more successful the hot gas cleanup, the less demanding are the materials requirements, and vice versa.

The performance of high-temperature, high-pressure heat exchangers for EFCC power generation systems is currently limited by the properties of available materials. In particular, the maximum operating temperature of approximately 1090°C (2000°F) would not provide efficiencies significantly higher than state-of-the-art pulverized coal systems. The corrosive environment resulting from coal combustion imposes additional severe demands on materials. The ability to reach operating temperatures of 1370–1425°C (2500–2600°F)—corresponding to the inlet temperatures of future advanced gas turbines—represents a major materials challenge and is far from the current state of the art.

Inorganic membranes with high separation efficiencies and long-term resistance to high-temperature corrosive environments have the potential to improve the economics of power generation from coal, particularly for systems using advanced turbines. Materials development is required to improve the separation efficiency of ceramic membranes used for hot gas and flue gas cleanup. Improvements in durability at elevated temperatures in corrosive environments are also needed. Additional research opportunities exist to investigate membrane separation of methane from very dilute coalbed methane streams.

*1 μm = 10⁻⁶m.
†1 nm = 10⁻⁸m.
10. Strategic Planning for Coal

In Section 4 a strategic planning framework was established to assess planning for coal-related RDD&C. The framework is based on projected scenarios for future energy demand and markets for coal technologies, taking into account likely future environmental requirements, competing energy sources, institutional issues, international activities, and other factors affecting the demand for coal. The overall objective of DOE’s coal program should be to provide the basis for technological solutions to likely future demands, as reflected in the scenarios. Three planning horizons—near-term (1995–2005), mid-term (2006–2020), and long-term (2021–2040) periods were identified for which scenarios were formulated and requirements for coal outlined. Analysis of these scenarios indicated that coal will continue to be a major energy source in the U.S. economy over all three planning horizons. Thus a sustained program of RDD&C for coal technologies is important for the economic, environmental, and security interests of the United States.

The strategic planning framework identified two priority areas for the DOE coal program: (1) conversion of coal to electricity, representing the principal market for coal for all planning periods, (2) conversion of coal to liquid and low- and medium-Btu gaseous fuels, in the mid to long term. EPACT requirements for coal use emphasize the need for high efficiency, low environmental impacts, and competitive costs. These needs are generally consistent with DOE’s objectives for coal RDD&C, as defined in the most recent planning documents. The DOE planning horizon, however, currently extends only to 2010. Specific objectives have been formulated for that period for advanced power systems and advanced fuel systems. These objectives are discussed below in the sections on electric power generation and clean fuels from coal.

10.2. Coal Preparation, Coal–Liquid Mixtures, and Coalbed Methane Recovery

Coal preparation—or cleaning—is a widely used commercial process for removing mineral matter from as-mined coal to produce a higher-quality product. Current physical cleaning processes are used primarily to reduce the ash content of as-delivered coal, although some sulfur reduction (typically 20–30%) is also achievable in coals with high pyrite content. Because coal is an abundant and relatively low cost fuel, the incremental cost of coal cleaning is a major factor limiting the degree of impurity reductions that are economically feasible.

DOE research in recent years has focused on advanced processes to clean fine coal fractions to achieve a relatively low-ash, low-sulfur product suitable primarily for premium applications, such as the production of coal–liquid mixtures that can be substituted for petroleum-based fuels. More recently, attention has also focused on the potential for coal cleaning to remove trace species as a means of reducing power plant emissions of air toxics. A series of RD&D goals has been defined.

Coal–liquid mixtures or slurries—primarily coal–oil and coal–water fuels—are another commercial technology that allows coal to be substituted for liquid fuels in combustion applications. R&D in this area peaked during the late 1970s and early 1980s when oil prices were high and coal-based substitutes were attractive. Commercial interest waned, however, as oil prices declined and oil price projections remained stable. Nonetheless, DOE has continued to fund basic and applied research related to CWSs (coal–water slurries), primarily at universities.

Finally, interest in recovery of coalbed methane has been stimulated by concern about greenhouse gases and EPACT requirements. Methane recovery technology for high methane concentrations is commercially available, and recovery is practiced by the gas and coal mining industries where local conditions justify the investment. However, systems for the capture and use of dilute coalbed methane streams, which are found in many coal mining operations, are not sufficiently mature for commercial implementation. As noted in Section 3, increased efforts will likely be needed to reduce coalbed methane released from underground mining, in accordance with the Climate Change Action Plan. The research challenge is to economically recover coalbed methane from very dilute gas streams.

10.2.1. Conclusions

1. Coal preparation is a highly developed, commercially available technology that is widely used in the coal industry. However, only limited opportunities exist for R&D to significantly lower the cost of advanced coal preparation processes. Continued research with extensive industry participation should achieve further improvements in existing and emerging technologies.

2. There may be opportunities through sustained fundamental research on cleaning processes to improve the environmental acceptability of coal.

3. Given the mature status of technologies for the production and use of coal–liquid mixtures and the very limited market for these mixtures, no further development by DOE appears necessary.

4. Although the collection and use of concentrated coalbed methane streams are not widely practiced in the coal mining industry, relevant technologies are available for commercial application.

5. Additional reductions in emissions of coalbed methane could be achieved through the development
<table>
<thead>
<tr>
<th>Technology (target year for commercial design)</th>
<th>Design efficiency (%)</th>
<th>Coal conversion components</th>
<th>Power generation components</th>
<th>Particulate control system</th>
<th>SO₂ control system</th>
<th>NOₓ control system</th>
</tr>
</thead>
<tbody>
<tr>
<td>New pulverized coal (commercial baseline)</td>
<td>38-42</td>
<td>Supercritical boiler</td>
<td>3500 to 4500 psi steam turbine</td>
<td>ESP or fabric filter</td>
<td>Wet lime or limestone FGD</td>
<td>Low NOₓ burners + SCR</td>
</tr>
<tr>
<td>Group 1 systems</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LEBS (2000)</td>
<td>42</td>
<td>Supercritical boiler</td>
<td>4500 psi steam turbine</td>
<td>Cyclones + fabric filter</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PFBC-1 (2003)</td>
<td>~40</td>
<td>Bubbling and circulating bed PFBC units</td>
<td>1800 psi steam turbine + gas turbine</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IGCC-1 (1977)</td>
<td>~40</td>
<td>O₂-blow entrained-bed gasifiers</td>
<td>2350°F gas turbine + HRSG/turbine</td>
<td>Cold gas quenching</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Group 2 systems</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EFCC (1977)</td>
<td>45</td>
<td>Slagging combustor + 2300°F heat exchanger</td>
<td>2350°F gas turbine + HRSG/turbine</td>
<td>Fabric filter</td>
<td>Wet FGD</td>
<td></td>
</tr>
<tr>
<td>PFBC-2 (2005)</td>
<td>45</td>
<td>Circulating PFBC + coal pyrolyzer</td>
<td>2350°F gas turbine + 2400 psi steam turbine</td>
<td>Hot gas filtration</td>
<td>In-bed limestone or dolomite</td>
<td>Combustion controls (+ SCR if needed)</td>
</tr>
<tr>
<td>IGCC-2 (2002)</td>
<td>45</td>
<td>Oxygen- or air-blown fluidized-bed gasifier</td>
<td>2350°F or 2500 +°F gas turbine + HRSG/turbine</td>
<td>Hot gas filtration</td>
<td>Hot gas desulfurization + in-bed limestone (optional)</td>
<td>Combustion controls (+ SCR if needed)</td>
</tr>
<tr>
<td>Group 3 systems</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HIPPS (2003)</td>
<td>50</td>
<td>High-temperature advanced furnace</td>
<td>2500°F gas turbine + HRSG/turbine (+ auxiliary fuel if needed)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Improved PFBC-2 (2010)</td>
<td>≥50</td>
<td>Circulating PFBC + coal pyrolyzer</td>
<td>2600°F turbine + 4500 psi steam turbine</td>
<td>Hot gas filtration</td>
<td>In-bed limestone or dolomite</td>
<td>Combustion controls (+ SCR if needed)</td>
</tr>
<tr>
<td>IGAC (2010)</td>
<td>≥50</td>
<td>Oxygen- or air-blown fluidized-bed gasifier</td>
<td>2600°F gas turbine (humidified)</td>
<td>Hot gas filtration</td>
<td>Hot gas desulfurization + in-bed limestone (optional)</td>
<td>Combustion controls (+ SCR if needed)</td>
</tr>
<tr>
<td>IGFC (2010)</td>
<td>≥60</td>
<td>Oxygen- or air-blown fluidized-bed gasifier</td>
<td>Molten carbonate fuel cell (1200°F) + HRSG/turbine</td>
<td>Hot gas filtration</td>
<td>Hot gas desulfurization + in-bed limestone (optional)</td>
<td>Combustion controls (+ SCR if needed)</td>
</tr>
</tbody>
</table>

*Final system not yet selected.
HRSG, heat recovery steam generator.
ESP, electrostatic precipitator.
FGD, flue gas desulfurization.
SCR, selective catalytic reduction.
Table 31. Strategic objectives of the DOE Advanced Power Systems program

<table>
<thead>
<tr>
<th>Objective</th>
<th>2000</th>
<th>2005</th>
<th>2010</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Efficiency (%)</td>
<td>42</td>
<td>47</td>
<td>55</td>
<td>60</td>
</tr>
<tr>
<td>Emissions (NSPS)*</td>
<td>1/3</td>
<td>1/4</td>
<td>1/10</td>
<td>1/10</td>
</tr>
<tr>
<td>Cost of energy</td>
<td>10–20% lower than currently available pulverized coal technology</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*NSPS. New Source Performance Standards. Current federal standards apply to emissions of sulfur dioxide, oxides of nitrogen, and particulates from coal-based steam generators.

Source: DOE.²

of technologies for the capture and use, or destruction, of dilute coalbed methane streams.

10.3. Electric Power Generation

10.3.1. Power generation systems

The availability of high-performance gas turbines and low-cost natural gas has resulted in the use of natural-gas-fired combustion turbines for many recently installed power generation facilities. In the next decade and beyond, decreasing availability and higher costs for natural gas are expected to result in a resurgence of construction and repowering of coal-based power generation facilities, with requirements for greatly improved emission controls and higher efficiency. Substantial improvements over past practices are technically possible. A large fraction of DOE RDD&C on power generation is devoted to systems designed to meet anticipated emission control and efficiency requirements.

The advanced coal-based power generation systems under development with DOE funding can be divided into three groups based on projected efficiency:

Group 1—approximately 40% efficiency—includes the low-emission boiler system (LEBS), first-generation PFBC (PFBC-1), and first-generation IGCC (IGCC-1).

Group 2—approximately 45% efficiency—includes EFCC, second-generation PFBC (PFBC-2), and second-generation IGCC (IGCC-2).

Group 3—50–60% or greater efficiency—includes HCPPS, improved second-generation PFBC (improved PFBC-2), integrated gasification advanced-cycle (IGAC), and IGFC.

Important features of these systems are summarized in Table 30. Information on state-of-the-art commercialized pulverized coal systems is included in the table as a baseline. Current DOE funding levels for these various technologies were summarized in Sections 2 and 7.

10.3.1.1. Efficiency and cost targets. As shown in Table 30, DOE’s efficiency goals for advanced power systems rise to 60% for the year 2010 (best current new plant levels are about 38% for the United States and 42% worldwide). In the DOE plan the highest efficiencies are expected to be achieved with IGFC technology.² A number of other systems are projected to achieve efficiencies of 45–55% using advanced combustion and gasification-based approaches and high-performance gas turbines. A major objective of the DOE plan is to achieve these higher efficiencies at an overall cost of electricity that is 10–20% lower than that of today’s coal-fired power plants while also meeting more stringent environmental requirements (see Table 31).

The DOE efficiency goals, especially for the later years, appear quite optimistic. For example, the efficiency goals of 55% for systems using 1290°C (2350°F) gas turbine topping cycles exceed the performance capabilities of about 50% efficiency for current combined-cycle systems using natural gas. While turbine improvements are expected to raise the efficiency on natural gas to about 57% (see Section 7), coal gasification and gas cleanup energy losses will decrease efficiency by five–ten efficiency points when using the gasification systems being demonstrated in the CCT program (see Section 6). Thus, substantial reduction of gasification-related losses is needed to achieve the DOE target system efficiency with IGCC. The hybrid second-generation pressurized fluidized-bed combustion system, which gasifies only part of the coal, is estimated to have a potential for approximately four percentage points higher efficiency than IGCC systems where all the coal is gasified.⁸³ Conceivably, this system could achieve the DOE efficiency goal; however, substantial technical hurdles remain to be overcome. Similar comments apply to the 60% efficiency goal for IGFC systems.

The goal of 10–20% reduction in the cost of power, concurrent with significant efficiency increases and emissions reductions, may be especially difficult to realize. For example, roughly 30% of the cost of electricity today for a new coal-fired plant represents the cost of fuel.⁴⁶ Thus, reducing fuel requirements by one-third by raising plant efficiency from about 40–60% would lower the overall electricity cost by about 10%, which is DOE’s minimum cost reduction objective. A smaller efficiency gain would yield still smaller cost savings. These estimates assume that the nonfuel costs—principally the initial capital cost—remain constant. DOE targets show lower capital costs for advanced technologies than current commercial systems. While projections of the cost and performance of new technologies are subject to great uncertainty.¹²³

A more realistic cost goal for the DOE advanced power systems program might be to achieve efficiency improvements at an overall electricity cost comparable to that for new coal plants today. For the future U.S. market, some cost premium could even be acceptable if justified by the improved envi-
vironmental performance and reduced externality costs associated with advanced technologies. Indeed, future environmental regulations may well require such higher performance, creating new incentives for investment in higher-efficiency systems. To be competitive overseas, advanced technologies would require the lowest possible capital costs consistent with the environmental and other requirements of specific foreign markets. In short, despite DOE's current planning estimates, it remains to be seen whether high performance and smaller investment costs are in fact compatible objectives.

10.3.1.2. Group 1 systems. Assuming that Group 1 performance and cost objectives can be met, the market for Group 1 technologies will probably be limited to installations where there is no economic penalty for carbon dioxide (CO₂) emissions. Although the baseline scenarios assume no such penalties for the near term (1995–2005), it envisions new regulations or penalties aimed at forcing CO₂ reductions during the mid-term period (2006–2020). Technologies in Group 1, with their limited efficiency improvements over existing plants, would then be at a disadvantage relative to the newer Group 2 systems emerging in the mid-term period. The 'less demanding' scenario discussed in Section 4 assumes that economic penalties on CO₂ emissions might not be imposed for the foreseeable future. This might well be the case in developing countries such as China, and Group 1 technologies might therefore be of potential export interest.

10.3.1.3. Group 2 and 3 systems. Technologies in Groups 2 and 3 have greater potential to meet further power generation efficiency and associated environmental requirements: all technologies in these two groups make use of advanced components to achieve higher efficiencies and lower emissions. Major questions of system integration and reliability will need to be addressed, and early pioneer installations could serve as a basis for improved systems.

The riskiest components appear to be the high-temperature heat exchanger and furnace required for the indirectly fired systems, and the hot gas cleanup systems for the advanced PFBC and gasification-based systems. It is not established that high-temperature gas turbines can tolerate the chlorine and alkali metals that may be present with hot gas cleanup in PFBC or products in the gasifier products of IGCC systems. Although hot gas cleanup is a component of advanced IGCC systems, cold gas cleanup could still allow the technology to succeed, if at a lower efficiency. In this sense, IGCC is a somewhat less risky technology than PFBC.

The 1370–1425°C (2500–2600°F) gas turbine required for Group 3 systems is within the state of the art for aviation systems but is still under development for electric power generation systems and will require demonstration and testing. The IGCC-2 and IGAC systems with an advanced gas turbine may not be significantly more expensive than first-generation systems if the turbine development effort is successful.

As noted previously, integrated gasification fuel cell systems offer the highest efficiencies and emission controls. Systems using molten carbonate or solid oxide fuel cells incorporate a steam bottoming cycle to maximize efficiency. Molten carbonate and solid oxide fuel cells operate at high temperatures (650°C [1200°F] and 980°C [1800°F], respectively). Since the maximum voltage produced by a fuel cell decreases with increasing temperature, the higher-temperature solid oxide fuel cell produces a smaller fraction of the total system power. However, the potentially lower cost of the solid oxide fuel cell provides an incentive for continued research on these systems. The potential market for fuel cell technologies is quite large, especially for distributed power generation. However, fuel cell systems may still not be cost competitive with gas turbine systems without environmental incentives for higher efficiencies.

Gas turbine and fuel cell activities are currently funded under the national gas portion of DOE's FE R&D program. However, gas turbines and fuel cells could be used with coal-derived gas, with the addition of gasification and gas cleanup facilities. The principal operating difference between natural gas and coal-derived fuel gas in these applications relates to the contaminants in coal-derived gas. Cold gas cleanup is capable of removing contaminants to a negligible level; however, there is an efficiency penalty of about two percentage points, along with the production of liquid waste streams that must be treated, adding to system complexity and cost. Hot gas cleanup is potentially more efficient but at the expense of less complete removal of contaminants, especially volatilized species that are not captured in current hot gas cleanup designs.

The requirements for cleanup of coal-derived fuel gas are expected to differ for fuel cell and gas turbine systems. System optimization will be required and needs to be established as part of the DOE coal program. For the molten carbonate fuel cell, ammonia, hydrogen sulfide, chlorine compounds, trace metals, and particulates would interact with the electrodes and with the carbonate electrolyte, necessitating electrolyte replacement and disposal of resulting watersoluble solid waste. For high-temperature gas turbines, damage to the blades is of greatest concern (see Section 9). Degradation caused by contaminants would limit maximum turbine inlet temperature, thereby limiting attainable system efficiency.

Thus, for fuel cell systems, the major development challenge is to reduce both fuel-cell costs and balance-of-plant costs. For gas turbines, the major goal is to maximize turbine inlet temperature. Increasing turbine inlet temperature from the current maximum of 1290°C (2350°F), beyond the 1370–1425°C (2500–2600°F) proposed for integrated gasification advanced-cycle systems, to the 1540–1650°C (2800–3000°F) used in high-performance
turbines would bring system efficiencies to a level approaching that expected for molten carbonate fuel cells. These major development goals for fuel cells and gas turbines apply to systems fueled with either natural gas of coal-generated gas. No special considerations for coal-derived fuel gas appear necessary at this time, beyond those described above for the coal program.

To use coal, both fuel cell and gas turbine systems depend on coal gasification technology; both can accept methane and light hydrocarbons in the fuel gas. As discussed in Section 6, coal gasification results in a loss of five to ten percentage points in overall power generation efficiency compared to natural gas. Development of maximally efficient gasification technology is thus essential for future high-efficiency utilization of coal for both fuel cell and gas turbine systems.

10.3.1.4. Magnetohydrodynamics. The use of topping cycles—as in fuel cells, gas turbines, and MHD generators—to achieve efficiencies higher than those attainable in the simple steam Rankine cycle has been adopted worldwide, and is the major focus of the ongoing DOE program on advanced technologies for electricity generation. Advances in gas turbine and fuel cell technologies have essentially closed the original efficiency gap that stimulated a large worldwide effort on MHD during the 1960s and 1970s. Over the past decade, this MHD effort has been greatly reduced. Within the DOE FE Advanced Clean/Efficient Power Systems Program, no further funds are allocated for MHD, except for closeout of the proof-of-concept study. EPACT Section 131I recommends that an integrated documentation of the results of the extensive proof-of-concept work should be prepared, to capture the ‘lessons learned’ and to establish a reference point for any possible development of MHD systems in the future.

10.3.2. Emissions control technologies

Environmental control requirements for coal-based power plants are expected to become increasingly stringent in response to more demanding federal, state, and local requirements. In the near term, new control requirements for nitrogen oxides (NOx) and air toxics are anticipated, along with new ambient standards for fine particles. Over the longer term, significant reductions in CO2 and solid wastes may be needed.

10.3.2.1. Targets. DOE’s strategic objectives for criteria air pollutants (SO2, NOx, and particulates) express future goals relative to the 1979 federal New Source Performance Standards (NSPS) for coal-fired power plants (see Table 31). These emissions goals apply to advanced power systems in Groups 2 and 3. DOE’s goals for 2000 and 2005 can already be met or exceeded by technology in commercial use today, although cost reduction remains an important objective. Because environmental control requirements show a strong tendency to become more stringent, and because DOE’s emissions goals for the next decade already are being achieved with modern technology (see Section 3), it is not clear that the DOE goals will be adequate to meet all necessary environmental standards for coal plants a decade or more from now. The 2010 target of 1/10 NSPS represents a relatively demanding level of emissions reduction, but one that should be achievable by a number of coal-based systems much sooner than 2010 (although not all advanced systems may be able to meet the objective readily for all pollutants). Whether DOE’s emission goals will be adequate to meet regional and local environmental quality constraints—which tend to be the most demanding—cannot be foreseen.

Emissions control requirements for hazardous air pollutants (air toxics) have yet to be defined by the EPA (U.S. Environmental Protection Agency). The most likely need in this area will be for control of volatile species, such as mercury, which escape collection in existing gas cleaning systems. Studies are in progress to assess baseline emission levels for current and advanced technologies.

In the mid- to long-term periods a critical environmental issue for coal use is likely to be the need to reduce emissions of CO2 and other greenhouse gases. DOE’s primary strategy is to reduce coal-related CO2 emissions by improving the energy efficiency of new power generating plants.

The DOE program plan includes the cross-cutting area of control technology, whose general goal is to achieve ‘ultra-low’ emissions beyond the goals for 2010. No specific targets are set. However, the historical evidence shows a strong trend toward requiring emissions from new coal plants to be reduced to the maximum extent achievable, within reasonable constraints on economic cost. In this context, a possible vision for longer-term environmental R&D goals is to benchmark emissions of air pollutants from coal plants relative to cleaner but more costly competing fuels, particularly natural gas. With the exception of CO2 content, it appears feasible to match the quality of natural gas by cleanup of coal-derived gas. Since natural gas will continue to be used, a consistent set of requirements for coal-derived gas and natural gas may be appropriate as an R&D objective. To the extent that such a goal for ultra-low emissions can be achieved, the environmental acceptability of coal relative to competing energy sources will be enhanced. The long-term challenge for the DOE program, then, would be to develop systems that achieve targeted emissions reductions from coal plants at reasonable cost. If this long-term goal is attained, the primary environmental concern remaining for coal-based systems, aside from CO2 emissions, will be solid wastes.

The increasing cost and decreasing availability of landfill disposal options, particularly near urban and suburban population centers, will require increased attention to waste minimization, recycle, and re-use
methods. DOE’s goal of reducing solid wastes from advanced pulverized-coal systems by half appears to be realistic for near- to mid-term technologies. More ambitious goals than the targeted 50% waste utilization from advanced power systems by 2010 are appropriate for the long term, when higher waste disposal costs will provide greater incentives for waste reduction at the source.

10.3.2.2. Technology development needs. A number of technologies now being demonstrated in the CCT program offer potentially lower emissions control costs in the near term for conventional air pollutants, for both new and retrofit plants. The most challenging problem for DOE is to achieve reliable and cost-effective emissions control using hot gas cleanup for advanced power systems. The most critical need is for high-temperature, high-pressure particulate removal. This technology is essential for the advanced PFBC systems; it is one way to achieve higher efficiencies with advanced IGCC systems. Hot gas desulfurization technology similarly remains to be developed for advanced IGCC systems. While current hot gas cleanup devices achieve very low levels of SO₂ and particulate emissions, to-date neither hot gas particulate removal nor hot gas desulfurization systems have approached the durability and reliability requirements needed for a commercial system. Furthermore, current hot gas cleanup systems do not control volatile air toxics or nitrogen oxides (NOₓ). DOE remains optimistic that these critical problems will be solved through continued R&D. Nonetheless, the promise of advanced PFBC and the potential efficiency gains of IGCC and IGFC systems will not be realized until significant progress is demonstrated. For gasification-based systems, existing or improved cold gas cleanup systems can meet anticipated environmental requirements but at an efficiency penalty of about two percentage points.

To achieve larger or more rapid reductions in CO₂ emissions than can be achieved by improving the thermal efficiency of coal-based power plants, technological options for the removal and storage of CO₂ from conventional and advanced power systems could also be needed. The current DOE plan provides for such a contingency, in its objective of demonstrating by 2010 the capability to reduce and sequester CO₂ emissions by about 80% at a cost premium of not more than 20%. Given the current state of technology in this area, the most pressing need is for research related to CO₂ storage.

One of the most demanding long-term technical challenges for the DOE coal program is the reduction or elimination of solid wastes—a major environmental concern—through innovative and cost-effective recycle and reuse options, perhaps as part of an integrated ‘coal refinery’.* At present, DOE has only a relatively small program ($2.4 million per year) in solid waste management. At least one of DOE’s advanced coal technologies—the second-generation PFBC system—generates more solid waste than today’s best commercial plants meeting stringent standards for SO₂ removal (98% or more). This underscores the need to find effective solutions that will allow coal to compete environmentally with alternative fuels for power generation.

10.3.3. Conclusions

10.3.3.1. Power generation systems. 1. DOE’s selection of efficiency, emissions, and cost as key attributes of advanced coal-based technology is appropriate for strategic planning. However, its specific efficiency and cost objectives for advanced power systems appear to be overly optimistic given the current state of technology. On the other hand, DOE’s power plant emission goals appear to be challenging relative to the capabilities of current commercial technology and the environmental demands expected on future coal use.

2. For Group 2 and 3 systems with 45–60% targeted efficiency, new technological achievements are required to achieve the goals defined by DOE, including development of high-temperature gas turbines, high-temperature heat exchangers, hot gas cleanup systems, and advanced fuel cells.

*The term ‘coal refinery’ is understood as a system consisting of one or more individual processes integrated so as to allow coal to be processed into two or more products supplying two or more markets.
3. Overall, gasification-based systems offer the lowest risk and highest potential for lower emissions and higher efficiency than current technology, but cost expectations need to be more clearly defined.

4. System optimization cost and market studies are needed to define the roles and relative merits of the systems now being funded.

5. While most of the DOE gas turbine program is funded under the DOE natural gas budget, the future of many of the high-efficiency options for efficient coal use depends on firing these same turbines with gas from coal gasification or pressurized fluidized-bed combustion.

6. The gas turbine program under the DOE coal budget is appropriately focused on assessing the problem of trace material contamination (e.g., alkali metals) and possible solutions, such as special turbine materials, especially when hot gas cleanup is used.

7. The integrated gasification fuel cell system offers the highest efficiency and lowest emissions of power generation systems under development within the DOE program. However, high fuel cell cost may be a significant barrier to widespread use, and a carefully documented projection of the potential for cost reduction is needed to establish program priorities.

8. The highest efficiency for IGFC systems will be obtained with hot gas cleanup; however, the requirements for contaminant removal need to be established.

10.3.3.2. Emissions control technologies. 1. Overall, DOE can make an important contribution to reducing the costs and improving the performance of emissions control technologies by careful selection of critical problems for research in conjunction with industry.

2. Hot gas particulate cleanup is an especially critical technology at this time, since it will be an essential element in the success of high-performance PFBC and could improve the efficiency of gasification-based systems.

3. Hot gas cleanup for sulfur removal is another critical development needed for advanced PFBC systems where high-efficiency sulfur removal still needs to be demonstrated at acceptable reagent stoichiometries. There would also be efficiency benefits for advanced IGCC systems.

4. A thorough understanding is needed of options for the control of hazardous air pollutants, especially volatile air toxics, such as mercury and chlorine, across the set of advanced combustion and gasification-based technologies.

5. NO\textsubscript{x} control measures meeting DOE's performance targets for advanced power systems with hot gas cleanup and high-temperature turbines remain to be fully specified and demonstrated. Selective catalytic reduction or other add-on technologies could well be required in addition to the combustion-based NO\textsubscript{x} controls now envisioned.

6. Solid waste reduction is needed for all coal-based systems. Waste minimization, by-product recovery, and re-use options will become increasingly important and merit additional attention.

7. Currently, the primary focus of DOE's coal R&D to reduce CO\textsubscript{2} emissions is improving power plant efficiency. Should future policy measures require an accelerated rate of CO\textsubscript{2} reductions, additional measures to remove and dispose of CO\textsubscript{2} from gas streams, to avoid CO\textsubscript{2} emissions to the atmosphere, could also be warranted.

10.4. Clean Fuels and Specialty Products from Coal

Clean gaseous and liquid fuels derived from coal have the potential for substantial future use. At present, natural gas and refined petroleum are much less costly than comparable products from coal. However, both of these resources are expected to become more costly.\textsuperscript{17}

As natural gas prices rise, relative to coal, production of medium Btu gas (a mixture of carbon monoxide and hydrogen) for industrial and power generation fuel is projected to become competitive with natural gas during the mid term (2006–2020). Conversion of medium but gas to pipeline quality methane would follow at a later time.

DOE’s stated primary strategic objective for advanced fuel systems is to demonstrate by 2010 advanced concepts for producing liquid fuels and other products from coal that can compete with products produced from petroleum, when petroleum prices are $25/bbl (1991 dollars) or greater.\textsuperscript{*} At this price, coal-derived liquids may become competitive with nonconventional oil sources, such as tar sands and shale, and may also compete with the higher worldwide oil prices projected for the mid to long term.

It is likely that national efforts to reduce CO\textsubscript{2} emissions, as well as other environmental legislation and regulatory actions, could lead to increased emphasis on improved efficiency for technologies that convert coal to gaseous and liquid fuels. However, the cost of coal alone is too low to justify large additional investments for efficiency improvement. To date, DOE has not adopted environmental emission goals for coal liquefaction process plants, as it has for electric power plants. Future plants will likely have to meet air, land, and water emission requirements that are more stringent than those in place today, which could increase the overall cost of coal conversion processes relative to processes that use oil or gas.

\textsuperscript{*} DOE's costing method employs assumptions common among electric utilities but not among oil companies. In particular, the interest rates assumed in amortizing the capital cost of a liquefaction plant are based on a lower assumed risk and therefore lower rates of return than are commonly used by the petroleum industry (see Section 2 and Glossary). This difference in required rate of return will result in higher costs compared to DOE estimates.\textsuperscript{18}
10.4.1. Coal gasification

The conversion of coal to cleaned gas with current technology incurs a loss of the inherent useful energy in the coal of approximately 20%, corresponding to an efficiency loss of 10 percentage points in IGCC systems using coal-derived gas. This loss can be largely attributed to temperature cycling and increased energy requirements for compression. Commercial high-temperature, oxygen-blown, entrained-flow systems with cold gas cleanup would have a loss of around 13 percentage points. Further improvements in gasification technology are quite feasible, and cooperative programs with industry could help identify opportunities to improve both fluidized-bed and moving fixed-bed systems, leading to increased efficiency of advanced power generation systems.

For coproduct systems producing clean fuels and electricity, requirements for maximizing system efficiency are much alike. However, air-blown systems would be at a disadvantage. If oxygen systems are used, minimized oxygen consumption is important for process economics, and low-temperature gasification with methane production would require less heat and therefore less oxygen. Catalytic fluidized-bed systems offer potential for this application and have been studied in the past, but there are no currently active programs.

The ongoing CCT program includes demonstration of six commercial gasification technologies. In addition, the proposed FY 1995 FE coal R&D program budget for Advanced Clean/Efficient Power Systems includes significant funding for construction of an advanced air-blown, moving fixed-bed gasifier, which has the potential to meet the IGCC-2 efficiency goal of 45% with minimized production of coal tar. However, since air rather than oxygen is used, this system would not be well suited for the production of clean fuels requiring hydrogen or syngas.

10.4.2. Products from coal-derived gas

10.4.2.1. Hydrogen production. Production of pure hydrogen from fossil fuels involves oxidation and separation, together with conversion of CO and water to H₂ and CO₂ by the water–gas shift reaction. This set of processes is quite mature but is being improved by competing catalyst manufacturers and developers of hydrogen production technology, with ammonia manufacture a main outlet. Apart from advanced research on separation processes, there appears to be minimal need for DOE participation developing processes for manufacture of merchant hydrogen.

Production of pure hydrogen is expensive and a major consumer of energy. Clean fuels production processes that conserve hydrogen and involve in situ conversion of CO and water to H₂ provide important gains in efficiency and cost reduction through heat integration and provide a preferred option for synthetic fuels manufacture.

10.4.2.2. Synthetic natural gas production. While the current low cost of natural gas makes synthetic gas (SNG) from coal uneconomical, there have been important advances in synthesis processes from industrial and government-funded R&D. These advances allow use of the low H₂:CO ratios from advanced gasifiers, increased tolerance for sulfur, and improved design of reactors for the highly exothermic methanation reaction. Processes for direct production of methane by coal pyrolysis and low-temperature catalytic gasification followed by cryogenic separation offer additional pathways. It has been estimated<sup>36</sup> that these newer technologies can reduce the cost of stand-alone SNG production by approximately 25%. However, the resulting cost will still be higher than projections by the EIA (Energy Information Administration) for natural gas wellhead prices of about $3.50/Mcf or less in 2010. Thus, development of an economic incentive for large single-product plants is not expected before the late mid- or long-term periods (2020–2040). The DOE coal program does not include major programs devoted to catalytic SNG synthesis. This seems appropriate in view of the long time horizon and the excellent capabilities outside DOE. Advanced low-temperature gasification processes, however, ultimately have the potential to increase efficiency and reduce the cost of manufacturing SNG, liquid fuels, and chemicals.

Separating the methane formed directly in gasification processes by pyrolysis and by reactions in low-temperature gasification can be achieved cryogenically or by diffusion. The latter requires advances in high-temperature selective diffusion membranes.

10.4.2.3. Methanol from syngas. Methanol has been an important commodity for many years, with uses in the chemical industry and as a solvent. It can be used directly as a motor fuel and, with the requirement for inclusion of oxygenates in gasoline, its use in preparing oxygenated components by reaction with olefins has grown rapidly. Manufacture of methanol from coal is currently more expensive than manufacture from natural gas.

Methanol is made by the catalytic conversion of syngas at about 250°C (480°F) at 60–100 atm. The current commercial processes use a fixed-bed catalytic reactor in a gas recycle loop. A wide range of mechanical designs are used to control the heat released from the reaction. New developments in methanol technology include fluidized-bed methanol synthesis and use of a liquid-phase slurry reactor for methanol synthesis. The slurry technology offers improved control of temperatures; it was developed in LaPorte, Texas, in a joint DOE/industry program.

There is relatively little industrial R&D activity on processes using syngas with low H₂:CO ratios and the sulfur concentrations achievable with hot gas desulfurization. For use of coal, such a process could be less costly and more efficient than current
technology and could be integrated advantageously with electricity generation in a coproduct system.

10.4.2.4. Liquid hydrocarbons from syngas (Fischer-Tropsch synthesis). While gasoline hydrocarbons can be manufactured from methanol by the Mobil methanol-to-gasoline process, production by F-T (Fischer-Tropsch) synthesis is currently favored for new overseas facilities when low-cost gas is available. F-T synthesis can produce premium-quality diesel and jet fuel with minimum processing. Gasoline is also produced but requires more extensive upgrading to meet octane number specification. DOE has been active in applying the slurry reactor technique to this process. The ability of this process to handle high-molecular-weight wax and to use the low H₂:CO ratio gas from coal without the need for shifting to a higher ratio is important. Limited DOE development work is being conducted in LaPorte, Texas, in cooperation with industry groups.

Recent DOE-sponsored systems and cost studies using the DOE utility financing basis (see Section 2 and Glossary) have projected equivalent crude prices of $30–35/bbl for stand-alone production of high-quality gasoline and distillate fuels (diesel, aviation). When production of F-T liquids was combined with gasification-based power generation, the equivalent crude cost was reduced by $5–7/bbl, bringing it closer to the EIA reference case projected price for crude oil of $28/bbl in 2010. Thus, the studies indicate the possibility of coal-based fuels production in the mid-term period (2006-2020), which is about the same period as major construction of gasification-based power generation facilities.

Further cost reductions can be anticipated by continued systems studies; however, critical examination of the premium fuel credit should be included. Opportunities for cost reductions by research include optimization of once-through processes and development of catalyst systems compatible with sulfur levels attainable using hot gas cleanup.

10.4.3. Products from direct liquefaction and pyrolysis of coal

10.4.3.1. Direct coal liquefaction by hydrogenation. Following the OPEC oil embargo of 1973, direct liquefaction was the subject of intensive R&D, both industry and DOE funded. Since then, the drop in oil prices has led to abandonment of all large-scale development and drastic reductions in both industrial and DOE research activities. The products of direct liquefaction can be refined to produce highly aromatic high-octane gasoline and high-quality diesel fuel. Jet fuels and heating oil can also be produced. A design, systems, and cost analysis based on results from DOE’s advanced liquefaction R&D facility in Wilsonville, Alabama, projected an equivalent crude price based on utility financing of approximately $33/bbl using Illinois No. 6 coal. Use of lower-cost western coal might reduce the cost to approximately $30/bbl. There is optimism at DOE and among some industry groups that with continued R&D and systems analyses the DOE goal of $25/bbl (1991 dollars) for liquids from coal can be reached.

The aforementioned estimate based on Wilsonville data concerned dedicated coal liquefaction plants. Coproduction of liquids and electricity with advanced gasification systems can be expected to reduce costs. The reduction would likely be significant but probably less than the $5–7/bbl estimated for F-T liquefaction. Coprocessing of coal with residual fuel or tar in oil refineries has been studied by both industry and DOE.

While use of coal introduces both coal and ash handling requirements, improved process performance and continued low cost of coal are expected to revive commercial interest in the mid-term period (2006–2020) if oil prices follow EIA projections. Several research areas offer promise for reducing the cost and improving the efficiency of direct liquefaction by hydrogenation: use of raw coal gasifier product with a catalyst capable of in situ shifting of CO to H₂, removal of the oxygen in coal as CO₂ rather than water, use of a low-pressure reactor, and minimized production of light hydrocarbons.

10.4.3.2. Direct coal liquefaction by pyrolysis. Controlled heating of coal in pyrolysis can produce modest yields of liquids. The heat of pyrolysis is small, and, if the char product can be used without cooling, high thermal efficiencies can be achieved. The pyrolysis liquids are low in hydrogen and high in oxygen compared to petroleum residuum or bitumen but could be coprocessed with bitumen or fed to a direct coal liquefaction unit. Their tendency to polymerize on storage limits their use as a supplementary fuel for power generation without further processing. While probably of lower value to a refinery than bitumen, it seems possible that coproduction with gasification could make pyrolysis liquids competitive with tar in the same period as deployment of advanced power generation systems. DOE studied coproduction of pyrolysis char and coke (mild gasification) and began construction of demonstration facilities, but no further funding has been requested under the FY 1995 budget. A CCT demonstration of this technology using low-sulfur western coal is under way; the plan is to market pyrolysis liquids as power plant fuel oil and to burn the coke.

10.4.4. Coal refineries and coproduct systems

The energy industries are mostly specialized, oriented to a narrow range of products and markets. Electric utilities supply electricity along with some steam to local users; oil refineries supply liquid fuels along with some petrochemical feedstocks; and gas suppliers collect, purify, and transmit natural gas to end users. Government regulations differ for these areas, and separate speciality business units have
been established to deal with these separate regulatory systems. As discussed in Section 2, this regulatory environment has been changing to make it more attractive for groups outside the traditional utilities to generate and sell electric power.

The concept of a coal refinery, analogous to an oil refinery, has been discussed for many years, but the availability of low-cost petroleum has provided a disincentive to implement the coal refinery concept. More recently, EPACT directed DOE to examine the potential of coal refineries, and a report has been published.\textsuperscript{71} Screening studies by the Mitre Corporation\textsuperscript{72} identified major synergies between advanced power generation based on gasification and production of clean fuels and chemicals. The preceding discussion identified several examples of cost and energy savings from the manufacture of a variety of products from coal gasification. The available data\textsuperscript{61,72} indicate an equivalent crude cost of $5–7/bbl less for a combination of F–T synthesis and electric power generation than for stand-alone plants for liquids production. In these estimates the economic return on electric power production was held constant and the savings were applied to the liquid coproducts.

There are many other product combinations besides coal liquids and electric power, and quantitative studies can provide essential strategic guidance for both R&D and identification of optimized combinations of electric power, fuels, and chemical products. The incentives for coproduction by refineries, chemical plants, or independent producers of clean gas and other products will vary widely with location and the organizations involved. Cooperation with potential users is important to the success of such strategic planning studies.

The funding for DOE programs to produce clean liquid fuels from coal has declined significantly in recent years (see Section 6). The discussion above has indicated the possibility of introducing liquid fuels from coal at about the same time as new IGCC-based electric power generation facilities might be constructed. The timely availability of appropriately demonstrated technology will depend on initiating programs to investigate opportunities and develop coproduct systems as soon as possible.

10.4.5. \textit{Conclusions}

1. Gasification plays a critical role as the first and most costly step in the production of electric power by combined-cycle systems and in the production of clean gaseous and liquid fuels and chemical products.

2. Gasification options exist that offer potentially greater efficiencies than currently available commercial systems. Among the relatively unexploited options, low-temperature fluidized-bed gasification systems, with the possible use of catalysts, appear to be the most versatile for providing the entire array of future products from coal. A few examples of such systems are under development, but there are additional opportunities for further development.

3. The current DOE gasification program is devoted almost entirely to gasifier technology for power generation. However, gasification efficiency improvements are also needed to produce clean gaseous and liquid fuels.

4. Materials research leading to membrane diffusion techniques for recovering a by-product hydrogen stream is a major opportunity for DOE coal research relating to the production of pure hydrogen from coal-derived gas.

5. Production of SNG from coal is not expected to be of importance until late in the long term, i.e. near 2040.

6. The major opportunity to improve thermal efficiency and cost in SNG production is in the gasification step.

7. High-efficiency oxygen-blown gasifiers developed for combined-cycle power generation would also be applicable to use in SNG manufacture.

8. For large single-product plants, direct coal liquefaction offers a 5–10\% higher efficiency with correspondingly less CO\textsubscript{2} production than coal-based F–T syntheses, with production of methanol falling between these two limits. Similarly, the cost of producing a slate of refined transportation fuels by direct liquefaction is potentially lower than for the coal-based F–T synthesis gas-based fuels.

9. An estimate of the petroleum crude oil prices at which the products from a large direct liquefaction plant meeting current refined fuel specifications could compete is around $30/bbl using western coal and utility financing. For F–T liquids the equivalent crude oil price would be approximately $5/bbl higher (i.e. $35/bbl), with methanol production about the same as direct liquefaction. With typical oil industry financing, the equivalent crude prices would be of the order of $5–10/bbl higher.


11. Recent cost estimates for coproduction of coal liquids and electric power indicate that coal liquids might compete with petroleum at $25/bbl or less, with the possibility of coal-derived liquid fuel production at about the same time as installation of advanced IGCC power generation facilities.

12. Continued research in conversion chemistry and process optimization have the potential to reduce the cost of coal liquids from large liquefaction plants to the DOE goal of $25/bbl (1991 dollars).

13. There is little need at this time for large pilot plant or demonstration programs, but a bench-scale and small pilot plant program is needed to evaluate promising leads and to provide focus for laboratory-scale research in direct liquefaction.

14. Advances and maintenance of core competencies in direct coal liquefaction technology in the
United States depend increasingly on DOE activities, since R&D on direct coal liquefaction has dwindled to a very low level in industry.

15. Continued reductions in funding will cause a major degradation in the effectiveness of the DOE coal liquefaction program. This trend places the nation's long-term coal liquefaction option at risk because government support has become critical in sustaining U.S. competency in this area.

10.5. Systems Analysis and Strategy Studies

One critical activity that is not highlighted in DOE's current planning documents is systems analysis. This activity is essential to assessing coal R&D needs and priorities and to strategic planning. Given the expanding number of process options for advanced power generation, fuels production, and environmental controls, which designs are the most promising to pursue? How should complex processes be configured to achieve optimal results? How should individual components be designed to maximize performance and minimize cost? How do advanced process concepts compare to currently commercial technology and to each other? What are the most promising markets for advanced technologies, and what are the greatest technical risks? How do the various technical and economic uncertainties for new process designs affect projections of performance and cost, and how can targeted R&D best reduce critical uncertainties? A well-designed systems analysis program should be able to address such questions.

The DOE Fossil Energy program already has in place a significant systems and engineering analysis activity at both its Morgantown Energy Technology Center (METC) and its Pittsburgh Energy Technology Center (PETC) with additional capabilities at DOE headquarters in Washington. Each of these offices is involved in analysis and evaluation of processes and programs within selected areas of DOE activity. Analytical approaches of varying sophistication are employed for process analysis and evaluation, often with reliance on outside contractors in addition to in-house staff.

A preliminary look at DOE's ongoing activity in systems analysis indicates a significant amount of activity spread among METC, PETC, and headquarters. A major shortcoming, however, appears to be a lack of systematic assumptions and design premises within and across the full suite of DOE's advanced energy conversion and environmental control research programs. Rather, it appears that different parts of the DOE organization, working with a variety of different contractors, employ different assumptions and approaches—circumstances that preclude rigorous comparisons or evaluations of technologies in a given category (e.g. advanced power systems or advanced fuel systems).

Communicating the results of analyses to interest groups within and outside DOE is another important contribution of systems studies (see, for example, NRC[129]), a contribution that could be greatly improved by consistency and clarity in the assumptions and methods used for analysis. Similarly, greater efforts to incorporate feedback from industrial and other stakeholders, coupled with timely and systematic publication of results, are also needed. A more coherent approach to systems analysis could be of real value for strategic R&D planning.

Of substantial value are the advanced analytical and computer-based methods for analysis, synthesis, and design of complex processes that DOE has begun to develop in recent years. For example, new methods to address technical and economic uncertainties are especially critical to characterize advanced processes and designs properly at the early stages of development. Characterization and analysis of uncertainties are also critical to identifying robust system designs, risks, potential markets, and key problem areas that should be targeted for research to reduce technological risks. While DOE has supported the development of advanced modeling approaches for systems analysis and design, and is beginning to adopt some of these methods for R&D management, more rapid implementation of a rigorous systems analysis methodology could be of significant value for long-term strategic planning.

10.5.1. Conclusions

The growth in opportunities to use coal to produce electricity, fuels, chemicals, and coproducts calls for expanding and strengthening DOE's Office of FE systems analysis activity, which plays a critical role in coal-related RDD&C and strategic planning.

10.6. Technology Demonstration and Commercialization

An important goal for the DOE coal program, as specified by EPACT, is to accelerate the development and commercial introduction of new technologies related to coal use. A major additional objective is to increase the competitiveness of U.S. firms engaged in supplying equipment and advanced technology to the power-generating industry at home and abroad. Before commercialization, large-scale demonstration is generally necessary to provide credible evidence of improved performance and practicability. These demonstrations are expensive and are generally cost shared by DOE and industry. The DOE role can vary from operating and managing a cost-shared facility to cofunding a program located at an industrial site and managed by the industrial partner.

The demonstration programs under DOE's FE R&D budget are generally of the first type, while the
CCT demonstration projects are generally of the second type, with DOE operating only as a cofunding agency. The annual budget for FE coal R&D demonstration programs is approximately $150 million/year; additional funding for demonstrations of fuel cells and advanced turbines is included in the Office of FE's natural gas budget. The CCT program will expend about $6.9 billion over 14 years on 45 projects, with industry contributing more than two-thirds of the total funding. The major CCT effort is expected to result in commercial applications. While most of the activities are not yet completed, most of the programs seem to be well chosen, based on the level of private support. Significant future use of these technologies will depend on a follow-up commercialization program that alleviates concerns about costs and reliability of advanced technologies (see Section 8). The extent of DOE involvement necessary to stimulate private sector investment in such a program requires further assessment, taking into account any social costs resulting from delay in the implementation of advanced coal-based systems.

The National Coal Council also recently completed a study of commercialization opportunities and recommended a strategy for overcoming the barrier of the high costs and risks involved in using 'pioneer technologies'. It was recommended that approximately $1.4 billion be provided over 15 years (1995-2010) to provide about 10-15% of total capital and to help offset operating risks for the first plant after the demonstration plant, with a decreasing amount for the next three-five installations. Cost sharing would be for a percentage of that part of the commercial application that represents technical and economic risks not present in commercially available technology. This initiative would be in addition to the DOE FE R&D and CCT programs for technology demonstration.

10.6.1. Conclusions

1. Adequate technology demonstration and commercialization programs are essential for timely commercial application of new coal use technologies.

2. The timely introduction of clean coal technologies will depend on further demonstrations of a few pioneer installations beyond the CCT program to allay concerns about costs and reliability; some federal participation will be necessary to stimulate private sector investment.

3. Cost sharing of the risk differential between pioneer plants and commercially available technologies will accelerate the commercial acceptance of many of the new coal-based technologies.

10.7. Advanced Research Programs

The principal aims of the DOE coal advanced research program are to pursue technology goals and exploratory research opportunities while maintaining a balance between revolutionary research and evolutionary engineering development programs. This assessment of the DOE coal advanced research activities did not aim to provide a comprehensive list of research opportunities. However, some critical areas for coal-related research were identified. These include research on combustion, gasification, materials, coal conversion and catalysis. Special importance is placed on research areas unlikely to be addressed outside the FE coal R&D program, such as the study of coal chemistry and catalytic reactions. Advanced research activities within the coal program should be directed toward meeting the strategic objectives defined for advanced clean/efficient power systems and clean fuel systems, with more effort devoted to mid- and long-term requirements than is now the case. Sections 6 and 7 identify ample opportunities for major contributions to fuels and power generation problems from advanced research. However, DOE's recent budget reductions for advanced research—e.g., a 30% real decline between FY 1988 and FY 1994—with further reductions proposed for 1995 are not commensurate with the requirements for advancement of coal technology, notably the increasing needs for lower-cost, more efficient, and more environmentally acceptable use of coal.

10.7.1. Conclusions

1. There are increased needs and opportunities for advanced research directly related to achieving cost reduction and improved performance goals for advanced power systems and fuels production.

2. The recent trend in decreasing support for coal-related advanced research activities is not commensurate with the expanding needs to support DOE's mission.


In this Act, Congress provided guidance on content and priorities for the DOE coal program. A detailed discussion of DOE's response to specific EPACT provisions can be found in the full NRC report on which this article is based. It was concluded that DOE has responded to some degree to all sections of EPACT identified in the study. However, the extent of response varies widely.

In the case of power generation systems, the DOE Advanced Clean/Efficient Power Systems program is very responsive to the EPACT requirements to 'ensure a reliable electricity supply' while complying with environmental regulations and controlling emissions (see Section 7). In contrast, DOE's activities in coal liquefaction fall short of EPACT requirements. Given the likely growth in demand for coal liquids
over the mid- to long-term periods, and the decline in industry-supported liquefaction research, the priority that EPACT gives to DOE liquefaction activities appears to be well founded. Coproduction of electricity and other products, such as coal liquids, also is accorded relatively high importance by EPACT (Sections 1304, 1305, and 1312), but it does not represent a major element of DOE's current program.

In comparing all activities within DOE's current coal program and those mandated by EPACT, there is a significant discrepancy in priorities. The current DOE program focuses on relatively near-term projects, notably the development, demonstration, and commercialization of coal-based power generation systems by 2010, at the expense of longer-term research programs. Such longer-term programs would position the United States to respond to future energy scenarios in which coal assumes increasing importance for uses other than power generation. In contrast to the DOE approach, the coal-related provisions of EPACT endorse the development of a longer-term, more balanced spectrum of coal-based technologies.

10.8.1. Conclusions

1. The current DOE program is appropriate and responsive to EPACT sections related to coal-based electric power generation.

2. EPACT places significant emphasis on programs related to the expansion of coal use for manufacture of liquid and gaseous fuels and specialty products.

3. The DOE program covering uses of coal beyond power generation has decreased in recent years.

10.8.1.1. General summary. Coal is by far the largest fossil fuel resource in the United States, and known reserves are adequate to meet expected demand without major increases in production cost throughout the 21st century. Its use, however, is strongly dependent on the outcome of competition with other resources and on requirements for control of emissions and CO₂, which are expected to become increasingly restrictive. The domestic natural gas resource is sufficiently limited that price and availability problems will weaken its ability to compete with coal for power generation in the U.S. during the next 10–30 years. Renewable and nuclear energy sources are not expected to displace coal to a major extent during the 1995–2040 time period considered here. For manufacture of liquid and gaseous fuels, coal is projected to become competitive with other resources (petroleum, oil shale, and bitumen) in the latter half of the 2020–2040 time period. It is believed that future requirements to minimize emission of CO₂ will make improvement of efficiency for both power generation and production of clean gaseous and liquid fuels a major long-term goal for technological advances in systems for coal use.

The current DOE coal program emphasizes activities through 2010 and is focused almost exclusively on power generation with small and decreasing programs on other uses.

The power generation program is divided between near-term goals that do not offer significantly higher efficiency and more ambitious goals where use of high over current modern performance gas turbines or fuel cells will potentially provide a 10–15 efficiency point increase. All of these approaches face significant barriers which require extensive R&D for their resolution. For fuel cells, cost appears to be the major problem. For the gas turbine systems, production of a hot gas stream of sufficient purity to allow use of the very high efficiency to gas turbines being developed for use with natural gas offers the major challenge. Critical components include:

- High temperature filters for PFBC system.
- High temperature air/furnace heat exchanger.
- Hot gas cleanup system for PFBC and for gasification based system.
- High temperature turbine blades that are compatible with trace impurities that may escape the high temperature gas cleanup system.
- High thermal efficiency gasification.

Solution of these challenging problems will require a continued program of advanced research and component development. The gasification step invokes a 7–10% efficiency point penalty compared to use of natural gas or direct coal combustion. The PFBC and heated air systems avoid gasification but are dependent on major advances. Choice of winners from the large array of contenders will require augmented use of systems studies and development of realistic commercialization strategies.

As natural gas prices rise, production of cleaned coal-based medium Btu gas for use in natural gas fueled-combined cycles and for industrial heat becomes economic and can relieve pressure on supply of natural gas for other uses. Conversion of this gas to methane (SNG) might follow towards the end of the 2028–2040 time period. High efficiency oxygen blown-coal gas cleanup gasification would be used. At present, however, the DOE gasification program is concentrated on air blown processes specifically aimed at integration with power generation. The choices between use of air or oxygen and hot versus cold gas cleanup will depend on the success of hot gas cleanup on all possible turbine efficiency reductions from partly cleaned gas.

Production of medium Btu (synthesis gas) will allow concurrent production of hydrogen or Fischer–Tropsch liquids. Here use of simplified once through processes with production of electric power from unconverted feed and low value products (such as methane) can bring costs of premium liquid fuels to a level where they can compete with $25–30/bbl imported crude oil (DOE financing basis). This option could then be competitive in the 2020–2040 era.
Direct liquefaction costs with continued R&D are believed to be approximately the same; but with 5–10% higher efficiency and correspondingly less production of CO₂. Because of the long-term nature of these opportunities, DOE is believed to have a special responsibility for ensuring continued progress on both cost reduction and efficiency improvement of technologies for these potentially important uses of this major national resource.

10.9. Summary

In brief summary, electric power generation is expected to dominate the use of coal, although a growing production of merchant medium Btu gas and liquid transportation fuels is anticipated during the period 2021–2040. The current DOE coal program emphasizes activities through 2010 and is focused almost exclusively on power generation technologies with small programs on other uses. Funding for many of the latter programs has been reduced significantly in recent years. The present study, with its longer time horizon, proposes an increasing emphasis on clean fuels research and on advanced research that addresses the barriers to higher efficiency in both power generation and fuels production to reduce CO₂ emissions. Improvements will also be needed in control of air pollutants and the discharge of solid wastes.

The power generation program addresses both near-term goals that do not offer significantly higher efficiency, and also more ambitious goals based on combined cycles utilizing high performance gas turbines or fuel cells to potentially provide a 10–15 point increase in efficiency. These increases in efficiency will require extensive R&D to overcome technological barriers. For fuel cells, high cost appears to be the major problem. For the gas turbine systems, production of hot gas stream of sufficient purity to allow use of the very high efficiency gas turbines being developed for use with natural gas presents the major challenge. Critical components include:

- High temperature filters for PFBC systems.
- High temperature air/furnace heat exchange for indirect fixed systems.
- Hot gas cleanup system for PFBC and for gasification-based systems.
- High temperature turbine blades compatible with trace impurities that may escape the high temperature gas cleanup system.
- High thermal efficiency gasification.

Solution of these challenging problems will require a continued program of advanced research and component development. Choice of winners from the large array of technologies will also require augmented use of systems studies and development of realistic commercialization strategies.

As natural gas prices rise, production of cleaned coal-based medium Btu gas for use in existing natural gas fueled-combined cycles and for industrial heat becomes economic and could relieve the pressure on the supply of natural gas for other uses. Conversion of this coal-based medium Btu gas to methane (SNG) might follow towards the end of the 2021–2040 time period. For this use, high efficiency oxygen blown-cold gas cleanup gasification is needed. At present, however, the DOE gasification program is concentrated on air blown processes specifically aimed at integration with power generation.

Production of medium Btu (synthesis gas) will allow concurrent production of hydrogen or Fischer–Tropsch liquids. The use of simplified once-through processes with production of electric power from unconverted feed and low value products (such as methane) could bring costs of premium liquid fuels to a level competitive with $25–30/bbl imported crude oil (DOE financing basis). Current projections indicated that the price of imported crude oil could be in this range in the 2021–2050 time frame.

Direct liquefaction costs, with continued R&D, are believed to be approximately the same as indirect liquefaction, but with 5–10% higher efficiency and correspondingly less production of CO₂. Given the long-term nature of opportunities for production of coal-derived gaseous and liquid fuels, DOE has a special role to play in supporting technology development aimed at cost reduction and efficiency improvement for these potentially important uses of coal.

Acknowledgements—This article is based on the work of the Committee on the Strategic Assessment of the U.S. Department of Energy’s Coal Program and on many contributions from organizations and individuals. The committee members were: John P. Longwell (Chairman), MIT; Edward S. Rubin (Vice-Chairman), Carnegie Mellon University; Merrel H. Cohen, Exxon Research and Engineering Company; A. Denny Ellerman, Center for Energy and Environmental Policy, MIT; Robert D. Hall, Amoco Corporation; John W. Larsen, Lehigh University; Peter T. Luckie, The Pennsylvania State University; Maurice D. McIntosh, Duke Power Company; George T. Preston, EPRI; Eric H. Reichl, Princeton, New Jersey; Larry D. Woodfork, West Virginia Geological and Economic Survey; John M. Wootten, Peabody Holding Company, Inc. The Department of Energy is to be especially commended for their extensive and essential interaction with the committee in supplying needed background and perspective. In addition, presentations from organizations outside DOE augmented the background of the committee members and their contributions are incorporated throughout this study. These presenters and their organizations were: Gary Styles, Manager, Special Projects, Southern Services Company; Donald Hafer, Manager,Cogeneration and Performance, American Electric Power Company, Inc.; Larry Papay, Vice President and Manager of Research and Development, Bechtel Group, Inc.; John Bachman, Associate Director, Office of Air Quality Planning and U.S. Environmental Protection Agency; William Burnett, Senior Vice President, Technology Development, Gas Research Institute; Jae Edmonds, Battelle Pacific Northwest Laboratories; Harold J. Gluskoter, U.S. Geological Survey.
REFERENCES

44. Rohrbacher, T. J., Teeters, D. D., Osmonson, L. M.
Coal: Energy for the future

357


59. Oil and Gas Journal, Alternate fuels: China’s, 92, 35 (1994).


114. DOE, *Fossil Energy Advanced Research: Strategic...*


GLOSSARY AND CONVENTIONS

APPENDIX A

Cost of Coal Conversion Processes

The cost of producing electricity or clean gaseous and liquid fuels from coal is highly dependent on the level of capital investment and, therefore, on the return required by investors. This return depends on both the prime rate, which reflects the anticipated effects of inflation and the desire of the Federal Reserve Bank to control inflation, and the investors' assessment of risk.

The electric utility industry, with its relatively predictable selling prices for electricity and stable production costs, can attract capital at a lower prime rate than, for example, the oil industry, where future product and feedstock prices are much less certain. Major investments are frequently split between a component with relatively assured, but lower, return and a higher-return component that will incur a larger risk. In the utility industry, a substantially larger component of low-risk borrowed money is more common than in the petroleum industry, where 100%, equity financing has been more commonly practiced. Hence, the term 'utility financing' is frequently used to describe highly leveraged investments, whereas 'petroleum financing' describes investments with the smaller component of borrowed money generally employed in that industry.

The costs presented by the U.S. Department of Energy (DOE) and used in this report are based on leveraged financing. Key assumptions are summarized below. It has also been assumed that sufficient plants have been built to reach a stable cost (with plant costs; see Section 8).

Key assumptions for capital cost estimation:

- Bank interest rate (%) 8
- % equity 25
- % internal rate of return 15
- Years of construction 5
- Years of operation 25
- Depreciation, years 10
- Maintenance, % initial capital 1
- Working capital, % revenue 10
- Working capital, % liquid 50
- Owner's cost, % initial capital, first-year operation 5
- Federal income tax rate, % 34
- General inflation, % 3
- Raw material price escalation, % (same as general inflation) 3
- State tax 0
- General inflation of 3% per year was applied to all costs and selling prices. As mentioned above, an assumed rate of inflation was included in the investment required by investors.

APPENDIX B

Economic Conventions

Throughout this article, all costs, prices, and so forth, are given in constant 1992 dollars unless otherwise specified.

A Gross Domestic Product Implicit Price Deflator* has been used to adjust current dollars to 1992 dollar figures. An exception is DOE budget data, which are quoted in current dollars.

**Thermal Efficiency**

Throughout this article all thermal efficiency figures are based on the higher heating value (HHV) of fuel, which is the convention most widely used in the United States for coal-based systems. HHV credits the fuel with the heat of vaporization of water formed in the combustion reaction; that is, water is assumed to exist in the liquid phase after combustion. This is consistent with the standard thermodynamic conditions of 25°C (77°F) and 1 atm used to calculate the heat of formation or reaction of any chemical compound (recall that 'heating value' is simply the name commonly used for the heat of reaction of a hydrocarbon used as fuel).

In parts of Europe and elsewhere, however, the lower heating value (LHV) is commonly used in reporting thermal efficiencies. In the United States LHV is commonly used to quote efficiencies based on natural gas as a fuel. The LHV assumes that water formed in combustion remains in a vapor state, as in actual combustion systems that discharge flue gases at temperatures of several hundred degrees. Thus, the energy potentially recoverable by condensing water in the flue gas is assumed to be unavailable and not credited to the fuel. Since the LHV assumes that fuel delivers less energy input than the HHV, any thermodynamic efficiency, $E$, based on LHV will be higher than one based on HHV in simple inverse proportion; that is, $E_{LHV}/E_{HHV} = HHV/LHV$.

The numerical difference between LHV and HHV depends on the fuel. The difference is smallest for coal (where LHV is roughly 4% less than HHV) and greatest for natural gas (where LHV is about 10% lower). Accordingly, a power plant efficiency of 40% based on HHV would be reported as 42% based on LHV using coal and about 44% based on LHV using natural gas.

---