DOE/PC/93035--T5

PREPUBLICATION COPY

COAL: ENERGY FOR THE FUTURE

Committee on the Strategic Assessment
of the
U.S. Department of Energy's Coal Program

Board on Energy and Environmental Systems
Commission on Engineering and Technical Systems
National Research Council

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This report and the study on which it is based were supported by Grant No. DE-FG22-93PC93035 from the U.S. Department of Energy.

Library of Congress Cataloging-in-Publication Data (to come)

Printed in the United States of America

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Preface

This report was prepared in response to a request by the U.S. Department of Energy (DOE). The principal objectives of the study were to assess the current DOE coal program vis-à-vis the provisions of the Energy Policy Act of 1992 (EPACT), and to recommend the emphasis and priorities that DOE should consider in updating its strategic plan for coal.

A strategic plan for research, development, demonstration, and commercialization (RDD&C) activities for coal should be based on assumptions regarding the future supply and price of competing energy sources, the demand for products manufactured from these sources, technological opportunities, and the need to control the environmental impact of waste streams. These factors change with time. Accordingly, the committee generated strategic planning scenarios for three time periods: near-term, 1995-2005; mid-term, 2006-2020; and, long-term, 2021-2040.

It was assumed that coal would not be resource limited during these time periods. Supplies of domestic natural gas were taken to be adequate for current uses, although prices will likely increase because of increased finding and production costs. Imported oil also was assumed to be available at a price that is likely to be more uncertain and that will probably increase faster than that of coal. The committee also assumed that the required level of control of all waste streams from coal systems would increase with time. In particular, the issue of global warming is expected to provide a powerful driving force for improvement in the conversion efficiency of coal to electric power and clean gaseous and liquid fuels.

The most appropriate role for DOE in developing cost competitive, environmentally acceptable coal technologies, as required by EPACT, is strongly dependent on the needs and opportunities for technological advancement in the near-, mid-, and long-term periods and on domestic and foreign RDD&C programs outside DOE. Comparison of DOE programs and plans with these other activities, with the committee's strategic planning scenarios, and with the goals set by EPACT forms the basis for the committee's recommendations.

At the first committee meeting in November 1993 and at the meetings of the power generation and fuels subgroup and the strategy and policy subgroup, both in January 1994, presentations from DOE staff and others provided an essential information base. Two further committee meetings in March and May 1994, together with a writing group meeting in April attended by John Longwell, Edward Rubin, Robert Hall, George Preston, John Wootten, Harold Schobert, and National Research Council staff, permitted the committee to develop and refine its conclusions and recommendations and to assemble a full draft of the report. The rapid pace at which this complex task was completed called for a high level of participation by committee members and for vigorous and pro-active involvement by the National Research Council program officers, Dr. Jill Wilson and Dr. James Zucchetto, and the project assistant, Ms. Wendy Orr. These contributions, together with those of the many DOE staff members who provided advice and consultation, were noteworthy and highly appreciated.

JOHN P. LONGWELL, *Chair*
Committee on the Strategic Assessment of
the Department of Energy's Coal Program

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Executive Summary

The outlook for coal use in the United States is governed by two major factors, namely, the desirability of using an abundant, low-cost, and secure domestic energy resource and the need to comply with increasingly stringent environmental control requirements. Over the time periods considered in this study (ranging from the present through 2040), the production cost of domestic coal is not expected to increase significantly. In contrast, rises in the cost of domestic natural gas are anticipated because of resource limitations. There are also likely to be significant increases in the price of imported petroleum (EIA, 1994). While continued growth in the use of renewable energy forms is expected, along with a potential resurgence in nuclear power, there will be a powerful economic driving force for major and expanded use of coal over the next several decades, with concomitant pressures to reduce environmental impacts through improved technologies. In addition, in countries of South Asia and the Pacific Rim, notably China, rapid economic growth coupled with substantial indigenous coal supplies will likely contribute significantly to an expected worldwide growth in coal utilization over the next 15 years or more (DOE, 1993a).

In this context the Energy Policy Act of 1992 (EPACT) directs the U.S. Department of Energy (DOE) to establish programs for developing environmentally acceptable coal-based technologies for a broad range of applications, notably electric power generation and the manufacture of liquid and gaseous fuels and nonfuel products, such as carbons and coal-derived chemicals. A number of the coal-related provisions of EPACT emphasize the need to ensure the availability of technologies for commercial use by 2010, reflecting both anticipated requirements for coal-based power generation and a desire to capitalize on earlier federal research and development (R&D) investment. This report of the National Research Council's (NRC) Committee on the Strategic Assessment of the U.S. Department of Energy's Coal Program addresses the future role of DOE in research, development, demonstration, and commercial application (RDD&C) programs on coal-based technologies. In particular, 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 responding to EPACT. The committee's major recommendations are given in this Executive Summary. Detailed conclusions and recommendations regarding DOE's coal program, and its relationship to EPACT, can be found in Chapter 10. Throughout the report, costs are based on utility financing, and fuel higher heating value (HHV) is used as the basis for energy efficiency figures (see Glossary).

THE DOE COAL PROGRAM

Coal-related activities within DOE currently fall under two main budget categories: Fossil Energy (FE) R&D and the Clean Coal Technology (CCT) program. The CCT program was initiated in 1986 and is scheduled to run through 2004, with the specific objective of demonstrating advanced coal technologies at a large enough scale for the marketplace to judge their commercial potential. All CCT projects involve cost sharing between DOE and industry, with the industrial partners contributing at least 50 percent of the cost of the technology demonstration, as well as playing a major role in project definition and in ensuring eventual commercialization. Five solicitation rounds (CCT-I through CCT-V) have been conducted, resulting in 45 active projects with total funding of $6.9 billion, of which DOE is providing $2.4 billion (34 percent).[1]

The congressionally mandated CCT program complements the FE R&D program, which has been in existence since the inception of DOE and forms the continuing basis of DOE's coal program. The annual funding level for the FE R&D program, which encompasses oil, natural gas, and coal, has remained relatively constant at the low- to mid-$400 million level for fiscal year (FY) 1992 through FY 1994. However, the oil and natural gas budgets have grown at the expense of the coal budget, which was $167 million in FY 1994, with a proposed reduction to $128 million for FY 1995. However, DOE also has proposed that the natural gas budget for fuel cell and gas turbine activities be increased from $74 million in FY 1994 to $112 million in FY 1995. These two programs are also integral components of advanced coal-based power systems. The FY 1995 budget proposal reflects an overall increase in the FE R&D budget for advanced power generation technologies.

The coal portion of the FE R&D program is divided into three major components: Advanced Clean Fuels, Advanced Clean/Efficient Power Systems, and Advanced Research and Technology Development. The Advanced Clean Fuels program aims to develop systems that can produce coal-derived transportation fuels, chemicals, and other products at costs competitive with oil-derived products when petroleum prices reach $25/barrel (bbl) or greater in 1991 dollars. Total funding for this program has decreased significantly in recent years, from $59.6 million in FY 1992 to $40.9 million in FY 1994. The FY 1995 budget request of $20.1 million reflects a proposed further decline in DOE activities in this area.

The Advanced Clean/Efficient Power Systems program supports the development of systems based on coal combustion or gasification that will become commercial in different time periods. Program goals for efficiency, levels of emissions, and energy cost to be achieved in 2000, 2005, 2010, and 2015 have been established. Some technologies are funded under the FE coal R&D advanced power systems activity, the FE natural gas R&D program, and the CCT program. For example, subsystem and component testing, environmental and economic studies, and pilot plant tests for pressurized fluidized-bed combustion (PFBC) systems are funded under the FE coal R&D program, while demonstrations of first- and second-generation PFBC systems will be conducted under CCT funding. These systems will employ advanced turbines developed in the natural gas R&D program. The advanced power systems program experienced a funding

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[1]Throughout this report, all costs, prices, and so forth, are given in constant 1992 dollars unless otherwise specified. An exception is DOE budget data, which are quoted in current dollars.

reduction from $187.1 million in FY 1992 to $97.1 million in FY 1994, but this decline is largely the result of completion of the magnetohydrodynamics proof-of-concept program and transfer of the fuel cells activity from the coal program to the natural gas program in FY 1994.

All DOE coal advanced research programs fall within the FE coal R&D budget category, although they are not confined to the Advanced Research and Technology Development program. Advanced research on fuels and power generation is also funded under the Advanced Clean Fuels and Advanced Clean/Efficient Power Systems budget categories, respectively (see Chapter 9). The advanced research budget for coal declined about 30 percent in real terms between FY 1988 and FY 1994, with a further decrease of approximately 25 percent to $22.4 million proposed for FY 1995.

STRATEGIC PLANNING

The development of a strategic plan for coal requires an understanding of the factors likely to influence coal use over the time horizon of interest. As a basis for developing a set of strategic planning scenarios, the committee reviewed markets for coal and coal utilization technologies, major coal uses—notably, electric power generation, the availability of competing energy sources, and the impact of existing and likely future environmental regulations affecting coal use.

The domestic coal resource base is abundant, constituting over 94 percent of proven U.S. fossil fuel reserves. Coal is not projected to be resource limited in the time period considered in this study (i.e., through 2040). U.S. coal prices have declined over the past decade, and no rapid price increases are anticipated in the near future. Imports of South American coals, which are competitive with U.S. coals on a delivered price basis in certain locations in the eastern United States, are likely to play a role in keeping domestic prices low. While U.S. coal exports are significant (10 percent of 1992 production of 998 million tons), technology developments within the DOE coal program are not likely to open any major new markets for U.S. coal. In contrast, demands for new and retrofit coal-based electricity generation technologies in developing countries, notably China and in Eastern Europe, represent a potentially large export market for U.S. technology. Nonetheless, the extent of U.S. participation in overseas markets for advanced coal utilization technologies is difficult to forecast, given the competition from overseas companies and the complex political and economic factors governing international trade.

The single largest use for coal in the United States is for power generation; electric utilities consumed 87.4 percent of the total 1992 domestic consumption of 892 million tons. However, the demand for new coal-fired power generating capacity in the United States is expected to remain low for the next 10 years. Overcapacity, while declining, still exists in some regions, and low-cost natural gas is more attractive than coal for the addition of peaking capacity since capital costs are lower and the lead time for plant construction is shorter.

A resurgence in demand for new coal-based generating capacity is anticipated by 2010, as existing plants reach the end of their useful life and baseload electricity demand increases. Natural gas prices will likely increase by this time, to the point where a return to coal-based technologies is favored. However, increasingly stringent environmental regulations governing emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_x), fine-particulate air pollutants, and possibly air toxics from power plants, as well as solid waste issues, will place severe demands on coal-fired power plant performance. Furthermore, concern over the potential impacts of global warming may lead to penalties on carbon dioxide (CO_2) emissions from coal combustion, resulting in increased emphasis on high efficiency for coal-based power generation systems designed to operate through the middle of the twenty-first century.

The market for synthetic gaseous and liquid fuels from coal is currently small due to the widespread availability and low cost of petroleum and natural gas. This situation is expected to persist for the next 15 years, with increases in oil and gas prices unlikely to be large enough to stimulate major investment in processes for the manufacture of synthetic natural gas or liquid fuels from coal (EIA, 1994). However, by the second decade of the twenty-first century this situation may change, as the cost of synthetic fuels is reduced by process and systems advances and as concerns over the supply and price of competing fuels increase.

On the basis of the above factors influencing coal use, the committee developed a set of strategic planning scenarios summarizing requirements for future coal utilization to 2040 (see Chapter 4 and below). DOE's current strategic planning objectives extend through 2010, largely in response to the EPACT requirement to develop commercial technologies by that date. However, coal will continue to be a major source of energy well beyond 2010, with the potential in the longer term for a changing emphasis in coal use in response to resource limitations and increasing prices for competing fuels.

The committee recommends that the planning horizon for DOE coal RDD&C programs extend beyond the agency's current planning horizon of 2010. The committee recommends the use of three time periods for strategic planning: near-term (1995–2005), mid-term (2006–2020), and long-term (2021–2040). The main objective of DOE's coal program in all periods should be to provide the basis for technological solutions to likely future demands, in a way that is robust and flexible.

The above timeframes correspond to anticipated major trends in coal utilization. In the near term the scenarios for coal use will resemble today's, with power generation persisting as the dominant market, despite limited demand for new coal-fired baseload generation capacity. The mid term will likely be a transition period. Power generation will remain the major use of coal, and there will be a significant demand for new baseload capacity using advanced high-efficiency coal technologies to meet increasingly stringent air pollution control and solid waste disposal requirements, plus possible penalties for CO_2 emissions. In addition, increasing international oil prices will result in a growth of interest in the production of synthetic transportation fuels from coal, and increases in natural gas prices will stimulate interest in coal gasification. Coproduct systems that manufacture two or more saleable products might provide attractive market-entry opportunities for liquid fuels from coal. For example, gasification technology could provide a common basis for both power generation and the production of liquid fuels.

In the long term (beyond 2020) the production of liquid and gaseous fuels from coal will likely become increasingly important. Although coal use for power generation will continue to be significant, increasingly stringent controls on emissions, particularly of greenhouse gases, will impose severe demands on efficiency and emission control systems, stimulating interest in alternative energy sources for power generation. Environmental concerns, including greenhouse issues, will also affect the production of clean fuels from coal. Nonetheless, the demand for these products is expected to grow once gas and petroleum resources dwindle or rise substantially in price. The committee recognizes that planning for the long-term period will necessarily be less well defined and will entail greater uncertainty than near- and mid-term planning.

These scenarios suggest a change in future priorities within the DOE coal program. As a consequence of the widespread availability of natural gas and petroleum, industry R&D on technologies for producing clean fuels from coal is currently very modest in scope, apart from the development of coal gasification technologies for integrated gasification combined-cycle (IGCC) power generation systems. Thus, the committee saw DOE as uniquely able to play a leading role in maintaining and developing technological expertise in fuels production and positioning the United States to respond to potential demands for coal-based fuels in the mid to long term.

The committee recommends that within the DOE coal program there be an increasing emphasis on the production of clean fuels and other carbon-based products over time.

A further consequence of the committee's recommendation that the strategic planning scenario be extended beyond 2010 is the need to reassess the role and priorities of DOE's advanced research programs. As noted above, there has been a significant decrease in the advanced research budget since 1988. To some extent, this decline reflects the transition of advanced power generation systems from R&D to demonstration status. However, significant reductions have also occurred in funding for coal liquefaction and other advanced research areas. In the opinion of the committee, the DOE budget reductions for advanced research are not commensurate with the increasing needs for lower-cost, more efficient, and more environmentally acceptable use of coal through the next 50 years and beyond. The decline in DOE activities is all the more serious given the decreasing private sector investment in long-range research on coal-related technologies.

The committee recommends that increased resources be devoted to advanced research activities to support DOE's strategic objectives for coal, with emphasis on needs identified for mid- and long-term improvements in efficiency, emissions reduction, and cost for both power generation and fuels production.

POWER GENERATION

Technology Development

Research, development, and demonstration (RD&D) of advanced power generation technologies is conducted under the Advanced Clean/Efficient Power Systems component of the

FE coal R&D program. DOE goals for efficiency, emissions, and cost have been established. Efficiencies are projected to rise from current new plant levels of 38 to 42 percent to 60 percent within the next two decades. A number of interim systems are proposed with target efficiencies of 45 to 55 percent. DOE's target for emissions of SO_2, NO_x, and particulates is one-tenth the 1979 federal New Source Performance Standards (NSPS) by 2010. An important feature of the DOE plan is to achieve the above efficiency improvements and emissions reductions at an overall cost of electricity generation that is 10 to 20 percent lower than today's coal-fired power plants. In the view of the committee these objectives, while laudatory, may be overly optimistic. In general, advanced technologies tend to perform less well and cost significantly more than originally envisioned as they move from concept to full-scale commercial operation (Merrow et al., 1981). In the case of technologically complex advanced power systems, the objective of achieving high efficiency and low emissions with a 10 to 20 percent reduction in the cost of electricity may be particularly challenging. A more realistic goal would be to achieve the proposed efficiency improvements at an overall cost comparable to current new coal plants.

The committee also notes that many of DOE's emission goals for 2000 to 2010 already can be met with current commercial emissions control technology, which many state and local governments now require. The expected trend toward increasingly stringent environmental regulations could demand emissions levels that are more stringent than the current DOE goals, thereby increasing plant costs. The committee concluded that DOE's power plant emissions goals are insufficiently challenging given the capabilities of current commercial technology and anticipated environmental demands on future coal use.

Despite reservations regarding program goals for the cost of electricity and the environmental emissions, the committee noted the important role of DOE's advanced power systems program in stimulating the development of new technologies to meet anticipated electricity demand early in the next century. Participation by DOE in technology development is particularly important given the reluctance of the utility industry to invest heavily in RD&D of advanced coal-based technologies in today's increasingly competitive environment.

For the purposes of this study, the committee divided the advanced coal-based power generation technologies under development with DOE funding into three groups, based on target efficiencies and approximate dates for commercial availability:

- Group 1 technologies—low-emission boiler systems (LEBS), first-generation PFBC systems, and first-generation IGCC systems—have target efficiencies in the range of 40 to 42 percent and should be available around the year 2000.
- Group 2 technologies—externally fired combined-cycle (EFCC) systems, second-generation PFBC systems, and second-generation IGCC systems—are projected to have efficiencies of approximately 45 percent and to be available no later than 2005.
- Group 3 technologies—high-performance power system (HIPPS), advanced second-generation PFBC systems, integrated gasification advanced-cycle (IGAC) systems, and integrated gasification fuel cell (IGFC) systems—have projected efficiencies of 50 percent or greater and are expected to be available in the 2010 to 2015 time period.

Given the low projected demand for new coal-fired generating capacity prior to 2005, the U.S. market for Group 1 systems will likely be small. These systems are essentially based on proven components and do not offer an efficiency advantage over state-of-the-art pulverized coal systems. Projected performance and cost enhancements come from improved systems design and integration. There may be opportunities to market these technologies overseas, where demands for new coal-based power generation capacity are greatest. Despite their limited commercial potential, the first-generation PFBC and IGCC systems constitute important steps toward the development of higher-efficiency Group 2 and Group 3 systems. In contrast, the LEBS does not offer comparable growth potential, since it employs a simple steam (Rankine) cycle, whereas all of the Group 2 and Group 3 systems use combined cycles with potentially higher efficiencies.

The committee recommends that future investment of DOE resources in first-generation systems be based on realistic market expectations and value as an entry into new technology with high growth potential. At least 50 percent industry cost sharing should be required to demonstrate private sector confidence in these technologies.

Group 2 and Group 3 power generation systems depend on the successful development of several critical components, including high-temperature gas turbines, high-temperature heat exchangers, advanced high-temperature furnaces, fuel cells, hot gas cleanup technology, and high-efficiency gasification. The riskiest components appear to be the high-temperature ceramic heat exchanger required for the externally fired combined-cycle system and the hot gas cleanup systems required for advanced PFBC and needed for maximum-efficiency IGCC and IGFC systems. The 1370 °C to 1430 °C (2500 °F to 2600 °F) gas turbine required for Group 3 systems is within the state of the art for aviation systems but requires further development, demonstration, and testing for power generation applications. Fuel cells hold significant promise for efficiency advantages, but their high cost may be a barrier to widespread use of IGFC systems.

Gas cleanup is necessary to comply with environmental requirements and to protect advanced gas turbines from corrosive impurities, notably chlorine, volatile alkali metals, and particulates. Commercially available cold gas cleanup technology could be used for IGCC and IGFC systems, although this would incur higher costs and an efficiency penalty of approximately 2 percentage points for air-blown second-generation systems. In contrast, advanced PFBC systems require hot gas filtration since cooling the high-temperature, high-pressure combustion products would eliminate the advantages of PFBC. Thus, IGCC is a somewhat less risky technology than PFBC. Environmentally, IGCC has the advantage of producing by-product sulfur or sulfuric acid, whereas the use of limestone or dolomite for in-bed sulfur capture in PFBC systems can as much as double the amount of solid waste compared with IGCC systems. As suggested above, IGCC is also less risky than indirectly fired cycles (EFCC and HIPPS), which require significant technological development of high-temperature heat exchange components.

Gasification-based power generation systems offer the highest efficiencies for advanced systems, with IGFC efficiencies projected by DOE to be about 60 percent. Potential advantages of coal gasification combined-cycle systems include the high efficiencies obtained with a combined-cycle configuration, superior environmental performance, and the capability to replace natural gas combined-cycle systems in existing power plants. Thus, a strong incentive has been established for the development of high-efficiency coal gasification technologies optimized for power generation. The committee notes that gasification is also an important first step in the production of clean gaseous and liquid fuels from coal, as discussed below. Given the high cost of developing advanced power generation systems, the committee does not consider large-scale demonstration of numerous technology options with significant DOE cost sharing to be justified.

The committee recommends that second- and third-generation gasification-based systems be given the highest priority for new plant applications. Work on all the advanced systems should focus on acquiring the cost, emissions control, and efficiency information needed to select the most promising systems for further development. The limitations of critical components, such as heat exchangers, turbines, and fuel cells, and the timing and probability of technological success should be taken into account. This process should begin before FY 1996 and should include a rigorous comparative study of the design options.

The proposed FY 1995 budget supporting advanced combined-cycle systems in the FE R&D program is $173 million, split between the natural gas program ($113 million for fuel cells and advanced turbines) and the coal program ($60 million for IGCC, PFBC, and indirectly fired cycle [IFC]). In contrast, the proposed FY 1995 budget is $8 million for advanced pulverized coal. Within the coal program, DOE accords the highest funding level proposed for FY 1995 to the gasification combined-cycle systems ($28 million).

The Advanced Turbine Systems program, funded under the natural gas component of the FE R&D program, is charged with considering alternative fuels to natural gas, including coal-derived gas. In the opinion of the committee, advanced turbine materials alone will not be capable of resisting the corrosive effects of impurities in coal-derived gas, and a high level of gas cleanup will be needed. While cold gas cleanup can meet the necessary requirements for IGCC systems, hot gas cleanup has the potential for a simpler and lower cost approach and is an important part of the program to achieve DOE's efficiency goals for advanced technologies. Thus, hot gas cleanup is a high-priority area for both the CCT and the FE coal R&D programs. To date, neither hot gas desulfurization systems nor the more critical hot gas particulate removal systems has achieved the performance or cost requirements for commercial systems.

The committee recommends that a critical assessment of hot gas cleanup systems for advanced IGCC and PFBC be undertaken immediately to determine the likely costs and the ability to meet, within the next three to five years, all requirements for future high-temperature (>1260 °C [2300 °F]) turbine operation and environmental acceptability.

Commercialization Efforts

The increased complexity of advanced power generation systems implies not only that commercialization of new technology will be expensive but also that prudent stepwise scale-up from pilot plant through demonstration to commercial systems is necessary to minimize the technical risk at each stage. Thus, demonstration plants—such as those being constructed and operated under the CCT program—are an important step in establishing a commercially available technology. Given the high cost of advanced technology demonstrations, the committee recognizes the need for DOE cost sharing to promote U.S. technical leadership and competitiveness, particularly in environmental technologies. The majority of the ongoing CCT projects address advanced electric power generation systems and associated high-performance pollution control devices. While most of the demonstrations are not yet complete, the level of private sector support suggests that the programs have generally been thoughtfully chosen.

The committee recommends that DOE support of the current Clean Coal Technology program be continued and that the ongoing program be completed. While no further solicitations are planned under the existing CCT program, the FE coal R&D program should continue to cofund demonstrations of selected Group 2 and Group 3 advanced clean coal technologies beyond those currently being demonstrated by the CCT program.

When advancing a new technology to commercial maturity, the first-of-a-kind (or pioneer) commercial plant is generally more costly to build than subsequent plants and provides only partial information about operating, maintenance, and cost issues. Between two and five applications of a new technology are generally required for it to be considered mature and commercially demonstrated. The committee concluded that federal cost sharing of the risk differential between pioneer coal-based power plants and commercially available technologies has the potential to accelerate the commercial acceptance of many of the new technologies such that they will be available to meet market needs in the mid-term period (2006–2020).

The committee recommends that an incentive program be developed and implemented that would offset the capital and operating cost risks associated with early commercial applications of technologies previously demonstrated at a commercial scale.

CLEAN FUELS FROM COAL

Coal gasification is a costly and energy-consuming first step for all advanced coal uses. Current industry and DOE development of gasification systems, notably under the CCT program, focuses on needs for IGCC power generation; significant improvements in efficiency over current commercial systems are possible. In light of the outstanding promise of IGCC systems, as well as the production needs for clean gaseous and liquid fuels, the committee considers gasification to be an important area for R&D.

The requirements for gasification systems optimized specifically for power generation can differ from gasification systems suitable for production of marketable industrial gas, synthetic natural gas (SNG), and liquid transportation fuels. For example, air-blown systems with hot gas cleanup—if workable—might be appropriate for isolated power generation facilities, whereas for other uses and coproduct systems a higher level of cleanup is generally required, and dilution by nitrogen is undesirable. The committee considers gasification systems for both power generation and fuels production to be of importance for the DOE coal program, although there is currently little DOE activity on gasifiers aimed at the latter application. Opportunities for improvement are discussed in Chapters 6 and 9, where the committee identified an important role for DOE.

The committee recommends that an expanded DOE role be established to ensure the timely availability of the most efficient and economic gasification systems for future uses of coal in power generation and the production of clean gases and liquids.

Syngas can be converted by the Fischer-Tropsch process to produce liquid fuels and chemicals (indirect liquefaction), or it can be converted to hydrogen for subsequent reaction with coal to produce clean liquid fuels (direct liquefaction). The thermal efficiencies of direct and indirect liquefaction are estimated to be 60 percent and 50 to 55 percent, respectively.

For indirect liquefaction using Eastern bituminous coal and utility financing,[2] recent estimates of equivalent crude price fall between $30 and $35/bbl. Use of lower-cost Western coals is projected to reduce this cost by approximately $4/bbl. Studies of once-through Fischer-Tropsch synthesis with coproduction of electricity in an advanced IGCC facility indicate an equivalent crude cost reduction of $5 to $7/bbl. For stand-alone direct liquefaction plants, equivalent petroleum prices also are estimated to be in the $30 to $35/bbl range. Use of lower-cost Western coal together with coproduction of electricity and hydrogen for direct liquefaction would further reduce costs.

The above estimated costs of coal liquids are substantially lower than the costs presented in an earlier National Research Council study (NRC, 1990). The differences result from a combination of technological advances, higher prices for the low-sulfur and high-hydrogen content of the transportation fuels produced, the economic bases for the estimates, and, in some cases, the higher efficiencies resulting from coproduction with electricity. While the Fischer-Tropsch process is of great current interest to the petroleum industry for use in parts of the world where low-cost natural gas is available, R&D in direct liquefaction is, to an increasing extent, dependent on the DOE program to reach the target price of $25/bbl (1991 dollars; DOE, 1993b). However, a substantial reduction in funding (50 percent) for the DOE liquefaction program has been proposed for FY 1995. Given the historically unpredictable behavior of international oil markets and the current very limited industrial R&D on coal liquids, the committee believes that an important role for the DOE coal program is to maintain and develop U.S. technical expertise in coal liquefaction, thereby establishing the potential to reduce U.S. petroleum imports.

The more attractive economics for coal-derived liquids suggested in recent studies are dependent on the substantial premium now paid for diesel and jet fuels with zero aromatic and sulfur content. This premium accounts, in part, for the current international interest in converting natural gas to these products; however, overproduction could reduce the premium and diminish the attractiveness of liquids from coal. While such uncertainties reduce the incentive for large pilot plant and demonstration programs, the committee believes that there is a clear incentive for continued cost reduction through systems studies and research, including the evaluation of innovative concepts for direct liquefaction. Since 10 to 15 years are necessary to

[2]Utility financing assumes 25 percent equity and 15 percent internal rate of return. See Chapter 2 and the Glossary for a more complete discussion of financing.

complete a development and commercialization program, and since an equivalent crude price in the mid-$20/bbl does not seem unreasonable by 2010, there appears to be an opportunity for an important contribution by DOE to coal liquefaction technology.

The committee recommends that DOE's program for coal liquefaction technologies be continued at least at the FY 1994 level, with the goals of decreasing the cost of coal liquids and increasing overall efficiency.

Another opportunity lies in the coproduction of coal liquids and electric power. The commercial deployment of IGCC power systems is anticipated in the mid-term period, and opportunities may arise to establish coproduct plants—or "coal refineries"—to meet demands for both power generation and fuels. This strategy would reduce the financial risk associated with constructing large stand-alone liquefaction plants, although some increase in the financial risk associated with the power plant may be anticipated.

The committee recommends that an assessment of strategies for coproduction of premium liquid fuels with gasification-based power be an important component in planning a program for the introduction of liquid fuels from coal.

SYSTEMS ANALYSIS

Advanced coal-based systems for the production of electricity, fuels, and other products are characterized by increasing technical complexity and an expanding number of process options. Given the constraints on funding for DOE's coal program, and the high cost of developing and demonstrating advanced systems, the committee noted a need for quantitative assessment of the relative merits of different systems and subsequent choice of options to be pursued. Systems analysis has the potential to assist in such assessments, notably in selection of the most promising designs, optimization of complex process configurations, assessment of performance and cost advantages, process risks and trade-offs, and targeting of R&D to reduce critical uncertainties. Although DOE has a systems analysis activity spread among headquarters and its Morgantown Energy Technology Center (METC) and its Pittsburgh Energy Technology Center (PETC), the committee concluded that a major shortcoming of the current approach is a lack of systematic methods, assumptions, and design premises within and across the full suite of advanced energy conversion and environmental control processes.

The committee recommends an expanded and more prominent role for systems analysis in the development of RDD&C strategies within DOE's coal program. This activity should establish a clearly stated and consistent set of criteria, assumptions, and design premises that can be applied to all technologies in a given category to facilitate rigorous comparisons. Advanced methods of analysis, design, and risk evaluation should be adopted, and extensive interaction with the user community—notably U.S. industry—and active dissemination of major study results and methods should be pursued.

One application of the systems analysis activity identified by the committee is a thorough assessment and optimization of gasification systems, taking into account the likely future spectrum of gasification products. Similar assessments are also required for advanced power systems.

EPACT

In developing its conclusions and recommendations regarding future emphasis and priorities for DOE's coal program, the committee used a set of strategic planning criteria and scenarios for the near-, mid-, and long-term time periods, as discussed above and elaborated in Chapter 4. A major input to strategic planning is encompassed in the coal-related provisions of EPACT, which list technology areas and actions to be pursued by DOE.

In the final part of Chapter 10, the committee's conclusions and recommendations are interpreted in the context of EPACT. The committee's comments on DOE's response to individual coal-related sections of EPACT are summarized in Table 10-4. Priorities are given for DOE activities based on the committee's strategic planning approach, the development status of the technologies, and other industrial and federal programs. For example, if technologies are available commercially, the committee generally recommended low priority for DOE activities. Similarly, if there is extensive R&D in the private sector, the committee recommended that DOE leverage these efforts. The committee concluded that the current DOE coal program is responsive in varying degrees to all the coal-related provisions of EPACT addressed in the study. However, the committee observed that the balance of activities in the current DOE coal program differs from that mandated by EPACT.

The committee concluded that the DOE Advanced Clean/Efficient Power Systems program responds to the EPACT sections relating to coal-based power generation and is consistent with projected market demands for new generating capacity in the mid- and long-term periods (2006–2040). In this context the committee endorses DOE's decision to terminate the magnetohydrodynamics proof-of-concept program. Magnetohydrodynamics does not appear to offer significant advantages over other high-efficiency systems, and the next step in development would involve a costly demonstration program with high technical risk. While the committee considered the current CCT program to be an excellent start in the commercialization of advanced power generation technologies, it concluded that prevailing conditions in the power generation industry will necessitate further federal cost-sharing programs to accelerate commercial acceptance of many of these new technologies. The committee's major recommendations pertaining to EPACT Section 1301 (c), subparagraphs c(3), c(4), and c(5) are given above (see "Commercialization Efforts").

In contrast to power generation, the committee concluded that DOE activities in coal liquefaction fall short of EPACT requirements. Given the likely growth in demand for coal-based liquid fuels in the mid- to long-term periods and the decline in industrial liquefaction R&D, the committee considered that the priority accorded DOE liquefaction activities within EPACT is well founded and should be reflected in a revised DOE coal program. The committee recognizes that the decline in DOE support for liquefaction in recent years may be the result of funding constraints, a decline in international oil prices, and a high priority on shorter-term requirements to develop advanced power generation technologies. Nevertheless, the committee concluded that DOE should redress the balance of its fuel and power generation activities within the coal program to reflect the priorities of EPACT, commensurate with a planning horizon that assumes coal will continue to be a major domestic energy source well beyond 2010.

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PART I

STRATEGIC PLANNING FOR COAL

1

Introduction and Scope of the Study

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 percent of the nation's primary energy consumption. The domestic coal resource base is extensive, representing over 94 percent of proven U.S. fossil energy reserves (DOE, 1993). While the United States imports significant amounts of oil and gas, coal is a net export commodity for the U.S. economy.

Coal prices declined in real terms through most of the 1980s, due primarily to higher mining productivity, overcapacity, and competition from natural gas. The abundance and low cost of coal make it an attractive fuel, but the environmental controls required for coal combustion, together with the inconvenience of handling a solid fuel, have made natural gas and oil the fuels of choice in developed nations for many domestic, commercial, and industrial applications. Of the total 1992 U.S. domestic energy production, 32 percent (21.6 quadrillion Btu) was coal, 27 percent natural gas, and 23 percent crude oil, with the remaining 18 percent from nuclear power and renewables (EIA, 1993a).

Electricity generation is the single largest use of coal in the United States. Electric utilities consumed 87.4 percent of the total 1992 coal consumption of 892 million tons, while industrial users consumed 8.3 percent and coke plants 3.6 percent (EIA, 1993b). Over the past 20 years the electric utility industry's coal consumption has doubled. In 1992 coal-fired steam electricity generating plants accounted for 56 percent of the electricity produced in the United States.

Coal's continued viability as a domestic energy source will be strongly linked to its environmental acceptability relative to that of competing fuels such as natural gas. 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 assesses the directions of coal RDD&C strategies and priorities for the United States, with emphasis on programs funded by the U.S. Department of Energy (DOE).

The scope and objectives of this National Research Council study and the committee's approach to its task are further detailed below. Prior to reviewing DOE's coal programs and planning in Chapter 2, some essential background is provided in this chapter on relevant coal-related provisions of the Energy Policy Act of 1992 (EPACT) and on coal-related research and development (R&D) outside DOE, both in the private sector and overseas.

THE ENERGY POLICY ACT OF 1992

The major impetus for this study, EPACT, represents the culmination of several years of energy policy deliberations, prompted largely by the Bush administration's 1991 National Energy Strategy proposals (DOE, 1991). EPACT provides congressional guidance on a wide range of energy-related issues. Its provisions are intended to support a more competitive economy, a cleaner environment, and increased energy security.

EPACT enumerates many coal-related RDD&C activities, specifically as shown in Box 1-1. (Key coal-related provisions of the act are discussed further in Chapter 10 and reproduced in full in Appendix B.) The act gives the Secretary of Energy certain responsibilities for DOE's coal program and further requires the Secretary to submit reports to the Congress, including a plan to meet the objectives defined in the act's Title XIII—Coal, Section 1301. These high-level objectives focus on ensuring a reliable electricity supply, increasing the environmental acceptability of coal technologies, and achieving the cost-competitive conversion of coal to transportation fuels. Relevant technologies are to be available for commercial use by 2010. In addition to Subtitle A, subtitles B and C of Title XIII and Subtitle A of Title XX identify other coal-related activities to be implemented by DOE.

The principal technical areas EPACT identifies in sections relating to coal are electric power generation and conversion of coal to liquid and gaseous fuels. Nonfuel uses of coal—for coke, chemical feedstocks, and other products—also are addressed. EPACT emphasizes improving the environmental acceptability of the entire coal fuel cycle, from coalbed methane recovery, through power generation and conversion to fuels, to the utilization of coal wastes. A distinction is made between RDD&C activities described in Subtitle A of Title XIII and the Clean Coal Technology (CCT) program described in subtitles B and C. As discussed in Chapter 2, the latter program specifically addresses the need for cost-effective, high-efficiency, low-emission coal technologies ready for commercial application by 2010.

STUDY SCOPE AND OBJECTIVES

In May 1993 the DOE's Acting Assistant Secretary for Fossil Energy requested that the National Research Council assess DOE's coal program. In keeping with this request, the National Research Council formed the Committee on Strategic Assessment of the U.S. Department of Energy's Coal Program (see Appendix G for biographical sketches of committee members), to address the broad priorities that DOE's Office of Fossil Energy ought to consider in updating its strategic plan and in responding to EPACT. Recent or current DOE programs have addressed, or are addressing, many of the areas identified in EPACT.

The National Research Council committee was specifically charged as follows:

- Review the DOE coal program, including the current version of the coal strategic plan and additional details contained in the administration's budget requests for fiscal year (FY) 1994 and FY 1995, as appropriate.
- Review the relevant sections of EPACT (identified above in Box 1-1) and the DOE coal program vis-à-vis both EPACT provisions and coal-related R&D outside DOE.

- Recommend objectives, including performance and schedule, that ought to be emphasized for those areas in EPACT that are not in the current DOE coal program.
- Make recommendations pertaining to EPACT Section 1301(c), especially subparagraphs c(3) through c(5), which relate to the modification and extension of existing demonstration and commercialization programs to ensure the timely availability of advanced coal-based technologies.
- Identify priorities for DOE's future coal program, based on the foregoing reviews and recommendations and on the assumption that the future budgets appropriated for the DOE coal program will remain at the FY 1994 level in real terms.

(See Appendix A for a detailed description of the project and the charge to the committee.)

THE COMMITTEE'S APPROACH

To address its charge, the committee conducted four major tasks: (1) acquisition and review of information on DOE's current coal programs and planning; (2) development of a strategic planning framework, including criteria for program objectives, timing, and priorities; (3) assessment of current and alternative coal RDD&C activities in the context of EPACT and the committee's strategic planning framework; and (4) development of conclusions and recommendations based on all the foregoing committee activities.

DOE's "Coal Strategic Plan" was still in preparation and not available during the conduct of the study. The committee therefore used a number of other documents that DOE provided to obtain an overview of current and planned coal-related RDD&C activities. Documentation provided by DOE is referenced as appropriate throughout this report. This information was supplemented by DOE staff presentations to the committee (see Appendix F).

In developing a framework for strategic assessment of the DOE program, the committee sought to reflect the key factors likely to affect future coal use in the United States and elsewhere. Scenarios were developed for three time periods: near-term (1995–2005), mid-term (2006–2020), and long-term (2021–2040). The committee defined these time periods based on anticipated major trends in coal use. For the near-term period—over the next 10 years—scenarios for coal use will likely remain similar to those of today. Power generation will continue to be the principal U.S. use of coal, although the need for new baseload power generation facilities will be low. The mid-term period (2006–2020) will likely be one of transition. Power generation will remain the largest coal use, with substantial demand for new generating capacity. Interest in the production of synthetic fuels from coal will also likely increase significantly in response to rising international oil prices. In the long term (2021–2040) the balance of coal uses may well shift, with liquids and other clean fuels from coal becoming increasingly important compared to power generation. The emphasis on power generation will continue to be significant, but the need to minimize carbon dioxide (CO_2) and other emissions will impose severe demands on efficiency and emission control systems, resulting in increased interest in other energy sources.

To develop scenarios for the three periods and related RDD&C planning criteria, the committee devoted significant effort to identifying those factors that would affect the use of coal (see Chapter 3). The committee explored alternative views of future energy needs, environmental control requirements, institutional factors, international developments, and resource availability. The information and perspectives developed were then used to assess current DOE programs and to draw conclusions and recommendations consistent with the committee's strategic planning framework and its overall charge.

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.

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 electricity, 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 CCT program.

International Activities

In Organization for Economic Cooperation and Development (OECD) countries, 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 (SO_2), oxides of nitrogen (NO_x), and CO_2 emissions from power plants (IEA, 1993). 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 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 percent 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 percent of the program costs (ECUs = European currency units; at present 1 ECU = US$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, NO_x emission controls, atmospheric fluidized-bed combustion (AFBC), pressurized fluidized-bed combustion, gasification, and an integrated gasification combined cycle (IGCC) plant (Commission of the European Communities, 1992).

ORGANIZATION OF THE REPORT

The remaining chapters in Part I of this report elaborate on issues and findings central to the committee's formulation of a strategic planning framework. Chapter 2 provides an overview of current DOE coal-related programs and planning, highlighting the current program structure and recent budget trends. Chapter 3 discusses principal issues for future U.S. coal use, including potential markets, the requirements for coal use, the domestic energy resource base, and competing energy sources for various applications. Special attention is given to environmental requirements and the institutional factors that will shape the future of coal technologies. The findings presented in chapters 2 and 3 were used by the committee to develop a framework for DOE strategic planning, a framework summarized in Chapter 4. This framework provides the basis for a more detailed assessment of DOE programs and planning.

Part II of the report (chapters 5–9) provides more detailed evaluations of current DOE programs with respect to the strategic planning criteria. Chapters 5 through 7 follow the fuel cycle, with Chapter 5 addressing coal preparation, coal-liquid mixtures, and coalbed methane recovery: Chapter 6 addresses coal conversion to clean fuels and specialty products, and Chapter 7 covers electric power generation. Chapter 8, on technology demonstration and commercialization, and Chapter 9, on advanced research programs, describe a variety of cross-cutting activities within DOE's coal program. In all cases the discussions focus on the main technical issues, including both risks and opportunities, that must be considered in developing a coal program.

In the final section of the report, Part III, the information in parts I and II is synthesized to develop conclusions and recommendations on the strategic priorities for DOE's RDD&C on coal-related technologies and to address other provisions of the committee's charge related to EPACT (Chapter 10). Appendixes provide additional background in support of the committee's work. A glossary provides explanations of the acronyms used and of major technical and economic conventions the committee adopted.

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Box 1-1
Sections of the 1992 Energy Policy Act Considered by the Committee

TITLE XIII—COAL

Subtitle A: Research, Development, Demonstration, and Commercial Application
- Section 1301: Coal Research, Development, Demonstration, and Commercial Application Programs
- Section 1302: Coal-Fired Diesel Engines
- Section 1303: Clean Coal, Waste-to-Energy
- Section 1304: Nonfuel Use of Coal
- Section 1305: Coal Refinery Program
- Section 1306: Coalbed Methane Recovery
- Section 1307: Metallurgical Coal Development
- Section 1308: Utilization of Coal Waste
- Section 1309: Underground Coal Gasification
- Section 1310: Low-Rank Coal Research and Development
- Section 1311: Magnetohydrodynamics
- Section 1312: Oil Substitution Through Coal Liquefaction

Subtitle B: Clean Coal Technology Program
- Section 1321: Additional Clean Coal Technology Solicitations

Subtitle C: Other Coal Provisions
- Section 1332: Innovative Clean Coal Technology Transfer Program
- Section 1336: Coal Fuel Mixtures
- Section 1337: National Clearinghouse

TITLE XX—GENERAL PROVISIONS; REDUCTION OF OIL VULNERABILITY

Subtitle A: Oil and Gas Supply Enhancement
- Section 2013: Natural Gas Supply

2

Overview of U.S. Department of Energy Programs and Planning

This chapter reviews trends in DOE's coal program since the late 1970s and outlines the current program structure and recent budgets. DOE's current strategic planning also is summarized.

MAJOR TRENDS IN THE DOE COAL PROGRAM

Trends in federal funding for coal-related R&D since DOE's inception are illustrated in Figure 2-1. 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 Figure 2-1 shows.

The intense interest in and funding of federal energy R&D during the 1970s was replaced by the Reagan administration with 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 phase-out 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 (see Appendix C). 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 Figure 2-1. 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 percent of total demonstration cost.

During the Bush administration, the National Energy Strategy report was published, providing an overall administration strategy for energy policy (DOE, 1991). 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 (Clinton and Gore, 1993). 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 CO_2 per unit of energy than coal or oil), improved energy efficiency, and renewable energy technologies that release no net CO_2 to the environment. As discussed below, decreased coal R&D funding has accompanied these new emphases.

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.

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 (Figure 2-2).[1] 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 controls 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 2-1 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 percent (almost 30 percent 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) to 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[2] components of the coal program experienced funding reductions of about 30 percent (in current dollars) between FY 1992 and 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.

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 I through CCT-Round V), in which industry would provide at least 50 percent of the cost of design, construction, and operation of the

[1]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 Figure 2-2.

[2]Excluding the fuel cell activity.

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 2-2 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.

DOE'S STRATEGIC PLANNING

The Department of Energy Strategic Plan

DOE's overall strategic plan (DOE, 1994b) defines the department's mission as follows:

> The Department of Energy, in partnership with our customers, is entrusted to contribute to the welfare of the Nation by providing the technical information and the scientific and educational foundation for the technology, policy, and institutional leadership necessary to achieve efficiency in energy use, diversity in energy sources, a more productive and competitive economy, improved environmental quality, and a secure national defense.

The DOE plan provides a vision, goals, strategies, and success indicators for each of the department's five business areas. Under "Industrial Competitiveness," DOE's laboratory system, R&D capabilities, and core competencies in such areas as energy and environmental technologies are considered valuable resources the private sector can tap through collaborative programs. DOE work under "Energy Resources" is based on the assumption that fossil fuels will remain critical components of energy supply in every nation for the foreseeable future. In the United States, coal, natural gas, and oil will continue to provide most of the energy for electricity generation and the building, industrial, and transportation sectors. A major focus in this area is using fossil fuels more efficiently and cleanly. The business area "Science and Technology" faces the challenge resulting from the continuing industry shift away from basic research. Given constraints in federal spending, DOE must balance its long-term fundamental research against R&D that will help industry compete effectively in the near term. Specific goals include providing the science and technology core competencies that will enable DOE's other businesses to succeed in their missions and adding value to the U.S. economy through the application of new and improved technologies. "National Security" is concerned primarily with transformation of the nuclear weapons complex, activities that are not within the scope of this report. Similarly, "Environmental Quality" addresses mainly nuclear issues, namely, the decontamination and decommissioning of weapons complex facilities and nuclear power plants.

The current DOE strategic plan generally expands on EPACT goals. EPACT will continue to provide guidance to the department in achieving its energy objectives, although, as DOE's plan notes, fulfilling EPACT's detailed requirements "will be difficult in this era of fiscal constraint."

Clean Coal Technologies Research, Development, and Demonstration Program Plan

DOE's Office of Fossil Energy is currently developing a "Coal Strategic Plan." As noted in Chapter 1, this document was not available during the conduct of this study. In the meantime, 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 (DOE, 1993b). This planning document should be distinguished from the similarly named but programmatically distinct Clean Coal Technology program, that is, the program usually referred to as the CCT program. Activities described in the Clean Coal Technologies RD&D Program Plan include, but are not limited to, the CCT program. For example, development of PFBC systems will involve subsystem and component testing, environmental and economic performance studies, and pilot plant tests, all funded under the FE R&D program; first- and second-generation PFBC demonstrations will be conducted under the CCT program.

The RD&D Program 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 percent of the demonstration costs.

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. Specifically, the following two program goals are defined:

- enabling the use of coal as a secure, low-cost domestic energy source to support economic competitiveness and employment growth and
- contributing to the environmental acceptability of coal utilization.

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 CCT activities, and the detailed organization and funding of advanced research and cross-cutting technology programs is complex (see Chapter 9).

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 reduced environmental impacts, higher efficiency, and higher reliability levels and to accelerate commercialization of such technologies. This program's strategic objectives are shown in Table 2-3. More specific objectives for individual technologies are presented in the RD&D Program Plan (DOE, 1993b).

The advanced fuel systems program described in the RD&D Program Plan supports technologies to produce clean gaseous and liquid fuels and chemicals 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 (DOE, 1993b), 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 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 percent equity financing has been more commonly practiced. Hence, the term "utility financing" is frequently used to describe highly leveraged investments, 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 the committee notes that 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 (DOE, 1993b). 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.

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 Chapter 10). The study's conclusions and recommendations on DOE program goals and priorities stem from that evaluation.

SUMMARY

Federal funding for coal R&D has fluctuated substantially over the past two decades, particularly in response to the energy supply uncertainties of the 1970s. The DOE coal R&D budget increased rapidly in the late 1970s, reaching a peak of over $1 billion per year in FY 1981 (current dollars), but declined sharply in the early 1980s, especially funding for coal liquefaction R&D. The FY 1994 FE coal R&D budget was less than $200 million per year (current dollars), representing a decrease of approximately 50 percent in real terms over the past 10 years. Over the past three years, the oil and natural gas components of the FE R&D program have grown at the expense of the coal component. The increase in natural gas funding is largely in response to the availability and environmental acceptability of low-cost natural gas, although the possibility of using coal-derived gas is recognized.

Since 1986, the CCT program, which is budgeted separately from the coal R&D program, has been appropriated $2.75 billion in federal funding for the demonstration of advanced coal technologies, with emphasis on clean, efficient power generation systems. The CCT program represents a marked departure from traditional DOE FE R&D programs in that industry partners must contribute at least 50 percent of the demonstration cost. In addition, there is a strong emphasis on technology commercialization.

DOE's strategic planning for coal focuses on the need to exploit coal as a secure, low-cost domestic energy resource and to increase the environmental acceptability of coal use. DOE has defined corresponding quantitative goals for the advanced power and fuel systems programs. Partnership with industry is envisaged as a key component in the future development of coal-based technologies.

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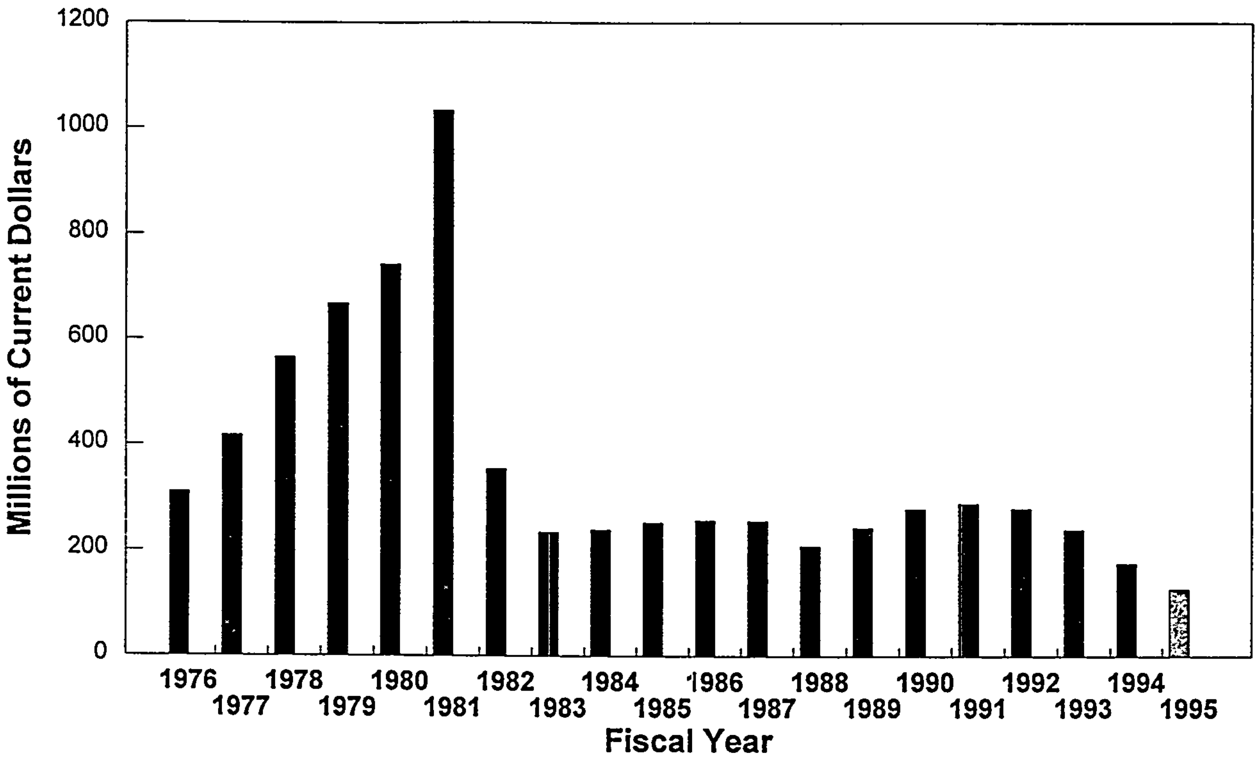

Figure 2-1 History of funding for coal R&D under DOE's Office of Fossil Energy R&D budget. Sources: DOE budget archives; DOE (1994a).[a]

[a]Data shown in Figure 2-1 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 supplementals, rescissions, reprogrammings, etc., that took place after enactment of the appropriations bills. 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 C.

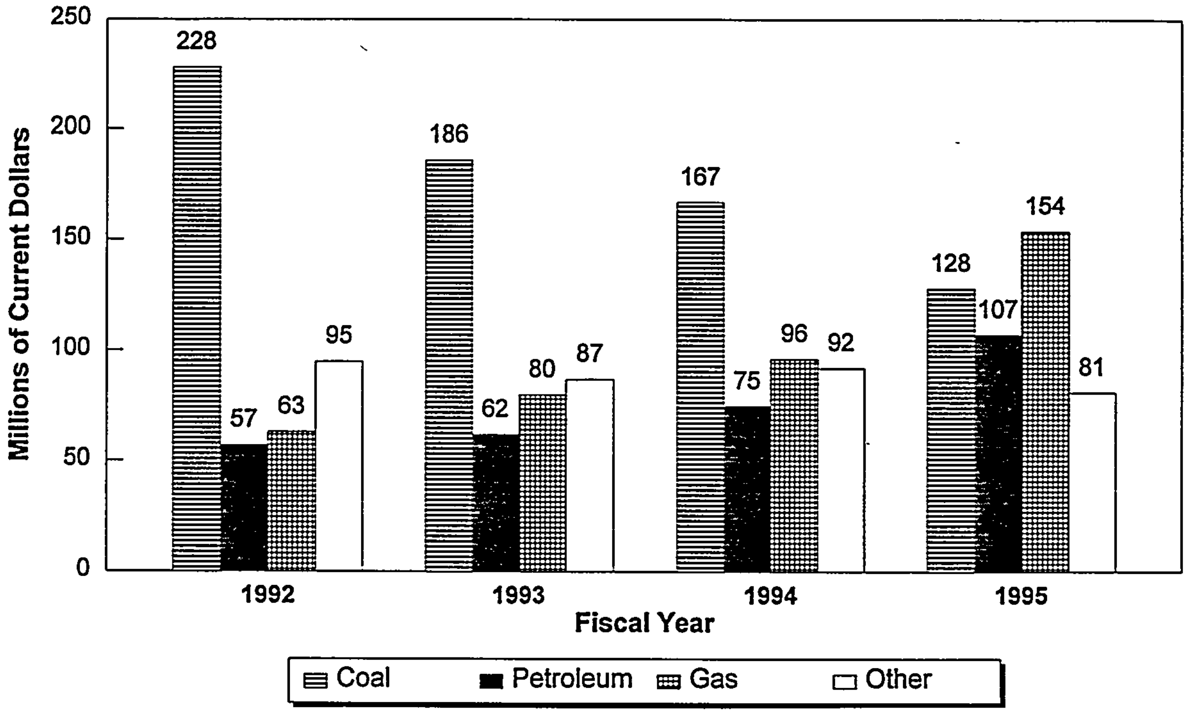

Figure 2-2 Recent budget trends for DOE's FE R&D programs. Sources: DOE, 1993a, 1994a.

Table 2-1 Fossil Energy Coal R&D Program Budget (millions of current dollars appropriated)

Program Element	FY 1992	FY 1993	FY 1994	FY 1995 (request)
Advanced Clean Fuels				
Coal Preparation	15.1	9.9	11.3	5.5
Direct Liquefaction	19.4	15.7	11.4	5.6
Indirect Liquefaction	13.7	16.2	9.1	7.6
Advanced Research and Environmental Technology	7.1	5.9	5.2	0.8
Systems for Coproducts	4.3	1.5	3.9	0.6
Subtotal	59.6	49.2	40.9	20.1
Advanced Clean/Efficient Power Systems				
Advanced Pulverized Coal-Fired Power Plant	8.2	9.1	9.1	7.6
Indirect-Fired Cycle	24.6	12.1	14.4	11.9
High-Efficiency IGCC[a]	18.0	19.5	27.2	28.1
High-Efficiency PFBC[b]	18.6	18.5	24.1	20.4
Advanced Research and Environmental Technology	26.8	21.7	17.8	13.4
Magnetohydrodynamics	39.9	29.9	4.8	—
Fuel Cells[c]	51.0	51.1	—	—
Subtotal	187.1 [136.1][d]	161.9 [110.8][d]	97.4	81.4
Advanced Research and Technology Development				
Coal Utilization Science	4.0	1.9	3.1	3.1
Materials and Components	9.2	8.9	10.7	7.8
Technology Crosscut	10.8	9.6	9.3	9.4
University/National Laboratory Coal Research	5.9	5.9	5.9	6.0
Subtotal	29.9	26.3	29.0	26.3
TOTAL	276.6 [225.6][d]	237.4 [186.3][d]	167.3	127.8

[a]Integrated gasification combined-cycle.
[b]Pressurized fluidized-bed combustion.
[c]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).
[d]Excluding fuel cells.
Sources: DOE (1993a, 1994a).

Table 2-2 Authorized Funding for the CCT Program (millions of current dollars)

Solicitation Round	FY 1986–FY 1994	FY 1995	FY 1996	FY 1997	Total
CCT-I	398				398
CCT-II	575				575
CCT-III	575				575
CCT-IV	450	100	50		600
CCT-V	225	275	100		600
Total	2,223	375	150	0	2,748

Source: DOE (1994c).

Table 2-3 Strategic Objectives of DOE's Advanced Power Systems Program

	Period			
Objective	2000	2005	2010	2015
Efficiency[a] (percent)	42	47	55	60
Emissions[b]	1/3	1/4	1/10	1/10
Cost of energy	10 to 20 percent lower than currently available pulverized coal technology			

[a]Based on fuel higher heating value (see Glossary). A DOE presentation to the committee also noted CO_2 reduction objectives of 24, 32, 42, and 47 percent for each of the four periods, respectively, based on energy efficiency improvements (Feibus, 1993). All these values are calculated assuming a base plant efficiency of 32 percent.

[b]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 (1993b).

3

Trends and Issues for Future Coal Use

The present chapter reviews those 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. The introductory section on markets for coal and coal utilization technologies highlights the importance of coal to the U.S. economy and addresses international issues to the extent that they are likely to influence U.S. coal use and U.S. development of coal-based technologies. A major part of the chapter is devoted to a discussion of coal use for electricity generation, the single largest consumer of coal in the United States. Recent changes in the electric utility industry are considered, especially regarding the commercialization of new coal-based power generation technologies and opportunities for joint production of electricity and other products. Following a brief overview of projected U.S. electricity requirements, trends in the availability and use of competing energy sources for power generation are discussed. Issues associated with other uses of coal, namely, the manufacture of clean fuels and other products, are then addressed. Finally, the chapter discusses the environmental regulations affecting coal use.

DOMESTIC AND INTERNATIONAL MARKETS

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 to 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 (IEA, 1993a). China is a special case: it is the world's largest coal producer, but almost all of its coal is consumed domestically (Doyle, 1987). 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 (DOE, 1993a).

In the United States, as elsewhere, coal production has a significant impact on the domestic economy. A recent study from the Pennsylvania State University notes that the direct contribution of coal production to the economy has a value of $21 billion annually, while indirect contributions reach $132 billion (Energy Daily, 1994).

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. These trends are expected to continue, with environmental constraints on coal combustion becoming more stringent.

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 to $6/per metric ton cheaper than U.S. coals (Coal Week International, 1994). About 10 percent of the coal used in the United States during the first decade of the next century will likely be imported (EIA, 1994a).

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 per year or more, the average price at the mine decreased in 1992 for the tenth straight year, to $21.03 per ton (NCA, 1993a).[1] 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 percent), Asia (20 percent), and North America (15 percent) (IEA, 1993a). 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 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. For example, U.S. coal with an energy content of 12,000 Btu/lb is delivered to Rotterdam from Baltimore at a price of $\$1.51/10^6$ Btu, while similar coal from Colombia is delivered at $\$1.31/10^6$ Btu and from South Africa at $\$1.27/10^6$ Btu (Coal Week International, 1993). These and other competitor producing countries are expanding their coal exporting capability. Thus, exporting U.S. clean coal technology will probably not open any significant new markets for U.S. steam coal.

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[1]Unless otherwise noted, all "tons" referred to in the text are short tons (i.e., 2,000 lb or 0.91 metric tons).

Markets for 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 (DOE, 1993a). 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 percent larger in total size than the market for new capacity. About 45 percent of the retrofit market lies in developing countries, notably China. Significant markets also exist in Eastern Europe and the former Soviet Union (DOE, 1993a).

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 (Coal and Synfuels Technology, 1993). 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 (DOE, 1993b).

Other major factors affecting coal technology markets will be the balance between the costs of mining and transporting coal and the higher capital costs of cleaner, more efficient plants. Where coal is abundant, mining and transportation costs are low, and environmental requirements are minimal, there will be little driving force to use the more expensive technologies. Such circumstances generally hold now in China. As environmental constraints develop or fuel prices increase, there will be incentives to use more efficient and cleaner technologies. Indeed, China, with its abundant coal reserves, rapidly industrializing economy, and large population, is undoubtedly the largest potential market for U.S. clean coal technology over the long term. For the near term, however, new power plants in China will most likely use well-demonstrated technology and cheap Chinese coal to produce low-cost power.

Domestic markets for coal utilization technologies are discussed in the remaining sections of this chapter, with emphasis on opportunities and requirements for electricity generation.

COAL USE FOR DOMESTIC ELECTRICITY GENERATION

Electric power generation is by far the largest market for coal in the United States, representing over 80 percent of annual coal consumption. Assessing current and projected electricity demand is thus essential to understanding the future role of coal and the scope of an appropriate RDD&C program. The following section reviews the changing structure of the U.S. electric utility industry, current projections of future electricity demand, and the outlook for competing sources of energy for power generation over the time periods of interest for this study.

Changing 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 nonutility 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 (Harunuzzaman et al., 1994). 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 report 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.

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 (Harunuzzaman et al., 1994) 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. Federally supported R&D is unlikely to be an adequate substitute for industry-funded R&D over all timeframes. However, in the near term some federal support may facilitate more rapid development of technological solutions to problems of national importance, such as reducing the environmental impact of coal-based power generation as required by EPACT, Title XIII, Section 1301.

The Availability of Coproducts

Under traditional regulation, electric utilities specialized in, and had a monopoly on, the production and distribution of electricity. 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 Chapter 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.

Projected Electricity Requirements

Table 3-1 gives growth rates observed and projected by the Energy Information Administration (EIA) for U.S. electricity demand from 1960 through 2010. According to the most recent EIA projections (EIA, 1994a), electricity demand will grow 1.0 to 1.5 percent per year to 2010, while the gross domestic product over the same period will grow 1.8 to 2.4 percent 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 percent per year from 1993 to 2010, during which time there will be a 2.3 percent annual increase in the gross domestic product (Makovich and Smalley, 1993). 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 Figure 3-1 (EIA, 1994a). 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 73 GW, accounting for a large share (40 percent) of total new capacity additions of 183 GW over the forecast period. Figure 3-1 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 (Makovich and Smalley, 1993).

Table 3-2 compares several forecasts of total U.S. generating capacity in 2000 and 2010. Detailed comparison of these estimates is difficult because of differences in the reporting of generating capacity, such as the inclusion or exclusion of cogeneration capacity. However, all the projections for 2010 indicate a need for significant generating capacity increases compared with the 1992 value of 742 GW (EIA, 1994a). An energy forecast that relies less on historical trends and more on market forces and rapid deployment of new, high-efficiency technologies projects a total generating capacity in 2010 of 712 GW (The Alliance to Save Energy et al., 1992). Despite these different assumptions, coal is still 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 (Makovich and Smalley, 1993), 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 (Makovich and Smalley, 1993). 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 to 45 years), utilities appear to be planning to continue using them for the foreseeable future (EIA, 1994b).

The choice of technologies to meet additional generating capacity requirements depends on both peak load and baseload needs. Peak load 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 (EIA, 1994a), 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. Peak load requirements are anticipated to increase from 589 GW in 1994 to 804 GW in 2010 (Makovich and Smalley, 1993).

Energy Sources for Power Generation

How much of the projected demand for electricity is likely to be supplied by coal? This section addresses the major competing sources of energy for electric power generation over the time periods of interest for this study. More extensive discussions can be found in the various references cited throughout this section.

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 (EIA, 1992). 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; EIA currently uses an estimate of 56 percent of the DRB, which equals 265 billion tons. Estimates of recoverable reserves vary with location. They are typically about 60 percent of DRB for eastern underground mines and 90 percent of DRB for western surface mines (NCA, 1993b).[2] 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 3-3. Estimates of coal's share of the power generation market in 2010 range from 45 to 58 percent, slightly lower on average than the current value of 56 percent. New coal-steam units are expected to account for 25 percent (42 GW) of all new capacity additions through 2010, with approximately three-fourths of the new coal-fired capacity coming online after 2000 (EIA, 1994a). This 42 GW of new coal capacity is equivalent to 140 new power plants in the 300-MW size range.

Natural Gas

In recent years natural gas has become the fuel of choice for new capacity additions because of its lower prices and lower capital investment requirements and more stringent environmental rules. While domestic gas resources are adequate to support this trend in the near term, the depletion of domestic gas resources will likely result in their 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 (Potential Gas Committee, 1993). 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 3-4 gives National Petroleum Council estimates of the effect of wellhead price on the recoverable resource.

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 3-4). 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 depletion. Major technological advances would extend the period of economic gas production.

EIA and GRI projections for the supply of natural gas and its disposition (see Table 3-5) indicate that domestic production and imports will increase to meet demand. The increase in domestic production will require the use of new gas recovery technology, which will account

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[2]The fraction of the DRB that is recoverable has recently been estimated for the Central Appalachian coal mining region, which encompasses the states of Kentucky and West Virginia. The study revealed that only 50 percent of the reserve base was potentially recoverable because of various mining, environmental, social, economic, and regulatory factors (Carter and Gardner, 1993). Considering additional restrictions in the form of coal mining factors, recovery factors, and economic factors further reduced the economically recoverable coal resource to between 4.2 and 26.4 percent of the DRB (Rohrbacher et al., 1993).

for 29 percent (7.5 quads[3]) of the 2010 gas supply. By 2010, gas imports will have risen to approximately 15 percent (3.8 quads) of the total supply, and power generation will consume between 4 and 5 quads of gas, or approximately 18 percent of the supply.

Projections for delivered gas prices for electric utilities are summarized in Table 3-6. Both EIA and GRI projections show these prices increasing, EIA more so than GRI. As natural gas prices increase, there will be a point at which coal-derived electricity is more economical. For greenfield natural gas-fired combined-cycle units versus coal gasification combined-cycle units, this crossover price is in the range of $4.00 to $5.00/million Btu.[4] The crossover gas price depends on a number of factors, such as the capacity factor at which the power-generating unit is operated, the lifetime of the investment, and the delivered price of coal. The price range just given represents capacity factors between 50 and 70 percent, coal prices between $1.00 and $1.60/million Btu (between $21.0 and $33.6 per ton), and a power plant lifetime of 30 years. A higher-capacity factor may apply to advanced coal plants; this would decrease the crossover price, while a shorter amortization period would raise it.

Similar analyses can be made for repowering applications using coal-fueled integrated gasification combined-cycle (IGCC) or pressurized fluidized bed combustion (PFBC) technology. Under the same assumptions as before, coal-based systems become economical when gas prices reach $3.50 to $4.50/million Btu.[5] The gas price projections in Table 3-6 suggest that advanced coal technology will become more economical than gas for both repowering and greenfield applications between 2005 and 2010.

Construction of a power plant in 2005, for example, will involve assessing the likelihood of increasing gas prices and decreasing supply during the 30-year (or longer) plant lifetime. In addition, extended growth in high-priority residential and commercial gas consumption is anticipated (EIA, 1994a). Thus, the EIA projection that new electric generating capacity will depend primarily on coal after 2000 seems well founded.

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 currently. Several LNG facilities were built on the East and Gulf coasts of the United States

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[3]One quad (= 10^{15} Btu) = 0.97 Tcf, assuming an average Btu content for natural gas of 1,028.4 per cubic foot.

[4]Personal communication from N.A. Holt to G.T. Preston and J.H. Wootten, April 1994.

[5]Ibid.

during the 1970s. At the time, domestic natural gas availability was limited, and rolled-in pricing permitted the high LNG cost to be cross-subsidized by low-priced, regulated gas.[6] 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.

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. Although world reserves of crude oil are not as large as those of natural gas, they are still very large, and the cost of landing crude oil in the United States is substantially less than comparable costs for LNG. 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 did in the past.

Nuclear Power

Nuclear power accounted for 21 percent of U.S. electric power generation in 1993 and 14 percent 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 fission, 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 likely to impede any significant growth of nuclear capacity

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[6]"Rolled-in pricing" is the term used for the practice of purchasing high-cost gas to mix with low, price-controlled gas. The resulting average price was not prohibitively high, and natural gas continued to be in demand. Also, there was an apparent market for the high-cost supplies. The system worked only so long as there was a price-controlled "cushion" of low-cost supplies. With price controls gone, all gas is now priced at the market, and there is no longer an ability to mix high- and low-cost gas.

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. The support of further development and use of nuclear power in the United States and worldwide will depend on growth in overall electricity demand, regulatory evolution, the direction of the global climate change debate, and resolution of public concerns with operational safety and waste disposal. Policy actions that increase the cost of fossil fuel use would make nuclear power more competitive.

Renewable Energy

Most electricity from renewable resources in the United States comes from hydroelectric power, which in 1993 accounted for about 10 percent of installed generating capacity and 9 percent of electricity generation. Other renewable sources accounted for 0.3 percent of electricity generation in 1993: geothermal, biomass wastes (almost all forest industry, with a small contribution 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 3-7). These data indicate likely decreases 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 (Preston, 1994). 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 percent by 2010, according to EIA, 1994a), they are not expected to become dominant sources of bulk power generation during the periods addressed in this study.

COAL USE FOR LIQUID AND GASEOUS FUELS

While electric power generation is expected to be the principal use of 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. The outlook for coal-derived liquid and gaseous fuels is discussed in Chapter 6.

Resource Base for Petroleum and Bitumen[7]

Liquid hydrocarbon resources can be classified on the basis of viscosity as conventional petroleum, heavy oil, and tar (or bitumen).[8] 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, current production is restricted by the higher production and refining costs. Estimates of world and U.S. petroleum resources are shown in Table 3-8.

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[9] (Riva, 1991). The total world resource for heavy oil is estimated to be 600 billion bbl (equal to 35 percent of the conventional petroleum resource). About 50 percent of the heavy oil resource occurs in Venezuela and about 30 percent in the Middle East. The total resource for tar sands is approximately 3,500 billion bbl, but only 5 to 10 percent of this amount is currently considered to be economically recoverable. Here Canada is dominant, with 75 percent 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,[10] the delivered 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.

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[7]The resource base for natural gas was discussed above in the context of fuels for power generation.

[8]Defining viscosities are as follows: conventional petroleum, less than 100 centipoise (cp); heavy oil, 100 to 10,000 cp; tar or bitumen, greater than 10,000 cp.

[9]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.

[10]Based on projected minemouth price in 2010 of $30.9/ton (EIA, 1994a) and Btu content of approximately 21 million Btu/ton.

OTHER USES OF COAL

Coal still has some limited 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 (EIA, 1994a). 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 3-9. 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 derived substances principally from 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 practical 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.

ENVIRONMENTAL ISSUES FOR COAL USE

Environmental concerns will have the greatest influence on future coal use for power generation in the industrialized countries (IEA, 1993b). 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 information on the current status of control technologies. Appendix D reviews recent trends in U.S. regulatory policy and technology approaches to address environmental issues. Emissions control technologies are discussed in more detail in Chapter 7.

National ambient air quality standards for particulate matter, sulfur dioxide (SO_2), nitrogen dioxide (NO_2), and photochemical ozone were promulgated under the 1970 Clean Air Act to protect human health and welfare throughout the country.[11] 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, both 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 concerns, including 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 (CAAAs) 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 Figure 3-2. Air pollution control devices today achieve emission levels well below federal NSPS. The most efficient wet scrubbers reduce SO_2 emissions to about one-fourth to one-sixth of NSPS requirements (98 percent control). The most efficient commercial systems yield particulate emissions of about one-half to one-quarter NSPS levels (99.9 percent 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 to 60 percent control). In Japan and Germany, postcombustion controls achieving up to 80 percent NO_x reduction (about one-third to one-sixth NSPS levels) are in widespread use on low-sulfur coal plants. These controls have 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_x controls that employ selective catalytic reduction have been

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[11]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 (NRC, 1992a).

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_x reductions at existing and new coal-based power plants are likely to achieve national ambient air quality standards for tropospheric ozone. Also possible are new standards for fine particulates. Future NO_x controls would likely exceed the modest reductions (10 percent 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 to 25 tons per 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 to 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 (Zeugin, 1992). 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_2) from coal combustion. Over the mid to long term, CO_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_2 emissions controls. However, the preponderance of scientific opinion—as reflected, for example, by a recent NRC study (NRC, 1992b)—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_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_2 emissions.

The most cost-effective method of reducing CO_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 Chapter 2). Technology exists to remove CO_2 from combustion gases and other coal-based gas streams, but the costs of doing so are high (MIT, 1993), and no proven methods yet exist for disposing of the collected CO_2. Beyond the 2040 planning horizon considered in the present study, 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 (NRC, 1990).

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.[12] About 30 percent of concentrated methane from wells in the coal seam is now collected and used. The ventilation air exhaust, which typically contains less than 1 percent methane, is not generally collected and makes up over 70 percent of the total methane released to the atmosphere from coal mining (CIAB, 1992). Estimates indicate that the greenhouse effect of the methane released from underground coal mining represents up to 8 or 9 percent of the greenhouse effect of the CO_2 released in burning the mined coal.[13] For a 40 percent 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 percent. 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.

Emissions of nitrous oxide (N_2O), another greenhouse gas, also arise from coal combustion. Because N_2O is formed primarily at relatively low temperature and pressure, the largest emissions rates are associated with atmospheric fluidized-bed combustion systems. Overall, N_2O emissions from coal combustion worldwide are estimated to contribute less than 1 percent of total global warming emissions. The primary sources of N_2O worldwide are fertilizers and agricultural wastes (NRC, 1992b).

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 control of hazardous or toxic trace chemical species and a general tightening of effluent emission standards at existing and new facilities (Rubin, 1989). 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,

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[12]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).

[13] 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_2. On a weight basis, the direct and indirect effects of methane have been estimated to be 21 times more powerful than CO_2 as a greenhouse gas (NRC, 1992b). The greenhouse effect of the methane released from mining compared to the effect of CO_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.

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 reuse 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.

SUMMARY

The principal findings from the preceding review, summarized here, form the basis for the strategic planning scenarios developed by the committee and presented in Chapter 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 through 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 through 2010 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, 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. However, 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 to $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.

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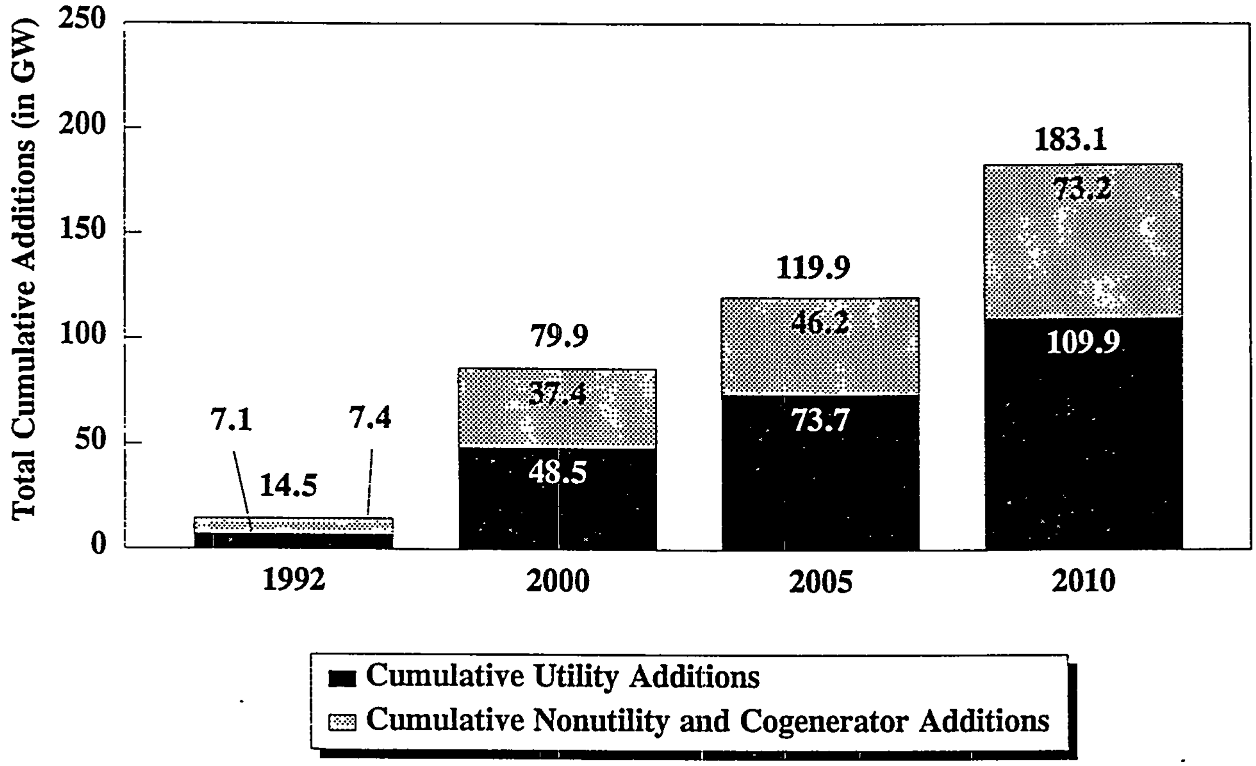

Figure 3-1 EIA reference case projections for new capacity additions. Source: EIA, (1994a).

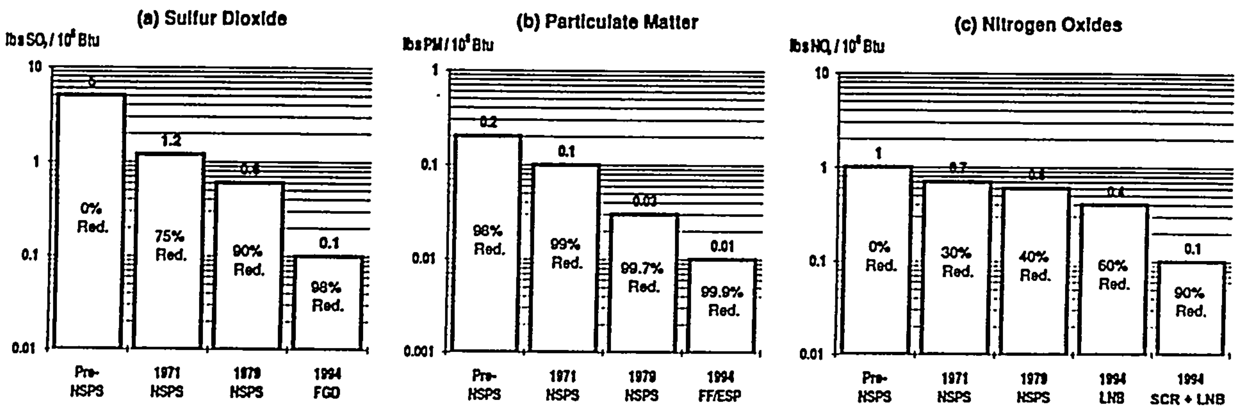

Figure 3-2 Trend in emission rates of criteria air pollutants from a new pulverized coal power plant.

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 percent sulfur, 12 percent ash, and 10,000 Btu/lb. Percentages on the bars are percent 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.

Table 3-1 Annual Growth in Gross Domestic Product and Electricity Demand by Decade, 1960–2010 (percent)[a]

Period	Gross Domestic Product Growth	Electricity Demand Growth
1960–1970	3.8	7.3
1970–1980	2.8	4.2
1980–1990	2.6	2.6
1990–2010	*1.8–2.4*	*1.0–1.5*

[a]Italics indicate projected values.
Source: EIA (1994a).

Table 3-2 Various Projections of Total U.S. Generating Capacity, 2000 and 2010 (GW)

Year	EIA[a]	WEFA	GRI	DRI	NERC	EEI	NERA
2000	784	747	788	792	719	813	789
2010	857	878	861	879	NA	925	NA

NOTES:
EIA data correspond to reference case and include cogeneration capacity.
WEFA (Wharton Economic Forecasting Association, The WEFA Group) projections include cogeneration capacity.
GRI (Gas Research Institute) projection represents nameplate capacity, which is typically 5 to 10 percent higher than net summer capacity.
DRI (DRI/McGraw-Hill) projection includes cogeneration and represents nameplate capacity.
NERC, North American Electric Reliability Council.
EEI (Edison Electric Institute) projection includes cogeneration.
NERA, National Economic Research Association.
NA, not available.
Source: EIA (1994a).

Table 3-3 Various Coal Consumption Forecasts, 2000 and 2010 (in millions of tons)

Year/Forecast	EIA AEO94	DRI	GRI	WEFA
2000				
Production	1,081	1,090	1,091	1,060
Consumption	958	961	973	958
Power generation	837	844	863	847
2010				
Production	1,223	1,379	1,333	1,278
Consumption	1,079	1,237	1,182	1,165
Power generation	950	1,004	1.077	1,053

NOTES:
EIA AEO94, Energy Information Administration, Annual Energy Outlook, 1994.
DRI, Data Resources, Inc./McGraw Hill.
GRI, Gas Research Institute.
WEFA, Wharton Economic Forecasting Association, The WEFA Group.
Source: EIA (1994a).

Table 3-4 National Petroleum Council Estimate of Remaining Recoverable Domestic Natural Gas[a,b]

Wellhead Price[c] (1992 dollars/10^6 Btu)	Current Technology (Tcf)	Advanced Technology[d] (Tcf)	Resource/1992 Consumption (Years)[e]
Unspecified	1,065	1,295	72
$3.74	600	825	46
$2.67	400	600	33

[a]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 13 percent of the total resource.

[b]Total U.S. natural gas production up to 1990 was approximately 700 Tcf.

[c]The EIA projects a wellhead price rise to $3.50/million Btu by 2010 (EIA, 1994a). 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 (EIA, 1994a).

[d]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.

[e]U.S. consumption in 1992 was 18 Tcf.

Source: Potential Gas Committee (1993).

Table 3-5 U.S. Natural Gas Supply and Disposition, 1992-2010 (quads)

Category/Source	1992	2000	2005	2010	Annual Growth (percent)
Production					
EIA	18.51	19.63	20.87	20.89	0.7
GRI	18.10	20.00	21.20	22.40	1.2
Net Imports					
EIA	2.49	2.95	3.32	3.86	2.5
GRI	2.10	3.10	3.70	3.80	3.3
Total Supply					
EIA	21.00	22.58	24.19	24.75	0.9
GRI	20.20	23.20	24.90	26.20	1.5
Total Consumption					
EIA	20.15	22.67	24.31	24.89	1.2
GRI	20.30	23.10	NA	26.10	1.4
Power Generation					
EIA	2.86	4.36	5.24	5.10	3.3
GRI	2.88	3.91	NA	4.32	2.3

NA, not available.
Sources: EIA (1994a), GRI (1994).

Table 3-6 Projected Natural Gas Prices for Electric Utilities (dollars/million Btu)

Source	1992	2000	2005	2010	Annual Growth (%)
EIA	2.28	3.03	3.88	4.43	3.8
GRI	2.47	3.15	NA	3.78	2.4

NA, not available.
Sources: EIA (1994a), GRI (1994).

Table 3-7 Comparative Costs of Electricity from Wind, Photovoltaic, and Biomass Sources (cents/kWh)

Source	1990	2000	2010
Wind	8–10	4	3–4
Photovoltaic	37–53	11–32	9–16
Biomass	5–9	5–6	4–5

Source: Preston (1994).

Table 3-8 World and U.S. Petroleum Resources

Source	1992 Resource Consumption (billion bbl)[a]	Total Resource (billion bbl)	Resource/ 1992 Consumption (years)
World	20.4	1,700[c]	83
United States[b] (domestic)	3.1	99–204[d]	32–66

[a]Data from EIA (1994a).
[b]Total U.S. petroleum consumption in 1992 was 6.2 billion bbl, with about 50 percent accounted for by oil imports (EIA, 1994a). If total consumption were used for the last column, the resource/consumption value for the United States would decrease to 16–33 years.
[c]See Riva (1991).
[d]Low number based on current technology and price of $20/bbl; high number based on advanced technology and price of $27/bbl (NRC, 1993).

Table 3-9 Projections for Domestic Coal Consumption by End Use, 1990–2010 (million short tons)[a]

End Use	1990	1992	2000	2005	2010
Residential and commercial	7	6	6	6	5
Industrial	76	74	87	94	101
Coke plants	39	32	28	24	21
Electricity generation	774	780	837	862	950

[a]Data for 1990 and 1992 are actual rather than projected values.
Source: EIA (1994a).

4

The Strategic Planning Framework

This chapter outlines the methods and strategic planning framework used to assess DOE's coal program, in keeping with the committee's charge. To establish an analytic framework, the committee defined optimal planning horizons; national coal technology requirements corresponding to those horizons, under the most probable and alternative scenarios; and, finally, criteria that might be used to set DOE coal program priorities in view of these considerations, DOE's mission, and the requirements of EPACT.

As seen in Chapter 2, DOE's coal program planning has generally focused on planning horizons only to 2010, with the objective of developing technologies that will be deployed and yield benefits in subsequent years (Randolph, 1992). However, as the discussions in Chapter 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. The committee thus concluded that a longer planning horizon 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. The committee developed scenarios for each of these three planning periods, reflecting likely U.S. energy demands, resource and environmental constraints, and likely coal use outside the United States.

BASELINE STRATEGIC PLANNING SCENARIOS

The committee's baseline strategic planning scenarios, reviewed in Table 4-1, describe demanding, but not unreasonable, circumstances against which the requirements for coal RDD&C can be assessed. It will be seen that these scenarios are based on the major findings of Chapter 3 and encompass a range of requirements envisioned by the committee as likely to arise. While circumstances less demanding can be envisioned, it is the belief of the committee that a major role of DOE is to provide technological insurance for a credibly demanding future. For example, in the view of the committee, 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 (see Chapter 2). Further, the coal program should be sufficiently robust and flexible to accommodate evolving needs. After the baseline scenarios are presented, alternative scenarios that are more and less demanding are also reviewed.

ALTERNATIVE SCENARIOS

Given the inherent uncertainty of predictions, the committee 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.

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 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 CO_2 emissions, encouraging faster development and use of very high efficiency coal-based systems and greater R&D on CO_2 removal and disposal options.

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, CO_2 sequestration methods, and the use of nuclear energy to reduce greenhouse gas emissions.

SCENARIO IMPLICATIONS FOR RDD&C PLANNING

The committee's 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.

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. The committee's strategic planning framework therefore employed further criteria, consistent with the goals of EPACT and the National Energy Strategy (DOE, 1991). 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) and consistent with its charge, the committee developed the following additional criteria to evaluate the strategic importance of individual DOE programs for the three planning periods defined, namely; the near-term (1994–2005); mid-term (2006–2020); and long-term (2021–2040) periods.

General criteria

- 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?
- What is the potential for technological success?

Economic criteria

- 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?
- Does a market exist for the technology and how large is it? What export potential does the technology have?
- What potential does the technology have to increase the international competitiveness of U.S. firms?
- What potential is there to accelerate application of the technology?

Environmental criteria

- What potential does the technology have to economically control, reduce, or eliminate environmentally important wastes, notably criteria air pollutants (NO_x, SO_2, fine particulates), air toxics (inorganic and organic), greenhouse gas emissions (CO_2, methane), solid wastes (hazardous and nonhazardous), and liquid wastes (organic and inorganic) from coal-based facilities for power generation and fuels production?

• What is the technology's applicability to new and existing plants in both the United States and other countries?

The DOE role

• 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?
• 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; and
• 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 chapters. 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. To best assess DOE's coal program in terms of the above criteria, the committee focused its discussions of coal-based technologies in Part II on several areas: the state of the art of the technology; the technical issues, risks, and opportunities; and the current status of DOE and other programs. Thus, the areas addressed cover not only the technology's current status but also its potential for performance and cost improvements, the likelihood of its successful further development, and the existence of domestic and overseas markets. For each technology or group of technologies examined in Part II, a set of findings summarizes the critical issues to be addressed in any continuing or future DOE program.

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Table 4-1 Baseline Scenarios to Assess Coal RDD&C Needs

Area	Near-Term, 1994–2005	Mid-Term, 2006–2020	Long-Term, 2021–2040
Electric power generation (domestic)	• Demand for new baseload electric power generation stations will be low. • Sufficient natural gas will be available to meet limited needs for new capacity. • Natural gas prices may rise but not enough to justify investment in new coal plants. • Growing concerns about future natural gas supply and price, and about future environmental restrictions, stimulate planning for cleaner, more efficient, coal-based technologies. • Growing trend toward smaller, more decentralized power generation systems in response to utility deregulation and increased competition; emphasis on reliable, low-risk technologies.	• Substantial need exists for new generating capacity. • Concerns about future natural gas supply and price result in new demand for coal-based capacity. • Economic incentives for efficiency improvements increase. • Continued trend toward decentralization and risk aversion for new power generation technologies.	• Due to higher prices for natural gas, advanced coal-based technologies used increasingly. • Power generation using natural gas and 1970s and 1980s nuclear technologies decreases. • Renewables a significant but not predominant source of electric power. • Construction of advanced nuclear power plants begins during this period, providing new competition for coal-based systems.

Table 4-1 Baseline Scenarios To Assess Coal RDD&C Needs (Continued)

Area	Near-Term, 1994–2005	Mid-Term, 2006–2020	Long-Term, 2021–2040
Environmental constraints	• Existing Clean Air Act requirements met by modifying existing coal plants using current or near-term control technologies. • By the end of the period, more stringent regulations on fine particulates, NO_x, and air toxics may be in place. Concerns may be growing about CO_2 emissions. • State and local requirements for facility siting and operation continue to push use of state-of-the-art environmental controls.	• Air pollution control and solid waste disposal requirements become more severe. • New CO_2 emissions penalties provide new incentives to install high-efficiency, coal-based generating systems and to continue R&D on CO_2 removal and disposal options.	• Maximum-efficiency coal-based systems are required to minimize CO_2 emissions; attention is given to establishing CO_2 removal and disposal options. • Pressure continues to reduce all emissions to absolute minimum and to reuse or recover solid wastes as by-products; advanced emissions control systems are required for coal-based plants.
Foreign Markets (power generation systems)	• New capacity needs are met by existing technology, but interest grows in more advanced and lower-cost systems for environmental controls.	• Markets develop for advanced coal-based power generation systems to provide new capacity.	• Markets grow for proven high-performance systems, but cost competition is severe.
Synthetic fuels from coal	• Oil and natural gas prices rise but not enough to justify investment in processes to manufacture liquid fuels or synthetic natural gas from coal.	• International oil prices rise toward the level where products from dedicated coal liquefaction can compete with petroleum products. • Production of lower-cost, coal-based liquids in conjunction with gasification combined-cycle systems for power generation becomes economic.	• High international oil prices lead to major production of liquids from coal. • High natural gas demand and prices lead to pioneer plants for synthetic natural gas production in the latter part of this period.