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A Feasibility Study of Coal Technology and Research and Development (R&D) Opportunities

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Energy Division

A FEASIBILITY STUDY OF COAL TECHNOLOGY AND RESEARCH AND DEVELOPMENT (R&D) OPPORTUNITIES

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EXECUTIVE SUMMARY

This is a report of a feasibility study aimed at determining whether an adequate conceptual framework and sufficiently reliable cost data exist to help guide coal research and development (R&D) allocation decisions. The central objective of this effort was to determine the viability of a major detailed study to develop a quantitative procedure for informed coal R&D allocation decisions, and to make a recommendation on whether such a study should be undertaken. Hopefully in the best tradition of research, we found the data took us substantially beyond the initial scope of the study.

It should be emphasized that the findings reported here are based on the qualitative judgments of the authors. This report is not, and does not purport to be, a scientific study which presents findings that an independent investigator could replicate. The portion of the report beginning on page 15 is intended solely to provide background to put our findings in context. The data do not provide incontrovertible support for our recommendations.

In the Conclusions and Recommendations section, we report our findings on both the initial questions posed, plus a more general set of findings. The remaining portion of the report consists of the:

1. Introduction, which summarizes how the feasibility study was carried out;

2. Coal Technology Descriptions, Cost Data, and R&D Options which supported our conclusions and recommendations;

3. Two Appendices, an outline of what would be included in a major detailed study, and a description of how our cost calculations were made.

CONCLUSIONS AND RECOMMENDATIONS

Conclusion I:

Data on the costs of coal technologies and on the cost reductions that would result from specific R&D successes are too unreliable to provide a useful basis for allocating R&D funds.

Reliable cost data are available for commercial, off-the-shelf, technologies such as mechanical coal cleaning, industrial boilers, and pulverized coal steam-electric plants. For the non-commercial technologies, cost data are much less reliable. In those instances where test plants have been built and run, data reliability varies with the size of the test plant relative to a plant of commercial size. Solving the problems of scale up to commercial size is primarily a trial and error process. Estimating the cost of commercial scale plants from smaller scale plants is inherently unreliable. Estimating costs for commercial scale plants from laboratory experiments is, of course, even more difficult and unreliable.

In fact, many cost estimates for non-commercial technologies are not based on what is thought to be technically possible, but on what is deemed necessary for a technology to be commercially competitive. Thus cost estimates for non-commercial coal technologies are frequently design goals. Such estimates, of course, reflect the assumption that the goals can be achieved. In some cases, however, there are substantial technical barriers to commercial viability, and it is uncertain how long it will take and how much it will cost to overcome them. Under these circumstances cost projections must be regarded with skepticism.

In the coal industry, efforts to compare the costs of commercial technologies with non-commercial technologies must deal with another factor. This is the great emphasis placed on performance reliability by those who operate commercial scale coal facilities.

These plants are, with a few exceptions, large facilities which must handle large volumes of solids over 20 to 40 year lifetimes. Nothing is of greater importance to those who run cleaning, utilization, or conversion plants than that they operate reliably over long periods of time, that is, they have high and predictable capacity factors.

Confidence in a technology's reliability is established only after it has performed over a number of years. Since coal facilities involve large capital costs, significant periods of unexpected down time can have large impacts on the cost of end use energy. For example, Office of Technology Assessment (OTA) estimates that a synfuels plant operating at a 50% on-stream factor rather than a 90% factor increases the cost of produced fuels by 60 to 70% (OTA, Increased Automobile Fuel Efficiency and Synthetic Fuels, p. 174).

Since R&D is inherently risky, estimates of end use energy cost reductions that would result from successful R&D must be seen as soft. In some cases it is not clear that there are any bases for making reliable calculations.

Even for commercial technologies estimating potential R&D benefits is difficult. Most proposals for improvement involve complex interdependent system-wide modifications. In such cases a cost reduction in one part of the system may mean a cost increase in another. For example, it may require increased costs within a Flue Gas Desulfurization (FGD) unit to reduce disposal costs for its waste products. Also, the most attractive mix of costs may vary from one location to another. Reliable generalized estimates of potential cost reductions from successful R&D on most commercial technologies are difficult to make and highly unreliable.

As suggested previously, for some non-commercial technologies additional R&D is an assumption built into the cost estimates. Assessing the actual state of technology compared to the design goals, and then putting reliable cost reduction numbers on the R&D that must be done to achieve the goals is, at best, difficult and more likely impossible. For those technologies, such as biological coal cleaning, which are conceptual possibilities extrapolated from work in basic science, reliable cost estimates are simply not possible.

Recommendation I:

No full scale detailed study of the potential cost reductions from coal R&D should be undertaken.

Conclusion II:

The framework adapted from Energy Alternatives (EA) offers a simple and useful basis for a qualitative comparison of the range of coal technology and R&D options.

As shown in Fig. 1 (see page 17) starting with just three coal types there are potentially well over 200 trajectories (routes) to five end-use energy forms. The vast majority of the technologies which make up these alternative trajectories are not commercial and require R&D if they are ever to become commercial. Each of the technologies has been proposed or developed, however, because it is believed to have potential advantages over existing technologies.

We were unable to find in our survey of the literature any single up-to-date document which provides, in terms intelligible to a layperson, the range of coal technology options and their stages of development. The usefulness of such a document appears significant. First, for those involved in the coal R&D decision making process who are part-time participants, an easily intelligible reference document would be useful. Second, such a document would provide a basis for more effective communication between the expert and non-expert members of the decision making community. Third, for people newly concerned with coal policy it would serve as a useful introduction.

Our conclusion concerning the utility of a technically accurate study understandable to non-experts was heavily influenced by interviews with Congressional staff. It was repeatedly noted that the lack of a readily available overview of the options had become evident as the Congress investigated a proposed $750 million program aimed at coal clean up. Confusion over the options and their potential benefits had been, and continues to be, a problem in the minds of those we interviewed.

Our review of the coal research literature suggests the following 1) the quantity of literature is large; 2) studies are generally technology or process specific and highly detailed; and 3) studies are normally aimed at the expert community.

Recommendation II:

A descriptive qualitative study of coal technology and R&D options should be carried out. It should be organized around the adapted EA framework and should be technically accurate and understandable to the interested non-expert.

This study should provide its users with a map of the alternative ways of cleaning, utilizing or converting coal. It should briefly describe the technology options and characterize their stage of development. Finally, it should indicate the major areas where R&D is needed or could make significant contributions to a technology's performance.

An important focus of the study could be to assess the actual states of development of non-commercial technologies, and the nature of the technical barriers to their commercialization.

Conclusion III:

Coal R&D allocation decisions should aim at achieving maximum flexibility and responsiveness to a range of future energy conditions.

This conclusion addresses issues that go far beyond the initial scope of the feasibility study. In reviewing the literature and conducting interviews on coal technologies, certain data and findings repeatedly appeared. Their implications were so compelling, we concluded that a set of broader findings should be included in this report.

Coal's future role in the nation's energy system will be heavily influenced by two certainties and three uncertainties.

The certainties are: 1) U.S. coal reserves and resources are huge and geographically widely distributed. Therefore, coal has no foreseeable supply constraints. 2) Coal utilization and/or conversion will have to be carried out in an evironmentally acceptable manner. Coal use will, at a minimum, have to meet environmental standards that are as stringent as those presently in place; the probability is great that those standards will become even more stringent.

The three uncertainties result from the unpredictability of future demand for coal in meeting the nations's needs for: electricity, synthetic natural gas, and synthetic liquids. Coal will play the key role in meeting the nation's future electricity needs. Once the presently committed nuclear power plants come on line, it is not likely that nuclear power will be a viable near term alternative to coal in the construction of new electricity generation facilities. Similarly, oil fired power plants will offer no competition. Natural gas fired electric power plants are presently not competitors because of the ban mandated by the Power Plant and Fuel Use Act. Thus, until that legislation is modified, natural gas will not be a competitive fuel for use in new electric generation facilities.

The uncertainty concerning the future quantity of coal needed to generate electricity flows from uncertainty about the rate of growth in electricity demand. Two elements cause this uncertainty. First, projections of future demand posit different relationships between growth in electricity demand and growth in Gross National Product (GNP). During 1983 and 1984, electricity consumption grew at between 85 and 90 % of GNP growth. Experts disagree, however, on whether that reflects a long term relationship between GNP and electricity growth.

The second element causing uncertainty about future growth in electricity demand results from the unpredictability of GNP growth itself. Recent history suggests that the ability of economic forecasters to project GNP growth is unreliable even over the short term. Given the absolute size of the electric power system, even relatively small percentage fluctuations result in large absolute variations in electricity demand over a very few years.

Unlike the uncertainty associated with electricity, that associated with oil and gas results from supply, not demand unpredictability. All projections show domestic production of oil declining between now and the year 2000. Pessimists project domestic production at 4 mmbd and optimists project a level of 9.2 mmbd (OTA, Oil and Gas Technologies, p. 24). Most projections assume consumption will remain roughly stable at between 15 and 16 million barrels per day. Thus, the U.S. must either increase imports or produce synthetic liquids. A future tightening of world oil supply, or a sudden disruption of imports could drive prices up to a point where synthetic liquids become attractive. Predicting if and when this will occur is fraught with uncertainty.

Although the future supply of domestic natural gas is less uncertain than oil, estimates of the nation's ultimately recoverable gas resources vary greatly. A recent OTA (U.S. Natural Gas Availability) report suggests a range for conventional gas reserves of between 430 TCF to 900 TCF (p. 20). The same report indicates conventional natural gas production in the year 2000 could vary between 9 and 19 TCF (p. 14). Some estimators are projecting the end of the present gas bubble by 1990. A tightening of supply will most likely bring an increase in prices. At some point, synthetic natural gas from coal may become an attractive option. When and if that will occur is highly uncertain.

In sum, the central question must be, what are the prudent or appropriate coal R&D choices given an uncertain energy future?

Recommendation III:

The primary R&D priority should be intermediate Btu coal gasification and its associated technologies: combined cycle electricity, indirect liquefaction, and high Btu gas upgrading.

Faced with the mix of certainties and uncertainties presented above, prudence suggests that primary emphasis should be given to those coal R&D options that offer maximum future flexibility. Intermediate Btu syngas technology offers that flexibility. First, it can potentially produce end-use energy in an environmentally acceptable manner. Second, it offers a route to meeting future energy demand in any of four end-use forms: electricity, liquids, high Btu gas, and chemical feedstocks. Third, in the form of the Texaco gasifier, a number of plants have been built and run at near commercial scale.

Every effort should be made to facilitate and accelerate R&D which will increase the reliability and reduce the cost of intermediate Btu gas plants. As previously noted, confidence in new technologies can only be developed by demonstrating the capacity of these plants to operate predictably and efficiently over a number of years. Since intermediate Btu gasification is relatively advanced, it offers the nation its best opportunity for a commercially reliable backup in each major end-use energy form.

Particular R&D support should be given to efforts to develop and debug the combined cycle gasification electricity option. Full advantage should be taken of the apparent technical success of the Cool Water plant. The Cool Water plant appears to have attracted much favorable industry interest. Every effort should be made to demonstrate this technology's reliability and improve its cost performance.

Reliable, cost competitive, environmentally acceptable combined cycle gasification plants offer an additional attraction. Given the unpredictability of future growth in electricity demand, it is important to develop a flexible supply response. Large plants, which may take ten years to bring on line, create conditions which may lead to either surplus or shortage in generating capacity. The ability to meet future electricity demand would be enhanced if the industry were able to add generating capacity in relatively small increments over short periods of time. One to two hundred megawatt plants with construction lead times of a few years would be ideal. Combined cycle gasification plants fall in the one to two hundred megawatt range and hopefully can be constructed over relatively short periods. Additionally, their performance offers the prospect of meeting stringent environmental standards and, thus, may trigger less environmental opposition.

The intermediate Btu gasification to liquefaction option offers a means of reducing the uncertainties associated with declining domestic oil production. Clearly the most likely future difficulty will be in the area of transportation liquids. In this area the possibility exists of linking an intermediate Btu coal gasification system with a gas-to-methanol indirect liquefaction system and then a Mobil methanol-to-gasoline (MTG) system to produce transportation liquids. MTG is now being tested in New Zealand, and the commercial-scale experience there can provide a basis for the future development of full-scale coal-to-liquids indirect liquefaction systems.

Finally, intermediate Btu coal gasification offers a route to synthetic natural gas should that be needed.

Recommendation IV:

The second R&D priority should be pre-combustion chemical coal cleaning.

The prospect of substituting lower cost pre-combustion cleaning for post-combustion cleaning is obviously attractive. Removal of both pyritic and organic sulfur as well as ash requires some type of chemical processing in addition to physical cleaning. Although there is a great deal of uncertainty in the results of R&D on chemical coal cleaning, there is a wide range of potential benefits. The ability to produce cost competitive clean coal not only offers a substitute for FGDs, but also a way to improve the environmental performance of presently unregulated industrial and utility combustion facilities. Again, the major attraction of pre-combustion chemical cleaning is that the clean coal can be used in a wide range of energy conversion technologies.

Recommendation V:

<u>The third R&D priority should be basic work in coal science, particularly coal chemistry.</u>

Two observations appear and reappear as litany about coal science. Coal has an exceedingly complex chemistry, and the present understanding of that chemistry is limited. The value of increasing understanding of coal chemistry is so large that it warrants a major and sustained R&D effort. Particular emphasis needs to be given to the importance of a stable, sustained research program. Better understanding comes only from programs which attract efforts by high quality researchers. They, in turn, will work only in areas with stable, long-term funding.

Recommendation VI:

<u>R&D on utilization or conversion technologies should focus on three generic areas: 1) coal feed into hot and/or pressurized environments;</u>

2) the development of materials that perform well when subjected to high temperatures and/or corrosion and erosion; and 3) cleanup of hot effluent gases from gasifiers or combustion chambers. Whenever possible, this generic R&D should be tested on intermediate Btu gasification and its electricity, high Btu gas, and indirect liquefaction options.

The above three generic problem areas limit the reliability and efficiency of several coal technology options. Solutions to these generic problems would, therefore, potentially enhance the performance of a wide range of technologies.

Whenever possible, R&D efforts aimed at understanding and overcoming these generic problems should be tested on intermediate gasification and its three potential end-use energy outputs: electricity, gas, and liquids. In this way, coal R&D will gain maximum leverage vis-a-vis the possible future uses of coal. One major leverage goal should be to move coal technologies to the point of commercial competitiveness. Another major leverage goal should be to push commercial scale development which offers multiple end-use energy options. Intermediate Btu gasification offers both potential benefits plus an opportunity to solve generic problems applicable to a number of other coal utilization or conversion technologies.

Conclusion IV:

The present DOE coal R&D program supports work on all the significant R&D needs and problems we identified. Given the available

<u>funds for R&D, this coverage of all areas of need-opportunity may spread the resources too thin for rapid progress to be made.</u>

Our previous conclusions and recommendations indicate where we believe the major areas for high coal R&D payoff to be. The research for this study was not carried out in sufficient detail to give us a basis for recommending specific reallocations of R&D resources. We did, however, develop three solidly held observations. First, there is a disproportionate emphasis on electricity generation within DOE's energy R&D budget (roughly 80% of the overall energy related funding and 50% of the coal funding). The existing technical capability to produce electricity from coal, and the abundance of coal make the issue of electricity generation a less than compelling <u>technical</u> issue. Clearly, management, regulatory, funding, cost, and future demand problems are major. The technical capability to generate electricity from coal in an environmentally acceptable manner is not a major problem.

Second, the potential benefits of utility scale fluidized bed combustors are limited. Potential efficiency improvements over pulverized coal boilers appear so limited that they may not compensate for the problems associated with increased complexity. The one seemingly clear advantage is the ability of fluidized bed combustors to use lower quality, lower cost, coal. Given limited R&D funds, however, this advantage does not appear to be sufficient to warrant directing much effort to the development of utility scale fluidized bed boilers.

Third, the focus on developing coal technologies aimed at backing oil out of the electric utility sector appears unwarranted. The reason for this observation is that oil is already being backed out. Over the last several years, the quantity of oil used in this sector has dropped from nearly 2 million barrels per day to slightly more than 0.5 million barrels per day. Focusing R&D on technologies aimed at achieving what has already been achieved appears hard to justify.

INTRODUCTION

This paper reports the findings of a feasibility study aimed at answering two questions. First, do adequate cost data exist on coal cleanup, utilization, and conversion technologies, and on the cost reduction potential of various R&D options to provide useful assistance to decision makers in allocating R&D funds? Second, does the framework used in Energy Alternatives provide a useful basis for making coal R&D allocation decisions?

The central goal of this feasibility study was to determine whether a major detailed study of coal technology costs and potential R&D payoffs should be carried out. Certain assumptions about decision making guided this effort. First, the study assumed that coal R&D allocation decisions would benefit from reliable information on the potential benefits of successful R&D. Second, R&D decision making is the result of a process that includes experts on coal technologies and a variety of non-experts. In the case of federally funded coal R&D decision making, participants range from designers, builders and users of coal technologies through those doing R&D through a variety of executive branch participants to Congressmen and members of Congressional staffs.

Maximum utility from a major study of potential R&D payoffs would result if it could provide noncontroversial cost data, and a basis for comparing those data, that was credible to experts yet easily understood by non-experts. We emphasize that if such an optimistic goal was achieved, it would surely not eliminate controversy and the need for judgement in coal R&D allocation decisions. Inevitably these choices involve many noncost variables. Our focus, however, was on the single variable: cost.

In designing this feasibility study we found it necessary to lay out the basic design for a full scale study. The first step in this process was to identify each of the major coal technology options, and develop a technology configuration that illustrates the means of production of five end-use energy forms: 1) steam, 2) electricity, 3) chemcial feedstock, 4) high Btu gas, and 5) liquids. The framework used (see Fig. 1) was adapted from Energy Alternatives.

Note that the simple flow diagram in Fig. 1 offers a straightforward way to calculate end-use energy costs delivered through more than two hundred trajectories. (Any particular coal type moving through any combination of technologies is referred to as a "trajectory.") In fact, of course, the number of real or even potential trajectories is much smaller than two hundred since many of the technologies provide cleanup as an integral part of utilization-conversion. Similarly, the products of some of the cleaning-enhancement processes may be unsuitable for specific utilization-conversion processes.

The second step in designing a major study was to define the data requirements necessary for meaningful cost comparisons. For each technology it was judged necessary or useful to: 1) define and describe the technology; 2) calculate the delivered cost of its energy; 3) determine

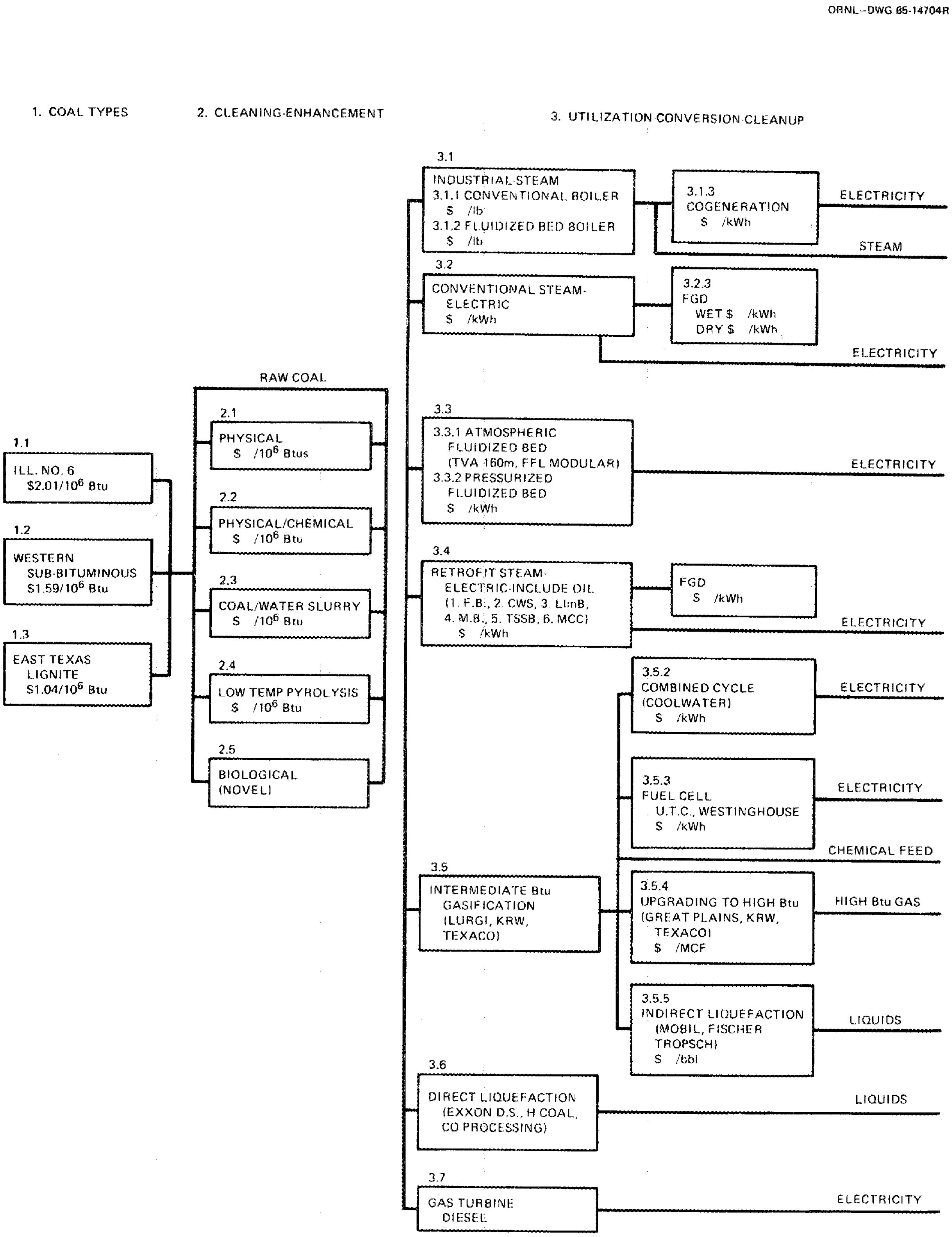

Fig. 1. The coal delivery system

its sulfur removal, NO_x emissions, and/or ash removal; 4) identify and describe its R&D needs or opportunities; 5) calculate cost reductions that would result from successful R&D; and 6) where possible, provide estimated R&D costs.

In Appendix A we have provided an outline of the descriptive material and data that would be needed for a major study. Appendix B provides our definitions and parameters for calculating end-use energy costs. It is essential to calculate costs in a uniform manner if they are to be useful in the allocation of R&D support. In selecting definitions and parameters for calculating costs we chose to represent end-use costs in the units normally used: 1) Btus of steam; 2) kWhs electricity; 3) MMCF of synthetic natural gas; or 4) barrels of oil. The decision to calculate costs in each of the commonly used end-use energy units represents our judgment that R&D allocations decisions are made in the context of these units, and that these are more intelligible to non-technical participants than are Btus, calories, quads, etc.

Having adapted the EA framework, defined the data needs, and selected the parameters for cost calculations, we carried out a broad survey of the technical community to collect data and gather opinions on the current state of the technologies. Our goal was to assess the availability and reliability (hardness) of two bodies of data. First, cost data on existing or proposed technologies. Second, data on the needed or possible technology improvements which would allow for calculating cost reductions that would result from successful R&D.

Our data survey involved two components. A review of a large body of reports and other literature available in the ORNL Library plus interviews with ORNL staff, DOE staff, OTA staff, plus telephone conversations with several experts. In addition, data and opinion were collected during interviews in the United Kingdom with staff at the International Energy Agency's Coal Service, the Science Policy Research Unit at the University of Sussex, the National Coal Board, and the Coal Research Establishment.

In the following section of the report we summarize the information we received and collected. For most of the major technologies shown on Fig. 1, we provide very brief characterizations of the technology, estimates of end-use energy costs at the plant output, and characterizations of the primary R&D needs and opportunities. End-use energy costs are uniformly calculated using the definitions and parameters described in Appendix B.

Recall that one of our objectives was to determine the level of reliability of cost estimates. Initially, we sought to do this by using data from multiple sources and making the cost calculations using our definitions and parameters. Our assumption was that when the cost numbers showed rough agreement, it would indicate a consensus within the technical community, and, therefore reliability. This assumption proved to be strikingly naive.

Consensus cost numbers may result from at least three circumstances, only one of which would meet any common sense standard of reliability.

First, a consensus on costs may result from broad experience with off-the-shelf technologies (e.g., pulverized coal steam-electric plants). Second, consensus numbers may result from shared design goals, that is, views of what would be necessary for a new technology to be competitive (e.g., fluidized bed steam-electric power plants). In this case, a consensus reflects common goals to which developers aspire, but hardly reflects reliable cost estimates. Third, consensus may reflect the multiple and cumulative use of an initial estimate from a widely respected source. It appears that Electric Power Research Institute (EPRI) has such a reputation, and the EPRI cost estimates are widely cited in the coal literature. We do not question the quality of the work done at EPRI, but it is clear that this process can result in perpetuation of any questionable assumptions and calculations. We find it hard to attribute reliability to such estimates.

We suspect that in many of the instances where the technical community seems to have developed a consensus on costs for non-commercial technologies, it is the result of both shared agreement on performance goals, and the cumulative use of initial estimates from an authoritative source.

For the above reasons, we concluded that there was little value in collecting cost calculations from an exhaustive set of sources. We have included here illustrative samples of costs derived from what appear to be reputable sources.

The next stage of this investigation involved a survey of the expert community to determine where R&D opportunities and needs exist.

Our goal was to determine whether confident estimates could be made of the cost reductions that would follow from successful R&D. It quickly became evident that this was not possible for most specific R&D areas. Thus, we have provided only brief narrative characterizations of the R&D options in the following section.

Finally, a small number of the technologies included on Fig. 1 receive no treatment in the following section. Given the limited time available, we chose not to focus attention on technologies which are at the early research stage (e.g., biological coal cleanup) or are concerned with coal retrofit of oil fueled facilities (e.g., coal-fired diesels).

COAL TECHNOLOGY DESCRIPTIONS, COST DATA, AND R&D OPTIONS

The technology descriptions and cost calculations included in this section are self-contained. They are labeled and numbered in accordance with the boxes shown on Fig. 1. All dollar values are scaled to December 1984 price levels.

2.1 Physical Cleaning and Enhancement

For certain users, it is advantageous to purchase coal that has been through some set of pre-combustion physical preparation processes. These usually take place at the mine-mouth and can consist of size reduction and classification, blending, cleaning, and drying. The advantages of using prepared coal include reduced transportation and handling costs, lower plant operation and maintenance costs, increased efficiency, and reduced ash disposal and sulfur emissions. All of these advantages accrue primarily from the reduction of mineral matter that, when burned, forms ash and produces sulfur emissions.

The first generic category of coal preparation operations is size reduction. Equipment for this includes roll crushers, rotary breakers, and hammer mills. Size reduction makes removal of sulfur and ash considerably easier. However, energy consumption increases substantially as the coal is reduced to finer sizes. There are several ways to separate the crushed coal into uniform size categories. These include sets of screens of increasingly fine mesh and wet concentrating tables that separate by vibrating the coal on a slightly tilted platform. In addition, coal can be separated according to density by jigging, a process in which a pulsating flow of fluid through a bed of particles causes the particles to stratify in layers of increasing density.

Another important preparation area is coal washing. Dense medium washers are used to separate impurities with different specific gravities. Cyclones use swirling vortexes of dense media or water to separate refuse from finely ground coal. Finally, froth flotation cleans finely ground coal in a chemical/water slurry by selectively attaching air bubbles to the organic components causing them to float, but leaving the ash.

The last major class of operations is drying and dewatering. The water content of slurries can be reduced centrifugally. Thermal dryers and vacuum filters are used for the more complex task of reducing moisture within the coal. This is beneficial because remaining water lowers the heating value of the coal, and increases transportation costs which are based on tonnage.

The technology for physical coal cleaning is mature and offers known benefits with little risk. In recent years, however, there has been a decrease in clean coal production attributed to two factors, the growth in mine-mouth utility plants which do not benefit from savings in transportation costs realized when shipping clean coal, and the increased use of Western coal which is generally not suited for coal preparation.

Physical Cleaning and Enhancement - R&D

Physical coal preparation involves a set of well established processes. They could be improved, however, through increased automation of the process control systems. Currently, most coal cleaning plants rely primarily on manual methods of control which result in wide fluctuations in output parameters, and significant losses of coal.

Automatic control systems, utilizing small scale computers and real-time sensors throughout the process, could closely monitor and correct fluctuations as they occur, improving the consistency of the product.

For the most part, current coal cleaning technologies focus on differences in the specific gravity between the organic and inorganic portions of the coal. R&D aimed at developing processes that use differences in magnetic or electrostatic properties may offer opportunities for improved physical cleaning.

Technology: 2.1 Cleaning - Enhancement/Coarse Mechanical

I. Physical Characteristics

1. Plant size - 2.9 x 10^6 tons/year (nominal output)
2. Capacity Factor - 45%
3. Efficiency - 95.2%
4. Coal Type - Ill. no. 6
5. Annual Quantity Input - 3.05 x 10^6 tons/year

II. Cost Assumptions Dec. 1980 $s

1. Overnight Capital Cost - $\$21.6 \times 10^6$
2. Annual Capital Charge - $\$2.67 \times 10^6$
3. Annual Operating Costs

   A. Fixed
   B. Variable

   $\left.\begin{array}{l}\text{A. Fixed}\\ \text{B. Variable}\end{array}\right\}$ $\$3.4 \times 10^6$

4. Annual Coal - $\$5.12 \times 10^6$
5. Coal Price - $\$1.65/10^6$ Btu
6. Output Cost - $\$.217/10^6$ Btu coal cleaned

III. Cleanup

	Before	After	% Removed
1. Sulfur	3.4%	3.3%	2.9%
2. NO_x			
3. Ash	16.5%	12%	27.3%

Data Source: EPRI TAG Appendix B-27

Technology: 2.1 Cleaning - Enhancement/Intensive Mechanical

I. Physical Characteristics

1. Plant size - 2.8 x 10^6 tons/year (nominal output)
2. Capacity Factor - 42%
3. Efficiency - 95.2%
4. Coal Type - Ill. no. 6
5. Annual Quantity Input - 2.94 x 10^6 tons/year

II. Cost Assumptions Dec. 1980 $s

1. Overnight Capital Cost - \$38.4 x 10^6
2. Annual Capital Charge - \$4.7 x 10^6
3. Annual Operating Costs
   A. Fixed } \$4.7 x 10^6
   B. Variable }
4. Annual Coal Loss - \$4.93 x 10^6
5. Coal Price - \$1.65/10^6 Btu
6. Output Cost - \$.290/10^6 Btu coal cleaned

III. Cleanup

	Before	After	% Removed
1. Sulfur	3.4%	3.2%	5.9%
2. NO_x			
3. Ash	16.4%	9.2%	44%

Data Source: EPRI TAG Appendix B-28

2.2 Physical/Chemical Cleaning and Enhancement

New chemical coal cleaning processes can potentially make greater reductions in ash and sulfur content than are possible with even the most advanced physical coal cleaning methods. Preliminary data from laboratory tests indicate that 90% sulfur removal and 1 to 2% final ash content may be practical using chemical techniques. The principal interest in this type of cleaning has been to enable coal to be used as an oil replacement fuel in existing oil designed boilers. If the costs of chemical coal cleaning were sufficiently low, however, it could also replace such techniques as flue gas desulfurization (FGD) as a means of lowering sulfur emissions to environmentally acceptable levels in coal fired plants.

Gravimelt is a chemical coal cleaning process that has been successfully tested in the laboratory. Gravimelt uses a molten alkali salt to remove high percentages of both pyritic and organic sulfur. In general, physical processes cannot remove the sulfur that is organically bound to the coal, hence they are inherently more limited in their cleaning potential. What is not clear is if chemical coal cleaning will be able to compete economically with physical cleaning methods and flue gas desulfurization. Current studies indicate that chemical cleaning will more than double the cost of delivered coal. This makes it unattractive compared to FGD systems. Chemical coal cleaning technology is in a very early stage of development, however, and any cost estimates must be regarded as extremely soft.

Physical/Chemical Cleaning and Enhancement - R&D

Chemical coal cleaning is a relatively difficult and high risk research undertaking. Current processes are not well developed and substantial work is needed to determine if they can be made economically viable. The potential payoffs are, however, quite large. Chemical coal cleaning could make coal a usable oil substitute in many situations. It could virtually eliminate the need for costly FGD in coal burning plants, and it could allow the use of high sulfur coals that can be mined at low cost.

Fundamental research on coal and its chemical properties would clearly be beneficial. In parallel, a program of empirical experimentation could lead to cost competitive processes. This appears to be an area of relatively modest cost R&D which could have high payoff.

Technology: 2.2 Physical/Chemical Cleaning and Enhancement

I. Physical Characteristics

1. Plant size - 2.5×10^6 tons/year (nominal output)
2. Capacity Factor - 90%
3. Efficiency - 93.5%
4. Coal Type - Ill. no. 6
5. Annual Quantity Input - 2.75×10^6 tons/year

II. Cost Assumptions Dec. 1980 $s

1. Overnight Capital Cost - $215 - 295×10^6
2. Annual Capital Charge - $26.5 - 36.4×10^6
3. Annual Operating Costs - (incremental)
   A. Fixed } $57 - 79×10^6
   B. Variable }
4. Annual Coal Loss - $6.26 $\times 10^6$
5. Coal Price - $1.65/$10^6$ Btu
6. Output Cost - $1.99 - 2.69/$10^6$ Btu coal cleaned

III. Cleanup

	Before	After	%Removed
1. Sulfur	3.4%	1.8%	47%
2. NO_x			
3. Ash	16.5%	7.6%	54%

Data Source: EPRI TAG Appendix B-29

2.3 Cleaning & Enhancement/Coal-Water Slurry

The purpose of the Coal-Water Slurry (CWS) process is to create a liquid substitute for heavy fuel oil that can be used in modified, existing industrial and electric boilers. CWS systems may be attractive in retrofit situations for the following reasons:

- no storage space or handling equipment for coal is required;
- the fuel supply system is simpler since the fuel is liquid and pumpable;
- the cost of boiler retrofit can be considerably less.

There are a number of incentives for potential users of CWS fuels. First, CWS offers an assured supply of domestic fuel. Second, CWS is available in the near term; there are no substantial advances in technology needed to provide CWS commercially. Third, CWS conversion costs are low compared to the cost of other types of retrofits to coal.

There are fundamentally two groups of oil fired boilers in which CWS could be used. The first consists of boilers originally designed to burn oil; the second, those designed to fire coal that have been subsequently converted to oil. The latter group is generally more amenable to CWS retrofit as the designs can more readily accommodate the higher levels of ash produced by coal. It should be emphasized, however, that each retrofit is unique. In general, only high-grade, low ash coals can be used in CWS retrofit boilers.

A major factor in the economic analysis of CWS conversion is the choice of onsite or offsite CWS production. Typically, smaller users (i.e. industrial) will find it more attractive to purchase the finished slurry, while larger utilities will find it worthwhile to buy raw or cleaned coal and slurry onsite. This choice depends, of course, on plant location and the fuel specifications.

Of equal significance in the economic analysis are the costs of the plant retrofit. These may include any of the following:

- CWS receiving - tanks, pumps, piping
- fuel distribution - pumps, lines, burners
- boiler - bottom modification, soot blowers, air preheater
- stack - baghouse/precipitators, ash handling, sulfur removal.

Finally, the conversion to CWS often results in boiler derating. This decreased capacity can be especially significant for large, baseload plants.

The first step in the production of CWS involves grinding the coal so that the coal particles have the required size distribution with the largest particles being about 200 microns. The milled coal can then be cleaned; froth flotation has proven effective and economical with the following ranges reported:

feed coal ash levels	6 - 15%
product ash levels	1 - 4%
energy recovery	90 - 99%
pyritic sulfur removal	40 - 90%

Froth flotation produces output streams of 10 to 25% solids. These are then thickened and filtered to a final slurry consisting of approximately 70% coal by weight.

Realistically, the conversion to CWS is implicitly linked to boiler retrofit. The following CWS plant cost calculations do not include boiler conversion costs. Further detail on the boiler retrofit can be found in Sect. 3.4.2.

CWS - R&D

CWS technology is currently in the commercial development stage. Several small "pilot" plants (10-100 k tons/yr) are in operation and others in the 100-250 k ton/yr range are under construction. To serve a large utility however, 1-2 million ton/yr of coal would have to be slurried. The main R&D areas are associated with scale up problems and improvements in the CWS properties. For example, stability (the degree to which coal particles remain suspended in the slurry) is a desirable characteristic that often must be sacrificed when pumping CWS over long distances. Different additives are being tried to correct this tendency. In addition, development work is in progress to widen the scope of suitable coals towards those of lower quality (and cost) without increasing the need for expensive emissions control measures.

Technology: 2.3 Cleaning-Enhancement/Coal-Water Slurry

I. Physical Characteristics

1. Plant size - 150 tons coal/hr = 20,000 bbl cws/day
   (will serve a 420 MW boiler)

2. Capacity Factor - 80%

3. Efficiency

4. Coal Type - Eastern (<6% ash / <.8% sulfur, 13,200 Btu/lb)

5. Annual Quantity Used - 1.05×10^6 tons/yr

II. Cost Assumptions - 1983$'s, 15 year life, 6% inflation

1. Overnight Capital Cost - $\$71.8 \times 10^6$ (includes boiler retrofit)

2. Annual Capital Charge - $\$8.9 \times 10^6$

3. Annual Operating Costs

   A. Fixed
   B. Variable
   $\left.\right\}$ $\$23.6 \times 10^6$

4. Annual Coal Cost - $\$52 \times 10^6$

5. Coal Price - $\$1.88/10^6$ Btu (includes delivery)

6. Output Cost = $\$3.36 - 3.50/10^6$ Btu = $20.8 - 23.9/bbl

III. Cleanup

1. Sulfur

2. NO_x

3. Ash

Data Source: Occidental Research Appendix D. Page 12

Technology: 2.3 Cleaning-Enhancement/Coal-Water Slurry

I. Physical Characteristics

1. Plant size - 400 tons coal/hr (will serve 1200 MW plant)
2. Capacity Factor - 80%
3. Efficiency
4. Coal Type - Eastern (<6% ash / <.8% sulfur)
5. Annual Quantity Used

II. Cost Assumptions - Mid 1983$'s, 15 year life, 6% inflation

1. Overnight Capital Cost - $\$120 \times 10^6$ (includes boiler retrofit)
2. Annual Capital Charge - $\$14.8 \times 10^6$
3. Annual Operating Costs
   - A. Fixed
   - B. Variable

   $\$54$ x 106
4. Annual Coal Cost - $\$139 \times 10^6$
5. Coal Price - $\$1.88/10^6$ Btu (includes delivery)
6. Output Cost - $\$3.08/10^6$ Btu = $\$20.1$/bbl

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: "Evaluation of Coal Water Mix Economics" Occidental Research Appendix D. page 16

Technology: 2.3 Cleaning-Enhancement/Coal-Water Slurry

I. Physical Characteristics

1. Plant Size - 2.5 M tons/yr
2. Capacity Factor - 84%
3. Efficiency - 93%
4. Coal Type - Eastern
5. Annual Quantity Used - 2.69 M tons/yr

II. Cost Assumptions - Mid 1983 $s

1. Overnight Capital Cost - $108.1 x 10^6
2. Annual Capital Charge - $13.3 x 10^6
3. Annual Operating Costs

A. Fixed
B. Variable

$\left.\begin{array}{l}\text{A. Fixed}\\ \text{B. Variable}\end{array}\right\}$ \$40.9 x 10^6

4. Annual Coal Cost - $143.8 x 10^6
5. Coal Price - $1.88/$10^6$ Btu
6. Output Cost - $2.96/$10^6$ Btu

III. Cleanup

	Before	After	
1. Sulfur	1.41%	.7%	
2. NO_x			by weight
3. Ash	10.33%	3.23%	

Data Source: Economic Assessment Draft Report ICEAS/E8, January 1985, pp. 26-31

2.4 Low Temperature Pyrolysis

When heated under conditions where incomplete combustion occurs (pyrolysis), coal will produce liquid and gaseous products. Depending on the temperature and coal type, the amount and quality of products varies. By selecting the appropriate temperature, it is possible to process coal in this manner to produce a light liquid that with mild treatment is suitable as a transportation fuel or for use in an industrial, commercial, or residential furnace. The char which is also produced can be used as a boiler fuel or as a feedstock for a gasifier. Some feel that this is one of the most efficient techniques to produce liquid products from coal, because, compared to direct or indirect liquefaction, the processing required is considerably less. The disadvantage is that the economic potential depends on establishing a dedicated market for the char product.

There are many coal pyrolysis processes. While the British have commercial pyrolysis processes to make "smokeless coal," there are no commercial processes presently operating in the United States. The costs presented here are, then, strictly conceptual and should be considered very soft.

Low Temperature Pyrolysis - R&D

Only small scale tests of coal pyrolysis have been carried out in the U.S. Therefore the problems of scale up are not well understood. In addition, there are clearly problems associated with pyrolyzing the caking coals common in this country. R&D needs, then, fall in the areas of scale up and handling caking coals.

3.1.1 Industrial Steam-Conventional

Industry has been burning coal to produce steam for well over a century. The basic technology improvements have come from improvements in the firing system. Industrial coal fired boilers are typically one of two types. They either pulverize the coal and blow it with air into the boiler, or the coal is simply crushed and fed mechanically with a driver called a stoker. The stoker fired boiler can burn the coal in a mass on a moving grate, or partly in suspension by throwing the coal into the boiler and onto the moving grates with a spreader stoker. The trade-off between the two basic firing systems is high capital costs and high combustion efficiency (99%) for pulverized coal boilers versus lower capital costs and lower efficiency (90 - 98%) for stoker fed boilers. The stoker system has much lower fly ash emissions because at least half the ash stays with the burning mass on the grate, while nearly all the ash in a pulverized system goes up the stack. In either case where Federal Air Emission Standards must be met, a control device must be installed to remove the ash from the flue gas. This can be either a fabric filter or an electrostatic precipitator. Because the sulfur-dioxide emission regulations vary for industrial boilers they can be met in several ways. Either coal with low sulfur content can be burned or a flue gas desulfurization system can be installed. These technologies are commercial and reliable cost data are available. Costs do, however, vary considerably depending on the size of the boiler, the location, and the particular vendor. The costs presented here are for one size and are generic in nature.

Industrial Steam-Conventional - R&D

The coal combustion technology for industrial steam applications is well developed. The improvements desired are lower capital cost and higher efficiency. These goals probably will not be met with conventional systems but will require development of an advanced concept system. The primary R&D issues involve control of NO_x, SO_x and particulate emissions. There are technologies to remove SO_x and particulates but they are very expensive. There are no commercial NO_x removal systems, and control is accomplished through control of combustion. Development of lower cost SO_x removal systems appears to be the primary R&D concern for conventional industrial boilers.

Technology: 3.1.1 Industrial Steam - Conventional

I. Physical Characteristics

1. Plant Size - 250 x 10^6 Btu/hr (steam out)
2. Capacity Factor - 50%
3. Efficiency - 81.9%
4. Coal Type - Eastern
5. Annual Quantity Used - 6.6 x 10^4 tons

II. Cost Assumptions Jan. 81 $s

1. Overnight Capital Cost - \$29 x 10^6
2. Annual Capital Charge - \$3.6 x 10^6
3. Annual Operating Costs

	Boiler	Scrubber
A. Fixed	\$1.335 x 10^6	\$.475 x 10^6
B. Variable	\$.0565 x 10^6	\$.427 x 10^6

4. Annual Coal Cost - \$2.46 x 10^6
5. Coal Price - \$1.65/10^6 Btu
6. Output Cost - \$9.19/10^6 Btu

III. Cleanup

1. Sulfur 94%
2. NO_x - Meets NSPS
3. Ash

Data Source: ORNL/TM-8144 pp. 183-207

Technology: 3.1.1 Industrial Steam - Conventional

I. Physical Characteristics

1. Plant Size - 250 x 10^6 Btu/hr (steam out)
2. Capacity Factor - 50%
3. Efficiency - 77.4%
4. Coal Type - Western
5. Annual Quantity Used - 8.82 x 10^4 tons

II. Cost Assumptions Jan. 81 $s

1. Overnight Capital Cost - $32 x 10^6
2. Annual Capital Charge - $4 x 10^6
3. Annual Operating Costs

	Boiler	Scrubber
A. Fixed	\$1.443 x 10^6	\$.467 x 10^6
B. Variable	\$.06 x 10^6	\$.1125 x 10^6

4. Annual Coal Cost - $1.84 x 10^6
5. Coal Price - $1.30/$10^6$ Btu
6. Output Cost - $8.72/$10^6$ Btu

III. Cleanup

1. Sulfur 94%
2. NO_x - Meets NSPS
3. Ash

Data Source: ORNL/TM-8144 pp. 183-207

3.1.2. Industrial Steam - Fluidized Bed

Fluidized bed combustion (FBC) is an alternative firing system to conventional coal burning. Combustion occurs in a bed of crushed material, usually sand or limestone. This bed of material is fluidized by passing a stream of air up through the bed at a high enough velocity to cause the bed to behave like a fluid. When the bed of material is hot, coal is injected and burns, partially in the bed and partially in the freeboard above the bed.

If the feed system and bed are designed appropriately, the FBC can fire nearly any fuel. Further, when limestone is used as the bed material, it reacts with the sulfur providing environmental control which may eliminate the need for a flue gas desulfurization system.

There have been many different industrial scale fluidized bed systems sold and operated. Their performance is fairly well understood and this experience provides a moderate amount of confidence in the cost estimates.

FBC - R&D

Although the commercial viability of industrial FBC systems has been demonstrated, technical problems remain. Designing a coal feed system that handles a wide variety of fuel and is reliable remains a challenge. Similarly, erosion and corrosion of feed systems and bed internals remains a problem. R&D aimed at improving the combustion and sulfur capture of industrial FBCs appears to be a continuing need.

Technology: 3.1.2 Industrial Steam - Fluidized Bed

I. Physical Characteristics

1. Plant Size - 250 x 10^6 Btu/hr (steam out)
2. Capacity Factor - 50%
3. Efficiency - 85.9%
4. Coal Type - Eastern
5. Annual Quantity Used - 6.3 x 10^4 tons

II. Cost Assumptions Jan. 81 $s

1. Overnight Capital Cost - $32.7 x 10^6
2. Annual Capital Charge - $4.1 x 10^6
3. Annual Operating Costs
   - A. Fixed $1.752 x 10^6
   - B. Variable $.472 x 10^6
4. Annual Coal Cost - $2.1 x 10^6
5. Coal Price - $1.65/$10^6$ Btu
6. Output Cost - $9.24/$10^6$ Btu

III. Cleanup

1. Sulfur 94%
2. NO_x - NSPS
3. Ash

Data Source: ORNL/TM-8144 pp. 183-207

Technology: 3.1.2 Industrial Steam - Fluidized Bed

I. Physical Characteristics

1. Plant Size - 250 x 10^6 Btu/hr (steam out)

2. Capacity Factor - 50%

3. Efficiency - 82.8%

4. Coal Type - Western

5. Annual Quantity Used - 8.25 x 10^4 tons

II. Cost Assumptions Jan. 81

1. Overnight Capital Cost - \$32.2 x 10^6

2. Annual Capital Charge - \$4.0 x 10^6

3. Annual Operating Costs

   A. Fixed \$1.887 x 10^6

   B. Variable \$.0925 x 10^6

4. Annual Coal Cost - \$1.72 x 10^6

5. Coal Price - \$1.30/10^6 Btu

6. Output Cost - \$8.48/10^6 Btu steam

III. Cleanup

1. Sulfur 70%

2. NO_x - NSPS

3. Ash

Data Source: ORNL/TM-8144 pp. 183-207

3.2 Conventional Electric Power Plants

Pulverized coal combustion for utility scale electric power production has been commercial for roughly half a century. Most modern systems blow pulverized coal into a large combustion chamber lined with boiler tubes where steam is generated. The exhaust gas is then cooled by passing through a series of heat exchangers that variously reheat and super heat the steam, and preheat the feed water and the combustion air. The steam is then sent to a series of steam turbines that produce electricity. In those plants subject to air emission regulations the exhaust gases are cleaned. The fly ash is removed by either an electrostatic precipitator or a fabric filter. The sulfur dioxide content is reduced by a flue gas desulfurization (FGD) system. The FGD systems can be any of a variety of designs but most current systems are towers that spray a lime or limestone water slurry into the flue gas that reacts with the SO_2. Because the technology is commercial for both pulverized coal boilers and FGDs, there is a wealth of cost information available. The costs for the conventional system are felt to be reliable.

Conventional Electric Power - R&D

The opportunities for lowering the cost of electricity from pulverized-coal-fired boilers that meet current emission standards lie primarily in two areas. First is the development of advanced FGD systems that have lower capital and operating costs. Second is the development of advanced supercritical steam systems that could increase thermal efficiency from the current maximum of about 37% to 41 or 42%.

In the case of FGD systems, possible cost reductions could result from improvements in one or some combination of the following: lower cost sorbents, more efficient use of sorbents, regeneration of sorbents, reduced maintenance costs, and lower cost waste disposal. Alternatively, improved super critical steam systems require development or use of new alloys and the ability to fabricate those alloys for use in boilers and turbines which can handle higher temperatures and pressures. In both cases the challenges involve complex high cost system-wide modifications and will contribute only incremental improvements. There is little evidence that the technical community sees opportunities for major cost saving breakthroughs in pulverized coal plants, but even small improvements can have a very large payback in these large systems.

Technology: 3.2 Conventional Electric - Wet FGD

I. Physical Characteristics

1. Plant Size - 1069 MW
2. Capacity Factor - 70%
3. Efficiency - 35.3%
4. Coal Type - Eastern
5. Annual Quantity Used - 3.13×10^6 tons

II. Cost Assumptions Jan. 1980 $s

1. Overnight Capital Cost - $\$833 \times 10^6$
2. Annual Capital Charge - $\$102.8 \times 10^6$
3. Annual Operating Costs
   A. Fixed $\$34.7 \times 10^6$
   B. Variable $\$28.2 \times 10^6$
4. Annual Coal Cost - $\$104.2 \times 10^6$
5. Coal Price - $\$1.65/10^6$ Btu
6. Output Cost - $.0557/kWh

III. Cleanup

1. Sulfur 90%
2. NO_x
3. Ash

Data Source: Alternative AFBC Systems, EPRI CS 2275

Technology: 3.2 Conventional Electric - Wet FGD

I. Physical Characteristics

1. Plant Size - 1078 MW
2. Capacity Factor - 70%
3. Efficiency - 35.1%
4. Coal Type - Western
5. Annual Quantity Used - 4.0 x 10^6 tons

II. Cost Assumptions Jan. 1980 $s

1. Overnight Capital Cost - $807 x 10^6
2. Annual Capital Charge - $99.6 x 10^6
3. Annual Operating Costs
   - A. Fixed $28.4 x 10^6
   - B. Variable $12.6 x 10^6
4. Annual Coal Cost - $84.0 x 10^6
5. Coal Price - $1.30/$10^6$ Btu
6. Output Cost - $.0460/kWh

III. Cleanup

1. Sulfur 70%
2. NO_x
3. Ash

Data Source: Alternative AFBC Systems, EPRI CS 2275

Technology: 3.2 Conventional Steam Electric - Wet FGD

I. Physical Characteristics

1. Plant Size - 1000 MW
2. Capacity Factor - 65%
3. Efficiency - 36.1%
4. Coal Type - Ill. No. 6
5. Annual Quantity Used - 2.66×10^6 tons

II. Cost Assumptions Dec. 1980 $s

1. Overnight Capital Cost - $\$950 \times 10^6$
2. Annual Capital Charge - $\$117.3 \times 10^6$
3. Annual Operating Costs
   A. Fixed $\$15.3 \times 10^6$
   B. Variable $\$23.9 \times 10^6$
4. Annual Coal Cost - $\$88.8 \times 10^6$
5. Coal Price - $\$1.65/10^6$
6. Output Cost - $.0526/kWh

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI TAG Appendix p. 54

Technology: 3.2 Advanced Pulverized Coal Steam Electric

I. Physical Characteristics

1. Plant Size - 725 MW
2. Capacity Factor - 69.3%
3. Efficiency - 38.4%
4. Coal Type
5. Annual Quantity Used

II. Cost Assumptions 1978 $s, 6% infl.

1. Overnight Capital Cost - \$628 x 10^6
2. Annual Capital Charge - \$77.6 x 10^6
3. Annual Operating Costs

   A. Fixed \$14.5 x 10^6

   B. Variable \$7 x 10^6
4. Annual Coal Cost - \$54.1 x 10^6
5. Coal Price - \$1.38/10^6 Btu
6. Output Cost - \$.0541/kWh

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI - CS-2555 Assessment of Advanced P.C. Plant (G.E.)

Technology: 3.2 Advanced Pulverized Coal Steam Electric

I. Physical Characteristics

1. Plant Size - 773 MW
2. Capacity Factor - 69.3%
3. Efficiency - 40.9%
4. Coal Type - Eastern bituminous
5. Annual Quantity Used

II. Cost Assumptions 1978 $s, 6% infl., 10% int. rate, 5 yr. construction

1. Overnight Capital Cost - $\$398 \times 10^6$
2. Annual Capital Charge - $\$49 \times 10^6$
3. Annual Operating Costs

   A. Fixed
   B. Variable

   $\left.\begin{array}{l}\text{A. Fixed}\\\text{B. Variable}\end{array}\right\}\ \$34 \times 10^6$

4. Annual Coal Cost - $\$54 \times 10^6$
5. Coal Price - $\$1.38/10^6$ Btu
6. Output Cost - $.0454/kWh

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI - CS-2223, Assessment of Advanced P.C. Plant (Westinghouse)

3.3.1 Atmospheric Fluidized Bed Electric Power Plants

Atmospheric Fluidized Bed (AFB) boilers differ from conventional pulverized boilers in the character of their combustion. In AFBs, combustion occurs at atmospheric pressures in a mass or "bed" of small particles through which flow large volumes of gases. The incoming combustion air moving through the beds cause the mass of particles to behave like a fluid.

In the most well developed form of AFB, crushed coal and a chemically active sorbent such as limestone are fed into the bed of hot particles. The most attractive feature of the AFB for electric power generation is that the sorbent captures sulfur in the coal during combustion. The efficiency of this capture is such that it reduces or eliminates the need for add-on sulfur removal equipment.

Although there are several versions of the AFB combustor, the most developed for commercial electric power use is the bubbling bed design. Following are performance and cost data estimates for two different new (grass roots) AFB plants. The smaller, 163 MWe plant, is similar to a demonstration plant being built at Paducah, Kentucky. Although performance and cost estimates for both plants must be considered soft since neither has been used commercially for electric power, estimates for the larger 1000 MWe plant, are to be viewed with particular skepticism since they are derived solely from paper extrapolation.

AFB-R&D

The commercial competitiveness of AFB steam-electric power plants must still be demonstrated. Successful commercial use of the AFB requires the solution of two process problems. The most important unresolved problem concerns the design of a reliable coal feed mechanism that adequately distributes coal to the bed. This problem becomes progressively more difficult as the bed is enlarged. An elaborate feed design is required; and the size and moisture content of the coal must be carefully controlled. Without adequate distribution the coal is not efficiently burned and plant efficiency declines and fuel costs rise.

The second major problem which may stand in the way of AFB commercialization is erosion and corrosion of materials which are in contact with the bed or particulate laden gases. These potential materials problems and the associated operations and maintenance costs may make the AFB uneconomic. They are, therefore, a primary focus of R&D.

The above two AFB problem areas require continued development work before this technology can become commercial, that is, have costs comparable to or lower than a conventional pulverized coal boiler with FGD.

Technology: 3.3.1 Atm. Fluidized Bed Steam Electric

I. Physical Characteristics

1. Plant Size - 163 MW

2. Capacity Factor - 65%

3. Efficiency - 35%

4. Coal Type

5. Annual Quantity Used

II. Cost Assumptions 1983 $s

1. Overnight Capital Cost - $205-258 x 10^6

2. Annual Capital Charge - $25.3 - 31.8 x 10^6

3. Annual Operating Costs

A. Fixed
B. Variable

$\left.\begin{array}{l}\text{A. Fixed}\\ \text{B. Variable}\end{array}\right\}$ \$7.1 x 10^6

4. Coal Cost Annual - $16.1 x 10^6

5. Coal Price - $1.78/$10^6$ Btu

6. Output Cost - $.0545 $.0617/kWh

III. Cleanup

1. Sulfur 90%

2. NO_x - Meet NSPS

3. Ash

Data Source: Informal communication from Office of Technology Assessment

Technology: 3.3.1 Atm. Fluidized Bed Steam Electric

I. Physical Characteristics

1. Plant Size - 1000 MW
2. Capacity Factor - 65%
3. Efficiency - 35.4%
4. Coal Type: Ill. No. 6
5. Annual Quantity Used - 2.7×10^6 tons

II. Cost Assumptions Dec. 1980 $s

1. Overnight Capital Cost - $\$780 \times 10^6$
2. Annual Capital Charge - $\$96 \times 10^6$
3. Annual Operating Costs
   - A. Fixed $\$8.5 \times 10^6$
   - B. Variable $\$24.5 \times 10^6$
4. Coal Cost Annual - $\$90.5 \times 10^6$
5. Coal Price - $\$1.65/10^6$ Btu
6. Output Cost - $.0500/kWh

III. Cleanup

1. Sulfur 90%
2. NO_x - Meet NSFS
3. Ash

Data Source: EPRI TAG Appendix B-60

3.3.2 Pressurized Fluidized Bed Electric Power Plants

As in their atmospheric counterpart, combustion in Pressurized Fluidized Bed (PFB) boilers occurs in beds of crushed stone and coal fluidized by the combustion air. In the PFB, however, combustion air is pressurized to several times atmospheric pressure. Most designs of PFB boilers involve a combined cycle system. Power is produced by both a gas turbine and a steam turbine. The gas turbine is usually driven by the PFB's hot exhaust gases and the steam is generated both in boiler tubes in the bed and down stream from the gas turbine.

PFB combined cycle systems have potentially significant advantages over the AFB because they offer a higher thermal efficiency. Since it is pressurized, the bed of hot particles can be much deeper, affording more complete combustion and sulfur capture plus better load control. Further, because it is pressurized the boiler is physically smaller and can perhaps be shop fabricated, reducing the capital costs.

There are no PFB systems near commercialization in the United States. A 13 MW(e) Curtis-Wright pilot plant has been built under contract to DOE but there are no funds for operating the system and its future is uncertain.

Since there is no experience with commercial construction or operation of a PFB boiler, the cost estimates must be viewed as conceptual.

PFB-R&D

It is widely believed within the technical community that the technology currently exists to build a PFB that uses a gas turbine turbo charger operating on relatively low temperature exhaust gas. This would be used to pressurize the PFB system and therefore demonstrate its size reduction and combustion performance advantages. Considerable development work is still needed to bring even this moderate performance system to operation.

Substantial technical challenges must be overcome before a high efficiency system can be developed. These challenges lie in four principal areas:

- Erosion/corrosion of the gas turbine blades
- Fuel and sorbent feeding against high pressure
- Load control
- Erosion of bed internals

The first two are the most significant problems. As the temperature and pressure of the exhaust gas is increased the electrical efficiency increases. However the damage to the turbine blades through erosion by the hot suspended ash particles and corrosion also increases. There are two possible solutions: either the development of hot gas cleanup systems, or stronger and more durable turbine components. Feeding solids into a high pressure environment is a technical problem PFB's share with several other coal technologies.

Technology: 3.3.2 Pressurized Fluidized Bed - Combined Cycle

I. Physical Characteristics

1. Plant Size - 650 MW
2. Capacity Factor - 65%
3. Efficiency - 40.3%
4. Coal Type - Eastern
5. Annual Quantity Used - 1.55 x 10^6 tons/yr

II. Cost Assumptions December 1980 $s

1. Overnight Capital Cost - $539.5 x 10^6
2. Annual Capital Charge - $66.6 x 10^6
3. Annual Operating Costs
   - A. Fixed $7.4 x 10^6
   - B. Variable $14.4 x 10^6
4. Annual Coal Cost - $51.8 x 10^6
5. Coal Price - $1.65/$10^6$ Btu
6. Output Cost - $.0463/$10^6$ Btu

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI TAG, Appendix B-63

3.4.1 Retrofit Steam Electric - Pulverized Coal

The retrofit options described here involve the conversion of oil-burning plants to coal-firing. There are basically two types of plants that are candidates for such a conversion. Those originally designed to burn coal and subsequently converted to oil, and those intended to burn only oil. Retrofit costs are generally lower for plants originally designed to burn coal, but they can differ widely even within each category depending upon the plant under consideration.

For those units originally designed to burn coal, reconversion can involve changes in several areas. Boiler modifications generally will be small, especially if the new coal type is similar to that used originally, and the boiler derating usually will be small to moderate. Pollution control typically requires, at minimum, a new or upgraded electrostatic precipitator. A flue gas desulfurization (FGD) system may also be required depending upon the applicable SO_x regulations. Sludge and ash disposal systems may have to be added or renovated. And finally, coal handling and storage facilities can prove to be costly if the previous coal handling system has been demolished or is in poor repair.

The conversion of plants designed to burn oil is normally more complex. The design of an oil-fired boiler is significantly different than a coal-fired boiler with regard to furnace volume, heat release rates, exit gas temperatures, gas velocities, and so forth. Even extensive modifications cannot insure that the conversion to coal can be accomplished without a significant boiler derating. In addition, coal silos and ash disposal equipment must be constructed in association with the modified boiler. A major constraint in this type of conversion may be space.

As with the CWS retrofit, it is difficult to show a comprehensive set of cost calculations, hence the samples here are meant to be representative.

PC Retrofit - R&D

The technology for the retrofit of oil-fired plants to coal is current. The main areas for R&D include less costly FGD systems and improvements in boiler efficiencies via higher temperatures and cleaner coals.

Technology: 3.4.1 Retrofit Steam Electric - Pulverized Coal

I. Physical Characteristics

1. Plant size - 518 MW
2. Capacity Factor - 65%
3. Efficiency - 35%*
4. Coal Type - low sulfur
5. Annual Quantity Input - .97 x 10^6 tons

II. Cost Assumptions Mid 1982 $s

1. Overnight Capital Cost - $113.9 x 10^6
2. Annual Capital Charge - $14.1 x 10^6
3. Annual Operating Costs
   A. Fixed
   B. Variable
   (A and B together) $4.7 x 10^6
4. Annual Coal Cost - $74.9 x 10^6
5. Coal Price - $2.6 $/$10^6$ Btu
6. Output Cost - $.0345/kWh

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: Kimel, Kurtzrock Conference 830483, Vol. 2.

*Coal to electricity efficiency not provided - 35% efficiency assumed for this calculation.

3.4.2 Retrofit Steam Electric - Coal-Water Slurry

The extent to which a conventional boiler system must be modified to burn coal-water slurry (CWS) clearly depends upon the fuel handling and burning capability of the existing facilities. Changing an oil-designed boiler to CWS is, with respect to combustion characteristics and ash effects, essentially a conversion to coal. However, the fuel storage and distribution requirements for CWS are similar to those for oil. It is possible that existing oil storage tanks can be used for CWS with only minor changes; for example, agitators may be needed for long-term CWS storage. CWS has a lower energy density than oil, however, so additional tanks may be required to maintain an equivalent number of days supply of fuel. If the plant currently receives coal, then, of course, liquid storage and handling capability must be built.

A boiler designed to burn coal will possess many of the necessary characteristics to burn CWS. Nevertheless, some of the following changes may be needed:

- installation of fuel piping and pumping equipment;
- installation of CWS burners;
- modifying secondary air preheating arrangements;
- upgrading the wall de-slaggers and soot blowers;
- upgrading the ash handling system.

An oil-firing boiler will require more extensive modification including:

- rearrangement of gas recirculation ductwork;
- installation of wall de-slaggers and soot blowers;
- provision of ash handling and storage systems;
- improved stack gas cleaning facilities;
- modifying the secondary air preheater;
- installation of CWS feed system.

In both the oil and coal cases, the extent of the modifications depends upon the tolerable derating of the boiler. In general, the derating caused by CWS conversion is high, and this can be counteracted only by making major changes in the boiler configuration. CWS retrofit thus includes a wide variety of possible alternatives. An exhaustive set of cost calculations would be prohibitively large, hence we have shown here only some representative samples.

<u>CWS Retrofit - R&D</u>

The technology for CWS retrofit is presently available, but is not yet in commercial use. An important reason for this is that the slurry itself is not yet commercially available. CWS retrofit R&D needs thus focus on the fuel production and use. For more information on this, see Sect. 2.3 (CWS Production).

Technology: 3.4.2 Retrofit Steam Electric - CWS

I. Physical Characteristics

1. Plant size - 518 MW
2. Capacity Factor - 65%
3. Efficiency - 35%*
4. Coal Type
5. Annual Quantity Input - 1.35 tons/year

II. Cost Assumptions Mid 1982 $s

1. Overnight Capital Cost - $\$78.4 \times 10^6$
2. Annual Capital Charge - $\$9.7 \times 10^6$
3. Annual Operating Costs - (incremental)

   A. Fixed
   B. Variable

   (A and B) $\$3.6 \times 10^6$

4. Annual Slurry Cost - $\$100.6 \times 10^6$
5. CWS Price - $\$3.50 /10^6$ Btu
6. Output Cost - $.0419/kWh

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: Kimel, Kurtzrock, CONF 830483 Vol. 2.

*Coal to electricity efficiency not provided - 35% efficiency assumed for this calculation.

3.5.1 Intermediate Btu Gasification

Coal can be gasified into low, intermediate, or high Btu gas; the processes for synthesizing low and intermediate Btu gases are, however, less costly, more efficient, and closer to being competitive with other fuels. Intermediate Btu gas is a very flexible form of energy. Its uses include: combined cycle electrical generation, fuel cells, indirect liquefaction, and upgrading to a high Btu substitute for natural gas.

Intermediate Btu gas (250-350 Btu/Scf) is composed chiefly of carbon monoxide (CO), and hydrogen (H). Low Btu gas (90-170 Btu/Scf) is similar but also contains significant quantities of nitrogen (N_2). Synthetic gas is produced when coal is reacted with steam and an oxidant (oxygen in the case of intermediate Btu gas and air in the case of low Btu gas) to produce a hot, raw gas. The raw gas must be cleaned of particulates, oils, ammonia, acids, and water to meet environmental and operational constraints.

Gasifiers are usually one of three types, fixed bed, fluidized bed, or entrained bed, and each of these may involve quite different designs depending on the performance criteria of concern to the designers. The commercially used designs include the Winkler fluidized bed, and the Lurgi process. More recently, Texaco and Kellog-Rust-Westinghouse (KRW) have begun offering high pressure gasifiers that have the advantages of smaller size and a more usable end product. There are however, many areas in which commercially available gasifier technology is inadequate. Inadequacies are reflected in process complexity, environmental performance, capital costs, construction lead times, operating costs and efficiencies, and problems with the handling of certain readily available coals. Gasification technology on a widespread commercial level must still be considered developmental. The cost estimates shown here are based upon large plants with high capacity factors beyond what can be currently achieved, hence they should not be regarded as projections.

Intermediate Btu Gasification - R&D

The scientific basis for coal gasification is well understood. It has been possible to construct workable gasifiers for well over a century. What is needed are improvements in construction costs, the costs of operation (including emission control), and the capability to use more of the coals available in the United States. These problems are sufficiently serious to preclude the commercial competitiveness of coal gasification at present natural gas prices unless significant advances are made.

The most pressing problem is the continuous feeding of the solid fuel into the gasification chamber. This is especially troublesome in the pressurized gasifiers. These systems are much smaller than their atmospheric counterparts of equal capacity, hence the capital cost is lower. In addition, they are more efficient; the output gas is already compressed so it needs no costly pressurization before it can be utilized. These benefits cannot be realized in large scale facilities however until the coal feed problem is solved. Towards this end, Texaco has tried, with moderate success, to inject the fuel as a coal-water mixture.

Another important task involves improving the flexibility of the gasifiers with regard to the type of coal that can be used. Gasifiers can be built to convert nearly every type of coal to gas, however, most of those built to date are limited to coals with a fairly narrow range of such characteristics as moisture content, ash fusion temperature, and coal type. If, in the future, the United States is forced to rely more heavily upon domestic coal as a basic energy resource, gasifiers that can tolerate changes in the supply of specific varieties of coal will be extremely important.

Finally, R&D efforts are needed to improve the cost effectiveness of environmental protection technologies. These include the separation and removal of acid gas, removal of particulates at high temperatures, and the control of effluents.

Technology: 3.5.1 Intermediate Btu Gasification - Texaco

I. Physical Characteristics

1. Plant size - 168 x 10^9 Btu/Day
2. Capacity Factor - 90%
3. Efficiency - 68%
4. Coal Type - Ill. no. 6
5. Annual Quantity Input - 2.73 x 10^6 tons

II. Cost Assumptions Dec. 1980 $s

1. Overnight Capital Cost - $637 x 10^6
2. Annual Capital Charge - $78.6 x 10^6
3. Annual Operating Costs
   - A. Fixed
   - B. Variable

   $21.46 x 10^6 (A and B together)
4. Annual Coal Cost - $149 x 10^6
5. Coal Price - $1.65/$10^6$ Btu
6. Output Cost - $4.96/$10^6$ Btu gas

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI TAG Appendix B-36

3.5.2 Combined-Cycle Coal Gasification

Combined-cycle systems are a combination and adaptation of two technologies: gas turbines and steam turbines. Combined-cycle systems were originally developed as high efficiency power units utilizing either distillate oil or natural gas as the fuel. The combined-cycle concept discussed here consists of a coal gasifier which feeds a high temperature gas turbine followed by a heat driven steam turbine bottoming cycle. Coal gasification combined cycle plants offer two potential advantages: effective-efficient control of air pollutants and high energy efficiencies.

While there are no commercial coal fueled units in operation in the United States, there is a demonstration plant built by EPRI and Southern California Edison at the Cool Water Power Station. This project, widely characterized as a technical success, serves as the basis for the cost estimates used in this report.

Combined-Cycle Coal Gasification - R&D

For combined cycle coal gasification systems to be competitive electricity generation options, their reliability must be demonstrated and their efficiency improved. The major focus of R&D attention to date has been the output stream from the gasifier. This stream includes energy in two forms: heat and intermediate Btu gas which is then combusted in the gas turbine.

With current technology, energy is lost because the intermediate Btu gas must be cooled prior to introduction into the gas turbine. Cooling is required for two reasons: (1) effluent streams contain both sulfur and ash particles that must be removed prior to entry into the gas turbine. Sulfur removal is necessary for environmental reasons, and particle removal is necessary to protect the turbine from damage. Present cleanup technology requires that the effluent gas be cooled prior to cleaning. (2) Present material capabilities limit the turbine inlet temperatures of the gas to 2000°F. Were it possible through R&D to clean hot gases and/or develop materials which are resistant to erosion and corrosion while maintaining the necessary structural properties at temperatures of 2400°F or more, substantial efficiencies could result. In the most optimistic case, a 25% thermal efficiency improvement may be possible. For the overall system this would increase the conversion efficiency from coal to electricity from 35 to 41%.

Increasing the gas turbine inlet temperature may have two effects. First, the higher temperature makes the gas turbine itself more efficient. Second, because the exhaust would be at a higher temperature, the steam conditions in the heat recovery steam bottoming cycle would contribute to greater overall system efficiency.

Gasifier efficiency improvements may also be possible with development of better coal feed systems. For example, the Texaco gasifier system uses a coal-water slurry feed that is typically 50 to 70% coal solids and 30 to 50% water. Maintaining a high solids concentration is both technically difficult and an important contributor to efficiency. For instance, a system feeding solids at 50% concentration will be 2.5 percentage points lower in efficiency than one with 67% solids concentration. From an efficiency standpoint, it is as important to develop reliable high concentration slurry pumping systems as it is to develop advanced gas turbine technology, although most development has been directed toward turbine technology. For further discussion see the gasification section (3.5.1).

In the ideal case better coal feed to the gasifier plus the ability to use higher temperature effluent streams from the gasifier could give coal to electricity efficiencies of about 43%.

Technology: 3.5.2 Combined Cycle-Texaco Gasifier/2400°F Turbine

I. Physical Characteristics

1. Plant Size - 1157 MW
2. Capacity Factor - 70%
3. Efficiency - 39%
4. Coal Type - Eastern
5. Annual Quantity Used

II. Cost Assumptions 1978 $s

1. Overnight Capital Cost - $\$866 \times 10^6$
2. Annual Capital Charge - $\$107 \times 10^6$
3. Annual Operating Costs
   A. Fixed $\$23.9 \times 10^6$
   B. Variable $\$2.7 \times 10^6$
4. Annual Coal Cost - $\$102.9 \times 10^6$
5. Coal Price - $\$1.65/10^6$ Btu
6. Output Cost - $.0519/kWh

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI AP 1725

Technology: 3.5.2 Combined Cycle-Lurgi Gasifier/2400°F Gas Turbine

I. Physical Characteristics

1. Plant Size - 988 MW
2. Capacity Factor - 70%
3. Efficiency - 35%
4. Coal Type - Eastern
5. Annual Quantity Used

II. Cost Assumptions 1978 $s

1. Overnight Capital Cost - $817.6 x 10^6$
2. Annual Capital Charge - $100.9 x 10^6$
3. Annual Operating Costs
   A. Fixed $26.7 x 10^6$
   B. Variable $6.1 x 10^6$
4. Annual Coal Cost - $97.5 x 10^6$
5. Coal Price - $1.65/10^6$ Btu
6. Output Cost - $.0594/kWh

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI AP 1725

Technology: 3.5.2 Combined Cycle - Texaco Gasifier

I. Physical Characteristics

1. Plant Size - 1000 MW
2. Capacity Factor - 65%
3. Efficiency - 36.1%
4. Coal Type - Ill. No. 6
5. Annual Quantity Used - 2.67×10^6 tons

II. Cost Assumptions Dec. 1980 $s

1. Overnight Capital Cost - $\$995 \times 10^6$
2. Annual Capital Charge - $\$122.8 \times 10^6$
3. Annual Operating Costs
   A. Fixed $\$17.7 \times 10^6$
   B. Variable $\$12.5 \times 10^6$
4. Annual Coal Cost - $\$88.8 \times 10^6$
5. Coal Price - $\$1.65/10^6$ Btu
6. Output Cost - $.0518/kWh

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI TAG Appendix B-64

3.5.3 Fuel Cells

Direct conversion of chemical energy into electricity through a fuel cell bypasses the mechanical step in steam-electric plants and is thus not limited to the Carnot efficiency. Thermal efficiencies greater than 50% are theoretically possible and have been demonstrated on a laboratory scale. Fuel cell technology is nearly as old as wet-cell batteries. As in conventional batteries, a fuel cell employs a pair of electrodes separated by an electrolyte. The electrolyte is a medium for ion transport from one electrode to the other. Fuel usually in the form of hydrogen, although carbon monoxide and methane can be used in some designs, is fed into the electrolyte. The hydrogen electrochemically combines with oxygen, which is fed in the form of air, to form water releasing heat and electricity. To gain maximum efficiency the heat is usually envisioned as powering a steam bottoming cycle. There are several fuel cell concepts that have been developed including alkaline, phosphoric acid, molten carbonate, solid oxide and solid polymer fuel cells. For the purpose of this study only phosphoric acid and molten carbonate fuel cells are considered. The phosphoric acid cell represents commercial technology and the molten carbonate fuel cell represents an advanced system.

United Technologies has built 65 12.5 kW phosphoric acid fuel cells and completed a 4.8 MW demonstration plant. The costs presented here are conceptual and not backed by actual experience.

Fuel Cell-R&D

The overall thermal efficiency of a fuel cell power plant depends heavily on the temperature at which it operates. There are two reasons for this. First, at a higher temperature, the electrochemical reactions occur more rapidly than they do at lower temperature and the internal losses are less. Second, at higher temperatures, the rejected heat makes the bottoming cycle more efficient. This, then, is the impetus to develop the higher temperature molten carbonate system.

However, even the more well developed phosphoric acid fuel cell presents difficult technical problems. The shortness of active cell life is probably the most critical technical, and, therefore, economic problem since it requires frequent replacement of the fuel cell stack. The engineering compromises involved in building fuel cell stacks lead to a host of problems such as plate warping, internal shorts, electrolyte leakage, and increases in contact resistance between elements of the cell stack. Available data on cell life indicate operating times of 500 to 2000 hours. This is about 10 times less than the 10,000-20,000 hours that are considered necessary for commercial operation.

Programs aimed at improving the cell life of phosphoric acid systems and overall development of the higher temperature molten carbonate fuel cells have potential for improving the economics of the fuel cell system.

Technology: 3.5.3. Fuel Cells (Molten Carbonate) - Texaco Gasification

I. Physical Characteristics

1. Plant Size - 1430 MW
2. Capacity Factor - 70%
3. Efficiency - 48%
4. Coal Type - Eastern
5. Annual Quantity Used

II. Cost Assumptions 1978 $s

1. Overnight Capital Cost - $1038 x 10^6
2. Annual Capital Charge - $128 x 10^6
3. Annual Operating Costs
   A. Fixed $26.4 x 10^6
   B. Variable $2.6 x 10^6
4. Annual Coal Cost - $103.5 x 10^6
5. Coal Price - $1.65/10^6 Btu
6. Output Cost - $.0462/kWh

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI AP 1725

Technology: 3.5.3. Fuel Cell (dispersed) - Texaco Gasification (not included)

I. Physical Characteristics

1. Plant Size - 30 MW
2. Capacity Factor - 65%
3. Efficiency - 41%
4. Gas Type - Int. Btu from Texaco Process
5. Annual Quantity Used

II. Cost Assumptions Dec. 1980 $s

1. Overnight Capital Cost - $\$18 \times 10^6$
2. Annual Capital Charge - $\$2.2 \times 10^6$
3. Annual Operating Costs
   A. Fixed $\$.068 \times 10^6$
   B. Variable $\$.512 \times 10^6$
4. Annual Gas Cost - $\$5.5 \times 10^6$
5. Gas Price - $\$3.88/10^6$ Btu
6. Output Cost - $.0597/kWh

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI TAG Appendix B-87

Technology: 3.5.3 Fuel Cells (Phosphoric Acid) - Texaco Gasification (included)

I. Physical Characteristics

1. Plant Size - 1500 MW
2. Capacity Factor - 65%
3. Efficiency - 32.2%
4. Coal Type - Ill. No. 6
5. Annual Quantity Used - 4.5 x 10^6 tons

II. Cost Assumptions Dec. 1980 $s

1. Overnight Capital Cost - $1448 x 10^6
2. Annual Capital Charge - $178 x 10^6
3. Annual Operating Costs
    A. Fixed $24.8 x 10^6
    B. Variable $85.4 x 10^6
4. Annual Coal Cost - $149.5 x 10^6
5. Coal Price - $1.65/$10^6$ Btu
6. Output Cost - $.0626/kWh

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI TAG Appendix B-69 (CERL IR E 85/94 pp. 64.)

3.5.5 Indirect Liquefaction - Description

Indirect Liquefaction refers to a set of processes that convert a feedstock gas to usable liquid fuels. Feedstock gas can come from an intermediate Btu coal gasification process or more directly from natural gas. Although many different process designs exist and have been experimented with, the two which have experienced the most development are Fischer-Tropsch (FT) and Mobil methanol-to-gasoline (MTG). These two are the focus of this discussion. The Fischer-Tropsch process can convert feedstock gas into gasoline, diesel fuel, fuel oil, and alcohols. Alternatively feedstock gas may be converted into methanol via methanol synthesis, and then to gasoline by the (MTG) process.

The F-T process was invented prior to WWII and has been operated on a commercial scale. Currently the only commercial scale F-T indirect liquefaction operation is SASOL in South Africa where the justification for the construction was national security, not economic competitiveness. Under most future petroleum price scenarios, the high cost of commercial scale F-T liquid production makes it economically unattractive.

The MTG process is relatively new. The first commercial scale plant is currently being built in New Zealand to produce 13,000 bbl/day of gasoline from natural gas via methanol. New Zealands's lack of natural liquids combined with its plentiful supply of natural gas gives it the ideal economic characterists for commercial indirect liquefaction. The much larger capital investment required for coal-based feedstock gas production makes indirect liquefaction in the United States unattractive at present world oil prices.

Indirect Liquefaction - R&D

Although indirect liquefaction technologies are near the commercial development stage, there are many areas where continued R&D is needed. Of prime importance in the U.S. is efficiency improvements and cost reductions in the coal gasification process. For more information on this topic see Sect. 3.5.1, Intermediate Btu Gasification.

Finally, there are areas for technical improvement in the liquefaction process itself. Increased thermal efficiencies and improvements in catalyst activity rates and more selective catalysts can increase system output and lower costs. Significant improvements are needed before indirect liquefaction becomes commercial.

Technology: 3.5.5 Indirect Liquefaction (Methanol from Coal)

Texaco Gasification

I. Physical Characteristics

1. Plant size - 210 x 10^9 Btu/day
2. Capacity Factor - 90%
3. Efficiency - 57.8%
4. Coal Type - Ill. no 6
5. Annual Quantity Used - 3.42 x 10^6 tons

II. Cost Assumptions Dec. 1980 $s

1. Overnight Capital Cost - $1.415 x 10^9
2. Annual Capital Charge - $175 x 10^6
3. Annual Operating Costs

   A. Fixed } $75.9 x 10^6
   B. Variable }

4. Annual Coal Cost - $196.7 x 10^6
5. Coal Price - $1.65/$10^6$ Btu
6. Output Cost - $7.92/$10^6$ Btu = $20.8/bbl

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI TAG Appendix B-34

3.6 Direct Liquefaction

Direct coal liquefaction provides a means of producing useful liquid fuels from coal without going through the gasification stage. Several direct liquefaction processes have been built and tested at small scale [e.g., H-coal, Exxon Donor Solvent (EDS)], but large scale development of these technologies has not looked economically attractive. The major potential advantages of direct liquefaction are high thermal efficiencies, and high yield of high quality liquid products (e.g., gasoline). The principal problems stem from the severe operating conditions involving coal slurries, the high degree of integration found among process steps, and the high capital and operating costs.

The H-Coal process is a direct catalytic hydroliquefaction process. A heated slurry (33% coal) is forced into a pressurized reactor and moves through a catalyst bed causing the bed to fluidize. Because the catalyst is in a constant state of fluidization, fresh catalyst can be added as necessary to maintain the desired reactions. The H-Coal process can produce a broad spectrum of hydrocarbon liquids ranging from low-sulfur fuel oil to an all-distillate syn-crude.

The EDS process uses a feed of coal in a solvent that has been catalytically hydrogenated to improve its hydrogen donor properties. The EDS process has the advantage that it does not require a separate catalyst. The reactor effluent is distilled to recover the solvent which is rehydrogenated and recycled back to the main reactor. The liquid products include naphtha, low-sulfur fuel oil and C_3 - C_4 LPG.

Small scale direct liquefaction plant tests indicate that liquid fuels from commercial scale operations would cost about 50% more than the current price of crude oil. It must be emphasized, however, that the inherent uncertainties associated with scale up to commercial size make these cost estimates soft.

Direct Liquefaction - R&D

Some argue that the H-Coal process is technically ready for commercialization but R&D is clearly needed to make it economically competitive. One area of need involves improving the range of the output products. The goal is to increase the percentage of high quality transportation fuels produced.

Another area for improvement in liquefaction involves the more efficient use of hydrogen. Currently, up to 25% of the total hydrogen is consumed in the production of complex hydrocarbons. Reduction in process hydrogen consumption would lower product cost.

Studies of coal liquefaction indicate that the process takes place in a series of sequential reactions that may have very different optimum reaction conditions. This suggests that it would be advantageous to carry out the process in separate stages. Most work in the United States has focused on single stage or reactor processes. What seems clear is that there are multiple options available for direct liquefaction and much R&D is necessary before the optimal approach is identified.

Technology: 3.6 Direct Liquefaction - H-Coal

I. Physical Characteristics

1. Plant size - 250 x 10^9 Btu/day
2. Capacity Factor - 90%
3. Efficiency - 68.4%
4. Coal Type - Eastern
5. Annual Quantity Used - 4.06 x 10^6 tons

II. Cost Assumptions Dec. 1980 $s

1. Overnight Capital Cost - $1.415 x 10^9
2. Annual Capital Charge - $175 x 10^6
3. Annual Operating Costs
   A. Fixed
   B. Variable
   (A and B) $96.1 x 10^6
4. Annual Coal Cost - $197 x 10^6
5. Coal Price - $1.65 Btu
6. Output Cost - $6.97/$10^6$ Btu = $45.7/bbl Liquid

<u>Products</u>
naphtha
turbine fuel
distillate boiler fuel

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI TAG Appendix B-30

Technology: 3.6 Direct Liquefaction - H-Coal

I. Physical Characteristics

1. Plant size - 250 x 10^9 Btu/day
2. Capacity Factor - 90%
3. Efficiency - 61%
4. Coal Type - Western
5. Annual Quantity Used - 5.11 x 10^6 tons

II. Cost Assumptions Dec. 1980 $s

1. Overnight Capital Cost - $\$1.6 \times 10^9$
2. Annual Capital Charge - $\$197.5 \times 10^6$
3. Annual Operating Costs

   A. Fixed
   B. Variable

   $\left.\begin{array}{l}\text{A. Fixed}\\ \text{B. Variable}\end{array}\right\}$ $\$119 \times 10^6$

4. Annual Coal Cost - $\$174 \times 10^6$
5. Coal Price - $\$1.30/10^6$ Btu
6. Output Cost - $\$7.33/10^6$ Btu = $\$42/10^6$ bbl

Products
naphtha
turbine fuel
distillate boiler fuel

III. Cleanup

1. Sulfur
2. NO_x
3. Ash

Data Source: EPRI TAG Appendix B-30

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APPENDIX A

OUTLINE OF PROPOSED COAL TECHNOLOGY AND R&D COST STUDY

I. Introduction

1. Statement of Purpose
2. Description of Approach

II. Technology and R&D Options

1. Coal Types
   - 1.1. Illinois No. 6 Bituminous
     - A. Cost
     - B. Sulfur Content
     - C. Ash Content
   - 1.2. Western Subbituminous
     - A. Cost
     - B. Sulfur Content
     - C. Ash Content
   - 1.3. East Texas Lignite
     - A. Cost
     - B. Sulfur Content
     - C. Ash Content
2. Cleaning - Enhancement
   - 2.1. Physical
     - 2.1.1. Describe
       - A. Cost
       - B. Sulfur Removal
       - C. Ash Removal
     - 2.1.2. R&D Options
       - A. Describe
       - B. Estimated Cost Reduction
       - C. Estimated R&D Cost
   - 2.2. Physical/Chemical
     - 2.2.1. Describe
       - A. Cost
       - B. Sulfur Removal
       - C. Ash Removal
     - 2.2.2. R&D Options
       - A. Describe
       - B. Estimated Cost Reduction
       - C. Estimated R&D Cost
   - 2.3. Coal/Water Slurry
     - 2.3.1. Describe
       - A. Cost
       - B. Sulfur Removal
       - C. Ash Removal

2.3.2. R&D Options
- A. Describe
- B. Estimated Cost Reduction
- C. Estimated R&D Cost

2.4. Low Temp Pyrolysis

2.4.1. Describe
- A. Cost
- B. Sulfur Removal
- C. Ash Removal

2.4.2. R&D Options
- A. Describe
- B. Estimated Cost Reduction
- C. Estimated R&D Cost

2.5. Biological

2.5.1. Describe
- A. Cost
- B. Sulfur Removal
- C. Ash Removal

2.5.2. R&D Options
- A. Describe
- B. Estimated Cost Reduction
- C. Estimated R&D Cost

III. Utilization - Conversion

3.1. Industrial Process Steam
(Boiler Size 250 million Btus per hr. heat input)

3.1.1. Conventional Boiler

3.1.1.1. Describe
- A. Cost
- B. Sulfur Removal
- C. NO_x Emissions

3.1.1.2. R&D Options
- A. Describe
- B. Estimated Cost Reduction
- C. Estimated R&D Cost

3.1.2. Fluidized Bed Boiler

3.1.2.1. Describe
- A. Cost
- B. Sulfur Removal
- C. NO_x Emissions

3.1.2.2. R&D Options
- A. Describe
- B. Estimated Cost Reduction
- C. Estimated R&D Cost

3.1.3. Cogeneration

3.1.3.1. Describe
- A. Cost
- B. Sulfur Removal
- C. NO_x Emissions

3.1.3.2. R&D Options
- A. Describe
- B. Estimated Cost Reduction
- C. Estimated R&D Cost

3.2. Conventional Steam-Electric
- 3.2.1. Describe (Base Load)
  - A. Cost
  - B. Sulfur Removal
  - C. NO_x Emissions
- 3.2.2. R&D Options
  - A. Describe
  - B. Estimated Cost Reduction
  - C. Estimated R&D Cost
- 3.2.3. Describe FGD (Dry, Wet)
  - A. Cost
  - B. Sulfur Removal
  - C. NO_x Emissions
- 3.2.4. R&D Options
  - A. Describe
  - B. Estimated Cost Reduction
  - C. Estimated R&D Cost

3.3. Fluidized Bed Steam Electric
- 3.3.1. Atmospheric
  - 3.3.1.1. Describe
    - A. Cost
    - B. Sulfur Removal
    - C. NO_x Emissions
  - 3.3.1.2. R&D Options
    - A. Describe
    - B. Estimated Cost Reduction
    - C. Estimated R&D Cost
- 3.3.2. Pressurized
  - 3.3.2.1 Describe
    - A. Cost
    - B. Sulfur Removal
    - C. NO_x Emissions
  - 3.3.2.2. R&D Options
    - A. Describe
    - B. Estimated Cost Reductions
    - C. Estimated R&D Cost

3.4. Retrofit Conventional Steam Electric
[(1) Fluidized Bed; (2) Coal Water Slurry; (3) Lime Injection (LIMB); (4) Multistage Burners; (5) Two-Stage Slagging Burner; (6) Micronized Coal Combustion; (7) FGD]
- 3.4.1. Describe All Above
  - A. Cost
  - B. Sulfur Removal
  - C. NO_x Emissions

3.4.2. R&D Options
A. Describe
B. Estimated Cost Reduction
C. Estimated R&D Cost

3.5. Intermediate BTU Gasification
3.5.1. Describe
3.5.1.1. A. Cost
B. Sulfur Removal
C. NO_x Emissions
3.5.1.2. R&D Options
A. Describe
B. Estimated Cost Reduction
C. Estimated R&D Cost
3.5.2. Combined Cycle - Coolwater
3.5.2.1. Describe
A. Cost
B. Sulfur Removal
C. NO_x Emissions
3.5.2.2. R&D Options
A. Describe
B. Estimated Cost Reduction
C. Estimated R&D Cost
3.5.3. Fuel Cells (UTC, Westinghouse) (Phosphoric Acid)
3.5.3.1. Describe
A. Cost
B. Sulfur Removal
C. NO_x Emissions
3.5.3.2. R&D Options (Molten Carbonate)
A. Describe
B. Estimated Cost Reduction
C. Estimated R&D Cost
3.5.4. Upgrading - High Btu Gasification - 1) Lurgi (Great Plains); 2) KRW; 3) Texaco
3.5.4.1. Describe
A. Cost
B. Sulfur Removal
C. NO_x Emissions
3.5.4.2. R&D Options
A. Describe
B. Estimated Cost Reduction
C. Estimated R&D Cost
3.5.5. Indirect Liquefaction - 1) Mobil; 2) Fischer-Tropsch
3.5.5.1. Describe
A. Cost
B. Sulfur Removal
C. NO_x Emissions

3.5.5.2. R&D Options
A. Describe
B. Estimated Cost Reduction
C. Estimated R&D Costs

3.6. Direct Liquefaction
3.6.1. Describe
A. Cost
B. Sulfur Removal
C. NO_x Emissions
3.6.2. R&D Options
A. Describe
B. Estimated Cost Reduction
C. Estimated R&D Cost

3.7. Gas Turbine/Diesel
3.7.1. Describe
A. Cost
B. Sulfur Removal
C. NO_x Emissions
3.7.2. R&D Options
A. Describe
B. Estimated Cost Reduction
C. Estimated R&D Cost

III. Summary and Conclusions

IV. Recommendations

APPENDIX B

COST DEFINITIONS AND PARAMETERS

<u>Costs</u>. All costs have been calculated in Dec. 1984 dollars. In converting costs to Dec. 1984 $s, it was assumed that all costs escalated at the same rate. Thus, energy output costs were first calculated in the various $s in which they were presented. Next, the output cost was converted to December 1984 $s using the Consumer Price Index for all goods and services.

RAW COAL

Because various technologies and processes may be appropriate to one coal and not to another, we selected three representative coal types.

Each of these coals was assigned a delivered cost per million Btus. These prices were taken from the EPRI Technical Assessment Guide (TAG) (Appendix B-8) and are:

1. Ill. No.6 — $\$2.01/10^6$ Btus
   (Delivered to Illinois-Wisconsin area)
2. Western Bituminous — $\$1.59/10^6$ Btus
   (Delivered to Illinois-Wisconsin area)
3. East Texas Lignite — $\$1.04/10^6$ Btus
   (Minemouth Plant)

This investigation assumes the above coal costs to be those paid at the entrance to the coal cleaning, enhancing, utilization or conversion facilities.

CALCULATING CLEANING, UTILIZATION, OR CONVERSION COSTS

Plant costs. Plant costs are of two kinds: Capital and Operating.

In this study capital costs refer to overnight or instantaneous costs. The overnight capital costs are the costs that would be incurred if the plant could be built instantaneously. (It should be emphasized that overnight capital costs do not include the cost of financing the construction. In extreme cases long construction times have resulted in real capital costs that are multiples of overnight capital costs.) Annual capital costs were calculated assuming a 30 year plant life and a 12% cost of capital. The 12% cost of capital assumes no inflation but does assume such costs as taxes and insurance. Individual users of the report may wish to use different amortization periods or costs of capital. This may be done by substituting the appropriate numbers in the following formula.

$$a = \frac{(1 + i)^n - 1}{i\ (1 + i)^n}$$

a = capital charge factor

i = cost of capital

n = amortization period

In this report the annual capital charge rate for each technology is determined by dividing the overnight capital cost by a capital charge factor of 8.1. (For example, a plant with an overnight capital cost of \$1 billion would have an annual capital charge rate of $\frac{\$1\text{ billion}}{8.1}$ = \$123.5 million.)

Operating costs include the cost of the raw coal plus labor, maintenance, and overhead costs. End-use energy costs are calculated by adding annual capital, operating and fuel costs, and dividing the sum by the annual energy output. This gives the cost in terms of: (1) $s per million Btus of cleaned coal or enhanced solids; (2) $s per million Btus of steam; (3) per kWh $s of electricity; (4) $s per thousand cubic feet of gas; or (5) $s per barrel of liquids.

The quantity of input raw coal, is calculated in three steps. First, we assume the plant operates at 100% of capacity when running Second, the actual annual energy output is calculated by multiplying 100% of output capacity by the capacity factor (percentage of the year it is in operation). Third, the quantity of input coal is calculated by dividing the plant's efficiency into the plant's annual energy output.

The calculation of annual coal cost then involves multiplying the cost of each 10^6 Btus of coal times annual quantity of 10^6 Btus of coal input.

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