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BY THE COMPTROLLER GENERAL

Report To The Congress

OF THE UNITED STATES

DOE Funds New Energy Technologies Without Estimating Potential Net Energy Yields

Public Laws 93-577 and 96-294 (title II) require the Department of Energy to analyze the potential net energy yields of new energy technologies proposed under the Acts before funding them. DOE has spent hundreds of millions of dollars on projects without doing this.

GAO demonstrates that net energy analysis is methodologically feasible to perform and that its performance is useful to policymakers in the Congress and DOE because (1) it offers them a basis for minimizing total energy use and for conserving domestic energy resources in the production of new energy products, (2) it guarantees them the opportunity to consider the net energy yields of proposed new energy technologies independent of economic risk questions, (3) it permits them to compare the net energy yields of specific plants and processes as well as their relative impacts on existing domestic resources and on imported premium fuel requirements, and (4) it gives them a method for deciding the introduction rates of energy-intensive technologies so as to avoid the creation of large energy deficits.

GAO recommends that the Congress require DOE to consider the potential net energy yields of proposed technologies and to provide the analytic support needed to implement net energy analysis. GAO also recommends ways to strengthen the quality of the data base necessary not only for net energy analysis but also for the economic analysis used for comparing the costs of new energy technologies.

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COMPTROLLER GENERAL OF THE UNITED STATES
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To the President of the Senate and the
Speaker of the House of Representatives

This report demonstrates the development and application of a method for performing net energy analysis, an analytical tool that introduces valuable concepts and data to assist in understanding the contribution of specific new energy technologies to national energy policy objectives. Implementation of net energy analysis will help prevent misallocation of Federal energy development and conservation funds in the existing imperfect energy market situation.

Copies of this report are being sent to the Director, Office of Management and Budget, to the Secretary of Energy, and to the Chairman, Synthetic Fuels Corporation.

Charles A. Bowsher

Comptroller General
of the United States

COMPTROLLER GENERAL'S
REPORT TO THE CONGRESS

DOE FUNDS NEW ENERGY TECHNOLOGIES WITHOUT ESTIMATING POTENTIAL NET ENERGY YIELDS

D I G E S T

The Federal Nonnuclear Energy Research and Development Act of 1974 (Pub. L. 93-577) requires DOE to analyze and consider not only the gross but also the net energy yield of a new technology at its commercial stage before deciding whether to support it under the Act. Title II of the Energy Security Act of 1980 (Pub. L. No. 96-294) requires DOE to calculate detailed information on the net energy yield of biomass energy projects. A net energy yield can be estimated by net energy analysis (NEA)--it is the gross amount of energy produced minus the amount of energy needed to produce it. DOE has questioned the feasibility and utility of NEA; it has not performed or used NEA as required under these statutes. GAO's purpose in this report is to examine the methodological feasibility and the utility of NEA. (pp. 1-3)

Future financial support of new energy technologies is presently uncertain because it is not yet clear which, if any, Federal entities will carry out future responsibilities for research, development, and demonstration activities and under which authority the support will be provided. Meanwhile, decisions are being made that ignore the statutory requirements to perform NEA. For example, as recently as August 1981, DOE awarded a $2.02 billion conditional loan guarantee for a commercial coal gasification plant without evaluating its potential net energy yields. (pp. 54-55)

If DOE used NEA, its policymakers would have a better basis for minimizing total energy use, conserving domestic energy resources, and reducing the amount of premium fuel that has to be imported. NEA would measure physical energy flows and identify the types and amounts of energy consumed in the production of energy. NEA thus guarantees to policymakers the opportunity to compare the net energy yields of proposed new technologies (pp. 49-50) and to consider them independently from their economic aspects. It provides a much more precise understanding of those yields than can the measurements given by thermal efficiency estimates, which exclude indirect energy inputs, or the dollar measurements of energy inputs and products given by economic analysis. Dollar measurements do not substitute for NEA because they are not based on explicit physical energy requirements and because of imperfections in the energy marketplace. (pp. 9 and 51)

The continued use of economic analysis remains essential for judging the financial risks associated with a new project. However, a Federal perspective suggests that net energy yields are also important in deciding which technologies should be supported. Without NEA, a new technology may be funded because it appears economically attractive, even though its net energy yield has not been adequately estimated and may be unfavorable. The results for the two ethanol facilities examined in this report (which show that they are only marginal net producers of premium fuels) point up the risks of using estimates from economic analysis or thermal efficiency--energy directly produced divided by energy directly consumed--as the sole basis for evaluating proposals. (pp. 48 and 51)

FINDINGS

GAO finds no evidence that NEA has been considered in DOE's proposal evaluation process or that NEA has been performed in a manner responsive to the statutory requirements of either the Nonnuclear Act of 1974 or the Energy Security Act of 1980. Although DOE does conduct thermal efficiency and other energy analyses, these have failed to include and account for the indirect energy inputs necessary to determine net energy yield (pp. 7-8) or have been carried out in ad hoc fashion, using different analytical boundaries and techniques, so that comparisons between facilities could not be made. Others have been generic in character with little bearing on the site-specific NEA's contemplated in the statutes. (p. 4) DOE officials stated to GAO that this neglect was the result of methodological problems with NEA that render it infeasible to perform and the prevailing DOE view that economic analysis is an adequate substitute for NEA. (pp. 1-4)

With regard to the methodology developed and its application here, GAO finds that despite difficult data problems resulting from the present inadequate data base, the approach taken permits both the inclusion of indirect energy inputs and the comparison of the net energy yields of different processes and technologies in a manner consistent with the requirements of the two relevant statutes. (pp. 49-50)

The results of the analysis illustrate some of the types of design-oriented information that can be obtained, ranging from the rank ordering (for comparative analysis) of different technologies and of different technological processes on a site-specific basis to the pinpointing of potential areas of concern and uncertainty regarding the design choices for specific technologies and processes. (pp. 36-41 and 46-50)

In consequence, GAO finds NEA a useful tool for policymakers because it helps them maximize effective energy use and conserve domestic energy resources in the production of new energy products. NEA also allows policymakers and managers to (1) emphasize production processes that result in the highest quantity or quality of fuels, (2) focus on process questions whose resolution can improve the effectiveness and efficiency of energy production (pp. 37-38), (3) compare competing technologies and processes with regard to their relative net energy yields and their relative impacts on the use of domestic and imported resources (pp. 34, 46, and 49), and (4) decide on the most advantageous rate of introduction for new energy-intensive technologies in order to avoid the creation of large energy deficits at any given time (p. 38).

OBSERVATIONS

GAO applied its NEA methodology to direct coal liquefaction and ethanol production technologies because domestic resources of coal are vast and because Federal subsidies for the development of their technologies are large. (pp. 31-50) GAO does not, however, advocate the technologies it analyzed. GAO's purpose was to demonstrate the methodology for measuring physical net energy yields; other considerations, including economic and environmental factors, must also be addressed before deciding the relative merits of the technologies GAO analyzed for this report.

The data problems encountered in performing this demonstration show that there is a real need to improve the quality and consistency of the energy and economic analysis data bases. (pp. 38-41) The ability to perform NEA routinely will also require a data base of the indirect energy inputs associated with the capital investment and raw materials that energy facilities use. Industry sources estimate the cost of obtaining the data base required for NEA to be $300,000 to $750,000. The cost of maintaining the data base and conducting NEA can be absorbed by DOE's existing structures for maintaining models and data bases and for reviewing proposals. The prudent choice of new energy technologies for public financial support--techologies that will make the best use of domestic energy resources--justifies the relatively small incremental cost of improving the selection process. (p. 53; app. V)

Finally, GAO believes that the arguments that have been advanced by DOE officials--that it is not feasible to perform NEA because of methodological problems and that such performance is unnecessary because other decisionmaking tools can be substituted--do not hold up. GAO has demonstrated that the methodological problems are not insurmountable given proper analytic support and has shown that other decisionmaking tools are not substitutes for NEA. Therefore, it would seem that the impediments to DOE's compliance with its statutes (Pub. L. No. 93-577 and Pub. L. No. 96-294), both of which require the performance and use of NEA, have been or can be overcome.

AGENCY COMMENTS AND GAO'S EVALUATION

DOE states that it does not and has never questioned the methodological feasibility of conducting NEA. (app. VIII) However, NEA's methodological infeasibility was the major problem raised by DOE officials explaining DOE's neglect of NEA during interviews with GAO for this report.

DOE also states that it performs NEA and that it is in compliance with the Nonnuclear Act (Pub. L. No. 93-577) requiring the use of NEA in evaluating proposals. However, GAO has found no evidence of such performance or use, DOE officials have explicitly recognized this lack, and neither the data base of indirect energy inputs required for performing NEA nor the guidelines required for its use in proposal evaluation have been developed by DOE.

DOE rejects the utility of NEA for policymaking despite the evidence of its usefulness given by the six plant examples in GAO's report (p. 46) and the limitations of economic analysis and thermal efficiency estimates (pp. 9, 51, and 56).

Finally, DOE rejects GAO's recommendations for improving the data bases for economic as well as net energy analysis and concludes that to follow GAO's recommendations would waste the taxpayers' resources.

GAO is pleased that DOE no longer contests the methodological feasibility of performing NEA. However, GAO believes that DOE should reconsider its positions on improving the data base and the utility of performing NEA. First, decisionmaking that spends taxpayer resources on the basis of inconsistent, unvalidated, and low-quality data constitutes an inefficient management of public funds. (p. 53) Second, continued neglect of NEA runs counter to the statutory requirements stated in Public Laws 93-577 and 96-294 and to DOE's explicit promise to the House Committee on Government Operations to implement NEA. (p. 56)

RECOMMENDATIONS TO THE SECRETARY OF THE DEPARTMENT OF ENERGY

The Secretary of the Department of Energy should issue directives necessary for

--performing net energy analysis on all technologies proposed under authority of Public Laws 93-577 and 96-294

--developing the additional data base for the analysis of indirect energy flows.

Uncertainties exist regarding which Federal entities will carry out future energy research, development, and demonstration activities; nevertheless, the recommendations above would apply to the administrators of succeeding agencies. Additional recommendations to the Secretary of the Department of Energy regarding data quality are included in chapter 8. (p. 57)

RECOMMENDATION TO THE CONGRESS

In Public Laws 93-577 and 96-294, the Congress has expressed its interest in net energy analysis; GAO has demonstrated the feasibility and value of conducting net energy analysis; DOE has not conducted net energy analysis. Therefore, the Congress should require the Department of Energy or succeeding entities to demonstrate, during oversight and appropriations hearings, that the potential ability of proposed energy technologies to produce net rather than gross premium fuels and energy at their commercial stage was analyzed and considered before DOE funded the development of those technologies. (p. 58)

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ABBREVIATIONS

bfoe	Barrel of fuel-oil equivalent
bpd	Barrels per day
Btu	British thermal unit
DDG	Distillers dried grain
DOE	U.S. Department of Energy
EDS	Exxon Donor Solvent
ERDA	Energy Research and Development Administration
ERG	Energy Research Group
GAO	U.S. General Accounting Office
H/C	Hydrogen-to-carbon ratio
IF	Idaho Falls plant
I-O	Input-output
LPG	Liquefied petroleum gas
NEA	Net energy analysis
psi	Pounds per square inch
PX	Plant X
scf	Standard cubic foot
SDU	Study Design Update
SRC	Solvent Refined Coal
tpd	Tons per day
tpsd	Tons per stream day

CHAPTER 1

INTRODUCTION

A major objective of the Nation's energy program is to increase efficient use of domestic energy resources and thereby reduce dependence on foreign fuel. To meet this objective, the U.S. Department of Energy (DOE) has funded projects to develop new technologies that convert coal, an abundant domestic resource, into premium fuels--oil and gas--and thus lessen the need to rely on imports. The Federal Nonnuclear Energy Research and Development Act of 1974 (Pub. L. No. 93-577), commonly called the Nonnuclear Act, requires DOE to consider the net energy to be produced by a proposed technology before granting funds to such projects. Also, title II of the Energy Security Act of 1980 (Pub. L. No. 96-294) requires that both gross and net premium fuels be a major consideration in DOE's funding decisions of certain biomass energy technologies. 1/

Because DOE is not using net energy analysis (NEA) in its proposal evaluation process, however, it is initiating major technological development and procurement processes without first estimating which ones most efficiently produce premium fuels that can reduce U.S. dependence on foreign supplies. DOE officials have reported that this neglect is the result both of methodological problems in the conceptualization and application of NEA that make it infeasible to perform and of DOE's belief that economic analysis is an adequate substitute for NEA. It is our purpose in this report, therefore, to examine the methodological feasibility and usefulness of net energy analysis.

FEDERAL SUPPORT FOR NEW TECHNOLOGY

The Congress established, with the Nonnuclear Act, a national program of applied research and development, including a provision for funding demonstrations of practical applications of all potentially beneficial energy sources and end-use technologies. Formerly the responsibility of the Energy Research and Development Administration (ERDA), the program is now administered by DOE. Among DOE's tasks in designing and executing the comprehensive program in research, development, and demonstration is this one, pertaining to the analysis of net energy:

> The potential for production of net energy by the proposed technology at the stage of commercial application shall be analyzed and considered in evaluating proposals. (Pub. L. No. 93-577, sec. 5(a)(5))

1/Certain funding decisions by the Secretary of Agriculture are also covered by the 1980 Act.

That is, the statute requires DOE, when deciding whether to support a technology under the Act, to consider not just the gross but also, specifically, the net energy yield of that technology at its commercial stage.

More recently, addressing new biomass energy technologies in title II of the Energy Security Act of 1980, the Congress further required that both gross and net premium fuels be a major consideration in DOE's funding decisions regarding certain biomass energy projects:

> Priority for financial assistance under this subtitle, and the most favorable financial terms available, shall be provided to a person for any biomass energy project that . . . uses a primary fuel other than petroleum or natural gas in the production of biomass fuel, such as geothermal energy resources, solar energy . . . . Financial assistance under this subtitle shall be available for a biomass energy project only if the Secretary concerned finds that the Btu content of the motor fuels to be used in the facility involved to produce the biomass fuel will not exceed the Btu content of the biomass fuel produced in the facility. (Pub. L. No. 96-294, title II, sec. 217(a)(1)(A) and (a)(2)(A))

The Congress also emphasized, in section 235(a)(2)(B), that gross and net premium fuels were to be a criterion in DOE's funding decisions for municipal waste energy projects.

Moreover, the Congress required DOE to estimate how the fuel products of a biomass energy facility could substitute for motor fuels or other petroleum products:

> In making the determination under subparagraph (A), the Secretary concerned shall take into account any displacement of motor fuel or other petroleum products which the applicant has demonstrated to the satisfaction of the Secretary would result from the use of the biomass fuel produced in the facility involved. (Pub. L. No. 96-294, title II, sec. 217(a)(2)(B))

To analyze the net energy yield of a new technology, one must subtract from the gross amount of energy to be produced the amount of energy needed to produce it. At the time the Nonnuclear Act mandated DOE to perform such analysis, however, there was still considerable confusion about the proper methodology to employ and some consequent uncertainty about how to apply NEA to public policy analysis. Such confusion and uncertainty are typical of almost any new analytical technique. Given that to perform NEA, using any methodology, there are many things to be accounted for and many ways to account for them, it is not surprising that assumptions, boundaries, and data-estimating techniques vary significantly among studies that have calculated net energy yields subsequent to the Act. Findings from the different studies are, consequently, difficult to compare and often lead to different conclusions (as we reported in Potential of Ethanol as a Motor Vehicle Fuel, EMD-80-73, June 1980). Unfortunately, the confusion and uncertainty have remained, largely because DOE has failed to provide the leadership and the analytical support needed to implement and refine the methodology for conducting NEA.

DOE'S NEGLECT OF NET ENERGY ANALYSIS

In a 1977 report, Net Energy Analysis: Little Progress and Many Problems (EMD-77-57), written three years after the passage of the Nonnuclear Act, we found that ERDA had not been using net energy analysis in analyzing net yields of new energy technologies as the Nonnuclear Act had intended it to. We recommended that ERDA develop and implement a research plan to assess the potential usefulness of NEA, particularly for policy and decisionmaking. ERDA responded by saying that NEA was insufficiently developed methodologically, that expert opinion did not agree on a preferred methodology or standard approach for conducting NEA, and that the usefulness of NEA for decisionmaking had not been demonstrated. ERDA added that NEA studies had been performed on energy supply systems, on electric conversion processes, and on end-use applications and that it planned to make a comparative evaluation of NEA techniques, to prepare guidelines for the use of NEA, and to study the use of NEA in policy and decisionmaking at ERDA. ERDA stated that it would use NEA in planning and implementing research and development activities if NEA could be adequately defined and could be found to be beneficial. (U.S. GAO, 1977, pp. 164-65) 1/ However, none of these efforts was ever carried out. We have found no evidence that NEA has been defined, tested, performed, or used in the decisionmaking processes developed by DOE despite the fact that DOE was required by statute to use NEA.

OBJECTIVES, SCOPE, AND METHODOLOGY

Our objectives in undertaking the present report, therefore, are to (1) examine DOE's use of NEA since 1977, (2) determine whether it is feasible to perform NEA by specifying an NEA methodology, (3) apply such a methodology to fuel conversion technologies to illustrate the kind of information it is possible to derive from NEA, and (4) determine whether an improved NEA methodology would be a valuable decisionmaking tool for the Congress and DOE.

To determine DOE's present use of NEA in response to the mandate of the Nonnuclear Act of 1974, we interviewed DOE officials and, to determine whether DOE has either analyzed or considered NEA in its proposal evaluation process, we reviewed proposal solicitation documents, proposals submitted for funding,

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1/For details of publication of all interlinear bibliographic citations, see appendix VII.

evaluation guidelines, proposal review reports, and proposal selection statements.

DOE staff provided us with one example of NEA's indirect mention in proposal solicitations. This was the development of alcohol fuel plants. DOE noted that many old alcohol beverage distilleries used natural gas to fire their boilers, which would affect the net premium fuel produced. DOE made it known that plants using coal-fueled boilers would be given preference.

We identified another proposal solicitation that mentioned NEA in its technical project factors section, under "energy factors." The category requirement was "Describe the thermal efficiency of the project including net energy analysis." However, there were neither guidelines on how to conduct an NEA nor requirements to insure consistency of results. Moreover, there was no evidence that NEA had been considered in the evaluation process.

Although DOE does conduct thermal efficiency analyses, these have either failed to include the indirect energy inputs necessary to determine net energy yield or have been carried out ad hoc with no standardized analytical boundaries or techniques, so that comparisons could not be made, or else generic analyses of a broadly defined type of technology have been performed that typically have little bearing on the net energy yields of a specific facility. The NEA of a particular ethanol plant like Idaho Falls, for example, could be expected to have substantially different energy inputs and outputs and technical sophistication from the NEA of the generic technology, ethanol production. In this regard, the Energy Security Act requires site-specific rather than generic analyses.

Our objectives in this report thus flow from our finding that DOE officials have not implemented the statutory requirements to perform and use NEA and from their explanation that this neglect is the result of methodological problems with NEA along with their view of economic analysis as an adequate substitute.

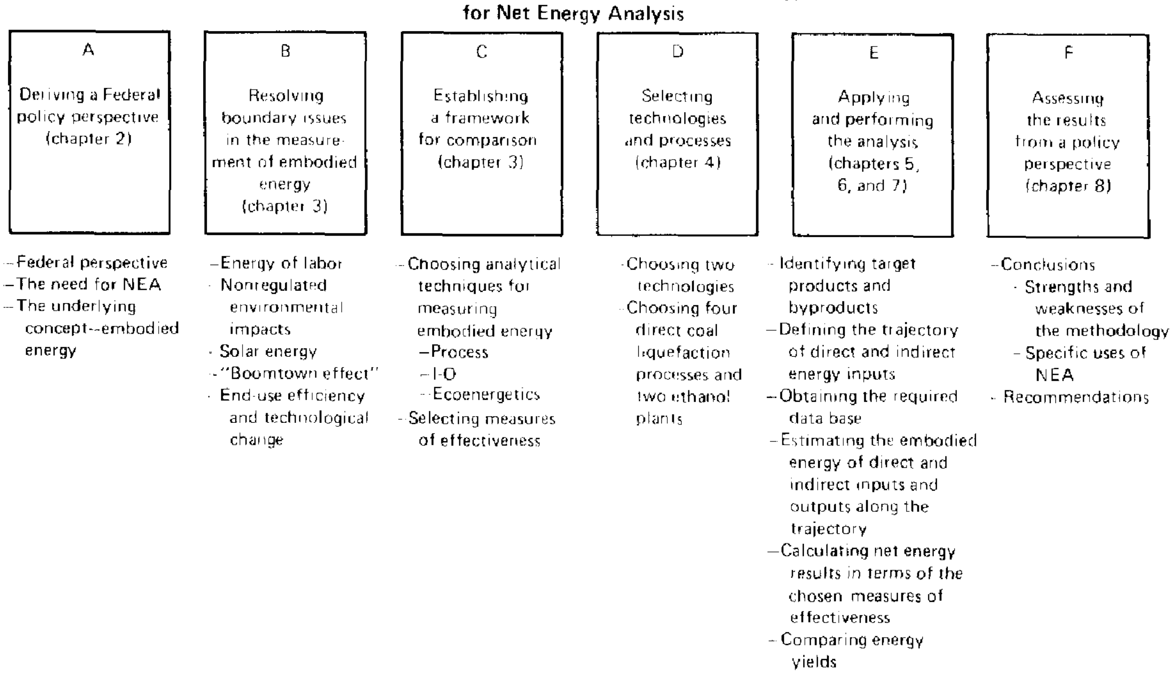
To fulfill our objectives, we gathered data from technical reports and other literature on net energy analysis, coal liquefaction, ethanol production, coal mining, agricultural production of corn, the environmental impact of new energy sources, and the transportation of coal and liquid fuels. In addition to interviewing DOE officials, we also interviewed personnel of the National Alcohol Fuels Commission, the Environmental Protection Agency, and the following private organizations directly involved in the development of coal liquefaction processes: Ashland Synthetic Fuels, Inc. (Catlettsburg, Kentucky, and Houston, Texas), Electric Power Research Institute (Palo Alto, California), Exxon Research and Engineering Company (Florham Park, New Jersey), Hydrocarbon Research, Inc. (Lawrenceville, New Jersey), International Coal Refining Company (Allentown, Pennsylvania), and Solvent Refined Coal International (Denver, Colorado). In addition, we discussed NEA with various authorities, including Dr. R.

Constanza of the Center for Wetlands Research at Louisiana State University at Baton Rouge, Dr. D. Klass of the Institute of Gas Technology in Chicago, and Dr. H. Odum of the Department of Environmental Engineering at the University of Florida in Gainesville. Also, as consultants, Dr. Robert Herendeen of the Energy Research Group of the University of Illinois at Champaign-Urbana and Dr. Donald Hertzmark of the Solar Energy Research Institute in Golden, Colorado, provided us with extremely valuable assistance.

In the main body of this report, we give details of our specification and application of a methodology for net energy analysis. The steps that we followed and that govern the structure of the report are summarized in figure 1. In chapter 2, we set NEA in a policy perspective. In the first part of chapter 3, we show how we resolved the boundary issues in measuring embodied energy, explaining the procedures we used to do this. In the rest of chapter 3, we establish a framework for comparing the available analysis techniques.

The next step was to choose an analytical technique and measures of efficiency to apply to a coal conversion technology. Accordingly, in chapter 4, we illustrate some of the logical and some of the technological reasons for selecting direct coal liquefaction over other available technologies to which to apply

Figure 1
Steps in Developing and Applying a Methodology for Net Energy Analysis



net energy analysis. We also discuss in chapter 4 the basis for our choosing four particular direct liquefaction processes; each has been funded by DOE, and each is suitable for comparison with the others.

In chapter 5, we show the results of our identification of target products and byproducts of direct coal liquefaction and the network of industries that contribute materials, energy, capital and equipment, and transportation to their production. Having isolated this "trajectory" of direct and indirect energy inputs, we discuss our compilation of a data base adequate for analysis. Our sources included project solicitation documents, design reports, and records of capital costs and operating and maintenance expenditures as well as extant process analyses and other documents. Finally, we report on our estimations of the embodied energy of direct and indirect inputs and outputs and calculations of energy ratios that measure the productivity of energy facilities in each of the four coal liquefaction processes.

In chapters 6 and 7, we show the results of our application of net energy analysis to the four direct coal liquefaction processes (chapter 6) and also, for purposes of completeness in making our comparisons, to coal-fired ethanol production (chapter 7). It is these two chapters that enable us to present our principal findings. Gaps and other problems with the data base--stemming from DOE's lack of quality control in data management (as discussed in chapter 6)--prevent us from making definitive conclusions. Nevertheless, we have been able to make quite detailed comparisons across similar and also dissimilar technologies.

Our estimations and calculations and the principles and data on which we based them are collected in five technical appendixes at the end of the report. In appendix I, we define and explain the most common techniques for net energy analysis. In appendixes II and III, we show the calculations necessary to support the net energy analysis of coal liquefaction and of coal-fired ethanol production. In appendix IV, we present our estimates of transportation energy in the overall trajectory. In appendix V, we summarize the costs of using a process analysis data base. A glossary of terms and an extensive bibliography on net energy analysis appear as appendixes VI and VII.

We conclude our report in chapter 8 with an outline of the strengths and weaknesses of the methodology of net energy analysis that we have developed and present here, following this (also in chapter 8) with a summary of our assessment of DOE's position, given the results of our analysis. DOE and others have read and commented on a draft of this report, and we respond to their comments both in chapter 8 and in the more detailed appendix VIII. Finally, we offer recommendations to the Secretary of the U.S. Department of Energy and to the Congress with respect to the potential value of using net energy analysis in making policy decisions about the Nation's ability to use its domestic energy resources efficiently and effectively.

CHAPTER 2

DERIVING A FEDERAL POLICY PERSPECTIVE

Federal policy perspective on net energy analysis derives from a recognition of the need for NEA results, of their ability to contribute to policy and program decisionmaking, and of the responsibility to facilitate NEA's performance. The discussion in this chapter expands on phase A of figure 1 in chapter 1.

THE FEDERAL PERSPECTIVE ON NET ENERGY ANALYSIS AND DOE'S MANDATE

The Federal perspective on NEA is shaped by the nature of U.S. energy shortages. Declining domestic supplies of valuable premium fuels such as oil and gas have forced the United States to rely on foreign premium fuels while vast domestic supplies of coal have remained untapped. Therefore, trying to correct this imbalance, the Federal Government has supported the conversion of coal to more useful, liquid premium fuels. Thus, an NEA methodology would be most advantageous if it could measure the contributions that energy technologies make in meeting the demand for premium fuels by using domestic coal resources efficiently.

Despite the consequent Federal responsibility to facilitate the implementation of net energy analysis, significant limitations have been imposed on its applications. Federal support for developing the required data base and refining analytical methodologies has been delayed in some cases and in others is absent. DOE has neither developed a consistent, well-documented data base on the energy consumed and produced in the U.S. economy nor resolved the significant conceptual issues of NEA. For these reasons, energy analyses performed by DOE have fallen short of the statutory requirements for NEA established by Public Law 93-577 and title II of Public Law 96-924.

THE CONCEPT OF NET ENERGY ANALYSIS AS EMBODIED ENERGY

One of the most important concepts underlying the use of NEA in Federal policymaking is its ability to tell us about the energy required to generate a product like electricity and also about the energy required to equip, operate, and maintain the industries that participate directly and indirectly in producing the electricity. This energy--the energy required both directly and indirectly to generate a product--is called embodied energy. Net energy is, then, the difference between the energy produced and the embodied energy required to produce it. Both the energy product and the embodied energy can be expressed in common physical units of measurement, such as Btu's. 1/

1/A British thermal unit, or Btu, is the amount of heat required to raise the temperature of 1 pound of water by 1 degree Fahr-

Analyzing both direct and indirect inputs of embodied energy is critical in performing a net energy analysis of new technology to obtain an accurate net energy yield. Excluding indirect inputs could lead to overstatements of the net energy yield. This is especially critical when the type of indirect energy consumed and produced is scarce--as premium fuels are. It is, however, the ability to measure embodied energy, and especially the indirect energy inputs, that has been the source of the greatest impediment in the performance of net energy analysis.

The Congress mandated net energy analysis as a tool for energy decisionmaking because it emphasizes the physical measurement of the energy that is required to produce energy products. In a coal-burning electric power plant, for example, electricity is generated after the coal has been mined, transported, and burned; but mining and transporting the coal, constructing and operating the power plant, and manufacturing the mine equipment, trucks, and trains all require energy. Thus, the energy that a power plant requires to produce electricity includes not only the coal it consumes directly but also the energy required to equip, operate, and maintain all the industries that participate, directly and indirectly, in producing the electricity. However, current techniques and an inadequate data base do not allow us to measure this total energy consumption.

Economic analysis has long been used to measure the relative productivity of energy technology in monetary terms. The costs of capital, materials, and energy inputs can be compared with the revenue derived from the sale of energy products. In an economic analysis, the efficiency of a technology using energy and other resources to produce energy is measured by its profit potential. Thus, the underlying assumption is that the dollar values of energy products like coal and gasoline measure

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enheit at 39.2 degrees Fahrenheit. Although one Btu of energy is equal to any other Btu of energy, its quality--that is, its ability to do work--varies from one form of energy to another. One Btu of electricity is of higher quality than one Btu of coal, for example. In thermodynamic terms, this is described as "availability"--the extent to which a given amount of energy is able to do work--and is measured in units of "free energy." Consequently, the unit that best expresses the objective of NEA is free energy. Nonetheless, because it is difficult to compute free energy changes for many processes and because the error in using Btu's rather than free energy for most energy-intensive fuels (oil, coal, etc.) is on the order of only 10 percent, Btu's have been adopted as a sufficiently accurate measure. In fact, the Energy Security Act of 1980 (title II, sections 217 and 235) specifies Btu as the unit of measurement appropriate in analyzing net premium fuel yields.

the value of these fuels to society, including their heat content, their cleanliness, their potential as transportation fuels, and so on.

Economic analysis, however, cannot clearly and accurately present the direct and indirect inputs to energy products for two reasons. First, direct and indirect physical energy requirements of a technology are not explicitly measured by economic analysis. That is, direct energy inputs are included as part of the dollar cost of equipping, operating, and maintaining a power plant, for example, but they are not presented in physical terms like British thermal units. In the case of indirect energy requirements, economic analysis offers even less information because the Btu's of natural gas, coal, and electricity required to produce indirect materials inputs (steel, chemicals, maintenance equipment) are hidden in the prices of those inputs.

Second, even when dollar values do measure energy values, they may measure them inaccurately because of imperfections in the energy marketplace. Price controls on domestic natural gas and, until recently, on petroleum products have artificially depressed the prices of these products. Government subsidies in the form of construction loans and grants, research and development support, product purchase guarantees, and price supports for energy industries are not included in an economic analysis. Consequently, energy prices are lower than they would be under free market conditions. (Renyl and Steele, 1976)

Net energy analysis, on the other hand, clearly presents direct and indirect energy flows and, because it relies on physical measures of energy, can provide a detailed understanding of the types of energy that are consumed directly and indirectly in producing energy. This is a critical point with regard to Federal decisions on funding competing energy technologies. It gives NEA a major advantage over economic analysis in the effort to examine the effects of energy technologies on the Nation's energy posture.

CHAPTER 3

DEVELOPING A NET ENERGY ANALYSIS METHODOLOGY

Three conceptual issues had to be considered and resolved to develop an NEA methodology. The issues are as follows. What factors would be included (setting boundaries)? What analytical techniques would be appropriate (selecting analytical techniques)? How can effectiveness be measured (choosing measures of effectiveness)? This chapter corresponds to phases B and C of our approach as shown in figure 1 in chapter 1.

SETTING BOUNDARIES

As with other analytical tools, the question of boundaries, or what factors to include, affects both the complexity and the outcome of the analysis. In considering this question, our objective was to minimize complexity while capturing the major factors contributing to the net energy yield of the new energy technologies. Our resolution of the boundaries issue does not preclude other perspectives and their boundary selections.

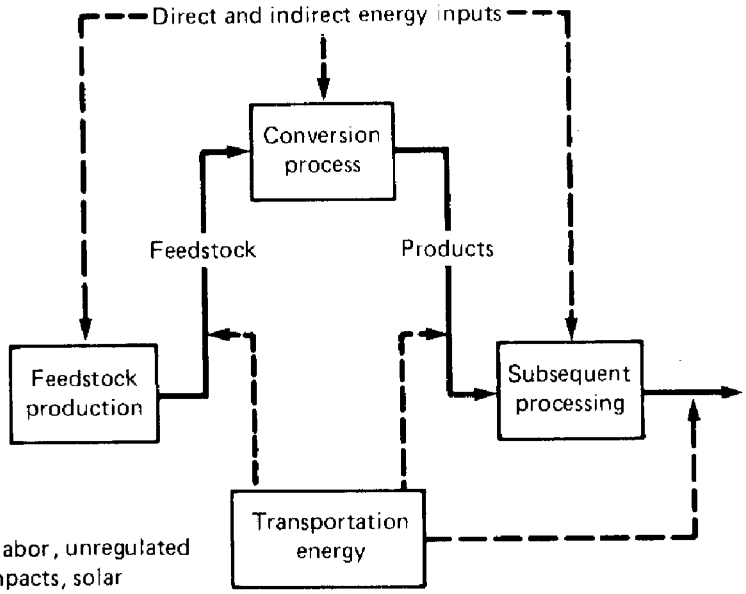
We caution against diminishing returns, however. That is, analysts should beware of increasing the complexity of an NEA by excessively extending boundaries in an effort to reach for higher-order energy inputs that because of their small magnitude have little, if any, impact on the net energy yields in comparative analysis. The major boundary questions considered and resolved here in developing an NEA methodology involved the handling of the energy of labor, environmental impacts, solar energy, "boomtown effect," and end-use efficiency and technological change. Figure 2 summarizes our resolution of the boundary questions.

Energy of labor

Should the embodied energy of labor be included in NEA? Previous NEA's have generally excluded it; we did too, because, in our opinion, only the energy embodied in the subsistence of the laborer and the laborer's family should be evaluated. Federal and State unemployment programs and transfer payments already provide such subsistence, and we assume, therefore, that the incremental energy requirements resulting directly from employment in new energy facilities are minimal.

It might be argued that the possibility of variation in the labor intensities of different proposed technologies requires that labor be considered. We agree. However, we also think that NEA must always be viewed as a complement to other analytical methods in energy policy analysis. In this particular case, combining economic analysis with NEA provides information for making comparative analyses of proposed technologies having different labor intensities.

Figure 2
Establishing Boundaries for Measuring Net Energy



Excludes energy of labor, unregulated environmental impacts, solar energy, "boomtown effect," and end-use efficiency and technological change

Environmental impacts

Should an NEA of a new technology include the energy required to control currently unregulated environmental impacts? In our methodology, embodied energy estimates were provided only for pollution abatement technologies that contractors reported they were required to use. The currently unregulated environmental effects of the new energy technologies analyzed in this report, particularly those of coal liquefaction, are being researched. Since the data base for the capital and operating costs of prospective treatment technologies has not yet been developed as part of separate environmental analysis, we could not analyze their embodied energy.

Solar energy

Should we include a measure of the solar energy consumed in the production of natural resources, agricultural products, and forestry products? Should the solar inputs to the animal and vegetable matter that eventually become fossil fuels--coal, petroleum, and natural gas--be incorporated in measuring the embodied energy of these fuels? In our methodology, we calculated embodied energy in terms of the heat of content, as measured in Btu's, of the fuels consumed in producing energy and nonenergy products.

A principal objective of our effort was to develop an NEA methodology that would allow comparative analysis of new and existing energy technologies both for the way they help reduce dependence on imported premium fuels and for the way they deplete domestic energy sources, especially nonrenewable ones. Given this context, we decided not to analyze the solar energy embodied in either the corn feedstock consumed in the ethanol technologies or the fossil fuels consumed in the ethanol and coal liquefaction technologies.

We assumed that corn feedstock will be produced regardless of whether it is destined for an ethanol plant or a cattle feedlot. Morever, the protein value of corn feedstock remains in the solid ethanol byproducts that are sold as feed supplements, and a byproduct feed supplement retains the solar energy that is used by the corn and converted to protein food energy. We treated the free solar energy, therefore, as not consumed as an energy input to ethanol production. In the case of fossil fuels, the embodied energy of fossil energy resources is measured in terms of their ability to generate heat to perform work. The solar origin of that heat is irrelevant when the objective is to evaluate a technology's efficiency in converting energy inputs into energy products.

"Boomtown effect"

Should the embodied energy associated with establishing whole towns--their infrastructure and buildings, their social and educational structures, in a kind of "boomtown effect"--be included in NEA? As we discuss below and in appendix I, the energy input-output model we present estimates the direct and indirect energy impacts of an energy facility on other sectors of the economy. The methodology we developed does not preclude analysts from conducting an all-inclusive NEA--that is, from including the "boomtown effect" and tracing all higher-order inputs. As we stated above, one of our objectives in developing our methodology was to demonstrate the flexibility of applying NEA to a selected sample of energy conversion processes. Because we included in the boundary only major factors contributing to the net energy yields and because we deemed the phenomenon of "boomtown effect" not to be a major factor in the selected samples, we did not include it in our analysis.

End-use efficiency and technological change

Should an NEA of alternative fuel technologies include the effects of anticipated changes in their use? Should possible technological advances in producing and consuming energy be incorporated in an NEA? Practicality and simplicity dictated that we hold energy production and consumption technologies constant in developing and applying the NEA methodology. Thus, we assumed that the high value now placed on liquid and gaseous premium fuels will continue. We also assumed that the productive efficiency of the technologies we analyzed will be constant over their lifetimes.

Comparisons of new technologies are always made among "moving targets," but this is a problem only if it is not understood. Moreover, the simplifying assumptions we made are not essential to the methodology. To the extent that other analysts care to construct plausible scenarios of technological change, an NEA could incorporate those assumptions and yield sensitivity analysis on those changes.

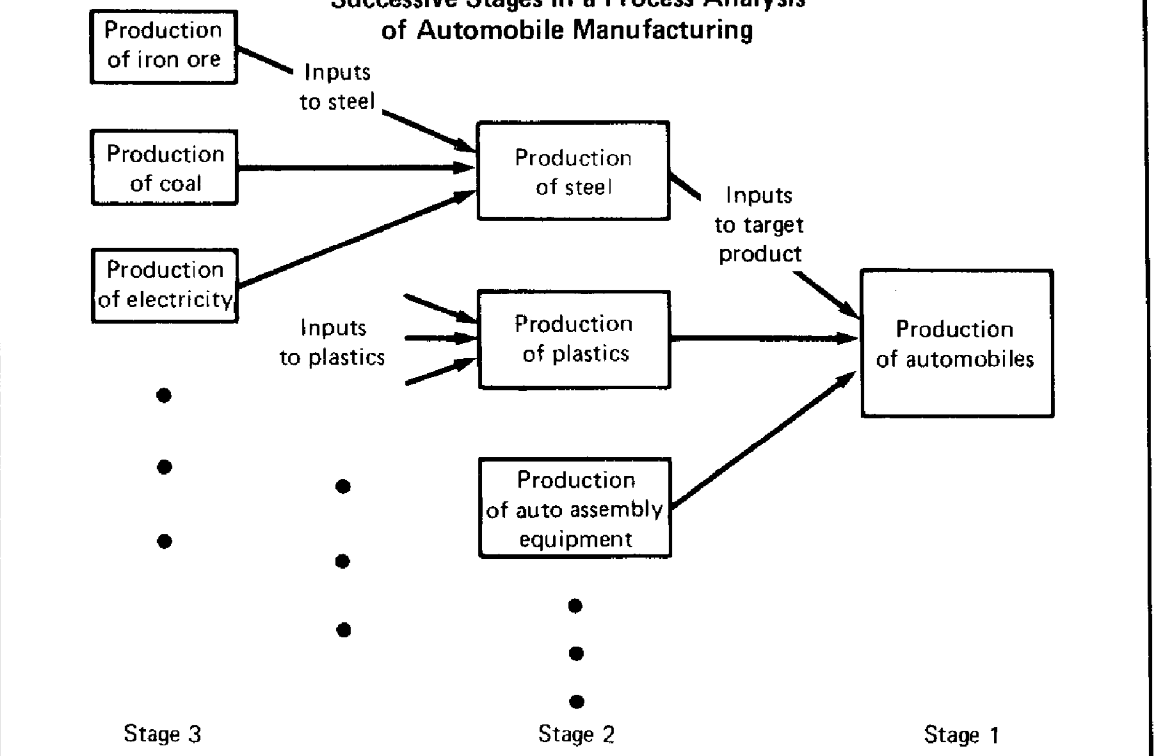
SELECTING ANALYTICAL TECHNIQUES

The second issue we had to resolve in developing an NEA was what analytical technique to choose. Three are available--process analysis, input-output analysis (I-O), and ecoenergetics. We describe each in detail in appendix I. We summarize them briefly and explain reasons for our choices in this section.

Process analysis

Among all energy analysis techniques, process analysis provides the most detailed information. In theory, it identifies each step in an industrial process that produces energy.

Figure 3
Successive Stages in a Process Analysis of Automobile Manufacturing



Three steps are involved in such an analysis--defining the trajectory, estimating the embodied energy, and calculating the net energy.

To determine the embodied energy in an automobile, for example, one must measure first the direct energy (such as fuel and electricity) that the automobile factory consumes, then the embodied energy used to produce and deliver the manufactured materials (steel and plastics) that the factory uses, and then the embodied energy that is needed to produce the raw materials (coal and iron ore) used in the manufactured materials. (See figure 3.) Theoretically, this process continues until all energy has been measured. In actual application, however, it ends when the major energy inputs have been analyzed.

I-O analysis

Input-output analysis (I-O) uses an existing data base to determine the relationship between sectors in the economy. It is a type of economic analysis, but under certain assumptions and with additional data it becomes a powerful tool for tracing the flow of embodied energy through the economy. The steps in I-O analysis are the same as in process analysis--defining the trajectory, estimating the embodied energy, and calculating the net energy.

I-O analysis is especially valuable as an alternative means of accounting for higher-order effects in a process analysis. That is, it helps account for the energy requirements of industries that provide the most indirect of inputs in an industrial process.

The strength of process analysis is, as we have already seen, that it provides the most detailed and accurate estimates of an energy technology's raw materials and energy inputs. However, obtaining data for more indirect, higher-order energy inputs would be impractical for process analysis, given the great number of industries that we would have to analyze. The weakness of process analysis is, thus, the costly and time-consuming procedure of collecting and calculating energy contributions from second-stage or third-stage industries. I-O analysis, on the other hand, estimates the indirect energy flows through industries along the trajectory, and its strength is that it is therefore a highly practical tool for estimating the energy of higher-order industries. Its weakness is that it does not give a detailed understanding of the energy flows within plants, firms, or industries that are not easily represented by the generically defined "average" industry in an I-O sector. 1/ Thus,

1/This "aggregation" problem in energy I-O is shared by all economic I-O models, since energy I-O models are transmuted economic I-O models. In order to obtain mathematical tracwhen we require a detailed understanding of the direct energy and raw materials input of a facility, our methodology calls for process analysis instead.

Ecoenergetics

Ecoenergetics attempts to measure the energy requirements of industrial processes in broader terms than either process or I-O analysis. Modifying process analysis, ecoenergetics explicitly includes nonmarket energy inputs. It uses ecological modeling techniques to trace solar energy flows through the environment. Thus, it takes an expansive view of energy and of NEA, which allows analysts to include concepts not necessarily accounted for in the two other approaches.

Ecoenergetics has broad appeal in its emphasis on the fullest possible measurement of the embodied energy of labor, environmental systems, and solar energy, but its analytical boundaries are more extensive than seems appropriate for the analysis of alternative energy technologies, as we explain at greater length in appendix I. Moreover, a set of consistent quantitative methods has yet to be developed for it. Therefore, we chose not to use ecoenergetics. As we have already said, we decided instead to employ process and I-O analysis complementarily, so that the strengths of one technique could compensate for the weaknesses of the other.

CHOOSING MEASURES OF EFFECTIVENESS

The third source of controversy we addressed involved selecting appropriate measures of effectiveness to establish a framework for comparing competing energy technologies and technological processes. The net energy of technology is defined as the difference between the embodied energy of its products and byproducts and the embodied energy directly and indirectly required to produce them. Technologies that have larger energy facilities are put at an apparent advantage, however, if we calculate absolute differences, as in merely subtracting inputs from outputs. Therefore, we chose to use energy ratios--dividing energy outputs by energy inputs--rather than absolute differences.

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tability, I-O modelers (including the Congressional Budget Office, the U.S. Department of Commerce, and others) have minimized the size of the linear-programming matrices that represent industrial relationships in the economy. In so doing, they have traded off some detail for greater ease of computation. The matrix we used in our analysis was 355 by 355 and sacrificed no more to aggregation errors than models Commerce and the Congressional Budget Office presently use to conduct detailed sectoral analyses of the U.S. economy.

Previous NEA's have generally used only one energy ratio (total energy output divided by total energy input) as a measure of effectiveness. We have already pointed out, however, that this "obscures the real objective: producing usable liquid fuels." (U.S. GAO, Controlling, 1981, p. 24) Therefore, we selected two additional measures so as to shed more light on the real objective of the Nation's energy program, as we discussed in chapter 1. The measures of effectiveness selected are as follows:

Premium fuels ratio	$\frac{\text{Total premium fuels output}}{\text{Total premium fuels input}}$
Total energy ratio excluding coal feedstock	$\frac{\text{Total energy output}}{\text{Total energy input excluding coal feedstock}}$
Total energy ratio including coal feedstock	$\frac{\text{Total energy output}}{\text{Total energy input including coal feedstock}}$

The premium fuels ratio is a measure of the extent to which a technology contributes to the goal of reducing dependence on imported premium fuels, since every net cubic foot of pipeline gas or barrel of premium fuel that is produced can replace a cubic foot of imported natural gas or a barrel of imported premium fuel. The Congress has required DOE (in title II of the Energy Security Act of 1980) to determine the net premium fuels yield of new biomass energy technologies and to fund only those that produce more premium fuel than they consume.

Since the purpose of the alternative energy technologies we analyzed is to convert domestic coal resources into premium fuels, the total energy ratio excluding coal feedstock--the principal raw material input to the energy conversion process --measures a technology's energy requirements above and beyond the coal it has directly consumed. This ratio indicates the extent to which energy is produced through the consumption of energy previously produced elsewhere in the economy. The total energy ratio including coal feedstock measures the total energy produced per unit of total energy required and is an overall measure of how much alternative energy technologies deplete domestic resources in comparison to each other.

As with the boundaries issue, analysts charged with different sets of questions may choose measures of effectiveness that are more appropriate, calculating transportation fuels ratios or heating oils ratios, for example. NEA does not restrict the selection of measures of effectiveness. 1/

1/Neither does NEA restrict the way in which measures of effectiveness can represent net energy yields over time. We must

SUMMARY

Our framework for comparing the net energy yields of competing technologies has the following characteristics. The boundaries do not include the embodied energy of labor, nonregulated environmental impacts, solar energy, the "boom-town effect," end-use efficiency, and technological change. The methodology uses process analysis and input-output analysis techniques. The measures of effectiveness against which technologies can be ranked and otherwise compared are relative rather than absolute and presume no time-discounting of embodied energy.

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emphasize that there is no energy equivalent to a discount rate, which represents the effect of inflation on the purchasing power of money. The heating value of a Btu is by the laws of thermodynamics worth the same today as it will be at any time in the future, but the value society places on the Btu's of various energy sources may change over time. In this analysis, we have assumed that a Btu's "social value" is constant. Thus, the embodied energy of construction capital consumed long before a facility has begun to produce energy is annualized over the life of the facility and not discounted. However, should a decisionmaker seek an understanding of the timing of a facility's energy inputs and outputs, the embodied energy of its capital inputs can be recorded early in the life of the project while the operating energy inputs and product outputs can be recorded for each year of the project's operation. This will provide an estimate of the project's demands on and contributions to the Nation's energy supplies over time. It will also allow a decisionmaker to explicitly apply any "social energy discount rate" to represent the value of future net energy production requiring capital and operating energy inputs in the present.

CHAPTER 4

SELECTING CANDIDATE TECHNOLOGIES AND PROCESSES

To perform our analysis, we selected technologies that produce premium fuels--oil and gas--from coal. Direct coal liquefaction and coal-fired ethanol production have received considerable Federal support. Both use an abundant domestic resource to produce premium fuels. In this chapter, we address phase D as shown in figure 1 in chapter 1. That is, we show how we chose the technologies, processes, and plants that we use in our analysis.

COAL LIQUEFACTION TECHNOLOGY

Coal is converted to liquids by increasing the coal's hydrogen-to-carbon ratio. The hydrogen-to-carbon ratio in bituminous coal, for example, is less than 1.0 ($H/C = 0.8$), but increasing this beyond 1.5 yields first a low-sulfur ash-free solid and then liquids such as heating oil and naphtha. Different types of coal and different liquefaction technologies yield significantly different products. The three major types of coal liquefaction technology are called "pyrolysis," "indirect liquefaction," and "direct liquefaction."

Pyrolysis

Pyrolysis is the thermal decomposition of organic compounds in the absence of oxygen. Exposing coal to very high temperatures in an inert atmosphere produces high char, gas, some tar, and a small amount of liquid. Pyrolysis processes are currently at the laboratory testing stage and are not expected to be available commercially for at least a decade.

Indirect liquefaction

In indirect liquefaction, coal is combined with steam and oxygen at high temperatures and moderate pressures to produce a synthesis gas--a hydrogen and carbon monoxide mixture. Then the synthesis gas is converted to high-octane gasoline or diesel or jet fuel.

Direct liquefaction

In direct liquefaction, crushed coal is "slurried" or suspended in a process-derived solvent and made to react directly with hydrogen at high temperatures and high pressures. Some solids in the form of unreacted coal and ash always remain in the reactor effluent. Separating and treating these materials is an important aspect of the development of direct liquefaction technology.

SELECTING DIRECT LIQUEFACTION PROCESSES

We selected direct liquefaction as the technology for applying the NEA methodology, partly because it has an estimated advantage over indirect liquefaction in terms of thermal efficiency. The estimated efficiency for indirect liquefaction is 45 to 60 percent, with yields in the range of 1.6 to 1.7 barrels of fuel-oil equivalent per ton of coal (bfoe/t). 1/ For direct liquefaction, the estimate is 65 to 70 percent, with yields in the range of 2.5 to 3.0 bfoe/t.

Another reason for not choosing indirect liquefaction is that the plants are highly complex and the capital cost per unit of product is high because of the range of products, the many steps of the process, and the chemistry involved. It should be noted, however, that indirect liquefaction has been proven commercially to produce higher-grade synthetic fuels quickly, on schedule, and at a predictable cost. 2/

We selected four direct liquefaction processes for analysis --H-Coal, Exxon Donor Solvent, and the processes of Solvent Refined Coal, SRC-I and SRC-II. All four are being developed through cooperative agreements between private industry and the U.S. Department of Energy. In the remainder of this section, we briefly describe the history of DOE's funding of these processes and their different technical approaches.

H-Coal

The H-Coal process has been under development since 1964 with mixed sponsorship from government and private industry. To execute a pilot program, the Energy Research and Development Administration (ERDA), now DOE, entered into an agreement in 1974 with Ashland Synthetic Fuels, Inc., to establish an H-Coal facility in Catlettsburg, Kentucky. It is estimated to cost $150 million; the total H-Coal project is estimated to cost $296 million, with DOE providing 87 percent of this.

1/It has been shown that indirect liquefaction configured for use in the United States, where there is no need for reforming the methane stage, could have an efficiency as high as 60 percent. (See Singh, 1981, p. 138.)

2/Fuel grade, in this context, indicates the subjective value society places on transportation fuels regardless of their thermodynamic qualities. Products that can be used directly as transportation fuels have the highest grade and products requiring additional processing have a lower grade, the grade being inversely related to how much additional processing is required.

The goal in operating the H-Coal facility is to process 600 tons of coal per day (tpd) in order to produce 1,800 barrels of primarily low-sulfur residue fuel oil per day (bpd). The alternative goal is to process 200 tpd in order to produce 600 bpd of distillate product. 1/

An engineering effort is under way to refine estimates for designing, constructing, and operating a commercial plant to process 18,000 tpd of coal in order to produce 50,000 bpd of hydrocarbon liquid and liquid equivalent. This plant, to be located in Breckinridge County, Kentucky, is estimated to cost $2.6 billion, with its operation to begin in 1988. Based on estimates of additional capital requirement to provide for interest, inflation, and operation cost through start-up increases, the capital requirement for the project is $5.2 billion. U.S. Synthetic Fuels Corporation was asked in a preliminary proposal submitted to it in March 1981 to provide a maximum loan guarantee of $3 billion.

In the H-Coal process, crushed and dried coal is slurried with recycled oils and combined with hydrogen, heated, and sent to the reactor. The mixture is combined with a catalyst in an ebullated bed reactor at a temperature of about 800 to 850 degrees Fahrenheit and a pressure of 2,200 to 3,000 pounds per square inch. The reactor uses an upward flow of liquid to expand the catalyst bed and maintain the suspended catalyst particles in random motion. Catalyst deactivation is rapid. Fresh catalyst has to be added, and contaminated catalyst must be withdrawn continuously.

The vapor product leaving the top of the reactor is cooled to separate heavier components as liquids. Light hydrocarbons (propane, mixed butanes), ammonia, and hydrogen sulfides are absorbed from the remaining gas, leaving a hydrogen-rich gas that is recompressed, recycled, and combined with the input slurry. The liquid-solvent product, containing unconverted coal, ash, and oil, is further processed and the materials that boil off are passed to a distillation unit in which the light and medium cuts are separated from the top. The bottom products (solids and heavy oil) are further separated with a hydroclone, a liquid-solid separator unique to the H-Coal process. Clarified oil is returned to the slurry tank to be recycled with the feedstock. The remaining unconverted coal,

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1/That is, the first goal is to produce heavier oils like No. 5 and No. 6, heavy diesel, Navy special, and bunker oils that remain after distillate fuel oils and lighter hydrocarbons have been boiled off during refinery operations, and the other goal is to produce lighter oils like No. 1, No. 2, No. 4, heating oil, and diesel fuel oils, whose major uses are for heating and for highway and railroad diesel engines.

ash, and heavy oil are sent through another process that yields heavy distillate and concentrated slurry, which in turn is sent to the gasifier to produce make-up hydrogen.

Exxon Donor Solvent

Exxon started the Exxon Donor Solvent (EDS) project in 1966, using an engineering-and-design technology similar to that of the petroleum industry. In 1977, ERDA agreed to fund 50 percent of the cost of designing, constructing, and operating a pilot facility to convert 250 tpd of coal into 600 bpd of synthetic crude. Estimated to cost $118 million, the facility is located in Baytown, Texas, and began operating in June 1980. The total estimated cost for the EDS project is $340 million.

Revising a 1975-76 study design, a detailed 1981 engineering study of the conceptual design of a coal conversion plant using the EDS liquefaction process considers two separate cases. One uses steam-reforming of hydrocarbon gas (steam-reforming being a reaction with steam in the presence of nickel catalysts) to supply plant hydrogen. The other uses hydrogen supplied through the partial oxidation of a portion of the vacuum pipestill bottoms. We chose steam-reforming in our analysis.

A plant to be located in western Illinois will have an estimated feed rate of 25,000 tons per steam day (tpsd) of clean dry coal. Liquid products will include liquefied petroleum gas (LPG), naphtha, and fuel oil; the plant will also produce crude phenols, ammonia, and elemental sulfur byproducts. 1/ The estimated cost for completion late in 1988 is $4.78 billion for steam-reforming and $4.39 billion for partial oxidation.

In the EDS process, coal is ground and slurried with recycled solvent. A catalyst speeds the addition of hydrogen, but it is kept in a separate vessel. Solvent circulating through this vessel picks up hydrogen atoms and then passes into the main reactor, where it "donates" the hydrogen to the dissolved coal--hence the name "donor solvent." This technique offers the advantage of not exposing the catalyst to the contaminants in the coal and thus not reducing its deactivation, as happens with H-Coal.

The slurry is heated, mixed with molecular hydrogen, and passed through a reactor at 800 to 850 degrees Fahrenheit and

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1/LPG is propane, butane, or a mixture of these. Naphtha is liquid hydrocarbon fractions recovered during distillation and used usually as a feedstock for producing gasoline and aviation fuels. The fuel oil consists of distillates and residuals. Crude phenols are also known as tar or carbolic acid and usually used as a feedstock in petrochemical production.

a pressure of 1,500 pounds per square inch. The resulting product is sent to a solid-liquid separation stage. Hydrogen for in-plant use is provided by steam-reforming the light hydrocarbon gases. A portion of the middle distillates is used to produce the donor solvent. The remaining slurry is further treated by "flexicoker" (an Exxon proprietary process) to produce additional liquids and fuel gas.

Solvent Refined Coal

Solvent Refined Coal (SRC) is a noncatalytic process developed by the Pittsburgh and Midway Company, a subsidiary of Gulf Oil Company, that converts high-sulfur high-ash coals to nearly ash free and low-sulfur fuel. The process has two different modes of operation--SRC-I and SRC-II--and we discuss these next.

SRC-I

After the SRC-I process had successfully demonstrated that it could process 50 pounds per hour in 1965, a 50-tpd pilot facility was constructed that began operation in 1974. A second facility with a 6-tpd capacity also began operating in 1974. Later, working from a conceptual design completed in 1979, DOE announced that one of five full-scale modules in a commercial SRC-I plant will be constructed in Newman, Kentucky. Under a cost-sharing agreement, Kentucky is to contribute $30 million, the International Coal Refining Company $90 million, and DOE the remainder of the estimated $1.6 billion. The plant will convert 6,000 tpd of coal into the equivalent of about 20,000 bpd of crude oil.

In SRC-I, crushed and dried coal is slurried with a process-derived solvent. Hydrogen is added, and the mixture is heated to about 700 degrees Fahrenheit and sent to the reactor at a pressure of 1,000-2,000 pounds per square inch. The reactor effluent is sent to the vapor-liquid separation stage. The high-pressure hydrogen-rich gas is processed into recycled hydrogen, fuel gas, and sulfur. Process solvent and liquid components are removed from the product slurry, and the remaining slurry is sent to a de-ashing step in which it is separated into a molten SRC stream and a solid residue stream. The residue stream is sent to the gasifier, where it is converted into an inert slag and make-up hydrogen.

In early designs, the molten SRC stream was to go to the solidification unit to produce solid SRC, but to respond to market demand for liquid fuels, a new design for processing the molten SRC was developed. The molten stream is processed in three separate units. One unit will catalytically convert between one-third and two-thirds of the molten SRC into additional liquids and low-sulfur solid SRC. About another third of the molten stream goes to another unit to produce anode grade coke for use in the aluminum industry. Only the balance of the molten SRC goes to the solidification unit.

SRC-II

Development of the SRC-II process began in 1977 when the 50-tpd SRC-I pilot facility was modified to produce liquid products at 30 tpd. As with SRC-I, DOE announced that one of five full-scale modules in a commercial SRC-II plant designed in 1979 will be constructed in Morgantown, West Virginia. The Federal Republic of Germany and Japan are to contribute 25 percent of the estimated $1.4 billion cost, with the Pittsburgh and Midway Coal Mining Company contributing $100 million and DOE the remainder of the cost. As with SRC-I, the plant is to convert 6,000 tpd of coal into the equivalent of about 20,000 bpd of crude oil.

SRC-II is similar to SRC-I except that it uses proportionally more hydrogen and a portion of the product slurry is recycled to increase the severity of the conversion reaction. As a result of the increased severity, only liquid and gas are produced, so the additional steps of de-ashing the solid residue stream and further processing the molten SRC are eliminated. The solid residue stream is sent directly to the gasifier to produce make-up hydrogen.

DIRECT LIQUEFACTION PRODUCT SLATES

Products from the four liquefaction processes vary from some that meet or exceed commercial specifications to others that require different degrees of post-processing. Beyond the pipeline and liquefied gases consumed primarily by gas utilities, most of the products will go to the fuel-oil market. It is foreseen, for instance, that H-Coal's distillate oil will be used as a cutter stock for refinery derived crude-oil bottoms used by the residue-oil market, while it is expected that SRC-I's medium and heavy oils will replace No. 2 and No. 6 fuel oils. Product slates for commercial and demonstration plants are listed in table 1 on the next page.

High-grade fuels make up a smaller portion of the product slates. In this respect, H-Coal produces the highest grade of fuel, because its reformate is a blend stock that can go directly to the gasoline pool in conventional refineries. Naphtha from EDS, on the other hand, requires further processing before it can be used as a gasoline blend stock and, therefore, it has a lower grade.

SRC-I's uniquely low sulfur and ash solid is destined primarily for coal-fired boilers, although some experts question its marketability. In their opinion, coal can be burned acceptably and at lower cost with existing environmental control technology. SRC-I's anode grade coke is a valuable raw material for

Table 1

Commercial and Demonstration
Coal Liquefaction Product Slates

	Commercial plant		Demonstration plant	
	H-Coal	EDS	SRC-I	SRC-II
Coal feedstock (million lbs/yr)	11,613	6,343	3,696	4,409
Pipeline gas (million standard cubic ft/yr)	7,300	--	--	16,450
Liquids (million barrels/yr)				
Propane	2.044	--	--	0.840
Butane	1.351	--	--	0.584
LPG-C3 and C4	--	1.712	--	--
Light naphtha	1.314	--	--	--
Naphtha	--	7.450	1.929	--
Reformate a/	3.760	--	--	--
Distillate, light, and medium oil b/	8.505	--	1.526	--
Fuel oil c/	--	11.729	--	4.198
Heavy oil d/	--	--	0.316	--
Solids (million lbs/yr)				
SRC	--	--	715.4	--
Coke	--	--	430.7	--

a/Blendstock for gasoline.
b/Lighter fuel oils--such as No. 1 and No. 2 heating oil, No. 4 fuel oil.
c/Higher boiling range than kerosene; while generally classified as distilled (medium oils) and residuals (heavy oils), in this case, a mixture.
d/Higher viscosity fuel oils such as No. 5 and No. 6 and often called "bunker" oils.

producing aluminum and is intended to displace petroleum-based coke, a refinery byproduct, which will allow diversion of the petroleum feedstock to the production of lighter hydrocarbons.

SELECTING ETHANOL PRODUCTION TECHNOLOGY

We also selected coal-fired ethanol production of liquid premium fuel from coal for testing NEA. We did this for two reasons, one substantive and one methodological. Our substantive reason was that domestic coal is used in ethanol production as a feedstock heat source to produce premium liquid fuels from agricultural products.

Our methodological reason was that using coal-fired ethanol production enabled us to test two important features of NEA--its ability to identify indirect energy flows and its ability to measure the type of energy consumed in producing energy products. The major indirect energy input in ethanol production is the energy required for farming, but a major portion of farming energy comes from premium fuels. Thus, by illustrating the effect of the indirect consumption of premium fuels on the net energy yield of ethanol facilities, we expected to be able to demonstrate the need for analysis of indirect as well as direct measures of the quantity and type of energy consumed by alternative energy technologies.

We selected two plants of greatly different size in order to determine whether the net energy yields of ethanol facilities reveal economies of scale. In the two plants, the technology for producing fuel is basically the same as that for producing distilled spirits. Corn is cleaned and milled to small, uniform particles and mixed with water and gelatinizing enzymes, which break up the starch granules in the pulverized grain to form a gel of soluble starch and dextrins, or simple sugars. The gelatinized mash enters a cooker, in which additional enzymes convert the mash carbohydrates into dextrins. A coal-fired boiler generates the steam used as a heat source throughout the plants, although some plants use natural gas or liquid fuels.

After being cooked, the dextrin-rich mash is pumped into fermentation tanks, in which enzymes start the conversion of dextrins to glucose. Fermentation produces a "beer" 6 to 12 percent ethanol by volume that is pumped into a well until the product is ready for distillation. During distillation, heat vaporizes the ethanol out of the beer. It is condensed and stored as 95 percent pure ethanol before being dehydrated. Any one of several dehydration processes can be used to extract the remaining water from the condensed ethanol--solvents such as benzene or gasoline can be used to separate water from ethanol, after which the water is removed by further distillation, solvent extraction, or gravity. Semipermeable membranes can also be used to dehydrate ethanol by selectively absorbing water, leaving it almost water free.

Mash byproduct solids collected from the bottom of the distillation column have a high feed value since they contain most of the protein of the original corn feedstock as well as the yeast and enzymes added during cooking and fermentation. These byproduct solids are dried and sold as feed supplements called "distillers dry grains."

Idaho Falls ethanol plant

DOE fully financed the Idaho Falls small-scale fuel alcohol plant in order to be able to evaluate it as a standard reference design for farmers and farm cooperatives interested in producing ethanol. DOE also assumed that individual farmers and cooperatives would be unable to take the significant capital risks in constructing, operating, testing, and refining unfamiliar and sophisticated ethanol production technology. In financing the design, construction, and initial tests of the operation of the plant, DOE required designers to rely on off-the-shelf technology that was sufficiently automated and reliable to require only limited on-site operational control by people not expert in the technology.

The plant was designed by DOE's Idaho National Engineering Laboratory early in 1980 and construction was completed in November 1980. The initial operations test, performed over the winter of 1980-81, showed yields of 2.7 gallons of ethanol per bushel of corn. The plant is designed to process 59,568 bushels of corn into 176,281 gallons of 199.0 proof ethanol per year denatured with 10,030 gallons of gasoline. (Proof is a measure of ethanol content; 2 proof equals 1 percent by volume.) Plant process steam is produced by burning 204 tons of coal each year. DOE is presently testing the plant's energy efficiency by measuring the raw material and energy requirements per gallon of ethanol product. Since these data are only now being compiled, our plant operation expense estimates are uncertain.

The Idaho Falls plant has no dehydration capability, so its product contains 7.6 percent water. It has less heating value than fuel grade ethanol, which is 99.5 percent ethanol and 0.5 percent water. DOE has, however, estimated capital cost and operating energy for a molecular sieve dehydration system that could function with the Idaho Falls plant. With this dehydration system, the plant could produce each year 176,281 gallons of fuel grade, 199 proof ethanol. The molecular sieve has not been constructed because of its cost and technical problems; however, because its capital and operational energy data were the only data available for a dehydration system compatible in size with the Idaho Falls plant, we used it in the NEA.

Ethanol Plant X

Ethanol Plant X is to be a large-scale commercial facility producing 20 million gallons of anhydrous ethanol denatured with one million gallons of gasoline. Unlike Idaho Falls, which was a test bed for a small, automated facility requiring little expertise in its use, ethanol Plant X will be a full-scale commercial plant staffed by experts. DOE gave us data on capital and operating cost estimates and raw materials requirements for Plant X, but proprietary reasons (DOE and the contractors are currently negotiating the levels of DOE's construction subsidy) prevent us from divulging information on its costs, raw materials requirements, and production technology, although we can say that many of its basic processes are larger versions of processes used at the Idaho Falls plant.

ETHANOL PRODUCTION PRODUCT SLATES

For this analysis, we assumed that the Idaho Falls plant includes a retrofitted dehydration system and produces 176,281 gallons annually of 199 proof ethanol. The ethanol product requires no additional refining once it leaves the ethanol plant and, because it is anticipated to have only 0.5 percent water, it is not assumed to require a distribution system (pipelines, tank trucks, storage tanks) separate from that used for gasoline distribution. 1/

The Idaho Falls plant also produces annually 482 tons of partially dehydrated solids (distillers dry grains, or DDG) from the distillation column. This byproduct retains much of the protein content of the original corn feedstock and also protein and minerals from the yeasts and enzymes added during fermentation. The product is currently sold by major distilleries as a feed supplement for livestock and poultry.

Plant X purchases 8.4 million bushels of corn and 38,500 tons of coal per year, and it sells 20 million gallons of fuel grade ethanol and 72,000 to 75,000 tons of distillers dry grain byproducts over a wider market than that covered by the Idaho Falls facility. Like Idaho Falls, Plant X will produce ethanol requiring no further refining before sale to gasoline distributors. The ethanol produced by both plants will have the same heating value at 84,000 Btu's per gallon. Since Plant X will be producing, storing, and shipping such a large volume of DDG byproducts, they will be fully dried to prevent their spoiling.

1/In the significant controversy about the effect of ethanol-gasoline mixtures on automobile performance, some analyses estimate that alcohol-gasoline mixtures will improve vehicle fuel mileage while others estimate that it will retard it. Such inconclusiveness led us to assume for this analysis that the mileage effects are negligible and thus do not affect the net energy balance of the two plants. For a comparison of ethanol mileage effects as calculated by various studies, see TRW, Energy, 1980, pp. 116-25; see also Gasohol, 1979, pp. 11-12.

CHAPTER 5

APPLYING THE NEA METHODOLOGY

The NEA methodology we developed is designed to produce information valuable for the comparative analysis of proposed energy technologies. It combines the analytical techniques of process analysis and input-output analysis in six basic steps: (1) identifying target products and byproducts, (2) defining the trajectory of direct and indirect energy inputs, (3) obtaining a data base, (4) estimating the embodied energy of direct and indirect inputs and outputs along the trajectory, (5) calculating net energy results in terms of the chosen measures of effectiveness, and (6) comparing net energy yields. These are the steps of phase E, figure 1, chapter 1. In this chapter, we explain these steps in preparation for describing the actual tests of the methodology in chapters 6 and 7.

IDENTIFYING TARGET PRODUCTS AND BYPRODUCTS

In identifying the target products and byproducts of a technology, we group products according to type of energy--liquid, gas, or solid fuels, electricity, space heat, process steam, and so on. Then we record the quantity of each energy product and the unit and total energy value for each product. If the product saves energy because of conservation, what kind and how much are indicated. The quantity of nonenergy commodities produced simultaneously with the energy products is also recorded.

A standard unit of time, one year, is used to measure the output quantity and energy value of these products and byproducts, avoiding confusion that could arise in comparing daily or monthly production volumes across facilities with different maintenance schedules and downtimes.

DEFINING THE TRAJECTORY OF DIRECT AND INDIRECT ENERGY INPUTS

In defining the trajectory, we identify the network of industries that contribute raw materials, energy, equipment, capital facilities, or transportation directly or indirectly to the production of target products. After all direct inputs and outputs along the trajectory have been identified, this information is summarized as in the flow diagram in figure 3 (in chapter 3). Because process analysis is used to provide the most exacting and detailed understanding of the direct energy inputs and raw materials inputs for each technology (as we discuss in appendix I), this step requires that the data be extensive and specific so that the energy efficiencies of technologies producing the same commodity can be compared.

Next we track the indirect energy and materials inputs. Because I-O analysis is used to estimate indirect energy flows, yielding embodied energy estimates for generic industrial sectors, such information is especially important when we are analyzing generally defined industries that feed raw materials to particular technologies. Moreover, the industrial relationships defined within an I-O model provide valuable information on the structure of a production trajectory feeding into an energy technology.

The I-O model indicates the relative magnitudes of energy flows from different industries along a trajectory. Therefore, it is also used to indicate a need for more detailed process analysis of an industry in the trajectory. An I-O model also indicates where to halt further estimates of energy flows between two sectors when the flow is negligible.

A third task involves us with the energy products and byproducts. If the product is saving energy by conservation, the type and quantity of energy saved are indicated at this point, as is the quantity of nonenergy commodities being produced simultaneously with the energy products. In one other task, we identify industries whose products are the most similar to the byproducts of the energy facility. This is the first step in estimating the energy credits for a technology's byproduct.

OBTAINING THE DATA BASE

As we have already noted, DOE has supported the four direct coal liquefaction processes we selected for testing our NEA methodology. DOE's lack of requirements for quantity and quality of information, however, makes the available data inadequate for comparative analysis. Therefore, in cases in which we found data were minimal or nonexistent, we were obliged to use averages, make assumptions about likely relationships, calculate plausible scenarios, and the like.

With regard to target products and byproducts, we found that the most useful sources of data were project solicitation documents and design reports. The most useful sources of data for defining the trajectory included operating and maintenance expenditure data and capital cost data for the energy facilities. Tracking the indirect energy and materials inputs was more difficult. One source of such information is an I-O model indicating the sectors producing inputs for each industry in the economy. Another is published summaries of process analyses for multiple industries. (See Bechtel, 1978, and Hamel, 1979.) In estimating the energy credits for a technology's byproduct, analysts can find either I-O data or multi-industry process analyses to be useful data sources.

ESTIMATING THE EMBODIED ENERGY OF DIRECT AND INDIRECT INPUTS AND OUTPUTS

Once the trajectory has been identified, it is necessary to identify the industries along the trajectory that will require the most extensive energy analysis--that is, process analysis--and the industries that can be analyzed with I-O analysis. We begin with I-O analysis, identifying the relative magnitudes of energy and materials flows in order to determine which flows require no further energy analysis and which require more extensive analysis. If the data are sufficient, we conduct detailed process analysis of the industry. If they are not, then we use I-O analysis to estimate the embodied energy flows through the industry.

In sum, either process analysis or I-O analysis is applied, as appropriate, to industries along the trajectory, enabling us to estimate the energy embodied in their products. We use process analysis only if detailed analysis is required and sufficient data are available. The end of this step in the analysis is an estimate of the embodied energy of the direct and indirect inputs to the target energy product. We give examples of embodied energy calculations for coal liquefaction (calculations for plants, process inputs and outputs, and displacement energy credits) in appendix II and for ethanol production (calculations for plants, process inputs and outputs, corn and soybean farming, and displacement energy credits) in appendix III.

CALCULATING ENERGY RATIOS IN TERMS OF THE CHOSEN MEASURES OF EFFECTIVENESS

The fifth step in applying the NEA methodology is to calculate energy ratios. Three energy ratios measure the productivity of energy facilities:

Premium fuels ratio $\dfrac{\text{Total premium fuels output}}{\text{Total premium fuels input}}$

Total energy ratio excluding coal feedstock $\dfrac{\text{Total energy output}}{\text{Total energy input excluding coal feedstock}}$

Total energy ratio including coal feedstock $\dfrac{\text{Total energy output}}{\text{Total energy input including coal feedstock}}$

Our discussion of the application to both technologies and of the final step in the methodology--comparing energy yields--is in chapters 6 and 7.

CHAPTER 6

PERFORMING THE ANALYSIS AND COMPARING THE RESULTS-- DIRECT COAL LIQUEFACTION

We analyzed four direct coal liquefaction processes. The quantity and quality of the data base were not adequate for a definitive comparative analysis, however, because of gaps in DOE's information requirements. In this chapter, we trace figure 1, phase E, steps 1 through 6, for the four processes.

PERFORMING THE ANALYSIS

To test our methodology, we began by analyzing each major stage in the coal conversion trajectory, from mining the coal to producing the fuel. We encountered uncertainties associated with the environmental impact of coal liquefaction. We also had to develop a technique for considering the contribution of nonfuel byproducts. We describe these three efforts--analyzing the trajectory, estimating environmental impacts, and assessing displacement energy credit--in the rest of this section.

Trajectory analysis

The four major stages in the trajectory for converting coal into a finished product are mining the coal, transporting it to the liquefaction facility, converting it, and transporting the products to market.

Mining

For estimates of the energy required to mine the coal, we relied on an analysis conducted by the Energy Research Group (ERG) at the University of Illinois. (Hannon, 1980) ERG used I-O analysis to estimate the energy requirements for the capital construction and operation of an average U.S. coal mine. (The average was weighted for surface and underground.) The ERG study estimates show that in the United States every Btu of coal mined requires an average of 0.0102 Btu's of premium fuel energy and 0.0225 Btu's of total energy.

We calculated the impact of mining on the overall liquefaction trajectory from the ERG estimates of coal mining energy. Although the data are based on plants in eastern locations, there are no indications as to the type of mine used as a coal source. Therefore, our calculations as shown in appendix II represent not specific locations or mine types but a nationwide average.

Transportation

Data on transportation specifications for feedstock coal and liquefaction products and byproducts were either minimal or nonexisting for all processes. Consequently, we had to assume probable transportation scenarios, including equipment, standard hauls, and so forth. We explain the specifications that were available with assumptions and calculations in appendix IV. The transportation impacts on the overall liquefaction trajectories are not the actual projection for each process. Rather, they are scenarios whose plausibility allowed us to demonstrate the technique for determining transportation impact.

Conversion

Analyzing the conversion stage of the trajectory or the coal liquefaction process involves calculating both premium fuel and total energy contents of the inputs and outputs. At this stage, the only outputs considered are those that can be measured by their heat of content--that is, fuel products. Products such as anode coke and byproducts are evaluated in terms of displacement credits, as they are not considered direct energy sources.

In addition to calculating the obvious premium fuel and total energy contents of electricity and the heat of content of the coal feedstock, we calculated the energy impact of catalyst and chemicals, maintenance materials, and capital investments such as buildings and process equipment. The detailed calculations of inputs and outputs by process are in appendix II.

Environmental analysis

Because the United States has no commercial coal liquefaction plants and because research on the impact of demonstration plants has only recently been completed, environmental control regulations pertaining to liquefaction have not been adopted. The energy and dollar costs of obtaining and operating pollution controls and water treatment equipment to meet existing regulations are an integral part of the proposed demonstration and commercial plants. 1/ Therefore, we analyzed them as part of the conversion stage.

In discussions with officials of the Environmental Protection Agency and in reviewing draft regulations, we have, however, been able to determine that the cost of meeting existing and proposed standards will be 10 to 20 percent of the total capital cost of a commercial plant. This will be true for the proposed EDS commercial plant. Exxon's estimate of 10.9 percent (shown in table 2) may increase if more stringent controls are promulgated. Additional controls may become necessary as indicated by high toxicity in coal base liquid fuels, some of which

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1/Beyond water treatment, water availability is also of concern for energy development with liquefaction plants in the energy-rich but water-short West. Examining this issue in 1980, we concluded that water will be adequate in the West at least through the year 2000. (See U.S. GAO, Water Supply, 1980.)

Table 2

Environmental Control Costs
of EDS Commercial Plant
(Millions of Dollars 4th Quarter 1978)

Direct material and labor excluding indirect charges and processes and project contingencies		
Onsite pollution abatement		
Sulfur plant	$12.8	
Trail gas cleanup unit	3.1	
Hydrogen sulfide removal unit	32.7	
Sour water treating and ammonia recovery	7.9	
DEA regeneration	5.2	
Phenol extraction	10.2	
DEA scrubbing	2.8	
Total		$ 74.7
Offsite pollution abatement		
Wastewater		
Treating	24.3	
Reuse	0.9	
Effluent pipeline	14.9	
Wastewater solids handling		
Boiler solids	17.0	
Flexicoking solids	20.4	
Disposal landfill	5.2	
Cooling-water facilities	10.3	
Total		93.0
Total direct pollution abatement		$167.7
Total plant direct material and labor		$1,538.0
Percentage of direct material and labor for pollution abatement		10.9

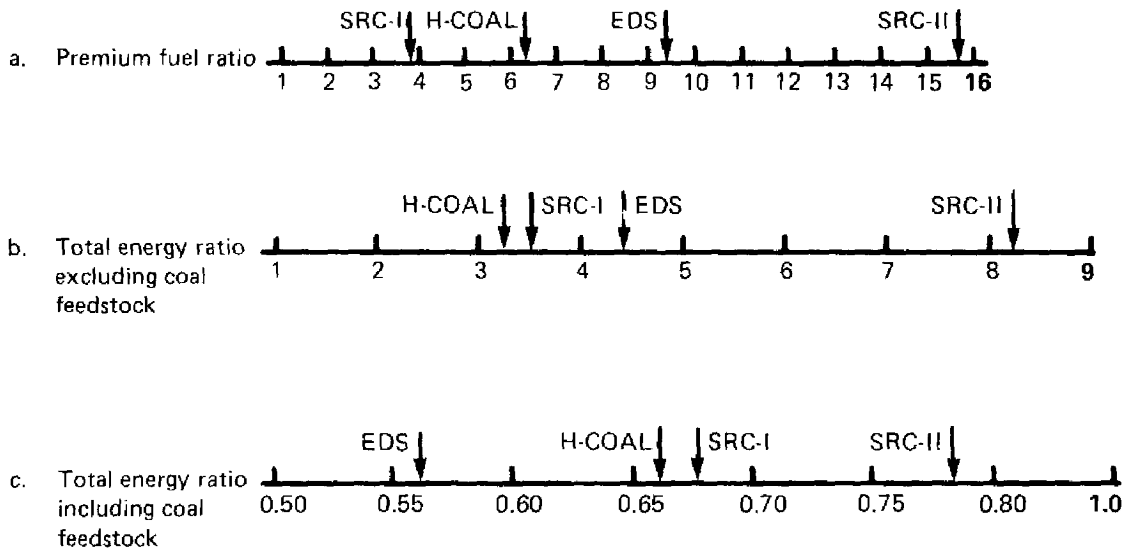
Source: Exxon Research and Engineering Co., EDS Coal Liquefaction Process Development, Phase IV, EDS Commercial Plant Study Design Update (Washington, D.C.: U.S. Department of Energy, March 1981).

have been found carcinogenic and mutagenic. Dangerous products may require additional treatment and, thus, energy to make them safe for handling and use.

Displacement analysis

Two aspects of displacement analysis must be considered--the calculation of the energy credit and the energy contribution of the byproducts. Liquefaction-based products provide an energy bonus beyond one-for-one displacement for equal amounts of petroleum-based refinery products--that is, the energy saved

Figure 4
Output-Input Ratios of Four
Direct Liquefaction Processes a/



a/The magnitude of the advantage for SRC-II is questionable, because it could be the result of unverified optimistic performance parameters.

in not having to refine crude petroleum to end-products equal to those resulting from the liquefaction processes. We calculated the energy credit, or refinery energy savings, by determining petroleum refineries' energy requirements and types of energy and then comparing the refinery upgrading steps with those of the liquefaction processes. (See appendix II.) The results in thousands of Btu's per barrel are

	H-Coal	SRC-I	EDS	SRC-II
Premium fuel	477.2	463.7	403.6	257.7
Total energy	534.5	519.4	452.0	288.6

The results demonstrate, as expected, that refinery energy savings are directly related to the quality of the product slate. H-Coal, with the highest grade products reformate and naphtha, presents the highest savings, and SRC-II, with its lower grade oils, presents the lowest savings.

These are conservative figures for three reasons. The petroleum refinery energy requirements seem optimistic. Possible long-term savings from reducing refinery constructions as a result of a larger coal liquefaction industry were not included. Probable savings from the higher octane of coal-based gasoline blendstocks were not calculated.

Table 3

H-Coal Trajectory Results a/

	Premium fuel	Total energy
	(10^{12} Btu/yr)	
Outputs		
Products	97.327	97.327
Byproducts	3.046	3.805
Refinery savings	8.100	9.073
Total	108.473	110.205
Inputs		
Mining	1.327	2.926
Transportation	1.160	1.302
Conversion		
Electricity	8.656	22.564
Catalyst and chemicals	3.948	4.814
Maintenance materials	0.254	0.318
Capital	1.616	2.398
Total excluding coal feedstock	16.961	34.322
Coal feedstock	--	130.066
Total including coal feedstock	16.961	164.388
Output-input ratios		
Premium fuel	6.345	--
Total energy excluding coal feedstock	--	3.211
Total energy including coal feedstock	--	0.670

a/The six significant digits are not meant to be a definitive representation of the level of accuracy of the information.

Table 4

EDS Trajectory Results a/

	Premium fuel	Total energy
	(10^{12} Btu/yr)	
Outputs		
Products	119.401	119.401
Byproducts	3.957	4.947
Refinery savings	8.431	9.442
Total	131.807	133.840
Inputs		
Mining	2.111	4.656
Transportation	0.233	0.359
Conversion		
Electricity	8.380	21.844
Catalyst and chemicals	1.986	2.422
Maintenance materials	0.427	0.533
Capital	0.904	1.385
Total excluding coal feedstock	14.041	31.199
Coal feedstock	--	206.955
Total including coal feedstock	14.041	238.153
Output-input ratios		
Premium fuel	9.387	--
Total energy excluding coal feedstock	--	4.290
Total energy including coal feedstock	--	0.562

a/The six significant digits are not meant to be a definitive representation of the level of accuracy of the information.

Table 5

SRC-I Trajectory Results a/

	Premium fuel	Total energy
	(10^{12} Btu/yr)	
Outputs		
Products	19.534	29.707
Byproducts	0.336	7.929
Refinery savings	1.749	1.959
Total	21.619	39.595
Inputs		
Mining	0.481	1.060
Transportation	0.206	0.234
Conversion		
Electricity	2.867	7.473
Catalyst and chemicals	0.827	1.008
Maintenance materials	0.247	0.308
Capital	0.828	1.144
Total excluding coal feedstock	5.461	11.233
Coal feedstock	--	47.124
Total including coal feedstock	5.461	58.357
Output-input ratios		
Premium fuel	3.959	--
Total energy excluding coal feedstock	--	3.525
Total energy including coal feedstock	--	0.678

a/The five significant digits are not meant to be a definitive representation of the level of accuracy of the information.

Table 6

SRC-II Trajectory Results a/

	Premium fuel	Total energy
	(10^{12} Btu/yr)	
Outputs		
Products	48.911	48.911
Byproducts	0.672	0.844
Refinery savings	1.449	1.622
Total	51.032	51.377
Inputs		
Mining	0.602	1.328
Transportation	0.246	0.293
Conversion		
Electricity	1.088	2.836
Catalyst and chemicals	0.408	0.498
Maintenance materials	0.295	0.368
Capital	0.617	0.937
Total excluding coal feedstock	3.256	6.260
Coal feedstock	--	59.040
Total including coal feedstock	3.256	65.300
Output-input ratios		
Premium fuel	15.673	--
Total energy excluding coal feedstock	--	8.207
Total energy including coal feedstock	--	0.787

a/The five significant digits are not meant to be a definitive representation of the level of accuracy of the information.

The other aspect of displacement analysis is to determine the energy contributions of the resulting byproducts. These are, in thousands of Btu's per barrel,

	H-Coal	SRC-I	EDS	SRC-II
Sulfur	171,550	69,350	326,510	58,400
Ammonia	62,050		64,985	10,950
Phenols			20,605	2,555

The heat of content is not considered in determining the energy contribution of byproducts or the anode coke product of SRC-I because they are not direct sources of energy. Their contribution is measured by the total energy and premium fuels saved by not having to produce equal amounts of the same material by conventional means. That is, a displacement energy credit is calculated for each byproduct. The calculations are similar to those for the refinery energy savings associated with products (see appendix II). Tables 3-6 and figure 4 show the results.

COMPARING THE RESULTS OF THE FOUR PROCESSES IN TERMS OF THE THREE OUTPUT-INPUT RATIOS

The temptation is strong to make conclusions after comparing the trajectory results we discussed in the preceding section, but there are hazards in doing this. For one, data quality, consistency problems, and the lack of actual indirect energy inputs make the data base highly vulnerable. Thus, our confidence in the validity of conclusions drawn from comparative analysis based on the data in this report is very low.

Moreover, it must be emphasized that NEA alone cannot yield definitive conclusions regarding the advisability of investing in new energy technologies, particularly when those technologies have similar net energy yields. Other analytical methods such as economic and environmental analysis must also be incorporated into decisions on new energy technologies.

Finally, no conclusion drawn from a site-specific NEA of a given technology can be generalized into a conclusion about other energy facilities in the same generic technology category. As we have shown for the liquefaction and ethanol facilities analyzed in this report, net energy yields can differ widely for plants sharing the same or similar technologies.

In order to demonstrate the value of NEA, however, given the existence of a reasonably accurate data base, we compare the processes in terms of the defined measures of effectiveness. It is clear that such comparison is feasible if the data are adequate. The inference to be made in this report is not that one process is better than another; the data problems cited invalidate any such inference. Rather, the inference to be made is that in the presence of reasonably accurate data, NEA is a valuable tool in illustrating the relative net contributions that each energy facility makes to the Nation's energy supplies.

Premium fuels ratio

The relative advantage of SRC-II in terms of premium fuels can be understood in light of its product slate, made up mostly of lower grade premium fuels (fuel oil and pipeline gas). 1/ EDS, its closest contender, produces medium and heavy oils but also naphtha. Naphtha requires further processing before it can be used as a gasoline blendstock, but it is still a high-grade premium fuel. Similarly, H-Coal produces light oils, while its reformate can go directly to the gasoline pool. The same is true of SRC-I's naphtha cut, although SRC-I is at a disadvantage in this measure because a major portion of its product slate is solid (coke and SRC), not premium fuels (see chapter 4).

Total energy ratio excluding coal feedstock

This ratio indicates the extent to which energy is produced through the consumption of energy produced previously and elsewhere in the economy. H-Coal, SRC-I, and EDS are clustered so closely that, more likely than not, this measure could not be used to choose among the three. The magnitude of SRC-II's advantage is suspect here, too. The relative advantage can be understood in terms of lower grade slate. The fact that SRC-I produces even lower grade fuel (SRC), however, raises another question regarding the validity of SRC-II data. On the other hand, it could be that refining SRC-I naphtha to a gasoline blendstock is so energy-intensive as to eliminate any advantage from the facility's production of low-grade solid fuel.

Total energy ratio including coal feedstock

This ratio would be an overall measure of how new energy technologies deplete domestic resources if all the inputs relied exclusively on domestic energy. The clustering and the questionable magnitude of SRC-II's advantage are not as pronounced in this ratio. SRC-I leads H-Coal and EDS and could be the first indication of an advantage in producing low-grade solid fuel. If there is an advantage, however, the ratio of SRC-II should be less than that of SRC-I, unless processing SRC-I naphtha erases its advantage.

The value of the NEA methodology

We have demonstrated that it is feasible to perform NEA and achieve results that can be valuable for comparative analysis in

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1/The size of this advantage is questionable; it could result from unverified optimistic performance parameters. We are dubious because SRC-II deviates from the obvious clustering of the other processes on each effectiveness measure. Such clustering is expected in relatively similar technologies.

its narrowest sense--the rank ordering of technologies in terms of their net energy yields. Thus, a decisionmaker who wanted the highest production of premium fuels, regardless of their grade, could find the analysis showing that SRC-II would be the right choice, given the validity of its advantage. If the higher grade fuels such as naphtha and reformate were preferred, analysis would show the choice to be between EDS and H-Coal.

For decisionmakers, NEA results are useful in a broader sense as well, in that they indicate potential areas of concern. Why does SRC-II deviate so much from the obvious clustering of the other processes? Why are SRC-I total energy ratios so close to those of EDS and H-Coal when a major portion of its slate is a low-grade fuel? Is it because of SRC-I's refining of naphtha? If so, is the refining desirable? Is H-Coal's production of reformate desirable, given that it decreases its total premium fuels production? These and other questions like them might be raised.

NEA is also useful in assessing the optimal rates of introduction of a new technology during a period of energy scarcity. Under conditions of short energy supplies, an immediate and heavy investment in alternative energy sources may place an even greater strain on scarce energy resources. New energy technologies often require extensive energy inputs in their developmental phases before they begin to produce significant amounts of energy. Thus, it may be desireable to invest less intensively in a new technology to avoid large net energy shortfalls during the developmental stage. This is particularly important for energy-intensive technologies such as nuclear and solar thermal systems, which require large initial inputs of energy.

Beyond specific results from analyzing the four processes, however, applying the methodology seems also to indicate that the premium fuels ratio is the differentiating measure for intratechnology comparisons. It is possible that the two total energy ratios differentiate only among intertechnology comparisons. A comparison of liquefaction and ethanol production will shed more light on this question, as we shall see in the next chapter.

THE QUALITY OF THE PROCESS DATA

The quality of the data contained in the technical reports submitted to DOE or the U.S. Synthetic Fuels Corporation is uncertain and this uncertainty cannot be quantified. Neither quantitative uncertainties--numerical confidence intervals around point estimates of cost and performance parameters--nor data bases adequate for calculating them are available from DOE or its industrial partners. A qualitative understanding of how "hard" the data are is possible, however, from studying the technical risks associated with the process and from examining current experience with cost estimate uncertainty.

Technical risk

In any development program, known and unknown technical problems make the validity of estimated performance parameters and associated operating costs questionable. We could not consider all the technical risks associated with each process, but we wanted to provide a qualitative understanding of the risks associated with the liquefaction processes. Therefore, we selected areas of concern that represent these risks. We know, for example, that all four processes face the same generic risks in the actual liquefaction step--in the dissolver reactor --namely, the risks in scaling up a pilot-size reactor to commercial size. They also face similar problems downstream from the reactor--that is, in steps after the actual liquefaction.

Reactor scale-up

The risks associated with "scaling up" the reactor size suggest that EDS and H-Coal data have the smaller degree of uncertainty compared to SRC-I and SRC-II because with the former the highest such risk has already been passed. In terms of reactor diameter, for example, H-Coal has been scaled up from a diameter of 6 to 8-1/2 inches in its process development unit to a diameter of 4 feet 6 inches in its operating pilot facility. The reactor proposed for the commercial plant would have a 13-foot diameter. On the other hand, the proposed SRC-I demonstration facility (the first module in a five-module commercial plant) requires scaling up the reactor to an 11-foot diameter from the 12-inch diameter at the pilot facility. SRC-II is similar. Scale-ups of such magnitude are considered to be a high technical risk at best.

The high-risk scale-ups compound the uncertainty of the data, as the reactor effluents determine downstream requirements for handling gases, liquids, and solids. Consequently, the parameters and, necessarily, the operating cost data are much less certain.

Downstream technology

Downstream from the reactor, the highest risk--shared by all four processes--is the close coupling of the process with gasification. No gasifiers are in any of the existing facilities. Consequently, hydrogen generation and ash residue present problems of critical uncertainty.

Another major downstream problem is the corrosive effect of ash on let-down valves. Even though the technology has improved, the reliability and maintainability of the valves is still questionable. The problem is further complicated when the required scale-up is considered. For instance, in SRC-I a valve that "lets-down" from 2,000 to 100 pounds of pressure per square inch has to increase in diameter from 2 inches to between 12 and 16 inches.

Finally, an additional risk for SRC-I is in the proposal to convert the original SRC solid fuel to a cleaner solid fuel and to transportation fuels, which would increase uncertainty about performance parameters. It would also significantly affect capital investment, since estimates are that it will add $69 million to the final cost, as well as operating costs, since hydrogen production requirements, electricity consumed, and catalysts used will all increase. Furthermore, the SRC-I proposal adds a hydrotreater to further refine its liquid products (by catalytically stabilizing or removing objectionable elements from lighter products, such as light and medium oils, by reacting them with hydrogen). Although we did obtain estimates for the additional cost, no revised product slate was available. We were told by International Coal Refining Company officials that the best estimate was a decrease of about 10 percent, in terms of total Btu's from the final slate, because of energy consumed internally to operate the hydrotreater.

Cost estimate uncertainty

To understand the uncertainty associated with cost estimates for the proposed liquefaction plants, it must be realized that, as Rand stated in its discussion of cost estimates for energy process plants:

> Estimates of capital cost of pioneer energy process plants have been poor predictors of actual capital costs. Predesign and early design estimates (even in constant dollars) have routinely understated definitive design estimates or ultimate costs by more than 100 percent . . . . (Rand, 1979)

We have shown earlier that the H-Coal and EDS cost growth between baseline cost and predicted final cost for the demonstration plants were 66 percent and 24 percent, respectively. (U.S. GAO, Controlling, 1981) For SRC-I and SRC-II, the initial estimates in the 1979 "Phase O Documents" were $548 million and $785 million, respectively. (Air Products, 1979; Pittsburg and Midway, 1979) In 1980, DOE estimated a final cost of $1.6 billion for SRC-I and $1.4 billion for SRC-II.

It is a well-documented fact that final or end-cost forecasting of new technologies is risky. (See, for example, Harsch, 1974; Timson and Tihansky, 1972; Weida, 1977.) There is even more uncertainty when there are no requirements to insure that similar or comparable cost-estimating methods will be used or that engineering efforts will acceptably support cost estimates. We found no evidence that DOE requires similar or even comparable cost-estimating methods. On the contrary, the cost estimates that it has used have been based on proprietary approaches relying heavily on individual experience with the particular process. Such cost-estimating approaches lack internal transparency and cannot be externally validated. DOE has not taken steps independently to validate the cost estimates submitted by each contractor. 1/ We found no evidence that DOE has tried to reduce cost-estimating uncertainties by specifying acceptable levels of engineering effort. Consequently, estimates for performance and resulting operating costs and capital investments are usually optimistic.

For specific processes, the latest estimates for EDS and H-Coal are based on operational data from larger pilot facilities and yield figures of 250 and 600 tons per day, respectively, whereas comparable estimates for SRC-I and SRC-II, also based on pilots, yield 6 and 30 tons per day. The projections for the first two processes are the more useful. Moreover, Exxon's conceptualization of a commercial plant is impressive in its methodological and engineering effort. Two obvious explanations for this are that Exxon has ample resources and it is in Exxon's own best interest to undertake such efforts, given its scheduled contribution of about 25 percent of the final cost of the plant. The estimates for H-Coal are the result of an ongoing $10 million site-specific study as well as product-marketing and comprehensive equipment-reliability evaluation by Bechtel Petroleum for Ashland Synthetic Fuels, Inc., and DOE.

DATA INCONSISTENCY AND LACK OF INDIRECT ENERGY INPUTS

Data inconsistency became obvious when we reviewed the four coal liquefaction processes. Inconsistency in the capital data submitted is significant, for example (see appendix II). This also points up the need for similar or comparable cost-estimating methods, because inconsistency makes comparisons very difficult. All proposals for projects should include standardized and consistent data on energy and materials inputs and on final products and byproducts.

No data were available from DOE that presented the indirect energy required in the energy facilities we evaluated. Although data were available on the direct energy inputs (such as fuels and electricity) to the facilities, we were given no estimates for the indirect energy required to construct, operate, and maintain coal liquefaction and ethanol production facilities. We needed indirect energy measures for energy to manufacture and construct the facilities, energy to mine, manufacture, or farm the raw material and energy products used in operating and maintaining the facilities, and energy to transport the raw materials and products to and from the facilities. We compensated for this lack of data by using process analysis and I-O analysis to estimate the indirect energy required at each stage of a facility's production trajectory. However, such approximations are only illustrative of the methodology; they are not conclusive estimates of the net energy yields of the facilities we analyzed.

1/This is true of the coal liquefaction projects and most major acquisition projects. (See U.S. GAO, Department, 1981.)

CHAPTER 7

PERFORMING THE ANALYSIS AND COMPARING THE RESULTS-- COAL-FIRED ETHANOL PRODUCTION

We analyzed two plants that produce a liquid fuel from corn. One plant is a model for farmer cooperatives; the other is a full-scale commercial plant. As with coal liquefaction, data base problems did not allow for a definitive comparative analysis. In this chapter, we again address figure 1, phase E, steps 1 through 6.

PERFORMING THE ANALYSIS

As with direct coal liquefaction, we began by analyzing each major stage of the ethanol production trajectory. In addition, we estimated an energy credit appropriate for the ethanol byproduct distillers dry grain. Finally, we considered the effect of additional environmental restrictions on the net energy yield of ethanol production.

Trajectory analysis

We have broken into four stages the industrial relationships that culminate in the production of fuel-grade ethanol--corn farming, coal mining, transporting raw materials and products to and from an ethanol facility, and ethanol production.

Corn farming

The corn used as a feedstock in the two ethanol plants is a hybrid planned as feed for livestock; it is not the higher quality sweet corn destined for human consumption. In Energy and U.S. Agriculture: 1974 Data Base, the Department of Agriculture extensively surveyed the energy used in national agricultural production. (U.S. Department of Agriculture, 1977) This study, soon to be updated, is the most detailed analysis of farm energy consumption available. The energy consumed in corn farming was placed in four categories: (1) field operations, or fuels and electricity used for planting, cultivating, and harvesting equipment; (2) irrigation, or fuels and electricity used to pump irrigation water; (3) raw materials, or the energy required to manufacture fertilizer, pesticides, limestone, and seedcorn; and (4) capital construction, or the energy required to manufacture and construct the capital equipment and facilities used in farming.

The energy requirements for corn used at Idaho Falls and Plant X are shown at the top of the next page. Average U.S. corn farming requires 121,749 Btu's of premium fuel energy and 147,157 Btu's of total energy per bushel; these energy requirements are fully described in appendix III. It must be emphasized that these farm energy estimates are national averages; there is

Ethanol plant	Annual corn inputs (thousand bu/yr)	Embodied energy value (10^6 Btu/yr) Premium fuel	Total
Idaho Falls	59.568	7,252.344	8,765.848
Plant X	8,400.000	1,022,691.600	1,236,118.800

substantial variation in State corn farming energy estimates. In addition, given the rising cost of energy since the time of the survey, the amount and kind of farm energy use may have changed.

Mining

Coal combustion is the source of process steam for the Idaho Falls plant and ethanol Plant X. In appendix III, we give the calculations of premium fuel and total energy required to mine the coal used annually at the Idaho Falls plant. These mining energy estimates are based on the coal mining energy analysis conducted by the Energy Research Group of the University of Illinois. (Hannon and Blanco, 1980)

Transportation

Neither ethanol plant clearly specified the transportation requirements for its raw materials, products, and byproducts by mode, whether truck, rail, or waterway, or by distance. Therefore, we had to make assumptions regarding modes, transport equipment requirements, shipping distances, and size of hauls. In appendix IV, we give details of these assumptions as well as methodology and conclusions regarding the energy requirements for transportation at the two ethanol plants. It must be emphasized that our estimates represent assumed scenarios and that we present them to demonstrate the techniques for estimating transportation energy.

Ethanol production

To analyze the net energy yield of the two ethanol plants, we calculated the premium fuel and total energy embodied in their inputs and products. The energy value of the ethanol products is measured in terms of heating value, or Btu's per gallon. The annual production volume and total heating value of the ethanol produced annually by each plant are

Ethanol plant	Annual ethanol production (10^3 gal)	Total heating value (10^6 Btu)
Idaho Falls	186.317	16,062.104
Plant X	21,000.000	1,805,000.000

In these figures, annual ethanol production includes 10,036 gallons of gasoline denaturant for Idaho Falls and 1 million gallons for Plant X; total heating value assumes 84,000 Btu's per gallon of 199 proof ethanol.

Estimating the energy embodied in the inputs to the plants is more complicated. Inputs such as electricity must be analyzed not only for their heating value (at 3,413 Btu's per kilowatt hour) but also for the energy consumed in the process of generating electricity (including a weighted value of efficiency losses associated with the conversion of heat energy into electric power). Inputs such as chemicals and enzymes must be analyzed in terms of the energy consumed during their manufacture. Finally, the energy used in manufacturing and constructing capital equipment and facilities must be analyzed. Appendix II gives a detailed energy analysis of the inputs and products of the two ethanol plants.

Environmental analysis

Both Idaho Falls and Plant X meet all current environmental standards for air and water pollutants and solid wastes. We have included the capital and operating energy requirements for environmental controls in the analysis of the embodied energy of capital and operating inputs as described in appendix II. Therefore, the trajectory results include the energy required to meet all current air, water, and solid waste regulations.

Displacement analysis

Energy consumed in production cannot be used elsewhere in the economy but energy saved can be. This energy savings is the basis for the displacement energy credit we calculated for the distillers dry grains (DDG) byproducts of ethanol distillation. 1/

The DDG byproducts of both ethanol plants are collected from the bottom of the distillation columns to be sold as a

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1/Some ethanol analysts have advocated an additional energy credit for ethanol based on its potential as an octane booster when mixed with gasoline. An octane boost would reduce the energy required to refine the gasoline component of gasohol to a given octane value; this "saved" gasoline-refining energy would be credited to ethanol. There is significant controversy among technical experts regarding ethanol's octane improvement potential. For example, a study by the Office of Technology Assessment (1979, p. 11) claims that the octane-boost credit may be high, while the American Petroleum Institute states that it is unclear whether ethanol significantly increases the research and motor octane levels in gasohol (Alcohols, 1976). Moreover, given the "driveability" problem cited by API, it is unclear whether additional additives can overcome such problems as stalling, vapor lock, and surging under cruise conditions.

livestock feed supplement. 1/ Since DDG contains most of the original corn protein as well as the yeasts and enzymes added during cooking and fermenting, it is a valuable protein supplement when mixed with low-protein livestock feeds. It has a similar nutritive value in soybean meal used as a feed supplement.

The effects of the DDG byproducts on the net energy yield of the plant are calculated by estimating the protein equivalents of the amount of soybean meal that could be replaced by the annual DDG production of Idaho Falls (482 tons) and Plant X (75,000 tons). The National Academy of Sciences has published a detailed study of the nutritive values of various cattle feeds. (National Academy of Sciences, 1976)

The digestible protein in a pound of DDG is 23.4 percent; in soybean meal it is 43.8 percent. Therefore, a pound of DDG can replace 0.53 pounds of soybean meal with respect to protein equivalence. Since a bushel of soybeans yields 47.24 pounds of soybean meal, we can estimate the number of bushels of soybeans that can be replaced by the annual DDG produced in Idaho Falls and Plant X. The figures below present the annual DDG output for the ethanol plants and the equivalent amount of soybeans that the DDG can replace. They also show the annual energy credit for soybeans replaced by DDG given that the energy required for soybean farming is 126,163 Btu's of premium fuel energy and 145,675 Btu's of total energy. (As with corn farming, this is a national average.) Appendix III describes the energy analysis of soybean farming.

Ethanol plant	Annual DDG production (pounds)	Protein equivalence soymeal (pounds)	Protein equivalence soybeans (bushels)	Embodied energy credit for replaced soybean production (10^6 Btu/yr) Premium fuel	Embodied energy credit for replaced soybean production (10^6 Btu/yr) Total
Idaho Falls	964,184	511,018	10,817	1,364.705	1,575.766
Plant X	150,000,000	79,500,000	1,682,896	212,319.208	245,155.875

Two important points must be emphasized about the displacement analysis from which we derived the byproduct credit. First, we did not assess the energy savings of soybean milling. If DDG protein displaces an equivalent proportion of soybean meal protein from the market, then the milling energy normally required for that meal would be recorded as an energy credit. Even if this added 10 percent to the byproduct energy credit, the net energy balance of the ethanol trajectories would not be altered significantly.

Second, there is reason to believe that our byproduct energy credit is overstated rather than understated. Even if DDG were

1/DDG from Plant X is dried for shipment to distant purchasers, while Idaho Falls produces a wet distillers grain that is to be used on nearby farms and feedlots. However, we refer to the stillage byproducts of both ethanol plants as "DDG."

available in the feed supplement marketplace, there is no guarantee that it would immediately replace soymeal as a protein supplement. To estimate the economic displacement of soymeal by DDG, a detailed analysis of the substitution of corn, soybeans, soymeal, and DDG in domestic and foreign markets is required. In the absence of an economic analysis, the conclusions drawn from the analysis of protein-based substitution of corn for soymeal must be viewed as an upper-bound estimate of the DDG products' energy credit.

COMPARING THE RESULTS OF THE TWO PLANTS IN TERMS OF THE THREE OUTPUT-INPUT RATIOS

As in the coal liquefaction analysis, we used the three defined measures of effectiveness to conduct the comparative analysis. The comparison of the ethanol plants is greatly simplified since only a single product, fuel-grade ethanol, is produced. Because data were available for only two ethanol plants, we cannot make general statements regarding overall ethanol production technology.

Before any conclusions are drawn from the trajectory results in tables 7 and 8 and figure 5 for Idaho Falls and Plant X ethanol production, it must be emphasized that they are significantly uncertain because of problems with the

Figure 5
Output-Input Ratios of Two Ethanol Production Plants

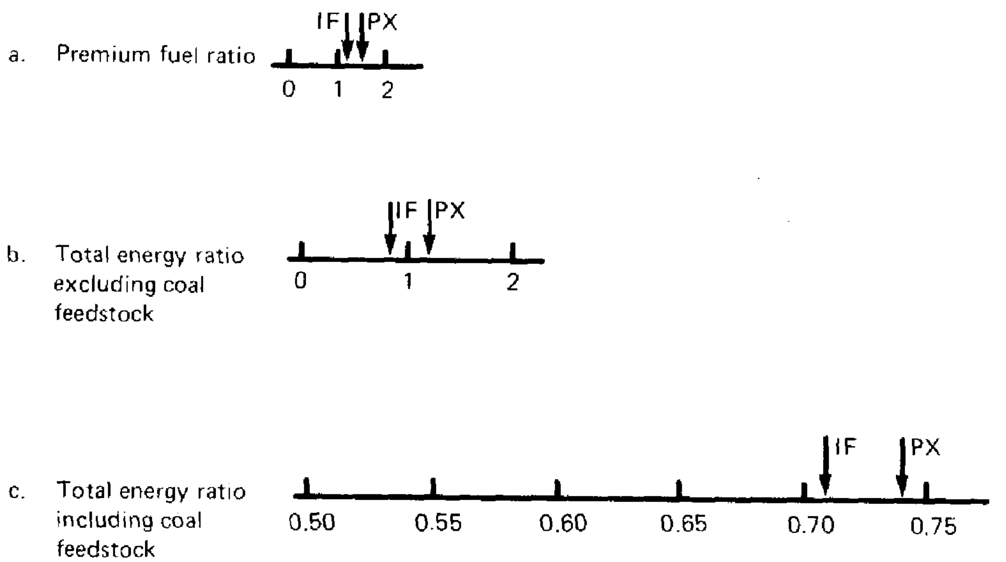


Table 7

Idaho Falls Trajectory Results a/

	Premium fuel	Total energy
	(10^9 Btu/yr)	
Outputs		
Products	16.062	16.062
Byproducts	1.365	1.576
Total	17.427	17.638
Inputs		
Corn farming	7.252	8.766
Mining	0.046	0.102
Transportation	1.218	1.654
Process		
Gasoline	1.335	1.444
Electricity	2.263	5.899
Yeast, enzymes, and chemicals	0.336	0.396
Repairs and maintenance	0.107	0.134
Capital	1.340	2.001
Total excluding coal feedstock	13.897	20.402
Coal feedstock	--	4.531
Total including coal feedstock	13.898	24.933
Output-input ratios		
Premium fuels	1.254	--
Total energy excluding coal feedstock	--	0.864
Total energy including coal feedstock	--	0.707

a/The five significant digits are not meant to be a definitive representation of the level of accuracy of the information.

Table 8

Plant X Trajectory Results a/

	Premium fuel	Total energy
	(10^9 Btu/yr)	
Outputs		
Products	1,805.000	1,805.000
Byproducts	212.319	245.156
Total	2,017.319	2,050.156
Inputs		
Corn farming	1,022.692	1,236.119
Mining	9.739	21.483
Transportation	27.162	31.005
Process		
Gasoline	133.013	143.913
Electricity	92.473	241.049
Catalyst and chemicals	72.864	88.715
Repairs and maintenance	12.162	15.171
Capital	23.678	34.846
Total excluding coal feedstock	1,393.783	1,812.301
Coal feedstock	--	954.800
Total including coal feedstock	1,393.783	2,767.101
Output-input ratios		
Premium fuels	1.447	--
Total energy excluding coal feedstock	--	1.131
Total energy including coal feedstock	--	0.741

a/The seven significant digits are not meant to be a definitive representation of the level of accuracy of the information.

available data bases. The Idaho Falls plant has no dehydration capability, the capital costs of Plant X have not been fully negotiated, and no data on technical or cost uncertainties are available for either plant. Consequently, as with coal liquefaction, we have little confidence in the validity of any comparative analysis of the net energy yields of the plants.

Premium fuels ratio

The premium fuels ratios for the two plants indicate that Plant X has a slight advantage over Idaho Falls. Both, however, are marginal producers of premium fuels, consuming nearly as much as they produce.

Total energy ratio excluding coal feedstock

Similarly, in terms of total energy ratios excluding coal feedstock (meaning the coal used as a heat source for plant process steam), both plants are close to the breakeven point. Plant X barely produces more energy than it receives from other sectors of the economy. Idaho Falls consumes more energy than it produces.

Total energy ratio including coal feedstock

The total energy ratio including coal feedstock provides the most significant difference between the two plants and shows Plant X having the advantage over Idaho Falls. 1/

The results for ethanol production indicate the importance of measuring indirect energy inputs in analyzing the energy balance of energy production. For both plants, an indirect input, corn-farming energy, is the largest energy input. More importantly, farming energy is predominantly premium fuels. Including this large premium fuel input in the analysis brings the net premium fuel ratio of these plants close to one.

At this point, it should be recalled that our results are based on nationwide averages for corn farming. If we substitute site-specific farming energy requirements, the result will vary in direct relation to the farming energy requirements of the specific location. Where farming energy requirements fall below the average, ethanol production will be more attractive; where they rise above the average, using ethanol production to increase the availability of premium fuels would be highly questionable.

1/The higher premium fuel and total energy ratios for Plant X may well be attributable to economies of scale.

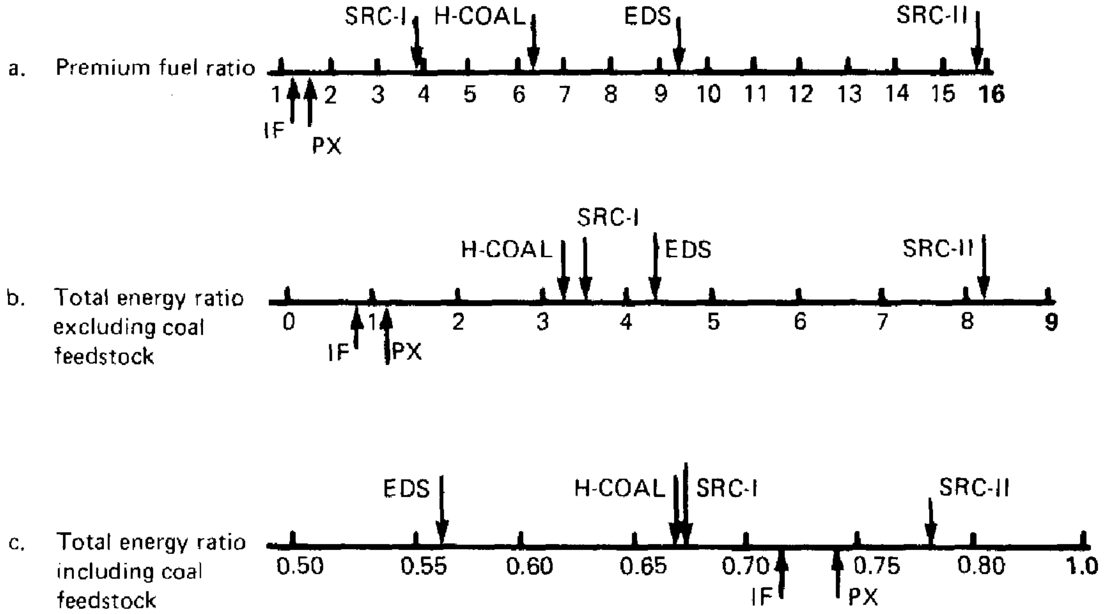


Figure 6
Output-Input Ratios of the Two Technologies a/

a/The magnitude of the advantage for SRC-II is questionable, because it could be the result of unverified optimistic performance parameters.

COMPARING THE NET ENERGY RESULTS
OF THE TWO TECHNOLOGIES--DIRECT
COAL LIQUEFACTION AND COAL-FIRED
ETHANOL PRODUCTION

Having completed analyses for the separate technologies and made comparisons within each technology, we have demonstrated the use of NEA. The methodology also gives us the ability to compare across technologies, even quite dissimilar ones. Now we turn to the issue of NEA's usefulness in comparing the two energy technologies that served as our test vehicles.

Premium fuels ratio

The results for coal liquefaction and ethanol production as measured by the premium fuels ratio are shown in figure 6. Liquefaction is a greater net producer of premium fuels than is ethanol production. Thus, the premium fuel ratio appears to be valuable in showing differences in intertechnology comparisons.

It must be emphasized that the products of coal liquefaction and ethanol differ greatly. Coal liquefaction technologies yield a range of liquid fuels whose qualities or grades differ greatly, ranging from the high-quality H-Coal reformate to the low-grade light and heavy oils of SRC-II. On the other hand, the ethanol produced by Plant X and Idaho Falls is a high-quality fuel requiring no further refining before being used as a transportation fuel.

The value of the premium fuels ratio in showing differences in intratechnology comparisons is less clear. For coal liquefaction, the premium fuels ratio shows a considerable difference in the yields between processes; for ethanol, the difference in yield is much less.

Total energy ratios

The total energy ratio excluding coal feedstock shows major differences in the ratios between ethanol production and coal liquefaction, with liquefaction being the greater net energy producer. Thus, the ratio appears to be useful in intertechnology comparisons but less useful in intratechnology comparisons.

The results of ethanol production and coal liquefaction when measured by the total energy ratio including coal feedstock are shown in figure 6. This ratio seems to be useful for both intratechnology and intertechnology comparisons.

CHAPTER 8

ASSESSING THE RESULTS-- CONCLUSIONS, AGENCY COMMENTS, AND OUR RECOMMENDATIONS

In the Nonnuclear Act of 1974 and the Energy Security Act of 1980 (title II), the Congress required DOE to make decisions about the expenditure of public funds after considering the net energy yields of proposals it receives. DOE has not done this, as we have discussed in chapter 1. DOE's explanation was that such analysis is not methodologically feasible and that, in any case, economic analysis is an adequate substitute. In this report, we have described the work we did to develop and apply a feasible NEA methodology. We used direct coal liquefaction and coal-fired ethanol production technologies as vehicles for the application.

Even though our purpose was not to evaluate all aspects of coal liquefaction or ethanol production programs, the need for an improved data base for net energy and economic analysis of such programs has become apparent. Moreover, although it was not our intention to audit expenditures for new energy technologies, it is clear that the costs of these technologies to the public are in the hundreds of millions of dollars.

CONCLUSIONS

Our effort has demonstrated that it is methodologically feasible to perform NEA and that it provides information to DOE administrators important for making the financially significant decision of whether to emphasize one approach in generating energy products or another. Economic analysis, which assesses technological efficiency according to its profit potential, cannot measure the direct and indirect inputs of energy required to produce every product. NEA can. Therefore, the arguments that have been made that NEA has been neglected because of its methodological problems and because of the ability to substitute other decisionmaking tools do not hold up. It is clear that the methodological problems involved in performing NEA can be surmounted and that DOE could have overcome them if it had provided proper analytical support for applying and refining NEA.

Strengths and weaknesses of the methodology development and application

The most significant strength of the NEA methodology is that its use guarantees policymakers the opportunity to consider the question of net energy yield independently from profit potential and other financial and economic questions. The ethanol facilities results, which show them to be marginal premium fuels producers, point up the risks of omitting NEA. Economic analysis and thermal efficiency analysis do not measure the indirect energy inputs that allow the specification of net energy yields. Thus, NEA introduces new information to aid policymakers and managers in understanding how specific energy production technologies affect specific national energy policy objectives. The methodology emphasizes the measurement of physical energy flows from industrial sectors that produce raw materials and energy inputs that new energy technologies use. This emphasis on physical rather than dollar measurements of energy identifies the type of energy consumed, both directly and indirectly, in producing new energy. Therefore, NEA can be used to make comparative analyses of net energy yields of new energy technologies and to analyze their effect on requirements for imported premium fuels and domestic energy resources.

Additionally, NEA is a useful tool for policymakers in that it helps them assess the optimal rate of introduction of a new energy technology during a period of energy scarcity. Under conditions of short energy supplies, an immediate and heavy investment in alternative energy sources may place an even greater strain on scarce energy resources. New energy technologies often require extensive energy inputs in their developmental phases before they begin to produce significant amounts of energy. Thus, it may be desirable to invest less intensively in a new technology to avoid large net energy shortfalls during the developmental stage. This is particularly important for energy-intensive technologies such as nuclear and solar thermal systems.

NEA has been shown to be a highly versatile tool. The methodology can be adjusted to meet the needs of decisionmakers. Thus, as a natural part of its request-for-proposals process, DOE could specify the proper NEA perspective--that is, measures of effectiveness and their boundaries--for competing proposals, much as we have done in this report. The methodology we have developed can be applied to all types of energy production and conversion processes. Despite the considerable data problems we encountered, the test we performed has demonstrated the methodological feasibility of NEA and its special ability to measure both direct and indirect energy flows and its consequent significance for policymaking.

Thus, NEA allows policymakers and managers to make decisions about production processes that can increase either the quantity or the quality of fuels. The methodology allows them to focus on process questions in improving the effectiveness and efficiency of energy production. And, finally, it allows them to compare competing technologies and processes with regard to their net energy yields and their effects on domestic resources and import needs.

If it is true that the Federal role in energy policy is related to achieving independence from foreign imports as well as minimizing the use of domestic resources, then a fully developed NEA is a strong tool for the executive agencies and for the Congress once agencies have integrated it into their proposal evaluation process. This is not to suggest that NEA should take the place of other analytical techniques; it is to suggest, rather, that NEA could complement them by adding to our understanding of the net energy effect of competing technologies in ways that other approaches do not. Just as these other tools are not substitutes for NEA, so NEA is not a substitute for conventional decisionmaking tools.

Among the present weaknesses of the NEA methodology must be counted the numerous data problems we encountered in developing and testing it. While we believe that both NEA and our NEA methodology are feasible and useful, future applications of NEA clearly require attention to data problems.

Data quality and inconsistency

The need for improved data for NEA and for economic analysis as well is urgent. The quality of data provided to DOE on the proposed technologies cannot be quantified, because the proposal documents provide no quantitative uncertainties associated with point estimates of cost, performance parameters, material inputs, and final products and byproducts. Furthermore, there is no evidence of specific DOE requirements to insure that (1) bidders use similar or comparable cost-estimating methods, based on acceptable levels of engineering effort, in developing proposals, (2) cost estimates are reasonably validated, and (3) bidders submit standardized and consistent data on the energy and materials inputs and final products and byproducts. No additional cost burden to DOE would result from improving the data base. The deficiencies we mention here can be corrected by requiring quality data in proposal documents. The task of reasonably validating such data could be absorbed by the existing proposal review validating process.

The incremental cost and analytical burden of conducting NEA

The only additional data DOE requires for conducting NEA routinely are the data bases necessary for calculating the indirect energy inputs associated with the capital investment and raw-material needs of a technology. We relied on an energy input-output model of the economy to track them. DOE's Office of Economic Analysis presently maintains similar models and supporting data bases for tracking energy flows through the economy. The I-O model requires no additional acquisition or operation cost in performing NEA.

Since many new technologies and industries are not well represented by the aggregate data in an I-O model, process analysis data bases should be developed and refined as supplements to the I-O data base. The process analysis data can be used to revise and update energy estimates in selected I-O sectors. Such data bases have been developed by private industry, and these could be further refined by the Office of Economic Analysis.

In response to a request for data to support our effort, industry source estimates of the one-time cost of obtaining a process analysis data base ranged from $300,000 to $750,000 (see appendix V). We expect no additional cost to be associated with maintaining this data base since DOE's Office of Economic Analysis already maintains a number of models and data bases to track energy flows through the economy.

The cost of conducting NEA can be absorbed within DOE's existing proposal review process, which should incorporate NEA as follows:

--DOE should prescribe uniform standards to be used by bidders for plant-specific process analysis.

--Bidders should perform plant-specific analysis in accordance with DOE standards. It should be noted that this is not an additional burden to bidders. Plant-specific analyses are performed routinely as part of engineering efforts to estimate thermal efficiency.

--DOE should then estimate the relevant indirect energy inputs associated with constructing, maintaining, and operating each facility. This effort would be supported by the ongoing input-output data base analyses that the Office of Economic Analysis performs and would be supplemented by the new process analysis data base.

Net energy analysis contributes to a more effective selection of the most energy efficient of the technologies that convert domestic energy resources into usable energy products. The prudent choice of new energy technologies for public financial support--technologies that will make the best use of domestic energy resources--justifies the relatively small incremental cost of improving the selection process.

Expenditures for new energy technologies

It was not our intention to audit expenditures associated with the Nonnuclear Act, but it is nonetheless clear that the public cost of new technologies is in the hundreds of millions of dollars. For example, in terms of the four coal liquefaction processes examined in this study alone, the estimated program cost (excluding development stages) for the two existing pilot plants for EDS and H-Coal is $646 million. Government and private industry share in their sponsorship, but DOE contributes at least 50 percent of this cost.

Except for SRC-II, which is not to proceed beyond the pilot stage of development, future financial support for the liquefaction processes is uncertain. A preliminary H-Coal proposal to the U.S. Synthetic Fuels Corporation requests a loan guarantee of $3 billion for a commercial plant estimated to cost more than

$5.2 billion. There are no similar proposals from EDS or SRC-I. It is important to realize that although these processes were initiated under the Federal Nonnuclear Energy Research and Development Act (Pub. L. No. 93-577) and should have incorporated NEA, no such requirement applies to projects supported by U.S. Synthetic Fuels Corporation. Authority for support it gives comes from title I of the Energy Security Act (Pub. L. No. 96-294), which does not require that net energy yields be considered in evaluating projects.

The future of financial support for other new energy technologies and of the applicability of the requirements to conduct NEA are also uncertain. A number of issues must be addressed before the future of NEA in Federal energy decisionmaking can be resolved. Among them are the question of what Federal entities will carry out future energy research, development, and demonstration. Under what authority--Public Law 93-577 or the Energy Security Act (which requires NEA only under title II)--will the support be provided? When will a final determination of these issues be made? In the meantime, decisions on projects under the Nonnuclear Act and title II of the Energy Security Act have been made to support new energy technologies that ignore the NEA requirements. For example, on August 16, 1981, DOE awarded a $2.02 billion conditional loan guarantee under authority of the Nonnuclear Act to assist in constructing a commercial coal gasification plant.

We are aware that any recommendation we make may apply in future to an agency other than DOE. We are also aware that our recommendations may not apply if financial public support of future technologies is not provided under authority of Public Law 93-577 or title II of Public Law 96-294. We are confident, however, that we have demonstrated that it is important for policymakers and managers to know the net energy yields of proposed new energy technologies when they decide on financial support for developing them. Therefore, even if it were not required by statutory mandate, NEA should be incorporated as an integral part of the decisionmaking process. Candidates for NEA include nuclear, oil shale, solar (photovoltaic, thermal, biomass), power plant conversion, and conservation technologies. It is particularly important, as we have previously stated, in the case of energy-intensive technologies, such as nuclear and solar, because it provides a method for avoiding the creation of large energy deficits, by indicating their appropriate deployment rates.

AGENCY COMMENTS AND OUR RESPONSE

We sent a copy of a draft of this report, requesting official comments, to the Department of Energy and the principal industrial partners in the coal liquefaction projects, Ashland Synthetic Fuels, Inc., and Exxon Research and Engineering Company. We also sent a copy of the draft to International Coal Refining Company and to Solvent Refined Coal International. We received comments from DOE, Ashland, and Exxon and in appendix VIII we reprint their letters. In that appendix, we also respond in detail to the comments made by DOE. Here, we highlight those comments and our response. Specific factual errors in the report pointed out by Ashland and Exxon have been corrected, and we considered their suggestions and changes in terms of message or emphasis and, when we deemed it appropriate to do so, we incorporated them in the report.

We also asked a number of other technical experts to review the draft, including Hydrocarbon Research, Inc., Colorado School of Mines Research Institute, and the Office of Engineering Programs of George Washington University. Although we have not reprinted their comments, we are grateful for them because they were very valuable in helping us complete the final draft.

DOE comments that it does not now and never has questioned the feasibility of conducting NEA. However, our records document that NEA's "methodological infeasibility" was the major problem raised by DOE officials when they were interviewed for this report and explained DOE's neglect of NEA. On the other hand, DOE does question NEA's utility. Our view is that the experience of the ethanol plants makes very clear the need for NEA. The use of other forms of analysis made them appear to be attractive candidates for the investment of public funds, but NEA results show that both plants are marginal producers of premium fuels. In appendix VIII, we cite specific pages in the report that we believe do clearly show the utility of NEA. Additionally, Ashland's reviewer stated that "we believe the subject to be an important consideration in establishment of national energy policy and are supportive of the General Accounting Office's efforts," while the reviewer for the Colorado School of Mines also supported our position, stating that "my experience in net energy analysis leads me to concur with GAO in your findings and report."

DOE also claims that economic analysis provides a proven system for valuing both energy inputs and outputs, but we believe that in doing so, DOE overlooks the limitations of economic analysis for measuring energy inputs and outputs. We gave our reasoning on pages 8 and 9. Ashland points out that "Obviously, policy making using conventional economic analysis alone will not lead to the most cost effective allocation of funds between candidate technologies and projects." Indeed, we do not advocate substituting net energy analysis for economic analysis. Our position is that NEA should be used as a complement to other analytical tools.

In its comments on our report, DOE expresses the conviction that it has observed the requirements to consider the potential for producing net energy. Nevertheless, we find, after multiple interviews and careful examination of DOE documents and processes, that DOE has considered NEA in neither its decisionmaking nor its proposal evaluation procedures and it has not implemented the congressional requirements of Public Law 93-577 and title II of Public Law 96-294. Moreover, DOE has not fulfilled its promise to the House Committee on Government Operations to implement NEA, which it made in response to our 1977 report Net Energy Analysis: Little Progress and Many Problems (EMD-77-57).

Ashland and Exxon are of the opinion that NEA is less valuable for intratechnology comparisons. On page 50, we have stated that based on the results of our application, the value of the net premium fuels and net energy (excluding coal feedstock) ratios for intratechnology comparisons is not as clear. Ashland also believes that "although less comprehensive," thermal efficiency estimates are of "unquestionable value" in supplementing economic analysis. We do not argue against the use of either economic or thermal efficiency analysis. We do assert, however, that such analyses do not constitute net energy analyses. Thermal efficiency estimates exclude the indirect energy inputs required in NEA. This is a significant omission. As it is clearly demonstrated in ethanol production, the indirect inputs of corn farming are the second highest energy inputs and can determine whether the process is or is not a net producer of premium fuels or total energy.

DOE concludes that following our recommendations would waste "scarce taxpayer resources." We believe that DOE should reconsider its position on improving the data base and on the utility of performing NEA. First, decisionmaking that spends scarce taxpayer resources on the basis of inconsistent, unvalidated, and low-quality data constitutes an inefficient management of public funds. Second, continued neglect of NEA runs counter to the statutory requirements of Public Law 93-577 and title II of Public Law 96-294 and DOE's explicit promise to the House Committee on Government Operations to implement NEA.

RECOMMENDATIONS TO THE SECRETARY OF THE DEPARTMENT OF ENERGY

The Secretary of the Department of Energy should issue directives necessary for

--insuring that similar or comparable cost-estimating methods, based on acceptable levels of engineering effort, are used in developing proposal documents and that their results are tested for validity;

--obtaining uniform data on the cost, performance parameters, energy, materials inputs, and final products and byproducts of energy facilities in proposal documents, along with their associated quantitative uncertainties;

--developing the additional data base for the analysis of indirect energy flows;

--providing the leadership and analytical support required to conduct net energy analysis; and

--performing net energy analysis on all technologies proposed under authority of Public Laws 93-577 and 96-294.

Uncertainties exist regarding which Federal entities will carry out future research, development, and demonstration activities. The recommendations above would also apply to the administrators of succeeding agencies.

RECOMMENDATION TO THE CONGRESS

In Public Laws 93-577 and 96-294, the Congress expressed its interest in net energy analysis; we have demonstrated the feasibility and value of conducting such analysis; DOE has not conducted net energy analysis. Therefore, the Congress should require the Department of Energy, or succeeding entities, to demonstrate during oversight and appropriations hearings that the potential ability of proposed energy technologies to produce net rather than gross premium fuels and energy at their commercial stage was analyzed and considered before DOE funded the development of those technologies.

NET ENERGY ANALYSIS TECHNIQUES

PROCESS ANALYSIS

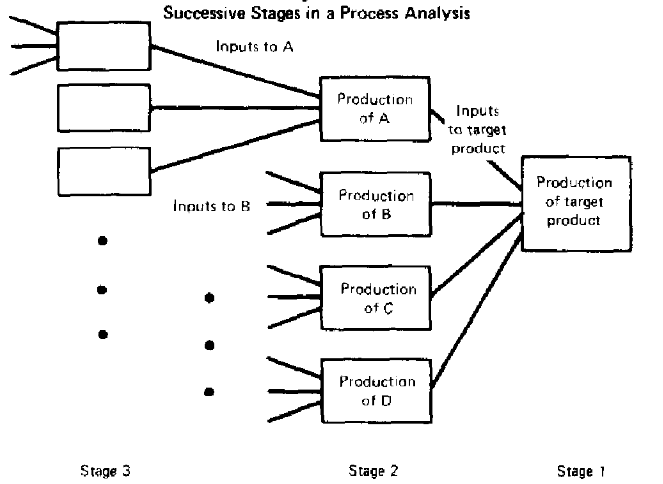
Process analysis is the most detailed of all energy analysis techniques. It identifies target commodities, whether in energy sources such as coal or in nonenergy commodities such as steel. If the target product is an energy source, the product is expressed in some appropriate physical measure, such as the Btu. Then it analyzes thermodynamically each production step in producing and delivering the target commodity. Process analysis itself has three steps.

The first step in process analysis is trajectory definition --defining and identifying the network of production sectors or industries that directly and indirectly contribute to the production of the target commodity. Figure 7 shows a production trajectory. Direct contributions include the energy such as coal, fuel oil, and electricity directly consumed during the production of the target product. Indirect contributions include the energy required to produce the nonenergy raw material inputs such as chemicals, maintenance materials, and supplies and the energy required to construct the energy facility itself. Usually, the information is summarized in a diagram showing the flow of all direct and indirect inputs and outputs along the trajectory.

The second step in process analysis is to estimate the embodied energy values assigned to each input and output in the trajectory and to calculate the quantity of energy delivered, consumed, wasted, and produced in each stage of the process.

The third step is to calculate the embodied energy of all trajectory inputs against the embodied energy of all the outputs, yielding a net energy value for the target energy product.

Figure 7
Successive Stages in a Process Analysis



INPUT-OUTPUT ANALYSIS

Input-output analysis (I-O) describes the flow of goods and services in the U.S. economy. It has been used as a powerful tool of economic theory since the 1940's but it has only recently been extended to include flows of energy. In an economic I-O analysis, every U.S. industry is placed in a sector defined according to some common characteristic, such as a coal-mining sector, a tobacco-producing sector, and so on. The U.S. Department of Commerce has developed a data base dividing the U.S. economy into 368 I-O sectors. Other I-O models have different numbers of sectors.

The economic activity in each sector is represented by a linear equation that indicates the dollar value of inputs required from every other sector in the economy to produce a single dollar's worth of a given commodity. In the steel-producing sector, for example, the commodity would be steel. The transactions, measured in dollars worth of sales per year, between each sector and all other sectors are then tabulated and displayed in a matrix whose size is determined by the total number of sectors in the model.

The percentage of a product's value that can be traced back to a particular industry or sector is then calculated by dividing dollars purchased from that sector by total gross output. Repeating this calculation for all elements of the matrix yields a table of direct or technical coefficients similar to the one shown here. The table describes quantitatively the process

	Output			
Input	Sector W	Sector X	Sector Y	Sector Z
Sector W	.20	.37	.01	.08
Sector X	.05	.06	.18	.02
Sector Y	.15	.07	.26	.04
Sector Z	.23	.03	.04	.29

each industry uses to produce its product. Each cell of the table indicates the amount of input required from the industry or sector named in the lefthand column to produce a dollar's worth of output from any of the industries named along the top. In other words, each coefficient describes what an industry uses to produce its product.

To convert an economic I-O model to an energy I-O model requires additional data on the direct and indirect consumption of energy of the sectors in the model. Once these energy data have been substituted for the flow of dollars, it is possible to calculate the total direct and indirect energy consumption embodied in a dollar's worth of goods and services purchased from any sector.

NEA using an energy I-O model requires steps similar to those in a process analysis. First, the trajectory is defined. As in process analysis, the objective is to identify and define the network of production sectors that directly and indirectly contribute to producing target commodities. The industrial sectors and their relationships must conform to the structure of the I-O model.

Next, embodied energy is estimated. As in process analysis, values--in this case, embodied energy values--are assigned to each input and output for the various sectors in the trajectory. Embodied energy values are derived directly from the sectoral energy flows in the sectors defined in the model.

Finally, net energy is calculated. The embodied energy of all the trajectory inputs is netted against the embodied energy for all the outputs to yield a net energy value for the target energy product.

ECOENERGETICS

Ecoenergetics is a technique for measuring the energy requirements of industrial processes in broad terms such as the energy of labor or the energy of natural systems. It was developed by Howard T. Odum and his associates at the University of Florida, and the method is shown graphically in figure 8. (See also National Science Foundation, 1975, and Odum, 1971, for sources and further discussion of this illustration.)

According to ecoenergetics theory, the energy of natural phenomena such as sunlight, wind, rain, tides, and residual earth heat has been converted into energy and nonenergy natural resources that are consumed in the process of economic activity. (Odum, 1979, p. 8) For example, the energy embodied in sunlight, wind, and rain is an input to industries like agriculture and forestry. In addition, ecoenergetics theory maintains that the environmental effects of industrial activity are measured in terms of the energy required to return damaged ecosystems such as estuaries and watersheds to their original condition.

Ecoenergetics also holds that labor services and government services should be incorporated in energy analysis because both require direct and indirect energy and both are necessary for economic activity. (Odum, 1979, p. 209) Thus, ecoenergetics takes a more expansive view of energy and NEA. It connects the energy requirements of industrial activity with the processes that form natural resources and also with environmental processes and labor and other services.

APPENDIX I

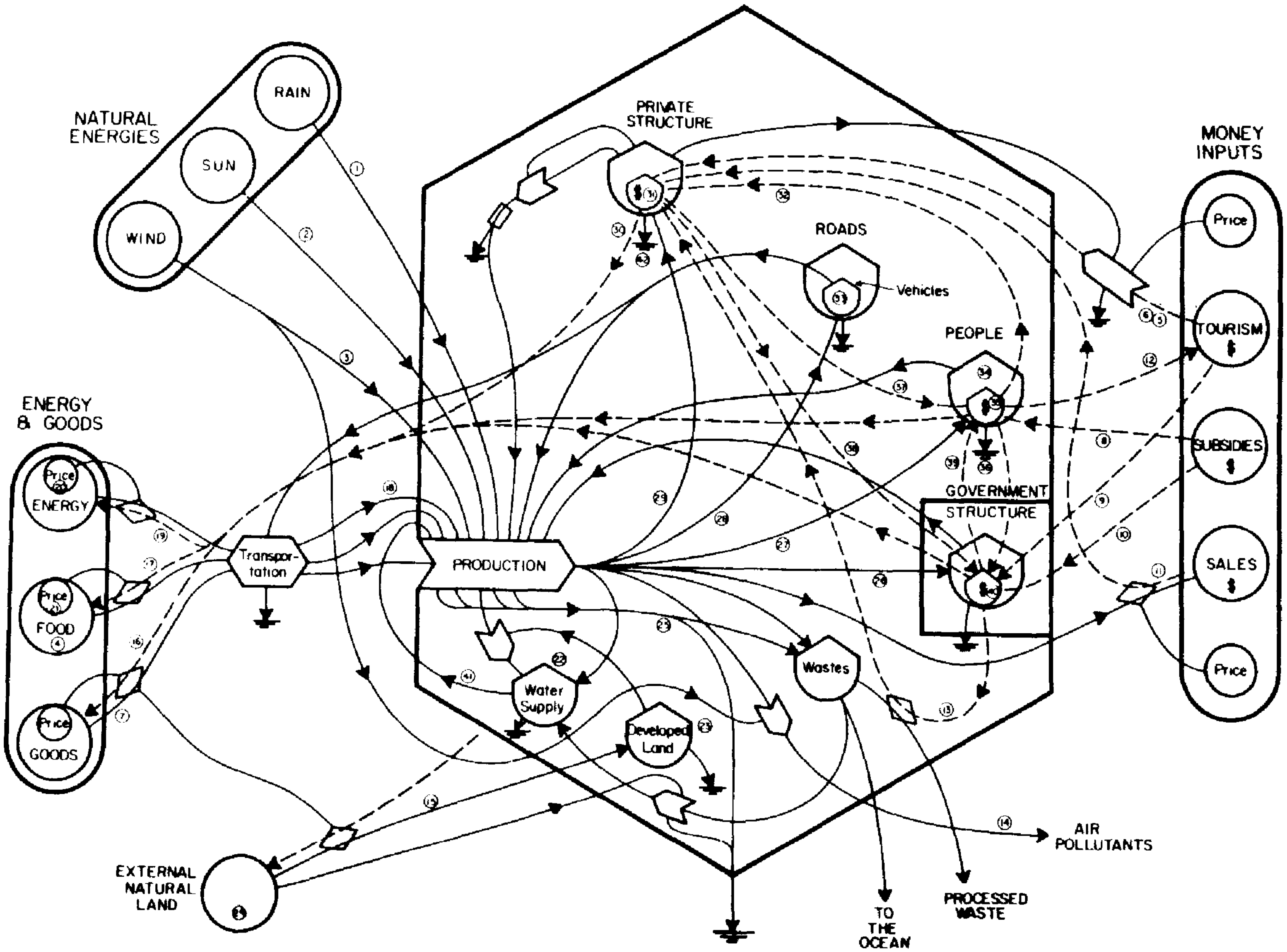


Figure 8

An Ecoenergetic Analysis

COAL LIQUEFACTION

This appendix is divided into three main sections. In the first, we present plant characteristics for H-Coal, SRC-I and SRC-II, and EDS; these are shown in tables 9 through 18. In the second section, we discuss our embodied-energy calculations for energy inputs and outputs for the four plants, and we show these in tables 19 through 35. Last, we present our displacement analysis for ammonia, sulfur, phenol, and anode coke byproducts, beginning with a discussion of our calculations for petroleum-based and liquefaction-based refinery products. The displacement analysis is summarized in tables 36 through 44.

PLANT DATA

Tables 9 through 18 show characteristics and cost summaries for the H-Coal and EDS commercial plants and for the demonstraation plants for SRC-I and SRC-II.

Table 9

H-Coal Commercial Plant Characteristics

Location	Breckenridge County, Kentucky	
Life	20 years	
Operating factor	87% (318 stream days/yr)	
Feedstock	18,259 tons of coal/stream day	
Transportation	Barge	
Annual operating cost a/	Electricity	229,623 kw
	Catalysts and chemicals	$50.85 M
	Maintenance materials	$13.08 M
Capital cost a/	$2.62 billion	
Products	Propane	5,600 bpd
	Mixed butanes	3,700 bpd
	Light naphtha	3,600 bpd
	Reformate	10,300 bpd
	Distillate oil	23,300 bpd
	Pipeline gas	20 M cu ft/day
Byproducts	Sulfur	470 tons/calendar day
	Ammonia	170 tons/calendar day

a/In 1981 dollars; embodied energy estimates were made for only $2.082 billion of this capital.

Table 10

H-Coal Commercial Plant Capital Cost Summary
(in 1981 Dollars)

Activity	Capital investment
Coal receiving, storage, and handling	$ 15,260,000
Coal washing and secondary crushing	42,089,700
Coal drying pulverizing	61,476,100
Coal slurry preparation	11,251,400
Preheating and reaction	427,333,300
Primary separation	45,796,400
Recycle slurry preparation	20,397,000
Recycle hydrogen concentration and compression	6,930,100
Gas plant	36,352,500
Cryogenic hydrogen purification (Airco)	11,336,000
Sour water stripping and ammonia recovery	14,741,400
Sulfur plant	21,967,900
Gasification and purification	310,546,100
Vacuum bottoms flaking	910,300
Oxygen plant (Airco)	98,863,000
Distillate separation	34,122,000
Naphtha treating and reforming	30,662,600
Flare system	9,984,400
Tankage	26,701,500
Interconnection piping	23,296,900
Instrument and plant air system	26,625,000
Purgen and flush oil systems	33,281,300
River facilities	8,320,300
Plant security and parking	13,312,500
Rail, truck, and pipeline	13,189,000
Power supply and distribution	41,601,600
Communications system	3,328,100
Steam generating (Bechtel) and BFW treatment	303,064,800
Stack gas scrubbing	132,326,000
Water system	43,265,600
Fire system	9,984,400
Sewers, drains, and wastewater treatment	71,550,100
Plant maintenance shops and storehouse	33,281,300
Sanitary system	8,320,300
Inert gas system	16,640,600
Settling ponds	1,590,100
Landfill	7,468,000
Buildings	49,921,900
Land a/	13,159,300
Site preparation	14,343,600
Contingency a/	282,277,300
Initial catalyst and chemicals a/	24,805,700
Working capital a/	218,204,400
Total estimated capital investment	$2,620,345,700

a/Excluded from estimation of embodied energy of capital, yielding $2,081,899,000 requiring estimation of its embodied energy.

Table 11

SRC-I Demonstration Plant Characteristics a/

Location	Davies County, Kentucky	
Life	20 years	
Operating factor	90% (330 stream days/yr)	
Feedstock	5,600 tons of coal/stream day	
Transportation	Rail 150 miles round trip	
Annual operating cost	Electricity 73,280 kw Catalysts and chemicals b/ Maintenance materials none estimated	
Capital cost c/	$487.0 M d/ 60.6 M e/ 69.0 M f/	
Products	SRC solids	980 tons/calendar day
	Coke	590 "
	Naphtha	730 "
	Medium oil	730 "
	Heavy oil	160 "
Byproducts	Sulfur	190 tons/calendar day

a/One of five modules in a commercial plant.
b/See table 14.
c/We are using the initial cost, Phase O Document, and additional costs of LC fining and hydrotreating because detailed breakdowns of the latest estimate (about $1.6 billion) were not available. See Air Products/Wheelabrator-Frye, Solvent Refined Coal-I Refinery, DE-AC05-78-ORO-3054 (Washington, D.C.: U.S. Department of Energy, July 31, 1979).
d/In 1977 dollars.
e/Additional cost of hydrotreating to upgrade liquid products, in 1977 dollars.
f/Additional cost of LC fining to liquefy portion of SRC solids, in 1980 dollars.

Table 12

SRC-I Demonstration Plant Capital Cost Summary
(in 1977 Dollars)

		Included in energy costing
Material subcontracts		
Process equipment (direct material and subcontracts)	$145,700	$145,700
Bulk materials	75,500	75,500
Subcontracts (bulk materials)	48,300	48,300
All risk insurance, legal liability, etc.	1,300	
Sales tax	700	
Total	$271,500	$269,500
Field labor		
Field labor (including fringes)	$ 74,800	
Payroll burden	12,500	
Total	$ 87,300	
Other field charges		
Supervision, office personnel, office expense, planning	$ 15,700	
Construction equipment and tools	10,500	$ 10,500
Total	$ 26,200	$ 10,500
Home office expenses		
Mechanical engineering		
Price engineering		
Estimating, planning, and cost analysis		
Purchasing, expediting, and shop inspection		
Accounting, industry relations, general administration, and construction management		
Total	$ 38,500	
Other	$ 63,500	
Total	$487,000	$280,000

Table 13

SRC-I Demonstration Plant Estimate Subsummary
(in 1977 Dollars)

Fired heaters and boilers	$ 17,000	$ 5,500
Stacks	700	
Reactors and internals	9,300	100
Towers and internals	4,200	1,500
Heat exchanger equipment	13,200	
Cooling towers	300	700
Vessels, tanks, drums, and internals	4,700	1,500
Pumps and drivers	14,100	
Blowers and compressors	12,500	
Elevators, conveyors, materials handling equipment	13,600	1,300
Miscellaneous mechanical equipment	5,500	800
Tankage	2,200	5,700
Filters, centrifuges, separation equipment	14,300	600
Agitators and mixers	1,100	
Scrubbers and entrainment separators		200
Machine tools and machine shop equipment		
Heating, ventilating, air conditioning duct	100	300
Control (process only)		
Package units	10,300	600
Freight	3,800	
Total	$126,900	$18,800
Piping	$ 36,000	$ 3,200
Sewers		600
Instrumentation	11,600	
Electrical	6,400	8,300
Concrete	5,100	100
Structural steel	7,700	4,500
Fireproofing		100
Buildings	1,500	4,500
Site development	700	11,900
Insulation		10,100
Painting and protective coatings		3,900
Field testing		
Chemicals and catalyst		
Piling		1,100
Total	$195,900	$67,100
Miscellaneous direct charges		
Storehouse accounts		
Construction supplies and petty tools	$ 3,600	
Testing welders		
Temporary piping and electrical facilities		
Temporary construction buildings	2,900	
Temporary site development		
	=======	======
Total direct costs = $269,500	$202,400 +	$67,100

Table 14

SRC-I Demonstration Plant Preliminary Baseline Chemical and Catalyst Consumption (December 1980 Prices Obtained March 1981 and Revised June 1981)

Chemical/catalyst	Initial charge	Consumption: Quantity	Consumption: Annual cost
Parsons			
Shift catalyst $260/cu ft	5,500 cu ft	2,200 cu ft/yr	$572,000.00
Claus catalyst $20/cu ft	4,603 cu ft	2,302 cu ft/yr	46,040.00
BSRP catalyst $91/cu ft	850 cu ft	425 cu ft/yr	38,675.00
Selexol 8.64 lb/gal @ $1.25/lb	183,000 gal	141 lb/day	58,162.50
DEA (100%) 9.14 lb/gal @ $0.535/lb	4,000 gal	159 lb/day	28,071.45
NaOH (50%) 8.5 lb/gal @ $230/ton	17,300 gal	826 lb/hr	752,320.80
Carbon $48/cu ft	50 cu ft	27 cu ft/yr	1,296.00
Diatomaceous earth $206/ton	200 lb	110 lb/month	135.96
R-12 refrigerant $0.48/lb	118,000 lb	18 lb/day	2,851.20
Absorption oil $0.80/gal	10,360 gal	38 gal/day	10,032.00
ADA $7.90/lb	7,090 lb	71 lb/day	185,097.00
Vanadium $7/lb	14,193 lb	103 lb/day	237,930.00
Na_2CO_3 $112/ton	53,250 lb	3,990 lb/day	73,735.20
Catalytic			
Critical solvent $1.40/gal	10,000 bbl	4 gal/min	2,661,120.00
Creosote oil $1/gal	80,000 bbl	--	
Lummus			
Antifoam agent $1.82/lb	--	14 lb/day	8,408.40
Soda ash $112/ton	--	95 lb/hr	42,134.40
LC-fining catalyst $3.75/lb initial, $3.25/lb consumption	528,000 lb	3,700 lb/day	3,968,250.00

APPENDIX II

(Table 14 continued)

Chemical/catalyst	Initial charge	Consumption Quantity	Consumption Annual cost
APCI			
ASU $2.42/hp/yr	--	40,000 hp	$ 96,800.00
Absorbent $0.72/lb	22,200 lb	11,100 lb/yr	7,992.00
Oil $0.67/gal	4,000 gal	10 gal/day	2,211.00
Rust			
Wetting agent $216/55-gal drum	1,400 gal	60 gal/day	77,760.00
Chlorine $145/ton	9 ton	390 lb/day	9,330.75
Polyelectrolyte $0.24/lb	2,500 lb	36 lb/day	2,851.20
Alum 8.5 lb/gal @ $0.16/lb	10,000 gal	2,500 lb/day	132,000.00
Caustic soda (50%) 8.5 lb/gal @ $230/ton	8,000 gal	20 gal/day	6,451.50
Tri-Na phosphate $48.25/100 lb	1,500 lb	45 lb/day	7,165.13
Di-Na phosphate $39/100 lb	1,500 lb	45 lb/day	5,791.50
Rock salt $32.60/ton	20 ton	2,895 lb/day	15,572.20
Na-hexameta-phosphate $2.42/lb	100 lb	1 lb/day	798.60
Hydrazine 8.4 lb/gal $2.50/lb	450 gal	10 lb/day	8,250.00
Sulfuric acid 131 gal/ton 95% concentrate @ $89/ton	4,000 gal	10 gal/day	2,241.98
Phosphoric acid $0.29/lb	2,000 gal	450 lb/day	43,065.00
Hydrogen peroxide 9.28 lb/gal @ $0.35/lb (interm)	300 gal	10 gal/hr	257,241.60
Manganous sulfate 10 lb/gal @ $110/ton (interm)	275 lb	10 gal/hr	43,560.00
Powdered activated carbon $0.58/lb (interm)	30,000 lb		
Ferrous sulfate polymer 1.0 lb/gal @ $0.03/lb (interm)	3,000 lb	5 gal/hr	1,188.00
Dowtherm A8.34 lb/gal @ $1.03/lb	70,000 gal	12,000 gal/yr	103,082.40
Total			$\$9.508612 \times 10^6$

APPENDIX II

Table 15

SRC-II Demonstration Plant Characteristics a/

Location	10 miles north of Morgantown, West Virginia		
Life	20 years		
Operating factor	90% (329 stream days/yr)		
Feedstock	Pittsburgh seam coal from northern West Virginia 6,700 tons of coal/stream day		
Transportation	Rail (35 cars/hr, 1 shift/day, 5 days/week)		
Annual operating cost b/	Electricity	27,900	kw
	Catalysts and chemicals	$3.29	M
	Maintenance materials	$11.38	M
Capital cost c/	$784.925 M		
Products	Pipeline gas	45	M cu ft/calendar day
	Propane	2,300	bbl/calendar day
	Butane	1,600	"
	Fuel oil	11,500	"
Byproducts	Sulfur	160	tons/calendar day
	Ammonia	30	"
	Tar acids (phenols)	7	"

a/One of five modules in a commercial plant.
b/In 1978 dollars.
c/In 1978 dollars. We are using the initial cost, Phase O Document, because detailed breakdowns of the latest estimate (about $1.4 billion) were not available. See Pittsburg and Midway Coal Mining Co., SRC-II Demonstration Project, Phase Zero, DE-AC05-780R0-3055 (Washington, D.C.: U.S. Department of Energy, July 31, 1979).

Table 16

SRC-II Demonstration Plant Direct Capital Cost
Breakdown by Cost Element
(in Millions of Dollars)

	Nov. 1978 $	Dec. 1977 $
Engineering		
Prime contractor	$ 66.500	$ 61.166
Subcontractors	11.000	10.118
Total	$ 77.500	$ 71.284
Equipment and materials		
Shop-fabricated equipment	$159.390	$146.606
Field-erected equipment	29.960	27.557
Construction materials	136.000	125.092
Battery limits units	54.650	50.267
Total	$380.000	$349.522
Construction		
Direct field labor	$ 90.800	$ 83.517 a/
Indirect field costs	100.200	92.163 b/
Installation subcontracts	84.439	79.506
Battery limits unit	15.061	13.853
Total	$292.500	$269.039
Total	$750.000	$689.845

a/Excluded from estimation of embodied energy of capital.
b/Indirect capital costs $34.925 million excluded except for $6.5 million initial catalyst and chemical load.

Table 17

EDS Commercial Plant Characteristics

Location	Western Illinois
Life	30-31 years
Operating factor	86.8% (317 stream days/yr)
Feedstock	Illinois No. 6 coal (25,000 tons/stream day to process 778 tons/stream day to offsite)
Transportation	Conveyor belt, one 0.5 mile and two 6.0 miles each
Annual operating cost	Electricity 223,000 kw Catalysts and chemicals $12 million a/ 6 " b/ Maintenance materials none estimated
Capital cost	$4.78 billion c/
Products	LPG (C3) 2,900 bbl/stream day LPG (C4) 2,500 " Naphtha (C5/350° F) 23,500 " Fuel oil (C5+) 37,000 "
Byproducts	Phenols 65 tons/stream day Sulfur 1,030 " Ammonia 205 "

a/Third quarter 1978 dollars escalated at 6 percent per year to first quarter 1985.
b/First quarter 1985 dollars.
c/Third quarter 1987 to third quarter 1988. Mechanical completion of first module in third quarter 1987 and of second module in third quarter 1988.

Table 18

EDS Commercial Plant Investment Summary
(in Millions of Dollars)

	Material	Labor	Subcontracts	Total
Direct costs				
Onsite	$598	$187	$233	$1,018
Offsite	168	113	240	521
Total	$766	$300	$473	$1,539
Indirect costs				
Field labor overhead				$ 332 a/
Burden				177 a/
Contractor's engineering				104
Engineering and erection fee				59
Loss on surplus, insurance, and vendor representatives				23
Total project cost				$2,234
Other costs				
ER&E charges				$ 60 a/
Escalation b/				1,295 a/
Project contingency (25%)				898 a/
Process development allowance (8.1%)				293
Total				
Total erected cost c/				$4,780

a/Excluded from energy costing of capital.
b/Mechanical completion fourth quarter 1978 to third quarter 1988.
c/Implies mechanical completion of second module will occur in the third quarter of 1988; mechanical completion of the first module is to be in the third quarter of 1987.

PROCESS ENERGY INPUTS AND OUTPUTS

Table 19 provides a summary of the H-Coal facility's annual energy inputs and outputs. Production volumes for the various items on the plant's product slate are presented in barrels per year or millions of standard cubic feet per year. The combustion energy values for each product are used to calculate a total energy value equivalent for each product.

Coal

Annual coal consumption in the H-Coal plant is 11.613 x 10^6 pounds per year. Given that each pound of this coal contains 11,200 Btu's, the heat of content of the coal consumed annually is 130.066 x 10^{12} Btu's per year.

Mining

The coal-mining energy intensity factors derived from ERG's I-O data indicate that mining a single Btu of coal energy requires 0.0102 Btu's of premium fuel and 0.0225 Btu's of total energy. Multiplying these mining-energy intensity factors by the coal heat content given above yields 1.327 x 10^{12} Btu's of embodied premium fuel energy and 2.926 x 10^{12} Btu's of embodied total energy for coal mining.

Table 19

H-Coal Plant Energy Output and Input Summary

	Production volume (10^6 bbl/yr)	Energy conversion factor (10^6 Btu/bbl)	Embodied energy value (10^{12} Btu/yr) Premium fuel	Total
Output				
Propane	2.044	3.836	7.841	7.841
Mixed butane	1.351	4.326	5.844	5.844
Light naphtha	1.314	5.248	6.896	6.896
Reformate	3.760	5.253	19.751	19.751
Distillate	8.505	5.825	49.542	49.542
Pipeline gas	7.3x10^9 a/	1,021 b/	+ 7.453	+ 7.453
Total			97.327	97.327
Input				
Electricity			8.656	22.564
Catalysts and chemicals			3.948	4.814
Maintenance materials			0.254	0.318
Capital			1.616	2.398

a/Standard cubic feet per year.
b/Btu's per cubic foot.

For simplicity, we use this format to indicate a commodity's premium fuels energy intensity and its total energy intensity. We use two types of energy intensity factor. One indicates how many Btu's of premium fuel and total energy inputs are required to produce a single Btu of output energy (Btu input/Btu output); it is the type of energy intensity factor used in the mining analysis. The other indicates how many Btu's of energy are associated with the sale of one dollar's worth of a commodity from Industry A to Industry B (Btu input/$); it is the type of energy intensity factor used in the catalysts and chemicals analysis.

Electricity

Electricity requirements are given as 229,623 kw. Given a 24-hour day and 318 days of operation per year, the total annual electricity requirement is 1752.48 x 10^6 kwh/year. Applying the electricity energy conversion factor of 3,413 Btu/kwh and the electricity energy intensity factors (1.447; 3.772) yields the following:

Annual consumption volume	1752.48 x 10^6 kwh/yr
Energy conversion factor	3,413 Btu/bbl
Energy intensity factor	
Premium fuel	1.4472 Btu/Btu
Total energy	3.7724 Btu/Btu
Embodied energy value	
Premium fuel	8.656 x 10^{12} Btu/yr
Total energy	22.564 x 10^{12} Btu/yr

Catalysts and chemicals

The expenditure for catalysts and chemicals is given as $50.852 x 10^6 per year in 1981 dollars, or $45.40 x 10^6 in 1980 dollars when deflated, using a 12 percent deflator. We treat catalysts and chemicals as if they reside in I-O sector 27.01 (industrial chemicals) and are sold to sector 31.01 (petroleum refining). The appropriate intensities are 86,962 Btu; 106,047 Btu per 1980 dollar. Multiplying expenditures by these intensities yields 3.948 x 10^{12} Btu/year for premium fuel energy and 4.814 x 10^{12} Btu/year for total energy.

Maintenance materials

The yearly maintenance materials cost of the H-Coal plant is given as $13.08 x 10^6 in 1981 dollars, which is deflated to $11.68 x 10^6 in 1980 dollars using a 12 percent deflation factor. We assume that the energy intensity of annual maintenance materials is that of I-O sector 12.02 (maintenance and repair construction) as sold to I-O sector 31.01 (petroleum refining). The appropriate intensities are 21,794 Btu; 27,187 Btu per 1980 dollar and, when multiplied by the annual expenditures, yield 0.254 x 10^{12} Btu/year for premium fuels energy and 0.318 x 10^{12} Btu/year for total energy. Table 20 summarizes these data for maintenance materials and also for catalysts and chemicals.

Table 20

Coal Embodied Energy of Plant Operations Expenditures

	Annual expenditures (1980$)	Energy intensity factor (Btu/$) Premium fuel	Total	Embodied energy value (10^{12} Btu/yr) Premium fuel	Total
Catalysts and chemicals	45.40×10^6	86,962	106,047	3.948	4.814
Maintenance materials	11.68×10^6	21,794	27,187	0.254	0.318

Capital

The total capital construction costs for the H-Coal facility are $\$2.082 \times 10^9$ in 1981 dollars, which is deflated to $\$1.859 \times 10^9$ in 1980 dollars, using a 12 percent deflator. We assume that the energy intensity of this capital expenditure is that of I-O sector 11.03 (new construction, public utilities) as sold to sector 31.01 (petroleum refining). Multiplying the appropriate energy intensities 16,350 Btu; 24,538 Btu per 1980 dollar by the capital cost yields 30.395×10^{12} Btu/year for premium fuels energy and 45.616×10^{12} Btu/year for total energy.

The initial catalyst and chemical load to the plant should also be costed as a capital item. The cost of $\$24.806 \times 10^6$ in

Table 21

H-Coal Annualized Embodied Energy of Capital Construction Costs

	Capital cost	Energy intensity factor (Btu/1980$) Premium fuel	Total	Embodied energy value (10^{12} Btu/yr) Premium fuel	Total
Construction	1.859×10^9	16,350	24,538	30.395	45.616
Initial catalysts, chemicals	22.148×10^6	86,962	106,047	+1.926	+2.349
Total				32.321	47.965
				(divided by 20)	
Annualized energy				1.616	2.398

1981 dollars, when deflated by 12 percent, is 22.148×10^6 in 1980 dollars. The appropriate energy intensities are 86,962 Btu; 106,047 Btu per 1980 dollar and represent the energy flows associated with sales from I-O sector 27.0 (inorganic and organic chemicals) to sector 31.01 (petroleum refining). Multiplying the catalyst and chemical cost by these intensities gives 1.926×10^{12} Btu's for premium fuels energy and 2.349×10^{12} Btu's for total energy. The embodied energy values for the H-Coal plant and its initial chemicals load must be divided by 20 years to find the annual capital embodied energy value.

Table 22

SRC-I Demonstration Plant Energy Output and Input Summary

	Production volume (10^6 bbl/yr) a/	Energy conversion factor (10^6 Btu/bbl) b/	Embodied energy value (10^{12} Btu/yr) Premium fuel	Embodied energy value (10^{12} Btu/yr) Total
Output				
SRC solid	715.4 a/	15,000 b/	--	11.303
Light oil (naphtha)	1.929	5.248	10.123	10.123
Medium oil	1.526	6.287	9.594	9.594
Heavy oil	0.316	6.287	1.987	1.987
Total			21.704	33.007
10% reduction c/			2.170	3.300
Total			19.534	29.707
Input				
Electricity			2.867	7.473
Catalysts and chemicals			0.827	1.008
Maintenance materials			0.247	0.308
Capital			0.828	1.144

a/SRC solid measured as 10^6 lb/yr.
b/SRC solid measured as Btu/lb.
c/Estimated by SRC-I contractor to be the change in the product slate resulting from internal energy consumption to upgrade the naphtha cut.

Table 23

SRC-I Embodied Energy of Annual Coal and Electricity Consumption a/

	Annual consumption	Energy conversion factor	Energy intensity factor (Btu/Btu) Fuel	Energy intensity factor (Btu/Btu) Total	Embodied energy value (10^{12} Btu/yr) Fuel	Embodied energy value (10^{12} Btu/yr) Total
Coal feedstock	3696.0×10^6 lb	12,750 Btu/lb	--	--	--	47.124
Coal mining	b/		0.0102	0.0225	0.481	1.060
Electricity	580.38×10^6 kwh/yr	3,413	1.4472	3.7724	2.867	7.473

a/Fuel is premium fuel.
b/Heat of content of coal, or 47.124×10^{12} Btu/yr.

Table 24

SRC-I Embodied Energy of Annual Plant Operations Expenditures a/

	Annual expenditures	Energy intensity factor (Btu/$) Fuel	Energy intensity factor (Btu/$) Total	Embodied energy value (10^{12} Btu/yr) Fuel	Embodied energy value (10^{12} Btu/yr) Total
Catalysts and chemicals	$\$9.51 \times 10^6$ b/	86,962	106,047	0.827	1.008
Maintenance materials c/	$\$9.51 \times 10^6$ d/	25,924	32,340	0.247	0.308

a/Fuel is premium fuel.
b/In 1980 dollars.
c/Based on SRC-II maintenance materials expenditure as rescaled to reflect 5,000 tons per day SRC-I rather than 6,700 tons per day SRC-II.
d/In 1978 dollars.

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In table 25, we have to make the following estimates to derive energy intensity factors for calculating the embodied energy value for the SRC-I two-stage liquefaction TSL facility, whose capital equipment, materials, and subcontract costs are insufficiently defined to allow their placement into appropriate I-O sectors. We calculate the average energy intensity for plant construction items (from table 26) by dividing the value for premium fuel embodied energy by the total cost of construction capital--that is, 6.260 x 10^{12} Btu's divided by 280.0 x 10^6 in 1977 dollars yields 22,357 Btu's per dollar. Dividing the value for total embodied energy of plant construction (from table 26) by the total cost of construction capital yields an average for the total energy intensity--that is, 9.667 x 10^{12} Btu's divided by 280.0 x 10^6 in 1977 dollars yields 34,525 Btu's per dollar.

Table 25

SRC-I Annualized Embodied Energy of Capital Construction Costs a/

	Capital cost (1977$)	Energy intensity factor (Btu/$)		Embodied energy value (10^{12} Btu/yr)	
		Fuel	Total	Fuel	Total
Plant construction b/	280.00x10^6	c/		6.260	9.667
Hydrotreater d/	39.31x10^6	e/		0.869	1.345
Initial catalyst and chemicals	63.50x10^6	131,256	160,061	8.335	10.164
TSL f/	49.11x10^6	22,357	34,525	1.098	1.696
Total				16.562	22.872
				(divided by 20)	
Annualized total				0.828	1.144

a/Fuel is premium fuel.
b/See table 23.
c/See table 26.
d/See table 24.
e/See table 27.
f/The TSL cost is specified as \$69.0 x 10^6 in 1980. Using a 12% deflator yields \$49.11 x 10^6 in 1977 dollars.

Table 26

SRC-I Detailed Energy Analysis of Plant Construction Costs a/

	Total capital costs ($x10^6$ 1977$)	Energy intensity factor (Btu/$)		Embodied energy value (10^{12} Btu/yr)	
		Fuel	Total	Fuel	Total
Concrete	5.193	48,503	71,735	0.252	0.372
Heating equipment	17.309	23,187	33,582	0.401	0.581
Fabrication					
Stressed steel	7.840	27,423	53,717	0.215	0.421
Plate work	35.229	24,115	45,584	0.850	1.606
Miscellaneous metal work	4.480	30,376	59,418	0.136	0.266
Pipes and valves	36.654	23,632	31,585	0.866	1.158
Construction machinery	26.371	18,285	26,072	0.482	0.688
Power handtools	3.665	16,570	28,632	0.061	0.105
Pumps and compressors	14.356	18,070	25,508	0.259	0.366
Blowers and fans	12.727	20,161	30,094	0.256	0.383
Refrigerating and heating	0.102	22,503	35,577	0.002	0.004
Mechanical measuring devices	11.811	16,776	24,110	0.198	0.285
General industrial machinery	25.047	20,145	28,925	0.504	0.724
Electrical equipment	6.516	21,267	34,163	0.138	0.223
Miscellaneous machinery	+ 5.600	17,220	29,896	+ 0.096	+ 0.167
Nonsubcontract capital	212.900			4.716	7.349
Subcontracts	+ 67.100	23,018	34,545	+ 1.544	+ 2.318
Total	280.000			6.260	9.667

a/Fuel is premium fuel.

Table 27

SRC-I Detailed Energy Analysis of Hydrotreater Costs a/

	Total cost ($x10^6$ 1977$)	Energy intensity factor (Btu/$)		Embodied energy value (10^{12} Btu/yr)	
		Fuel	Total	Fuel	Total
Process equipment	19.406	22,151	34,519	0.430	0.670
Materials	14.313	22,151	34,519	0.317	0.494
Construction equipment	1.380	18,285	26,072	0.025	0.036
Subcontracts	4.210	23,018	34,545	0.097	0.145
Total				0.869	1.345

a/Fuel is premium fuel.

In table 27, the following estimates are necessary for deriving energy intensity factors for calculating the embodied energy value for the SRC-I hydrotreater. This is because its process equipment and materials costs are insufficiently defined to allow their placement into appropriate I-O sectors. The average premium fuel energy intensity of nonsubcontracted construction items (from table 26) is calculated by dividing

Table 28

SRC-II Demonstration Plant Output and Input Summary

	Production volume (10^6 bbl/yr) a/	Energy conversion factor (10^6 Btu/bbl) b/	Embodied energy value (10^{12} Btu/yr)	
			Premium fuel	Total
Output				
Propane	0.840	3.836	3.222	3.222
Butane	0.584	4.326	2.526	2.526
Fuel oil	4.198	6.287	26.393	26.393
Pipeline gas	16,425 a/	1,021 b/	16.770	16.770
Total			48.911	48.911
Input				
Electricity			1.088	2.836
Catalysts and chemicals			0.408	0.498
Maintenance materials			0.295	0.368
Capital			0.617	0.937

a/Pipeline gas measured as 10^6 scf/yr.
b/Pipeline gas measured as Btu/scf.

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Table 29

SRC-II Embodied Energy of Annual Coal and Electricity Consumption a/

	Annual consumption	Energy conversion factor	Energy intensity factor (Btu/Btu) Fuel	Energy intensity factor (Btu/Btu) Total	Embodied energy value (10^{12} Btu/yr) Fuel	Embodied energy value (10^{12} Btu/yr) Total
Coal feedstock	4408.6×10^6 lb	13,392 Btu/lb	--	--	--	59.04
Coal mining	b/		0.0102	0.0225	0.602	1.328
Electricity	220.3×10^6 kwh/yr	3,413 Btu/kwh	1.4472	3.7724	1.088	2.836

a/Fuel is premium fuel.
b/Heat of content of coal, or 59.04×10^{12} Btu/yr.

Table 30

SRC-II Embodied Energy of Annual Plant Operations Expenditures a/

	Annual expenditures (1978$)	Energy intensity factor (Btu/$) Fuel	Energy intensity factor (Btu/$) Total	Embodied energy value (10^{12} Btu/yr) Fuel	Embodied energy value (10^{12} Btu/yr) Total
Catalysts and chemicals	$ 3.29×10^6	124,190	151,445	0.408	0.498
Maintenance materials	11.38×10^6	25,924	32,340	0.295	0.368

a/Fuel is premium fuel.

the total cost of nonsubcontracted construction items--that is, 4.716 x 10^{12} Btu's divided by 212.9 x 10^6 in 1977 dollars yields 22,151 Btu's per dollar. Dividing the value for total embodied energy by the total cost of nonsubcontracted items yields an average for total energy intensity--that is, dividing 7.349 x 10^{12} Btu's by 212.9 x 10^6 in 1977 dollars yields 34,519 Btu's per dollar.

The SRC-II capital equipment and materials costs are insufficiently defined to allow their placement into appropriate I-O sectors as was done for SRC-I capital equipment and materials in table 26. Therefore, we use estimated energy intensity factors based on SRC-I hydrotreater capital equipment and materials costs for calculating the embodied energy value for SRC-II capital equipment and materials. The estimated intensities are 22,151 Btu's per dollar (in 1977 dollars) for premium fuels and 34,519 Btu's per dollar (in 1977 dollars) for total energy. (See the discussion at table 27 for a description of the estimation procedure for these energy intensity factors.)

Table 31

SRC-II Annualized Embodied Energy of Capital Construction Costs a/

	Capital cost b/	Energy intensity factor (Btu/$) Fuel	Total	Embodied energy value (10^{12} Btu/yr) Fuel	Total
Engineering, construction	$164.64x10^6$	23,018	34,545	3.790	5.687
Equipment, materials	$349.52x10^6$	22,151	34,519	7.742	12.065
Initial catalysts and chemicals	$6.50x10^6$	124,190	151,445	0.807	0.984
Total				12.339	18.736
				(divided by 20)	
Annualized total				0.617	0.937

a/Fuel is premium fuel.

b/Initial catalysts and chemicals in 1978 dollars; all the rest in 1977 dollars.

Table 32

EDS Plant Energy Output and Input Summary

	Production volume (10^6 bbl/yr)	Energy conversion factor (10^6 Btu/bbl)	Embodied energy value (10^{12} Btu/yr) Premium fuel	Total
Output				
LPG-C3	0.919	3.836	3.525	3.525
LPG-C4	0.792	3.836	3.038	3.038
Naphtha	7.450	5.248	39.098	39.098
Fuel oil	11.729	6.287	73.740	73.740
Total a/			119.401	119.401
Input				
Electricity			8.380	21.844
Catalysts and chemicals			1.986	2.422
Maintenance materials			0.427	0.533
Capital			0.904	1.385

a/Byproduct credits not included.

The EDS materials costs are insufficiently defined to allow their placement into appropriate I-O sectors as was done for SRC-I capital equipment and materials in table 26. Therefore, we use estimated energy intensity factors based on SRC-I hydrotreater capital equipment and materials costs for calculating the embodied energy value for EDS capital construction materials. The estimated intensities are 22,151 Btu's per 1977 dollar for

Table 33

EDS Annualized Embodied Energy of Capital Construction Costs a/

	Capital cost	Energy intensity factor (Btu/$) Fuel	Total	Embodied energy value (10^{12} Btu/yr) Fuel	Total
Materials	666.1×10^6 b/	22,151	34,519	14.755	22.993
Subcontracts	636.0×10^6 c/	19,449	29,189	12.370	18.564
Total				27.125	41.557
				(divided by 30)	
Annualized total				0.904	1.385

a/Fuel is premium fuel.
b/$766 x 10^6 in 1978 dollars deflated to $666.1 x 10^6 in 1977 dollars using a 15 percent deflator.
c/In 1978 dollars.

Table 34

EDS Embodied Energy of Annual Coal and Electricity Consumption a/

	Annual consumption	Energy conversion factor	Energy intensity factor (Btu/Btu)		Embodied energy value (10^{12} Btu/yr)	
			Fuel	Total	Fuel	Total
Coal feedstock	$16,343.25 \times 10^6$ lb	12,663 Btu/lb	--	--	--	206.954
Coal mining	b/		0.0102	0.0225	2.111	4.656
Electricity	1696.58×10^6 kwh/yr	3,413 Btu/kwh	1.4472	3.7724	8.380	21.844

a/Fuel is premium fuel.
b/Heat of content of coal, or 206.954×10^{12} Btu/yr.

Table 35

EDS Embodied Energy of Annual Plant Operations Expenditures a/

	Annual expenditures	Energy intensity factor (Btu/$)		Embodied energy value (10^{12} Btu/yr)	
		Fuel	Total	Fuel	Total
Catalysts and chemicals	$\$15.99 \times 10^6$ b/	124,190	151,445	1.986	2.422
Maintenance materials	16.49×10^6 c/	25,924	32,340	0.427	0.533

a/Fuel is premium fuel.
b/In 1978 dollars; includes $12 million in 1978 dollars and $6 million in 1985 dollars deflated to $3.99 million in 1978 dollars using an EDS-supplied percentage deflater.
c/In 1980 dollars; estimated by adjusting the H-Coal maintenance materials expense of $11.68 million (in 1980 dollars) to reflect the higher coal tonnage that EDS processes. We divided EDS daily coal tonnage, or 25,778 tons, by H-Coal daily coal tonnage, or 18,259 tons, which gave 1.412; we multiplied this by the H-Coal estimate, which gave $16.49 million (in 1980 dollars).

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premium fuels and 34,519 Btu's per 1977 dollar for total energy. (See table 27 for a description of the estimation procedure for these energy intensity factors.) Table 33 summarizes the EDS annualized costs for embodied energy of capital construction, while tables 34 and 35 show the EDS embodied energy of consumption and operations expenditures.

DISPLACEMENT ANALYSIS

Beyond a one-for-one displacement for equal amounts of petroleum-based refinery products, liquefaction-based products provide an additional energy bonus in terms of the energy savings in not having to refine crude petroleum to end products equal to those of the liquefaction process.

We begin by adjusting the total energy requirements for petroleum refining as given by Oak Ridge National Laboratory--707.0 x 10^3 Btu's per barrel of feed to the process to 675.0 x 10^3 Btu's per barrel. 1/ (Oak Ridge, 1976, p. 135) Table 36 presents the Oak Ridge estimates and the adjusted estimates.

We assume that coal is the energy source for purchased steam. Applying an 80 percent combustion efficiency factor to the steam input requirements, we can estimate the Btu's of coal that are required as follows:

$$\frac{47.6\text{x}10^{2}\text{ Btu steam required}}{0.80\text{ coal combustion efficiency factor}} = 59.5\text{x}10^{12}\text{ Btu coal required}$$

The 59.5 x 10^{12} Btu's of coal required for steam production are added to the 5.2 x 10^{12} Btu's of coal required as a refining input, yielding 64.7 x 10^{12} Btu's of total coal energy required.

We reestimate the embodied energy of electricity because Oak Ridge assumes that 10,000 Btu's are required to generate a kilowatt hour and we assume that 3,413 Btu's are required. The Oak Ridge estimate of 231 x 10^{12} Btu's of electricity required in refining implies that 231 x 10^8 kilowatt hours are required, using the Oak Ridge conversion factor of 10,000 Btu's per kilowatt hour. Multiplying 231 x 10^8 by our factor of 3,413 Btu's per kilowatt hour yields 78.84 x 10^{12} Btu's of electrical energy.

We apply the relevant energy intensity factors as derived from the Energy Research group's I-O model to estimate the premium fuel and total embodied energy for each refining input. Having calculated the overall embodied energy value of refinery in terms of premium fuel (708.0 x 10^3 Btu/bbl) and total energy

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1/This estimate of energy consumed by U.S. refineries is similar to the U.S. average of 650 to 700 x 10^3 Btu's per barrel reported by the Bureau of Mines and about the same as values reported for the U.S. districts with the lowest consumption.

Table 36

Energy Consumed in Petroleum Refining in 1974 a/

Energy source	Total energy input (10^{12} Btu/yr)		Energy intensity factor (Btu/Btu)		Embodied energy value (10^{12} Btu/yr)	
	Initial	Adjusted	Fuel	Total	Fuel	Total
Fuel oil	316.3	316.3	1.0641	1.1513	336.575	364.156
Gas						
LPG	39.5	39.5	1.0641	1.1513	42.032	45.476
Refinery b/	1043.1	1043.1	1.0558	1.0604	1101.305	1106.103
Natural	1072.3	1072.3	1.0667	1.1503	1143.822	1233.467
Coke b/	374.0	374.0	1.0558	1.0604	394.869	396.590
Coal	5.2	64.7	0.0102	1.0225	0.660	66.156
Electricity purchased	231.0	78.8	1.4472	3.7724	114.039	297.265
Steam purchased	47.6	--	--	--	--	--
Total	3129.0	2988.7			3133.302	3509.213
c/	707	675			708	793

a/Fuel is premium fuel.

b/Refinery gas and coke are derived from the petroleum feedstocks. Therefore, the appropriate energy intensity factor for crediting these energy sources is crude petroleum, which measures the energy required for extracting crude petroleum products.

c/10^3 Btu/bbl; assumes 4,425.743 x 10^6 barrels produced in 1974.

APPENDIX II

Table 37

Coal Liquefaction Refining Energy Credit a/

	% refining energy not required	Embodied energy value of refining energy savings (10^3 Btu/bbl)		Product (10^6 bbl/yr)	Embodied energy value of refining energy savings (10^{12} Btu/yr)	
		Fuel	Total		Fuel	Total
H-Coal	67.4	477.2	534.5	16.974	8.100	9.073
SRC-I	65.5	463.7	519.4	3.771	1.749	1.959
EDS	57.0	403.6	452.0	20.890	8.431	9.442
SRC-II	36.4	257.7	288.6	5.622	1.449	1.622

a/Fuel is premium fuel.

(793.0×10^3 Btu/bbl), we have to make an additional step to determine the appropriate refinery energy savings credit for each liquefaction process. We estimate this percentage by comparing the refining and upgrading steps performed in each of the liquefaction processes with the percentage of the refinery energy consumption, as given by Oak Ridge, in equal or similar refinery steps. (Oak Ridge, 1976, p. 17, fig. 2a) The first column in table 37 shows the percentages of refinery energy not required. Multiplying the percentages by the overall embodied energy values and by the annual barrels of product of each process gives the annual embodied energy values of refinery energy savings.

It must be noted that these refinery energy savings do not take into consideration the possible savings associated with any reductions in refinery construction resulting from a large coal liquefaction industry. Because of a lack of available data, we have excluded also the savings possible by assuming that a portion of petroleum-based naphtha cuts will be blended with higher-octane coal-based naphthas, which reduces the amount of octane upgrading that is required.

The embodied energy of coal liquefaction byproducts, ethanol, and the anode coke product of SRC-I cannot be determined in terms of their combustion energy inasmuch as they are not direct energy sources. Instead, they are treated in a way that is similar to the refinery energy savings calculation. That is, a displacement energy credit is obtained by estimating the energy savings in not having to produce equal amounts of the given byproduct by conventional means. In the rest of this appendix, we describe how each of these displacement energy credits is estimated for ammonia, sulfur, phenols, and anode coke.

Table 38

Ammonia Displacement Energy Credit (10^{12} Btu/yr)

	EDS	H-Coal	SRC-II
Annual ammonia production (10^3 tons/yr)	64.99	62.05	10.950
Embodied energy value			
Premium fuel	2.516	2.402	0.424
Total energy	3.137	2.995	0.528

Ammonia

To estimate the displacement energy credit for ammonia byproducts, we refer to estimates of the energy required to produce ammonia used as a fixed nitrogen fertilizer, a major industrial use of ammonia. Dovring and McDowell have estimated that the total energy required to produce ammonia is 29,300 Btu's per pound of nitrogen. (Dovring and McDowell, Energy, 1980) They express the energy requirements of ammonia in terms of nitrogen, since nitrogen is the desired component of ammonia fertilizer.

To convert this embodied energy value to pounds of ammonia (NH_3), we note that the atomic weights of nitrogen and hydrogen are 14 and 1, respectively. Since the total atomic weight of ammonia is 17, we have to apply an adjustment factor of 14/17 (nitrogen's atomic weight divided by ammonia's atomic weight) to the initial embodied energy value to find an embodied energy of ammonia, which is 24,130 Btu's per pound of ammonia.

Next, we estimate the premium fuels energy component of ammonia. Referring to the ERG energy intensity tables for fertilizers, we form a ratio of premium fuels energy to total energy to find an adjustment factor--236,036/294,156 = .8024. This is then multiplied by the embodied energy value of ammonia, yielding the total embodied energy of ammonia as 24,130 Btu/lb, or 48.26 x 10^6 Btu/ton, and the premium fuels embodied energy of ammonia as 19,362 Btu/lb, or 38.72 x 10^6 Btu/ton. Table 38 presents the total annual production volume of byproduct ammonia from the three coal liquefaction plants and the embodied energy value of the energy credit that they should receive.

Sulfur

Sulfur is produced by mining operations and by gas reclamation; sulfur is also extracted from pollution streams in order to meet pollution guidelines. The total energy required to produce sulfur by mining is 7 x 10^6 Btu/ton. For reclamation, the energy is approximately 1 x 10^6 Btu/ton. (See Sulfur Institute and Davis, cited in Dovring and McDowell, Energy, 1980.)

Table 39

Embodied Energy Values for Sulfur

Production system	Embodied energy value (10^6 Btu/ton) Fuel	Total	Weighting factor (%)	Average embodied energy value (10^6 Btu/ton) Fuel	Total
Mined	5.561	7.0	62	3.448	4.34
Reclaimed	0.814	1.0	38	+ 0.309	+ 0.38
Total				3.757	4.72

To estimate the premium fuels required to mine sulfur, we calculate a ratio of premium fuel to total energy from ERG's I-O data for chemical and mineral mining (sector 10.00). Multiplying the ratio (79.44 percent) by 7 x 10^6 Btu/ton yields 5.561 x 10^6 Btu's of premium fuel energy required per ton. A similar ratio of premium fuel to total energy for reclamation is estimated from I-O data for inorganic and organic chemicals (sector 27.01). We multiply this ratio (81.44 percent) by 1 x 10^6 Btu/ton to find 0.814 x 10^6 Btu's of premium fuel energy required to reclaim one ton of sulfur.

In 1977, there were 5,198 tons of sulfur mined and 3,185 tons produced by recovery operations. To estimate the energy credit to apply to sulfur byproducts from coal liquefaction, we must develop a weighting factor to apply to the estimates of the embodied energy of mined and recovered sulfur. The factor is determined by the relative proportion of total U.S. sulfur production in 1977 (5,198 + 3,185 = 8,383 tons) from mined sulfur (62.0 percent) and from recovered sulfur (38.0 percent).

Table 39 presents the embodied energy values for mined and reclaimed sulfur. Applying the weighting factor yields an embodied energy value per ton for average U.S. sulfur production of 3.757 x 10^6 Btu's of premium fuel energy per ton and 4.72 x 10^6 Btu's of total energy per ton.

Table 40 presents the annual sulfur byproduct output of the four coal liquefaction plants. It also shows the embodied energy

Table 40

Sulfur Displacement Energy Credit (10^{12} Btu/yr)

	EDS	H-Coal	SRC-I	SRC-II
Annual sulfur production (10^3 tons/yr)	326.51	171.55	69.35	58.400
Embodied energy value				
Premium fuel	1.227	0.644	0.260	0.219
Total energy	1.541	0.810	0.327	0.276

Table 41

Energy Requirements of Phenol Production

Input	Input volume (Btu/lb)	Energy intensity factor (Btu/Btu) Fuel	Total	Embodied energy value (Btu/lb) Fuel	Total
Electricity	740	1.4472	3.7724	1,070.93	2,791.58
Fuel	4,293	1.0641	1.1513	4,568.18	4,942.53
Total				5,639.11	7,734.11

value of each plant's sulfur output. It should be kept in mind that the embodied energy values represent savings in the energy required for sulfur produced from mining and recovery operations.

Phenols

To estimate a displacement energy credit for the phenol byproducts of the three coal liquefaction plants, we rely on process analysis information for the average facility manufacturing phenols and other cyclic crude and intermediate chemicals. Material and energy flows in this plant represent averages for U.S. facilities producing cyclic crudes and intermediates and are presented in the Department of Energy's Energy Analysis of 108 Industrial Processes. (Hamel, 1979) After reviewing the energy input data and process flow diagrams for the average phenol facility, we make allocations of process energy to phenols, as shown in table 41.

Table 42 presents the annual production volume of phenols for three coal liquefaction plants and the total embodied energy value of those phenols.

Table 42

Phenol Displacement Energy Credit (10^{12} Btu/yr)

	EDS	SRC-II
Annual phenol production (10^3 tons)	20.605	2.555
Embodied energy value		
Premium fuel	0.232	0.029
Total energy	0.319	0.040

Table 43

SRC-I Anode Coke Displacement Energy Credit

Annual coke production volume	215.35×10^3 ton
Total coke combustion energy value	5.599×10^{12} Btu
Coal-to-coke conversion factor	1.328 Btu/Btu
Total coal energy required	7.435×10^{12} Btu
Coal energy intensity	
Premium fuel	0.0102 Btu/Btu
Total energy	1.0225 Btu/Btu
Embodied energy value (SRC-I anode coke)	
Premium fuel	0.076×10^{12} Btu/yr
Total energy	7.602×10^{12} Btu/yr

Anode coke

The SRC-I plant produces annually 215,350 tons of anode coke. We estimate its embodied energy credit with data provided by the Energy Research Group. (Blazek et al., forthcoming) Given a combustion energy of coal-derived coke as 26×10^6 Btu's per short ton (see U.S. Department of Energy, Monthly, 1981) and ERG's conversion factor of 1.328 Btu's of coal energy required to produce a Btu of coke, we estimate that 34.528×10^6 Btu's of coal energy are required to produce a ton of coke.

Coke oven gas is also used as a process heat source, but this is a recycled energy flow already accounted for in the coal input energy. Table 43 presents the annual production of coke from the SRC-I plant and, using the coal-to-coke conversion factor, the amount of coal that would be needed to produce an equivalent amount of coke. The table also shows the premium fuels and total embodied energy values for that coal. Table 44 summarizes coal liquefaction displacement credits for the four byproducts.

Table 44

Coal Liquefaction Displacement Credits (10^{12} Btu/yr) a/

	H-Coal		EDS		SRC-I		SRC-II	
	Fuel	Total	Fuel	Total	Fuel	Total	Fuel	Total
Ammonia	2.402	2.995	2.516	3.137	--	--	0.424	0.528
Sulfur	0.644	0.810	1.227	1.541	0.260	0.327	0.219	0.276
Phenols	--	--	0.232	0.319	--	--	0.029	0.040
Anode coke	--	--	--	--	0.076	7.602	--	--
Total	3.046	3.805	3.975	4.997	0.336	7.929	0.672	0.844

a/Fuel is premium fuel.

ETHANOL PRODUCTION

PLANT DATA

Table 45

Idaho Falls Ethanol Plant Characteristics

Location	Idaho Falls, Idaho	
Life	10 years	
Operating factor	80% assumed (292 stream days/yr, 24 hrs/day, 7,008 hrs/yr)	
Feedstock	Corn assumed available within 60 miles of plant 59,568 bu/yr	
	Coal assumed available within 60 miles of plant 204.108 tons/yr	
Transportation	Truck for all inputs and products	
Annual operating cost	Materials	
	Lime	35.04 lb/yr
	H_2SO_4	64.24 lb/yr
	Yeast	7,300.00 lb/yr
	Amylases	4,776.36 lb/yr
	Nitrogen a/	137.82 lb/yr
	Gasoline	10,036.04 gal/yr
	Electricity (kwh/yr)	
	Ethanol plant	96,900.20
	Molecular sieve	361,262.40
	Total	458,162.60
Capital cost b/		
Ethanol plant	Capital equipment	$451,523
	Construction contract	219,414
Molecular sieve c/	Capital equipment	$119,500
	Construction contract	77,600
Products	199 proof ethanol	176,281 gal/yr
	Gasoline (denaturant)	10,036 gal/yr
	DDG byproduct (dried weight)	482.092 ton/yr

a/Nitrogen is used to replace losses from the nitrogen-pressurized molecular sieve.
b/In 1980 dollars.
c/Molecular sieve is oversized by a factor of 2 to allow for uncertainties in the lifetime of the sieve's materials.

Table 46

Idaho Falls Annual Energy Output and Input Summary

	Annual production volume (gal/yr)	Energy conversion factor (Btu/gal)	Embodied energy value (10^6 Btu/yr) Premium fuel	Total
Output				
Ethanol	176,281	84,000	14,807.604	14,807.604
Gasoline	10,036	125,000	1,254.500	1,254.500
Total			16,062.104	16,602.104
Input				
Electricity			2,263.002	5,898.941
Gasoline			1,334.908	1,444.301
Chemicals a/			0.165	0.277
Yeast and enzymes			335.841	395.389
Repairs and maintenance			107.183	133.706
Corn farming			7,252.344	8,765.848
Annualized capital			1,340.223	2,000.862
Coal mining			46.218	101.953
Total			12,679.884	18,741.277

a/Includes lime, sulfuric acid, yeast, and enzymes from subsequent tables.

PROCESS ENERGY INPUTS AND OUTPUTS

Table 46 summarizes the annual energy inputs and outputs of the Idaho Falls ethanol facility. The ethanol production volume is calculated in barrels per year and the energy value of the ethanol product (84,000 Btu/gal) is based on the heating value estimates of chemically similar ethanol from Plant X. The embodied energy value of inputs is derived from the other tables in this appendix.

COAL AND ELECTRICITY

Table 47 presents the embodied energy of coal and electricity required to power the Idaho Falls plant. Although the plant can burn coal, it is currently generating steam in a rented LPG boiler. Therefore, we had to estimate the annual coal requirements of Idaho Falls as follows. Plant data state that 1.552×10^7 Btu/day are required as a heat input for process steam. We assume that each ton of coal has a heating value of 22.2×10^6 Btu; this is a national average for bituminous coal consumed domestically. Since the plant data do state that 1.552×10^7 Btu are required as a heat input for process steam per operating

Table 47

Idaho Falls Embodied Energy of Coal Mining and Electricity Requirements a/

Input	Annual input quantity	Energy conversion factor	Energy intensity factor (Btu/Btu)		Embodied energy value (10^6 Btu/yr)	
			Fuel	Total	Fuel	Total
Coal mining	204.11 tons/yr	22.2×10^6 Btu/ton	0.0102	0.0225	46.218	101.953
Electricity	458,163 kwh/yr	3,413 Btu/kwh	1.4472	3.7724	2,263.002	5,898.941

a/Fuel is premium fuel. Energy conversion factor from U.S. Department of Energy, Monthly Energy Review (Washington, D.C.: Energy Information Administration, 1981).

APPENDIX III

day, we can calculate the coal requirements as follows:

$$\frac{(1.552\times10^{7})\times(292)}{22.2\times10^{6}} = \frac{\text{heat input for steam} \times \text{operating days/yr}}{\text{coal energy per ton}} = 204.108 \text{ tons coal per year}$$

To estimate the energy required to mine that coal, we multiply the annual Btu equivalent of the coal (1.552×10^7 Btu/day x 292 days/yr) by the energy intensity factors for coal as shown in table 47. The facility's electricity requirements are given as 458,162.6 kwh/yr. (This includes 96,900.2 kwh/yr for ethanol production and 363,262.4 kwh/yr for molecular sieve dehydration.) Applying the electricity conversion factor of 3,413 Btu/kwh and the electricity intensity factors yields the results in table 47.

CHEMICALS

Estimates of embodied energy for lime, sulfuric acid, and nitrogen were derived from Energy Analysis of 108 Industrial Processes, prepared by Drexel University for the U.S. Department of Energy. (Hamel, 1979) This document presents detailed process analyses of 108 industrial sectors based on measurements of the direct energy flows into an average plant representing each industry. The results are presented in table 48.

Table 48

Idaho Falls Embodied Energy of Annual Chemical Requirements a/

Input	Annual input quantity	Embodied energy: Estimates (Btu/lb) Fuel	Embodied energy: Estimates (Btu/lb) Total	Embodied energy: Value (10^6 Btu/yr) Fuel	Embodied energy: Value (10^6 Btu/yr) Total
Lime	35.04 lb/yr	3,124	3,601	0.109	0.126
Sulfuric acid	64.24 lb/yr	30	137	0.002	0.009
Nitrogen	137.824 lb/yr	396	1,030	0.054	0.142
Gasoline	10,036.000 gal	133,012 b/	143,912	1,334.908	1,444.301
Total				1,335.073	1,444.578

a/Fuel is premium fuel.
b/Btu/gal estimates based on combustion energy (125,000 Btu/gal) times embodied energy intensity estimates for refined petroleum products of 1.0641 Btu of premium fuel energy per Btu of product and 1.1513 Btu of total energy per Btu of product.

Table 49

Idaho Falls Embodied Energy of Annual Plant Operations Expenditures a/

Operation	Annual expenditure	Energy intensity factor (Btu/$) Fuel	Total	Embodied energy value (10^6 Btu/yr) Fuel	Total
Yeast and enzymes	$21,154	15,876	18,691	335.841	395.389
Repairs and maintenance	4,918 b/	21,794	27,187	107.183	133.706

a/In 1980 dollars. Fuel is premium fuel.
b/Estimate derived by scaling down Plant X repair and maintenance expense based on the relative magnitude of 199 proof ethanol production from the two facilities.

OTHER IDAHO FALLS OPERATIONS EXPENSES

Table 49 presents the embodied energy estimates for yeasts and enzymes and repairs and maintenance expenses at Idaho Falls. The facility produces 176,282 gallons of 199 proof ethanol per year. The Department of Energy estimates that yeast and enzymes expenses are 12 cents per gallon. Given an annual yeast and enzyme expenditure of $21,154 in 1980 dollars, we use energy intensity factors for I-O sector 27.03 (agricultural chemicals) to estimate the embodied energy value of those materials.

Since Idaho Falls provided no annual plant operations cost estimates, we estimate the annual expenditure for repairs and maintenance by scaling down similar expenditures for Plant X based on the relative magnitude of 199 proof ethanol production from the two facilities.

CAPITAL COSTS

Table 50 presents estimates of the embodied energy of capital costs for the Idaho Falls facility in terms of premium fuels and total energy. The table is based on the detailed energy analysis of capital required for the basic ethanol plant (table 51) and the molecular sieve facility (table 52). Each capital cost item was multiplied by the appropriate I-O sector energy intensity factor to yield an embodied energy value.

Table 50

Embodied Energy of Idaho Falls Capital Costs

	Total capital cost	Embodied energy value Premium fuel	Total
Ethanol plant		11,582.017	17,113.611
Molecular sieve		1,820.214	2,895.008
Total		13,402.231	20,008.619
		(divided by 10-yr plant life)	
Annual capital embodied energy		1,340.223	2,000.862

Table 51

Idaho Falls Ethanol Plant Detailed Analysis of Capital Equipment Costs (in 1980 Dollars) a/

I-O sector	Total capital costs	Energy intensity factors (Btu/$) Fuel	Total	Embodied energy value (10^6 Btu) Fuel	Total
36.11 Concrete	$ 18,500	23,783	32,031	439.986	592.574
36.17 Insulation	40,000	29,091	33,129	1,163.640	1,325.160
40.03 Heating equipment	200,131	17,894	25,196	358.144	5,186.595
40.06 Fabric, platework	57,735	18,006	34,038	1,039.576	1,965.184
40.07 Sheetmetal work	2,685	22,281	37,292	59.824	100.129
42.08 Pipes, valves	13,879	17,605	23,530	244.340	326.753
44.00 Grain feed equipment	2,160	15,950	23,803	34.452	51.414
45.01 Construction equipment	2,058	13,711	19,550	28.217	40.234
48.01 Food production machinery	37,587	10,843	19,105	407.556	718.100
49.01 Pumps, compressors	14,103	13,735	19,390	193.705	273.457
49.07 General industrial machines	2,807	15,324	22,004	43.014	61.765
62.02 Mechanical measuring instruments	56,780	12,235	17,584	694.703	998.420
45.01 Construction equipment	3,098	20,801	29,001	64.441	89.845
Total capital equipment	$451,523			7,994.598	11,729.630
11.03 Construction subcontracts	219,414	16,350	24,538	3,587.419	5,383.981
Total capital	$670,937			11,582.017	17,113.611

a/Fuel is premium fuel.

Table 52

Idaho Falls Molecular Sieve Detailed Analysis of Capital Equipment Costs (in 1980 Dollars) a/

I-O sector	Total capital cost	Energy intensity factor (Btu/$) Fuel	Total	Embodied energy value (10^6 Btu) Fuel	Total
40.06 Fabric, platework	$46,550	18,006	34,038	838.179	1,584.469
49.01 Pumps, compressors	400	13,735	19,390	5.494	7.756
49.03 Blowers, fans	6,000	14,801	22,094	88.806	132.564
52.04 Measuring, dispensing pump	500	16,882	28,012	8.441	14.006
11.03 New construction public utility	18,250	16,350	24,538	298.388	447.819
27.01 Industrial chemicals	6,680	86,962	106,047	580.906	708.394
Total	$78,380			1,820.214	2,895.008

a/Fuel is premium fuel.

CORN AND SOYBEAN FARMING

Energy requirements of corn farming

Table 53 summarizes the energy requirements of U.S. corn production as presented in Energy and U.S. Agriculture: 1974 Data Base, an analysis of energy use in U.S. farming compiled by the Federal Energy Administration and the U.S. Department of Agriculture. (See U.S. Department of Agriculture, Energy, 1977.) This data base includes energy used for on-farm business purposes for

Table 53

Energy Used in U.S. Corn Production 1974

Farm activity	Embodied energy value (10^{12} Btu/yr) Premium fuel	Total
Field operations	260.148	296.383
Irrigation	49.670	63.243
Fertilizer	215.094	268.062
Pesticides	12.308	15.625
Total	537.220	643.313
Btu/bu (4.648 x 10^9 bu)	115,581	138,406
Capital, seed, and lime energy (Btu/bu)	+ 6,168	+ 8,751
Total corn energy (Btu/bu)	121,749	147,157

1974. While corn production yields for 1974 reflected the adverse impact of bad weather, this survey remains the most complete analysis to date of the energy requirements of farming. The table also includes energy estimates for farm capital construction and seed and lime used in corn farming as compiled by Agriculture's Economics, Statistics, and Cooperatives Service. (U.S. Department of Agriculture, Cost, 1980)

Tables 54 through 58 show the energy requirements of corn farming for field operations, irrigation, and fertilizer and pesticide use. We use the energy intensity factors compiled by ERG to estimate the premium fuel and total embodied energy value of the various fuels and electricity required as inputs to farm operations and irrigation. (Hannon, 1981)

Table 56 presents the energy requirements for fertilizer used in corn production. The annual fertilizer requirements are derived from Energy and U.S. Agriculture: 1974 Data Base. (U.S. Department of Agriculture, 1977) The energy intensity factors are derived from an analysis of the energy used in U.S. fertilizer production conducted by the Department of Agricultural Economics of the University of Illinois. (Dovring and McDowell, February 1980) Since the fertilizer energy study presents only total energy requirements, we estimate the premium fuels portion of that total energy by using the ratio of premium fuels to total energy contained in the Energy Research Group's input-output energy model for sector 27.02 (fertilizer).

Table 57 presents the energy required in pesticides and herbicides used in corn farming. The annual chemical requirements are derived from Energy and U.S. Agriculture: 1974 Data Base. (U.S. Department of Agriculture, 1977) The energy intensity factors are derived from an analysis of the energy used in pesticide production conducted by the Department of Agricultural Economics at the University of Illinois. (Dovring and McDowell, December 1980) To estimate the premium fuels portion of the total energy estimates provided in that report, we have to use the same premium-to-total-energy ratio technique that we used in the fertilizer analysis.

Table 58 presents estimates of the embodied energy of capital replacement, seed, and lime required in corn production. Capital replacement is the cost of replacing depreciable capital equipment and facilities. The dollar estimates of capital, seed, and lime requirements are derived from Agriculture's projections of annual per-acre costs for corn farming. (U.S. Department of Agriculture, Cost, 1980) The energy intensity factors for each cost item are derived from ERG's input-output energy model. Multiplying the intensities by the per-acre costs yields premium fuel and total embodied energy values per acre. (Hannon, 1981) (The I-O sectors and their SIC codes are, for capital, farm equipment, 44.00; for seed, agriculture, forestry, and fishery services, 4.00; and for lime, stone, clay, and gravel mining, 9.00.) We relied on Agriculture's corn yield estimate of 107

Table 54

Embodied Energy of Field Operations of Corn Production a/

Energy input	Input volume	Energy conversion factor	Energy intensity factor (Btu/Btu) Fuel	Total	Embodied energy value (10^{12} Btu/yr) Fuel	Total
Gasoline	685.4×10^6 gal	125×10^3 Btu/gal	1.0641	1.1513	91.167	98.638
Diesel	470.7×10^6 gal	140×10^3 Btu/gal	1.0641	1.1513	70.122	75.868
Fuel oil	11.3×10^6 gal	140×10^3 Btu/gal	1.0641	1.1513	1.683	1.821
LPG	585.1×10^6 gal	95×10^3 Btu/gal	1.0641	1.1513	59.147	63.994
Natural gas	25.9×10^9 cu ft	1,020 Btu/cu ft	1.0667	1.1503	28.180	30.389
Electricity	$1,994 \times 10^6$ kwh	3,413 Btu/kwh	1.4472	3.7724	9.849	25.673
Total					260.148	296.383

a/Fuel is premium fuel. Premium fuel and total energy intensities are from ERG model. Energy conversion factor is derived from U.S. Department of Agriculture, Energy and U.S. Agriculture: 1974 Data Base, Vol. 2, Commodity Series of Energy Tables, FEA-D-77-140 (Washington, D.C.: U.S. Government Printing Office, April 1977), except for natural gas, which is from U.S. Department of Energy, Monthly Energy Review (Washington, D.C.: Energy Information Administration, 1981).

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Table 55

Embodied Energy of Irrigation Required in Corn Production a/

Energy input	Input volume	Energy conversion factor	Energy intensity factor (Btu/Btu) Fuel	Total	Embodied energy value (10^{12} Btu/yr) Fuel	Total
Gasoline	8.5×10^6 gal	125×10^3 Btu/gal	1.0641	1.1513	1.131	1.223
Diesel	66.3×10^6 gal	140×10^3 Btu/gal	1.0641	1.1513	9.877	10.686
LPG	86.7×10^6 gal	95×10^3 Btu/gal	1.0641	1.1513	8.764	9.483
Natural gas	21.7×10^9 cu ft	1,020 Btu/cu ft	1.0667	1.1503	23.610	25.461
Electricity	$1,273 \times 10^6$ kwh	3,413 Btu/kwh	1.4472	3.7724	6.288	16.390
Total					49.670	63.243

a/Fuel is premium fuel. Premium fuel and total energy intensities are from ERG model. Input volume and energy conversion factor are from U.S. Department of Agriculture, Energy and U.S. Agriculture: 1974 Data Base, Vol. 2, Commodity Series of Energy Tables, FEA-D-77-140 (Washington, D.C.: U.S. Government Printing Office, April 1977).

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Table 56

Embodied Energy of Fertilizer
Used in Corn Production 1974 a/

Material input	Input volume (10^6 lbs) b/	Energy intensity factor (Btu/yr) Fuel c/	Total d/	Embodied energy volume (10^{12} Btu/yr) Fuel	Total
Nitrogen	6,627.499	25,076	31,251	166.191	207.116
Phosphate	3,587.970	10,030	12,500	35.987	44.850
Potash	3,576.778	3,611	4,500	12.916	16.096
Total				215.094	268.062

a/Fuel is premium fuel.
b/See U.S. Department of Agriculture, Energy and U.S. Agriculture: 1974 Data Base, Vol. 2, Commodity Series of Energy Tables, FEA-D-77-140 (Washington, D.C.: U.S. Government Printing Office, April 1977), p. 49.
c/See F. Dovring and D. McDowell, Energy Used for Fertilizers (UrbanaChampaign: University of Illinois, Department of Agricultural Economics, February 1980), p. 13.
d/Estimates of premium fuel energy intensity were derived by calculating ratio of premium fuels to total energy from ERG model (I-O sector 27.02 Fertilizers) and multiplying by total energy intensity estimates of Dovring and McDowell (see note c above).

Table 57

Embodied Energy of Pesticides
Used in Corn Production 1974 a/

Material input b/	Input volume (10^6 lbs)	Energy intensity factor (Btu/Btu) c/ Fuel	Total	Embodied energy value (10^{12} Btu/yr) Fuel	Total
Herbicide	107.096	96,655	122,690	10.351	13.140
Insecticide	20.858	93,843	119,120	1.957	2.481
Total				12.308	15.625

a/Fuel is premium fuel.
b/See U.S. Department of Agriculture, Energy and U.S. Agriculture 1974 Data Base, Vol. 2, Commodity Series of Energy Tables, FEA-D-77-140 (Washington, D.C.: U.S. Government Printing Office, April 1977).
c/See F. Dovring and D. McDowell, Energy Used for Pesticides (Urbana-Champaign: University of Illinois, Department of Agricultural Economics, December 1980), p. 8.

Table 58

Embodied Energy of Capital Replacement, Seed, and Lime Used in Corn Production

Material input	Input expenditure (1980$/acre)	Energy intensity factor (Btu/1980$) Premium fuel	Total	Embodied energy value (Btu/acre) Premium fuel	Total
Capital	23.45	15,950	23,803	374,028	558,180
Seed	12.98	17,817	23,341	231,265	302,966
Lime	1.49	36,713	50,463	54,702	75,190
Btu/acre				659,995	936,336
				(divided by 107 Bu/acre)	
Btu/Bu				6,168	8,751

bushels per acre in 1980 to calculate embodied energy values per bushel of corn.

Energy requirements of soybean farming

Table 59 presents the energy used in soybean production from the same data bases and analytic techniques used to estimate corn energy requirements. Tables 60 through 64 present the detailed calculations for the energy needs of soybean production in terms of field operations, irrigation, fertilizers, and pesticides and capital, seed, and lime costs. We must emphasize that these farm energy estimates are national averages; there is substantial variation in State soybean farming energy estimates.

Table 59

Energy Used in U.S. Soybean Production 1974

Farm activity	Embodied energy value (10^{12} Btu/yr) Premium fuel	Total
Field operations	110.415	119.175
Irrigation	1.827	2.222
Fertilizer	17.813	22.198
Pesticides	7.675	9.743
Total	137.730	153.338
Btu/bu a/	109,396	121,793
Capital, seed, and lime energy/bu	+ 16,767 b/	+ 23,882 b/
Total soybean energy/bu	126,163 b/	145,675 b/

a/1.259 x 10^9 bushels in 1974. See U.S. Department of Agriculture, Energy and U.S. Agriculture: 1974 Data Base, Vol. 2, Commodity Series of Energy Tables, FEA-D-77-140 (Washington, D.C.: U.S. Government Printing Office, April 1977).
b/Btu/bu.

Table 60

Embodied Energy of Field Operations of Soybean Production 1974 a/

Energy input	Input volume b/	Energy conversion factor (Btu/input unit) b/	Energy intensity factor (Btu/Btu) c/		Embodied energy value (10^{12} Btu/yr)	
			Fuel	Total	Fuel	Total
Gasoline	387.5×10^6 gal	125×10^3 Btu/gal	1.0641	1.1513	51.542	55.766
Diesel	342.9×10^6 gal	140×10^3 Btu/gal	1.0641	1.1513	51.083	52.269
LPG	37.9×10^6 gal	95×10^3 Btu/gal	1.0641	1.1513	3.831	4.145
Natural gas	2.0×10^9 cu ft	1,020 Btu/cu ft	1.0667	1.1503	2.176	2.347
Electricity	361×10^6 kwh	3,413 Btu/kwh	1.4472	3.7724	1.783	4.648
Total					110.415	119.175

a/Fuel is premium fuel.
b/See U.S. Department of Agriculture, Energy and U.S. Agriculture: 1974 Data Base, Vol. 2, Commodity Series of Energy Tables, FEA-D-77-140 (Washington, D.C.: U.S. Government Printing Office, April 1977).
c/Premium fuel and total energy intensities are from ERG model.

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Table 61

Embodied Energy of Irrigation Required in Soybean Production 1974 a/

Energy input	Input volume b/	Energy conversion factor (Btu/input unit) b/	Energy intensity factor (Btu/Btu) c/		Embodied energy value (10^{12} Btu/yr)	
			Fuel	Total	Fuel	Total
Gasoline	0.5×10^6 gal	125×10^3 Btu/gal	1.0641	1.1513	0.066	0.072
Diesel	1.2×10^6 gal	140×10^3 Btu/gal	1.0641	1.1513	0.179	0.193
LPG	2.2×10^6 gal	95×10^3 Btu/gal	1.0641	1.1513	0.222	0.241
Natural gas	1.1×10^9 cu ft	1,020 Btu/cu ft	1.0667	1.1503	1.197	1.291
Electricity	33×10^6 kwh	3,413 Btu/kwh	1.4472	3.7724	0.163	0.425
Total					1.827	2.222

a/Fuel is premium fuel.
b/See U.S. Department of Agriculture, Energy and U.S. Agriculture: 1974 Data Base, Vol. 2, Commodity Series of Energy Tables, FEA-D-77-140 (Washington, D.C.: U.S. Government Printing Office, April 1977).
c/Premium fuel and total energy intensities are from ERG model.

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Table 62

Embodied Energy of Fertilizer Used in Soybean Production 1974 a/

Material input	Input volume (10^6 lbs) b/	Energy intensity factor (Btu/lb) c/ Fuel	Total	Embodied energy value (10^{12} Btu/yr) d/ Fuel	Total
Nitrogen	221.233	25,076	31,251	5.548	6.914
Phosphate	847.917	10,030	12,500	8.505	10.599
Potash	1,041.127	3,611	4,500	3.760	4.685
Total				17.813	22.198

a/Fuel is premium fuel.
b/See U.S. Department of Agriculture, Energy and U.S. Agriculture: 1974 Data Base, Vol. 2, Commodity Series of Energy Tables, FEA-D-77-140 (Washington, D.C.: U.S. Government Printing Office, April 1977), p. 119.
c/See F. Dovring and D. McDowell, Energy Used for Fertilizers (Urbana-Champaign: University of Illinois, Department of Agricultural Economics, February 1980), p. 13.
d/Estimates of premium fuels energy intensities were derived by calculating ratio of premium fuels to total energy flow from ERG model (I-O sector 27.02 Fertilizers) and multiplying by total energy intensity estimated by Dovring and McDowell (see note c above).

Table 63

Embodied Energy of Pesticides Used in Soybean Production 1974 a/

Material input	Input volume (10^6 lbs) b/	Energy intensity factor (Btu/lb) Fuel	Total	Embodied energy value (10^{12} Btu/yr) Fuel	Total
Herbicides	72.888 c/	96,655	122,690	7.045	8.943
Insecticides	6.713	93,843	119,120	0.630	0.800
Total				7.675	9.743

a/Fuel is premium fuel.
b/See U.S. Department of Agriculture, Energy and U.S. Agriculture: 1974 Data Base, Vol. 2, Commodity Series of Energy Tables, FEA-D-77-140 (Washington, D.C.: U.S. Government Printing Office, April 1977), p. 120.
c/Includes 20,700 lbs of fungicide; we assume the embodied energy of fungicide to be the same as that of herbicides.

Table 64

Embodied Energy of Capital Replacement, Seed, and Lime Used in Soybean Production a/

Material input	Input expenditure (1980$/acre) b/	Energy intensity factor (Btu/1980$) c/		Embodied energy value (Btu/acre)	
		Fuel	Total	Fuel	Total
Capital	20.06	15,950	23,803	319,957	477,488
Seed	9.56	17,817	23,341	170,331	223,140
Lime	1.26	36,713	50,463	+ 46,258	+ 63,583
Total Btu/acre				536,546	764,211
Bu/acre b/				(divided by 32)	
Btu/bu				16,767	23,882

a/Fuel is premium fuel.

b/See U.S. Department of Agriculture, Energy and U.S. Agriculture: 1974 Data Base, Vol. 2, Commodity Series of Energy Tables, FEA-D-77-140 (Washington, D.C.: U.S. Government Printing Office, April 1977), p. 40.

c/See B. Hannon et al., Energy and Labor Intensities for 1972 (Urbana-Champaign: University of Illinois, Energy Research Group, April 1981). The I-O sectors and their SIC codes are, for capital, Farm equipment, 44.00; for seed, Agricultural, forestry, and fishery services, 4.00; and for lime, Stone, clay, and gravel mining, 9.00.

TRANSPORTATION

We calculated two types of estimates to arrive at the impact of transportation energy in the overall trajectory. We calculated the energy embodied in the equipment required for transportation for both inputs and products and also the energy embodied in the fuel consumed in transportation. To arrive at the embodied energy of transportation equipment, we took the following steps:

1. We estimated the quantities of the various inputs and products from each energy facility.

2. We gathered equipment information on various land and water transportation modes such as the average load capacity, cost, life of equipment, and amount of equipment for a standard haul. Tables at the end of this appendix show the information we drew from and also our calculations.

3. From the specified amounts of inputs and products and the information obtained in step 2, we calculated the number of pieces of equipment needed to ship the various inputs and products over the useful life of each facility.

4. We calculated the capital cost of transportation equipment in 1980 dollars for each input and product as follows:

$$\text{(number of transport equipment items required)} \times \text{(cost/item)} \times \frac{\text{(useful life of energy facility)}}{\text{(useful life of transport equipment item)}}$$

5. We multiplied these equipment costs by the appropriate energy intensity factors to arrive at the embodied energy of equipment required to ship both inputs and products.

To arrive at the energy consumed to operate transportation equipment, we took the following steps:

1. We gathered information on the energy efficiency of each mode and expressed it in terms of Btu's per ton-mile.

2. We determined the mileage of a specified haul from available plant data or assumed the haul length.

3. To calculate the ton-miles per year for each commodity, we multiplied the mileage of the haul by the yearly tonnage.

4. We multiplied the ton-miles per commodity by Btu's per ton-mile for the relevant mode to arrive at the Btu's consumed for each input and product shipped.

5. We multiplied the Btu estimates by energy intensity factors to arrive at the annual embodied energy of transporting the input and product shipments for each facility.

Table 65

Transportation Equipment Data

Mode/item	Average cost 10^3 $ (1980 $)	Average capacity	Life of item (years)	Energy efficiency by mode (Btu/ton-mile)
Truck				
Dump	22.5	20 tons	7	average 2,800
Trailer	20.0	1,300 bu	10	
Tank	37.5	9,000 gal	8	
Tractor	47.5		5	
Barge				
Rake	279.0	1,400 tons	40	average 650
Box	282.0	1,600 tons	40	
Tank	500.0	11,000 bbl	40	
Towboat	3000.0		25	
Rail				
Open hopper	41.5	100 tons	15	average 687
Hopper	37.5	3,200 cu ft	15	
Tank	45.0	595 bbl	15	
Locomotive	900.0		15	
Pipeline				
8-inch	76.5/mi		20	average 320
10-inch	88.4/mi		20	
12-inch	100.3/mi		20	
18-inch	144.9/mi		20	
Pump	1.0/hp		20	
Conveyor belt	2534.0/mi		8	determined by kw used

APPENDIX IV

We use the H-Coal process to demonstrate how we calculated the transportation estimates. The coal input to the H-Coal plant is brought by barge from mines assumed to be 200 miles away. The liquid products are transported by barge to an unspecified location that is assumed to be a standard 100-mile haul. The ammonia byproduct is moved by truck locally a distance that is assumed to be 100 miles. The pipeline gas byproduct is transported locally by pipeline a distance that is assumed to be 20 miles. The sulfur product is moved by barge to the Gulf Coast, a distance of 1,300 miles.

The capital cost of transportation equipment required for H-Coal input and product shipment inputs is estimated to be $40,090,000 over the life of the plant with an annualized premium fuel energy value of 0.033×10^{12} Btu's and an annualized total energy of 0.060×10^{12} Btu's. (See table 68.) The operating energy per year for H-Coal transport is estimated to be 1.147×10^{12} Btu's in premium fuel energy and 1.242×10^{12} in total energy. (See table 69.) The tables in the rest of this appendix show the estimated annualized capital and operating energy required to transport the inputs and products of coal liquefaction and ethanol plants.

Table 66

Capital Energy Intensities for Transportation

Mode/sector	Premium fuel intensity (Btu/1980 $)	Total energy intensity (Btu/1980 $)
Rail	17,362	32,017
Trailer truck	19,211	33,559
Tractor truck	17,207	26,113
Ship	14,983	27,419
Pipeline	17,605	23,530
Conveyor	17,978	29,717

Table 67

Transportation Fuel Energy Intensities

Fuel	Sector	Premium fuel	Total
Diesel (rail, truck, barge)	Refined petroleum products	1.0641	1.1513
Electricity	Electric utilities	1.4472	3.7724
Natural gas (methane pipeline)	Gas utilities	1.0667	1.1503

APPENDIX IV

Table 68

H-Coal Commercial Plant Embodied Energy of Transportation System Capital Requirements

Commodity shipped	Mode	Capital cost of equipment (10^6 1980 $)	Energy intensity factors (Btu/1980 $) Premium fuel	Energy intensity factors (Btu/1980 $) Total	Embodied energy value (10^{12} Btu) Premium fuel	Embodied energy value (10^{12} Btu) Total
Input						
Coal	Barge	21.66	17,362	32,017	0.376	0.693
Product						
Liquids	Barge	10.50	14,983	27,419	0.157	0.288
Byproduct						
Pipeline gas	Pipeline	1.83	17,605	23,530	0.032	0.043
Sulfur	Barge	5.25	14,983	27,419	0.079	0.144
Ammonia	Truck					
	Tractor	0.57	17,207	26,113	0.010	0.015
	Tank	0.28	19,211	33,559	0.005	0.009
Total		40.09			0.659	1.192
					(divided by 20)	
Annualized total					0.033	0.060

Table 69

H-Coal Commercial Plant Embodied Energy of Transportation System Operations a/

Commodity shipped	Volume (M tons/yr)	Shipping miles b/	Mode	Ton-miles shipped (M/yr)	Operational energy (10^{12} Btu/yr) c/	Embodied energy value (10^{12} Btu/yr) d/ Premium fuel	Embodied energy value (10^{12} Btu/yr) d/ Total
Input							
Coal	5.806	200	Barge	1161.2	0.755	0.803	0.869
Product							
Liquids e/	2.470	100	Barge	247.0	0.161	0.171	0.185
Byproduct							
Pipeline gas	0.167	20	Pipeline	3.3	0.001	0.001	0.001
Sulfur	0.172	1,300	Barge	223.0	0.145	0.154	0.167
Ammonia	0.062	100	Truck	6.2	0.017	0.018	0.020
Total						1.147	1.242

a/Note some errors because of rounding.
b/One way only.
c/Based on the following modal energy efficiencies: barge 650 Btu/ton-mile; pipeline 365 Btu/ton-mile; truck 2,800 Btu/ton-mile.
d/Calculated by multiplying operational energy requirements by the following energy intensity estimates: (1) barge and truck (fueled by refined petroleum products) energy intensity factors are 1.0641 for premium fuels and 1.1513 for total energy; (2) pipelines are assumed to require the same transport energy as natural gas lines having energy intensity factors of 1.0667 for premium fuels and 1.1503 for total energy.
e/Includes propane, butane, naphtha, and reformate and distillate oils.

APPENDIX IV

Table 70

Transportation Energy for Coal Liquefaction Plants a/

Plant	Embodied energy of capital (10^{12} Btu/yr) Fuel	Total	Operating energy (10^{12} Btu/yr) Fuel	Total	Combined capital and operating energy Fuel	Total
SRC-I	0.016	0.029	0.195	0.211	0.211	0.240
SRC-II	0.036	0.065	0.210	0.228	0.246	0.293
H-Coal	0.033	0.060	1.127	1.242	1.160	1.302
EDS	0.027	0.044	0.206	0.315	0.233	0.359

a/Fuel is premium fuel. Note that although H-Coal consumes 5.8 million tons of coal per year and EDS consumes 8.2 million tons, the EDS coal is transported only 12.5 miles by on-site conveyor belts while coal is assumed to be shipped 200 miles by barge to the H-Coal plant. This is the reason for the high operating and total embodied energies of the H-Coal plant relative to EDS.

Table 71

Transportation Energy for Ethanol Plants a/

Plant	Embodied energy of capital (10^9 Btu/yr) Fuel	Total	Operating energy (10^9 Btu/yr) Fuel	Total	Combined capital and operating energy (10^9 Btu/yr) Fuel	Total
Idaho Falls	0.680	1.076	0.538	0.583	1.218	1.659
Plant X	2.356	4.166	24.806	26.839	27.162	31.005

a/Fuel is premium fuel.

COST OF PROCESS ANALYSIS DATA BASE

At various stages in this analysis, we required detailed process analysis data on the energy requirements of selected industries. Our source for much of this data was Energy Analysis of 108 Industrial Processes, a report produced by Drexel University for DOE. (Hamel, 1979). This study presented the energy (such as fuel and electricity), utilities (such as air, water, steam, coolant), and raw material inputs for each industrial process and presented fuel requirements and thermal efficiencies per pound of product, per unit of input, and so on for each industrial process. Figure 9 (on the next page), representing a process flow chart from that study, shows the energy and materials flows recorded in the data base.

The data base was compiled from industrial process flow sheets, industrial consultants, Census of Manufactures data, on-site plant surveys, and other sources. From that data, the study derived process energy flows for a representative plant in a given industry. The process energy data necessarily represented industrial aggregates; there may be different production processes used by firms producing the same category of goods.

While the level of data aggregation may be acceptable for the NEA demonstration contained in the report, larger and more definitive process analysis data bases are available. The Industrial Plant Energy Profile (IPEP) is one example. Developed jointly by DOE and General Energy Associates of Philadelphia, it provides detailed data on the energy and raw materials inputs and outputs for 300,000 U.S. manufacturing plants.

General Energy Associates estimates that it could provide that data base to DOE for $750,000 if DOE were to protect the identities of and data for the individual plants. DOE has already used the data base in a study of existing and potential sites for cogeneration in manufacturing industries. In making technical comments on our draft, the Colorado School of Mines Research Institute estimated that an adequate process analysis data base could be developed for $300,000.

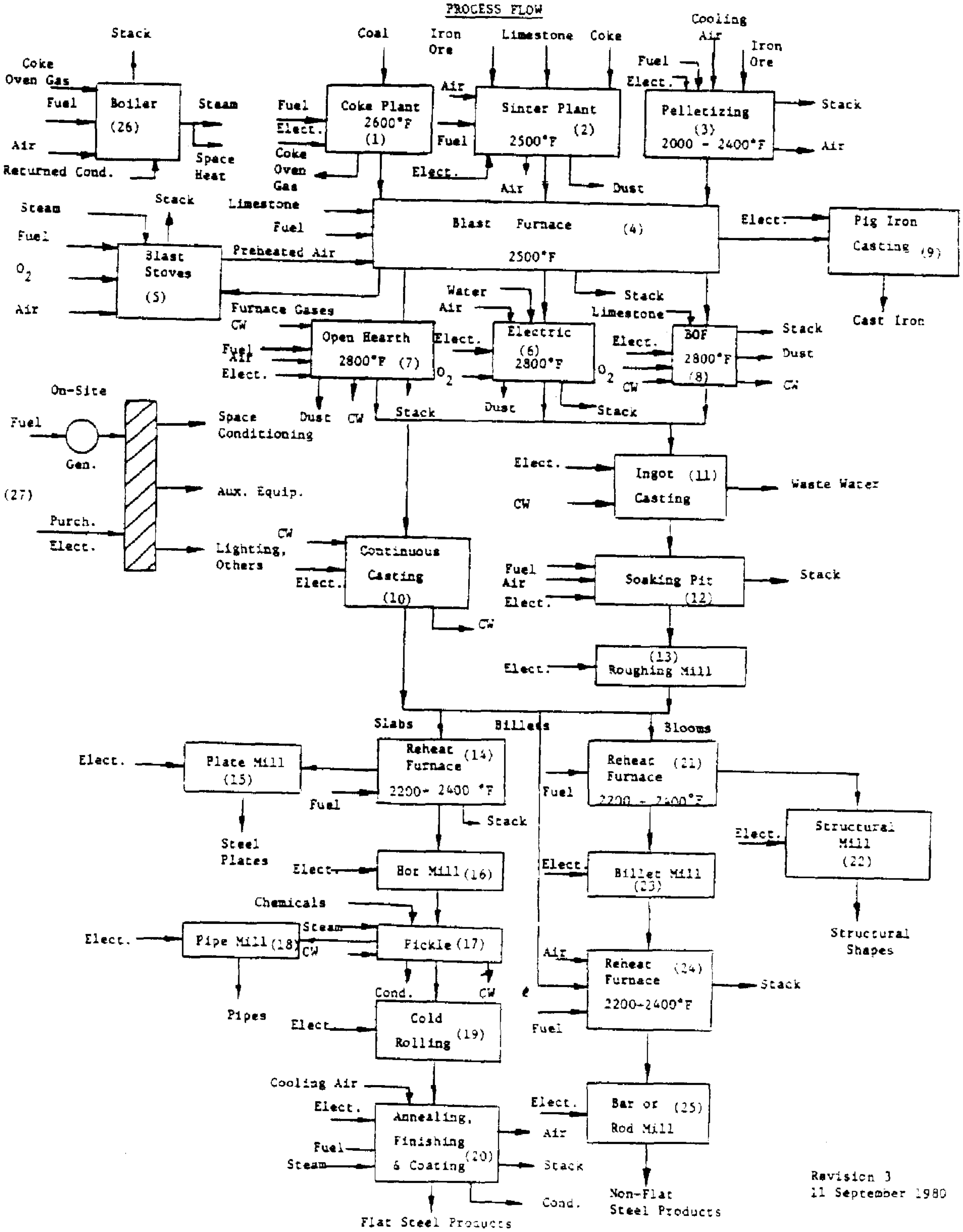
APPENDIX V

Figure 9

Industrial Process Flow Chart

3312 - BLAST FURNACES AND STEEL MILLS

PROCESS FLOW



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GLOSSARY

Alcohol. The family name of a group of organic chemical compounds of carbon, hydrogen, and oxygen; a series of molecules that vary in chain length and are composed of a hydrocarbon plus a hydroxyl group, as in CH_3-(CH_2)n-OH, including methanol, ethanol, isopropyl alcohol, and others.

Amylase. An enzyme that converts starch into sugar.

Anhydrous. A compound that contains no water either absorbed on on its surface or in crystallization.

Barrel. A liquid measure equal to 42 U.S. gallons.

Barrel of oil equivalent. A unit of energy equal to the energy in a barrel of crude oil, or 5.8 million British thermal units.

Biomass. Plant material including cellulose carbohydrates, ligniferous constituents, and others.

British thermal unit. The amount of heat required to raise the temperature of 1 pound of water 1 degree Fahrenheit at or near its point of maximum density (39.1° F).

Calorie. The amount of heat required to raise 1 gram of water 1 degree centigrade.

Cellulose. The main polysaccharide in living plants that forms the skeletal structure of the plant cell wall and can be hydrolyzed to glucose.

Column. A vertical cylindrical vessel used to increase the degree of separation of liquid mixtures in distillation and extraction.

Condenser. A heat-transfer device that reduces a fluid from vapor to liquid.

Crude oil. A petroleum liquid as it comes from the ground.

Cubic foot of gas. The amount of gas required to fill a volume of 1 cubic foot at a pressure of 14.65 pounds per square inch absolute (psia) and a temperature of 60 degrees Fahrenheit; a standard cubic foot (scf).

DDGS. See Distillers dried grain.

Dehydrate. To remove 95 percent or more of the water from any substance by exposing it to high temperature or by some other technique of extraction.

Denature. To add a substance to ethyl alcohol to make it unfit for human consumption; the denaturing agent may be gasoline or some other substance specified by the Bureau of Alcohol, Tobacco, and Firearms.

Dewater. To remove the free water from a solid substance.

Dextrin. A polymer of D-glucose intermediate in complexity between starch and maltose; it is formed by hydrolysis of starches.

Distillate fuel oil. A light fuel oil distilled during refining; includes products known as ASTM grades No. 1 and No. 2 heating oils, diesel fuels, and No. 4 fuel oil. The major uses of distillate fuel oils are for heating, on-and-off highway diesel engines, and railroad diesel engines.

Distill. To separate the components of a liquid mixture by heating it and successively collecting the components at their various boiling points and condensing the vapors again into liquids.

Distillers dried grain (DDG). The byproduct of grain fermentation that may be used as a high-protein (28 percent) animal feed; see Distillers grain.

Distillers grain. The nonfermentable portion of grain mash comprising protein, unconverted carbohydrates and sugars, and inert material.

Ebullated bed. A gas containing a relatively small proportion of suspended solids; a high-density fluid with bubbles and having the appearance of boiling liquid.

Embodied energy. The amount of energy required directly and indirectly to produce a product.

Energy. The capacity of a body to do work because of its position or its condition; synonymous with fuel, electricity, and heat. Forms of natural energy include gravitational, potential, chemical, nuclear, heat, kinetic, wave, and radiation energy; other forms include strain (spring), spin (rotational kinetic), latent heat (evaporating and melting), electromagnetic wave, electric, and magnetic energy.

Enzyme. A catalytic protein that is produced by living microorganisms and that mediates and promotes the chemical processes of life without itself being altered or destroyed.

Ethanol. C_2H_5OH or the alcohol product of fermentation used in alcoholic beverages, for industrial purposes, or blended with gasoline to make gasohol; also known as ethyl alcohol or grain alcohol.

Fahrenheit scale. A temperature scale in which water's boiling point is 212° and water's freezing point is 32°. To convert

Fahrenheit to centigrade, subtract 32, multiply by 5, and divide by 9.

Feedstock. The base raw material that is the source of sugar for fermentation.

Fermentable sugar. Sugar (usually glucose) derived from starch and cellulose that can be converted to ethanol; also known as reducing sugar or monosaccharide.

Ferment. To transform organic substances, especially carbohydrates, by means of a microorganically mediated enzyme; the process is generally accompanied by the evolution of a gas.

Fossil fuel. Any fuel such as coal, oil, and natural gas deriving from once-living matter and producing heat by combustion (oxidation); sometimes called conventional fuel or conventional energy source because most energy used today is derived from it; distinguished from less conventional energy sources such as nuclear, geothermal, and solar energy.

Free energy. Energy measurable not directly but only as change. A decrease in free energy is the amount that can be completely converted into work in a reversible change at constant temperature; in a chemical reaction, the free energy decrease is a measure of the driving force of the reaction.

Fuel oil. The petroleum fraction with a higher boiling range than kerosene generally classified as a distillate or residual. Distillates (No. 1, No. 2, and No. 4) are the lighter oils used primarily for central heating in homes, small apartment houses, and commercial buildings and for transportation; residuals (No. 5 and No. 6), often called bunker oils, are heavier high-viscosity oils that usually require to be heated before they can be pumped and are used in industry and large commercial buildings and for generating electricity.

Gasify. To convert a solid or a liquid to a gas.

Gasoline. A volatile, flammable liquid obtained from petroleum and having a boiling range of approximately 29° to 216° centigrade, used as fuel for spark-ignition internal combustion engines.

Gelatinize. To rupture starch granules by temperature to form a gel of soluble starch and dextrin.

Glucose. A monosaccharide, $C_6H_{12}O_6$, that occurs free or combined and is the most common sugar.

Hydrocarbon. Any one of several organic compounds of carbon and hydrogen occurring in petroleum, natural gas, coal, and bitumen.

Hydrogenate. To add gaseous hydrogen to a substance in the presence of a catalyst under high temperature and pressure.

Kilowatt. 1,000 watts.

Kilowatt hour. A unit of work or energy equal to the energy used by 1,000 watts in 1 hour; most statistical summaries of demand for electricity are quoted in kilowatt hours.

Liquefied petroleum gas. Propane, butane, or a mixture thereof that is kept as a liquid by pressure or refrigeration to facilitate handling.

Low-sulfur coal and oil. Generally coal or oil that contains 1 percent or less of sulfur by weight.

Megawatt. 1,000 kilowatts.

Megawatt hour. 1,000 kilowatt hours.

Middle distillate. Any derivative of petroleum, including kerosene, home heating oil, range oil, stove oil, and diesel fuel with a boiling point in the ASTM standard distillation test of between 371° and 700° F; excludes kerosene-base and naphtha-base jet fuel, No. 4, No. 5, and No. 6 heavy fuel oil, intermediate fuel oils (blends containing No. 6 oil), and all specialty items such as solvents, lubricants, waxes, and process oil.

Molecular sieve. A column that separates molecules by adsorbing them selectively by size.

Naphtha. A liquid hydrocarbon fraction recovered by the distillation of crude petroleum.

Petroleum. A naturally occurring gaseous, liquid, or solid material composed mainly of carbon and hydrogen.

Proof. A measure of ethanol content equal to 0.5 percent.

Protein. Any of a class of polymer compounds of high molecular weight composed of amino acids joined by a peptide linkage.

Residual fuel oil. A heavy oil that remains after distillate fuel oils and lighter hydrocarbons are boiled off in refinery operations; includes products known as ASTM grades No. 5 and No. 6 oil, heavy diesel oil, Navy Special Oil, Bunker C oil, and acid sludge and pitch used as refiner fuels and is used for producing electric power, for heating, and for various industrial purposes.

Resource. A naturally occurring solid, liquid, or gas in or on the Earth's crust such that a commodity can be economically extracted.

<u>Saccharify</u>. To hydrolyze a complex carbohydrate into a simpler, soluble, and fermentable sugar such as glucose or maltose.

<u>Short ton</u>. A unit of weight equal to 20 short hundredweights or 2,000 avoirdupois pounds used chiefly in the United States, Canada, and the Republic of South Africa.

<u>Slate</u>. The list of products of a fuel facility.

<u>Solar energy</u>. Radiation energy from the Sun.

<u>Steam reform</u>. To produce hydrogen by the reaction of methane and steam in the pressure of nickel catalysts.

<u>Substitute or synthetic natural gas (SNG)</u>. A substitute for natural gas generally produced by gasifying coal or oil.

<u>Synthetic liquid fuel</u>. A liquid hydrocarbon mixture produced from solid-fossil fuels.

<u>Trajectory</u>. A network of industries that directly and indirectly provide raw materials, energy, equipment, capital facilities, and waste-handling and transportation services used in the production of a given product.

<u>Vacuum distill</u>. To separate two or more liquids under reduced vapor pressure, reducing their boiling points.

<u>Watt</u>. A unit of electrical energy equal to 1 ampere under a pressure of 1 volt.

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AGENCY COMMENTS AND OUR RESPONSE

In this appendix are reprinted letters we received from the U.S. Department of Energy, Ashland Synthetic Fuels, Inc., and Exxon Research and Engineering Company that comment on a draft of this report. We present highlights of our response to these comments in chapter 8; here, we respond to DOE in more detail.

All three letters reprinted here refer to page numbers of the draft copy; these numbers became obsolete when we processed the draft for printing and publication. In the body of our response to DOE, we translate the old page numbers into their corresponding page numbers as they appear in the printed report. The numbers along the left-hand margin of the DOE letter enumerate the paragraphs of DOE's letter, so that we can answer each point in turn and the reader can easily find each comment we are responding to.

Since we do not respond in the same detail to the letters from Ashland and Exxon, there has been no need to enumerate the paragraphs of their letters. However, we have inserted page numbers and table numbers, footnote numbers, and the like along the right-hand margins of their letters wherever Ashland and Exxon have referred to old numbers in the draft; the numbers in the margins of the letters from Ashland and Exxon, therefore, are located near a reference to an old number in the draft and translate that number into the corresponding new number as it appears here in the printed report.

Our response to DOE is threefold. We have inserted brief comments in the text of the letter, beginning on the next page; following DOE's letter, we give first a summary of our response and then detailed comments to each of the issues raised by DOE. The letters from Ashland and Exxon follow DOE's letter and begin on pages 163 and 171, respectively.

 APPENDIX VIII

Department of Energy
Washington, D.C. 20585

DEC 4 1981

Mr. J. Dexter Peach
Energy and Minerals Division
U.S. General Accounting Office
Washington, D.C. 20548

Dear Mr. Peach:

1 The Department of Energy (DOE) appreciates the opportunity to review and comment on the GAO draft report entitled "DOE Spends Hundreds of Millions on New Energy Technologies Without Knowing Net Energy Yields." In the cover precis, GAO states the report demonstrates both the feasibility and importance of net energy analysis (NEA).

2 DOE does not question the feasibility of net energy analysis. Given the state-of-the-art and lack of an acceptable value system, DOE does question both the utility of net energy analysis and the wisdom of spending millions of dollars to repeat such analyses. Although a substantial effort by GAO is reflected in this report, the result is far from convincing. GAO has demonstrated the feasibility of NEA. GAO has not demonstrated its use in making a policy decision. The question is not how the numbers are calculated, but what is done with the results even if the numbers are right. Even a definition of net energy analysis remains a subject for dispute.

[GAO responds: Our records show that DOE officials, in interviews we held with them for this report, believed NEA's "methodological infeasibility" the major reason for DOE's neglect of NEA. (See page 155.) The utility of NEA is that it permits policymakers to know whether or not they are funding marginal producers of premium fuels like the two ethanol facilities we discuss. (See page 161.)]

3 DOE believes that the important and useful energy analysis, the process analysis of energy yield and thermal efficiency, is performed for each energy facility proposed as stated by GAO on page 8-6 of the draft report. The DOE position has not changed since its November 8, 1977, response to GAO report EMD-77-57 that "net energy analyses have been performed on virtually all

energy supply systems, all viable electric conversion processes, and a number of end-use applications." The methods proposed by GAO are those used by ERDA and DOE in most of those analyses. Additional net energy analyses have been performed by and for DOE since the 1977 report. In particular, studies have been done on various sources and technologies for alcohol fuels. Thus, repeating the analysis would not provide new information. Further, the results of all the net energy analyses were of little value to decisionmakers for two major reasons. Experience demonstrates that minor changes in definition or choice of boundaries lead to significant differences in results and cast doubt on the validity of conclusions of net energy analyses. The second reason is that Btu's are neither a valid nor meaningful standard of value.

[GAO responds: Our finding is that DOE has not performed NEA; hence, it has not used the methodology we present here. Had DOE performed NEA, it would have corrected the data problems we found, and we would not have had to develop our methodology. The Btu is specified by Public Law 96-294 as the unit of measurement appropriate for analyzing net energy yields. (See page 157.)]

4 GAO, in its report, analyzes net energy requirements of four different coal liquefaction processes according to three ratios. After all this effort, GAO is unable to reach any significant judgment relative to these processes based on the analysis which they present. This is in accord with DOE's view that the benefits of such analysis are not worth the time and effort involved for general application. This result also belies GAO's assertions that its report demonstrates the feasibility for use of such analysis.

[GAO responds: Our inability "to reach any significant judgment" is a reflection not of our methodology or analysis but of our caution about the quality of data DOE obtains and DOE's failure to verify that data. (See page 157.)]

5 DOE is limiting its criticism of net energy analysis as presented by GAO to two major areas. The first is the value system and its relationship to energy policy and program decisions. The second is the methodological choice and theoretical problems that tend to render useless and conflicting results even if there were a valid value system.

[GAO responds: That NEA poses methodological and theoretical problems does not mean that it should be ignored. (See page 153.)]

6 The GAO claims, page 2-1, "Since NEA has not in fact been used to analyze energy technologies,...." This is incorrect. NEA has been used to analyze the various technologies. It is the results of the NEA's that proved useless.

[GAO responds: As we noted above, DOE has not performed or used NEA in a way that is consistent with the requirements of Public Law 93-577 and title II of Public Law 96-294. (See pages 155-56.)]

7 The GAO avoids a direct confrontation with the value issue. However, by implication, it agrees there is a problem. GAO adopts an <u>ad hoc</u> classification of energy into three different ratios, page 3-11. So called premium fuels supposedly have a different value from other energy, but it is not clear how much different. The actual issue of Btu value is touched upon in footnote 2 on page 3-12: "Yet, the value which society places on the Btu's of various energy sources may change over time. In this analysis, we have assumed that a Btu's 'social value' is constant over time." DOE would add a much more significant point. The current values of all Btus are not the same, and more important, NEA does not offer a means of either determining or assigning a differential value.

[<u>GAO responds</u>: Our classification is not ad hoc; it parallels the classification given in Public Law 96-294. The purpose of NEA is not to assign social value to energy sources. (See page 157.)]

8 Economic analysis provides a proven system for valuing both energy inputs and outputs--the price system of interaction between demand and supply. Demand is the expression of utility and supply of cost. Unfortunately, NEA provides no such measure, and an energy standard of value is demonstrably unsatisfactory (see GAO reference 3, Alessio, for a comprehensive analysis of this issue). In this footnote (pages 3-12 and 3-13), GAO goes on to say that NEA enables the decisionmaker to apply his or her own "social energy discount rate" to represent the value of future net energy. In other words, after all of this expensive analysis, its value is a judgement to be made by an individual decisionmaker.

[<u>GAO responds</u>: Weighing and acting on the results of analysis always require decisionmakers to make judgments. No analysis can or should be the exclusive basis for a decision. (See page 158.)]

9 The diversity of methods used by practitioners in performing NEA is more difficult to cope with than indicated by GAO. However, this response is limited to a few major problems with the method selected and applied by GAO. In fact, the useful parts of the process analysis portion are accepted and used by DOE. However, it is not clear why Congress should, as recommended by GAO, insist that DOE spend an additional $750,000 (page 8-6) to acquire a particular process analysis data base whose development DOE funded previously (pages V-1 and V-3). The input-output (I-O) analysis that is a major part of the GAO recommended method poses some particular problems for R&D policymaking.

[<u>GAO responds</u>: The process analysis data base "accepted and used by DOE" is extremely limited. (See page 158.) We have given the cost for an expanded data base as $300,000 to $750,000, depending on the estimate. (See appendix V.)]

10 Because Section 5(a)(5) of the Federal Nonnuclear Energy Research and Development Act of 1974 (P.L. 93-577) is the single reference to net energy in any of the DOE legislation, the utility of further NEA to R&D policymaking is the essential test. In this framework, I-O analysis has some exceptional problems. It is a static method providing considerable detail on inter-industry relationships for some past point in time. The most recent available I-O tables are for 1972 and are unlikely to reflect current patterns of production and distribution. It will be several years, and would require substantial funding, before post-1973 I-O tables can be completed. Other shortcomings include the lack of information on economies of scale and the degree of capacity utilization. In short, I-O is a sadly deficient tool for forecasting when substantial technological change is not only expected but an objective of the program.

[GAO responds: Public Law 96-294 also requires that NEA be conducted in certain biomass energy technologies. With regard to IO-analysis, see page 159.]

11 The GAO report states on page 1-2; "When mandated, however, there was still considerable confusion about the proper methodology for NEA and some consequent uncertainty about applying NEA to public policy analysis...." DOE agrees and finds this confusion has increased rather than lessened since 1974. The DOE has considered net energy yields of all major technologies and found no net losers. DOE does not believe the Congress intended that substantial funds be wasted in repeating such analyses. In fact, the Congress in the Conference Report to S.1283 (enacted as P.L. 93-577) where Section 5(a)(5) is explained (H. Report No. 93-1563, Dec. 11, 1974, pages 22-23) recognized the nature of R&D policy and technological change as follows: "The conferees recognize that in the early research or development phases of new technologies, the projected applications may even involve a net loss of energy. This principle is not intended in any way to deter such research or to deter the demonstration of new technologies which are not energy efficient or cost effective in the early stages of development." It is unfortunate GAO did not consider this more before entitling its report "DOE Spends Hundreds of Millions on New Energy Technologies Without Knowing Potential Net Energy Yields." A reading of the Rand study quoted on page 6-19 provides, for example, convincing documentation that the performance of pioneer plants can not be predicted.

[GAO responds: DOE's statement that it "has considered net energy yields of all major technologies and found no net losers" is incorrect since the analyses performed did not include indirect energy inputs. With regard to the congressional intent, our response is that Public Law 96-294 requires DOE to provide detailed net energy analyses of all biomass energy projects.]

12 The Department of Energy is convinced it has observed the mandate to consider the potential for production of net energy. The GAO report demonstrates the feasibility, never disputed, of doing net energy analysis. However, the choice of method is arbitrary and results are not demonstrably of significant value to R&D policymakers. Indeed, there is not a single example where a decision would have been changed from that made on the basis of economic analysis. Unless there is a significant and unexpected breakthrough in the state-of-the-art or theory of value, DOE believes it would be a waste of scarce taxpayer resources to follow the recommendations of GAO.

[GAO responds: We repeat our finding that DOE has not considered, implemented, or used NEA as contemplated by the two relevant statutes. With regard to an "example where a decision would have been changed," our response is that the behavior of policymakers cannot be predicted from analysis alone. However, the possibility of a changed decision is raised by our discussion of the two ethanol facilities, which are not only marginal net producers of premium fuels but also supported through DOE with scarce taxpayer resources. DOE's bases for supporting them are economic analysis and thermal efficiency analysis, both of which fail to include indirect energy inputs. (See page 161.)]

Sincerely,

William S. Heffelfinger
William S. Heffelfinger
Assistant Secretary
Management and Administration

OUR RESPONSE TO THE LETTER FROM DOE

Our purpose in this appendix is to provide a detailed response to the letter dated December 4, 1981, from the U.S. Department of Energy. In our response, we discuss individual statements in DOE's letter in some detail, but first we respond more generally to DOE's comments on the feasibility, performance, and utility of NEA.

Feasibility and performance of NEA

DOE states in its December 4 letter that it does not now and never did question the feasibility of conducting NEA. However, our records show that the Energy Research and Development Administration (now DOE) questioned the methodological feasibility of performing NEA in a 1977 response to GAO. NEA's methodological infeasibility was the major explanation that DOE officials gave for DOE's neglect of NEA. We cannot reconcile DOE's current statement with its earlier one in this regard. We assume that the current statement is DOE's position regarding NEA's feasibility, and we agree with that statement.

However, we do not agree with DOE's statements (in paragraph 3) that it performs "important and useful energy analysis" (that is, that DOE estimates thermal efficiencies) and has used NEA to analyze all the various energy technologies and (in paragraph 6) that the results of these NEA's "proved useless" and (in paragraph 12) that DOE is therefore in compliance with the congressional "mandate to consider the potential for production of net energy."

DOE states that it has performed thermal efficiency estimates of specific processes and that it has conducted net energy analysis of all new energy technologies. Consequently, DOE's opinion is that it has met the requirements set by the Nonnuclear Act of 1974 (Pub. L. No. 93-577), which according to DOE (paragraph 10) contains "the single reference to net energy in any of the DOE legislation."

DOE does perform thermal efficiency and other analyses, but these do not constitute net energy analysis as required by the statutes. (The statutes are the Nonnuclear Act of 1974, cited above, and the Energy Security Act of 1980 (Pub. L. No. 96-294).) Thermal efficiency analyses do not include indirect energy inputs, and without direct energy inputs, net energy yields cannot be estimated. The significance of this omission has been demonstrated for ethanol production, in which indirect farming energy accounts for a large proportion of ethanol's energy inputs. With regard to the energy analyses of all new energy technologies, those that DOE has performed were conducted by various analysts using different analytical boundaries and techniques, and no comparisons between these nonstandardized analyses can be made. Additionally, the analyses were generic, conducted on several types of technologies, and as such are of little, if any, use when comparisons are made of site-specific and process-specific proposals for public financial support. Since the Energy Security Act of 1980 requires DOE to provide a detailed NEA of certain biomass energy projects, in addition to the requirements of the Nonnuclear Act of 1974 that DOE use NEA in its proposal evaluation process, and since we could find no evidence that DOE has performed and used NEA as required by these statutes, we question whether DOE can be said to have observed these legislative mandates.

Utility of NEA

DOE questions NEA's utility for policymaking and reaffirms its preference for economic analysis. In our opinion, we have shown not only NEA's feasibility but also its utility. This opinion is strengthened by the comments we received from other reviewers of this report, especially two participants in the technology demonstration projects DOE funded (see, for example, the last paragraph of Ashland's comments, which begin on page 163 below). We have also demonstrated the limitations of economic analysis in an "imperfect energy market." In addition, we believe that DOE undervalues decision factors other than those measuring economic feasibility.

The need for NEA--that is, its utility--exists because it allows selection of the energy-producing technologies that make the most effective use of energy resources. Its use guarantees to policymakers that they will have the opportunity to consider the critical public question of how much energy is spent in a new technology's production of energy. In fact, the Congress has required its use not in one piece of legislation but in two--the Nonnuclear Act of 1974 and the Energy Security Act of 1980.

The utility of NEA for policymaking is not that it can provide perfect measures for differentiating among social values for various energy sources. That is not its purpose. Its presence, however, makes it possible for policymakers to consider a key national issue--the relative effects of new energy technologies on existing domestic resources and on imported premium fuel requirements. No other type of analysis does this. Economic analysis, which assesses technological efficiency according to its profit potential, cannot measure the direct and indirect inputs of energy required to produce every product. Thermal efficiency analysis also excludes indirect inputs. Indeed, the failure to perform net energy analysis virtually excludes consideration of relative net energy yields from funding debates.

The consequence of this failure is well exemplified by the ethanol production plants we examined for this report. Both plants had only marginal net premium fuel yields because of the large quantities of premium fuel required to farm corn, which points up the risk of ignoring indirect inputs by using economic analysis or thermal efficiency analysis as the sole basis for evaluating proposals. If the results of NEA had been available to DOE policymakers, the ethanol facilities might have appeared less attractive to them as opportunities for the investment of public funds.

DETAILED DISCUSSION OF DOE'S COMMENTS

In paragraph 2 of its letter, DOE states that ". . . DOE does question both the utility of net energy analysis and the wisdom of spending millions of dollars to repeat such analyses." We believe we have illustrated the utility of NEA for policy decisions on pages i-ii, iv, 7-9, 37-38, and 51-53. Comments by Ashland Synthetic Fuels (in the first six paragraphs of its letter) support our position on NEA's utility. Additionally, the Colorado School of Mines Research Institute (CSMRI) has commented separately, as follows:

> I must compliment GAO on this work, and state that my experience in net energy analysis leads me to concur with GAO in your findings and report.
>
> I take the liberty of enclosing several other documents which may be useful to you. These are preliminary applications of Net Energy Analysis for Environmental Impact Statements for the U.S. Department of Interior. These applications corroborate your recommendations, I believe. You will note that, at the request of the Federal Project Manager on these studies, we presented our data as total Btu's, rather than breaking it out into various energy types, especially into critical and noncritical types. I believe that, in general, data should be presented by energy type, as GAO recommends.
>
> CSMRI is now developing a handbook, or guidebook, for conducting Net Energy Analysis for the U.S. Bureau of Land Management. We will complete our handbook by March 1, 1982. Again, this indicates that the subject of conducting net energy studies is not so complex, confusing or fraught with conflict that it should be ignored.
>
> I would like to request a copy of your final report when it is released; presumably, at that time, we could reference it in our handbook for the BLM.
>
> I can cite two studies we have performed where the private sector has found NEA to be of considerable value. One highlighted the quantities of critical energy used in materials processing and in recycling, along with the conservation associated with various recycle alternatives. The second identified a significant weakness in the preliminary engineering of a proposed project which could have affected its economics.

Moreover, in a draft to DOE entitled Review of Net Energy Analysis Methodologies (Contract DE-AC01-80ET13800, August 27,1981), the Mitre Corporation noted:

The process of producing or refining fuel deposits and forms of energy into "higher quality," or more readily useable energy forms, requires the consumption of energy. Net energy analysis provides a means to estimate the energy expense involved with transforming primary energy sources into delivered energy products. Such analysis may be particularly useful when various processes designed to deliver a specific product are to be evaluated and compared against one another. The net energy implications of some energy processes are quite different from other processes.

While net energy implications may be a useful measure for those who analyze or set energy policy, they must be used in the context of other indicators and considerations. One important consideration is the form of energy that is produced. Excess baseload electric energy can be stored as potential energy in a pumped hydro-storage system and can then be reconverted to electric power during periods of peak demand. The process requires a large net expenditure of energy to change one form of electricity (baseload) to another (peaking). The net energy balance of this process is negative. On a purely economic basis, it may be advantageous (profitable) to produce peak electricity using pumped hydro-storage because of the higher value of peaking power while on an energy basis, the process requires an appreciable net energy expenditure.

Finally, as to DOE's claim that it would cost millions of dollars to conduct NEA, we addressed this issue on pages 53-54 and in appendix V. While one industry source estimates a one-time $300,000 acquisition expense for a process analysis data base, and another source estimates $750,000, we emphasized that the administrative cost of conducting NEA could be absorbed into the existing DOE proposal evaluation process.

About NEA in paragraph 2, DOE also says that "GAO has not demonstrated its use in making a policy decision." We believe the report does show, as we have stated above, how NEA can contribute to policy decisionmaking. Further, as Ashland says on the last page of its comments,

> Implementation of GAO's NEA methodology or some improved version of same will help prevent misallocation of Federal energy development and energy conservation funds in the current "imperfect energy market situation."

We believe that paragraph 3 of DOE's letter confuses the issues, obligating us to address each sentence in the paragraph. In the opening sentence, DOE says that "DOE believes that the important and useful energy analysis, the process analysis of energy yield and thermal efficiency, is performed for each facility as stated by GAO on page 8-6 of the draft report." We recognized on that page (now page 54) that project proposals have included plant-specific process analysis of inputs and outputs to determine thermal efficiency. This is not the issue, however. The issue is that the analyses DOE has performed do not constitute net energy analysis. The plant-specific analyses exclude indirect energy inputs required for NEA. This is a significant omission, as can be seen in the case of ethanol production, since the indirect energy of corn farming inputs is the second largest input to the process. Also, DOE's analyses are not performed in a manner that is standardized and consistent and that facilitates comparison of energy yields.

In the second sentence of paragraph 3, DOE adds that "The DOE position has not changed since its November 8, 1977, response to GAO report EMD-77-57 that 'net energy analyses have been performed . . . .'" In response, our first point is that the net energy analyses performed before 1977 were not process-specific but generic in nature and not representative of processes DOE selected for public financial support. Second, as DOE said in its response to EMD-77-57, "The state-of-the-art of net energy analysis has not sufficiently developed" nor was there agreement on a methodology. In other words, the pre-1977 analyses used questionable and inconsistent methodologies. Such analyses, in our opinion, are of little use in evaluating and comparing specific processes competing for public funds.

In the third sentence of paragraph 3, DOE states that "The methods proposed by GAO are those used by ERDA and DOE in most of those analyses." That process and input-output analysis have been performed individually by DOE in some cases is not at issue. The issue is that these "methods" were not combined systematically to perform an NEA, nor were they used in a uniform or standardized manner; as DOE said in its response to EMD-77-57, there was no decision made on "one methodology." The "methods" were used ad hoc without DOE guidance for developing uniform methodology, but uniform methodology is a necessary condition if individual processes are to be compared.

In the fourth sentence of paragraph 3, DOE says that "Additional net energy analyses have been performed by and for DOE since the 1977 report." When we began this effort, DOE officials stated that NEA was considered methodologically infeasible to perform, that it therefore had not been directly pursued, and that DOE had developed no guidelines or methodology. In addition to analyzing extensively the documents we obtained for each of the processes we discuss in this report, we reviewed proposal documents, evaluation guidelines, and contract selection statements provided by DOE. We found only two documents--two energy technology proposals--in which NEA was even mentioned. The net energy analyses performed by and for DOE since 1977 were generic and ad hoc. We must emphasize that an NEA of a generic technology like ethanol production has little bearing on an NEA of a specific facility like the Idaho Falls ethanol plant, whose energy inputs and outputs and technical sophistication may be substantially different from the generic technology. As the Congress required in title II of the Energy Security Act of 1980, it is the site-specific rather than the generic analyses that are necessary in decisions regarding Federal support for new energy technologies.

It should be noted that in DOE's response to EMD-77-57, DOE promised a four-point implementation plan, as follows:

1. Completion of draft net energy analysis guidelines for supply technologies to be completed before the end of the month.

2. Completion of a study on the use of net energy analysis in research development and demonstration planning. A DOE-wide seminar will be held to obtain reactions before finalizing the report.

3. Exploration of similarities and differences in the major net energy analysis methodologies and an attempt to reconcile approaches.

4. Revision of net energy analysis guidelines to completely encompass the end-use technologies and to incorporate new findings on methodological approaches. These revisions will be completed next fiscal year.

None of these efforts was carried out. We believe that DOE's failure to complete the four steps has continued to limit its application of NEA.

The last issue addressed by DOE in paragraph 3 is that "the results of all the net energy analyses were of little value to decisionmakers for two major reasons. Experience demonstrates that minor changes in definition or choice of boundaries lead to significant differences in results and cast doubt on the validity of conclusions of net energy analyses. The second reason is that Btu's are neither a valid nor meaningful standard of value." Regarding the first assertion, we state on the opening page of chapter 3 of the report that the choice of boundaries affects the outcome of any analysis, including the economic analysis preferred by DOE. Any rational decision involving a choice of one energy process over another rests on certain assumptions, whether stated or unstated. An important point for any analysis is that the assumptions that are made should be clearly articulated and understood. We have made an effort to be explicit about our assumptions here, as we would in any analysis.

As to the second assertion, we have made no attempt in the report to set Btu's as a standard of value to replace a monetary theory of value. We do state, however, in the opening of chapter 2, that monetary measures fail to represent clearly and accurately the direct and indirect inputs to energy generation. By relying on a physical measure of energy (the Btu), NEA provides a meaningful and accurate account of different energy inputs and allows identification of sources that are domestically in short supply.

Congressional preference for measuring with Btu's is explicit in Public Law 96-294, title II, subtitle A, section 217, and subtitle B, section 235. For example, in subtitle B, the Congress required that the Btu content of the biomass fuel product substantially exceed the Btu content of any petroleum or natural gas used in projects. However, DOE's comment in paragraph 10 that Public Law 93-577 contains "the single reference to net energy analysis in any of the DOE legislation" leaves open the possibility that DOE is unaware of the NEA mandate in Public Law 96-294.

In paragraph 4, DOE says that ". . . GAO is unable to reach any significant judgment relative to these processes based on the analysis which they present." Our inability to reach any "significant judgment" is a reflection not of the methodology we present but of our caution about the quality of the data available to us. As we have stated on pages 38-40, we believe that DOE has not always obtained reasonably accurate data or taken steps to verify data. This is why we recommend in the report that DOE strengthen the data bases for NEA as well as for economic analysis.

In paragraph 6 of its letter, DOE says that "NEA has been used to analyze the various technologies." We have addressed this comment in response to DOE's paragraph 3. (DOE's reference to draft page 2-1 is to the first page of chapter 2.) DOE adds that "It is the results of the NEA's that proved useless." We have addressed this in our response to DOE's paragraph 2.

In the third sentence of its paragraph 7, DOE says that "GAO adopts an *ad hoc* classification of energy . . . ." Our classification *is not* ad hoc; it represents congressional interest in premium fuels as stated in Public Law 96-294, title II, subtitle A, section 217, requiring that the Btu content of the motor fuels used not exceed the Btu content of the biomass fuel produced.

The last sentence of DOE's paragraph 7 is "The current [social] values of all Btu's are not the same, and more important, NEA does not offer a means of either determining or assigning a differential value." NEA is not a method for assigning social value to different energy sources. The methodology does permit acknowledging different social values, as we did in making a distinction between premium fuels and other fuels. Our selection of three different measures of effectiveness demonstrates NEA's flexibility in allowing a decisionmaker to differentiate and account for Btu's that are of particular concern at a given time.

DOE begins paragraph 8 of its letter with "Economic analysis provides a proven system for valuing both energy inputs and outputs . . . ." We have demonstrated, on pages 7-9, the limits of economic analysis as a tool for measuring net energy yields. We make three key points. (1) Direct energy inputs are not explicitly measured in physical terms (Btu's) when economic analysis is used. (2) Indirect energy requirements are hidden in the prices of material inputs. The importance of such inputs is dramatically demonstrated in the analysis of ethanol production. (3) Even when economic values (prices) are taken as a proxy for the energy value of inputs, their measurement is inaccurate because of imperfections in the energy marketplace. (Ashland further supports this last point on the second page of its letter.)

While we have demonstrated in this report the inability of economic analysis to accurately measure energy inputs and outputs, we do not advocate that NEA be used as a substitute for economic analysis. Rather, we emphasize that NEA is a complementary analytic tool to be used by decisionmakers in conjunction with other analytic tools, such as economic and environmental analysis. We agree with Secretary Edwards of the Department of Energy, who stated during his confirmation hearings on January 12, 1981, that

> The mission of the Department of Energy is to serve the President, Congress, and the Nation, to assure reliable supplies of reasonably priced energy, balancing net energy increments with cost and benefits, while maintaining the national security and protecting the public health and safety.

We believe that one cannot balance net energy increments without first having established them.

DOE concludes paragraph 8 by adding that ". . . GAO goes on to say that NEA enables the decisionmaker to apply his or her own 'social energy discount rate' to represent the value of future net energy. In other words, after all of this expensive analysis, its value is a judgement to be made by an individual decisionmaker." (DOE refers in this passage to the footnote that was on page 3-12 of the draft and is now on page 16. "GAO reference 3, Alessio," remains in appendix VII under "Alessio.") The "social energy discount rate" that we refer to is the effect of economic, social, and political conditions on the value society places on various energy types. In our opinion, DOE should provide a global perspective in analyzing the results of NEA. In all analyses, weighing the results always requires a judgment by an individual decisionmaker.

In paragraph 9, DOE states that "In fact, the useful parts of the process analysis portion are accepted and used by DOE." We addressed this comment in response to paragraph 3. DOE adds: "However, it is not clear why Congress should, as recommended by GAO, insist that DOE spend an additional $750,000 . . . ." (DOE's reference in the rest of that sentence to page 8-6 is to the recommendation now on page 58. For the reference to pages V-1 and V-3, the reader should turn to appendix V.) We have already noted that DOE did provide the funding necessary to finance Drexel University's development of a process analysis data base on 108 industrial processes; we discuss this in appendix V. We state on the first page of that appendix, however, that "While the level of data aggregation may be acceptable for the NEA demonstration contained in the [Drexel] report, larger and more definitive process analysis data bases are available." Our opinion is that DOE should rely on those data bases--the one developed, with DOE funding, by General Energy Associates is an example. The cost estimates we gave range from $300,000 to $750,000.

In the second sentence of paragraph 10, DOE says that "In this framework, I-O analysis has some exceptional problems" and proceeds to say what these are. We share DOE's concerns about the problems of I-O analysis. We must emphasize, however, that I-O remains the best alternative available. The methodology we describe in the report uses I-O only to trace indirect inputs, and the effect of technological change is thus analyzed inside each facility in question. The static nature of I-O analysis is a problem that DOE correctly identifies and that is well understood by the Department of Commerce, the Congressional Budget Office, and other Federal users of I-O. Because DOE uses I-O analysis for short-, medium-, and long-term analyses of energy supply and demand conditions, we believe DOE is aware of the difficulties associated with using I-O for "forecasting when substantial technological change is not only expected but an objective of the program" (the last sentence of DOE's paragraph 10).

Paragraph 11 of DOE's letter begins "The GAO report states on page 1-2 [now pages 1 and 2] . . . . DOE agrees and finds this confusion has increased rather than lessened since 1974." The confusion DOE refers to is about the proper methodology for NEA. We agree that there remains significant controversy among NEA experts regarding the appropriate methodology and use of NEA in public policy analysis. Indeed, our report is an attempt to clarify and resolve the major issues in NEA in order to facilitate its implementation by DOE. But we emphasize that DOE has failed to fulfill its NEA mandate and failed to follow up on its own implementation plan for NEA. Had DOE completed the four elements of its 1977 plan, the methodological controversies would have been addressed in the course of DOE's decisionmaking.

DOE's next sentence in paragraph 11 is "The DOE has considered net energy yields of all major technologies and found no net losers." DOE's contention is incorrect. It is incorrect even when the lower-grade energy inputs (coal feedstock) are not considered. In other words, even if only the inputs of already available energy in society (energy subsidies) are considered, there still are net losers. We cite two examples.

First, the MITRE draft to DOE states, in reference to "peak electricity," that "the net energy balance of this process is negative" (page 154 above). Second, as we have demonstrated in this report, the net energy ratio (excluding coal feedstock) of the Idaho Falls plant (funded by DOE) seems to be less than one (that is, it is a net loser). If the plant were to use corn from energy-intensive farming, there would be no question of its being a net loser. For the same reason, even when we consider only net premium fuels, the Idaho Falls plant and Plant X could easily become net losers of premium fuels.

In paragraph 11, sentence 4 (beginning in line 7 of the paragraph), DOE states that it "does not believe the Congress intended that substantial funds be wasted in repeating such analyses." On the contrary, the congressional intent is explicit. As we have mentioned previously, Public Law 96-294 requires detailed net energy analyses of each biomass energy project.

Toward the end of its paragraph 11, DOE states that "It is unfortunate GAO did not consider this more before entitling its report . . . ." Our reference to "hundreds of millions" in our draft title is clearly not to expenditures on early research efforts. Nonetheless, we have deleted that reference from the title to avoid misunderstanding. We recognize in the report the uncertainty associated with development programs (see especially pages 38 and 40). Such uncertainties, however, do not explain DOE's lack of effort in projecting net energy yields at the commercial stage. Our position is not that NEA should be conducted on a pilot or a demonstration plant but, rather, that when projections are made to the commercial stage, to justify public financial support, they should include potential net energy yields. We have demonstrated in this report that such projections, given accurate data, can be useful to decisionmakers just as are the projections DOE presently requires for economic, environmental, and thermal-efficiency analyses.

DOE closes paragraph 11 with the statement that "A reading of the Rand study quoted on page 6-19 [now page 40] provides, for example, convincing documentation that the performance of pioneer plants can not be predicted." The implication is that net energy yields cannot be made because performance parameters are unpredictable. However, DOE uses unpredictable parameters to project economic and environmental analyses and thermal efficiencies. The Rand study concludes that "the importance of cost estimates in decisionmaking" should be "downplayed" in favor of depending "more heavily upon other factors such as theoretical energy conversion efficiencies." We do not agree with downplaying cost estimates, but we do agree that other factors should be equally considered, one of these being net energy yields. Rand adds as a suggestion that attempts be made "to limit the scope for optimism in cost estimates. This might be done by establishing cost estimation quality criteria and obtaining independent evaluations of estimates." We say as much on page 40 and in our recommendations to the Secretary of Energy on page 57.

DOE begins paragraph 12, its final paragraph, with "The Department of Energy is convinced it has observed the mandate to consider the potential for production of net energy." We believe and argue in the opening pages of chapter 1 that DOE has not considered NEA in its decisionmaking as required by the Congress. DOE has not even fulfilled its promised plan to the House Committee on Government Operations to implement NEA. DOE continues by adding that in our report the "results are not demonstrably of significant value to R&D policymakers." We addressed this in our response to DOE's paragraph 2.

Continuing paragraph 12, DOE states that "there is not a single example where a decision would have been changed from that made on the basis of economic analysis." It is always possible that no decision would in fact have been changed as a result of projecting energy yields. The following examples, however, show that such projections raise issues that DOE has not considered.

1. While both ethanol production plants analyzed in our report may have been projected as financially attractive, their potential ability to meet the goal of producing net premium fuels, or even net energy already available, is highly questionable. This issue is raised by NEA and is supported by other reviewers of this report, who agree that neither the Idaho Falls plant nor Plant X is representative of efficient energy plants. Even so, DOE supported their development (see DOE's concluding sentence).

2. Our analysis of the SRC-II process provides ample evidence of the previously mentioned optimism in estimates. Those estimates date back to July 1979, yet DOE continued to support the development of SRC-II without taking steps to correct such unsupported optimism.

3. As is stated in the MITRE draft report in its reference to a hydrostorage system: "The net energy balance of this process is negative. On a purely economic basis, it may be advantageous (profitable) . . . ." We have also stated that a Federal perspective suggests that net energy yield should also be important in deciding which technologies should be supported with public funds. The Federal interest in such projects differs from that of the private lender or investor.

DOE's final sentence in paragraph 12 concludes that ". . . DOE believes it would be a waste of scarce taxpayer resources to follow the recommendations of GAO." We believe that DOE should reconsider its position in view of (1) our demonstration of the potential value of NEA, (2) the support of other reviewers of the report, (3) the requirements of Public Law 93-577 and title

 APPENDIX VIII

II of Public Law 96-294, (4) the Secretary of Energy's view of DOE's mission, and (5) DOE's unfulfilled promise to the House Committee on Government Operations. DOE should also reconsider taking the steps that are necessary, and that we recommend in this report, to strengthen DOE's currently inadequate data base.

ASHLAND SYNTHETIC FUELS, INC. • c/o BECHTEL, INC. • POST OFFICE BOX 2166 • HOUSTON, TEXAS 77001

JOHN B. GRANT
Project Director
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November 25, 1981

Ms. Eleanor Chelimsky, Director
United States General Accounting Office
Institute for Program Evaluation
441 G Street, N.W.
Washington, D.C. 20548

Dear Ms. Chelimsky:

Subject: Review of Draft Report "DOE Spends Hundreds of Millions on New Energy Technologies without Knowing Potential Net Energy Yields"

We appreciate having been given the opportunity to review the subject draft report. We believe the subject to be an important consideration in establishment of national energy policy and are supportive of the General Accounting Office's efforts in expediting the implementation of net energy analysis.

The energy supply problem has become a national concern and Federal involvement in energy supply has increased. We believe that this Federal involvement is most effective when concentrated on long range supply and demand questions.

Prior to public awareness of the energy supply problem, there existed a very substantial public sector involvement in energy pricing - particularly in natural gas, crude oil and electricity pricing. This public sector involvement in pricing is being reduced with strong bipartisan support in the belief that less constrained marketing conditions will tend to increase energy supplies as well as providing economic incentives for capital investment in energy conservation.

The private sector, in evaluating energy production and conservation projects, uses short and medium term projections for construction cost, electricity and fossil fuel escalation to establish the relative merits of projects and to optimize equipment configurations within individual projects. These projections are an integral part of the economic analysis which is the principal basis for private sector capital allocation among projects.

The public sector is currently involved in the development of longer range, higher risk energy supply and conservation technologies. Obviously, policy making using conventional economic analysis alone will not lead to the most cost effective allocation of funds between candidate technologies and projects -

Ms. Eleanor Chelimsky
U.S. General Accounting Office

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particularly when reduced public sector involvement in energy pricing is changing the long term relative values of various forms of energy. The net energy analysis concept is particularly useful in detecting conflicts between short term economic analysis and the long range value of various forms of energy.

This important value of NEA - helping to bridge the period during which price decontrol takes place - first appears at the bottom of page 2-3. Our first general review comment is that the "imperfections in the energy market place" justification should be brought up front in the report and be one of the major thrusts of the report. 9

Our second general review comment is that we believe the value of NEA is much greater in inter-technology comparisons than in intra-technology comparisons. In the instance of intra-technology comparisons and more specifically coal liquefaction, coal mining, product refining, capital investment, maintenance materials and catalyst and chemicals effects are common to all of the technologies. The principal public policy question relative to "energy market place imperfections" is differences in relative amounts of imported electricity. DOE can resolve this problem by insisting that developers present at least one case wherein the proposed facility is self-sufficient in that no electricity is imported. Other differences are due to capital investment/ thermal efficiency trade-offs specific to the individual projects. We do not believe that NEA analysis is required in addition to conventional economic analysis (imported electricity perhaps excepted) to choose between direct coal liquefaction technologies. Further, we believe that currently available economic analysis data is not sufficiently accurate to permit selecting the most attractive coal liquefaction technology in any case. Among the more advanced technologies, each may prove to be attractive in specific marketing situations with particular coals. Of more importance will be the degree of commercial readiness of the technology, the technical risks, and the availability of a competent operating - engineering - financing team to manage the project.

In the instance of inter-technology comparisons, susceptibility to marketplace imperfections is much greater. For example, in Figure 7.2, the premium fuel ratio comparison and the total energy ratio present reliable comparisons of coal liquefaction and ethanol production from a policy standpoint. In our opinion, the differences are real although not of the magnitude depicted in Figure 7.2. We see NEA as a valuable tool in allocation of Federal funds among technologies. It is less valuable as a means of allocating funds within technologies due to optimization nuances and data reliability problems. fig.6

Our last general comment is that the draft report title and the digest of the report are framed in a manner that will almost certainly lead to unbalanced treatment of the issues by the press. Implicit throughout the digest is the thought that refusal by the DOE to implement NEA has resulted in sponsoring questionable projects. In reality, while not using NEA, DOE has fairly consistently obtained thermal efficiency estimates which, although less comprehensive than NEA, are of unquestionable value in supplementing economic analysis. We would rather see the issues as:

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- o NEA is required by law.
- o GAO has developed an NEA methodology and shown it to be useful.
- o Implementation of GAO's NEA methodology or some improved version of same will help prevent misallocation of Federal energy development and energy conservation funds in the current "imperfect energy market" situation.

Specific editorial comments follow in abbreviated format in the attachments. Attachment H is being sent directly from our Ashland, Kentucky office.

Yours very truly,
ASHLAND SYNTHETIC FUELS, INC.

John

John B. Grant
Project Director

JBG/HNH/js
Attachments

APPENDIX VIII

Attachment A

[to Ashland's letter]

EDITORIAL NOTES

Digest page IV, Editorial Comments i

- o This would be a logical place to introduce the "imperfect energy market" concept.

page VIII deleted

- o The comment on cost estimating methods is certainly valid however relative to NEA, cost estimating does not seem very important. It would seem to us that this is a separate issue and of equal or greater importance than NEA.

page IX v

- o Development of the input for NEA requires that projects and technologies proceed through significant engineering and definition. Premature development of an NEA will lead to unreliable estimates. It should be emphasized that NEA should be carried out when adequate data is available for a meaningful estimate.

page 1-4 3

- o Failure to state that the DOE has been obtaining overall plant thermal efficiency estimates tends to exaggerate the "DOE neglect of NEA"

page 4-10 24

- o We have attached the most recent Breckinridge Project material balance which is in substantial agreement with Table 4.1 except for the pipeline gas production which is significantly higher. table 1

page 4-11 23

- o There is little difference between H-Coal and EDS raw naphtha. The EDS naphtha once processed thru hydrotreating and reforming steps produces a reformate equivalent to the H-Coal reformate. The issue here, should the naphtha processing be at the coal liquefaction plant or at a refinery, will be resolved differently by the various projects. The decision will be based on economics, existing refinery capacities, etc. and NEA considerations will be relatively unimportant since the processing must take place at one location or another.

- o The SRC I coke is indeed a valuable electrode raw material, however, this market is limited. The market constraint needs to be highlighted since only a few commercial plants would lead to oversupply of coke.

 APPENDIX VIII

Editorial Comments - pg 2

page 6-6 33

- We are not able to follow the logic in Appendix II of the refinery energy savings.

page 6-8 35

- Catalyst and chemicals - As a consequence of the H-Coal technology, significantly greater amounts of catalyst are consumed than in other direct liquefaction processes. The catalyst and chemicals costs for H-Coal consist then principally of catalyst cost and to a lesser extent chemicals. In future iterations of NEA it may be appropriate to use a special methodology for high cost catalysts where use of average chemical energy consumptions tends to distort the NEA. The most recent estimate of catalyst and chemicals requirements for the Breckinridge Project is attached.

- Maintenance Materials - Maintenance materials and maintenance and materials are used interchangeably in Appendix II. The methodology is specific to materials since labor is excluded. The text should be edited to delete the "and."

- Capital - The capital related energy for H-Coal cannot be significantly greater than EDS since the estimated capital costs of the facilities in $1981 is quite similar. We suspect that the use of different methodologies has exaggerated the capital related energy consumption. The Breckinridge Project Phase Zero capital estimate breakdown is included for your information.

page 6-11 35

- There is an obvious error in the outputs in this table. The total energy ratio of 0.784 is impossible. This error weakens the entire analysis. table 6

page 6-15 37

- First paragraph - The interpretations are based on such sketchy data that the entire paragraph should be deleted. penult.

- Second paragraph - The sentence "for example ...... if its advantage were not suspect." is particularly weak in view of the obvious error in the SRC II data. We suggest that after correction of the error, the sentence be rewritten. last full

- Third paragraph - We suggest deletion of the entire paragraph. last

page 6-16

- First paragraph - We suggest deletion of the first sentence in that it is based on questionable data. same

Editorial Comments - pg 3

page 6-18 39

- Third paragraph - We suggest deleting the entire paragraph since it is based on conjecture. The continuation on page 6-19 should also be deleted. 3rd under head

page 6-20 39

- We believe that the problems with cost estimating accuracy are a separate issue, albeit a very important one. These problems should be the subject of a separate report.

page 6-21 40

- The H-Coal information included in Appendix II is based on preliminary work by ASFI without Bechtel participation. Subsequently, Bechtel and ASFI have developed a capital estimate based on estimating data which is probably more extensive than the EDS data. A copy of the latest H-Coal estimate summary is attached. The estimate is based on approximately $10MM of engineering and estimating work on a site specific design at Addison in Breckinridge County, Kentucky. Although it is probably not appropriate to revise the report to include this information, a clarifying sentence would be appreciated.

page 7-1 42

- The data from Energy and U.S. Agriculture: 1974 Data Base appears high by approximately a factor of 1.7. The attached ASME Statement on Alcohol, Attachment H, indicates the consumption of 36,000 Btu in the corn production needed for one gallon of ethanol, whereas, your data equates to 61,800 Btu.

page 7-2 42

- Footnote 2 leads the reader to believe that more energy is being used in growing corn since the study was made. The energy costs of raising corn may have increased while fuel consumption remains the same or even drops. last par.

page 7-4 44

- The first paragraph assumes electricity consumed in ethanol production is derived from 38% premium fuels. We take exception to this assumption in that site specific ethanol plants may generate their own electricity from coal or purchase electricity from a coal burning generator.

page 7-5 44, fn 1

- South Point Ethanol of which Ashland Oil is a 50% partner feels that its primary market for ethanol is as an octane booster.

APPENDIX VIII

Editorial Comments - pg 4

page 7-7 46

- You recognize a problem that is critical to the analysis. Neither Idaho Falls nor plant X are representative of the energy efficient plants. The South Point Ethanol facility has a process guarantee of 49,171 Btu/gallon of ethanol, the ASME study, Attachment H, estimates 56,000 Btu/gallon of ethanol, whereas Plant X consumes between 65,000 and 75,000 Btu/gallon of ethanol on a comparable basis.

page 7-10 46

- Figure is useful if data is correct. fig. 5

page 7-11 48

- Premium fuel ratio could be as high as 2.5-3.0 using the other data mentioned above. Similar comments are valid for the other two ratios.

page 7-12 48

- Recognition of the variability in energy requirements for growing corn should be emphasized much earlier in the report.

II-3 64

- Table II-2 - We have attached the capital cost estimate resulting from the Phase Zero effort which supercedes the $2.6MMM. The footnote seems to be superfluous or the tabular reference has been omitted. table 10

II-9 70

- Maintenance and materials - please delete "and."
- Pipeline Gas - Why is the pipeline gas in parenthesis. The quantity produced from 6700 tons of coal seems very high based on typical SRC II yields.

II-14 74

- The updated material balance is included for your information.
- Catalysts and chemicals overstates energy requirements. An updated catalysts and chemicals table is included for your information.
- Maintenance & Materials - delete &.
- See attached thermal efficiency calculations for coal heating value.

APPENDIX VIII

Editorial Comments - pg 5

II-15 75

- The updated electrical consumption is included for your information.

II-16 76

- Maintenance and materials - delete "and". Also in following text two times and in table.

II-19 77

- Maintenance & Materials - delete &.

II-20 78

- Maintenance & Materials - delete &.
- M&M expenditure - delete &.

II-24, II-25, II-26, II-27 81,82,84,85

- Maintenance & materials - delete &.

III-4 96

- The following statement might be appropriate:

  "the Idaho Falls Plant cannot be as energy efficient as a commercial plant over 100 times its size."

III-11,14 104,106

- This data indicates the annual consumption of 40-45 gallons of fuel/acre for field operations. Intuitively, this seems high. The 3 lb of fertilizer per bushel of corn seems reasonable. However, the assumption that fertilizer contains 80% premium fuel rules out the possibility of producing ammonia from a non-premium fuel such as coal. This is a severe penalty on the ratio of premium to total fuels.

III-13 102

- Typographical error in Table III - 10 column 8 in which 1,877 should read 9.877. table 55

III-14 106

- Typographical error in units of input volume in which 10^9 lbs. should read 10^6 lbs.

HNH/js

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G.C. LAHN
Manager

November 30, 1981

Mr. Luis J. Gonzalez
United States General Accounting Office
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Dear Mr. Gonzalez:

The purpose of this letter is to provide our comments on your draft report entitled "DOE Spends Hundreds of Millions on New Energy Technologies Without Knowing Potential Net Energy Yield." We understand that the purpose of this report is to advocate the use of net energy analysis (NEA) by the DOE and the Congress to compare new energy technologies.

In your report, you have illustrated the use of your NEA methodology by applying NEA to direct coal liquefaction and ethanol production technologies. In evaluating direct coal liquefaction, you have compared four alternative processes including the Exxon Donor Solvent Coal Liquefaction Process. We understand that the examples shown are for illustrative purposes only and we agree with your comments contained in Chapter 6 that no valid conclusion regarding the relative merits of the direct coal liquefaction alternatives can be drawn despite the differences shown in your analysis.

We believe that to a large extent the differences between liquefaction alternatives shown in your report are more likely a result of inconsistencies in the data and assumptions used to evaluate the alternatives than a reflection of any fundamental differences in energy efficiency. In addition, by showing a single example for each technology, the comparison does not reflect the flexibility of each of the alternatives to vary product slate or process configuration in a way that could give significantly different measures of energy efficiency (total energy ratio) or ratio of premium products to premium energy utilization (premium fuel ratio).

The EDS case which you have chosen for comparison with other technologies involves a configuration which includes FLEXICOKING of the EDS bottoms and production of hydrogen by steam reforming of C_2- gas. An alternative configuration involving FLEXICOKING of bottoms and partial oxidation of coal to produce hydrogen would show an increase in energy ratio from .56 to .62 as well as a significantly higher premium fuel ratio. By going to an operation in which a portion of EDS bottoms is recycled to the liquefaction reactor we can further increase the premium fuel ratio without significantly reducing the total energy ratio. There are other feasible EDS

- 2 -

configurations which can give even higher efficiencies, such as the use of a hybrid boiler to generate steam and process heat from EDS bottoms and coal, and partial oxidation of bottoms to produce hydrogen. This configuration would give a total energy ratio of about 0.64 vs. 0.56 for the case shown in your report. These examples show that it is essential to consider the full range of feasible process options for each technology on a consistent basis to arrive at meaningful conclusions using NEA.

As you are well aware, the quality of the data base is a critical factor affecting the validity of a comparative efficiency analysis, particularly for "intratechnology" comparisons where the technologies being compared utilize the same energy resource and aim to produce similar types of products. Our studies have shown that it is important to assure that for each of the alternatives being evaluated, yields are based on anticipated product recovery. This requires an analysis of all of the alternative operations of the plant considering downtime for the various plant sections and processing components. It is necessary to assure that yields and utility requirements for all of the options are estimated on a consistent basis with regard to plant energy conservation, environmental control, operating flexibility, steam power optimization and product upgrading. An example of the impact of changing the assumption regarding the amount of heat integration incorporated within the plant is shown in the EDS Study Design Update (GAO report reference 55). By investing more money in heat recovery/exchange equipment to recover all heat down to 250°F, efficiency can be increased by about 5 percentage points. The extent to which such detailed information is available for each process option will depend on the stage of development of the process and level of engineering that has gone into the process evaluation. We, therefore, question the usefulness of NEA in comparing the coal liquefaction options which are at different stages of development and for which equivalent quality information may not yet be developed. Exxon, 1981.

We recognize that you have qualified the results of your direct coal liquefaction comparison as evidenced by your statement in Chapter 6 that "any conclusions of substance would stretch the bounds of credibility at best." However, in order to assure that the information shown in your report is not taken out of context or misunderstood, we recommend that a qualifying statement also be included in the Conclusions section of the report digest. Specifically, we believe that the Conclusions contained in the report digest should clearly state that the coal liquefaction processes were compared for illustrative purposes only and that because of inconsistencies in the data base and a need to show a full range of feasible configurations/operations for each technology, no valid conclusions can be drawn regarding the relative energy efficiency of the alternative direct coal liquefaction processes.

 APPENDIX VIII

The following points summarize additional comments:

- On page 4-5 you refer to the cost of the 250 ton/day pilot as being 350M$. This is incorrect. The total cost for the EDS Project, including the 250 T/D plant, is estimated to be about 340M$. The large pilot plant by itself cost 118M$. 21

- On page 6-18 you refer to another major downstream problem as being the corrosive effect of ash on letdown valves. Within the EDS Project we have had excellent success in demonstrating satisfactory operability of the slurry letdown valve. No significant erosion or corrosion of the valve occurred after 128 days of operation on Illinois coal in the once-through mode. Although somewhat higher erosion resulted following operations on Wyoming coal in the bottoms recycle mode, the performance of the valve is regarded as satisfactory for commercial scale-up. Based on our large pilot plant experience, we do not regard the slurry letdown valve as a significant downstream problem in the EDS process. 39

- On page 4-5 you describe the two alternative cases contained in the EDS study design update and indicated that you chose the steam reforming case for your study. We believe that you should also point out in this paragraph that there are alternative configurations which give more favorable energy and premium fuel ratios which should be considered in evaluating the process alternatives using NEA. 21

- In your description of the EDS process on page 4-6, you indicate reactor conditions of 800 to $850^{\circ}F$ and 1500 psi. We suggest that you add a description of alternative operations with bottoms recycle up to pressures of about 2500 psi. As previously noted, with bottoms recycle, a portion of the heavy vacuum bottoms is recycled to the liquefaction reactor to produce additional premium products. This case will, of course, give a higher premium fuel ratio than the case chosen in your comparison. 21

- In discussing the direct liquefaction product slate, it should be pointed out that there is significant flexibility to vary the EDS product slate. For example, heavy vacuum gas oil can be recycled to eliminate production of heavy fuel oil and produce more naphtha and distillate products.

We hope that these comments will be useful to you. Please contact me if you have any questions or would like additional information on the EDS processing options. If you wish, we will be happy to meet with you in Washington for further discussions of this matter. We look forward to hearing from you if you have any further questions.

Very truly yours,

G. C. Lahn

G. C. LAHN

GCL:ra

c: W. R. Epperly

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