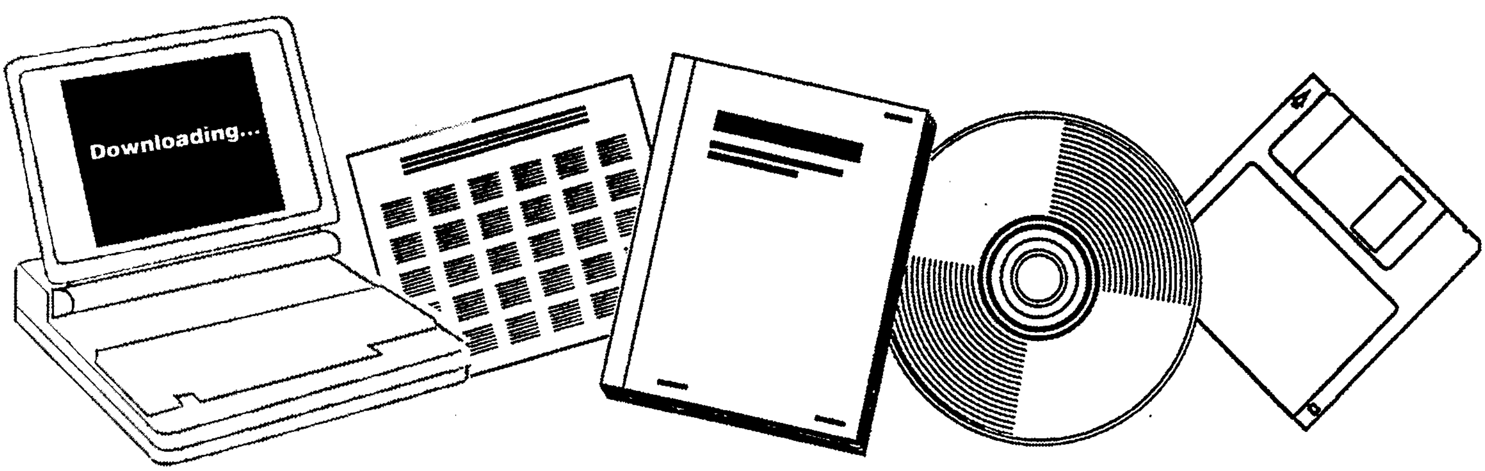
AN ASSESSMENT OF NEW OPTIONS IN ENERGY RESEARCH AND DEVELOPMENT

OFFICE OF SCIENCE AND TECHNOLOGY,
WASHINGTON, D.C. ENERGY ADVISORY PANEL

NOV 1973



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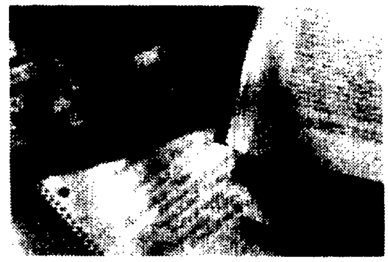

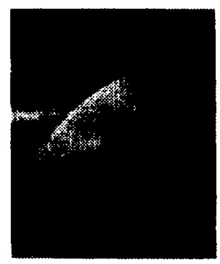

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AN ASSESSMENT OF NEW OPTIONS IN ENERGY RESEARCH AND DEVELOPMENT

November 1973

ENERGY ADVISORY PANEL
OFFICE OF SCIENCE AND TECHNOLOGY
EXECUTIVE OFFICE OF THE PRESIDENT

A REPORT OF A STUDY ORGANIZED BY THE OFFICE OF SCIENCE AND TECHNOLOGY WITH THE PARTICIPATION OF THE FEDERAL COUNCIL FOR SCIENCE AND TECHNOLOGY AND WITH PARTIAL SUPPORT FROM THE NATIONAL SCIENCE FOUNDATION

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FOREWORD

The President, in his June 4, 1971 Energy Message, stated: "The key to meeting our twin goals of supplying adequate energy and protecting the environment in the decades ahead will be a balanced and imaginative research and development program."

He announced at that time a commitment to demonstrate the Liquid Metal Fast Breeder Reactor (LMFBR), and an expanded Federal effort in coal gasification and sulfur oxide removal from stack gas. He further requested his Science Advisor "to make a detailed assessment of all of the technological opportunities...and to recommend additional projects which should receive priority attention."

In response to that request the Office of Science and Technology (OST), with funding assistance from the National Science Foundation, contracted with Associated Universities in the summer of 1971 to develop a study methodology for assessing energy research and development options in the context of their ultimate impact on the nation's energy and environmental future.

The Reference Energy System utilized in the study was developed by Associated Universities, Inc. as the first phase of this study. Dr. Philip Palmedo and Dr. Kenneth Hoffman of AUI also provided valuable assistance in the technology assessment phase of the study and in the preparation of this report.

Panels of experts from government, industry and universities were organized through the Federal Council for Science and Technology (FCST) to review the state of technology and prepare a listing of R&D opportunities in each of eleven technical areas.*

Mr. Fred Weinhold, a member of OST's energy staff, was chairman of the FCST committee which organized and carried out the identification and evaluation of technological opportunities for meeting future energy needs. His efforts and those of the FCST Panels in assembling material for the review of OST and its Energy Advisory Panel were invaluable in this assessment.

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* Resource extraction, solar, geothermal, coal utilization, advanced cycles for power generation, alternate breeder reactors, fusion, hydrogen and synthetic fuels, electrical transmission, transportation and urban and residential energy utilization. Panel reports are available through the National Technical Information Service, Springfield, Va. 22151.

OST utilized its Energy Advisory Panel (See Appendix A) to aid in directing and evaluating the panel efforts. The Energy Advisory Panel was broadly representative of the energy R&D community. Members were drawn from industry and academia and their collective experience covered all technical areas of concern in the study. Their judgment in evaluating the realism of technical, economic and time schedule projections and in identifying those options required for a balanced program was essential.

The program recommendations in this report do not embody a complete energy R&D program in that it was undertaken in response to the Presidential request in his June 1971 Energy Message to identify "additional projects which should receive priority attention." The fission program had been such a program and thus it was excluded from consideration in this study, with the exception of alternate breeder reactor programs. The panel would certainly endorse the high priority given to fission R&D in the past and support an expanded effort in the future, particularly in the areas of reactor safety, radioactive waste disposal, gas cooled reactors and related technology and uranium enrichment.

Program funding levels are presented in 1973 dollars in each case and runout costs, particularly for the more costly pilot and demonstration plant projects, can be expected to escalate with time. The funding levels recommended are judged to be the minimum needed in each area for a nationally planned and managed program. While some support will likely be obtained from industry, particularly for pilot and demonstration scale projects, it is the panel's feeling that the program recommendations are of sufficient national importance so government should be prepared to underwrite the total cost if necessary. Non-governmental funding of energy R&D related to the special interests of industry and universities will continue and hopefully complement these program objectives. However, this should not be taken for granted; it is the realization of the program objective that is paramount, not the total number of dollars spend in any given area.

OST completed its study in the Fall of 1972 and the results were useful in preparing its recommendations for energy R&D in the FY 1974 budget. This report, prepared for distribution to the energy community at large, represents the output of a continuing study by the Energy Advisory Panel which extended beyond the date when OST was abolished by the President's Executive Reorganization Plan I. The National Science Foundation, through the Office of Energy R&D Policy provided continuing support of the Panel's activity. The report in its present form represents the collective judgment of this panel and should not be assumed to represent the views of the Executive Office of the President or the National Science Foundation.

Richard E. Balzhiser

Chapter I - OBJECTIVES AND SCOPE OF THE ASSESSMENT

A. INTRODUCTION

This study addressed an important and complex question: what constitutes a balanced national program in energy R&D and what impact can that program have on meeting future energy needs?

The importance of that question relates to the pervasive role of energy in our society and our present dependence on non-renewable fossil fuel resources. The complexity of the question arises from the magnitude of the energy delivery system itself and the need to consider not only the technological but also the social, environmental, political and economic factors in formulating program priorities.

In the United States we have, until recently, taken energy for granted. It was always available and at nominal cost compared with other goods and services. Recently, we have become aware of the consequences of the historical "cheap and abundant" attitude. First of all, the growth of energy consumption has been so rapid that the rate at which acceptable fuel resources are being consumed is now significant relative to the original stocks with which the country was endowed. Furthermore, the traditional methods of using these fuels are creating intolerable environmental effects. Practically all of our air pollution and much of our water pollution is created by the burning of petroleum derivatives and coal. Just when the abundance and cheapness of energy seemed assured, the duration of abundance became questionable and the cheapness was seen as illusory, created through the neglect of hidden costs to society.

Two aspects of energy, therefore--its character as a consumer of non-renewable resources and its effect on environmental quality--form the basic concerns at the heart of this assessment. Cost continues to be a concern, of course, but must be expanded in concept to include external as well as internal costs.

B. THE ROLE OF TECHNOLOGY

Technology is only one of the means through which the energy system can be improved and the nation's needs met, but it is an important one. The most cursory examination of the many methods for consuming fuels discloses that our energy system is relative primitive. Many energy-conversion and energy-consuming devices are relatively inefficient, and the management of our resources has been haphazard. This is, in large part, a consequence of the illusory cheapness of most forms of energy until recent times. The energy system has been, and continues to be, amenable to major improvement through technology. This is particularly important at a time when our perspective on energy problems is changing. Historically, the changes in energy production and conversion have aimed at increasing central station power plant efficiencies, lowering cost and adding to the fuel mix available to the consumer. Technological innovation is just beginning to be turned toward the goals of reducing environmental effects, increasing overall efficiency in energy use, reducing consumption of non-renewable resources and increasing reliance on domestically available resources.

The technological focus of this assessment does not imply that the best way of solving any or all of the problems besetting the energy system is through technological change. In many instances other actions can produce much swifter ameliorative response. For example, the supply of natural gas might be influenced much more directly by increasing gas prices at the wellhead or accelerating offshore leasing programs than through R&D on coal gasification. But while these two approaches differ in their response times they also differ in the length of time into the future over which they provide solutions.

Similar situations arise in other instances, for example in reducing energy growth by conservation policies relative to increasing the technological efficiency of components of the system. An analysis of specific solutions to specific problems as a function of time shows that what appear to be alternatives really are not. Neither changes in non-technological policies nor new technologies can provide all the solutions at all points in time. Both are required. The present analysis of technological "alternatives" was carried out with full cognizance of the need to exercise other policy options.

It is imperative to recognize that the problems of 70's must be solved for the most part with existing technologies, some of which have not yet had a major impact on the nation's energy system. Solar space conditioning systems, fission and LNG are examples of technological options which could assume a more prominent role this decade. Stack gas cleaning systems and the High Temperature Gas Reactor (HTGR) are examples of technologies that are about to be commercially demonstrated. The former will require about three years to design and install, once utilities can be assured of performance--probably some time in 1974. The HGTR should be demonstrated on a commercial scale at Fort St. Vrain, Colorado with startup scheduled in 1973. Orders for these systems have been placed for the 1979-80 time frame so their impact in this decade will be negligible. The point of importance is that most new energy technologies will require three to eight years to get on line once their technical and economic viability is demonstrated and decisions are made to proceed with commercialization. Demonstration projects for the breeder reactor, oil shale, coal gasification and liquefaction and central station solar power are even less advanced and options cannot make an appreciable contribution to our clean energy needs before the 1970's or 1990's.

Resources and Efficiency

Two kinds of technical innovations can have an effect on energy resource use: those which increase the efficiency with which a given resource is used to satisfy a given need and those which make available previously non-useable resources. Both kinds were sought out in this study. In fact, the two kinds of innovations are hard to distinguish in some instances; the fast breeder reactor can be considered either as using uranium more efficiently than water reactors or as making U-238 available as an energy resource. Increases in efficiency can, of course, occur anywhere along the line from fuel production to the end use of the energy. From a resource point of view these are equivalent; a penny saved is a penny earned. From the environmental point of view, however, there may be an advantage in saving a penny at the utilization end of the chain, for an improvement at that point has a beneficial effect both at the end point and at all previous points at which there are adverse environmental effects. Furthermore, there appears to be a considerably greater opportunity for improvement at the utilization end, where low cost and abundance in the past have led to wasteful practices.

Environment

The importance of environmental effects as a criterion for judging future energy technologies was emphasized in the President's 1971 energy message and was a basic element of this study. By "environmental effects" we really mean all the external social costs of energy production and use. By reducing adverse environmental effects, then, we mean the reduction of external diseconomies and non-market costs per unit of energy supplied. These effects would include environmental degradation during the extraction, transportation and processing of fuel, conversion to electricity, ultimate end use and disposal of waste. It would also, importantly, include all public safety and health effects throughout the system.

Clearly, our understanding of how to evaluate these effects is rudimentary at best. We do not know how to assign dollar values to many environmental effects, nor do adequate data exist regarding the health implications of many pollutants. Such knowledge is very important, but was not critical to this assessment. The technological options that were sought were those with major impacts on these effects. As will be shown below these options seem highly probable and the prioritization of R&D programs necessary to make them available does not require a detailed cost/benefit analysis before proceeding.

One should note the strong interaction between environmental and resource criteria. For example, the environmental effects of SO_2

released in fossil fuel combustion severely limit high-sulfur coal as a fuel resource. Techniques such as coal gasification that remove sulfur from coal thus have a large effect on usable energy resources.

Economics

The criterion of cost (as conventionally defined) enters somewhat differently from the criteria of beneficial environmental and resource effects. Technologies which are more expensive, but have significantly less environmental effect, were considered for evaluation whereas cheaper but more damaging technologies were not. In the long run it is the "total" cost that counts, not the cost that happens to be internalized at a given time. Of course, it must be recognized that in order for a technology to be accepted it must be competitive in the market. However, energy costs are changing rapidly at the present time and are extremely difficult to forecast over the time periods required to bring many of the technological options reviewed to fruition. Thus a technology which today appears to have too high a cost, could in the future become relatively attractive, not only as a result of successful R&D, but also due to cost increases of competing systems.

Technology Development and Commercialization

The need to broaden our resource base, to improve efficiencies in energy conversion and utilization, and to minimize the environmental consequences of an energy-intensive society has been clearly established. To many the task seems trivial in comparison with placing a man on the moon or developing super-sophisticated weapon systems. In these instances cost has been a secondary consideration, clearly subordinated to national prestige and/or security.

The energy systems required to meet our energy needs must be economically viable as well as technically feasible. They will be utilized by a highly diversified and competitive energy industry as opposed to government alone. Nuclear power became attractive for military propulsion systems long before it became competitive in the generation of electricity in the nation's utility systems; solar energy is currently utilized to power space craft and satellites, but can't begin to compete with fossil or nuclear sources for central station power purposes. In both of these cases it is not technical feasibility alone that determines their suitability for use in our energy system, but economics considerations as well.

While society occasionally benefits from high visibility Apollo-like efforts associated with military or space technology, the additional step of going from technical feasibility to economic viability is frequently far more challenging and time consuming. In order to completely understand the challenge that engineers face in developing technology to improve our energy system, it is imperative that one understand the necessary steps in the process--research, development and commercial demonstration. It is equally important to understand the role that government and industry have traditionally played in the technology development process and how it might be modified to improve the rate at which possible options can be commercialized. Research in addressing these institutional factors that affect technology development, while not addressed in this study, is equally important.

Industry's past commitment to research has been a major factor in this nation's technological development and the increasingly dominant position of many U.S. corporations in world markets. However, increased competition and labor costs have cut profits in many industries with the result that research that is not directly related to a company's near term earnings has become increasingly difficult to justify to management. In the energy area corporate expenditures for research and development exceed one billion dollars at the present time, excluding research expenditures related to produce development and marketing. Most of the research and development in the oil and gas industries and in the generation and transmission of electrical energy (other than nuclear power) has been and continues to be done by industry. In recent years environmental concerns have forced most of these companies to commit a large fraction of their research dollar to eliminating the adverse environmental consequences of present technology. The combination of all these factors has made it increasingly difficult for industry to invest in research relating to new energy sources or advanced systems where the options are many, the risk is often great and the payoff too far in the future. Further uncertainty results from the government's regulatory role of various elements of the energy industry.

Government's role in research and development has typically complemented industry's in that it has carried a large part of the cost of basic research in government laboratories and universities. It is essential that this support continue. Other high technology efforts in support of the nation's defense and space programs have also had important applications outside these areas. Fission is an example of a complex and costly technological development, originally focused on weapons production, in which the government has made the major investment. Fusion is progressing in a similar way. The costs and risks are judged to be too great and the ultimate commercialization too far in the future for industry to commit substantial research dollars.

While there are some exceptions to this pattern, this is not an unreasonable arrangement under normal conditions. However, the perceived urgency in resolving the nation's energy problems creates a somewhat abnormal situation in which the rate of evolutionary change in energy technology is judged by many to be too slow to avoid shortages in the future. Shortages of oil and gas and environmental problems with coal and uranium utilization have made obsolete much of the technology developed to date and have required rather revolutionary changes in others. In addition, completely new technology must be developed to utilize new energy sources and increase the efficiency with which we use all forms of energy.

The cost of such a broadly based program is very large, yet it represents only a small portion of the future investment in the energy sector to which it applies. The size of the R&D program, its current urgency and the risks involved make it imperative that government funding increase. GOVERNMENT SUPPORT MUST INCREASE NOT ONLY IN NUCLEAR AREAS, WHERE IT HAS PLAYED A MAJOR ROLE TO DATE, BUT ALSO IN AREAS THAT

HAVE TRADITIONALLY BEEN THE DOMAIN OF INDUSTRY, NAMELY FOSSIL FUELS AND ENERGY CONVERSION.

Since most of the technical expertise in these areas resides in industry and since decisions to utilize new technology will presumably be made by industry, it is essential to involve industry in all phases of the development of these technologies as well as in new areas such as oil shale, solar and geothermal. Many of the most promising programs in these areas are emerging from industrial programs which include proprietary technology. If government support is to be used most effectively, it is imperative that it be used to support the best approaches in a given field and not just efforts in the national laboratories.

At the same time sufficient incentive must exist for individuals and firms to utilize government support to accelerate their innovations and, more importantly, to continue to invest in research and development even when the road to commercialization may be long and uncertain. The public interest is best served in this instance by making the best technological options available as rapidly as possible. The President's patent policy of August 1971, if fully implemented, is responsive to this point.

Many of the synthetic fuels options for supplementing our oil and gas resources will require demonstration of commercial feasibility before the energy industry will be willing to invest hundreds of million dollars in plant facilities. Such demonstrations must be conducted on a scale sufficiently close to full scale to verify process operability and economics. These projects require substantial funding, typically in excess of that which even our largest corporations are prepared to commit. The uncertainty in government policy regarding gas pricing and import policy, coupled with the inherent uncertainty in estimating the extent of as yet undiscovered oil and gas resources result in market uncertainties which make it even more speculative for industry to make these large financial commitments.

Government support in terms of demonstration plant funding or assured markets for synthetic fuel products from pioneering plants is needed to advance synthetic fuels technology at a rate sufficient to insure that future needs can be met with domestic resources. Partnership arrangements such as those established for coal gasification, stack gas cleaning and the liquid metal breeder reactor must be utilized for other coal conversion technologies, oil shale and other advanced concepts. The funding policy should have sufficient flexibility to assist in more rapidly commercializing proprietary technology, as well as that which emerges from government laboratories, and under conditions which properly compensate the innovator while protecting the public interest.

The Japanese have been highly successful in combining the innovativeness of the private sector with the financial resources of government to further their national interest. It is equally important that the U.S. develop comparable procedures to utilize fully its technological capabilities.

C. ENERGY POLICY AND R&D ASSESSMENT

The energy system is determined by a complex conjunction of social, political, technical and economic factors. The technical options available at any given time act as limiting conditions on the system's mix, but are by no means the only factors of significance. In the context of government decision-making, it is useful to specify the relationship between questions of a purely policy nature and the technical (or meta-technical) questions that were addressed in this study.

The ultimate purpose of the study was to provide the most favorable combination of technical options for the future evolution of the energy system in this country. Its immediate aim was to define areas of R&D which will add to or supplement current R&D activities to provide those options. In order to do that, one must consider the various future policy directions that may be found desirable. Consider, for example, the question of national independence from foreign sources of fuel. This study was not intended to recommend the degree to which we should be independent, but rather to recognize independence as a possible policy desideratum and to make clear, in the case of each future technology, the implications in terms of that criterion. The weight given to the factor of independence relative to other factors (economics, environmental quality, etc.) must be determined externally to the study. As it turned out, most of the technological opportunities that were evaluated in the study would tend to decrease our dependence on fuel imports.

D. ANALYTICAL APPROACH

One of the most difficult analytical problems in the assessment of energy technologies results from the wide range of technologies involved. How does one compare the benefit of investing in research on fusion with the gains possible in developing more efficient transportation systems? Yet comparison of disparate research goals is a necessity imposed by the multiple interconnections and possible substitutions in the energy system. The unpredictable but long time scale of energy R&D further complicates the analytical problem.

To aid in the analysis of R&D options a methodology using Reference Energy Systems was developed. A Reference Energy System embodies the set of technologies that are employed to convert energy resources into useful forms of energy. It covers the entire spectrum of end uses. By projecting energy demands and fuel mixes, reference systems were constructed for selected years in the future. Associated with each Reference Energy System are various environmental impacts, resource consumptions and costs. In order to evaluate the impact of a new technology a "perturbed energy system" (for the appropriate year) is produced incorporating the new technology. One can then derive the resulting impacts on resource consumption, economics and environmental effects. It is those impacts that can be compared between technologies.

In the next chapter the basic data that are associated with the Reference Energy Systems are discussed. Using those models a more specific analysis of the problems facing the energy system can be made. In Chapter III the most promising areas of R&D in energy are discussed in some detail. In each case the impacts on the appropriate Reference Energy Systems are also presented.

Chapter II - ANALYSIS OF THE PROBLEM

A. INTRODUCTION

In this chapter much of the information that forms the factual basis for the choice of energy R&D priorities is presented.

First, the current energy system of the United States will be described. The description will include the resource base which is currently supporting the system and the first order environmental effects of the system. The year chosen for this description was 1969, the last year for which a detailed resource-supply-consumption picture could be drawn.

Second, the characteristics of the system are projected into the future. These projections, made under the assumption of no new R&D initiatives, will be used to define the major problems facing the system as a function of time into the future. They will also be used to evaluate the impact of potential new technologies. The way in which the present system is defined and the way in which the projections were made were very much conditioned by the requirements of the assessment. The projections were designed specifically to provide a framework for the assessment of R&D options. The final category of factual information contained in this chapter is the array of energy R&D currently being carried out in this country.

B. RESOURCES

As discussed above, a primary concern related to our energy system as it is now composed is its heavy reliance on non-renewable resources. This section briefly summarizes the pertinent statistics on U.S. resources.

Many conflicts and inconsistencies exist among the numerous compilations of energy resource data. Many such discrepancies result from a gradual process of vitiation as the data are conveyed through successive generation of documents. Special qualifications, explanatory notes, disclaimers, etc., which appeared with the original data, are lost in subsequent versions of the material and consequently the original significance is obscured. In some cases, apparent discrepancies arise merely from the use of differing criteria or assumptions in assembling the data.

The data presented in the following tables are not represented as being "best values" (if indeed such terminology has any meaning in this case). Where large discrepancies exist, a range of numbers is indicated. In general, for the purpose of this assessment it was decided that, where conflicts between sources had to be resolved, conservative estimates should be chosen. In this context, a conservative estimate is a low estimate. The bases for such choices are discussed below and in notes to the tables. Thus, even though the listings cannot be viewed as "best values" they are suitable for use as "reference resource values" in this assessment.

The emphasis is on resources that are usable by current technologies.

Definition of Reserves and Resources

In general, the concepts "reserves" and "resources" are ill-defined and there is no standard usage among the various energy industries. Furthermore, geologic data are inadequate for calculating precise values. In spite of these obvious deficiencies, it is apparent that even order-of-magnitude estimates of "reserves" and "resources" have considerable value in predicting the endurance of a given commodity, and in anticipating the approximate time at which alternative commodities must begin to be substituted in the market.

Insofar as practical, we have adopted the definitions and terminology proposed by V. E. McKelvey,(1) in which deposits are expressed in terms of two quantities: 1) degree of certainty, and 2) feasibility of economic recovery. This system is represented in Figure II-1.

The degree of certainty for remaining deposits is described by the terms proved, probable and possible, all three of which are classified as identified; and a remaining category termed undiscovered. (These terms are similar to the frequently used terms: measured, indicated, inferred and speculative.)

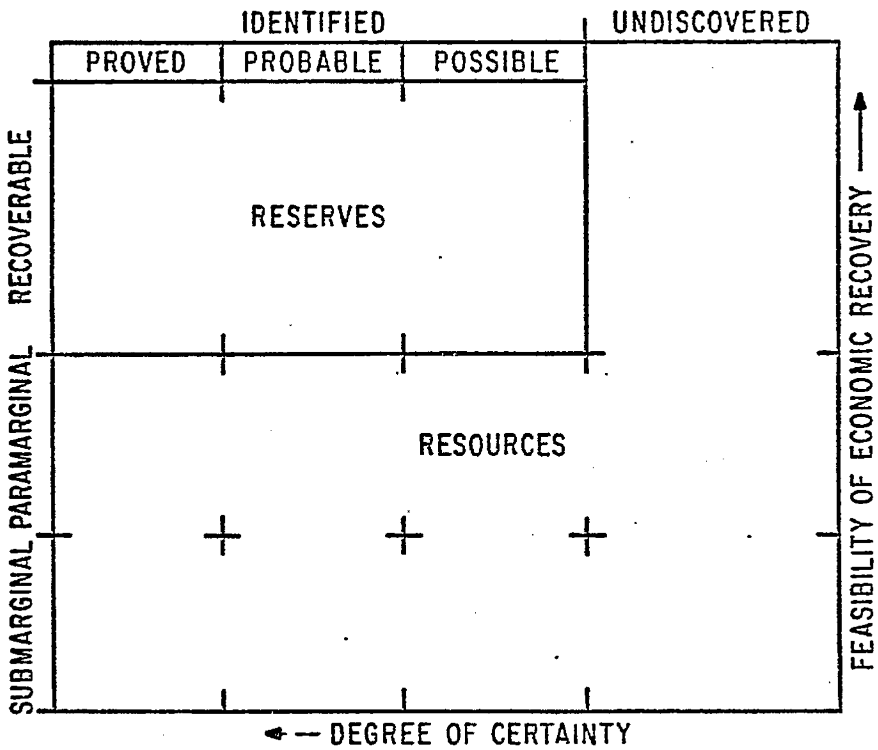


Figure II-1. Classification System Recommended by V.E. McKelvey [1]

The feasibility of economic recovery is described by the terms recoverable, paramarginal and submarginal. McKelvey defines paramarginal resources as those which are recoverable at prices as much as 1.5 times prevailing prices.

For example, in this terminology the petroleum proved reserves would be classified as proved-recoverable, various oil shale deposits would be classified as proved-paramarginal or proved-submarginal. Natural gas obtained through nuclear stimulation would be classified possible-paramarginal, etc.

We shall refer to "reserves" as being those deposits in the proved, probable and possible categories which are recoverable. The undiscovered and the paramarginal and submarginal categories in addition to reserves shall be called "resources."

Data on domestic fuel reserves and resources are summarized in Table II-1 and II-2. In the first table, the values are given in traditional units (tons, barrels, etc.). In the second, energy units are used. In some cases ranges are cited to acknowledge the fact that expert judgments are at variance.

Coal

The coal resources of the United States have been calculated by P. Averitt[2] using the most complete data available as of the end of 1967. There appears to be no justification in the form of new data for revising his estimates which are in fact commonly used in other compilations.[3] According to Averitt "measured or proved resources" consisted of 54×10^9 tons as of January 1, 1967. (We shall list these resources as proved-recoverable, although perhaps they belong partially in the probable- and possible-recoverable categories.) The value cited assumes that 7% of the estimated deposits lying within 1000 feet of the surface have seam thicknesses 28 inches or greater and an average 50% recovery factor. To obtain the proved-recoverable reserves at 1969 year-end, we subtract 1.7×10^9 tons for production between January 1, 1967 and December 31, 1969 and obtain 52.3×10^9 tons. Cumulative production

TABLE II-1

DOMESTIC ENERGY RESERVES AND RESOURCES

The 1969 Production is Compared with Cumulative Production and Proved-Recoverable Reserves. A range is listed for the estimated remaining recoverable resources to indicate variations among the estimates of experts.

Commodity	1969[a] Domestic Production	Cumulative Production to End of 1969	Reserves (Proved Recoverable) at End of 1969	Estimated Remaining Recoverable Resources	Unit
		--(quantities in traditional units)--			
Coal[b]	0.571	39.7	52.3	1600-3200	10^9 tons
Petroleum (Crude Oil)	3.372	89.5[c]	39.2[c,d]	106-343	10^9 bbls
Natural Gas Liquids	0.580	11.9[c]	8.1[c,d]	41-49	10^9 bbls
Natural Gas (Dry)	19.83	370.6[c]	301.0[c,d]	840-1500[e]	10^{12} ft^3
Oil Shale	Neg.	Neg.	20[f]	188[f]	10^9 bbls
Uranium ($/lb U_3O_8 Cut-Off Price)					
$8/lb	12.595[g]	203.69[g]	273[h]	733[h]	10^3 tons
$10/lb	-	-	423[h]	1073[h]	10^3 tons
$15/lb	-	-	625[h]	1600[h]	10^3 tons
$30/lb	-	-	800[h]	2400[h]	10^3 tons
$50/lb	-	-	4800[h]	8400[h]	10^3 tons
$100/lb	-	-	8800[h]	17,400[h]	10^3 tons
Thorium, $10/lb	Neg.	Neg.	65[i]	400[i]	10^3 tons

[a] 1969 production data from Bureau of Mines (ref. 3).

[b] Coal data from ref. 2, adjusted to 1960; remaining recoverable-resources include paramarginal deposits.

[c] API and AGA data (ref. 4).

[d] Includes revised 1969 additions for Prudhoe Bay, Alaska, ref. 5.

[e] See table of ranges in text.

[f] Ref. 6, pp. 155-169.

[g] Ref. 7.

[h] Uranium Reserves and Potential Resources are revised data as of Jan. 1, 1972, ref. 8.

[i] Private communication, June 22, 1972, USAEC Supply Evaluation Branch

TABLE II-2

DOMESTIC ENERGY RESERVES AND RESOURCES (in Btu)[a]

The 1969 Production is Compared with Cumulative Production, and Proved-Recoverable Reserves. A range is listed for the estimated remaining recoverable resources to indicate variations among the estimates of the experts.

Commodity	1969 Domestic Production	Cumulative Production to End of 1969	Reserves (Proved-Recoverable) at End of 1969	Estimated Remaining Recoverable Resources
	--(in units of 10^{15} Btu)--			
Coal	14.951	1040	1087	33,000 to 47,000
Petroleum (Crude Oil)	18.883	501	219.5	590 to 1920
Natural Gas Liquids	2.378	49	33	168 to 201
Natural Gas (Dry)	20.447	382	310	870 to 1500
Oil Shale	Neg.	Neg.	112	1053
Uranium ($/lb Cut-Off Price)[b]				
$8/lb	754	12,194	16,340	43,880
$10/lb	-	-	25,300	64,234
$15/lb	-	-	37,400	97,279
$30/lb	-	-	48,000	144,000
$50/lb	-	-	287,000	503,000
$100/lb	-	-	527,000	1,042,000
Thorium, $10/lb	Neg.	Neg.	3900	24,000

[a] Values were calculated from data in Table II-1 using conversion factors cited in the text.

[b] Entries for uranium are for 100% of U^{235} and U^{238} fission energy content. These numbers must be multiplied by the absolute efficiency of the reactor fuel cycle. Approximate values are: Light Water Reactor ~0.01; Fast Breeder Reactor ~0.70 to ~0.75.

to the end of 1969 was approximately 39.7×10^9 tons. Remaining resources to a depth of 6000 ft are estimated to be 3210×10^9 ton of which Averitt estimates 50% can ultimately be recovered (i.e. recoverable and/or sub-marginal). Since coal exploration of the contiguous 48-states is relatively complete, there is not likely to be appreciable coal resources in the undiscovered classification.

In calculating the energy content of the past production of coal shown in Table II-2 it was assumed that the coal was primarily bituminous. Thus a conversion factor of 26.2×10^6 Btu/ton was used. The proved reserves and remaining resources were converted by rank using the factors: anthracite 25.4; bituminous 26.2; sub-bituminous 19.0; and lignite 13.4×10^6 Btu/ton. The weighted average of these conversion factors was 20.7×10^6 Btu/ton.

Petroleum

The proved-recoverable reserves of crude oil at 1969 year-end were estimated by the American Petroleum Institute to be 29.6×10^9 bbls.(4) This value does not include the Prudhoe Bay field in Alaska which has subsequently been estimated(5) at 9.6×10^9 bbls.

Estimates of the ultimate domestic production to the end of the industry and of oil originally-in-place vary widely. Particularly, M. K. Hubbert(9) estimates the complete cycle of U.S.A. crude-oil production (lower 48 states) to be 165×10^9 bbls and the complete production of Alaskan crude oil to be approximately 30×10^9 bbls. The National Petroleum Council estimates(10) the U.S. petroleum potential to be 397×10^9 bbls for the lower 48 states including off-shore and 35×10^9 bbls for Alaska, for a total of 432×10^9 bbls. Various other estimates lie in the range of the latter. Nevertheless, annual production and new discoveries seem to be following the Hubbert curves.

For Table II-2, crude oil has been converted at the rate of 5.60×10^6 Btu/bbl.

Natural Gas Liquids

The proved-recoverable reserves of natural gas liquids at 1969 year-end was 8.14×10^9 bbls[4] not including Prudhoe Bay, Alaska. Approximately 0.4×10^9 bbls must be added for Prudhoe Bay.[5] Hubbert estimates the ultimate recoverable resources for the lower 48 states to be 35 and approximately 6 for Alaska[9] for a total of 41×10^9 bbls, whereas the National Petroleum Council estimates a total of 49×10^9 bbls.[10]

A weighted average conversion factor for natural gas liquids was calculated using the 1969 production distribution,[11] and the heat rate: natural gasoline 4.62; liquid petroleum gases 4.011; and Ethane 3.082×10^6 Btu/bbl. The calculated weighted average was 4.1×10^6 Btu/bbl.

Natural Gas (Dry)

The proved-recoverable reserves of natural gas at 1969 year-end was 275.1×10^{12} cubic feet.[4] This value did not include the gas reserves of the Prudhoe Bay area which were not listed until a year later when the total Alaskan Reserve was cited as 31.1×10^{12} cubic feet.[5] Cumulative production to 1969 year-end was 370.6×10^{12} ft^3. Estimates of the ultimate production show wide variations:

Ref.	Lower-48	Alaska	Total	Remaining
	(in units of 10^{12} cubic feet)			
(9)	1031	180	1211	840
(12)	1132	184	1316	945
(10)	1305	238	1543	1172
(13)	1499	358	1857	1486

Natural gas was converted at the rate of 1031 Btu/ft^3 at 14.7 psi and $60^\circ F$.

Uranium

The domestic proved-recoverable reserves of uranium have increased steadily in recent years as exploration has progressed. At 1969 year-end the proved-recoverable reserves at a cost less than \$8/lb were estimated as 204,000 tons.[14] By 1971 year-end they had increased to 273,000 tons,[8] with an additional 460,000 tons in the probable-reserve or possible resource classification. The total potential resources under \$15/lb exceeds 1.6 million tons. The values cited are in excess of cumulative past production which at 1969 year-end was 203,690 tons.[7]

The fission energy content of uranium was taken to be 59.86×10^{12} Btu/ton U_3O_8. A calculation of the practical energy which can be extracted in a power reactor must take into account the entire reactor fuel cycle. Approximate values of the absolute efficiencies are 1% for light water reactors and 70-75% for fast breeders.[5]

Thorium

Thorium compounds are used in small quantities in non-energy uses. Although a few reactors are partially fueled with thorium no significant quantities will be required for the next several years. By 1980 an annual market of 500 tons of ThO_2 is anticipated fo fuel High Temperature Gas-Cooled Reactors (HTGR) with some 3000 tons per year projected for after 1990.[14] Domestic proved- or probable-recoverable reserves of ThO_2 costing under \$10/lb are estimated as 400,000 tons.[8] There has been no economic incentive to explore for thorium, however and it is generally assumed that when and if a market develops the domestic resources will prove to be extremely large.

The ene: y content of thorium has been calculated assuming eventual fission of 100% of the initial thorium which gives 60×10^{12} Btu per ton of ThO_2.

Oil Shale

Although for the purposes of this assessment the extraction of oil from shale is not considered currently an economically viable technology, a recent report of a task group for the National Petroleum Council[6] evaluated oil shale resources and reserves. In that study, "reserves" are identified as well defined deposits of at least 30-foot thicknesses yielding at least 35 gallons/ton. Such deposits which must be classified as submarginal resources because of extraction and processing costs, are equivalent to 34×10^9 bbls of oil; however, at an estimated recovery rate of 60% this is reduced to 20×10^9 bbls. Total resources are estimated to be 1781×10^9 bbls of which 188×10^9 bbls are classified as potentially recoverable.

Crude oil from shale has been converted at the rate of 5.60×10^6 Btu/bbl (the same as crude oil) for lack of a more appropriate value.

World Production and Reserves

For purposes of comparison, the 1969 world production, estimated reserves and resources are listed in Table II-3.

Sulfur Content of Fuels

In terms of its potential for producing air pollution, one of the most important characteristics of fossil fuels is the sulfur content. Emission standards for SO_2 and the lack of effective sulfur removal technology restrict the sulfur content of fuels that can be used in some circumstances. The quite uneven distribution of sulfur content both as a function of rank of coal and of geography adds another dimension to the supply problem. Data on these matters are given in the literature[15-20] and have been summarized in a previous report.[21]

If the current new source emission standards for SO_2 are to be met by low sulfur oil and coal, approximately 70% of domestic petroleum reserves and about 40% of the coal reserves can be used. Furthermore, in the case of coal, more than a third of the acceptable resource is in the form of low grade lignite deposits in the northwestern states. It is these facts which justify the priority attention given in the President's energy message to R&D on removal of sulfur from stack gases.

C. PRODUCTION CAPACITIES AND SELLING PRICES

Table II-4 lists the 1969 year-end domestic production capacities and 1969 national average selling price. Some data cited for refined petroleum products are typical day's refinery outputs rather than

TABLE II-3

COMPARISON OF 1969 WORLD AND UNITED STATES PRODUCTION

AND ESTIMATED RECOVERABLE RESOURCES

(The World Data Include U.S. Production.)

Commodity	1969 United States Production[a]	1969 World Production	Estimated Recoverable Resource	Units
Coal	0.571	3.171[b]	16,830[c]	10^9 tons
Petroleum	3.372	15.220[b]	1350 to 2100[d]	10^9 bbls
Natural Gas Liquids	0.580	NA	250 to 420[d]	10^9 bbls
Natural Gas	19.8	34[b]	8000 to 12,000[d]	10^{12} ft^3
Uranium (U_3O_8)				
<$10/lb	12,595	21,262[a,e]	1,903,000[f]	tons
$10-15/lb	-	-	1,497,000[f]	tons

[a]See Table II-1
[b]Ref. 11
[c]Ref. 2
[d]Ref. 9
[e]Includes only the "free" world
[f]Ref. 14
NA: Not available

TABLE II-4

1969 PRODUCTION CAPACITY AND AVERAGE UNIT VALUES[a]

Commodity/End Use	Operable Domestic Production Capacity	Average f.o.b. Selling Price[b] Traditional Units	Average f.o.b. Selling Price[b] Cents/10^6 Btu	Average Delivered Cost to Consumer Traditional Units	Average Delivered Cost to Consumer Cents/10^6 Btu
Coal (bituminous, lignite)	694 x 10^6 tons/annum[c]	$4.99/ton	19.0	$7.09/ton	27.1
Electric Utility				$6.57/ton[d]	26.6
Petroleum (crude oil)	11.6 x 10^6 bbls/day	$3.09/bbl	55.1	$3.51/bbl	62.6
#2 fuel (space heating)	2.3 x 10^6 " "	10.3 cents/gal	74.2	17 cents/gal	122.5
Jet fuel	0.89 x 10^6 " "	11.2 " "	83.0	16.5 " "[e]	122.2
Gasoline (automotive)	5.48 x 10^6 " "	12.2 " "	97.4	24.3 " "[f]	194.1
Diesel (railroad)	0.4 x 10^6 " "	10.25 " "	73.9	12.0 " "[e]	86.4
Residual (elec utility)	0.73 x 10^6 " "	$1.71/bbl	27.2	$2.01/bbl[d]	31.9
Natural Gas Liquids	3.2 x 10^6 " "	$1.90/bbl	46.3	- - -	- - -
Natural Gas (Dry), Average	100 x 10^6 Mcf/day	$0.167/Mcf	16.2	51.5 cents/Mcf[g]	49.9
Residential				104.7 cents/Mcf[g]	101.5
Commercial				78.1 cents/Mcf[g]	75.7
Industrial				30.1 cents/Mcf[g]	29.2
Electric Utility				26.2 cents/Mcf[d]	25.4
Uranium, Ore	27,650 tons/day[h]	$16.02/ton	--		
U_3O_8 (in concentrate)	115,000 lbs/day[i]	$5.94/lb	--		
Separative Work	6.9 x 10^6 kg S.W.U.[j]	$26/kg S.W.U.[h]	--		
Nuclear Fuel Burnup Costs				1.50 mills/kwh[k]	13.9[l]
Electricity, Average	312.6 x 10^6 kw	3.53 mills/kwh		15.4 " "	450.9
Residential[m]				20.9 " "	612.4
Small Light & Power[m]				19.9 " "	583.1
Large Light & Power[m]				9.0 " "	264.9
Other[m]				16.0 " "	468.8

[a] Unless otherwise noted, data are taken from Ref. 11.

[b] Price at mine-mouth, well-head, refinery output, etc.

[c] 1968 data last available, capacity for 280 days/annum.

[d] Ref. 22 Average price per ton (etc.) calculated using: 24.7 x 10^6 Btu/ton coal, 6.29 x 10^6 Btu/bbl residual oil, and 1.032 x 10^6 Btu/Mcf gas.

[e] Cost after loading into aircraft or locomotive.

[f] Typical day average spot pump price per Oil and Gas Journal, Feb. 3, 1969, pp 139-140 (taxes not included).

[g] Ref. 23.

[h] Ref. 7.

[i] Estimated from 1969 input/output

[j] Separative Work Units (S.W.U.) capacity for 2000 MW power (Ref 14.

[k] Datum cited is for a 500 MWe plant. Cost includes mining, milling refining, enriching, fabricating, and credit for recovery (Ref. 24.

[l] Calculated assuming an average net plant efficiency of 0.3168. In this case, the "consumer" is the electric utility.

[m] Ref. 25 Categories correspond roughly to: small light and power = commercial; large light and power = industrial; other includes street lighting and railways.

[n] Production ("Busbar") cost is approximately 1/2 average cost to consumer (Ref. 26).

installed capacity, and spot prices rather than annual average. During 1969 installed domestic production capacity for crude oil declined by 4.1%, for natural gas liquids by 3.3% and for natural gas by 4.8%. Installed electrical generating capacity increased by 8.3%.

It should be noted that selling prices vary with geographical location and fluctuate from month-to-month. Details can be obtained from the references cited.

It must also be recognized that sharp rises in fuel costs have occurred since the 1969 base year. Therefore, the data listed in Table II-4 are not representative of current prices. As an example, some typical f.o.b. spot prices in early 1972 were: bituminous coal, \$8.50/ton; crude oil \$3.40/bbl; residual oil (max. 1% sulfur), \$2.60/bbl; and natural gas, 20.5¢/Mcf. Delivered in New York City, coal was \$13.00/ton and residual oil (max. 0.3% sulfur) \$4.75/bbl.

At this point in time, projections of future fuel costs are highly speculative, and the evaluation of such projections was beyond the scope of this project. Nevertheless, certain data are available which set significant limits and might prove of interest to those making use of the reference system. For example, economic studies have been made on several substitute fuels. Presumably these fuel options would tend to establish ceilings on prices of crude oil and natural gas. Data of this type are summarized in Table II-5.

Although further economic data on the energy system were provided to the assessment[21] it proved difficult to use such data effectively. For technologies having the possibility of relatively near-term availability, a detailed level of comparative engineering economic analysis was required which was not possible within the framework of the study. For technologies of a more futuristic sort only very rough cost analyses were appropriate. Thus on both counts detailed economic analysis was found not to be appropriate.

TABLE II-5

MEDIUM-TERM ESTIMATES OF FUEL COSTS[a]

Fuel	Cost (Traditional Units)	Cost Cents/10^6 Btu	Comments
Uranium (U_3O_8)	$8/lb	--	See Table II -2
Nuclear Fuel Cycle			
LWR	1.6 mills/kwh[b]	14.85[c]	Uranium Cost ($8/lb U_3O_8) 40% of total
LMFBR	0.6 mills/kwh[d]	7.0[e]	
Coal (underground mined)	$6.55-$11.80/ton	25-45	Estimate for next 15 years[f]
(surface mined)	$3.93-$6.55/ton	15-25[f]	Does not include cost of land reclamation which at $3000/acre would add approximately 2¢ per 10^6 Btu[g]
Synthetic Crude Oil from Shale	$4.35-$5.30/bbl	80-90[h]	3-year construction, 20 operating, 52% tax rate, 15% depletion allowance, 15% discounted cost-flow rate of return/NPC[h]
Synthetic Crude Oil from Coal	$6.00-$6.25/bbl	100-125[i]	Large plants using Western surface-mined coal[i]. Note that these are not available technologies and considerable development must be carried out before such costs can be attained.
Low Sulfur Heavy Fuel Oil for Power Plant use from Coal	$4.50-$5.50/bbl[i]	71.5-87.4	Fuel oil of about 0^o API gravity with 0.3-0.5% sulfur[i]
Synthetic Pipeline Gas from Coal	86¢-106¢/Mcf	90-110[j]	Uses western strip-mined coal @ 15¢/10^6 Btu converted to gas at 68% efficiency cost of coal is 25% of total/NPC
Liquefied Natural Gas (LNG) Imported	$1.12/Mcf[l]	109	Weighted average of FPC short-term natural gas import application.

---

[a]Constant 1971 Dollars.

[b]Ref. 6, p 135

[c]Calculated assuming an average net plant efficiency of 0.3168.

[d]Ref. 7 and 27.

[e]Calculated assuming an average net plant efficiency of 0.400

[f]Ref. 6, p 135

[g]Ref. 28

[h]Ref. 6, p. 167, see also Ref. 29, p. IV-6.

[i]Ref. 6, p 142.

[j]Ref. 6, p 140; converted @ 960 Btu/ft^3

[k]Ref. 29, Chapter III

[l]Ref. 30, p 149, Table 31.

D. ENVIRONMENTAL FACTORS

Introduction

This section deals with the major environmental effects of the energy system. In particular, an attempt is made to identify all important external effects of the technologies that are included in the Reference Energy Systems. In this section these effects are expressed as unit quantities--amount of pollutant, etc. per unit of energy or installed capacity. Cumulative effects, based on these unit quantities are tabulated in the next section along with the Reference Energy Systems.

Three sort of difficulties immediately arise when one attempts to define externalities. The first is the basic difficulty of quantification. For example, aesthetic factors are clearly of importance but virtually impossible to quantify in a significant way.

The second difficulty is one of prediction. It is relatively straight-forward to catalogue all of the emissions from current energy uses--and we essentially do this for the 1969 reference case--but control technology is in a state of rapid change. Thus the characterization of the environmental effects of future reference systems depends on evaluations of future control technologies. In making these evaluations, major reliance has been placed on studies performed by the Environmental Protection Agency in establishing air quality criteria and source performance standards. Again, the heuristic nature of these projections should be emphasized. They are meant as instruments for the evaluation of new technologies and not as predictions of the future.

The third difficulty is one of properly reflecting the concerns that lead us to worry about "environmental effects." Ideally, one would like to have numbers that relate various emissions, say, to the cost to society (in dollars and/or health) of those emissions. Given the level of knowledge that exists in this area, however, and the scope of this study, we limited ourselves to a consideration of first order effects, basically the amount of emissions of various kinds for various elements of the reference systems.

Fossil Fuel Emission Factors

Table II-6 gives the emission factors that apply to the combustion of fossil fuels. As specified in the notes to the table, the factors take into account current and future EPA standards where appropriate.

Nuclear Power Emissions

The radiation dose to the population from normal operation of nuclear power plants is determined, as an upper bound, by the standards set for the permissible dose at the plant boundaries. New regulations currently under review would limit off-site doses to 5 mrem per year,[37] a factor of 100 lower than those currently in effect. Current practice is consistent with such a limit. At these relatively low exposure levels, the quantity of interest is the total accumulated dose to the population in man-rems. The new limits would correspond to a dose of about 400 man-rems per year per 1000 Mwe installed capacity.[38] In 1969 the actual population dose corresponded to less than half that amount.[39] (The average dose to those living within 50 miles of a nuclear plant was calculated to be 0.01 mrem/year.) In any event, the resultant dose, either now or projected, is low compared to that due to natural background.[40]

Of more long term significance is the Kr-85 and tritium produced in the nuclear reactors and released primarily at the reprocessing plants. The total amount of high level radioactive waste is also a potential major concern. The unit production rates for these materials are shown in Table II-7 for light water reactors (LWR's) and liquid metal cooled fast breeders (LMFBR's).

The activity of high level waste is shown as a function of time in Figure II-2. The curves are based on calculations reported in Reference 41, effective burnups of 33,000 Mwd(th)/ton, for both reactors, an efficiency of 0.33 for the LWR, and an efficiency of 0.40 for the LMFBR.

Land Use

The major uses of land related to the energy system are summarized below.

TABLE II-6 AIR POLLUTION EMISSION FACTORS FOR FOSSIL FUELS[a]

	CO_2	CO	SO_2[b]	NO_x	PARTIC.	HYDRO-CARBONS	ALDE-HYDES	NOTES
RESIDENTIAL								
Oil (Distillate)								
($lb/10^3$ Gal)		5	142 S	12	10	3	2	
($lb/10^6$ Btu)	170	0.0360	1.022 S	0.086	0.0720	0.0216	0.014	
Gas ($lb/10^6$ ft^3)		20	0.6	50	19	8	10	
($lb/10^6$ Btu)	122	0.0193	0.00058	0.0484	0.0184	0.00775	0.00968	
COMMERCIAL								
Oil (Distillate)								
($lb/10^3$ Gal)		0.2	142 S	40	15	3	2	
($lb/10^6$ Btu)	170	0.0014	1.022 S	0.288	0.108	0.021	0.014	
Gas ($lb/10^6$ ft^3)		20	0.6	100	19	8	10	
($lb/10^6$ Btu)	122	0.0193	0.00058	0.0968	0.0184	0.00775	0.00968	
Coal (Bituminous) (lb/ton)		10	38 S	6	4[c]	3	0.005	
($lb/10^6$ Btu)	224	0.405	1.529 S	0.241	0.162	0.120	0.0002	
ELECTRIC UTILITIES - <u>EXISTING</u>								
Oil (Residual)								
($lb/10^3$ Gal)		0.04	157 S	105	8	2.0	1.0	
($lb/10^6$ Btu)	170	0.0002	1.047 S	0.700	0.054	0.013	0.007	
Coal (Bituminous) (lb/ton)		1.0	38 S	20	26[d]	0.3	0.005	
($lb/10^6$ Btu)	224	0.040	1.529 S	0.81	1.054	0.0121	0.0002	
Gas ($lb/10^6$ ft^3)		0.4	0.6	390	15	40	3	
($lb/10^6$ Btu)	122	0.000387	0.00058	0.378	0.0145	0.0387	0.0029	
ELECTRIC UTILITIES - <u>NEW PLANT</u>								
Oil (Residual) ($lb/10^6$ Btu)	170	0.0002	0.8[e]	0.30[e]	0.054[e]	0.013	0.007	
Coal (Bituminous)								
($lb/10^6$ Btu)	224	0.040	1.2[e]	0.70[e]	0.20[e]	0.0121	0.0002	
Gas ($lb/10^6$ Btu)	122	0.000387	0.00058	0.20	0.0145	0.0387	0.0029	

[a] Table is continued on the next page. Footnotes appear there.

TABLE II-6 (Cont'd)

	CO_2	CO	SO_2	NO_x	PARTIC.	HYDRO-CARBONS	ALDE-HYDES	NOTES
INDUSTRIAL								
Coal (Bituminous) (lb/ton)		2	38 S	15	45.5[f]	1	0.005	
($lb/10^6$ Btu)	224	0.081	1.529 S	0.608	1.844	0.0405	0.0002	
Gas ($lb/10^6\ ft^3$)		0.4	0.6	120	18	40	3	
($lb/10^6$ Btu)	122	0.000387	0.00058	0.116	0.0174	0.0387	0.0029	
Oil (Residual) ($lb/10^3$ Gal)		0.2	157 S	40	23	3	1	
($lb/10^6$ Btu)	170	0.00133	1.047 S	0.267	0.153	0.020	0.0067	
Oil (Distillate)								
($lb/10^3$ Gal)		0.2	142 S	40	15	3	2	
($lb/10^6$ Btu)	170	0.0014	1.022 S	0.288	0.108	0.021	0.014	
TRANSPORTATION								
Automobile ($lb/10^6$ Btu)								
1970	149	17.08	0.04	1.46	0.071	2.992		(g)
1973-1974	149	8.95	0.04	0.688	0.071	0.78		(h)
1975	149	0.78	0.04	0.688	0.071	0.094		(h)
1976	149	0.78	0.04	0.092	0.071	0.094		(h)
Diesel ($lb/10^6$ Btu)								
1970	170	1.62	0.194	2.58	0.094	0.266	0.022	
Aircraft ($lb/10^6$ Btu)								
1970	149	1.070	0.082	0.206	0.329	0.700	0.021	(i)

[a] Emission factors are from AP-42 (Ref. 33), unless indicated otherwise.

[b] S stands for percentage of sulfur in fuel.

[c] Given by 13A $(1-\eta)$, where A=10, percentage of ash, and $\eta=0.8$ is the assumed precipitator efficiency.

[d] Given by $2A(1-\eta)$, where A and η are as in (c).

[e] From EPA standards, Federal Register (Ref. 34).

[f] Given as in (b), where here $\eta = 0.65$.

[g] From EPA (Ref. 35).

[h] From EPA standards, Federal Register (Ref. 25).

[i] Based upon fuel consumption during landing-takeoff cycle.

TABLE II-7

ENVIRONMENTAL EFFECTS OF NUCLEAR POWER PLANTS

Effect	Quantity/1000 Mwe-yr.		Basis
	LWR[a]	LMFBR[b]	
Population Exposure due to normal releases	588 man-rem[c]	588 man-rem[c]	Proposed standards (37)
Kr-85 production[d]	5.3×10^5 Ci	1.0×10^5 Ci	2.9×10^{-3} atoms/U-235 thermal fission 0.79×10^{-3} atoms/Pu-239 fast fission
Tritium production[d]	1.9×10^4 Ci	2.7×10^4 Ci	Production of fuel rods at the rate of: 1.3×10^{-4} atoms/U-235 fission 2.5×10^{-4} atoms/Pu-239 fission
High level waste			
as liquid[e]	1.10×10^4 gal	0.91×10^4 gal	100 gal/10,000 Mwd(th) (41)
as solid[f]	110 ft^3	91 ft^3	1 ft^3/10,000 Mwd(th) (41)

[a]LWR burnup = 33,000 Mwd(th)/MT, efficiency = 0.33.

[b]LMFBR average burnup - 33,000 Mwd(th)/MT, efficiency = 0.40

[c]Based on 400 man-rem/1000 Mwe installed capacity and 0.68 load factor.

[d]See Appendix B of Reference (21)

[e]See Figure II-1 for activity as a function of time following separation.

[f]For storage in salt formations, 110 ft^3 of high level waste requires approximately 0.3 acres of salt area(42).

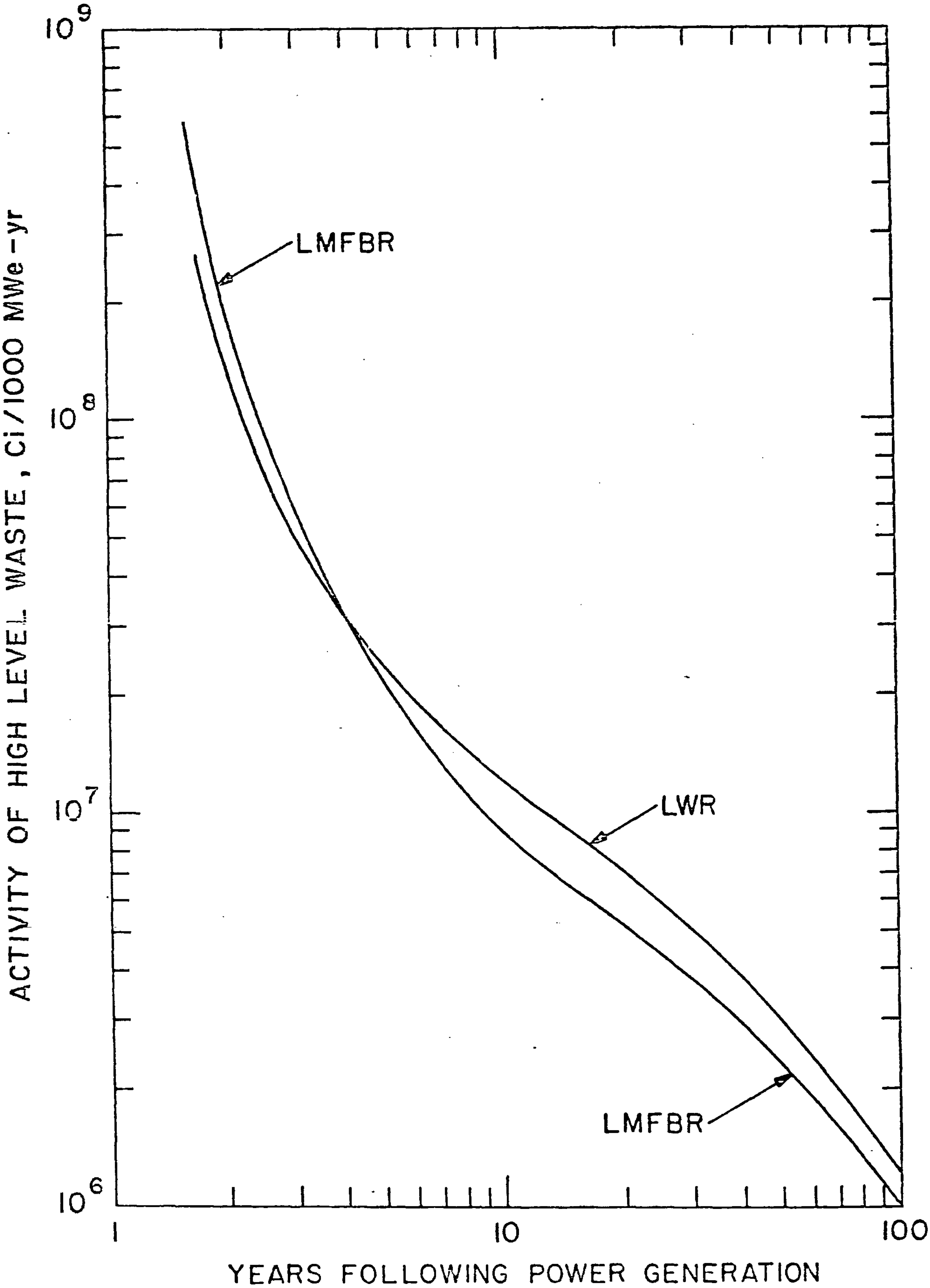


Figure II-2. Activity of High Level Waste as a Function of Time for Light Water Reactors (LWR's) and Liquid Metal Cooled Fast Breeders (LMFBR's)

TABLE II-8

LAND USE

Use	Amount	Basis
Coal Strip-Mining	$0.021 \times 10^{-6} mi^2/10^6 Btu$	Past and projected rate,[43,44] 26.2×10^6 Btu/ton
Power Plants		3-1000 Mwe plants at same site[45]
Coal	$1.6\ mi^2$/1000 Mwe	On-site coal storage and ash disposal
Oil	$0.40\ mi^2$/1000 Mwe	Adequate on-site fuel storage
Gas	$0.24\ mi^2$/1000 Mwe	Pipeline delivery and modest on-site fuel storage
Nuclear	$0.47\ mi^2$/1000 Mwe	Based on exclusion area requirements
Electrical Transmission	$19\ mi^2$/1000 Mwe	Projected transmission line right-of-way and electrical capacity requirements for 1990[46]

Oil Spills, etc.

Although the most sensational form of ocean pollution by petroleum hydrocarbons is the "oil spill," accidents account for a relatively minor fraction of the total.[47] It has been estimated that about 2.1×10^6 metric tons of crude and refined oils found their way into the ocean in 1969 with the main contributions coming from normal tanker operations, refineries and industrial and automobile wastes.* This corresponds to about 0.1% of the total crude oil production. Thus, as a rough approximation one can assume that an amount of petroleum products corresponding to 0.1% of the oil consumed in this country enters the ocean directly.

The amount of petroleum hydrocarbons entering the oceans indirectly--through release to the atmosphere accompanying combustion and eventually

* Other estimates have been as high as 4.9×10^6 metric tons for this quantity.[48]

reaching the oceans--may be significantly greater than that entering directly. Given a number for the fraction of hydrocarbons emitted that end up in the ocean,[47] the approximate quantities can be calculated from the hydrocarbon emissions tabulated in the next section.

Heat

Two aspects of the potential environmental difficulties due to heat effects will be reflected in the reference energy systems: the total amount of heat rejected to the atmosphere (to a good approximation equal to the total energy use) and the total amount of condenser cooling required in the electrical sector.

The Problem of Scale

A primary difficulty in the direct use of the emission factors given above arises from the different geographical scales on which various pollutants are of concern. For some, the primary effects are local. Others are of major concern on the regional or global scale. For example, CO_2 and Kr-85 are of concern because of the possibility of long-term buildup in the atmosphere. CO is of most immediate concern on a local scale, particularly in urban situations. Particulates are of interest from both a local and a global point of view, but with the reason for concern in the local case (health effects) being quite different from the reason for concern in the global case (the heat balance of the earth). Table II-9 gives a rough indication of the scale on which the various pollutants considered here are of most immediate concern.

Heat is included in the table although under certain conditions it cannot be considered as a pollutant. In fact there are a number of beneficial uses to which "waste heat" can be put. Nevertheless, the current mode of operating the U.S. energy system does not make use of this heat. Furthermore, since virtually all energy "consumed" eventually becomes degraded to thermal energy, there are possible regional and global meteorological effects that may result from the total amount of energy used in the region.

The scale of analysis of this assessment made it difficult to reflect accurately the real effects of the various pollutants shown in the table. Total emissions form a valid indicator of effect only when the major scale of effect is the global one. As seen in Table II-9, that is the case for only a few of the pollutants under consideration. Furthermore, the pollutants which are of greatest current concern are those having health implications at the local or regional level, i.e. SO_2, CO, NO_x and particulates.

E. REFERENCE ENERGY SYSTEMS AND IMPACTS

Current Energy Use

An analysis of energy use in the United States was recently performed by the Stanford Research Institute.[31] That analysis, which was for 1968, provided the basis for the estimates of demands and fuel used here. To provide data for our reference year, 1969, the data for 1968 were escalated by one year at either the average 1960-1968 growth rate or the 1967-1968 rate, whichever appeared to be more appropriate in a given instance. The reference values for energy demand and fuel mix are given in Table II-10. Note that the column headed "Electric" refers to the consumption of energy as electricity (i.e. the electricity use is converted at 3412.8 Btu/Kwh). This does not account for energy lost in the conversion process, which is shown in the row titled "Electric Utility."

Projections of Energy Supply and Demand

Some of the technologies analyzed in this assessment applied to very specific end uses. Thus the projections used in the Reference Energy Systems had to be highly disaggregated. Furthermore, since in some cases the analysis involved the substitution of one end use technology for another, the efficiency of end uses had to be specifically included.

The procedure for developing the projections was as follows: starting with the fuel demands for 1969 referred to above, and considering the efficiency with which each fuel was used, a basic energy demand

TABLE II-9

SCALE OF EFFECT OF POLLUTANTS RELATED TO ENERGY USE[a]

	Scale of Effect			
			Global	
Pollutant	Local	Regional	(Weather)	(Health)
SO_2[b]	X	x		
NO_x[b]	X	x		
CO_2			X	
CO	X			
Particulates	X	x	X	
Toxic Metals	x			X
Short-lived radioisotopes	X	x		
Long-lived radioisotopes				X
Heat	X	X	x	

[a]Most important effects indicated by large X; effects of lesser consequence (as now perceived) by small x.

[b]Scale of effect dependent on manner of release (tall stack, etc.). Global effects may occur through conversion to particulates (Ref. 49).

TABLE II-10

SUMMARY OF ENERGY DEMAND AND FUEL MIX, 1969

	Energy Use, 10^{15} Btu							
	Natural Gas	Oil	Coal	LWR	LMFBR	Hydro[a]	Electric[b]	Total Direct Use
RESIDENTIAL:								
Space Heat	3.35	3.10					0.18	6.63
Air Conditioning							0.18	0.18
Water Heat + Cooking	1.57						0.33	1.90
Misc. Electric							0.87	0.87
SUBTOTAL	4.92	3.10					1.56	9.58
COMMERCIAL:								
Space Heat	1.27	2.55	0.52					4.34
Air Conditioning	0.11						0.40	0.51
Water Heat + Cooking	0.56						0.10	0.66
Misc. Electric							0.73	0.73
SUBTOTAL	1.94	2.55	0.52				1.23	6.24
INDUSTRIAL:								
Cement	0.21	0.04	0.24				0.03	0.52
Iron and Steel	0.68	0.14	2.29				0.13	3.24
Aluminum	0.04		0.08				0.22	0.34
Misc. Heat	7.50	2.91	2.56					12.97
Electric Drive							1.59	1.59
Petrochemicals	0.54	2.98	0.16					3.68
SUBTOTAL	8.97	6.07	5.33				1.97	22.34
TRANSPORTATION:								
Automotive		7.81						7.81
Bus		0.12						0.12
Truck		3.43						3.43
Rail + Subway		0.55					0.02	0.57
Air		2.09						2.09
Ship		0.91						0.91
SUBTOTAL		14.91					0.02	14.93
ELECTRIC UTILITY	3.60	1.60	7.43	0.14		1.10		9.09[c]
NATURAL GAS FIELD USE	1.57							1.57
TOTAL RESOURCES CONSUMED	21.00	28.23	13.28	0.14		1.10	(4.78)[d]	63.75

[a]Hydropower resource consumption is based on a conversion efficiency of 80%.

[b]Gives energy consumed as electricity at 3412.8 Btu/kwh. For fuels consumed in producing electricity see row labeled "Electric Utility".

[c]Taken as total resources consumed by utilities less electricity delivered to end use.

[d]Not included in horizontal sum.

was calculated for each end use category. These energy demands are independent of the fuel or energy form used.

The basic energy demand defined in this manner is projected into the future by including any saturation effects that may be present and the effect of overall growth in households or other consuming activities that are considered to be the driving force behind the end use. The fuel mix is then specified, again reflecting the relative efficiencies of the various fuels that can satisfy that basic demand. The rationale behind the projections assumed in each demand sector is summarized in Table II-11. The specific assumptions made in each demand category and the saturation effects included are given in Reference 21 along with a more detailed description of the techniques used in the projections.

It is more accurate to think of the efficiencies used here as being relative effectivenesses since, in addition to reflecting the technical efficiency of an end use device, differences in utilization practices, such as energy conservation measures, may also be taken into account. Employing this concept, the use of improved insulation in homes, for example, would be reflected by increasing the effectiveness. Indeed the "efficiency" that is derived from 1969 data for space heating supplied by electricity has a value of 1.58 as compared to 0.75 for gas and probably reflects the improved insulation that is generally used with that form of heat as well as different use patterns.

The basic energy demands specified in all residential categories are increased in future years in proportion to the growth in households that is forecast by the U.S. Bureau of the Census. The series 2 household forecast,[23] which does not reflect the recent decline in birthrates, is extrapolated to 2020. It is anticipated that the decline in birthrate will not have an impact on the formation of households through 1985 but it could reduce the formation rate after that time below the level assumed in this projection.

The basic demands in the commercial sector are projected from the 1969 levels in proportion to residential demands. In the transportation and industrial sectors the basic demands are escalated by various means derived from several sources that are explicitly cited in Reference 21.

TABLE II-11

PROJECTION OF BASIC ENERGY DEMANDS

Sector	Category	Escalation based on
Residential	All	No. of household, Ref. (23)
Commercial	All	Proportion to residential
Industry	Cement	Last 10 yr growth rate, Ref.(23)
	Aluminum	Projection to 2000,Ref. (50)
	Iron	Projection to 2000,Ref. (50)
	Steel	AUI projection
	Petrochemical	Last 10 yr growth, Ref. (31) reduced after 1985
	Process Heat	Last 10 yr growth rate, Ref. (31)
	Electric Drive	Last 10 yr growth rate, Ref. (31)
Transportation	Automotive	Projection to 1990, Ref. (51)
	Bus	Projection to 1990, Ref. (52)
	Truck	Constant fraction of automotive
	Rail	Projection to 1990, Ref. (52)
	Air	Projection to 1990, Ref. (51)
	Ships	AUI estimates

In making up the Reference Energy Systems, specific reference technologies are identified. The only new technologies included in the reference systems are the LMFBR and coal gasification to pipeline quality gas. In some instances, however, effectiveness values may be increased over time to reflect the implementation of the best current technology.

Some specific features that were employed in projecting the fuel mix are:

1. Electric heat is considered to be a fixed multiple of the electric air-conditioning load to reflect a balanced summer/winter electrical peak in the years 2000 and 2020. Such a balance is feasible in most regions of the country and may be accomplished nation-wide by improved regional transmission interties.
2. Phantom energy demands are included in the residential sector and in the industrial thermal energy demand category. These are intended to reflect new uses of energy that could arise in the future. Such new uses are implied by the conventional extrapolations of overall energy demand, but would otherwise not be accounted for in the disaggregated type of projection used here. It is probable that these new uses will involve electric energy more than other fuels. The phantom industrial energy demand in 2000 and 2020 could be distributed among other sectors, but has been concentrated for clarity and convenience.
3. The apportioning of nuclear electric generating capacity between LWR's and LMFBR's was based on U.S. Atomic Energy Commission systems analysis studies.[32,53,54]

The reference projections of energy demand and fuel mix are summarized in Table II-12, 13, 14, and 15 for the years 1977, 1985, 2000, and 2020. As for electricity, methane is treated as a secondary energy form; the energy delivered to each end use in the form of methane (natural gas or coal through gasification) are tabulated in a separate row entitled, "methane production." Entries are included in the tables for 1969 and 1977 to account for field uses of natural gas.

TABLE II- 12

SUMMARY OF ENERGY DEMAND AND FUEL MIX, 1977

Energy Use, 10^{15} Btu

	Natural Gas	Oil	Coal	LWR	LMFBR	Hydro[a]	Electric[b]	Total Direct Use
RESIDENTIAL:								
Space Heat	3.52	3.26					0.38	7.16
Air Conditioning							0.28	0.28
Water Heat + Cooking	1.70						0.49	2.19
Misc. Electric							1.30	1.30
SUBTOTAL	5.22	3.26					2.45	10.93
COMMERCIAL:								
Space Heat	1.22	2.46					0.59	4.27
Air Conditioning	0.15						0.44	0.59
Water Heat + Cooking	0.61						0.12	0.73
Misc. Electric							0.94	0.94
SUBTOTAL	1.98	2.46					2.09	6.53
INDUSTRIAL:								
Cement	0.27	0.05	0.32				0.04	0.68
Iron and Steel	0.79	0.12	2.48				0.17	3.56
Aluminum	0.07		0.11				0.32	0.50
Misc. Heat	9.67	3.74	3.32					16.73
Electric Drive							2.35	2.35
Petrochemicals	0.79	4.41	0.24					5.44
SUBTOTAL	11.59	8.32	6.47				2.88	29.26
TRANSPORTATION:								
Automotive		10.20						10.20
Bus		0.17						0.17
Truck		4.48						4.48
Rail + Subway		0.62					0.06	0.68
Air		5.00						5.00
Ship		1.07						1.07
SUBTOTAL		21.54					0.06	21.60
ELECTRIC UTILITY	3.82	3.11	9.56	5.66		1.10		15.77[c]
NATURAL GAS FIELD USE	1.96							1.96
TOTAL RESOURCES CONSUMED	24.57	38.69	16.03	5.66		1.10	(7.48)[d]	86.05

[a]Hydropower resource consumption is based on a conversion efficiency of 80%.

[b]Gives energy consumed as electricity at 3412.8 Btu/kwh. For fuels consumed in producing electricity see row labeled "Electric Utility".

[c]Taken as total resources consumed by utilities less electricity delivered to end use.

[d]Not included in horizontal sum.

TABLE II-13

SUMMARY OF ENERGY DEMAND AND FUEL MIX, 1985

	Energy Use, 10^{15} Btu								
	Natural Gas	Oil	Coal	LWR	LMFBR	Hydro[a]	Electric[b]	Methane[c]	Total Direct Use
RESIDENTIAL:									
Space Heat		3.12					0.95	3.40	7.47
Air Conditioning							0.57		0.57
Water Heat + Cooking							0.71	1.68	2.39
Misc. Electric							1.79		1.79
SUBTOTAL		3.12					4.02	5.08	12.22
COMMERCIAL:									
Space Heat		2.67					0.82	1.29	4.78
Air Conditioning							0.49	0.20	0.69
Water Heat + Cooking							0.17	0.65	0.82
Misc. Electric							1.33		1.33
SUBTOTAL		2.67					2.81	2.14	7.62
INDUSTRIAL:									
Cement		0.06	0.42				0.06	0.36	0.90
Iron and Steel		0.12	2.81				0.23	0.91	4.07
Aluminum			0.16				0.48	0.10	0.74
Misc. Heat		4.84	4.29					12.52	21.65
Electric Drive							3.46		3.46
Petrochemicals		6.49	0.35					1.17	8.01
SUBTOTAL		11.51	8.03				4.23	15.06	38.83
TRANSPORTATION:									
Automotive		12.10							12.10
Bus		0.25							0.25
Truck		5.32							5.32
Rail + Subway		0.55					0.17		0.72
Air		10.50							10.50
Ship		1.25							1.25
SUBTOTAL		29.97					0.17		30.14
ELECTRIC UTILITY		3.94	11.46	16.17		1.15		3.58	25.07[d]
METHANE PRODUCTION	26.56		2.12						2.82[d]
TOTAL RESOURCES CONSUMED	26.56	51.21	21.61	16.17		1.15	(11.23)[e]	(25.86)[e]	116.70

[a]Hydropower resource consumption is based on a conversion efficiency of 80%.

[b]Gives energy consumed as electricity at 3412.8 Btu/kwh. For fuels consumed in producing electricity see row labeled "Electric Utility".

[c]Includes natural gas and gasified coal. See row labeled "Methane Production".

[d]Taken as resources consumed less product delivered to end use.

[e]Not included in horizontal sum.

TABLE II-14

SUMMARY OF ENERGY DEMAND AND FUEL MIX, 2000

	Energy Use, 10^{15} Btu								
	Natural Gas	Oil	Coal	LWR	LMFBR	Hydro[a]	Electric[b]	Methane[c]	Total Direct Use
RESIDENTIAL:									
Space Heat		3.41					1.77	3.56	8.74
Air Conditioning							1.06		1.06
Water Heat + Cooking							1.08	1.82	2.90
Misc. Electric							2.90		2.90
SUBTOTAL		3.41					6.81	5.38	15.60
COMMERCIAL:									
Space Heat		3.34					1.12	1.58	6.04
Air Conditioning							0.66	0.19	0.85
Water Heat + Cooking							0.27	0.76	1.03
Misc. Electric							2.02		2.02
SUBTOTAL		3.34					4.07	2.53	9.94
INDUSTRIAL:									
Cement		0.11	0.70				0.09	0.60	1.50
Iron and Steel		0.14	3.54				0.32	1.18	5.18
Aluminum			0.33				0.97	0.21	1.51
Misc. Heat		5.79	4.96				4.68	14.82	30.25
Electric Drive							7.22		7.22
Petrochemicals		8.73	0.48					1.57	10.78
SUBTOTAL		14.77	10.01				13.28	18.38	56.44
TRANSPORTATION:									
Automotive		14.70							14.70
Bus		0.49							0.49
Truck		6.47							6.47
Rail + Subway		0.96					0.29		1.25
Air		14.50							14.50
Ship		1.36							1.36
SUBTOTAL		38.48					0.29		38.77
ELECTRIC UTILITY		5.46	19.50	25.54	20.48	1.44		3.90	51.87[d]
METHANE PRODUCTION	27.89		6.97						4.67[d]
TOTAL RESOURCES CONSUMED	27.89	65.46	36.48	25.54	20.48	1.44	(24.45)[e]	(30.19)[e]	177.29

[a] Hydropower resource consumption is based on a conversion efficiency of 80%.

[b] Gives energy consumed as electricity at 3412.8 Btu/kwh. For fuels consumed in producing electricity see row labeled "Electric Utility.

[c] Includes natural gas and gasified coal. See row labeled "Methane Production".

[d] Taken as resources consumed less product delivered to end use.

[e] Not included in horizontal sum.

TABLE II-15

SUMMARY OF ENERGY DEMAND AND FUEL MIX, 2020

	Energy Use, 10^{15} Btu								Total Direct Use
	Natural Gas	Oil	Coal	LWR	LMFBR	Hydro[a]	Electric[b]	Methane[c]	
RESIDENTIAL:									
Space Heat		4.75					2.51	4.97	12.23
Air Conditioning							1.50		1.50
Water Heat + Cooking							1.53	2.58	4.11
Misc. Electric							4.09		4.09
SUBTOTAL		4.75					9.63	7.55	21.93
COMMERCIAL:									
Space Heat		4.62					1.63	2.23	8.48
Air Conditioning							0.99	0.18	1.17
Water Heat + Cooking							0.47	0.92	1.39
Misc. Electric							2.87		2.87
SUBTOTAL		4.62					5.96	3.33	13.91
INDUSTRIAL:									
Cement		0.21	1.39				0.19	1.20	2.99
Iron and Steel		0.21	4.81				0.47	1.67	7.16
Aluminum			0.86				2.54	0.54	3.94
Misc. Heat		7.07	6.24				16.46	17.76	47.53
Electric Drive							19.19		19.19
Petrochemicals		12.99	0.71					2.33	16.03
SUBTOTAL		20.48	14.01				38.85	23.50	96.84
TRANSPORTATION:									
Automotive		17.60							17.60
Bus		1.20							1.20
Truck		7.75							7.75
Rail + Subway		2.01					0.60		2.61
Air		17.30							17.30
Ship		2.50							2.50
SUBTOTAL		48.36					0.60		48.96
ELECTRIC UTILITY		3.51	43.67	27.74	84.47	1.62		3.51	109.48[d]
METHANE PRODUCTION	29.23		16.90						8.24[d]
TOTAL RESOURCES CONSUMED	29.23	81.72	74.58	27.74	84.47	1.62	(55.04)[e]	(37.89)[e]	299.36

[a]Hydropower resource consumption is based on a conversion efficiency of 80%.

[b]Gives energy consumed as electricity at 3412.8 Btu/kwh. For fuels consumed in producing electricity see row labeled "Electric Utility".

[c]Includes natural gas and gasified coal. See row labeled "Methane Production".

[d]Taken as resources consumed less product delivered to end use.

[e]Not included in horizontal sum.

It must be emphasized that the fuel mix projections are not to be interpreted as forecasts. They were prepared to satisfy the specific needs of the assessment by providing a detailed relationship between demands, and the supply and end use technologies that are employed to satisfy those demands.

The projected installed electrical generating capacity, by fuel input and excluding peaking and hydroelectric plants, is given in Table II-16, along with the annual energy output for each powerplant class. The light water reactors (LWR) are fueled with enriched uranium while the liquid metal fast breeder reactor (LMFBR) is assumed to use the reference oxide core fueled with mixed plutonium and uranium oxide. The electrical requirements for uranium enrichment plants are not included in any demand sectors but are reflected in the efficiency assigned to the LWR. This is taken as 31%, reduced from the actual LWR efficiency which is 33%.

Reference Energy Systems

The Reference Energy System for 1969 and those corresponding to the projections discussed above are shown in the series of energy flow diagrams, Figures II-3 through II-7. The reference systems are generally constructed about existing technologies which are defined in the diagrams. Two emergent technologies, coal gasification (to methane) and the liquid metal cooled fast breeder reactor (LMFBR) are also incorporated in the reference systems for 1985, 2000 and 2020. The reference systems provide a uniform set of figures on future energy demands; resource consumption, and environmental impacts are derived from them.

The energy demands, by specific end use, and the resource consumptions are indicated on the flow diagrams. Each activity, from extraction of the resource through transport, conversion, distribution and utilization, is indicated, along with the flow of energy and the efficiency, or measure of relative effectiveness, associated with that activity. In cases where no efficiency figure is indicated, the value may be taken as unity. Cost data on some of the reference technologies were given above.

TABLE II-16

INSTALLED CAPACITY AND GENERATION FOR

CENTRAL STATION POWER PLANTS[a]

Year	Type of Plant	Installed Capacity[b] (10^3 MWe)	Power Generated (10^9 kW-hr)
1969	Hydropower	53	246
	Gas turbine and I-C	14	15
	Gas-Steam	78	368
	Oil-Steam	40	150
	Coal-Steam	143	761
	LWR	4	13
	Total	332	1553
1977	Hydropower	53	246
	Gas turbine and I-C	36	25
	Gas-Steam	81	392
	Oil-Steam	61	293
	Coal-Steam	203	980
	LWR	90	514
	Total	524	2450
1985	Hydropower	55	257
	Gas turbine and I-C	57	40
	Gas-Steam	79	367
	Oil-Steam	78	364
	Coal-Steam	250	1175
	LWR	258	1469
	Total	777	3672
2000	Hydropower	72	320
	Gas turbine and I-C	86	60
	Gas-Steam	90	400
	Oil-Steam	112	500
	Coal-Steam	447	2000
	LWR	407	2320
	LMFBR	422	2400
	Total	1636	8000
2020	Hydropower	86	360
	Gas turbine and I-C	142	100
	Gas-Steam	86	360
	Oil-Steam	62	260
	Coal-Steam	1070	4500
	LWR	443	2520
	LMFBR	1739	9900
	Total	3628	18000

[a]Includes industrial self-generation.

[b]1969 capacity from reference (23), p 497. Post 1969 capacities are derived from the power generation figures using plant factors of 0.08 for gas turbine and I-C plants and 0.65 for nuclear plants. The plant factor of fossil fueled steam plants is taken as 0.55 in 1977 and decreases thereafter to approximate the overall system load factors indicated in reference (55) for 1977 and 1985.

REFERENCE ENERGY SYSTEM, YEAR 1969

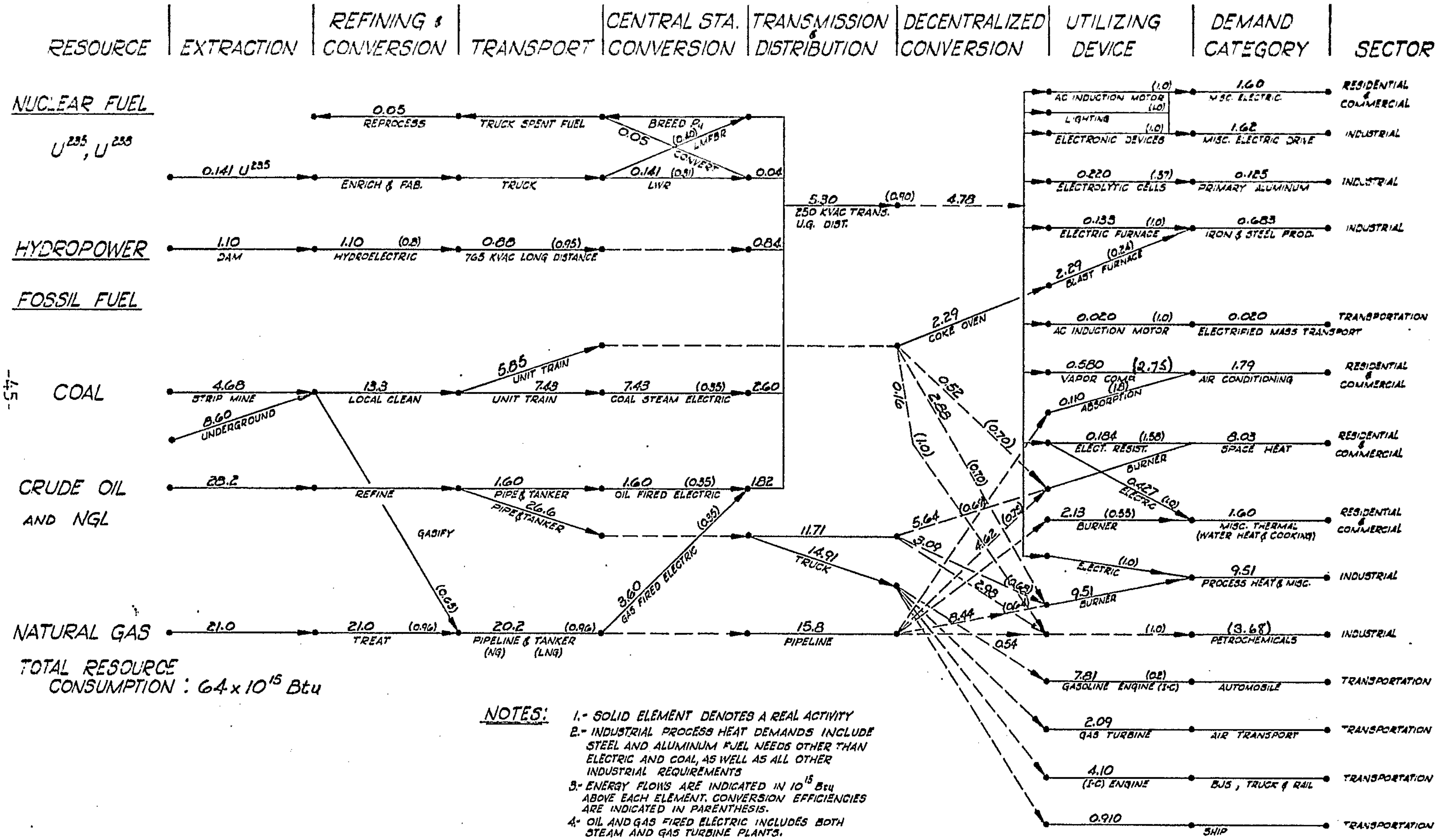
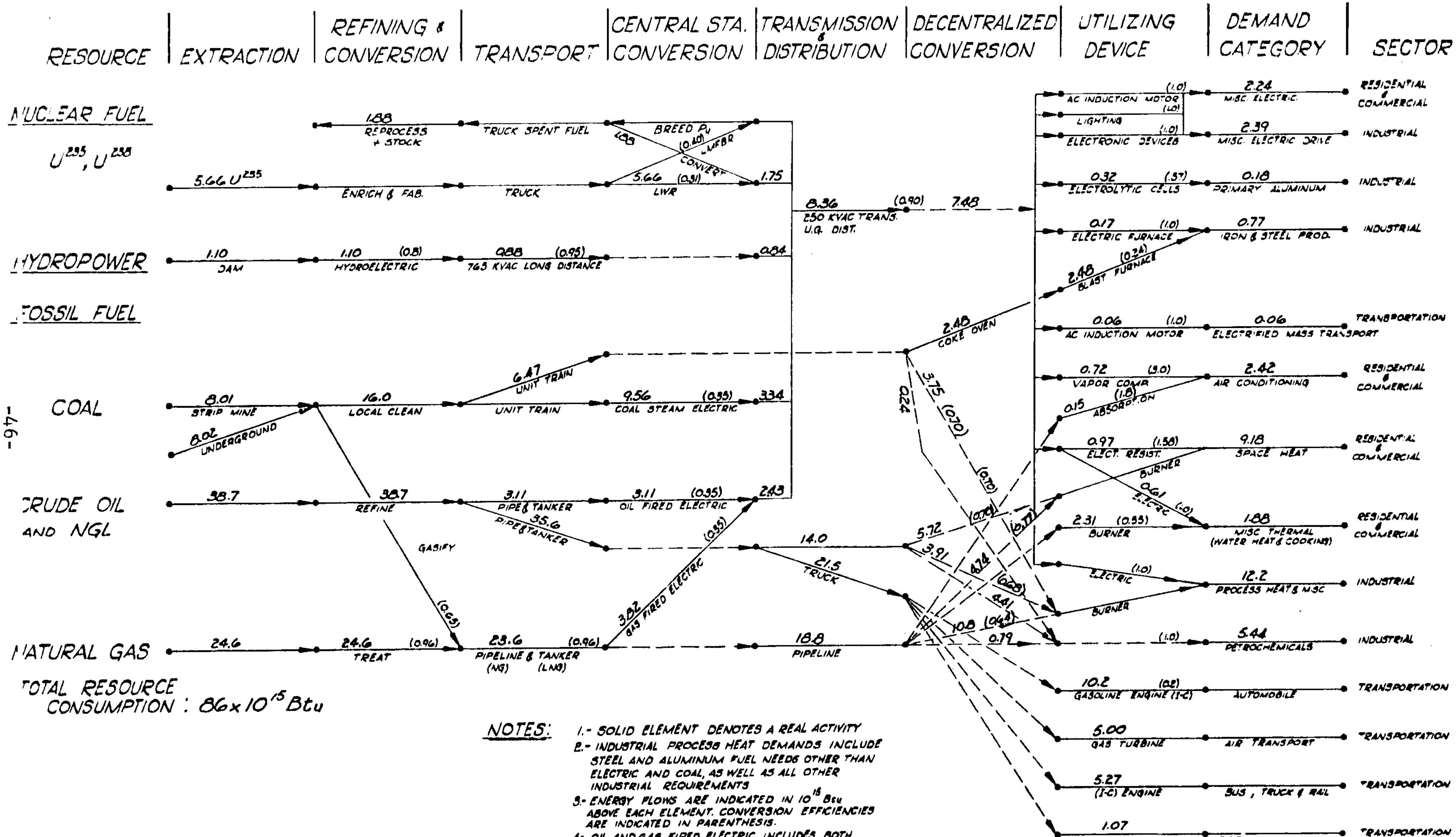


Figure II-3

REFERENCE ENERGY SYSTEM, YEAR 1977

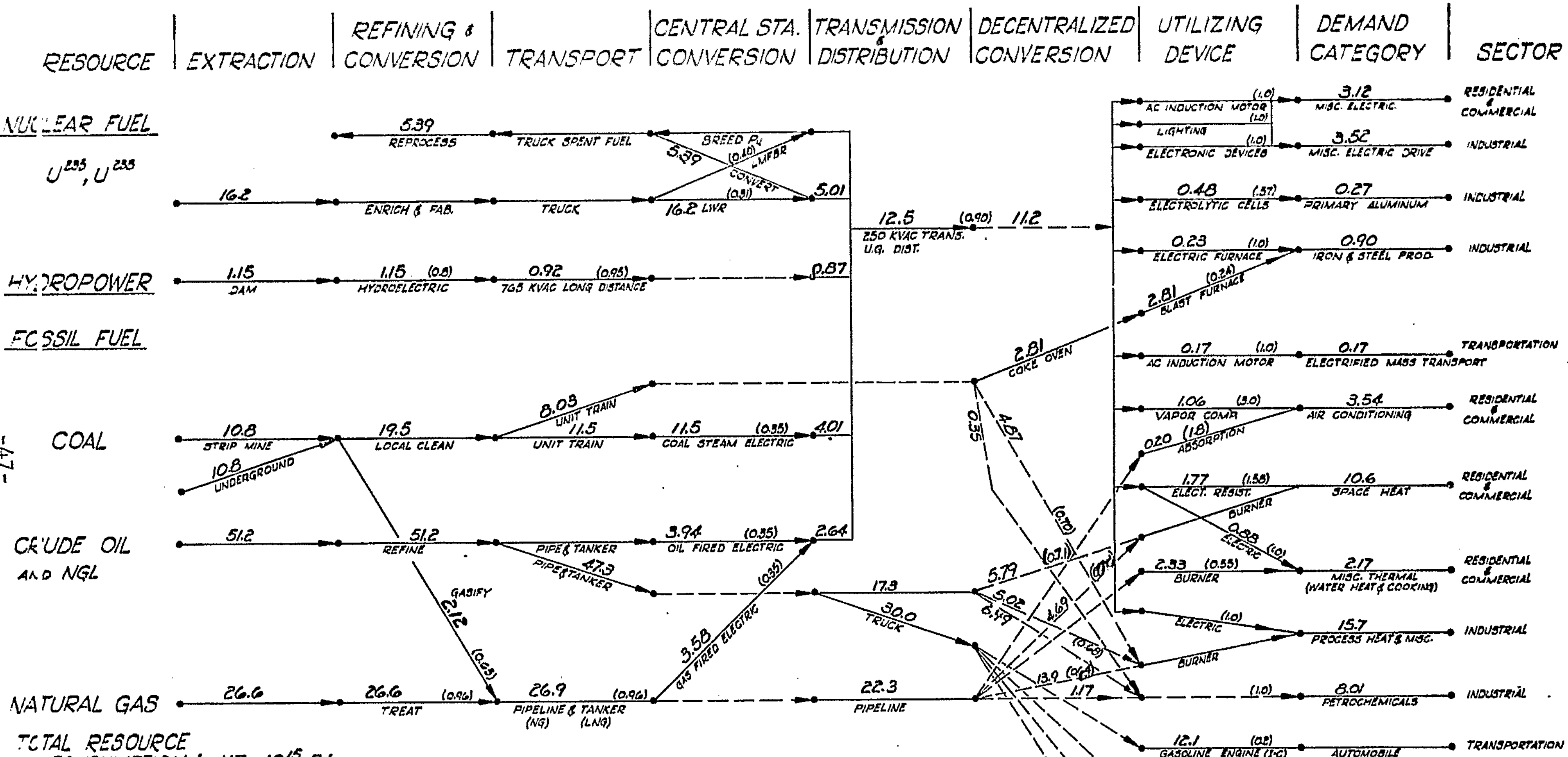


NOTES:

1. SOLID ELEMENT DENOTES A REAL ACTIVITY
2. INDUSTRIAL PROCESS HEAT DEMANDS INCLUDE STEEL AND ALUMINUM FUEL NEEDS OTHER THAN ELECTRIC AND COAL, AS WELL AS ALL OTHER INDUSTRIAL REQUIREMENTS
3. ENERGY FLOWS ARE INDICATED IN 10^{15} Btu ABOVE EACH ELEMENT. CONVERSION EFFICIENCIES ARE INDICATED IN PARENTHESIS.
4. OIL AND GAS FIRED ELECTRIC INCLUDES BOTH STEAM AND GAS TURBINE PLANTS.

Figure II-4

REFERENCE ENERGY SYSTEM, YEAR 1985



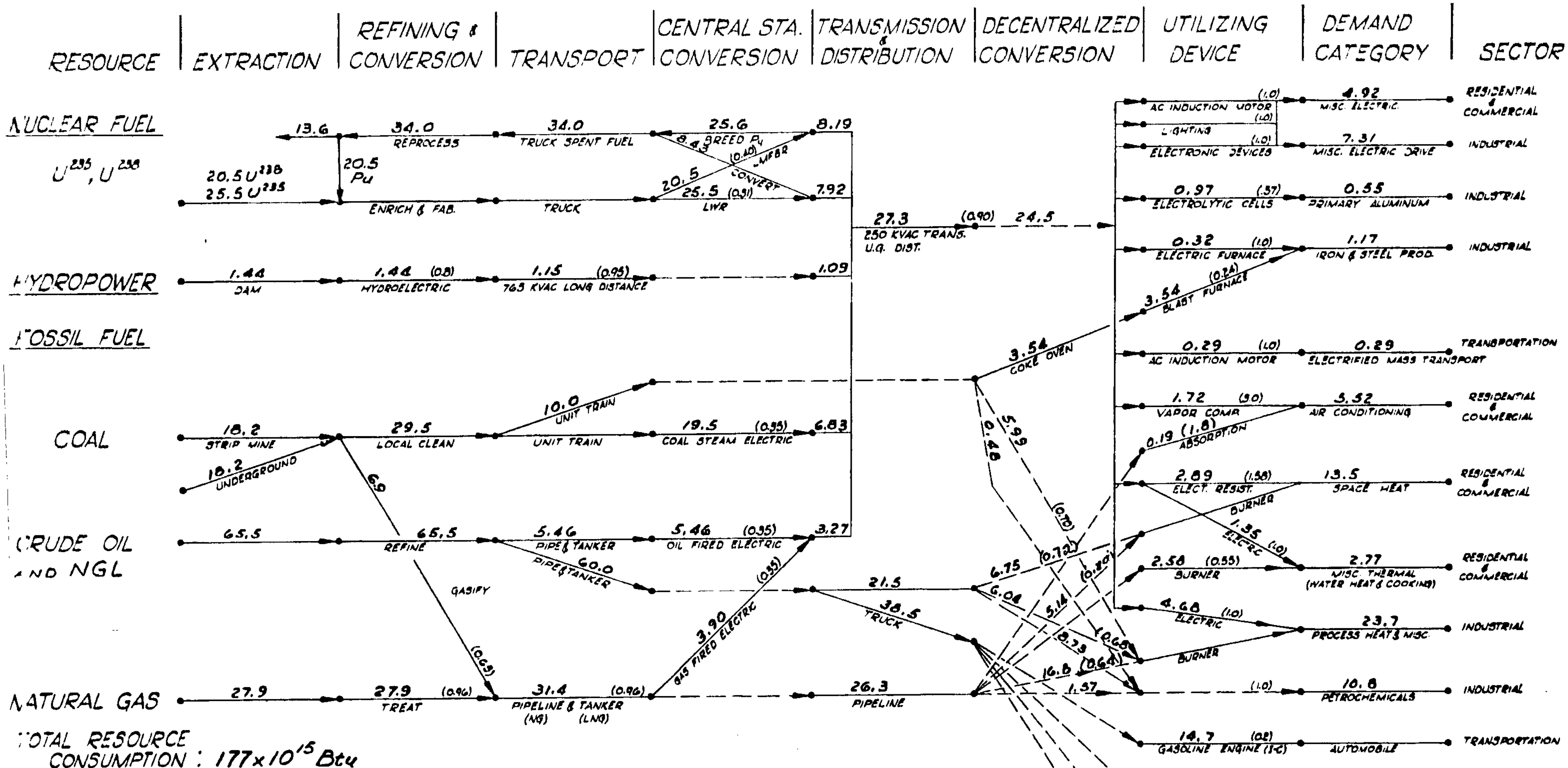
TOTAL RESOURCE CONSUMPTION : 117×10^{15} Btu

NOTES:

1.- SOLID ELEMENT DENOTES A REAL ACTIVITY
2.- INDUSTRIAL PROCESS HEAT DEMANDS INCLUDE STEEL AND ALUMINUM FUEL NEEDS OTHER THAN ELECTRIC AND COAL, AS WELL AS ALL OTHER INDUSTRIAL REQUIREMENTS
3.- ENERGY FLOWS ARE INDICATED IN 10^{15} Btu ABOVE EACH ELEMENT. CONVERSION EFFICIENCIES ARE INDICATED IN PARENTHESIS.
4.- OIL AND GAS FIRED ELECTRIC INCLUDES BOTH STEAM AND GAS TURBINE PLANTS.

Figure II-5

REFERENCE ENERGY SYSTEM, YEAR 2000

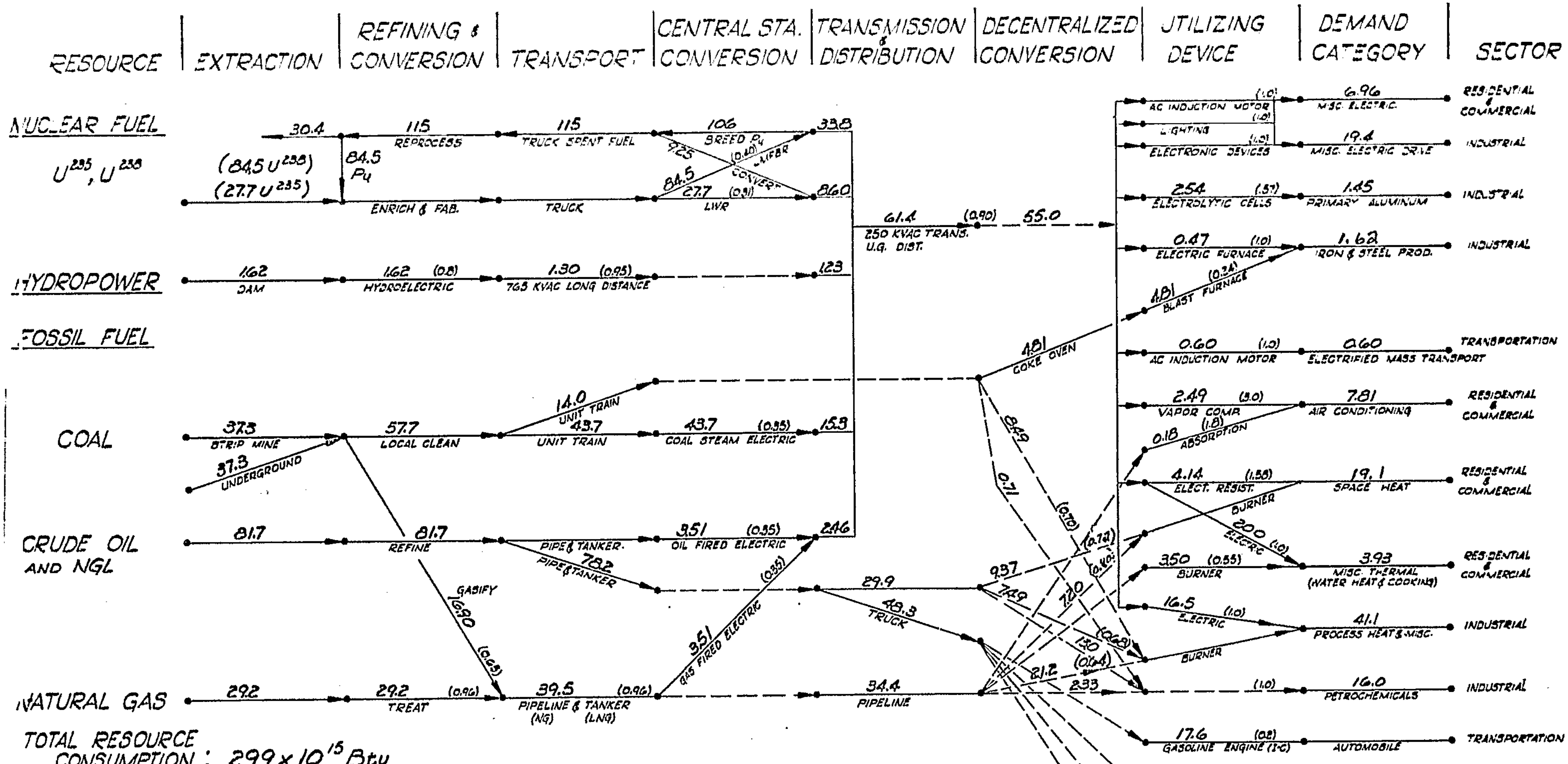


NOTES:

1.- SOLID ELEMENT DENOTES A REAL ACTIVITY
2.- INDUSTRIAL PROCESS HEAT DEMANDS INCLUDE STEEL AND ALUMINUM FUEL NEEDS OTHER THAN ELECTRIC AND COAL, AS WELL AS ALL OTHER INDUSTRIAL REQUIREMENTS
3.- ENERGY FLOWS ARE INDICATED IN 10^{15} Btu ABOVE EACH ELEMENT. CONVERSION EFFICIENCIES ARE INDICATED IN PARENTHESIS.
4.- OIL AND GAS FIRED ELECTRIC INCLUDES BOTH STEAM AND GAS TURBINE PLANTS.

Figure II-6

REFERENCE ENERGY SYSTEM, YEAR 2020



TOTAL RESOURCE CONSUMPTION: 299×10^{15} Btu

NOTES:

1. SOLID ELEMENT DENOTES A REAL ACTIVITY
2. INDUSTRIAL PROCESS HEAT DEMANDS INCLUDE STEEL AND ALUMINUM FUEL NEEDS OTHER THAN ELECTRIC AND COAL, AS WELL AS ALL OTHER INDUSTRIAL REQUIREMENTS
3. ENERGY FLOWS ARE INDICATED IN 10^{15} Btu ABOVE EACH ELEMENT. CONVERSION EFFICIENCIES ARE INDICATED IN PARENTHESIS.
4. OIL AND GAS FIRED ELECTRIC INCLUDES BOTH STEAM AND GAS TURBINE PLANTS.

Figure II-7

Environmental Impacts

Unit environmental effects (emission factors, etc.) were presented in Tables II-6, 7 and 8. These factors have been applied to the Reference Energy Systems to obtain annual production rates for the important effects. These are shown in Tables II-17 through II-21 for each of the reference years.

The unit emissions from automobiles and central station power plants change as a function of time as new regulations become effective and some additional calculations are required in order to apply the proper emission factors. Those calculations are presented in Reference 21.

Only carbon dioxide emissions are tabulated for the methane production category. These emissions account for the field uses of natural gas and for the carbon dioxide that is released in the coal gasification process.

The jet fuel emissions are calculated by applying emission factors measured for the landing and take-off cycle (includes flight under 3500 ft altitude) to all of the jet fuel consumed in the reference years. It is estimated that about 20% of the aircraft fuel is consumed at altitudes of less than 3500 ft and the corresponding fraction of the total emissions are produced below this altitude.

In many cases cumulative environmental impacts are important. In Table 11-22 the cumulative use of land for various elements of the energy system is presented.

Total Energy Use

Figure II-8 shows the calculated fuel use and total energy use over the time considered in this study. The general features of the projections can be understood from the nature of the technologies incorporated in the reference systems. The rate of increase in the use of oil decreases around 1985 due to competition from LWR's. The introduction of the LMFBR, in turn, accounts for the decrease in the growth rate for the LWR around 1990. The increased growth rate for coal after 1995 is due to the demand for gasified coal.

TABLE II-17

1969 PRODUCTION OF AIR POLLUTANTS AND RADIOACTIVE MATERIALS[a]

Location	Air Pollutants[b]							Radioactive Materials[c]			
	CO_2	CO	SO_2	NO_x	Particulates	Hydrocarbons	Aldehydes	T	Kr	Solid high level waste	Exposure to population
	10^{12} lb/yr	10^9 lb/yr						10^6 Ci/yr	10^6 Ci/yr	10^3 ft^3/yr	10^3 man-rem/yr
At point of end use											
Residential & Commercial											
Gas	0.837	0.132	0.004	0.426	0.127	0.053	0.067				
Oil	0.961	0.116	3.46	1.00	0.498	0.121	0.079				
Coal	0.116	0.211	0.80	0.125	0.084	0.062	0.0001				
Industry											
Gas	1.03	0.003	0.005	0.978	0.147	0.326	0.024				
Oil	0.525	0.004	0.949	0.89	0.334	0.065	0.043				
Coal	1.16	0.419	23.7	3.14	9.53	0.209	0.001				
Transportation											
Gasoline	1.57	180.2	0.422	15.4	0.75	31.6					
Diesel Fuel	0.231	2.20	0.264	3.51	0.128	0.361	0.030				
Jet Fuel	0.311	2.24	0.171	0.431	0.688	1.46	0.044				
SUBTOTAL	6.74	185.1	29.8	25.9	12.3	34.3	0.288				
At central facility											
Electric Generation											
Gas	0.439	0.001	0.002	1.36	0.052	0.139	0.010				
Oil	0.272	0.0003	3.85	1.12	0.086	0.021	0.011				
Coal	1.66	0.297	31.8	6.02	7.83	0.090	0.001				
LWR								0.028	0.784	0.163	0.870
LMFBR											
Methane Production	0.191										
SUBTOTAL	2.56	0.298	35.7	8.50	7.97	0.250	0.022				
Total	9.30	185.3	65.5	34.4	20.3	34.6	0.310	0.028	0.784	0.163	0.870

[a]Includes production attributable to energy conversion only. Industrial process emissions that are not related to fuel combustion are not included here.

[b]Based on Emission Factors given in Table II-6.

[c]Based on factors given in Table II-7.

TABLE II-18

1977 PRODUCTION OF AIR POLLUTANTS AND RADIOACTIVE MATERIALS[a]

Location	Air Pollutants[b]							Radioactive Materials[c]			
	CO_2	CO	SO_2	NO_x	Partic-ulates	Hydro-carbons	Alde-hydes	T	Kr	Solid high level waste	Exposure to population
	10^{12} lb/yr	10^9 lb/yr						10^6 Ci/yr	10^6 Ci/yr	10^3 ft^3/yr	10^3 man-rem/yr
At point of end use											
Residential & Commercial											
Gas	0.878	0.139	0.004	0.445	0.132	0.055	0.070				
Oil	0.972	0.120	3.51	0.998	0.501	0.122	0.080				
Coal											
Industry											
Gas	1.32	0.004	0.006	1.25	0.188	0.418	0.031				
Oil	0.66	0.005	2.40	1.13	0.422	0.082	0.055				
Coal	1.40	0.504	7.91	3.79	11.48	0.252	0.001				
Transportation											
Gasoline	1.75	163.3	0.47	14.33	0.834	21.13					
Diesel Fuel	0.504	4.80	0.575	7.65	0.279	0.788	0.065				
Jet Fuel	0.745	5.35	0.41	1.03	1.645	3.50	0.105				
SUBTOTAL	8.23	174.2	15.3	30.6	15.4	26.3	0.407				
At central facility											
Electric Generation											
Gas	0.466	0.002	0.002	1.17	0.055	0.148	0.011				
Oil	0.529	0.001	2.46	1.68	0.168	0.040	0.022				
Coal	2.14	0.383	11.9	7.32	6.81	0.115	0.002				
LWR								1.11	31.1	6.45	34.4
LMFBR											
Methane Production	0.239										
SUBTOTAL	3.37	0.386	14.4	10.2	7.033	0.303	0.035				
Total	11.6	175.0	29.7	40.8	22.4	26.6	0.442	1.11	31.1	6.45	34.4

[a]Includes production attributable to energy conversion only. Industrial process emissions that are not related to fuel combustion are not included here.

[b]Based on Emission Factors given in Table II-6.

[c]Based on factors given in Table II-7.

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TABLE II-19

1985 PRODUCTION OF AIR POLLUTANTS AND RADIOACTIVE MATERIALS[a]

Location	Air Pollutants[b] CO_2 10^{12} lb/yr	CO 10^9 lb/yr	SO_2 10^9 lb/yr	NO_x 10^9 lb/yr	Particulates 10^9 lb/yr	Hydrocarbons 10^9 lb/yr	Aldehydes 10^9 lb/yr	Radioactive Materials[c] T 10^6 Ci/yr	Kr 10^6 Ci/yr	Solid high level waste $10^3 ft^3/yr$	Exposure to population 10^3 man-rem/yr
At point of end use											
Residential & Commercial											
Gas	0.88	0.139	0.004	0.453	0.132	0.056	0.07				
Oil	0.984	0.116	3.55	1.04	0.513	0.124	0.081				
Coal											
Industry											
Gas	1.69	0.005	0.008	1.61	0.242	0.538	0.040				
Oil	0.853	0.007	3.08	1.45	0.542	0.105	0.070				
Coal	1.72	0.622	9.75	4.67	14.2	0.311	0.002				
Transportation											
Gasoline	2.01	53.2	0.54	5.20	0.96	7.46					
Diesel Fuel	0.802	7.64	0.915	12.2	0.443	1.25	0.104				
Jet Fuel	1.56	11.2	0.861	2.16	3.46	7.35	0.221				
SUBTOTAL	10.5	73.0	18.7	28.8	20.5	17.2	0.588				
At central facility											
Electric Generation											
Gas	0.437	0.001	0.002	0.939	0.052	0.138	0.011				
Oil	0.670	0.001	3.13	1.73	0.213	0.051	0.028				
Coal	2.57	0.458	14.03	8.47	5.72	0.139	0.029				
LWR								3.19	88.9	18.5	98.6
LMFBR											
Methane Production	0.567										
SUBTOTAL	4.24	0.460	17.2	11.1	5.99	0.328	0.068				
Total	14.7	73.5	35.9	39.9	26.5	17.5	0.656	3.19	88.9	18.5	98.6

[a]Includes production attributable to energy conversion only. Industrial process emissions that are not related to fuel combustion are not included here.

[b]Based on Emission Factors given in Table II-6.

[c]Based on factors given in Table II-7.

TABLE II-20

2000 PRODUCTION OF AIR POLLUTANTS AND RADIOACTIVE MATERIALS[a]

Location	Air Pollutants[b]							Radioactive Materials[c]			
	CO_2	CO	SO_2	NO_x	Partic-ulates	Hydro-carbons	Alde-hydes	T	Kr	Solid high level waste	Exposure to population
	10^{12} lb/yr	10^9 lb/yr						10^6 Ci/yr	10^6 Ci/yr	10^3 ft^3/yr	10^3 man-rem/yr
At point of end use											
Residential & Commercial											
Gas	0.965	0.153	0.004	0.505	0.146	0.062	0.076				
Oil	1.15	0.128	4.14	1.25	0.607	0.144	0.095				
Coal											
Industry											
Gas	2.05	0.007	0.010	1.95	0.292	0.651	0.049				
Oil	1.03	0.008	3.70	1.74	0.652	0.127	0.085				
Coal	2.13	0.772	12.1	5.79	17.6	0.386	0.002				
Transportation											
Gasoline	2.21	13.2	0.592	1.49	1.04	1.67					
Diesel Fuel	1.33	12.7	1.52	20.2	0.735	2.08	0.172				
Jet Fuel	2.16	15.5	1.19	2.99	4.77	10.2	0.305				
SUBTOTAL	13.1	42.6	23.3	35.9	25.8	15.3	0.784				
At central facility											
Electric Generation											
Gas	0.476	0.002	0.002	0.78	0.057	0.151	0.011				
Oil	0.928	0.001	4.37	1.64	0.295	0.071	0.038				
Coal	4.37	0.781	23.42	13.7	3.9	0.236	0.004				
LWR								5.03	140.4	29.1	155.7
LMFBR								7.40	28.5	24.9	162.3
Methane Production	1.31										
SUBTOTAL	7.08	0.783	27.9	16.1	4.25	0.458	0.053				
Total	20.1	43.4	51.1	52.0	30.1	15.8	0.837	12.43	168.9	54.0	318.0

[a] Includes production attributable to energy conversion only. Industrial process emissions that are not related to fuel combustion are not included here.

[b] Based on Emission Factors given in Table II-6.

[c] Based on factors given in Table II-7.

TABLE II-21

2020 PRODUCTION OF AIR POLLUTANTS AND RADIOACTIVE MATERIALS[a]

	Air Pollutants[b]							Radioactive Materials[c]			
	CO_2	CO	SO_2	NO_x	Particulates	Hydrocarbons	Aldehydes	T	Kr	Solid high level waste	Exposure to population
Location	10^{12} lb/yr	10^9 lb/yr						10^6 Ci/yr	10^6 Ci/yr	10^3 ft^3/yr	10^3 man-rem/yr
At point of end use											
Residential & Commercial											
Gas	1.33	0.21	0.006	0.687	0.200	0.085	0.105				
Oil	1.59	0.177	5.74	1.74	0.842	0.200	0.132				
Coal											
Industry											
Gas	2.58	0.008	0.012	2.46	0.368	0.819	0.061				
Oil	1.27	0.010	4.59	2.16	0.809	0.157	0.105				
Coal	2.98	1.08	16.9	8.09	24.5	0.539	0.003				
Transportation											
Gasoline	2.62	13.7	0.704	1.62	1.25	1.65					
Diesel Fuel	1.86	17.8	2.13	28.3	1.03	2.92	0.241				
Jet Fuel	2.58	18.5	1.41	3.56	5.69	12.1	0.363				
SUBTOTAL	16.8	51.5	31.5	48.6	34.7	18.5	1.01				
At central facility											
Electric Generation											
Gas	0.428	0.001	0.002	0.702	0.051	0.136	0.010				
Oil	0.597	0.001	2.81	1.05	0.19	0.046	0.025				
Coal	9.78	1.75	52.4	30.6	8.73	0.528	0.009				
LWR								5.47	152.5	31.6	169.1
LMFBR								30.5	117.5	102.8	664.5
Methane Production	2.75										
SUBTOTAL	13.6	1.75	55.2	32.4	8.97	0.71	0.044				
Total	30.4	53.3	86.7	81.0	43.7	19.2	1.05	35.97	270.0	134.4	833.6

[a]Includes production attributable to energy conversion only. Industrial process emissions that are not related to fuel combustion are not included here.

[b]Based on Emission Factors given in Table II-6.

[c]Based on factors given in Table II-7.

TABLE II-22

CUMULATIVE LAND USE,[a] 10^3 SQUARE MILES

	1969	1977	1985	2000	2020
Strip mining of coal[b]	0.100	1.08	2.57	7.06	18.3
Central Station Electric Plant Sites[c]					
Coal fired	0.229	0.325	0.400	0.715	1.712
Oil fired	0.016	0.024	0.031	0.450	0.250
Gas fired	0.019	0.019	0.019	0.022	0.021
Nuclear	0.002	0.042	0.121	0.390	1.026
SUBTOTAL	0.266	0.410	0.571	1.577	3.009
Electric Transmission	5.035	8.265	12.635	28.082	64.600
TOTAL	5.401	9.755	15.776	36.719	85.909

[a]Based on land use factors in Table II-8.

[b]Gives the cumulative amount of land strip-mined after 1968.

[c]Does not include hydroelectric,gas turbine, or internal-combustion plant sites.

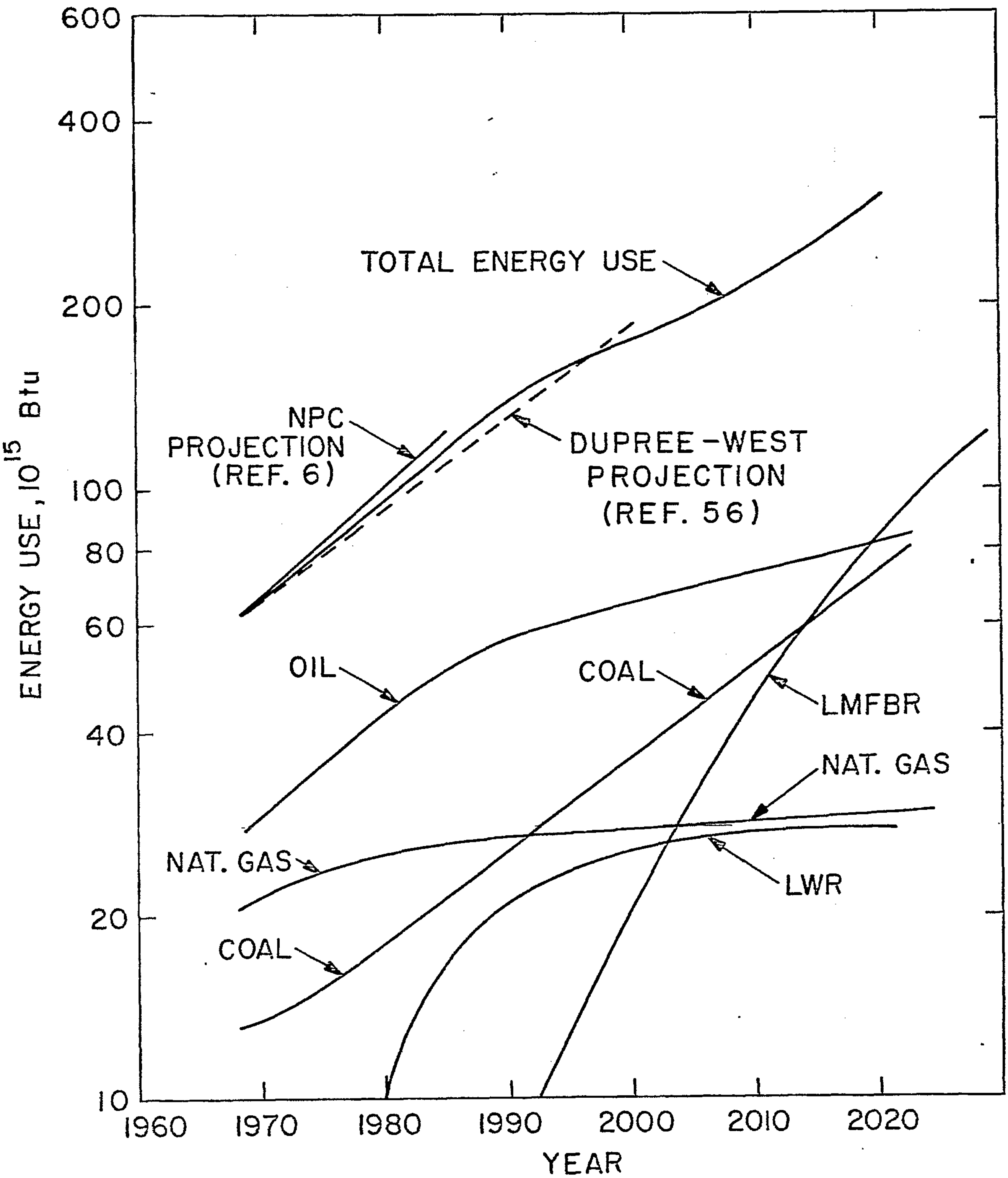

Figure II-8. Reference Projections for Fuel Uses and Total Energy Use

The shape of the curve for total energy consumption is accounted for mainly by two factors: saturation effects which gradually lower the growth rate (particularly before the year 2000) and the increased use of relatively inefficient means of energy conversion, particularly the increased electrical fraction, beyond that year.

Also shown in the figure are two other projections of total energy use. The projection by the National Petroleum Council[6] (labeled NPC) was prepared only to the year 1985. The Dupree-West [56] projection is based on macroeconomic factors and was prepared in the Department of the Interior.

It may be useful to consider this projected growth in total resource consumption in relation to overall economic activity as indicated by the gross national product (GNP). The GNP and other economic indicators, such as the Index of Industrial Production, are frequently correlated with energy demand.

Figure II-9 is a plot of energy demand divided by GNP as a function of time. Historical data are used to define the curve up to 1970 and the curves after that time are defined by the total energy resource consumption projected as shown in Figure II-8 with several different assumptions regarding future growth in GNP. With a 3% assumed growth rate, the energy demand per unit GNP increases until about 1985 and then exhibits a decline after that time. With a 4% assumed growth rate after 1970 the curve declines steadily over future years. The relationship is also plotted assuming a 4% annual rate of increase in GNP until 1985 with a 3% rate thereafter. This latter assumption results in a curve that corresponds roughly to the past 20-year experience.

The relationship between production and service components of the GNP and energy demand are not well understood. Therefore, there is little basis for determining which of the growth rate assumptions corresponds best to the demand projections made in this analysis.

It should be noted that in the projections made for this study and those to which it is compared in Figure II-9, virtually no account is taken of the effect of energy supply and price on demand. There has been considerable discussion in the literature[57,58] of the danger of

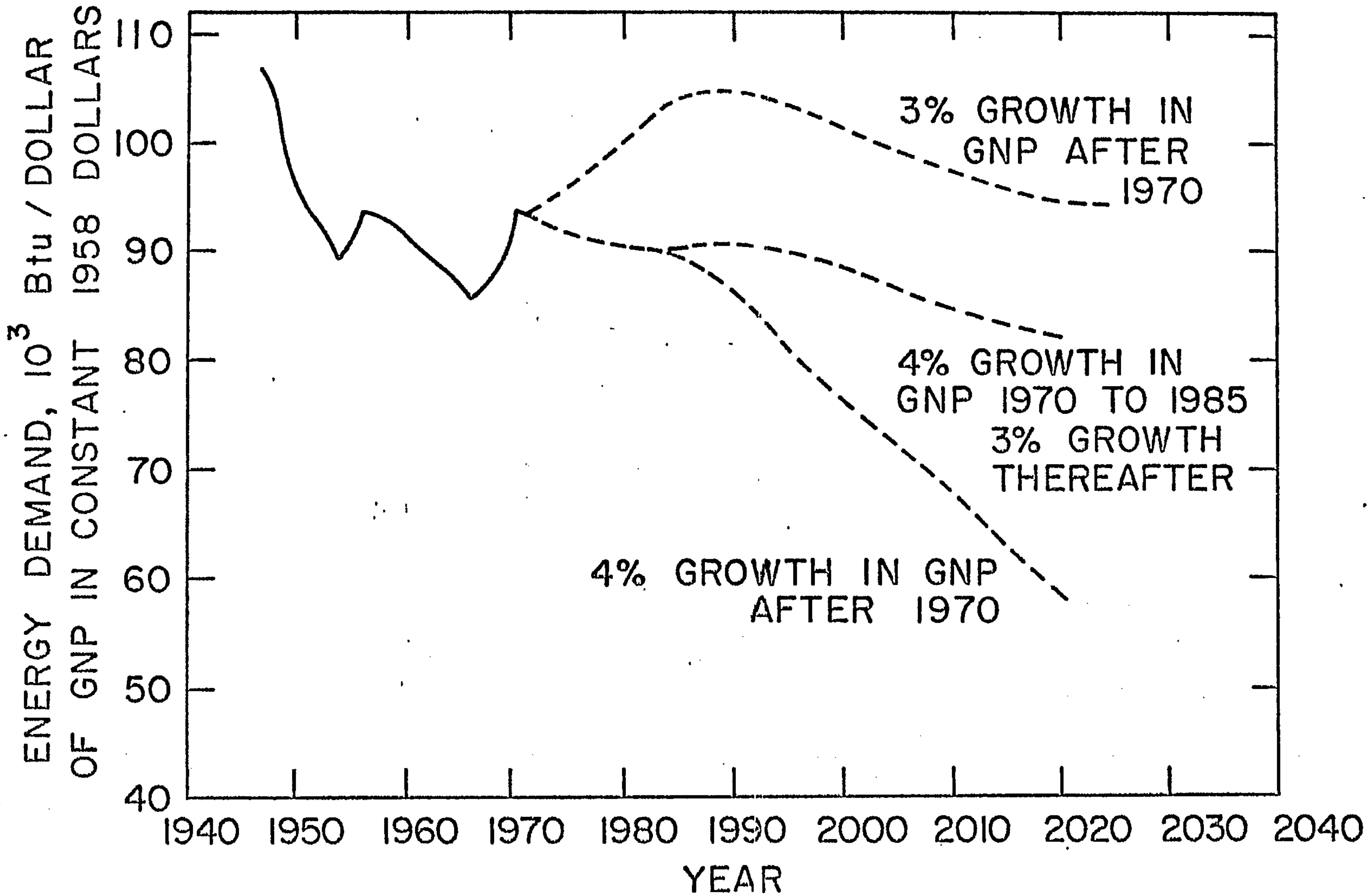

Figure II-9. Ratio of Projected Energy Demand to Gross National Product overestimating demand in this way. Unfortunately, at the present, price elasticities of energy demand are very poorly known. Furthermore, when the basic question is the determination of R&D priorities the conservative demand projection to use is a high one.(59)

Resource Consumption

It is now of interest to compare the cumulative consumption of energy resources implied by the Reference Energy Systems to the resource estimates presented above. These comparisons are not presented as predictions of future exhaustion of supply. The laissez-faire nature of the reference systems must be recalled. The comparisons will, however, give a rough indication of the extent of indiginous energy resources as measured against unconstrained growth uninfluenced by new technology.

Figure II-10 presents the situation for petroleum. The curves with and without imports clearly show the forces behind oil importation. The importation rate shown is derived from National Petroleum Council figures which, for example, project that in 1985 57% of the petroleum consumed in the U.S. will be imported. In any event, domestic production of petroleum appears to be passing through its maximum at the present time. The decline in production in the coterminous U.S. may be offset by Alaskan production.

The data shown in Figure II-11 suggest that exploitation of coal will not be resource-limited during the next few decades. It is possible, however, that other constraints will control the growth of coal production, e.g., power plant emission standards, decreasing productivity in underground mines, shortages of new capital, labor, and transportation capacity.

Projections of natural gas supply and demand indicate that never again will supply of domestic natural gas satisfy demand.(6,60) The comparison of domestic supply and cumulative consumption shown in Figure II-12 makes that prognosis appear quite reasonable.

Figure II-13 shows the relationship between uranium supply and demand as implied by the Reference Energy Systems. Due to the large number of simplifications made, this comparison gives only a rough indication of the supply-demand relationship. For example, no Pu recycle is considered

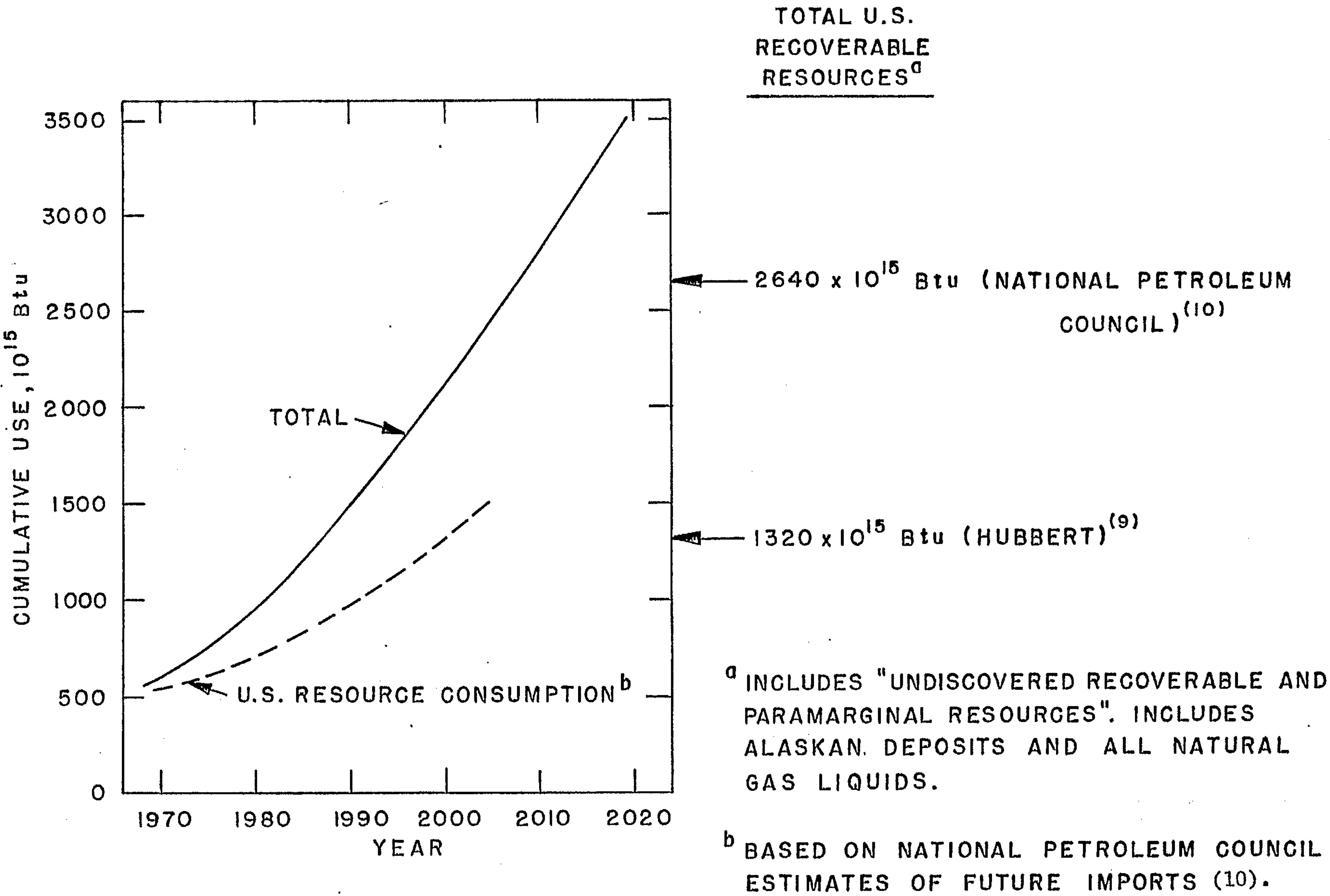

Figure II-10. Reference Demand for Petroleum and Domestic Supply

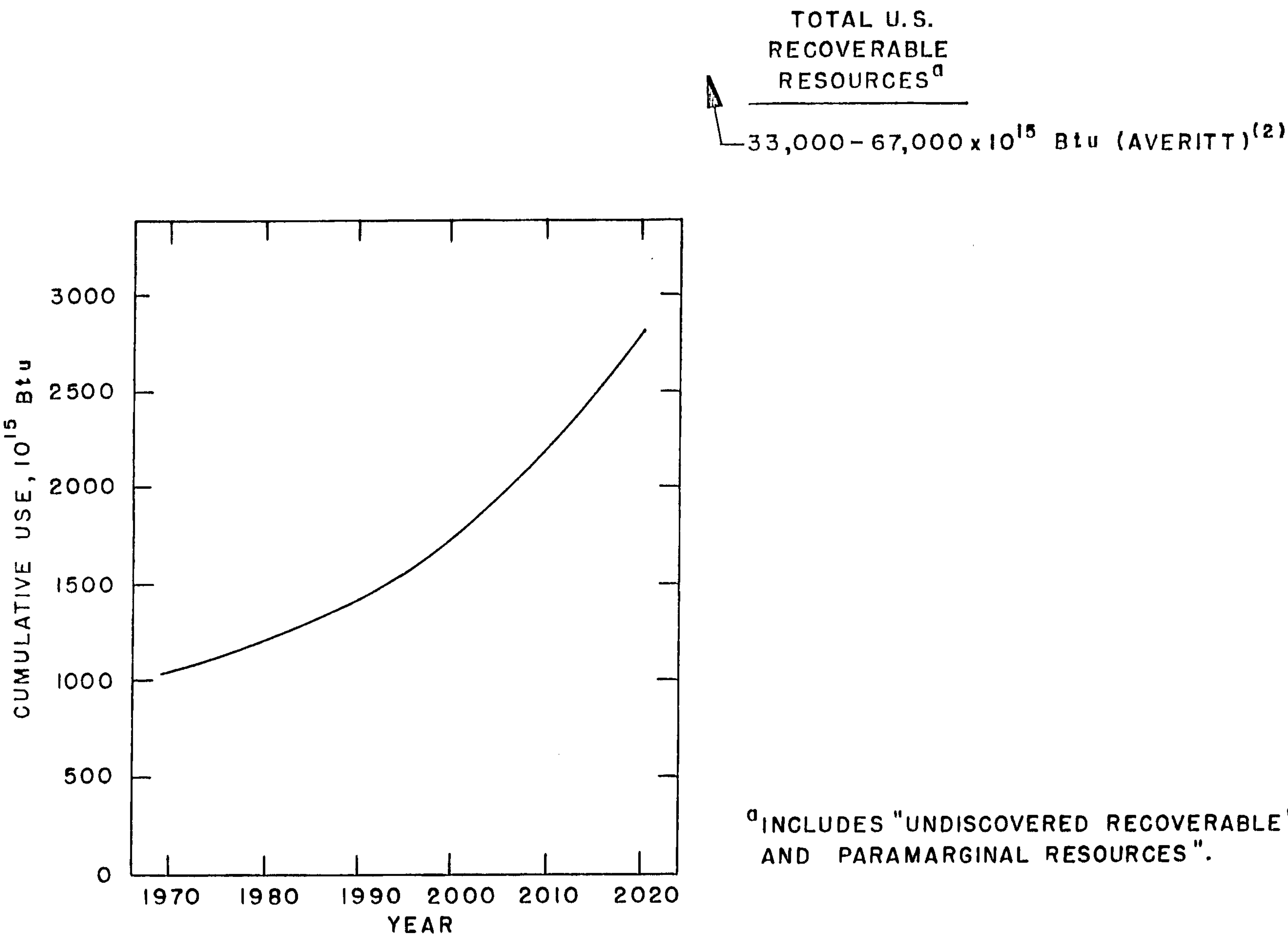

Figure II-11. Reference Demand for Coal and Domestic Supply

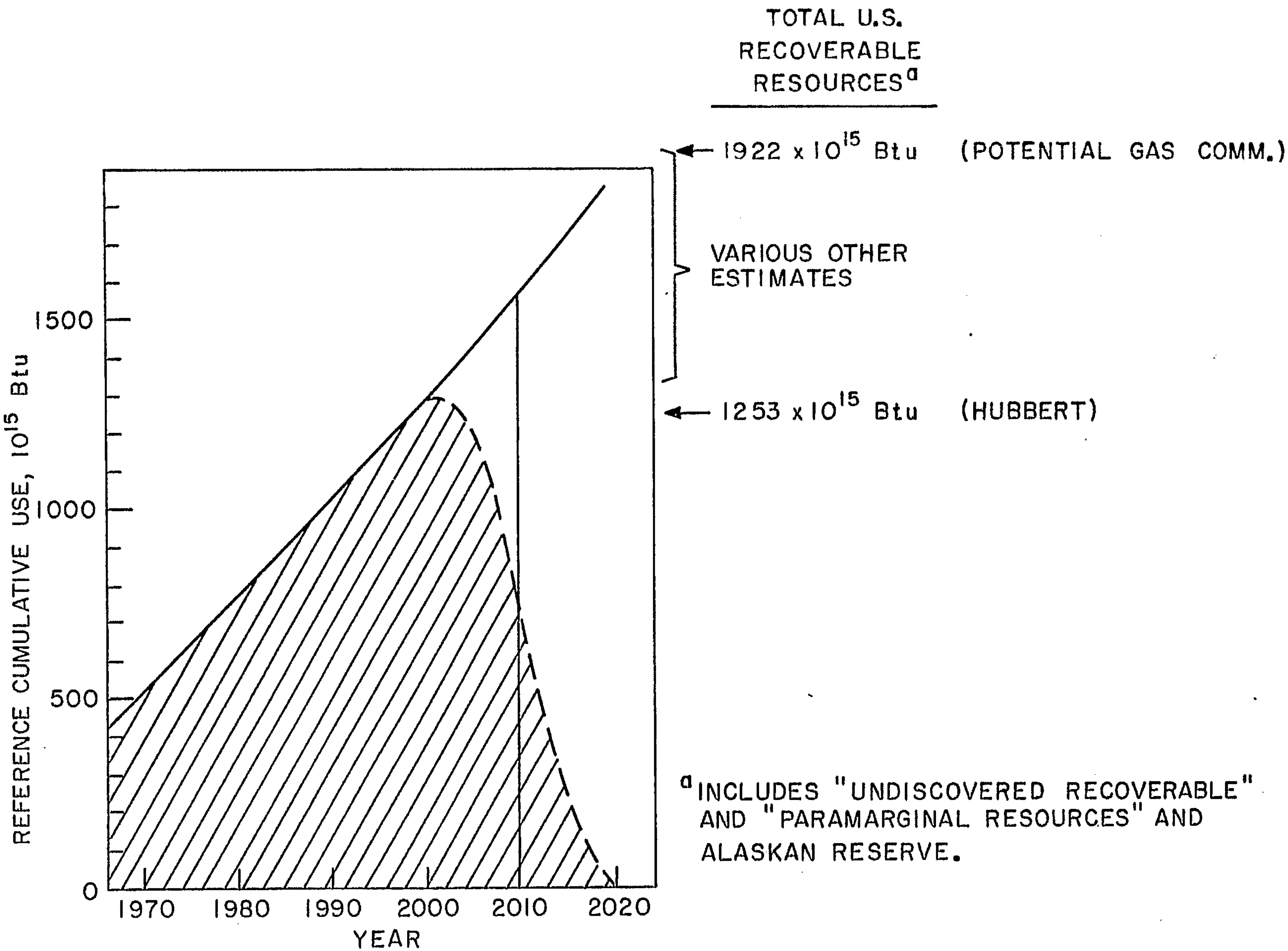

Figure II-12. REFERENCE DEMAND FOR NATURAL GAS AND DOMESTIC SUPPLY

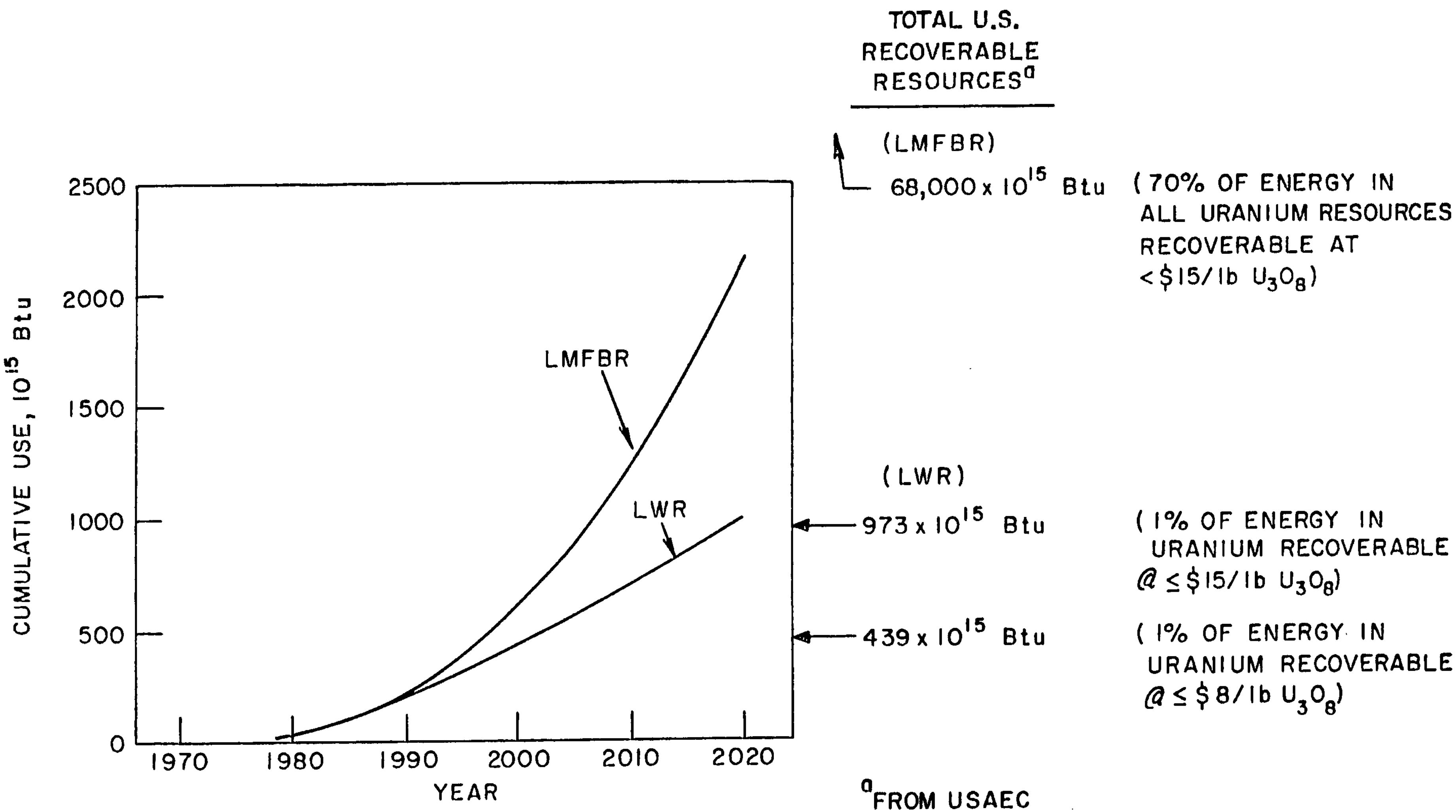

Figure II-13. REFERENCE DEMAND FOR URANIUM AND DOMESTIC SUPPLY in LWR's. With recycle, a significantly larger portion of the uranium is usable than the U-235 content implied in the figure. Light water reactors are assumed to convert 1% of the energy in the uranium while the LMFBR is assumed to convert 70%.

It should be noted that no account is taken of the high temperature gas-cooled reactor (HTGR) although commercial plants of this type have been ordered. Such plants would allow use of the Th U-233 cycle, and, to that degree, decrease uranium resource consumption.

F. MAJOR PROBLEMS FACING THE ENERGY SYSTEM

The preceding sections have drawn a picture of the current U.S. energy system and its future evolution that reveals many of the problems against which new technologies must be measured. Those problems will gradually change with time. It is convenient to discuss them in terms of three eras: Near Term (1974-1985), Intermediate Term (1985-2000), and Long Term (2000-2025).

The Near Term (1974-1985)

It is not necessary to speculate about the nature of the problems because they are already with us. Only the severity of the problems and their implications are open to speculation. Increased fuel prices and sporadic shortages of petroleum products, natural gas, and electricity are occurring and appear likely to become more frequent.

As Figures II-10-13 indicate, current shortages of fuel are not due to basic resource constraints. Rather, two other factors are responsible. The most basic is the abrupt recognition of the environmental costs of energy use--particularly urban air pollution. New SO_2 emission standards for central station power plants have impacted particularly on the use of coal, the most popular fuel for electricity production. Oil supply to utilities was similarly, though somewhat less, affected by restrictions on sulfur content. At the same time the installation of nuclear plants was affected by licensing delays. The other causitive factor was Federal regulation of imports of foreign oil and, particularly, regulation of natural gas prices. The latter policy had the effect of stimulating increased demand for this clean fuel while discouraging exploration for new reserves.

In the near term several specific problems face the energy system.

1. Coal Production and Use: Environmentally acceptable methods must be found to extract and use coal for electricity production. Both legislative and technological attention is being directed to problems associated with underground and surface mining. As will be discussed below, attention is also being focused on sulfur removal from power plant stack gases and from coal before combustion.

2. Natural Gas Production: Projections of potential demand and potential production indicate that the demand-supply deficit will increase rapidly in the Near Term. Pipeline imports and LNG imports cannot be in sufficient quantity to close the projected deficit ; however, they might approximately compensate for anticipated declining domestic production. Synthetic pipeline gas from coal gasification will gradually become available around 1980, but the projected capacity will be too small to alter the outlook appreciably in the Near Term. Therefore, in the Near Term other sources of energy must compensate for gas shortages. It is commonly assumed that imported petroleum must fill most of this gap.

3. Oil Importation: The domestic production of petroleum does not satisfy today's demand. In 1971 we imported 28.6% of the petroleum that we consumed. Projections indicate that demand will continue to increase whereas domestic production will remain about constant or decrease. As reflected in Figure II-10, this implies a significant increase in petroleum imports in the Near Term. Such imports are undesirable both from the national security point of view (dependent, of course, on the exporting country), and from the point of view of balance of payments.

4. Financial Requirements: The National Petroleum Council has estimated that the capital outlays required for resource development, manufacturing facilities and primary distributions in the U.S. would total approximately $375 billion between 1971 and 1985. Funds from

the operations of energy industries at current prices would fall far short of meeting these requirements.[6]

5. Urban Air Quality: The crux of the environmental problems related to energy use is that of urban air quality. As discussed above this problem is closely related to the problems of fuel availability that are now evident.

A serious restriction on the solution of many of these short term problems is the slow response time of the energy system. The benefits of actions taken today cannot be realized for a long time in the future. Most new increments of "conventional" energy supply--systems which are already developed--take from 5 to 10 years to evolve from concept to production. For example, a new oil or gas field requires approximately 5 years to develop from discovery to production. It now takes about 10 years to plan, license and build a nuclear power plant.

Because of the long lead time required for major new installations, short-term solutions to partially alleviate today's shortages must necessarily be somewhat less than satisfactory, usually requiring undesirable compromises. For example, if sulfur emission standards were to be relaxed some fuel shortages would be eased, but only at the expense of the public health. Gas turbines can substitute for pumped storage and even for base load plants whose construction is delayed, but only with a penalty in fuel costs and poorer air quality.

Even the response of energy demand to higher prices is sluggish. In many sectors the delay time might be several years. This is due to the combination of the facts that: 1) energy cost is usually a small part of the cost of using a device; and 2) most devices have a long useful life, discouraging prompt replacement. The price elasticities for the various energy forms and various end uses are not well defined. Ultimately rising prices will stimulate energy conservation, but the rate of price increase coupled with the lag in response does not indicate a significant impact in the near term.

The Intermediate Term (1985-2000)

Many of the problems of the near term, such as those relative to the use of coal and those related to urban air quality will persist into the intermediate term. In this period, basic resource limitations will be fact and domestic production of crude oil and natural gas may decline rapidly. Competition for foreign oil may greatly increase prices. The challenge will be to develop means to exploit new domestic energy resources to replace petroleum and natural gas and to reduce dependence on foreign resources. To achieve this goal we must exploit our domestic coal, uranium and oil-shale deposits.

As indicated in the Reference Energy Systems, the production of synthetic pipeline gas from coal gasification should increase rapidly during the intermediate term. Coal, along with oil shale, is also a logical source of liquid fuels. The problems of environmental control of these coal conversion processes will be awesome. Because of the enormous quantities of coal which will be needed, the extraction, the waste disposal, the land reclamation, and the control of effluents will pose difficulties on a large scale. The reference systems show the use of coal for generating electricity increasing although the coal share of the electrical market will decrease.

The reference projections indicate a production rate of electricity at the end of this period of some five times that in 1969. This presents a major problem of environmentally-acceptable energy transmission.

The Long Term (2000-2025)

By the start of the next century domestic natural gas and petroleum resources will be severely depleted. Coal and oil shale will be the primary alternate sources of gaseous and liquid fuels and nuclear power will be the primary source of electricity. Low cost uranium ores may be exhausted. We will be dependent on the successful development of the breeder to avoid being significantly affected by rising prices of uranium feedstocks. The very large transmission requirements may mean that above-ground high voltage transmission lines will be rarely installed and existing lines will be gradually retired in favor of underground transmission. The move to underground will be motivated by public demand and difficulty of obtaining rights of way despite unfavorable economics.

The depletion of fossil fuels in this period and environmental effects associated with very large energy use present a significant challenge. Part of the solution must be major technological innovation.

G. RECENT FEDERAL FUNDING OF ENERGY R&D

As background to the discussion of new options in energy R&D funding it is well to review briefly the recent history of Federal funding in this area. Table II- 23 presents a summary of energy R&D funding between FY 1969 and FY 1973. The figures refer to work in exploration, production, conversion and transmission. Funding for mobile applications is not included.

The total Federal funding during the 1969-1973 period increased by about 72% representing a compounded growth rate of more than 11% per year. Major parts of the increase was due to expansion of the fast breeder program, coal gasification to high-Btu gas, SO_2 removal from stack gases and the controlled fusion program. The current programs in many of these areas are discussed in the next chapter.

A considerable amount of energy R&D is also carried out in the private sector, particularly by the petroleum industry and equipment manufacturers. The tradition of proprietary R&D in industry, however, makes it difficult to assess the absolute magnitude of those efforts. The electric utility industry is planning a major expansion in their R&D efforts which will be carried out under the newly formed Electric Power Research Institute.(74)

TABLE II-23

FEDERAL ENERGY R&D FUNDING[a]

FY 1969 through FY 1973
(in millions of dollars)

	Agency	FY 69	FY 70	FY 71	FY 72	FY 73
Coal Resources Development						
Production and Utilization R&D, incl. gasification, liquifaction and MHD	DOI - BOM	$12.3 M	$13.2 M	$15.4 M	$14.7 M	$19.0 M
	DOI - OCR	8.7	13.5	18.8	31.1	45.3
Mining Health and Safety Research	DOI - BOM	2.3	3.7	14.8	31.0	30.1
Petroleum and Natural Gas						
Petroleum Extraction Technology	DOI- BOM	2.6	2.7	2.7	3.2	3.1
Nuclear Gas Stimulation[b]	AEC	2.4	3.7	6.1	7.0	7.5
Oil Shale	DOI- BOM	2.5	2.4	2.7	2.6	2.5
Continental Shelf Mapping	DOI- GS	-	-	-	5.0	7.0
	DOC	6.0	6.0	6.0	6.0	6.0
Nuclear Fission						
LMFBR[b]	AEC	132.5	144.3	167.9	236.6	259.9
	TVA				0.8	1.6
Other Civilian Nuclear Power[b]	AEC	144.6	109.1	97.7	90.7	94.8
Nuclear Fusion						
Magnetic Confinement[b]	AEC	29.7	34.3	32.3	33.2	40.3
Laser-Pellet[b, c]	AEC	2.1	3.2	9.3	14.0	25.1
Energy Conversion with Less Environmental Impact						
Cleaner Fuels R&D-Stationary Sources	EPA	10.7	19.8	17.4	24.5	29.5
SO_x Removal	TVA	-	-	-	2.6	15.2
Improved Energy Systems	HUD	0.3	0.8	3.0	2.4	2.8
Thermal Effects R&D	EPA	0.5	0.8	0.6	0.7	1.0
	AEC	0.8	1.5	1.8	3.2	6.8[d]
General Energy R&D						
Energy Resources Research[e]	NSF		1.1	5.0	9.8	13.4
Geothermal Resources	DOI	0.1	0.2	0.2	0.7	2.5
Engineering Energetics Research	NSF	2.9	2.9	2.7	4.0	4.7
Underground Transmission	DOI	-	-	0.8	0.9	1.0
Cryogenic Generation	NBS	-	-	-	-	1.0
Non-Nuclear Energy R&D	AEC	-	-	-	-	1.5
		$ 361.0M	$ 363.2 M	$ 405.2 M	$ 524.7M	$ 621.6 M

Footnotes - Table II-23

[a]The funding listed in these tables cover the Federal R&D programs in development-exploration and production, conversion, and transmission of our energy resources. This funding includes energy conversion R&D for stationary applications only; R&D funding for improved mobile applications (e.g., automotive, rail, seagoing) are not included. Fundamental research on environmental health effects of combustion products and low-dose radiation exposure) is not included.

[b]This funding includes operating, equipment, and construction costs.

[c]The primary applications of the multipurpose laser-pellet effort are for other than energy production.

[d]This entry includes $1.5 million for dry cooling tower R&D under the AEC's new Non-Nuclear Energy R&D category. Other related work is carried out under Other Civilian Nuclear Power.

[e]The NSF RANN Program includes research on solar energy as well as fundamental energy policy studies.

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Chapter III - ENERGY RESEARCH AND DEVELOPMENT OPTIONS

A. INTRODUCTION

In this chapter research and development programs are recommended in eleven technological areas. Each subsequent section of the chapter is divided into four parts. In an introductory part the general importance of the technological area is briefly discussed. There follows a discussion of the current status of the technology and, then, a consistent R&D program is outlined. In a final part, the R&D program is assumed to be successful and the impact of the introduction of the technology is assessed. The potential impact of each technology, relative to current and future problems of the energy system, is, of course, the primary justification for investment in the R&D program. In discussing the importance of the technological area, the general context is the specific set of problems facing the energy system as outlined in Chapter II. Thus the discussions of the impact of the technology can be assessed in the context of goals toward which energy policy is directed.

The discussion of the current status of each technology is necessarily very brief but aims at giving an impression both of the technology's current role (if any) and the main scientific, technological or economic barriers to its development and use. The current status of R&D is then briefly outlined. In both the discussion of current status and the recommended R&D program which follows, considerably more detail is given in the panel reports prepared for the assessment.

In developing the R&D program described in the next part of each section emphasis was placed on a balanced R&D strategy both in terms of the individual technological area and in terms of the over-all energy R&D package. Although in a number of areas significant increases over current funding is anticipated, such increases were always considered to be well justified by potential future benefits and well within the capability of the particular R&D sector. Only the broad outlines of R&D programs are given in this report. In most cases greater detail is given in back-up panel reports. In some cases specific programs require better definition including the identification of milestones, key decision points and a phase by phase statement of program objectives.

Between technological areas there is considerable differences in the appropriate division between Federal and private industrial support for the R&D program. In the fusion area, for example, the research must be essentially all Federally supported. In the electrical transmission area, on the other hand, a large fraction of the program should be supported by industry, and there is considerable interest within industry to do so. Much of the developmental work supported by Federal funds has been and should continue to be carried out by industry as contrasted with government laboratories. Other programs are uniquely suited to national laboratories or to universities. In presenting the overall research strategies, however, no attempt has been made to specify in detail the institutional arrangements under which the R&D programs should be carried out. Close attention should be paid to those questions in the elaboration and implementation of the R&D strategies.

A further point should be made relative to the R&D programs that are outlined here, particularly with regard to the long-term programs. R&D has a highly unpredictable quality; thus the long range programs and funding are subject to significant changes as the program progresses. What is projected here is only a current best approximation of future requirements.

The final part of each section assumes the successful completion of the recommended R&D program and evaluates the impact of the technology assuming some rate of implementation. These impact analyses were performed using the Reference Energy System methodology described in Chapter II. For various reasons these impact analyses cannot be considered as highly accurate. They do serve, however, as rough guides to the potential benefits from the defined R&D programs.

B. FOSSIL FUEL EXTRACTION*

INTRODUCTION

As the demands on the nation's finite fossil fuel resources increase at a rapid rate, it will become necessary to exploit lower grade deposits along with those that pose more difficult extraction problems. The development of technologies for the extraction of resources can lead

* This section is based in part on References 1, 2 and 3.

to more effective recovery techniques with reduced environmental impact. The technical areas in resource extraction that are covered in this section are: (1) improved recovery techniques to increase the production of oil and natural gas, (2) development of oil shale, (3) underground gasification of coal, (4) energy recovery from organic wastes, and (5) advanced coal mining systems.

The development of techniques to increase recovery from known oil and gas fields can reduce the quantities of these fuels that must be imported in the near future. Although oil recovery efficiency has been improving for several decades by an estimated 0.5% per year, still only about 30% of the original oil in place is recovered on the average. The known fields contain nearly 60 billion barrels of oil and 300 trillion cubic feet of gas that cannot be economically recovered at current prices with existing technology. In the intermediate term, additional quantities of liquid and gaseous general-purpose fuels can be obtained from oil shale and organic wastes, both of which are abundant resources in the U.S.

Technologies for the conversion of coal into gaseous and liquid fuels and for the combustion of coal with minimal air pollution are required to enable this abundant fuel to play a greater role in the U.S. energy system. Such technologies are discussed in the section on Clean Fuels from Coal. Improved techniques for the mining of coal are equally important. Only a portion of the vast coal reserves are economically recoverable with present technology and costs are increasing as additional constraints are imposed. Underground mining is one of the most hazardous occupations and mining costs have risen sharply since passage of the Coal Mine Health & Safety Act. Surface mining can be damaging to the environment and it too will be subject to new legislative actions in the near future. Specific factors to be addressed in the development of underground coal recovery technology are increased productivity and safety. Underground (*in situ*) gasification could provide an alternative technique for the extraction of energy from coal, oil shale and unrecoverable oil reserves without having to actually mine or produce the resource by conventional methods. While further study on reclamation of surface mined areas is required, particularly in the West, the scale of operations is considerable larger and revegetation is complicated by climatic conditions.

CURRENT STATUS OF EXTRACTION TECHNIQUES

The current state of the energy resource extraction technologies will be discussed in terms of the resources involved.

Improved Recovery of Petroleum and Natural Gas

The production of oil from a reservoir may be increased by a variety of secondary and tertiary recovery techniques. These techniques add to the production costs and thus their use depends strongly on market conditions. As crude oil prices increase many of these technologies which have been developed largely by industry will be employed more widely.

Waterflooding is the most commonly used and most successful fluid injection technique. It generally doubles the amount of oil that can be recovered from a well. Reservoirs that contain low gravity-high viscosity crude oil, however, do not respond well to fluid injection methods. Effective recovery of this type of crude oil requires a reduction of viscosity through the addition of heat or solvents. *In situ* combustion (fire-flooding), steam injection, and carbon dioxide injection have been shown to be technically, and in some cases economically, feasible.

In some oil and gas reservoirs, production is limited by the low permeability of the rock. In such cases fracturing techniques are employed for secondary recovery. Induced hydraulic fracturing treatments have added about 8 billion barrels of oil to the U.S. reserves during the 1946-1970 period, or 11% of the addition to reserves during that period. Studies of natural earth-fracture systems indicate that they are complicated geological occurrences. Directional trends for fracture systems can be observed by various surface observations and can be a valuable tool in determining directional subsurface trends. Wells may be purposely aligned with natural or induced reservoir fracture systems to obtain higher flow rates, and fewer wells thus may be required to drain the reservoir.

Detrimental effects also can occur if earth fracture systems are not clearly understood. In secondary-recovery operations, poor area sweep efficiencies can adversely affect the recovery of additional oil. When fracture systems control subsurface fluid movement, the injected fluid can channel through highly fractured areas and bypass large volumes of trapped oil. Clearer definition of fractures that traverse a rock formation will permit optimization of well locations and prevent early breakthroughs of the injected fluid.

Most research in improved oil recovery technologies has been conducted by private industry. The Federal Government has funded modest efforts in the Bureau of Mines, but these efforts are small relative to industrial activity. While much of the corporate work is proprietary and thus not generally available to the industry, most companies are willing to license the technology for reasonable fees. In recent years there has been an increasing willingness to share information in this area at technical symposia. However, antitrust concerns still inhibit the exchange of some information.

For reservoirs that do not respond to fluid injection or hydraulic fracturing, chemical and nuclear explosives have been proposed for reservoir stimulation. Chemical explosive products are designed for wellbore applications and for displacement from the wellbore into fractures for and detonation within the formation. Several field tests of this stimulation technique have been performed on gas wells. The results ranged from no improvement to a 250% increase in flow capacity. However, chemical explosive fracturing presents serious safety problems due to the energy content and the sensitivity of the chemicals used.

The Department of the Interior and the Federal Power Commission's Natural Gas Survey estimate that as much as 600 trillion cubic feet of gas (approximately 1/3 of our estimated gas resources in place) exist in tight gas sands, located primarily in Colorado, Utah and Wyoming. This gas is not producible at all without first fracturing the gas bearing formations which may extend over several thousand feet at depths ranging from less than 10,000 ft in the Piccance Basin of Colorado and Uinta Basin of Wyoming to 10,000-15,000 feet in the Green River Basin of Wyoming.

A research and development program using nuclear devices to fractures tight gas sand formations is being conducted by the U.S. Atomic Energy Commission and industry with additional technical assistance provided by the Department of the Interior. In this stimulation technique the nuclear explosive is used to create chimneys of broken rock with fractures radiating from the chimneys. Three joint government-industry experiments have been conducted: Gasbuggy, Rulison and Rio Blanco. These detonations were followed by production testing programs. Flow tests at Gasbuggy indicated a five- to eight-fold increase in production over that observed in nearby conventionally stimulated wells. The Rulison test is estimated to have produced a three- to ten-fold increase in production. Results from Rio Blanco, the first multi-device test, are not yet available.

Each of these tests which were part of the AEC's Plowshare program have met with heated opposition from citizen groups and in some cases oil shale interests. The latter group's concern arises because of the risk to oil shale deposits which overly the gas sands in the Piccance Basin. Environmentalists have expressed concern over possible radiation release from the detonation itself as well as the tritium content of the gas. The gas contained in the chimney initially contains iodine, krypton and tritium. The former decays rather rapidly, but the latter two are sufficiently long lived so that the initial gas produced must be flared or used on site and not charged to a pipeline until radiation standards are not exceeded.

Concern has also been expressed for the seismic consequences of the many detonations required for field development. Perhaps the greatest barrier to the use nuclear stimulation, even if safety and seismic problems do not prove serious, will be public acceptance. This problem can likely be overcome if non-nuclear options for producing the gas prove infeasible and/or the public can be better educated as to the risks/benefits associated with its utilization.

Oil Shale

Oil shale reserves represent the primary domestic supplement to oil reserves in the United States. While not as attractive as the tar sands of Canada, shale resources are superior to the known tar sand deposits in the U.S. and presently appear more attractive economically than coal as a source of supplemental oil. Their potential has been recognized for many years during which time industry and government have successfully piloted several retorting processes and experimented with mining and *in situ* extraction of the resource. The technology for a conventional room and pillar mining operation and for retorting the shale is reasonably well developed, although several industrial programs in retorting technology are continuing. Oil from oil shale is still projected to cost $.50-$1.00 above domestic crude oil, but with world oil prices rising rapidly the market conditions could change in the future.

A series of field experiments are in progress to study methods of fracturing and retorting the Tipton member of the Green River oil shale formation. Various methods of fracturing are being tested and two large retorts, with nominal capacities of 10 and 150 tons, are being operated. At the present time it appears that hydrotreating of some shale oil fractions will be required to lower their nitrogen fractions to acceptable levels for catalytic cracking, so a program is being carried out to study the hydrogenation of oil shale.

The principal constraints inhibiting industry at the present time are less technological than economic and institutional. Most of the high grade reserves are located on Federal lands and the government's leasing program has been delayed by the need to satisfy requirements for an environmental impact statement. A larger leasing program may well have to wait for results from this prototype program. The solid waste disposal problem is complicated by the increase in volume experienced by the shale in the retorting process. Proposed solutions for disposal can be better evaluated once experience with a commercial operation is obtained.

Perhaps the greatest inhibition to oil shale development has been the uncertainty as to government policy with regard to oil imports. The investments in opening a mine and constructing retorting and support facilities are too large to commit if the market price for oil is to fluctuate at the whim of government policy makers or the oil rich nations. The combination of these constraining factors plus the inherent technical risk in scaling up from the pilot to commercial scale have deterred industry from building commercial facilities to date.

Extensive deposits of nahcolite, a bicarbonate containing mineral with potential applications in stack gas cleaning, and dawsonite, an aluminum containing mineral with possible applications in wastewater treatment, are located adjacent to some of the deeper oil shale formations. The by product value of these minerals improves the overall economics of oil shale recovery as well as providing additional space for disposing of spent shale. The economics and technology for this combined operation appear attractive at the present time.

Research is also being conducted on in situ processing to determine how composites of oil produced by this technique compare with those produced by above ground retorting. The advantages of eliminating the enormous solids handling and waste disposal problems inherent in surface retorting have led to increased interest in further research on in situ approaches. Industry interest in pursuing such a program has been expressed.

Underground Gasification of Coal

Underground gasification involves the partial combustion of coal in situ to produce such products as combustible gases for power plant firing and associated by products such as light oils and tars. Underground gasification methods essentially involve the preparation of an underground generator complete with inlet, outlet, and a passage through the coal bed. The passages may be natural; induced hydraulically, electrically, or by explosives; or drilled. The coal is ignited and air, oxygen, and steam or other gases are pumped through the system. This installation constitutes a single gasification unit with limited capacity.

To attain a desired production capability (e.g., to supply fuel for an electric generating plant), it is necessary to simultaneously operate a number of gasification units covering a large portion of the coal seam.

Several nations with substantial coal resources have attempted to establish a viable underground gasification technology. These efforts date back to 1868, with the major activity occurring in the period 1945 to 1960. Only limited success was achieved. In the United States, the Bureau of Mines began laboratory tests and small-scale experiments in 1947 in West Virginia and moved to a large-scale field program in Alabama in 1949. Also in 1949, the British initiated a program that culminated in a demonstration of a semi-commercial operation utilizing the product gases for the generation of electricity. Experiments were stopped in both the United States and Britain in 1959.

By 1941, gas was being obtained from five underground gasification installations in the USSR. By 1957, several operations in the USSR were being used in commercial installations to produce electricity for local industries. However, in Russia as in other countries, economic evaluation of the system in comparison with coal mining and with other fossil fuel sources led to abandonment of underground gasification in the 1960's.

At present, there is no known utilization of <u>in situ</u> coal gasification. However, the increasing costs of underground mining, the hazards still inherent in the industry and the large number of marginal coal seams that are not likely to prove economically attractive utilizing conventional mining systems combine to keep interest in <u>in situ</u> extraction technology alive. Many of the problems are similar to those associated with <u>in situ</u> oil shale extraction. Coal, because it would be consumed, would create voids that could create subsidence problems. Earlier efforts have also resulted in lengthy, uncontrolled underground burning of coal seams.

Utilization of Organic Wastes

Nearly 1 billion tons (dry basis) of organic wastes are discarded each year in the United States. These wastes are of a cellulosic nature and consist principally of manure, domestic refuse, logging and wood processing residues, and agricultural and industrial wastes. Some wood wastes are used industrially for steam production in paper pulp mills. In Europe, and in a few instances in the U.S. on a trial basis, incineration of urban refuse is carried out in equipment to generate steam. However, at the present time, only a very small portion of the organic wastes are combusted for useful production of energy.

Recently, interest has been aroused in the production of oil and gas from organic wastes as well as in combustion of wastes for energy purposes. This has prompted research activity and the development of some new concepts. Some of the interest stems from the need for environmentally acceptable methods for waste disposal, and some from a desire to provide additional energy sources. Research approaches for conversion of organic wastes to energy include:

...Continuous conversion to oil using carbon monoxide and steam,

...Pyrolysis to produce oil, gas, and char products,

...Incineration, including fluidized boilers,

...Gasification,

...Hydrogenation to produce oil, and

...Anaerobic conversion to methane.

The development of processes for converting wastes to fuels still is in too early a stage to define cost factors accurately. However, with present results it can be stated that all manure or organic wastes can be converted in relatively high yield to oil and/or gas, at temperatures and pressures within normal industrial practice. Further, the economic situation is improved when provided with the dual incentives of value for the product and value for getting rid of an unwanted product. For example, the value of low-sulfur fuel oil may be $4 to $5/bbl and disposal costs approach $8/ton of garbage.

Coal Mining

Surface Mining - Surface mining methods include area stripping, contour stripping, auger mining or often a combination of the two latter methods. From the standpoint of recovery, area stripping is the most attractive since more than 90% of the coal can be recovered. A major portion of current strip mine production is by this method. Its use is confined almost entirely to the central and western coal fields where the coal beds are continuous over large areas, and are often near the surface on lands that are flat or rolling. Electrically operated shovels and draglines as large as 200-yards and tractor-trailer units of 100 to 120 ton capacity are used to expose the coal in a series of consecutive cuts from 50 to 100 feet wide and to depths of 100 feet or less. Single seam mining is a common practice in the industry but the large machines now permit multiple seam mining in areas favorable to this practice. Stripping ratios as great as 18:1 (cubic yards of overburden to each ton of coal) are not uncommon in the midwestern states. Favorable markets and long-term contracts are essential for economical operation. Lead time from planning and engineering to production is from three to five years.

Contour stripping takes its name from the practice of bench mining flat lying beds that outcrop in the narrow valleys of the Appalachian Region. The development time is usually less than a year, the mines are comparatively small and short lived. Flexibility is the most important consideration in selecting mine equipment. Capital investment will range from about $3 to $12/ton of annual mine capacity.

Contour mining is often supplemented by auger mining in which coal is removed from the exposed coalbed with a horizontal auger that penetrates the coalbed to depths of about 200 feet. Augers range in size from 18 in. to 7 ft in diameter. Smaller augers are sometimes ganged so that a high production rate can be achieved from thin coalbeds. Multiple head machines can cut in excess of 1,000 tons per 8 hour shift. The capital investment for a 1,000 ton per day mine will amount to about $3.00 per annual ton of mine capability. Like contour stripping, large tracts of coal reserves are not necessary. Lead time for installation is very short, only a few months are required. Coal recovery ranges up to 50% but is more usually 20-25%.

Pending State and Federal legislation seems certain to place strict limits on strip mining of steeper slopes and to require adequate reclamation of mined lands. These limitations will impact surface mining activities in Appalachia more severely than in the midwest and western states. They will certainly increase the cost of surface mined coals, but will not likely require new technology development to comply. Studies to determine the optimum vegetation and means of assuring its survival will be needed particularly in arid regions of the west. Technology which will permit the continued mining of other deposits on steeper slopes without creating permanent damage to the landscape are needed if a large portion of our eastern reserves are to be tapped in the future.

Underground Mining - Underground mining is on the decline, both in number of mines and production, while strip and auger mining continue to increase. Amont the principal reasons are that costs at underground mines are increasing at a faster rate than for strip mining. Much of the recent difference is because underground mines are affected more by health and safety requirements, including the need for new types of permissible underground equipment, changes in dust control and ventilation requirements, and many other operating factors. The changing pattern is reflected by the decrease in underground productivity from 15.6 tons per man-day in 1969 to 13.8 tons in 1970.

Most underground mining is by one of the two major methods, room and pillar or longwall. Room and pillar mining has been used for centuries and is named by the practice of leaving pillars between "rooms" from which coal has been extracted to provide support for the overlying rock and soil. Starting in the 1930's room and pillar mining has been increasingly mechanized until nearly all production is now by continuous mining equipment. Only 8.4 million tons (1.5%) was mined by conventional (non-mechanized) methods in 1971, and this amount is expected to be reduced because of the Coal Mine Health and Safety Act of 1969 and increased labor costs. Overall coal recovery varies from 40 to 60% using this method.

Longwall mining was introduced in this country from Europe in the 1960's and has rapidly gained acceptance in those areas suited for its use. Basically it consists of a coal-cutter and conveyor of one of several types continuously traversing a block of coal 200 to 650 feet wide and 2000 to 3000 feet long. Roof support is provided for the machine and operators by self-advancing hydraulic props but the mine roof is permitted to cave in immediately after mining. Coal recovery of 80-85% and high production rates are achieved by this method but capital costs are high, the equipment is not versatile, and not all deposits are physically suited to longwall mining.

The shortwall mining method is being introduced into the United States from Australia where it has had considerable acceptance. It is very similar to longwall mining with the exception that the longwall coal cutter and conveyor are replaced by conventional continuous mining machines and shuttle cars. This system is expected to find wider acceptance than longwall mining because it is somewhat more versatile and does not require as large a capital investment. Furthermore, except for self-advancing props, it utilizes equipment that most modern mines have on hand.

PROGRAM RECOMMENDATIONS

The formulation of a research and development program in resource extraction must recognize the need to improve recovery of conventional resources, coal, oil and gas, in the near term. Institutional inertia will minimize the impact of new systems and energy sources in the next 10 years in spite of the rapidly growing domestic shortages of conventional fuels. Industry has been and continues to do R&D in oil and gas recovery. Higher oil and gas prices are providing increased incentive for private R&D in this area. Government efforts are likely to be less important, considering its activities to date, than in other areas.

Coal mining research and development has not fluorished in the United States because of the fragmented nature of the industry and the past uncertainty of its future. Equipment suppliers are continuously improving mining machines and the government has launched a sizeable health and safety research program following passage of the Coal Mine Health and Safety Act. These efforts must continue, but longer range programs to develop remotely operated mining systems and in situ extraction could have an immense payoff in reducing environmental and health and safety problems in the industry. Improved productivity and access to lower grade resources should increase the supply and stabilize or lower the cost.

The development of oil shale technology has been underway for over 30 years in the United States. Its utilization has been delayed in this country by the factors cited earlier, but in other countries, such as Brazil, it is now being used. Further improvements are certain to occur, but these can best be realized by beginning to operate on a commercial scale. Industry should be encouraged to initiate several such plants with appropriate governmental participation to offset existing market uncertainties and land and environmental constraints. Oil shale can offer the U.S. important leverage in dealing with OPEC countries in the near term if even marginally successful commercially operations can be demonstrated.

The proposed program elements are intended to supplement the ongoing efforts of government and industry in these areas. Particular attention has been given in formulating these program recommendations to those areas in which government support is considered necessary. New programs or ones where an increased level of effort is justified are included. Ongoing R&D programs are not necessarily considered to be of lesser importance by virtue of not having been included in the following. In some instances, however, funded programs were judged to be of lower priority than those recommended.

Improved Oil and Gas Recovery

Earth Fracture Studies - The recovery of oil and natural gas can be enhanced by exploiting the natural fracture systems, or heterogeneities, of the earth. Likewise, the effectiveness of secondary recovery projects can be increased by avoiding premature breakthroughs arising from earth heterogeneities. Information may be obtained on such fracture characteristics from core studies and field or well performance data. Through such studies new methods may be developed for evaluating the fracture studies in order that well locations and fluid injection techniques can be optimized. A funding level of $22 million over 11 years is recommended for this activity. Industry participation is required along with academic and government geologists. A program plan should be formulated in the first year by an organization with expertise in this area.

Fracturing of Tight Gas Sands - Nuclear stimulation of these sands has proved promising in tests conducted to date. Results from the recent Rio Blanco shot should be evaluated and the need for further device development evaluated in light of non-nuclear options for producing the gas and the ultimate acceptability of nuclear stimulation technology. Device development is carried on in AEC laboratories, and thus the program is controlled by government, even though industry has expressed a willingness to provide a substantial portion of the costs for continuing the program.

Development and testing of hardened devices capable of sequential firing in a single well bore should be continued. Such devices could produce the required fractures while significantly reducing the seismic disturbances and lessening the impact on surface and subsurface structures. An estimated 20 million dollars over the next five years is required for this effort with industry expected to contribute at least half of the amount.

Non-nuclear fracturing experiments utilizing hydraulic fracturing and chemical explosives should proceed rapidly. While the promise of higher gas prices will increase industry's willingness to fund this research, government should be prepared to participate in such a program to ensure the prompt exploration of all promising approaches. The funding level for this program will depend on the number and caliber of proposals, but will likely require at least 10 million dollars over a five year period.

This program should have as its objective the commencement of field development of tight gas sand resources in no less than five years. Decisions will have to be made on the use of nuclear vs. non-nuclear technology in this time frame. Since most of this resource is on public lands, plans must be made for an accelerated leasing program. In the event nuclear devices prove more cost effective, plans to fabricate and commercialize their use must also be made by the AEC. In addition to the economic and environmental assessments required to evaluate the options, consideration should also be given to the overall resource development of these areas, particularly oil shale and the nahcoloite and dawsonite deposits present in Colorado. Every effort should be made to arrive at a development plan for these resources which minimize conflict between the many interests of the region. Energy needs of the future will require access to both the gas and shale reserves. Both resources are vast and will require many years to fully develop.

Advanced Oil Recovery - Industry efforts to improve oil recovery technologies are expected to continue, spurred by world oil shortages and higher prices. Although average oil recovery is only around 30%, individual field recoveries well above that level have been realized. Nevertheless, large amounts of oil are virtually certain to remain in the ground after the best of conceivable advanced recovery methods are utilized. A program directed at the <u>in situ</u> extraction of the non-producible oil as a gaseous fuel should be explored. The initial effort should include studies of possible options. Experimental efforts would be based on these analyses plus information gained from <u>in situ</u> efforts with coal and oil shale.

Government support should also be available for exploring potentially attractive methods which have not evolved from industrial programs. At the present time, such support is difficult to obtain from the Federal government. The use of nuclear devices in improving oil recovery should be evaluated more thoroughly in light of USSR experience in this field. Their detonation of 3 devices in a carbonate dome above a producing reservoir led to an estimated 50% increase in the fields production. The reasons seem only partially understood and worthy of further study.

Federal funding of these efforts should be made available as opportunities arise, but a base program, of 1 million dollars should be sustained to review and evaluate industry progress, fund basic research and advanced field tests and initiate study activities.

Oil Shale

Although industrial efforts to improve retorting technology continue at the pilot scale, the construction of several commercial prototype plants would advance the retorting technology as well as the mining and general systems approach to shale development. If government were to share the risk in these pioneering plants through government loans, product purchase or some other mechanism, such plants would likely be operative much sooner than if industry must assume the risk alone. These plants would provide a basis for evaluating environmental effects, for further improvements in mining and retorting technologies and for the launching of an industry rapidly if international developments necessitate.

A 50,000 barrel/day demonstration plant should be started as soon as possible. Industry funding for the plant is probable if an acceptable arrangement for risk sharing can be negotiated. Proposals should be solicited in 1974 with the first plant operative by 1978. Plans for a second plant should follow shortly. A purchase guarantee of \$.50-\$1.00/barrel above today's oil prices would likely be sufficient to activate industry. By the time the plant is operative it may not be required. In the event it is, a nominal tax on imported oil could easily finance the program.

While it is possible that the prototype leasing program will lead to plant construction, there is no assurance that this commitment will be made as quickly as it should. Any activity by industry on its own should be regarded as a bonus and a combined government-industry demonstration plant program launched as indicated. Since most of the commercially attractive oil shales are on public land, plans for leasing