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WASH-1535
(VOL. 3 OF 7)

PROPOSED FINAL ENVIRONMENTAL STATEMENT

LIQUID METAL FAST BREEDER REACTOR PROGRAM

VOLUME III

DECEMBER 1974

MASTER

U.S. ATOMIC ENERGY COMMISSION

MASTER

WASH-1535

ENVIRONMENTAL STATEMENT

LIQUID METAL FAST BREEDER REACTOR PROGRAM

VOLUME III

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U.S. ATOMIC ENERGY COMMISSION

DECEMBER 1974

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EDITORIAL NOTE

This Environmental Statement has been prepared in seven volumes, each containing one or more Sections, the titles of which are listed on the flyleaf. A Table of Contents is contained in each volume and a summary is provided in front of each Section. The outline and contents of the Statement generally follow the subject coverage required by the National Environmental Policy Act (NEPA) of 1969.

VOLUME I contains a summary of the entire Environmental Statement and background information on the U.S. energy economy, the LMFBR Program and the relationship between the two. It includes discussion of the past, current and projected uses of energy and its importance to society, and describes the role of electricity, including that produced by nuclear reactors, in helping to meet the Nation's energy requirements. This volume also summarizes the origins and history of the LMFBR Program and provides a brief discussion of the several experimental and special purpose fast reactors that have been built in the United States since the late 1940's. Volume I also reviews the fast reactor programs in other industrialized nations. A discussion of the current U.S. LMFBR program is offered which highlights the important program planning mechanisms, the key reactor plants now under design and construction, and the various supporting studies on LMFBR costs, technology, environmental impacts, and program planning. This volume lays the background for examination of the environmental characteristics of the LMFBR.

VOLUME II describes the direct environmental impact of each element of the LMFBR fuel cycle. It examines the power reactors, fuel fabrication plants and fuel reprocessing plants that make up the LMFBR fuel cycle and discusses for each the siting considerations, plant characteristics, effects on the environment from construction and normal operation, and environmental monitoring programs that together entail a complete environmental evaluation. Volume II also includes an evaluation of the potential environmental impacts of various types of accidents in the facilities comprising the LMFBR fuel cycle. In addition, this volume examines the transportation of radioactive materials between these facilities and the management of radioactive wastes produced in LMFBR activities, and analyzes in detail the properties of plutonium and its behavior in the environment, and the resulting health effects. Extensive supporting data are provided in the appendices to Volume II. The volume concludes with an examination of the related sociopolitical impacts of the LMFBR.

VOLUME III examines individually the various alternative technologies, nuclear as well as nonnuclear, that might be utilized in conjunction with or instead of the LMFBR to satisfy the Nation's future electric power requirements. The options considered include the further implementation of various types of nuclear power reactors such as the already existing Light Water Reactor and High Temperature Gas-Cooled Reactor, as well as the development of alternative breeder reactors such as the Gas-Cooled Fast Reactor, Light Water Breeder Reactor and Molten Salt Breeder Reactor. The development of another potential nuclear energy system, controlled thermonuclear fusion, is also addressed. The possibilities of increased emphasis on the use of conventional fossil fuels, namely coal, oil and natural gas, and the development of unconventional fossil fuels such as oil shale and domestic tar sands are discussed next, followed by consideration of the further development of additional nonnuclear energy sources such as hydroelectric power systems, geothermal energy, solar energy, and other potential sources of power. Each option is examined as to the extent of its energy resource base, the research and development program that would be required (if any) to bring the option into commercial use, the environmental implications of its utilization and the costs and benefits associated with its use, in order to assess its capability for satisfying projected energy requirements. This volume also discusses the use of improved energy conversion and storage devices such as gas turbines, fuel cells and magnetohydrodynamics, and concludes with an examination of the various elements of a potential national effort in energy conservation to assess their capabilities for reducing projected energy demands and thereby replacing partially or entirely the need for additional power sources such as the LMFBR.

VOLUME IV provides a broad overview of the many implications of LMFBR program implementation, up to and encompassing a fully developed LMFBR power plant economy, including the secondary impacts, the unavoidable adverse environmental impacts, cumulative environmental impacts, and cost-benefit analyses, and also discusses alternative energy strategies. Under the heading of secondary impacts, it examines the national implications of the availability of electricity from LMFBRs, and the specific economic impacts of the LMFBR program. This volume also discusses the currently feasible alternatives and potential future alternatives for mitigating adverse environmental impacts of the LMFBR fuel cycle, and in this context analyzes the problems of safeguarding special nuclear material from potential diversion to unauthorized purposes. Also covered in Volume IV are the cumulative environmental effects of LMFBR operation to the Year 2020, the decommissioning of LMFBRs and fuel cycle facilities upon the completion of their useful life, the irreversible and irretrievable commitments of resources that will accompany implementation of an LMFBR economy, and an analysis of the costs and benefits of implementing the LMFBR Program.

VOLUMES V - VII contain copies of all formal comments received on the Draft Statement and copies of the AEC's replies. Where appropriate, these comments have been identified and discussed in the text, and are further identified by footnotes indicating the letter and page number in which the comment appears. Finally, Volume VII includes information concerning the public hearing held on April 25-26, 1974.

ALPHABETICAL LIST OF ABBREVIATIONS, SYMBOLS AND ACRONYMS USED IN THE STATEMENT

A	ampere
AC	alternating current
ACRS	Advisory Committee on Reactor Safeguards
ADU	ammonium diuranate
AEC	Atomic Energy Commission
AEC-RL	AEC - Richland Operation
AI	Atomics International
AMAD	activity median aerodynamic diameter
ANL	Argonne National Laboratory
ANPO	Aircraft Nuclear Propulsion Office
ARHCO	Atlantic Richfield Hanford Company
AWSF	Alpha Waste Storage Facility
Ag	silver
Am	americuim
As	arsenic
Ar	argon
Avg.	average
BEIR	Biological Effects of Ionizing Radiation (Committee)
Btu	British thermal unit
BRC	Breeder Reactor Corporation
BWR	boiling water reactor
B&W	Babcock and Wilcox
Bi	bismuth
Br	bromine
CCD	counter-current digestion (ore leach process)
CE	Combustion Engineering
CEA	Commissareat à l' Energie Atomique
CEQ	Council on Environmental Quality
CIA	Central Intelligence Agency
CF	Confinement factor
CFR	Code of Federal Regulations
CRBR	Clinch River Breeder Reactor
CTR	Controlled Thermonuclear Reactor
CWP	Coal worker's pneumoconiosis (black lung)
Cf	californium
cfs	cubic feet per second
°C	degrees Centigrade
Ci	curie
C	carbon (carbide)
Ca	calcium
Ce	cerium
Cm	curium
cm	centimeter
cm^2	square centimeter
cm^3	cubic centimeter
Co	cobalt
Cs	cesium
CO	carbon monoxide
CO_2	carbon dioxide
DC	direct current
DF	decontamination factor
DOD	Department of Defense
DOP	dioctyl phosphate
DOT	Department of Transportation
DTPA	diethylenetriaminepentaacetic acid
diam.	diameter
EBR-I	Experimental Breeder Reactor - I
EBR-II	Experimental Breeder Reactor - II
EEI	Edison Electric Institute
EHV	Extra High Voltage
EIAP	Environmental Impact Assessment Project
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
Eu	europium
°F	degrees Fahrenheit
FBI	Federal Bureau of Investigation
FEA	Federal Energy Agency
FHA	Federal Housing Adminstration
FFTF	Fast Flux Test Facility
FPC	Federal Power Commission
ft	foot (feet)
ft^2	square feet
ft^3	cubic feet
Fe	iron
GAC	Gulf Atomic Corporation
GAO	General Accounting Office
GCFR	Gas Cooled Fast Reactor
GE	General Electric Company
GI	gastro-intestinal
GNP	gross national product
GW	gigawatt
GWe	gigawatt electric
GWt	gigawatt thermal
g	gram
gal	gallon
gpd	gallon per day
gpm	gallon per minute
H	hydrogen
H-3	tritium
HCDA	hypothetical core disruptive accident
HEDL	Hanford Engineering Development Laboratory

HEPA	high efficiency particulate air (filter)
HEW	Health, Education and Welfare (Dept. of)
HF	hydrogen fluoride
HPOF	high pressure oil filled (cable)
HTGR	High Temperature Gas Reactor
HVDC	high voltage direct current
hr.	hour
I	iodine
IAEA	International Atomic Energy Agency
ICC	Interstate Commerce Commission
ICRP	International Commission on Radiological Protection
ID	inside diameter
IRAP	Interagency Radiological Assistance Program
in	inch (es)
K	potassium
Kr	krypton
Kv	kilovolt
k eff	effective multiplication constant
kCi	kilocurie (1000 curies)
kg	kilogram
km	kilometer
kV	kilovolt
kW	kilowatt
kWe	kilowatt electric
kWhr	kilowatt-hour
kWt	kilowatt thermal
LASL	Los Alamos Scientific Laboratory
LAMPRE	Los Alamos Molten Plutonium Reactor Experiment
LE	limit of error
LET	linear energy transfer
LLL	Lawrence Livermore Laboratory
LNG	liquid natural gas
LMFBR	Liquid Metal Fast Breeder Reactor
LOCA	loss of coolant accident
LSA	low specific activity
LWBR	Light Water Breeder Reactor
LWR	Light Water Reactor
l	liter
lb	pound
Max	maximum
MeV	million electron volts
MHD	magnetohydrodynamics
MIT	Massachusetts Institute of Technology
MPC	maximum permissible concentration
MSBE	Molten Salt Breeder Experiment
MSBR	Molten Salt Breeder Reactor
MT	metric ton (tonne)
MTU	metric ton of uranium (metal)
MUF	material unaccounted for
MW	megawatt
MWd	megawatt-day
MWe	megawatt electric
MWt	megawatt thermal
m	meter
m^2	square meter
m^3	cubic meter
mCi	millicurie (10^{-3} curie)
μCi	microcurie (10^{-6} curie)
MCi	megacurie (10^6 curies)
μm	micrometer
mg	milligram
min	minute
ml	milliliter
mph	miles per hour
Mn	manganese
mrem	millirem
NASA	National Aeronautics and Space Administration
NAS-NRC	National Academy of Sciences - National Research Council
NEPA	National Environmental Policy Act
NFS	Nuclear Fuel Services
NGSF	Noble Gas Storage Facility
NRDC	Natural Resources Defense Council, Inc.
NRTS	National Reactor Test Station
NSF	National Science Foundation
NSSS	nuclear steam supply system
Nb	niobium
Np	neptunium
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
nCi	nanocurie (10^{-9} curie)
OD	outside diameter
OMB	Office of Management and Budget
OP	oxygen pressure process (ore leach process)
ORNL	Oak Ridge National Laboratory
PCRV	prestressed concrete reactor vessel
PMC	Project Management Corporation
PNL	Pacific Northwest Laboratory
PSAR	Preliminary Safety Analysis Report
P&W	Pratt and Whitney
PWR	Pressurized Water Reactor
pCi	picocurie (10^{-12} curie)

ppb	parts per billion
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch, absolute
psig	pounds per square inch, gauge
Pb	lead
Pm	promethium
Pu	plutonium
PuO_2	plutonium dioxide
°R	degrees Rankine
R	Roentgen
R&D	research and development
RSSF	Retrievable Surface Storage Facility
rpm	revolutions per minute
Rb	rubidium
Ru	ruthenium
SAR	Safety Analysis Report
SEFOR	South-East Fast Oxide Reactor
SIPI	Scientist's Institute for Public Information
SNG	synthetic natural gas
SNM	special nuclear material
SRE	Sodium Reactor Experiment
STP	standard temperature and pressure
SWU	separative work unit
scfm	standard cubic feet per minute
sec	second
sq. ft.	square feet
Sb	antimony
Sr	strontium
SO_2	sulfur dioxide
SO_x	oxides of sulfur
TEG	thermoelectric generator
TFE	thermionic fuel element
TGLM	task group lung model (ICRP)
TVA	Tennessee Valley Authority
TVR	Tennessee Valley Region
Te	tellurium
Tonne	metric ton
U	uranium
UHV	ultra high voltage
UMRB	Upper Mississippi River Basin
UO_2	uranium dioxide
U_3O_8	black oxide of uranium
UF_6	uranium hexafluoride
UNSCEAR	United Nations Scientific Committee on the Effects of Atomic Radiation
USAEC	United States Atomic Energy Commission
USGS	United States Geological Survey
W	watt
We	watt electric
WEP	water extended polyester
WLM	working-level month
wt.%	weight percent
w/o	without
Xe	xenon
Y	yttrium
yr	year
Zr	zirconium

VOLUME III

SECTION 6

ALTERNATIVE TECHNOLOGY OPTIONS

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6A′ ALTERNATIVE ENERGY SOURCES FOR PRODUCTION OF ELECTRICITY

6A.1 OTHER FORMS OF NUCLEAR POWER

LIST OF FIGURES (Continued)

PERSPECTIVE ON ALTERNATIVE TECHNOLOGY OPTIONS

In meeting the objective of a sufficient electrical energy supply, several courses of action are available. For almost any path that is chosen, there are alternative paths which might be proposed to arrive at the same goal. These alternative actions are examined objectively, and one is selected while the others are assigned lower priorities for various reasons: the technology is too difficult to bring them to fruition within the time frame available; the resource base behind the technology is insufficient to meet the long-term requirements; the alternative, while equally promising, would be far more expensive; and so on. Sometimes the goal is so vast and enduring that no one alternative can meet the entire need and several alternatives must be pursued simultaneously. The latter situation corresponds most closely to the problem of meeting the Nation's growing electrical energy requirements.

The energy requirements of the United States are so large and are expected to expand such that no single method currently available for meeting our needs is completely adequate for the job. The situation is made more complex by the necessity to protect environmental values while at the same time meeting the challenge to the economy posed by our growing oil and gas shortages and our increasing dependence on unreliable foreign sources. Thus, the energy crisis has stimulated a re-examination of all possible means of producing and conserving energy to determine which have the potential of significantly contributing to meeting our energy needs, in the near term as well as in the more distant future, in environmentally acceptable ways.

This Section will attempt to put in perspective all reasonably foreseeable options for generating and conserving electrical energy--those already in existence, those approaching commercial utilization, and those which are only conceptual at this time--so as to assess their potential for meeting the Nation's electrical energy requirements. No attempt will be made to assess the potential of each energy system for meeting other energy requirements (such as, for example, the transportation or petrochemical industries). However, when such an application is particularly pertinent, attention is drawn to the fact that other uses for the energy source exist. Similarly, energy systems which may have application in other countries with different economic structures and which have been considered but bypassed in the United States in favor of other energy production systems are not discussed. A case in point is the heavy water reactor system which has had favorable operating experience in Canada, is vigorously supported by the Canadian government, and is attracting interest in other parts of the world where the capital structure is favorable and the capability of this reactor type to operate on natural uranium is a major consideration. The AEC recently re-evaluated the heavy water cooled and moderated system and reaffirmed the position it has held for several years that the system does not warrant increased consideration in the United States primarily because of licensability and cost considerations.*

In the following assessments we will attempt to:

(1) Examine the extent of the energy resource to determine whether it is sufficient to support all, or a significant portion, of the Nation's energy requirements.

(2) Examine the technology and the amount of research and development necessary to bring each system to the point of commercial utilization. Where possible, estimates of the research and development costs and schedules will be provided. In this regard, the less developed a system is, the less accurate such estimates will be. In many cases, insufficient work has been done on the concept to warrant making other than generalized estimates.

(3) Evaluate the environmental impact of each alternative system to determine whether the impact is acceptable or what would need to be done to make it acceptable.

(4) Evaluate the costs and benefits of each system to determine whether it has the potential to compete economically with existing conventional electrical energy production systems or with other alternatives. For many of these systems, only qualitative evaluations of costs and benefits can be made. Economic competitiveness is an important factor because energy costs have a major effect on the economic well being of the consumer.

(5) Finally, bring each system into perspective by assessing its probable role in the energy supply picture to the year 2000 and beyond.

In a discussion of this sort where many systems are examined which vary in maturity from fully developed, tested and proven systems to conceptual systems that have not as yet been developed, certain milestones must be delineated so that meaningful comparisons can be made. Otherwise, those systems on which little or no work has been done will inevitably look most attractive since the natural enthusiasm of their

*See response to Professor Richard Wilson, Comment Letter 9, for a detailed discussion of these points.

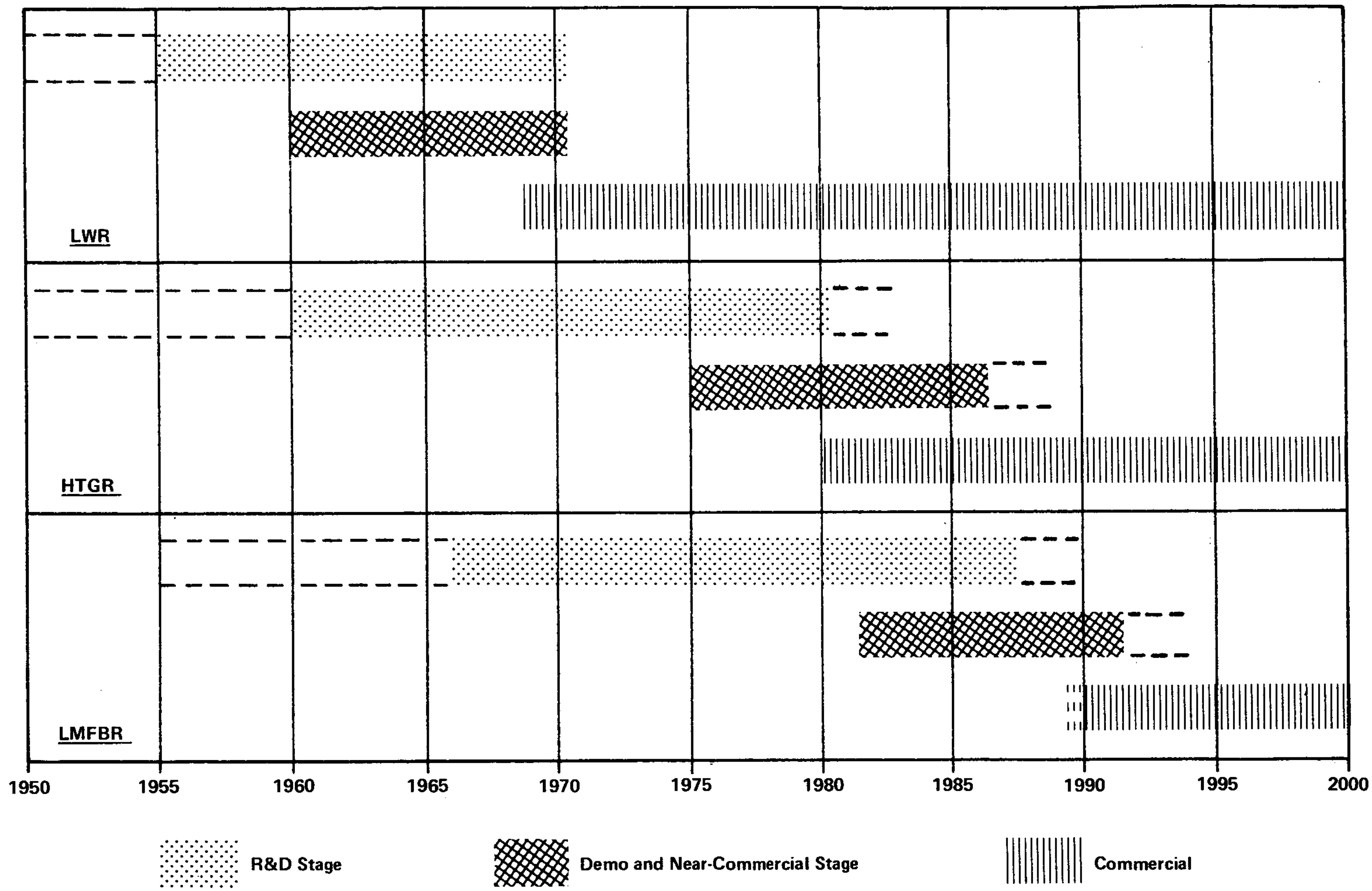
proponents will highlight the advantages of the system while the difficulties and limitations are minimized or, most likely, have not been discovered.

These milestones are based on past experience in bringing other concepts from the early stages of establishment of feasibility to commercial utilization. Past experience has demonstrated that three phases of development are usually followed in bringing a technology to maturity:

(1) The initial research and development phase in which feasibility is established and the basic technical aspects of the concept are confirmed through analytical investigations, laboratory scale experiments, and conceptual engineering.
(2) The second phase in which engineering and manufacturing capabilities are developed. This development requires in-depth engineering and proof testing of first-of-a-kind components and systems utilizing complex and costly experimental installations and supporting test facilities to assure adequate understanding of design and performance characteristics.
(3) The third phase in which the utilities make large-scale commitments--first through participation in the construction and operation of one or more demonstration plants to establish whether or not the system is reliable, safe, and economical--and then through commitment to full-scale commercial utilization.

Figure 6P-1 illustrates the stages for three nuclear power reactor systems: a mature system, LWR; a nearly mature system, HTGR; and a system entering the demonstration reactor phase, LMFBR. The general similarity in the time scales for each system is notable. An attempt will be made in Section 6A to identify the phase within which each concept lies so as to assess its potential to help meet the Nation's energy needs.

In addition to expanding our energy resources by developing electrical energy production systems using new fuels such as uranium and deuterium or exploiting the natural energy available in geothermal formations, the tides, and the sun, much might be done in more effectively utilizing the conventional fuels we currently depend upon. Several types of energy conversion and storage devices are available or under development which might have the potential for significantly improving or complementing the steam turbine cycle, the electrical generation system in most prevalent use today. Included in this category are the internal combustion engine, gas turbine, binary cycle, magnetohydrodynamic, thermoelectric, thermionic, fuel cell, and battery



REACTOR DEVELOPMENT TIME SCALES

Figure 6P-1

systems. These will be reviewed in Section 6B under the same guidelines and objectives as those used for alternative energy sources.

Finally, the alternative need not be an electrical energy production system. A number of energy conservation measures are available which could be employed to reduce consumption of energy and thereby lead to more closely balancing supply and demand. These range from improving the yield of useful energy extracted from the ground (e.g., increasing the percentage of oil recoverable from an oil field) to utilizing waste heat, reducing energy transmission losses, and reducing wasteful consumption of energy at the industrial, commercial, and consumer levels. The extent to which such measures might be successful and therefore become at least a partial substitute to the development of a new energy source such as the LMFBR is considered in Section 6C.

Several commenters have charged that the energy research and development budget is unbalanced and that the rate of research and development effort on alternative energy options should be accelerated. Thus, the Environmental Policy Center* stated,

> ...the fusion alternative will not be available in demonstration form before the mid-1990's ... the reason that the wait may be so long is related to the relative funding levels for fusion reactors vs. the breeder reactors more than it is to technological availability.

Also,

> With sufficient funding, other major geothermal deposits can be developed to provide a definite alternative to the LMFBR within the time span specified by the AEC in WASH-1535. The FY 1975 federal energy budget calls for spending only $44.7 million in geothermal energy research, hardly a serious amount.

Similarly,

> A major problem in demonstrating competing solar technologies is the disparity in federal funding.

And finally,

> The panel** found that 1.546 x 10^{12} Kw-hrs of wind power could be developed in the U.S. by the year 2000, with a substantial federal

*Comment Letter 42, pp. 36, 38, 42-44.

**Referring to the NSF/NASA Solar Energy Panel report, "An Assessment of Solar Energy as a National Resource," December 1972.

development program. The panel suggested a 10-year development program of $610 million. The FY 1975 federal budget calls for spending about $7 million in wind power.

The Natural Resources Defense Council, quoting views expressed at the 23rd Pugwash Conference,* stated,

> ...research and development on alternative energy sources - particularly solar, geothermal and fusion energy, and cleaner technologies for fossil fuels - should be greatly accelerated.

The Friends of the Earth** stated,

> When what this nation needs is a cogent statement of why we should spend $5.1 billion on the breeder program rather than on other energy alternatives, the AEC has given us a statement that tells us why we should spend $5.1 billion on the breeder program rather than not spend it at all.

Mr. Robert W. Freedman† stated,

> It is not obvious that solar energy can be eliminated from consideration as an acceptable alternative. The time scale depends to a significant extent upon the extent of research funding.

Other commenters†† expressed similar views. However, one commenter§ sees the problem from a somewhat different perspective. The Project Management Corporation states,

> There has been discussion about the large percentage of the energy R&D budget which is applied to nuclear energy. The Environmental Statement indicates that at present nuclear energy and the LMFBR are the optimum alternatives for electric power generation and hence should receive priority for R&D money. We would agree that more money should be made available to energy R&D and applied to alternative technologies; however, in a limited funding situation we must apply these limited resources where the greatest likelihood of success exists. If this is not done, we will not have a new technology available when we need it.
>
> Pursuing the LMFBR Program through the technology development and demonstration plant stage does not irrevocably commit the nation to the commercial utilization of the breeder. If at any point a more attractive alternative becomes available, the breeder could be put aside. In fact, the utility's responsibilities to provide power to

*Comment Letter 38b, p. 3, quoting from 23rd Pugwash Conference on Science and World Affairs, Aulanko, Finland, Aug. 30 to Sept. 4, 1973.
**Testimony at Public Hearing, p. 278.
†Comment Letter 32, p. 21.
††Comment Letters 26, p. 12; 25, p. 25; 41, all; 40, pp. 1-3; 52, p. 4.
§Comment Letter 45, p. 1, 2.

its customers at reasonable cost would dictate that this be done. However, if the LMFBR Program were not pursued and if alternative energy sources were not realized, then the cost to society would be too large to measure in dollars alone. If on the other hand, the LMFBR Program is given priority attention, and if the subsequent development of alternative technologies obviates the need for the LMFBR, then the costs incurred are analogous to the cost of an insurance premium to buy the protection the LMFBR can offer. When the consequences or risks of not pursuing the LMFBR Program are balanced against the highest costs that might be incurred from pursuit, it becomes obvious that the public interest demands vigorous pursuit of the LMFBR.

Specific treatment of each alternative, its research and development requirements and the funding levels recommended for each, is given in the appropriate parts of Section 6 and will not be addressed here. However, the general tenor of the views expressed above merits discussion. There appears to be a shared conviction among the majority of these commenters that supporting development of the LMFBR automatically forecloses adequate development of other technology options. This is not the case, either from the viewpoint of foreclosing use of other energy systems merely because the LMFBR has been developed at great cost and therefore must be used to recover the investment, or from the viewpoint that the costs of developing the LMFBR are so large there is no money available for developing competing systems.

With regard to the first point, it should be understood that the LMFBR program is purely a research and development program with the goal of developing a viable energy production system option. Whether or not that option is exercised will depend upon the relative merits of this energy option as compared with the merits of other options available. It is axiomatic that no energy option, LMFBR included, should be exercised if it is unsafe or environmentally unsound. Ideally, the full costs of making an energy technology safe and environmentally acceptable will be reflected in the total costs of the engineered and administrative systems, including the ancillary costs of all its service functions such as fuel reprocessing, mining, safeguard procedures, and waste management, so that a proper economic assessment can be made. In this regard, the LMFBR is perhaps further advanced in recognizing and taking these external costs into account (i.e., internalizing the costs*) than many potential alternative energy technologies which have not as yet progressed far enough to readily identify and evaluate these costs. With regard to the second point, the report, "The Nation's Energy Future,"** which lays out an integrated

*"Internalizing the costs" refers to adding directly to the cost of the energy those "external" costs which in the past have often been ignored (e.g., the environmental costs of mine wastes, strip mining, and sulfur dioxide emissions in the coal and electric utility industries).

**"The Nation's Energy Future," A Report to the President of the United States by the Chairman, USAEC, Report WASH-1281, December 1973.

energy research and development program for the Nation at the request of the President, allocates about one-quarter of the projected five-year energy research and development budget for the LMFBR while three-quarters is reserved for other systems. It is evident that LMFBR research and development should not, and does not, preclude pursuing any other promising energy technology.

Also, with respect to relative energy research budgets, the opinion is often expressed by the commenters cited above that far too much money is directed to LMFBR research and development as compared with alternative technologies. Some of the commenters then state that if there were more equal funding among the alternatives they would be developed more quickly and the LMFBR would not be needed. This argument neglects two key points: the relative stage of the technologies and the speculative nature of assuming that the alternative technologies will indeed prove out their potential and become viable energy options.

With regard to the first point, the LMFBR is a high cost technology which is in the final and most costly stages of its development, the large scale testing and demonstration phases. Other high cost technologies, such as controlled thermonuclear fusion, are in the initial stages of development where research costs are less and the expensive, large-scale equipment and machines are only beginning to be required. It is misleading to compare annual costs in a year such as FY 1975 for two technologies in such disparate stages of development. A better gauge would be to compare the total projected development costs of CTR (estimated at this early stage to be in the $8 to 10 billion range for either magnetic confinement or laser fusion) with a total projected cost for the LMFBR of about the same magnitude.

For other technologies, such as solar energy, geothermal, and wind power, the research and development costs are relatively less substantial and the funding level should be correspondingly lower. An optimum level of support should be determined and each concept funded at a level as close to the optimum as possible. Determining an optimum level, however, entails many factors in addition to determining the total funds needed. Many potential alternatives, as the word potential implies, have substantial uncertainties associated with them, such as the amount of energy actually convertible to economic use, the geographical distribution of the energy (in order to determine the importance of the energy source), and the requirement for ancillary technology such as energy storage (in order to make the energy system functionally meaningful). These uncertainties must be explored either in advance of full-scale technology development or at the very least in parallel with it. It would be improvident to abandon or delay an energy technology option which is in a mature stage of development and whose contribution to the Nation's energy research supply can be clearly seen in order to pursue other seemingly attractive, but unproven, energy options at a faster than optimum pace. This course would run the real risk of having no adequate energy option available when it is needed.

SUMMARY

This section examines individually the various options other than the construction of LMFBRs that might contribute to meeting the Nation's electric power requirements. The options considered include the further implementation of various types of nuclear power reactors such as the already existing light water reactor and high-temperature gas-cooled reactor, as well as the development of alternative breeder reactors such as the gas-cooled fast reactor, light water breeder reactor, and molten salt breeder reactor. The section also addresses the development of another potential nuclear energy system--controlled thermonuclear fusion.

The possibilities of increased emphasis on the use of conventional fossil fuels, namely coal, oil, and natural gas, and the development of unconventional fossil fuels such as oil shale are discussed. Also considered is the further development of additional non-nuclear energy sources such as hydroelectric power systems, geothermal energy, solar energy, and other potential sources of power.

Each option is examined as to the extent of the energy resource, the research and development program that would be required (if any) to bring the option into commercial use, the environmental implications of its utilization, and the costs and benefits associated with its use in order to assess its capability for satisfying projected energy requirements.

The section also discusses the use of improved energy conversion and storage devices such as gas turbines, fuel cells, and magnetohydrodynamics, which, while not alternative energy sources per se, can contribute toward alleviating the Nation's energy resource problem by utilizing these resources more efficiently.

Finally, the various elements of a national effort in energy conservation are examined to assess their potential for reducing the need for additional power sources. These elements include improved extraction of energy resources and increased efficiencies of power plant energy conversion, transmission, distribution, and utilization of electricity as well as end-use conservation measures.

In summary, the alternative energy options available to the Nation if the LMFBR is not pursued can be classified as: (1) other means of exploiting nuclear energy, (2) non-nuclear energy sources, (3) more efficient means of converting energy resources to useful forms, and (4) more conservative means of using the available energy. Combinations of various options will most likely be necessary to meet the Nation's future energy needs.

In the first category, nuclear energy can be extracted either through the fissioning of heavy metals (notably uranium, plutonium, and the thorium derivative, U-233) or by the fusion of light elements (particularly deuterium and tritium, derived from lithium). In the nuclear energy area, fission processes are more advanced in develment and a substantial light water reactor (LWR) industry is well established. A comparable high-temperature gas-cooled reactor (HTGR) industry is in the process of becoming established with the placement of several orders by utilities for large HTGR power plants. Both of these options depend, however, upon uranium-235 (U-235) as their primary fuel, and the relative scarcity of U-235 in relation to its far more plentiful fertile counterpart uranium-238 (U-238) limits the exploitation of uranium resources to about 1 to 2% of the total energy available in natural uranium. Another fission option for which much of the technology is highly developed is the light water breeder reactor (LWBR), which has the potential for self-sustaining operation on the uranium-thorium fuel cycle and thereby gives promise of utilizing a far greater percentage of the energy available in nuclear resources than do the LWR and the HTGR.

Other fission options are less well developed but also give promise of utilizing far greater percentages of the energy available in uranium than can be realized using present types of LWRs. These are the molten salt breeder reactor (MSBR), which also uses the uranium-thorium fuel cycle, with a liquid fuel and continuous on-line fuel processing to achieve modest breeding with acceptable doubling times, and the gas-cooled fast reactor (GCFR), which is designed to operate on the same fuel cycle, uranium-plutonium, as the LMFBR but has the potential for higher breeding ratios because of its more energetic neutron spectrum. As pointed out, none of these has been fully developed nor are there any assurances that any will progress to full commercial utilization. These fission reactor systems have fundamentally the same environmental impact as the LMFBR and do not offer any significant difference in that respect. Although thorium-uranium-233-fueled reactors do not have to deal with the problems of plutonium, they substitute the high-energy radiation problems associated with the handling of U-232. This consideration is not as important for the MSBR, however, since it operates with essentially continuous on-line fuel reprocessing which greatly reduces the formation of U-232.

The remaining nuclear energy option is the controlled thermonuclear reactor (CTR) system which has not yet been demonstrated to be scientifically feasible. It is estimated that even with a successful, vigorous research and development effort the CTR option cannot contribute significantly to our energy supply until well after the start of the next century. However, the extensive energy resources this option can exploit, coupled with the avoidance of most of the environmental problems associated with fission-product production in fission reactors, makes worthwhile a serious effort to develop this system to its full potential.

In the category of energy sources that do not depend on nuclear reactions, the fossil fuels--coal, oil, and gas--are not only fully established but comprise the great bulk of our energy resources today. However, several problems limit the capability of these fuels to maintain their pre-eminent share of the energy market. First, oil and gas have peaked in production in this country and cannot be expected to sustain their current place in the electrical generation market, much less keep pace with our steadily expanding requirements. Recent developments have shown that oil and gas imports are not adequate solutions to this fuel gap. Second, there is a continuing and mounting need for our oil and gas resources in the transportation and petrochemical fields and for residential use. Efforts are under way to develop additional oil and gas supplies from our large oil shale deposits. Successful development of this source would add substantially to oil and gas reserves and ameliorate current supply problems. It would not, however, change the basic, long-range situation.

Although coal reserves are far more plentiful than reserves of oil and gas, the problems of significantly increasing coal's role in meeting the Nation's energy requirements and the associated environmental problems are severe. Mr. Thomas V. Falkie, chairman of the Interagency Coal Task Force has estimated* that doubling the Nation's coal output by the year 1985 will only increase the share of the Nation's energy needs provided by coal from 18 to 21% if energy requirements continue to increase at the rate of 4.5% per year. Very large amounts of capital are needed to increase the Nation's coal mining and coal transportation capacity if coal is to meet the expanded energy role contemplated for it. Wilbur Heit of the National Coal Association has estimated** that reaching the goal of doubling the Nation's coal production by 1985 would involve opening one new surface mine and one new deep mine every month for the next ten years. The required capital investment in mining facilities and associated transportation would reach $23 billion, more than $2 billion a year, which is more than five times what the industry invested in 1970. Even if the needed capital is made available, there are short-term deficiencies in the industrial capacity needed to provide the additional equipment for these activities. The backlogs in ordering new equipment will hamper expeditious expansion of coal production. Of course, neither of these two problems,

*As reported in the Washington Post, October 8, 1974, p. A18.
**As reported in Weekly Energy Report, September 23, 1974, p. 4.

high capital investment requirements and industrial capacity deficiency, is unique to coal; indeed, they are common to the energy production industry, including the LMFBR. Means must be found to resolve these problems if the Nation's energy requirements are to be met.

The environmental problems associated with the use of coal range from despoilment of large areas in the mining processes to air and water pollution from its combustion products. Research and development efforts are being intensified to find means to alleviate these problems, and these efforts must prove successful if coal is to maintain or increase its share of the energy market. In the final analysis, the practical difficulties involved in greatly expanding coal production, along with the cost and efficacy of the measures taken to make coal environmentally acceptable, will determine the extent of the role that coal will play in the energy economy. Clearly, coal alone cannot provide sufficient energy to meet the Nation's energy needs.

Conventional hydroelectric power provides a modest percentage (15%) of our current electrical generating capacity, and, because of limitations on the extent of this resource and the geographical restrictions on suitable sites, its share of the energy market is expected to decline to about 7% in 1990. Greater utilization of hydroelectric power can be achieved through the use of pumped storage modes of operation, but hydroelectric power would still provide a rather small amount of the Nation's total energy.

Geothermal energy has the potential for providing a significant contribution to the Nation's energy resources in those geographical areas where it is abundant and feasible to tap. These areas are predominantly in the western third of the contiguous United States and Alaska. Estimates vary widely as to the extent of the available resources, ranging from about a one-half year supply at the projected consumption rate for the entire Nation in the year 2000 to several orders of magnitude higher, depending upon estimates of probable and undiscovered reserves, the quality of the heat, and the technological feasibility of extracting the energy at economical prices. At the present time, only a very small amount of this energy source is being tapped, although activities in this area are being significantly accelerated. However, the technology required to exploit the most widely distributed and largest source of geothermal energy is not in hand, and research and development to verify the practicality of extracting energy from hot dry rock formations must be undertaken and proven successful if geothermal energy is to achieve its full potential. Further efforts to develop known geothermal resources are in order. A strong attempt to narrow the wide range in estimation of the extent of this resource seems to be warranted so that a better assessment can be made of its potential and the importance of pressing ahead vigorously with full-scale technological and commercial development.

Solar energy utilization has great appeal because it is the most direct, plentiful and renewable form of energy known. Enormous amounts of solar energy are intercepted by the earth continually at a rate of about 130 watts per square foot (W/ft^2). Various factors such as night, weather, latitude, and atmosphere reduce this to an average of 17 W/ft^2 for the United States, which is still the equivalent of 700 times the energy we produce from conventional fuels. Unfortunately, the poor efficiencies of the available systems for collecting and transforming solar energy into useful forms, the wide fluctuations over the period of a day in the energy received (requiring energy storage systems), and the dilute nature of the energy (requiring large collection areas) militate against large-scale use of this energy form for central station power application--in the next few decades at least. Home heating and possibly some residential electricity production, which would reduce requirements for central station power generation, appear to be the most likely near-term applications for solar energy, since technology to accomplish these applications is available. However, the high cost, energy storage problems (necessitating backup heating and electricity units), aesthetics and site restrictions of solar homes, and social acceptability in general are likely to hamper rapid and extensive introduction of this form of solar energy. Research and development looking toward more extensive applications of solar energy is certainly warranted considering the extent of the energy resource potentially available.

There are other energy resources that are solar-related, particularly wind power and ocean thermal gradients. Proponents of these options as well as proponents of tidal energy can marshal impressive statistics as to the total energy inherent in each of these energy resources. However, each of these suffers to some extent from extractability problems and geographic, economic, and practical limitations that make these systems more likely to be useful in specific situations rather than as broad-based energy sources of large significance.

Energy conversion and storage devices are means by which existing and prospective energy sources can be more efficiently utilized either by directly increasing the efficiency of energy production (magnetohydrodynamics, binary cycles, gas turbines), by transforming energy into a more convenient form (fuel cells, synthetic fuels), or by providing means of energy storage (fuel cells, batteries) so that it can be used at more convenient times. Many of these devices are in commercial use today in limited applications, and all of them are under investigation for more widespread and large-scale use. They deserve attention so that the full potential and the attendant technical and non-technical difficulties and limitations of each are understood and so that proper choices for development into large-scale commercial utilization can be made.

In addition to new energy sources and conversion methods, a wide variety of energy conservation measures exists and could be considered as a means of reducing projected energy growth demands, thereby making the necessity of developing new energy options such as the LMFBR less urgent. The potential of each of these measures varies considerably. A number of potential conservation measures, while attractive in principle, do not appear capable of offering major relief from fuel scarcities and growing demands, and some might lead to significant economic or environmental penalties. Included in this category are most possible improvements in methods of resource extraction for coal, oil, gas, and uranium; greater efficiencies in the transmission and distribution of electricity; and conventional improvements in power plant conversion efficiencies, such as a reduction in the energy devoted to pollution control. Although each of these methods is worthy of further study and is likely to be implemented to some extent, their costs and benefits will have to be carefully balanced before a decision is made to proceed on a large-scale basis.

Other conservation methods, particularly those in the end usage of energy, appear to satisfy most energy, economic, and environmental criteria and should be implemented where practicable. Foremost among these is the more efficient usage of electricity in commercial, industrial, and residential applications. By eliminating waste, switching to more energy-efficient processes, and otherwise making optimum use of the electricity that is consumed, appreciable energy savings are possible. However, although short-term savings have been achieved in response to the energy crisis over the last year, the long-term achievement of these savings presupposes various degrees of success in the following respects:

(1) that governmental bodies will encourage and financially support, to a much greater extent than in the past, research and development into mechanisms and processes for conserving energy;

(2) that improved energy conservation measures will be developed and prove successful in practice over the years in reducing energy usage to the projected extent;

(3) that industry and the public will accept the considerably higher energy prices inherent in some of the conservation strategies and measures proposed; and

(4) that the public will accept the moderate to severe inconveniences and changes in lifestyle that would inevitably accompany a number of the proposed conservation measures.

If all these problems are satisfactorily resolved, then, according to several studies by government agencies and private organizations, energy savings perhaps on the order of 30% of total projected consumption by the year 2000 might be achieved. These are, of course, theoretical projections rather than firm predictions based on practice or experience, and there is no assurance that conservation measures will yield the projected savings. Further, reductions in total energy demand do not necessarily imply correspondingly large reductions in electrical energy demand. In fact, in some areas relatively accelerated electrification may result, as energy conservation may emphasize the use of available and environmentally acceptable energy sources. Thus, the objective of conserving highly mobile fossil fuels may require electrification of ground transportation and residential energy uses. In general, optimum allocation of fuel resources and minimization of environmental impact may require increased electrification and commensurate increase of central station power generation utilizing abundant, clean fuels.

CONCLUSIONS

After reviewing the spectrum of alternative technology options, the following conclusions have been reached:

(1) No single energy option is sufficient to meet the Nation's long-term electrical energy needs. Each of the alternatives now in use has its individual drawbacks and limitations. For example, gas and oil usage for utility boiler fuel is becoming more and more restricted; available hydroelectric power sites are limited and encounter environmentalists' objections; fission reactors, while economically insensitive to rising costs of uranium ore, face rising environmental concerns as the mining of lower-grade, higher-cost uranium ores becomes necessary. The supply of coal appears to be sufficient to last from 50 years to several centuries, depending upon how extensively it is relied upon. However, the practical problems associated with greatly expanding coal production are severe, and the environmental effects associated with mining and burning this fuel are great. These problems must be resolved if coal is

to take the substantial role in electrical energy production that is foreseen for it in the near term.

(2) A number of alternatives taken in combination have the potential to form a viable energy economy, but none of those not already in widespread use is sufficiently developed to assure that it will successfully prove its potential both technically and economically.

(3) One of the most attractive alternatives, in principle, is solar energy. However, the high costs and large land areas associated with its use as a central station power source and the high cost, social acceptability, and the inertia associated with local, distributed use militate against this form of electrical energy production making a substantial contribution in this century. A severe handicap is the lack of a practical energy storage system to compensate for the extreme variability and interruptibility of this energy source.

(4) Other solar-related energy sources, particularly wind power and ocean thermal gradients, also offer large reservoirs of energy which, in principle, could be tapped and put to use. Wind power suffers from the same disabilities as direct solar power--variability, interruptibility, lack of energy storage, and large area requirements. Ocean thermal-gradient power suffers from the low-grade heat which must be exploited which makes the equipment size and pumping power enormous and the technical problems of extraction severe.

(5) Geothermal power is another attractive source of "natural energy" which, in principle, could provide substantial amounts of electrical energy. To date, the magnitude of this energy source has not been adequately assessed and this assessment should be expeditiously made. With current technology, utilization of geothermal resources is largely limited to the western third of the Nation. Technology must be developed to utilize the more extensive resources of hot dry rock. Corrosion and erosion of machinery appear to be major problems of this technology, and the environmental consequences of geothermal energy extraction are not trivial.

(6) Controlled thermonuclear fusion is attractive in that it can exploit an extremely large energy source available in deuterium and lithium. However, scientific feasibility has yet to be established, and fusion is not expected to make a significant contribution to meeting the Nation's energy needs until the next century.

(7) Recital of the above limitations and problems of various alternative energy options does not mean that they should not be explored thoroughly to determine the extent of their contribution to the energy resource capital

of the Nation. On the contrary, it is essential that the Nation develop and exploit all the possible energy options available to assure that a sufficient amount of energy will be available to sustain the economic life of the country.

(8) Energy conversion improvement systems can make a contribution towards meeting the Nation's energy needs by improving the efficiency with which energy sources are transformed into electrical energy. The principles of many of these systems have been known for years, but they have not for one reason or another, technical or economic, received extensive acceptance. The current energy crisis warrants further exploration and research and development to determine which of these systems can make an economic contribution.

(9) Finally, energy conservation is a recognized means of bringing energy supply and demand into balance and should be vigorously pursued. It appears that energy conservation in combination with increased reliance upon coal and current nuclear power systems is the best hope for meeting the Nation's short-term energy needs. In addition, conservation has substantial potential as a supplement to new energy sources. The extent to which this potential may be realized in the long term, however, is subject to question. Several conditions, such as technical feasibility and public acceptance, must be met before the full promise of energy savings via conservation may be relied upon. While energy conservation alone does not appear to be an adequate substitute for the development of new energy sources such as the LMFBR, it can provide some mitigation of the energy supply problem in the transition period during which new energy options are being developed and brought into use, and it is worthy of vigorous implementation. Those conservation measures that meet all necessary technical, economic, social, and other appropriate criteria should be made a part of the Nation's energy use patterns as soon as practicable.

6A

ALTERNATIVE ENERGY SOURCES

FOR

PRODUCTION OF ELECTRICITY

6A.1 OTHER FORMS OF NUCLEAR POWER

6A.1.1 Light Water Reactors

6A.1.1.1 Introduction

6A.1.1.1.1 General Description

Plants known as Light Water Reactor (LWR) plants use light (i.e., ordinary) water both to moderate* the fission neutrons and to transfer the heat generated in the nuclear fuel to the steam-generating equipment or directly to the turbine-generator in the form of steam. Fuel for LWR plants is derived from naturally occurring uranium ores through the processes of: (1) mining and milling of the ore to produce a uranium concentrate, (2) further purification of the concentrate and conversion to a chemical form suitable for isotopic enrichment, (3) enrichment of the U-235 isotope from its natural abundance of 0.71 weight percent to 2-4 weight percent, and (4) conversion of the slightly enriched product to useable fuel forms. These processes are discussed in following sections.

There are two types[1] of LWR plants, those using Pressurized Water Reactors (PWRs) and those using Boiling Water Reactors (BWRs). BWRs, as the name implies, generate steam by bulk boiling of pressurized water in the nuclear core. In PWRs, the pressurized water surrounding the nuclear core is not allowed to go into bulk boiling, but rather is used to generate steam in equipment external to the nuclear core. In either case, pressurized steam is produced as the working fluid used to spin a turbine-generator and produce electricity. Fossil-fueled electric generating plants use pressurized steam in the same manner.

The heat energy produced during operation of LWRs comes basically from the fissioning of the easily fissioned U-235 atoms in the fuel, with a small contribution (about 5%) from the fissioning of U-238 atoms (the fission of U-238 occurs only with very energetic neutrons). As the reactor operates, however, another easily fissioned atom--plutonium-239 (Pu-239)--is produced from U-238 atoms.** For each gram of U-235 consumed in LWR fuel, as much as 0.9 g of fissile Pu-239 and Pu-241 is formed within the fuel. Generally more than half of the plutonium

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*Moderate refers to the process of slowing down the fast neutrons generated during nuclear fission to the low energies at which they can readily fission U-235.

**On the average, each fissioning atom in LWR fuel ejects two neutrons, one of which is needed to sustain the fission chain reaction. Those neutrons not entering into fission reactions either leak from the fuel or are captured by surrounding materials. When U-238 captures a neutron not sufficiently energetic to cause its fission, it transforms spontaneously to neptunium-239 which in turn transforms to plutonium-239 over a relatively short time span. Smaller quantities of Pu-240 and Pu-241 isotopes are subsequently produced by successive neutron captures.

formed undergoes fission in place, thus contributing significantly to the energy produced in the power plant. Plutonium that escapes fission (about 0.30 g Pu-239/Pu-241 per gram of U-235 consumed) is recovered from the spent LWR fuel when it is removed from the power plant and sent to a reprocessing plant (see Section 6A.1.1.3.3).

6A.1.1.1.2 History

Commercial nuclear electric power was introduced in the U.S. 17 years ago (1957) through the operation of the 60-MW(e)* Shippingport nuclear steam-electric plant, a joint venture of the Atomic Energy Commission (AEC) and the Duquesne Light Company in Pennsylvania. The Shippingport reactor is based largely on technology that had been developed for Naval nuclear propulsion units. In 1960 and 1961, respectively, the Dresden-1 (200 MWe) BWR and the Yankee Rowe (175 MWe) PWR plants were placed in operation. These plants drew heavily upon Naval reactor base technology but used different nuclear core designs. The growth of commercial LWR capacity, to date, is indicated in Table 6A.1-1.[2]

Table 6A.1-1

GROWTH OF COMMERCIAL LWR CAPACITY IN THE USA[a]

Year[b]	No. of Units	MWe, Net	MWe, Cumulative
1957	1	90	90
1960	1	200	290
1961	1	175	465
1962	1	265	730
1963	1	69	799
1964	1	22	821
1965	1	70	891
1966	0	0	891
1967	0	0	891
1968	2	1,005	1,896
1969	2	1,265	3,160
1970	3	1,776	4,936
1971	6	3,459	8,396
1972	8	5,546	13,941
1973	10	7,769	21,710

[a]Source: Division of Reactor Development and Technology, "Status of Central Station Nuclear Power Reactors--Significant Milestones," Report WASH-1208 (1-74), U.S. Atomic Energy Commission, Washington, D.C. 20545.

[b]Year in which commercial operation was achieved, except 1973, for which all plants achieving initial criticality are included.

*Later increased to 90 MWe.

6A.1.1.1.3 Status

LWR plants are by far the predominant type of nuclear power plant being purchased and installed by U.S. utilities at this time. As of December 31, 1973, U.S. utilities had built, ordered, or announced plans for 217 commercial nuclear electric plants (209 LWRs and 8 HTGRs), having an aggregate capacity of about 200 thousand electric megawatts.[2] Thirty-nine LWRs and one high temperature gas-cooled reactor (HTGR) were then in operation. Six more LWRs were added to the total of built, ordered, or announced plants in the first three months of 1974. Projecting from present trends in the purchase of fossil and nuclear plants by the utilities, it appears likely that nuclear energy will become the predominant source of electricity in the U.S. within the next 20 years or so.[3] AEC projections of the growth of the nuclear electric industry are discussed in Section 6A.1.1.8.

6A.1.1.2 Extent of Energy Resources

6A.1.1.2.1 U.S. Uranium Supply

The currently estimated U.S. uranium reserves at a cut-off cost of $8 per pound of U_3O_8* are 277,000 tons. An additional potential resource of 450,000 tons is estimated to occur in known favorable geologic environments. At higher cut-off costs, the resources are larger. Resources up to $30 per pound of U_3O_8 are primarily in deposits such as those currently being mined, primarily tabular pods in sandstones, sometimes referred to as conventional deposits (Table 6A.1-2).[4,5] Large quantities

Table 6A.1-2

ESTIMATED U.S. URANIUM RESOURCES[a,b]

U_3O_8 Cost up to: ($/lb)	Reserves	Potential	Total
	(cumulative thousands of short tons U_3O_8)		
8.00	280	450	730
10.00	340	700	1040
15.00	520	1000	1520
30.00	700	1700	2400

[a]Source: USAEC, "Potential Nuclear Power Growth Patterns," Report WASH-1098, Supt. of Documents, U.S. Government Printing Office, Washington, D.C. 20402, May 1973.

[b]Source: USAEC, Division of Production and Materials Management, Nuclear Fuel Supply," Report WASH-1242, Supt. of Documents, U.S. Government Printing Office, Washington, D.C. 20402, May 1973.

*AEC reserve estimates represent the calculated maximum amount of uranium that could be produced at specified costs. Sales prices are determined by the market, and will likely be higher than the AEC production cost estimates.

of uranium also occur in certain shales and granites but the uranium occurs in small concentrations in comparison with conventional deposits (Figure 6A.1-1).[6] The cost of production from these sources would be much higher, and very large tonnages of "ore" would need to be mined and milled to produce significant amounts of uranium (see Section 6A.1.1.6). The environmental impact of using these low grade resources would also be significantly greater.

The currently known conventional uranium deposits are located in the western part of the U.S., principally in the states of Colorado, New Mexico, Texas, Utah, Washington, and Wyoming. Figure 6A.1-2[7] shows the locations of known reserves and producing areas. Most conventional uranium deposits are small, containing several hundred tons of U_3O_8 on the average. A relatively few large deposits have the bulk of the reserves. About 10% of the known deposits contain 85% of the \$8/lb reserves.[5,7] The average uranium content of ore mined in 1972 was about 0.21% U_3O_8 (or 2100 ppm).

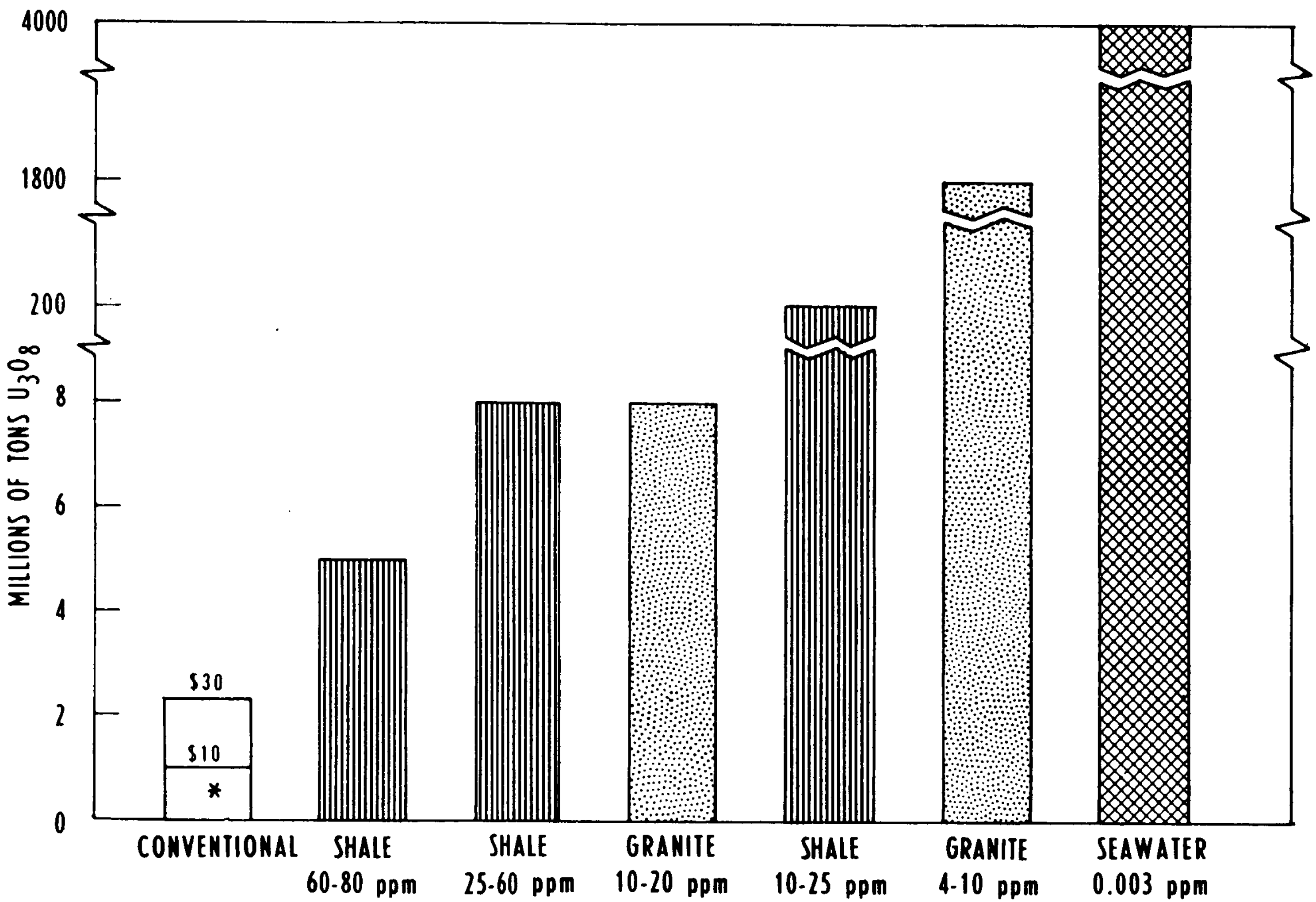
An important characteristic of the U.S. conventional sandstone deposits is depicted in Figures 6A.1-3 and 6A.1-4. Most of the uranium in a typical deposit is found in those portions which assay at 0.1% U_3O_8 and higher. By mining to a cut-off in the assay range corresponding to \$30 per pound of U_3O_8 recovery cost, substantially all of the uranium in the deposit would be recovered. The quantities of uranium that could be recovered at costs in excess of \$30 per pound of U_3O_8 from conventional deposits appear to be very small.

While a large number of wide-spread exploratory drillings have been made in the western portion of the U.S., there is no evidence of large deposits of low-grade uranium ores which could bridge the apparent gap between the sandstone deposits (at \$8 to \$30 per pound of U_3O_8) and the Chattanooga shales (second and third bars of Figure 6A.1-1) with currently estimated recovery costs ranging upwards of \$90 per pound of U_3O_8 (see Section 6A.1.1.9). This does not necessarily mean that there are no such deposits, but rather that the existence of such deposits has not been established from the considerable amount of data on hand.*

6A.1.1.2.2 Foreign Uranium Supply

Foreign reserves[5] at a cut-off of \$10/lb U_3O_8 are estimated at about 800,000 tons of U_3O_8, and potential additional resources at 500,000 tons at the same cut-off

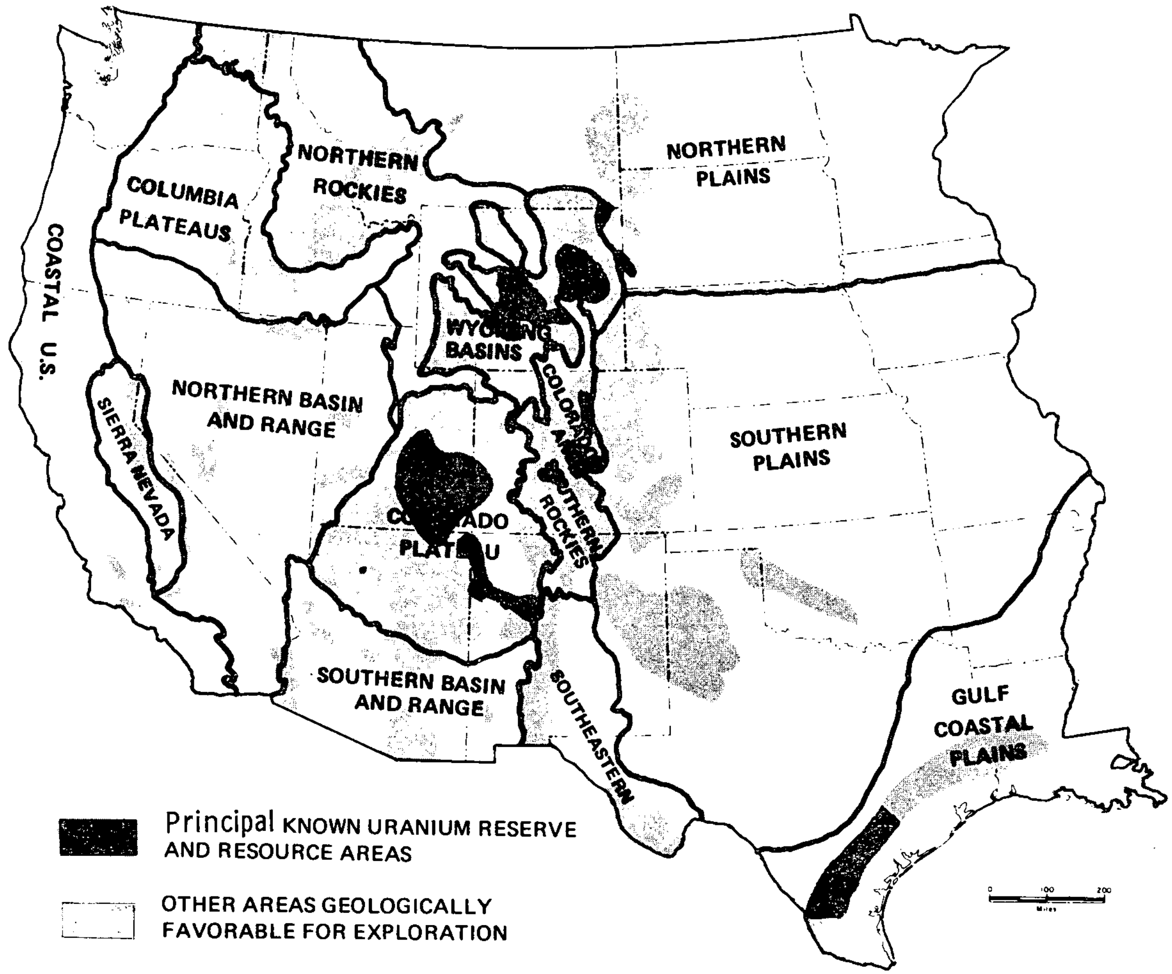
*Some compensation is made for this uncertainty in the estimated uranium prices used in the LMFBR cost-benefit analysis. Table 11.2-29, Section 11.2, is based on a range of assumptions, including the assumption that portions of the Chattanooga shales would yield U_3O_8 at costs within the apparent \$30 to \$90 gap.



* 700 - 2100 ppm

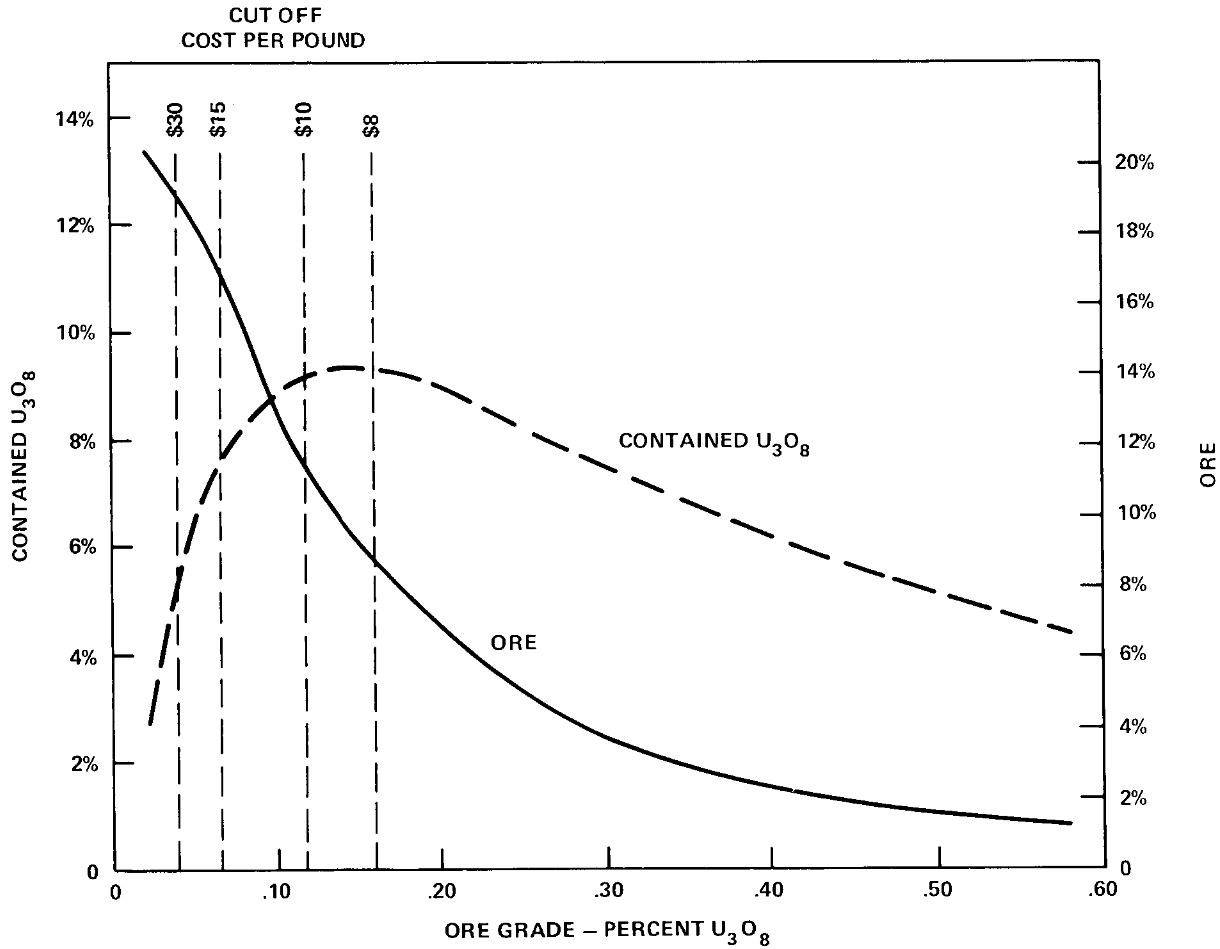
U. S. URANIUM RESOURCES AT $10 TO $? PER LB U_3O_8

Figure 6A.1-1



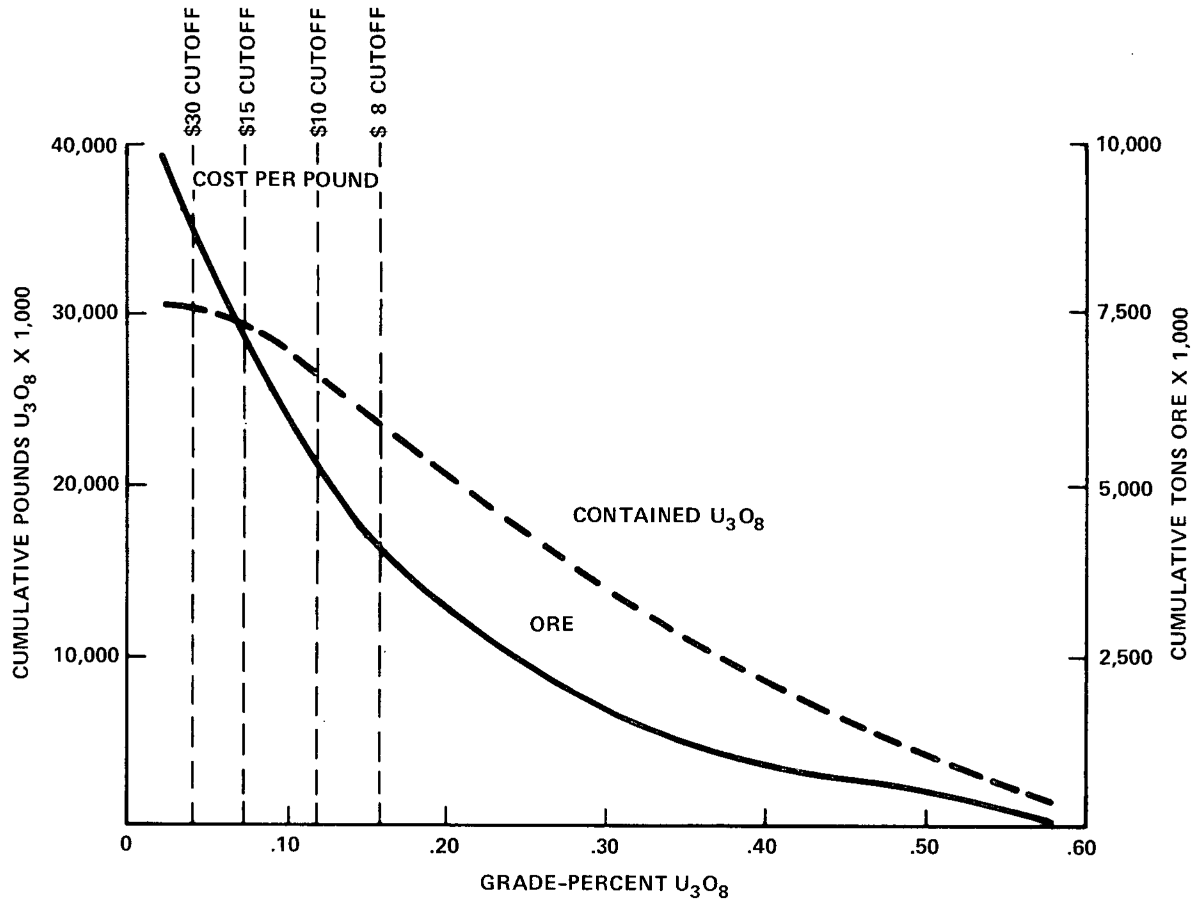
URANIUM RESOURCES IN WESTERN UNITED STATES

Figure 6A.1-2



INCREMENTAL DISTRIBUTION OF RESERVES BY GRADE AND CUTOFF COST PER POUND
FOR A TYPICAL SANDSTONE TYPE URANIUM DEPOSIT

Figure 6A.1-3



CUMULATIVE DISTRIBUTION OF RESERVES BY GRADE AND CUTOFF COST PER POUND FOR A TYPICAL SANDSTONE TYPE URANIUM DEPOSIT

CUMULATIVE DISTRIBUTION OF RESERVES

Figure 6A.1-4

cost. Australia, Canada, South Africa, and South West Africa have about 75% of these resources. The remainder is primarily in Central Africa and Europe.

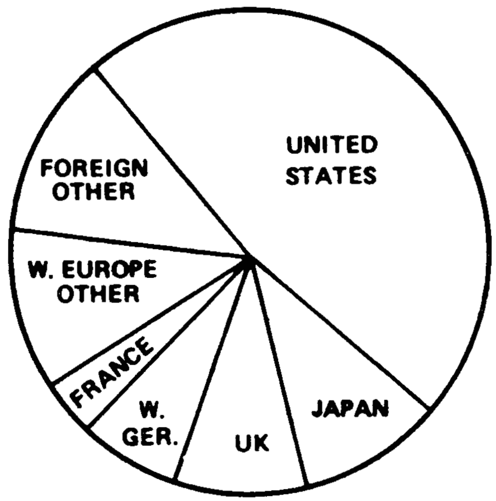
Despite an apparently better supply position with respect to low-cost ores than is currently evident in the U.S., there are limitations on the production rates attainable. South African uranium is a byproduct of gold mining. Canadian and South West African resources are contained in a few deposits for which there are physical and economic limitations on production levels.

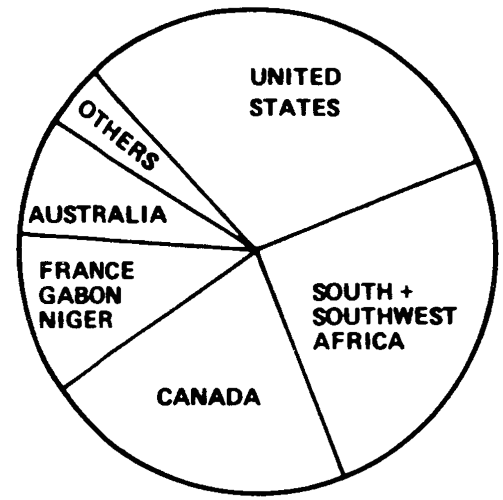
As depicted in Figure 6A.1-5,[6] the foreign uranium supply-demand[7] situation is expected to be much like that expected in the U.S. (See following section and Section 6A.1.1.8.) To foresee to what extent foreign uranium will be available in the long run as a source for U.S. use is difficult. It seems unlikely, considering foreign demands, that the U.S. can rely on the availability of large amounts of foreign uranium.

6A.1.1.2.3 Estimated Availability and Consumption of Uranium

Uranium requirements in the U.S. are currently about 12,000 tons of U_3O_8 per year (1974), and are expected to increase rapidly--in the range of 30,000 to 36,000 tons/year by 1980 and 84,000 to 125,000 tons/year by 1990.[8] Current mining/milling capacity in the U.S. is about 18,000 tons U_3O_8 per year so that the mining/milling industry is facing a period of major growth. Enlargement of U.S. uranium resources will be a necessary part of the expansion in production that will be needed to meet projected requirements. This will necessitate substantial capital investment in exploration several years in advance of production and construction of new mining and milling facilities. Between 1973 and 1990, the capital investment needed is estimated at $10 billion, of which $6 billion would be for exploration.[5] The need for substantial exploration stems from the following factors.

(1) Ore reserves are far less than forecast requirements for the next few decades. The estimated potential listed in Table 6A.1-2 is yet to be discovered, and additional potential resources also must be identified. The potential resources listed in Table 6A.1-2 have been estimated by the AEC by comparing the characteristics of known deposits and their geologic environment to other similar geologic areas. While there is a reasonable expectation that the estimated quantities of ores exist in these areas and will be found, it will take time and effort to discover and delineate the deposits. Exploration effort in the U.S. the last few years has not expanded reserves significantly (see





REQUIREMENTS THRU 1985	THOUSAND TONS U_3O_8	%
UNITED STATES	474	47
JAPAN	106	10
UNITED KINGDOM	92	9
WEST GERMANY	65	7
FRANCE	40	4
W. EUROPE OTHER	107	11
FOREIGN OTHER	116	12
TOTAL	1,000	100

RESERVES - $10/LBU_3O_8$	THOUSAND TONS U_3O_8	%
UNITED STATES	330	29
So. + SOUTHWEST AFRICA	300	26
CANADA	236	20
FRANCE, GABON, NIGER	124	11
AUSTRALIA	92	8
OTHERS	68	6
TOTAL	1,150	100

WORLD URANIUM REQUIREMENTS AND RESERVES

Figure 6A.1-5

Figure 6A.1-6).[6] Increased efforts will be needed in the future to maintain a satisfactory resource base.

(2) As a practical matter, ore reserves at any time should be equal to at least the following eight years' requirements (see Figure 6A.1-7). Eight years is the approximate lead time between initiation of exploration and initial production of U_3O_8. A reserve base is necessary for justification of investment in mines and mills, for amortization of capital, and for contracting for sale of products. From 700,000 to 950,000 tons of U_3O_8 must be produced to satisfy requirements between the beginning of 1973 and the end of 1990. An eight-year reserve at that time would be about another million tons in the ground.

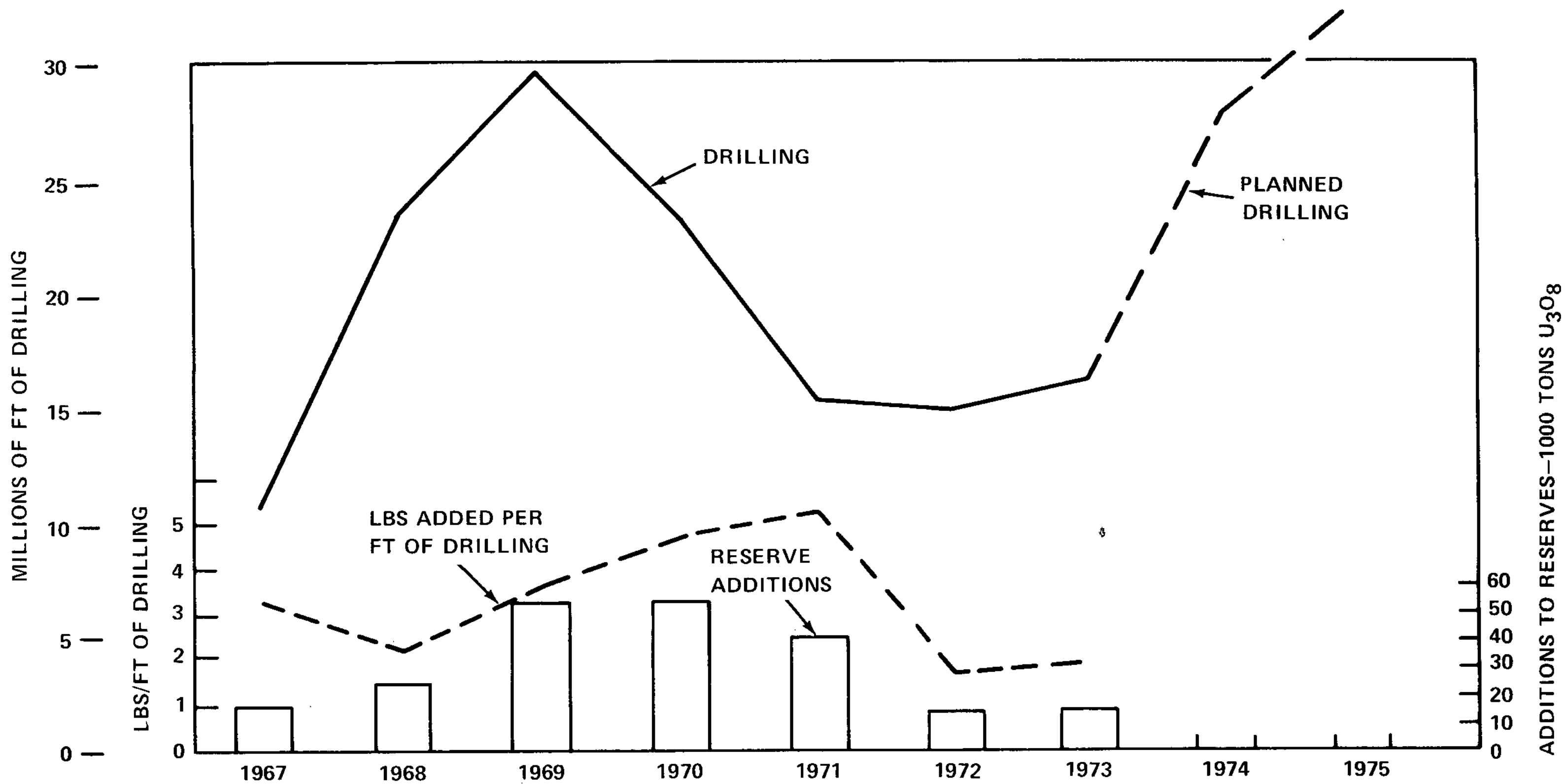
Today there is about a 10-year forward reserve[7] of U_3O_8 in the \$8/lb category in the U.S. The practically achievable production from ore reserves and estimated potential \$8/lb resources would evidently fall behind demand in the early 1980's. To keep up with requirements beyond that time will require discovery of additional resources or production from progressively higher-cost and lower-grade conventional ores, and/or use of non-conventional ores.

Expansion of Resources

AEC evaluation of U.S. uranium resources has been, until recently, largely concentrated in and around the established uranium mining areas. A question remains as to the magnitude of resources which may exist beyond those included in AEC estimates. Viewpoints vary widely among knowledgeable people in the uranium industry.

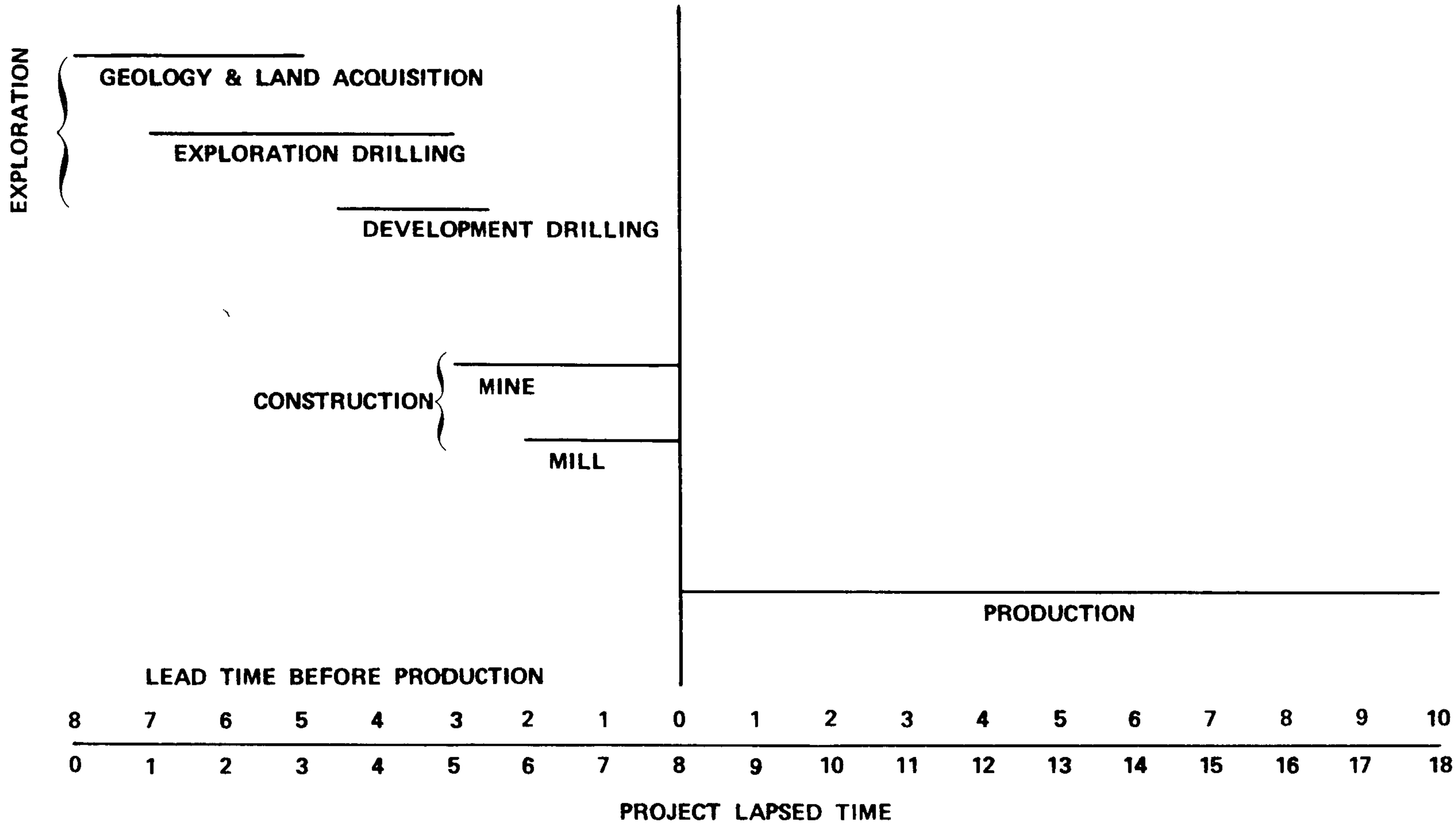
On the one hand, some believe that past exploration has been so extensive that all major districts have now been found and, while some minor additions are likely within those districts, no large additions to low-cost resources are likely.* On the other hand, there are a few who believe that many other sedimentary environments in the United States are just as favorable for uranium deposits as the Grants mineral belt and the Wyoming basin areas. They, in effect, think that ample resources will be found as needed.** Between these two extremes is the more common viewpoint that known districts are likely to expand and some additional districts remain to be discovered, but that exploration will become increasingly difficult.

*Paper presented by John A. Patterson, USAEC, at the Gulf Coast Association of Geological Societies Annual Meeting, Corpus Christi, Texas, entitled, "Nuclear Power and Uranium," October 13, 1972, p. 11.
**Comment Letters 14, p.1; 38g, pp. 46-54; 55, pp. 2-5.



DRILLING, RESERVE ADDITIONS AND DISCOVERY RATES
(at up to \$8/lb U_3O_8)

Figure 6A.1-6



TYPICAL ACTIVITY TIME SCALE--URANIUM PRODUCTION FACILITY

Figure 6A.1-7

In any case, uranium resources minable at a given cost are finite and will not expand indefinitely in response to exploration effort. A further concern to many evolves from the short time frame in which exploration must be done to keep up with demand, whatever the resource viewpoint. To meet projected needs at reasonable costs, little time remains to effect expansion of U.S. resources.

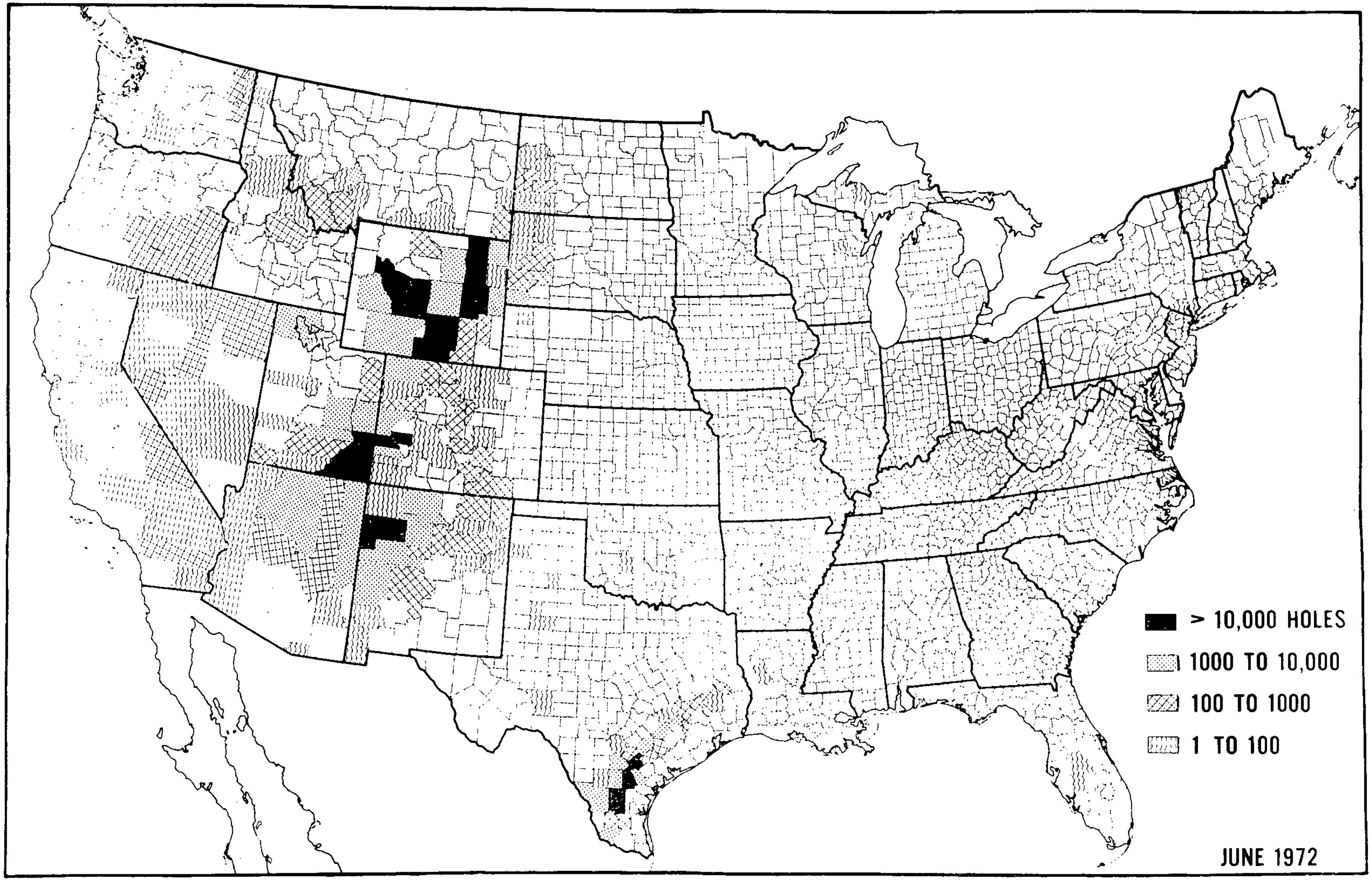
U.S. Exploration History

Some insight as to where the development of uranium resources in the United States stands can be gained by reviewing exploration history and what has been accomplished. Since the late 1940's over 700,000 holes amounting to about 210 million ft have been drilled in the search for uranium in the U.S. Figure 6A.1-6 illustrates historic annual drilling activity including additions to reserves per foot of drilling, a measure of exploration success.

Discovery rates in the 1950's increased as new districts were found and the geology of uranium became understood. Discovery rates of over ten pounds U_3O_8 per foot were reached. More complete delineation of uranium districts and lack of discovery of new districts in the late fifties and early sixties reduced discovery rates to less than 5 lb/ft. In the second exploration surge in the late 1960's and early 1970's, much higher exploration levels were reached but with less success than in the 1950's. Furthermore, recent exploration has produced quite variable results. For example, rates for the U.S. as a whole over the 1967-1971 period, which involved 103 million ft of drilling, averaged 3.8 pounds of U_3O_8 per foot drilled. However, the average for the State of New Mexico was 9.6 lb/ft, while that for the rest of the country was only 2.4 lb/ft. Thus, in most of the geographic area where the large 1967-1971 exploration effort was performed, success ratios have been very much less than previously experienced.

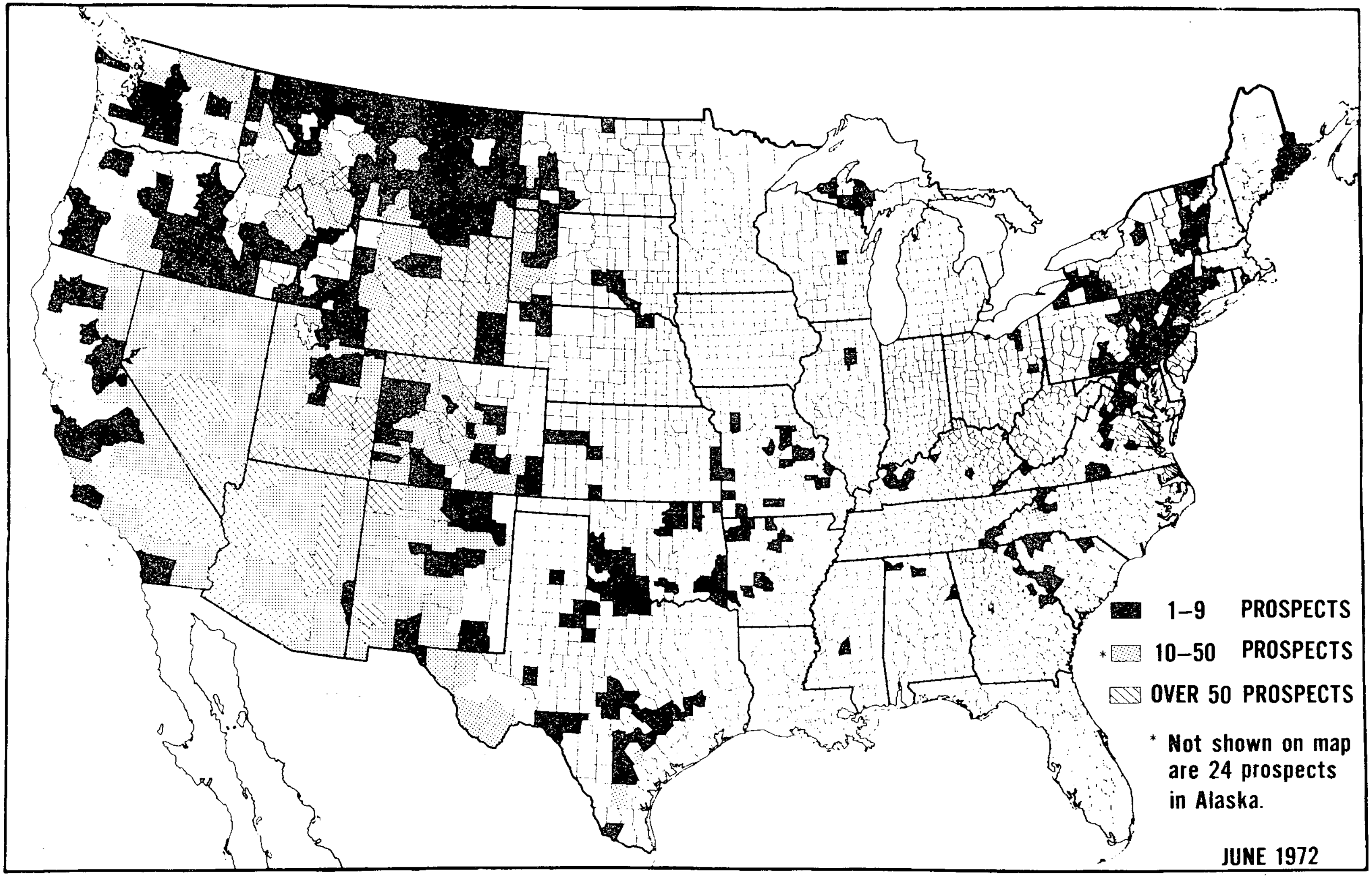
Geographically, drilling has been quite widespread in the West, as illustrated in Figure 6A.1-8. Twenty-one states have had some drilling effort for uranium.

An additional index of exploration effort is shown in Figure 6A.1-9, which locates prospects examined by AEC or USGS geologists during the 1950's. A preliminary reconnaisance report was prepared after each of these brief investigations. Over 7,000 examinations were made in 42 states including Alaska involving a diversity of geologic environments over large land areas. The actual area prospected during this period obviously would be considerably larger. In addition, exploration has been conducted through gamma-ray surveys and water sampling.



EXPLORATION DRILLING FOR URANIUM
BY COUNTIES, 1955 TO 1971

Figure 6A.1-8



URANIUM PROSPECTS EXAMINED BY GOVERNMENT GEOLOGISTS BY COUNTIES, 1950-1958

Figure 6A.1-9

While considerable effort was expended over the last 25 years in the search for uranium in the United States, the largest exploration effort ever undertaken for a metal, much remains to be done in relatively unexplored areas or where exploration work has been inconclusive or incomplete.

National Uranium Resource Evaluation

The AEC has undertaken a study of the entire country to develop a comprehensive national uranium resource assessment. In this project, the country has been subdivided into 19 major geologic areas and a number of smaller subareas, each of which will be studied, comparing its characteristics with those of known uranium districts in the United States and other countries. Completion of a preliminary national evaluation is scheduled for 1976. Since data will be incomplete for many areas, this evaluation is likely to be only qualitative for large segments of the country. The information gathered, however, will provide a basis for planning acquisition of the additional data needed for a proper evaluation of those areas. An additional several years of effort will be required to develop adequate geologic data to allow satisfactory evaluation of national potentialities.

Research and development work is planned to improve technology for discovering deposits including geophysics, geochemistry, and geology. Work on improved mining and processing methods for uranium ores is also planned. The Department of Interior, through the Geological Survey and the Bureau of Mines, is participating in this national effort to improve understanding of United States resources and improve technology.

As part of its program to evaluate potential uranium resources, the AEC recently completed a study employing a new method that statistically evaluates the opinion of experts. The method, the Delphi or subjective probability technique, involved judgments of 36 experts from industry, universities, and government. The experts provided their individual evaluations for each of 64 areas covering the entire state of New Mexico. Information provided by each expert was tabulated and the results recirculated seeking to develop a consensus of the experts. It is interesting to compare results for the San Juan Basin, which includes the Grants mineral belt, the largest known uranium resource area in the U.S., as well as large areas not known to be uranium bearing. Twelve of the 36 experts estimated that the Basin contained less than 100,000 tons of U_3O_8 and four estimates were over one million tons of U_3O_8. The median (middle) estimate was 150,000 tons. The average of the 36 estimates was 450,000 tons of U_3O_8. The AEC estimate for the Basin is 740,000 tons of U_3O_8 (at cost under \$30 per pound of U_3O_8) well towards the higher end of the range of values for the experts. The study suggests that AEC potential estimation methods, including areas well beyond the known mining districts, give values that are in the high range of the opinions of informed workers. There was certainly no indication from this study that one should conclude that U.S. resources are significantly higher than as estimated by the AEC methods.

Exploration Activities

Exploration activity and discovery rates over the next decade will in large measure determine the course of our future uranium supply. Industry has in the past been responsive to increased demand and prices for uranium. A rapid increase in exploration drilling effort in the United States occurred in the late 1960's in response to buying activities of utilities. Efforts were reduced in the early 1970's but, as a consequence of increased buying activities and higher prices, are now on the upswing. Plans have been reported for drilling about 29 million ft in 1974 and 34 million ft in 1975, almost double the level of effort in 1973. As the time is appropriate for expanded exploration activity, industry's plans are encouraging. There is some question however that these higher drilling rates will be reached. Drilling equipment and drillers are in tight supply as a result of increased exploration activity for other commodities, particularly coal.

In the last several years, the additions to reserves resulting from exploration have not been as high as in previous years. If future discovery rates continue to be at such low levels, there will be a need for even larger exploration effort or other supply development strategies.

Exploration activity has continued to be concentrated in the well established mining areas. About 90% of the drilling in 1973 was in the Wyoming basins, Grants mineral belt, and Texas Gulf Coast areas. Exploration in these areas continued to be productive. However, diversification of exploration effort would probably be beneficial by identifying new favorable environments and perhaps finding new major uranium districts. Considering the large future need for uranium, new districts, perhaps with new kinds of deposits, would seem to be a promising way to develop the large resources that will be needed.

6A.1.1.2.4 Potential Effect of Advanced Enrichment Processes on Resource Conservation

Some Characteristics of Enrichment by Gaseous Diffusion

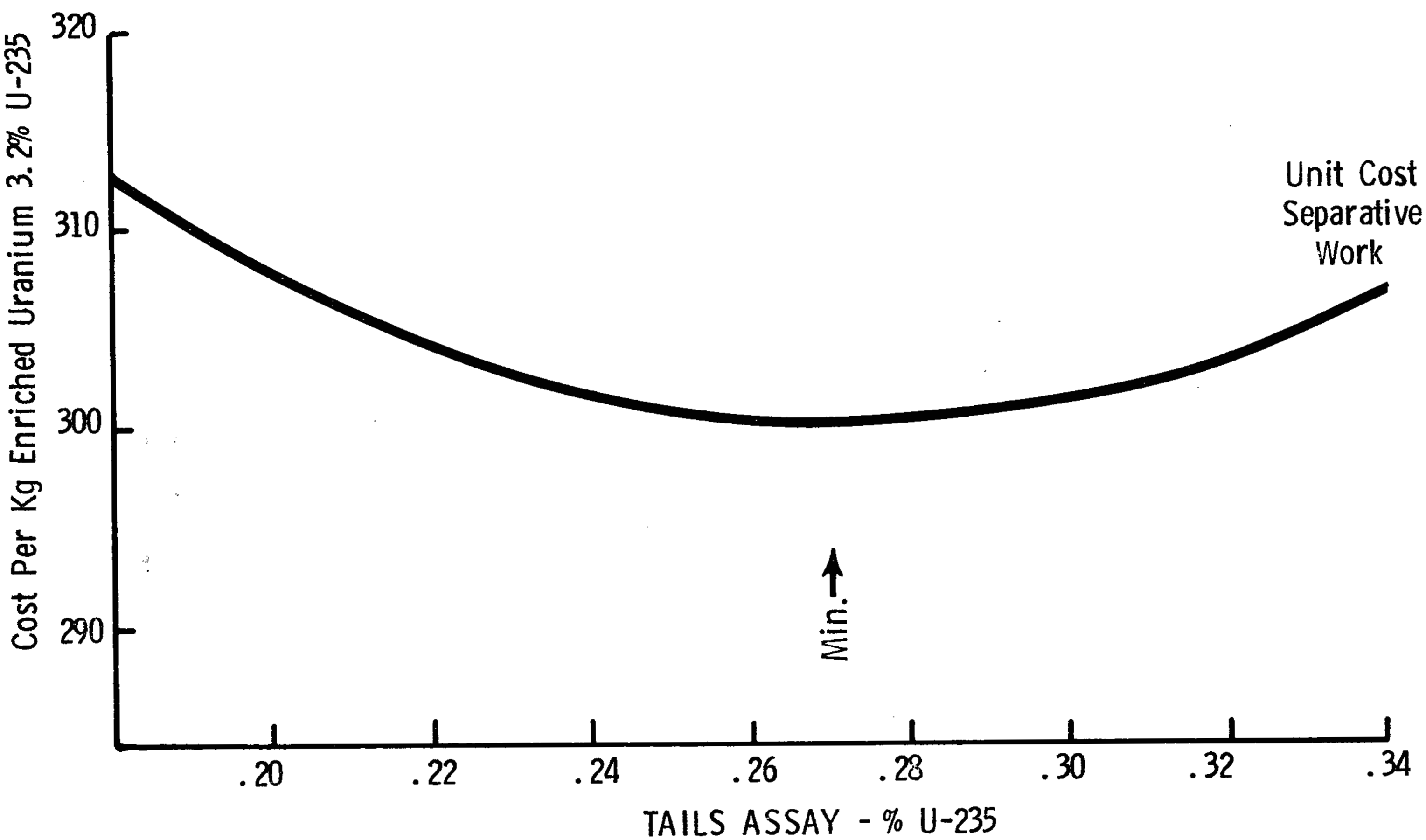
Natural uranium introduced as feed to a gaseous diffusion enrichment plant is separated into a product enriched in U-235 content and a waste stream, or tails, depleted in U-235 content. The tails assay (i.e., residual U-235 content of the tails expressed in weight percent) can be selected more or less independently of feed and product assays, but the actual choice of a tails assay involves a number of practical considerations.

The tails assay of the AEC gaseous diffusion plants is currently set at 0.3% U-235. As shown in the simple cost curve in Figure 6A.1-10, this tails assay is consonant with essentially minimum unit cost for a 3.2% enriched product,* assuming $8 per pound of U_3O_8 feed concentrate price and $36 per separative work unit. These assumptions are close to prices that have prevailed in the past, but must be expected to change. Figure 6A.1-11 shows that the tails assay for optimum product cost would have to be shifted downward as feed price increases, all other factors remaining the same.[7]

For 3.2% enriched product, a 0.3% tails assay places about 63.9% of the incoming U-235 into the enriched product; the balance, 36.1%, remains in the tails. More efficient utilization of U-235 could be achieved by setting the tails assay at a lower value. At 0.1%, for example, the resultant recovery would be 88.7% of the U-235, corresponding to a 28.1% reduction in the quantity of feed required per unit of enriched product. The consequence, however, would be the spending of a larger fraction of separative work capability on stripping the tails to the lower assay, with a resultant increase in cost of more than $50 per kilogram of enriched product and a substantial decrease in annual product output (Table 6A.1-3).

Thus, the use of low tails assays in the currently available separations plants, for more complete U-235 recovery, would be unfavorable to product costs and would hasten the time when additional separations capacity would be needed to satisfy the presently growing product requirements. As feed prices increase, there will be an economic incentive to set tails assays at lower values, but this would also be at

*Also true for a product of any other enrichment derived from $8 concentrate and $36 per separative work unit, although product cost increases with increased product assay.



SENSITIVITY OF PRODUCT COST TO TAILS ASSAY
(U_3O_8 at $8 per pound)

Figure 6A.1-10

Table 6A.1-3

PRODUCT COST AND OUTPUT AS A FUNCTION OF TAILS ASSAY[a]

Tails Assay (wt.% U-235)	Product Cost ($/kg U)	Annual Product Output (metric tons U)	Annual Feed Input (short tons U_3O_8)
0.3	301.86	2641	24,200
0.273	300.88	2498	21,700
0.2	308.59	2107	16,100
0.1	355.48	1523	10,000

[a]Bases: 10,000,000 separative work units per year; feed price \$8/lb U_3O_8 (\$23.46/kg U as UF_6); separative work cost \$36.00 per kg unit; feed assay 0.711% U-235; product assay 3.2% U-235.

the expense of reduced product output and accelerated need for additional separations capacity in an expanding requirements situation.

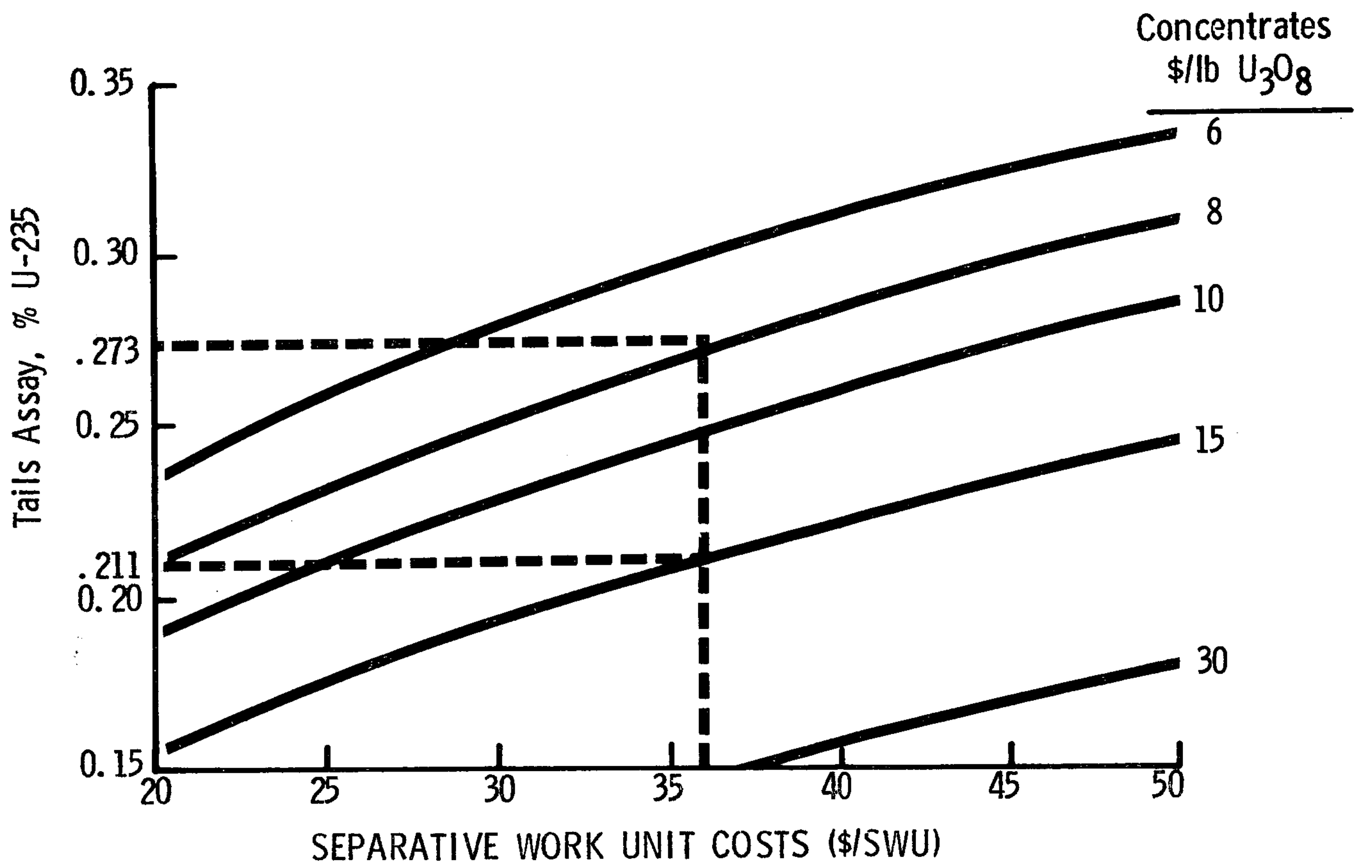
The Possibility of Laser Enrichment Processes

As suggested by Figure 6A.1-11, a substantial lowering of separative work costs would permit more efficient separation of U-235 while maintaining favorable product cost. Large cost reduction is not a reasonable expectation in gaseous diffusion technology.* On theoretical grounds, however, the most promising approaches to more or less complete separation of uranium isotopes at low product costs would be through processes that take advantage of the small, inherent energy state differences between molecules of the isotopes, instead of mass differences on which currently feasible (e.g. electromagnetic,** gas centrifuge, gaseous diffusion) processes depend.

The advent of lasers and a rapidly developing laser technology has enhanced the possibility of developing commercial-scale processes for the separation of uranium (and other) isotopes, at low cost and high separations efficiency, through the mechanism of selective photon excitation of molecules. This possibility is suggested by: (1) the large amounts of coherent light energy that can be obtained from lasers; (2) the range of laser frequencies available; and (3) the frequency purities attainable.

*Product costs from gas centrifuge separations plants could prove to be somewhat lower than the same products from gaseous diffusion plants, but would not be the large cost reductions contemplated herein.[9]

**The electromagnetic process was used briefly during World War II but was abandoned in favor of gaseous diffusion on economic grounds.



OPTIMUM TAILS ASSAY AS A FUNCTION OF
SEPARATIVE WORK AND CONCENTRATE UNIT COSTS

Figure 6A.1-11

In principle, laser photons with properly selected energy (frequency) could be resonantly absorbed by one kind of isotopic molecule without affecting the other (non-resonant) isotope molecules. The selective absorption would raise the energy level of the desired isotopic molecules, and the higher energy state could then be exploited in a variety of chemical or physical processes leading to actual separation of the isotopes. Work toward this end is in progress at the AEC's Los Alamos Scientific Laboratory and at the Lawrence Livermore Laboratory (LLL) on a somewhat different approach.*

An assessment of the maximum potential effect of prospective laser-activated isotope separation processes on uranium resource (i.e., U-235) conservation can be made by assuming that: (1) isotopic separation would be essentially complete (i.e., approaching zero tails assay) at very low separative costs relative to alternative technologies; and (2) such costs would also be low enough to make eventual rework of accumulated tails from alternative processes (e.g., gaseous diffusion, gas centrifuge) economically attractive.

A uranium isotope separation process with these assumed characteristics would require about 36% less natural uranium feed, per unit of enriched product, than does the gaseous diffusion process with current operation at 0.3% tails. Additionally, the assumed process could, at some future date, extend previously used resources by recovering U-235 from accumulated tails, to an extent depending on the average assay of previously accumulated tails. In sum, such a process could reduce ultimate U_3O_8 requirements by as much as 36% in comparison with what the demand would be if today's technology and practices were used throughout the period of U_3O_8 utilization. There is additional discussion of this subject in Section 11.2.4.2.7 in connection with the specific assumptions used in the cost-benefit analysis of the LMFBR.

The assumed laser process would also have some economic impacts. Presumably, it would make alternative separation technologies economically obsolete. It would also contribute to lower fuel cycle costs for those reactors using enriched uranium. The maximum extent to which LWR fuel cycle costs could be lowered can be estimated by assuming no separation costs, coupled with 100% recovery of U-235 from the feed. On this basis, LWR fuel cycle costs would be the Case II values of Table 6A.1-4. As noted in the table footnotes, plutonium values have been scaled to equivalent enriched uranium values for the cases considered.

*Similar laser-oriented work is also in progress under the joint auspices of Exxon Nuclear, Incorporated and AVCO Everett Research Laboratories. There are indications that uranium isotope separation on a microgram scale may have been accomplished in both the Exxon/AVCO and the LLL development work to date.[10,11]

Since zero dollars for separation costs and zero tails assay are not realistic assumptions, the actual costs that might be achieved as a result of a successful laser process would unquestionably be somewhat greater than the stated values. The Case III values of Table 6A.1-4 are calculated with the arbitrary assumption of $5 per separative work unit and 0.05% tails. There is no basis for these assumed numbers, other than a judgment that they would be small, but not zero.

The reader is reminded that this discussion of prospective laser isotope separation impacts is highly speculative. While laser separation research and development is being conducted as a serious business, its success is indeterminate at this time. Thus, while the potential impacts of a successful laser separations technology are noted at various places in this Statement, it has not seemed appropriate to factor these potentialities into the Environmental Impact Statement considerations as if they were an accomplished fact.

6A.1.1.3 Technical Description of LWR Systems

The various steps required for the support of LWR operation, from the mining of the uranium ore to the ultimate disposal of wastes, are known as the nuclear fuel cycle.[12,13] These steps consist of: (1) mining the ore; (2) treatment of the ore to obtain a uranium concentrate; (3) conversion of the concentrate to a chemical form suitable for enrichment; (4) enrichment in gaseous diffusion plants; (5) conversion of the enriched product to a chemical form suitable for fuel; (6) fabrication of fuel; (7) use of fuel in power plant; (8) annual removal of a portion of spent fuel from power plant and storage for about five months; (9) shipment of spent fuel to a reprocessing plant; (10) reprocessing of spent fuel, with recycle of recovered uranium to enrichment plant or to storage and recycle of recovered plutonium to fuel fabrication or to storage; (11) treatment of radioactive wastes for disposal; and (12) packaging and shipment of low-level radioactive wastes for burial and solidification and of high-level wastes to a Federal repository.

Descriptions of these various steps are necessarily brief and conceptual in this document, but more detailed descriptions are available in cited references.

6A.1.1.3.1 LWR Fuel

Fuel for commercial LWRs is derived from naturally occurring uranium which is made up of the isotopes U-238 (99.284%), U-235 (0.711%), and U-234 (0.005%). For use in LWR fuel, natural uranium must be enriched in its U-235 content such that U-235 constitutes about 3% of the enriched product. An isotope enrichment process known

Table 6A.1-4

POTENTIAL EFFECT OF LASER ISOTOPE SEPARATION ON LWR FUEL CYCLE COSTS

Feed Price (\$/lb U_3O_8)	Case I (mills/kWe-hr)	Case II (mills/kWe-hr)	Case III (mills/kWe-hr)
8	1.67	0.83	0.91
10	1.80	0.91	1.00
15	2.09	1.10	1.20
20	2.36	1.29	1.41
30	2.86	1.68	1.83
50	3.86	2.45	2.66
100	6.09	4.39	4.74

Bases: Case I - Gaseous diffusion enrichment; \$36/kg separative work unit; optimum tails assays at 0.273, 0.251, 0.212, 0.184, 0.148, 0.109, and 0.067% for \$8 to \$100 feed prices respectively.

Case II - Laser enrichment @ 0 tails assay and 0 separative cost.

Case III - Laser enrichment @ 0.05% tails assay and \$5 per kg feed (net) for separative work.

Spent fuel credit @ 0.93% U-235 in fuel discharged from reactor operating at 32.5% thermal efficiency and 33,000 $\frac{\text{MWt-day}}{\text{metric tons U}}$.

Pu credit assigned from base case of \$7.50 per gram of fissile Pu @ \$8 per lb of feed, 0.2% gaseous diffusion tails, by the following ratio:

Pu credit = 0.164 x $\frac{\text{cost 90\% U-235 at given tails assay}}{\text{cost 90\% U-235 at 0.2\% tails assay}}$; see *Federal Register* 30:3886 (1965).

Indirect charges based on methods given in "Guide for Economic Evaluation of Nuclear Plant Design," Report NUS-531, Nuclear Utility Services, Rockville, Md., January 1969.

as the gaseous diffusion process is used for this purpose. The fuel used in LWRs, therefore, contains a mixture of about 3% U-235 atoms and 97% U-238 atoms, both in the form of uranium dioxide (UO_2)* pellets encased (clad) in either stainless steel or zirconium alloy (zircaloy) tubing (see Figure 6A.1-12). The fuel pellets are right cylinders usually about one-half inch long with the diameter varying from about 3/8 in. to over 1/2 in., depending on reactor core design,[1] ground to close dimensional tolerances. The voids in the fuel rod, especially the annulus (0.003-in. to 0.005-in. diametral gap) between the pellet and the cladding, are filled with helium under varying degrees of pressure, commensurate with the anticipated range of external pressure forces during reactor operation.

Completed rods are inspected and assembled into fuel bundles. When inserted in the pressure vessel of a LWR along with associated control rods and structures, the fuel assemblies (bundles) collectively are called the nuclear core of the reactor.

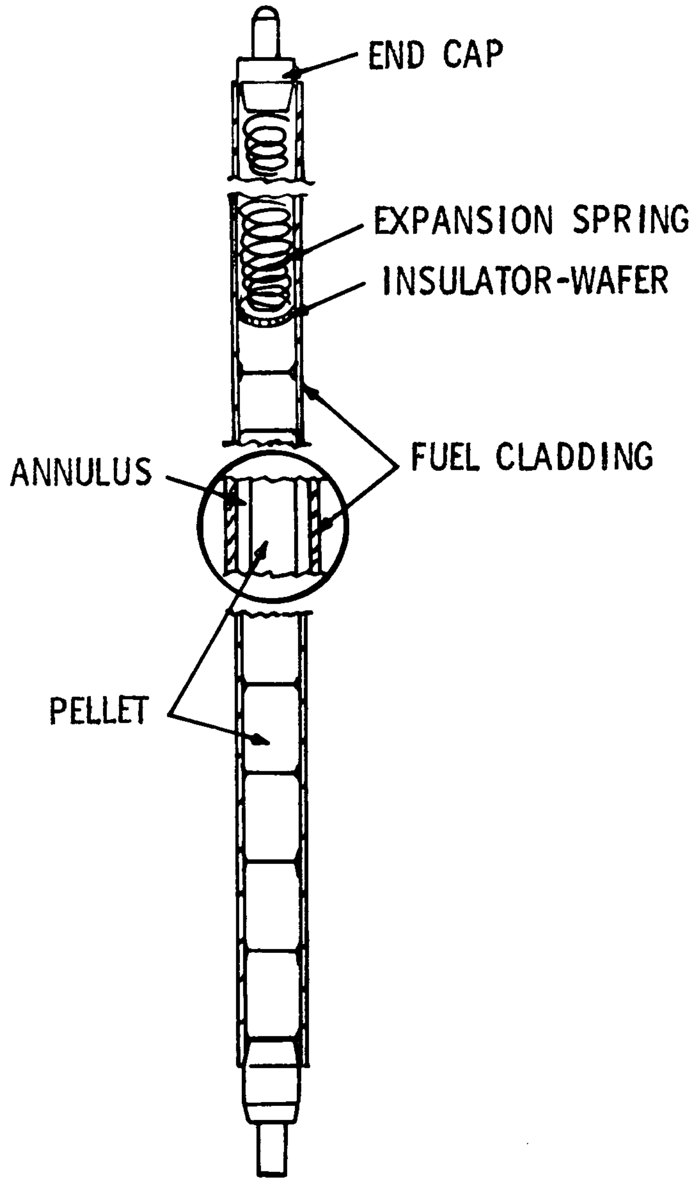
Large PWR and BWR plants typically employ partial refueling annually; in BWRs, about one-fourth of the fuel assemblies are removed and replaced with fresh fuel each year, while in PWRs about one-third of the assemblies are replaced annually. Spent-fuel assemblies are stored under water at the power plant for a period of five to six months prior to shipment to a fuel-reprocessing plant.

6A.1.1.3.2 Nuclear Steam Supply Systems

BWR Description

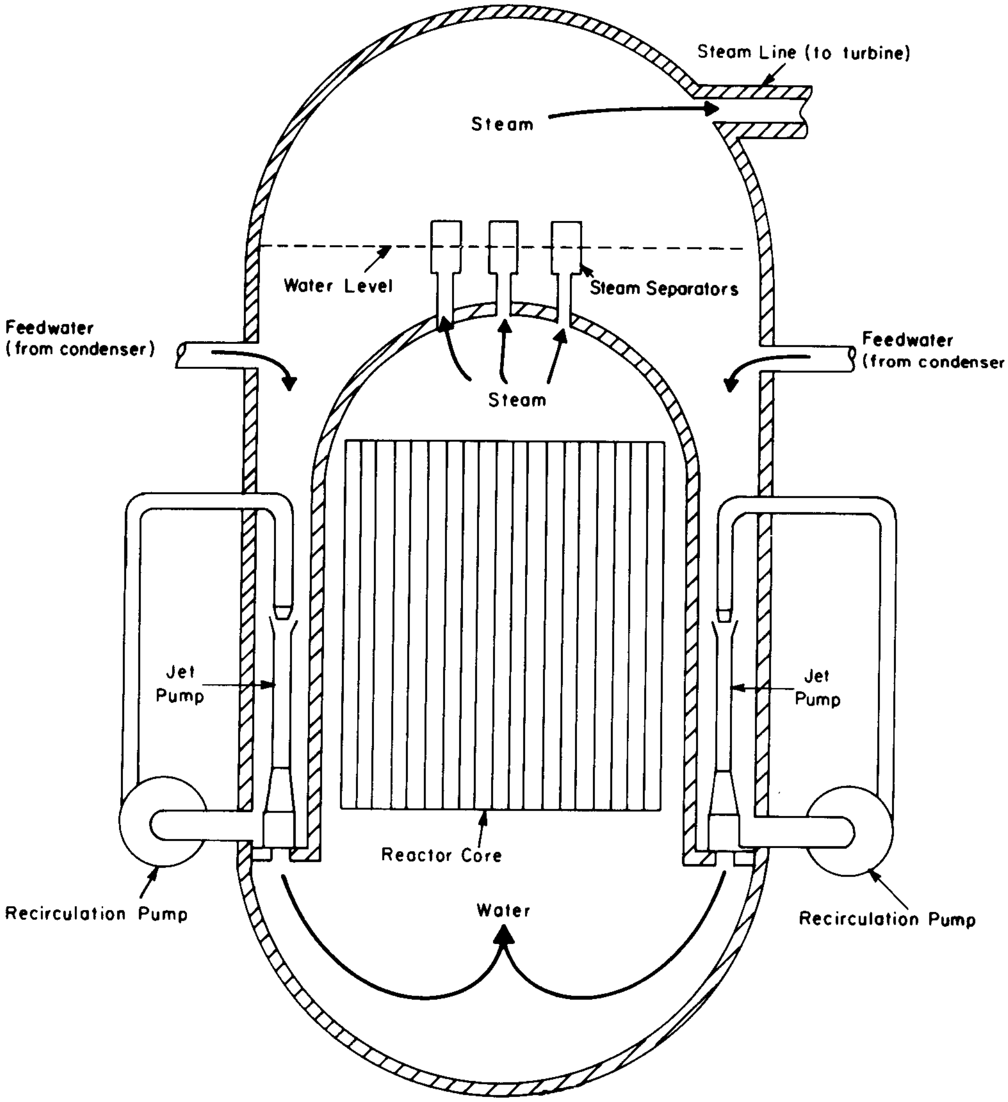
The nuclear steam supply system (NSSS) of a BWR[1] consists primarily of the reactor vessel and equipment inside the vessel. (See Figures 6A.1-13 and -14.) The nuclear fuel assemblies are arranged inside a core shroud in the reactor vessel. Water boils in the core, and a mixture of steam and water flows out the top of the core and through steam separators at the top of the core shroud. Steam from the separators passes through dryers to remove all but traces of entrained water and then leaves the reactor vessel through pipes to the turbine generator. Water from the steam separators and water returned from the turbine condenser mix, flow downward through the annulus between the core shroud and the reactor vessel, and return to the bottom of the core. Because the energy supplied to the reactor coolant (water) from the hot fuel is transported directly (as steam) to the turbine, the BWR system is termed a "direct cycle" system. The pressure in a typical BWR is maintained at

*Prior to LMFBR operation, an appreciable fraction of the fuel in some replacement fuel cores will contain plutonium (PuO_2 in place of the U-235 oxide) in a mixed oxide, UO_2/PuO_2, pellet.



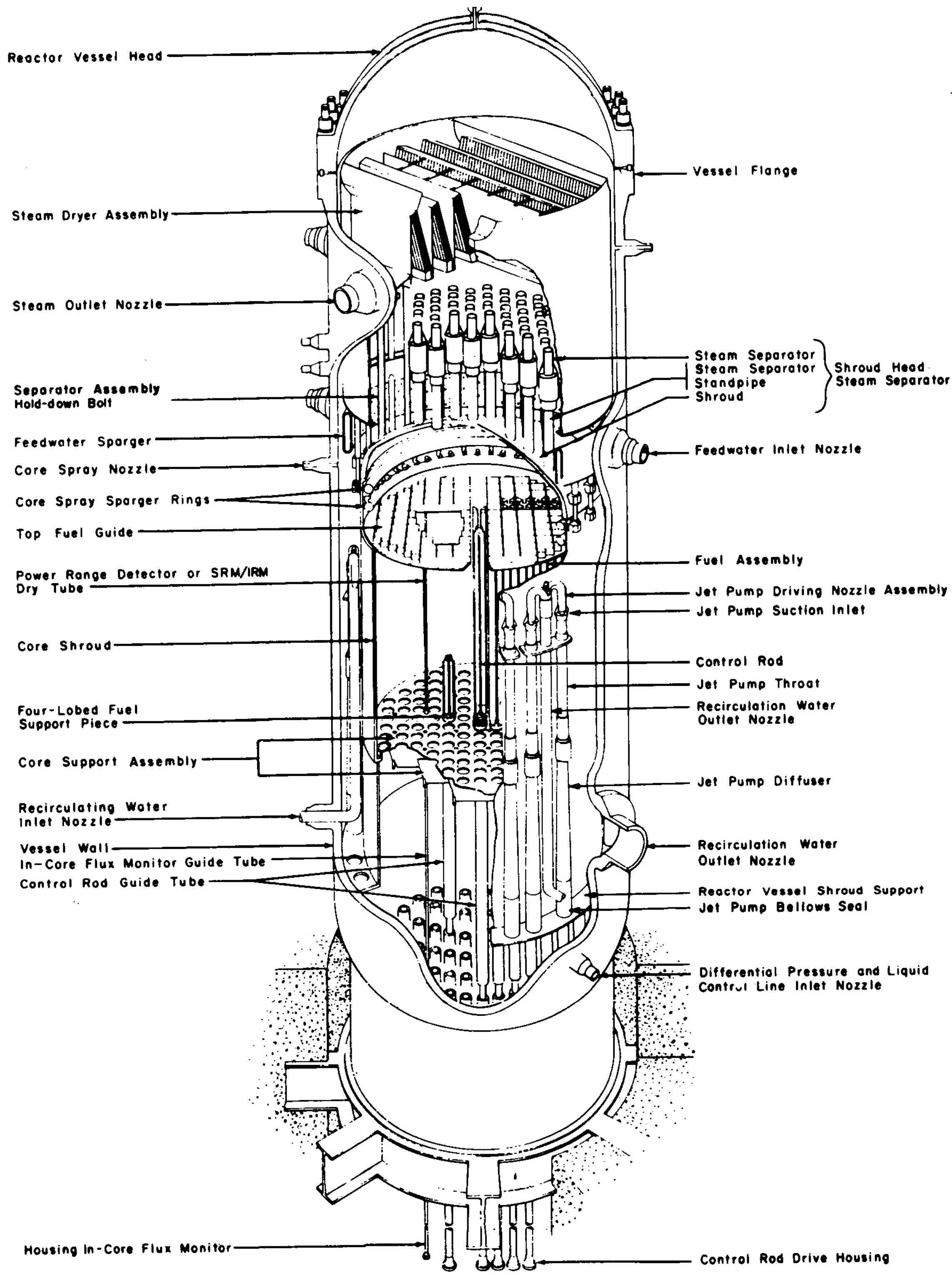
CUTAWAY OF OXIDE FUEL FOR
COMMERCIAL LWR POWER PLANT

Figure 6A.1-12



SCHEMATIC ARRANGEMENT OF BWR NSSS

Figure 6A.1-13



CUTAWAY VIEW OF INTERNALS OF TYPICAL BWR VESSEL

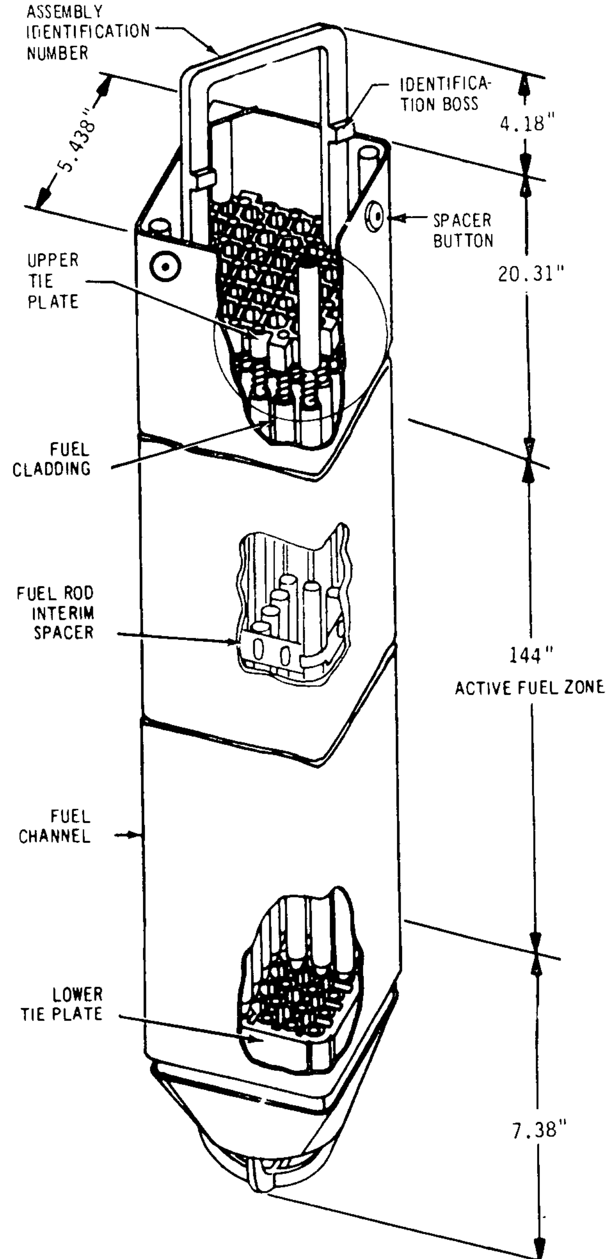
Figure 6A.1-14

about 1000 pounds per square inch (psi); at this pressure water boils and forms steam at about 545°F.

Details of the reactor vessel and internals for a typical BWR are shown in Figure 6A.1-14. Steam flows from the reactor vessel to the turbine-generator in multiple main steam lines. The head of the vessel and the steam separators and dryers are removable for refueling the core. Neutron-absorbing control and safety elements in the reactor core are connected to rods that pass through fittings in the bottom head of the vessel and are operated by hydraulic drives mounted below the vessel. Because the reactor heat output is sensitive to the rate-of-flow of coolant through the core, partial control of the power is effected by varying the driving flow to the pumps that can recirculate some of the water through the core.

Sixty-four fuel rods (49 rods in older models, as shown in Figure 6A.1-15) are installed in a metal channel of square cross section to form a fuel assembly. The channel is open at the top and bottom to permit coolant to flow upward through the assembly; however, the closed sides prevent lateral flow of coolant between adjacent assemblies in the reactor core. The core of a large BWR of current design may contain as many as 764 fuel assemblies (at 64 rods per assembly, the total is almost 49,000 fuel rods per reactor) with a total weight of uranium dioxide of more than 372,000 lb.

The amount of heat that can be extracted from a BWR core of a given size depends on, among other things, the rate of recirculation of water through the core. In current BWRs, jet pumps are provided in the annulus outside the core shroud to greatly increase the circulation rate over the natural circulation induced by the boiling in the core. The arrangement of the nuclear steam supply system is shown schematically in Figure 6A.1-13. BWRs have multiple provisions for cooling the core fuel in the event of an unplanned depressurization or loss-of-coolant from the reactor. The provisions may differ from plant to plant, but all plants have several independent systems[1] to achieve flooding and/or spraying of the reactor core with coolant upon receiving a signal of either high drywell pressure or low reactor vessel water level. Typical emergency core cooling systems involve either a high-pressure core spray system (early BWRs) or both core sprays and a high-pressure coolant-injection system (latest BWRs) to assure adequate cooling of the core in the event of a leak that results in depressurization of the reactor system.



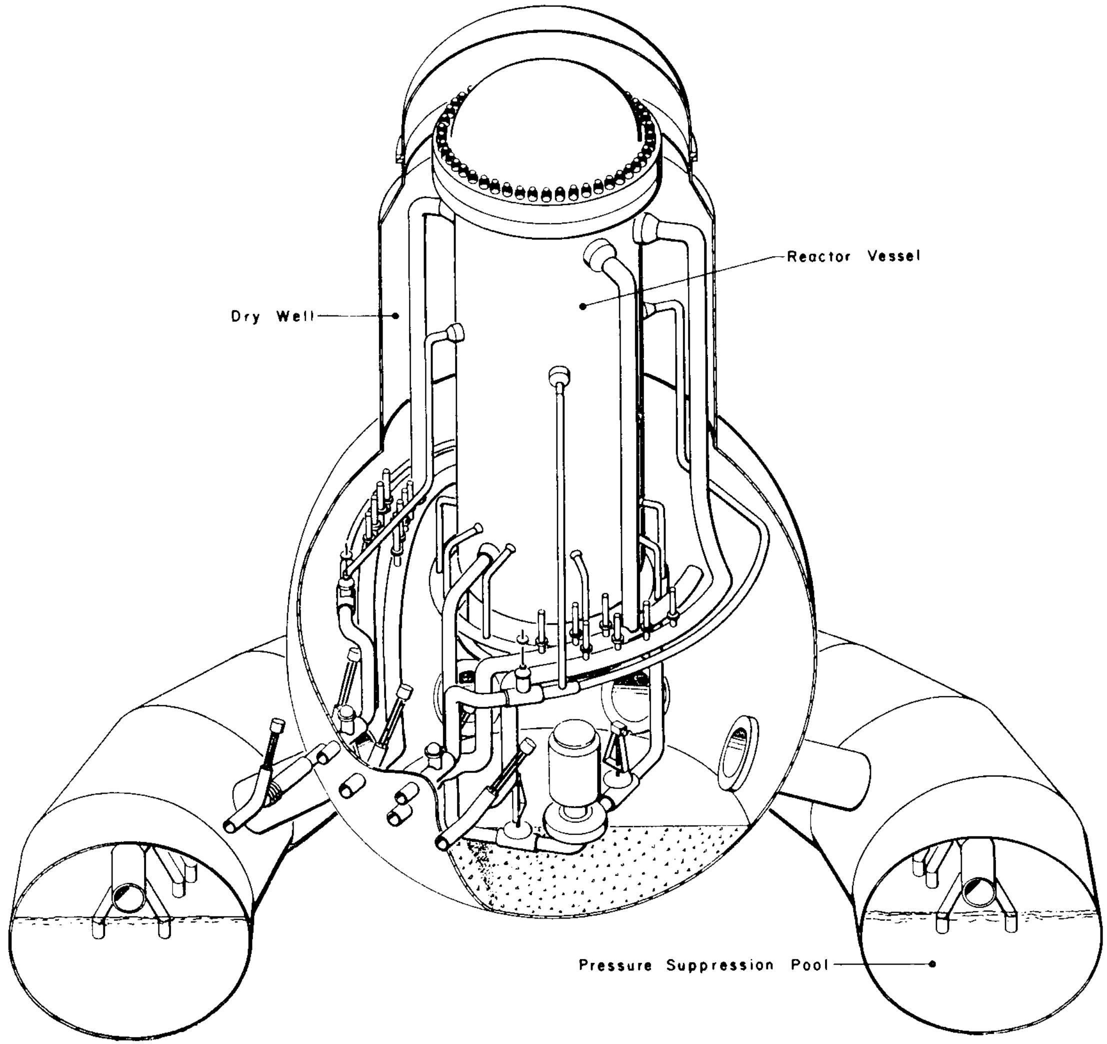
BWR FUEL ASSEMBLY

Figure 6A.1-15

Containment systems of BWRs generally provide both "primary" and "secondary" containment. For current applications, the former is a steel pressure vessel surrounded by reinforced concrete and designed to withstand peak transient pressures which might occur in the most severe of the postulated, though unlikely, loss-of-coolant accidents. This primary containment employs a "drywell," enclosing the entire reactor vessel and its recirculation pumps and piping. It is connected through large ducts to a lower-level pressure-suppression chamber which stores a large pool of water as shown schematically in Figure 6A.1-16. Under accident conditions, valves in the main steam lines from the reactor to the turbine-generators would automatically close, and any steam escaping from the reactor system would be released entirely within the drywell. The resulting increase in drywell pressure would force the air-steam mixture in the drywell down into and through the water in the pressure-suppression chamber, where the steam would be completely condensed. Steam released through the pressure-relief valves of the automatic depressurization system also would be condensed in the pressure-suppression pool, and this pool serves as a potential source of water for the emergency core cooling system. Systems[1] for the control of combustible gases from metal-water reactions and radiolytic decomposition of the water are also provided to assure that flammable concentrations are not reached in the containment.

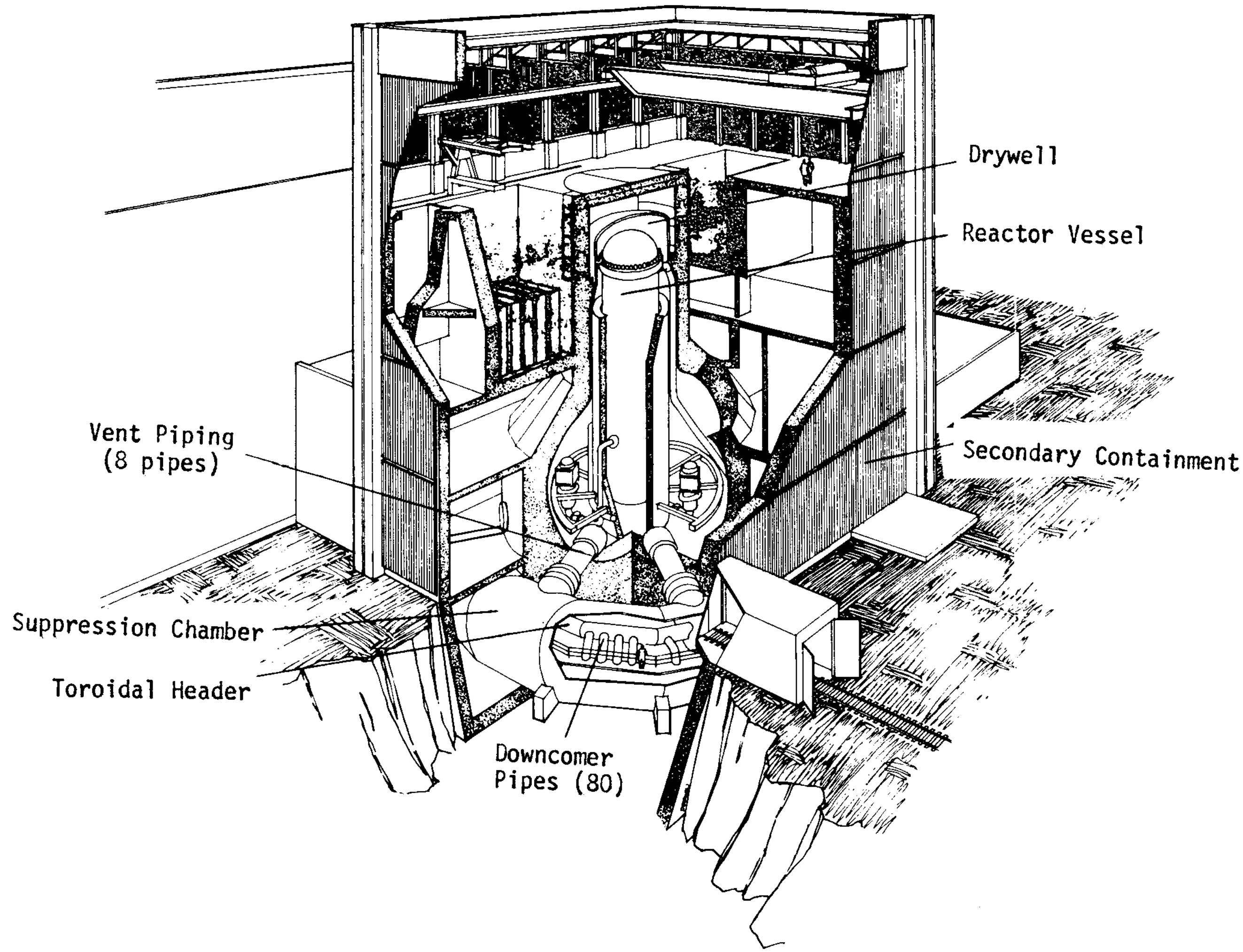
The secondary containment system is the reactor building that houses the reactor and its primary containment system; a typical on-line system appears in Figure 6A.1-17 and a schematic for the most advanced plants is shown in Figure 6A.1-18. The buildings, substructures, and exterior walls up to a level above the top of the drywell are of poured-in-place reinforced concrete. The secondary containment of operating BWR plants is designed for low leakage and has sealed joints and inter-locked double-door entries. Under postulated accident conditions, the normal building ventilation system automatically would shut down, and the building would be exhaust-ventilated (so as to maintain a slight negative pressure therein) by two parallel standby systems which discharge through the plant stack or roof exhaust system, to minimize ground-level exfiltration possibilities. The effluent gas passes through treatment systems which include high-efficiency particulate air (HEPA) filters and solid adsorbents for trapping radioactive halogens, particularly iodine, that might have leaked from the primary containment.

The most advanced BWR plants use a separate free-standing leak-tight containment shell inside of a sealed building (see Figure 6A.1-18) which provides a further



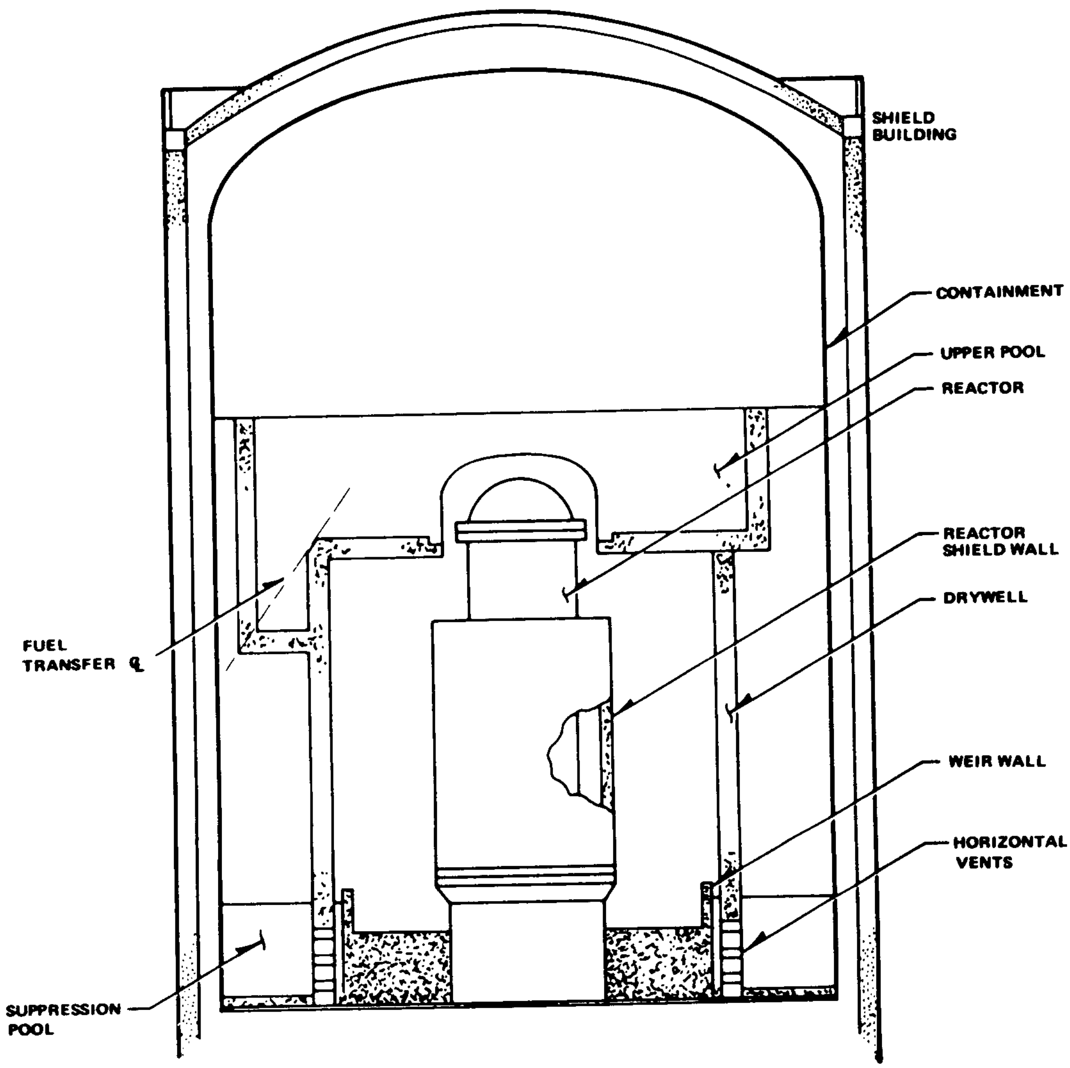
SCHEMATIC ARRANGEMENT OF BWR PRIMARY CONTAINMENT SYSTEM

Figure 6A.1-16



BWR SECONDARY CONTAINMENT BUILDING
SHOWING PRIMARY CONTAINMENT SYSTEM ENCLOSED

Figure 6A.1-17



MULTIPLE CONTAINMENT SYSTEM
FOR RECENT LARGE BWR PLANTS

Figure 6A.1-18

barrier to the escape of gaseous effluents, as well as a shielding to further reduce the escape of radiation emanating from the reactor proper.

PWR Description

Unlike the direct in-vessel boiling of BWRs, all PWRs[1] employ dual coolant systems for transferring energy from the reactor fuel to the turbine and are called "indirect cycle" systems. The high-pressure circuit comprising the reactor vessel, piping, the necessary pumps, and the inner tube-side of the steam generators is termed the "primary system"; the lower pressure circuit is called the "secondary system." (A schematic arrangement of a 1000-MWe PWR system, with four steam generators and one or two pumps for each steam generator, is shown in Figure 6A.1-19.)

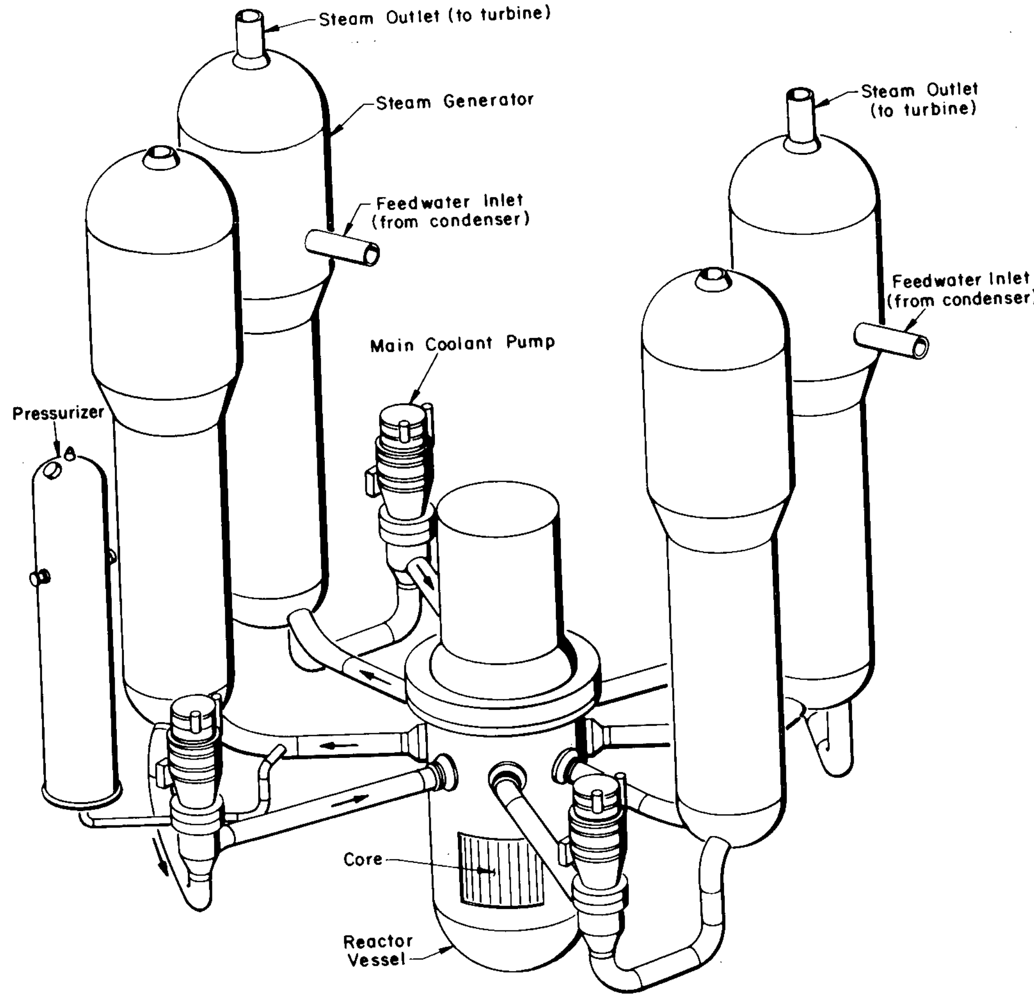
The pressure maintained in a typical large PWR system, about 2250 psi, permits water to be heated to about 650°F without boiling. The high-pressure water, heated to an average temperature of around 600°F, is piped out of the reactor vessel into two or more steam generators. Heat from the high-pressure reactor coolant water is transferred through heat exchanger tubes into a secondary stream of water at considerably lower pressure and temperature than the former and causes the water of the secondary stream to boil and produce steam for the turbine.

A cutaway view of a typical PWR reactor vessel and its internals is shown in Figure 6A.1-20. The vessels have removable top heads (for refueling) provided with fittings to accommodate the mechanisms for driving neutron-absorbing rods into and out of the core to control the nuclear chain reaction. Additional control of the chain reaction is provided through the use of variable-concentration neutron-absorbing chemicals, such as boric acid, dissolved in the primary system coolant.

The core of a large PWR contains nearly 40,000 fuel rods, totaling about 100 tons of slightly enriched uranium dioxide. For current PWRs, 176 to 264 fuel rods are assembled into a bundle of square cross section which normally is about 8-1/2 in. on a side. PWR fuel assemblies are not surrounded by a channel, but are relatively open arrays which permit some radial mixing of coolant (see Figure 6A.1-21).

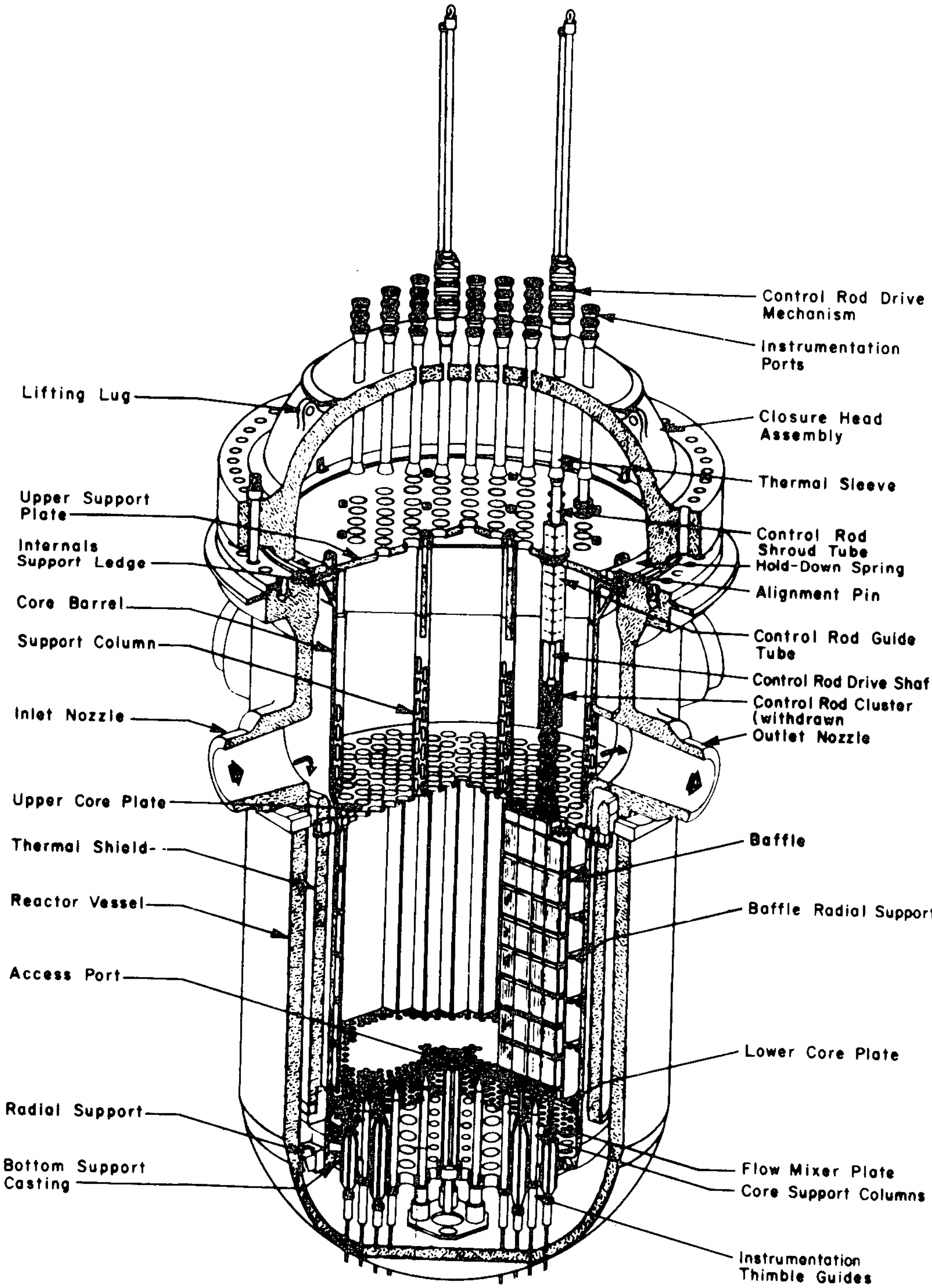
The PWR plant circulates the primary coolant through large conventional heat exchangers. The high-performance primary-coolant pumps are designed to operate at 650°F at pressures up to 2500 psi and are manufactured to stringent specifications.

PWR steam supply systems are equipped with pressurizers[1] (Figure 6A.1-19) to maintain required primary coolant pressure during steady-state operation, to limit



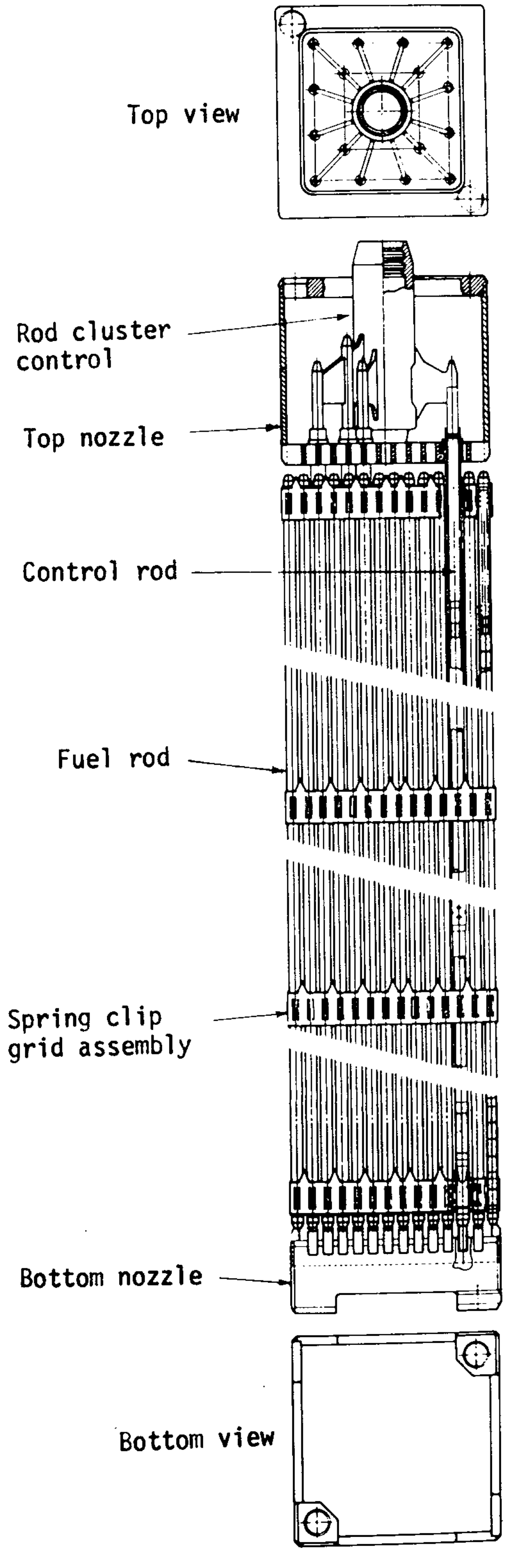
SCHEMATIC ARRANGEMENT OF PWR NSSS

Figure 6A.1-19



CUTAWAY VIEW OF INTERNALS OF TYPICAL PWR VESSEL

Figure 6A.1-20



PWR FUEL SUBASSEMBLY
Figure 6A.1-21

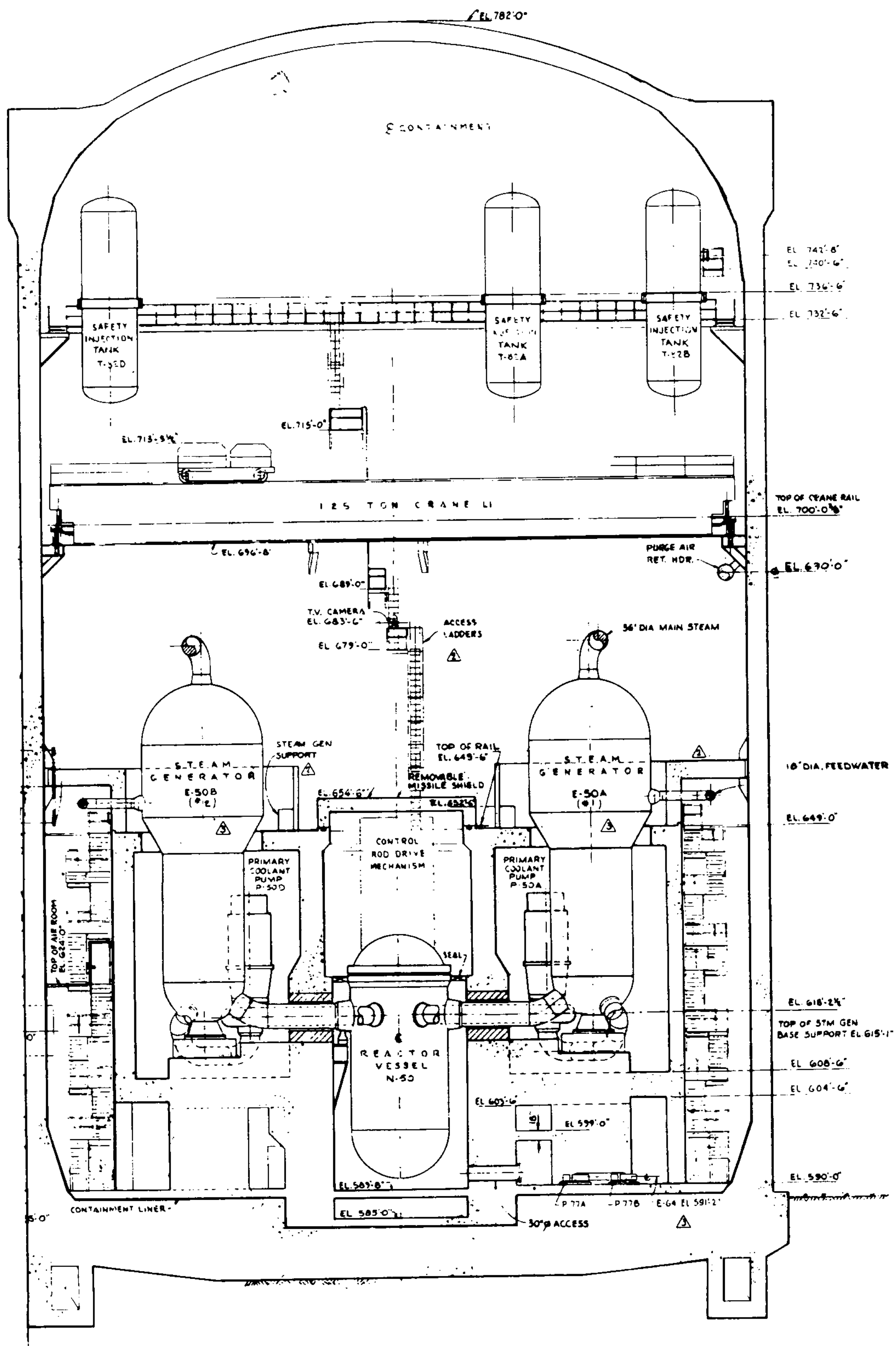
pressure changes caused by coolant thermal expansion and contraction as plant loads change, and to prevent coolant pressure from exceeding the design pressure of the entire primary system. Like the reactor vessel, the steam generators, the pumps, and all other parts of the primary system, the pressurizer is also located in the containment.

The major function of the emergency core cooling system of a PWR is to supply sufficient water to cool the core in the event of a break that permits water to leak from the primary system. The break most probably would be very small but accommodation of the effects of rupture of the largest coolant pipe in the system is a design requirement. PWR emergency core cooling systems[14] consist of several independent subsystems, each characterized by redundancy of equipment and flow path. This redundancy assures reliability of operation and continued core cooling even in the event of failure of any single component to carry out its design functions. Although the arrangements and designs of PWR emergency core cooling systems vary from plant to plant, depending on the vendor of the steam supply system, all modern PWR plants employ both accumulator injection systems and pump injection systems, with redundancy of equipment to assure desired operation.

More detailed discussions of design considerations for specific safety systems, practices for assuring safety and analyses of hypothetical accident sequences are presented in refs. 1 and 12.

Most present-day PWR containments are constructed of reinforced concrete with a steel liner (Figure 6A.1-22). All are sized and designed to withstand the maximum temperature and pressure that would be expected from the steam produced if all the water in the primary system were expelled into the containment. Refinements in containment technology are still being made, and containment systems vary widely from plant to plant. For example, in some PWR plants, the containment space is kept at slightly below atmospheric pressure so that leakage through the containment walls would, at most times, be inward from the surroundings. Other systems have double barriers against escape of material from the containment space.

Two kinds of additional measures are taken in PWR plants to minimize the potential for escape to the environment of any accidental release of radioactive materials. In some plants, cold-water sprays are provided to condense the steam resulting from a major escape of primary system coolant into the containment; in other plants, stored ice is used for this purpose. By condensing the steam, and thus lowering the containment pressure, the driving force for outward leakage is reduced. Another



PWR CONTAINMENT

Figure 6A.1-22

safety measure provides blowers to recirculate containment atmosphere through filters and absorption beds to remove airborne radioactive materials. When sprays are used in the containment, chemicals are usually added to the spray solution to increase the retention of airborne radioactive materials that dissolve in and become entrained by the spray. Systems for the control of hydrogen from both metal-water reactions and radiolytic decomposition of the water are also provided to assure that flammable concentrations are not reached in the containment.[1]

Effluent Treatment Systems

Nuclear power plants require equipment for the control of radioactive material,[13] wherever it may be encountered in the plant (outside of the fuel rods). Small quantities of radioactive and nonradioactive gases as well as soluble and insoluble solids are formed in the primary coolant system by neutron activation and corrosion; additional quantities may enter the primary system from leaks in the fuel cladding. Some of these radioactive materials may enter the liquid wastes from the primary coolant system through small leaks that may develop in the equipment used to purify the coolant. Gases that must be withdrawn from the coolant loop are diverted to off-gas systems. Additional leakage from fuels with failed cladding can occur during refueling operations or during storage of the spent fuel under water in canals.

The atmospheres in the reactor containment and fuel storage areas, and in other areas where the leakage of radioactive gases may be expected, are monitored continuously and the gases are generally passed through charcoal adsorbers and filters to remove particulate radioactive materials prior to release of the gases. Other gaseous effluents, such as the small amounts that may leak through turbine seals into large volumes of turbine building air, are discharged directly to the atmosphere. All plant liquid wastes, including that from laundry and showers, are monitored and treated as necessary, before release to the environment.

Conventional waste treatment systems at recently built BWR and PWR[15] plants are designed to concentrate and contain radioactive materials by means of filtration and holdup for gases and by demineralization, filtration, and evaporation for liquids.

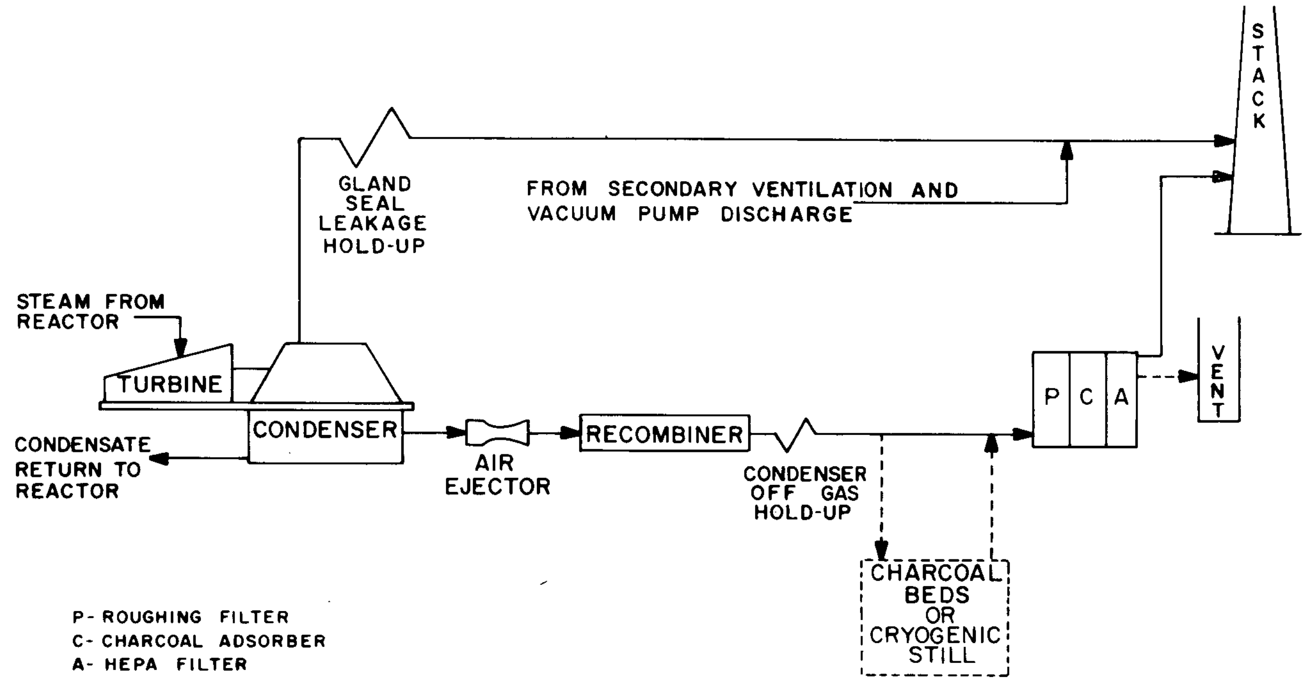
The amount of radioactive gaseous materials released to the environment can be significantly reduced by storing the gases for a sufficiently long period of time to allow the short-lived radionuclides to decay to very low levels. This is accomplished at BWR plants (see Figure 6A.1-23) by retaining the gases for a minimum of 30 min in large holdup pipes or by adsorbing the radioactive gases on large charcoal beds for periods of approximately 16 hr for radioactive krypton and 9 days for radioactive xenon. At PWR plants (see Figure 6A.1-24), the gases from the primary coolant are retained in tanks for 30 to 60 days before release. Systems for the bottling and long-term storage of radioactive noble gases from LWR primary systems are now offered commercially (see Section 4.6.3.2.2 for discussion of a noble gas storage facility concept).

The waste treatment methods described above do not remove tritium from water; in fact, there is no economical method for separating waste tritium from water, today. In both PWRs and BWRs, any of the primary coolant water which leaves the primary system is collected, purified by demineralization or evaporation. Since tritium is not separated from the water by such treatment, it remains in the primary coolant inventory if recycled to the primary system or enters the hydrosphere if discharged with the condenser cooling water. Tritium release experience from PWRs and BWRs in 1971 is shown in Table 6A.1-5. The larger quantities of tritium released from PWRs as compared with BWRs is primarily due to the use of soluble boron compounds in the primary coolant of PWRs for control purposes. Tritium forms from neutron interactions with the boron, which is not used in BWRs. Some recent reactor system (plant design and operating procedures) concepts have proposed to recycle all liquids and provide for containment of all primary-system gases (with selective retention of radioactive gases until the isotope of radiological health hazard has decayed to acceptable levels).

6A.1.1.3.3 <u>"Out-of-Reactor" Fuel Cycle Operations</u>

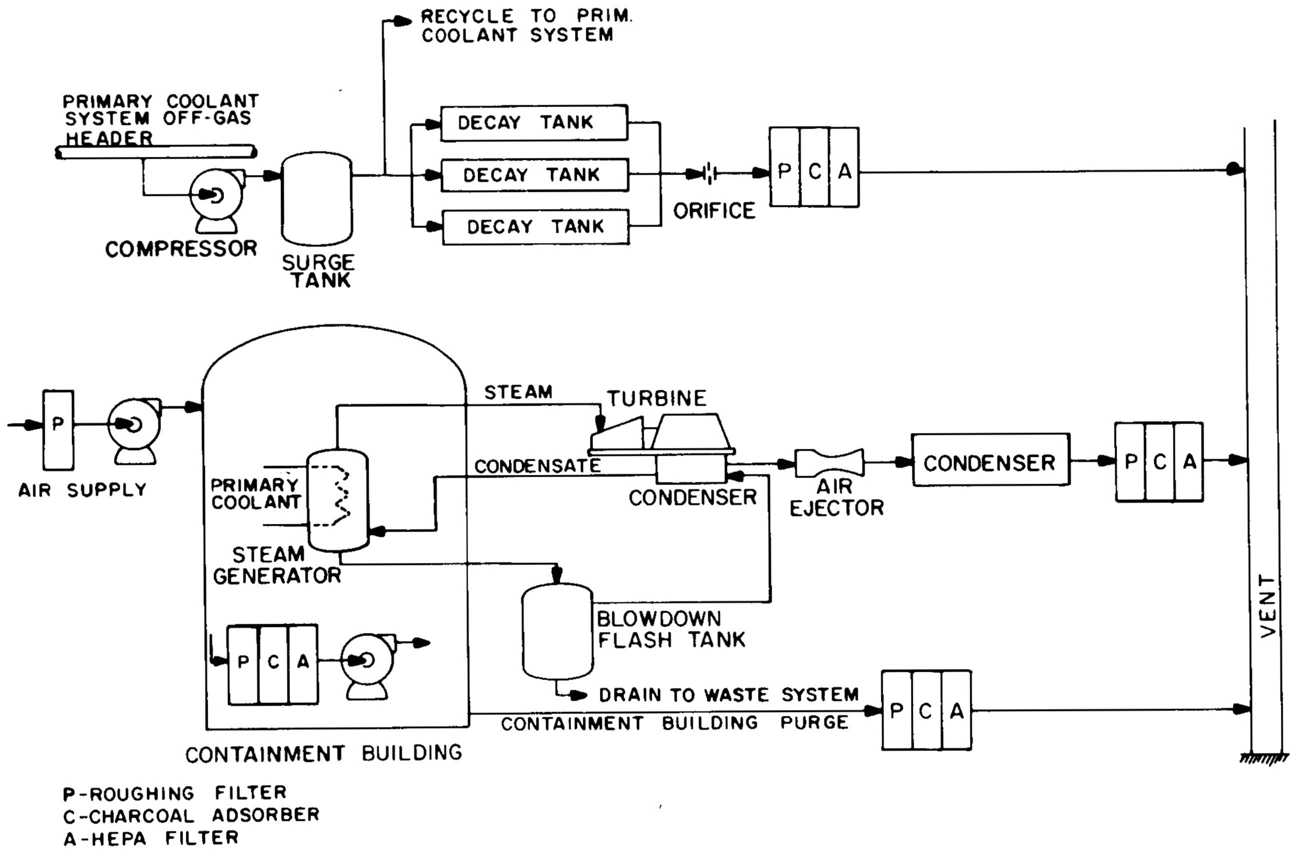
The "out-of-reactor" fuel cycle operations[12] include: both underground- and pit-mining of uranium ores; uranium milling to concentrate uranium values from the ores and to produce a semi-refined uranium oxide product called "yellowcake" (assayed as equivalent U_3O_8); conversion of yellowcake to a pure volatile compound (UF_6) which is amenable to isotopic enrichment via gaseous diffusion techniques; the enrichment of uranium hexafluoride in the fissile isotope, U-235, to produce an enriched product and a depleted stream known as diffusion plant "tails"; conversion to oxide; fabrication of fuel shapes, encapsulation, and assembly into fuel elements; and ultimately the reprocessing of irradiated fuel for recovery and decontamination of uranium and plutonium values; and radioactive waste management.

Brief descriptions of the uranium-mining, milling, and enrichment operations follow, because they are unique to the enriched-uranium fuel cycle of LWRs. For descriptions



BWR GASEOUS WASTE SYSTEM

Figure 6A.1-23



PWR GASEOUS WASTE SYSTEM

Figure 6A.1-24

Table 6A.1-5

RELEASES IN LIQUID EFFLUENTS DURING 1971 COMPARED WITH PROPOSED DESIGN OBJECTIVES[a]

Facility	Mixed Fission and Corrosion Products		Tritium	
	Curies Released	Concentration (Ci/liter)	Curies Released	Concentration (Ci/liter)
PWRs				
Indian Point	81	220	725	1890
Yankee Rowe	0.0115	0.041	1685	5940
San Onofre	1.54	2.4	4570	7200
Conn. Yankee	5.88	1.3	5830	7800
Ginna	0.96	1.38	154	210
H. B. Robinson	0.736	11.5	118.3	1860
Point Beach	0.15	0.27	266	450
BWRs				
Oyster Creek	12.1	11.3	21.5	78
Nine Mile Point	32.2	69	12.4	27
Dresden 1	6.15	21	8.7	30
Dresden 2 & 3	23.2	17	8.5	30
Humboldt Bay	1.84	11.4		
Big Rock Point	3.46	34	10.3	60
Millstone	19.65	26	12.7	18
Monticello	0.014	0.054	0.59	24

[a]Numerical guides for liquid effluent design objectives in proposed Appendix I of 10 CFR Part 50 are: for radioactive material except tritium, 5 curies annually and an average concentration of 20 picocuries/liter; and for tritium, an average concentration of 5000 picocuries/liter.

of the other fuel cycle operations, omitted here, the reader is referred to Section 4 of this report, where similar operations in the LMFBR fuel cycle are discussed.

Uranium Mining-Milling Operations

Uranium mines usually are located in remote areas where average population densities are 5 to 10 people per square mile[12]. The high plateau regions of the Rocky Mountain States contain most of the uranium mines and about 90% of the known conventional ore reserves.

Two methods--open-pit and underground mining--produce the bulk of the uranium in the U.S.A. Open-pit mining usually has a cost advantage over underground methods for deposits occurring less than about 400 ft below the surface.

Underground operations are essential for deep deposits and are characterized in appearance by service buildings, a head-frame with ore handling facility, a mine waste pile, and, in some cases, a flow of water pumped to surface drainage from underground sumps in the mine complex. The ground area occupied by the surface facilities may be only a few acres, but the reach of the underground workings often range to a mile or more. The volume of the mine waste pile is related to the gross volume of ore processed. The volume of ventilating air, usually downcast through the production shafts and distributed through ore-haulage ways for discharge through vent holes/shafts at the extremities of the workings, is large enough to dilute the radon gas (emanating from uranium ore) to safe levels.

Open-pit mining has a highly visible effect on the local environment. A model mine, equivalent to about 5.3 annual requirements for a 1000-MWe LWR operating on enriched uranium fuel, would produce about 1600 metric tons of ore per day for 300 days per year for ten years. At an average U_3O_8 content of 0.2%, this output is equivalent to about 960 metric tons of U_3O_8 per year. The ratio of overburden volume to ore volume is estimated to be about 30 to 1 (although ratios of 50 to 1 may occur at times). This overburden, stored for later reclamation of the mined area, averages about 9.5 million yd^3/year. An open-pit mine is characterized by a large open excavation, large piles of earth and rock overburden placed nearby, a network of operating roads and yards, possibly a flow of mine water pumped to surface drainage, a number of service buildings, and an assortment of heavy earth-moving equipment. Surface heap leaching facilities also are often present.

The uranium milling operation usually is located adjacent to an operating mine. The mill employs a mechanical crushing/screening technique to control reaction rate in the uranium leach step, uses either an acid leach or a sodium carbonate leach to extract the uranium values from the pulverized ore, concentrates the uranium by ion exchange or solvent extraction processing, recovers the uranium by chemical precipitation, and dries and packages the product for shipment as "yellowcake" (sodium or ammonium diuranate). Although the acid leach process involves greater water consumption and aqueous waste discharge, it is amenable to more ores than the sodium carbonate leach process.

A model uranium milling operation[12] is assumed to be adjacent to a mine of equivalent capacity and to use the acid-leach process. The model mill temporarily occupies about 300 acres of land, of which about 250 acres are devoted to a tailings retention system. This latter includes a pond, about 2.5 acres attributable to each 1000-MWe LWR served, for the permanent disposal of mill tailings and process waste solutions. The mill will be comprised of an ore storage/blending area, a crushing and sampling building, an ore grinding building, a solvent extraction building, a product concentrating/drying/packaging building, an off-gas scrubber system and stack, the tailings pond treatment system, and service buildings.

Uranium Hexafluoride Production

The "yellowcake" concentrate of uranium must be converted to pure volatile uranium hexafluoride for isotopic enrichment by the gaseous diffusion process. Either the hydrofluor process (continuous successive reduction, hydrofluorination, and fluorination followed by fractional distillation to produce a pure product) or wet chemical purification followed by reduction/hydrofluorination/fluorination is used in current plants. Although both processes produce the same product, their waste effluents are quite different (i.e., hydrofluor process generates gaseous and solid effluents, and the wet process produces mostly liquid effluents). Since both processes are in current use, the model conversion plant is assumed to share equally the 5000 metric tons of uranium throughput (annual fuel requirements for about 27.5 of the 1000-MWe LWRs) by both flowsheets. The plant site occupies about 70 acres and is comprised of a wet process building, a gas reactions building, an off-gas treatment system and stack, a product packaging and storage facility, a liquid effluent treatment system and holding pond, and service buildings. Toxic chemical wastes ultimately are recovered from the liquid effluent treatment complex and the off-gas treatment system and are currently disposed of by burial.

Isotopic Enrichment of Uranium

The present facilities for isotopic enrichment of uranium are government-owned and use the gaseous diffusion process for raising the U-235 content (from 0.71 wt.% for natural uranium to about 2 to 4 wt.%, the initial enrichment for LWR fuel) of a pure uranium hexafluoride product stream, while depleting the bulk of the natural uranium to a "tails" enrichment of 0.3 wt.%, at present. These plants are very large in size, investment, and electrical power consumption. The AEC plants are characterized by very large continuous-floor-area buildings on reasonably flat land and require access to abundant and inexpensive electric power and process cooling water. The total AEC complex presently has an estimated capacity of 10.5 x 10^6 kg of separative work units per year while requiring the output from about 3250 MWe of electrical power; the annual requirements of the model 1000-MWe-LWR fuel cycle are about 116,000 kg of separative work units. It is anticipated that an extensive program[12] of process improvement and up-rating of the AEC plants will raise the total capacity by 1980 to 27.7 x 10^6 kg of separative work units per year and the required electric power consumption to 7380 MWe/year.

6A.1.1.3.4 Energy Transmission

All nuclear, fossil-fueled, and hydroelectric power stations will require transmission lines for the distribution of the electrical energy they produce.[16,17] Transmission line locations and designs are major aesthetic concerns. Fortunately, the design[17] of transmission lines has improved considerably in recent years so that it is now possible to deal effectively with most objections of an aesthetic nature. The environmental impact of transmission lines will be minimized through advanced planning and careful design and through review and approval of proposed transmission facilities by appropriate Federal, state, regional, and local authorities.

6A.1.1.4 Research and Development Program

Components and systems technology for producing nuclear power in LWRs has advanced to the status of commercial applicability, and any further research deemed necessary to optimize systems and economics lies within the purview of those industries which will benefit therefrom. While the accumulated information in nuclear technology, as in any other body of knowledge, is not without gaps and uncertainties in the accuracy of data, there are many options available in design, engineering, and operation of nuclear plants to compensate for uncertainties and to reduce associated risks to acceptable, low values. Redundancy in components and instruments, conservative engineering practices to provide substantial margins, redundant safety devices and systems, fission product barriers, and a wide range of choices in operating parameters are being used to produce safe and reliable plant designs. Similar flexibility in engineering and operational practices is available to resolve additional questions that may arise during design, construction, testing, and operation of a nuclear facility.

Although further optimization of LWR systems has been left to the responsible industries, the AEC continues to undertake and support research[18,19] on safety issues relevant to implementing the agency's licensing responsibilities. The safety research and development programs are conducted at National Laboratories, contractors' sites, and university laboratories.[13,18] These programs involve:

(1) probabilistic studies of reactor accidents to develop methodology and collect basic data for evaluating the probabilities of different accidents;
(2) a program on primary systems integrity to obtain data on materials and components which can be used to assess margins of safety between operating conditions and predictions of fracture or failure which may lead to an accident;
(3) development of non-destructive inspection techniques for detecting material flaws during fabrication and reactor operation as a means of precluding piping or vessel failure during the lifetime of the plant;
(4) research and development work in the area of emergency coolant and core behavior following a loss-of-coolant accident which includes large scale engineering tests as well as tests to be conducted in the 55-MW LOFT facility;
(5) fuel behavior experiments to obtain data on fuel rods and clusters under a wide range of accident conditions, including flow blockage, reactivity accidents, and fuel meltdown phenomena; and
(6) assessment, development, and verification of analytical methods and computer codes that are used to describe accident behavior and consequences and ensure the applicability of experimental results to the analyses of full-size reactor plants.

Other AEC-sponsored safety-related tasks include: the study of synergistic effects of steam pressurization on containment leakage to better predict the performance of containment systems during a postulated loss-of-coolant accident (LOCA); seismic studies to improve the model for calculating transmission of seismic motions through soils and into reactor structures and systems; thermal effects studies to evaluate the environmental impacts of power plant waste-heat discharges at selected sites; and the development of both near-term and long-term solutions to the problem of perpetual isolation of toxic radioactive wastes from man's biosphere. These studies are described in Section 4 of this report in the context of support for the LMFBR Program, but their results are equally applicable to the design and understanding of future LWR systems.

The recent report on "The Nation's Energy Future"[20] recommends a five-year program of research and development on nuclear safety, waste storage management, and the technology to reduce the environmental impacts of nuclear converter reactors. This program is expected to cost $719,200,000 over the FY 1975-79 time period. Additional funding of $294,200,000 over the same time period is recommended to develop improved uranium enrichment processes including gaseous diffusion, gas centrifuge, and isotope separation using lasers.

6A.1.1.5 Present and Projected Application

6A.1.1.5.1 Current Use

As discussed in Section 6A.1.1.3, 209 LWRs having an aggregate capacity of about 200,000 MWe have been built, ordered, or announced as of the end of 1973.[2] LWR generating capacity in service at that time was about 24,000 MWe, or slightly more than 5% of the country's on-line generation potential. The total power generated by LWRs in 1973 was approximately 83 x 10^9 kWhr, or 4.4% of the total electric energy produced.

6A.1.1.5.2 Projected Use

The probable role of the LWR in the electrical energy supply picture up to the year 2000 and beyond is discussed in some detail in Section 6A.1.1.8.

The application of LWRs would appear to be confined to central station electric power generation. During the remainder of this century the LWR, along with the HTGR, most probably will be the major source of nuclear energy power production, while the LMFBR and other alternative energy systems are being developed and brought into significant commercial utilization. It is anticipated that during this period and for a considerable time thereafter LWRs would provide a major portion of the Nation's electrical energy while consuming uranium and producing plutonium. In addition, the enrichment process required for LWR fuel would produce large stores of depleted natural uranium.

In the interim period while the LMFBR is undergoing development and initial introduction into the electric utility economy, substantial portions of the plutonium produced in LWRs will be recycled in the LWRs to provide additional energy. Thereafter the LWR plutonium production will be used to fuel new LMFBRs (and/or GCFRs) as they come on-line, and the depleted uranium "tails" will be used to provide core and blanket material for these breeders. Thus, LWR operation will provide fuel material for breeder reactors sufficient to last many decades into the next century thereby reducing drastically the requirements for uranium mining in that time period.

6A.1.1.6 Environmental Impacts

6A.1.1.6.1 Environmental Impacts of LWR Power Plants

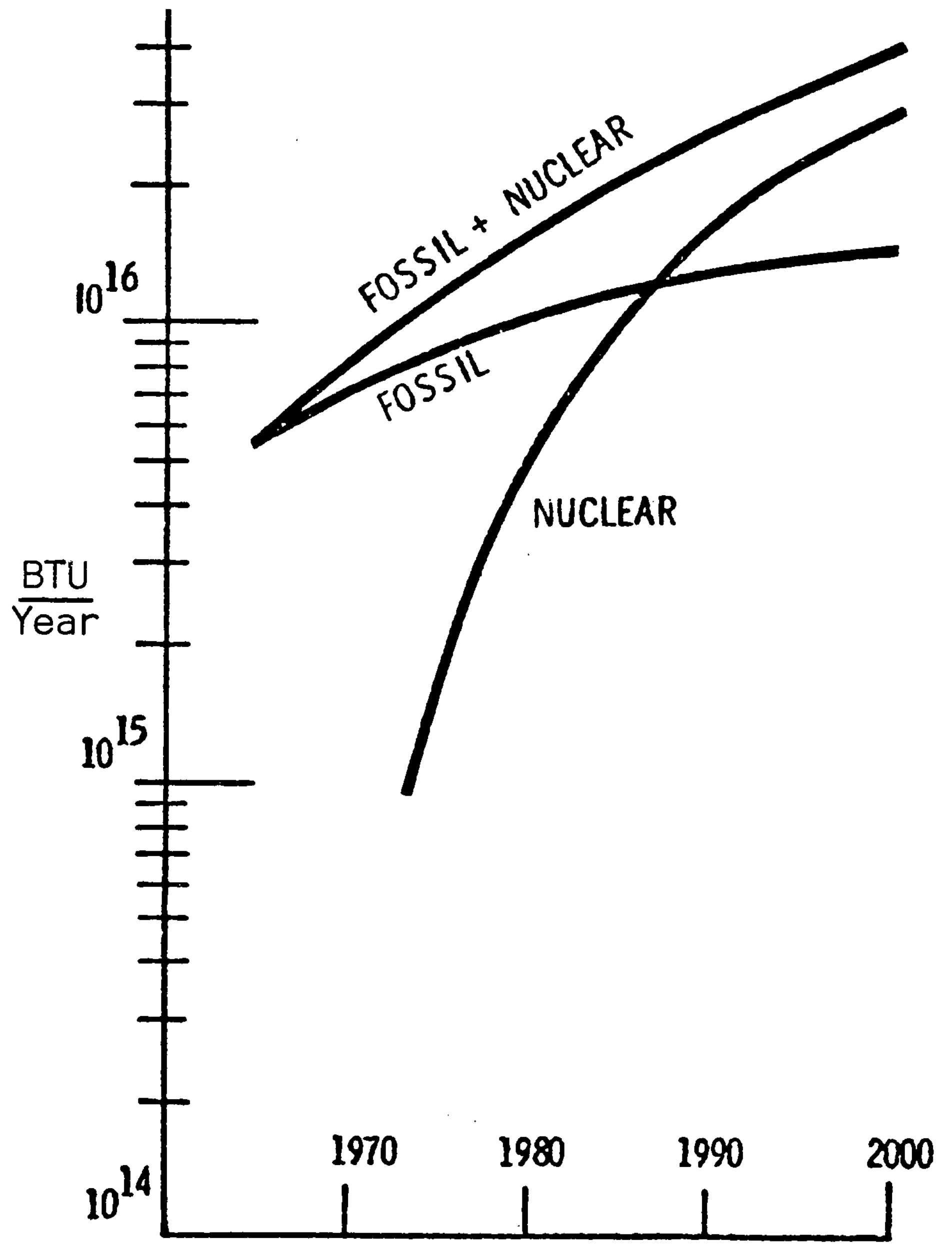
Impacts on Land, Water, and Air

Multi-reactor sites involve controlled land areas of roughly 1000 acres; however, a typical 1000-MWe LWR will require the commitment of less than 200 acres of this site to industrial-type use and the remainder of the site provides a controlled buffer zone. This buffer zone can be dedicated to recreational or other uses, consistent with applicable controls, during the normal operating lifetime of the power plant.

Thermal. Because a current LWR will reject one-fourth to one-third more waste heat into its condenser coolant than does a current fossil-fueled plant (or a future LMFBR plant) of comparable capacity, the required heat-sink capacity of the site must be proportionately larger for an LWR facility than for fossil-fueled or LMFBR applications.[21] About 50% of the estimated waste-heat to be rejected by all electric power plants in 1985 (Figure 6A.1-25)[17] is expected to be from LWR plants. Pre-operational ecological studies are made of each site and its biota to serve as a basis for defining design-life thermal effects on the site biota and hydrology and to ensure that no significantly adverse effects result.

Increasingly restrictive water temperature standards will increase tthe use of methods of heat dissipation other than direct discharge. The alternative methods now being used offer relief from thermal effects in the receiving water body, but involve other environmental effects and economic penalties; these alternative methods include applications of man-made bodies of cooling water and cooling towers.* While artificial lakes or cooling ponds can have very decided advantages, such as for recreation, they can only be used where the needed land is available.

*Recently proposed rulemaking by EPA would, if adopted, require virtually all steam electric generating plants to use closed cycle cooling. See Federal Register, Volume 39, Number 43, Part III, dated March 4, 1974.



HEAT REJECTION FROM POWER PLANTS
Figure 6A.1-25

On the other hand, cooling towers may pose aesthetic problems. In certain portions of the United States, only dry cooling towers can be used because there is no suitable supply of make-up water for a wet cooling tower system. Coupling of a proposed power plant with dry cooling towers would effectively eliminate the "availability of natural waters" as a major constraint in siting the plant. A wet cooling tower requires the availability of adequate make-up water and adds large amounts of water to the atmosphere in the immediate vicinity of a power plant; under certain atmospheric conditions this addition could result in fog, ice formation on roads and power lines, reduction in visibility, and even the formation of snow. Heat rejection systems using a combination of wet and dry cooling towers may be used to minimize costs under some circumstances.

For more detailed treatment of the thermal impact of waste heat rejection, see Section 4 of this Statement, where the topic is discussed in the context of heat rejection by LMFBR facilities.

Chemical. Chemical releases by LWR facilities, or any nuclear power plants, are negligible and generally enter the environment via a blowdown stream from a closed-cycle cooling system. Further discussion of this potential for environmental pollution is presented in Section 4 of this Statement, in the context of LMFBR operations.

Radiological. See pertinent discussion in Section 4.

Impacts on Flora and Fauna

Shelter/Food. Necessary clearing of wooded areas for plant sites and access roads will result in the relocation of some bird and animal life; however, the fields and trees of the controlled buffer zone may be able to accommodate most of these displacements.

Dredging activities required during establishment of water intake and outfall channels will temporarily interrupt marine feed supplies and may destroy some established beds of mollusks. If pre-operational studies indicate that such incursions would cause excessive destruction of native marine life, some of it may be relocated.[22] Biological and botanical samples of the biota will be examined throughout the construction and operation phases of each power plant's life to ensure that any inadvertent damage to the biota is detected and remedied.

Thermal. See pertinent discussion in Section 4.

Chemical. See pertinent discussion in Section 4.

Radiological. Nuclear power plant effluents have not added significantly to the natural radioactivity inventory. Table 6A.1-6 indicates[23,24] that LWR power facilities thus far have contributed a dose of very much less than 1 millirem/year per person in this country, on the average. The AEC has estimated that future individual-dose exposures will continue to be less than 1 millirem/year.[16] probably less than 0.2 millirem/year,[25] on the average, by the year 2000 when there may be about 1000 nuclear power plants in operation.

6A.1.1.6.2 Environmental Impacts of Other Fuel Cycle Operations

Environmental considerations influence the design, licensing, and operation of LWR-supported industries which provide the out-of-reactor fuel cycle operations depicted in Figure 6A.1-26. These operations,[12,13] outlined in Section 6A.1.1.3.3, include: (1) both underground- and pit-mining of uranium ores; (2) milling and refining ores to produce uranium concentrates called "yellowcake"; (3) conversion and refining of the "yellowcake" concentrates into high-purity uranium hexafluoride; (4) isotopic enrichment in fissile content of the uranium hexafluoride, via gaseous diffusion processing, to produce feed material for LWR fuels; (5) conversion of the enriched hexafluoride to oxide, fabrication of the oxide into fuel shapes, encapsulation of these fuel shapes, and assembly of the fuel capsules (rods) into fuel elements; (6) reprocessing of irradiated fuel materials to recover and decontaminate uranium (and other fissile values) from the associated radioactive fission products (previously discussed in Section 6A.1.1.3.3); (7) storage and management of high-level and low-level radioactive wastes at Federal and commercial waste repositories; and (8) the various inter-site transportation needs associated with these operations. General characteristics of the associated nuclear materials industries, for the LWR fuels market in 1972, are presented in Table 6A.1-7. Typical materials requirements for a 1000-MWe-LWR fuel cycle are listed in Table 6A.1-8.

Impacts on Land, Water, and Air

Typical industrial plants to provide these LWR fuels cycle services, the operations thereof, and the environmental considerations resulting from such operations are described in ref. 12. Summaries of these environmental considerations on a "per 1000-MWe LWR-year" basis, assuming an 80% plant factor, are presented in Table

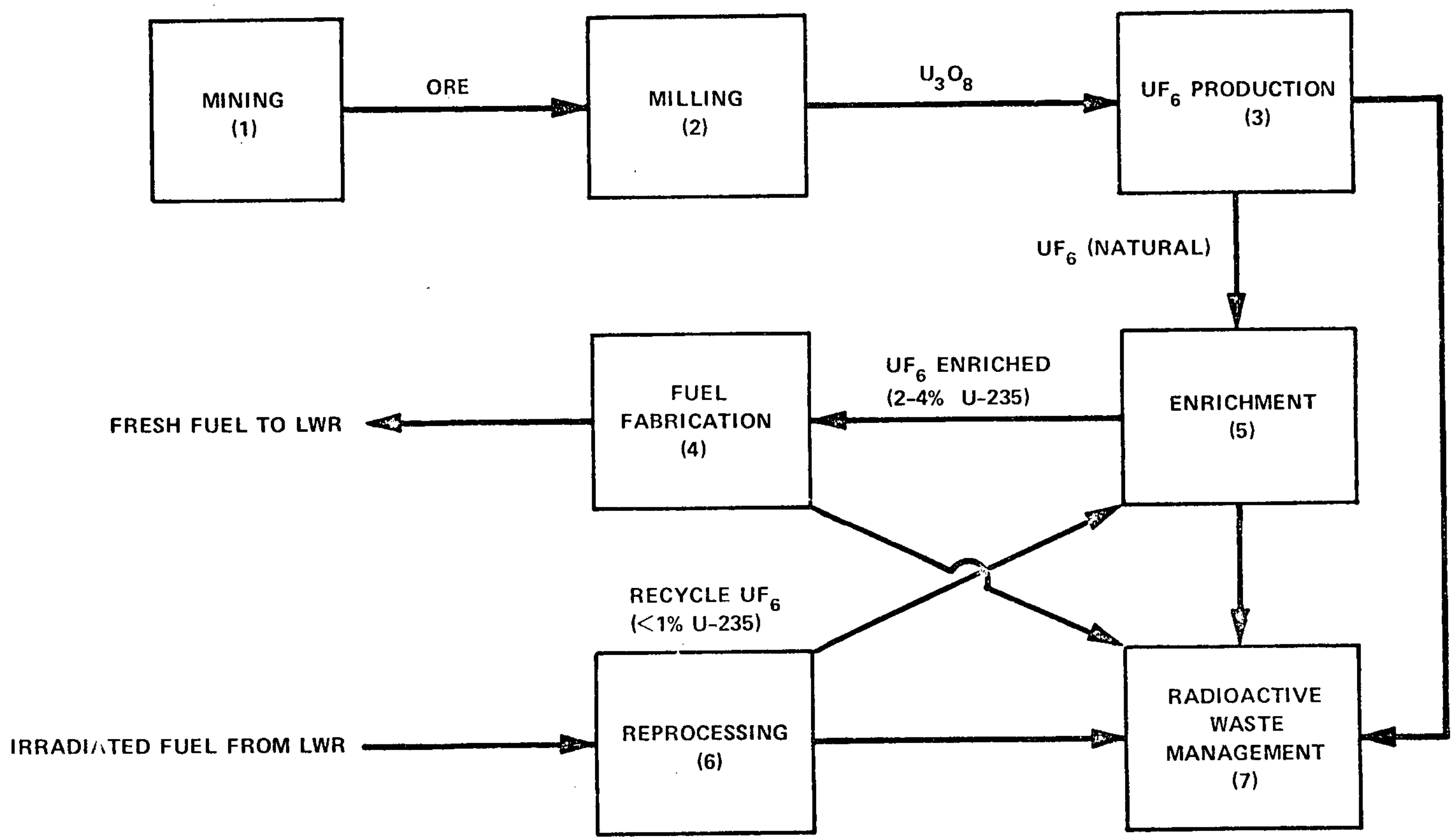
Table 6A.1-6

CURIES OF NOBLE GASES RELEASED AND ASSOCIATED DOSES FOR 1971

				Within 50 Miles	
Type	Facility	Curies Released	Boundary Dose (millirems)	Average Individual Dose (millirem)	Population Dose (man-rem)[a]
PWR	Indian Point	360	0.035	0.00005	0.77
PWR	Yankee Rowe	13	0.3	0.0003	0.41
PWR	San Onofre	7,670	2.2	0.002	6.3
PWR	Conn Yankee	3,250	5.6	0.003	11
PWR	Ginna	31,800	5.0	0.004	4.5
PWR	H. B. Robinson	18	0.05	0.00002	0.015
PWR	Point Beach	838	0.2	0.0008	0.15[b]
BWR	Oyster Creek	516,000	31	0.013	46
BWR	Nine Mile Point	253,000	4.8	0.009	8.2
BWR	Dresden (1,2,3)	1,330,000	32	0.057	420
BWR	Humboldt Bay	514,000	160	0.54	61
BWR	Big Rock Point	284,000	4.6	0.026	3.1
BWR	Millstone	276,000	5.5	0.0056	15
BWR	Monticello	76,000	4.4	0.0036	4.4

[a]The man-rem dose for a group of people is the product of the average dose to those people and the number of people.

[b]Man-rem dose is for the population within 40 miles for this facility.



NUCLEAR FUEL CYCLE--LIGHT WATER REACTORS
URANIUM DIOXIDE FUELED--NO PLUTONIUM RECYCLE
Figure 6A.1-26

Table 6A.1-7

NUCLEAR FUEL CYCLE INDUSTRY

1972

Type of Plant	Plant Average Annual Capacity (thousands of metric tons)	Total Industry Annual Capacity (thousands of metric tons)	∿ Annual Demand from Nuclear Power Generation (thousands of metric tons)	Number of Plants Available	Approximate Number of Plants Required to Meet Power Needs
Uranium Mines--Ore	250 to 750	8200	4500	220	10
Uranium Mills--U_3O_8	0.5 to 1.1	19	9	20	12
UF_6 Production--U	5 to 15	19	8	2	1+
Isotopic Enrichment--SWU	6	10	5	3	1
Fuel Fabrication--U	0.3 to 0.5	3	1.2	10	3+
Fuel Reprocessing--U	0.3	0.15[a]	0.2	2	1

[a]One plant in operation for about 6 months.

Table 6A.1-8

CHARACTERISTICS OF 1000-MWe LWR
MAXIMUM FUEL CYCLE REQUIREMENTS

	Initial Core	Annual Reload	Lifetime Average Annual Fuel Requirement
Irradiation Level (MWt-day/MTU)[a] x 10^{-3}	24	33	33
Fresh Fuel Assay (wt% U-235)	2.26	3.21	3.21
Spent Fuel Assay (wt% U-235)	0.74	0.90	0.90
Ore Supply (ST) x 10^{-3}	237	91	96
Yellowcake U_3O_8 Supply (ST)[a]	498	191	201
Natural UF_6 (ST)[a]	624	239	252
Separative Work (MT SWU)[a]	174	94	99
Enriched UF_6 (ST)[a]	196	53	56
Enriched UO_2 (ST)[a]	150	41	43
Fuel Loading (STU)[a]	132	36	38

[a] Bases
- Reactor plant load factor--75%
- Enrichment tails assay--0.3%
- No plutonium recycle
- Reloads include recovered uranium
- Losses of 1% each in fuel fabrication and reprocessing

ST = short ton = 2000 lb
STU = short ton uranium
MTU = metric ton uranium
MT SWU = separative work units in metric tons

6A.1-9, for each fuel cycle operation, and in Table 6A.1-10, for the collective fuel cycle.

Only the first four steps in the LWR fuel cycle are missing from the LMFBR fuel cycle; hence the environmental impacts of only these steps will be discussed here. General comments on subsequent steps of the fuel cycle are presented in Section 4 of this report, and summaries of detailed environmental considerations for the total out-of-reactor fuel cycle follow, as Tables 6A.1-9 and 6A.1-10.

Uranium Mining-Milling. Recent information from the U.S. Bureau of Mines indicates that essentially equivalent tonnages of coal and crude uranium ore are produced per acre of material mined; however, the nominal specific energy content of the crude uranium ore is 35 to 40 times greater than that for coal. On an equivalent power generation basis,[12] it would appear that about 35 times more land is disturbed from mining coal. The land permanently committed (see Table 6A.1-9) by uranium ore mining amounts to about 2 acres for the annual fuel requirements of the model (1000-MWe) LWR.

> Of the approximately 2.9 acres of total land usage attributable to the model LWR annual fuel requirement, approximately 2.4 acres are devoted to a pond for the permanent disposal of mill tailings. In effect, nearly the entire mass of ore processed by the mill ends up in the tailings pond. Although the model plant tailings pond area will be restored to resemble the surrounding terrain after the 20 years of plant life, the land will most likely be removed from further unrestricted use, except possibly for grazing.[12]

Approximately 123 million gallons of water (see Table 6A.1-9) are pumped from the model uranium mine for the annual fuel requirements of the model LWR, but the bulk of this water recycles through natural seepage and evaporation and eventually returns to the groundwater from which it was pumped.

Approximately 65 million gallons of water, attributable to the annual fuel requirements of the model LWR, are discharged from the mill to the tailings pond from which they evaporate. Any mill waters that return to the environment by failure of a dike in the tailings pond or other misadventure are not expected to have an appreciable effect on the environment since any materials contained in these waters would be deposited through sedimentation[12] over a relatively short distance. Recovery would be straightforward, with either burial-in-place or return to the pond of all waste materials and contaminated soils.

Table 6A.1-9

SUMMARY OF ENVIRONMENTAL CONSIDERATIONS FOR NUCLEAR FUEL CYCLE - I
(Normalized to 1000-MWe LWR's Annual Fuel Requirement)

Natural Resource Use	A Mining	B Milling	C UF_6 Prod.	D Enrichment	E Fuel Fab.	F Reprocessing	G Waste Management	H Transportation	Total
Land (Acres)									
Temporarily Committed	55	0.5	2.5	0.8	0.2	3.9			63
Undisturbed Area	38	0.2	2.3	0.6	0.16	3.7			45
Disturbed Area	17	0.3	0.2	0.2	0.04	0.2			18
Permanently Committed	2	2.4	0.02	0	0	0.03	0.2		4.6
Overburden moved (MT x 10^{-6})	2.7								2.7
Water (gallons x 10^{-6})									
Discharged to air		65	3.7	90		4.0			163
Discharged to water bodies			41	11000	5.2	6.0			11052
Discharged to ground	123								123
Total Water	123	65	44.7	11090	5.2	10.0			11338
Fossil Fuel									
Electrical energy (MW-hr x 10^{-3})	0.25	2.7	2.1	310	1.7	0.45			317
Equivalent Coal (MT x 10^{3})	0.09	0.97	0.76	113	0.62	0.16			116
Natural Gas (scf x 10^{-6})		68.5	31		3.6				103

Table 6A.1-9 (cont'd)

SUMMARY OF ENVIRONMENTAL CONSIDERATIONS FOR NUCLEAR FUEL CYCLE
(Normalized to 1000-MWe LWR's Annual Fuel Requirement)

	A	B	C	D	E	F	G	H	
	Mining	Milling	UF_6 Prod.	Enrichment	Fuel Fab.	Reprocessing	Waste Management	Transportation	Total
Effluents									
Chemical (MT)									
Gases (1)									
SO_x	3.5	37	29	4300	23	6.2			4400
NO_x	0.9	15.9(2)	10(3)	1130	6	7.1(4)			1170
Hydrocarbons	0.009	1.3(2)	0.6(2)	11	0.06	0.02			13.0
CO	0.02	0.3	0.2	28	0.15	0.04			28.7
Particulates	0.9	9.7	7.6	1130	6	1.6			1156
Other Gases									
F^-			0.11	0.5	0.005	0.05			0.7
Liquids									
$SO_4^{=}$				5.4		0.4			5.8
NO_3^-				2.7	23	0.2			26
Fluoride					0.4				0.4
Ca^+				5.4					5.4
Cl^-				8.2		0.02			8.2
Na^+				8.2		5.3			13.5
NH_3					10				10
Tailings Solutions (x 10^{-3})		240							240
F				0.4					0.4
Solids		91,000	40	0.2	26				91,000

(1) Estimated Effluents Based Upon Combustion of Equivalent Coal for Power Generation
(2) Combined Effluent from Combustion of Coal and Natural Gas
(3) 25% from natural gas use
(4) 77% from process

Table 6A.1-9 (cont'd)

SUMMARY OF ENVIRONMENTAL CONSIDERATIONS FOR NUCLEAR FUEL CYCLE
(Normalized to 1000-MWe LWR's Annual Fuel Requirement)

	A	B	C	D	E	F	G	H	
	Mining	Milling	UF_6 Prod.	Enrichment	Fuel Fab.	Reprocessing	Waste Management	Transportation	Total
Effluents (cont'd)									
Radiological (Curies)									
Gases (including entrainment)									
Rn-222		74.5							83
Ra-226		0.02							0.02
Th-230		0.02							0.02
Uranium		0.03	0.014	0.002	0.0002				0.046
Tritium (x 10^3)						15.7			15.7
Kr-85 (x 10^3)						350			350
I-129						0.002			0.002
I-131						0.02			0.02
Fission Products						1.0			1.0
Transuranics						0.004			0.004
Liquids									
Uranium & Daughters		2	0.33	0.02	0.02				2.4
Ra-226			0.027						0.027
Th-230			0.27						0.27
Th-234					0.01				0.01
Tritium (x 10^{-3})						2.5			2.5
Other Uranium daughters					0.01				0.01
Ru-106						4			4
Solids (buried)									
Other than high level		1200	0.3		0.06				1200
Thermal (Btu x 10^{-9})		69	30	3200	9	61		0.03	3370

Table 6A.1-10

SUMMARY OF ENVIRONMENTAL CONSIDERATIONS FOR NUCLEAR FUEL CYCLE - II
(Normalized to 1000-MWe LWR's Annual Fuel Requirement)

	Total	Maximum Effect per Annual Fuel Requirement of Model 1000 MWe LWR
Natural Resource Use		
Land (acres)		
Temporarily committed	63	
Undisturbed area	45	
Disturbed area	18	Equivalent to 90 MWe coal-fired power plant
Permanently committed	4.6	
Overburden moved (MT x 10^{-6})	2.7	Equivalent to 90 MWe coal-fired power plant
Water (gallons x 10^{-6})		
Discharged to air	163	~ 2% of model 1000 MWe LWR with cooling tower
Discharged to water bodies	11,052	
Discharged to ground	123	
Total	11,338	<4% of model 1000 MWe LWR with once-through cooling
Fossil Fuel		
Electrical energy (MW-hr. x 10^{-3})	317	<5% of model 1000 MWe LWR output
Equivalent coal (MT x 10^{-3})	116	Equivalent to the consumption of a 45 MWe coal-fired power plant
Natural gas (scf x 10^{-6})	103	<0.2% of model 1000 MWe LWR energy output

Table 6A.1-10 (cont'd)

SUMMARY OF ENVIRONMENTAL CONSIDERATIONS FOR NUCLEAR FUEL CYCLE
(Normalized to 1000-MWe LWR's Annual Fuel Requirement)

	Total	Maximum Effect per Annual Fuel Requirement of Model 1000 MWe LWR
Effluents - Chemical (MT)		
[1]Gases (including entrainment)		
SO_x	4400	
[2]NO_x	1170	Equivalent to emissions from 45 MWe coal-fired plant for a year.
Hydrocarbons	11.3	
CO	28.7	
Particulates	1156	
Other Gases		
F^-	0.7	Principally from UF_6 production and enrichment - Conc. within range of state standards-below level that has effects on human health.
Liquids		
$SO_4^=$	5.8	From enrichment, fuel fabrication, and reprocessing steps. Components that constitute a potential for adverse environmental effect are present in dilute concentrations and receive additional dilution by receiving bodies of water to levels below permissible standards. The constituents that require dilution and the flow of dilution water are: NH_3 - 600 cfs; NO_3^- - 20 cfs; F^- - 7 cfs
NO_3^-	26	
Fluoride	0.4	
Ca^+	5.4	
Cl^-	8.2	
Na^+	13.5	
NH_3	10	
Fe	0.4	
Tailings Solutions ($\times 10^{-3}$)	240	From mills only - no significant effluents to environment.
Solids	91,000	Principally from mills - no significant effluents to environment.

[1]Estimated effluents based upon combustion of equivalent coal for power generation.

[2]1.2% from natural gas use and process.

Table 6A.1-10 (cont'd)

SUMMARY OF ENVIRONMENTAL CONSIDERATIONS FOR NUCLEAR FUEL CYCLE
(Normalized to 1000-MWe LWR's Annual Fuel Requirement)

	Total	Maximum Effect per Annual Fuel Requirement of Model 1000 MWe LWR
Effluents - Radiological (curies)		
Gases (including entrainment)		
Rn-222	83	Principally from mills - Maximum annual dose rate < 4% of average natural background within 5 miles of mill. Results in 0.06 man-rem per annual fuel requirement. Due to dilute concentration and short half-life of principal component, exposure beyond a 5-mile radius is miniscule relative to natural background.
Ra-226	0.02	
Th-230	0.02	
Uranium	0.046	
Tritium ($\times 10^{-3}$)	15.7	Principally from fuel reprocessing plants - Whole body dose is 4.4 man-rem for population within 50-mile radius. This is < 0.005% of average natural background dose to this population.
Kr-85 ($\times 10^{-3}$)	350	
I-129	0.002	
I-131	0.02	
Fission Products	1.0	
Transuranics	0.004	
Liquids		
Uranium & daughters	2.4	Principally from milling - included in tailings liquor and returned to ground - no effluents; therefore, no effect on environment.
Ra-226	0.027	From UF_6 production-concentration < 5% of 10 CFR 20 for total processing of 27.5 model LWR annual fuel requirements.
Th-230	0.27	
Th-234	0.01	From fuel fabrication plants-concentation < 10% of 10 CFR 20 for total processing 26 annual fuel requirements for model LWR.
Other uranium daughters	0.01	
Ru-106	4	From reprocessing plants-maximum concentration < 4% of 10 CFR 20 for total reprocessing of 26 annual fuel requirements for model LWR.
Tritium ($\times 10^{-3}$)	2.5	
Solids (buried)		
Other than high level	1200	From mills-included in tailings returned to ground-no significant effluent to the environment.
Thermal (Btu $\times 10^{-9}$)	3370	< 7% of model 1000 MWe LWR.

Although airborne radionuclides and particulate matter result from uranium mining operations (see Table 6A.1-9), underground mines are adequately force-ventilated to dilute radon concentrations effectively to background levels at the site boundaries. Any mine ventilation malfunction would be immediately remedied, and any resulting transient exhaust conditions of excessive radon concentration would be too small to be detected beyond the site boundaries.

Airborne radionuclides and particulate matter are generated during uranium milling operations; however, off-gas treatment and particulate settling reduce the off-site concentrations of airborne contaminants to levels well below limits defined in 10 CFR 20.

Uranium Hexafluoride (UF_6) Production. Temporary commitment of about 2.5 acres of land are attributable to production of UF_6[12] for the annual fuel requirements of the model LWR. Only about 0.02 acres of land, used for burial of toxic wastes generated by production of said amount of UF_6, is permanently committed.

Of the approximately 45 million gallons of water used by the model UF_6 production process and attributable to the annual fuel requirements of the model LWR (see Table 6A.1-8), more than 90% is used primarily as process coolant and then returned directly to the water body from which it came. The remainder, or process waters, leave the plant as raffinates and plant wastes and are held indefinitely in sealed holding-ponds which allow the water to return to the biosphere via evaporation, and the solid residues ultimately are recovered and buried. Analyses of groundwater samples obtained in the vicinity of an established UF_6 production plant showed that even fluoride and nitrate concentrations are well within recommended limits for drinking water sources.[12]

Process off-gas streams are generated which contain volatilized solids, combustion products, gaseous reactants, and small amounts of radioactive materials (see Table 6A.1-9). Several off-gas treatments are employed to reduce airborne concentrations of contaminants to levels below limits established by 10 CFR 20.

Isotopic Enrichment of Uranium. Less than one acre of land is temporarily committed to the enrichment of the annual fuel supply for a model LWR,[12,26] and the bulk of this area serves only as a controlled-access area.

The model gaseous diffusion plant requires the evaporation (and make-up) of about 90 million gallons of cooling water for enrichment of the annual fuel supply of the model LWR. (In addition, off-site generation of the electricity consumed by this enrichment process employs--assuming once-through cooling and return to natural water bodies--approximately 11 billion gallons of water per annual fuel requirement of the model LWR.) The primary potential for contamination of man's hydrosphere by this fuel cycle step lies in "blowdown" from operation of the closed-cycle evaporative cooling towers; current plants have adequate quantities of river water to permit dilution of these periodic discharges to levels below established limits for natural water bodies.

By far the primary source of environmental impact[12] associated with the enrichment of uranium is related to the gaseous effluents from the coal-fired plants which generate the required electric power. Waste gas emissions, including particulates, of approximately 6600 metric tons are attributable to the production of an annual fuel supply for the model LWR. This impact will be reduced in the future as the fraction of electricity produced by nuclear plants increases and as breeder reactor power plants (which need no enrichment) begin to generate this power. Associated with this generation of electricity is the rejection to the environment of roughly twice as much energy as waste-heat. Various power plants would reject their waste-heat to air while others would reject it into available water bodies.

Impacts on Flora and Fauna

Effluents from the out-of-reactor fuel cycle operations are monitored and processed as needed, and subjected to controlled-releases to ensure that the concentrations of any toxic materials therein are kept below licensed levels, that is, "as-low-as-practicable" release limits. With due consideration of natural ecosystems pathways for potential redistribution or concentration of elements, conscientious efforts will be made to ensure that any adverse effects on public health and safety are kept to a negligible level.[12,13,25]

Uranium Mining-Milling. The mining and milling of uranium resources usually are accomplished on contiguous acreages which are relatively remote and in regions of low population density. During these operations, roughly five acres of forage land per annual fuel requirement for the model LWR are temporarily (at least for a decade) removed from use by wildlife; however, it is expected that current site reclamation requirements would assure the return of most of this acreage to something approaching its former natural status within a few years after the discontinuance of plant operations.

Uranium Hexafluoride (UF_6) Production. UF_6 production plants are relatively large throughput operations[12] and are located in regions of low population density. Less than 10% of the plant site need be disturbed from its natural state during production operations, the bulk of the site serving as a controlled-access area to reduce the off-site impact of any plant malfunction. These plants are designed for and operated with virtually complete recovery of uranium values, total utilization of fluorine, and high utilization of other reactants; consequently, there should be no more than minor detrimental effect to the natural flora as a result of plant effluents. Fauna permitted to graze without restriction on all of the undisturbed controlled-access acreage conceivably could be exposed to some accidental releases of hazardous or toxic gases (e.g., F_2 or HF) that could be harmful even though the exposure was brief. However, no accidents having a detrimental environmental effect have occurred to date.

Isotopic Enrichment of Uranium. Substantial amounts of process heat are rejected into the atmosphere at the gaseous diffusion plant[12] and, although occasional misting and fogging results on the site near the cooling towers, experience indicates that the thermal impact on the local flora and fauna is insignificant.

Although small quantities of airborne fluorides and oxides of nitrogen and sulfur are released at the diffusion plant site, experience indicates that the off-site concentration of each of these contaminants is too low to have a deleterious on the local biota.

6A.1.1.6.3 Irreversible and Irretrievable Commitments of Resources

LWR fuels are clad in zirconium-base alloys which become radioactive as the result of neutron absorption; roughly one-quarter metric ton of zirconium is committed for every ton of fuel charged to a current PWR, or about 7.5 metric tons of zirconium are consumed/committed per year per 1000-MWe LWR.

As indicated in Tables 6A.1-8, -9 and -10, better than 82,000 metric tons* of uranium-bearing ore, located under the surface of 2.0 to 4.4 acres of mining-milling land, are committed each year in support of a typical 1000-MWe LWR.[8,12] Whenever it becomes necessary to mine lower-grade conventional ores, the quantities of ore removed will become proportionately greater.

*Assumes a U_3O_8 content of 0.20% or 2000 ppm.

Although the LWR currently consumes less than 2% of the potentially available nuclear energy in the contained uranium (roughly 30 metric tons U of design enrichment throughput per year per 1000-MWe LWR), the unburned uranium values are chemically recovered after LWR irradiation and are retained either for recycle in the LWR (after some enhancement of its fissile content) or for use as both fertile and fissile material in the LMFBR fuel cycle. The generation of all anticipated nuclear power by LWRs only, through the end of the century, might require exploiting progressively lower grades of uranium ores to produce the 150,000 tons of natural uranium oxide, U_3O_8, required each year by the year 2000. Figure 6A.1-1 identifies estimated quantities of uranium in some of the various known sources of uranium in the U.S. and in the ocean. Aside from those labeled "conventional," it is apparent that the bulk of the uranium occurs in very small concentrations in shales, granites, and seawater. The economic and environmental consequences of having to tap these low-grade sources for the quantities, and at the rates, required to sustain a large burner/converter industry have not been evaluated in detail. Some idea of these consequences may be gained, however, from the following discussion.

The Chattanooga shale lies under some 150 ft of cherty limestone of which the upper portion, about 7 ft thick and containing about 60 ppm of uranium, was previously estimated to cost about $40 per pound of U_3O_8 to recover. This estimate was based on underground mining due to depth of the shale. A "rule-of-thumb" updating of this estimate (see Section 6A.1.1.9) indicates that the previous estimate of $40 is now more like $90, exclusive of any return on investment. Note that the energy available from a tone of this shale is not much different from the energy available from a ton of coal.

Mining and milling to produce 150,000 short tons of U_3O_8 per year would require the mining of about 9 million tons of shale per day throughout the year.* Milling of this ore would require hundreds of plants (the largest western plant at present has a capacity of 7000 tons/day), requiring a total investment of $50 to $85 billion; the labor force is estimated at about 700,000 by analogy with the coal mining industry. The operations would be expected to use about five times the current U.S. consumption of sulfuric acid for all purposes, and in excess of one billion gallons of water per day. Because of the quantity of water involved, some method of recycle would have to be found.

*Assumes 70% recovery of U in the leaching process, because the uranium concentration is very low and is distributed through a myriad of fine veins throughout the shale.

6A.1.1.7 Cost and Benefits

The nuclear power industry that exists in the United States today is limited largely to light water reactor designs, although the high temperature gas reactor (HTGR) will begin to share this market in the relatively near future. The LWR is offered as an alternative power source to fossil-fueled steam electric plants and has received an increasingly larger share of the market each year. In 1973 approximately 43,000 MW of nuclear capacity and about 30,000 MW of central station fossil capacity were ordered. The increasing quantity of nuclear orders in the past years is evidence of a strong trend to nuclear power.

While nuclear power plants have higher capital costs than coal-fueled power plants (oil and gas are no longer seriously considered as fuel options for central station power plants), the differential in fuel costs favors nuclear to the extent that in most areas of the country total power costs are lower for nuclear power plants. It appears that the demand for coal will be greatly increased in the near future. At the urging of President Nixon, electric generating facilities are being switched from oil to coal. This change is estimated to result in an increase in coal use of nearly 70 million tons/year by the end of next year. There are other industrial uses of oil that will switch to coal, and coal will also be used as a resource for synthetic liquid or gaseous fuel. It is expected, therefore, that the position of nuclear power costs relative to fossil power costs will further improve due to increases in power plant coal prices resulting from this increased demand.

Table 6A.1-11 provides a comparison of costs and environmental impacts of electric energy production from coal-fueled power plants and light water reactor power plants.[27] Gross direct environmental impacts of extracting, processing, and transporting fuel--so visible in the coal fuel cycle--are essentially absent in the nuclear fuel cycle because of the high-energy content (on a mass or volume basis) of nuclear fuels. Similarly, nuclear power plants do not discharge large quantities of airborne pollutants.

The current generation of nuclear power plants--the light water reactors--discharge about one-third more heat to the environment than do modern fossil plants. Though relatively small in mass and volume, material flows and residuals in the nuclear fuel cycle are not without potential hazard. For this reason, nuclear systems are designed, fabricated, and operated with numerous safeguards, high performance radioactive waste systems, redundancies, and stringent quality assurance programs and standards.

Table 6A.1-11

COMPARISON OF COSTS AND IMPACTS OF COAL AND LIGHT WATER REACTOR PLANTS[a]

	Coal[b]	LWR[b]
POWER PLANT AND ENERGY SYSTEM EFFICIENCIES		
Electrical Energy (billion kWe-hr/year)	6.57	6.57
Power Plant Heat Rate (Btu/kWe-hr)	9,100	10,850
Power Plant Thermal Efficiencies (kWe/kwt,%)	38	32
Energy System Efficiency (kWe-hr consumer/ kWt-hr input, %)	35	28
CONSUMPTION OF NON-RENEWABLE FUEL RESOURCES		
Power Plant Fuel Consumption (annual)	2.3 metric tons	~130 tons U
Fraction of Reserves Consumed (annual)	0.000006	0.0002
CONVENTIONAL COSTS (mills/kWe-hr)[c]		
Plant	6.8	8.5
Operation and Maintenance	0.53	0.73
Fuel	4.4	2.1
Total	11.7	11.3
SELECTED ABATEMENT COSTS (mills/kWe-hr)[c]	2.5	0.6
OCCUPATIONAL HEALTH AND SAFETY		
Occupational Health (man-days lost/year)	600	480
Occupational Safety		
Fatalities (deaths/year)	1.1	0.1
Non-Fatal Injuries (number/year)	46.8	6.0-7.0
Total (man-days lost/year)	9,250	900-1000
PUBLIC HEALTH AND SAFETY		
Public Health		
Routine Pollutant Release (man-days lost/year)	N.E.[d]	180-210

Table 6A.1-11 (cont'd)

	Coal[b]	LWR[b]
Public Safety		
Transportation Injuries		
Fatalities (deaths/year)	0.55	0.009
Non-Fatal Injuries (number/year)	1.2	0.08
Total (man-days lost/year)	3,500	60
ENVIRONMENTAL DEGRADATION		
Land		
Land Use, Inventory (acres)	22,400	∿1,000
Land Use, Consumption (acres/year)	740	12
Air		
SO_2 Release, w/o[d] Abatement (tons/year)	120,000	3,600
SO_2 Release, w/Abatement	24,000	720
NO_x Releases, w/o Abatement (tons/year)	27,000	810
Particulate Releases, w/o Abatement (tons/year)	270,000	8,000
Particulate Releases, w/abatement	2,000	60
Trace Metals Releases (tons/year)	0.5 Hg	Small
Radioactivity Releases (Ci/year)	0.02	$250\text{-}500 \times 10^3$
Thermal Discharge, Power Plant Stack (billion kWt-hr/year)	1.64	0
Water		
Cooling Water Use (billion gal/year)	263	424
Process Water Use (billion gal/year)	1.46	0.095
Radioactivity Releases (Ci/year)	0	500-1000
Other Impacts (billion gal/year)	16.8	Small
Thermal Discharge, Power Plant (billion kWt-hr/year)	9	14

[a]Basis: 1000-MWe power plant, 75% capacity factor. Source: USAEC, "Comparative Risk-Cost-Benefit Study of Alternate Sources of Energy," Report WASH-1224, in publication.

[b]The number of digits shown is not generally indicative of precision. In many cases, several digits are retained merely for calculational purposes.

[c]1980 dollars

[d]N.E. = not evaluated; w/o = without; w/ = with.

6A.1.1.8 Overall Assessment of Role in Energy Supply

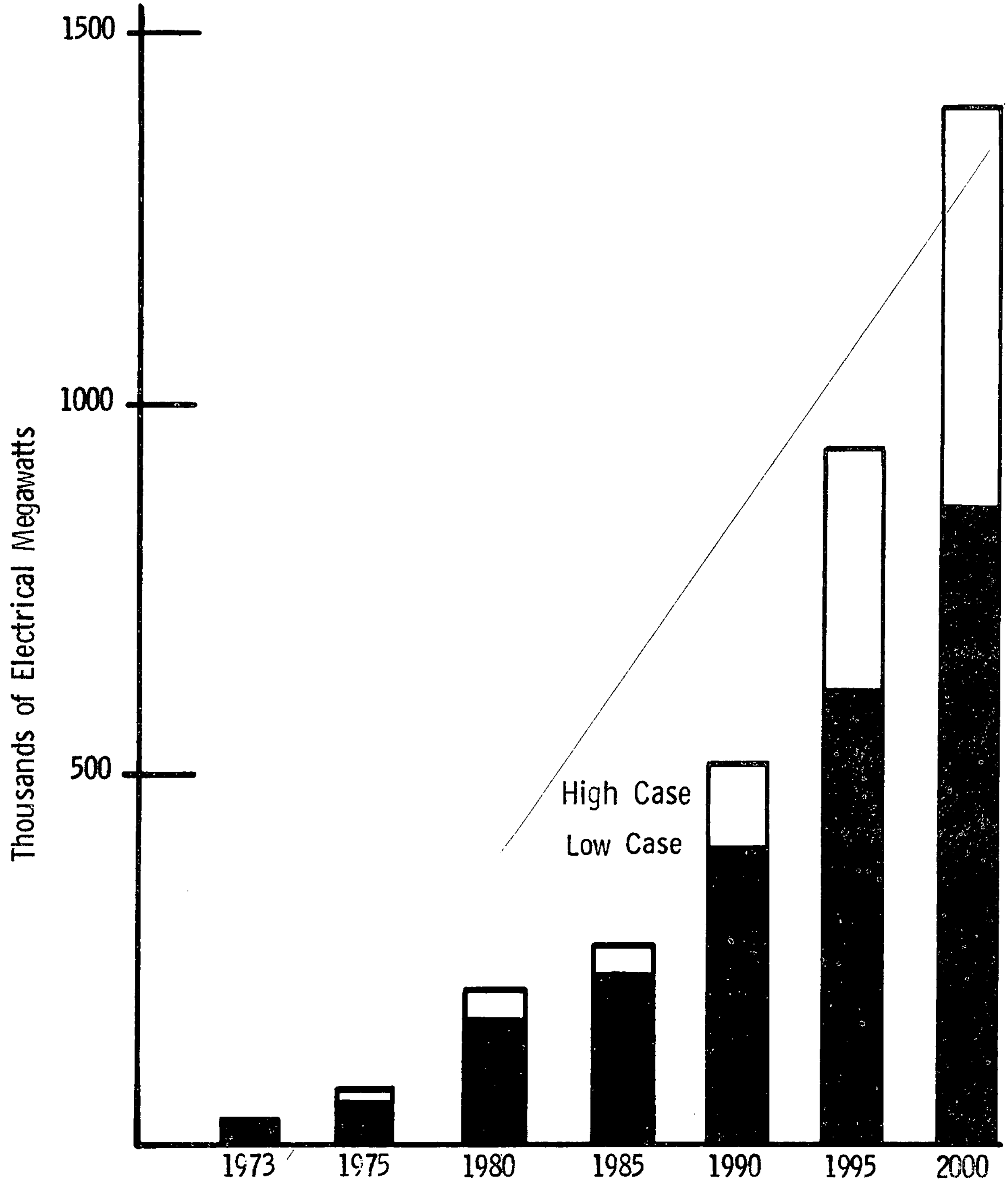
6A.1.1.8.1 Probable Role up to Year 2000

The introduction and use of fission energy for the large-scale generation of electricity in this country will necessarily be a two-phase process. Phase I is the current era of "burner/converter" reactors--now principally LWRs, but with growth expected in the use of HTGRs. Phase II will be the era of breeder reactors, beginning with the Liquid Metal Fast Breeder Reactor (LMFBR), which could be an option available to the utilities by the mid- to late 1980's.

Most recent projections[8] by the AEC of nuclear power growth in the U.S. is summarized in Figure 6A.1-27. A range of 850 to 1400 GWe of installed nuclear-electric capacity is estimated for the end of year 2000. This capacity is expected to consist of LWRs, HTGRs, and LMFBRs if commercial introduction of LMFBRs begins in 1986, as is assumed. The installed nuclear electric capacity in the year 2000 is expected to account for about 55% of the total installed electric generation capacity in the U.S., with breeder capacity by end of year 2000 estimated at 124 to 232 GWe.

One assumption inherent in these estimates is that sufficient uranium will be available in a price range that will permit the projected burner/converter plants to be economically competitive, over their service lives, with alternative ways of generating electricity. As previously noted (Section 6A.1.1.6), there will be large environmental and economic incentives for making the transition from the burner/converter era to the breeder era without having to use the very low-grade sources of uranium. Thus, it is reasonable to suppose that the conventional uranium ore supply outlook at any given time will be a critical factor in a utility's choice of a burner/converter plant for needed additional capacity.

Table 6A.1-12 shows the cumulative amounts of uranium required to support increasing amounts of installed burner/converter capacity over the service lives of the plants. It is keyed to the Report WASH-1139(74) projections and assumes that the nominal service life of a nuclear plant is 30 years. The second entry for the year 2000 assumes that breeder introduction is delayed to 2001 and that burner/converter capacity is built in lieu of breeders up to that time.



INSTALLED NUCLEAR CAPACITY--UNITED STATES
FEBRUARY 1974 FORECAST

Figure 6A.1-27

Table 6A.1-12

PROJECTED URANIUM REQUIREMENTS

Year	Installed Burner/Converter Capacity (GWe)	U_3O_8 Consumption through Year 2000 (millions of short tons)	Ultimate U_3O_8 Requirement to Support Installed Capacity (millions of short tons)
1985	231 - 275	0.9 - 1.1	1.1 - 1.3
1990	406 - 570	1.3 - 1.8	1.9 - 2.7
2000[a]	726 - 1168	1.8 - 2.7	3.4 - 5.4
2000[b]	850 - 1400	1.9 - 2.9	4.0 - 6.5

Bases: 0.3% enrichment plant tails; average lifetime plant factor 65%; nominal service life 30 years; U_3O_8 consumption cumulated from beginning 1973; Pu recycle in LWRs during 1/3 of service life.

[a] First commercial breeder 1986
[b] No breeder through year 2000.

Recalling that currently known and estimated potential conventional uranium resources, up to the $30 per pound of U_3O_8 level, are estimated at about 2.4 million tons of U_3O_8, one can see from Table 6A.1-12 that continued growth of burner/converter capacity beyond about 1990 could require eventual use of low-grade/high-cost uranium, unless large additional quantities of conventional ores were located on a timely basis.* Additional quantities would have to be identified within the next decade or so to have a timely influence on utility decisions. Decisions to purchase nuclear plants to be in operation by the early 1990's will have to be made in the early to mid-1980's and could be adversely affected by large uncertainties in the future cost of uranium.

In summary, LWRs will dominate the nuclear electric scene through the year 2000. The rate of growth of LWR and HTGR capacity beyond 1990 is currently uncertain and likely depends upon finding additional sources of conventional ores, either domestic or foreign, prior to that time. To achieve a projected 700 to 1100 GWe of installed burner/converter capacity by the year 2000 would require a considerable expansion of presently known and estimated conventional resources.**

*Availability of a commercial laser enrichment process, such as discussed in Section 6A.1.1.2.4, sometime prior to 1990, could extend the period of growth to about 1995 for the high growth case and to about year 2000 for the low growth case, within the constraint of 2.4 million tons of conventional resources.

**To actually produce the 1.8 to 2.7 million tons of U_3O_8 needed by the year 2000, and at the required rates, would require locating much more U_3O_8 in the ground. The same consideration applies to uranium requirements beyond the year 2000, unless use of the Chattanooga shales is assumed.

6A.1.1.8.2 Probable Role Beyond Year 2000

While speculative, it seems prudent to assume that conventional uranium resources probably will not support continued growth of burner/converter capacity beyond the turn of the century. With this assumption, there would be a steady decrease in installed burner/converter capacity beyond year 2000, although some new burner/converter plants would probably be built. Within the first decade of the next century, all of the plants built prior to 1980 will be reaching the end of their nominal 30-year service lives, and by 2030 the residual burner/converter capacity on-line would have become a very small fraction of total electric capacity.

6A.1.1.9 Appended Material

6A.1.1.9.1 Factors Influencing Uranium Recovery Costs from Chattanooga Shales

Discussion in this section is based on ORNL-CF-74-5-26[28] and is offered only as a rough "rule-of-thumb" type of updating. The AEC expects that a more thorough assessment, currently under way (see Section 6A.1.1.9.2), will provide firmer estimates.

Original Cost Estimate

The cost of recovery of uranium from Chattanooga shale was estimated[29] in 1960. The major items were mining shale, leaching uranium either by sulfuric acid (CCD) or oxygen pressure (OP), and recovery of uranium by solvent extraction. Although neither process has been tested in a pilot plant, the CCD process probably is on a firmer basis because of its similarity to processes used on Colorado Plateau ores. The OP process, which produces acid from sulfides in the shale, presents serious equipment design problems because of corrosion and scaleup and requires a higher capital investment. Pertinent data for both processes are in Table 6A.1-13.

The cost of uranium from a mill (20-year depreciation) having a daily capacity of 20,000 tons shale containing 60 ppm uranium at 70% recovery was estimated at about \$40 per pound of U_3O_8 for the CDD process and about \$38 per pound of U_3O_8 for the OP process. These figures can be converted to possible sales prices of \$57 per pound of U_3O_8 for the CCD process and \$66 per pound of U_3O_8 for the OP process, respectively, by allowing 20% of capital for return on investment which was not included in cost numbers reported in the reference report. Capital requirements (exclusive of mining capital) were \$55 million for the CCD process and \$90 million for the OP process for the production of approximately 325 tons of U_3O_8 per year.

Table 6A.1-13

DATA FOR CHATTANOOGA SHALE PROCESSING FROM RMO-4015[a]
Capacity: 20,000 tons shale/day
Assay: 60 ppm U x 70% recovery = 42 ppm

Items	CCD	OP
Operating factor, days/year	330	330
Shale, tons/year	6,593,400	6,593,400
Solution processed, gal/year	789,270,000	1,653,178,000
U product, lb/year	551,100	556,050
U_3O_8 product, lb/year	649,900	665,700
Cost[b] (20-year depreciation), \$/lb U	47.35	45.19
\$/lb U_3O_8	40.15	38.32
Water in, tons/day	23,418	34,307
Water out with solids (ore x 30%)	6,000	6,000
Waste water, tons/day	17,418	28,307
Waste water, gal/ton ore	218	354
Net waste water to be treated (assume 100 gal/ton recycled), gal/ton	120	250

[a]Source: "Recovery of Uranium from Chattanooga Shale," Report RMO-4015, USAEC, Washington, D.C., September 1960.
[b]Manufacturing cost only; does not include return on investment.

Adjusted Cost Estimate

The reference costs have been adjusted for: (1) escalation of plant cost by the Chemical Engineering[30] plant construction cost index which has increased from 100 for 1959 to 151 for January 1974; (2) cost of waste treatment, \$9.50/1000 gal liquid (120 gal/ton shale for CCD and 250 gal/ton shale for OP) and \$2.00/ton shale for stabilization of solids with cement. The waste liquid contains radioactivity and objectional salts which prohibit discharge to the environment. The concentration of radium-226 and thorium-230 probably will be greater than maximum permissible concentration (MPC) based on data from western mills. Treatment by neutralization and evaporation in a metal evaporator reduces pollution and saves on water requirements. The leached shale is in the form of a slurry of fine particles which can be stabilized by addition of portland cement (1 part cement to 10 parts shale) before disposal in the mine or on the surface--the volume of shale is approximately 80% greater after processing so that not all of it can be returned to the mine. The excess must be placed in surface waste piles which will despoil considerable land. The cost of retention dikes and stabilization of the surface has not been estimated. Low-grade concrete formed by addition of cement to tailings has been used successfully in Canada as backfill in mines. At ORNL, low-level radioactive wastes are mixed with cement to form a grout having low leach rates by water.

The adjusted cost of uranium from shale containing 60 ppm U at 70% recovery and providing for escalation and waste disposal is \$92 per pound of U_3O_8 for the CCD process and \$102 per pound of U_3O_8 for the OP process. Allowing 20% of capital for return on investment implies prices of \$126 and \$158 respectively. Capital requirements for a 20,000-ton/day mill are \$111 million for the CCD process and \$182 million for the OP process. Details are shown in Table 6A.1-14.

Table 6A.1-14

ADJUSTMENTS TO ORIGINAL COST ESTIMATE IN RMO-4015[a]
(20,000 tons of shale/day)

Cost Items	CCD	OP
Capital, $\$10^6$		
Original	54.6	89.6
Escalation (original X 0.51)	27.8	45.7
Waste Liquid Treatment	17.1	35.6
Waste Solid Treatment	11.3	11.3
Total	110.8	182.2
\$/lb U_3O_8		
Original (no return on invest.)	40.15	38.32
Escalation (original X 0.51)	20.48	19.54
Waste Liquid Treatment	11.52	24.00
Waste Solid Treatment	20.21	20.21
Return on Investment	33.94	55.80
Total	126.30	157.87

[a]Source: "Recovery of Uranium from Chattanooga Shale," Report RMO-4015, USAEC, Washington, D.C., September 1960.

Requirements for 150,000 Tons U_3O_8 per Year

The production of 150,000 tons of U_3O_8 per year would require 460 reference mills (20,000 tons/day) processing a total of 9 million tons of shale per day. The total capital investment is \$51 billion for the CCD process and \$84 billion for the OP process. Water requirements are 700 million gal/day with recycle of evaporator condensate and 1.8 billion to 3 billion gal/day without evaporator recycle. The average flow rate of the Caney Fork river which supplies the Corps of Engineering Center Hill Reservoir is 2.5 billion gal/day. The average flow of the Tennessee River at Watts Bar Reservoir located about 80 miles away is 17 billion gal/day. No estimate of the cost of supplying water from sources which may be a considerable distance from the mine and processing plant has been made. The cement requirement is 300 million tons/year which is more than four times the current U.S.

production.[31] The required sulfuric acid is 180 million tons/year which is approximately six times the U.S. production.[32]

Mining

In RMO-4015,[29] the mining cost was estimated to be \$1.33/ton of shale. After applying the escalation factor used in the present report, the adjusted cost would be \$2.01/ton. Many people in the mining field believe that this cost is too low, possibly by a factor of two or three. If this is true, an extra \$20 to \$40 per pound of U_3O_8 must be added to the processing costs. Lacking substantial review of this cost item, a more definitive projection is not made here. However, it seems virtually certain that the actual mining costs would be significantly greater than those used in past estimates.

It should be noted that in order to produce 150,000 tons of U_3O_8 per year, the required mining effort would be huge. Over 3 billion tons of shale would be required each year. In comparison, the U.S. bituminous coal industry in 1970 produced about 600 million tons of coal with a labor force of about 140,000 people. Slightly more than 40% of the production was by strip mining which is less labor intensive than the underground mining which would presumably be necessary for nearly all of the Chattanooga shale. By analogy, it may be estimated that over 700,000 men would be needed for shale mining. This, of course, does not include the large labor force that would be required to operate the hundreds of mills or people required to furnish the multitude of needed services.

Sulfuric Acid

In order to produce 150,000 tons U_3O_8 per year, the annual H_2SO_4 requirement would be 184×10^6 short tons using the direct leaching process. This is six times the total H_2SO_4 production in the United States in 1973. It is not certain at this time that such a H_2SO_4 requirement for shales can be met, although the problem might be alleviated or solved by the simultaneous development of a coal gasification and/or liquefaction industry that produced sufficient byproduct sulfur in an elemental or otherwise transportable form.

The large consumption of sulfuric acid by the direct leach process argues for use of the oxygen pressure leach process which requires no additional sulfur other than that already present in the shales. However, as pointed out earlier, the practicability of the latter process is not assured because of unknowns regarding the life span of the equipment.

6A.1.1.9.2 AEC/Bureau of Mines Study

The Atomic Energy Commission and the Bureau of Mines are initiating studies on recovery of uranium from the Chattanooga shale to update the recovery process and cost data developed in the 1950's. This investigation will of necessity be done in the light of current environmental considerations and restrictions as well as in the light of present costs and new technology and will be conducted on a much more detailed basis than the cursory assessment described above.

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6A.1.2 High-Temperature Gas-Cooled Reactors

6A.1.2.1 Introduction

6A.1.2.1.1 General Description

The high-temperature gas-cooled reactor (HTGR) is an advanced converter reactor operating on the thorium-uranium fuel cycle. Helium is used as the reactor coolant, and graphite is the moderator and core structural material. The fuel is a mixture of thorium and highly enriched uranium particles coated with thin layers of pyrolytic graphite. These particles are then bonded into fuel rods and inserted into large blocks of graphite. The use of helium as a coolant has the fundamental advantages that the coolant always remains in the same phase and is chemically inert. However, because of its relatively poor heat conduction properties, moderately high pressures must be used. The graphite is used both as a moderator and a core structural material; it has excellent thermal conductivity, high strength even at high temperatures, and extremely high melting and vaporization temperatures. A potential disadvantage of graphite is its tendency to react with steam (which might enter the reactor core if there should be a leak in a steam generator). The resulting steam-graphite reaction might lead to structural damage to the graphite core and the generation of combustible gases. Engineered safety features to prevent or mitigate such occurrences therefore are incorporated into the design (e.g., moisture monitors to detect and limit through feedback mechanisms the amount of water that can enter the core).

The HTGR system operates with coolant temperatures high enough to permit use of optimum plant steam conditions. Thus, overall thermal efficiencies of about 40% are achievable as compared with approximately 33% for present generation LWRs. In addition, an advanced HTGR concept using gas turbines and a bottoming cycle (vapor turbines to extract electrical power from the reject heat) has the potential for achieving thermal efficiencies of up to 50%.

6A.1.2.1.2 History

The use of gas coolant for nuclear reactors dates back to 1943 when the X-10 reactor was operated at Oak Ridge National Laboratory. The United Kingdom adopted this type of reactor in the mid-1940's when air was used as the coolant in the Windscale plutonium production reactors. Because of the initial success of this concept, the UK continued to use gas (carbon dioxide) as the coolant for their nuclear reactors, which are fueled with natural uranium. However, this concept is not completely satisfactory, and it appears that no more of this type of reactor will be built.

Gas-cooled reactors using natural uranium fuel have not been adopted for commercial power generation in the United States, primarily because the capital costs of these reactors are greater than enriched-uranium-fueled designs and the private capital funding structure in this country made the power cost of these systems too high. However, in 1957, General Atomic Company* (a subsidiary of Gulf Oil Corporation and Shell Nuclear Ltd.) initiated conceptual designs of a helium-cooled, graphite moderated power plant using enriched uranium fuel.[1] The results of these studies indicated that the concept had sufficient merit to proceed to a demonstration phase. In 1958, Philadelphia Electric Company and other members of the High-Temperature Reactor Development Associates, a consortium of utility companies, formally proposed to the AEC the construction of a 40-MWe prototype HTGR under the Power Reactor Demonstration Program. In 1960, an application for a construction permit was submitted by Philadelphia Electric for a prototype plant at Peach Bottom, Pennsylvania. This reactor was placed in commercial operation in May 1967 and operated satisfactorily until its shutdown in mid-1974. The operating experience with this Peach Bottom reactor[2] has established the potential of the HTGR as a large-scale power source.

6A.1.2.1.3 Status

Continued research and development directed toward adopting the basic features of the Peach Bottom reactor to larger, commercial sized systems resulted in an agreement in 1965 between the Public Service Company of Colorado, the AEC, and General Atomic for the construction of a 330-MWe HTGR, the Fort St. Vrain Reactor (FSVR), to be constructed near Plattville, Colorado. Construction began in 1968, initial criticality occurred in January 1974, and commercial operation of the plant is expected by mid-1975. This plant provides a link between the small, 40-MWe Peach Bottom Reactor and the larger units (770 and 1160 MWe) which are being offered for sale by General Atomic Company. The FSVR is the first U.S. reactor to use a prestressed concrete reactor vessel (PCRV). The use of this type of vessel produces a more compact plant design and simplifies operation and maintenance.

Several large HTGRs have been ordered by utilities. In August 1971, Philadelphia Electric announced the purchase of two 1160-MWe plants. Since that time, two smaller (770-MWe) HTGRs have been ordered by Delmarva Power and Light, and two 1160-MWe plants have been sold to Louisiana Power and Light Co. The Delmarva application for a construction permit for one of its two plants was docketed on August 16, 1973.

*At that time a division of General Dynamics Corporation.

An AEC projection indicated that by 1990 about 15% of the non-breeder nuclear power plants were expected to be HTGRs;[3] the recent cancellations and deferrals of orders for HTGR plants indicate that this projection is probably too high. The successful startup and operation of the FSVR is expected to provide the final proof of the concept and thus add assurance of the commercial viability of the HTGR system.

6A.1.2.2 Extent of Energy Resource

An 1160-MWe HTGR requires about 1600 kg of 93% enriched uranium and 37,500 kg of thorium for its initial core. Assuming enrichment tails of 0.25% U-235, 380 tons of natural U_3O_8 are required for the initial core loading. For subsequent reloads (assuming recycle of the U-233 produced from the Th-232), approximately 8000 kg of thorium and 390 kg of 93% enriched uranium will be needed annually. The natural U_3O_8 requirement is about 130 tons/year. A discussion of the availability of uranium is presented in the review of light water reactors (Section 6A.1.1.2).

The estimated U.S. thorium resources by cost is presented in Table 6A.1-15.[4] In addition, the availability of thorium throughout the world is presented in Table 6A.1-16. These tables show that thorium availability will not be a deterrent to the full utilization of the HTGR concept. For example, the amount of thorium available in Canada as a by-product of uranium mining operations alone will be sufficient to fuel all of the HTGRs which will be built in the U.S. during recycle, to fuel a nuclear power reactor economy based predominantly on HTGR reactors throughout the period under study in this Statement and well beyond.

Insofar as the extent of helium resources available to serve as coolant for gas-cooled reactors is concerned, the U.S. Government has been storing helium processed from natural gas since 1961.[5] This policy was terminated in early 1973 by which time an assured supply of about 45 billion ft^3 of helium was available. A U.S. Bureau of Mines report[6] states that the amount of helium in the "proved" U.S. natural gas resources was estimated to be 253 billion ft^3 in 1960, and about 80% of this would be economically recoverable with current technology. However, the helium will have to recovered from leaner natural gas at an increased cost. The Bureau of Mines report provides estimates of the possible availability of helium in the natural gas forecast to be produced annually in the U.S. The helium potentially available in the annual U.S. natural gas production would decline from about 20 billion ft^3 in 1975 to about 12 billion ft^3 in 2010 as the natural gas resources are depleted. These quantities could be available from the natural gas resources

Table 6A.1-15

ESTIMATED U.S. THORIUM RESOURCES[a]

Cutoff Cost (dollars per lb ThO_2)	Thousands of Short Tons of ThO_2 Reasonably Assured	Estimated Additional	Total
10	65	335	400
30[b]	200	400	600
50[b]	3,200	7,400	10,600

[a]Source: Estimates prepared by the USAEC, Division of Production and Materials Management, May 1973.

[b]Includes lower cost resources.

Table 6A.1-16

WORLD THORIUM RESOURCES--$10/lb ThO_2
(tons ThO_2)

		Reasonably Assured	Possible Additional	Total
India[a]		300,000	250,000	550,000
United States[b]		65,000	335,000	400,000
Canada		100,000[c]	155,000	255,000
Africa[a]		50,000	50,000	100,000
Australia[a] & S.E. Asia		10,000	--	10,000
Brazil[a]		10,000	20,000	30,000
TOTAL		535,000	810,000	1,345,000
		UNITED STATES		
Lemhi Pass, Idaho & Montana		47,000	335,000	382,000
Placers:				
Southeastern U.S.	(6,600)			
Idaho & Mont.	(11,400)			
Placers Total		18,000	--	18,000
TOTAL U.S.		65,000	335,000	400,000

[a]ENEA, 1965. Africa includes Central Africa, South Africa, and Madagascar.

[b]USAEC Division of Production and Materials Management, 1973.

[c]Canada, Mineral Bulletin 117, 1971. Mostly by-product of uranium mining. Reasonably assured given as over 100,000 tons; possible additional not given.

containing more than 0.09% helium at an estimated cost of $80 or less per thousand ft^3, which is about two to three times the current price.

The price of helium has very little effect on the power-generating cost for helium-cooled reactors. At the current cost of about $35 per 1000 ft^3, helium represents 0.002 mills/kWhr of the generating cost. At $1000 per 1000 ft^3 (a cost estimated for recovery from air), this cost would increase to 0.06 mills/kWhr.[7] Thus as the price of helium rises, there will probably be sufficient helium in the U.S. natural gas resources to recover the amounts needed if a large national commitment to the HTGR (or Gas-Cooled Fast Reactor) were to occur later in this century.

To put this supply in perspective, one 1000-MWe HTGR will require an initial inventory of about 2×10^6 standard cubic feet (scf). At an average helium leakage rate of 0.1%/day from the coolant system, the plant will need about another 20×10^6 scf of gas to maintain its coolant supply over a 30-year lifetime. Therefore, the total helium gas reserve in storage today, if used solely for that purpose, could supply about 2000 gas-cooled reactors (HTGRs and GCFRs) of 1000-MWe size. There are, of course, other requirements for the stored helium, so that alternative supplies from leaner natural gas, foreign sources, and perhaps air-extraction plants at substantially higher (but presumably acceptable) costs will be necessary to support an expanded gas-cooled reactor economy.

6A.1.2.3 Technical Description of the Energy System

6A.1.2.3.1 Power Generation Plant

The operating parameters of an 1160-MWe steam cycle power plant now being marketed are given in Table 6A.1-17.[8-10] The most striking feature of the HTGR is the Prestressed Concrete Reactor Vessel (Figure 6A.1-28). The PCRV contains the reactor core and entire primary coolant system, including steam generators and helium circulators. The PCRV also serves as the primary coolant system pressure boundary and provides the necessary biological shielding. The vessel consists of a central cylindrical cavity containing the core, surrounded by six cavities containing the steam generators and main helium circulators and by three smaller cavities containing the auxiliary gas circulators and heat exchangers.

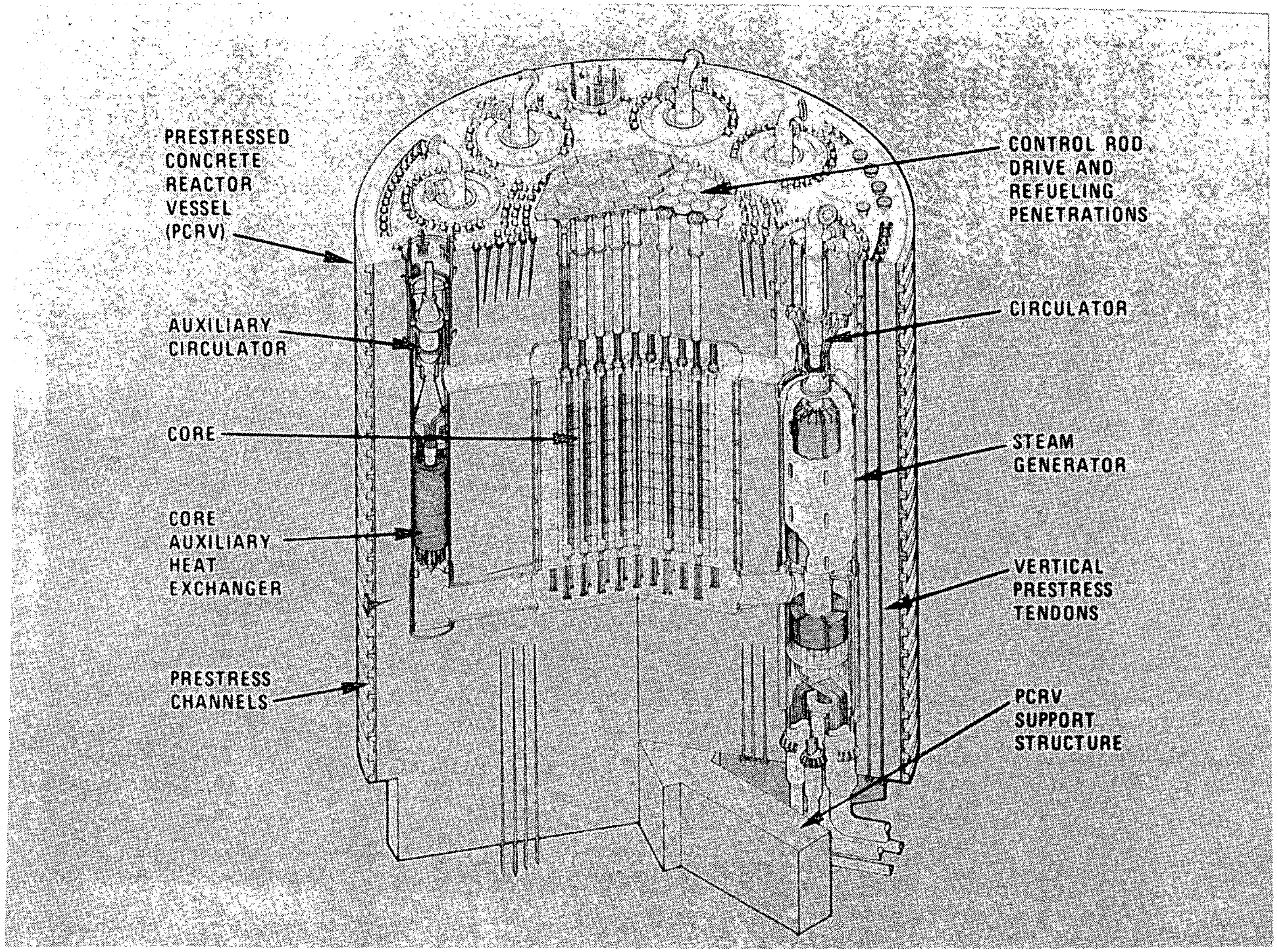
The cavities and all penetrations are lined with welded carbon steel, which acts as a leak-tight barrier. The top head above the central cavity of the PCRV contains a number of penetrations that house control rod drives, the reserve shutdown system, and the core orificing mechanism. When this equipment is removed, the fuel is

Table 6A.1-17

OPERATING PARAMETERS FOR A LARGE HTGR

General	
Thermal Power	3000 MWt
Electric Power	1160 MWe
Plant Lifetime	40 years
Conversion Ratio[a]	0.66
Reactor	
Fuel, Startup	Th/U^{235} (93% enriched)
Recycle	Th/U^{235} (93% enriched) / U^{233} (recycle)
Fuel Form	Coated particles in cylindrical bonded rods
Moderator	Graphite
Avg. Power Density	8.4 kW/liter
Outlet Temperature	1366°F
Temperature Rise across Core	760°F
Fuel Temperature, Avg./Max.	1634/2467°F
Reactor Vessel, Height	20.8 ft
Reactor Vessel, Diameter	27.8 ft
Coolant Inlet Pressure	710 psi
Vessel Material	Prestressed Concrete
Other Components	
Number of Circulators	6
Circulator Speed	7050 rpm
Number of Steam Generators	6
Steam Conditions	
Pressure	2400 psi
Temperature	950°F

[a]The conversion ratio of 0.66 shown in the table is the current economic optimum for the fuel cycle. It is adjustable upward as uranium prices escalate.



HTGR NUCLEAR STEAM SYSTEM

Figure 6A.1-28

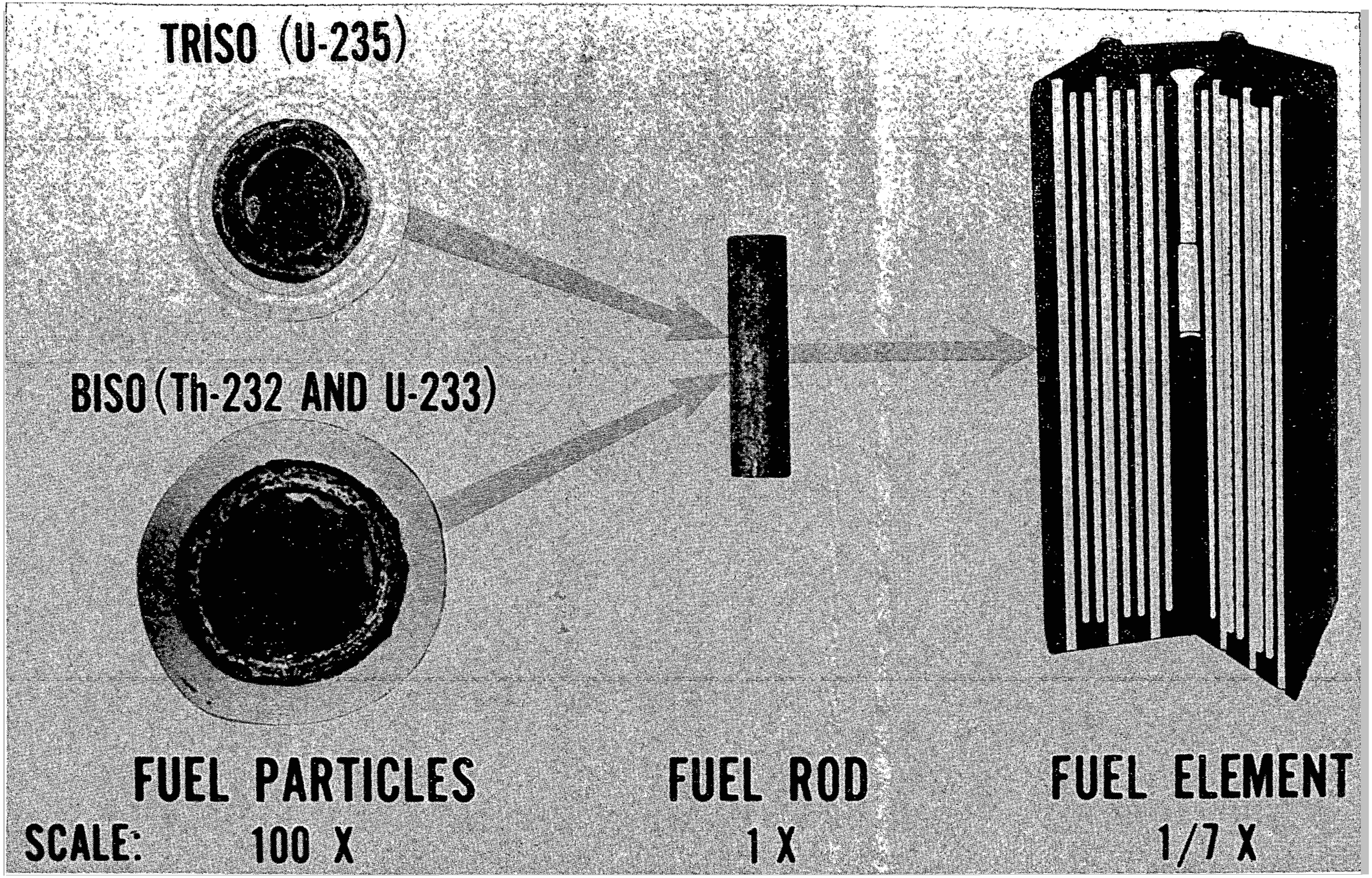
handled through these penetrations. This head also contains wells that house helium purification equipment, source range instrumentation, and neutron detectors.

The HTGR uses a U-233/Th fuel cycle, graphite for moderation and core structure, and helium coolant. The reactor core consists of vertical columns of hexagonal graphite blocks supported by a graphite core support structure. The core is divided into regions, each consisting of a central control rod element column and six surrounding fuel columns. The initial fueling consists of thorium and 93% enriched uranium particles. These particles are coated with pyrolytic carbon and bonded into rods that are loaded into the hexagonal graphite fuel blocks. The particle coatings provide the primary barrier for gaseous fission product retention. The particles containing U-235 are also coated with silicon carbide, which acts as a barrier for the retention of metallic fission products. Later in the fuel cycle, U-233 bred from the thorium will be used to reduce the requirement for enriched U-235 makeup.[11] The HTGR fuel components are shown in Figure 6A.1-29.

Reactivity control is accomplished by means of 73 pairs of control rods and drives. The drives are located in refueling penetrations in the PCRV and are powered by electric winches that raise and lower the control rods by steel cables. Gravitational force acts to insert the control rods into the core following a reactor trip.

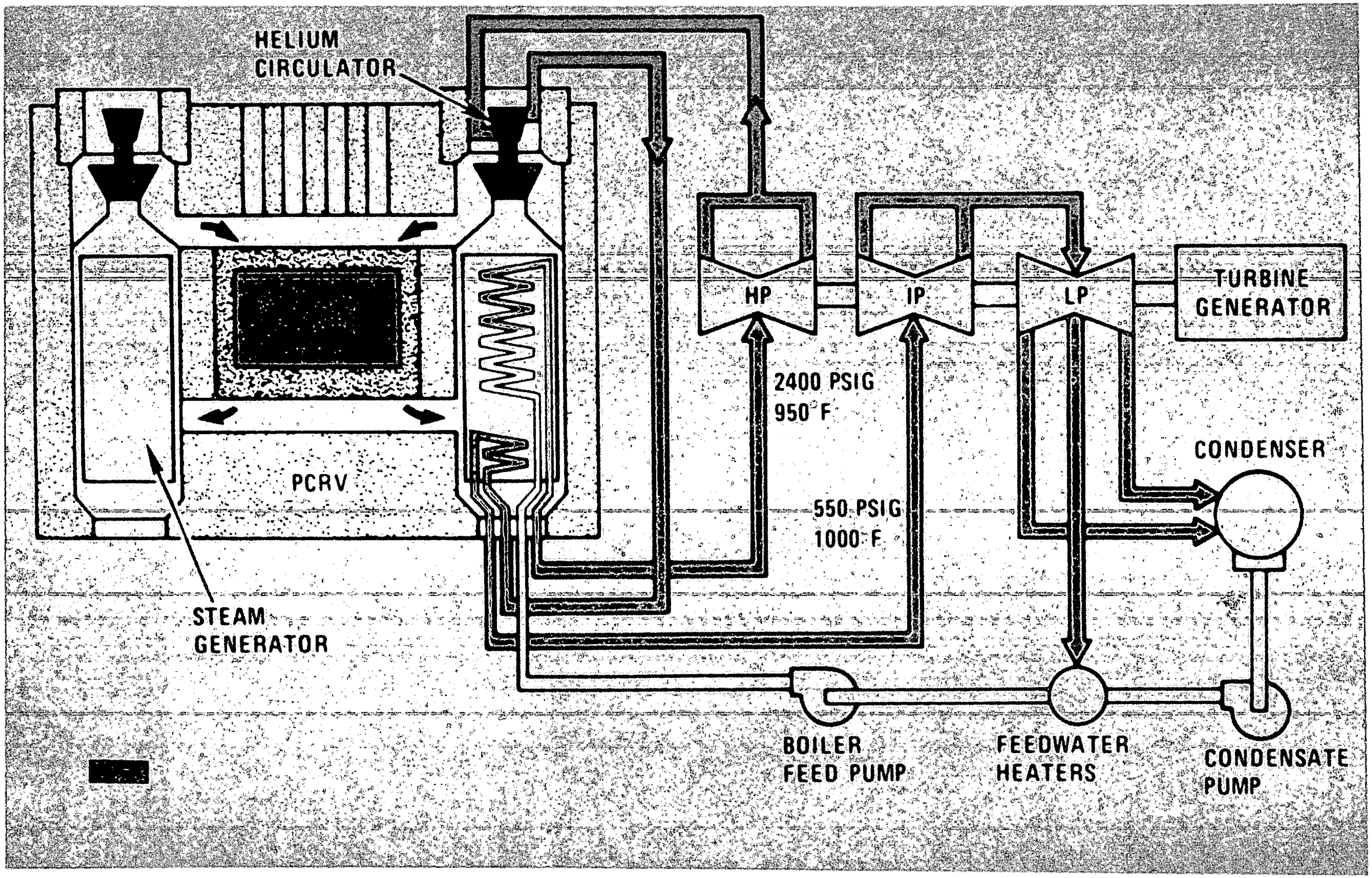
Each of the six primary circuits in an 1160-MWe plant is equipped with a helium circulator. Each circulator consists of a single-stage axial flow helium compressor and a single-stage steam turbine drive. Motive power is provided by cold reheat steam from the main turbine. The circulators are water-lubricated and have a helium buffer seal that is designed to prevent helium leakage from the primary coolant or water in-leakage to the coolant.

Each steam generator consists of a single helical tube bundle arranged in an annulus of a center duct. Helium leaves the core at 1400°F and enters the steam generator. The resultant steam generator outlet conditions are 955°F and 2400 psig. The outlet from the reheat section is 1002°F and 550 psig. This results in a net plant efficiency of 39%. The power conversion system for the HTGR is diagrammed in Figure 6A.1-30.



HTGR FUEL COMPONENTS

Figure 6A.1-29



HTGR POWER CONVERSION SYSTEM

Figure 6A.1-30

6A.1.2.3.2 Fuel Cycle

The HTGR operates on the thorium-uranium fuel cycle with the fuel encased in small coated spherical particles.[12,13] A plutonium fuel cycle could also be used in the HTGR although the economics favor the thorium-uranium cycle.

The HTGR fuel cycle is slightly more complicated than the LWR cycle because it has both uranium and thorium input; it is of approximately the same complexity as the LMFBR fuel cycle, which uses plutonium and natural or depleted uranium. The uranium requirement of over 113 tons of U_3O_8 per year for a 1000-MWe HTGR is considerably below the annual needs of an LWR but is, of course, above that for an LMFBR. The annual thorium requirement is almost 8 tons of ThO_2, the oxide being the usual form of thorium in the ore. Thorium is present in some uranium ores in Canada. This by-product thorium has been accumulating in tailings piles in Canada for some time with the result that the reserves in these tailings dumps are thought to contain about 100,000 tons of ThO_2. Considering the relatively small amount of thorium required for HTGR operation, the by-product thorium in these Canadian tailings piles is more than enough to last the U.S. HTGR industry beyond 1990 even if the HTGR achieves full commercial acceptance. Furthermore, the typical annual HTGR thorium requirement is only about 10% of the annual HTGR uranium requirement. Economically exploitable reserves of ThO_2 in the U.S. have been estimated at 400,000 tons.

The U_3O_8 is separated from the ore by processes which were described in Section 6A.1.1.3.3. Thorium oxide is milled in a similar manner; the Rn-220 released from the ore enters the mill ventilation system. A good fraction of the Rn-220 would be expected to decay before discharge through the stack; the effluent would be filtered to remove particulate matter on which decay products tend to collect.

The thorium oxide is then sent directly to the preparation and fabrication plant, while the U_3O_8 goes to the conversion plant where it is converted to gaseous UF_6 as in the LWR fuel cycle. The gaseous UF_6 is sent to the gaseous diffusion plant, from which the product stream in the case of the HTGR is UF_6 with its uranium consisting of approximately 93 wt % U-235. The tails stream contains depleted uranium having a U-235 concentration the same as the tails from enrichment for LWRs. These tailings are stored for possible future use.

Enriching uranium to 93 wt % U-235 for HTGR fuel takes more separative work effort than enriching uranium to only 2 to 4% U-235 as is done for LWRs. However, the uranium requirements of the HTGR are so much lower than those of the LWR that the annual separative work at the enrichment plant turns out to be slightly lower for a 1000-MWe HTGR than for an LWR of the same size.

At the fabrication plant the three input streams of fuel materials are the enriched UF_6 from the gaseous diffusion plant, the thorium oxide from the mill, and the recycled uranium from the reprocessing plant. The recycled uranium is mainly U-233 which was converted from thorium during exposure in the reactor core. The use of the recycled uranium cuts down on the natural uranium which must be mined and enriched to fuel the HTGR. The most important factor in the handling of recycled U-233 is the presence of a small amount of U-232 (72-year half-life) in the recycled uranium. The rapid buildup of the decay products of U-232 following purification makes remote, well-shielded fabrication of this uranium a virtual necessity.

The fabricated HTGR fuel will have two types of small spherical particles containing oxides or carbides of uranium and thorium and will be coated with pyrolytic carbon. The fertile particles in the recycle mode contain the thorium and recycled uranium. The fissile particle contains the enriched uranium (U-235). Fissile particles will have an extra inner layer of silicon carbide to enhance the retention of fission products and allow separation of the particles during reprocessing.

That fuel-fabrication processes for the HTGR will be sufficiently different from the LWR processes to require special or separate facilities is evident. Very small quantities of some radionuclides will unavoidably be released to the environment within standards; however, the economic incentive to recover the fuel and the necessity for remote procedures tend to minimize possible releases.

The fabricated fuel is then sent to the reactor. Following about four years of residence time in the reactor, the spent fuel will be removed and stored at the reactor for five months. This cooling period allows a significant amount of the fission products to decay at the reactor site before shipment and also allows most of the protactinium-233 (27-day half-life) to ddecay to the desired U-233. The spent fuel is shipped in heavily shielded casks via railroad or truck to a reprocessing facility to recover the remaining U-233 and U-235. The spent fuel is reprocessed and the recovered uranium is sent to the fuel-refabrication plant. The fission products which are recovered are treated as high-level radioactive waste and will be sent to a Federal repository for safe storage.

The fissile and fertile particles will be separated at an early stage of reprocessing. Laboratory studies indicate that this could be accomplished mainly by making use of the impenetrability of the silicon carbide coating which the fissile particle has and the fertile particle does not. The graphite, which is shipped to the reprocessing plant along with the fuel imbedded in it, is burned, and the burner off-gas is filtered and scrubbed before discharge to the atmosphere through the plant stack. The off-gas contains C-14 (formed from neutron absorption by C-13 and by neutron reaction with N-14). The total activity of C-14 released from the fuel of a 1000-MWe HTGR may approach 200 Ci/year depending upon the concentration of N-14 in the fuel elements. Although it is recognized that the dose resulting from this release at the site boundary will be a function of the distance to the boundary at the specific site chosen for the reprocessing plant, of the height of release, of local atmospheric conditions, and various other factors, the dose from this release is currently estimated to be well within that permitted by AEC regulations.

Other off-gases will be filtered and treated by various systems before release. Discharges to the environment from an HTGR reprocessing plant are estimated to be similar to those that are expected during the reprocessing of LWR and LMFBR fuels (see Section 4.3).

The uranium and thorium recovered from the fertile particles are decontaminated and separated by several solvent extraction steps. The resulting purified uranium is concentrated and shipped to the fabrication plant. The recovered thorium will probably not be used immediately due to the relatively high concentration of Th-228, whose daughter products emit high energy gamma radiation. Instead, if abundant low-cost natural thorium is available, the recovered material will be stored for possible future use. Some thorium may be recycled after roughly a 12-year storage period, but this depends on the price of fresh thorium and storage costs. The uranium in the fissile particles may be recovered for reuse in the HTGR or sold if the economics are favorable. If not recovered, this uranium will become part of the high-level waste and will be treated the same as fission products, that is, sent to a Federal repository for safe storage.

6A.1.2.3.3 Safety Aspects

The HTGR has a number of features which are inherent in its design that give this reactor concept somewhat different safety characteristics from either the LWR or the LMFBR. These are:

(1) The large mass of graphite in the core with its attendant high heat capacity ensures that any temperature change resulting from a reactivity insertion or loss of cooling will be slow.
(2) The use of helium gas coolant with its low neutron cross section and low density results in the reactivity of the core being insensitive to changes in coolant density.
(3) The use of the PCRV eliminates the need for external coolant piping, thus avoiding the concerns of primary pipe rupture that are encountered in sodium or water-cooled reactors. However, the integrity of vessel closures and flow limitation devices must be assured.
(4) The use of coated fuel particles reduces the amount of fission products that would be released from any one fuel failure, as compared to those which would be released from failure of the metal cladding on a fuel pin in an LWR or LMFBR. However, coated particle fuel does lead to the routine presence of some fission products in the coolant stream, due to diffusion through the coatings. The fission product activity level in the coolant must be maintained within specified limits by the helium purification system.

In addition to these desirable characteristics, the use of graphite introduces the problem of the reaction of carbon with any steam that may leak into the system as a result of failure of any of the steam generator tubes. If large amounts of steam enter the primary system, the reaction could result in loss of some of the structural graphite and release of any metallic fission products which were deposited on the graphite. However, moisture monitors in the systems are designed to shut down the reactor before large quantities of steam enter the system. Other features of the HTGR such as the PCRV and gas coolant result in different potential accident initiation or mitigation mechanisms from other reactor concepts such as the LMFBR or LWR. Although safety research for HTGRs is still going on, as it is for other reactor types, the basic safety of the concept appears well in hand. Large HTGRs are now in the licensing process; based on experience with Peach Bottom #1 and the FSVR, it is expected that licensing will proceed, as one might predict at this early stage of development, with no major unresolved safety issues expected to surface.

6A.1.2.4 Research and Development Program

The successful operation of the Peach Bottom #1 reactor since 1967 has satisfactorily demonstrated the use of the HTGR concept for power production. This accomplishment along with the construction and preoperational testing of the FSVR has shown that further extensive research and development activities are probably not required for the successful construction and operation of the FSVR type and size plant. Safety research is under way related to fuel reprocessing and refabrication, to reducing design conservatism, and to the attainment of higher outlet temperatures needed for the direct cycle HTGR. The needed research is not directly related to the safety of the plants now being licensed. With respect to HTGR fuel recycle, processes must be developed to reprocess the spent fuel and to fabricate the recovered U-233 into coated particles for reinsertion into the reactor.

The key problem in the reprocessing of the fuel is development of a process that will permit separation of the fissile (U-235) particles from the kernels containing thorium and U-233. As mentioned in Section 6A.1.2.3.2, the fuel kernels can be separated from the graphite by burning the graphite, and the two type particles may be separated based on the fact that the SiC-coated fissile particle will not disintegrate on burning while the Th/U-235 particle will. The reprocessing steps beyond the head-end process (dissolution and solvent extract) have been demonstrated in large-scale facilities.

The requirement to fabricate the recovered U-233 in shielded facilities, because of the presence of U-232 and its daughters and the accompanying high energy gamma radiation, will necessitate the development of processes and equipment to perform these operations. The key to this fabrication development is construction of equipment that can be remotely operated and maintained. Progress has been made in the development of such equipment but an integrated refabrication line has not been built.

Large-scale demonstrations of the reprocessing and fabrication technologies in the AEC's Idaho Chemical Processing Plant and in the Thorium Uranium Fuel Cycle Development Facility at ORNL, respectively, have been planned.

While the research and development programs related to the fuel cycle are essential to the commercialization of the HTGR, other activities are being carried out to develop a better understanding of the reactor system, to improve the performance of the system, and to provide increased knowledge about its safety characteristics. Thus, programs are in progress to improve understanding of: the behavior of the fuel; the mechanism of the steam-graphite reaction; plate-out of fission products in the primary system; the mechanisms for release of fission products; and the high-temperature properties of the PCRV and component materials. In addition, research is continuing on the development of fuels which will have improved fission product retention and higher temperature capability. Efforts are also on-going to develop a direct cycle HTGR which would use a gas rather than a steam turbine.[14] Development of this latter concept, when combined with dry air heat rejection, would reduce the thermal pollution and consumption of water. The gas turbine HTGR with a bottoming cycle (use of a low-temperature vapor turbine to use the reject heat to generate electricity) has potential for achieving a thermal efficiency of 50%, which would further reduce environmental effects and conserve ore resources. The reject heat from the gas turbine HTGR could also be economically used for water desalination by distillation because the heat is rejected at the comparatively high temperature of 400°F.

The required research and development program fulfilling all the above objectives over the next five years has been estimated in the recent report to the President entitled "The Nation's Energy Future,"[15] to cost about $164 million.

6A.1.2.5 Present and Projected Application

The present use of the HTGR is for the generation of electric power. As noted earlier, the 40-MWe plant (Peach Bottom) has been shutdown recently for decommissioning after seven years of successful operation. A 330-MWe plant (Fort St. Vrain) is expected to go into full power operation by mid-1975, and six larger plants (two 770-MWe and four 1160-MWe) have been ordered, the first of which is expected to be operational in 1980. A long-range projection[3] indicated that HTGR capacity would be 23,000 MWe by 1985. The recent cancellations and deferrals of HTGR plant orders now indicate that the projection should be revised downward to a range of 5,000 to 10,000 MWe by that date.

Because of the potential for high-temperature operation of the reactor, consideration is being given in the U.S., Europe, and Japan for using the HTGR not only for power generation but as a process heat source. Thus, if technology could be developed to permit reactor outlet temperatures in excess of 1650°F, the reactor could be used for coal gasification; an 1800°F helium temperature would permit use of the reactor for steelmaking if such temperatures could be accommodated in the entire system. Other process applications such as hydrogen production, heavy oil recovery, and tar sands mining have also been proposed. If successful, they could lead to reduced consumption of some fossil fuels and to more efficient utilization of others.

As noted in Section 6A.1.2.4, research and development is under way toward use of HTGRs in conjunction with direct-cycle gas turbines and dry cooling towers to possibly lower plant cost, but more importantly to reduce the need for large amounts of evaporative (makeup) cooling water, as currently used by power plants operating on the steam cycle, such as LWRs, LMFBRs, and fossil-fueled plants. This capability may be possible due to the higher temperature reject heat from the gas turbine cycle as opposed to the steam cycle and the compatibility of the gas turbine with dry cooling towers. The developer of this system has proposed that the gas turbine HTGR could be in operation, with a thermal efficiency of about 36%, within the next decade. The 36% efficiency would be a reduction of 10% from the 40% efficiency available from modern steam cycle plants, and this would have to be taken into consideration. However, estimates have been made of efficiencies in excess of 47% for the gas turbine HTGR if it were coupled with a bottoming cycle.

6A.1.2.6 Environmental Impacts

The environmental impacts from an HTGR are generically the same as for other fission reactors, including the LMFBR. An exception to this statement is the amount of uranium ore that must be mined to fuel each reactor. The HTGR, as is the case for any other converter reactor, will require more uranium ore than an LMFBR, because the HTGR system is non-breeding. Whereas the uranium requirements for an LMFBR will be met by using the "tails" from the diffusion processes, a 1000-MWe HTGR will require approximately 113 tons of natural U_3O_8 and 8 tons of ThO_2 per year. If a symbiotic power generation system were to be developed (see Section 6A.1.4.5) wherein a fast breeder such as the GCFR (or LMFBR) produces U-233 for use in the HTGR, uranium makeup needs would be eliminated.

The use of direct-cycle helium turbines with the HTGR has the potential to reduce the requirements for cooling water because dry cooling towers can be used in place of a cooling pond, wet towers, or once-through systems. An advanced direct cycle system would utilize an organic "bottoming" cycle. If this system can be developed, thermal efficiencies approaching 50% can be realized. The reduced need for cooling water in a direct-cycle HTGR may potentially be of considerable environmental (and resource) significance. Some studies have shown that adequate supplies of cooling water for evaporative use by power plants will be a problem by the year 1990 to 2000. The potential capability of the HTGR to alleviate this problem is significant. In addition, the potential siting flexibility in not being dependent on large supplies of cooling water would be an important advantage.

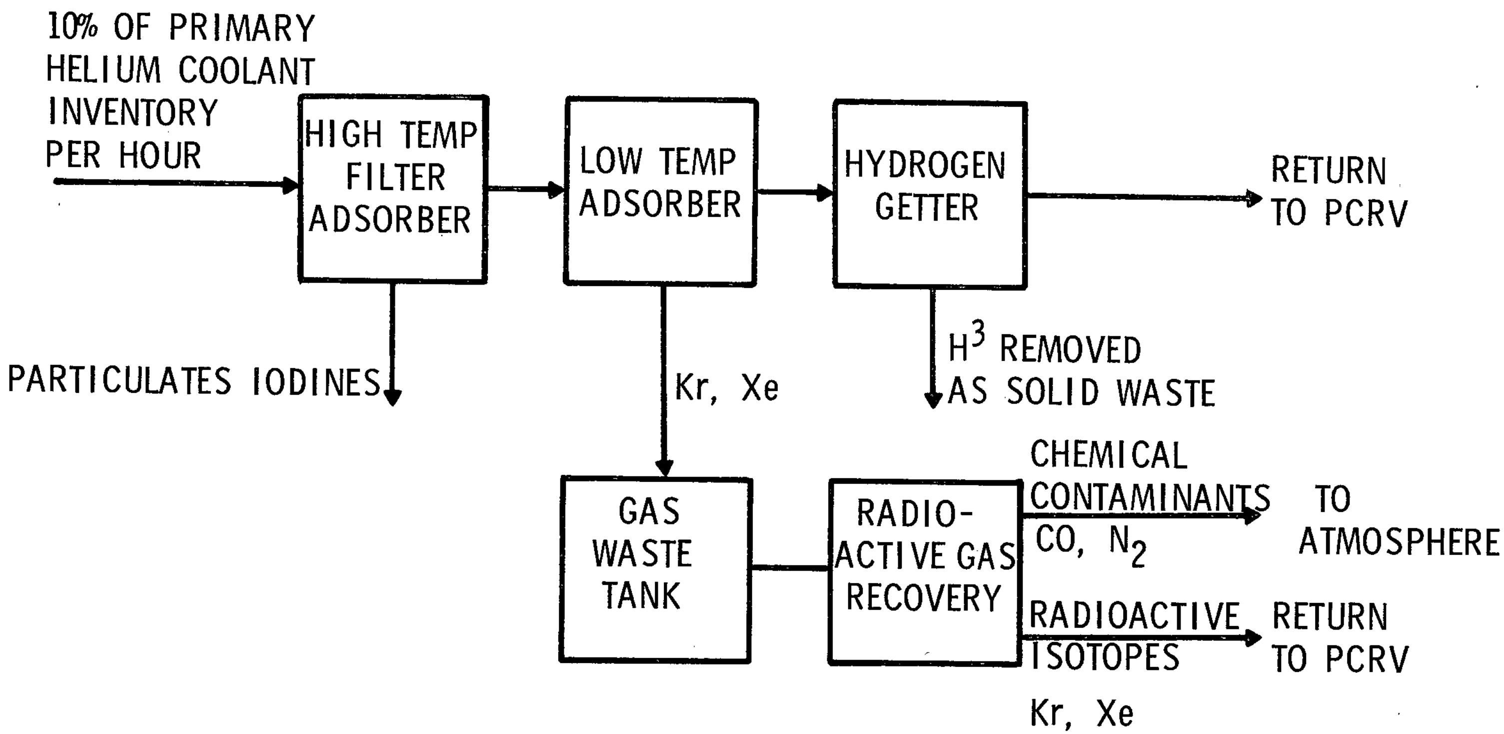
From the standpoint of radiological impact the HTGR offers a situation similar to all other reactor systems. The use of thorium introduces a problem similar to that encountered during uranium mining. Natural thorium has only a single isotope, Th-232, which decays with a half-life of 14 billion years. Included in the decay chain is Rn-220, which is gaseous and diffuses into mine atmospheres although its short half-life of 55 sec indicates that this radon isotope has less chance for escape to the atmosphere than the Rn-222 (3.8-day half-life) in the U-238 series. The daughters of Rn-220 are also relatively short-lived and include some alpha particle emitters, which give the principal dose to the lungs. Thus, thorium mining would be expected to have an associated increased respiratory cancer risk, as has already been discussed for uranium. (See Section 6A.1.1.6.2.)*

Tritium is produced in the HTGR by ternary fission and is mostly retained in the fuel particles and the graphite matrix. Tritium is also produced by neutron activation reactions with helium (He-3) and lithium. The activation of He-3 is the main source of tritium in the coolant. The tritium is removed from the coolant by the hydrogen getter (absorber) unit in the helium purification system, through which a fraction of the helium passes rather than going through the reactor. The titanium sponges in these getter units are replaced monthly and are shipped off site as solid waste. The tritium release to the environment from a large HTGR is expected to be less than 5 Ci/year.

The krypton and xenon isotopes will also be removed from the coolant in the helium purification system by using a low-temperature absorber delay bed. Rather than being released after regeneration of the low-temperature delay (mostly long-lived Kr-85 as the other radionuclides have decayed), the gas can be bottled for offsite disposal or it can be returned to the primary coolant system where it will be taken out again by the low-temperature absorber. The lifetime inventory of krypton can be retained this way with the result that less than 10 Ci of Kr-85 are expected to be released to the environment annually at a large HTGR. Figure 6A.1-31 is a diagram of the helium purification system. Liquid wastes will be accumulated at the HTGR from decontamination operations or as a result of equipment failure such as a steam generator tube leak. Under normal conditions the liquid radioactive waste is expected to be about 10 Ci/year. Treatment systems utilizing devices such as those which are used in LWRs will keep liquid releases as low as practicable. The radioactive liquid waste system is shown in Figure 6A.1-32.[16]

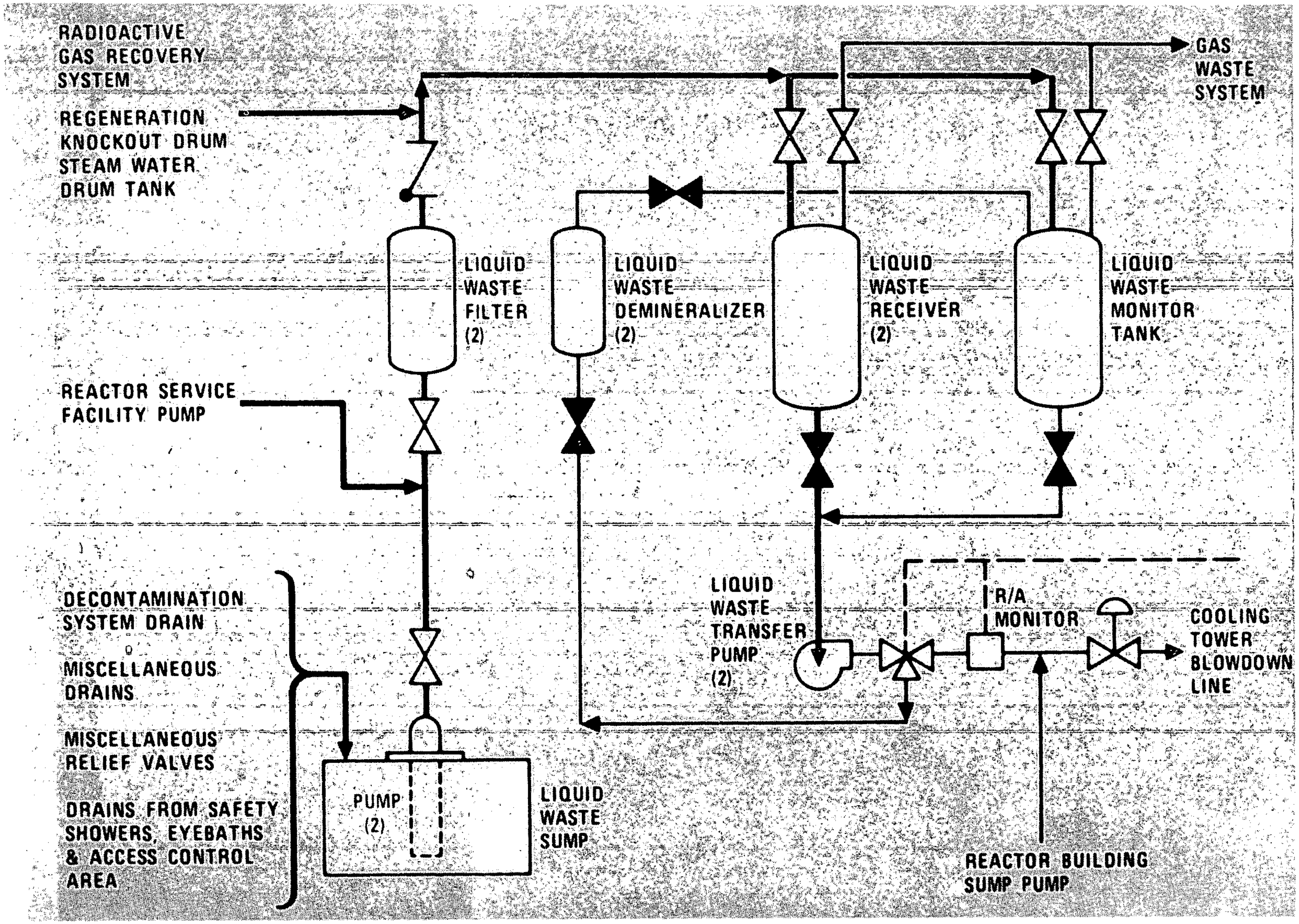
Compared with the LWR, the HTGR produces a somewhat lower volume of solid wastes to be shipped to the Federal repository or commercial burial grounds. This is mainly due to the higher thermal efficiency of the reactor, the elimination of cladding

*Note, however, that while additional uranium mining will be required for HTGRs and LWRs, none will be required for LMFBRs for many decades. The use of already mined uranium tails eliminates the need for additional uranium mining for LMFBRs well beyond the period under consideration in this Statement.



HTGR HELIUM GAS PURIFICATION SYSTEM

Figure 6A.1-31



HTGR RADIOACTIVE LIQUID WASTE SYSTEM

Figure 6A.1-32

hulls, and the relatively high amount of thermal energy extracted per unit mass of fuel material in the HTGR. The burial ground area needed to store the solid wastes from an HTGR has been estimated to be about 70% of the area needed for a similarly sized PWR.

Most of the transportation steps in the HTGR fuel cycle are similar to those in the LWR and LMFBR fuel cycles. One attractive feature of the HTGR cycle is that, under current plans, the reprocessing plant and the fuel-fabrication plant would be located at the same site, thereby avoiding the need for off-site transportation. However, the transportation of the recycled uranium from the fabrication plant to the reactor in the HTGR fuel cycle presents special considerations because of the relatively rapid buildup of decay products of U-232. Also, the shipment of highly enriched U-235 as required by HTGRs from the gaseous diffusion plant and fabrication plant presents some special problems, especially with respect to safeguards. The extra difficulties encountered in these shipments are balanced somewhat by the fact that the HTGR has significantly less material to be shipped in most steps in the fuel cycle compared to LWRs.

Table 6A.1-18 summarizes annual data[17] for a 1000-MWe HTGR operating at 75% plant factor, that is, power plant and fuel cycle data corresponding to the production annually of 6.57 billion kilowatt hours of electrical energy. A more complete discussion of the environmental impacts of the complete HTGR fuel cycle, including shipping considerations, is provided in refs. 18 and 19.

6A.1.2.7 Costs and Benefits

6A.1.2.7.1 Costs

The capital costs for an HTGR will be less than those for a comparably sized LMFBR due to several differences in their engineering design. Although the use of a PCRV and associated equipment in an HTGR would be more costly than that of the steel pressure vessel in an LMFBR, the need for an intermediate heat exchanger loop in the LMFBR more than offsets the additional costs of the PCRV. An AEC-supported study concluded that the relative costs of other structures, buildings, and equipment for an HTGR or LMFBR will not be so different in a mature industry as to affect the overall cost differential caused by the two major engineering differences. The basis for this conclusion is that there are some areas wherein it appears that an HTGR will be more costly (higher pressure containment building and larger and more complex fuel storage facilities and radioactive waste building), but there will also be features in which the LMFBR will be more expensive (such as the need for more

Table 6A.1-18

ANNUAL EFFECTS OF A 1000-MWe HTGR AND ITS SUPPORTING FUEL CYCLE

	Mining	Milling and Fabrication[a]	Reactor Power Plant	Reprocessing Transportation[b]	Totals
Conventional Costs (10^6 $) (1980 dollars)					
Fuel	1.1	7.5	3.5[c]	1.5	15
Plant Capital			57		57
Operation and Maintenance			4.8		4.8
Rounded Total					77
Abatement Costs (10^6 $) (1980 dollars)					
Cooling Towers			2.4		2.4
Occupational Accidents					
Deaths	0.05	0.003	0.01	0.002	0.07
Non-Fatal Injuries	1.8	0.75	1.3	0.06	3.9
Man-Days Lost	383	47	110	14	354
Mining and Milling Impacts					
Strip Mining of Uranium & Mill Tailings (acres)	2.7	1.2	-	-	3.9
Tailings Produced @ Mill (10^3 metric tons)	-	43	-	-	43

Basis: 6.57 billion kWhr (one year operation @ 75% CF)

Table 6A.1-18 (cont'd)

ANNUAL EFFECTS OF A 1000-MWe HTGR AND ITS SUPPORTING FUEL CYCLE

	Mining	Milling and Fabrication[a]	Reactor Power Plant	Reprocessing Transportation[b]	Totals
Public Accidents in Transportation of Nuclear Fuels (Excluding exposures to radioactivity)					
Deaths	-	-	-	0.009	0.009
Non-Fatal Injuries	-	-	-	0.08	0.08
Man-Days Lost	-	-	-	60	60
Occupational Health					
Miners' Radiation Exposure (miner-working level month)	58	-	-	-	58
Other Occupational Exposure (man-rads)	-	15	300	12	327
Solid Radioative Waste Disposal					
Volume (10^2 ft^3)	-	31	22	10	63
Burial Area (acres)	-	0.06	0.04	0.26	0.4
Effects at the Power Plant					
Thermal Discharge (10^{10} kWt-hr)	-	-	1.1	-	1.1
Net destruction of uranium (metric tons)	-	-	0.3	-	0.3
Net destruction of thorium (metric tons)	-	-	0.5	-	0.5

Table 6A.1-18 (cont'd)

ANNUAL EFFECTS OF A 1000-MWe HTGR AND ITS SUPPORTING FUEL CYCLE

	Mining	Milling and Fabrication[a]	Reactor Power Plant	Reprocessing Transportation[b]	Totals
Routine Radioactive Releases to the Atmosphere (Ci)					
H-3	-	-	4	16000	16000
Kr-85	-	-	9	570000	570000
I-129	-	-	-	0.0003	0.0003
I-131	-	-	-	3.	3.
Xe-131m	-	-	-	-	-
Xe-133	-	-	-	-	-
Cs-137	-	-	-	0.002	0.002
Rn-222 and 220	-	23	-	-	23
C-14	-	-	-	200	200
U-232	-	0.4	-	∿0	0.4
U-233	-	0.2	-	∿0	0.2
Total U	-	0.7	-	∿0	0.7
Others	-	-	-	2.	2.
Routine Radioactive Releases to Waterways (Ci)					
H-3	-	-	-	350	350
I-129	-	-	-	0.0002	0.0002
I-131	-	-	-	0.02	0.02
Cs-137	-	-	-	0.004	0.004
U-232	-	9	-	-	9
U-233	-	4	-	-	4
Total U	-	14	-	-	14
Others	-	0.01	4	2	6

Table 6A.1-18 (cont'd)

ANNUAL EFFECTS OF A 1000-MWe HTGR AND ITS SUPPORTING FUEL CYCLE

	Mining	Milling and Fabrication[a]	Reactor Power Plant	Reprocessing Transportation[b]	Totals
Population Exposure from Routine Releases of Radionuclides					
Global Model: All-Time Commitment, Long-Lived Nuclides					
World (whole-body man-rads)					
Kr-85	-	-	-	256	256
H-3	-	-	-	21	21
Total World					277
U.S. (whole-body man-rads)					
Kr-85				12.0	12.0
H-3				2.3	2.3
Total U.S.					14.3
Local Model: Airborne Short-Lived Noble Gases and Tritium					
Total man-rems within 50 miles					
High-Population Assumption					48
Medium-Population Assumption					4.8
Low-Population Assumption					0.69

[a]Milling, conversion, enrichment, and preparation and fabrication.

[b]Includes all transportation stops.

[c]Working capital charges.

primary system service equipment and components and a more complex fuel-handling system). Based on current and anticipated designs, the AEC believes that a capital cost advantage for structures, buildings, and equipment cannot be claimed by either reactor system. On the other hand, General Atomic Company believes that the HTGR does have a cost advantage over the LMFBR in this area, as noted in their letter of April 29, 1974 which provided comments on the Draft Environmental Statement.*

In Section 11 of this Statement, the relative capital costs in \$/kWe of several reactor types are compared; in 1985 these costs would be \$419 and \$520 for a 1300-MWe HTGR and LMFBR respectively. If the use of direct-cycle power conversion in the HTGR should prove successful, then the capital cost of HTGRs would be reduced even further due to the more compact nature of this power conversion equipment (elimination of the heat transfer loop in conventional HTGRs). Future potential engineering changes in LMFBR systems, such as the possible elimination of the need for an intermediate cooling loop, could also change the cost differential between HTGRs and LMFBRs if implemented.

The operating and maintenance costs for an HTGR would also tend to be lower than those for an LMFBR, as shown in Section 11. The respective annual costs for 1300-MWe plants introduced before 1990 are estimated at \$12.7 million for an HTGR vs \$14.5 million for an LMFBR, both operating at 80% plant factor.

With regard to fuel cycle costs, the HTGR is obviously less advantageous than the LMFBR as the HTGR does not breed new fuel. However, in comparison with other "burner" reactors such as the LWR, the HTGR shows up quite favorably. This results from the HTGR's operation on the thorium cycle and its relatively higher conversion ratio. U_3O_8 ore requirements for a 1000-MWe HTGR are half those of a similarly sized LWR. The impact of this is that while a 100% increase in U_3O_8 costs results in an increase of about 0.5 mills/kWhr for the LWR, it results in only a 0.3 mills/kWhr increase for the HTGR. Thus, in the year 2000, the savings to the public if ore costs were to double, and assuming the HTGR represents a conservative 7% of the electric generating capacity in the U.S., would be \$112 x 10^6 when compared to the LWR.

Developmental costs for the HTGR will be considerably less than those for the LMFBR. The major reactor questions appear to have been resolved, and further development will likely be directed to improvements in fuel performance, added safety

*Comment Letter 34, p. 12.

assurance, demonstration of economical fuel reprocessing, and various other fields, rather than to the major developmental and prooftesting type of activities still ahead for the LMFBR.

6A.1.2.7.2 Benefits

The main benefit that may accrue from HTGRs as compared to LWRs is the significantly lower thermal discharge of the HTGR. Because of the small quantities of both liquid and gaseous radioactive wastes requiring processing at the reactor site, the HTGR is expected to make control of effluent release relatively simple.

In addition, HTGR operation on the uranium-thorium fuel cycle will help conserve uranium and thorium resources by utilizing thorium reserves with high efficiency. Finally, as noted in Section 6A.1.2.5, the HTGR's potential for use with a direct-cycle gas turbine and dry cooling towers could significantly reduce the need for large amounts of makeup cooling water as currently needed by power plants operating on the steam cycle. As growing power needs draw more and more heavily on the Nation's cooling water resources, this potential feature of the HTGR could become of greater significance.

6A.1.2.8 Overall Assessment of Role in Energy Supply

6A.1.2.8.1 Probable Role Up To Year 2000

Based on current plans, research and development status, and projections, the HTGR is expected to provide approximately 5 to 6% of the electrical generating capacity and about 10% of the nuclear capacity by the year 2000.[3] These percentages are subject to change depending upon the success of the first large HTGRs, the date of introduction of the LMFBR, the number of manufacturers available to provide HTGRs, and the relative role of other energy sources.

6A.1.2.8.2 Possible Role Beyond Year 2000

In later years, the HTGR is expected to decrease in use because it, like the LWR, is dependent upon enriched U-235 for fuel, and as the costs of ore and separative work increase, the use of any system requiring enriched U-235 will decrease in favor of a breeder system. Of course, if a symbiotic power generation system were to be developed, this consideration would not apply and the use of HTGRs as thorium fuel burners might continue indefinitely.

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6A.1.3 Light Water Breeder Reactor

6A.1.3.1 Introduction

6A.1.3.1.1 General Description

The light water breeder reactor (LWBR) utilizes the U-233/Th fuel cycle in a light water cooled and moderated thermal (slow) neutron spectrum to obtain breeding of nuclear fuel. It is one of several concepts potentially capable of improving the utilization of nuclear fuel resources over that currently available in LWRs. The LWBR possesses the added feature of using proven LWR technology and is compatible with conventional pressurized water reactor plant designs without major plant modifications.[1]

To confirm the technology of this system, a breeding core (net 50 MWe) for the pressurized water reactor plant at Shippingport, Pennsylvania has been designed and is being fabricated. This Shippingport core is designed to simulate a large core environment in its central portion and to breed in the entire core.

6A.1.3.1.2 History and Status

The LWBR program, building on technology developed in the Shippingport project which was begun in 1953, was initiated in 1965. Initial funding for the Shippingport breeding core was provided in the AEC budget for fiscal year 1969.[2] The breeding core and associated hardware needed to install it in the Shippingport reactor vessel are being manufactured.[3,4] Installation of the breeding core in the Shippingport reactor plant is expected to begin in late 1975 with start up in 1976.

6A.1.3.2 Extent of Energy Resource

6A.1.3.2.1 Geographic Distribution and Estimated Availability

The primary energy resource for the LWBR system is thorium. A limited amount of natural uranium (between 1300 and 3000 tons of U_3O_8) is required to provide the fissile fuel needed to establish an equilibrium breeding cycle in a 1000-MWe plant. The geographical distribution of both fuels is worldwide, with major reserves in both the United States and Canada. Information on the distribution of thorium and uranium resources is provided in Sections 6A.1.2.2 and 6A.1.1.2, respectively. The amount of energy potentially obtainable from the reasonably assured reserves of thorium ore is well in excess of that obtainable from fossil fuel resources.[5] The estimated U.S. thorium reserves according to price range are discussed in Section 6A.1.2.2, wherein it is shown that there is an ample supply of thorium.

6A.1.3.3 Technical Description of Energy System

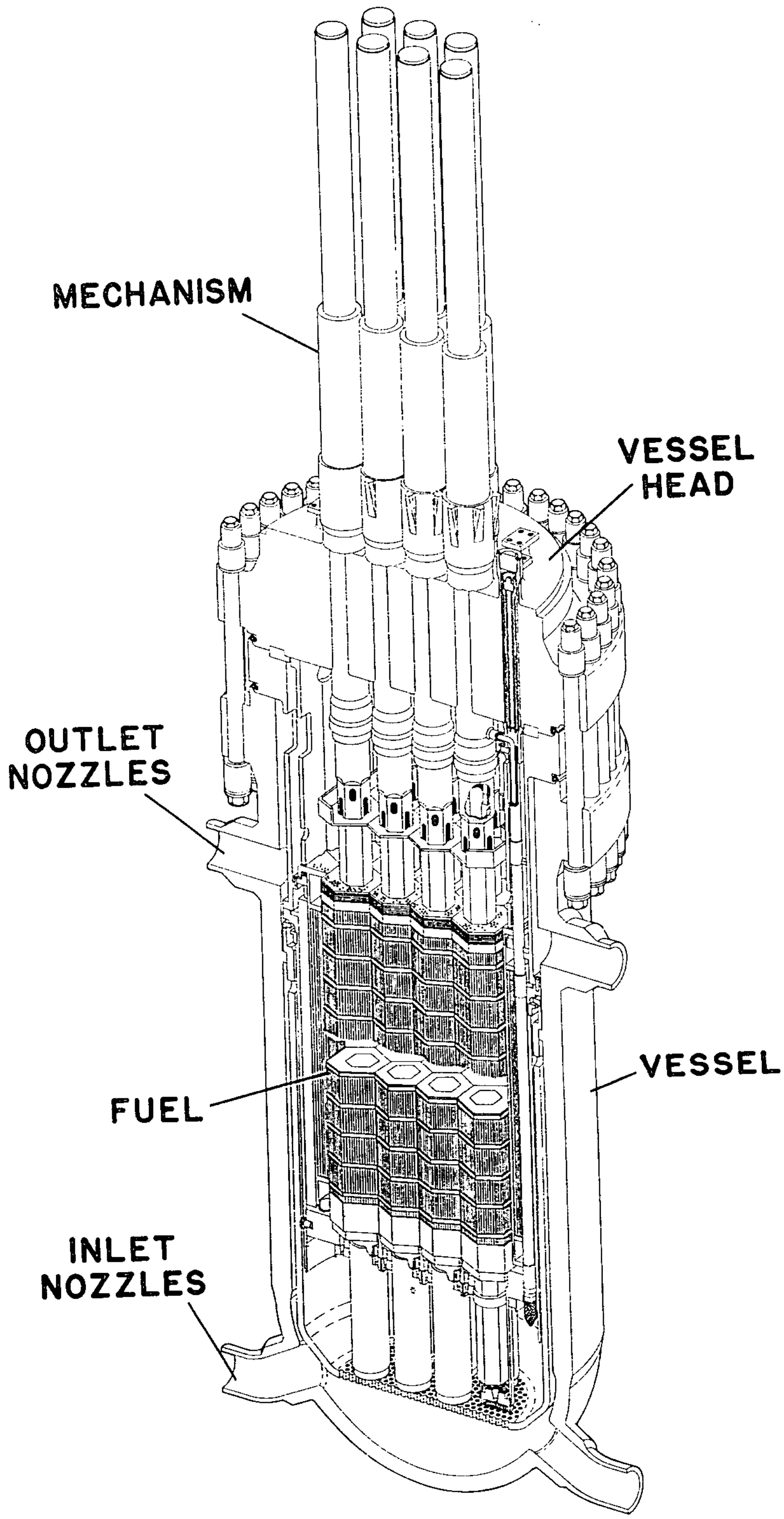
6A.1.3.3.1 Power Generation Plant

The plant cycle is the same as for other pressurized water reactors, as discussed in Section 6A.1.1.3. The cycle begins with a nuclear heat source that transfers heat to the primary coolant (pressurized water at approximately 2000 psi) which is then circulated to heat exchangers. Within these heat exchangers, heat is transferred from the primary plant to the secondary plant where saturated steam is formed which, in turn, drives the plant turbine generator. After exiting from the heat exchangers, the primary fluid is returned to the reactor vessel. The primary plant fluid is pressurized ordinary light water of high purity and is operated in its own closed system at subcooled conditions.

The major primary plant components typically include: the nuclear reactor core, pressure vessel (Figure 6A.1-33), and reactor coolant system consisting of typically two to four reactor coolant loops each connected in parallel to the reactor. Each coolant loop contains a heat exchanger as well as a pump which circulates the primary coolant in that loop. An electrically heated pressurizer is connected to one of the loops to maintain pressure in the primary plant system during plant operation.

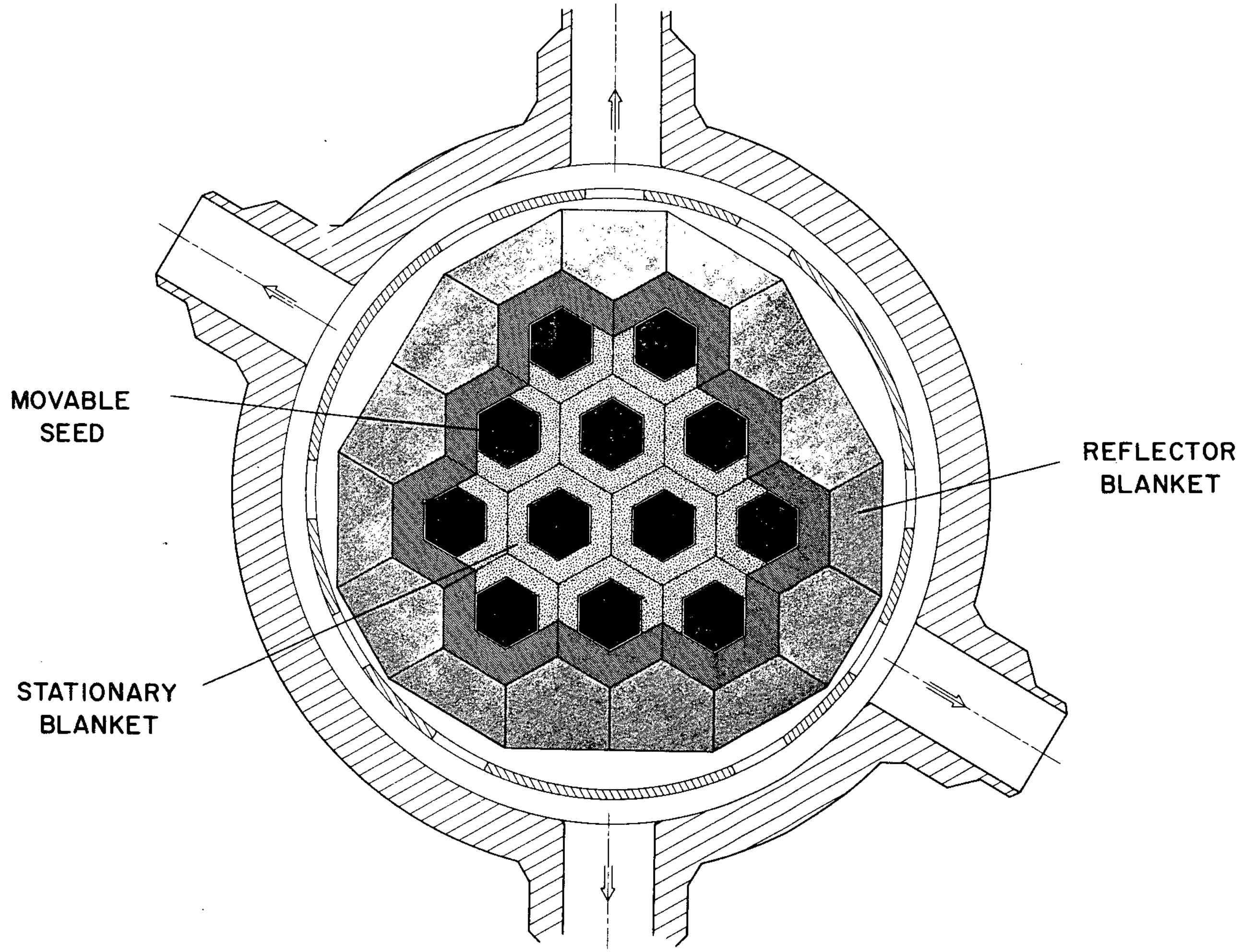
The steam produced in the secondary side of the heat exchanger is carried by steam lines to the turbine generator unit to generate electrical power for distribution by the utility power transmission system. The turbine exhaust is discharged to a condenser where the unused energy is dissipated. The resulting liquid is then returned to the heat exchanger.

A typical fuel module in the Shippingport LWBR core contains a central, axially-movable, hexagonal seed and a stationary, annular, hexagonal blanket (see Figure 6A.1-34). The Shippingport core will be a breeder core rather than a pre-breeder core (see Section 6A.1.3.3.2 below). The seed is made up of full length Zircaloy-4 clad fuel rods about 0.3 in. in diameter. The seed fuel consists of solid thorium oxide (ThO_2) pellets containing 0 to $\sim$6 wt % U-233 oxide ($^{233}UO_2$). The blanket fuel rods are about 0.6 in. in diameter and the ThO_2 pellets contain 0 to $\sim$3 wt % $^{233}UO_2$. The fuel height in both the seed and blanket rods is 8-1/2 ft, including about 9-in.-long natural thoria (ThO_2) reflector blanket regions at the top and bottom of each rod. The seed and blanket rods also contain gas plenums designed to accommodate fission gas release.



LWBR CORE IN SHIPPINGPORT VESSEL

Figure 6A.1- 33



SHIPPINGPORT LWBR CORE CROSS SECTION

Figure 6A.1-34

The nuclear design is such that the more highly loaded seed has a neutron multiplication factor greater than 1, and the lower loaded blanket has a neutron multiplcation factor less than 1. Reactivity is controlled by varying the leakage of neutrons from the small seed regions into the subcritical blanket regions. This variation is achieved by axially positioning the seed section of the module so as to change module geometry rather than by using conventional parasitic neutron-absorbing materials. With this method of control, which is one of the major features of the seed-blanket concept, excess neutrons will be absorbed in fertile thorium material and good neutron economy can be achieved. The reactivity worth of the movable seed is increased by using partial lengths of natural thoria in some of the seed and blanket rods.

The design of the LWBR system module evolved from the technology developed in PWR (Shippingport) Core 1 and Core 2. The control mechanisms used in the Shippingport LWBR for reactor control are of the same demonstrated basic design previously used for positioning the PWR control elements. The seed fuel assemblies are slowly raised to increase reactivity and bring the reactor to full power. Reactor shutdown is accomplished by lowering the movable seed assemblies.

The Shippingport core will normally be fueled and defueled by removing complete modules after the vessel closure is removed. Removal of the seed of an individual module is also possible through a hole in the vessel closure after the associated control drive mechanism is removed.

Surrounding the 12 fuel modules of the Shippingport LWBR core is a natural thoria region about 8 in. thick that serves as a reflector blanket. The reflector blanket will limit neutron leakage from the core to less than about 0.8% of all neutrons. Larger light water breeder cores (1000 MWe) can be designed with leakage of 0.1% or less, thereby achieving even better breeding performance than in the Shippingport LWBR core. Use of this peripheral reflector blanket in the small Shippingport LWBR core assures an unambiguous quantitative determination of breeding within the entire core.[1]

6A.1.3.3.2 Fuel Cycle

For a large LWBR reactor, initially fissile fuel is required to operate a pre-breeder core to build up the necessary inventory of U-233 by irradiation of thorium. Either enriched U-235 or plutonium could be used. After about ten years of pre-breeder core operation, sufficient U-233 would be available to fuel a breeder core. Once a core can be operated on the breeding cycle, there would be no further need for enriched uranium or plutonium and the only makeup material required for the fuel cycle would be thorium. When a plant operating on this breeding cycle reaches the end of its useful life (30 to 40 years), replacement of its electrical generation capacity could be by a plant started up directly as a breeder using the fissile inventory from the old plant, without requiring further mining or enrichment of uranium.[6] The LWBR core being built for installation in Shippingport is designed to confirm the breeding potential of this concept.

The equilibrium fuel cycle of an LWBR system is similar to that of the PWR system. The mining and preparation involves natural thorium in the LWBR system instead of uranium as in a conventional pressurized water reactor. The thorium is sent directly to the fuel element fabrication point where it is added to reprocessed uranium and thorium as makeup for the fissioned fuel and reprocessing losses of the previous cycle.

The refabricated fuel elements are then installed for another cycle of reactor power operation. At the end of core life, the fuel modules are removed and, following a radioactive cooling period, are shipped to a fuel reprocessing plant.

In the fuel reprocessing plant, the thorium, uranium, and fission products are chemically separated. The reprocessed uranium is sent back to the fuel element fabrication plant to be refabricated into fuel elements while the fission products and radioactive wastes are placed in appropriate long-term storage (see Section 6A.1.2.3). The reprocessed thorium, which will contain some radioactive Th-228, could be sent back for refabrication or stored for later use depending upon the resource availability and economic situation prevailing at the time.

6A.1.3.3.3 Energy Transmission

The electrical power distribution system associated with an LWBR nuclear central station would be similar to that for any other electricity generating station.

6A.1.3.4 Research and Development Program

Research and development for the LWBR, building on the technology developed by the Shippingport reactor program which started in 1953, has been under way since 1965. Most of the necessary research has been completed to the point where fabrication of the Shippingport breeding core is currently under way toward a 1976 start of operation in the Shippingport reactor plant.[3,4] Research and development at reduced levels is planned to continue as necessary to support the Shippingport breeding core operation and to confirm that breeding actually occurred. This effort is included as part of the program described in "The Nation's Energy Future."[7]

For the LWBR to proceed beyond the current Shippingport breeding core phase into full-scale commercial use, additional research and development will be required. One area that will require further development is the design of pre-breeder cores. Other areas that might require research and development include improvement in breeder core design and performance, as well as extension of the technology now being used in the manufacture of the Shippingport breeding core to a large-scale commercial process for refabrication of reprocessed U-233 into fuel elements. Refabrication is complicated by the fact that the recycled fuel is radioactive. If nuclear power is to be a major energy source in the future, however, all fission reactor cycles will, of necessity, use recycled fuel.

6A.1.3.5 Present and Projected Application

6A.1.3.5.1 Current Use

Although LWBRs are not yet in use, the technology has advanced to the point that, as noted above, a core is being manufactured and will be used to confirm the breeding capability of a U-233/Th-fueled LWBR-type core in an existing pressurized light water reactor plant. Successful completion of this program will demonstrate technology that could permit the conversion of existingand future pressurized water reactor plants to self-sustaining breeders. This conversion could turn out to be a practical approach to obtaining the high fuel utilization needed to make nuclear power fulfill its promise of providing mankind an essentially unlimited energy source. This approach would avoid many of the technical problems associated with other high fuel utilization systems while making use of highly developed light water technology. The performance of this small breeding core can be extrapolated to predict the performance of large light water breeder reactors.[1,3,4]

6A.1.3.5.2 Projected Use

Following successful operation of the Shippingport breeding core (50 MWe), the next step in exploiting the potential of the light water breeder system would be design and construction of large light water breeders (1000 MWe) that would achieve a high degree of fuel utilization on a long-term basis. As previously stated, pre-breeder cores would be needed for about the first ten years of operation. Once the breeding cycle cores are operating, only thorium would be needed as makeup to the fuel cycle and about 50% of the thorium added would eventually be utilized to generate power. This high degree of fuel utilization would represent a very significant increase over present types of light water power reactors which utilize only 1 or 2% (including plutonium recycle benefits) of the energy potential of the mined uranium.

6A.1.3.6 Environmental Impacts

6A.1.3.6.1 Energy Conversion Plant

The environmental impact resulting from the operation of an LWBR core is essentially the same as for a PWR of comparable capacity except in the following two areas. First, the LWBR requires significantly less mining, milling, and enrichment of uranium, and second, the LWBR uses the uranium-thorium fuel cycle which produces mainly isotopes of uranium rather than plutonium. All other aspects will be about the same as would result from operation of a PWR of comparable capacity.

The fuel elements in the LWBR consist of pelletized nuclear fuel materials encapsulated in high-integrity zircaloy rods. The design of these elements utilizes the fuel-element design experience gained from years of operation of PWR plants. The ability of the LWBR fuel system to withstand the effects of irradiation has been confirmed from PWR operations and extensive irradiation testing. Hence, any release of fission product activity that might occur is expected to be about the same for an LWBR as that experienced in PWRs (see Section 6A.1.1.6).

A typical LWBR plant is expected to provide three independent containment barriers between the fissile fuel and the plant environment. These are (1) the cladding that encapsulates the pelletized fuel materials, (2) the walls of the reactor coolant system, and (3) the containing structure surrounding the reactor plant. These barriers are all designed, fabricated, and inspected to ensure high integrity. A more complete discussion of reactor safety is provided in Section 4.2.3.2.

It is concluded from the foregoing discussion that the installation and operation of a large-scale LWBR plant will have no significant effect on the quality of the environment beyond that of a pressurized water reactor nuclear central station of comparable capacity and will reduce the environmental impact of mining, milling, and enriching uranium ore. The economic and social impacts would essentially be no different than those resulting from the installation and operation of an ordinary pressurized water reactor plant.

6A.1.3.6.2 Offsite Support Activities and Facilities

The LWBR system utilizes an integrated fuel cycle that involves reprocessing and refabricating of fuel material as is typical of all other nuclear fuel systems.

Commercial facilities capable of fuel reprocessing and refabrication to accommodate U-233/Th reactor systems would have to be provided as noted in Section 6A.1.3.4 and would have to operate with minimal effect on the environment. The design of these plants will be regulated by very stringent criteria such as those associated with existing commercial reprocessing plants and with plutonium recycle facilities.

6A.1.3.6.3 Irreversible and Irretrievable Commitments of Resources

The LWBR breeding fuel cycle is based on converting fertile thorium to fissile U-233 at a rate faster than U-233 is consumed to generate power. Thus, the only irretrievable commitment of resources would be the gradual consumption of thorium. The decrease in the supply of thorium by conversion to and use as a nuclear fuel would be relatively minor compared with the availability of thorium resources, as shown in Section 6A.1.2.2. During about ten years of operation of the pre-breeder cores, it is estimated that somewhere between 1300 tons and 3000 tons of U_3O_8 is required to provide the fissile fuel needed for each 1000 MWe of generating capacity.[6]

The installation and operation of a large-scale LWBR plant would result in no irreversible and irretrievable commitments of local environmental resources. The land occupied by the buildings and the use of source water to reject plant heat are the only impacts on the local environment and are reversible. Irretrievable and irreversible commitments of resources include the following:

(1) Quantities of construction materials that cannot be economically retrieved.

(2) Spent nuclear fuel that is converted into radioactive waste material or other materials which become radioactive.

6A.1.3.7 Costs and Benefits

6A.1.3.7.1 Energy Production Costs

The energy production costs for large LWBR reactors based on present costs of U_3O_8 are estimated to be slightly higher than for present types of light water reactors of comparable size. The energy production costs of a nuclear power system are normally broken into three categories: capital costs, operating and maintenance costs, and fuel cycle costs. On the basis of the information currently available, it is reasonable to assume that the first two categories, which contribute approximately two-thirds of the total, would be the same for an LWBR system and a PWR system of the same capacity because they both would be applicable to the same plant. The fuel cycle costs (based on present costs of U_3O_8) that contribute the remaining approximately one-third are higher in the LWBR system due to the features necessary to achieve breeding and to the use of recycled radioactive fuel in the core. However, if nuclear power is to be a major energy source in the future, all reactor cycles will of necessity eventually use recycled fuel. The difference in energy production cost is not expected to be a barrier to use of LWBR-type nuclear central stations when other energy resources become limited and the cost of U_3O_8 increases.

No valid quantitative fuel-cycle cost comparisons of large scale LWBRs and LWRs can be made at this time. However, the fuel-cycle cost of LWBRs would be higher than that of LWRs until the cost of U_3O_8 increases. In view of the uncertainty of future large-scale LWBR and LWR fuel performance limits and fuel cycle costs, the value of U_3O_8 that would result in LWBR fuel-cycle costs being equal to LWR fuel-cycle costs cannot be determined at this time.

The environmental cost of LWBR operation would be the same as for a pressurized water reactor of comparable capacity (as discussed in Section 6A.1.1.6) except the LWBR would require mining of small amounts of thorium and much less uranium, as previously discussed.

6A.1.3.7.2 Development Costs

Most of the development work associated with the LWBR system has been completed as discussed above. The major foreseeable area of future developmental costs would be development of the design of prebreeder cores. Other areas of possible future development include improvements in breeder core design and performance as well as refabricating techniques for reprocessed thorium and U-233.

6A.1.3.7.3 Benefits

The major benefit of the LWBR system is the use of existing pressurized water reactor technology with high fuel utilization, i.e. the potential that approximately 50% of the mined thorium could be used to generate electricity compared with only 1 or 2% of the mined uranium in present types of light water reactors (PWR or BWR including plutonium recycle). Although enriched uranium or plutonium is required to establish a self-sustaining LWBR breeding cycle, none would be required after the ten-year pre-breeder period for as long as the cycle is continued. This system would be subject to higher uranium ore prices only to the extent that enriched uranium is necessary to fuel pre-breeders. This system also has the potential that it can be backfit into existing PWR plants, thus converting them to breeders with higher fuel utilization.[1,3,4]

6A.1.3.8 Overall Assessment of Role in Energy Supply

6A.1.3.8.1 Probable Role up to Year 2000

The probable role of the LWBR system in the world's energy production up to the year 2000 is either as replacement cores for conventional PWR cores in large electric generating plants or as new electric plants. If the LWBR concept proves successful, many LWBR systems may have gone through the pre-breeding portion of their cycles and be operating as self-sustaining breeder systems by the end of the century, thereby contributing significantly to better fuel utilization for the industry. The magnitude of the energy fraction produced by this system will be dependent upon the acceptance of the LWBR system by the electric power industry following operation of the LWBR breeding core at Shippingport.

6A.1.3.8.2 Possible Role Beyond Year 2000

An expanded role is possible for the LWBR system beyond the year 2000. This role is dependent upon the growth of electrical energy demands and the success of development and economics of other energy sources.

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6A.1.4 Gas-Cooled Fast Breeder Reactor

6A.1.4.1 Introduction

6A.1.4.1.1 General Description

Although most of the development work on fast breeder reactors has been devoted to the use of liquid metal coolant, interest has been expressed for a number of years in alternative breeder concepts using other coolants. One concept in which interest has been retained is the gas-cooled fast reactor (GCFR).[1]

The GCFR, as the name implies, uses helium at high pressure to cool the reactor core. The core does not contain a moderator, so that a fast neutron spectrum is maintained and breeding is achieved. The plant arrangement is of the "integrated" type, with all major components of the primary system contained within a prestressed concrete reactor vessel (PCRV). The PCRV contains the reactor core, the entire helium flow system, the independent steam generating loops, and the auxiliary cooling loops. The use of helium as the coolant gas leads to several potentially favorable attributes of the GCFR. Helium is both optically and neutronically transparent, does not become radioactive, does not change phase, and is chemically inert. The GCFR has a potentially high breeding ratio resulting largely from the good neutronic properties of the coolant.

6A.1.4.1.2 History

GCFR development was initiated in November 1963 by the AEC under a contract with General Atomic Company (GAC)* to investigate the concept which had evolved from earlier privately-supported GCFR studies. The AEC-sponsored work outlined a development program that started with the objective of a gas-cooled fast reactor experiment of 50 MWt which was to lead to a demonstration power plant as a step towards a full-scale plant. An outcome of the next year of AEC-sponsored research (1964) was a conceptual design for a reactor experiment that would serve as a test bed for fuel development and would provide experience in designing and constructing a special PCRV.

In the period 1965-1968, the AEC and GAC continued studies of the GCFR. A conceptual design for a 1000-MWe GCFR power plant was evolved, which featured a horizontal PCRV instead of the original vertical arrangement and also differed in other important respects from the original concept. This effort incorporated

*General Atomic Company formerly was Gulf General Atomic and prior to that the General Atomic Division of General Dynamics Corporation.

ideas of the utility companies, particularly as to the layout and design of the nuclear steam supply components from the viewpoint of operation, maintenance, and safety. Also, a new design for a reactor experiment was developed to reflect engineering aspects of the new large-plant design. The 1000-MWe GCFR reference conceptual design prepared by GAC for study by the AEC Fast Breeder Reactor Alternate Coolant Task Force[2-4] was an extension of the above conceptual design. During 1967, to satisfy the needs of the Alternate Coolant Task Force as well as to meet AEC contractual requirements, a Preliminary Development Plan for the GCFR was also prepared.[5]

The AEC evaluated the GCFR concept in 1969 and issued "An Evaluation of Gas-Cooled Fast Reactors" (Report WASH-1089, April 1969), along with a companion report, "An Evaluation of Alternate Coolant Fast Breeder Reactors" (Report WASH-1090, April 1969). The results of this study indicated that:

> GCFR's are feasible to build and operate, and ... the concept has the potential of providing low power costs and high breeding gains. A sizable body of research and development work is required to guarantee safe and reliable operation at the design performance levels, but the basic feasibility of the concept does not depend upon an improbable degree of success in the development programs. In the components and plant areas, this concept depends to a considerable degree on the successful development of the HTGR and its introduction into utility systems.

Evolution of the GCFR concept has continued with the goal of developing a GCFR design that could take maximum advantage of the development work being performed in other reactor development programs, specifically the HTGR program, which is developing plant components similar to those needed in the GCFR, and the LMFBR program, which uses the identical mixed uranium-plutonium oxide reference fuel cycle as the GCFR. These efforts by General Atomic Company have been supported in part both by the Atomic Energy Commission and a group of interested electric utility companies.

Under the utility program, a conceptual reference design for a 300-MWe demonstration plant was completed in 1970. Modifications to this design were made in 1971 and 1972 to simplify the design to bring it more in line with applicable HTGR design modifications since 1970 and to meet specific design or safety requirements that have been clarified through reviews by AEC Regulation and the Advisory Committee on Reactor Safeguards (ACRS). In 1972, a preliminary plant cost estimate and a detailed development plant with associated schedules were completed.[6]

Research and development on the GCFR concept continued in 1973 and 1974 with the preparation by GAC of a detailed program plan for the development of a fuel element pressure equalization system (see Section 6A.1.4.3) and completion of irradiation experiments in the Oak Ridge Research Reactor (ORR) on GCFR fuel pins designed to demonstrate "proof-of-principle" of the pressure equalization system. Irradiation of other GCFR fuel pins to evaluate their performance in a fast reactor environment (EBR-II) was also begun. A critical experiments program plan for the physics evaluation of the proposed 300 MWe GCFR demonstration plant was prepared, and plans are under way to construct the initial critical experiment and begin taking measurements by early 1975.

6A.1.4.1.3 Status

Research and development are continuing on various elements of GCFR technology, with emphasis on fuels and materials development, physics, safety, program planning, and surveillance of LMFBR technology applicable to GCFRs. Fuel development is being carried out in a GAC-Argonne National Laboratory-Oak Ridge National Laboratory cooperative program supported by the AEC. In the fuel rod irradiation program, both thermal and fast irradiations are being conducted.

A Preliminary Safety Report for a 300-MWe demonstration plant has been submitted to AEC Regulation, and several hearings have been held with the ACRS and the ACRS subcommittee on the GCFR. The issues arising from this report and supplemental submissions are currently under evaluation. The program plan is being refined, and schedule and cost estimates are being prepared.

The utility industry continues to show interest in the GCFR concept. A Utility Review Committee reviewed the GCFR demonstration plant program plan[7] in 1972 and concluded that the GCFR continues to be a viable, economic alternative to other fast reactor types and that its development should proceed on an orderly basis. It also noted that a more detailed engineering design should be made to allow firmer estimates of costs and schedules and to meet licensing requirements. Based on this recommendation, a balance-of-plant design and cost estimate was carried out by Bechtel Corporation in 1973. A complete design report for the 300-MWe GCFR demonstration plant was completed in mid-1974. Conceptual design work on a demonstration plant in the 700-MWe range has been initiated.

In addition to U.S. work on this concept, several foreign groups are actively supporting research efforts. Core heat transfer and fluid flow studies are being performed at the Swiss Federal Institute for Reactor Research under a cooperative program with GAC. The Nuclear Energy Agency is supporting a significant effort on GCFR research, and eight companies from Western Europe have associated in the Gas Breeder Reactor Association to conduct related research.

6A.1.4.2 Extent of Energy Resource

The GCFR will use the identical fuel cycle as the LMFBR.* Consequently, the geographical distribution and estimated availability of its fuel resource (uranium) is the same as that for light water reactors, as presented in Section 6A.1.1.2. As noted therein, the status of uranium reserves for LWR operation is a cause of some concern and will require further exploration and discovery to support the industry in the next century. Breeder reactors, on the other hand, utilize 60% or more of the energy available in natural uranium (as opposed to 1 to 2% in converter reactors) and, in addition, the breeder fuel cycle cost is much less sensitive to ore cost than is the converter reactor so that the much more plentiful reserves of higher cost ore can be economically utilized. Moreover, as in the case of the LMFBR, present and projected tails** stockpiles accumulated from the uranium enrichment process will be sufficient to provide the uranium requirements of the breeders projected to be in operation well into the next century without any additional uranium mining required. All of these considerations point to the fact that a fast breeder economy can operate for many centuries on available uranium resources.

In addition to the fuel requirements, the supply of helium is a consideration in the growth of a GCFR economy although this factor does not appear to be a limiting one. This subject is discussed in Section 6A.1.2.2 on the high-temperature gas-cooled reactor (HTGR).

6A.1.4.3 Technical Description

The most complete GCFR plant design prepared is that for a proposed 300-MWe demonstration plant.[8] Conceptual designs have also been prepared for 1000-MWe commercial plants. A description of the demonstration plant with emphasis on its nuclear steam supply system follows. The remainder of the plant is typical of modern high-temperature steam-turbine practice.

The 300-MWe GCFR demonstration plant includes a reactor building, a fuel service building, and a turbine building. The reactor building, which contains the PCRV,

*See Section 6A.1.4.5.2 for discussion on using a thorium blanket in the GCFR.
**Tails--the natural uranium depleted in the U-235 isotope which remains after the gaseous diffusion process has produced the enriched uranium required for LWRs and HTGRs.

functions also as a secondary containment structure and includes the fuel-handling area and some reactor pplant process and service systems.

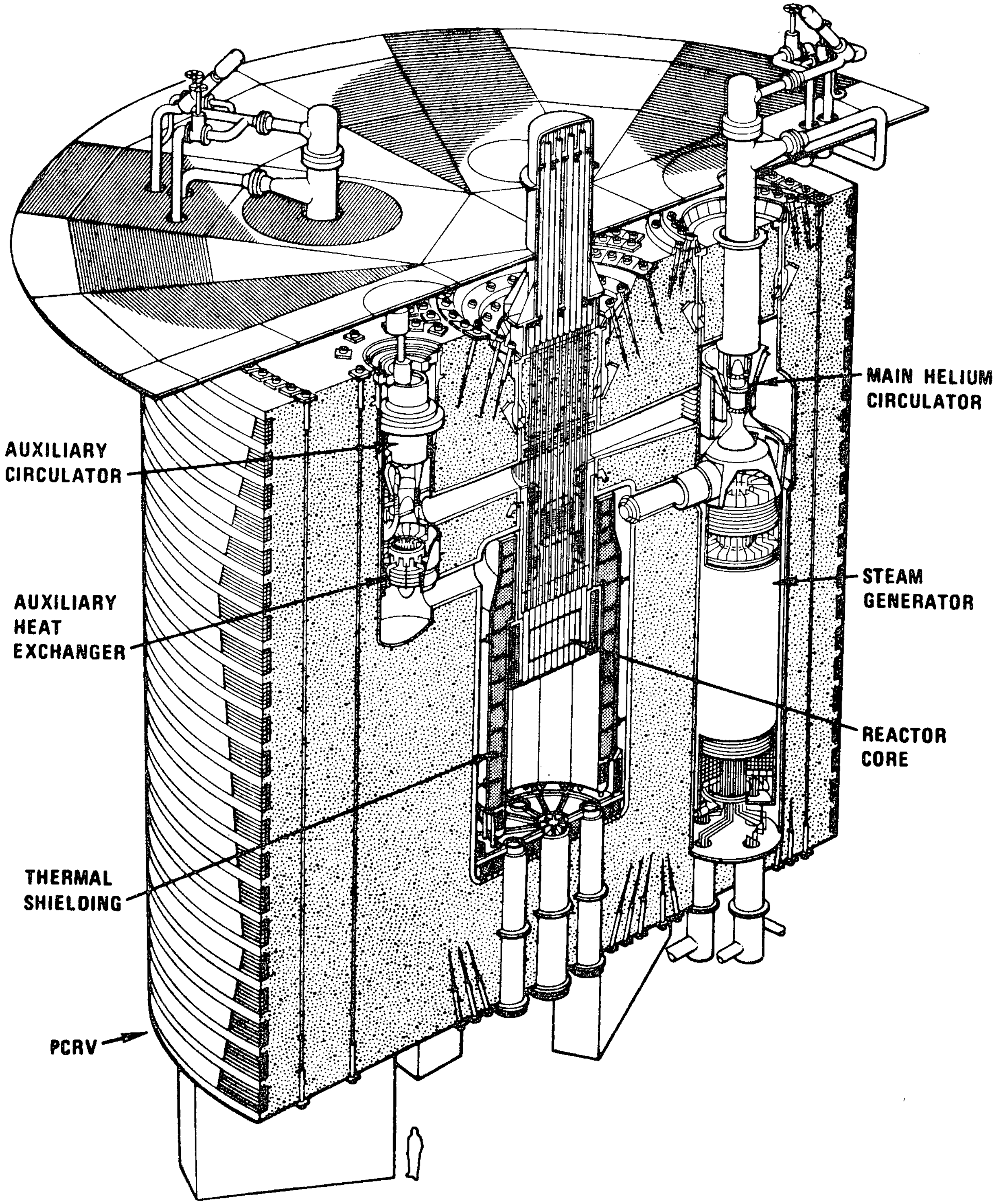
The entire primary system (see Figure 6A.1-35) is contained within the PCRV, which eliminates the possibility of rapid depressurization by major duct failure, and thus loss-of-coolant problems are restricted mainly to those associated with failure of penetration closures. To limit the maximum rate of depressurization into the secondary containment, structurally-independent flow restrictors are designed into each large PCRV penetration closure.

The primary coolant system contains three main loops, each with independent steam generators and circulators, and three auxiliary loops for long-term shutdown cooling. Each main loop and auxiliary loop is housed in a separate cavity in the multicavity PCRV. The helium coolant, at a pressure of about 1250 psia, flows downward through the core where it is heated to a temperature of 1010°F. The flow is also downward across the helically coiling tube banks of the once-through steam generators to accommodate the use of upflow boiling in the generators. Top-mounted circulators discharge the coolant to the reactor inlet plenum at a temperature of 595°F.

The main coolant circulator is a single-stage axial compressor driven by a series steam turbine in the high-pressure steam line. This arrangement provides the circulator power (22,300 hp each), avoids the need for external power sources, and makes each main loop as self-contained and independent of the others as possible. Thus, following shutdown, fission product decay heat initially provides power for its own removal. Circulation through backup auxiliary cooling loops is provided by centrifugal circulators, each driven by a 500-hp electric motor.

The reactor core contains 118 hexagonal fuel elements and 93 blanket elements. The elements are supported from a top-mounted grid plate and are clamped to the plate at their cold ends. Each standard fuel element contains 270 fuel pins and a thermocouple rod. The fuel pin consists of annular $(Pu\text{-}U)O_2$ pellets within a type-316 stainless-steel cladding about 20 mils thick. The surface of the fuel pin cladding is roughened to increase (double) the heat-transfer coefficient and thus reduce core size and fissile inventory. Upper and lower axial blankets are contained in the ends of the fuel pins and consist of depleted UO_2 pellets.

The fuel pin design conditions include a maximum mid-cladding temperature of 700°C (1292°F), including hot-spot factors. The maximum design burnup was chosen to be 100,000 MWd/T_e, and the maximum linear rating at full power is a conservative 12.5



300-MWe GCFR DEMONSTRATION PLANT

Figure 6A.1-35

kW/ft. These design parameters were selected after evaluation of existing irradiation data and are similar to values typical of LMFBR demonstration plant designs. A listing of some of the pertinent design characteristics of the GCFR demonstration plant is given in Table 6A.1-19.

An important feature of the GCFR core design is the fuel element pressure equalization system (see Figure 6A.1-36), which differs significantly from current practice in metal-clad oxide fuel reactor systems. The fuel pins are vented to equalize the internal gas pressure to that of the reactor coolant outside the pin. Assuming the venting feature performs its function throughout the fuel pin life, there will be no stress in the cladding due to internal gas pressure during normal operation. If internal gas pressure proves to be the determining factor in the pin failure mechanism, this feature could provide a basis for reducing cladding thickness, which would lead to an improved breeding ratio. Radiation monitors on the vent lines leading to the helium purification system provide means for detecting and locating any leaks in the fuel pin. The fuel elements contain charcoal-filled fission-product traps to delay the passage of the volatile and gaseous fission products long enough to minimize subsequent heat release. The flow of vent system gas from the element traps is swept by a purge gas flow through the grid plate connector into the lines to the helium purification systems. The main reactor coolant loop can be maintained at very low activity levels, even with leaking fuel rods.

Reactivity control is provided by 27 rods in the control fuel elements, which have central channels to accommodate the absorber rods. The control-rod drives are located above the reactor. Normal operation of the reactor is provided by 21 control rods. Six shutdown rods form a backup system capable of independently shutting down the reactor from any anticipated operating condition.

The PCRV liner and ducts are protected from neutron irradiation by thermal shielding. Around the core, this shielding is in the form of a replaceable inner layer of shielding blocks surrounded by an annular region consisting of steel containers filled with graphite. Cooling of the radial shielding is by a small bypass from the inlet helium.

The concrete plugs above the steam generators incorporate large central holes for circulator installation and smaller surrounding holes for steam pipes. Steam-generator tube plugging can be done externally; the main penetration closure is removed only for complete removal of a steam generator.

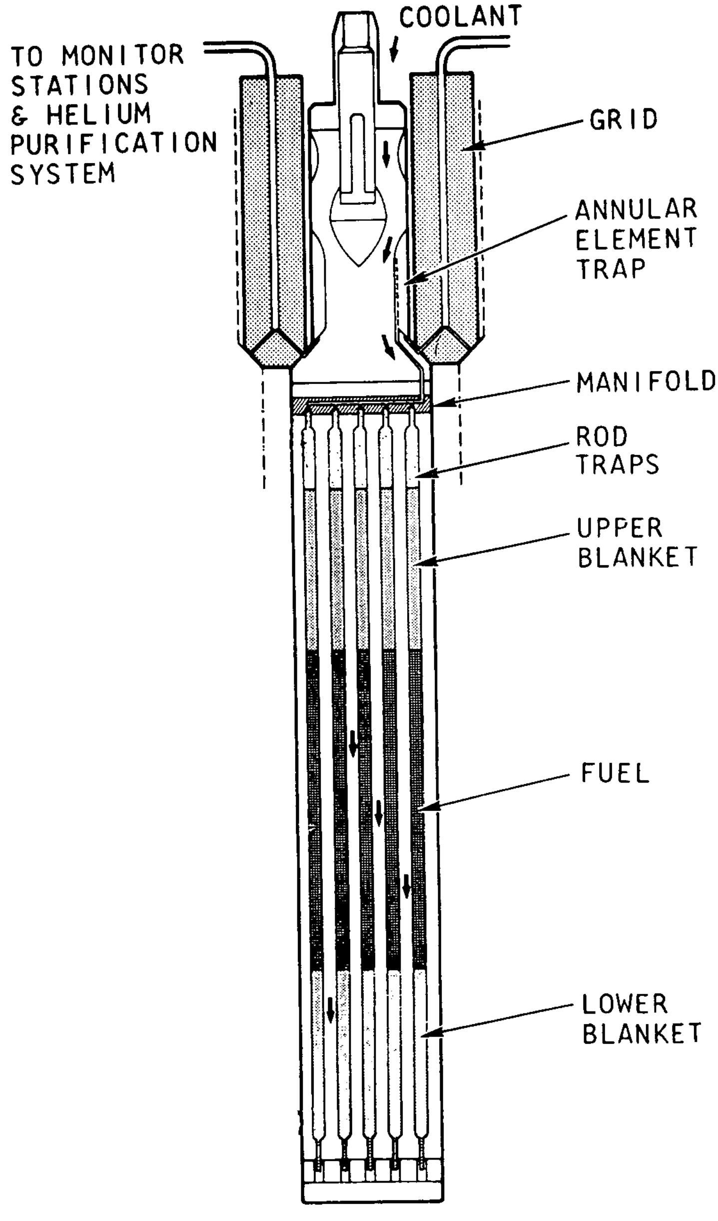
To limit the consequences of a possible penetration closure failure, separate secondary containment is provided, similar to that proposed for the large commercial

Table 6A.1-19

GCFR DEMONSTRATION PLANT PERFORMANCE CHARACTERISTICS

Net Electric Power	311 MW
Proportions:	
Fuel Rod Diameter	0.72 cm
Coolant Void Fraction	0.45
Core Diameter	200 cm
Core Length	100 cm
Reactor Vessel Diameter	84 ft
Reactor Vessel Height	71 ft
Operating Conditions:	
Maximum Cladding Hot Spot	700°C
Pressure	85 atm
Pumping Power (% thermal output)	5%
Gas in	595°F
Gas out	1010°F
Performance:	
Fuel Rating	0.6 MW/kg
Linear Rating, max	12.5 kW/ft
Overall Efficiency	36%
Conversion Ratio	1.33[a]
Doubling Time	21 years[a]

[a]These figures are for the 300-MWe demonstration plant. For the proposed 1000-MWe plant, the breeding ratio has been calculated to be in the range of 1.40 to 1.50, and the corresponding doubling time is 8 to 10 years.



SCHEMATIC OF FUEL ELEMENT PRESSURE
EQUALIZATION SYSTEM

Figure 6A.1-36

HTGRs. It performs two functions: it ensures a minimum coolant pressure (~2 atm) for core cooling following an accidental primary system depressurization, and it confines fission products that potentially could be released from the fuel.

6A.1.4.4 Research and Development Program

The research and development effort required to bring the GCFR to the status of a safe, reliable, economical power reactor plant is considerable. The technical areas that require further work are summarized below. A comprehensive research and development program is described in ref. 6. The need for GCFR research is also discussed in ref. 9, wherein a $140-million program is proposed over the next five years to provide the required technology.

6A.1.4.4.1 Component Development Needs

While the development of the GCFR depends to a significant degree on the successful operation, maintainability, and reliability of the Fort St. Vrain reactor and future large HTGRs, there are major problem areas unique to the GCFR design that require development effort and proof-testing, over and above HTGR needs.

(1) Containment of the entire primary coolant system within the PCRV is fundamental to the GCFR concept. Additional model testing is needed to validate the design at the higher GCFR pressure (1250 psi vs 700 psi for HTGR) although some of the PCRV development needed for GCFR will be accomplished as part of the HTGR development program.

(2) There are a number of first-of-a-kind components that represent a significant engineering extrapolation from other first-of-a-kind components, some of which have yet to be designed and built and others which have yet to be proof-tested under actual operating conditions or operated in a reactor plant. These components, in particular gas circulators and steam generators and their associated maintenance equipment, need to be developed, fabricated, and tested along with related development and proof-test facilities.

(3) Reactor mechanisms, such as control drives, have to be operated in hot helium with the attendant problems of lubrication, prevention of self-welding, vibration, metallurgical creep, and radiation damage in a fast neutron flux environment. In this regard, experience with similar HTGR components will be applicable.

(4) Providing spent-fuel cooling during removal from the core and transport to a water storage pool presents a difficult requirement. Such a requirement is influenced by the proposed vented fuel concept. Provisions for

sealing the fuel assembly to prevent ingress of water will have to be provided prior to transport to storage.

(5) Other components requiring first-of-a-kind engineering development and proof-testing include the GCFR refueling system and special reactor instrumentation.

(6) The GCFR core, because of the use of gas cooling with its heat transfer limitations, has a large core void fraction that leads to neutron streaming and leakage problems and might introduce problems relating to the internal shielding of components. The wider coolant channels do have the advantage that problems caused by irradiation-induced metal swelling and bowing are reduced.

6A.1.4.4.2 Fuel and Core Development Needs

To maximize the benefits to be gained from other ongoing activities, the GCFR effort in this category should utilize to the extent possible the spin-off technology from the large-scale efforts being carried out under the top priority LMFBR program. However, there are major areas unique to the GCFR concept that require development.

(1) Fuel venting introduces a number of questions that require substantial development effort to resolve, including the rate of release of fission products from the fuel pellets, their diffusion rate through the length of the rod to the charcoal traps, the effects of breathing at the juncture of the fuel assembly vent and the grid which occurs with changes in plant load, fission product plateout throughout the vent system, charcoal behavior under fast flux irradiation, the maintenance of alignment of seals under bowing and vibration stresses, and lastly the operation of the venting system as a whole under pressure transients with and without cladding leaks. Test information on this concept is being developed, but much more remains to be done before the reliability of vented fuel can be established. This work includes a variety of integral in-pile proof tests of prototypical fuel subassemblies and assemblies and safety tests relating to the vented concept, under a range of operating, transient, and shutdown conditions.

(2) The fuel pins proposed for the GCFR are different from those planned for LMFBR designs in that they have roughened outer surfaces and are designed for venting of fission gases from the fuel pins and assembly. Surface roughening may affect the strength of the cladding, and irradiation testing is required to evaluate such effects.

(3) While fast reactor physics methods and fundamental data developed for the

LMFBR program will benefit the GCFR program, additional effort is required to meet GCFR needs. Further work is needed on reactivity effects due to the presence of steam, which might be introduced into the core as a consequence of a steam generator tube failure.

(4) There are heat transfer questions to be resolved as to the effects of rod spacers, fuel-element box walls, and possible rod bowing. Knowledge of the heat transfer over the whole range of flow up to full power conditions would be required for transient and safety analysis purposes. Experimental heat transfer work with respect to these questions is being carried out in Switzerland in cooperation with GAC.

(5) Flow-induced vibration of the fuel rods and of the fuel element assembly is a potential problem to be overcome, including the effects of seismically induced loads.

(6) There are questions respecting the behavior of the interfaces at the spacer/fuel rod and the fuel element/grid in the hot helium environment.

(7) Difficult problems, common to any fast reactor, are those related to obtaining the desired fuel burnup of 100,000 MWd/T_e and coping with irradiation-induced swelling and creep for all metal parts in the core. Much reliable data are needed in these areas.

6A.1.4.4.3 Safety Needs

In addition to many of the problems that have been raised on other reactors a number of critical safety questions have been identified for GCFRs. Discussions of GCFR safety and licensing have been under way with AEC Regulation and the ACRS since 1971 aimed at resolution of these questions. Principal areas of concern are:

(1) More detailed assurances, including test data, are needed to assure that adequate reliability of core cooling in potential emergency and faulted conditions could be provided. Startup requirements and adequacy of reliability of the auxiliary cooling loops need to be further analyzed and demonstrated.

(2) Depressurization of the primary coolant system has been considered as the design basis for engineered safeguards in the GCFR. The maximum allowable depressurization rate depends on some type of flow-limiting devices in the large penetrations. This subject is being reviewed by AEC Regulation to assess whether the system design can accommodate the proposed depressurization accident. Assurance is needed that the design provides adequate margin for a more rapid depressurization than that associated with the design flow-limiting devices and for combinations

of other failures occurring simultaneously and/or separately in the main and auxiliary cooling systems, on three- or two-loop operation.

(3) Although analysis indicates that the reactivity change of the core is small and negative for all conceivable steam concentrations resulting from steam generator tube failures, additional analyses and critical assembly experiments would have to be carried out to confirm this.

(4) The use of a core support system in which the fuel elements are tightly clamped at one end into a thick grid plate with no additional radial restraint, along with the potential deleterious effects of such materials phenomena as radiation damage and stainless steel creep, has led to detailed questioning by the Regulation Staff and the ACRS on the integrity of the system and the reactivity effects under transients and earthquakes. These problems need to be resolved.

(5) The adequacy of the proposed protection provided by control system actions backed up by two independent shutdown rod systems against anticipated transients needs to be proven. Preliminary evaluations have been made of the consequences of failure of protective action in anticipated transients, but these have to be analyzed further to establish their acceptability.

(6) A design basis accident has not yet been established which is acceptable to the USAEC Regulation Staff.

6A.1.4.5 Present and Projected Application

6A.1.4.5.1 Current Use

The GCFR is in the early stages of development and consequently is not in current use. However, important aspects of GCFR technology are embodied in HTGR systems that are in the process of entering the commercial utility market. Also, the GCFR uses the same mixed uranium-plutonium-oxide fuel cycle as the LMFBR. This fuel cycle is undergoing extensive testing in the U.S. and abroad and is in the process of being demonstrated in prototype reactors in Europe.

6A.1.4.5.2 Projected Use

The GCFR as an alternative fast breeder option to the LMFBR will have similar utilization incentives. It will exploit the same abundant energy resource, uranium, have the same environmental advantages vis-a-vis thermal reactors, and have the same environmental problems with respect to fission-product containment and control. Since the GCFR is in an earlier stage of development, notwithstanding the benefits expected to accrue to it from the HTGR and LMFBR programs, the AEC expects that the GCFR will lag behind the LMFBR in date of commercial introduction. The extent of this delay will depend upon the amount of funding applied to its development. In FY 74 the GCFR research and development effort was supported at a modest rate in excess of $4,000,000 per year (including $2,000,000 per year of AEC support).

This rate of effort will have to be heavily increased if the GCFR is to be introduced within a decade of the time that the LMFBR is expected to become commercial. Appreciation of the need for acceleration is evidenced by the fact that an increase to about $5,000,000 has been proposed for research on the GCFR for FY 1975. As mentioned in Section 6A.1.4.4, the report, "The Nation's Energy Future"[9] calls for a total of $140,000,000 to be spent over a five-year period to develop GCFR technology on fuel and reactor core development, physics, critical assembly tests, and safety analyses.

In the event that the decision is made to pursue a vigorous parallel breeder program with sufficient funding and effort starting about FY 76, the AEC believes that commercial introduction of the GCFR might be achieved in the last decade of this century. It would thereafter compete directly with the LMFBR and other available sources of energy production on a straight economic basis taking into consideration the comparative environmental impacts of each option, as well as the relative industrial resources available to meet the demand. Note that proponents of the GCFR concept believe that "an adequately funded GCFR program will bring the GCFR into the marketplace within a few years of the LMFBR, and certainly not as long as a decade later."*

One rather novel application[10] of the GCFR proposed by its proponents is the use of a thorium blanket in a GCFR to produce U-233 for use as makeup fuel in HTGRs. This use would make the HTGR independent of the uranium enrichment process for its fuel and reduce the separative work** required to sustain the nuclear power economy. Presumably the GCFR would produce just enough plutonium to provide its own fuel supply and also produce enough U-233 to maintain several HTGRs. This symbiotic mode of operation would provide a means for exploiting thorium resources using uranium-plutonium as the driver fuel. This operation, of course, might also be done by using the LMFBR with a thorium blanket although not as effectively, because the LMFBR has a lower breeding ratio. Whether this mode of operation will be preferable to direct exploitation of the uranium-plutonium fuel cycle will depend upon system analysis studies performed at the time all the pertinent data becomes available.

*Comment Letter 34, p. 2, General Atomic Company.
**"Separative work" is a measure of the work required to enrich natural uranium in the gaseous diffusion plant to the U-235 enrichment needed in the reactor.

6A.1.4.6 Environmental Impacts

6A.1.4.6.1 Energy Conversion Plant

In all important respects the gas-cooled fast reactor will have approximately the same environmental impacts as those associated with the LMFBR. In particular, the GCFR has the identical fuel cycle as the LMFBR and a similar steam supply system. Accordingly, the environmental impacts determined in previous sections of this study for the LMFBR are generally applicable to the GCFR.

The major difference between the two systems lies with the coolant. The GCFR uses helium instead of sodium to cool the reactor and transmit heat to the steam generators. The use of helium as a coolant leads to several advantages with environmental significance. The minimum interaction between the coolant and the neutrons leads to significantly lower radioactivity in the coolant system. The chemical inertness of the gas permits elimination of the intermediate cooling loop required by LMFBRs and could simplify operation and maintenance. In addition, the environmental consequences of any leakage of coolant are correspondingly reduced. Also, since helium does not become radioactive, it does not present a waste disposal problem such as encountered with sodium. Nor is helium flammable, thereby avoiding the potential safety hazard of sodium fires which exists in an LMFBR.

On the other hand, helium is not a good heat transfer medium and therefore high coolant pressure and rapid flow is required to extract the heat from the reactor core. Any interruptions to the circulator flow or any depressurization incidents potentially threaten overheating of the reactor core and must be carefully guarded against. To assure coolant flow, the reliability of the forced circulation system must be very high and greater reliance must be placed in the GCFR on the auxiliary cooling system, in contrast, for example, to the HTGR which has a high heat capacity graphite-moderated core. The possible occurrence and extent of depressurization accidents are minimized by several safety features inherent in or specifically added to the PCRV for this purpose. However, in the unlikely event that one of these accidents should occur, a gas coolant does not offer any significant natural convection cooling, which is one of the attractive features of sodium.

Another substantive difference between the GCFR and the LMFBR which may have environmental significance is the planned use of vented fuel assemblies for the GCFR. Vented fuel, although advantageous for the several technical reasons described in Section 6A.1.4.3, eliminates the noble gas fission-product containment feature regarded as an important advantage of non-vented fuel, with its attendant implications on other plant characteristics such as maintenance and fuel handling. This feature effectively transfers the bulk of the noble gas fission-product handling problem from the reprocessing plant to the reactor site. One result of the use of vented fuel is that irradiated fuel elements could be shipped at lower internal pressures and lower fission product inventory, although at the expense of making provisions for sealing the vented fuel assemblies.

Since the GCFR is significantly behind the LMFBR with respect to its development, there is no certainty that it will be able to reach the same thermal efficiency as the LMFBR. If it does not, then it will require slightly more cooling water than the LMFBR, which, depending on the method of heat dissipation selected, might result in a somewhat larger cooling tower, a higher ΔT in once-through cooling water, or a larger cooling pond.

Other aspects of environmental concern of the GCFR appear to be equivalent to those for the LMFBR--land usage, need for and type of electrical transmission lines, size of operating crew, extremely low permissible level of gaseous radioactivity release, and the low probability of occurrence of accidents.

6A.1.4.6.2 Offsite Support Activities and Facilities

Since the associated offsite support activities and facilities of the GCFR, insofar as the environment is concerned, are essentially similar to the LMFBR (with the exceptions noted above), its environmental impacts on flora and fauna, its aesthetic, recreational and cultural impacts, and its economic and social impacts should be essentially the same as those encountered with the LMFBR as discussed in previous sections. Thus, any decisions eventually reached as to further development or commercial introduction of the GCFR will likely be based more on technical and economic reasons than on environmental characteristics.

6A.1.4.6.3 Irreversible and Irretrievable Commitment of Resources

Since the GCFR operates on the same fuel cycle as the LMFBR with essentially the same characteristics, the commitment of fuel resources for the GCFR is almost identical to the LMFBR. In fact, in either system little if any additional fuel resources are required beyond those already committed to the LWR program. The plutonium required to fuel the GCFR core would be provided from that produced as a by-product of LWR operation, and the uranium needed for the mixed-oxide fuel, and the blanket would be provided from the huge supply of diffusion plant "tails," which will be sufficient to meet projected demand for many decades.

Since the GCFR is a breeder, it would produce more plutonium than it would consume and therefore be a net producer of an energy resource. Of course, there would be a corresponding decrease in the supply of natural uranium, but on the breeder cycle there would be sufficient uranium to maintain the electric power generating economy for many centuries.

As noted, discussion of helium gas resources is provided in Section 6A.1.2.2. The makeup requirements of 20 x 10^6 scf over the 30-year life of one 1000-MWe HTGR, when multiplied by the number of gas-cooled reactors estimated to be in service in the year 2020 (see Section 11, Figures 11.2-1 and 11.2-2), represents a significant fraction of currently available helium reserves. Action should therefore be taken to assure that sufficient reserves would be available (such as through alternative helium production methods) and to decrease the gas leakage rate so that helium-cooled reactors are not limited by helium supplies from providing a significant part of the Nation's future nuclear power generating capacity.

6A.1.4.7 Costs and Benefits

The costs and benefits of the GCFR should parallel very closely those expected from development of the LMFBR, which are discussed in detail in Section 11. This similarity is so because of the similarity in purpose, function, fuel cycle, and operation. The major difference other than plant design between the two systems is one of timing, with the LMFBR expected by the AEC to become commercially available about a decade before the GCFR; however, as noted in Section 6A.1.4.5.2, proponents of the GCFR believe that if it is adequately funded, the GCFR could instead be commercially available within a few years of the LMFBR. The difference in timing between the AEC estimates and that of the chief proponent, GAC, reflects a fundamental difference in research and development philosophy. This difference is further reflected in widely different estimates of the cost of developing a commercially viable reactor system. The basis of the difference in philosophy lies in the GAC belief that sufficient data will be developed from the HTGR and LMFBR programs, along with a specific government-supported GCFR research program of relatively modest scope (∿ \$140 million), to proceed directly to the construction of a 300-MWt (or larger) demonstration plant and from that point to proceed directly to full-scale (1500-MWe) commercial reactor plants. The total cost of development of the GCFR to the point of commercial use is estimated by GAC to be 10 to 20% of the cost estimated by the AEC (\$4.5 billion).*

*Comment Letter 34, p. 2, General Atomic Company.

GAC is considering a development approach for the GCFR that by-passes the intermediate steps of constructing reactor experiments which were considered essential for the LWR, HTGR, and LMFBR programs. Consequently, the development cost of the GCFR consists of only the cost of the research and development and construction associated with the first demonstration plant. GAC states,

> "The cost of the 300-Mwe GCFR Demonstration Plant, based on 1973 dollars, including R&D for the Demonstration Plant, excluding escalation, interest during construction, and owner's cost has been estimated at somewhat less than $500 million."*

The approach recommended by GAC is believed by the AEC to be one having higher risks than the usual approach that the AEC has followed in its reactor development programs of proceeding through a series of test and smaller scale demonstration reactors to a reactor of commercial size.

The Atomic Energy Commission estimate of cost is based upon previous experience with other nuclear reactor programs such as the light water reactor which also depended heavily upon technology developed in a previous program, the Naval Reactors Program, and upon its experience to date with the LMFBR program which has had the benefit of many years of sodium reactor technology developed in other programs both in the United States and abroad. The major difference between the two approaches can be summarized as follows: the AEC believes that a prudent course of action for the first GCFR would be the construction of a reactor experiment of modest size (100 to 200 MWt) to test the operability, safety, and reliability, of the concept. GAC feels that an experiment of that size would not provide meaningful information because components and other characteristics of the experiment would not be typical of full-scale commercial plants.

The AEC believes that cost estimations made in the early stages of a research and development program have historically proven to be too low. This is particularly the case where first-of-a-kind large-scale facilities and demonstration reactors are concerned. The AEC is of the opinion that the research and development effort involved in the GCFR program and the construction of a GCFR demonstration plant in the absence of experience in construction and operation of a gas-cooled fast reactor will be even more susceptible to cost uncertainty.

Although there are other differences in approach involving number and complexity of

*Comment Letter 34, Attachment, p. 4.

facilities, the two major conflicts noted above account for most of the differences in cost and schedule estimates.

Referring back to the difference in timing between LMFBR and GCFR availability as estimated by the AEC, the consequences of this difference can be illustrated if one makes the assumption that the LMFBR does not materialize as a commercial power generation system and that the burden of providing the electrical generating capacity during the ten-year delay until the GCFR would become commercially available is relegated to fossil-fueled, LWR, and HTGR power plants. In that case there would be an increased need not only for fossil fuels but also for enriched uranium to fuel the converter (non-breeder) reactors. The extent of this increased enriched uranium requirement can be expressed in terms of separative work demand, which is a measure of the requirement for diffusion plant capacity. The increased demand for enriched uranium would translate into an increase in separative work demand of about 65 metric kilotons/year.[11] This increase in demand is approximately four times the total installed diffusion plant capacity in the United States today.

To provide this additional enriched uranium, about 1.2 million metric tons of additional U_3O_8 would have to be mined through the year 2020.[11] If one assumes an average ore grade of 0.2%, this effort would translate to 600 million metric tons of additional ore that would have to be mined.

As discussed in Section 6A.1.4.6, in nearly all other respects the environmental impacts of the LMFBR and the GCFR are similar. Their thermal efficiencies are almost the same so that waste heat effects should be similar. Chemical effluents from the plants relative to the operation and maintenance of their steam condensing systems would also be approximately the same.

The environmental impacts associated with irradiated fuel processing and transportation of the fuel should be similar since the same fuel is used in both reactor systems. However, the use of vented fuel in the GCFR would decrease both the inventory of stored fission products and the internal pressure in the fuel pins as they are transported to the reprocessing plant, because the volatile gases would be partially removed during operation in the reactor. As mentioned earlier, this venting transfers that portion of the radioactive waste problem from spent-fuel transportation and the reprocessing facility to the reactor site where the removed fission-product gases must be stored and eventually transported to a radioactive-waste depository site.

Releases of radioactive gases from either reactor system to the environment during operation will be negligible. The environmental impacts associated with construction of the generating plants and the transmission line systems should be identical.

The GCFR, of course, will not have the environmental problem of dealing with the contaminated sodium remaining after decommissioning of an LMFBR although this problem might be resolved by decontaminating the sodium to the degree desired and reusing it.

The reason for proceeding with the costly development of either the LMFBR or the GCFR is to provide the Nation with a new form of electric energy production that is environmentally acceptable and that enlarges our energy resource base significantly. In these respects both LMFBR and GCFR have similar advantages. Both reactors extend our economically useful uranium resources from decades to many centuries with minimal environmental impacts; however, the necessity for long-term storage of radioactive wastes may impose a continuing requirement on future generations.

The GCFR is expected to have a superior breeding ratio as compared with the LMFBR. This advantage would result in shorter doubling times for the GCFR if the specific power and fuel inventory of the two systems were similar. Some penalty in specific power in a GCFR relative to an LMFBR is expected due to the poorer heat removal capability of helium. The improved GCFR breeding ratio must more than compensate for this loss for there to be an improvement in doubling time. The potentially better doubling time for the GCFR could give it an advantage over the LMFBR as a "fuel factory," if the concept of symbiosis with HTGRs is pursued, because a GCFR would be able to service more HTGRs than an LMFBR would. Depending upon the relative doubling times of each concept with respect to the doubling time for electrical generating capacity demand, there might or might not be an advantage for the GCFR. That is, if the doubling time for the GCFR were shorter than the doubling time for electrical generating capacity and the doubling time of the LMFBR were longer, then the GCFR could meet the required demand while the LMFBR could not. On the other hand if the doubling times of both systems were shorter than the doubling time for electrical generating capacity, then there would be no advantage for either system from that standpoint.

One final possible benefit of the GCFR as opposed to the LMFBR might be mentioned. Because the GCFR does not use sodium as the coolant, it does not require an intermediate heat exchanger system and other equipment associated with the special handling of sodium. This fact makes the GCFR somewhat simpler in design and therefore might make its capital cost somewhat less expensive. On the other hand the higher pressure at which the GCFR operates, the large blowers and circulators required, and the massive PCRV add to GCFR costs. To make judgments on relative capital costs at this time is difficult since the GCFR is only in the early development stages, but the presumption might be made that the GCFR may have somewhat lower capital costs.

In summary, a cost-benefit analysis of the GCFR yields conclusions essentially similar to those for the LMFBR with the following exceptions. Due to its later introduction into the electric power economy, the GCFR would require the mining of a significantly larger quantity of uranium ore to maintain the converter reactors. In addition, although the GCFR does not have to contend with the operational consequences of using sodium as the coolant, it must deal with the poorer qualities of helium as a coolant with the precautions necessary to avoid loss of coolant.

6A.1.4.8 Overall Assessment of Role in Energy Supply

6A.1.4.8.1 Probable Role up to Year 2000

The AEC believes that the GCFR may not be ready for commercial introduction into the electric utility system much before the end of this century even if the decision is made to proceed with a full-scale research and development program that successfully achieves its goals. Consequently, its role up to the year 2000 will be minimal. The successful introduction of the GCFR in the last decade of this century would have an impact on future planning and trends which would begin to become apparent in the 1990's in the form of changed ratios of orders and commitments for the mix of power plants to be built in the years beyond 2000.

6A.1.4.8.2 Possible Role Beyond Year 2000

The role of the GCFR beyond the year 2000 is clouded, as is the case for all other systems, by the uncertainties of determining the extent of success achieved by other competing power technologies. When, and to what extent, will controlled thermonuclear fusion systems be available? What role will solar power play? Will the LMFBR be viable? What will the competing costs of each system be? An almost infinite variety of scenarios might be composed.

Restricting the possibilities to one example, if only breeder reactors prove to be economically feasible energy production systems, sufficient energy resources will be available for many centuries after the year 2000. Without a breeder reactor--LMFBR, GCFR, or both--converter reactor fuel prices will follow an inexorably rising curve similar to that now being experienced by fossil-fueled power plants as low-cost, easily extracted uranium ores are used up. Thus, inevitably our energy usage would be severely restricted by the need to burn increasingly scarce and more expensive fuels. Because breeder reactor power generation costs are very insensitive to uranium costs and the breeder increases utilization of the energy inherent in uranium by factors of about 30 to 50, the combined effect of increased utilization and ability to use very expensive ores without undue penalty in economic costs provides a vast energy resource base restricted ultimately only by the environmental considerations associated with mining very low-grade ores.

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6A.1.5 Molten Salt Breeder Reactor

6A.1.5.1 Introduction

The molten salt breeder reactor (MSBR) concept is based on use of a circulating fluid fuel reactor coupled with on-line continuous fuel processing. As currently envisioned, it would operate as a thermal spectrum reactor system utilizing a thorium-uranium fuel cycle. Thus, the concept would offer the potential for broadened utilization of the Nation's natural resources through operation of a breeder system employing another fertile material (thorium instead of uranium).

6A.1.5.1.1 History

The development of molten salt reactors began in the late 1940's as part of the U.S. Aircraft Nuclear Propulsion (ANP) Program. Subsequently, the Aircraft Reactor Experiment (ARE) was built at Oak Ridge, and in 1954, it was operated successfully for nine days at power levels up to 2.5 MWt and fuel outlet temperatures up to 1580°F. The ARE fuel was a mixture of uranium tetraflouride (UF_4), sodium-fluoride (NaF), and zirconium tetrafluoride (ZrF_4). The moderator was beryllium oxide and the piping and vessel were constructed of Inconel.

In 1956, Oak Ridge National Laboratory (ORNL) began to study molten salt reactors for use as central station converters and breeders. These studies concluded that graphite-moderated, thermal spectrum reactors operating on a thorium-uranium cycle were most attractive for economic power production. Based on the technology at that time, a two-fluid reactor, in which the fertile and fissile salts were kept separate, was thought to be required in order to have a breeder system. The single-fluid reactor, while not a breeder, appeared simpler in design and also seemed to have the potential for low power costs.

Over the next few years, ORNL continued to study both the two-fluid and single-fluid concepts, and in 1960 the design of the single-fluid 8-MWt Molten Salt Reactor Experiment (MSRE) was begun. The MSRE was completed in 1965 and operated successfully during the period 1965 to 1969.

Concurrent with the construction of the MSRE, ORNL performed research and development on means for processing molten salt fuels. In 1967 new discoveries were made which suggested that a single-fluid reactor could be combined with continuous on-line fuel processing to become a breeder system. Because of the mechanical design problems of the two-fluid concept and the laboratory-scale development of processes that would permit on-line reprocessing, ORNL determined that a shift in emphasis to the single-fluid breeder concept should be made; this single-fluid system[1] is the system that will be discussed in this report.

6A.1.5.1.2 Status

At present, the MSBR concept is essentially in the initial research and development phase, with emphasis on the development of basic MSBR technology. Government funding of research activities has recently been reestablished, and industrial support remains at a moderate level.

The basic feasibility of operating a fluid-fueled reactor for prolonged periods has been demonstrated by operation of the MSRE for about 13,000 equivalent full-power hours. However, there are many areas of molten salt reactor technology which must be expanded and developed in order to proceed from this small experiment to a safe, reliable and economic 1000-MWe MSBR with a 30-year life. Because of the present state of the technology, much of the following discussion concerning the description of the power plant and supporting facilities and the potential environmental impact of the MSBR must be considered very preliminary. These impacts may change due to improvements in design of the reactor system and as a result of the experience that may be gained from operating additional molten salt reactor systems.

6A.1.5.2 Extent of Energy Resource

Because the MSBR is a breeder reactor operating on the thorium cycle, the primary energy source is thorium. A discussion of the availability of this resource is presented in Section 6A.1.2.2 where thorium is shown to be in abundant supply. A moderate amount of uranium ore would also be required to provide the enriched fissile fuel needed to establish an equilibrium breeding cycle in an MSBR. The availability of uranium has been discussed in Section 6A.1.1.2.

An investigation has been made of the availability of, and the anticipated demand for, other materials of importance to the MSBR program.[2] Materials considered include the constituents of Hastelloy-N (the MSBR's main structural alloy) and the coolant salt, fuel salt, and materials required for construction and operation of the processing plant. The existing world reserves of these materials, namely lithium, beryllium, fluorine, and bismuth, are also in demand for non-MSBR uses; however, ample resources are available to sustain a large MSBR industry.

6A.1.5.3 Technical Description of Energy System

6A.1.5.3.1 Power Generation Plant

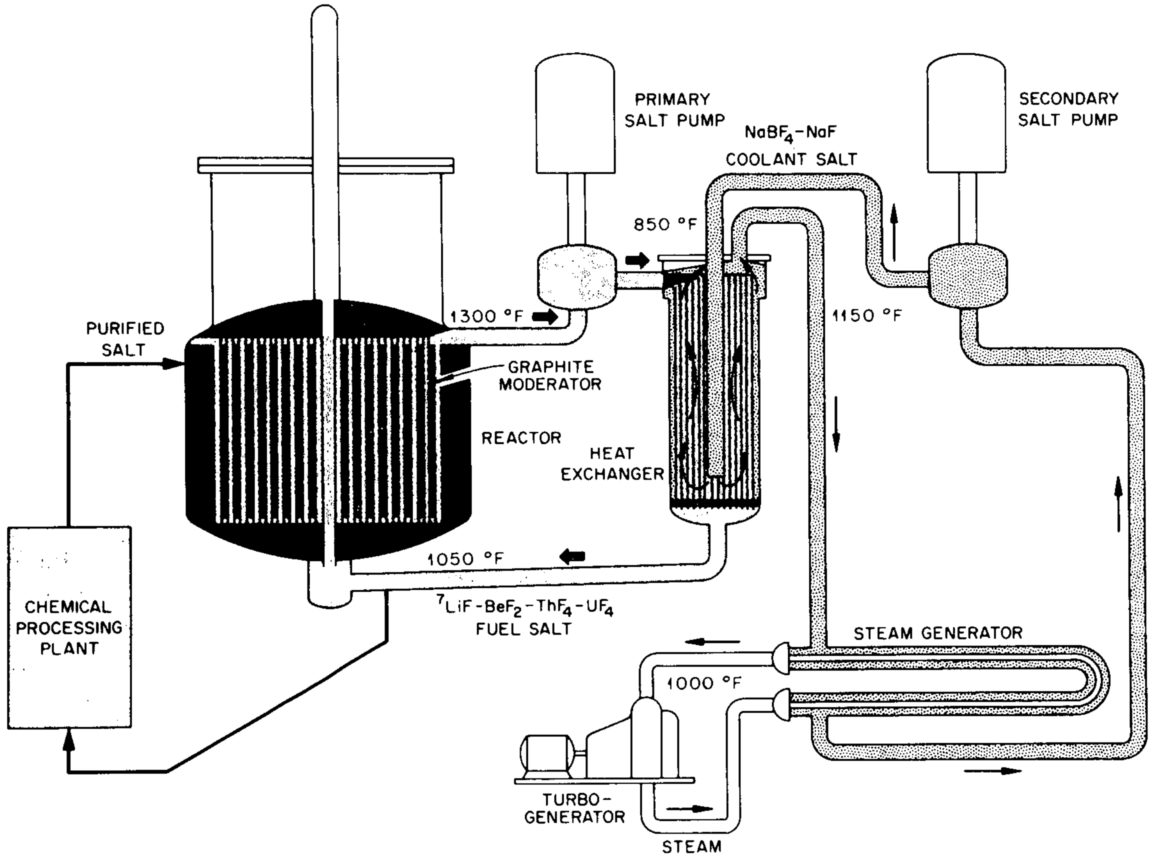
The development of the MSBR has not progressed to the stage where an exact description of a reactor and auxiliary systems can be provided. However, the following summary of a conceptual design study for a single-fluid, 1000-MWe MSBR prepared in 1971 provides some conceptual background.

The reference MSBR[3] (see Figure 6A.1-37) would operate on the U-233/Th fuel cycle, with both fissile and fertile materials incorporated in a single molten-salt mixture of the fluorides of lithium, beryllium, thorium, and uranium. This salt has a melting point of 930°F, adequate flow and heat transfer properties, and a very low vapor pressure in the operating temperature range. It is also nonwetting and virtually noncorrosive in the pure form to graphite and the Hastelloy-N container material.

The 22-ft-diam by 20-ft-high reactor vessel contains graphite for neutron moderation and reflection, with the moderating region divided into zones of different fuel-to-graphite ratios. As the salt flows upward through the passages in and between the bare graphite bars, fission energy heats it from about 1050 to 1300°F. Graphite control rods at the center of the core are moved to displace salt and thus regulate the nuclear power and average temperature, but these rods do not need to be fast scramming for safety purposes. Long-term reactivity control is by adjustment of the fuel concentration.

The core neutron power density results in a moderator life of about four years. The specific inventory of the plant including the processing system is about 1.5 kg of fissile material per megawatt of electricity (considerably less than that for the LMFBR), which together with the projected breeding ratio of 1.07, gives the MSBR an annual fissile yield of about 3.6% and a compound doubling time of 19 years.[3] The lower specific inventory of the MSBR is a significant advantage relative to fast reactors, and this feature allows a projected doubling time as low as 19 years for a breeding ratio of only 1.07. The heat-power system for the MSBR has a net thermal efficiency of over 44%, which makes a reactor plant of about 2250 MWt ample for a net electrical output of 1000 MWe.

A simplified flow diagram of the MSBR is shown in Figure 6A.1-37. The primary salt is circulated outside the reactor vessel through four loops. (For simplicity, only one loop is shown in the figure.) Each circuit contains a 16,000-gpm single-stage



REFERENCE MSBR SYSTEM

Figure 6A.1-37

centrifugal pump and a shell-and-tube heat exchanger. Tritium, xenon, and krypton are sparged from the circulating primary salt by helium introduced in a side stream by a bubble generator and subsequently removed by a gas separator. A 1-gpm side stream of the primary salt is continuously processed to remove Pa-233, to recover the bred U-233, and to adjust the fissile content. A drain tank provides safe storage of the salt during maintenance operations.

Heat is transferred from the primary salt to a secondary fluid, sodium fluoroborate, having a composition of $NaBF_4$-NaF (92 and 8 mole %, respectively) and a melting point of 725°F. Each of the four secondary circuits has a 20,000-gpm centrifugal pump with variable-speed drive. The secondary salt streams are divided between the steam generators and the reheaters to obtain 1000°F steam temperatures from each. Steam is supplied to a single 3500-psia, 1000°F (with 1000°F reheat) 1035-MWe turbine-generator unit exhausting at 1-1/2 in. Hg absolute. Regenerative heating and live steam mixing are used to heat the feedwater entering the steam generator to 700°F to provide assurance that the coolant salt remains liquid.

The principal operating parameters for a 1000-MWe MSBR power station are shown in Table 6A.1-20.

6A.1.5.3.2 Fuel Cycle

To achieve nuclear breeding in the single-fluid MSBR, an on-line fuel processing system is necessary. This system would accomplish the following:

(1) Isolate Pa-233 from the reactor environment so it can decay into the fissile fuel isotope U-233 before being transmuted into other isotopes by neutron irradiation.
(2) Remove undesirable neutron poisons from the fuel salt and thus improve the neutron economy and breeding performance of the system.
(3) Control the fuel chemistry and remove excess U-233 which is to be exported from the breeder system.

A fuel processing scheme has been proposed to accomplish breeding in the MSBR, and the flowsheet processes involve:

(1) Fluorination of the fuel salt to remove uranium as UF_6.
(2) Reductive extraction of protactinium by contacting the salt with a mixture of lithium and bismuth.

Table 6A.1-20

PRINCIPAL OPERATING PARAMETERS OF A 1000-MWe MSBR[a,b]

General	
Thermal Power	2250 MWt
Electric Power	1000 MWe
Plant Lifetime	30 years
Fuel Processing Scheme	On-line, continuous processing
Breeding Ratio	1.07
Reactor	
Fuel Salt	$^7LiF-BeF_2-ThF_4-UF_4$
Moderator	Unclad, sealed graphite
Reactor Vessel Material	Modified Hastelloy-N
Power Density	22 kW/liter
Exit Temperature	1300°F
Temperature Rise Across Core	250°F
Reactor Vessel Height	20 ft
Reactor Vessel Diameter	22 ft
Vessel Design Pressure	75 psia
Peak Thermal Neutron Flux	8.3×10^{14} neutrons/cm^2-sec
Other Components and Systems Data	
Number of Primary Circuits	4
Fuel Salt Pump Flow	16,000 gpm
Fuel Salt Pump Head	150 ft
Intermediate Heat Exchanger Capacity	556 MWt
Secondary Coolant Salt	$NaF-NaBF_4$
Number of Secondary Circuits	4
Secondary Salt Pump Flow	20,000 gpm
Secondary Salt Pump Head	300 ft
Number of Steam Generators	16
Steam Generator Capacity	121 MWt

[a]Source: R. C. Robertson, "Conceptual Design Study of a Single-Fluid Molten Salt Breeder Reactor," Report ORNL-4541, Oak Ridge National Laboratory, June 1971.

[b]Source: M. W. Rosenthal et al., "The Development Status of Molten Salt Breeder Reactors," Report ORNL-4812, Oak Ridge National Laboratory, August 1972.

(3) Metal transfer processing to preferentially remove the rare earth fission product poisons that would otherwise hinder breeding performance.

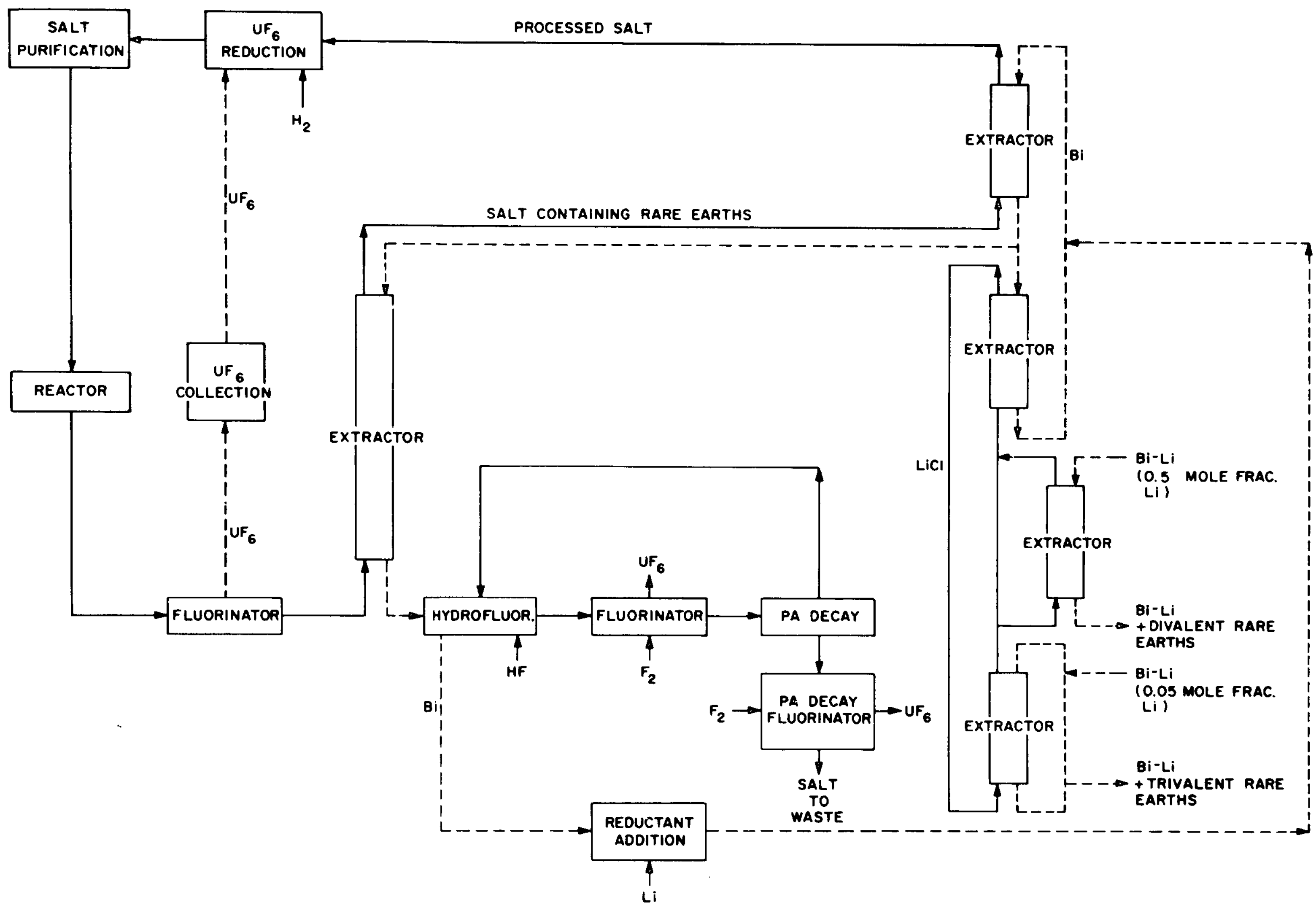
The fuel processing system shown in Figure 6A.1-38 is in an early stage of development at present and this type of system has not been demonstrated on an operating reactor.

In developing this conceptual design, ORNL assumed that the problems which have surfaced in the course of the development program would be resolved. The principal development questions, as discussed in Section 6A.1.5.4 below, relate to tritium confinement, fuel-salt processing, structural materials behavior in the presence of fission products and nuclear radiation, and development of components for a 1000-MWe power plant. Reports as to the status of MSBR technology and a more complete discussion of the required research and development needed to produce a viable system are presented in refs. 3 and 4.

6A.1.5.4 Research and Development Program

Consistent with the policy established for all power reactor development programs, the MSBR would require the successful accomplishment of three basic research and development phases:

(1) An initial research and development phase in which the basic technical aspects of the MSBR concept are confirmed, involving exploratory development, laboratory experiment, and conceptual engineering.
(2) A second phase in which the engineering and manufacturing capabilities are developed. This phase includes the conduct of in-depth engineering and proof-testing of first-of-a-kind components, equipment, and systems. These would then be incorporated into an experimental test reactor and supporting test facilities to assure adequate understanding of design and performance characteristics, as well as to gain overall experience associated with major operational, economic, and environmental parameters. As these research efforts progressed, the technological uncertainties would need to be resolved and decision points reached that would permit development to proceed with necessary confidence. When the technology was sufficiently developed and confidence in the system was attained, the next stage would be the construction of large demonstration plants.
(3) A third phase in which the utilities make large-scale commitments to electric generating plants by developing the capability to manage the



FLOWSHEET FOR PROCESSING A SINGLE-FLUID FUEL FOR AN MSBR BY FLUORINATION-REDUCTIVE EXTRACTION AND THE METAL-TRANSFER PROCESS

Figure 6A.1-38

design, construction, testing, and operation of these power plants in a safe, reliable, economic, and environmentally acceptable manner.

As in any reactor development program, achievement of economic MSBRs will require that the basic technology be well established in research programs and be demonstrated and expanded by the construction and operation of several increasingly large reactors and their integral processing plants. The technology program is in progress now, and the construction of a 150- to 200-MWt Molten Salt Breeder Experiment (MSBE) has been suggested as the next reactor in the sequence to an MSBR. The MSBE might have the power density and all the features and systems of a full-scale breeder reactor. Other steps are possible, including the construction of a larger but lower performance converter reactor that would evolve into a breeder. However, the more direct route of the high performance breeder experiment appears preferable.

In this research and development program, several advances must be made before the next reactor can be built and operated successfully. The most important problem is the surface cracking of Hastelloy-N. Some other developments, such as the testing of some of the components or the latter stages of the processing plant development, could actually be completed while a reactor is being designed and built. The major developments that should be pursued during the next several years are the following:

(1) A modified Hastelloy-N, or an alternative material that is less subject to attack by tellurium, must be selected and its compatibility with fuel salt demonstrated with out-of-pile forced convection loops and in-pile capsule experiments; means for giving it adequate resistance to radiation damage must be found, if needed, and commercial production of the alloy may have to be demonstrated; the mechanical properties data needed for code qualification must be acquired if they do not already exist.

(2) A method of intercepting and isolating tritium to prevent its passage into the steam system should be demonstrated at realistic conditions and on a large enough scale to show that such a method is feasible for a reactor.

(3) The various steps in the processing system must first be demonstrated in separate experiments; these steps must then be combined in an integrated demonstration of the complete process, including the materials of construction; and finally, after the MSBR plant is conceptually designed, a mock-up containing components that are as close as possible in design

to those that will be used in the actual process must be built and its operation and maintenance procedures demonstrated.

(4) The various components and systems of the reactor plant must be studied, developed, and demonstrated under conditions and at sizes that allow confident extrapolation to the next reactor plant size. These include the xenon stripping system for the fuel salt, off-gas and cleanup systems for the coolant salt (facilities in which these could be done are already under construction), steam generator modules, and startup systems and pumps. The construction of an engineering mock-up of the major components and systems of the reactor would be desirable, but whether or not that is done would depend on how far the development program had proceeded in testing various components and systems individually.

(5) Graphite elements that are suitable for the MSBR should be purchased in sizes and quantities that assure that a commercial production capability does exist, and the radiation behavior of samples of the commercially produced material should be confirmed. Methods for sealing graphite to limit xenon diffusion should continue to be explored.

(6) On-line chemical analysis devices and the various instruments that will be needed for the reactor and processing plant should be purchased or developed and should be demonstrated on loops, processing experiments, and mock-ups.

Further development will be required in a number of areas, including the development of design bases to provide a focal point for the MSBR technology program. This approach represents a desirable program for advancing and testing molten salt breeder technology in the absence of a commitment to build a reactor; successful achievement of this program will be necessary if a reactor is to be built.

6A.1.5.5 Present and Projected Application

6A.1.5.5.1 Current Use

As noted above, MSBRs are not yet in use, but the technology has been examined to the point that a breeder reactor experiment has been proposed, and other research is being conducted.

6A.1.5.5.2 Projected Use

If the technology proves technically, economically, and environmentally successful, MSBRs might be expected to produce a moderate part of our electricity requirements some time after the year 2000. There might also be other applications (e.g., process heat). The extent of the electricity market that might be captured by MSBRs is difficult to predict and would be dependent on the success of other reactor concepts as well as the solution of the technical problems currently envisioned for molten salt reactors.

In his comments dated April 22, 1974, on the Draft Environmental Statement, Dr. Henry Ott of Ebasco Services, Incorporated,* states that:

> ...by using Pu from LWRs, it would be possible to substitute molten salt reactors for the 400 GWe of breeder capacity of AEC's 'most likely' forecast through the year 2000 with essentially no difference in demands for U_3O_8 and separative work and ... the MSR can make a major contribution to the nuclear economy only if introduced before the fast breeder becomes commercial.

Dr. Ott also notes that the MSBR is projected to have lower fuel cycle costs than the LMFBR or GCFR, and he states on this basis that "there is a good chance that the molten salt reactor could become competitive with light water reactors and hence commercially acceptable at an earlier date than either fast breeder."

All of these comments are predicated on the assumption that the MSBR can be developed in the same time frame as the LMFBR and depend upon that assumption for the validity of the conclusions drawn by Dr. Ott. The AEC cannot agree with this position based on the technical uncertainties associated with the MSBR concept. The AEC cannot currently envision the development of the MSBR before the LMFBR, even with a highly accelerated MSBR program, unless the LMFBR program is delayed by unforeseen factors. The time lag between the two technologies is prohibitive to such rapid development of the MSBR which, as noted above, is being pursued primarily as a backup concept.

6A.1.5.6 Environmental Impacts

6A.1.5.6.1 Energy Conversion Plant

The environmental impacts resulting from construction and normal operation of an MSBR plant would likely be similar to those for an LMFBR plant of comparable size. The MSBR would utilize a U-233/Th fuel cycle, possibly with a requirement for enriched U-235 for startup, and thus would involve different mining, and possibly enrichment, requirements.

*Comment Letter 18, p. 6ff.

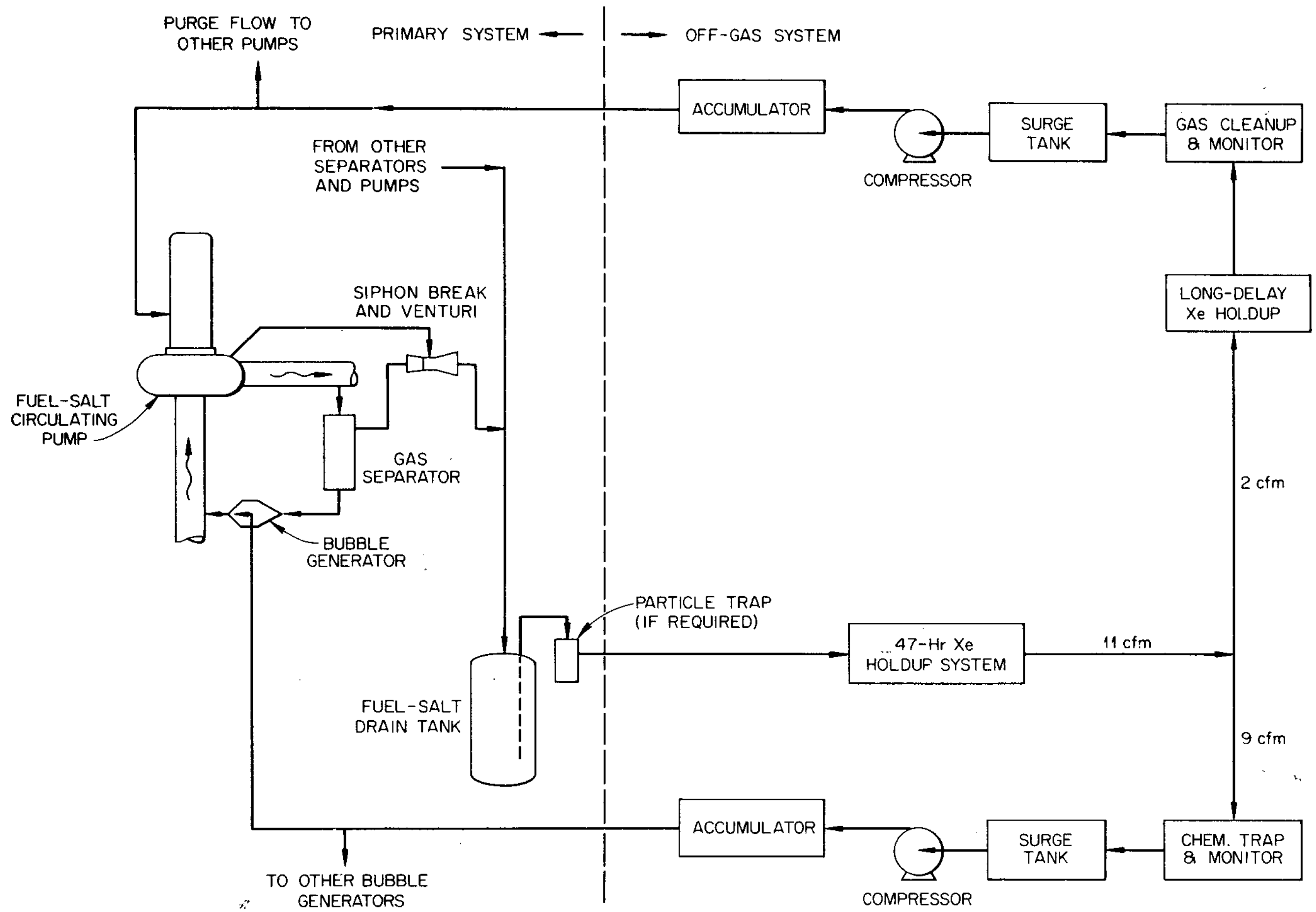
A major uncertainty with regard to the MSBRs environmental characteristics is the handling of tritium.[1,3,4] Tritium is produced in an MSBR through the interaction of thermal neutrons with the lithium according to the following reactions: Li-6 (n,α)H-3 and Li-7(n,α)H-3. Tritium is a special problem because of its high rate of production in the fuel salt and because it readily diffuses through metals at MSBR temperatures. Approximately 2400 Ci/day are produced by each 1000-MWe plant. In the current reference design, ORNL has estimated that approximately 800 Ci/day would be released in the 560,000-gpm stream of cooling water unless specific tritium control measures are implemented. The effluent concentration (0.26×10^{-3} μCi/ml) is a factor of 52 greater than the AEC's numerical guidelines for effluent from LWRs. Because of this "tritium problem," a method for the retention and control of tritium must be developed and proven before the MSBR concept can be considered viable. Several modifications in design and operation offer ways for reducing tritium escape. The objective of limiting tritium release to within present guidelines for light-water-cooled reactors appears attainable, but the best measures are yet to be chosen and demonstrated.[5]

The noble gases are continuously stripped from the fuel salt by a purge of helium. The system being considered (Figure 6A.1-39) would allow for the decay of the short-lived fission gases and total retention of all long-lived gaseous fission products. Therefore, the MSBR is not expected to release any noble gases.

6A.1.5.6.2 Offsite Activities

All high-level waste streams from the reprocessing plant will be combined in order to recover the residual uranium prior to disposal. The reference processing scheme would result in the discarding of about 0.3 ft^3/day of fuel salt containing the rare earth fission products and possibly significant quantities of thorium, although to recover and recycle the thorium may prove desirable in the interest of achieving higher resource utilization. This waste is expected to be in a form acceptable for storage in a Federal waste repository. Some of the fission products remain in the fuel salt, and these become a concern when the plant is finally decommissioned. At present, no demonstrable method exists for the ultimate disposal of this material.

With regard to other high-level and low-level solid, liquid, and gaseous wastes, the current state-of-the-art is such that an estimate of their quantity cannot be made, although their overall impacts should be comparable to those of other reactor systems.



MSBR OFF-GAS SYSTEM SCHEMATIC FLOW DIAGRAM

Figure 6A.1-39

6A.1.5.7 Costs and Benefits

6A.1.5.7.1 Costs

Based upon experience with other complex reactor development programs, the AEC estimates that a total government investment up to about $2 billion in undiscounted direct costs[6] could be required to bring the molten salt breeder or any parallel breeder to fruition as a viable, commercial power reactor. A magnitude of funding up to this level would be needed to establish the necessary technology and engineering bases, to obtain the required industrial capability, and to advance through a series of test facilities, reactor experiments, and demonstration plants to a commercial MSBR safe and suitable to serve as a major energy option for central station power generation in the utility environment.

With regard to capital and operating costs, the problem of assessment is more difficult because it not only involves uncertainties in MSBR costs but also uncertainties about what the cost of the competing system will be. The major cost item in the fuel cycle is the capital cost of the processing plant, and this cost is probably the most certain of the estimates. Based on (1) a reasonably conservative estimate, including, for example, an allowance of $200 per pound for the cost of fabricating the molybdenum used to contain bismuth (see Figure 6A.1-38), and (2) additional conservatism in the processing costs based on using the processing plant for only 1000 MWe of reactor capacity (whereas the unit costs of processing plants come down very rapidly if the throughput is increased), the AEC concludes the capital costs for MSBRs will be about the same as for LWRs.

The estimation of capital costs of plants to be built far in the future with some yet undeveloped technology is full of uncertainties. Because of the way LWR cost data were used, these uncertainties appear to have more to do with the design of the plant than with the ability to make cost comparisons for a given design. Nevertheless, there is limited room for error in the comparison with an LWR because the cost of "reactor equipment" (including the reactor itself, the salt pumps, the heat exchangers and steam generators, the salt storage tanks, and the off-gas system and other equipment) is only one-third of the total cost of the power plant.

Because the fissile inventory is fairly low and the credit for sale of bred fuel is modest, the fuel cycle economics of MSBRs are not very sensitive to these factors nor to the cost of enriched uranium. Increasing uranium ore cost from $8 to $16 per pound without reoptimization of the reactor would only increase the fuel cycle costs by about 0.1 mill/kWhr.

One other factor that can affect the power cost is plant availability. Because molten-salt reactors do not have to be shut down for refueling and because the frequency of graphite replacement is low and can be scheduled to coincide with major turbine maintenance, MSBRs start off with an inherent availability advantage over LWRs. However, the MSBR plant would have to have sufficiently high reliability to fully utilize this availability advantage and would have to be specially designed so that this inherent advantage is not offset by the increased difficulty of maintenance.

Based on earlier design studies, the cost of power from an MSBR has been estimated to be about 0.5 mill/kWhr less than that for power from an LWR at present uranium ore prices. If uranium ore costs were to increase by $8 per pound by the time molten salt breeders are introduced, the cost advantage of an MSBR would increase by 0.3 mill/kWhr. Thus, there is a fair margin for error in the comparison with present-day LWRs. However, LWR costs are certain to change over the next two or so decades, and the uncertainty of the nature of the nuclear reactor competition at that time (which will probably include LWRs, HTGRs, and LMFBRs) makes firm conclusions about the MSBR meeting cost criteria inappropriate.

6A.1.5.7.2 Benefits

Major potential benefits from MSBRs can be summarized as follows:

(1) Use of a fluid fuel and onsite processing would eliminate the problems of solid fuel fabrication and of handling, shipping, and reprocessing of spent fuel elements which are associated with all other reactor types under active consideration.

(2) MSBR operation on the uranium-thorium fuel cycle would help conserve uranium and thorium resources by utilizing thorium reserves with high efficiency.

(3) The MSBR has a lower specific fuel inventory than fast breeders, thereby requiring less ore and separative work for the initial fueling of a reactor.

(4) The MSBR is projected to have attractive fuel cycle costs. The major uncertainty in the fuel cycle cost is associated with the continuous fuel processing plant which has not been developed.

(5) The safety issues associated with the MSBR are generally different from those of solid fuel reactors. Thus, there might be safety advantages for the MSBR when considering major accidents. An accurate assessment

of MSBR safety is not possible today because of its early stage of development.

(6) Like other advanced reactor systems such as the LMFBR and HTGR, the MSBR would employ modern steam technology for power generation with high thermal efficiencies. This utilization would reduce the amount of waste heat to be discharged to the environment.

At this stage in the development of the concept, to evaluate the benefits or penalties that will be associated with the reactor is impossible. For example, development of methods for the control of tritium would prevent the release of this material to the environment and, therefore, consideration of the tritium problem would not be necessary. However, should the development efforts fail, then the release of some 800 Ci/day would probably prohibit use of this reactor.

6A.1.5.8 Overall Assessment of Role in Energy Supply

This early in the development program, an assessment cannot be made of the penetration that the MSBR would make if it were to become a viable reactor. Even if the AEC and the nuclear industry were to significantly increase the funding for the MSBR development program, the earliest that the system could be expected to be marketed would be in the 1990's, and thus the MSBR would not be expected to supply a significant amount of electrical energy until past the year 2000.

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6A.1.6 Controlled Thermonuclear Reactor Power Systems

6A.1.6.1 Introduction

Nuclear fusion is the process of joining together two light nuclei with the accompanying release of energy. This reaction can occur only when the reacting ions collide with sufficient energy to overcome the repelling forces between them; one method of accomplishing this is by raising the temperature of the reacting nuclei to a sufficiently high level. Fusion reactions brought about by this means are called thermonuclear reactions.

The Atomic Energy Commission supports two programs aimed primarily at utilizing the nuclear fusion process for commercial electrical power production. One program involves the use of magnetic fields to confine a plasma* of fusion fuels, while the other emphasizes the use of high-energy, short-pulse lasers focused on suitable thermonuclear pellets to compress, heat, and ignite the fuel to release the fusion energy. These programs are managed by the AEC Division of Controlled Thermonuclear Research and the Division of Military Application, respectively.

The goal of the AEC controlled thermonuclear research (CTR) program is the development of fusion as a major source of abundant, economical, and environmentally attractive energy, particularly for the generation of electricity. This is also one of the goals of the AEC laser-fusion program, but in addition, there are other applications of the laser-fusion program that are motivated by military needs rather than civilian electrical power generation. The primary fuels for fusion reactions are the hydrogen isotopes deuterium and tritium. These reactions can only take place at very high temperatures (about 100 million degrees), and at such temperatures the fuels are present as a state of matter called plasma. The central problem at present in the fusion research program is to confine a reacting fusion plasma at conditions of density, temperature, and confinement time sufficient to release more energy from fusion reactions than is necessary to initiate them. Achievement of these conditions would be a major accomplishment in Phase I of the controlled fusion reactor program. (See the opening part of this section, Perspective on Alternative Energy Options, for a discussion of the phases involved in any research and development program.)

*A fully ionized gas (i.e., one in which all the electrons have been stripped from the nuclei).

6A.1.6.1.1 Magnetic Confinement Program

One of the major approaches to meeting the requirements for achieving useful power from controlled thermonuclear reactors is that of magnetic confinement. The magnetic confinement program began in 1951 as a classified program called Project Sherwood. It was declassified in 1958 and a program summary was published that year.[1] By the early 1960's, plasmas had been created at the temperatures and densities required for fusion, and a number of scientific problems relating to containing the plasma for sufficiently long times were identified and a systematic study of them begun.

The difficulties that arose during these studies became the central problem of fusion research. The principal approach to this problem, then as now, was to confine a fusion plasma through the use of specially shaped magnetic fields, which were intended to control the motions of its individual ions and electrons. However, researchers soon discovered that spontaneously arising turbulence and unstable plasma oscillations significantly weakened the confining effect of the magnetic fields. As a result of several years of intensive theoretical and experimental research, the plasma instability problem was brought under reasonable control by the late 1960's. In fact, the understanding of instabilities and means for their control was sufficient to permit experiments that exhibited confinement conditions close to the "classical" upper limit--the theoretical maximum possible in a completely quiescent plasma at a particular density and temperature. This achievement was obtained in several different experiments, and it provided a basis for renewed optimism with respect to ultimate success.

Three concepts of magnetic confinement are under study in the United States. These are called low-beta,* high-beta, and open systems. Low-beta toroidal systems, principally the tokamak, are under investigation primarily at the Oak Ridge National Laboratory and the Plasma Physics Laboratory of Princeton University. These contain a plasma in a toroidal configuration at comparatively low particle density. High-beta systems, principally the theta pinch, are being developed at the Los Alamos Scientific Laboratory. These devices operate at conditions where the pressure generated by the plasma is almost as strong as the confining pulsed magnetic field. The latest experiment is being assembled in a toroidal configuration. Finally, experiments known as open systems, or magnetic mirrors, are being conducted at the Lawrence Livermore Laboratory. These systems contain a plasma in

*Beta is defined as the ratio of the outward pressure exerted by the plasma to the inward pressure that the magnetic confining field is capable of exerting.

magnetic bottles designed to reflect the charged particles repeatedly from regions of strong magnetic field.

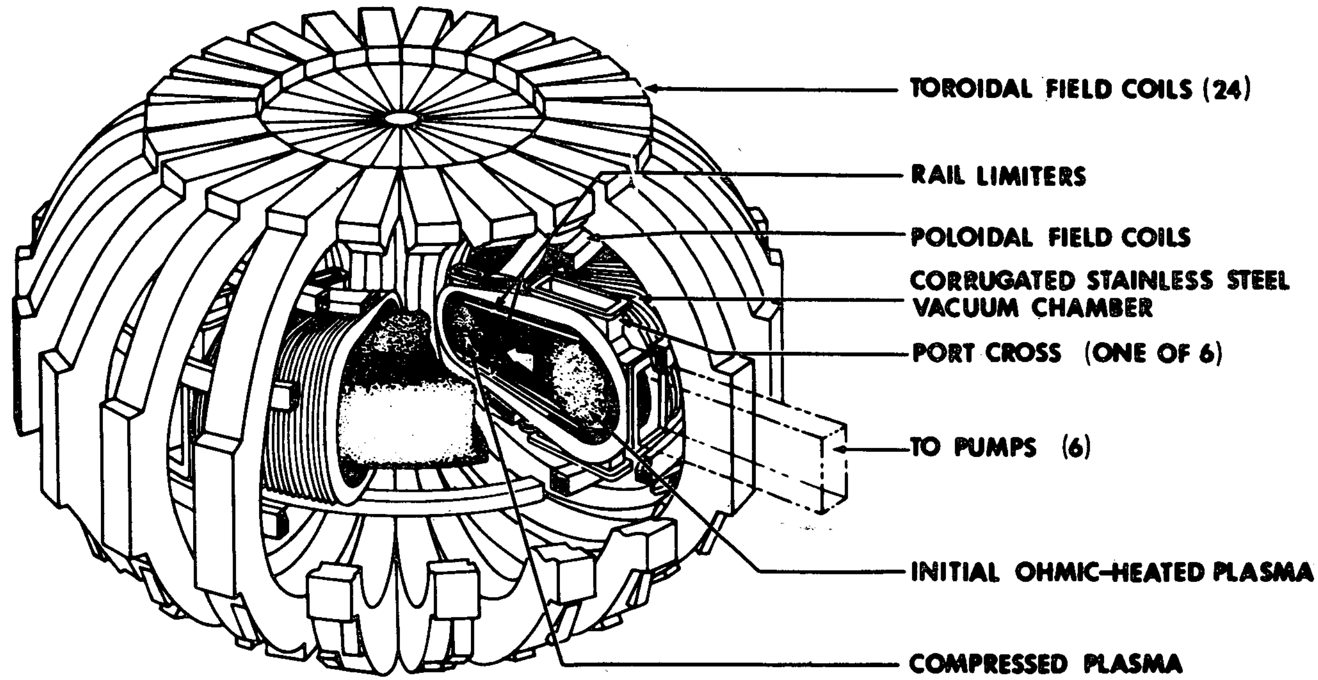
The 1972-1973 period has seen significant advances in the magnetic confinement program. Important experimental results were achieved in three major experiments designed to isolate the plasma from its surroundings through use of specially shaped magnetic fields--the principal approach to the development of first-generation fusion power plants.

The Adiabatic Toroidal Compressor (ATC) at the Princeton Plasma Physics Laboratory (Figure 6A.1-40) and the large-bore toroidal tokamak (ORMAK) at Oak Ridge National Laboratory (Figure 6A.1-41) successfully demonstrated two plasma heating techniques--plasma compression and neutral beam injection respectively. Each has the potential to boost plasma temperature past the ohmic heating barrier* to thermonuclear levels. Further, ORMAK confirmed that increases in size would result in better plasma parameters, and the ATC plasma was compressed to a density beyond that required for a tokamak reactor.

In the Scyllac experiment (Figure 6A.1-42) at Los Alamos Scientific Laboratory, stable confinement, terminated only by end effects, was observed in both the 5-m and 8-m sectors of the torus. Based on these results, the full torus, completed in April 1974, could possibly attain 50 to 100 μsec containment. Achievement of a containment time in this range would signify a confirmation of the correctness of our understanding of the basic physical laws governing high beta plasmas in toroidal geometry. The affirmation of our theories would be a major accomplishment in the high-density systems program and would provide us with a critical scaling law required in the design of a thermonuclear reactor based upon this concept.

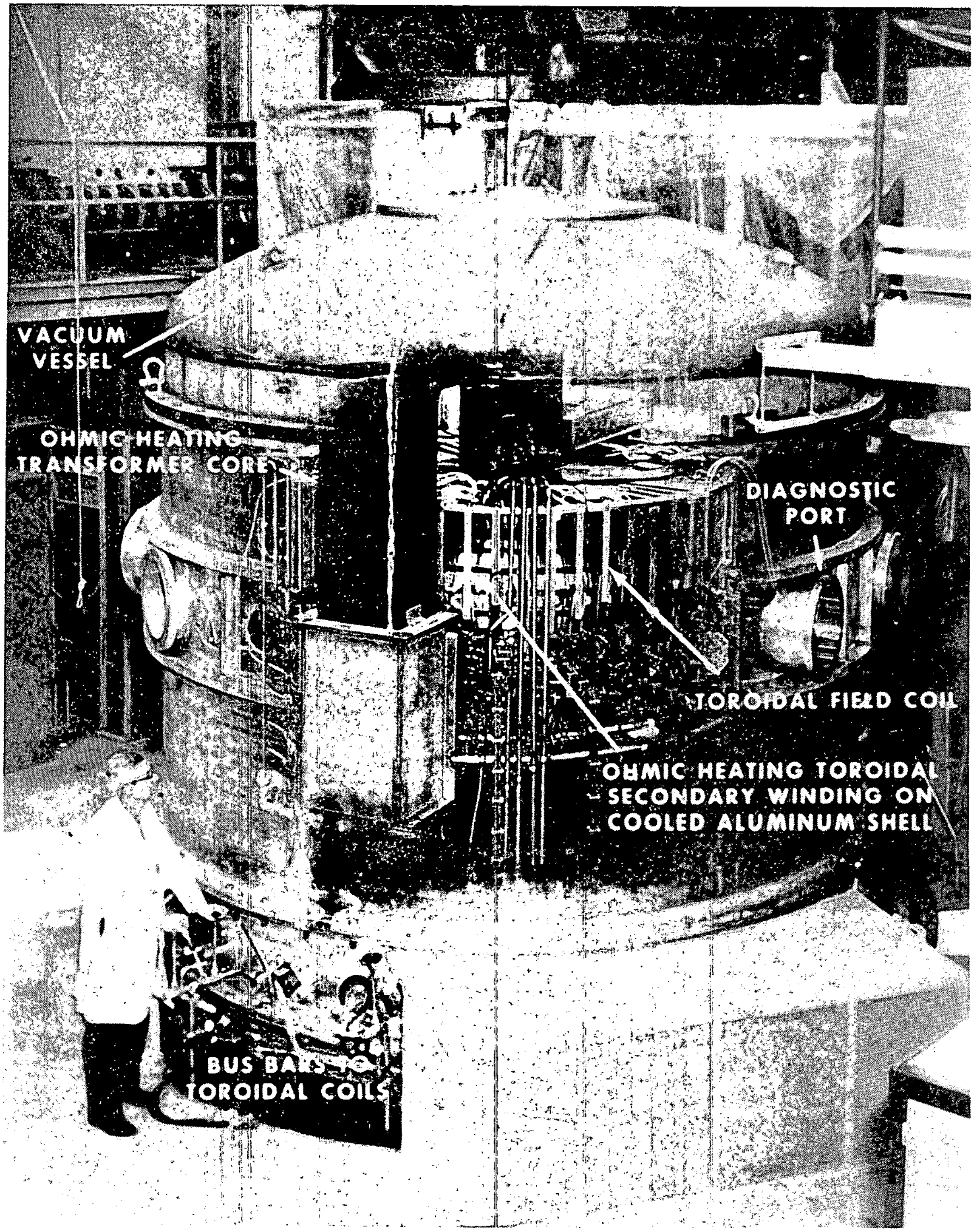
The parameter characterizing attainment of thermonuclear reactor conditions is the product of the plasma density, n, and the containment time, τ, for the reaction considered. Future deuterium-tritium (D-T) fusion reactors confining 10-keV (100,000,000°C) temperature plasmas are expected to require an $n\tau$ product of the order of 10^{14} sec cm^{-3}. Because the plasma density in the Scyllac device will be

*Ohmic heating is similar to the process that heats an electric toaster; the plasma electrons are resistively heated. The ohmic heating barrier is not specifically a limit on the current that can flow in the plasma but rather the point at which plasma losses (particularly bremsstrahlung) equal the effect of ohmic heating; plasma losses increase with plasma temperature while the effectiveness of ohmic heating decreases.



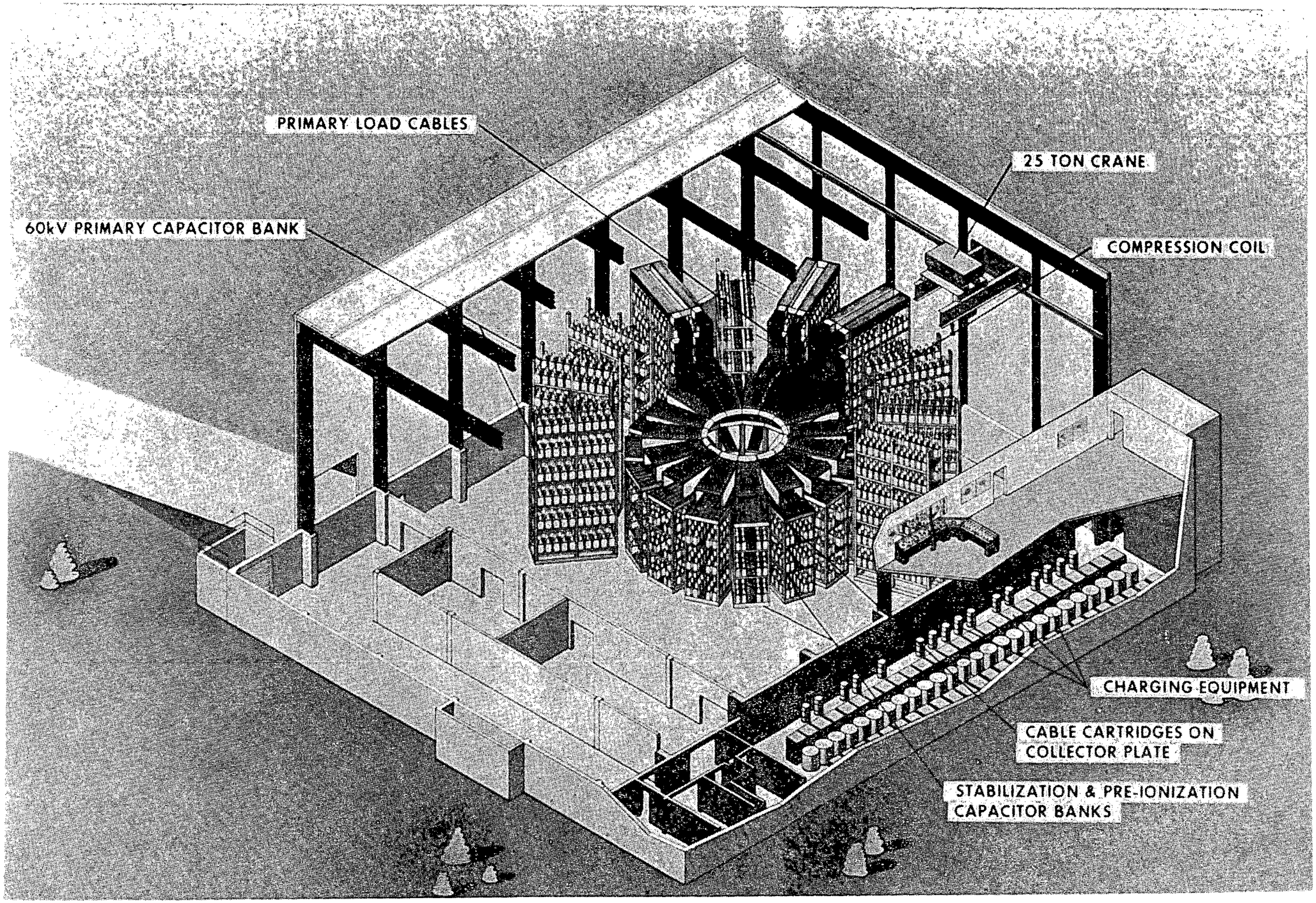
ADIABATIC TOROIDAL COMPRESSOR (ATC)

Figure 6A.1-40



ORMAK

Figure 6A.1-41



SCYLLAC

Figure 6A.1-42

2×10^{16} cm^{-3}, a demonstration of 50 to 100 μsec confinement time would yield an $n\tau$ value of 1 to 2×10^{12} sec cm^{-3}, a level of considerable physical significance.

Based on the above experiments and other advances in theory, experiment, and hardware development, the AEC expects that the U.S. program should have D-T burning experiments operating about 1980 producing the first significant release of controlled fusion energy for peaceful purposes. Following that, the principal second-phase milestone of operation of experimental power reactors producing usable amounts of power could be achieved in the later part of the 1980's, and the operation of a demonstration fusion power plant of 500 MWe or more could come in the late 1990's.

6A.1.6.1.2 Laser-Fusion Program

The laser-fusion program constitutes an alternative to the magnetic confinement fusion effort for producing commercial electric power. It involves the use of high-energy, short-pulse laser beams focused on suitable thermonuclear pellets to heat and compress the fuel, thus causing the release of fusion energy. This compression would be done repetitively with the energy converted to electrical power through a thermal cycle or other system.

The program was initiated by the AEC in 1962 as physics investigations to provide understanding of the military potential of lasers for the generation of plasmas. The effort was conducted at a modest level for several years, with greater emphasis on laser-fusion for energy commencing in 1969. This increase was due to increasing optimism for achieving laser-induced thermonuclear reactions resulting from (1) developments in laser technology that demonstrated the feasibility of high-energy, subnanosecond* laser pulses and (2) analyses based on thermonuclear principles that indicated that the laser requirements for achieving fusion were orders of magnitude less than those initially anticipated. Also, the potential of this new technology for civilian power application was more clearly perceived and was deemed sufficient to merit an energetic program even though portions of the program must be considered as having substantial uncertainty.

Since the late 1960's, the program has been broadened in scope and effort, and significant progress has been made in many of the basic technology areas involved, including laser developments, fast diagnostic instrumentation, and theory and understanding of laser-plasma interactions. These developments provide a firm technology base for further advances.

*1 nanosecond = 10^{-9} seconds.

The current AEC program is being conducted at the Lawrence Livermore Laboratory (LLL), Los Alamos Scientific Laboratory (LASL), and Sandia Laboratories-Albuquerque (SLA) with contract support by selected contractors, primarily the Naval Research Laboratory (NRL). Contract research is currently undertaken with organizations which have appropriate facilities and capabilities.

The program is strongly oriented, in the near term, toward evaluating the overall scientific feasibility of laser fusion. High-energy, spherical irradiation experiments are planned within the next few years to normalize the computer codes that are used for target design. These early, high-energy target irradiation experiments will define the probability of achieving laser-fusion feasibility.

Assuming success in these irradiation experiments, achievement of laser-fusion scientific feasibility, and advances in theory and hardware developments anticipated in this field, the AEC anticipates that net energy gain (fusion energy from pellet greater than total energy input to system) can be achieved by 1980--this would be for nonrepetitive pulse operation in contrast to repetitive reactor-type operation. This achievement would be followed by an experimental reactor in the mid-1980's and an experimental power reactor possibly by 1990. Subject to successful achievement of the experimental power reactor within this time frame, a demonstration power reactor might be feasible in the mid-1990's.

6A.1.6.2 Extent of Energy Resource

Because of its high energy gain and its relatively low plasma temperature, the D-T reaction is considered the most attractive for first-generation fusion power reactors. Deuterium is present in sea water and may be extracted at low fuel cost by means of proven processes. It is virtually an unlimited fuel resource. Tritium, on the other hand, does not occur naturally and must be bred by means of neutron absorption in lithium. Hence, the supply of lithium determines the capacity to utilize tritium in fusion reactors. Lithium is currently produced from pegmatitic rocks and by solar evaporation of subsurface brines. Known lithium reserves are large, and the potential for expanding lithium resources is excellent. Higher-cost lithium could also be recovered in substantial amounts from several sources. An assessment of the adequacy of lithium supplies[2] indicated that:

> Even the most conservative estimates of exploitable lithium supplies lead to the conclusion that DT fusion reactors, breeding their tritium from natural lithium, could meet an electricity demand much larger than today's for centuries.

In the future, when the technology has been developed to permit the commercial use of D-D reactions, requirements for lithium will be alleviated and the thermonuclear reactor industry could eventually be based upon the virtually inexhaustible deuterium resource.

The discussion of requirements and availability of material resources needed for fusion reactor construction given in Section 6A.1.6.6.3 below shows in some detail that a fully developed world fusion power economy would cause some resource use conflicts that would have to be resolved. However, design improvements and technology developments might provide possibilities for alternative materials utilization.

6A.1.6.3 Technical Description

In 1972, scoping studies were made of the four major fusion concepts--the tokamak, the theta pinch, the magnetic mirror, and the laser-fusion systems.[3] The first three involve magnetic confinement of the hot plasma to isolate it from the reactor chamber walls, thereby avoiding quenching of the plasma below the thermonuclear reaction temperature. Laser-fusion reactions, on the other hand, are envisioned to occur so rapidly that inertial forces provide adequate confinement during the thermonuclear fusion process.

Fusion power systems currently envisioned[3,4] would utilize the D-T fuel cycle ($D + T \rightarrow He\text{-}4 + n$), in which 80% of the fusion energy is carried by the neutrons. These systems will require a blanket region to convert the neutron kinetic energy to thermal energy and to breed tritium fuel by neutron absorption in lithium, present either as the liquid metal or as an inorganic salt. The blanket will also serve as the inner portion of the biological shield. A thermal power conversion system would be required for generation of electricity. Advanced fusion systems could have a large fraction of the total fusion energy carried by charged particles that might make direct power conversion an attractive alternative.

Materials of construction will dictate permissible operating temperatures in fusion power systems. For example, the torus of a tokamak reactor might be fabricated of an alloy of a refractory metal, such as vanadium, if assurance of a virtually oxygen-free coolant for contact with the vanadium structure were possible. Use of such an alloy should permit operation at elevated temperatures, with overall plant efficiencies of 40 to 50%. A vanadium alloy of this type has not been developed as yet and would require extensive research to assure that it would meet requirements necessary for purposes such as fabricability into large segments and compatibility with possible coolants. Vanadium materials known today require an essentially oxygen-free environment to prevent corrosion and consequent deterioration of mechanical properties. If this characteristic persists in the new alloys to be developed, designs using vanadium would have to assure that the coolant in contact with the vanadium structure would be virtually oxygen-free. Use of other refractory metals, such as niobium- or molybdenum-based alloys, would give rise to similar concern over effects of oxygen contamination.

Should use of stainless steel prove necessary, operating temperatures would be reduced from those for a vanadium alloy to prevent excessive corrosion by metallic lithium in the blanket. Steam at perhaps 900°F would be used to drive a conventional steam power plant and obtain an overall thermal efficiency of 30 to 36%.

Studies conducted to date have served primarily to define general operating conditions and provide a basis for more detailed assessments. Such assessments are presently under way for a theta pinch concept, a mirror concept, three variations on the tokamak confinement systems, and a number of power plants based on the laser-fusion process. These studies will provide a basis for determining further research and development requirements and will also permit a more detailed analysis of environmental impact of fusion power plants.

Transportation and storage of fusion reactor fuels would pose no problems, because neither the deuterium nor the lithium is radioactive and they can be shipped according to acceptable safe practice. The two fusion reaction products are stable He-4 and a neutron. Most of the neutrons are absorbed in the lithium blanket and the remainder in the structural members (resulting in activation of these members), while the helium is an inert product that may be separated from unburned D-T fuel and used as makeup for the helium refrigerant for the superconducting magnet system.

Present understanding indicates that fusion power plants could be built with the same electric output as other types--about 1000 MWe or larger.

6A.1.6.4 Research and Development Program

Both the magnetic confinement and laser-fusion programs have significant efforts under way which are in the early stages of the first phase of a research and development program (see the opening section, titled Perspective on Alternative Energy Options) leading to the determination of scientific feasibility. Many possible additional efforts in this phase have been identified. These efforts, and efforts of subsequent phases, will be undertaken in parallel or in sequence (as the logic of the program dictates) as prerequisites to the initiation of major engineering activities in the later phases of the program.

In view of the fact that scientific feasibility has yet to be established in either the magnetic confinement or laser-fusion approach to controlled thermonuclear power, the research and development program described herein, and particularly the schedules for progressive development in that program, have a large degree of uncertainty attached to them. The early stages of the research and development program deal with experiments designed to achieve scientific breakthroughs. These experiments can be scheduled, but there is no assurance that the results will be satisfactory or that they will be achieved on the anticipated schedules. At least three tasks can be identified that will have to be achieved before research leading to achievement of engineering feasibility can be successfully accomplished: the good plasma confinement already achieved in small experiments must be achieved in reactor-sized experiments; plasma heaters developed for small experiments must be scaled to larger-size units with reasonable efficiency; and development of the means for either continuously removing the helium "ash" produced or getting a sufficiently high burn-up of the fuel each cycle to much more than take care of the energy required to heat and ignite the plasma.

Research and development requirements for the different fusion power concepts have been assessed by several planning bodies. A report originally prepared as part of the work done for the Federal Council on Science and Technology's Energy Research and Development Goals Study[5] examined fusion research needs as they appeared in 1972. More recently, in "The Nation's Energy Future,"[6] a program of fusion research and development over the next five years was outlined. Objectives of this program, which were recommended to be funded at $1.45 billion, include the conducting of theoretical, computational, and experimental studies to predict the behavior of fusion experiments and the operating characteristics of fusion reactors; development of the technology to perform fusion research; establishment of the feasibility of various magnetic confinement systems and of laser fusion as a basis for practical fusion power generation; and development of components and an engineering base leading to the operation of prototype, demonstration, and commercial fusion power reactors. A summary of the elements of the research and development programs outlined in refs. 5 and 6, as modified by current AEC planning, is provided below.

6A.1.6.4.1 Magnetic Confinement Program

For all of the systems in the magnetic confinement program, the theoretical and experimental efforts are directed toward a common goal--the understanding of conditions necessary for creating, heating, and sustaining a D-T plasma so that it may be used as an energy source for the generation of electric power.

The major share of funding at present is allocated to relatively large and sophisticated experiments devoted to the study of plasma properties, particularly those techniques that may be employed to heat plasmas to thermonuclear temperatures. Many aspects of plasma physics, however, need not be studied in complex experiments, and there is a significant research program devoted to the development of plasma science by means of simpler experiments intended to build the necessary base of understanding. In addition to the experimental programs, development and technology programs are under way which concentrate on providing the engineering support, both design data and hardware, necessary for planned future experiments.

Plasma experiments in progress employ hydrogen, deuterium, or helium, because use of tritium would require special facilities to handle and control a radioactive gas safely. However, more complex facilities are now contemplated for construction as part of the next generation of plasma experiments so that the technology of burning D-T gas mixtures may be fully explored. Initially, these experiments would be operated with hydrogen plasmas to clarify appropriate questions of physics. They would then be fueled with D-T, and the physics and engineering problems relating to burning fusion plasmas would be studied.

In addition to D-T burning experiments, other experiments operating solely with hydrogen plasmas will be undertaken for the purpose of addressing separable physics and engineering problems. Such experiments will provide critical data without the necessity of providing tritium-handling capability and incorporating shielding for the neutrons generated in the D-T reactions.

Magnetic confinement experiments to be conducted in the future are anticipated to be as follows:

Phase I: Deuterium-tritium fusion test reactors, 1 to 10 MWt, two or three to be completed about 1980.

Phase II: Experimental Power Reactor No. 1, 20 to 50 MWe, to be completed about 1985.

Experimental Power Reactor No. 2, 100 MWe, to be completed in 1989-1990.

Phase III: Demonstration power reactor, 500 MWe, to be completed about the late 1990's.

Development and technology efforts will be expanded to provide the necessary hardware for the new large experiments and to begin those long lead-time efforts related to fusion power experimental power reactors and demonstration plants. The engineering requirements of power-producing systems may differ markedly from experiments designed solely to acquire data on operating characteristics; so conducting work in recognition of potential differences is critical. The most important development problems that must be faced in the near-term magnetic confinement fusion program include superconducting magnets, magnetic energy storage systems, and neutral beam sources.

The research program will also be expanded to develop further understanding of plasma behavior. To expect that there will be a continuing need for study of the basic principles of plasma physics to provide a greatly needed predictive capability is reasonable. For example, a greatly increased effort is to be undertaken on computer simulation of plasmas, including three-dimensional computer simulation. This task will permit modeling of proposed experiments to assure proper machine design and, in the longer term, will provide the capability to optimize fusion reactor power plants more easily.

Input to such computer codes will be largely dependent on progress in understanding of plasma behavior, in much the same way that fission reactor analysis is predicated on precise neutron cross-section data.

6A.1.6.4.2 Laser-Fusion Program

The laser-fusion program encompasses both theoretical and experimental efforts. The status of unclassified research has been periodically reviewed.[7-9] Program efforts to date have been directed predominantly toward laser research and laser-system hardware development, with increasing emphasis in recent years on lasers with high-energy outputs in subnanosecond pulses. This work has been supported and guided by theoretical and calculational efforts on laser-plasma generation, laser-energy absorption mechanisms, pellet configurations, and laser irradiation experiments using various target configurations and materials.

The first priority of the laser-fusion program is to obtain experimental data on the interaction of high-energy laser beams with target materials and thermonuclear pellets. Such data are critically needed to assess the validity of theoretical predictions of target performance. The small amount of tritium required for pellet experiments presents no difficult safety or handling problems, and the current program includes irradiation of targets containing tritium. The present output of glass lasers is sufficient to begin serious experimental studies but is too low in energy to achieve meaningful pellet compressions. Therefore, another high priority of the current program is to develop higher output lasers.

The best hope for substantial energy gains in the near-term lies in the further development of neodymium-glass lasers. A 10,000-joule (J) glass laser-system is under development. In the long-term, gas lasers appear much more promising for providing energies of 100,000-J and higher at reasonable costs. A 10,000-J CO_2 laser is under development to evaluate the designs and components for a proposed 100,000-J CO_2 system expected to be started in 1975. Larger follow-on systems are in the planning stage. A modest facility is planned for evaluating the potential of electron-beam technology for achieving fusion.

Future experiments in the laser-fusion program are anticipated as follows:

<u>Phase I</u>: Single-cavity experimental reactor at 50 MWt in early to mid-1980's.

<u>Phase II</u>: Experimental power reactor, 100 MWe, to be completed by 1990.

<u>Phase III</u>: Demonstration power reactor, single or multiple 100-MWe modules, to be completed about the mid-1990's.

As discussed above, these experiments will be supported by the development of lasers having increasingly higher energies and efficiencies, the design and fabrication of the required fuel pellets, and developments and tests of reactor components such as optical hardware, tritium processing, laser gas flow systems, cavity and blast containment vessels, and direct conversion systems.

As in the magnetic confinement program, more detailed attention will be given to assessment of the characteristics of laser-fusion power reactors. This study will permit identification of engineering developments necessary to reduce the laser-fusion process to practice initially in experimental and demonstration reactors. Theoretical studies will also continue to assure that the physics of laser-pellet interaction processes is well understood and that the techniques employed make maximum use of the incident laser energy.

6A.1.6.5 Present and Projected Application

Since the CTR program is in the early stages of its development effort, present and projected applications must be measured in terms of milestones along the way toward development of the technology. The major milestones anticipated to be achievable which are associated with the magnetic confinement fusion research program are as follows:

Phase I: Achievement of reactor-level plasma conditions in a hydrogen plasma in the late 1970's.
Achievement of D-T burning at the multi-megawatt level in about 1980 in fusion test reactors.

Phase II: Electrical power production about 1985 in a first-generation Experimental Power Reactor (EPR-1) at many tens of electrical megawatts.
Electrical power production in 1989-90 in a second-generation Experimental Power Reactor (EPR-2) at 100 MWe.

Phase III: Electrical power, 500 MWe or more, in a demonstration reactor in the late 1990's.
Commercial introduction of fusion power plants on a significant scale beginning in the early 21st century.

Milestones for the laser-fusion effort are as follows:

Phase I: Achievement of significant thermonuclear burn in the mid-1970's.
Achievement of scientific breakeven* in the late 1970's.
Achievement of net energy gain by about 1980.

*Fusion energy from the pellet equals the laser light energy incident on the pellet. Efficiency of laser would then determine how close to energy breakeven the system has approached.

Phase II: Operation of single-cavity experimental reactor at 50 MWt in mid-1980's.
Electrical power generation, 100 MWe, in an experimental power reactor by 1990.
Electric power, single or multiple modules, in a demonstration reactor in the mid-1990's.

6A.1.6.6 Environmental Impacts

Since the fusion research program encompasses three approaches to magnetic confinement and one to laser fusion and is only in the early phases of research and development, an attempt toward definitive assessment of environmental impact would be premature. However, a preliminary analysis was done for a so-called Reference CTR,[3] and others are to be undertaken based on more detailed power plant scoping studies completed in early 1974.* A summary of the anticipated environmental impact of fusion reactors based on the studies conducted to date is provided below.

6A.1.6.6.1 Energy Conversion Plant

Radioactive Effluents

Any radioactive releases that occur during routine operation of a fusion power plant will be due to tritium leakage. It is expected that these releases can be maintained at manageable levels. Tritium leakage that does occur will come about by:

(1) diffusion through the blanket region walls into the magnet shield region, directly and from that region to the atmosphere of the building,
(2) leakage from joints and/or components of the tritium handling system, and
(3) diffusion through heat exchanger walls into the working fluid of the thermodynamic cycle and subsequent leakage to the atmosphere.

Direct diffusion from the blanket region to the atmosphere is expected to be trivial because representative reactors (e.g., a tokamak) can be designed to surround with a cold wall the thermally hot section that contains the tritium. By evacuating the intervening space and drawing and recycling any tritium in this

*Reports to be published.

space, the tritium loss is expected to be inconsequential because the remaining diffusion path would be through a cold wall. The design and attainment of highly leak-tight blanket coolant systems will impose a severe engineering requirement on fusion systems. The actual severity of the requirement will depend on the allowable leak rate, which in turn may be highly dependent on the details of the system design and allowable dose rates.

For the systems utilizing a steam cycle, any tritium that diffused from the blanket system would interact with water in the steam cycle to form HTO. Recovery of the tritium once it is in this form would require use of an exorbitantly expensive isotope separation process. Conventionally, liquid losses from steam cycles occur due to intentional operational discharges to maintain control of coolant chemistry and leakage. The problems associated with maintenance and operation of steam cycles in fusion plants are expected to be identical with those encountered in present conventional steam-enerating systems. The potential presence of HTO in the steam cycle is a factor that will require evaluation of the applicability of current steam cycle design, maintenance, and operational practice to fusion plants. An attractive alternative to the steam cycle is the closed-cycle gas turbine power system such as will be used with high-temperature gas-cooled fission reactor power plants.

Operation of certain fusion power plants solely as burners may prove possible. The necessary fuel could be obtained from breeder fusion reactor systems located in more remote sites and shipped to the burner stations as needed. This practice would result in a minimum tritium inventory in burner stations and might permit urban siting of such fusion power plants.

Long-Lived Radioactive Wastes

Fusion reactors will produce nonvolatile, long-lived radioactive wastes in modest quantities. The primary wastes will be activated structural materials of the blanket, which will have a finite useful lifetime within the reactor owing to radiation damage. Table 6A.1-21 (from ref. 10) shows the principal long-lived activities of a blanket structure composed of vanadium or niobium. This table gives the annual rate at which activity is generated normalized to 1 MW of reactor thermal power, the accumulated activity resulting from 1000 years of continuous generation,* and the biological hazard potential associated with this amount of accumulated activity. Note that in Table 6A.1-21 the maximum

*In 1000 years the accumulated hazard potential will approach its steady-state value.

Table 6A.1-21

LONG-LIVED ACTIVITIES IN THE BLANKET STRUCTURE OF A FUSION REACTOR[a]

Nuclide	Life (years)	Activity Generation Rate[b] (Ci/MWt-year)	Accumulated Activity at 1000 years[c] (Ci/MWt)	Maximum Permissible Concentration in Water ($\mu Ci/cm^3$)	Biological Hazard Potential Activity at 1000 years ÷ MPC (km^3 of water/MWt)
			If Fabricated with Vanadium		
Long-Lived Activities Due to Activation of Niobium Impurity in Vanadium[d]					0.00014 - 0.0014
			If Fabricated with Niobium		
Nb-93m	19.6	8,800	173,000	4×10^{-4}	0.4
Nb-94	2.9×10^{4}	2.9	2,900	3×10^{-6}[e]	1.0

[a]Source: D. Steiner and A. P. Fraas, "Preliminary Observations on the Radiological Implications of Fusion Power," Nuclear Safety 13(5):353 (September-October 1972).

[b]Average generation rate based on 20 years of reactor service.

[c]Based on 1000 years of continuous generation.

[d]Assuming niobium is present at an atomic concentratation of 100 to 1000 ppm.

[e]"Default" value listed in USAEC Rules and Regulations, 10 CFR 20, Appendix B.

permissible concentration in water is used, which seems more appropriate than the value in air in the context of underground disposal.

The use of vanadium as the blanket structural material would dramatically reduce the problems associated with radioactive waste disposal. Vanadium exhibits no known long-lived activity as a result of activation; therefore, the long-lived activities result only from the activation of impurities and alloying additions within the vanadium. Niobium is typical of such an impurity and might be present in vanadium at an atomic concentration somewhere between 100 to 1000 ppm. In this concentration range, the biological hazard potential associated with the activated vanadium structure would be three to four orders of magnitude lower than that associated with the niobium structure (see Table 6A.1-21). The same arguments would also be valid for several promising vanadium alloys (e.g., those containing titanium and chromium). However, use of vanadium must be accomplished in a manner to maintain the oxygen content of the coolant low enough (on the order of 100 ppm) to prevent corrosion of vanadium structures. This susceptibility of vanadium to significant corrosion in the presence of low oxygen concentrations has limited its present use and minimized previous materials development programs on vanadium to a far smaller scale than those accomplished on niobium.

Structural material selections for fusion power plants are by no means fixed. Studies are under way to assess the suitability of blanket and structural materials that would minimize activation.[11] Materials such as graphite and aluminum are being assessed to establish whether they could meet all the engineering requirements imposed by the reactor operation.

Waste Heat Rejection

The D-T fuel cycle requires the use of a thermal power conversion system, although a potential exists for direct power conversion in both advanced mirror-fusion and laser-fusion systems. The efficiencies of thermal systems are determined in large part by the maximum temperature of the heat transfer fluid, which is determined by the maximum temperature of the core structure. A fusion reactor utilizing a refractory metal alloy might be capable of operation at 1000°C. Tests with Nb-1% Zr indicate that it might be suitable for this service and could be used with a potassium topping cycle superimposed on a conventional steam system. The combined cycle should give a plant efficiency between 50 and 60% depending on the auxiliary power requirements, particularly for fuel injection. Use of a closed-cycle gas turbine power system might result in efficiencies in the 40 to 50% range.

The use of cooling water vs wet or dry cooling towers has not been considered in detail for fusion reactors because the choice of heat rejection mode is such a sensitive function of plant site considerations. Obviously the high operating temperatures of a refractory metal fusion reactor would allow increased flexibility in optimization of a system using cooling towers over power cycles operating at lower temperatures. With a high peak cycle temperature, heat can be rejected from fusion power plants at 100 to 200°C without seriously reducing plant thermal efficiency. This heat might then be used in urban siting applications for building heating and cooling and/or industrial processes, before being ultimately rejected at lower temperatures.

Land Despoilment

There are two aspects of land despoilment related to the fusion power plant. The first is the direct land use by the power plant itself, which includes buildings, switchyards, transformer yards, transmission lines, and cooling equipment. To a significant extent, fusion reactors would be similar to fission reactors in this regard, and fusion fuel-storage space requirements will be negligible.

The second aspect of land despoilment is associated with the projected flexibility of fusion reactor siting. If the low radiological hazard potential of fusion reactors makes urban siting acceptable, then the large land areas usually required for power transmission from rural to urban areas would be significantly reduced.

Accident Hazards

Any reasonable appraisal of accident hazards requires a detailed examination of a specific design because many potential problems are in large measure dependent upon specifics of the system. As discussed in Report WASH-1239 (ref. 3), only one conceptual fusion reactor design has been examined in any depth in an attempt to maximize safety and minimize accident potential and that reference controlled thermonuclear reactor served as a basis for the analysis. (See p. 9 of ref. 3 for a description of the reactor and p. 28 for a discussion of the potential accident hazards involved.)

A listing of the principal hazards recognized as requiring attention in the research and development program is given below. Report WASH-1239 (ref. 3) discusses each of these in some detail with the general conclusion that the hazards are small and amenable to control by proper design:

(1) Stored energy in the system in nuclear and chemical forms--the largest source is the lithium in the blanket (see Table 6A.1-22).* The upper limit on the nuclear energy release via nuclear reaction of the fuel in the plasma region (∿1 g) would at worst provide a minor temperature perturbation.

(2) Plasma instabilities leading to a localized plasma dump onto an adjacent wall and consequent wall burnout with lithium leakage into the plasma. This event would quench the fusion reaction in a fraction of a second.

(3) Magnet failure leading to damage to the magnet system.

(4) Loss of coolant accident with consequent minor afterheat problems.

(5) Lithium leakage and the consequences of such leakage.

(6) Leaks in the potassium condenser-steam generator.

(7) Leakage of the tritium inventory in the fusion reactor including the lithium coolant.

Table 6A.1-22

ENERGY RELEASE POTENTIAL OF COMPONENTS OF A REFERENCE CTR PRODUCING 1000 MWe

	Energy (megajoules)	Equivalent Gallons of Fuel Oil
Plasma, Complete Fusion	6.9×10^4	∿430
Magnet	2.4×10^5	∿1500
Lithium + Water + Air	6.4×10^7	$\sim 4 \times 10^5$
Potassium + Water + Air	6.4×10^5	∿4000
Primary Vacuum Vessel	640	∿4
Secondary Vacuum Vessel	1.6×10^4	∿100

6A.1.6.6.2 Offsite Activities

Procurement of Materials

The major offsite activities from the power plant which contribute to environmental impact are associated with the procurement of the fuel and construction materials.

*Note that the selection of lithium as a coolant in some conceptual fusion reactor designs is very preliminary and could give way to more conventional fluids such as water or helium.

D-T fusion power plants would consume deuterium and lithium as fuels. Deuterium is obtained from water, which is universally available. Its extraction results in no despoilment, but it does result in the production of useful quantities of commercial grade hydrogen and oxygen and modest quantities of purified water.

Lithium is obtainable from surface and underground brines (the least expensive extraction process) and from the oceans (a more expensive process but still relatively insignificant in cost). The land despoilment associated with the extraction of lithium and the metals incorporated in the structure of a tokamak reactor[3] is shown in Table 6A.1-23, which shows that the ore residues resulting from extraction of lead and copper are of greatest concern.

Table 6A.1-23

YIELD OF REQUIRED METALS FROM THEIR ORES

Metal	Requirement for 10^7 MWe (metric megatons)	Approximate Average Yield of Metal from Crude Ore (percent)	Ore Requirement for 10^7 MWe (metric megatons)
Nb	7	2	350
Be	0.6	2	30
Cr	11	5	220
Ni	5	∿1	500
Li	5	∿5	100
Cu	40	0.9	4,400
Pb	107	1.5	7,100
Al	10	10	100
V	4	5	80
Mo	6	2	300
Sn	0.8	10	8
Fe	170	45	380
Zr	0.07	∿5	
		Total	13,600

Transportation

To start up a fusion power plant, an initial fuel charge of deuterium and tritium will be needed. Thereafter, a continuous supply of deuterium and lithium will be required at the rate of ∿1 kg/day. Tritium shipment will be necessary only to supply the initial charges to start new power plants (or to provide fuel for possible fusion burner plants--see Section 6A.1.6.6.1), because recycling within each plant is assumed to be the principal operating mode. Only about 10 kg of tritium would be expected to be shipped from each operating plant every few years on the average, depending upon the rate of growth of the fusion power industry. Thus, the transportation of nuclear fuels for fusion reactors is seen to be a relatively minor problem as compared with transportation for other nuclear or fossil-fueled power plants.

The blanket structure of a fusion plant will become radioactive during operation. This structure is expected to have a lifetime on the order of 10 to 20 years, and when it is replaced, the used activated unit will have to be shipped from the power plant to a site wherein it would be stored. The structure itself would be nonvolatile and consequently its hazard potential should be relatively low. It would not require a large amount of shielding during shipment nor would it present a difficult cooling problem. One design study has indicated that use of a niobium alloy could result in a shorter first wall lifetime (∿5 years) and increase the overall quantity of waste sent for disposal.[12] Ongoing studies are intended to establish how waste disposal will be influenced by reactor concept, structural alloy selected, operating conditions, and wall stresses; and designs resulting in minimum radioactive waste are being emphasized.[13] Clearly, more definitive assessments remain to be obtained.

6A.1.6.6.3 Irreversible and Irretrievable Commitment of Resources

A preliminary survey has been made of U.S. and world resources of the various materials needed for fusion reactor construction.[3] The results are shown in Table 6A.1-24 where, in order to emphasize maximum resource requirement, the largest quantity of a given material required by any of the several reactor designs is presented. For instance, a pulsed theta-pinch reactor would use more copper and less superconducting material than would a tokamak reactor. The larger needs for both materials are included in the table. Clearly, no one reactor design would use all of the materials listed, and this approach thereby overestimates the quantities of material needed.

In the extreme of a fully developed world fusion power economy, 10^7 MWe of electric power might be generated by fusion reactors. Therefore, the third column of the table shows the mass of materials in metric megatons needed to construct and operate ten thousand 1000-MWe fusion reactors. Plant replacement at about 5% per year would be required at a later time but is not considered here.

Table 6A.1-24

CTR RESOURCE UTILIZATION

Material	Approx. Mass In Metric Tons Per 1000 MWe Reactor	For Reactor[ƒ]	Mass In Metric Mega-tons For 10^7 MWe	Total Estimated Production in Year 2000 In Metric Megatons U.S.	Total Estimated Production in Year 2000 In Metric Megatons WORLD	Known Resources Present Prices Metric Megatons U.S.	Known Resources Present Prices Metric Megatons WORLD	Resources At Increased Prices In Metric Megatons U.S.	Resources At Increased Prices In Metric Megatons WORLD	Comments
Nb	400 structural, 130+180 in NbTi and Nb_3Sn	4,1,2	7	.009	.020	.07	6	.14	NA	Present mining operations are relatively nonpolluting; greatly increased demand might necessitate strip mining to obtain low grade deposits
Li	900	1	9	.01	.016	5	6-8	9	250,000	100 metric megatons probable land resources; extraction from sea water possible, 1.5 lbs. of Li/100,000 gal. of sea water
Be	60	2	.6	.002	.003	.026	.38	.072	1	Little information on world Be resources available, Be presents health hazards in mining and handling
Cr	1100 in SS	5	11	1	4.3	0	700	1.6	NA	Resources almost entirely outside of U.S.
Ni	500 in SS	5	5	.5	1.3	.2	68	5.0	NA	World estimates are based on fragmentary information and are possibly low
Ti	400 structural, 80 in NbTi	1,1	5	2.3	6.9	.15	6.4	.4	30	Significant quantities of mud and slimes result from dredging Ti minerals from sand deposits
He	350	3	4	.012	.015	1.2*	1.2*	5*	29,000+	*In the ground +Extracted from atmosphere at up to 30 times current prices
Cu	2900 coil, 1100 in NbTi	3,1	40	6-12	35	77	280	180	1,100	Considerable secondary recovery possible; significant land-use conflict will result from an expanded copper industry
Graphite	2200	1	22	.1	1.4	.5	> 100	NA	NA	Very rough estimates of world reserves available
Pb	10,700	1	107	3	7.3	32	86	45	95	Considerable secondary recovery possible
Al	570 structural, 390 in Nb_3Sn	3,2	10	30	75	12	2200	275	NA	Large land areas and great amounts of energy needed to mine and process Al
V	400	4	4	.03	.06	.1	9	3	NA	
Mo	400 structural, 200 in SS	4,5	6	.08	.24	2.9	5	NA	> 10	Substantial resources of sub-marginal-grade ore throughout the U.S. and world
K	20	1	.2	11	56	120	> 10,000	770	Virtually unlimited	
Sn	80 in Nb_3Sn	2	.8	.12	.41	.006	4	.042	7	Some secondary recovery possible
F	500 in flibe	2	5	2.2	7.5	4.9	35	NA	NA	Increased price would stimulate expanded exploration for fluorspar
Fe	12,600 steel,	1,5	170	180	800	2000	90,000	20,000	> 300,000	Potential reserves are vast.

[ƒ] Reactor code:
1) ORNL Tokamak, 2) PPPL Tokamak, 3) LASL Theta-Pinch, 4) LLL DT Mirror, 5) LLL D^3He Mirror

Also presented in the table are estimates of the total production of the various materials projected to be required in the year 2000, along with quantities of known reserves at present prices and estimates of resources available at increased prices.

A great many evaluations of U.S. and world raw materials resources have been made, but these are usually a matter of expert opinion. Consequently, values such as "known resources at current costs" vary widely from one source to another. Often the estimated quantities of a raw material available at increased costs are based on industrial projections. However, when adequate reserves of a given ore are available to supply the demand for 20 to 30 years, exploration for additional reserves is usually curtailed with the result that total projected reserves can be underestimated to a significant degree. Most of the values quoted are from the 1970 edition of "Mineral Facts and Problems." In addition to estimating materials needs, some comments concerning environmental problems associated with a particular raw material are included in Table 6A.1-24.[3]

Obviously, the production of 10^7 MWe of fusion power would give rise to some resource use conflicts that would have to be resolved. For example, the requirements for niobium could just be met by known reserves. However, additional reserves may be found or other superconducting materials developed. In addition to niobium other possible resource conflicts exist in the projected usage of nickel, chromium, beryllium, titanium, helium, lead, vanadium, and molybdenum; and some of these problems will also be common to other power-generating concepts.

6A.1.6.7 Costs and Benefits

6A.1.6.7.1 Costs

For the period fiscal year 1951 through fiscal year 1974, AEC funding of magnetic confinement fusion research totaled $544.4 million. Non-Government funds have been expended on fusion research for many years, but reliable estimates of cumulative funding are unavailable. Current industrial support is estimated to be in the range of $2 to 3 million per year.

Government funding of laser-fusion research totaled about $122.4 million for the period fiscal year 1963 through 1974. Non-Government research on laser fusion is funded by industry at a current rate of expenditure of about $4 million per year

Although estimates of the total funding requirements are based on incomplete data, funding of the order of $8 to 10 billion will probably be required to carry the fusion research program through the demonstration power plant operation phase. This phase would encompass both fabrication of experiments and all associated research and development.

Very preliminary studies[3] show that demonstration power reactor costs might be about $500 per kWe for a nuclear "island." Ultimate magnet costs (20 to 25% of current costs) would reduce mirror and tokamak reactor costs substantially. The superconducting coil in the theta-pinch reactor serves as an energy storage element separated from the plasma vessel, and it operates at low fields. Its cost is a small fraction of the system total cost and is little affected by the ultimate magnet cost patterns. Maturing of the fusion reactor industry should bring reductions associated with production quantity manufacturing and the removal of design uncertainties, further reducing costs. Projected fusion commercial reactor capital costs then correspond roughly to the level projected for other types of plants in the year 2000. Because of the uncertainties, the AEC believes that present cost estimates serve only to suggest that fusion power capital costs could be competitive with other energy sources. To conclude any capital cost advantage or disadvantage at this stage of development would clearly be premature.

Fusion fuel-cycle costs are determined by the costs of deuterium and lithium (from which tritium will be bred). Based upon current prices, calculations[3] show that deuterium plus lithium will be about 7×10^{-3} mill/kWhr. Fuel transportation costs will be negligible because of the small quantities of materials involved and because handling techniques for gases and liquid metals are already well developed and inexpensive.

6A.1.6.7.2 Benefits

The following benefits are associated with employment of fusion power systems:

(1) an effectively infinite supply of fuel;
(2) no possibility of nuclear runaway;
(3) a complete absence of chemical combustion products;
(4) relatively low radioactivity and attendant hazards;
(5) minor shutdown reactor cooling problem; and
(6) no use of uranium or plutonium, thus no possibility of the diversion of those materials for clandestine purposes.

Because of these very attractive features, fusion reactors may be acceptable for urban siting, particularly for systems designed to operate with small radioactive inventories (D-T burners that do not breed tritium in situ or D-D burners).

6A.1.6.8 Overall Assessment of Role in the Energy Supply

A successful, vigorously supported fusion program would be expected to lead to construction of a demonstration power reactor that would begin operation in the mid-1990's. Considering time requirements for accruing operating experience and reflecting such experience in the design of improved commercial power plants, fusion power plants could be expected to contribute significant quantities of electric power to the Nation early in the 21st century. The report "The Nation's Energy Future"[6] estimates that fusion reactors could add 18×10^{15} Btu of energy to our electrical system by the year 2020, which would provide about 8% of the energy input required for electrical generation at that time.

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6A.2 FOSSIL FUELS FOR CENTRAL-STATION ELECTRIC POWER GENERATION

Oil, gas, and coal provide about 93% of our current total energy needs,[1] distributed as follows:

	Domestic production	Imported	Total	Percent contribution to total energy
Oil (million barrels/day)	9.5	6.5	16	42
Gas (billion ft^3/day)	57	3	60	33
Coal (thousand tons/day)	1425	0	1425	18

Together, oil and gas supply one-fourth of the energy required by the electric utilities, over half the industrial energy requirements, and nearly all of the transportation and nonelectric commercial and residential requirements. Of the coal used domestically, electric utilities consume two-thirds and industry utilizes most of the rest. The remaining 7% of our total energy supply comes from hydroelectric and nuclear electric power plants and from wood. Our oil shale resources have not been developed as yet and, consequently, are not being used for energy production.

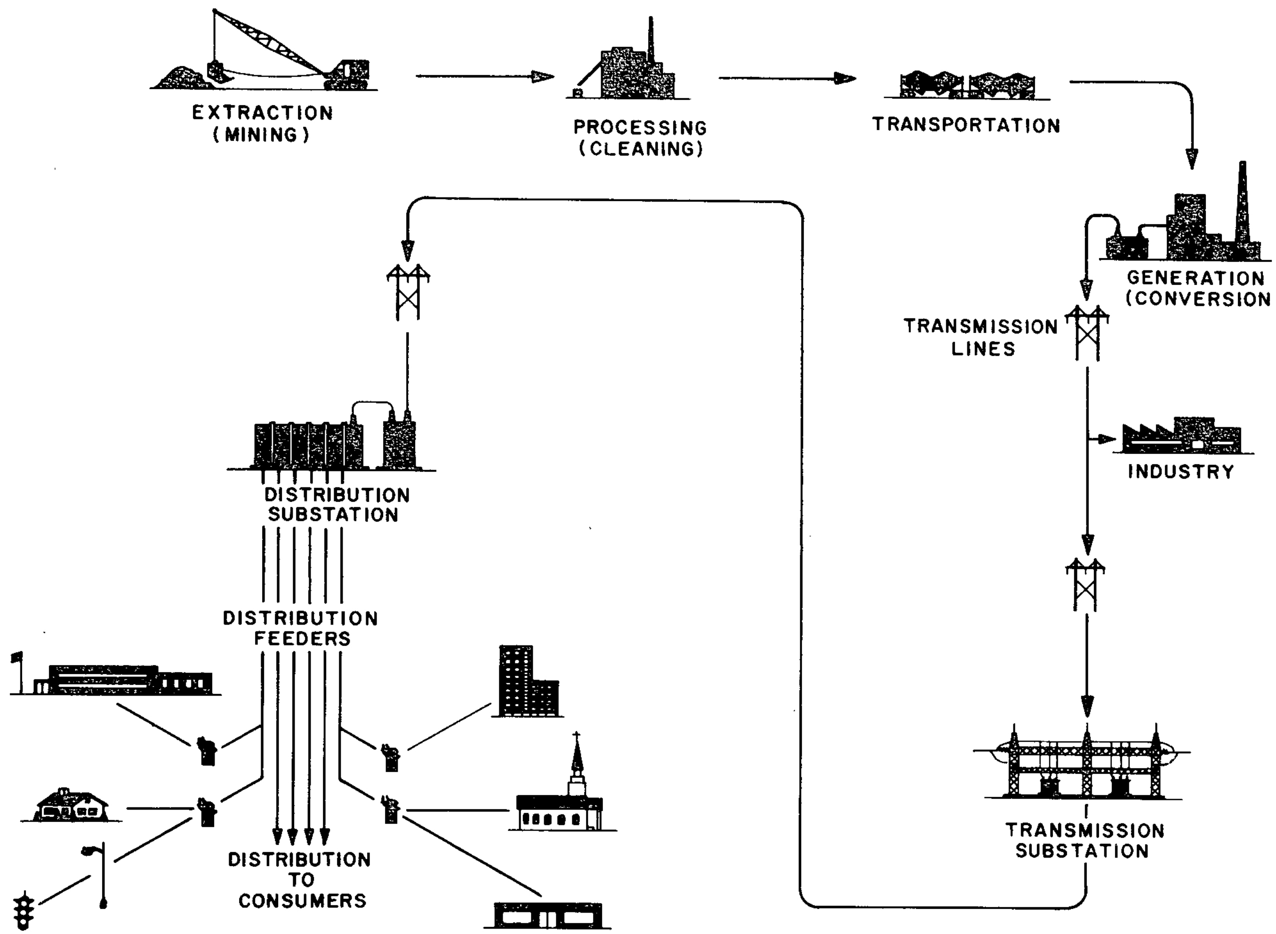
This section explores the use of these fossil fuels, their environmental impacts, and their use in the production of electricity projected to the year 2000 and beyond.

6A.2.1 Coal

6A.2.1.1 Introduction

6A.2.1.1.1 General Description

Coal, which represents well over 80% of the nation's fossil-fuel reserves in terms of energy value, is burned in large quantities to produce electricity. The essential elements of a coal-fired electric energy system are depicted in Figure 6A.2-1. The first step in the coal-energy system is extraction, and it involves either surface mining, which removes the overburden to expose the coal seam, or underground (deep) mining, which extracts the coal from beneath the overburden. After extraction, most of the coal mined in recent years for power plant use[2] has been processed by either wet or dry (pneumatic) cleaning to partially remove impurities before the coal is transported by railroad, truck, barge, conveyor belt, or slurry



SCHEMATIC OF COAL-FIRED ELECTRIC ENERGY SYSTEM

Figure 6A.2-1

pipeline to a power plant. At the power plant, the heat released by combustion of the coal in a boiler produces high-pressure steam to drive a turbine, which is linked to a generator that converts the rotary mechanical energy into electricity. The electricity is transmitted and distributed, usually by overhead power lines, to load centers such as homes, offices, and manufacturing facilities, where it is used for lighting, heating, air conditioning, powering machinery, and other purposes.

6A.2.1.1.2 Historical aspects

From 1900 through 1972, U.S. coal consumption[3] has totaled about 35 x 10^9 tons. Since 1905, total annual domestic use has dropped below 10 quads* (or about 385,000,000 tons) only during the depression years 1932 and 1933. The peak annual U.S. consumption occurred during the World War years 1918 and 1943, at 17 quads (about 654,000,000 tons). The 1970 total consumption of 13.6 quads (about 523,000,000 tons) was equaled during seven years in the period 1912-1948.**

6A.2.1.1.3 Status

Although the fraction of the Nation's total energy demand met by coal has declined from 78% in 1920 to about 18% at present,[1,5] the energy output of coal-fired electrical power plants has remained in the range of 46 to 54% of the total electrical energy production for the period 1955 to 1973.[6-8] Conversely, of all the coal consumed domestically, the portion used by electrical utilities has increased from 57% in 1970[4] to about 65% currently.[1,9] The current energy crisis is fostering a conversion of oil-fired electric power plants to coal. Some of these plants had only recently been converted to oil in order to meet environmental standards. These conversions, as they are implemented, could eventually significantly increase the percentage of the total electrical energy produced by coal.

The portion of U.S. coal surface-mined by all methods has increased from 3% in 1929 to 35% in 1969[10] to about 50% in 1971[3] and appears still to be growing. Essentially all additions of lignite and bituminous coal mined since 1970 have been obtained by stripping. This major change in mining pattern over the past few years is attributed principally to the higher productivity and lower costs achieved by stripping coal as compared with extracting it from deep mines. This process is a substantial reason for the number of United States coal miners dropping to about

*1 quad is 10^{15} Btu or 0.001 Q; 1 Q is 10^{18} Btu.

**In the preceding examples of consumption variation,[3,4] the thermal energy and tonnage values were interconverted by means of the relation[4] 26 quads = 10^9 tons of coal, which corresponds to a total heating value of 13,000 Btu/lb.

one-fifth of its historic peak.[3] There is some uncertainty regarding the amount of available coal that can be extracted by strip-mining techniques. Recent statements indicate that only 3 to 18% of the currently recoverable coal is economically strippable;[11,12] however, these estimates have been disputed by others who use different economic criteria to arrive at a substantially larger estimate (about 35%).[13]

Few new coal mines were opened during the 1960's because of competitive pressure from cheaper natural gas, increased oil importation, and the possibility of a significant market penetration by nuclear energy. The enactment of environmental legislation that restricts SO_x emissions and influences strip mining has introduced further uncertainties into the question of opening new coal mines.

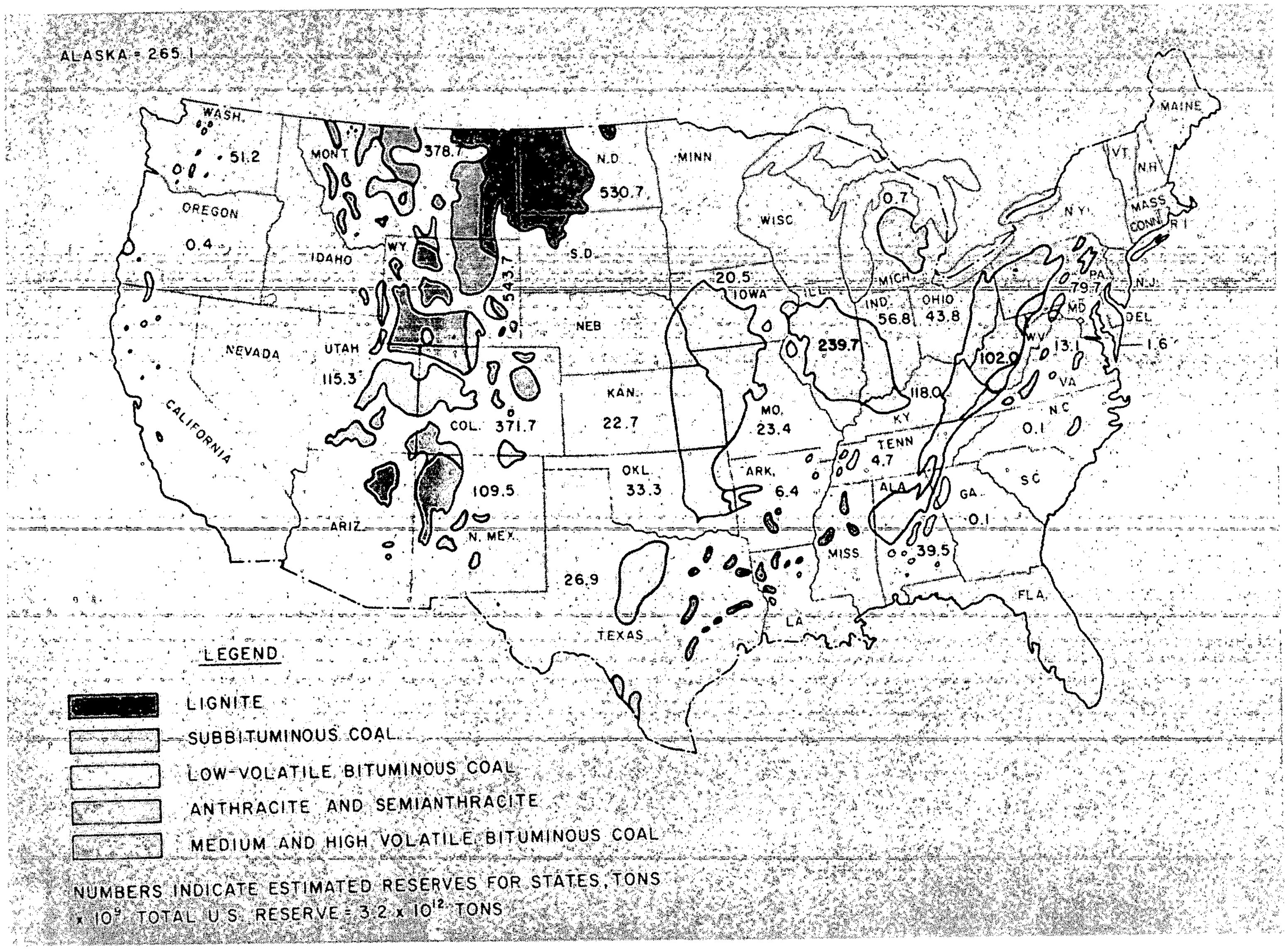
In 1971, the capacity of coal-fired steam plants (about 164,000 MW)[14] represented about half of the total national electric capacity. This type of plant has been operated for decades, its reliability is proven, its conversion efficiency is high, and the technology and maintenance are well-understood. President Nixon's Energy Message to Congress of April 18, 1973, urged expanded use of the Nation's coal resources, stating that "each decision against coal increases petroleum or gas consumption, compromising our national self-sufficiency and raising the cost of meeting our energy needs."[15]

6A.2.1.2 Extent of Energy Resource

6A.2.1.2.1 Geographical Distribution

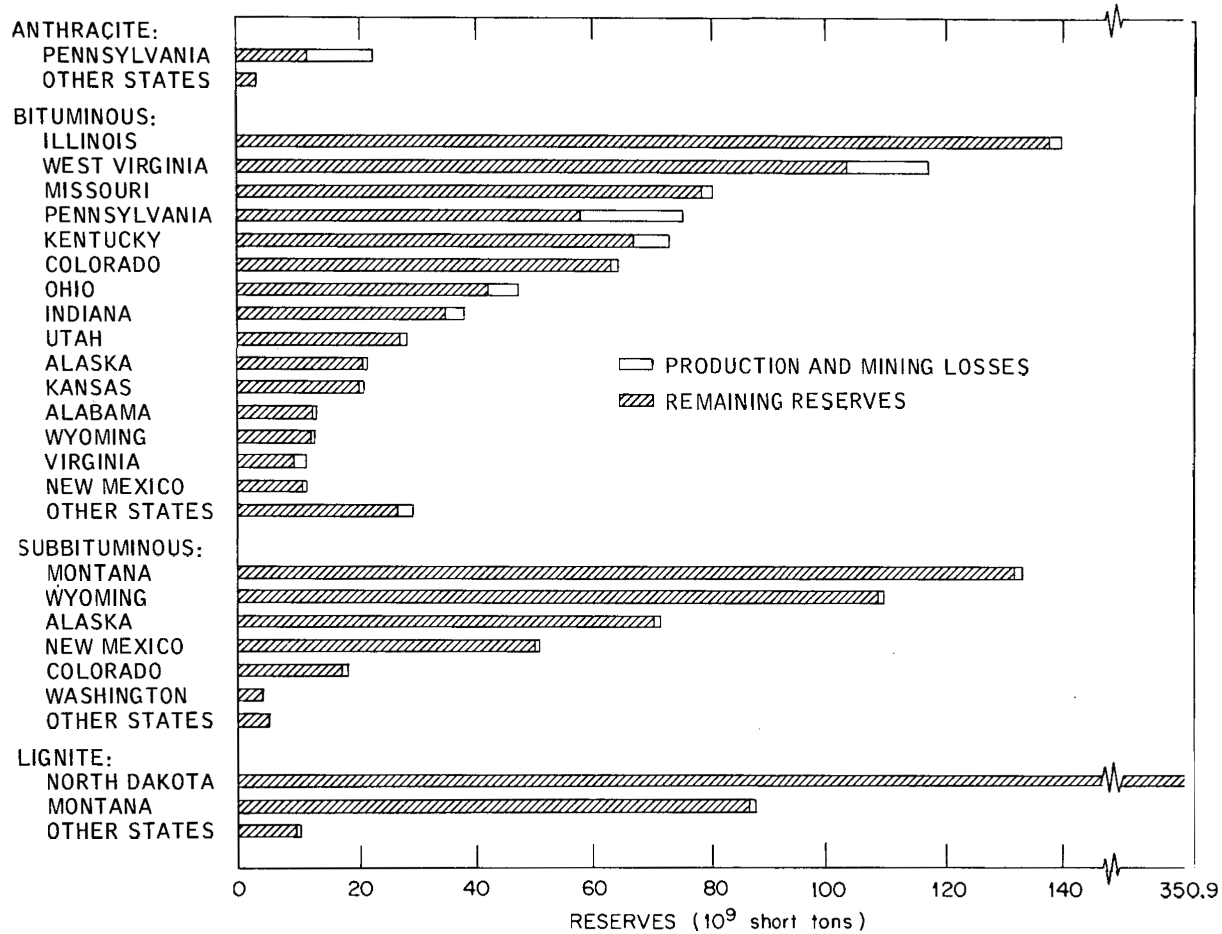
Coal deposits are widely distributed throughout the Nation, and major reserves exist relatively near many large centers of industry and population. In contrast,[16] about two-thirds of the known petroleum and natural-gas reserves lie in the West South Central Region, primarily in Texas, Oklahoma, and Louisiana, which contain only about 8% of the U.S. population. Other major potential fuel-resource bases are also remote from most of the major population centers; for example, oil shales are concentrated in the Green River formation in Colorado, Utah, and Wyoming, and the Athabasca tar sands are located in Alberta, Canada.

Figure 6A.2-2 is a map[6] that shows the major coal-producing areas. Known coal resources underlie about 459,000 square miles in 37 states.[10] Figure 6A.2-3 depicts the 1965 estimate of the original and remaining U.S. coal reserves,[6] by coal rank (type) and by state. The tonnages indicated include only coal in seams at least 14 in. thick and less than 3000 ft deep in explored areas. About 75% of the additional low-rank peat reserve of about 14 x 10^9 tons occurs in Minnesota, Wisconsin,



COAL FIELDS OF THE UNITED STATES

Figure 6A.2-2



ESTIMATED ORIGINAL AND REMAINING COAL RESERVES,
BY RANK, IN UNITED STATES, JANUARY 1, 1965

Figure 6A.2-3

and Michigan.[17] Of the total bituminous reserve indicated in Figure 6A.2-3, about two-thirds is located east of the Mississippi River. Of the high-rank coals (bituminous and anthracite) that contain 1.0% sulfur or less, the states east of the Mississippi River contain about 40% of the Nation's supply.[6] Illinois contains the largest reserves of bituminous coal of any state and, east of the Mississippi, it contains the largest total reserves.[16] About 98% of the Nation's lignite reserves (usually low in sulfur) are located in North Dakota and Montana. Estimates of coal reserves in Montana alone range from 222 x 10^9 tons (in seams 14 in. or more thick at depths less than 3000 ft)[6] to a total resource of 379 x 10^9 tons[6] to 700 x 10^9 tons.[18]

Very large beds of low-sulfur lignite, subbituminous, and bituminous coals suitable for power generation, liquefaction, and gasification occur in the Rocky Mountain States.[10] The billions of tons of low-sulfur fossil solids in the Upper Missouri Basin in thick seams (up to about 100 ft) that underlie modest earth overburdens in flat or rolling terrain and that promise to yield up to 10^5 tons/acre offer the potential[3] for transforming Montana, Wyoming, and the Dakotas into an immense new natural-energy center that may displace the premium fossil-fuel states of Texas, Louisiana, and Oklahoma.

6A.2.1.2.2 Estimated Availability

Use of Present Technology

The Department of the Interior estimates[10] that the U.S. total remaining coal resources are 3.20 x 10^{12} tons (to a depth of 6000 ft), with 1.60 x 10^{12} tons at depths less than 1000 ft; the first estimate represents 17 to 20% of the global coal resource.[19,20] The Department of Health, Education, and Welfare has reported[6] a total resource of 1.58 x 10^{12} tons for coal seams at least 14 in. thick at depths less than 3000 ft in explored areas.

Because of various technical and economic constraints, a large part of the estimated total resource base probably will not be recovered. Total estimated reserves technically recoverable, without regard to economics, range from 790 x 10^9 tons[6] to 850 x 10^9 tons,[16] or about one-fourth of the estimated total resource. Estimates of amounts commercially recoverable from established formations with present mining technology under current economic conditions have varied from 150 x 10^9 tons[20,21] to about 400 x 10^9 tons.[10,11,13,22] These quantities represent available reserves adequate for periods of 254 and 680 years, respectively, at the 1972 net coal-production rate. Considering only the low-sulfur bituminous, subbituminous, and lignite coal in the Rocky Mountain states, the recoverable resources to a depth of

1000 ft have been estimated to be 94 x 10^9 tons, of which 26 x 10^9 tons are so well identified and characterized that they are considered to be proven reserves.[10,23] A reasonable estimate of the recoverable reserve, using technology available through about 1975, is about 400 x 10^9 tons, or about one-eighth of the estimated total base.

For coal with a sulfur content of 1.0 wt % or less, a reasonably conservative estimate of the amount currently available can be made by calculating one-eighth of the estimated remaining low-sulfur reserves in seams at least 14 in. thick at depths less than 3000 ft in explored areas, as published in ref. 6. This procedure gives an estimated available low-sulfur national reserve of about 128 x 10^9 tons (about 1/25 of the estimated total base), distributed by coal rank as shown in Table 6A.2-1. The Chase Manhattan Bank has published a corresponding estimate[24] of 124 x 10^9 tons.

Table 6A.2-1

ESTIMATED AVAILABLE RESERVES
OF LOW-SULFUR COAL IN THE UNITED STATES

Rank	Amount[a] (millions of tons)	Percent of total[b]
Bituminous	26,878	29.5
Subbituminous	48,400	99.6
Lignite	50,752	90.7
Anthracite	1,844	97.1
All	127,874	64.8

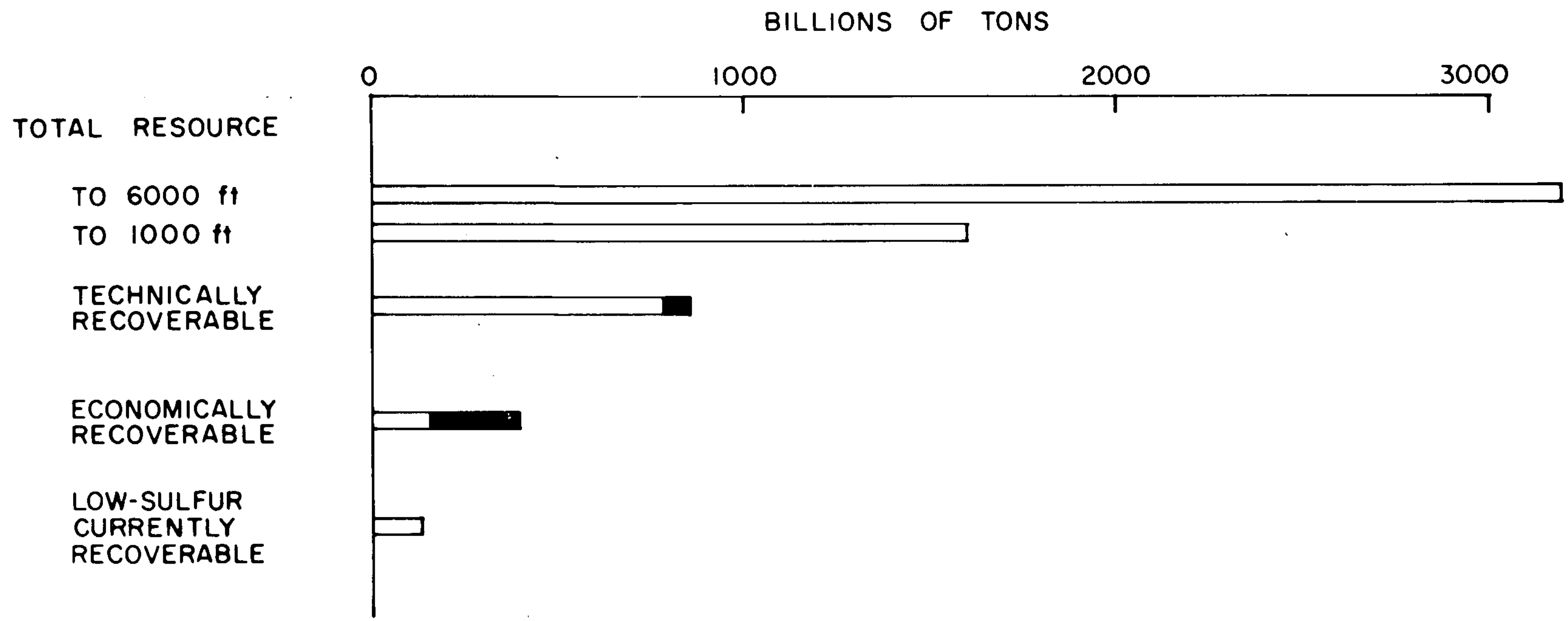
[a]With 1.0% maximum sulfur and based on availability of 12.5% of estimated reserve. Derived from Table 4-1 of "Control Techniques for Sulfur Oxide Air Pollutants," NAPCA Publication No. AP-52, U.S. Department of Health, Education, and Welfare, January 1969.

[b]Percent with sulfur content of 1% or less.

The preceding observations on estimates of resource availability based on various premises are summarized in Figure 6A.2-4, where the shaded bar areas indicate lower and upper bounds of the cited projections.

Use of Advanced Technology

Very large tonnages of coal are available by use of current mining technology



ESTIMATES OF UNITED STATES COAL SUPPLY

Figure 6A.2-4

(probably enough for four centuries at an average use rate of 10^9 tons/year). Expressed differently, only about 0.15% of this base would be required for the projected 1985 coal-fired electrical generation (Table 18 in ref. 9). Based on the current state-of-the-art, a 400×10^9 ton recoverable resource, used entirely in electrical power plants, would be sufficient to generate almost 900 billion MWhr of electrical energy. For this reason, technological development over the next several decades is likely to be oriented more to increasing production rates than to increasing availability. Since coal use has been deemphasized in recent years in favor of other fuel sources, the potential for technology advancement is probably large. Institutional actions that should increase the efficiency of coal-energy systems include increasing vocational training for miners, increasing the number of mining-school graduate engineers, and implementing a more active technology transfer program to convert research and development results from other areas to common practice in an industry that has been characterized as technologically conservative.

Controlled underground (in-situ) combustion and transfer of the heat to water tubes or extraction of the low-Btu-content gas generated could make available the energy in some coal deposits not economically mineable or in previously mined areas where about half the original coal remains. Conceivably, combined actions such as those enumerated above could lead to an available coal resource of 400×10^9 to 500×10^9 tons in the year 2000, even after allowance is made for probable extraction depletion beyond 1974. This estimated availability is based not only on the factors cited but also on the assumption that conversion systems will be successfully developed which will allow ultimate use of coal that contains more than 1% sulfur. Annual production rates, which are likely to attain very high levels toward the end of this time period,[3,16] could be made more feasible by improved systems analyses of mining cycles to minimize element mismatch, thereby maximizing average material flow rates, and by intensified study and implementation of other mining methods, including hydraulic (high-pressure water jet) extraction.[25]

6A.2.1.3 Technical Description

6A.2.1.3.1 Power Generation Plant

Processed coal for boiler firing is taken from pulverizers, which usually produce particles of about 75-μm diameter (about 200 mesh), by a stream of air supplied to the pulverizer at a temperature of 300 to 700°F, depending on the moisture content of the coal. The flow of fine coal and primary air is mixed and directed by fuel burners to ensure rapid ignition and to maximize combustion. In the commonly employed radiant-type boilers, virtually all the steam is generated in the tubes that form the furnace-enclosure walls by the heat radiated from the flame and from the hot combustion gases. To improve thermal efficiency, the high-pressure steam is superheated in tubular elements exposed to the combustion products and also is often reheated, in one or more stages, at lower pressures following expansion through the high-pressure turbine. After it is dried and purified, the steam is expanded through a 3600-rpm steam turbine, which is the driving element of a condensing turbine-generator set.

Turbine-inlet steam pressure and temperature in large plants are commonly in the ranges 1800 to 2400 psig and 1000 to 1100°F, respectively. A few units have been constructed in which the steam is at pressures to 5000 psig and temperatures to 1200°F, but many of the recent units operate at the 3500-psig level with initial temperature at about 1050°F, conditions that yield thermal efficiencies of 40 to 42%. The exhaust steam flows to a large water-cooled surface condenser, which produces a low back pressure (usually 1.0 to 3.5 in. Hg abs) at the turbine exhaust in order to improve the heat rate, to deaerate the condensate, and to conserve the condensate for reuse as boiler feed. The water from the condenser is then reheated and pumped again through the boiler. Comprehensive descriptions of steam cycle variations, boiler water circulation modes, and components (such as steam separators, economizers, air preheaters, condensers and air ejectors, feedwater heaters and pumps, and cooling towers) are readily accessible.[26,27]

Current Variations

To meet relatively brief peak power demands and emergency services requirements, power plants often employ pumped-storage installations, gas-turbine-driven generators, or diesel engine-generator units. The pumped-storage concept involves pumping water into a higher elevation reservoir during periods of low power demand for later release through reversible pump turbines when the power demand exceeds the base load. The 1973 installed capacity of pumped-storage installations was about 4500 MWe. Gas turbine and diesel peaking units operate at heat rates of 12,000 to 15,000 Btu/kWhr;[28] and at the end of 1972, these units represented installed capacities of 4800 MW (internal-combustion plants) and 28,000 MW (gas-turbine plants).[7]

Cyclone furnaces are sometimes used to retain most of the ash from low-ash-fusion-temperature coals in the slag, thereby minimizing ash flow past the heat-absorbing surfaces and reducing stack fly-ash emissions. In this variation the coal, crushed to a size of about 4 mesh, is admitted tangentially with the primary air. The coarser fuel particles are transported centrifugally to the outer furnace wall, from which, after final combustion, the molten ash drains through an opening in the boiler furnace floor into a slag-collection tank. Tangential admission of both primary and secondary air at high velocity (to about 300 ft/sec) produces high turbulence levels and volumetric heat-release rates (to about 5×10^5 Btu/hr per ft^3).

Future Variations

The technical feasibility of fluidized-bed combustion has been demonstrated.[29,30] The basic concept of a fluidized-bed boiler involves passing air upward through a grid plate supporting a bed, several feet thick, of granular, noncombustible material such as coal ash or lime. This air fluidizes the granular particles and, with the relatively small amount of air used to inject the coal, serves as the combustion air. Crushed or finely ground coal is fed near the base of the fluidized bed above the grid plate. The fuel burns rapidly in the suspended bed, and the bed temperature is controlled by water-tube walls or internal heat-transfer surfaces. Flue gases leaving the bed pass over a convection heat-transfer surface above the bed, and the elutriated ash is mechanically or electrostatically collected. Operated at atmospheric pressure, fluidized units would replace conventional boilers. Pressurized systems--coal-fired gas turbines fed by external fluidized combustors operated at pressures up to perhaps 25 atm--could achieve thermal efficiencies of about 45%. Such systems also could use low-grade coals and offer the potential of effective removal of the oxides of sulfur during combustion by burning the coal in the presence of a sulfur-acceptor such as limestone or dolomite. In addition, the relatively low operating temperature of about 1600 to 1800°F would reduce fixation of atmospheric nitrogen and significantly diminish NO_x emissions.

As far as electrical-energy generation is concerned, an additional major advantage relative to conversion of coal to fuel oil or to power (low-Btu) gas is that the cycle (coal mine to bus bar) efficiency is significantly improved by avoiding the losses, typically about 30%, involved in processes for converting coal to alternative fuels. Work in this area is active and rapidly accelerating. The report of Subpanel V,* one of the groups that contributed to the preparation of "The Nation's Energy Future,"31 notes the following:

(1) This program is one of the major alternatives.
(2) Such boilers will meet all environmental standards.
(3) Projected ultimate thermal efficiencies are promising: 40% (atmospheric system) and 47% (pressurized system).

*"Coal and Shale Processing and Combustion, "Report of Subpanel V (W. Crentz, Chairman) to USAEC, Oct. 27, 1973.

(4) Developed fluidized-bed boilers should capture at least 25% of the market for new coal boilers; this rate of implementation would result in minimum installed capacity of 3000 MWe in 1985 and 40,000 MWe in the year 2000. Using a common-basis costing procedure, estimates show that for a 600-MWe plant operating at a 70% load factor, the capital cost and electrical energy generating cost of a fluidized-bed boiler plant would be about 85% and 93%, respectively, of the corresponding costs of a conventional-boiler power plant.

(5) The primary barriers to implementation are: sorbent regeneration and sulfur recovery for the system variants involving regeneration: demonstration of high-temperature, high-pressure, particulate-removal technology for pressurized systems; and demonstration of the operability of the integrated boiler systems on a large scale.

Assessment of various alternative thermodynamic cycles,[4,32] including potassium-vapor topping and ammonia (or fluorocarbon) bottoming cycles, is continuing, but such systems are only one route to increased thermal efficiencies. Magnetohydrodynamic (MHD) power generation[4,32] is another process, several variations of which continue to receive attention. Of greater near-term interest is the combined gas-turbine steam cycle,[4,33] which entails combusting fossil fuel to drive a gas turbine and recovering the heat in the hot exhaust gas (about 1000 to 1200°F) with a waste-heat boiler to generate steam to drive a bottoming steam turbine. Low-Btu-content gas, obtained by onsite gasification, should constitute an environmentally acceptable fuel, because even with a high-sulfur coal feed, both particulate matter and sulfur would be reduced to acceptable levels prior to combustion. All of these systems are discussed in detail in Section 6B.

The results of studies to develop low-temperature superconducting electric generators have been promising,[4] and as generator-unit capacity continues to increase (1500-MVA units are currently available), the decreased rotor sizes and other advantages of such alternators would be significant. This development, once reduced to practice, could be used in any generation plant that uses turbine-generators.

Technical improvements such as those discussed above may be expected in the future. A successful outcome of current research and development in the areas of pre-, co-, and post-combustion coal treatment and of fluidized-bed combustion and binary cycle development could lead to future fossil-fueled power plants that would be significantly more efficient and environmentally acceptable than the average plant of this type now in operation.

6A.2.1.3.2 Fuel Cycle

Mining and Preparation

In underground mining, deep coal beds (which are grid- and contour-mapped in advanced operations) are made accessible by slope, drift, or vertical shafts, depending on the orientation of the seam relative to the terrain. The stages of cutting (sometimes by continuous machines), loading, and conveying (by narrow-gage rail car or by conveyor belt) in deep coal mining have become highly mechanized. Provisions are made for tunnel ventilation, atmosphere monitoring, dust control, water drainage, and safety equipment to fully satisfy the regulations established by the 1969 Coal Mine Health and Safety Act.

Near-surface coal (0 to about 200 ft deep) has been extracted increasingly by surface mining because of the favorable economics. Area strip mining is conducted when the terrain is flat or gently rolling; contour stripping is done along hillsides. After blasting, the overburden is removed with large power shovels, scrapers, and draglines. The coal is then scooped up with smaller power shovels and loaded into large trucks. A small amount of coal is auger-mined (3.3% in 1970)[34,35] with 2- to 7-ft- diam horizontal augers to penetrate vertical outcroppings to depths of about 200 ft. Recovery efficiencies (fraction of coal recovered from the worked bed) range from about 40% for auger mining to about 57% for deep mining to 80% for strip mining[2], although recoveries as high as 90% have been attained with area stripping.

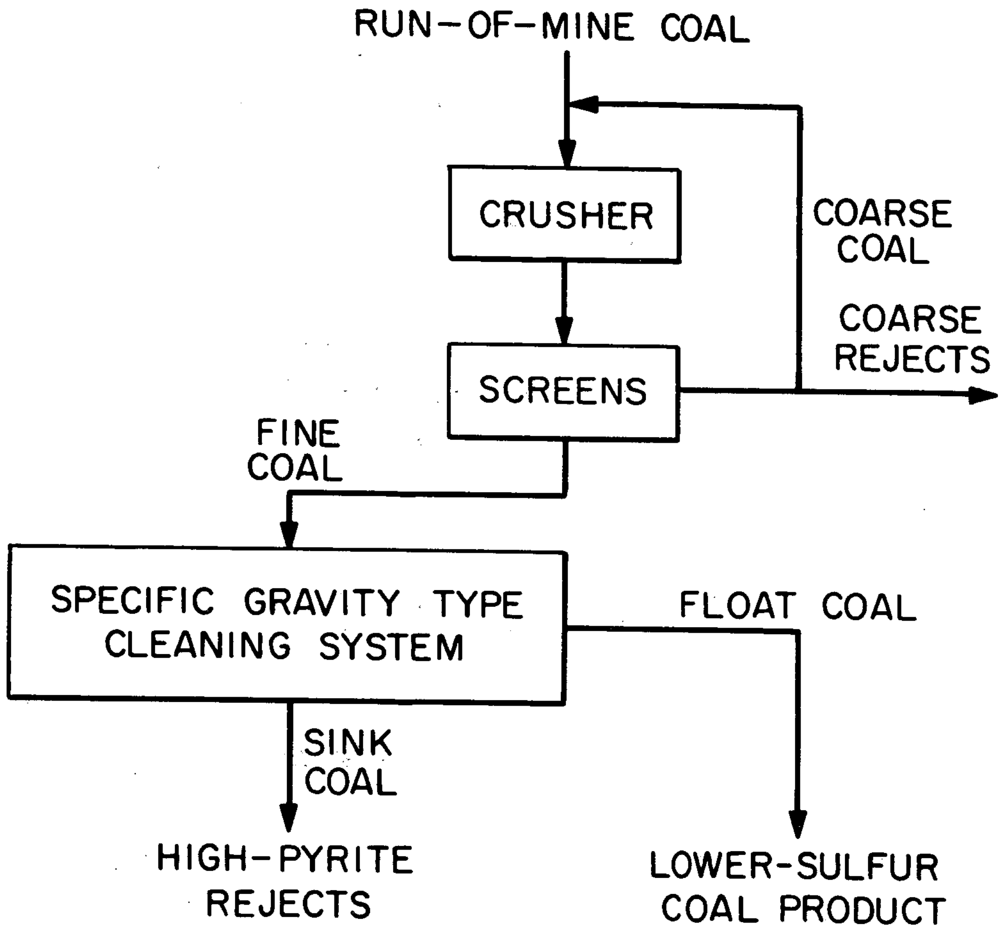
During the coal-preparation or cleaning step, gross impurities such as rock, shale, slate, and clay are removed first, and often the refuse is deposited in large piles near the mine or coal-cleaning plant. The introduction of mechanized mining has given impetus to coal cleaning and preparation because such mining does not differentiate well between coal and impurities. Further separation of impurities from steam coal is usually by a liquid-washing process based on differences in density (the coal being lighter than an equal volume of impurities). This cleaning process often significantly reduces the sulfur content by removing particles of pyrite (FeS_2). One study,[36] based on 1968 data from 113 mines, showed that when the raw coal was crushed to 3/8-in. diam and floated in a heavy medium (an organic liquid of 1.60 specific gravity), the coal from about 20% of the mines could be cleaned to 1% sulfur or less. A later and more extensive study,[37] using 322 coal samples obtained primarily from mines east of the Mississippi River producing coal for utilities, also showed that less than 30% of the samples could be cleaned to a total sulfur content of 1% or less. When 40% of the heavy impurities (leaving a 60% yield) were removed by specific gravity separation (float-sink) of coal first crushed to 3/8-in. diam, only 20 to 25% of the coals tested could produce a product containing 1% or less total sulfur. The overall operation can be fairly complicated;[38] a simplified schematic[6] is shown as Figure 6A.2-5.

Transportation and Storage

Of the coal loaded at the mine mouth, about 70% is carried by rail,[35] although some is later transferred to other carriers. In the electrical utility sector, 52% arrives by rail, 34% by barge, and the remainder by other means (truck, conveyor belt, and slurry pipeline).[35] The average transport distance from mine to power plant is 300 miles, by either rail or waterway.[2,35] Unit trains, which consist of conventional equipment operating continuously between a coal mine and a power plant in the service of one customer, are often used because rail car utilization is greatly increased and because transit time (as compared with a general train carrying mixed goods) is reduced.

The only operating commercial coal-slurry pipeline in the U.S. delivers coal a distance of 273 miles from the Black Mesa mine in Arizona to the 1580-MWe Mohave Power Plant in Nevada. Operating since mid-1970, the pipeline delivers about 660 tons of coal (0.3 to 0.8% sulfur content) per hour through an 18-in.-diam pipe. The slurry, which is 50 wt % coal (14-mesh particle size) flowing at about 6 ft/sec, is fed to centrifuges at the power plant to be dewatered to about 15 wt % water.[39] An earlier pipeline,[4] operated in Ohio from 1958 to 1963, used a combination of vacuum filtration and thermal drying to dewater the received slurry. After separation of the coal from the water, the spent water could be returned by a second pipeline for reuse or it could be used at the power plant for ash handling, cooling-tower makeup, or evaporation from disposal ponds.[10]

A recent article[40] indicates that a large number of long-distance, high-volume coal-slurry pipelines from western coal fields to midwestern load centers are being planned, including a 1000-mile, 38-in.-diam line that will transport 25 million tons of coal per year.



SIMPLIFIED FLOW CHART OF COAL PREPARATION

Figure 6A.2-5

Tests that used slurry (30 wt % water) directly to fire a cyclone boiler showed a reduction in boiler efficiency of only 4%. The suggestion that oil, rather than water, be used for slurrying to increase the energy throughput of coal slurry pipelines[4] may soon be implemented in Canada.[42] Recent reports[43] state that North Dakota lignite with a moisture content of 38.5 wt % has been burned successfully for 3 years in a 235-MW cyclone furnace. The crushed lignite was predried with hot air, and the coal and drying air were fed to the boiler furnace.

A 90-day coal supply at the power plant is generally considered desirable. Spontaneous heating of this coal pile, which may lead to ignition, is caused by oxidation of the coal, and the likelihood of spontaneous heating is greatest with coals of lower ranks and finer sizes. Overheating (beyond about 120°F) is usually prevented by compacting the pile in layers with a roller to minimize access of air.

Waste Processing and Disposal

In current practice, waste processing at the mine is minimal, and rejected solids are deposited in large refuse banks. In contour stripping, spoil material is generally dumped down slope. However, in area stripping, the overburden can be partially replaced by working long parallel trenches and by using the material excavated from the second cut to fill the first. Neither reclamation of surface-mined areas to a condition that approximates the original nor controlled backfilling of deep mines has been practiced in the United States to a significant degree. Settling ponds are commonly used in coal processing to reduce the discharge of black-water solids; these discharges would be about 250 times as large without such ponding.[2] Coal dust from dry processing and from thermal drying of some wet-processed coal is collected by cyclone separators, which pay for themselves in reclaimed coal.[2] At the power plant, electrostatic precipitators with collection efficiencies to about 99% collect fly ash, which is disposed of in settling ponds. Changes in stack-gas composition resulting from use of low-sulfur fuel, desulfurization by limestone addition, or changes in ash characteristics generally alter the precipitator performance and usually require larger units.[44] Some of the flue-gas sulfur-dioxide-removal processes under development control particulate emissions with high efficiency by wet scrubbing, but others require a high level of particulate removal as a preliminary treatment.

Of the large number of stack-gas sulfur-dioxide-removal systems that have been proposed and are under development, none are yet in routine full-scale operation on large boilers burning high-sulfur coal. The basic problem of post-combustion desulfurization is that of continuously removing a large fraction of a small concentration of sulfur dioxide from a very large flow of stack gas. For example, a modern power plant of 1000-MWe capacity, burning coal with a sulfur content of 2.5 to 3.0 wt %, will emit about 2×10^6 ft^3/min of flue gas with a sulfur dioxide concentration between 0.2 and 0.3 vol %.[45]

The main processes under consideration are listed in Table 6A.2-2.[46] Of these, the limestone-injection--wet-scrubbing variation is probably commanding the most attention. The mid-1973 technological status of the processes is summarized in Table 6A.2-3.[46] Through May 1973, the availability of stack-gas SO_x abatement systems ranged from nil to 33% (for one scrubber in a dual-scrubber installation), and the longest continuous on-stream time for any U.S. coal-fired plant was about three weeks.[47] Some persons anticipate that present difficulties will be overcome by continued development and that successful regenerative units will be installed on perhaps three-fourths of the coal electrical capacity by 1980.[48] In the fuel cycle, solid wastes generated by air-pollution controls--for example, fly ash and limestone sludge--would be disposed of in settling ponds and waste banks.

Fuel-to-Fuel Conversion

This subject, which includes conversion of coal into low-Btu gas for boiler firing and into either fuel oil or syncrude (synthetic crude oil convertible to motor fuels), is treated in some breadth by Hottel and Howard.[4] The importance of these processes is emphasized by their ability to also produce liquid fuels for the transportation sector--gasoline for cars, diesel fuel for trucks and locomotives, and jet fuel for airplanes--for which electric power from any source, fossil or nuclear, is not currently substitutable. A schematic that depicts some of the systems under development[49] is shown in Figure 6A.2-6.

Low-Btu gas (120 to 200 Btu/standard cubic foot, typically) is considerably cheaper per million Btu than synthetic or substitute natural gas of high-Btu pipeline-quality; and sulfur compounds, principally hydrogen sulfide, can be removed more easily and economically before combustion than after. Processes generally involve use of a gasifier in which hot coal or coke is contacted with air and steam at temperatures from 1500 to 2500°F and at pressures from 1 to 450 psig. After impurities have been removed from the reaction products, the principal constituents of the gas are carbon monoxide, hydrogen, nitrogen, carbon dioxide, water vapor, and methane. The principal processes for producing low-Btu gas from coal are summarized and are compared[46] in Tables 6A.2-4 and 6A.2-5. Processes currently

Table 6A.2-2

REVIEW OF PROCESSES FOR REMOVAL OF SO_x FROM FLUE GASES

Type of process	Sulfur disposal method	Demonstration plant status
MgO slurry scrubbing	Sale of 98% H_2SO_4	150-MW oil-fired in operation; 100-MW coal-fired under construction
Na solution scrubbing	Sale of sulfur[a] (5% of sulfur to Na_2SO_4 waste)	75-MW oil-fired in operation; 115-MW coal-fired under construction
Catalytic oxidation	Sale of 80% H_2SO_4	100-MW coal-fired in startup
Limestone into boiler with wet scrubbing	$CaSO_3$-$CaSO_4$ waste sludge	Several demonstration plants shut down due to operating problems; others canceled
Wet scrubbing with lime slurry feed	Same as above	150-MW operating with coal of 2% sulfur content; others under construction
Wet scrubbing with limestone slurry feed	Same as above with excess $CaCO_3$	175-MW coal-fired in startup stage; many others under construction
Dry limestone into boiler only	$CaSO_3$-$CaSO_4$ with ash	Inadequate sulfur removal (10 to 40%); no further operation planned

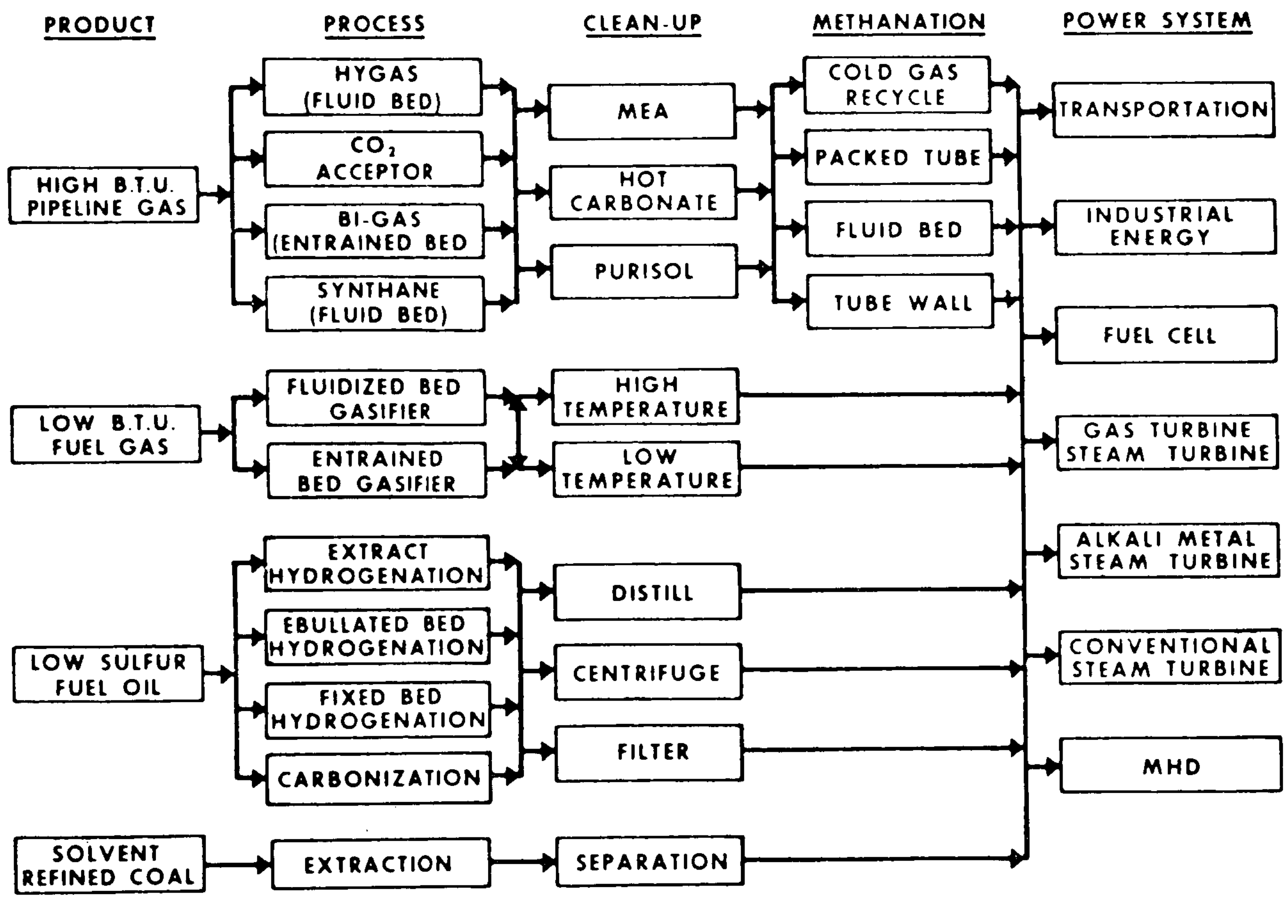
Basis for selection: These are processes for which a demonstration plant with a capacity of at least 100 MWe, using high-sulfur coal, has been completed, is under construction, or is anticipated.

[a]Concentrated SO_2 can also be converted to other products.

Table 6A.2-3

TECHNOLOGICAL STATUS OF SOME STACK-GAS SO_2-REMOVAL PROCESSES

Process	Major U.S. engineering activities	Status of demonstration plants		Status of process chemistry	Major technological problem areas
		U.S. plants operating on coal of >2% S	Other plants, U.S. and foreign, operating on oil or low-S coal		
MgO wet scrubbing	Chemico	100-MW unit near startup	Two 150-MW units in operation; U.S. on oil, Japan with throwaway cycle	No major uncertainties	Ash removal requirements
Na solution scrubbing	Wellman-Lord	125-MW unit under construction	250-MW unit near startup for coal of 1% S. Smaller units of several types operating without difficulty	Additives required to minimize oxidation to Na_2SO_4	Sulfate formation requires waste bleed and caustic makeup
Catalytic oxidation	Monsanto	100-MW unit completed in 1972 but not yet in operation	Small units for process development only	Apparently no problems	Ash removal requirements; high operating temperature; catalyst attrition; low H_2SO_4 quality
Limestone into boiler with wet scrubbing	Combustion Engineering	Shut down as a result of continuing operating difficulties	No additional plants; scheduled units have been canceled	Complex $CaSO_4$ scaling difficult to control	Severe boiler operating problems; poor limestone utilization; severe scaling, demister plugging
Wet scrubbing with lime slurry feed	Combustion Engineering, CHEMICO	Several near startup	Successful operation of 150-MW unit in Japan on coal of 2% S; other plants operating	Complex $CaSO_4$ scaling difficult to control	Severe scaling, demister plugging
Wet scrubbing with limestone slurry feed	Babcock & Wilcox, Combustion Engineering, TVA	175-MW unit completed in 1972; has not yet met acceptance tests; many others of >100 MW under construction	Small-scale development units only	Complex, not completely understood; blinding of limestone surface a problem	Demister plugging; poor dependability; low limestone utilization; waste sludge disposal



CLEAN ENERGY FROM COAL PROGRAM

Figure 6A.2-6

being used to produce fuel gas commercially include the Lurgi, Koppers-Totzek, and Wellman-Galusha; the Lurgi is the furthest advanced with respect to coal gasification on an industrial scale. Liquid processes for desulfurizing raw low-Btu gas[46] include seven in which absorption is accompanied by chemical reaction and five in which absorption takes place by physical solvent action alone. These processes operate at 0 to 260°F and 1 to 1000 psig and produce hydrogen sulfide or sulfur products.

Coal liquefaction-desulfurization may proceed by several routes. Table 6A.2-6 summarizes the current technological status of the major processes.[46] The Solvent Refined Coal product has a sulfur content below 1% and an ash content of about 0.1%, solidifies at 300 to 400°F, and has a heating value of about 16,000 Btu/lb. The Meyers process removes about 95% of the pyritic sulfur by simple chemical leaching, but the organic sulfur content is essentially unchanged.[46] The H-Coal process is inherently flexible because the proportions of fuel oil and synthetic crude can be varied over a wide range. For example, if the throughput in a given plant is increased, the contact time in the reactor is reduced, the degree of hydrogenation of the coal is less severe, and the ratio of fuel oil to lower-boiling naphtha produced is increased.

Flowsheets for the cited processes for producing gas, oil, and clean solid fuel from coal may be found in refs. 4 and 46, and simplified color schematics can be found in Lessing's article.[50]

6A.2.1.3.3 Energy Transmission

The energy-transmission system element is common to both fossil-fueled and nuclear electrical systems. Current practice involves overhead-line AC transmission at 230 to 765 kV followed by local distribution by means of either overhead lines or, in large metropolitan areas, buried cables. Average electrical transmission efficiency in 1969, expressed as power sold divided by power produced, was 91.2%.[2] Future additions of caloric oils and gases produced from coal would introduce the alternative of transporting energy by pipeline as synthetic fuel.

6A.2.1.4 Research and Development Program

This section considers the large-scale research and development program that is necessary in order for fossil fuels to complement other energy sources in meeting

Table 6A.2-4

A SUMMARY OF SOME PROPOSED PROCESSES FOR THE PRODUCTION OF LOW-BTU GAS FROM COAL

Process[a]	Gasifier type	Gasifier pressure (psig)	Oxidizing medium	Comments
Lurgi	Downward-moving stirred bed, nonslagging	300–450	Air	Process is in commercial operation on sized noncaking coal. Plans are under way to test operation on caking bituminous coal
Koppers-Totzek	Cocurrent solid-gas combustion, slagging	1–5	Oxygen or oxygen-enriched air	Process is in commercial operation using oxygen. Tests are planned using enriched air. Can handle any type of coal
Wellman-Galusha	Downward-moving stirred bed, nonslagging	1–300	Air	Process is in commercial operation using coke or noncaking coals, mostly in the steel and ceramics industries. Bureau of Mines has a pilot plant operating on caking coal at pressures up to 125 psig, capacity about 20 tons/day. Tests are planned at 300 psig to increase throughput
Union Carbide	Ash-agglomerating fluidized bed, separate fluidized regenerator	100	Air	Process is in the pre-pilot-plant stage. Plans are proceeding for design and construction of a 25-ton/day pilot plant
ATGAS (Applied Technology Corp.)	Coal is dissolved in molten iron with limestone-air injection	1	Air	Bench-scale unit operating (2.5 ft diam). Development work is in progress. Can handle any type of coal
General Electric	Slow-moving bed with inert bulk diluents	300	Air	Few details available. Process is in bench-scale stage. Uses extrusion feeder instead of lock hoppers; membrane scrubber for H_2S removal. Plans are under way for 6-ton/day pilot plant
Bi-gas	Two-stage entrained bed	300	Air	Pilot plant with 120-ton/day capacity is under construction. Process can handle any type of coal

[a]Processes such as Hygas, Synthane, and CO_2 Acceptor are not included in this table since they are intended primarily for high-Btu gas production.

Table 6A.2-5

PRELIMINARY COMPARISON OF SOME PROPOSED LOW-BTU GAS PROCESSES

Process	Claimed or potential advantages	Potential disadvantages or problems
Lurgi	1. Process is in large-scale commercial operation on noncaking coal	1. Possible problem with caking coals 2. Low degree of automation 3. High operating and maintenance requirements
Koppers-Totzek	1. Process is in commercial operation using O_2	1. May have difficulty operating with air instead of oxygen. Oxygen adds appreciably to cost 2. Not readily adaptable to high-pressure operation
Wellman-Galusha	1. Many gasifiers are in commercial operation on coke and noncaking coals, principally in steel and ceramics industries	1. Process is lower pressure than Lurgi, hence probably lower throughput per gasifier 2. Low degree of automation 3. High operating and maintenance requirements 4. Possible difficulty with swelling caking coals
Union Carbide ash-agglomerating fluidized bed	1. Can handle any type of coal 2. Fluidized-bed technique gives high throughput per unit volume 3. Separate regenerator permits use of air without nitrogen dilution of product	1. Process is still in the development stage 2. Possible difficulty in establishing proper conditions for fluidization of ash particles
ATGAS	1. Can handle any type of coal 2. Gas purification greatly simplified 3. Low cost claimed	1. Process is still in the development stage 2. Possible engineering and materials problems
General Electric	1. Can handle swelling caking coals 2. Eliminates lock-hopper feeders 3. Simplified H_2S removal 4. Eliminates stirring devices	1. Process is still in the development stage 2. Use of inert bulk diluents may pose problems
Bi-gas	1. Can handle any type of coal 2. Entrained-bed gasifier is simple and reliable 3. High throughput per unit volume	1. Process is still in the development stage 2. Molten ash may cause deposits in gasifier

Table 6A.2-6

TECHNOLOGICAL STATUS OF LIQUEFACTION-DESULFURIZATION PROCESSES

Process	Process developer and sponsor	Pilot plant			Major technological problem areas	Process improvement research and development
		Location	Capacity (tons coal/day)	Status and cost		
Solvent Refined Coal	Pittsburg and Midway Coal Mining Co.; Office of Coal Research (OCR)	Tacoma, Wash.	50	Under construction; startup fall 1974; $17 million	1. Solid separation of unreacted coal 2. Production of H_2 for process 3. Extent of sulfur removal	1. Solids separation techniques 2. Increased sulfur removal 3. Use of $CO + H_2$ instead of H_2 for hydrogenation 4. Gasification of unreacted solids for H_2 production
	Southern Services Co.; Electric Power Research Institute	Wilsonville, Ala.	6	Under construction; startup Jan. 1974; $6 million	Same as above	Same as above
Meyers process	TRW, Inc.; EPA	Redondo Beach, Calif.	Bench scale (12-ton/day pilot plant to be built)		1. Removal of elemental sulfur from the coal after the leach step	1. Studies of organic sulfur removal by solvent extraction
H-Coal process	Hydrocarbon Research, Inc.; OCR and group of oil companies	Trenton, N.J.	3–8 (250-ton/day pilot plant proposed)	Process development unit in operation	1. Solid separation of unreacted coal 2. Production of H_2 for process 3. Catalyst regeneration	1. Solids separation techniques 2. Evaluation of catalysts 3. Scale-up to commercial-sized equipment
Consol process	Consolidation Coal Co; OCR	Cresap, W.Va.	24	Operated 1967–1970; currently shut down; may be used for coal liquefaction demonstrations	1. Solid separation of unreacted coal 2. Equipment mechanical problems 3. Production of H_2 for process	1. Solids separation techniques 2. Mechanical modification of pilot plant to permit continuous operation
COED process	FMC Corp.; OCR Cogas Devel. Corp. (FMC Corp., Panhandle Eastern Pipeline Co., and Tenn. Gas Pipeline Co.)	Princeton, N.J.	36	In operation 1970 to date; $4.5 million	1. Separation of solids from oil produced during oil pyrolysis 2. Gasification of the residual char produced during coal pyrolysis	1. Development of an oil absorption system to eliminate oil filtration 2. Product evaluation studies 3. Development of char gasification techniques
Bureau of Mines Hydrodesulfurization process	U.S. Bureau of Mines	Bruceton, Pa.	0.5 (6-ton/day pilot plant proposed)	Began operation Aug. 1973	1. Solids separation of unreacted coal 2. Production of H_2 for the process 3. Scale-up of reactor to commercial sizes	1. Filter and centrifuge development for solids separation 2. Substitution of $H_2 + CO$ for H_2 used during hydrogenation 3. Determination of catalyst consumption

the total electrical and other energy demands of the Nation. Coordination and exchange of technology among participants--governmental agencies, utilities, vendors, and consortia--to avoid costly duplication of effort will be important because of the multiple demands on limited research funds for energy. As indicated by Lapp,[3] 19% of the total funding recommendations for research on energy contained in the initial fiscal year 1974 budget were designated for fossil fuels. Including the later supplemental funding for energy research during fiscal year 1974, this fraction increased to about 25%. Lapp, addressing coal conversion specifically, asserts that "the R&D effort demands a sense of urgency and concomitant technological daring that is lacking today."[3]

In the mining area, a need exists for extensively automating the already highly mechanized deep coal mines. If the need for miners to be underground were thus minimized, the high death and injury rates associated with U.S. deep mining could be reduced significantly. The same end could be achieved by development of combustion of underground coal in situ for extraction of heat or of low-Btu gas. Hydraulic mining with high-pressure water jets, in those areas where water supply is adequate, offers the potential of increased extraction rates, removal of the coal from the mine in a slurry (by using the cutting water and, in arid areas, recycling it), and the elimination of explosions caused by the ignition of methane or suspensions of coal dust by sparks from metal-rock impacts.

In addition, the mechanisms of delayed subsidence of deep mines should be determined, and control steps, including blind pressurized backfilling, should be developed and put into practice. If environmental-protection activity results in prohibition or (more likely) legislative restriction of strip mining, the demand for deep-mine extraction would increase severalfold, in which case the suggested research would take on added importance. The current primary need in surface mining appears to be application of existing technology (for example, land reclamation and siltation control) rather than a large research and development program. Steps such as limiting stripping to areas with slopes under 20° fall within the legislative domain. Section 6A.2.1.2.2 gives other general suggestions.

Research and development in fuel transportation should include the development of pipe with higher strength-to-weight ratios for gas transmission;[4] the development of general slurry preparation, fluid dynamics, and slurry utilization studies aimed at increasing the general usability of coal-slurry pipelines; and the development of commercial integral trains that are highly automated and consist of oversize gondolas, semi-permanently swivel-coupled and designed for rapid loading and unloading.

Processing research would entail continuing efforts to curtail emissions of undesirable effluents, to improve stack-gas plume rise and dispersion predictive capability, to increase the utilization of limestone in current stack-gas desulfurization processes, and to broaden studies of by-product uses, with and without beneficiation.

In power generation, the need for more intensive research and development oriented toward increasing thermal-conversion efficiencies seems generally accepted. This work would encompass the large-scale development of improved thermodynamic cycles, including gas turbines integrated with clean gas from coal, and the research necessary to build advanced fluidized-bed boilers and cryogenic alternators in sizes adequate to permit realistic evaluation.

In the area of fuel conversion, a greatly increased level of process research leading to large plants producing clean coal, low-Btu gas, and synthetic fuel oil is clearly needed. To prevent prematurely forced process decisions, extensive testing of the multiple attractive fuel-conversion combinations should be conducted, and the results evaluated, at the process-demonstration-unit stage. This program could lead to significant future reductions in power plant requirements for fly-ash removal and post-combustion SO_x controls of perhaps uncertain reliability. A common-basis technical and economic evaluation of competitive processes should be made and frequently updated by an objective, competent group, perhaps dedicated solely to this function.

A salient point made by the National Science Foundation Energy Task Force[51] is that satisfactory determination of energy-area research and development strategies is too complex and too important to be conducted under ad hoc conditions and that a long-term continuing multidisciplinary effort effectively located within the government is required. A program of this nature aimed at substituting the use of coal for oil and gas has been proposed as part of a national energy program described in "The Nation's Energy Future."[31] The coal recommendations included the following four essential elements:

(1) Development and demonstration of more productive, safe coal mining technology to the point where it can be used in greatly expanded future operations. This element will include: the development and demonstration of surface coal mining systems featuring integrated extraction and reclamation processes that meet environmental, social, and economic

constraints; the development of underground coal mining systems that increase average productivity to 30 tons/man shift with as complete extraction as possible in a manner that ensures safety and environmental protection; and the development of systems for mining oil shale in an environmentally safe and productive manner.

(2) Development of coal-fired boilers for electric power generation which have improved thermal conversion efficiency, reduced costs, and acceptable environmental impact. This process will include the completion of pilot-scale tests of four methods of clean combustion of coal and the construction and operation of one pressurized fluidized-bed boiler system.

(3) Development of technology for converting coal to clean liquid and gaseous fuels. This program element will cover the investigation of several processes for converting coal to pipeline quality gas and the construction and operation of a demonstration coal gasification plant; the construction and operation of three to five pilot plants and two combined-cycle demonstration plants to test four processes for converting coal to a low-Btu gas; the investigation of several processes for converting coal to liquid boiler and distillate fuels, the selection of three or more of these for further testing in pilot plants, and the design of one demonstration plant; and the construction of two commercial-scale plants incorporating state-of-the-art processes and techniques for producing oil and gas from coal and the measuring, monitoring, and evaluation of the operation of these plants.

(4) Provision of the necessary supporting research and development to achieve the other coal objectives and to develop the technology necessary for reducing to acceptable levels the environmental impact of commercial-scale coal processing, transportation, conversion, and combustion operations. The objectives of this program element would be to obtain data through laboratory research on materials and component development for various coal conversion processes, to provide exploratory data for development of new processes, to develop an economical method of removing sulfur dioxide from flue gas, to reduce impurity and pollutant discharges resulting from the combustion of coal, to improve the technology for impurity removal from coal by physical and chemical treatment, to ensure the environmental acceptability of commercial-scale processes of converting coal to gas and to liquids, to develop economical methods of disposing of wastes resulting from the use of coal, and to investigate the feasibility of converting coal to gas in situ.

A brief summary of the costs of conducting a coal research and development program of this scope and magnitude is included in Section 6A.2.1.7.2.

With regard to one particular area, namely the development and construction of advanced fluidized-bed boilers as discussed above in Section 6A.2.1.3.1, one commenter* on the Draft Environmental Statement has suggested that the prospects of this concept may be even more promising than reported:

> Of all of the research and development programs now in one stage or another of implementation the fluidized-bed furnance and steam generator is the most advanced. Most of the research work has been completed and the experimental furnace has been operated successfully under laboratory conditions demonstrating capability to meet the air pollution emission limitations utilizing high sulfur high Btu coal as a fuel. A prototype unit is under construction. Conceptual designs of a steam generator comparable in size to the proposed experimental LMFBR installation are available. The EIS gives only passing recognition to this fact in a one paragraph statement regarding its possibilities. The fluidized-bed combustion program is much farther advanced than the LMFBR program. If given appropriate emphasis at this time in the research and development picture the first large scale steam generator could be in full commercial operation prior to 1980 and a whole new generation of fluidized-bed electric power plants utilizing high sulfur, high Btu bituminous coal located in the major coal producing areas near the mines could be contributing to the energy self-sufficiency goal of this country by the mid-1980's.

This commenter** went on to note:

> A full environmental impact analysis of the current development program for the clean burning of coal may well indicate that greater priority should be given to some of these accompanied by a more orderly and longer term development program for LMFBR. I am confident that this will prove to be the situation in at least one case. A crash effort to develop the various concepts of the fluidized-bed boiler may well yield this result.

The AEC recognizes the potential contributions that may be made by fluidized-bed combustion in the future and supports the development of this power conversion concept. A National Fluidized Bed Program has been established in the Office of Coal Research (Department of the Interior) with fiscal year 1975 funding of about $34 million and plans for additional funding in future years. The AEC is in essential accord with this development program and feels that the recommended program plan will lead to fluidized-bed boiler power plants becoming an important

*Mr. Hamilton Treadway, Comment Letter 15, pp. 5-6.
**Mr. Hamilton Treadway, Comment Letter 35, p. 2.

contributor to the Nation's electrical power generation capacity in the 1980's, though probably not until three or four years later than suggested in the referenced comment letters. This argument does not imply that other energy generation systems, including nuclear fission reactors, will not also be needed. On the contrary, a mixture of power generation options will be required to meet the Nation's energy needs in the years to come.

6A.2.1.5 Present and Projected Application

Recent and current application of coal in the electrical energy sector was outlined in Section 6A.2.1.1.3. Projections reveal that coal's share of the total energy demand[2] will remain at the 1972 level of about 18% or it will decrease slightly until 1985, but the total amount consumed will increase by about 75% to 1.0×10^9 tons/year in 1985.[2,21] These projections, and others, are summarized in Table 6A.2-7.

Risser gives estimates[16] of coal production rates for synthetic natural gas and gasoline for the period 1980 to 2000 that are comparable with Linden's.[52] However, these synthetic-fuel projections may be low since production of 6,260,000 barrels of syncrude per day (25% of the estimated total United States petroleum demand in 1985[9]) would require about 800,000,000 tons of coal per year.

Lapp[3] estimates that his projection for the year 2000 would increase to about 3.4×10^9 tons/year if coal were substituted totally for the nuclear electrical generation anticipated for that year. Taking maximum total consumption rates from Table 6A.2-7 for the years 1985 and 2000 as 1.5×10^9 tons and 1.9×10^9 tons and increasing them by 8.9 and 7.6%, respectively, to account for export demand[53] gives total rates of 1.6×10^9 tons (1985) and 2.0×10^9 tons (2000). Currently, about 66% of the gross raw coal production is cleaned, about 23% of which is lost (12% coal and 11% rock).[2] If this cleaning loss of about 15% of gross production remains unchanged, the maximum total mining rates in 1985 and 2000 would be about 1.8×10^9 and 2.3×10^9 tons, respectively.

All recent projections, made by use of various probable energy-mix patterns, point to significantly increased coal consumption rates over the next 40 to 50 years for combined electricity generation and motor-fuel production. To meet increased energy demands and to satisfy current and future requirements of the Federal Clean Air Act of 1970 and the Water Quality Act of 1972, much of the new fossil-fuel technology under development must be on line to a significant degree within a decade.

Table 6A.2-7

PROJECTIONS OF DOMESTIC[a] COAL CONSUMPTION (TONS/YEAR)[b]

Year	Electrical generation[c]	Other	Total[d]
1980	460×10^6 (1) 500×10^6 (3, 4)	12×10^6 (2)[e] 205×10^6 (1)[f]	665×10^6 (1) 845×10^6[g] 967×10^6[h]
1985	600×10^6 (4) 613×10^6 (1) 645×10^6 (6)[i]	85×10^6 (2)[e] 280×10^6 (1)[f]	0.89×10^9 (1) 0.96×10^9 (5) 1.0×10^9 (6, 7, 8)[i] 1.5×10^9 (9) 0.99×10^9[j] 1.00×10^9[g] 1.30×10^9[k] 1.69×10^9[h] $\sim 1.80 \times 10^9$[l] 1.91×10^9[m]
1990	700×10^6 (4)	306×10^6 (2)[e]	1.01×10^9[n]
2000	750×10^6 (10) 755×10^6 (1) 1.0×10^9 (3)	555×10^6 (1)[f] 872×10^6 (2)[e]	1.3×10^9 (1,11)
2020	1.5×10^9 (10)		

FOOTNOTES FOR TABLE 6A.2-7

[a]About 10% of the net production was exported during 1970 to 1972.

[b]Reference numbers in parentheses refer to references on the following page.

[c]By 2000, coal's share of electrical generation is expected to decrease to about half its current contribution, that is, to 22%, (ref. 12) which will correspond to an electrical generation about 13% larger than the 1972 total generation (ref. 13).

[d]Except for ref. 1 projections, and projections for the year 1990, the tonnages in this column are not the sum of those in the two preceding columns.

[e]For production of synthetic natural gas and synthetic crude oil only.

[f]Industrial consumption, household and commercial use, and synthetic gas production.

[g]National Petroleum Council, "U.S. Energy Outlook, Coal Availability," pp. 13 and 89, 1973.

[h]"Energy Facts," Committee Print, Prepared for the Subcomm. on Energy of the Comm. on Science and Astronautics, U.S. House of Representatives, 93rd Congress, 1st Session, Nov. 1973, p. 180.

[i]Also reported in Business Week, p. 65, Nov. 17, 1973.

[j]Man, Materials, and Environment, Chapter 4, The MIT Press, Cambridge, 1973.

[k]National Academy of Engineering, "U.S. Energy Prospects: An Engineering Viewpoint," as reported in Chem. and Engr. News, p. 24, May 27, 1974.

[l]Report of the Cornell Workshops on the Major Issues of a National Energy Research and Development Program, College of Engineering, Cornell University, Dec. 1973, p. 81.

[m]"Mining-Coal and Oil Shale," Subpanel II (contribution to AEC Report WASH-1281), Summary, Table 2, 1973.

[n]Sum of "electrical" and "other;" underestimates actual total.

REFERENCES FOR TABLE 6A.2-7

1. W. G. Dupree, Jr., and J. A. West, "United States Energy Through the Year 2000," U.S. Department of the Interior, U.S. Government Printing Office, December 1972, Table 18, p. 33.

2. H. R. Linden, Inst. of Gas Technology, as reported in "Synthetic Fuels: What, When?," Chem. Eng., April 17, 1972, pp. 64-65.

3. A. W. Deurbrouck, "Sulfur Reduction Potential of the Coals of the United States," Bureau of Mines, Report of Investigations No. 7633, U.S. Government Printing Office, Washington, D.C., 1972.

4. Federal Power Commission, "The 1970 National Power Survey," U.S. Government Printing Office, December 1971, Part I, p. I-4-2.

5. The Chase Manhattan Bank, "Outlook for Energy in the United States to 1985," New York, June 1972, p. 46.

6. National Petroleum Council, "U.S. Energy Outlook, Fuels for Electricity," 1973.

7. Council on Environmental Quality, "Energy and the Environment: Electric Power," U.S. Government Printing Office, August 1973, pp. 40-45.

8. International Petroleum Encyclopedia, Petroleum Publishing Co., Tulsa, Okla., 1973, pp. 4-9.

9. C. Bagge, National Coal Association as reported in "Enough Energy--If Resources are Allocated Right," Business Week, Sp. Rept., April 21, 1973, p. 55.

10. Federal Council for Science and Technology, Committee on Energy R&D Goals, Draft Panel Report on Extraction of Energy Fuels, Section VI, "Primary Extraction of Coal," June 1972.

11. R. E. Lapp, "The Chemical Century," Bull. Atomic Scientists, September 1973, pp. 8-14.

12. Derived from Dupree and West, op. cit., Tables 8 and 10.

13. Derived from Dupree and West, op. cit., p. 19, and from Federal Power Commission News, 6(26): 13(1973).

Recently estimated commercial introduction dates that seem attainable, if the developments are funded at increased levels commensurate with the apparent need and without delay, include:

(1) SO_2 stack-gas cleanup:[48] scrubbers installed on about 10,000 MWe of coal capacity by late 1975, a transition to regenerative (vs throwaway) processes in the late 1970's, to units installed on about 75% of the coal electrical capacity in 1980.

(2) Improved stack-gas dispersion modeling:[54] by about 1977.

(3) Advanced steam-generator furnaces,[55] including fluidized beds:[30] by late 1970's to early 1980's.

(4) Alkali-metal topping[56] and ammonia bottoming[57] cycles: by early 1980's.

(5) Low-Btu gas from coal: from late 1970's to early 1980's;[58,59] 1980 earliest;[50] by 1985.[1]

(6) Combined gas and steam turbine cycles:[58] early 1980's, including the case of advanced gas turbines driven by gas from coal or oil.[33]

(7) Clean fuels from coal (desulfurized coal, syncrude, fuel oil, and low-Btu gas): early 1980's,[50,52,60] significant supply by early 1990's.[1]

Though some of these introduction dates are almost certainly more realistic than others, anticipation of the large-scale use by 1985 of most of these capabilities, if they are needed, appears reasonable.

If the "Decade Program" proposed by Wilson[61] were implemented, 50% of our total energy need would be met by coal by 1985, with the coal coming predominantly from western surface mines operated under strict restoration regulations. This program, which would reduce reliance on all energy imports to 10% of the national need by 1985, includes a tentative plan to meet 75% of the energy demand with coal by the year 2000. Wilson strongly urges the mobilization of a massive crash program of parallel pilot and demonstration plants for the promising coal-utilization processes, including production of synthetic oil and low-Btu utility gas, the direct firing of coal with pre- or post-combustion treatment, and, especially, the creation of an immense synthetic natural gas capacity. Even if the national energy growth rate were reduced to 3% per year by 1975, the actions proposed would require a coal consumption of about 2×10^9 tons/pyear by 1985.

Several expressions of support were received in the comments on the Draft Statement for placing greater reliance on fossil fuels, particularly coal, instead of nuclear power for meeting our expanding electricity needs in the future.* For example, Mr. Wilfred Beaver** noted:

> We support, instead alternative energy sources such as ... fossil fuels. ... These are the 'safe' alternatives nature has given us to use. We support the exploitation of our coal reserves as a second line of defense ..., Coal supplies appear to be sufficiently plentiful ... to provide for our electrical generation needs well beyond the next century, so that the choice between nuclear and fossil power generation will be made on economic considerations taking all costs, including pollution control, into account.

Another commenter† stated:

> I wish to urge my government to change its priorities from the fast breeder to other forms of cleaner and safer energy ... and in the meantime, making every effort towards cleaning up our coal.

Dr. Thomas Cochran, in suggestions†† submitted prior to the preparation of the Draft Statement, stated:

> It would appear that improved coal technology as well as ... (other) technologies could all be developed for a total program cost that will be smaller than the LMFBR Program.

Thus, there appears to be considerable support for relying on fossil fuels instead of nuclear power both in the near future and in the longer term. The AEC agrees with these views to a limited extent, and it supports the exploitation of our coal reserves. As indicated above, coal will be needed along with other energy sources to meet the Nation's energy requirements. Its use is shown in the tabulation of projections of domestic coal consumption in Table 6A.2-7, which reflects the sharply increased rates of coal utilization anticipated during the next several decades. However, constraints on availability of needed equipment, manpower, water, and capital may render attainment of the higher projections--that is, 1.9×10^9 tons/year by 1985--quite difficult. Also, although our inplace coal reserves are adequate to last well into the next century, the utilization of these reserves in an economically competitive, safe, and environmentally acceptable manner to provide

*Comment Letters 3, pp. 1-2; 8, pp. 5-7; 24, pp. 2-3; 42, pp. 34-35; Pre-draft Letter 15.
**Comment Letter 3, pp. 1-2.
†Ilene Younghein, Comment Letter 8, enclosure p. 7.
††Pre-draft Letter 15, encl, p. 2.

all our new electrical generating capacity over even the next several decades has been considered unrealistic by nearly every study group that has looked into the matter.[2,31,35,58]

In the long term, of course, we cannot rely on fossil fuels, because the universal agreement is that they will be essentially depleted within a few centuries at most--and even sooner if consumed as the major fuel for producing electricity at the higher demand levels projected in the future. Therefore, although an additional effort to develop all viable energy sources, including fossil fuels, is warranted if the Nation is to maintain its economic growth, the AEC does not believe that we can rely solely on non-renewable fuels for either the short- or long-term for meeting the Nation's energy needs.

6A.2.1.6 Environmental Impacts

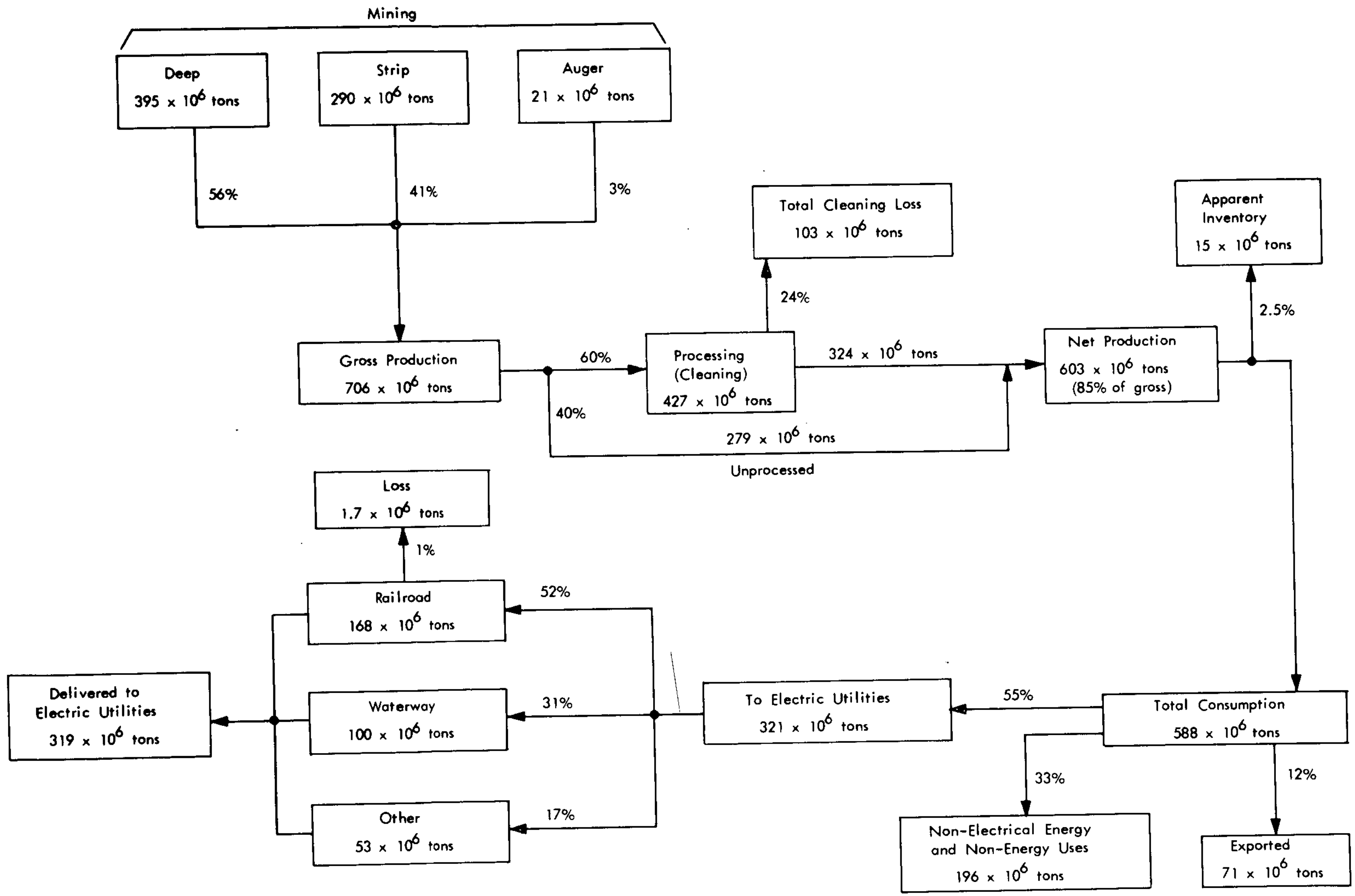
The principal environmental impacts considered in this section are those caused by coal-fired power plants and those related to offsite support activities, which include mining, cleaning (processing), transportation, and anticipated fuel-to-fuel conversion.

Figure 6A.2-7, adapted with minor modifications from ref. 35, and based on National Coal Association (NCA) data,[62,63] depicts the approximate production and disposition of U.S. bituminous coal in 1970. Some of the tonnages were necessarily inferred or estimated, because the NCA production figures are net--that is, the net yield after cleaning.

The relationship between the power plant and the offsite activities for a typical current coal-fired electricity system is shown in Figure 6A.2-8, adapted from ref. 2; average mass flows, losses, energy inputs, and stage efficiencies are shown. When the "reference" system or power plant is cited in this section, it is a reference to the system depicted by Figure 6A.2-8.

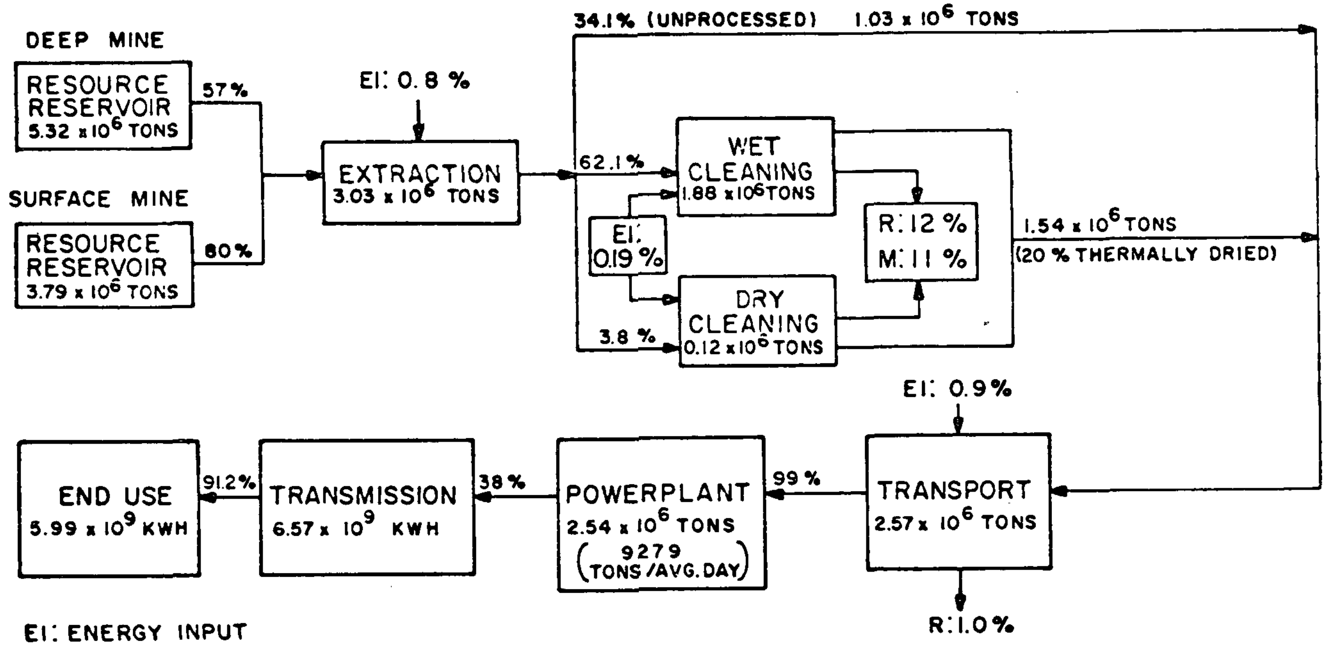
6A.2.1.6.1 Energy Conversion Plant

Typical coal-fired power plants emit significant quantities of particulates (fly ash) and noxious gases such as sulfur oxides, nitrogen oxides, carbon monoxide, and hydrocarbons. For each ton of coal burned, about 200 lb of ash are produced; and for a national-average sulfur content of 2.5 wt %, about 80 lb of sulfur dioxide gas are emitted.[35] With minimal or currently prevalent environmental controls, the reference plant of Figure 6A.2-8, that is, a 1000-MWe plant with a load factor of



PRODUCTION AND DISTRIBUTION OF U.S. BITUMINOUS COAL (1970)

Figure 6A.2-7



EI: ENERGY INPUT
R: RESOURCE LOST
M: NONRESOURCE MATERIAL DISCARDED
a: HEAT RATE = 9000 Btu / KWH; H.V. OF COAL = 11,639 Btu/LB.

COAL-FIRED ELECTRICITY SYSTEM FOR A 1000 MWe POWER PLANT
OPERATING ANNUALLY AT A 0.75 LOAD FACTOR

Figure 6A.2-8

0.75 and a heat rate of 9000 Btu/kWhr (38% conversion efficiency), burning pulverized coal with 10 wt % ash and 2.58 wt % sulfur, produces about 352,000 tons of air emissions per year, about 93% of which is SO_x and particulates[2] and about 6% oxides of nitrogen.

In an average pulverized-coal-fed furnace, about 80% of the ash in the coal appears as fly ash (about 160 lb/ton of coal), and the remaining 20% constitutes slag waste. For a cyclone-boiler plant, these ash percentages are approximately reversed, that is, 70 to 80% of the ash goes to slag. Preliminary estimates[2] indicate that a pulverized-coal reference plant produces roughly 800 tons of water pollutants per year that are almost entirely inorganic (about 77% suspended solids and boron compounds). Emitted hydrocarbons may contain small quantities of carcinogens such as benzo[a] pyrene,[35,64] but the total hydrocarbons comprise only about 0.1 wt % of the total air emissions;[2] other sources, especially autos and petroleum refineries, emit enormously greater amounts of hydrocarbon vapors. No quantitative data regarding this potential hazard from coal-fired plants appear to exist. Because coal contains traces of uranium, thorium, and radium, there has been a continuing debate regarding radionuclide emissions from coal plants; however, a 1000-MWe plant probably discharges a total of only about 2.2 curies annually.[2] Of this total, a plant equipped with efficient electrostatic precipitators emits about 0.03 curies/year to the atmosphere (as Ra-226 and Ra-228)[35] and over 98% is associated with the collected fly ash sent to settling ponds. The radiological dose to the population associated with these releases appears to be insignificant. Under certain climatic conditions, sulfuric acid mist may form in the atmosphere and cause damage to a wide range of objects, including stone buildings.[65]

Heat rejected by the condenser cooling water to rivers and lakes is considerable; in 1964, for example, of all industrial cooling water used in the United States, 81% was for electric power plants.[2] The heat rejected per unit of electrical energy produced in a coal-fired power plant is about the same as that from the HTGR and the proposed LMFBR, but is 40 to 50% less than that from current LWRs because of the fossil-fueled plant's higher thermal efficiency.

Any advancement in the thermal efficiency of either fossil or nuclear electrical generation provides the double environmental gain of reducing thermal and other waste emissions to the environment and conserving resources of natural fuels. The heat rate, or thermal energy consumed in producing electricity, is one measure of thermal efficiency. The national average value for fossil-fueled power plants has declined from about 14,000 Btu/kWhr in 1950 to 10,760 Btu/kWhr in 1960 to 10,300

Btu/kWhr in 1970, and "this value is expected to drop to about 8500 Btu/kWhr for the most efficient plants in operation by 2000."[66] The quoted projection seems somewhat conservative when compared with the 8600 ($\pm$70)-Btu/kWhr heat rates already achieved by the most efficient large coal-fired plants.[2,67]

The total land commitment for the reference 1000-MWe coal power plant with minimal environmental controls is about 700 acres,[2] or about 130% larger than for a current LWR with the same power rating. Solid wastes generated by air-pollution controls (fly ash and limestone sludge) require significant additional land use for disposal. An annual incremental land use of 15 acres for this purpose has been estimated for a controlled reference plant,[2] based on 99% fly ash removal (201,000 tons of dry ash per year averaging 33 ft^3/ton) and 85% SO_x removal (742,000 tons of limestone sludge per year averaging 22 ft^3/ton). Some of the environmental impact factors associated with six SO_x stack-gas removal processes[46] are given in Table 6A.2-8. In addition, if natural-draft wet cooling towers were used, they would occupy about 10 acres/1000-MWe capacity.

At the power plant stage, about 113 workers are involved per 1000-MWe capacity.[2] Because major accidents such as boiler explosions and transient high-concentration toxic-gas releases are now quite rare in coal-fired power plants, the occupational death and injury rates have been estimated to be low (0.012 death and 1.38 injuries per year for the reference plant of Figure 6A.2-8).[2]

Aesthetic intrusions and noise emissions of modern plants with environmental controls are generally low. Although difficulties are being encountered with some aspects of various programs for reducing the environmental impacts of coal-fired power plants, the impact factors are anticipated to be moderated to a significant degree by the application of available and emerging technologies.

6A.2.1.6.2 Offsite Support Activities and Facilities

Mining

Current mining practices, which are improvable in many regards, cause extensive environmental impacts, the nature of which depends on whether the mining is conducted underground or on the surface.

Deep Mining. In deep mining, workers are exposed to the hazards of fire and explosions (from methane and coal dust), slate falls, bronchitis, dyspnea, and "black lung" (coal workers' pneumoconiosis, or CWP). In recent United States

Table 6A.2-8

WASTE DISPOSAL AND ENVIRONMENTAL IMPACT FACTORS FOR PROCESSES FOR REMOVING SO_x FROM STACK GAS

Process	Additional dry solid waste	Additional solution waste	Additional slurry waste	Effect on particulate emissions
MgO wet scrubbing	None	None	None except ash scrubber	Excellent particulate removal necessary as a preliminary step
Na solution scrubbing	None	Na_2SO_4 purge; 0.02 ton per ton of coal as 15% solution	None except ash scrubber	Particulate removal necessary as preliminary process step
Catalytic oxidation	Small amount of catalyst fines	Low-quality H_2SO_4; 0.10 ton per ton of coal; might be considered a waste product	None	Excellent particulate removal necessary with minimum heat losses as a preliminary process step
Limestone into boiler with wet scrubbing	$CaSO_3$ and unreacted lime with ash, 0.1 ton per ton of coal	None	About 0.15 ton Ca compounds and ash per ton of coal; 40% H_2O	Electrostatic precipitators operate poorly, but wet scrubbing completes particulate removal
Wet scrubbing with lime slurry feed	None	None	About 0.15 ton Ca compounds per ton of coal; 30% H_2O	Wet scrubbing completes particulate removal
Wet scrubbing with limestone slurry feed	None	None	About 0.2 ton Ca compounds per ton of coal; 60% H_2O	Wet scrubbing completes particulate removal

Basis: Coal of 4% S; H_2SO_4 of >90% concentration, S, and SO_2 are not waste products experience, the incidence rates of simple and of complicated (acute) CWP are approximately 3.47 and 1.60 cases per thousand man-years, respectively. Other studies[35] indicate significantly lower rates in British experience: about two total cases per thousand man-years, and only about 0.2 acute case per thousand man-years, each following a minimal exposure time of 15 years. Occupational hazards in the United States in 1970 led to 0.65 death and 28.07 nonfatal injuries per million tons of coal mined and to an average of 55 workdays lost per injury.[2]

Subsidence caused by deep mining can damage surface structures, disrupt groundwater hydrology, and, if sudden, precipitate localized earth tremors. Subsidence affects about 0.2 acre/1000 tons of coal produced, and about 30% of the total area undermined for coal has already subsided to some extent.[2] The area potentially altered by subsidence varies inversely with the seam thickness for a given tonnage extracted; based on 1800 tons of coal per acre-ft and 50% recovery, the coal extracted increases from 9000 to 90,000 tons/acre as the seam thickness increases from 10 to 100 ft. A large United States deep coal mine produces about 2,000,000 tons/year. Average productivities[16,34] of about 14 tons/man-day for room-and-pillar-type mining have been attained; productivity has recently declined to about 11 tons/man-day because of the more stringent safety requirements of the 1969 Coal Mine Health and Safety Act. Increased use of the newer short-wall and long-wall deep-mining techniques and shifting to the much thicker western coal beds should lead to significant increases in productivity. The long-wall mining system can also attain 90 to 95% coal recovery and allows controlled subsidence of the surface to the point of natural stabilization.

The land disturbed by storage of underground mining wastes has been based, in one estimate,[2] on a use rate of 84,400 tons of waste per acre of waste bank, which corresponds to an average refuse density of 1.5 tons/yd^3 and a bank height of 35 ft.

Based on 1969 Appalachian-area data, the annual water-pollutant runoff[2] from a deep mine supplying the reference power plant of Figure 6A.2-8 would be approximately 2129 tons of sulfuric acid, 532 tons of dissolved iron salts, and negligible silt, probably continuing over a 15-year period. The acid drainage from deep mines contaminates receiving water bodies, although less seriously when the sulfur content of the coal is low, as in western areas.

Surface Mining. In surface mining, the U.S. death and nonfatal injury rates (1970) were 0.12 per million tons and 5.40 per million tons, respectively,[2] with an average of 36 workdays lost per injury. The incidence of CWP among surface miners is clearly lower than that among deep miners working in confined spaces, but the rate apparently has not yet been quantitatively determined. Surface mining, although safer than deep mining as currently practiced, disrupts large land areas, causing adverse effects on vegetation, crops, wildlife, habitat, and water supply and quality, as well as conflicting with timber, grazing, and other resource uses.

The land area disrupted by stripping varies inversely with the amount of coal recovered per acre. Contour stripping on hilly terrain in the eastern United States has yielded only about 1700 tons of coal per acre,[3] since the coal seams involved are often only 1 to 2 ft thick. The national average surface-mining recovery is about 3300 tons/acre.[2,35] Production of coal by area stripping of thicker beds can lead to greatly reduced surface-area disruption. Based on 1800 tons of coal per acre-ft and 80% recovery, the coal extracted increases from 14,400 to 144,000 tons/acre as the bed thickness increases from 10 to 100 ft. Of all United States land area disturbed by surface mining to 1965, 41% was attributable to coal[68] (and adding sand and gravel production accounts for 67% of the total).

According to the Council on Environmental Quality,[2] about 90% of the overburden from surface mining is redeposited on the site. The major solid waste produced by surface mining is silt, as shown by the following estimate[2] of annual water pollutants for a surface mine supplying the reference power plant of Figure 6A.2-8: approximately 166 tons of sulfuric acid, 42 tons of dissolved iron salts, and 35,612 tons of silt. Siltation of receiving water bodies, resulting from waste overburden runoff, was estimated at 3.0 tons/acre per year for 15 years. Siltation can lead to sedimentation and consequent increased possibility of flooding or to accelerated erosion rates.[11]

Under some geological conditions, waste piles and high walls (vertical earth banks left by mining) can slide or slump, causing property damage and posing a safety hazard to people[11] and animals. High dust concentrations can occur in the vicinity of pits, spoil piles, and haulage roads, and consequent wind erosion could contribute to dust storms. Noise and vibration levels generated by surface-mining activities such as drilling and blasting can be obtrusive. The demand on local water supplies may be excessive, especially in some western areas with limited rainfall.[69]

A large United States surface coal mine produces about 5,000,000 tons/year. Labor requirements can be estimated from recent average productivities of about 32 tons of coal per man-day for all strip mining[16] and about 36 to 40 tons/man-day[34,35] for area stripping.

For both deep and surface mining, the air emissions from burning coal seams and waste banks and from power mining equipment seem at present to be undetermined.

Processing Plant

A large coal processing plant may clean a million tons of raw coal per year,[2] occupy about 40 acres, and produce about 1.5 tons of waste water per ton of coal processed.[35] During cleaning of the raw mine product, about 24% of the feed is discarded, of which about half is coal.[2,35] Coal-dust emissions arise almost entirely from thermal drying of wet-processed coal; from data in ref. 2 (pp. 43 and 45), the 1968 emission rate can be calculated as about 15 tons of dust per thousand tons of cleaned and thermally dried coal. By adding wet scrubbers and air recirculation to the cyclone separators in common use, dust emissions can be reduced to about 0.2 ton/1000 tons of input coal.[2]

Solid waste forms refuse heaps, and the siltation rate from processing waste banks has been taken[2] to be 42 tons/acre per year for 15 years, a rate about 14 times that from present surface-mine waste banks. Black-water discharges, consisting of water-suspended fines from the washing operation, can be impounded by slurry dikes, but careful geological studies and dike design are necessary for safe, high-level retention. Death and injury rates for processing operations are much lower than for either surface or deep mining,[2] averaging 0.0147 death and 1.58 nonfatal injuries per million tons, with 39 workdays lost per injury.

For the reference system of Figure 6A.2-8, if half the coal is deep mined and half surface mined, the combined mining and processing fatalities total 1.2 per year, based on 1970 data.

Transportation

Surface transportation of coal by rail or truck requires land for right-of-way (about 50 ft width for rail)[2] and restricts free travel of people, animals, and other vehicles across the committed areas. Dust is caused by heavily loaded trucks on unpaved roads and by blowaway of coal from rail cars (about 1% unless wetted or covered).[2] Truck transport produces objectionable noise levels, and rail transport contributes to grade-crossing accidents, many of which are fatal. Two hundred ton-miles of cargo movement requires about 1 gal of diesel fuel rated at 136,000 Btu/gal. For an average shipping distance of 300 miles,[2,35,70] the diesel fuel energy expended, by train or water, is less than 1% of the energy content of the coal,[35] and the transportation-associated air pollution is negliglible compared with that from other sources.

Conversion

Processes for conversion of coal to clean solid fuel, oil, or gas would involve land commitment and water usage and the control of ash and slag from plants generating process steam and/or power. Potential environmental contaminants include solids (char, ash, spent catalyst, sulfur, and sludges from waste-water treatment), liquids (phenols, cresols, oils, tars, and ammonia solutions), gases (hydrogen sulfide and sulfur dioxide), and heat (probably released to the atmosphere from cooling towers). Techniques for controlling or disposing of these effluents are available or under development. Flowsheets for fuel-to-fuel conversion processes may be found, in increasing order of detail, in refs. 50, 4, and 46. Because some coal-derived liquids, especially the higher-boiling fractions, have been shown to exhibit carcinogenic activity[71,72,73] (primarily relating to skin cancer), data are needed for use in establishing limits for exposure to and inhalation and ingestion of coal-derived products.

6A.2.1.6.3 Irreversible and Irretrievable Commitments of Resources

Since the coal resource base is so large, relative resource depletion will be minor over the short term. Land surface dedicated to extraction, cleaning, conversion, and transportation is likely to be permanent only in part. Land at the mining and cleaning sites, for example, could be periodically reclaimed on a regular basis, such as at 6- or 12-month intervals, although this has not been common industry practice in the past. Surface disruption and subsidence caused by mining activities are potential irreparable consequences that are in some instances amenable to mitigation by surface reclamation of stripped areas and by backfilling, sealing, and chemical treatment of acid drainage from deep mines. Depending on the particular sites selected for various stages of the fossil-fuel energy system, some onsite and offsite ecological balances would be disturbed and potentially altered irreversibly in the framework of a human lifetime. Obvious examples include the complex interactions among soil condition, water quality, vegetation, crops, wildlife, and human habitation. High use rates of water supplied by deep wells in water-deficient areas could have a drawdown effect on shallower wells supplying people or livestock, and the lowered water table might prove irreversible in the same time context. Successful long-term reclamation of reseeded overburden spoil in arid areas has not yet been demonstrated.[11]

6A.2.1.7 Costs and Benefits

6A.2.1.7.1 Energy Production and Delivery Costs

Direct or Internal Costs

Direct or internal costs are difficult to estimate accurately because of the nonuniformly increasing costs being experienced in different areas of the electrical energy sector. A recent study by the Council on Environmental Quality[2] included an estimated 1973 electrical generation cost for the reference coal-fired 1000-MWe power plant of Figure 6A.2-8, with minimal environmental controls, of 7.66 mills/kWhr. Estimates[2] were also made for a controlled system, that is, one with efficient electrostatic precipitators, wet limestone stack-gas scrubbing, and wet natural-draft cooling towers at the power plant, disposal of solid wastes from air and water pollution controls, control of silt runoff and acid mine drainage, and land reclamation at the mine and processing sites after one year of use. The controlled-system generation costs totalled 9.79 and 10.07 mills/kWhr for plants using deep- and surface-mined coal, respectively. Most of the cost increase of 2.1 to 2.4 mills/kWhr was incurred by reducing the power plant SO_x emissions by 85% with the stack-gas scrubber system.

Some of the component costs (1973 dollars) included $180 per kW for the basic (uncontrolled) power plant, $0.35 per million Btu for fuel, 0.39 mill/kWhr for operation and maintenance, $2000 per acre for land reclamation, $10 per kW for the cooling towers, and $40 per kW for the scrubber system including settling pond (1.8 mills/kWhr annualized cost). After transmission and distribution an average distance, the increase in generation cost of about 30% would be felt by the average residential consumer as an increase of about 10 to 12%.

Some of the costs used in this estimate may be low. In some areas, for example, a land reclamation cost of $4000 per acre is doubtless more realistic; operation and maintenance costs and fuel costs may be double the value used; and higher scrubber-system cost forecasts have been made by many others, including about $60 to $66 per kilowatt,[46] $75 per kilowatt,[74] and up to $80 per kilowatt.[58] Total costs (capital and operating) for retrofit scrubber-system installations have been estimated to be as high as $0.85 per million Btu by some utility companies having experience with scrubber systems.[75]

Approximate estimates of low-Btu gas-production costs have varied from 60¢ to 85¢ per million Btu[46] (Lurgi and Bi-Gas processes) to about 95¢ per million Btu.[75] By contrast, current estimates of synthetic natural gas production costs are generally in the range of $1.05 to $1.50 per million Btu, or about one-third higher. Syncrude-production cost estimates vary from $1.00 to $1.60 per million Btu ($6 to $10 per barrel).[50,77] Hottel[78] has concluded that while gas from coal appears to have a slight edge today, not one of the processes has had its true cost established, and the Nation will almost certainly need both gas and oil from coal.

The 1968 average capital cost for large deep coal mines of about $10 per ton of annual capacity[16] is probably now about $13. The 1970 average cost for large surface mines of about $8 per ton of annual capacity[10] has likely increased to about $9.

Partial cost estimates that have been developed at Oak Ridge National Laboratory for use in Section 11 are summarized in Table 6A.2-9. The costs are for the power plants only, operating at an 80% load factor, and they are expressed in mid-1974 dollars. Startup times for coal-fired and nuclear plants are assumed to be 6.0 and 7.5 years, respectively. The coal-fired plants are assumed to be equipped with wet natural-draft cooling towers, electrostatic precipitators, and wet-limestone SO_x scrubbers; and they are assumed to burn coal containing 3.5 wt % sulfur and 20 wt % ash.

Table 6A.2-9

PROJECTED ELECTRICAL POWER PLANT COSTS

Plant Type	Capital cost ($/kWe) Twin 1300-MWe Units (to 1990)	Capital cost ($/kWe) Twin 2000-MWe Units (after 1990)	Operating and Maintenance Cost (mills/kWhr)
LWR	420	370	0.7
Coal	345	315	2.2
HTGR	420	370	0.7
LMFBR	*	*	0.8

*Currently anticipated to be approximately $100 per kWe more than the LWR costs.

Coal prices themselves rose sharply in late 1973 and early 1974, along with those of other fuels. Representative prices derived from several sources are shown in Table 6A.2-10.

Table 6A.2-10

REPRESENTATIVE PRICES (AT THE MINE) FOR COAL AS OF FIRST QUARTER 1974

	Heating Value (Btu/lb)	Cost/Ton ($)		Cost/M Btu (¢)[a]	
		Repr. Value	Repr. Range	Repr. Value	Repr. Range
Bituminous (Eastern)					
High Sulfur (> 3%)	11,500	14	10 to 18	60	43 to 78
Low Sulfur (< 1%)	11,500	20	16 to 25	86	69 to 108
Subbituminous (Western)					
Low Sulfur (∿ 0.5%)	8,500	4.25	3.40 to 6.80	25	20 to 40
Lignite (Western)					
Low Sulfur (∿ 0.5%)	6,750	2.50	1.60 to 3.25	18	12 to 24

[a]M Btu = 10^6 Btu.

Indirect or External Costs

Indirect or external costs are those not borne by the purchaser. The environmental effects of effluents that are controllable by modifications in mining and processing practices and by equipment added to the power plant would be transferred to direct costs recoverable from utility revenue. Adoption of full-cost pricing at all stages of the energy system--that is, internalizing the environmental costs of energy production and use--would significantly reduce but not eliminate these external costs.

The incremental cost per ton of coal associated with land reclamation is given in Table 6A.2-11 for various yields (tons per acre) and reclamation expenditures per acre. The operations involved in rehabilitating strip-mined land to a pleasing, natural contour include backfilling, compacting, soil conditioning, regrading, reseeding, and revegetating. Current basic cost estimates range from $2000 per acre[2,61] to $6000 per acre,[34] with the second figure corresponding to an anticipated incremental coal cost of 20¢ to 30¢ per ton[9,34] (for coal yields of 20,000 to 30,000 tons/acre). For western coal, the surcharge for extensive reclamation might be only 3¢ to 4¢ per ton.[69] A speculative projection has been made[34] that average reclamation costs may fall to a level as low as 1¢ to 2¢ per ton by the year 2020.

Table 6A.2-11

RECLAMATION COSTS IN INCREMENTAL CENTS PER TON OF COAL MINED

Tons of Coal Recovered Per Acre	Incremental Cost (cents) for Land Reclamation Cost (per acre) of					
	$1000	$2000	$3000	$4000	$5000	$6000
3,000	33	67	100	133	167	200
10,000	10	20	30	40	50	60
20,000	5	10	15	20	25	30
30,000	3.3	6.7	10	13	17	20
50,000	2	4	6	8	10	12
100,000	1	2	3	4	5	6

For deep mines, rehabilitation operations include backfilling (perhaps by pressurized slurry) to minimize subsidence, selective sealing to reduce access of water to acid-producing strata and of air to residual coal, and lime treatment of acid drainage. On an initial demonstration basis, a cost of $11,000 per acre has been estimated,[34] which is equivalent to an incremental cost of 37¢ per ton for a coal yield of 30,000 tons/acre. Cost forecasts for complete treatment of acid drainage and black-water emissions have ranged from 5¢ per ton[34] to 19¢ per ton.[2]

Indirect costs include a portion of those related to occupational health. Incidence rates for fatalities, nonfatal injuries, work time lost, and CWP ("black lung") and related disabilities are known reasonably well, but no estimates seem to have been made of the effect of significant system changes on these rates and associated costs.

6A.2.1.7.2 Development Costs

These costs (borne by all financial sources) are assumed to fund development through the stages of design, construction, operation, and evaluation of a prototype unit or demonstration plant smaller than commercial scale. The total development cost, obtained primarily from recent Federal Power Commission and Oak Ridge National Laboratory estimates, is approximately $1.7 billion (1973 dollars), of which about half would be required for development of desulfurized coal (Solvent Refined Coal and Meyers process) and of low-Btu gas and fuel oil from coal. The distribution by program is shown in Table 6A.2-12. High-Btu synthetic gas is not included since it is not an electric-utility fuel and is approaching full development.[52] When an estimate spanned a range, the higher cost was used. If the period of intensive development continues through 1985 and inflation rates remain at recent levels, this sum will easily exceed $2 billion. Extensive development in the areas of mining, land reclamation, fuel transportation, and energy transmission would require additional expenditures. The funding required to attain, at an accelerated pace, large-scale production of gas and synthetic oil from coal on an initial commercial basis is believed to be $2 billion to $3 billion.[50]

Table 6A.2-12

ESTIMATED DEVELOPMENT COSTS

Program	Cost (millions of dollars)
Synthetic fuel oil from coal	500
Low-Btu gas from coal	300
Desulfurized coal	100
SO_x stack-gas cleanup	75
NO_x abatement	15
Advanced steam-generator furnaces, including fluidized-bed combustion	85
Advanced (high-temperature) gas turbines	250
Alkali-metal topping cycle	200
Steam-ammonia cycle, including NH_3 turbine	110
Dry cooling-tower development	80
Improved stack-gas dispersion modeling	0.3
Total	1715.3

The more recently proposed research and development program described in ref. 31 and discussed briefly in Section 6A.2.1.4 would entail funding of $2.175 billion over the next five years. This cost would include $325 million on coal mining technology, $200 million on direct combustion, $1270 million on the production of synthetic fuels (oil and gas) from coal, and $380 million on general coal technology, including environmental control and supporting research and development. Whichever program or element thereof is selected for support, clearly, the potential funding that will be needed for coal development is substantial. The related benefits that may be expected to accrue are discussed below.

6A.2.1.7.3 Benefits

The major benefits derived from modernizing the coal electrical-energy system would include, on a cumulative basis over the next two decades: narrowing the projected energy deficit, moderating the environmental impacts of current units, and minimizing reliance on imported premium fossil fuels (oil and natural gas) with the associated balance of payments problem. The number of people employed in research and development, mining, transportation, construction, and plant operation would be large but would likely decrease as the system matures and becomes increasingly capital-intensive. By-product markets might develop but probably would not be of major economic significance. If other electrical energy programs, including the LMFBR, lag scheduled introduction dates or if they are, for any reason, followed at a more deliberate pace, an efficient and clean coal-based energy system would provide a potential alternative in the interim. Additionally, such a system could produce large quantities of synthetic motor fuels--a capability shared only by oil shale among the other options under current consideration. If circumstances combine in such a manner that we are dealing simultaneously with a shortfall in nuclear generating capacity, a decline in domestic petroleum and natural gas reserves, and a decreased access to foreign fuel, then availability of domestic fuel would override normal economic considerations, and the use of synthetic fuels produced from coal could become a necessity.

6A.2.1.8 Overall Assessment of Role in Energy Supply

To the year 2000, coal will probably continue to play a vital role both in electrical power production and in meeting total energy needs, and the total mining rate will probably be about 2×10^9 tons/year by that date, approximately half of which will be used in electrical utility power plants. Very large coal mines, with capacities of perhaps 40×10^6 tons/year, will probably be developed. Coal usage will increase if low-sulfur deposits in the western states are developed and if current efforts to produce clean oil and low-Btu gas from coal and to desulfurize stack gases are commercially successful. Selective relaxation of evolving environmental standards, if they occur, would contribute further to increased usage.

Beyond the year 2000, it seems likely that mined tonnages will be so large that even higher consumption rates will be deterred by limitations on the enormous amount of solids handling, from mining to waste disposal. In addition, stricter environmental standards and the substantial amount of electricity expected to be produced by other technologies will also act to deter further major expansion of our coal producing capacity.

6A.2.2 Natural Gas and Oil

As shown by the tabulation in the "General Introduction" of this section, oil and natural gas supply jointly about 75% of the total energy consumed in the United

States. During 1972, oil and gas supplied 15.6% and 21.5%, respectively, of the total electrical energy generated.[7] Projections of petroleum contributions to the total energy consumption[79] and to the electrical-energy sector[14] are shown in Table 6A.2-13. These projections, developed in 1972, are subject to a substantial margin of error, especially under present oil-import conditions. For example, a number of electric power plants that have only recently switched from coal to oil to meet environmental pollution standards have been directed to switch back to coal because of the current shortages in oil supply.

Table 6A.2-13

PROJECTED CONTRIBUTIONS OF OIL AND NATURAL GAS TO TOTAL AND ELECTRICAL ENERGY CONSUMPTION

	Contribution to energy use (%)			
	1975	1980	1985	2000
Total use				
Oil[a]	43.8	43.9	43.5	37.2
Natural gas	31.4	28.1	24.3	17.7
Electrical use				
Oil[a]	15.9	16.9	16.8	6.3
Natural gas	16.8	12.2	8.7	3.3

[a]Including natural-gas liquids.

The proportion of world natural-hydrocarbon production represented by U.S. output is declining, and at the same time, U.S. consumption has been increasing.[80] The recent import rate of crude oil and petroleum products was 6 to 7 million bbl/day. Even in 1970, the U.S. rate of consumption of natural gas exceeded the discovery rate;[75,81] since the gas demand has grown faster than can be satisfied by domestic production, substantial amounts of gas have been imported from Canada and Mexico (about 1 trillion ft^3/year), and these imports will be increased by the arrival of liquefied natural gas from North Africa in the near future. The leveling off of domestic gas production during 1971 to 1973 led to an unsatisfied demand for energy that could be met only by oil--in fact, only by imported oil.[81]

The ratio of proven reserves to annual production for domestic natural gas[80] has fallen from 37 in 1945 to about 12 in 1970; for domestic crude oil, this reserve ratio has declined during the same period[77] from about 15 to about 10. At the end of 1973, the ratio was 11.1 for both crude oil and natural gas.[82]

4

Estimates of the excess of U.S. oil and gas needs beyond domestic production in 1985 vary, but the consensus appears to be that the deficiencies, after allowing for Alaskan North Slope contributions and for expected discoveries, will be quite large[76]--around 16 x 10^6 bbl of oil per day and up to 36 x 10^9 ft^3 of natural gas per day.* If this entire 1985 oil deficit were to be imported in 250,000-ton tankers, an armada of 350 such ships would be needed, and one would dock every 2 hr around the clock.[76] If only one-third of the estimated 1985 gas deficiency of 36 billion ft^3/day were imported as liquefied natural gas in 100,000-ton cryogenic tankers,[76] a fleet of 120 would be required, with one ship docking every 10 hr.

If the Nation were to continue to rely as heavily in the future as in the past on natural fluid fuels, a growing import rate would be inescapable. Though the proven oil reserve of the world is large, amounting to 500 to 600 billion bbl,[19,81,83] it is by no means uniformly distributed, because at least 60%[81] and probably 70%[83] of the secure reserve is in the nations of the Middle East and North Africa, and is concentrated in the Persian Gulf countries. Of total proved non-Communist world reserves, 82% lies in the Middle East and Africa.[84] Further, the world's probable oil reserves, that is, those yet to be discovered which will supply the needs of the coming decades, probably lie predominantly in the Middle East.[81] The same pattern holds true for natural gas; of the world's proven reserve, less than 20% is in the United States.[19]

To increase the resource base, the technology of the oil and gas industries is focused on exploration for new producing fields and on increasing fractional resource recovery by secondary and tertiary techniques (see Section 6C.2.1). These methods include hydrofracturing of tight gas sands and gas-bearing rock to increase the flow rate, application of pressure to oil-bearing strata (or burning part of the oil in situ) to force out additional oil, and possible nuclear stimulation of low permeability formations.

Costs of oil and natural gas will almost certainly increase significantly in the future. Imported crude oil was selling in April 1974 for $10.50 to $11.00 per barrel on the East and Gulf Coasts, a price more than double that of half a year earlier and about five times the price paid in 1963.[20] Regulation of well head gas prices by the FPC may soon end, and the FPC has proposed that the field price of new-contract gas sold in interstate commerce be essentially deregulated.[35] Such

*This estimate does not consider oil that may become available from oil shale, which is considered separately in Section 6A.2.3.

actions could lead to a doubling of the average consumer price of natural gas from its present level of about 50¢ per thousand cubic feet. Natural gas imported in the future from new fields in the Alaskan and Canadian Arctic will probably cost at least $1.10 per thousand cubic feet, with transportation accounting for about three-fourths of the total cost.[35] In other words, natural-gas energy prices may be expected to double within one to two years.

To summarize, neither short-term nor long-term prospects for natural gas and oil in the U.S. energy economy are especially hopeful. Continued and extensive use of oil and gas as fuels for electric power plants does not appear to be warranted. The current situation with regard to these fuels serves to highlight the need to develop alternative energy sources and to shift partially to other resource bases to preserve these fuels for transportation and residential uses; to reduce future balance-of-payments deficits; to minimize the perils of dependence on unreliable foreign imports of crude oil, petroleum products, and liquefied natural gas; and to retain a sizable part of these dwindling domestic hydrocarbon supplies for petrochemical-industry feedstocks. This need is now well established and increasingly accepted as a current reality.

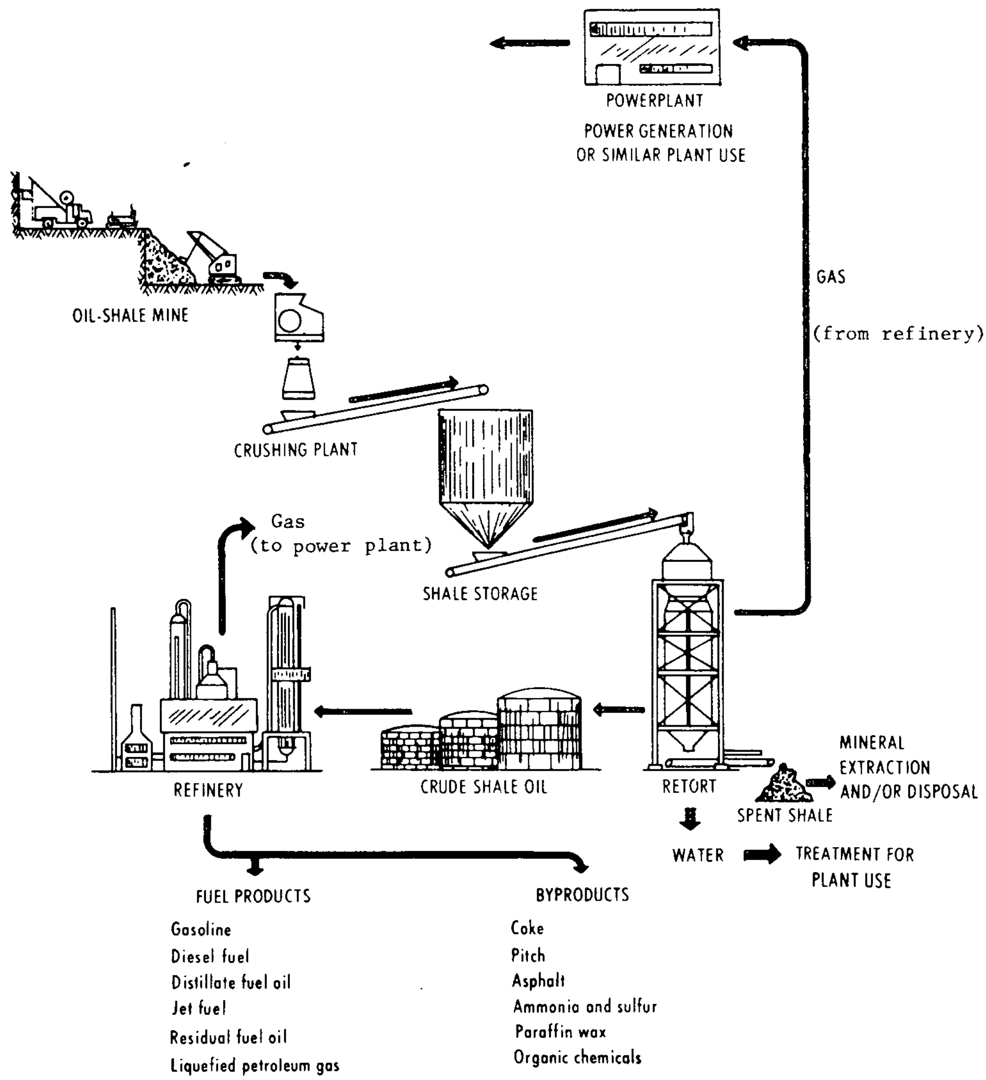
6A.2.3 Oil Shales

6A.2.3.1 Introduction

6A.2.3.1.1 General Description

Oil shale is a finely textured, sometimes laminated, sedimentary rock that generally contains about one-third mineral matter.[85] In the rich Colorado deposits, the shale is highly consolidated and impervious. Mixed with the marlstone host rock is a solid, insoluble, organic material called kerogen. The kerogen is a mixture of complex compounds, and a typical macromolecule is a polymer with a highly naphthenic structure[85] and a molecular weight exceeding 3000. When oil shale is retorted (heated), the kerogen decomposes and yields a crude oil that can be upgraded and refined to give various products. The potential oil shale resource in the U.S. is large, and its possible development must, therefore, be considered an alternative energy option independent of oil available from conventional sources.

If a domestic shale-oil industry is developed, a portion of the fuel products (residual fuel oil and gas) from the refinery could be used to fuel a central station producing electric power. The essential elements of oil-shale surface processing are depicted[86] in Figure 6A.2-9. The remainder of a shale-oil-fired electric-energy system, that is, the electrical transmission and distribution



SCHEMATIC DIAGRAM OF OIL SHALE SURFACE PROCESSING

Figure 6A.2-9

stages, would be similar to other systems as shown in Figure 6A.2-1. The component efficiencies and environmental impacts of both controlled and uncontrolled electric-energy systems using oil (onshore and offshore, domestic and imported) and natural gas are outlined in ref. 2 (pp. 46-54).

6A.2.3.1.2 Historical Aspects and Status

Of the eight oil shale industries developed over the past 100 years, only those in the Soviet Union and in mainland China are in existence today. Brazil currently has an experimental oil shale plant operating at a maximum rate of 2500 tons/day. The maximum shale throughputs attained in industries of the past are listed in Table 6A.2-14, which has been developed from Prien's historical review.[87] Depletion of the deposit forced closure of an operation in South Africa; in the other nations, the industries were discontinued for economic reasons when relatively inexpensive imported petroleum became widely available.

Table 6A.2-14

OIL SHALE INDUSTRIES OF THE PAST

Nation	Period of Operation	Peak Shale Throughput (tons/year)
South Africa	1935-1962	~250,000
Australia	1940-1952	350,000 (1947)
France	Until 1957	500,000 (1950)
Spain	Until 1966	1,000,000 (late 1950's)
Sweden	1940-1966	~2,000,000
Scotland	1862-1962	3,300,000 (1913)

Since the Soviet oil shale industry is one of the largest current users of this energy resource, an examination of its history and status is of interest. Of the 1971 Soviet production of about 24 million tons of oil shale, 77% was mined in the Estonian S.S.R., where significant production of the rich kukersite shales began in the 1920's. The Soviet industry is estimated to have mined shale at an average annual rate of 13 million tons/year during the period 1945 to 1970. The primary production in the past has been from 15 underground mines, but large, new open-pit mines with capacities to 9 million tons/year have been opened or approved; in a few years open-pit mining will probably account for nearly half the total Soviet shale production, which is scheduled to increase to 30 to 35 million tons/year by 1975.[87]

About 60% of the shale mined has been burned directly for power generation in pulverized-shale boilers with capacities to 1625 MWe (the Baltic Thermal Power Station at Narva). Because of the high kerogen content (double to triple that of U.S. shales), the heating value of the solid fuel shale has been, since 1965, about 5800 Btu/lb.[87] However, about 40 wt % of the shale fed appears as stack-gas fly ash; and because the dust collectors have not operated efficiently, an "almost insurmountable air pollution problem has been created in the Estonian oil shale area."[87] To minimize this problem, the cleaner route of burning ash-free liquid and gaseous hydrocarbons from retorted shale is being considered.

The remaining 40% of Soviet oil shale mined is retorted to produce crude naphtha, petrochemical feedstocks, specialty products, and heating gas. The fuel gas, with an average heating value of 450 Btu/ft^3, is produced in Estonia at a rate of 35 to 37 billion ft^3/year.[85,87] Two complexes, each to process 16 million tons of raw shale per year, were proposed in 1970 to generate electrical power and to produce chemicals. The current status of the proposals is unknown.

The nation processing the most oil shale is the People's Republic of China, in which production has been continuous since the 1920's. In 1970, 40 to 50 million tons of shale were processed, primarily in Manchuria, where crude shale oil production has increased from 3600 bbl/day during World War II[85] to perhaps 60,000 bbl/day in 1971.[87] Little more is known about the Chinese shale industry, but indications are that it is still expanding.

In the United States, no major shale-oil operation has yet been conducted, and views have been expressed[85,88] that Federal Government policies have discouraged adequate development and/or that it has been deliberately retarded by major petroleum company interests.[88] About 80% of the oil-shale lands are Federally owned and have been closed to leasing since 1930,[85] although one lease was made available in the 1960's; two bids were submitted, but both were rejected. The numerous and extraordinarily entangled technical, economic, political, legal, and institutional factors that have contributed to domestic shale lands remaining virtually untouched over the past 50 years have been addressed by Welles.[88]

Prien[87] rejects this obstructionist rationale and cites ample supplies of inexpensive petroleum products, the lack of a National energy policy, and uncertainties regarding shale-oil costs and environmental restraints as factors that explain the absence of a U.S. oil shale industry. Prien concluded in 1971, however, that "recent improvements in technology have reduced U.S. shale oil costs to the point where they are already more than competitive with new domestic petroleum."[87] A Final Environmental Statement on the Prototype Oil Shale Leasing Program for private development of up to six parcels of public oil shale lands has been released,[89] and the leasing of these Government lands has begun. Bidding on the first tract was completed in January 1974; the highest bid of $210,000,000 was submitted by Gulf Oil and Standard Oil of Indiana. The second tract received a high bid of $117,700,000 from The Oil Shale Corporation (TOSCO), Atlantic Richfield, Ashland Oil, and Shell Oil Company groups. The leasing program's goal, following development of a prototype industry with a capacity of about 250,000 bbl/day, is a mature industry producing 1,000,000 bbl of shale oil per day by 1985.

6A.2.3.1.3 Qualitative Overview of Relative Merits

Attractive features of oil shale include minimal exploration costs as compared with crude-oil production and a slightly higher hydrogen-to-carbon ratio than Canadian tar sands.[8,77] Compared with processes for deriving oil from coal, oil-shale processes are simpler[4] and at a more advanced stage of development,[52] and there is less apparent need to develop technically sophisticated methods for syncrude production. Because oil-shale beds are much thicker than coal seams, oil-shale mining would affect less acreage than mined coal with an equivalent energy content.[90] Raw oil from shale is relatively low in sulfur[90] (typically 0.7 to 0.8 wt %)[86] and extensive desulfurization would not be required. Advocates[88] have claimed that oil from shale could be produced at a much lower cost than oil from coal. Other estimates[4] do not support this claim, though some[52] indicate a significant advantage for syncrude from relatively rich oil shale. If in-situ (underground) retorting of oil shale is successfully developed, the difficult spent-shale disposal problem would be largely avoided; production costs would likely be less; and, compared with surface retorting, the oils produced would contain smaller quantities of heavy fractions and they should be more amenable to further processing.[91]

On the other hand, rich oil shale is not nearly as widely distributed across the Nation as coal. Total process water requirements seem rather uncertain, with the forecasts varying from 1.42 barrels to 4.50 barrels of water per barrel of shale oil.[92] Though the sulfur content of crude shale oil is low, the nitrogen content is relatively high, averaging about 2 wt %.[86] Techniques for economically mining oil shale at high rates are less developed than those for coal; open-pit mining of deep, thick beds, for example, has not yet been demonstrated.[4] In-situ processing of oil shale[4,85] will require the use of naturally occurring or artificially created permeability underground so that circulating gases can retort the shale in place. The spent shale from surface retorting amounts to 80 to 90 wt % of that processed;[4,87,93,94] and because the volume of spent shale, if uncompacted, is about 50% greater than that of the in-place shale and about 15% greater even after compaction,[86,90] a massive solids-disposal problem results. In addition, the oil yield from U.S. shale, in terms of barrels per ton of solid processed, is only about one-third of that obtainable from coal.

6A.2.3.2 Extent of energy resource

Though oil shale occurs in 30 states,[88] the richest deposits are concentrated in the Green River formation in Colorado, Utah, and Wyoming. On a basis of estimated total oil in place, the 1.8×10^{12} bbl in this formation[95] represent 82% of the 2.2×10^{12} bbl in the U.S.[85] The Green River formation (Eocene in geologic age) underlies about 25,000 sq miles of semiarid, sparsely populated land, at an elevation of 5000 to 8000 ft. Of this area, about two-thirds is thought to be commercially developable in the foreseeable future.[95] The richest regions in the formation are in the Piceance Creek (Colorado), Uinta (Utah), and Green River (Wyoming) basins.

In places, the formation is up to 1800 to 3500 ft thick, under an overburden of 1000 to 3000 ft.[88] Though yields vary from insignificant volumes to about 105 gal (2-1/2 bbl) of oil per ton of shale,[88] the usual range in the more commercially interesting regions is 15 to 35 gal of raw oil per ton of shale,[96] and a ton of shale yielding 33 gal of raw oil is considered relatively rich.[4] In the central portion of the Piceance basin, a 2000-ft bed that underlies about 1000 to 2000 ft of barren overburden should produce an average of 25 gal (0.6 bbl) of oil per ton of shale.[85]

Approximately one-third of the Green River formation oil, or about 600 billion bbl, is in beds at least 10 ft thick that assay 0.6 bbl or more per ton of shale,[95] an amount about two-thirds larger than the 1972 proved Middle East oil reserves of 355×10^9 bbl.[83] If 5% of the Green River formation proves suitable for near-term development, the equivalent shale oil reserve of 90×10^9 bbl would exceed twice the currently proved U.S. liquid petroleum reserve of about 39×10^9 bbl.[90] This vast quantity of oil could substantially ameliorate the national energy situation.

Since current technology has not yet been utilized on a commercial scale, estimates of future availability using advanced technology would be extremely uncertain.

6A.2.3.3 Technical Description

6A.2.3.3.1 Power Generation Plant

Residual fuel oil and gas from a shale-oil refinery would be burned in standard radiant-type boilers to generate steam to drive a condensing turbine-generator set. The power plant characteristics would be essentially identical to those of current oil-and gas-fired units.[97] Standard provisions would probably be made for meeting peak power and emergency services requirements, that is, pumped-storage installations, diesel engine-generator units, and gas-turbine-driven generators. The combined gas-turbine-steam cycle described in Section 6A.2.1.3.1 would be a probable future variation.

6A.2.3.3.2 Fuel Cycle

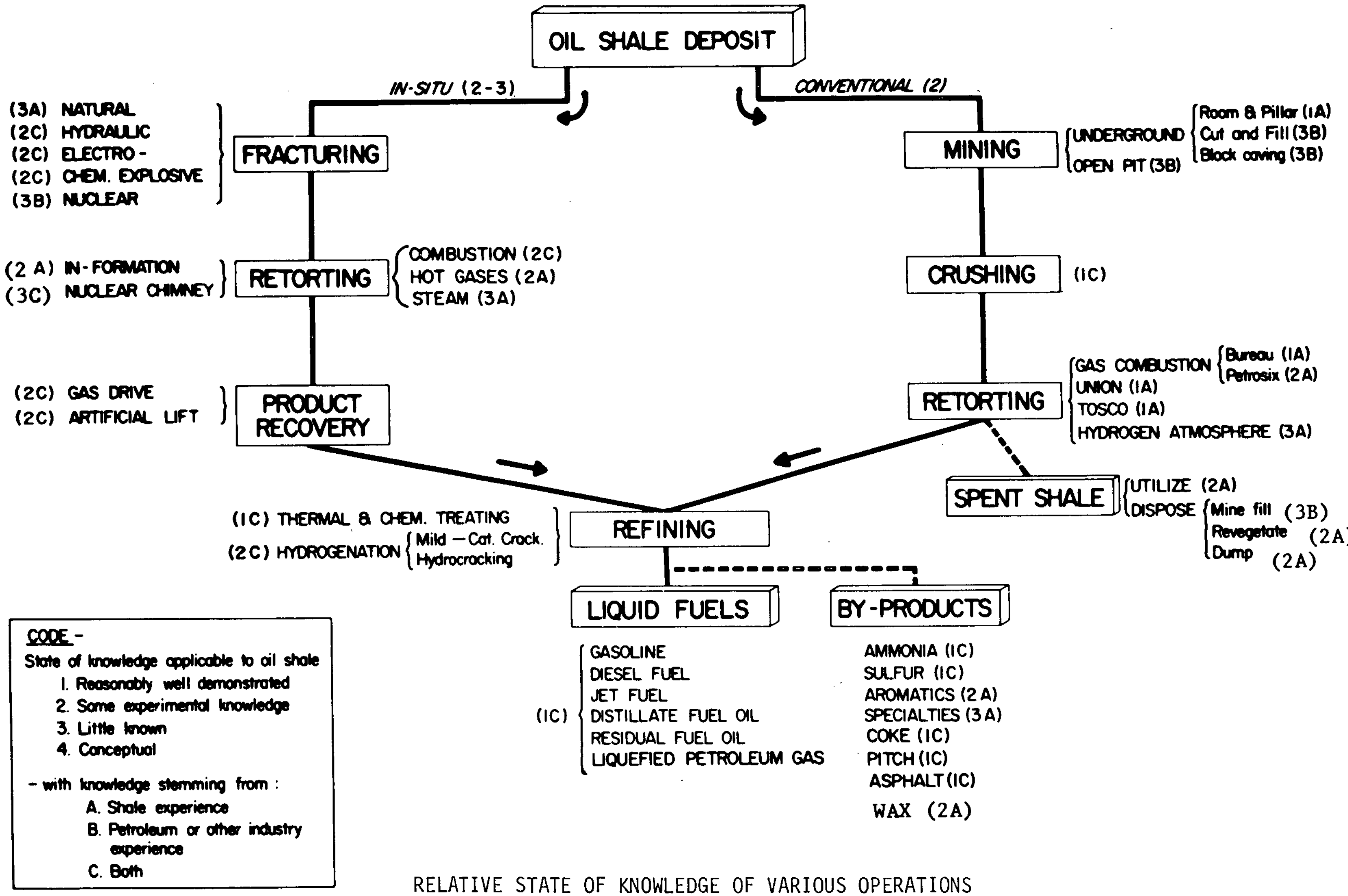
The relative state-of-the-art for the various operations involved in oil-shale processing is shown in Figure 6A.2-10. This figure, as well as the others in Section 6A.2.3, was taken from ref. 86.

Mining, Transportation, Preparation, Retorting, and Refining

Mining costs are expected to constitute a major fraction (perhaps 50%)[87] of the total cost of shale-oil production. For thin, shallow seams, room-and-pillar deep mining has been demonstrated.[4,86] Shale from thick, deep beds would probably be extracted by open-pit mining or with the "cut and fill" technique, in which continuous cutters remove the shale in horizontal layers and a portion (possibly two-thirds) of the spent shale is recycled for floor material on which to operate as higher shale levels are reached.

Only recently has an appreciable effort been devoted to the in-situ approach. There are a number of ways in which access to the shale can be achieved, heat can be supplied for retorting the shale, and the products can be recovered. However, so far only one--a combined mining and collapse technique to prepare the shale for retorting followed by combustion with air to supply the required heat--has been successfully demonstrated in an operation of sufficient size to indicate the possibility of near-term commercial application.

In an underground mine system, the shale after transportation to ground level, probably by conveyor belt, would be crushed and fed to a retort. Of the many surface retorting processes that have been proposed, only three have been developed in the U.S. to a significant extent and operated at a scale (maximum rates of 360 to 1200 tons of shale per day)[87] that permits realistic evaluation. In addition,



RELATIVE STATE OF KNOWLEDGE OF VARIOUS OPERATIONS
REQUIRED IN OIL SHALE PROCESSING

Figure 6A.2-10

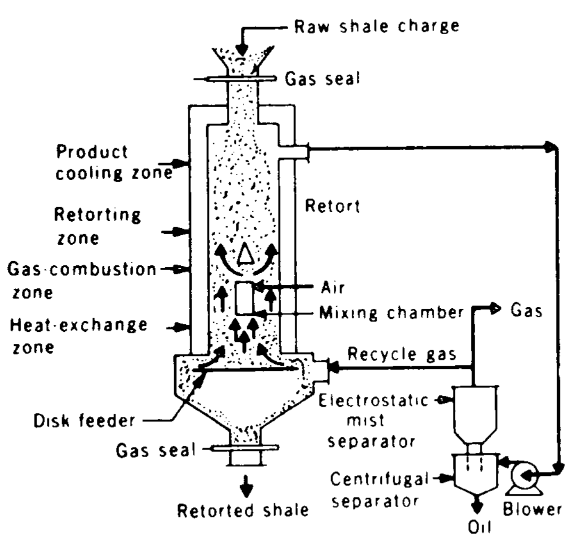
another system, the Petrosix process, has been operated at a 2500-ton/day rate in Brazil. The three U.S. systems (Bureau of Mines' Gas Combustion, Union Oil, and TOSCO II) are characterized by retorting-zone temperatures of about 900(±50)°F[4,88] and local temperatures as high as about 2200°F. These three retorting processes are shown schematically in Figure 6A.2-11.[86] Extraction efficiencies, defined as percent of Fischer assay of the feed, have varied from 90 to 105%.[4] Interior Department estimates are usually based on an upgraded oil yield of 90(±5) vol %, based on in-place crude shale-oil potential.[86]

The kerogen distills into about 66 wt % shale oil (usually a vapor initially), 25% coke-like solid, and 9% combustible gas containing some hydrogen sulfide.[88] The retort off-gas, which has a heating value of about 100 Btu/standard cubic foot, is usually recycled and burned to generate additional heat for retorting.[85] To prevent coking or clinkering and to optimize yields, some degree of temperature control is required in the preheating, combustion, retorting, and cooling zones of the retort chamber.

The raw oil--a dark, viscous liquid--would normally be upgraded, if destined for feedstock use, to reduce the viscosity and the dust, wax, nitrogen, and sulfur contents.[4] Refining would follow standard petroleum industry practice to yield low-sulfur liquid fuels and by-products such as ammonia, sulfur, coke, pitch, asphalt, and aromatic chemicals. Hydrogenation at 400 to 1500 psi, which reduces sulfur to hydrogen sulfide and nitrogen to ammonia, gives a desulfurized product representing about 98 wt % of the raw shale oil.[85] The processing described increases the heating value of the shale as rock (about 2600 Btu/lb for Colorado shale)[85] to about 5.8 x 10^6 Btu/bbl (about 18,000 Btu/lb) for product oil.[10] The shale can also be hydrogasified, which converts the kerogen to a methane-rich, >930-Btu/ft^3 gas by reaction with hydrogen at pressures of 1200 to 2000 psi and temperatures of 1000 to 1500°F.[85,87]

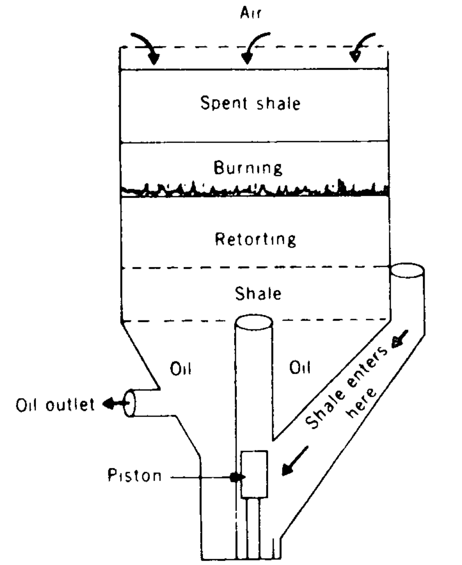
Waste Processing and Disposal

A 100,000-bbl/day oil plant would require the surface processing and disposal of about 45,000,000[16] to 60,000,000[20] tons of shale per year. For the same oil production, a plant processing tar sands would require about 70,000,000 tons of tar sand per year,[16] whereas a coal liquefaction plant would require only about 13,000,000 tons of coal input per year. Though some of the spent shale ash might be used to make cement, cellular building block, rock wool, and mortar, as in Estonia,[85] very large tailing volumes per unit of oil production would have to be disposed of by recycle to the mine, surface layer compaction, or disposal in nearby canyons.



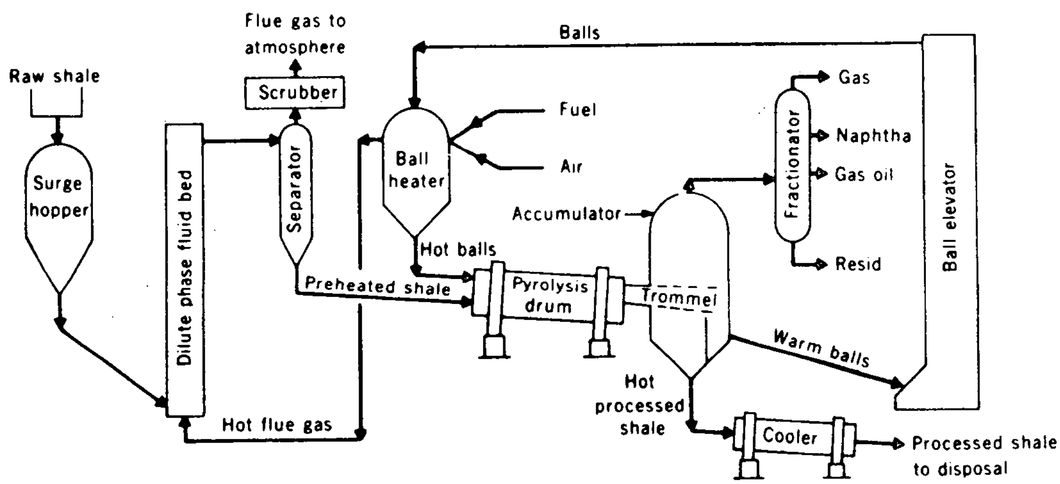
GAS-COMBUSTION RETORT

Recycle gas is mixed with air and burned within the retort. Gases flow upward and shale moves downward.



UNION OIL RETORT

Shale is introduced near bottom of retort and forced upward. Air enters at the top and flows downward.



TOSCO RETORT

Ceramic balls transfer heat to the shale. No combustion takes place in retort.

SCHEMATIC REPRESENTATIONS OF THREE OIL SHALE RETORTING PROCESSES

Figure 6A.2-11

For the reference 1000-MWe power plant of Figure 6A.2-8, the approximate annual requirements of oil shale, tar sand, and coal and the associated solid wastes would be those listed in Table 6A.2-15. The estimates do not include overburden solids.

Table 6A.2-15

APPROXIMATE ANNUAL TONNAGES OF SOLIDS PROCESSED AND OF ASSOCIATED SOLID WASTES FOR A 1000-MWe POWER PLANT[a]

Fuel source	Solids Processed (tons/year)	Solid Waste (tons/year)
Oil Shale[b]	13×10^6	11×10^6
Tar Sand[c]	15×10^6	13×10^6
Coal		
Direct Combustion	3×10^6	0.5×10^6
Solvent Refined Coal	4×10^6	1.5×10^6
Fuel Oil from H-Coal Process[d]	6×10^6	0.8×10^6

[a]The reference power plant of Figure 6A.2-8.

[b]Yield: 0.8 bbl of oil per ton of shale.

[c]Yield: 0.7 bbl of oil per ton of tar sand.

[d]Using light gas oil and heavier fractions as boiler feed (boiling point $\geq$400°F).

6A.2.3.3.3 Energy Transmission

The comments made in Section 6A.2.1.3.3 are applicable, except that caloric oils and gases would, in this case, be derived from oil shale rather than from coal.

6A.2.3.4 Research and Development Program

Areas worthy of research and development include new mining and ore-handling techniques; separation and utilization of associated saline minerals such as trona (sodium carbonate/sodium bicarbonate), dawsonite (sodium aluminum dihydroxy carbonate), and nahcolite (sodium bicarbonate); spent shale disposal and revegetation techniques; and fundamental heat transfer and fluid dynamics studies of gas flow through retorts with fixed and moving beds of crushed shale. To eliminate or minimize the spent-shale solids handling problem, research and development should be focused primarily on in-situ retorting and on the prefracturing by hydraulic pressurization (or chemical explosives) required to increase the shale porosity to allow adequate fluid flow between hot gas injection wells and nearby producing wells. The recent report on "The Nation's Energy Future"[31] discusses a five-year research program to increase the projected production of synthetic petroleum from oil shale by developing and demonstrating methods for processing oil shale in-situ to recover liquid products. In-situ retorting would be tested in the Rocky Mountain basins using a combination of several different fracturing techniques and retorting conditions. The recovery rates for each combination and the control problems encountered would be studied to determine optimum technical design.

6A.2.3.5 Present and Projected Application

The Interior Department recently issued a 3200-page, six-volume Final Environmental Statement for a proposed prototype oil shale leasing program;[10,86,89] the Statement describes a six-tract stepwise program for initial development of the Green River formation. Estimates show that about 5% of the 1.8×10^{12} bbl of oil in place is suitable for near-term development. A prototype program aimed at production of 250,000 bbl/day would require about 13,000 acres of land over a 30-year period, with initial oil costs in the range of \$3 to \$4 per barrel. An extended development producing 1,000,000 bbl/day would require about 80,000 acres of land, and the projected oil production costs are about \$2.25 to \$3 per barrel. The larger production capacity, utilizing both public and private lands and assuming introduction of second-generation extraction/retorting systems and possible initiation of commercial-scale in-situ retorting by the early 1980's, is thought by the Interior Department to be attainable by 1985. Other estimates place the probable 1985 production of shale oil at 300,000,[52] 400,000,[96] and 500,000[21] bbl/day. Production of 1,000,000 bbl/day would represent only 4% of the projected national crude-oil requirement for 1985.[79]

Water availability will probably set the upper limit to the size of industry that the region can sustain, and further increases in production would depend on technological improvements to reduce consumptive water requirements. Long-term (year 2000) upper limits to shale-oil production that have been suggested generally span the range of 3×10^6 bbl/day[52] to 5×10^6 bbl/day.[94]

6A.2.3.6 Environmental Impacts

The environmental impacts caused by both controlled and uncontrolled energy conversion plants using oil and gas are described in refs. 97 and 98.

Environmental impacts caused by offsite support activities and facilities (mining, retorting, upgrading, and refining, for example) are described in considerable detail in the Interior Department's Final Environmental Statement. Because the land area involved in the prototype oil shale leasing program is relatively small and distributed among six designated tracts, two in each of three adjacent states, the site-specific features of the impacts could be included in the Statement and are treated in some depth. The effects on the regional environment include those on land, water, air, and flora and fauna. Aesthetic, recreational, cultural, economic, and social impacts are also considered.

Other than the spent-shale waste disposal problem, the major physical impacts are runoff water pollution and water usage. Sodium and calcium salts leached from spent-shale waste piles by melted snow and summer showers could enter surface water and lower its quality. This effect would presumably be mitigated by leveling, compacting, and replanting the refuse piles. Process gases are not expected to be a major physical impact, since they are amenable to standard gas-treating methods developed for other industries.[91] Critical barriers are not foreseen in these areas,[94] but adequate definition and solution of such problems will require a continuing effort.

Water-requirement estimates for processing--including mining and crushing, retorting, oil upgrading, processed-shale disposal, power, revegetation, and sanitation--vary from a minimum of 1.4 to a maximum of 4.5 bbl of water per barrel of shale oil.[92] For a 1 million bbl/day capacity, the most likely water consumption rate has been estimated to be about 3 bbl of water per barrel of shale oil (3.3 as derived from ref. 90 and an average value of 2.9 from ref. 92). For a 1000-MWe, shale-oil-fired power plant, a processing water requirement of 3 bbl per barrel of oil would correspond to about 1.3×10^9 gal of water per year.

The best current estimates of irreversible and irretrievable commitments of resources are in the Interior Department's 1973 Final Environmental Statement (vols. I and III). These estimates include essentially permanent dedication of land surface to extraction, processing, and waste disposal; surface disruption not fully reclaimable; and regional disturbances of ecological balances.

6A.2.3.7 Costs and Benefits

6A.2.3.7.1 Shale oil costs

The costs and benefits of oil from shale in the electrical energy sector seem quite uncertain, since so little experience has been accumulated in the United States in developing this resource on a large scale. Recent estimates of future production costs of shale oil are given in Section 6A.2.3.5. A 1968 Soviet estimate of $2.85 per barrel has been cited.[87] In June 1971, The Oil Shale Corporation (TOSCO) announced an estimated cost of $1.95 per barrel at the plant gate,[87] including "all environmental protection systems, the recovery of by-products, inflation through 1974, and depreciation...," for a 66,000-ton/day plant processing shale assaying 0.86 bbl of oil per ton and producing 53,000 bbl/day of premium (upgraded) shale crude, which in turn was estimated to have a market value of $4.15 per barrel (including $0.20 per barrel by-product credits). Prien estimates that environmental protection costs for a new shale industry (one not requiring more expensive retrofit measures) will be about 6% of the production cost.[87]

In view of current and anticipated petroleum costs, shale oil at the estimated production costs would be "more than competitive."[87]

6A.2.3.7.2 Development Costs

To attain a significant production level by the mid- to late 1980's might require a development cost, through 1980, of approximately $200 million. This sum would be spent primarily for development of fracturing technology and in-situ retorting but would include amounts for improving surface processing and assessing more accurately the rich oil shale resource. The five-year research and development program discussed in ref. 31 and summarized in Section 6A.2.3.4 would cost $133 million for investigation of oil-shale mining techniques, in-situ combustion, assessment of resources, and improved environmental control of shale processing.

6A.2.3.7.3 Benefits

The major benefit of developing an oil-shale industry would probably be its ability to supplement available supplies of motor fuels and petrochemical feed stocks. This complementing of conventional domestic fuel supplies would also reduce dependence on imports, thereby improving the Nation's balance of payments position. The prospect of using shale oil fractions as fuel for significant electrical power generation, except for limited use by some western utilities, seems small.

6A.2.3.8 Overall Assessment of Role in Energy Supply

6A.2.3.8.1 Probable Role Up to the Year 2000

To the year 2000, successful development of the technology to extract oil from shale would make an appreciable contribution toward alleviating, though by no means eliminating, the Nation's shortage of domestic oil. It is unlikely to play a significant role in electrical power production.

6A.2.3.8.2 Probable Role After the Year 2000

Beyond the year 2000, fuels from oil shale probably will contribute a declining portion of the total energy requirement as other energy systems grow in importance.

6A.2.4 Other Fossil Fuels--Domestic Tar Sands

Tar sands, also known as oil sands and bituminous sands, are rocks whose interstices contain viscous to semisolid to solid hydrocarbon material which in its natural state is not recoverable by primary (i.e., conventional) crude-oil production techniques. The rock types range from consolidated and unconsolidated sandstone to shale, dolomite, limestone, and conglomerate.[94] The nonfluid bitumen (tar) content may be as high as 25 wt %[99] but is usually considerably lower, and a deposit with 14% or more bitumen is considered rich.[4,77]

Until 1967, only four of the world's major tar sand deposits had been exploited--LaBrea (Trinidad), Selenizza (Albania), Derna (Romania), and Cheildag (U.S.S.R.)--and none on a large commercial scale.[100] The first major venture for producing synthetic crude from tar sands was begun that year by Great Canadian Oil Sands, Ltd., in the Athabasca area in the northeastern part of the Province of Alberta, Canada. The Athabascan deposit, which contains approximately 700 billion bbl of bitumen, is the world's largest,[100,101] and the only other really sizable deposits occur in eastern Venezuela in the Orinoco Tar Belt and in the Llanos area of Colombia.[102] The South American deposits, each estimated to contain in excess of 500 billion bbl of in-place tar, have not been defined or validated to the same degree as those in Alberta.[102]

Tar sands in the United States are not comparable to those of Canada in extent. The maximum estimates of in-place resource are in the range of 27 to 29 billion bbl of bitumen.[99,102,103] Of this total, estimates of the proved and currently recoverable reserve in surface and near-surface deposits amenable to known mining methods vary from a minimum of ~1 billion bbl[77,78,104] to a maximum of ~5 billion bbl.[105] The higher estimate is based on unverified reserve estimates for seven states available in the literature in 1964.

At least 95% of the estimated U.S. resource is located in Utah in five major deposits;[99,103] and the state with the second largest resource base, California, contains only ~1% of the national total.[99]

Descriptions of the extraction and processing techniques currently used in Canada are widely available.[101,106] In brief, track-mounted bucket-wheel excavators strip the surface sands to a proposed depth of about 150 ft and transfer them to a conveyor belt feeding a hot-water extraction plant. About 3.5 tons of sand and overburden must be moved for each barrel of syncrude produced.[102] The separated crude bitumen is upgraded to a synthetic crude suitable for standard refining operations by hydrogen enrichment either by coking and hydrogenation of the coker distillates or by hydrovisbreaking followed by hydrogenation of the visbreaker distillates.[4,102] Based on the proven Athabascan-field recoverable reserve, to a depth of 150 ft, of 74 billion bbl of crude bitumen, an extraction efficiency of ~51%, and a combined efficiency for bitumen separation and conversion to syncrude of 70%, Great Canadian Oil Sands anticipates a potential recovery of ~27 billion bbl of syncrude.[106] Total Canadian production of syncrude from all operations is expected to attain ~800,000 bbl/day by 1985 and ultimately to reach a level of perhaps 3 million bbl/day.[106]

Several factors are likely to deter significant production of syncrude from domestic tar sands:

(1) Reserves of domestic coal and oil shale are much larger, as are their oil yields.
(2) The Utah sands are believed to be harder (more consolidated) and therefore more difficult to utilize than those of Alberta.
(3) Average overburdens are thicker in Utah than in Alberta, which sharply limits large-scale surface mining and would require the successful development of in-situ recovery methods usable on a commercial scale. Estimated bitumen recovery efficiencies by in-situ techniques such as steam-emulsion drive or "fire-flooding" are significantly lower than those for surface extraction.[102]
(4) Most of the Utah deposits underlie Federal lands and appropriate leasing arrangements would be necessary. In addition, public-use proposals have already been made for much of the subject surface area in Utah.
(5) Water supplies may be insufficient for significant exploitation.

The role of syncrude from domestic tar sands in the future U.S. energy supply seems at best a minor one. Assuming 4 billion bbl as the proved in-place reserve and using the recovery factors estimated for the Athabasca field, syncrude production would total 1.43 billion bbl which, over a 15-year period, would correspond to an average output of only 260,000 bbl/day. Summarized assessments of others include "not significant,"[78] "little incentive to develop the deposits in the near future,"[99] significant production improbable before 1985,[103] and "unlikely that such deposits will significantly affect the total U.S. energy supply... even to the year 2000."[102]

Canadian deposits will be the primary and probably the only North American source of tar-sand oil until at least 1985,[99,102] and negotiations to provide the U.S. with a share of this resource have been recommended.[107]

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6A.3 HYDROELECTRIC POWER SYSTEMS

6A.3.1 Introduction

6A.3.1.1 General Description

Hydroelectric generating systems are conceptually simple. Water is directed into a hydraulic turbine, where it impinges on the blades or buckets of a waterwheel, as Figure 6A.3-1 illustrates. The energy associated with the flow of the water causes the wheel to rotate and is thus transferred through a rotating output shaft to an electric generator.

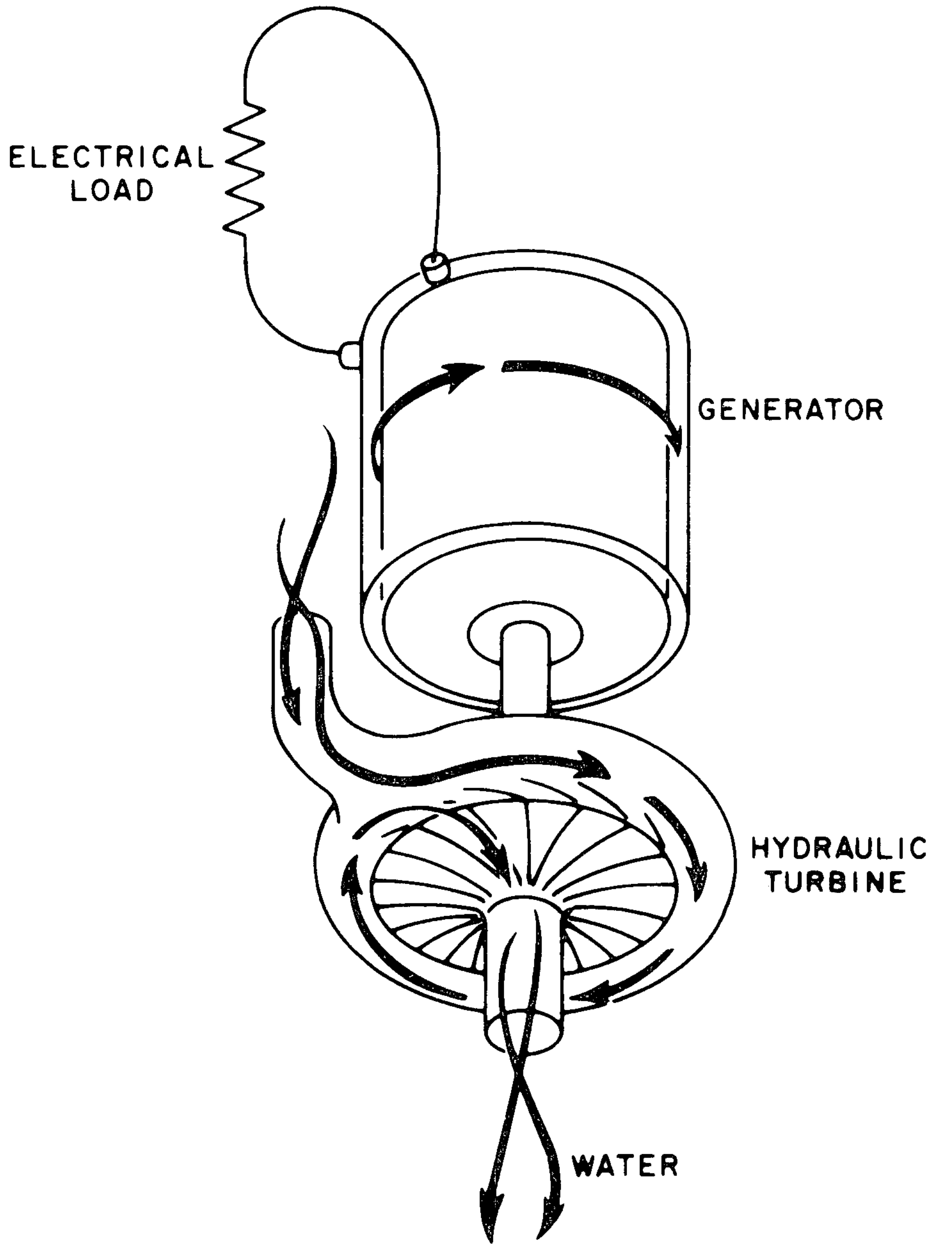
In most hydroelectric installations, large dams are built to store water in reservoirs; the dams provide control of the hydraulic head (the difference in elevation between the upstream and downstream water levels) and of the flow rate through the turbines. In this way, the available head can be localized at the dam, and water can be used as required and at an instantaneous flow rate through the turbines which can differ from the normal flow of the river.

An extension of this technique is the pumped-storage concept. During periods of low power demand and where power from other sources is available, the turbine-generator is used as a motor-pump to pump water up into a reservoir for release to the turbines during periods of greater electrical power demand. By use of low-flow rivers or lakes as the original water supply, pumped-storage plants can be located in areas unsuitable for conventional hydroelectric plants.

6A.3.1.2 History

The generation of electrical power from water power in the United States occurred first on the Fox River in Wisconsin in 1882. The rapid expansion of hydroelectric power generation after 1910 is credited as being one of the most striking engineering accomplishments of the first half of the twentieth century.

Most early hydroelectric plants were used to satisfy baseload electrical needs. About 30 years ago, hydroelectric power constituted 30% of the United States electrical capacity and supplied 40% of the electrical energy.[1] Although the absolute capacity of hydro plants has continued to expand, hydroelectric's fraction of total electrical capacity is declining, and the trend is to use the hydro plants as peaking units.



SCHEMATIC OF A HYDROELECTRIC GENERATING SYSTEM

Figure 6A.3-1

6A.3.1.3 Status

As of January 1971, the total installed conventional hydroelectric power was 51,900 MWe, which was about 15% of the total United States generating capacity.[2] About 46% of the conventional hydroelectric capacity is in the Pacific Coast States of Washington, Oregon, and California.[3] The Columbia River Basin alone provides 33% of the total United States hydroelectric capacity.

Despite the continuing increase in total conventional hydroelectric capacity, the number of active hydroelectric plants is actually decreasing. Many older plants with small capacities are being retired. The new plants tend to be of large capacity. The largest hydroelectric generating station in the United States is the John Day Dam, built by the Corps of Engineers on the Columbia River. The 2272-MWe plant went into operation in 1972 and has 16 hydroelectric generator units, each rated at 142 MWe.

Another significant trend in hydroelectric power is the increasing importance of pumped-storage plants.[3] The first pumped-storage plant, the Rocky River plant in Connecticut, was placed in operation in 1929. By the end of 1966, only nine plants were operating, with a total capacity of about 1500 MWe. At the end of 1970, total pumped-storage generating capacity amounted to about 3700 MWe. About half of this capacity was in the Northeast. California also had a significant share (22%).

6A.3.2 Extent of Energy Resource

From a strictly theoretical viewpoint, the ultimate hydroelectric potential (conventional) is fixed by the average flow of all streams and the change in the elevation of the flow as water moves to the oceans. On this basis, the hydroelectric potential of the United States (excluding Alaska and Hawaii) has been estimated to be as much as 390,000 MWe.[4] In the absence of suitable dam sites and because of constraints imposed by social, economic, and environmental considerations, the ultimate capacity can never be achieved.

The Federal Power Commission (FPC)[2] has estimated the conventional hydroelectric potential of the conterminous United States to be 147,200 MWe and of the 50 states to be 179,900 MWe. These estimates take into consideration probable engineering feasibility but do not consider economic feasibility, environmental constraints, and legislative prohibitions. These latter considerations will substantially reduce the number of developable sites.

The details of the FPC's estimate are shown in Table 6A.3-1. Of the 179,900-MWe potential of the United States, 128,000 MWe remained undeveloped as of December 1970. Of this undeveloped potential, 51% is located in the Pacific and Mountain States, whereas 25% is located in Alaska, far from load centers.

In contrast with conventional hydroelectric sites, pumped-storage sites require little or no streamflow. The availability of pumped-storage sites depends primarily on the existence of topography that permits development of a high head (elevation difference) between two reservoirs in the same area. Although no detailed studies have been made, the FPC staff[3] believes that several hundred potential pumped-storage sites exist.

6A.3.3 Technical Description

The power that can be developed by a hydroelectric generating unit is a product of the available hydraulic head and flow rate. The head, or difference in elevation between the water level upstream of the turbines and the level downstream of their discharge, may be provided by the existence of a natural waterfall but is more frequently created by the construction of a dam. In the United States, Niagara Falls is the only waterfall site that provides major amounts of power. The dams used to create water-supply reservoirs are constructed of earth and rock fill or of reinforced concrete. Water is carried to the turbines by inlet pipes (penstocks) that are constructed of welded steel or concrete or of both. The turbines provide a rotating-shaft output to drive generators. The generators usually produce three-phase, 60-Hz alternating current that can be fed directly to a power grid.

To maintain a steady output of electrical power as the reservoir empties and the available head decreases, larger flow rates must be provided. Generally, hydroelectric sites that have a hydraulic head of less than 30 ft are not economical to develop, but even for low-head cases, potential sites for economic development are limited. Providing 30 ft of head on a river that flows through a flat broad terrain might entail flooding of large areas of land or construction of many miles of levees. Usually, low-head units are justified as multipurpose projects where substantial benefits to navigation and to flood control are obtained by the installation of a dam. In some special situations, sites that provide heads as low as 21 ft have been developed.

Low rotational speeds and the pressure limitation fixed by the available hydraulic head combine to make possible rapid startup and shutdown of hydroelectric units as compared with steam turbine-generators. This ability to start quickly and to

Table 6A.3-1

PRESENT AND POTENTIAL CONVENTIONAL HYDROELECTRIC CAPACITY OF THE UNITED STATES

Geographic region	Potential power (10^3 MW)	Percent of total	Developed capacity (10^3 MW)	Percent developed	Undeveloped (10^3 MW)
New England	4.8	2.7	1.5	31.3	3.3
Middle Atlantic	8.7	4.8	4.2	48.3	4.5
East North Central	2.5	1.4	0.9	36.0	1.6
West North Central	7.1	3.9	2.7	38.0	4.4
South Atlantic	14.8	8.2	5.3	35.8	9.5
East South Central	9.0	5.0	5.2	57.8	3.8
West South Central	5.2	2.9	1.9	36.5	3.3
Mountain	32.9	18.3	6.2	18.8	26.7
Pacific	62.2	34.6	23.9	38.4	38.3
Subtotal (48 states)	147.2	81.8	51.8	28.5	95.4
Alaska	32.6	18.1	0.1	0.3	32.5
Hawaii	0.1	0.1			0.1
Total (50 states)	179.9	100.0	51.9	28.8	128.0

Source: U.S. Department of the Interior, *Final Environmental Statement for the Geothermal Leasing Program*, vol. I, 1973, p. IV-170.

rapidly change power output makes hydroelectric plants particularly well adapted for meeting peak loads and for frequency-control and spinning-reserve duty.

Hydroelectric generating stations are normally very efficient. The efficiency of modern hydraulic turbines in converting the potential energy of the water to shaft work is about 90 to 95% at the design load. The overall efficiency of converting the water's potential energy to electrical power is usually above 80% for conventional hydroelectric plants.

Since conventional hydroelectric plants consume no fuel and are based on the natural water cycle, the resource base is inexhaustible. However, pumped-storage plants are not a primary source of energy because they simply store energy produced by primary sources such as hydroelectric, fossil-, or nuclear-fueled plants. The effect of pumped-storage installations is to reduce the total required capacity of the primary sources. Nevertheless, primary fuel consumption is increased, because pumped-storage units return only about two units of electrical energy for each three units generated by the primary energy plant.

6A.3.4 Research and Development Program

The technology for the components of hydroelectric power stations is well established, and the technical feasibility of a particular project is seldom in question. Even so, refinements in existing technology would be beneficial. Of even greater importance is the need to understand long-term effects on the environment, in particular on fish and on wildlife, and to develop methods of alleviating adverse effects.

Maximal use of the hydroelectric power potential of the United States will require research and development in the following areas:

(1) methods to reduce silting of reservoirs;

(2) improve designs to reduce leakage from reservoirs and, in particular, pumped-storage systems;

(3) improvements in the efficiency and cost of transporting energy generated at remote hydroelectric sites;

(4) improvements in pump-turbine designs for pumped-storage applications;

(5) methods for improving the quality of water released from deep reservoirs;

(6) improved fish-passage systems for anadromous fish (fish that move upstream to spawning grounds); and

(7) improved understanding of effects of reservoir-level changes on aquatic life.

6A.3.5 Projected Application

According to FPC estimates,[2] the conventional hydroelectric power capacity of the conterminous United States will increase from 51,800 MWe in January 1971 to 82,000 MWe in 1990. A major portion (74%) of this projected increase will be in the western United States. Even though an absolute increase is expected, the proportion of total electric capacity attributable to conventional hydroelectric plants will decline from the present 15% to about 7% in 1990.

The largest increase in future hydroelectric capacity is expected to be in pumped storage. The FPC[3] estimates that pumped-storage capacity will increase from the 3700 MWe in 1970 to about 70,000 MWe in 1990. Most of this increase will be in the eastern United States.

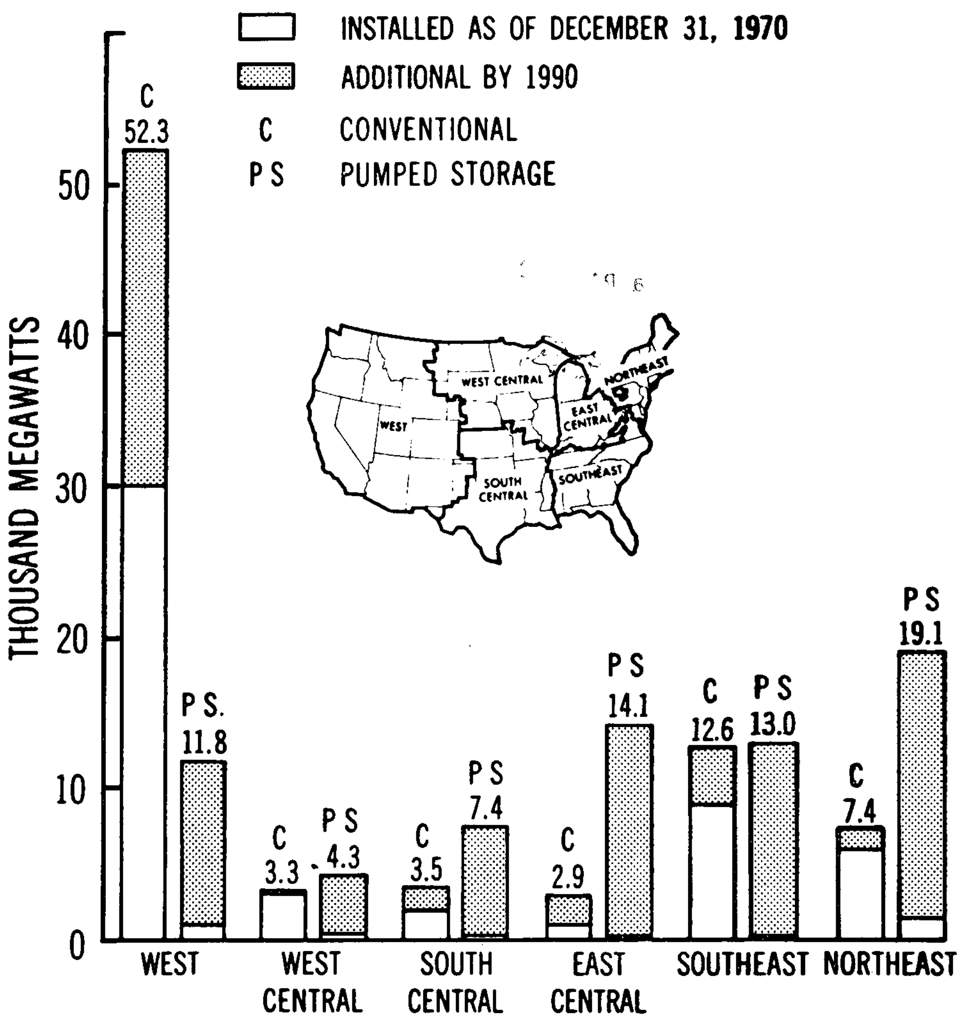
Figure 6A.3-2 summarizes the location and amount of existing and projected hydroelectric capacity.

6A.3.6 Environmental Impacts

The environmental impact of a hydroelectric power project results from: (1) interposition of barriers to upstream and downstream movement of aquatic life forms, suspended materials, and floating objects; (2) flooding of lands by the impounded waters and an increase in water depth above that of the former stream bed; (3) changes in the downstream flow--flow amounts may be changed from their normal daily, seasonal, and long-term patterns, and water composition may be altered; and (4) alteration of the appearance of the site.

Construction of a hydroelectric plant is an irretrievable commitment of the large amount of land area beneath a dam and lake. Lost resources include agricultural land, minerals, wildlife habitat, and recreation on a free-flowing river.

Hydroelectric plants may cause impairment of water quality, especially downstream of the project. At deep reservoirs, water released from the bottom may be extremely



HYDROELECTRIC CAPACITY EXISTING AND PROJECTED TO 1990
(INDUSTRIAL CAPACITY NOT INCLUDED)

Figure 6A.3-2

cold and devoid of oxygen. Even though cold water may benefit cold-water fisheries, such as trout and salmon, warm-water fisheries are adversely affected. Oxygen deficiency would be detrimental to all fish. Another water-quality problem is associated with dissolved nitrogen. At some dams, release of water over spillways causes the water to become supersaturated with nitrogen; high fish mortality results.

By proper design of a reservoir, water-quality impairment can be reduced.[3] The Corps of Engineers is testing several methods of reducing nitrogen supersaturation. The cold-water problem has been alleviated at a number of projects by designs that require the water to be taken from the upper levels of the reservoir to the hydraulic turbines. Oxygen concentration of the water has also been increased at some projects through various aeration techniques.

In addition to water-quality effects, hydroelectric plants may have other detrimental effects on certain species of fish. Although fish-passage facilities may be constructed for the protection of anadromous fish during their runs, the cumulative effect of a series of dams might be to substantially reduce such runs. Apparently, this is the case on the Columbia River.[3] Research is needed to improve fish-passage systems for high dams. Also, wide fluctuations in reservoir levels, which are especially characteristic of pumped-storage systems, could adversely affect the spawning of some fish. Hydroelectric dams also have the potential for hazardous accidents. Many river systems have geologic faults associated with them. Dam failures, while rare, can have catastrophic consequences in those areas where population centers are grouped along the river banks immediately downstream from the dam.[5]

In contrast with water quality, air quality is little affected by the operation of hydroelectric plants.

Not all environmental effects of water impoundment are considered to be detrimental. Lakes behind dams created for hydroelectric purposes provide recreational opportunities such as swimming, camping, and boating. Although running-water fishing may be reduced, the overall fishing opportunity may be greatly expanded. Flood control, irrigation water supply, and water transportation are also positive aspects of some impoundment projects.

The overall results of environmental changes, as they directly or indirectly affect people, depend strongly on the site. Whether the net consequences are beneficial or detrimental often depends on individual viewpoints. Even for those consequences clearly assigned to one category or the other, views will differ as to their importance or significance.

6A.3.7 Costs and Benefits

6A.3.7.1 Internal Costs

On the average, the investment cost per kilowatt for conventional hydroelectric plants can exhibit wide swings that reflect the variations in type, size, and location of project, cost of land, and relocation of existing roads and structures. Investment costs also are affected, to a lesser extent, by changes in labor, materials, engineering, and other factors in construction costs.

The most up-to-date cost information reported by the FPC for conventional hydroelectric plants includes two recently constructed units[6]--one non-Federal, the other Federal. For the non-Federal plant (118 MWe), the investment cost was $391 per kWe; for the Federal (405 MWe), $346 per kWe. The latter cost includes a portion of the cost of facilities, such as the dams and the reservoirs, that are used jointly for power and other purposes. The joint-use costs allocated to power, as well as the cost of all facilities provided specifically for power development, are recovered from power revenues.

Operating expenses per kilowatt-hour are substantially less in hydroelectric than in steam-cycle plants, principally because no fuel costs are associated with hydroelectric plants.

The weighted-average unit cost-of-operating expenses for 20 non-Federal utility hydroelectric systems, as reported by the FPC for 1970 operations, was 0.56 mill/(net kWhr). This cost was made up of 0.35 mill for operations and 0.21 mill for maintenance. For the Tennessee Valley Authority's system of 29 plants, the weighted average unit cost was 0.72 mill/kWhr, of which operation cost was 0.48 mill and maintenance cost was 0.24 mill.

Pumped-storage hydroelectric plants, as opposed to conventional hydroelectric units, are selected on the basis of low first cost and the ability to use low-cost off-peak pumping energy to generate high-value peaking energy. Costs of development depend largely on site topography and geological conditions. Reservoirs, dams, waterways, pump-turbines, and motor-generators account for about 70 to 75% of the total fixed costs.

At the end of 1970, seven pumped-storage installations combined with conventional hydroelectric developments and nine recirculating-type or "pure" pumped-storage projects were in operation, but operating-cost data were not available for these units. Limited information indicates that economically attractive pumped-storage projects will have a cost range of $75 to $125 per kWe.

6A.3.7.2 External Costs

A number of external costs are involved in the development of hydroelectric power plants. The presence of large dams has a major impact on site ecology, both upstream and downstream. Interference with normal river flow often alters water quality and temperature. An environmental argument against the further development of hydroelectric potential is made by those who are concerned about the shrinking wilderness area in the United States. The enormous land area required for the reservoir makes a major dam economically possible only in unsettled regions. The question becomes one of whether or not a significant fraction of our remaining wilderness, which is irreplaceable, should be given up for an increase in capacity to generate electrical energy.

6A.3.7.3 Benefits

The major benefit from hydroelectric plants is electricity, but reservoirs are also valuable for recreation and flood control. Hydroelectric generating plants can be started and stopped quickly; thus, they have the capacity to adjust rapidly to power-demand fluctuations. In addition, hydroelectric plants are essentially pollution-free relative to their effects on air quality, and they have no fuel-cycle wastes.

6A.3.8 Overall Assessment of Role in Energy Supply

Hydroelectric power is an important component of the electric-energy-generating system. Nevertheless, the percentage of total capacity is declining, and this trend will continue. Primary use in the future will be to meet peaking requirements. By 1990, conventional hydroelectic capacity will be no more than 7% of total need. Thus, the available hydroelectric power will not alter the need to develop alternative energy systems.

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6A.4 GEOTHERMAL ENERGY

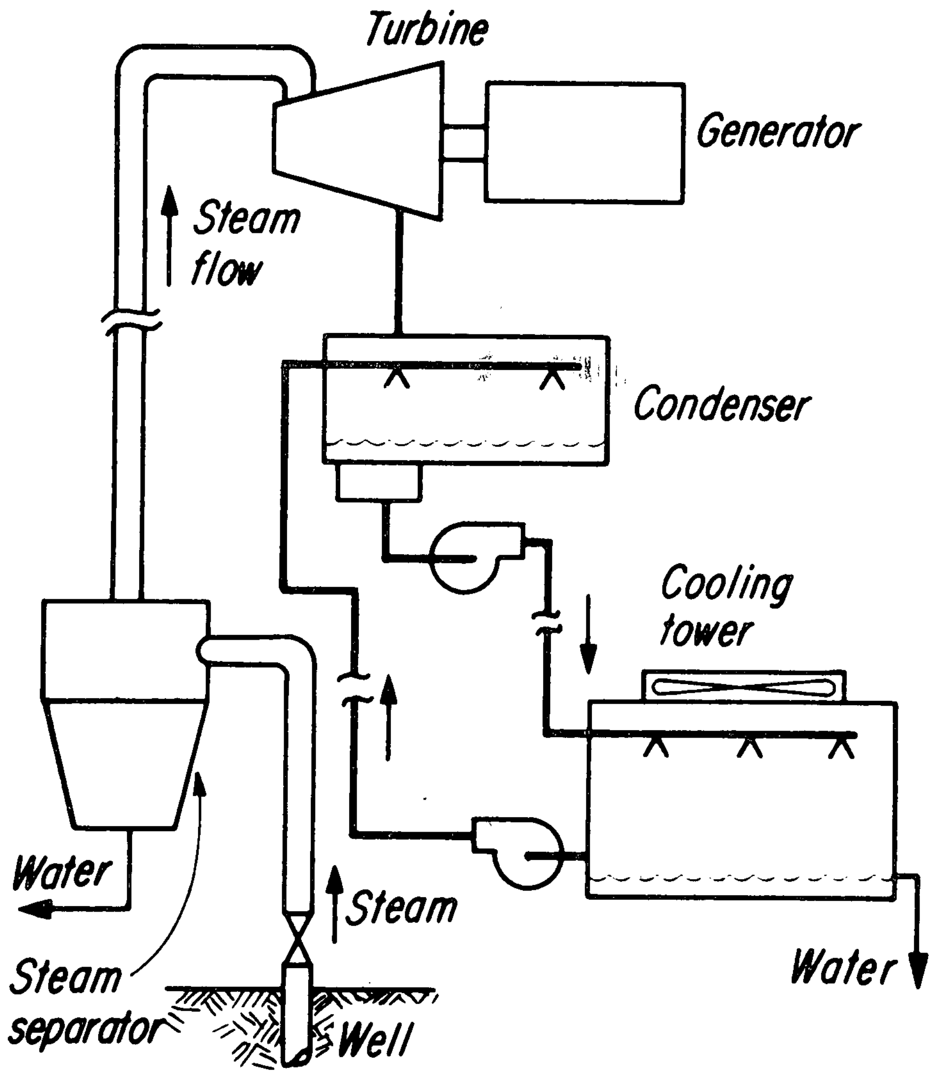
6A.4.1 Introduction

6A.4.1.1 General Description

The temperature of the earth increases with increasing depth, and except for a very thin crust the earth is extremely hot. Consequently, the interior of the earth is a vast energy reservoir that could be tapped for human uses such as space heating, industrial processing, and electricity generation. Figure 6A.4-1 is a schematic of a typical geothermal power plant. In this example, geothermal steam is used to drive a turbo-generator.

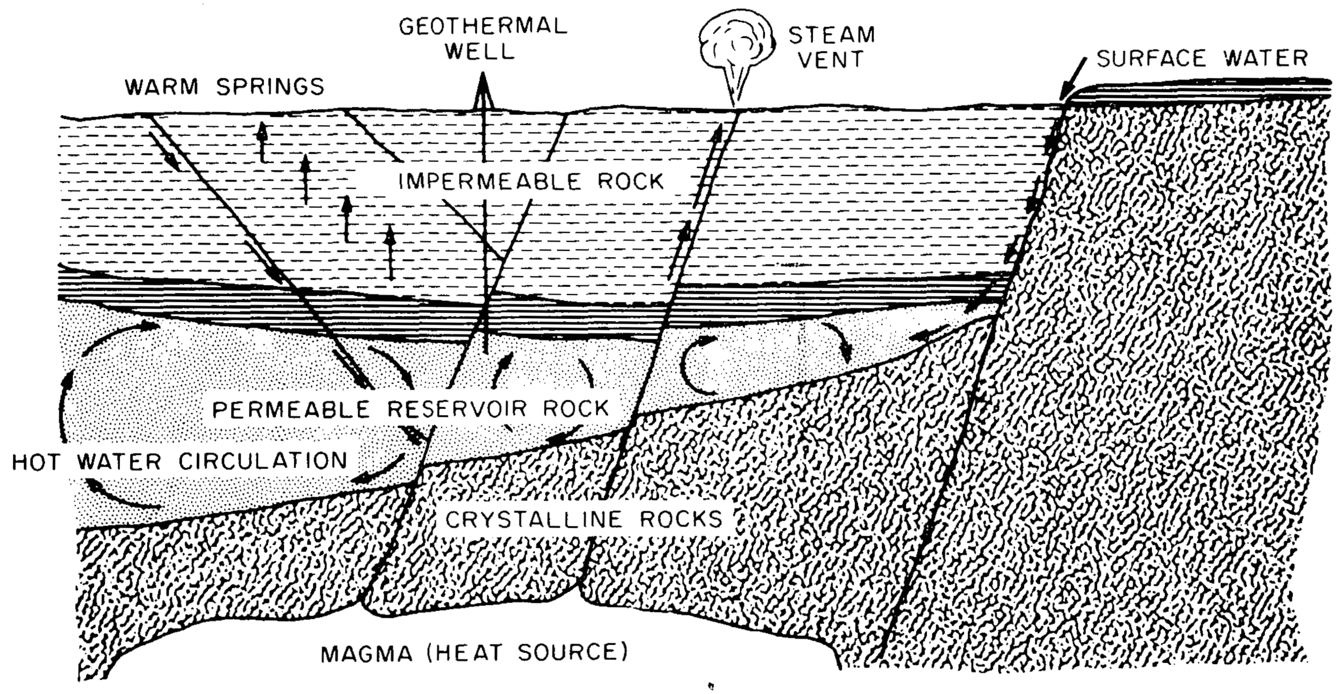
The three classes of geothermal reservoirs[1-3] are: hydrothermal-convection systems, geopressured reservoirs, and dry hot-rock systems. The hydrothermal-convection systems, which form the basis for all current geothermal power generation, are normally associated with regions of youthful volcanism, crustal deformation, and recent mountain building. Hydrothermal reservoirs are concentrated in the western third of the United States. Such reservoirs are created naturally when (1) a significant quantity of hot rock exists at depth, (2) the hot rock is overlain by a permeable formation by which groundwater can reach the hot rock, and (3) the aquifer is capped by an impermeable layer that prevents the loss of water and energy. As Figure 6A.4-2 illustrates, groundwater, which can percolate down to depths of several miles, is heated directly or indirectly by the underlying magmas and circulates by convection within the permeable formation. Hydrothermal systems may be further classified as "vapor-dominated" reservoirs or "liquid-dominated" reservoirs. When the fluid that circulates in at least the upper portion of the aquifer is either dry or superheated steam, the reservoir is said to be vapor-dominated. When temperatures are lower or pressures higher so that the circulating fluid is water or brine, the reservoir is liquid-dominated. Surface manifestations of a geothermal reservoir are geysers, hot springs, and fumaroles. However, geothermal reservoirs exist that do not have surface manifestations; to find such resources is one of the challenges in geothermal exploration.[4]

Geopressured reservoirs form another class of "wet" geothermal deposit. They contain highly porous sands and clay saturated with high-temperature, high-pressure brine with salinities ranging from a few hundred to 100,000 mg/liter. They are located in sedimentary basins that have undergone geologic deformation but, unlike hydrothermal systems, are believed not to be associated with magmatic intrusions or volcanism.



SCHEMATIC OF A GEOTHERMAL POWER PLANT

Figure 6A.4-1



SCHEMATIC OF A GEOTHERMAL RESERVOIR CAPPED
BY IMPERMEABLE ROCKS WITHIN A FAULTED STRUCTURE

Figure 6A.4-2

Apparently, geopressured zones arise from the trapping of normal heat flow by overlying clays that form an insulating layer. During the course of oil exploration, large geopressured zones have been found along the Texas and Louisiana Gulf coasts. In addition to the energy contained in the brines because of temperature and pressure, natural gas dissolved in the liquid may also be a potential energy source. Whether geopressured brines can be used to produce electric power is not yet known.[5]

As implied, the existence of a wet geothermal system requires some relatively specific combinations of geologic structure. Much more common are the "dry" geothermal resources. In principle, dry hot rocks of temperatures suitable for useful purposes can be reached from anywhere on the earth's surface by drilling to sufficient depths. Geothermal temperature gradients in what might be termed "normal" areas range from 4 to 28°F per thousand feet;[6] a typical value is about 16°F per thousand feet.[7] For power generation, temperatures of 300 to 400°F above surface temperatures are desirable, although lower temperatures are useful for non-electric applications. Thus, power generation from geothermal energy in most areas would require wells of 20,000-ft depth or greater. The difficulty of economically extracting energy from such depths suggests that most "normal" areas will be unsuitable for geothermal power development in the foreseeable future.[6] However, many areas have temperature gradients many times normal and are potentially promising for deriving useful energy from dry hot rocks. In the absence of a naturally occurring heat-transfer medium, such as exists in the wet geothermal systems, the exploitation of dry hot-rock reservoirs requires a man-made energy-extraction system. Such a system involves drilling a deep hole to rock of sufficiently high temperature, fracturing the rock by some means to produce a large amount of heat-transfer surface, drilling a second shallower hole into the fractured zone, and circulating water through the fractured rock by injecting the water into the deep well and removing it from the shallow well.[1]

6A.4.1.2 History

The first production of power from geothermal energy occurred in 1904 at Larderello, Italy. By the 1930's, the plants at this site totaled about 100 MW of capacity, but they were destroyed during World War II. The plants were rebuilt and expanded after the war and now have a capacity of over 300 MW. Marginally successful attempts at geothermal power production were made in 1922 in Japan and in California and in 1925 in New Zealand and Scotland. By 1930, Reykjavik, Iceland, was successfully using geothermal water for space heating. New Zealand achieved successful power production from the Wairakei power project between 1950 and 1960, after which a total of 160 MW of capacity was installed. These successes were followed by development programs in the later 1950's and early 1960's in Mexico, Japan, Russia, and the United States. Worldwide, about 20 countries are now involved in geothermal exploration and development.

Among the earliest developments of geothermal resources in the United States were the hot-spring spas in Arkansas and Georgia during the 19th century. Yellowstone National Park and several other recreational developments also were among the early users of geothermal energy. The Geysers area in Sonoma County, California, which is the only major source of geothermal power production in the United States, started as a spa in the late 1800's. Power-producing wells were drilled there in the 1920's, primarily to supply power to the spa. In the 1950's, Magma Power Company began to explore The Geysers area, and Pacific Gas and Electric Company constructed an electrical generating plant there in 1960.

The Imperial Valley region of California southwest of the Salton Sea was the second area in which exploration was started. A well drilled there in 1927 indicated that the quality of the steam was inadequate to produce energy. In 1957 during oil-exploration drilling operations, hot brine (22 to 26% solids at 600 to 680°F) was hit at a depth of about 5000 ft. This discovery resulted in renewed interest in mineral production from this area, but the highly corrosive liquid inhibited the development of power production.

In the late 1960's, the success of a 3.5-MWe power plant at Cerro Prieto, Mexico, stimulated interest in the potential for large-scale power production and for desalting in the Imperial Valley. Cerro Prieto, although not in the United States, plays a significant role in the history of geothermal development in the Imperial Valley because it is located in a common geologic feature, the Salton Trough. The first well was drilled there in 1956 and led to the construction of the 3.5-MWe experimental plant.

6A.4.1.3 Status

Geothermal energy is currently being used to produce power in several countries and its use is still expanding. A 75-MWe power plant is being erected at Cerro Prieto, and a portion of this plant went into operation in late 1973.[8] Experience gained at Cerro Prieto will probably be applied later in the Imperial Valley, although many areas are known to have much more saline brines than found at Cerro Prieto. The hope is that resources of the Imperial Valley can be used to produce desalted water, as well as electric power, and thus to augment the water supply based on the

Colorado River. The Bureau of Reclamation is currently conducting tests on geothermal desalting in the Imperial Valley.[9,10] Also, as noted above, The Geysers area in California is being used to produce electricity. The installed electrical capacity at The Geysers was increased to about 400 MWe in December 1973.

Because many of the areas of the United States that may be valuable for geothermal energy are on Federal land, the Geothermal Steam Act of December 24, 1970 (30 USC 1001-1025) provides for exploiting this resource. Pursuant to the Geothermal Steam Act, the U.S. Department of the Interior has issued proposed leasing and operating regulations along with a final environmental statement for the leasing program.[11] An announcement was made in December 1973 regarding the decision to proceed with the leasing program. Initial lease sales were held in January 1974.

6A.4.2 Extent of Energy Resource

6A.4.2.1 Geographical Distribution

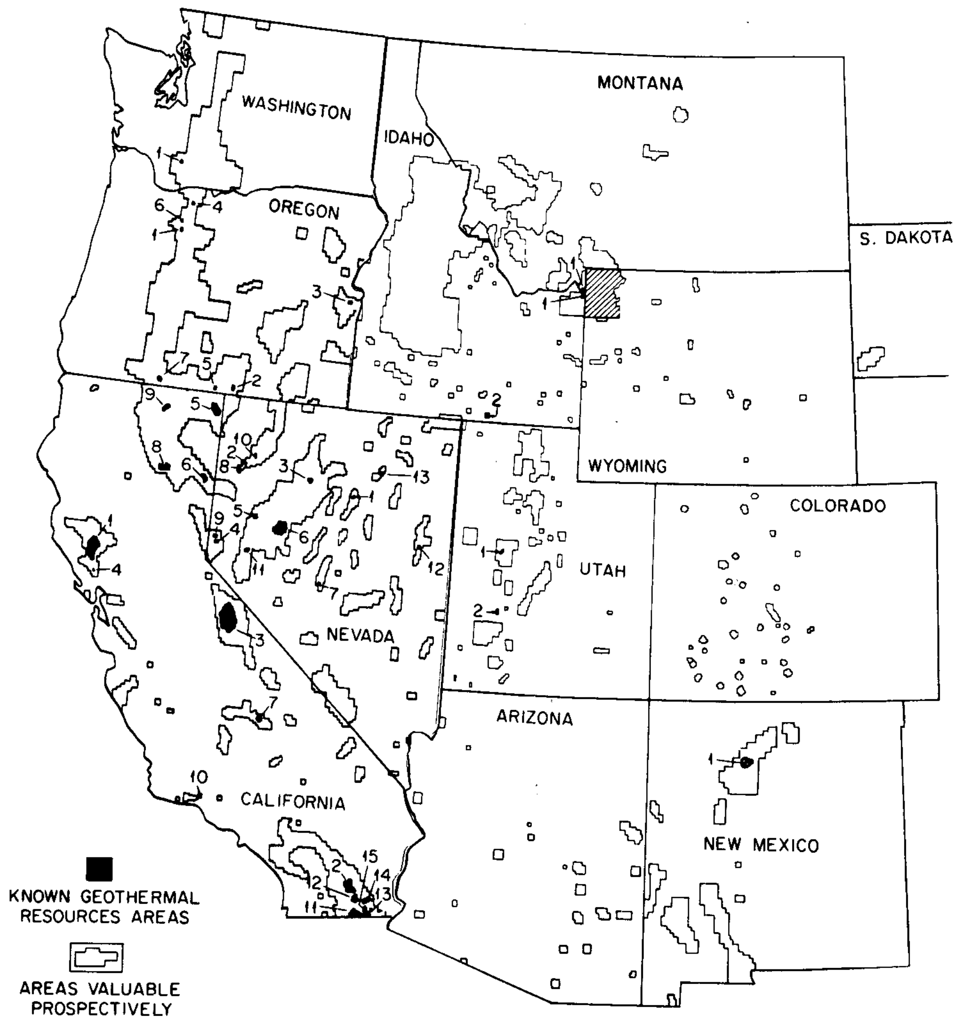
The U.S. Geological Survey has the responsibility to classify areas according to their potential geothermal-resource value. Areas are classified as known geothermal resource areas (KGRAs) when the "prospects for extraction of geothermal steam or associated geothermal resources from an area are good enough to warrant expenditures of money for that purpose."[12] Several factors are involved in identifying geothermal areas; two important ones are (1) the existence of geysers, mud volcanoes, fumaroles, or thermal springs that have temperatures at least 40F° above average ambient temperature; and (2) subsurface geothermal temperature gradients generally in excess of two times normal.[12] About 1.8 million acres of land have been designated as being within KGRAs.[13] All this land, except for two areas in Alaska, is in the western third of the United States, and 56% of the KGRAs involve Federal land. Table 6A.4-1 identifies the KGRAs in the conterminous United States; Figure 6A.4-3 shows their locations.

In addition to the 1.8 million acres classified as being within KGRAs, another 96 million acres in the western United States have been listed as having prospective value for geothermal resources.[13] Some areas outside the western United States have some geothermal resource potential; these are the geopressured brines along the Texas and Louisiana Gulf coasts and possibly the hot springs of Arkansas, Georgia, and the Appalachian Range.

Table 6A.4-1

KNOWN GEOTHERMAL RESOURCE AREAS WITHIN THE WESTERN CONTERMINOUS UNITED STATES AS OF AUGUST 1972

Name	Location on Figure 6A.4-3
California	
The Geysers	1
Salton Sea	2
Mono-Long Valley	3
Calistoga	4
Lake City	5
Wendel-Amedee	6
Cosco Hot Springs	7
Lassen	8
Glass Mountain	9
Sespe Hot Springs	10
Heber	11
Brawley	12
Dunes	13
Glamis	14
East Mesa	15
Nevada	
Beowawe	1
Fly Ranch	2
Leach Hot Springs	3
Steamboat Springs	4
Brady Hot Springs	5
Stillwater-Soda Lake	6
Darrough Hot Springs	7
Gerlach	8
Moana Springs	9
Double Hot Springs	10
Wabuska	11
Monte Neva	12
Elko Hot Springs	13
Oregon	
Breitenbush Hot Springs	1
Crump Geyser	2
Vale Hot Springs	3
Mount Hood	4
Lakeview	5
Carey Hot Springs	6
Klamath Falls	7
Washington	
Mount St. Helens	1
Idaho	
Yellowstone	1
Frazier	2
Montana	
Yellowstone	1
New Mexico	
Baca Location No. 1	1
Utah	
Crater Springs	1
Roosevelt	2



MAP OF GEOTHERMAL RESOURCE AREAS IN THE WESTERN UNITED STATES

Figure 6A.4-3

6A.4.2.2 Estimated Availability

Theoretically, the geothermal resource base of the United States is vast. For example, White[6] estimates that the stored heat above surface temperatures to a depth of 10 km (33,000 ft) in the United States is about 6×10^{24} cal. If 1% of that energy could be converted to electricity, the total generated would be about 8×10^{9} MWe-years, or enough for about 8000 years at the rate of consumption predicted for the year 2000 (annual consumption of 1 million MWe-years).[14] However, this estimated resource base does not constitute a recoverable resource because the estimate considers neither the cost nor technical feasibility of extracting energy from the earth's crust. The extent of the geothermal resource suitable for electricity generation is a matter of widely differing opinions among knowledgeable people.

White's estimates of the proved, possible, and probable geothermal-energy reserves are (1) 60,000 MWe-years recoverable at present costs and with present technology and (2) 200,000 to 400,000 MWe-years recoverable at a one-third increase in cost and with present technology.[6]

These estimates, which encompass the hydrothermal systems of sufficient temperatures to operate energy-conversion plants according to present technology, would indicate a fairly minor resource, equivalent to no more than one-half year of electricity supply at the consumption rate predicted for the year 2000. White notes, however, that with technological breakthroughs, including improvements in extracting and using low-temperature heat and new low-cost methods of drilling holes to great depths, the geothermal resources could be expanded substantially. In addition to low-temperature hydrothermal systems, White's estimates also exclude reservoirs of molten rock, abnormally hot rock of low permeability, and deep sedimentary basins of near "normal" conductive heat flow such as the Gulf Coast of the United States. The potential geothermal resources in these environments are at least ten times greater than the resources of the hydrothermal systems.[15] White does not consider these resources in the category of reserves.

Rex and Howell[16] appraise the United States geothermal resources as follows: (1) known reserves, about 3 million MWe-years; (2) probable reserves, 100 million MWe-years; and (3) undiscovered reserves, 7.4 billion MWe-years. The known reserves are the hydrothermal reservoirs in The Geysers area and in the Imperial Valley region. Probable reserves include all hydrothermal systems in the western third of the conterminous United States and Hawaii. In addition to including hydrothermal systems in the western United States (including Alaska and Hawaii), the estimate of undiscovered reserves assumes the development of dry hot-rock resources to a depth of 35,000 ft over 5% of the area of the western third of the United States. Rex and Howell also indicate that geothermal resources in the eastern and midwestern areas could substantially increase their estimates. In essence, then, their assessment is that known reserves could provide a three-year supply of electrical energy at the year-2000 consumption rate, but, if probable and undiscovered reserves are included, geothermal energy could satisfy our needs for a millenium. Implicit in this assessment is the assumption that new technology will be available to economically extract and convert the energy from the more difficult geothermal reservoirs, in particular the dry hot-rock systems.

Although enormous amounts of geothermal energy are generally acknowledged to exist, some people with interests in geothermal energy fail to make the distinction between a resource base and a recoverable resource noted above. Instead they resort to statements such as "if only 1% .... or even 5% of the total energy resource were utilized" without regard to whether or not these amounts are actually economically or technologically recoverable. For example, one commenter* on the Draft EIS states:

> Scientists at the United Nations, skilled in geothermal exploration and development projects, have calculated that the area of geopressured sediments along the Gulf Coast is of the order of 50,000--100,000 square miles, and state that 'we can show that even 5% of the geopressured energy in the U.S. part of the Gulf of Mexico, at a depth of 3 to 5 km., contains energy which is equivalent in calorific content to that contained in 100 billion tons of oil.' (Dr. H. T. Meidav, 1973, Global Geothermal Energy Estimates: United Nations, New York.)

Until the technology is available to economically extract this energy in an environmentally acceptable manner, the amount theoretically available is somewhat beside the point.

Factual information about the extent of geothermal resources and the economic and technological extractability of the energy in most cases is severely lacking. The interpretation and extrapolation of existing data inevitably lead to disparate estimates. Thus, part of the apparent disagreement on the size of the geothermal resource is related to a lack of knowledge about the nature of geothermal energy,

*Donald F. X. Finn, Hearing Letter 3, p. 2.

but perhaps a greater part concerns the definition of an energy resource. Any potential resource must be subjected to technical, economic, and social tests: Do technically feasible ways exist to extract the energy at reasonable costs--costs competitive with known alternatives--in a manner that society will accept? As would be expected, judgments on these questions, in the absence of hard data, vary considerably. However, a reasonable conclusion[6] is that (1) vapor-dominated geothermal systems, which are easiest to tap and which represent about 75% of present world geothermal electricity capacity, are relatively rare; (2) liquid-dominated reservoirs are much more plentiful than vapor-dominated; (3) dry hot-rock systems are the most common of all; and (4) most of the geothermal "hot spots" are located in the western third of the United States.

In terms of contribution to the Nation's future electrical energy needs, a reasonable interpretation of present information--although not necessarily a consensus--is that (1) if geothermal energy is limited to present technology and costs, the resource potential is limited to vapor-dominated reservoirs and, although important locally, is small in terms of national needs; (2) with some improvements in technology and some increases in cost the higher-temperature liquid-dominated reservoirs could be tapped and could have considerable regional significance in the West and would have some limited impact on a national basis when savings in imports of fossil fuels are considered; and (3) geothermal resources would be significant on a national basis only when the feasibility of tapping lower-temperature liquid-dominated reservoirs and dry hot rock systems has been demonstrated.

6A.4.3 Technical Description

6A.4.3.1 Systems Based on Vapor-Dominated Reservoirs

The technical characteristics[17,18] of The Geysers power station may reasonably represent geothermal electric plants based on vapor-dominated reservoirs. Production wells vary in depth from 600 to 9000 ft and have diameters that decrease from 20 in. at the surface to 8-3/4 in. at the bottom. Several wells (usually 14) are required to feed one centrally located power station of 110-MWe capacity which consists of two 55-MWe turbine-generators. Power plants tend to be relatively small, because the distance that steam can be transported from outlying wells is limited. Typically, five acres may be associated with each well. The areal extent of the field associated with each power station, determined through exploratory drilling prior to the construction of the power plant, is fixed so that new wells can be drilled as old ones become nonproductive, and thus the design power output can be maintained for the life of the plant (30 to 50 years).

The reservoir pressure of 450 to 500 psig reduces to about 126 psig at the wellhead. Restrictions to flow in the formation and in the well bore account for the pressure reduction. Steam flows through a centrifugal separator near each wellhead to remove particulate matter. Feeder steam lines, as small as 10 in. in diam, from each well feed into main trunk lines (36-in.-diam) to the power station. Relief valves are used in the steam lines to prevent overpressurizing the lines should the power plant shut down.

Steam is delivered to the turbines at 100 psig and 355°F and is exhausted at 4 in. Hg abs (125°F). The turbine is a single-shell, double-flow design with 23-in.-long last-stage blades. A direct-contact condenser is used, and heat is rejected by a mechanical-draft wet cooling tower. About 80% of the steam that flows to the turbine is evaporated in the cooling tower; the remaining 20% is reinjected into the less productive wells.

Noncondensable gases, which consist of carbon dioxide, hydrogen sulfide, methane, ammonia, nitrogen, hydrogen, and ethane, are removed from the condenser by a steam-jet ejector. The noncondensables constitute as much as 2 wt % of the steam flow.

6A.4.3.2 Systems Based on Liquid-Dominated Reservoirs

6A.4.3.2.1 High-Temperature Systems

In broad outline, the characteristics of a power system based on high-temperature geothermal brine would be similar to those for dry steam systems. However, some important differences exist which add technical complexity and increase cost. Experience in the use of geothermal brines for power generation has been obtained in New Zealand and at Cerro Prieto, Mexico.

At Cerro Prieto, well depths average about 5000 ft, and reservoir temperatures generally are greater than 550°F.[19] When well-bore pressures are lowered, some of the brine flashes to steam, and a mixture of brine and steam rises to the surface. About 20% (13 to 25%) of the mixture is steam,[19] which is separated from the brine by a cyclone separator.[9] Brine is discarded, and steam is piped to the turbine at an inlet pressure of about 75 psig.[20] The remainder of the steam cycle is similar to that described previously for The Geysers plant. Overall efficiency is somewhat lower but generally is in the range 10 to 15%.

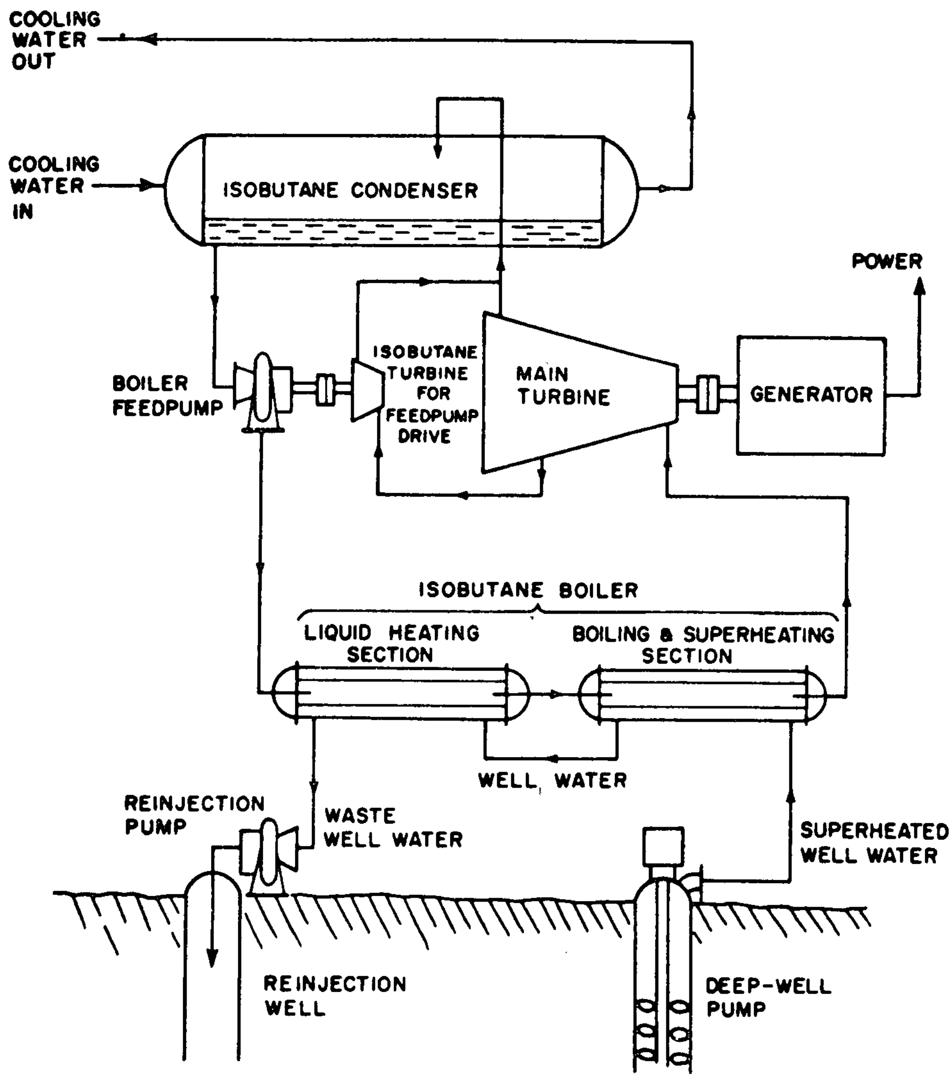
Several problem areas have been identified which make the geothermal-brine reservoirs more difficult to tap than are the dry-steam reservoirs. The highly mineralized water, which may contain silica, calcium carbonate, chlorides of sodium and of calcium, boron, ammonia, arsenic, and noncondensable gases, is a source of several potential problems.[6] Cooling of the brine on flashing and loss of dissolved carbon dioxide may cause precipitation and deposition of silica or calcium carbonate in wells and surface pipes. Down-hole pumps have been proposed as one method of extracting fluids from wells under sufficient pressure to prevent flashing and thus preventing deposition in wells and surface equipment.[5] If similar deposition should occur in the reservoir that immediately surrounds the well, the production rate of the well would be adversely affected, although it is not known whether this effect does occur. Disposal of the brine in an environmentally acceptable manner is another problem. Disposal through surface drains is used in New Zealand and at Cerro Prieto, Mexico, but reinjection of the brine is probably the most desirable method. Reinjection has not been tested extensively, and some concern exists that minerals contained in the concentrated effluent may precipitate out and reduce the permeability of the reservoir. In many fields, removal of a large volume of brine will cause ground subsidence, as has been observed at Cerro Prieto;[21] reinjection will be required to alleviate this problem.

6A.4.3.2.2 Low-Temperature Systems

A higher percentage of geothermal reservoirs are believed to contain low-temperature brine (below 360°F). These resources might be exploited with greater efficiency than steam cycles offer by using binary cycles in which heat is transferred from the brine to a secondary fluid (such as Freon or isobutane) that operates the turbines. The cooled brine would be reinjected. In general, binary systems require further development and demonstration that they are suitable for commercial power generation. Several such processes have been designed. Figure 6A.4-4 is a flow chart of one such system--the Magmamax process.[22]

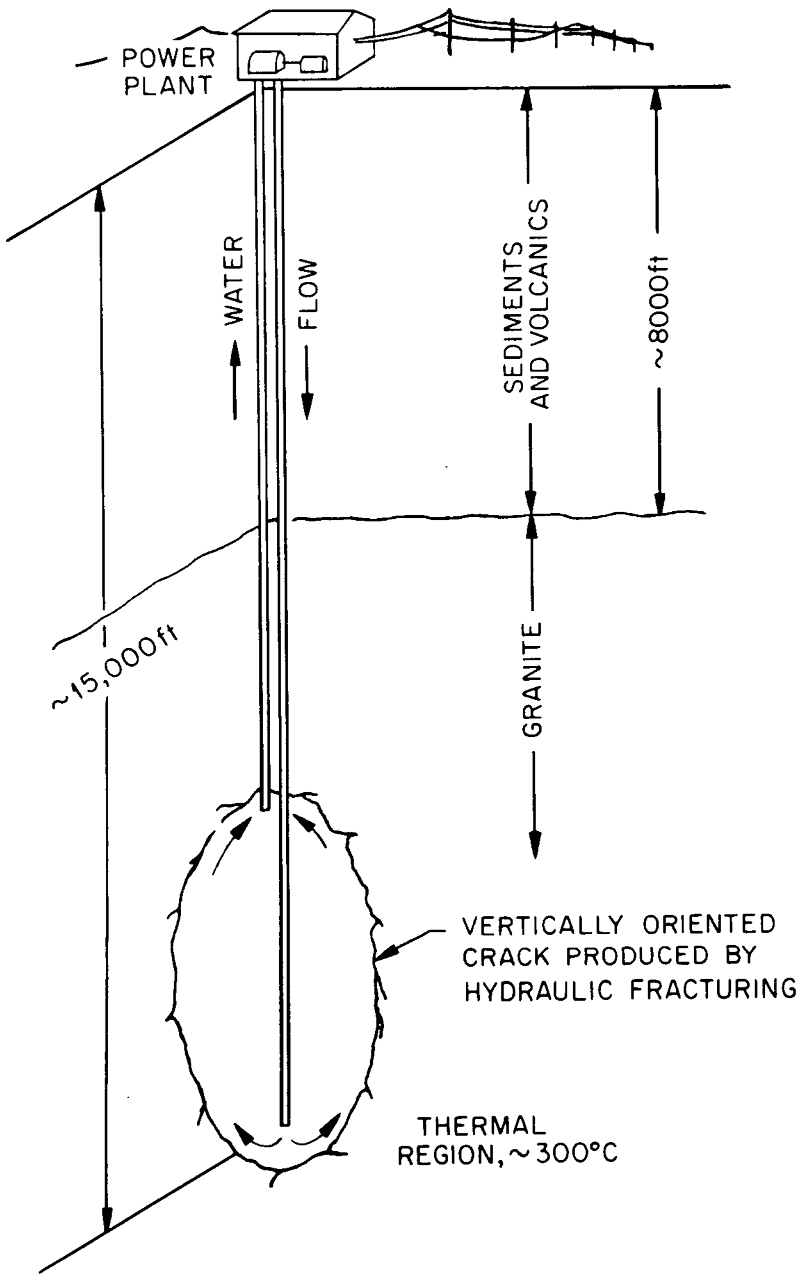
6A.4.3.3 Systems Based on Dry Hot Rock

Systems to exploit the energy contained in dry hot rock have been proposed by the Los Alamos Scientific Laboratory of the Atomic Energy Commission[1] and by the Battelle-Northwest Laboratories.[23] Figure 6A.4-5 illustrates the general concept. This system would consist of two or more wells, a heat exchanger, a turbine, and cooling towers for heat rejection. Water-injection wells would be drilled to depths of 6000 to 15,000 ft to reach rock having temperatures near 600°F if possible. Rock



SCHEMATIC OF THE MAGMAMAX PROCESS
(HOT WATER FROM A GEOTHERMAL WELL FLASHES ISOBUTANE)

Figure 6A.4-4



CONCEPTUAL DIAGRAM OF A DRY-ROCK GEOTHERMAL ENERGY SYSTEM DEVELOPED BY HYDRAULIC FRACTURING

Figure 6A.4-5

in the vicinity of the well bottom would be fractured hydraulically or with conventional or nuclear explosives. An additional well would be drilled into the fracture zone several thousand feet above the injection well. Water would be circulated by injection through the deep well, and hot water would flow out of the shallow well into a heat exchanger where it would vaporize the working fluid (steam, Freon, or isobutane).

6A.4.4 Research and Development Program

The Hickel Panel on Geothermal Energy Resources[24] identified the following areas in which the technology is not well enough developed to allow rapid exploitation of geothermal resources:

(1) Resources appraisal. Better estimates are needed of the extent and character of the geothermal resources in order to manage their development and use.

(2) Exploration methods. Better, faster, and cheaper methods are needed for geophysical prospecting, for drilling test holes, for logging wells, and for sampling fluids.

(3) Reservoir development and production. This technology includes mathematical modeling of reservoirs, investigation of recharge methods, geochemistry of fluids, control of scale, artificial stimulation by fracturing of rocks, and exploitation of hot rocks.

(4) Utilization technology and economics. Economical techniques, such as binary-fluid power cycles, are needed for use of moderately hot geothermal waters. Techniques are desired for direct utilization of geothermal energy for space heating and other uses such as recovery of minerals and desalting of water, in addition to power.

(5) Environmental. Techniques are required for control of pollutants such as hydrogen sulfide and for noise reduction.

The Hickel panel has proposed a ten-year development program of $500 million to $600 million to resolve these technical questions.[24]

In addition, geothermal energy has been examined as part of a comprehensive study on "The Nation's Energy Future."[25] In this review, a geothermal research and development program totaling $185 million has been proposed over the next five years. The objectives of this program would be:

(1) to increase present knowledge of the location, nature, and extent of the Nation's geothermal energy resources;

(2) to identify and resolve the environmental, legal, and institutional barriers to geothermal resource utilization;

(3) to advance, through development of technology, the operational efficacy and the efficiency of relevant components, devices, and techniques as required to achieve practical geothermal resource utilization; and

(4) to accelerate, through demonstration pilot plants, the commercial production of electricity from geothermal sources.

Under this program, important emphasis would be given to geothermal resource utilization ($79 million out of the $185 million total geothermal program). Several different types of geothermal resources would be examined, four different demonstration plants would be completed, and a fifth plant would be started. The potential results of the complete geothermal research and development program, if successful, in supplying useful electrical power are discussed in the following section.

Although there seems to be general agreement among geothermal experts that significant research is needed and justified, there is not universal agreement on this point among all persons with interests in geothermal energy. For example, Mr. Donald F. X. Finn* takes issue with the need for a research and development program, stating:

> We urge the Panel not to be misled by the Commission's plan for a significant R&D program. There is a proven technology readily available for commercially harnessing the vast geothermal resources of the West and the Gulf Coast.

Mr. Finn's viewpoint is not shared by experts making up the Hickel Panel[24] or the Subpanel VIII[5] group that prepared input to the report "The Nation's

*Hearings Letter 3, p.8.

Energy Future,"[25] although industrial opinions differ, particularly with respect to high-temperature liquid systems. However, the AEC does not find support for Mr. Finn's assessment, especially with reference to the technology for using the potentially more abundant moderate-temperature reservoirs, geopressured reservoirs, and dry hot-rock reservoirs.

6A.4.5 Present and Projected Application

Although several utilities and energy companies are working toward development of geothermal energy, the most definitive plan in the United States is that of Pacific Gas and Electric at The Geysers. The present (early 1974) capacity of about 400 MWe will be expanded by about 100 MWe each year[26] until the ultimate capacity of the field (estimated to be about 5000 MWe) is developed.[27] Beyond this development, firm plans for future geothermal capacity have not as yet been defined. Nevertheless, several estimates have been made, and the range of variation reflects the disagreement discussed previously on the extent of geothermal resources.

In a study by the National Petroleum Council, Kilkenny[28] estimated that generating capacity based on geothermal fluids might amount to 1500 MWe by 1975, 10,500 MWe by 1980, and 19,000 MWe by 1985. Only about one-half of the estimate for 1975 now appears achievable.

The Hickel Panel[24] made the following projections of installed geothermal power:

Year	Capacity with Moderate Research Program (MWe)	Capacity with Accelerated Research Program (MWe)
1980	10,500	36,000
1985	19,000	132,000
1990	35,000	242,000
2000	75,000	395,000

The lower estimates, which are identical with those of the U.S. Department of the Interior,[13] are based on the assumptions that a moderate research and development program will result in the discovery of more geothermal reservoirs and that the technology will be developed to tap the deeper and lower-temperature hot-brine systems. The higher estimates are based on the assumption that an intensive program will result in the technology needed to tap more difficult reservoirs, including dry hot rocks.

Rex and Howell[16] judge that 400,000 MWe of geothermal capacity "could be discovered and developed in the Western United States in 20 years by the resource industry." Their projection is based on the assumption that the dry hot-rock systems are technically and economically exploitable.

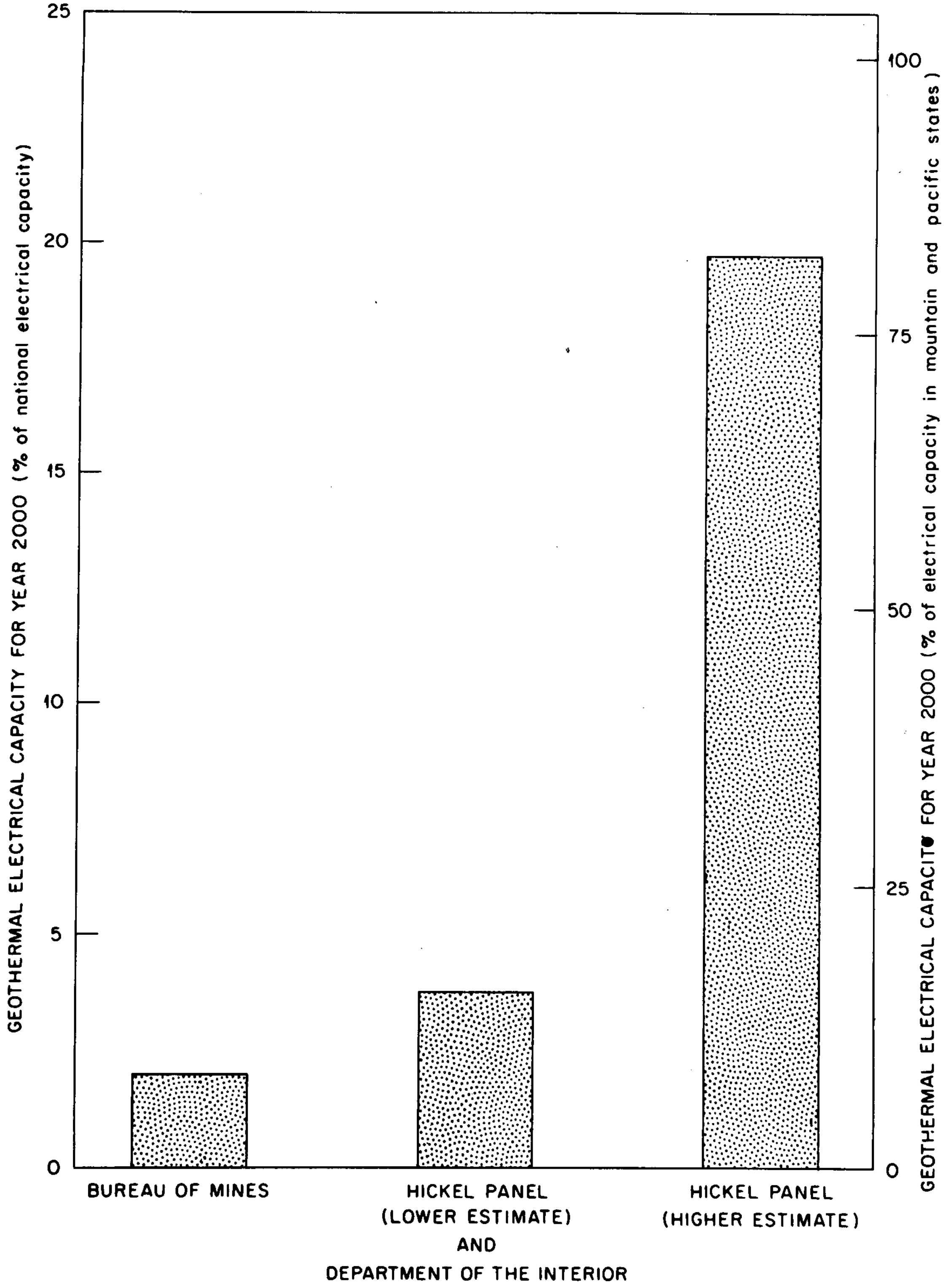
J. O. Horton,[29] Assistant Secretary of the Interior for Land and Water Resources, indicated in a statement to the Senate Interior and Insular Affairs Subcommittee on Water and Power Resources that "although we estimate that geothermal energy would constitute only 1 to 2 percent of the total United States energy supply forecast for the year 2000, it could mean up to 10 percent or more of the total energy supplies forecast in the western states by that time."

The results of analyses by the Bureau of Mines[13] forecast a geothermal electrical capacity of 4000 MWe in 1985 with an increase to 40,000 MWe in 2000. The 1985-to-2000 increase assumes that about 15% of new power-generation capacity in the western states would be from geothermal sources.

The research and development program proposed in ref. 23 is designed to stimulate the commercial production of at least 20,000 MWe by 1985 from various types of geothermal resources, plus important additional fuel savings through use of geothermal energy for such nonelectric purposes as space heating and air conditioning. The corresponding goals for the years 2000 and 2020 are 80,000 MWe and 200,000 MWe, respectively. The electrical capacity projections for 1985 and 2000 are seen to be approximately the same as those projected by the Hickel Panel for a moderate research program.

The Subpanel VIII group,[5] which provided input to the report on "The Nation's Energy Future,"[25] suggested that reasonable goals for the implementation of geothermal energy would be 30,000 MWe by 1985, 100,000 MWe by 2000, and 200,000 MWe by 2020.

Figure 6A.4-6 summarizes the range of some of these projections. Speculations on the projected application of geothermal energy by the year 2000 vary from an insignificant 2% to an important 20% of the predicted electrical capacity at that time. In reality, the amount of electrical capacity would be quite limited with currently developed and demonstrated technology. Therefore, advances on several fronts will be required for geothermal energy to have national significance. Technology is only one of several important limitations on the growth of geothermal-energy utilization. Other factors include legal and political constraints, environmental restrictions, and institutional and financial considerations.



THREE PROJECTIONS OF GEOTHERMAL ELECTRICAL CAPACITY
FOR YEAR 2000

Figure 6A.4-6

Many of the country's geothermal resources probably will not be developed until political and legal frameworks are provided to define ownership and to establish procedures for management and regulation of geothermal resources.[30] The lack of a sound legal framework may, in some cases, dampen enthusiasm for investment. But a factor of equal importance is that, with present technology in exploration, the magnitude of a given reservoir is difficult to define with confidence. Yet an electric utility must have assurance of sufficient steam reserves to sustain operation over the amortization period (30 to 40 years) of the power plant.

Large-scale geothermal development implies the establishment of a geothermal industry that, if the upper ranges of the above projections are accepted, must develop thousands of megawatts of power each year requiring a large number of trained geologists, engineers, exploration rigs, drilling equipment, and other resources. O'Conner[31] points out that, to meet the optimistic projections of implementation, geothermal drilling in the next decade will be comparable with that of the oil industry. The associated human and capital resources cannot be built up quickly enough without either government investment or the promise of large quick profits or both.

6A.4.6 Environmental Impacts

6A.4.6.1 General Nature of Environmental Impacts

Environmental studies[11] indicate that the major potential impacts of the use of geothermal energy are in the general areas of (1) surface and groundwater quality impairment as a result of fluid disposal, (2) air emissions, particularly hydrogen sulfide, (3) noise from drilling and steam venting during operation, (4) uncontrolled blowouts, (5) aesthetic impact, (6) land subsidence from fluid withdrawal, (7) seismic activity from fluid withdrawal or reinjection, (8) land use, and (9) damage to vegetation and wildlife. The environmental impact of geothermal generation is largely restricted to the generating site and its immediate surroundings--a contrast with fossil-fueled or nuclear generation, for which impacts occur at several locations (mines, processing plants, disposal sites).

The different types of geothermal systems have very different environmental impacts. Because of the relatively pure fluid in the vapor-dominated reservoirs, the fluid-disposal problem is relatively small compared with that of the hot-brine systems, whose high salinity is a potentially serious environmental impact. The environmental impacts of advanced geothermal power systems, such as binary cycles and proposed systems for dry hot-rock use, have not been thoroughly evaluated and will not be discussed. However, indications are that these advanced systems, which would extract geothermal energy with closed loops, may have much less environmental impact than do current systems, especially with regard to liquid and gaseous effluents from the geothermal fluid.

6A.4.6.2 Mechanism for Regulation of the Environmental Impacts

The proposed leasing and operating regulations issued pursuant to the Geothermal Steam Act of 1970[32] provide a framework for the regulation of exploration, development, and use of geothermal resources on Federal lands. The Secretary of the Interior and his official representatives are required to review the environmental impact of each proposed lease and to develop special stipulations when necessary to protect the environment and all other resources.

The Sierra Club, in commenting on the Department of the Interior's draft environmental statement on the geothermal leasing program,[33] stated that the proposed regulations lack specifics and might not be strictly enforced. They suggested that full-scale implementation of the Geothermal Steam Act be deferred pending successful completion of a carefully monitored pilot project. The regulations were subsequently revised, are now more specific in certain areas, and have since been published.

California provides for regulation of geothermal activities on non-Federal land comparable with that proposed by the Department of the Interior on Federal land. California also requires geothermal developers to comply with all applicable local ordinances, because county zoning commissions have considerable control over the use of private lands.

Other states have developed or undoubtedly will develop similar regulations when further geothermal development is proposed.

6A.4.6.3 Surface Effects

As noted previously, all the environmental impacts of geothermal power plants arise from the production site itself; the area of the site depends on the spacing of the wells. Well spacing is an important factor in the efficient use of a geothermal reservoir. The spacing of the wells should be such as to minimize the total number of wells required during the plant lifetime while exploiting the full energy potential of the field. Generally, wider spacing would require fewer replacement wells but would result in a larger area associated with each power plant. The extent of the area involved for a 1000-MWe plant that would operate for, say, 30 years can be inferred from data obtained at The Geysers.[17] Production data on wells with a density of one well per five acres indicate that production declines almost exponentially with a half-life (time required for well production to decrease by one-half) of five years. If this interpretation is correct and if short-term (5-year) data can be extrapolated, the implication is that new wells, which would number about 14% of the original number of wells, must be added each year. Based on an initial production rate of 7 MWe per well, the initial number of wells for 1000 MWe would be 140 in an area of 700 acres. For 30 years of production, the total number of wells needed would be 740 in an area of 3700 acres. Similar estimates for a density of one well per 45 acres indicate that, initially, 140 wells over an area of 6300 acres would be required. For 30 years of production, the total number of wells would be 280 over 12,600 acres. These figures are not necessarily valid for other reservoirs. Similar data from other geothermal fields will be necessary to evaluate impacts from those areas.

Surface environmental effects would be related to the construction and maintenance of roads, wells, steam lines, transmission lines, and power plants. A network of roads would be required to gain access to each well site. Roads would have to be built in accordance with an approved plan to control erosion and to minimize dust. Although these problems are fairly easy to solve in flat lands, they would require much more attention for steep terrain. During drilling of a well, provisions would have to be made for the disposal of drilling muds and fluids, prevention of blowouts, and containment of reservoir fluids. Backfilling of mud pits and fluid ponds, use of blowout preventers, and casing and cementing of wells are required by the proposed Federal regulations. Steam lines as large as 30 in. in diam would lace an area of 1/2- to 1-mile radius surrounding each power plant. These lines would be regularly inspected to detect leakage, and wellheads would be inspected by the operators and by regulatory inspectors for exterior corrosion damage or structural weakness to avoid blowouts or leakage. By comparison with the other portions of a geothermal development, the power plant, including switchgear and cooling towers, would be small; it would occupy only a few acres.

The facilities to transmit geothermal power would be similar to those for other central-station power plants, but the environmental impact might be greater than for other alternatives because of the long distances between geothermal fields and load centers and because of the need to transmit power from many small generating plants to the power grid. This problem would not occur, however, in the case of the two largest proven geothermal resources in the United States--The Geysers and

Imperial Valley, California. Both of these sites are very close to large load centers in northern and southern California, respectively.

Evidently, the development of a large geothermal field would restrict surface uses of the land over an area of several thousand acres. Where grazing is the predominant alternative use of the land, as at The Geysers, cattle might be allowed on the developed land among the wells and steam lines. Where other uses are prevalent, such as agriculture or recreation, those uses would be disrupted to some extent. If geothermal-energy extraction were properly regulated, it would not permanently damage land for future uses.

The Geysers area is a good example of a difficult site for road building and test drilling. The steep terrain and relatively loose soil create sediment that must be controlled by reseeding and by other means of protection until ground cover is established. The flat Imperial Valley would suffer minimal impact from road building and site excavation but is potentially more susceptible to unacceptable impacts such as land subsidence because of the highly developed agriculture of that area.

6A.4.6.4 Impact on Water

The proposed Federal regulations would minimize the impact of drilling and production-testing on water resources. The major potential impacts that would have to be avoided would be siltation of surface water from road construction and from drilling-site excavation; contamination of surface or groundwater from spills or uncontrolled blowouts; contamination of groundwater from improperly executed recharge; accidental interception of artesian aquifers that were not properly cased off; degradation of hot springs, fumaroles, and geysers; and contamination of freshwater aquifers by casing failures.

The Imperial Valley is subject to water-resource pollution in the event of accidents because of the agricultural nature of the valley, because of its use of groundwater for irrigation, and because of the presence of the Salton Sea. Some brines were discharged into the Salton Sea in 1962; they resulted in a 4.5% increase in dissolved minerals in just 90 days. Existing regulations prohibit such discharges and prohibit the raising of river temperatures more than 2°F. The potential for such impacts still exists, especially following blowouts, and must be guarded against very carefully.

In current or planned development programs, test-production fluids are to be channeled temporarily to settling or storage ponds for containment. At the end of test periods, the ponds can be filled in and replanted. For longer-term testing, reinjection of geothermal fluids is intended to be the most common method of eliminating water pollution. Reinjection will be made by properly planned and regulated methods.

Consumptive use of water for drilling muds would have a minor impact on local water resources but might prove troublesome in desert areas.

6A.4.6.5 Impact on Air

Venting of steam to the atmosphere can create environmental damage if the steam contains large quantities of undesirable gases such as hydrogen sulfide or ammonia. For example, the steam phase in New Zealand is reported to contain CO_2 (5400 ppm), H_2S (140 ppm), and NH_3 (15 ppm);[34] and The Geysers steam contains CO_2 (12,400 ppm), H_2S (330 ppm), NH_3 (250 ppm), and H_3BO_3 (18 ppm);[33] steam from Larderello is similar. Such gases could produce undesirable effects, and their removal might be required during the test-production stage. Other potential atmospheric effects include fogs in cold climates.

Mercury vapor and traces of radioactive elements have been found in some geothermal fluids. Fluids from each well should be analyzed for these elements. Technology for removal of these materials is not available; however, methods are available and should be used to prevent overexposure to employees.

6A.4.6.6 Ecological Impacts

Most of the impacts on fish and wildlife during field development would occur on or adjacent to well sites, although water-quality impairment might cause much more widespread damage. Habitat would be destroyed at well sites and in the vicinity of roads. Noise would displace wildlife, although the extent of disturbance cannot be accurately predicted.

The greatest potential impact on fish and wildlife would result from improper control of the geothermal fluid. If toxic geothermal effluents were to be discharged to surface streams or lakes, there is the danger that fishery habitats and waterfowl feeding and nesting areas would be adversely affected. Similarly, heated effluents could result in damage to the aquatic habitat. Finally, if toxic geothermal effluents are discharged into streams or lakes, they may be picked up by fish or wildlife and find their way into the human food chain. Adequate control measures are required to minimize such occurrences.

6A.4.6.7 Aesthetic and Recreational Impacts

Many of the geothermal resources of the western United States are in remote areas valued for wilderness and other natural aesthetic qualities such as volcanos, hot springs, fumaroles, and geysers. The national parks and some other designated wilderness areas are not subject to geothermal exploration. Decisions on whether to develop other scenic areas might be very difficult.

One of the principal aesthetic impacts of geothermal field development is the noise of the drilling operation and of the testing. Typical noise levels at 1500-ft distance from The Geysers are 55 decibels (dB) for air drilling and 65 dB for a muffled testing well (Table 6A.4-2). The actual aesthetic impact of noise depends on surrounding terrain, weather, and proximity to people, but the overall effect could be significant.

In the areas of natural scenic beauty, the greatest visual impacts would result from the construction of new roads with attendant hillside scarring, of a network of steam lines, of the power plant with associated cooling towers, and of transmission lines. The presence of steam plumes from steam wells and from cooling towers would also result in aesthetic impact. Drilling rigs would be conspicuous throughout the life of a geothermal reservoir.

Recreation might be influenced to the extent that access to a geothermal field would have to be limited for safety reasons. Also, destruction of vegetation and fisheries and any noise might affect recreation by disturbing wildlife and reducing the aesthetic enjoyment by sportsmen. The use of geothermal areas as spas or tourist attractions might be adversely affected by construction activities nearby.

6A.4.6.8 Blowouts

Uncontrolled blowouts represent an important potential hazard during geothermal development. The adverse effects associated with blowouts are noise, air contamination from gaseous emissions, possible pollution of surface water or groundwater, and waste of the resource. Proper casing design and drilling execution should prevent blowouts.

Nevertheless, a blowout that occurred at The Geysers in 1957 is still active. Its cause has been attributed to minor shifting of the land, which resulted in a casing failure that allows steam to escape from around the well. The casing extended to only 500-ft depth; present California and proposed Federal regulations require better casings, thus making such a blowout unlikely. They also require quickly operable

Table 6A.4-2

COMPARISONS OF NOISE LEVELS BETWEEN THE GEYSERS AREA AND OTHER SOURCES[a]

Source	Level [dB(A)]	Distance (ft)
	The Geysers Area	
Drilling Operation (air)	126	25
Drilling Operation (air)	55	1500
Muffled Testing Well	100	25
Muffled Testing Well	65	1500
Steam-Line Vent	100	50
Steam-Line Vent	90	250
	Comparative Levels	
Jet Aircraft Takeoff	125	200
Threshold of Pain	120	(Average)
Unmuffled Diesel Truck	100	50
Street Corner in a Large City	75	(Average)
Residential Area at Night	40	(Average)

[a]Source: U.S. Department of the Interior, Final Environmental Statement for the Geothermal Leasing Program, vol. II, 1973, p. V-56.

shutoff equipment at the wellhead to restrain any uncontrolled flow that might occur. About $1 million has been spent unsuccessfully to control The Geysers blowout.

More recent experiences at The Geysers, in the Imperial Valley, and in New Zealand indicate no serious blowouts in about 200 wells completed since 1960. Two blowouts have occurred at the Cerro Prieto field in Mexico. In 1961, one resulted from a mechanical failure due to vibrations in the wellhead equipment. This blowout was brought under control by directional drilling and by cement injection. The other blowout, which was uncontrolled for four months in 1972, started with water and steam being ejected from a large crater about 300 ft from the well. Several days later, a violent blowout occurred at the crater. This subsided, but emissions continued during the 4-month period while corrective measures were tried. Another mishap, at Beowawe, Nevada, occurred in August 1972 when three capped wells appeared to have been dynamited by vandals. Strong ejections of steam and water came from the damaged wells.

6A.4.6.9 Earthquakes

In some oil-production regions, the pressure changes resulting from drilling into a reservoir have been accompanied by increased seismic activity. Such instabilities due to production have occurred in the Wilmington oil field, California; others due to water injection have occurred at the Baldwin Hills oil field, California, and at the Rangely oil field, Colorado.[33] Also, the seismic activity associated with injection of waste waters at the Rocky Mountain Arsenal in Colorado gave rise to considerable publicity. Similar increases in seismic activity have also been noted in association with the filling of large surface reservoirs and with the attendant changes in hydrostatic head; the affected areas have included Lake Mead on the Colorado River and Lake Kariba in Africa. In general, such earthquakes have not proven disastrous, but the potential for a major quake cannot be ruled out. In any event, earthquakes must be counted as a potential environmental impact associated with geothermal development, and provisions must be made for seismic monitoring before and during major production. On the other hand, the argument is presented that the geothermal areas are naturally active seismic regions, and therefore it would be difficult to say that drilling at depths less than 10,000 ft can trigger earthquakes whose epicenters are several miles deep. The brines are reinjected at pressures much lower than those that caused seismic activity at other places, and the low-pressure fluids may lubricate slippage planes and gradually relieve stresses.

The problem is a major concern for large-scale development, and its solution probably lies in extensive base-line data collection prior to field development and in close monitoring of seismic activity during production.

6A.4.6.10 Subsidence

The many instances of land subsidence from freshwater production and from oil production are well documented. Therefore, concern is expressed that geothermal production will also contribute to land subsidence, which has been noted at Cerro Prieto, Mexico. Although subsidence can be predicted roughly by geological theory, the only safe way for development to proceed appears to be with base-line data and a good monitoring of elevation changes. The U.S. Geological Survey has initiated a program to monitor possible ground movement in The Geysers area and in the Imperial Valley.[29]

Reinjection of geothermal or other water into the geothermal area is cited as a possible method of alleviating subsidence. The feasibility of this approach may be related to the local geology and geochemistry. Monitoring of ground movement would still be required to inform the operator and the regulatory agencies of the consequences of production operations.

Land subsidence in some undeveloped areas may not be of significant concern; it would be of great concern in flat agricultural regions such as the Imperial Valley.

6A.4.6.11 Power-Plant Thermal Effects

Because of the relatively small temperature driving forces in geothermal power cycles, the overall thermal efficiency is low. For example, at The Geysers the heat rate is about 22,000 Btu/kWhr compared with 8000 to 9000 Btu/kWhr for a modern fossil-fueled plant or for an efficient nuclear plant such as the HTGR or the proposed LMFBR. In terms of the heat rejected to the atmosphere for a generating capacity of 1000 MWe, the comparison is: geothermal, 6140 MWt; fossil-fueled or advanced nuclear, 1500 MWt. Although geothermal plants reject more energy than do large central-station plants by a factor greater than 4, the increase in environmental impact may not be proportional to the increase in heat rejected because geothermal plants, and consequently heat rejections, would be dispersed over a large area. Nevertheless, the implications of the large amount of heat that would be associated with large-scale geothermal development have not been thoroughly evaluated.

6A.4.6.12 Economic and Social Effects

Geothermal development requires substantial investment in the drilling of wells and the construction of roads, pipelines, power and by-product plants, and transmission lines. Such investments result in an increased tax base for the area of development. The labor-intensive phase is short-term (during field development), and only a moderate number of people would later be required to operate and maintain a large geothermal field.

6A.4.6.13 Irreversible and Irretrievable Commitments of Resources

The principal commitment of resources would be the depletion of thermal energy and water from the local geothermal reservoir. Both are eventually renewable but not within the life of a specific project. No alternative use of the stored energy is foreseen, and the geothermal water might be developed for other uses after it had been used for power production.

Compaction and resulting land subsidence that might occur are potential irreparable consequences. Some onsite or related ecological features such as plant life and aesthetics would be irreversibly altered. The extent of such alterations would depend on the particular site and characteristics involved.

Finally, dedication of the land surface to use for wells, associated surface facilities, power plants, and transmission lines, while not permanent except for minor portions of the area, would represent an irreversible commitment in the context of human lifetimes. Normally, 30 to 50 years is required to amortize the investment in power facilities at a given field.

6A.4.7 Costs and Benefits

6A.4.7.1 Energy Production and Delivery Costs

6A.4.7.1.1 Direct Costs

The direct costs, or those costs that are accounted for in the price of geothermal energy, include the following major components: (1) steam supply, (2) power conversion, and (3) power transmission. Little is known about the cost of transmission should geothermal energy become a major electrical-energy source except that, should the geothermal field be in a remote area, the cost would probably be somewhat higher than that for central-station fossil-fueled or nuclear plants. However, the amount of this cost differential is not likely to be a major element in the overall cost of geothermal power.

Various estimates have been given of the cost to extract and convert geothermal energy. But these estimates, like many published estimates for nuclear and fossil-fuel energy, appear to be somewhat dated and, in particular, fail to take into consideration the rapid increases in all energy costs, including construction costs, experienced in the past year or two. Probably the best current estimate is that by Pacific Gas and Electric Company for their Geysers unit 14, scheduled to go on line in 1976.[26] The estimated production cost in terms of 1973 dollars is 9.11 mills/kWhr for a 70% plant factor and 8.55 mills/kWhr for a 90% plant factor. These costs would seem to represent a lower limit on geothermal-energy costs since dry-steam reservoirs, such as The Geysers, are generally conceded to be the least expensive to tap.

6A.4.7.1.2 Indirect Costs

Certain costs of geothermal energy will not appear in the market price of the products. These may include: (1) ground subsidence, (2) environmental effects of gaseous and liquid effluents, (3) withdrawal of land from other potential uses, and (4) increased seismic activity. Of course, not all of these will be present in every geothermal development, and some, such as environmental effects of effluents, may be controlled by added power-plant equipment and would thus be transferred to direct costs recoverable from power revenue.

6A.4.7.2 Development Costs

As noted in Section 6A.4.4, the Hickel Panel[24] has suggested a ten-year research and development program that would amount to $500 million to $600 million, and a five-year $185 million program has also been suggested as part of a national energy research program in the report "The Nation's Energy Future."[25]

6A.4.7.3 Benefits

The major benefit from geothermal energy in the context of the present study would be electric power with no dependence on externally acquired fuels. Other benefits might include: (1) desalted water, (2) commercial minerals and gases, and (3) process or space heat. The multiple-use aspects would appear to warrant increased attention because of the depletable nature of the resource and because of the small fraction of the stored energy that is available for power generation.

6A.4.8 Overall Assessment of Role in Energy Supply

A major advantage of geothermal energy is that electric power can be produced without the consumption of fuels. The potentially significant environmental impacts might, by research and development, be made acceptable. Knowledgeable people have made widely different judgments about the amount of the recoverable resource and the rate at which this resource can be exploited in the future. Present information indicates that geothermal energy might become an important source of energy in some regions of the western United States, especially at The Geysers and in the Imperial Valley, before the end of the century. This potential for regional significance could justify a significant research program. Also, the development of geothermal power in one part of the United States would release comparable amounts of fuel for consumption elsewhere.

Whether geothermal energy will become of national significance in the foreseeable future is uncertain. The successful use of energy in dry hot rocks would go far towards making it so, but this approach is now only in the conceptual stage. At any rate, the planning to meet a significant part of future energy needs cannot be based solely on geothermal energy. Therefore, no basis seems yet to exist for altering the course of development of other energy sources, including coal and nuclear energy.

The above conclusion is challenged by some. For example, the Natural Resources Defense Council (NRDC) states:

> Together with energy conservation, geothermal resources could account for some 2,250 to 2,550 GWe by 2020, in other words, at least the equivalent of the LMFBR capacity projected in the Draft EIS.*

NRDC then goes on to quote extensively from the Cornell Workshop on Energy and the Environment[35] on the subject of "Hot Dry Rock Geothermal Systems," which depicts the large amounts of energy potentially available from hot dry-rock systems and recommends:

> The economic and environmental impact has the potential of being so large that hot dry rock geothermal energy research should be assigned a high priority and be supported at a level sufficient to evaluate the concept and demonstrate feasibility and costs.**

*Comment Letter 38b, p.18.
**Comment Letter 38b, p. 20.

The NRDC further proceeds to quote from the study "Energy Research and Development,"[36] to the effect:

> Basic and applied research in the field of geothermal energy should be increased many times over the present level. Because little attention has been given to this area in the past, it is potentially highly leveraged. The investment of a few tens of millions of dollars now has the possibility of opening for development a vast new source of energy.
>
> There are two specific questions about geothermal energy that need answers: how large is the geothermal energy resource? Can we economically obtain energy from dry geothermal reservoirs? The first question can be resolved by a combination of terrestrial exploration and satellite studies of earth resources. The second question can only be answered by direct experimentation on a fractured, hot, dry, geothermal heat reservoir. This work on geothermal energy should receive highest priority.*

After citing these sources, the NRDC reaches the conclusion:

> The validation of this potential energy resource over the next few years could totally eliminate the need for the LMFBR. This consideration alone strongly suggests the prudent option of delaying any significant expenditure on the LMFBR program, particularly the commercial phase, over the next few years while the geothermal option is investigated.

The AEC agrees with the positions of the Cornell Workshop and the Task Force on Energy of the Committee on Science and Astronautics. It cannot agree with the conclusion drawn by the NRDC that, because a potential energy source <u>may</u> become available in sufficient magnitude to <u>assist</u>, along with energy conservation measures, in closing the energy gap, this is a sufficient reason for abandoning other promising energy options that are in advanced stages of development. This course would not be a prudent one to pursue in developing the Nation's energy options. Should geothermal energy prove to be as abundant as some hope, should the technology be successfully developed, and should the system prove economically competitive, then the time would come to decide whether other energy options should be pursued further; this decision should be made in the marketplace where all environmentally acceptable and technically and economically viable energy options should be made available.

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*Comment Letter <u>38b</u>, p. 20.

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6A.5 SOLAR ENERGY

6A.5.1 Introduction

6A.5.1.1 General Description

In response to the impending shortage of some fossil fuels, various proposals have been made to use solar energy as a substitute for other energy sources. The proposed applications include the production of electricity, thermal energy, and fuels. This section evaluates the methods of direct solar energy utilization based on artificial collection. The indirect manifestations of solar energy, such as wind, falling water, ocean thermal gradients, and organic wastes, are covered under separate headings in the Environmental Statement.

Energy from the sun falls on the earth's atmosphere at a rate of about 130 watts per square foot (W/ft^2).[1] Nights, weather, seasons, attenuation by the atmosphere, and variations in latitude reduce this rate to an average of 17 W/ft^2 for the surface of the United States.[2] Even so, the energy received from the sun exceeds the energy of all kinds that we produce from conventional fuels by a factor of nearly 700. This extremely large, daily renewable energy source has led some reviewers to claim* that "Solar energy actually offers the only continuous, unlimited source of energy, renewable daily. It offers us the only opportunity to live within our energy income, instead of on our finite energy capital." This claim can be made, and has been made, for indirect as well as direct solar-related energy phenomena including wind-power and ocean thermal gradients. The statement is, of course, basically true, although it deprecates the very large energy resources available in uranium and deuterium. An energy resource becomes recoverable when the state of its technology, the economics of its utilization, and its social acceptability all combine to make its exploitation feasible and desirable. In other words, the total amount of energy inherently available in a particular energy resource is not as important as the amount of energy extractable at costs--economic, environmental, and social--that are competitive with other available energy resources. The following discussion attempts to place the vast but extremely dilute and interruptible solar energy resource in its proper perspective in these regards.

The methods that have been proposed to produce electricity from solar energy are: (1) thermal conversion, (2) photovoltaic conversion (solar cells), and (3) burning

*Testimony of the Scientists Institute for Public Information in regard to the Atomic Energy Commission's Draft Environmental Statement in the LMFBR Program, April 25, 1974, Section V, p. V-3.

of photosynthetic materials. In the thermal-conversion process, shown schematically in Figure 6A.5-1, solar energy is collected in a heat-transfer fluid that is used in a thermodynamic cycle to generate electricity as in other steam-electric plants. In the photovoltaic process, solar energy is converted directly to electricity in solar cells. Electricity production based on photosynthetic materials would be accomplished primarily by combustion of vegetable carbohydrates in a conventional steam-electric plant. All of these methods may be applicable to central-station power generation, and the thermal conversion and photovoltaic processes have also been proposed for small units suitable for residential or commercial buildings. Solar cells, in particular, may be suitable for this application.

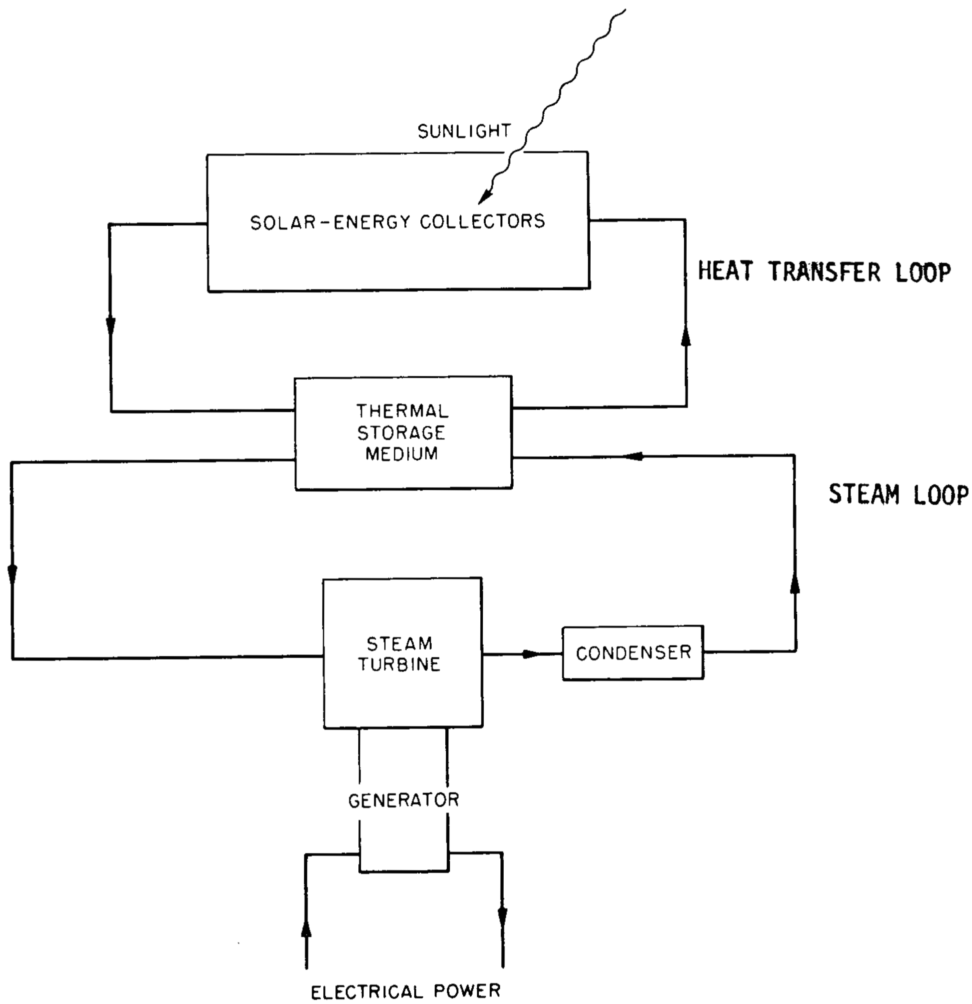
Thermal energy derived from solar radiation can also be used for space conditioning (i.e., heating and cooling of buildings) and residential water heating.

The production of high-energy fuels from solar energy involves two basic steps. The first step is the managed conversion of solar energy into plant tissue (e.g., trees, grasses, water plants, and algae) by photosynthesis. Because plant tissue has a low-energy content per unit volume, conversion to a high-energy gaseous, liquid, or solid fuel is desirable. Conversion methods include fermentation, pyrolysis, and chemical reduction.

6A.5.1.2 History

The collection and use of solar energy for thermal applications has been practiced for centuries. Early uses were primarily scientific in nature. "Burning lenses" were, and still are, used in chemical and metallurgical researches involving high temperatures.

Although electrical generation from solar energy by thermal conversion has not been attempted, the technical feasibility of doing so is not questioned. Thermal conversion to mechanical energy was demonstrated in the latter part of the 19th century. A workable solar-powered water pump was displayed by Mouchot at the Paris World Fair in 1878.[3] Frank Shuman, an American engineer, built a 100-hp solar-powered steam engine in Egypt in 1912.[3] But all attempts at a practicable system have been less than satisfactory, primarily because collectors have not been developed that will collect solar energy efficiently and, at the same time, provide high temperatures necessary for good efficiency of a heat engine.



SCHEMATIC OF A THERMAL-CONVERSION SOLAR POWER SYSTEM
Figure 6A.5-1

6A.5.1.3 Status

Most contemporary uses of solar energy are to provide thermal energy for buildings. Solar water heaters are manufactured and used in several countries including the United States; they were once common in Florida, but their use has diminished because of the availability of natural gas. Space heating by use of solar energy has been demonstrated in about 20 experimental buildings.[4] Under National Science Foundation (NSF) sponsorship, four schools in different parts of the country have recently been equipped with solar collectors to provide portions of the heating loads.[5] Some experimental work on solar-powered air conditioning by use of absorption refrigeration has been conducted, and an experimental house that uses solar energy for both heating and cooling has been constructed at Colorado State University.[5] This house is to be used as a solar energy laboratory for NSF-sponsored research. Solar energy systems for residential and commercial buildings that combine water heating, space heating, and air conditioning are considered to have the most promise because solar collectors and energy storage units, the major cost centers, are common to all three functions.

The recent resurgence of interest in thermal conversion is due primarily to the efforts of Drs. Aden and Margorie Meinel of the University of Arizona. They propose a solar collection system that would use selective surfaces and optical intensification; the hope is that the system would provide temperatures comparable with those achieved in modern fossil-fueled steam-electric plants.

Electric generation by use of solar cells is a well established technology for a number of specialized applications. Arrays of silicon cells are used in spacecraft to supply electrical needs. Terrestrial uses include power for navigation lights on offshore platforms, microwave repeater stations, air-navigation beacons, highway emergency call systems, and railroad signaling devices.[4,6] Solar-cell power units vary in size from a few watts to over 20 kW for Skylab. The annual United States production of silicon solar cells is 50 to 70 kW, most of which are for space applications.[4] Large photovoltaic systems for terrestrial applications are still in the research stage.

The production of high-energy fuels from solar energy has been demonstrated to be technically feasible but has not been applied commercially.[4] The managed production of raw photosynthetic materials for fuels would be analogous to tree farming for lumber and paper, the cultivation of grasses for hay, and algae culture for removing nutrients in sewage ponds. Conversion of the raw material to high-energy gaseous liquid and solid fuels by biological and chemical processes has been demonstrated on a pilot scale.[4]

Because of the renewed interest in solar energy, two separate panels of national stature have recently reported the results of their studies on (1) the state of technology, (2) the projected national impact, and (3) the research and development required to realize the full potential of solar energy. The first panel[4] was organized jointly by the National Science Foundation and the National Aeronautics and Space Administration (NASA), and its report was issued in December 1972. The second, and more recent, panel[7] was organized to provide input to "The Nation's Energy Future,"[8] a report to the President that defines and recommends a national five-year research program on energy. The second panel's report, entitled "Subpanel IX, Solar Energy Program," was completed in November 1973.

Most areas of research and development recommended by the above panels are now under study, and this work involves at least three Federal agencies--NSF, NASA, and AEC--as well as many industry and university groups.[9] The NSF Solar Energy Program covers all applications. NASA is involved in the heating and cooling of buildings, wind energy, and solar cells. The AEC work involves energy for buildings and improved solar concentrators.[10-12]

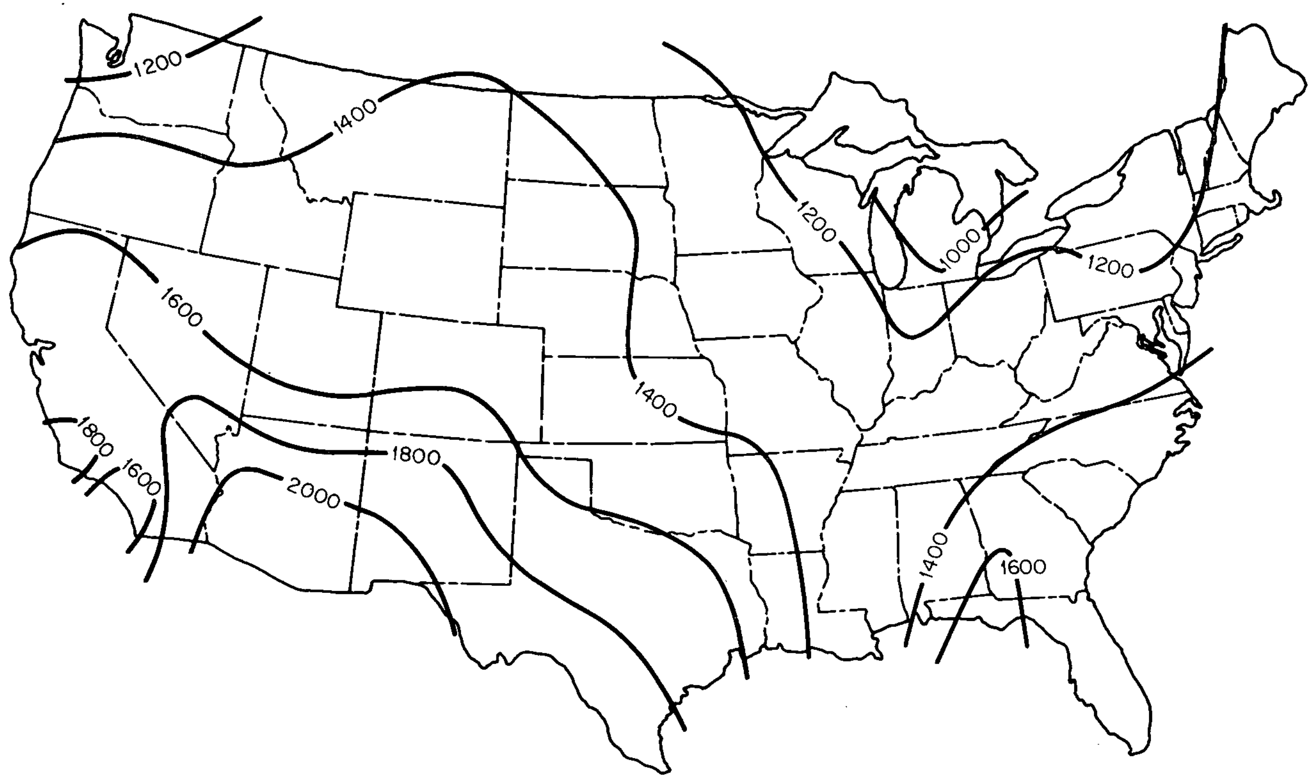
6A.5.2 Extent of Energy Resource

6A.5.2.1 Geographical Distribution

The resource base, that is, the rate at which solar energy is incident on the surface of the United States, is reasonably well established and amounts to about 1.43×10^9 MWt-years/year for the conterminous United States. If converted at 10% efficiency, solar energy could provide electricity at a rate greater than a hundred times the rate of consumption expected for the year 2000. The resource base is not uniformly distributed over the United States and ranges from an average of about 12 W/ft^2 for portions of Michigan and Wisconsin to about 24 W/ft^2 for southern Arizona and New Mexico. Figure 6A.5-2 shows the distribution of solar energy over the United States for an average day.[13]

6A.5.2.2 Estimated Availability

The resource base does not, of course, constitute a recoverable resource unless and until the cost of recovery is competitive with the costs of alternative energy sources. At the present, the recoverable resource is very small since the economic feasibility of solar energy has been demonstrated for only a few specialized applications.



DISTRIBUTION OF SOLAR ENERGY OVER THE UNITED STATES[a]

Figure 6A.5-2

[a]Figures give solar heat in Btu/ft^2 per average day.

For central-station electric power based on solar energy, the availability of large tracts of land with high solar inputs is essential. Most proposals for central-station plants are based on the assumption that the plants will be located in the desert Southwest. More than 100,000 square miles in the western United States are desert.[14] Some estimates[14,15] indicate that as little as 10% of this land would be needed to provide the electrical capacity required in the year 2000 (2 million MWe).

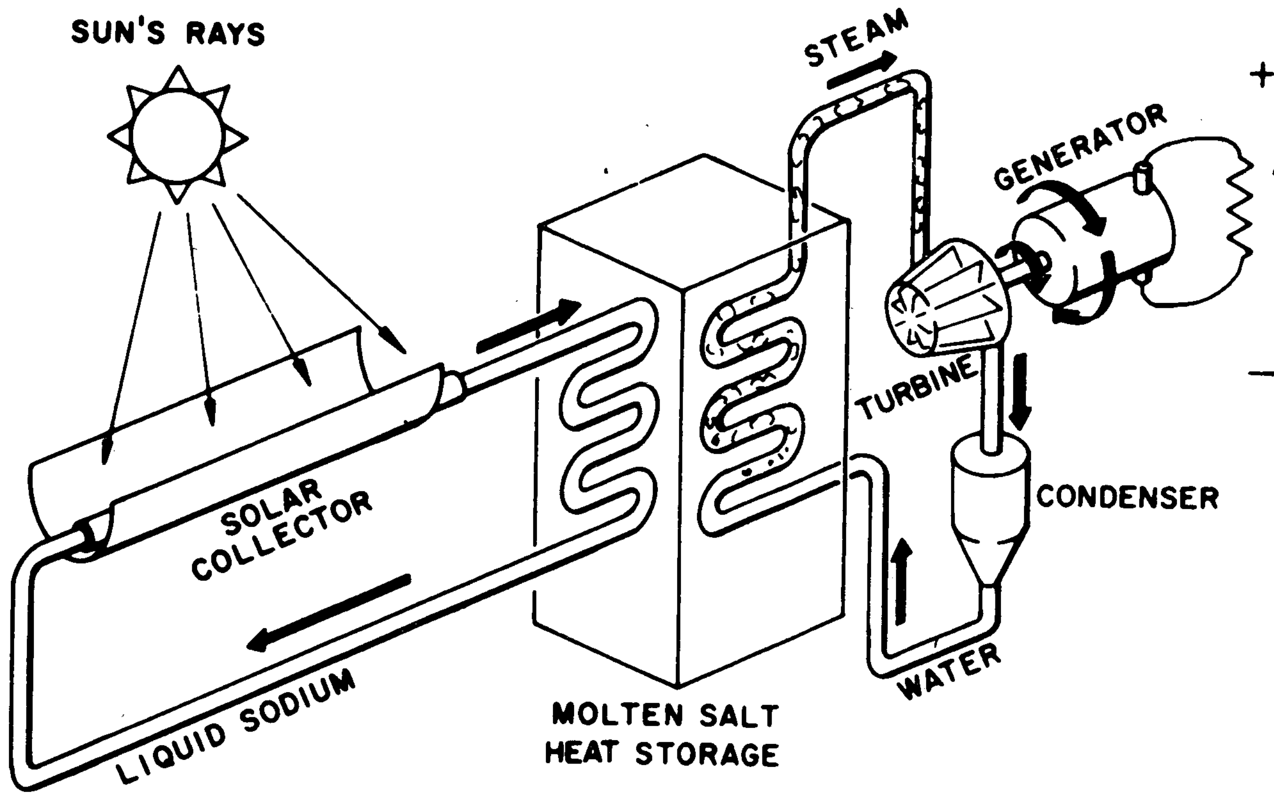
6A.5.3 Technical Description

6A.5.3.1 Thermal Conversion

Several variations of thermal-conversion systems are possible;[15] the one proposed by the Drs. Meinel[16] has attracted considerable attention, and the elements of their system are reasonably representative of others. The basic components of a thermal-conversion solar electric plant are: (1) an energy-collection system, (2) an energy-storage system, and (3) an energy-conversion system. Figure 6A.5-3 illustrates the system.

The Meinel concept for a collector system stems from recent developments in producing selective films that have high absorptivity for short-wavelength solar radiation and low emissivity for the long-wavelength infrared radiation.[17,18] Infrared radiation accounts for much of the energy loss of a heated surface. The use of selective films in conjunction with some optical concentration of the incident radiation by suitable lenses or mirrors may make possible the attainment of temperatures of the order of 1000°F in the collecting fluid. The collector pipes, containing a heat transfer fluid such as sodium, are oriented in an east-west direction, as a reasonable alternative to tracking the sun (with the attendant cost of the tracking mechanism). Each pipe is coated with a selective film and is located within an evacuated glass envelope. Either this enclosed pipe is located at the focus of a parabolic mirror, or, in an alternative arrangement, a Fresnel lens focuses the sun's rays on the collector tube.

Heat is transported from the collector field by circulation of molten sodium inside the collector tubes. From the sodium, the energy is transferred to a thermal storage tank, where it is stored as the heat of fusion of a eutectic salt. Energy storage is required if the plant is to be capable of operating continuously. The heat-storage unit serves as the source of energy to generate steam, which drives a conventional turbine-generator. Heat could be rejected from the cycle by any means suitable for fossil-fueled plants, but because most studies of solar thermal-conversion plants assume a desert location, dry cooling towers would seem to be required.



SCHEMATIC OF A SOLAR THERMAL-CONVERSION POWER SYSTEM

Figure 6A.5-3

Proponents of thermal conversion of solar energy believe that efficiencies of 20 to 30% (percent of incident radiation converted to electricity) can be achieved.[4] Others estimate the range to be 10 to 20%.

In the southwestern United States, a minimum of 6400 acres (10 square miles) would be needed for a thermal solar power plant of sufficient size to provide the electrical energy equivalent to that of a nuclear or fossil-fueled power plant of 1000 MWe operating, on the average, at 70% of capacity.[4]

6A.5.3.2 Photovoltaic Conversion

Photovoltaic conversion systems are based on the principle that in some solid-state materials (e.g., silicon) the absorption of photons (light) generates free electrical charges. These charges are collected on contacts applied to the surfaces of the semiconductor. The solar-cell materials most frequently mentioned are silicon, cadmium sulfide, and gallium arsenide.[19,20] The maximal theoretical conversion efficiency is about 25% for a single semiconductor device operating at room temperature.[4] Efficiencies of 13 to 14% for silicon cells and 4 to 6% for cadmium sulfide cells are achieved in terrestrial applications.[4]

Individual cells are connected in series-parallel arrays to obtain the desired direct current (dc) voltage and current. Several solar panels, the number depending on the application, would be assembled to form an electric power source. Essentially three types of electric plants that would use solar cells have been proposed: (1) terrestrial central power stations, (2) earth-satellite central power stations, and (3) power units for buildings.

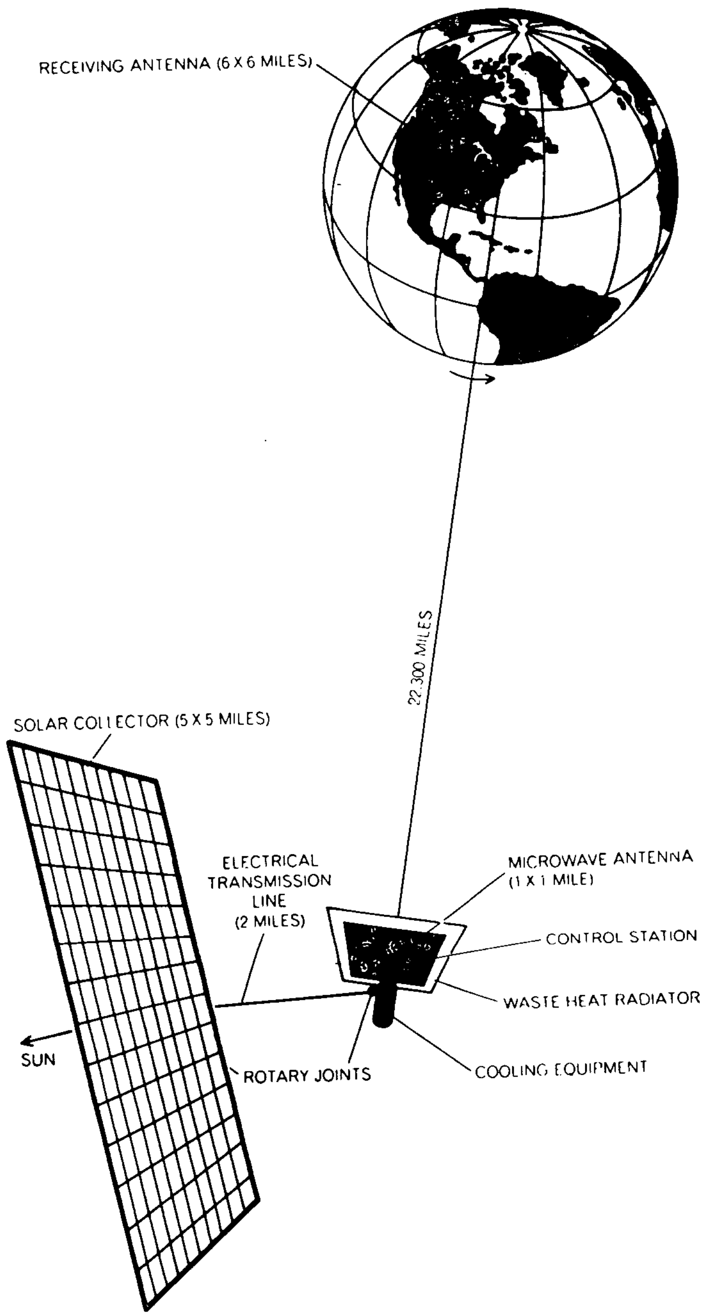
Terrestrial central power stations would consist of a large number of solar panels dispersed over a large area. The collector field would need to be prepared so as to protect the panels from damage during storms, to minimize dust formation on the cells, and to provide access for maintenance. If the plant were to be a continuous source of power, energy storage in a mechanical or chemical form would be necessary. The energy could be stored by use of batteries, pumped water, rotating masses, or electrolytic hydrogen.[21] Of these, batteries might be the most promising, although batteries for central-station energy storage are in the developmental stage. If the solar-energy plant were to be connected to an alternating current (ac) grid, dc-to-ac converters would be required. At an efficiency of 10% for the combined collection-storage-converter system, a 1000-MWe power station located in the southwestern United States would require about 9500 acres (15 square miles) of cell surface, which would cover a total area of about 19,000 acres (30 square miles).

The needed plant area is larger than the cell area because space is required between panels to eliminate shading and to provide access for maintenance.

Satellite central power stations, illustrated in Figure 6A.5-4, are the most imaginative of all solar-energy proposals.[22] Satellites containing fields of solar cells could be placed in synchronous orbit around the earth's equator. The 10,000-MWe station shown in Figure 6A.5-4 would require a 5- by 5-mile field of solar cells. Electricity generated in the solar-cell fields would be fed to micrwave generators arranged in the form of an antenna. The antenna would beam the microwave energy to a receiving antenna on earth, which would then convert the microwave energy back to electricity. The advantages of producing electricity this way are that a satellite receives solar energy unattenuated by the earth's atmosphere for the entire 24-hr day, except for short times at the equinoxes, and that microwaves can be transmitted to earth, even through cloud cover, with little loss.[23] Since satellite power plants would require technical achievements far beyond those needed for terrestrial solar-energy plants (including many flights by second-generation space shuttles, the development of space "tugs" to move the massive amounts of material required for the many square miles of solar panels, and orders of magnitude reductions in the cost of solar cells), satellite power plants are not likely to play a role in supplying energy in the foreseeable future.

The use of solar cells on buildings locates the generator at the place of the load, and the system matches the nature of distribution of solar energy to the pattern of distribution of the energy being consumed. Photovoltaic arrays would be mounted on buildings or incorporated within their structures; thus, no additional land would be required. Since most buildings require both thermal and electrical energy, the combination of solar-cell arrays with flat-plate thermal collectors has been proposed.[4] The estimate is made that the combined system would use as much as 60% of the available solar energy. As in all terrestrial solar-energy systems, energy storage would be needed. To provide local storage capacity for more than an average day's requirement is, in general, considered to be uneconomical.[4] Storage could be provided by batteries, flywheels, or a combination of electrolysis cells and fuel cells. In addition to collectors and energy storage, solar electric plants for buildings would also require an electrical power conditioning system to convert dc to 60-cycle ac of the appropriate voltage.

A consideration not discussed by solar energy proponents is that, unless sufficient energy storage can be provided, proposed solar electric systems for buildings would require an external source of electricity during a series of cloudy days. Thus, the



SCHEMATIC OF A 10,000-MWe SATELLITE SOLAR POWER STATION

Figure 6A.5-4

required external capacity (generating plant, transmission system, and distribution system) would not be reduced significantly. Therefore, solar electric systems for buildings would save fuel but would not materially affect the local utility's investment in power facilities.

6A.5.3.3 Combustion of Photosynthetic Materials

A power plant that burned wood, grasses, water plants, or algae would be similar to a conventional fossil-fueled steam-electric power plant. Because photosynthetic materials contain much less energy per unit volume than do fossil fuels, the transportation of such materials over long distances would probably be uneconomical, and power plants would therefore need to be located close to the growing site.

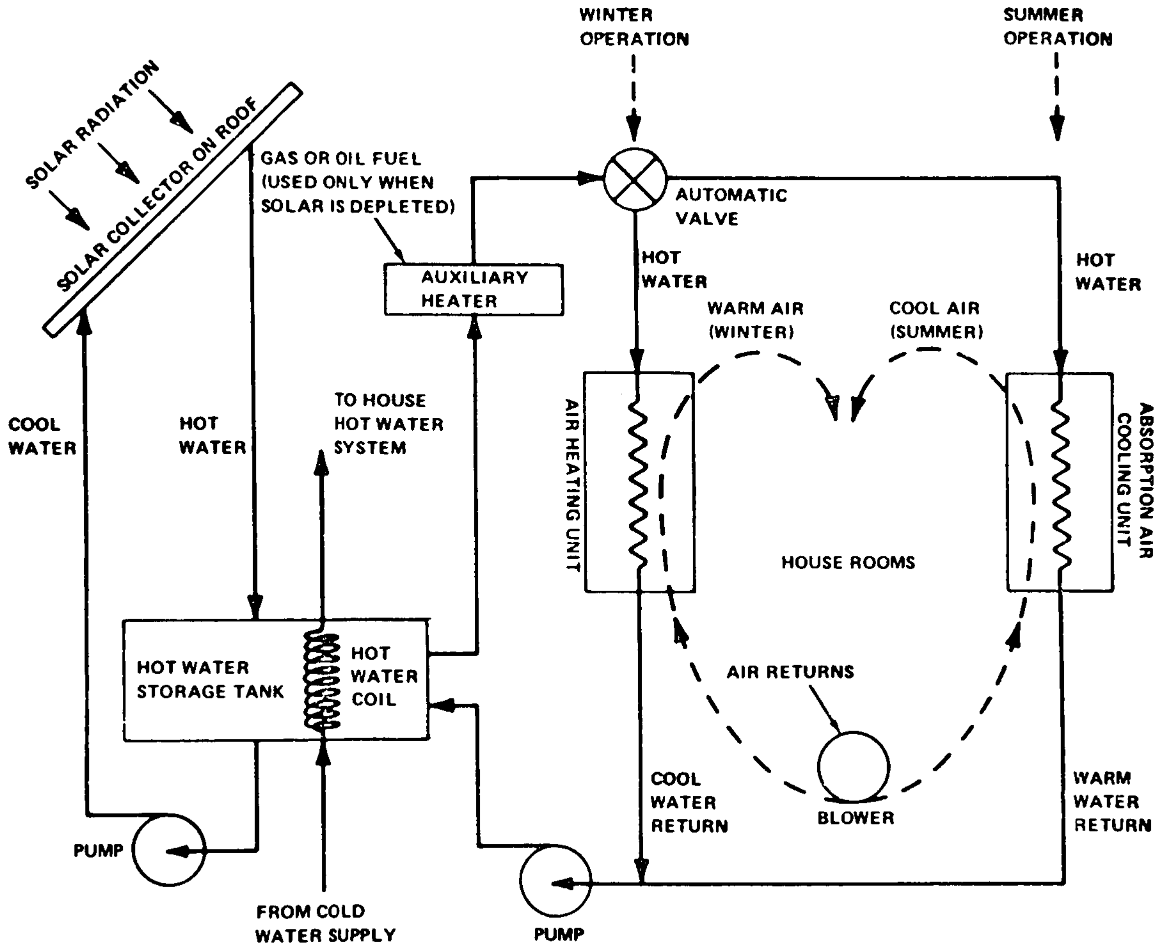
In ordinary agriculture, solar energy conversion to dry plant material is achieved at conversion efficiencies of about 0.1%. With intensive agriculture, some believe that conversion efficiencies might be improved to 3 to 5%.[4] If a power plant could convert this energy to electricity at 33 to 40% efficiency, the overall solar-energy to electrical-energy conversion efficiency would be 1 to 2%. Enormous amounts of land suitable for agriculture or tree farming would be required. For example, a 1000-MWe power plant has been estimated to require a "forest plantation" of 250,000 to 320,000 acres (400 to 500 square miles). Dual-purpose use of this land (e.g., recreation along with production of photosynthetic material) may be attempted if site conditions warrant.

In addition to the power plant and fuel "farm," facilities and equipment would be required to harvest, transport, and chip the wood.

6A.5.3.4 Thermal Collection

Hot water for household use as well as energy for space heating and cooling could be supplied by solar energy. Figure 6A.5-5 shows one such home energy system. The estimate[4] is made that in a temperate, sunny location in the central United States, a 1500-ft^2 house could be provided with about 75% of its heating and cooling needs by a 600- to 800-ft^2 collector and 2000 gal of hot-water-storage capacity. The additional 25% of heating and cooling energy needed under adverse weather conditions would be supplied by some auxiliary source.

In addition to a flat-plate collector, a system such as that in Figure 6A.5-5 would include an insulated storage tank, an auxiliary heat-supply system, an absorption air conditioner, and various pumps, controls, and ducts to circulate air from the conditioned space to either the heating or cooling unit. No additional land would



SCHEMATIC OF RESIDENTIAL HEATING AND COOLING WITH SOLAR ENERGY--
ONE ALTERNATIVE

Figure 6A.5-5

be required for most buildings since the surface of the structure would be of sufficient area for the collectors.

6A.5.3.5 Production of High-Energy Fuels

As noted previously, one drawback to the use of raw photosynthetic material for fuel is that it must be used near its source because of its low energy content per unit volume. Conversion to high-energy transportable fuels in the form of gases, liquids, or solids could be achieved by various processes. However, such processes convert the raw fuel at less than 100% efficiency; therefore, the land area required to yield a given amount of energy would be more than that required if the raw fuel were burned directly. One estimate[7] concludes that the production of 10% of the energy needs of the United States by photosynthesis would require about the total area currently farmed.

Anaerobic fermentation of organic materials produces a gas mixture that contains 50 to 70% methane, 30 to 50% carbon dioxide, and trace amounts of hydrogen sulfide and nitrogen. This crude product, with an energy content of 500 to 700 Btu/ft^3, could be burned in a power plant or be refined to remove carbon dioxide and other impurities. The pure methane, with a heating value of about 1000 Btu/ft^3, could be introduced into existing pipelines as a replacement for natural gas.

Pyrolysis is a process of destructive distillation carried out in a closed vessel in an atmosphere devoid of oxygen and at high temperature (900 to 1700°F). Organic materials treated by pyrolysis yield gases, oil-like liquids, and solids similar to charcoal. Typically, the gases are mixtures of hydrogen, methane, carbon dioxide, carbon monoxide, and lower hydrocarbons. Conversion efficiencies have been rather low in the past,[4] and the process is probably of greatest interest for reducing solid wastes.

6A.5.4 Research and Development Program

The NSF-NASA Solar Energy Panel[4] recommended a research and development program that would cover all aspects of solar energy applications. The Federal government would take a lead role in the program. Table 6A.5-1 lists major technical problems to be resolved, and Table 6A.5-2 gives the estimated funding for a 15-year program. This program would, according to the panel, develop solar energy sufficiently to provide the market penetrations discussed in Section 5.5.

Table 6A.5-1

SUMMARY OF MAJOR TECHNICAL PROBLEMS

Application	Major Technical Problems to be Solved
Thermal energy for buildings	Development of solar air conditioning and integration of heating and cooling
Renewable clean fuel sources	
Combustion of organic materials	Development of efficient growth, harvesting, chipping, drying, and transportation systems
Bioconversion of organic materials to methane	Development of efficient conversion processes and economical sources of organic materials
Pyrolysis of organic materials to gas, liquid, and solid fuels	Optimization of fuel production for different feed materials
Chemical reduction of organic materials to oil	Optimization of organic feed system and oil separation process
Electric-power generation	
Thermal conversion	Development of collector, heat transfer, and storage subsystems
Photovoltaic conversion	Development of low-cost long-life solar arrays
Systems on buildings	High-temperature operation and energy storage
Ground station	Energy storage
Space station	Development of light-weight, long-life, low-cost solar array; transportation, construction, operation, and maintenance; development and deployment of extremely large and light-weight structures

Table 6A.5-2

SUMMARY OF OVERALL PROGRAM FUNDING

Applications	Long-Range (15-year) Research Program ($ million)
Thermal energy for buildings	100
Renewable clean fuel sources	
Photosynthetic production of organic materials and hydrogen	60
Conversion of organic materials to fuels or energy	310
Electric-power generation	
Solar thermal conversion	1130
Photovoltaic conversion	780

The more recent report on "The Nation's Energy Future"[8] outlines a $140-million program over the next five years that would determine, through pilot applications, the effective use of solar thermal energy for heating and cooling of buildings; examine the use of solar thermal energy for electric power generation through operation of a 10-MWe pilot plant; determine the capability to produce economically competitive photovoltaic cells by laboratory experimentation and development of mass production concepts; and construct and operate a plant involving the conversion of wastes into methane. Additional funding on the order of $79 million for "indirect" applications of solar energy (e.g., wind power and ocean thermal gradients) is also proposed as discussed in Section 6A.6.

The Subpanel IX report, which provided input material for the report on "The Nation's Energy Future," contains detailed recommendations on research and development needs for both direct and indirect (wind and ocean thermal gradients) solar energy systems. The summary portion of the Subpanel IX report outlines a program consistent with that reported in "The Nation's Energy Future" as described above. However, individual sections of the Subpanel IX report recommend a much more ambitious five-year program for direct solar conversion amounting to $851 million for an accelerated program and $341.7 million for a minimum program.

6A.5.5 Present and Projected Application

As noted above, solar energy currently provides some thermal energy for buildings but is not yet used for the production of electrical power. Projections of future applications of solar energy for producing electricity, thermal energy, and high value fuels have been made by the NSF-NASA Solar Energy Panel, by the Subpanel IX group, and by the MITRE Corporation.[9] The various projections are summarized in Table 6A.5-3. All projections are based on the assumption that a substantial research program will be undertaken for each of the solar energy systems and that these programs will result in economically viable alternatives to conventional energy sources. The research and development requirements are discussed in Section 6A.5.4.

All three groups mentioned above agree that the most significant near-term impact of solar energy will be in the heating and cooling of new buildings. The projections of the portion of building thermal energy supplied by solar range from 10% (NSF-NASA) to 30% (Subpanel IX) by the year 2000. The corresponding range for the year 2020 is 31% (MITRE) to 50% (Subpanel IX). The electricity generation that could potentially be displaced by using solar thermal energy for buildings was not estimated by any of the groups. If solar is assumed to displace all building thermal

Table 6A.5-3

PROJECTIONS OF POTENTIAL SOLAR ENERGY APPLICATIONS

Application	Market Penetration by Year Given[a]					
	2000			2020		
	NSF-NASA	Subpanel IX	MITRE[b]	NSF-NASA	Subpanel IX	MITRE[b]
Thermal Energy for Buildings	10%	30%	18%	35%	50%	31%
Electric Energy						
Solar Thermal Conversion	1%	40,000 MW (peak)	12%-29%	5%	30%[e]	29%
Photovoltaic	1%	100,000 (peak) MW[c]	12%-29%	10%	10%	29%
Combustion of Organic Material	1%			10%		
Total Electric				20%[f]		
High Energy Fuels						
Gaseous	10%[g]	50%[d]		30%[g]		
Liquids	1%[g]			10%[g]		
Other						
Organic Fuels[g,h]			(7%)			(10%)
Process Energy[h]			(1%)			(10%)

[a]Figures show the percent of each energy market captured by solar unless otherwise specified.

[b]MITRE Corporation projections given in Report MTR-6513 are in terms of national energy consumption. Table values were computed using data on building thermal energy from Report AET-8, year 2000 electrical production from Dupree and West, and year 2020 electrical production from Report AET-8.

[c]Subpanel IX report gives various values for photovoltaic market projections including 1%, 2%, 5%, and 7% of electrical capacity by the year 2000. The 100,000-MWe (peak) figure was obtained from their year-by-year tabulation of installed photovoltaic capacity. This peak capacity would correspond to about 2% of projected electrical generating capacity in the year 2000. Similarly, solar thermal conversion peak capacity corresponds to less than 1%.

[d]Six percent from organic wastes and 44% from managed production of photosynthetic materials. Time period for achievement of given percentages unspecified in Subpanel IX report.

[e]Subpanel IX indicates that 30% is the ultimate potential of solar thermal conversion. Time period unspecified.

[f]Includes energy generated by wind and ocean thermal gradients.

[g]Includes high-energy fuels from organic wastes as well as managed production of photosynthetic materials.

[h]Parenthesized figures are percentages of national energy consumption.

energy sources (oil, gas, electricity) equally, then the above projections are equivalent to reducing electrical energy production by 2% to 6% in the year 2000 and by 4% to 7% in the year 2020. These estimates are based on projections of electrical energy needs in the year 2000 by Dupree and West[24] and in the year 2020 by Associated Universities.[25] Building thermal energy requirements used are those estimated in ref. 25.

Projections for the fraction of electrical energy needs supplied by solar in the year 2000 range from less than 5% by the NSF-NASA Solar Energy Panel to 12% to 29% each for thermal conversion and photovoltaic systems by MITRE. Projections for the year 2020 are (1) 20% by NSF-NASA (including wind and ocean thermal gradient systems), (2) 10% photovoltaic and 30% (ultimate potential) solar thermal conversion by Subpanel IX, and (3) 29% photovoltaic and 29% thermal conversion by MITRE. A number of comments* received on the draft LMFBR Program Statement noted that it did not consider the projections made by Subpanel IX; a major point of these comments was that Subpanel IX predicted that 7% of the electrical capacity in the year 2000 will be photovoltaic systems. In reality, the Subpanel IX report includes a number of statements on potential market penetrations, including 1%, 2%, 5%, and 7%, by the year 2000. The value shown in Table 6A.5-3 of 100,000 MWe (peak) is based on a year-to-year tabulation of the projected rate of application given in the Subpanel IX report. Assuming a peak-to-average power of 5 for photovoltaic plants and further assuming that such plants operate 100% of the time sunlight is available, the above peak capacity would generate 20,000 MW-years of energy in the year 2000; this amount is less than 2% of total electricity production projected for that year.

Concerning the production of high-energy fuels, the NSF-NASA Solar Energy Panel believes that 10% of the gaseous fuels and 1% of the liquid fuels needed in the year 2000 could be supplied from organic wastes and the managed production of photosynthetic materials. Corresponding figures for 2020 are 30% and 10% for gas and liquids, respectively. The Subpanel IX group projected that 50% of the gaseous fuel needs could be met by organic materials (44% from managed photosynthesis and 6% from organic wastes), but no time period was specified for this achievement.

Although there may be disagreement on some details of the expected market penetration for solar energy systems, all three assessments reviewed above express the view that almost all proposed schemes for utilizing solar energy could become important, if not

*Scientists Institute for Public Information in testimony at the Public Hearing on the LMFBR Program, April 25-26, 1974, pp. V-5 to V-7; Friends of the Earth in testimony at the Public Hearing on the LMFBR Program, April 26, 1974, pp. 281-282; Comment Letter 26, pp. 10-13; Comment Letter 42, p. 39.

in this century, then at least by 2020. But there are other viewpoints. For example, H. C. Hottel of the Massachusetts Institute of Technology, a well known scientist in the field of solar energy, summed up his assessment as follows:[26]

> The sun can possibly supply low-potential energy for domestic hot water, house-heating, and air conditioning, but the effect on the national energy balance cannot but be insignificant for decades. Solar energy as a source of power has poor prospects of economic significance until the distant future when fossil fuel supplies are several times and nuclear fuel supplies many times more expensive than at present.

George Löf of Colorado State University, another recognized expert on solar energy, expressed a similar viewpoint in his June 7, 1973, testimony[27] before the House Committee on Science and Astronautics. He is optimistic about the potential for residential heating and cooling but is less so on solar-generated electricity, as indicated by the following statement:

> This Committee has heard testimony related to the status and prospects of solar power-plants and can therefore appreciate the formidable technical and economic barriers to that application in the near future. In spite of some optimistic claims by enthusiastic proponents of various schemes for solar power generation, objective analysis shows that electricity from solar energy will cost at least several times the current cost of conventional power.

The Meinels, of the University of Arizona, who are among the leaders in solar energy technology, express a somewhat different view on the most promising applications for solar energy as follows:[15]

> In our opinion solar heating and cooling for the individual home is not going to be widely successful. People who like gadgets may find them interesting and satisfactory. Most people will simply not want to be bothered with them. Some who get them may be distinctly unhappy, feeling that they were the victims of oversell.
>
> We think that solar installations will be far more successful for apartments, condominiums and commercial buildings.

The Meinels believe[15] "...that solar energy will ultimately have its greatest impact and benefit for this country in electrical power production." Their viewpoint on the difficulty with managed photosynthesis is that "the principal problem that the use of a crop entails is caused by the low quantum efficiency of biological mechanisms and the large land areas needed to produce a significant portion of our energy needs. Crops require arable land, fertilizers and water. All three will be in increasingly short supply just to meet needs for food, fiber and pulp."

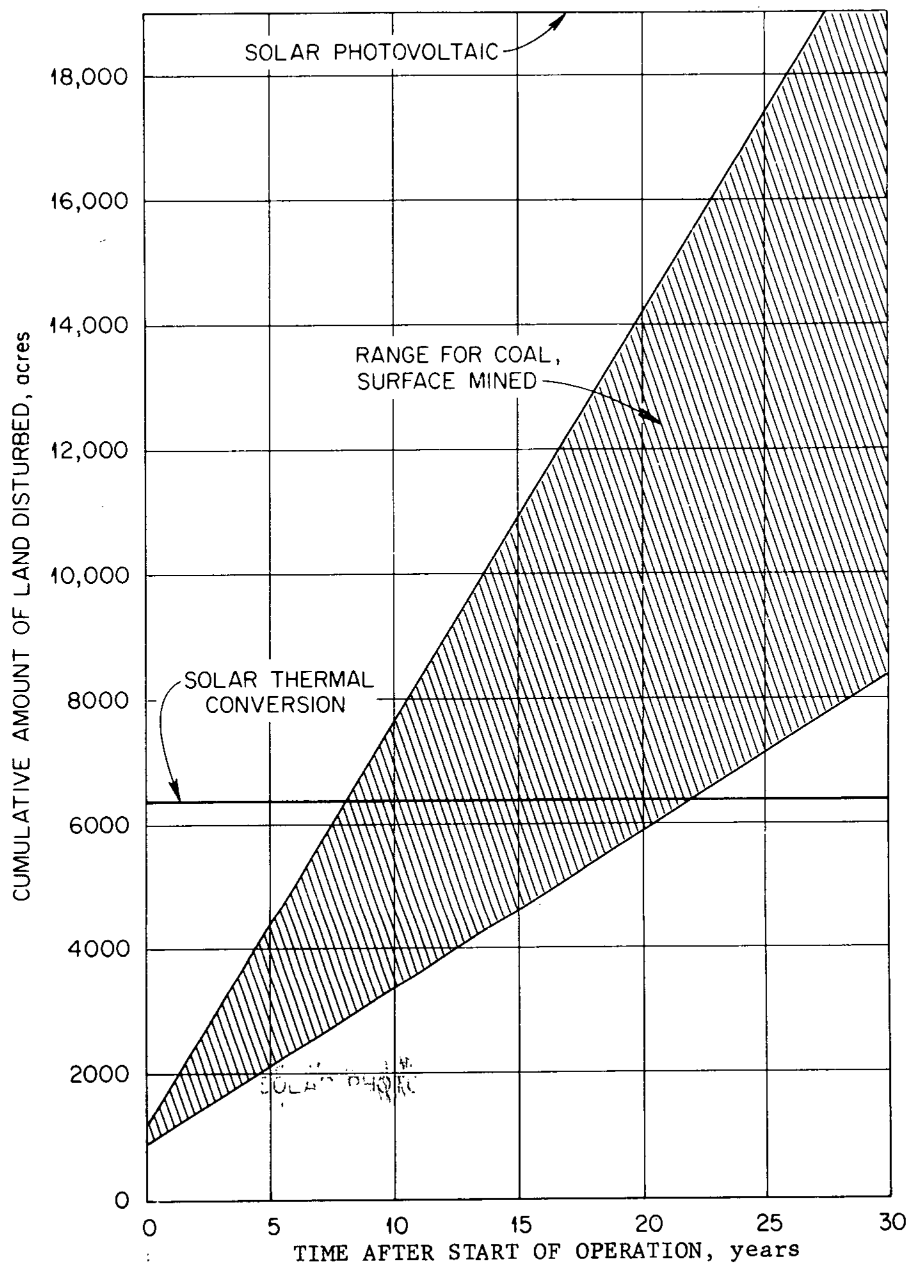
In contrast with the above judgments, which indicate at least some relatively near-term uses for solar energy, other groups[24,25] concerned with projecting energy requirements and energy resources estimate no significant contribution from any kind of solar energy system at least through the year 2000. Nevertheless, some basis appears to exist for the viewpoint that solar energy for the heating and cooling of buildings could make some contribution before the end of the century. Little basis exists for projecting a measurable contribution of solar energy to either electricity generation or high-energy fuels in this century since even optimistic projections of cost place solar conversion in a poor competitive position relative to either coal or nuclear energy. The significant market penetrations projected by some groups (see Table 6A.5-3) do not seem to be consistent with their projections of economic viability. The economic projections are reviewed in Section 6A.5.7.

6A.5.6 Environmental Impacts

6A.5.6.1 Central-Station Power Plants

6A.5.6.1.1 Surface Effects

Since energy from the sun is very diffuse, large land areas form one outstanding characteristic of solar-energy conversion systems. Estimated area requirements for a 1000-MWe plant are 6400 acres (10 square miles), 19,000 acres (30 square miles), and 320,000 acres (500 square miles) for power produced by thermal conversion, photovoltaic conversion, and combustion of photosynthetic materials, respectively. In reality, actual figures might be somewhat higher because these estimates are based on rather optimistic assumptions concerning achievable efficiencies. Nevertheless, the proposed use of land for thermal and photovoltaic conversion is not unreasonable. Figure 6A.5-6 shows a comparison of total land disturbed for surface-mined coal and for solar electric plants based on thermal and photovoltaic conversions. In terms of total land disturbed, the solar plants would be more economical than coal over the long term. Although the comparison is not strictly valid, if proper reclamation of surface-mined land is assumed, the figure does give some perspective to the proposed use of land for solar electric plants based on thermal and photoelectric conversion. In contrast, the proposed use of land for power plants based on combustion of photosynthetic materials does seem unreasonable, because these plants require extremely large areas of productive land. With the world facing shortages of pulpwood, lumber, and food, the use of land solely for thermal-energy production when it is potentially capable of alleviating these shortages is highly questionable, especially if alternative sources of energy exist. Thus, the environmental aspects of photosynthetically produced energy will not be discussed further.



COMPARISON OF TOTAL LAND DISTURBED FROM SURFACE-MINED COAL AND SOLAR ELECTRIC PLANTS--EACH A 1000-MWe PLANT

Figure 6A.5-6

The land now most likely to be used for central-station thermal conversion or photovoltaic solar plants is in the desert and semi-desert Southwest. Some open-range grazing is done on parts that receive a little rainfall. The vegetation is so sparse (chiefly creosote bush and white bur sage, with lesser amounts of saltbush, paloverde, catclaw, and cactus) that the land is not very valuable as graze land.[1] During the winter and summer rains, the desert usually has a lush cover of annual grasses and forbs and is valuable for grazing for a short period. This land is used for very little human habitation or industrial activity except in the cities. If solar power plants were developed, the economic value of adjacent land would undoubtedly increase but aesthetic values might be reduced.

To develop land for large solar power plants will necessitate the construction of roads and sites for the solar collectors. This process may involve destruction of much of the local ecosystems. On the other hand, some persons believe that if half the land were shaded, it could be greatly improved as graze land. This modification would require new plantings and management. Before a judgment could be made on the feasibility of this agricultural use of the land, agricultural research would be necessary.

The presence of the large solar-energy collectors that would cover half the surface in any given area would appreciably alter the surface wind conditions. Acting as an impedance to winds, the collectors would lessen the amount of erosion. Also, since the water runoff from the collectors could be directed back under the shaded area, water that would fall as rain or dew could be retained longer and would increase the quantity of vegetation. Care would have to be taken that the water-runoff patterns avoided erosion.

The shade itself would have a significant effect on the vegetation. Plants indigenous to the desert require high-intensity sunlight. Some ecologists believe that these plants would die out in shaded areas.[28]

Many species of mammals, reptiles, amphibians, birds, and invertebrates are in these desert regions. Some are threatened species. The construction of large central station solar plants might upset the ecological equilibrium, but to predict the changes that would occur in animal populations is difficult. The extent of change would obviously depend on the number and size of plants constructed.

6A.5.6.1.2 Effects on Air

No gases or particulates would be emitted from a solar plant, and no pollutant would be added to the air. In fact, by breaking up the wind, the collectors would probably decrease the dust in the air over the desert. In a thermal-conversion plant, about two-thirds of the heat collected would be discharged through the power-plant condenser, probably to dry cooling towers. Except for the updraft that this point source of hot air would cause, no atmospheric effects would result.

6A.5.6.1.3 Effects on Water

At the sites most likely to be chosen for solar plants, use of dry cooling towers with thermal-conversion plants might be necessary because water supply would be inadequate. However, if water were available and were used to condense the thermodynamic fluid, it would be evaporated in wet cooling towers, just as would be done in any other steam electric plant. For a photovoltaic plant, the water consumption would be negligible.

6A.5.6.1.4 Aesthetics

The appearance of a solar plant might not arouse serious objections, but a plant would virtually cover the visible landscape from any point near the plant. The appearance of the desert would be greatly altered; some observers might find the new appearance attractive, others might not. The opinions might depend on the number of large power stations built and their proximity to populated areas. In any case, the plant would be close to the ground and would not obstruct vision from a distance, except for cooling towers. Some sunlight probably would be reflected from the collector units. If electricity were transmitted by overhead power lines, these could produce an undesirable aesthetic effect, but this impact would also be characteristic of other energy sources.

Archaeologically and historically valuable sites could probably be avoided in siting the solar plants. In case of unavoidable archaeological site conflict, the continuation of at least some archaeological work on the plant site itself should be possible without adverse effect.

6A.5.6.1.5 Social Effects

Solar energy plants would be located in areas of such low population density that they would have no significant effect on existing populations. The changes that would occur in the general vicinity of the solar plant would open up new areas to social use. People would be attracted to jobs at the plant and in secondary occupations.

To the degree that transportation, raw materials, and water can be provided, industries that need large quantities of electric power might move into the region.

6A.5.6.1.6 Accidents

To imagine an accident to a solar plant which would directly affect the populace is difficult. Ruptures of heat-transfer lines could be troublesome but not catastrophic. Engineered safeguards should reduce these to a tolerable level. Of course, a plant that would cover such a large area would be fairly vulnerable to the forces of nature. Accidents of this kind could be costly, and, depending on the fluid used by the designer, a spill of heat-transfer fluid might have serious local environmental effects.

6A.5.6.2 Systems for Residential and Commercial Buildings

The use of solar energy systems to supply space heating, water heating, air conditioning, and electric power for individual buildings would have very little impact on the environment. No land in addition to that required for the building itself would be needed for most buildings--at least for single-story structures. The appearance of buildings would be affected somewhat, but with proper attention to architecture the appearance could be made pleasing. Local building codes would need to be changed, and sunlight rights would become an important factor.

6A.5.7 Costs and Benefits

6A.5.7.1 Internal Costs

6A.5.7.1.1 Thermal Conversion

Of the three main parts of a solar-conversion plant (collector field, storage system, and steam-electric generating system), the collecting field is the most costly. The design of large plants is still in the conceptual stage, and a good estimate of capital cost is extremely difficult to make. The NSF-NASA Solar Energy Panel estimated in 1972 that the cost of the solar-collection and -storage part of a thermal-conversion plant would be about \$600 per kilowatt of electrical capacity. Turbine-generator and other peripheral costs of the power plant would add an additional \$150 per kW. This expense would result in a power cost of 20 mills/kWhr based on 15.5% capital charges, a 70% plant capacity factor, and 1 mill/kWhr for operation and maintenance. Qualifications placed on the above estimates by the Solar Energy Panel are that the costs are for mass-produced components and that the

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solution to several unresolved problems is presupposed. In addition, the placement of at least the first demonstration solar power plants in the desert Southwest, far from population centers where the energy would be required, will significantly increase the cost of long-distance transmission of the electricity that will be produced.

The Oak Ridge National Laboratory[29] estimated that a first-of-a-kind solar thermal-conversion plant would cost over $3300 per kilowatt, but this cost might be reduced by a factor of 3 for advanced plants produced in quantity. Estimates of prices that coal and uranium ore would have to reach before solar energy would be competitive were $40 per ton of coal and $250 per pound of U_3O_8, respectively. The study concluded that (1) enough uranium ore would be available at prices below $250 per pound* to last over a century if burned in light water reactors and (2) sufficient coal is available in the United States at costs well below $40 per ton to last longer than the uranium even if an allowance is made for the cost of measures required to overcome the effects of coal mining and processing on the environment.

In a study by the MITRE Corporation[9] for the NSF, costs of solar thermal-conversion systems are estimated to be reduced to about $2000 per kilowatt (average) by the year 2020, and the cost of energy generated from such plants may exceed the cost of conventional power by over a factor of 2.

The above estimates are for solar thermal-conversion plants with some energy storage--generally overnight storage capacity. Researchers have pointed out[9,15] that for solar energy plants to provide firm power, several days of storage will be required. A MITRE study[9] indicated that even for the southwestern United States, four days of storage may be insufficient and up to 30 days may be required for some regions. Thus, most proposed solar thermal-conversion plants would not appear to be stand-alone systems; that is, they must be backed up with conventional power plants. In apparent recognition of the difficulty of providing sufficient storage, a different approach is proposed by the Subpanel IX group. Their view is that solar thermal-conversion plants could become economically viable by the late 1980's without significant energy storage (3-hr storage capacity proposed). They project electricity costs of 25 to 45 mills/kWhr based on an estimated capital investment of $450 to $800 per kilowatt peak ($1300 to $2500 average). The Subpanel IX group argues that this cost will be competitive with conventional plants producing peaking power, which they estimate to cost 30 mills/kWhr by 1985. If there were no cloudy

*As discussed in Section 6A.1.1.9, the availability of uranium from very low-grade sources (e.g., mining Chattanooga shale--$100 per pound and up) can be seriously questioned from the point of view of environmental impact.

days and if the peak power demand corresponded to periods of maximum solar insolation, the Subpanel IX comparison of solar power and conventional peaking power costs would have some validity.* Neither case seems to be true. Widespread cloudiness occurs in all regions of the country including the desert Southwest. The peak power demand for many regions occurs in the winter at 6 to 8 p.m.[30] For areas such as those served by TVA, where there is substantial space heating by electricity, the peaks occur in winter during early morning hours. Solar electric systems with limited energy storage would appear to need full capacity backup from conventional plants. Thus, power from such plants would not be peaking power but, rather, supplemental power. The value of the energy generated would be equal to the cost of the fuel saved by not operating the conventional plants. Assuming solar thermal-conversion plants could produce supplemental power for 25 to 45 mills/kWhr (as estimated by Subpanel IX), the prices of fuel resources at which the supplemental power from solar plants would be competitive are:

Oil: $11 to $20 per barrel (Peaking units at 25% efficiency)
Coal: $70 to $127 per ton (Base and intermediate load units at 40% efficiency)
Nuclear (LWR): $390 to $725 per pound of U_3O_8 (Baseload unit at 32% efficiency)

Thus, there is little possibility that solar thermal-conversion plants will displace either coal or nuclear generation since the supply of coal and uranium at prices significantly below those shown above would last well over a century. The only possible niche for solar plants would be as a supplemental source of power during periods in which peaking units are required.

6A.5.7.1.2 Photovoltaic Conversion

Present costs of solar-cell arrays are extremely high. For example, the Skylab solar arrays reportedly cost about $2 million per peak kilowatt. Cherry[31] estimates that, by improving the manufacturing process and using simple solar concentrators, silicon cell arrays could be produced for $10,000 per peak kilowatt and that this cost might be reduced to $2500 per peak kilowatt if an inexpensive process for mass-producing cadmium sulfide cells were developed. Ultimately, Cherry believes, cadmium sulfide cells could be produced at 50¢ per square foot ($50 per peak kilowatt), and he estimates that power could be produced for about 24 mills/kWhr. As noted in Section 6A.5.7.2, one potential difficulty with cadmium sulfide cells is that the U.S. cadmium resources would not support extensive power facilities based on this material.

*Even so, the comparison would not be completely valid because conventional peaking units fulfill an additional function. They provide backup during outages of base and intermediate load units.

The MITRE Corporation[9] estimated the cost of photovoltaic installations for residences or small commercial buildings. Capital costs, including collectors, energy storage, and power conditioning equipment were projected to be $1000 per peak kilowatt ($5000 per average kilowatt) by the year 2000 and $500 per peak kilowatt ($2500 per average kilowatt) by the year 2020. Total power costs were estimated as 86 mills/kWhr and 43 mills/kWhr for the years 2000 and 2020, respectively. The study indicated that solar costs would exceed conventional power costs by a factor of 4 in the year 2000 and by a factor of 1.7 in the year 2020.

The Scientists' Institute for Public Information, (SIPI), in its comments* on the Draft Statement indicated that the use of photovoltaic systems on buildings is especially promising because, "...according to NSF/NASA Solar Energy Panel, even with an expensive battery, the system could be economic because transmission and distribution costs are eliminated.[27]" This interpretation of the NSF-NASA study is believed erroneous. The NSF-NASA panel specifically noted (ref. 4, p. 55) that providing more than one day of storage would be uneconomical.[4] Thus, solar electric systems for buildings would require an external source of electricity during a series of cloudy days, and the required external capacity (generating plant, transmission systems, and distribution network) would not be reduced significantly. Solar electric systems for buildings would save fuel but would not materially affect the local utilities' investment in power facilities.

The report of Subpanel IX proposed a research and development program, emphasizing advanced silicon cells, that would culminate in the production of solar arrays for $300 per peak kilowatt ($1500 per average kilowatt) by 1986. Initial commercial implementation of these cells would take place in 1990. The above cost excludes construction of the power plant, power conditioning equipment, and energy storage. At a fixed charge rate of 15%, the capital costs of the solar arrays alone would contribute about 26 mills/kWhr to the total power cost.

As with other solar systems proposed by Subpanel IX, the argument is made that photovoltaic systems without energy storage will be economically viable as peaking units. As noted previously in the discussion of thermal-conversion systems, solar electric systems with limited energy storage will almost certainly require conventional standby capacity; the value of the power produced would be only the cost of conventional fuel saved. Since the estimated costs of photovoltaic plants generally fall

*Testimony of SIPI in regard to the AEC's Draft Statement on the LMFBR Program, April 25, 1974, p. V-21. The superscript 26 in SIPI's comment referred to the report: NSF/NASA Solar Energy Panel, "Solar Energy as a National Energy Resource," Washington, D.C., December 1972.

within the same range as those estimated for thermal-conversion plants, the previous conclusions concerning the outlook for thermal-conversion plants also apply to photovoltaic systems. These conclusions are that (1) there is little chance that solar electricity will displace either capacity or generation from coal or nuclear plants in this century and (2) the most reasonable potential application is in displacing some generation (not capacity) from peaking plants burning oil. Even in the latter case, some energy storage may be required so that the energy collected during the day can be dispensed during the period when peaking units are required. If low-cost storage systems (batteries, flywheels, and similar devices) are developed, the same devices could presumably be applied to conventional coal or nuclear plants. This application would allow low-cost, baseload energy to be used for peaking. Thus, the development of economical storage systems would not necessarily improve the relative competitive position of solar energy plants.

6A.5.7.1.3 Burning of Photosynthetic Materials

The cost of producing electricity from burning photosynthetic materials would be controlled by the cost of land. Since large areas would be required, the cost of producing energy by this means apparently would be high, especially since the land must be of reasonably good quality. One cost estimate[1] for a wood-burning power plant indicates a fuel cost of more than $2 per million Btu and a total power cost of at least 38 mills/kWhr.

6A.5.7.1.4 Space Heating and Air Conditioning

The cost of space heating, air conditioning, and water heating with solar energy is primarily related to the capital investment. Additional costs would be incurred from maintenance and fossil-fuel use during adverse weather conditions. The NSF-NASA Solar Energy Panel estimates the capital cost of water heating at $200 to $400, space heating at $1500 to $2500, and air conditioning at $3000 to $4000, all for a representative residence. The panel indicated that solar energy is less expensive for heating than is electricity for a variety of U.S. locations and that it is nearly competitive with oil and gas for other locations. Combined systems (i.e., hot-water heating, space heating, and air conditioning) were believed to be of even greater long-term promise. However, considerable engineering development of low-cost components will be required for solar energy to be a competitive alternative for residential use on a large scale.

6A.5.7.1.5 High-Energy Fuels

A major part of the cost of high-energy fuels would be the cost of producing the raw photosynthetic materials. For example, one estimate[4] of the cost of dry algae, with present technology, would be $0.05 per pound. If a methane conversion efficiency of 60 to 80% is assumed, then the cost of the raw-material component of methane would be greater than $7 per million Btu. This figure is several times that estimated for pipeline gas from coal, which may be on the order of $1.00 per million Btu.[32] The NSF-NASA Solar Energy Panel estimated that the cost of methane from algae grown on sewage wastes might be reduced to $1.50 to $2.00 per million Btu since a credit could be taken for sewage disposal. Although growing algae on sewage wastes is promising, the use of algae as a fuel may be questionable. Chlorella has a high protein content (50% relative to 39% for soybeans) as well as being rich in nutrients and vitamins.[33] As such it is an excellent supplement for animal feed as well as being potentially useful for direct human consumption. If it could be produced for ∿1 ¢/lb, as implied in the above estimate, the impact on the world food supply would be substantial. The profitability of algae production for food would be far higher than for fuel.

6A.5.7.2 External Costs

Generally speaking, environmental costs associated with the use of solar energy would be small. In some cases, the large-scale use of solar energy might alter the price structure and availability of certain raw materials. Two materials that could be affected are gold, which has been suggested for the selective surface on thermal-conversion collectors, and cadmium, which might be a basic material in low-cost solar cells. One estimate[7] is that if cadmium sulfide cells were used to produce 1% of the electricity required in the year 2000, the quantity of cadmium needed would exceed the known U.S. reserves available at 1971 prices. If photosynthetically produced fuels were widely used, the withdrawal of large tracts of land that could be used to produce food, fiber, pulpwood, and lumber would influence the prices of these products.

6A.5.7.3 Benefits

The benefits from solar-energy use would be electric power, thermal energy, and high-energy fuels. These products would be based on an inexhaustible energy supply and could be produced for most proposed applications with rather minor environmental impacts. Utilization of solar energy would decrease the dependence on fuel sources such as coal and nuclear.

6A.5.8 Overall Assessment of Role in Energy Supply

The use of solar energy as a substitute for other energy sources has very strong appeal. The resource is inexhaustible, and its use would have relatively minor environmental effects for most proposed applications. The major barrier to the exploitation of solar energy is cost. The use of solar energy is now uneconomical for all except very specialized applications. The outlook appears to be that solar energy has little potential as an economical, major source of electricity for at least several decades. In fact, the only proposed solar application that potentially could play a significant energy role in this century is as thermal energy for buildings. Although this use could be important, the impact on total electrical production is likely to be minor (∿2%), at least until the year 2000. Thus, it is concluded that the use of solar energy will not materially reduce the need for alternative electrical energy sources in this century.

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6A.6 OTHER NONNUCLEAR ENERGY SYSTEMS

6A.6.1 Wind Power

6A.6.1.1 History and Status

The kinetic energy of the winds can be used to produce mechanical energy or electric power. The potential amount of wind energy available is very large. For example, the estimate[1] has been made that the energy potential of the winds over the continental United States, the Aleutian arc, and the eastern seaboard is equivalent to 10^8 MWe. To convert a significant fraction of this energy potential to electricity would, of course, be impractical. The NSF-NASA Solar Energy Panel[1] identified a number of major areas--including the Great Lakes, the Great Plains, and offshore regions--that would be suitable for wind-driven electric plants and estimated the maximal potential energy generation from these areas to be equivalent to about 19% of the annual United States electricity production estimated for the year 2000.

Man's use of the wind dates back many centuries.[2] The ancient Chinese and other eastern peoples used windmills to pump water and employed sails to drive ships. The Crusaders carried the windmill concept from the Middle East to Europe. Later, the windmill became an important part of rural America, especially in the Midwest. Water pumping was the primary application, but many windmills were employed to generate electricity for farm lighting. Lead-acid storage batteries were used to store energy for use during calm periods. Electrification of rural areas along with the availability of low-cost, internal-combustion-engine-powered pumps led to the decline of the windmill; however, some are still in use in remote areas.

Relatively large wind-powered generators for bulk power production have been constructed in a number of countries,[2-4] but most are no longer in operation. The largest unit, the Smith-Putnam wind turbine[2-5] was constructed on Grandpa's Knob near Castleton, Vermont, in the early 1940's. This installation fed power into the grid of the Central Vermont Public Service Corporation. The generator was rated at 1.25 MWe and was driven by a two-blade propeller 175 ft in diameter. The Smith-Putnam windmill operated intermittently until 1945 when one blade failed. The project was abandoned primarily for economic reasons.

Uncertainties about future energy sources have stimulated renewed interest in windmills. A number of innovative wind-conversion systems are currently being investigated,[6-10] and several imaginative proposals for wind-energy utilization have been made.[11-14] These proposals range from small units, to be used for heating and electricity for individual buildings, to vast networks of wind machines for bulk power generation.

6A.6.1.2 Research and Development

The National Science Foundation (NSF) is the primary Federal agency involved in wind energy research and development.[2] Other government agencies with interests in wind energy include NASA, the Department of the Army, and the National Oceanic and Atmospheric Administration.[2] The NSF-NASA Solar Energy Panel[1] recommended a 10-year program amounting to about $610 million. A more recent and broader-based study[15] of potential energy sources, "The Nation's Energy Future," suggested a research and development program totalling $32 million over the next five years. It would include the construction of a series of experimental wind generator systems of increasing size and performance capability, starting with a unit of 100-kWe size. A multiunit system making up a wind "farm" up to 10 MWe would also be constructed.

6A.6.1.3 Projected Applications

The NSF-NASA Solar Energy Panel estimated that wind-powered generators might produce 1% of our electrical energy needs by the year 2000, assuming a successful research program. A much more optimistic view is given by the Subpanel IX[16] group; their estimate is that 19% of our electrical energy needs could be satisfied by wind power in the year 2000. This figure corresponds to the maximum available wind energy estimated by the NSF-NASA panel.

Whether the wind will provide any significant energy generation in the future will depend on the resolution of two problems: environmental disturbance and economics.

6A.6.1.4 Environmental Impacts

Potential environmental problems related to the large-scale use of wind turbines are land use, weather modifications, and aesthetics.[1-3] Heronemus[14] believes there are 350,000 square miles in the Great Plains that would be suitable for wind turbines. He proposes 600-ft towers, each containing an array of 20 machines with 50-ft diameter blades. The towers would be centered on each square mile of area. The total annual output from the 350,000 square miles would be 1400 billion kWhr or about 15% of expected electric energy generation in the year 2000. The land area is approximately equivalent to the combined areas of North Dakota, South Dakota, Nebraska, Kansas, and Oklahoma. Actually, the machines would physically occupy only a small portion of the area, but electrical interconnections and access roads would require additional land. There might be some resistance to the proposed use of land over such extensive areas. Large nmbers of densely concentrated wind-powered generators might also alter wind patterns and, therefore, weather. This potential effect has not been assessed. The most obvious environmental disturbance would be that of aesthetics.[2] Structures of the size and numbers required for large-scale power generation may not be palatable to many people. Some public utilities have been skeptical of gaining public acceptance of the tall structures proposed.[17]

6A.6.1.5 Economics

The question of economic feasibility is related primarily to the variability of winds. Because of this variability, windmills have a low use factor, and wind-driven power plants would require an energy storage system if they were to supply a firm source of power. Limited experience with the Smith-Putnam unit indicated an annual use factor of 14%.[18] A 200-kW(rated)* machine constructed near Gedser, Denmark, in 1957 is reported to have produced about 400,000 kWhr of electricity per year,[3] which would indicate a use factor of about 23%. One of the highest use factors (32%) was achieved with a 100-kW(rated) unit constructed in the U.S.S.R., near Yalta, in 1931.[2]

The storage capacity required to provide firm power will be substantial. The MITRE Corporation[2] estimates that individual units might require 60 days or more of energy storage capacity, depending on the region. Several methods of storage could be used, including batteries and pumped storage,[19] but the method most often mentioned is the electrolytic production of hydrogen; the hydrogen could then be burned in a power plant or used in a fuel cell.

Since the technology for economical energy storage suitable to wind power would not be available for many years, there is a feeling among many wind-energy experts that the development of wind power for bulk electricity production should not be tied to storage technology. The Subpanel IX group[16] that provided input data to the report on "The Nation's Energy Future"[15] recommended a program of development and implementation of wind energy systems without storage. Such systems would appear to serve as a supplemental source of power that could save conventional fuels but would not displace conventional capacity. Thus, one significant conclusion in the assessment of alternatives to the LMFBR is that wind energy systems with limited or no energy storage will not lessen the need to develop new sources

*"Rated" refers to the maximum design output of the wind turbine.

of firm power including the LMFBR and other advanced nuclear, coal, and geothermal power plants.

The value of power produced by a supplemental energy system is equivalent to the conventional fuel saved. The extent of conventional fuel displacement by wind machines will depend on the capital cost of such plants relative to the price of conventional fuels. Based on past experience with windmills, the capital investment is high. Studies at Oregon State University[20] indicate that the Grandpa's Knob wind turbine would cost $700 per kilowatt (rated) in terms of 1971 dollars. If this machine were constructed in a favorable location where a use factor of 30% could be achieved, the cost per average kilowatt would be about $2300. The cost would be somewhat higher in present (1974) dollars.

The 200-kW (rated) Gedser, Denmark, wind machine cost about $280 per kilowatt (rated) in 1957.[3] Costs were expected to drop to $190 per kilowatt (rated) if the unit were mass-produced. At a use factor of 23% (the value achieved by the Danish unit), the cost per average kilowatt of a production unit would have been about $800 in 1957. In terms of present (1974) dollars, the cost would be approximately double that in 1957.

The Subpanel IX group[16] expressed the view that technological improvements in wind machines would dramatically decrease the costs. Their estimate is that the cost of an advanced windmill located at a favorable wind site would be $300 to $500 per kilowatt average.

Heronemus[14] believes that the cost of large wind turbines will vary according to the number produced annually as follows: 1 to 100 units--$350 per kilowatt (rated); up to 1000 units--$250 per kilowatt (rated); up to 20,000 units--$100 per kilowatt (rated). In terms of average capacity at a favorable site (30% use factor), the preceding figures correspond to $1167, $833, and $333 per kilowatt, respectively. A recent study by the MITRE Corporation[2] for the NSF assumed that the cost of wind power plants could be reduced to $300 per kilowatt (rated) by 1985; using a 30% use factor, this figure corresponds to $1000 per kilowatt average. The National Research Council of Canada is developing a vertical-axis wind-turbine design[9] that its proponents estimate might be produced at costs as low as one-sixth the cost of the conventional horizontal-axis wind turbine.

6A.6.1.6 Overall Assessment of Role in Energy Supply

If wind power plants can be reduced in cost to $500 per kilowatt (average), then wind-generated electricity could displace conventional fuels (but no conventional capacity) at the following minimum prices for such fuels:

Coal--$29 per ton
Nuclear (LWR)--$146 per pound of U_3O_8

For most large power systems, where the mix of fuel sources is expected to contain more and more nuclear energy, the outlook for wind as a supplemental source of energy is not promising. For smaller systems and isolated communities that depend primarily on oil-fired power plants, the prospects for wind-energy applications as a supplemental source of electricity are more promising if low-cost wind turbines can be developed. For example, Van Sant[12] concluded that wind turbines would be economical as a supplemental source of power for a small Canadian community that uses diesel-electric plants.

As noted in Section 6A.6.1.5, wind energy systems with limited or no energy storage will not reduce the need for new sources of firm power. Although wind power might be able to satisfy some specialized energy needs, a reasonable prediction is that electricity from the wind will not be of national significance during the remainder of this century.

6A.6.2 Ocean Thermal Gradients

At many places in the tropical and subtropical regions of the world, the ocean surface temperatures are in the range of 75 to 85°F. The warm surface layer circulates toward the poles, where it is cooled, and flows back along the deep ocean trenches. In these lower layers of the ocean, say 2000 ft below the surface, the temperatures are 35 to 45°F. The temperature difference between the surface and the depths could be used to drive a Rankine-cycle heat engine.[21,22] Although the theoretical efficiency is 9% for a 50F° temperature difference,[1] the efficiency of a real power plant would be 2 to 4%. A number of working fluids have been suggested for the power cycle; the most promising ones seem to be water vapor, ammonia, propane, and one of the freons.

The first, and probably the only, ocean-thermal-gradient plant to produce electricity was a small demonstration plant built by Claude in Cuba in 1930.[21] He chose water vapor as the working fluid and produced the water vapor by boiling the tepid surface water in a vacuum chamber and condensing it in a spray condenser by use of the cold water pumped up from the ocean depths. The water vapor, which flowed in a pipe that connected the condenser with the boiler, generated electricity by driving a turbine-generator located in the pipe. Although Claude had considerable difficulty in constructing the plant and, in particular, in installing the long cold-water-inlet pipe, his plant demonstrated the technical feasibility of producing power (22 kW). The actual yield over the energy put into pumping the water into the vacuum condenser was small.

Ocean-thermal-gradient power plants have been visualized either as shore-built structures or as floating structures.[21,22] The shore-built structures would have to be located in areas where the water is deep near the shore. Claude's demonstration plant was in such an area, although ocean depth at that particular location was limited.[21] The floating plants are generally thought of as structures with the majority of their mass located beneath the ocean surface to minimize surface effects of waves and weather.[23] Much of the current work on ocean-thermal-gradient plants is being sponsored by the NSF.[2]

Two practical difficulties appear to exist with power plants operating on ocean temperature differentials. First, the temperature differences are rather small, and this characteristic gives rise to low efficiencies. Thus, a large amount of thermal energy would have to be transported through the system, and this transport would require much pumping and a large heat-transfer surface. The second problem is that, for the most part, sites suitable for ocean-thermal-gradient power plants are located out to sea, far from load centers, thus making the transmission of electrical energy difficult and expensive.

Although there are many technical problems to be resolved, there is little doubt that the small temperature differences between the surface and the depths of the oceans can be converted to shaft work. But the cost per unit of net energy produced is uncertain. Since no fuel is required, the main element of cost is capital investment. Judging from some of the literature, the capital investment would be modest. For example, some investigators[2,23] report that $168 per kilowatt may be an achievable cost, and this figure seems to be based on a 1965 estimate by the Andersons.[24] Both the NSF-NASA Solar Energy Panel[1] and Subpanel IX[16] indicate a maximum of $400 per kilowatt.

The MITRE Corporation[2] shows a cost range of $168 to $400 per kilowatt, but in their economic analysis, they assume $800 per kilowatt for a fully developed plant.

Heronemus reports:[25] "In our last costing exercise we came up with one least-cost configuration at \$289/kw and a highest-cost configuration at \$740/kw." The wide range of cost estimates is indicative of the embryonic stage of technology for ocean thermal gradient plants. To achieve costs near even the upper end of the range given above will require significant technological advances. For example, condensers for fossil-fueled power plants cost about \$7.25 per square foot of heat transfer area.[26] The ocean-thermal-gradient plant proposed by the Andersons uses 159 ft^2 of heat transfer area per kilowatt of output. On this basis, the cost of heat transfer surface alone would bbe \$1150 per kilowatt. If direct electricity generation and consumption (as opposed to indirect processes such as hydrogen production) is chosen as the application, electrical transmission through submarine cables would also be a significant cost item. Such cables for offshore nuclear plants cost about \$3.50 per kilowatt per mile.[27] MITRE[2] estimates that transmission distances for ocean-thermal-gradient plants will range from 25 to 160 miles. If an average transmission distance of 100 miles is assumed, the cost of energy transmission alone would be \$350 per kilowatt. The above figures suggest that even the highest cost estimates given in the literature may be much too low. Nevertheless, if one adopts the \$800 figure used by MITRE, the ocean-thermal-gradient plant is still not likely to be competitive with light water reactors for decades. Assuming a cost of \$420 per kilowatt for LWRs, a 15% fixed charge rate on capital, an 80% plant factor for both nuclear and ocean-thermal-gradient plants, and assuming that operating and maintenance costs for ocean-thermal-gradient and nuclear plants are the same, uranium ore would have to sell at \$110 per pound of U_3O_8 to make ocean-thermal-gradient plants competitive with LWRs. This figure is about an order of magnitude greater than the current price of uranium ore.

To avoid the cost of electricity transmission, many investigators[1,2,14,16] suggest the onsite production of electrolytic hydrogen. The hydrogen would be barged or pipelined ashore for use as a fuel. Presumably, if low-cost electrolytic cells could be developed, they could be applied to nuclear plants as well as ocean-thermal-gradient plants. At any rate, most studies indicate that clean gaseous fuels can be produced from coal at less cost than hydrogen by electrolysis (see Section 6A.6.4).

Because of the technical and economic problems described above, the commercial feasibility of ocean-thermal-gradient power plants is uncertain. Consequently, the NSF-NASA Solar Energy Panel[1] recommended an initial three-year program oriented toward problem definition, concept feasibility, and cost studies. The panel recommends that, if the results of this initial program are favorable, a 15-year research and development program, whose cost would amount to $530 million, be initiated. The panel projected a market penetration of 1% of the electrical power by the year 2000 if this program were successful.

The more recent report on "The Nation's Energy Future"[13] visualizes a $27 million program over the next five years, emphasizing the design, production, and testing of system components. The objective of this program would be to determine the technical feasibility of producing electric power from ocean thermal gradients by laboratory-scale testing of prototypes and full-scale testing of necessary components, including the heat exchanger, the deep-water pipe, and the overall plant structural design. A test facility would be constructed under this program.

Ocean-thermal-gradient plants are, at present, only in the conceptual stage. As such, there is very little basis on which to make a meaningful assessment. After completion of the five-year program recommended in "The Nation's Energy Future," technical and economic feasibility may be more clearly established. At present, however, there is no reasonable basis for projecting a significant energy contribution from ocean-thermal-gradient plants in this century.

6A.6.3 Tidal Energy

The estimate is made that the total amount of energy in the tides of the ocean, if it were accessible, would provide about half the energy needs of the entire world.[28] Because so few sites exist where the harnessing of this energy would be practical, use of only a small fraction of the potential amount would be possible, even if all the available sites were used.

The tidal movement of the ocean is caused principally by the gravitational effect of the moon, with the sun also exerting a smaller effect. On the open ocean, the average height of the tide is only about 2 ft. The physical characteristics of the shorelines, estuaries, and bays and the topography, together with wind conditions, greatly amplify the tides. In basins where these factors combine to establish resonance, amplifications of 50 to 100 times are attained. At such locations, tides might be used to generate electricity. Tidal energy could be converted into electric power by enclosing the basins with dams to create a difference in water level between the ocean and the basins and then using the water flow to drive hydraulic turbines to turn electric generators.[29]

Two sites in the United States are worthy of consideration for generating electricity by tidal action.[30] These are the Bay of Fundy area, which actually lies on the

Canadian-United States border, and the Turnagain Bay in Cook Inlet in Alaska. The Bay of Fundy has nine sites and a potential power production of about 29,000 MW. The Alaskan site could produce about 9500 MW. One site on the Bay of Fundy was subjected to detailed cost analysis[31] on the basis of 1968 price levels. The estimated cost was too high, relative to those of alternatives, to be of interest at the time of the study.

Because of lack of resources and potentially high cost, tidal power probably will not be an important factor in energy supply for the future.

6A.6.4 Hydrogen and Other Synthetic Fuels

Hydrogen and other synthetic fuels such as hydrazine, methanol, and ammonia are anticipated to play an important role in future energy uses.[32,33] These fuels are not a true alternative energy option in that they are not a primary source of energy, such as nuclear power, solar power, or coal; they are of interest because they may be derived from these abundant energy resources and provide a convenient fuel form for transport, storage, and utilization. Thus, they represent a potential alternative for supplying the long-term needs for gaseous and liquid fuels, as well as a possible means for central-station electric storage analogous to the pumped storage concept. The use of hydrogen would involve its production by electrolysis or thermochemical decomposition of water during periods of low power demand, its storage, and its reconversion back to electricity, perhaps in a fuel cell, during periods of peak power demand. Hydrogen could also be used for electricity production in small dispersed stationary plants to provide power for residential and commercial uses. Other applications of hydrogen and the synthetic fuels that may be derived from it include use as general purpose fuels for heating and industrial processes, as fuels for automotive and aircraft propulsion, and as materials in various industrial processes.

The principal use of hydrogen today is as an industrial chemical for the reduction of metals from ores and in the production of ammonia for agriculture. The main obstacles to the use of hydrogen in other applications at this time are its high cost relative to oil products and natural gas and, for motive applications, difficulties in storage of the fuel as a gas or liquid. These storage difficulties can be alleviated in varying degrees by use of alloys which form hydrides and by the use of the other synthetic fuels (e.g., hydrazine, methanol, or ammonia). However, for purposes of this discussion, the main interest in hydrogen is its possible future use as an energy storage mechanism in central-station electricity production or as a fuel supply to smaller electricity generating stations operating on fuel cells, gas turbines, or some other technology employing hydrogen.

The principal processes that are currently used for producing hydrogen include electrolysis of water and the partial oxidation of reforming of fossil fuels, principally natural gas. In the near future, hydrogen can be expected to be produced economically from coal and, perhaps, from oil shale. In the far term, as fossil resources decline, closed-cycle thermochemical cracking of water and re-emphasis on water electrolysis would seem to be potentially attractive methods of hydrogen production. The cost of hydrogen will depend on the cost of the primary source of energy, the efficiency of the process used to produce hydrogen, and the capital cost of the production facilities.

The current economics of electrolytic hydrogen are determined by the capital cost and utilization of the electrolysis plant and by the cost of electrical power. The capital cost of present large-scale plants[34] is about \$95 per pound of H_2 per day. At a fixed charge rate of 15% and a 90% plant factor, the capital charge is equivalent to 4.3¢/lb of H_2 or 84¢/10^6 Btu, assuming no credit for by-product oxygen. At an electric power cost of 5 mills/kWhr, the power cost in terms of hydrogen produced is about 10¢/lb of H_2, resulting in a total cost, excluding labor, maintenance, and overhead costs, of 14.3¢/lb of H_2, or about \$2.80/10^6 Btu. This cost is considerably higher than the cost of other fuels (e.g., low Btu gas can be produced from coal at a cost of about 60¢ to 95¢/10^6 Btu). The cost of electrical power used to produce hydrogen would depend, of course, on the type of generating plant providing the power and on the rate structure. Power may be obtained at a very low cost during off-peak demand periods and at a higher cost during periods of peak demand on the electric generating system. In any event, the ability to produce electricity by improved conversion methods (e.g., fuel cells) could lead to a cost for electricity produced by hydrogen that is competitive with that from other fuels.

Although water electrolysis is already a relatively efficient process, further improvements may be achieved through research and development. To reduce the energy requirements to around 13 to 15 kWhr/lb of H_2 may be possible with an attendant decrease in the portion of the cost of hydrogen attributable to the input electric power. There is only a moderate amount of research in progress on water electrolysis at the present time. Some work is being done by industry on lowering cell fabrication costs and on improving their performance and lifetime.

Additional research and development would also be needed in techniques for the storage of hydrogen, either as a liquid or as a metal hydride. The objective of such work would be to provide safe and convenient systems for both small portable storage applications and large-scale storage systems as may be required for central station electric storage.

With regard to its environmental characteristics, hydrogen is a clean fuel in that it is made from water and its combustion results primarily in water vapor, with little or no other pollutants or emissions of the type associated with most other fuels. There would, of course, be some environmental effects from the production of hydrogen, whether this would be directly from coal or electrolytically through the use of power generated in some other type of plant. In that case, the environmental effects from the use of hydrogen would depend indirectly on those from the type of power plant used in its production, whether this be nuclear, fossil, solar, or other. However, hydrogen can be produced at a site independent of the central electric generating facility, and if this hydrogen were then used to produce electricity at a smaller generating station (e.g., powered by fuel cells), the siting advantages inherent in this flexibility might be worthwhile.

As implied previously, the development and widespread use of synthetic fuels will not lessen the need to develop primary energy sources such as advanced nuclear systems. On the contrary, the substitution of hydrogen and synthetic fuels for petroleum and natural gas would emphasize the need to develop new primary sources of energy.

Several studies have been made of the potential means by which hydrogen may function as the base of a future energy economy. These include consideration of hydrogen production, distribution and storage networks for the various applications mentioned above. One study[34] assumed that 20% of the electrical energy delivered in the year 2000 is produced from hydrogen. Another evaluation[33] estimated that just to meet one-half of the projected transportation fuel needs for the year 2000 with electrolytically produced hydrogen would require an additional electrical generating capacity of nearly one million megawatts, or over twice the currently expected nuclear generating capacity at that time. However, if closed-cycle thermochemical production is used rather than water electrolysis to produce hydrogen, then only about one-third the expected nuclear generating capacity would be needed for this purpose.

Whether or not hydrogen and other synthetic fuels will be used to the extent currently envisioned by some planners will depend, as in the case of the other energy sources discussed in this Statement, on a myriad of technical, economical, environmental, political, social, and other factors, as well as on the relative success of other energy sources in achieving commercial and public acceptance. In particular, the need for a separate distribution and storage system, the development of vehicles and/or electric generating stations capable of efficiently using hydrogen, and the need for other renewable sources of energy that could be used to produce hydrogen pose important problems to the eventual establishment of a hydrogen energy economy.

6A.6.5 Energy from Organic Wastes

The quantity of raw organic wastes produced each year in the United States is well in excess of 2 billion tons. In many cases, these waste materials pose serious problems in proper disposal. Turning the wastes to usable energy could, in principle, alleviate the disposal problem as well as reduce the demand for depletable energy resources. There are two general methods for converting organic wastes to useful energy: (1) direct burning with the production of steam for space conditioning, industrial uses, or power generation, and (2) chemical processing to convert wastes to higher value liquid, gaseous, or solid fuels.

The production of steam and electric power by direct burning of urban solid wastes has been practiced to a limited extent in the United States but the major experience is in Europe, especially in Germany.[35] The lack of application in the U.S. has been influenced by the low cost of fossil fuels and low population density relative to Europe. Continued urbanization with attendant waste disposal problems and the impending shortage of some fossil fuels have served to stimulate interest in the potential for energy recovery from waste products. Recently, a number of demonstration projects involving heat recovery from urban waste incineration have been undertaken. For example, in Nashville, Tennessee, a waste incinerator-boiler providing energy for heating and cooling of mid-city buildings will go into operation in 1974.[36] The city of St. Louis, in a cooperative venture with the Union Electric Company, is providing municipal solid waste for use in power plant boilers.[37,38]

Chemical processing of solid wastes into high quality fuels, although technically feasible, is not practiced on a commercial scale because processes have not been fully developed. Research and development is currently being conducted on several processes.[35,39]

The quantities of wastes from various sources, as estimated by Anderson,[39] are shown in Table 6A.6-1. The listed data are for dry, ash-free, organic matter. The first column of Table 6A.6-1 gives the quantity generated, and the second column shows the quantity that might be available for energy production. Wastes in the second category are those that are currently concentrated by feedlot operation and municipal collection to such an extent that recovery may be feasible. Animal and farm wastes constitute a major portion of organic materials generated, but recovery of these wastes is difficult. Urban refuse represents the most abundant recoverable source of organic wastes. Since all raw wastes are rather low in energy content per unit weight and volume, their conversion to either electricity or other forms of energy would need to be accomplished locally; otherwise, transportation costs would be prohibitive.

The energy production potential of organic wastes, reasonably collectable in 1971, is illustrated in Table 6A.6-2. If all collectable wastes were converted to electricity at the national average conversion efficiency of 32%, the power production for 1971 would have been 205 billion kWhr or nearly 13% of the national demand. If all collectable wastes were converted to oil at a net production of 1.25 bbl per ton of waste,[39] the oil production for 1971 would have been about 171 million bbl or 2.9% of the national consumption for that year.

The best candidates for electricity production are the wastes generated in urban areas since a collection system exists; and waste generation corresponds geographically to the need for electricity. The urban-related wastes (urban refuse, industrial wastes, and sewage solids) would have accounted for about 7% of the national electricity demand for 1971. In the future, usable urban wastes will increase but not at the rate of electricity demand. For example, EPA[37] estimates indicate that urban waste collection will increase by about 3.4% per year to 1980 whereas electricity demand will increase at a rate roughly twice this amount. Thus, the potential electricity production from wastes will probably decline in relation to the total electrical demand.

As indicated earlier, heat recovery and power generation from wastes have not been practiced extensively in the United States primarily because fossil fuel costs have been sufficiently low to make energy recovery from wastes uneconomical. However, with fossil fuel prices increasing very rapidly, energy recovery from wastes is very likely to become competitive. In addition to providing a supplement to energy supplies for urban areas, the use of organic wastes for energy could help resolve the disposal problem. Nevertheless, energy from organic wastes will never

Table 6A.6-1

DRY, ASH-FREE, ORGANIC WASTES GENERATED AND POTENTIALLY COLLECTABLE FOR 1971[a]

Source	Quantity (millions of tons/year)	
	Total Generated	Total Available
Animal Wastes	200	26.0
Urban Refuse	129	71.0
Logging and Other Wood Refuse	55	5.0
Agricultural and Food Wastes	390	22.6
Industrial Wastes	44	5.2
Sewage Solids	12	1.5
Miscellaneous	50	5.0
Total	880	136.3

[a]Source: L. L. Anderson, "Energy Potential from Organic Wastes: A Review of the Quantities and Sources," Bureau of Mines Information Circulate IC-8549, 1972.

Table 6A.6-2

POTENTIAL ELECTRICITY AND OIL PRODUCTION FROM COLLECTABLE ORGANIC WASTES FOR 1971

Source	Annual Potential Power Production[a]		Annual Potential Oil Production[b]	
	(billion kWhr)	(% of demand)	(million barrels)	(% of demand)
Animal Wastes	39.0	2.4	32.5	0.6
Urban Refuse	107.0	6.6	88.8	1.5
Logging and Wood Wastes	7.5	0.5	6.3	0.1
Agricultural and Food Wastes	33.9	2.1	28.3	0.5
Industrial Wastes	7.8	0.5	6.5	0.1
Sewage Solids	2.3	0.1	1.9	nil
Miscellaneous	7.5	0.5	6.3	0.1
Total	205.0	12.7	170.6	2.9

[a]Based on 8000 Btu/lb of dry, ash-free wastes and conversion to electricity at 32% efficiency.
[b]Based on net production of 1.25 bbl per ton of waste.

have a large impact simply because the quantity of energy contained in collectable wastes is small in relation to the energy demand. It is concluded, therefore, that the need to develop other energy sources would not be materially changed if the full energy potential of organic wastes were utilized.

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6B

IMPROVED ENERGY CONVERSION
AND
STORAGE DEVICES

6B.1 GENERAL INTRODUCTION

The major portion of electric power generated in the United States today is based upon steam turbine energy systems. This process is well developed but converts only about 39% of the fuel energy into electrical power with the balance being wasted in the form of low-grade heat. More efficient conversion systems would not only reduce the amount of heat rejected to the environment but also conserve our limited fossil and nuclear fuel supplies.

Thermodynamic, technological, and economic considerations limit upper efficiency to the present value. Temperatures are available from the combustion of fossil fuels that would allow for higher efficiencies if suitable technologies were available to use them. Systems for direct conversion from chemical or nuclear energy to electrical energy, thus avoiding the heat engine cycle and consequent thermodynamic limitation, would be most desirable.

The following sections will briefly describe the most commonly used energy conversion system used today, the steam turbine, and other conversion concepts that have received or are receiving significant attention. Included in this discussion are

(1) internal combustion engines,
(2) gas turbines,
(3) binary cycles,
(4) fuel cells,
(5) thermoelectric converters,
(6) thermionic converters, and
(7) magnetohydrodynamics.

In addition to the development of more efficient energy conversion systems, major improvements in energy resource utilization can be achieved by developing practical, economic energy storage devices. The specific benefits of energy storage are: more efficient use of electric generating capacity, and fewer additional generating plants; improved operating economy of the utility systems; fuel substitution, i.e. cheap abundant fuels (coal, or nuclear) substituted for scarce and costly fuels (oil); and fewer new transmission and distribution facilities.

Electric utility industry estimates indicate that 15 to 25 percent of the daytime generating capacity of future utility systems could be provided by suitable energy storage devices. Electric energy generated at night or during other times of low demand (base load) would be stored for later use during times of high demand (peak load). Future storage units could improve overall fuel utilization and operating economy by increasing the base load, thereby allowing larger and more efficient generating units to produce a greater fraction of the total power generated. This benefit is especially important with the widespread implementation of nuclear power, since high capital costs and operating considerations make it desirable to operate nuclear plants continuously as base load plants. The range of alternative technologies which could meet the technical requirements for utility energy storage devices are:

(1) batteries
(2) hydrogen storage
(3) thermal storage
(4) flywheels
(5) compressed air storage
(6) underground pumped hydro
(7) superconducting magnetic energy storage

A study assessing advanced energy storage systems, designed to determine the most practical applications for electric utility generating systems, is underway. This study will evaluate the energy storage concepts listed above in terms of their technical feasibility, estimated costs, designed operating characteristics, anticipated problems which might block commercial development and research programs needed to advance the concepts. Other considerations include the safety, environmental impact and public acceptance of the various energy storage systems. Initial R&D work is underway on hydrogen and superconducting magnetic energy storage. The only energy storage concept that has received significant attention to date is batteries and it is described in Section 6B.7.

In summary, development of improved energy conversion and storage devices would

(1) conserve energy resources;
(2) reduce the extent of adverse environmental effects;
(3) provide for more efficient use of capital resources; and
(4) provide electrical power reserve capacity near the point of use.

For each concept a number of characteristics will be discussed. The intent is to describe the concept, examine its current and projected use, consider its costs and environmental impacts, and provide an overall assessment of its role in meeting our energy requirements. The systems reviewed are in varying stages of development. As discussed in the section "Perspectives on Alternative Energy Options," those systems in the early stages of development cannot be defined accurately with regard to costs of development, probability of achievement, or schedules for achieving commercial utilization.

6B.2 STEAM TURBINES

6B.2.1 Introduction

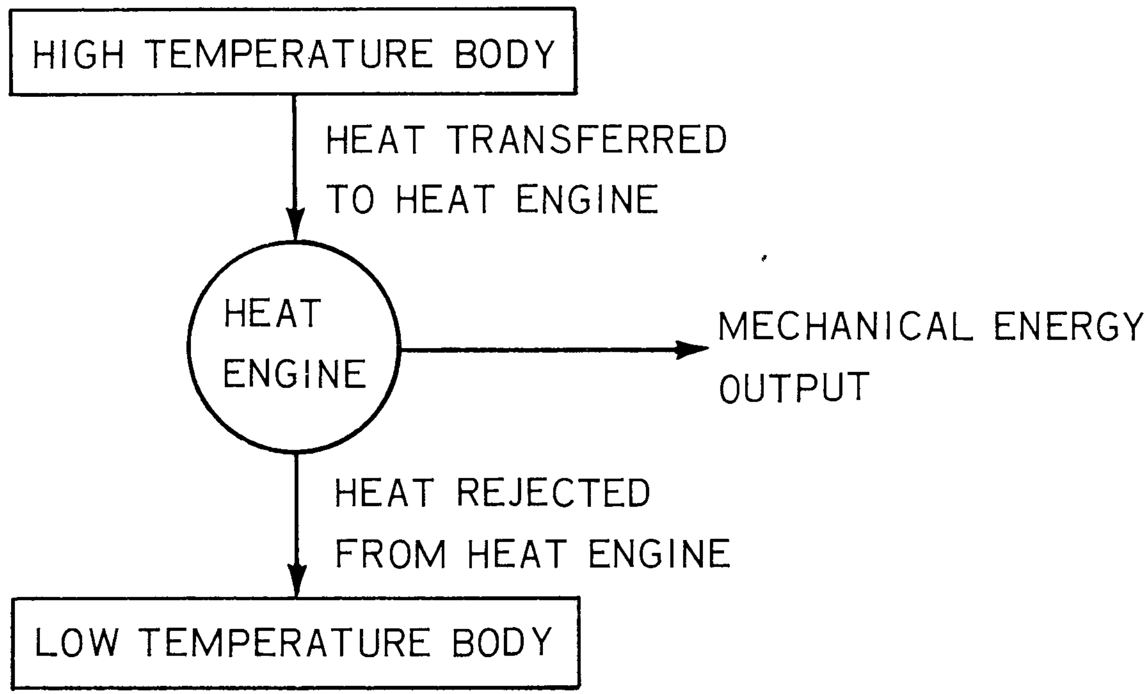
Approximately 78% of the electric generating capacity in the U.S. in 1970 was based on steam turbine energy systems, and this percentage is expected to increase slightly by the year 2000. The remaining 22% of capacity was supplied by hydroelectric (∿15%) and gas turbine and diesel electric (∿6%) power systems.[1-3]

6B.2.1.1 General Description

The steam turbine is a heat engine--as is any system that takes heat from a high temperature source, converts it into mechanical energy, and rejects waste heat at a lower temperature. A representation of the operation of a heat engine is shown in Figure 6B.2-1. According to the Second Law of Thermodynamics, to convert all of the transferred heat into mechanical energy is impossible; that is, a heat engine cannot be 100% efficient. The most efficient heat engine operating within the constraints of the Second Law is one that follows a theoretical concept known as the Carnot cycle. While the features of this cycle are not attainable in an operating heat engine system, the cycle is useful as a standard in evaluating the performance of actual heat engines.

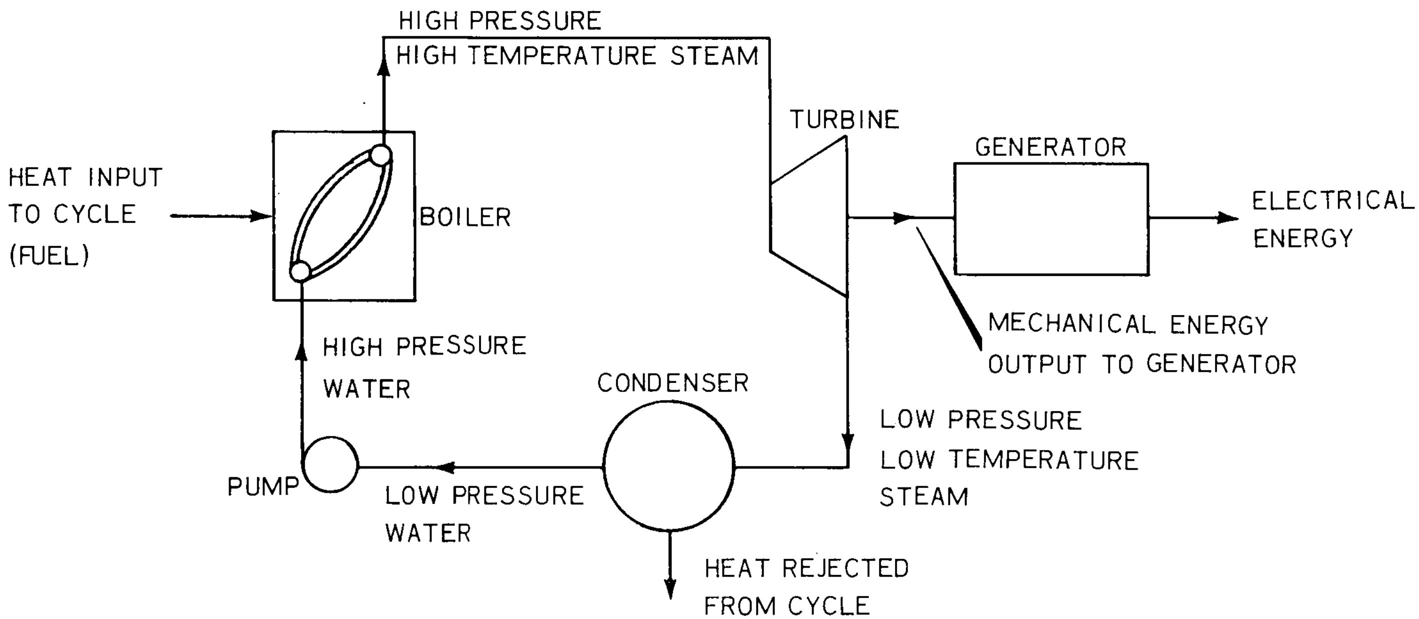
Steam turbine energy systems are based on the Rankine cycle, a practical modification of the Carnot cycle. In the Rankine cycle, heat from the energy source (fossil fuel combustion gases or nuclear fuel) is transferred to water at high pressure in a boiler and produces high-pressure, high-temperature steam. The steam enters the turbine where it expands to a low-pressure, low-temperature steam and in so doing does work against the turbine blades, causing a rotation of the turbine shaft which in turn drives an electrical generator. After the thermal energy in the steam has been converted to mechanical energy in the turbine, the discharged (spent) steam is converted back into water in a condenser. The water is then pumped back into the boiler and starts the cycle over again. The heat removed in the condenser is rejected to the environment through the use of cool bodies of water (i.e., lakes, ponds, or rivers) or of cooling towers. This cycle is shown in Figure 6B.2-2.

Modifications to the Rankine cycle which improve its thermal efficiency use the concepts of regeneration and reheat. In the reheat process, a portion of the steam that has partially expanded to an intermediate pressure in the turbine is reheated in the boiler and then returned to the turbine to complete the expansion process (Figure 6B.2-3). The regenerative process extracts a fraction of the steam from the turbine after partial expansion and uses it to heat the water leaving the



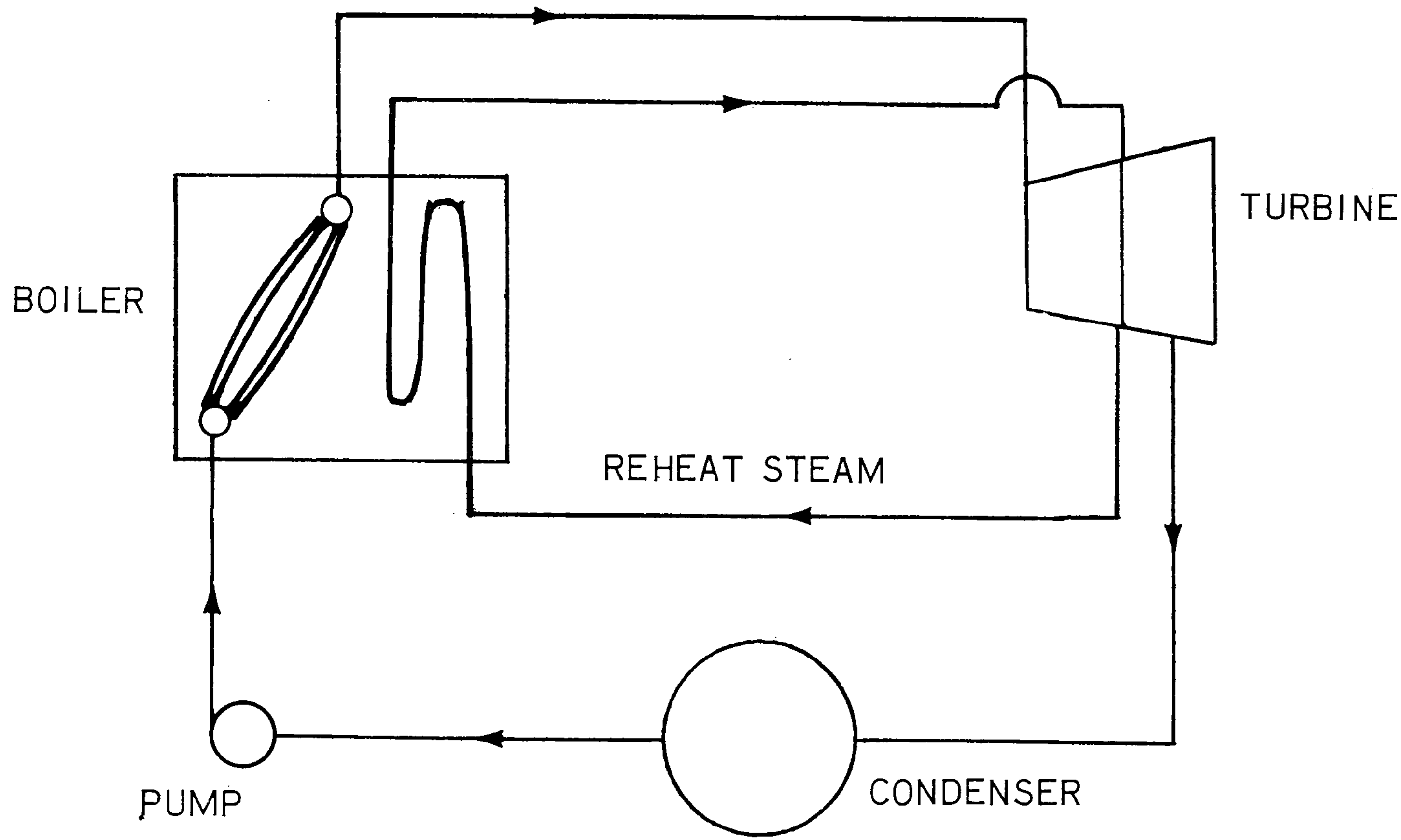
OPERATION OF A HEAT ENGINE

Figure 6B.2-1



BASIC COMPONENTS OF A RANKINE CYCLE HEAT ENGINE
AS USED IN STEAM TURBINE POWER PLANTS

<u>Figure 6B.2-2</u>



RANKINE CYCLE WITH REHEAT

Figure 6B.2-3

condenser before it enters the boiler. The device where this heat exchange occurs is called a feedwater heater. A number of feedwater heaters are generally used in modern systems. This process is shown in Figure 6B.2-4.

Typical steam power plants will use both reheat and regeneration. The extent of reheat and regeneration for a particular plant will be determined by economic considerations, principally the fuel cost. The light water reactor (LWR) nuclear plants in operation today, for the most part, use the regenerative process only, because the temperatures available in LWRs are not particularly economical for reheat purposes.

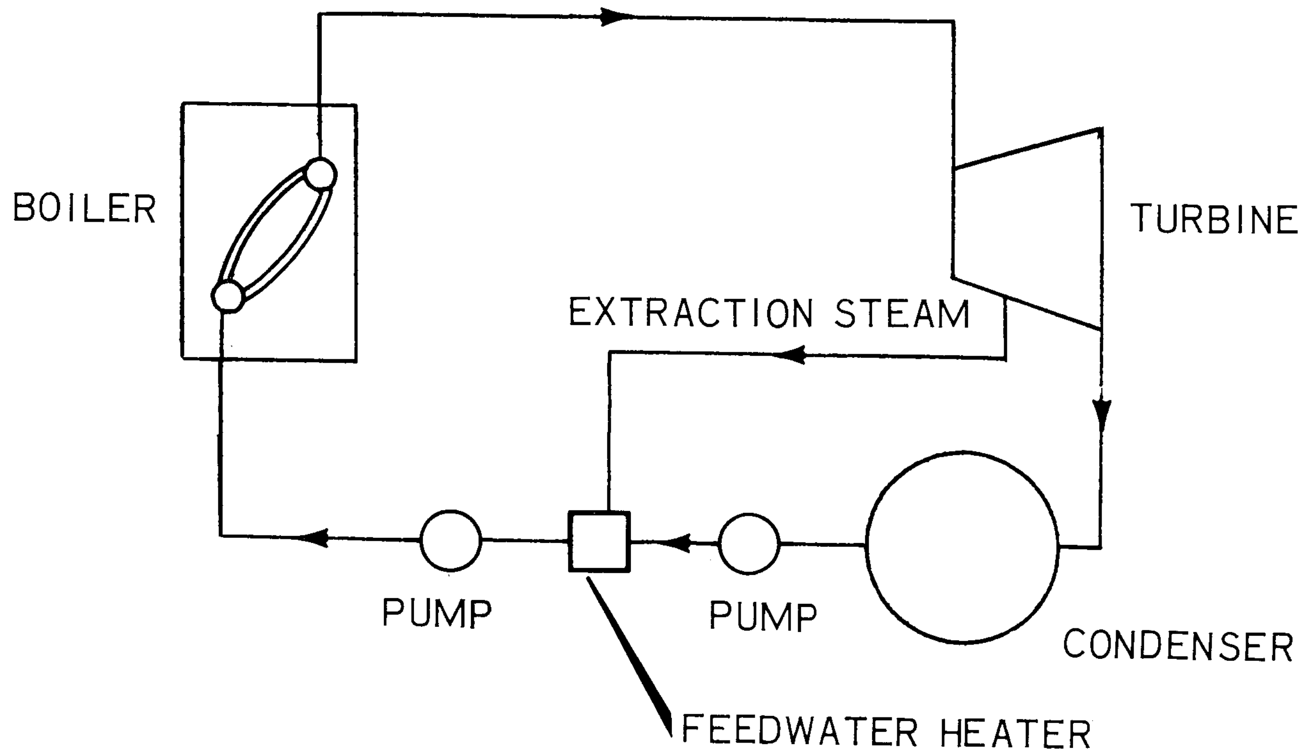
6B.2.1.2 History and Status

The first prime movers for generators to develop electric power were hydraulic turbines and reciprocating engines. Hydraulic turbines are discussed in Section 6A.3. The reciprocating engines initially used steam at moderate temperature and pressure as the working fluid in an engine similar to the internal combustion engines discussed in Section 6B.3. Expanding steam served the same function as the burning vapors of the internal combustion engine.

The steam turbine energy system became part of the electric power industry around 1900, roughly 20 years after the industry's beginning. Its importance grew, and it quickly overtook reciprocating steam engines and hydroelectric power as the principal means of electric generation. By 1930 it was responsible for 70% of the total generated capacity,[4] and since then the proportion has gradually increased to its current level of around 78%.

Advances in technology have provided continuous improvement in the design and performance of the steam turbine system. In 1903, the unit size being built was approximately 5000 kW, with initial steam conditions of 175 psi and 375°F and a plant efficiency of 9.2%.[5] Corresponding values for today's most modern plants have increased typically to 1,000,000 kW, 3500 psig, 1000°F with 1000°F reheat, and 39% efficiency. The trend to larger units is a result of lower capital, operating, and maintenance costs, on a per kilowatt basis, that are attainable as the unit plant size increases.

The steam conditions have, until recent years, increased in order to improve the thermal efficiency of the unit. This progress has been made possible by metallurgical advances resulting in alloys that can withstand the higher pressures and temperatures. The steam conditions declined and leveled off around 1960, because



RANKINE CYCLE WITH REGENERATION

Figure 6B.2-4

the small increase in efficiency, going from 3500 to 5000 psig and from 1050 to 1200°F, could not economically justify the increase in material costs and additional maintenance problems associated with these higher steam conditions.

Up to 1950, boilers were small and several would supply a single turbine. The continued increase in turbine size has required the design of higher output steam generators. Improvements in boiler design and metallurgy have made it both economical and reliable to have a single boiler for each turbine-generator unit.

The most significant change in the development of the steam turbine energy system, however, has not been improvements in system design but the use of nuclear fuel in place of the conventional fossil fuels. In these plants, the nuclear reactor, where the nuclear energy is released, and associated equipment takes the place of the conventional steam boiler used in fossil-fueled plants.

6B.2.1.3 Present and Projected Applications

As noted in Section 6B.2.1.2, the steam turbine energy system has consistently been applied to the generation of electric power since the year 1900. Estimated values for the remainder of the century indicate the percentage will increase somewhat over the 1970 value of 78%. This value includes its application to both fossil-fueled and nuclear steam supply systems.

The kinds of service provided by the various types of plants can be classified in terms of base, intermediate, or peaking load. Base-load units are large, efficient units that operate continuously at or near their full capacity. Typical annual *capacity factors* (percentage of annual output if operated continuously at maximum capacity) are around 80%. Intermediate-load units are smaller, less efficient, and typically are required to shut down and start up daily as demand varies. Capacity factors vary from 20 to 60%. Peak-load units provide power for short periods of the day, when the demand for electricity is at its maximum, and have capacity factors of 20% and less.

Steam turbine systems are predominantly used for base- and intermediate-load service. Base-load service is provided by large fossil-fueled and nuclear units, whereas intermediate service is provided by either older and smaller fossil-fueled units, originally designed for base-load, or newly designed fossil-fueled units built specifically for this service.

New peaking service is now generally provided by pumped storage, gas turbine, or diesel energy systems, rather than steam turbine systems, because of the quick startup requirements and the economics involved.

6B.2.2 Technical Information

6B.2.2.1 Availability

There are three U.S. suppliers, as well as several prominent foreign sources, for steam turbine equipment. Availability of steam turbine units in terms of lead time--the time from project announcement to commercial operation--depends on the type of unit. Approximately five years are required until operation of fossil-fueled plants begins. Nuclear plants, which utilize more sophisticated technologies and have more involved licensing procedures, require about eight years of lead time.

6B.2.2.2 Energy Source

The fuels currently used in steam turbine power generation systems are the fossil fuels--coal, oil, and natural gas--and nuclear fuels. Figure 6B.2-5 shows the current and projected electric power generation by these fuels and also hydroelectric energy. These fuels are discussed in considerable detail in Section 6A of this Statement.

6B.2.2.3 Efficiency

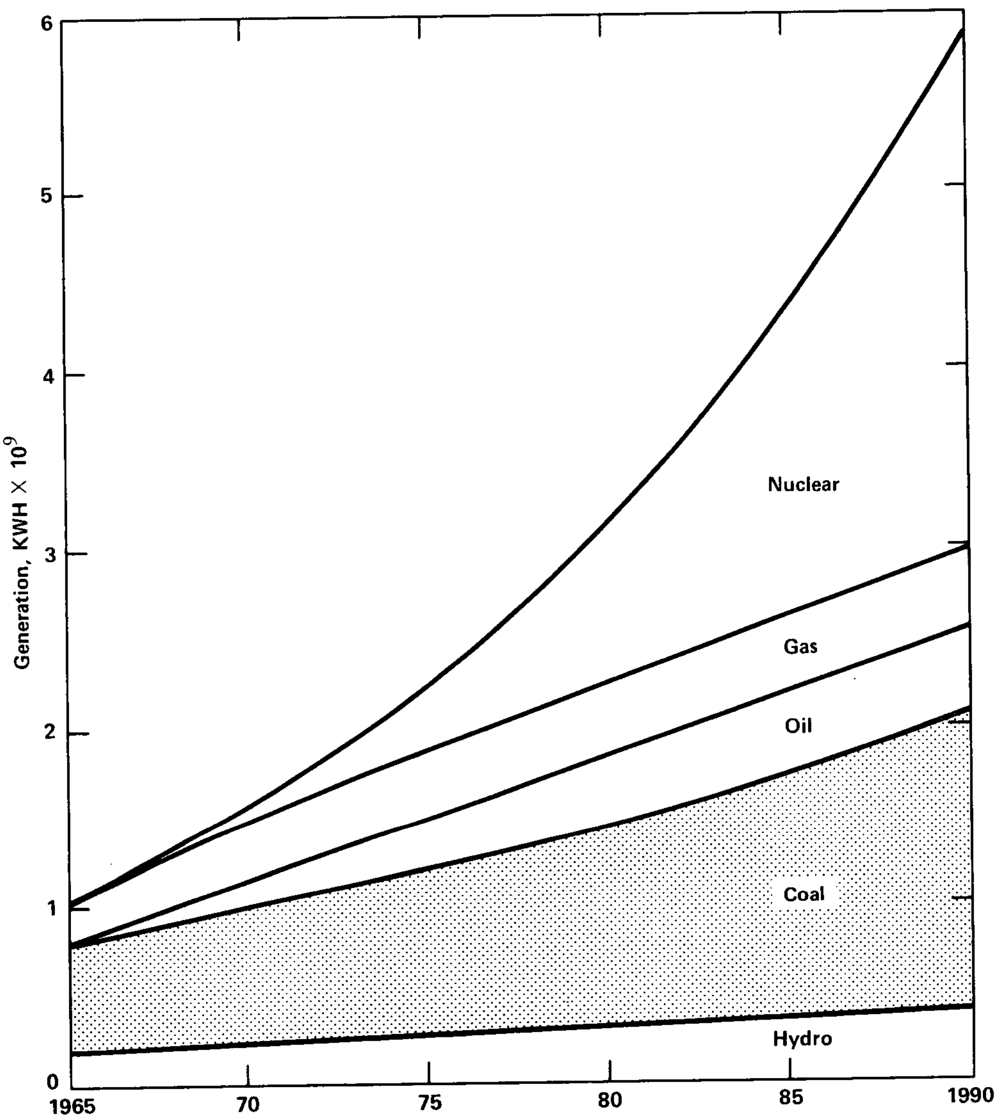
As discussed in Section 6B.2.1.1, the maximum efficiency for a heat engine is the Carnot cycle efficiency, which is a theoretical efficiency that cannot be achieved in practice but which serves as a measure of performance for actual cycles. The Carnot efficiency is

$$n_c = \frac{T_H - T_L}{T_H}$$

where n_c = Carnot cycle efficiency
T_L = Low temperature of heat rejection, °R
T_H = High temperature of heat addition, °R

The equation shows that theoretical efficiency is improved by increasing the heat addition temperature (T_H) and decreasing the heat rejection temperature (T_L).

Steam turbine systems typically operate between a maximum temperature of 1000°F (1460°R) and a minimum temperature of 70°F (530°R). A Carnot cycle operating



ESTIMATED ANNUAL ELECTRIC GENERATION
BY ENERGY SOURCE

Figure 6B.2-5

between these temperature limits of heat addition and heat rejection would have an efficiency of 65%.

Actual steam turbine plant efficiencies for units in the 1000-MW range are on the order of 38 to 40% for fossil-fueled and HTGR units and 31 to 34% for BWR and PWR units. Improvements to these efficiencies through the use of additional stages of reheat and regeneration are not economically practical at the present time, because the increased investment costs offset the operating savings.

Use of higher steam temperatures and pressures to improve efficiency of fossil units is limited because: (1) metals currently used are near their metallurgical limit and (2) metals that can withstand more extreme steam conditions are too costly to be economical and have a limited lifetime. Therefore, significant advances in efficiency are not expected in the immediate future.

The heat rejection temperature is limited by the temperature of the environment (water or air) to which the heat is rejected. This is, of course, dependent on geographical location and the type of heat rejection system chosen.

6B.2.2.4 Size Limitation

The size of steam turbine units is expected to increase above the present maximum of about 1300 MW in order to reduce capital, operating, and maintenance costs on a per kilowatt basis. Although these large units will require some improvements in turbine, generator, and boiler design, no major problems are expected.

Factors that may have an effect on plant size are cooling water and land area requirements. Because larger units require greater amounts of cooling water and regulations are being introduced that limit the amount of heat that can be discharged into natural bodies of water, sources of cooling water for large plants have become a problem. Greater land area requirements are a result of larger coal and ash storage areas, flue gas cleaning equipment, and cooling facilities for the condenser cooling water. Dry cooling towers are expected to occupy a position of greater prominence.

6B.2.3 Research and Development

It is believed that there are not likely to be any major improvements in steam turbine technology. Advanced blade technology, seals, and moisture-removal techniques as well as lower-cost, high-temperature alloys are areas receiving current attention. The use of superconductivity technology is also being explored for the construction of smaller, lighter, higher power output turboalternators (generators) since this currently represents a transportation restriction (manufacturer to power plant site). This particular application of superconductivity technology has been recommended for further development by the FPC Task Force[6] and AEC Subpanel VI.[7] This development includes research on higher transition-temperature superconducting wire as well as design, construction, and test of multi-megawatt generators.

Any major advances in efficiency will probably come from the use of topping (binary) cycles (see Section 6B.5) or alternative energy conversion devices.

6B.2.4 Environmental Impacts

The environmental impacts associated with steam-turbine electrical generating plants are discussed extensively in Section 6A of this report in those portions dealing with the power production systems using the steam turbine cycle.

6B.2.5 Costs and Benefits

The preponderance of the electric generating capacity of the United States today is based on the utilization of the Rankine cycle, which attests to its relative economics. The very wide range of conditions for which an individual unit may be designed (i.e., varying construction conditions, varying labor productivity) leads to significant cost differences of plants installed at different locations within the Nation. Environmental control costs will also add substantial amounts to the basic costs of the plant. (See Section 6A.2.1.7 for a detailed discussion.)

Disadvantages exist with the steam turbine energy system that are prompting investigations into alternative electric generation schemes. Principal factors are its associated adverse environmental effects and the desire for higher efficiencies than can practically be obtained from a steam Rankine cycle alone. Low efficiencies result in higher rates of (1) consumption of limited fuel reserves, (2) air pollution, and (3) thermal pollution. The indirect method of electric generation--energy transformations from chemical or nuclear to thermal, from thermal to mechanical, and from mechanical to electrical--along with the large and complex equipment used is also considered a system disadvantage when compared with other generation concepts.

Notwithstanding these considerations, the steam turbine system is currently the most economical and technologically developed energy system available to the electric power industry.

6B.2.6 Overall Assessment of Role in Energy Supply

The steam turbine energy system is, and is expected to remain for many years, the predominant means by which fossil and nuclear energy is converted to electrical power by central station plants. Most new plants are expected to be in the size range of 1000 MWe and beyond. No significant improvement in the efficiency of conventional steam turbine systems is foreseen. However, the development of advanced energy conversion systems such as gas turbines, binary cycles, and magnetohydrodynamics may provide the means of improving the efficiency of central station power plants.

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6B.3 INTERNAL COMBUSTION ENGINES

6B.3.1 Introduction

6B.3.1.1 General Description

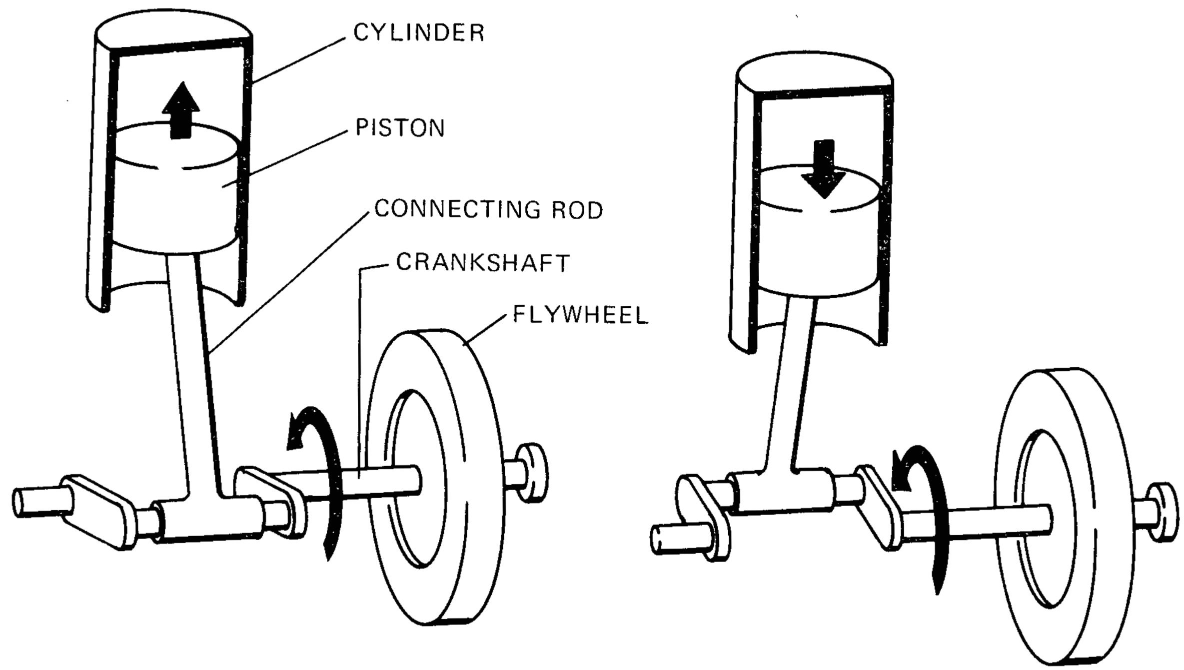
The principles of the internal combustion engine (IC) can be simply described as follows. If a mixture of fuel and air is burned in a confined space, the heat released elevates the temperature of the combustion products and remaining reactants and causes a pressure rise. If the chamber (cylinder) in which the fuel is burned is constructed with a movable wall (piston), the increase in pressure causes the piston to move. Connecting the piston to an eccentric shaft (crankshaft) through a linkage with movable joints (connecting rods) enables the pressure (power) moving the piston to be transmitted to the shaft, thus causing it to rotate. With suitable valves (the opening and closing of which are controlled by the rotating shaft) air, fuel, and the products of combustion can be admitted and discharged at appropriate times, supplying intermittent energy to the crankshaft. Usually a number of cylinders are mounted on a common shaft. A flywheel can be mounted on the crankshaft to assist in providing for continuous power output. The power output is in proportion to the number of cylinders, and if the cranks are properly phased, a uniform flow of power to the crankshaft can be obtained, with a resulting reduction in flywheel size and weight. A turbocharger is sometimes added to enhance engine performance. (See Figure 6B.3-1.)

6B.3.1.2 History and Status

The origin of the IC engine is generally credited to Christian Huygens (1629-1695), a Dutch scientist who proposed the construction of an engine using gunpowder as a fuel. Similar schemes for the design of IC engines were proposed over the next 200 years but were never reduced to practice.

In 1895, Rudolph Diesel built the first successful four-stroke compression-ignition engine that burned fuel oil injected, under pressure, into the cylinder. This pioneering work laid the foundation for the development of the piston-type engines used in electrical power generation today. The first electric power generated in America by an IC engine was in 1898.

Internal combustion engines of the piston type are familiar as the prime mover in the vehicular propulsion field. The IC engine can be fitted with an electric generator and used for small electric utility applications. The engines used in utilities are generally many times larger than those used in vehicles. They burn



(a)

COMPRESSION
AND EXHAUST
STROKE

(b)

EXPANSION
AND INTAKE
STROKE

SCHEMATIC DRAWING OF PISTON TYPE INTERNAL COMBUSTION ENGINE

Figure 6B.3-1

oil or gas and are of the diesel type. (Such plants are referred to as diesel electrics.)

Use of this type of engine for electric power generation stems from the relative simplicity of the completed plant, its ability to burn a variety of gaseous or liquid fuels, its minimal water requirements, and its relatively good efficiency. It is the preferred power plant with cooperative and municipal utilities where the total installed power is 10 MW or less.

6B.3.1.3 Present and Projected Application

The diesel electric generating plant dominates the low-power end (up to 10 MW) of requirements in the utility field. It is used for base-load power generation in small utilities, peaking power in large utilities, starting power in some steam power plants, and emergency power for practically all nuclear plants. Diesel electric plants have the ability to start unattended on command in about 10 seconds and assume full load within 30 seconds. High starting and operating reliability is required for this application.

Diesel electric generating sets are frequently used for steam-station auxiliary power. Installed primarily for use as independent sources of starting power for station steam units, these plants may also be used for small additional power generation for the system during periods of peak demand.

6B.3.2 Technical Information

6B.3.2.1 Availability

Of the 32 diesel engine manufacturers in the United States, only six could be considered as equipment suppliers to the electric utility industry. The combined product line of these six companies comprises well over 100 models and sizes, making it possible for any customer to select an engine meeting his needs.[1]

Utilities in the U.S. have not demanded large diesel-engine generating sets. While the average size in the U.S. is about 3500 kW,[2] the largest diesel engine in production has 12 cylinders on a single frame and develops over 10,000 shaft horsepower (7000 kWe at 93% electrical generator efficiency).

6B.3.2.2 Energy Source

Virtually any liquid or gaseous fuel can be burned in a diesel engine. The principal liquid fuel in use today is No. 2 fuel oil. Higher-density fuel oils, up to No. 6, and even crude oil--centrifuged to remove particulate matter that would clog the fuel-injection nozzles--are also used. The type of liquid fuel used is a matter of economics. The lower cost of poorer quality oils must be weighed against the effect on power output, increased emissions, and higher maintenance costs. Natural gas is typically used in dual-fuel or gas-burning engines and is used as-delivered from the gas utility. No special fuel pretreatment is required.

6B.3.2.3 Efficiency

The specific fuel consumption of practically all modern diesel engines used for electric power generation falls in a range near 0.40 lb/hp-hr. (Four-cycle engines have a slightly lower specific fuel consumption than two-cycle engines.) This is the equivalent of a heat rate of 9900 Btu/kWhr (∿35% efficiency) at the engine output shaft, which is comparable with modern steam plants whose power output may be a factor of 10 higher.

6B.3.3 Research and Development

After 75 years of intensive development of the diesel engine by some of the best engineering firms in the world, no basic development would seem to be required.

6B.3.4 Environmental Impacts

Pollution from a diesel engine comes from the engine cooling system and the cylinder exhaust. All diesels used in utility generating plants are water-cooled, the engine cooling water being circulated in a closed loop. Heat is rejected through either water-to-water or water-to-air heat exchangers.

Diesel exhaust emissions classed as pollutants are the same as from any other IC engine. These are CO, NO_x, unburned hydrocarbons, and particulate matter. Standards for stationary diesel engines emissions are being formulated by the U.S. Environmental Protection Agency and are expected to be available in 1974.

The diesel engine industry has been monitoring emission products from diesel engines burning both liquid and gaseous fuel; typical findings are shown in Table 6B.3-1.

Table 6B.3-1

DIESEL ENGINE EMISSION PRODUCTS

Engine Type	Fuel Form	Exhaust Emission (g/hp-hr) CO	NO_x	Hydrocarbons	Particulates
Two-Cycle, Spark Ignition	Gas	2.2	10.0	3.5[a]	NA[b]
Four-Cycle, Compression Ignition	Gas	2.3	4.6	5.6[a]	0.5
	Liquid	0.6	10.4	0.3	0.6

[a]Approximately 50% CH_4.
[b]NA = not applicable.

The clean-up of exhaust-gas emissions must await the establishment of EPA standards before the extent of the problem is known.

Diesel electric generating stations are generally noisy. This noise can be readily controlled and corrected by some redesign, soundproofing, and more extensive mufflers.

6B.3.5 Costs and Benefits

Two types of costs, capital and operating (power generation), are to be considered; both can vary widely.

A 2750-kW prepackaged Electro-Motive unit sold in 1972 for about $105 per kW. This price is also applicable to the bare, medium-speed, four-cycle engine. The slow-speed, two-cycle engine sold for about $30 per kW more. In addition, installation costs for this unit on the East coast ranged from $15 per kW for a single-unit plant to $8 per kW for a five-unit plant. Installation costs of a medium- or slow-speed diesel plant ranged from $40 to $50 per kW. These costs did not include fuel storage and the transformer station, cooling water, buildings, capital write-off, taxes, interest during construction, and architect's fees.

In 1970, power generation costs (including capital amortization) for base-load, diesel-electric generating plants averaged 9.54 mills/kWhr for a representative group of 45 plants.[3] Capacities ranged from 51,740 kW in thirteen units to 2361 kW in four units. Costs, half of which are fuel cost, ranged from a high of 18 mills/kWhr to a low of 4.87 mills/kWhr. Production costs vary inversely with the size of the plant, and peaking and standby plants have higher production costs than a base-load plant but are within the range noted.

While reasonably efficient and competitive with steam turbine units in the low-power range, diesel-electric plants do not reach the efficiency of large steam turbine units. While they are size-limited in individual units, multiple-unit plants can be arranged to give a desired power level. Capital costs are favorable, but such plants can only use liquid and gaseous fossil fuels.

6B.3.6 Overall Assessment of Role in Energy Supply

The diesel electric plant has its own place in the electric utility industry in providing modest blocks of power for municipalities and isolated areas. Aside from power generated in the small cooperative and municipal utilities, the diesel generating plant contributes little to our total electrical requirements. Of the 367,396 MW of installed electrical generating capacity in the United States in 1971, only 4466 MW, or 1.22% of the total, was diesel electric.[4] The total energy (kWhr) generated was an even smaller fraction, 0.39%.

Because of size limitations, the diesel electric plant will probably not be used to meet a system demand much in excess of 50 MW. However, it has established a position in the small municipal and cooperative electric system and has enjoyed a growth rate of about 4% per year during the past 15 years.[5]

With the exception of any restrictions that may be imposed by the increasing price and scarcity of oil, no new developments or environmental ramifications are anticipated that, in the immediate future, will affect the use of the IC engine in the electric utility field.

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5. Ref. 4, pp. 18, 19.

6B.4 GAS TURBINES

6B.4.1 Introduction

6B.4.1.1 General Description

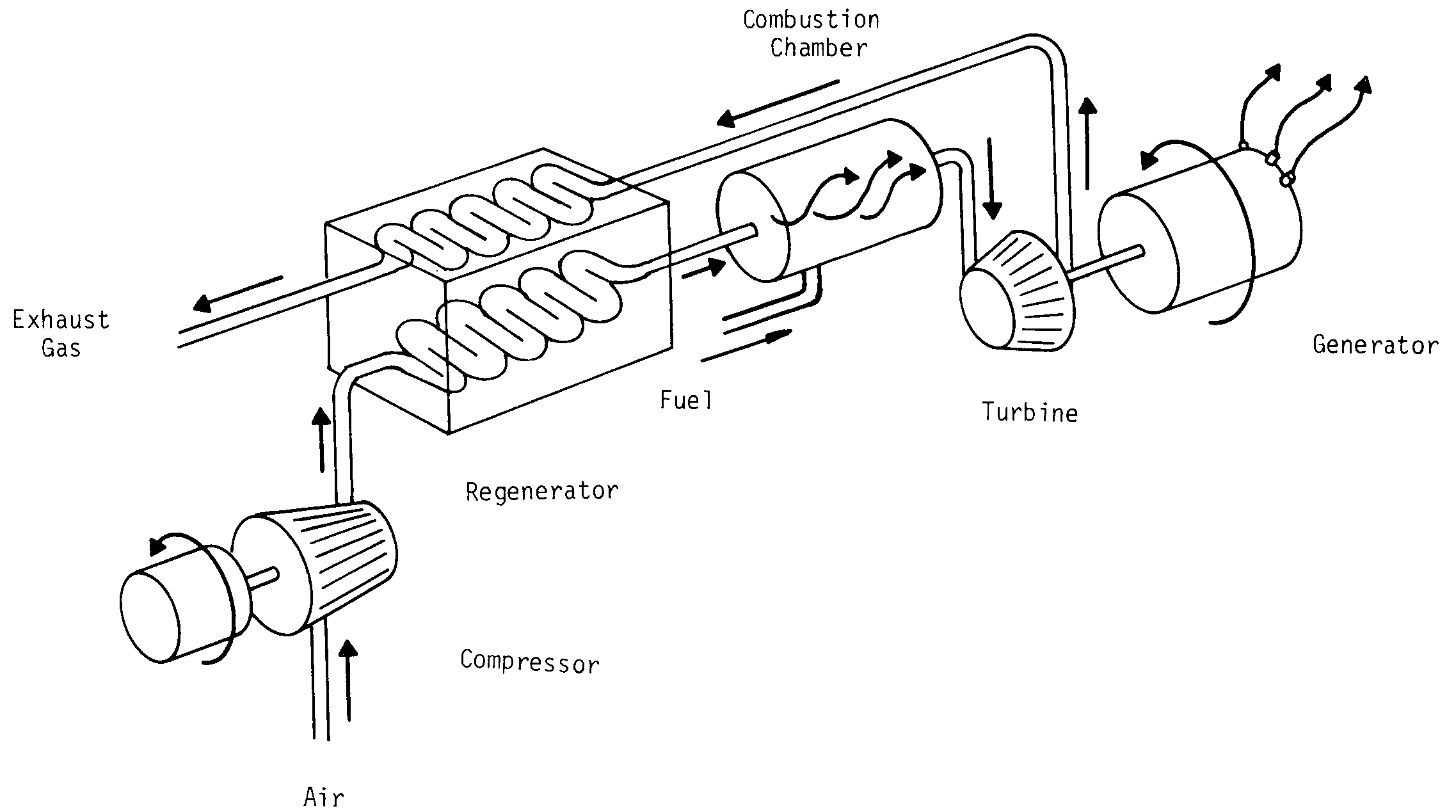
The gas turbine system has the function of converting input chemical energy of fuel into heated, compressed gas that expands while doing work on rotating blades similar to the steam turbine. The mechanical output is coupled to a generator shaft which in turn generates electrical power. Components of this system include a compressor, a combustion chamber, and one or more turbines together with heat exchangers, as called for by cycle design (see Figure 6B.4-1). In the simplest cycle, no heat exchangers are employed. An important characteristic of the gas turbine is the essential requirement for a clean (no particulates or corrosive components) gas flow through the turbine, forcing the need for a clean burning fuel or a source of high-temperature thermal energy, such as a nuclear reactor, where the fuel-element coolant is the high-pressure heated gas for the turbine expansion.

6B.4.1.2 History and Status

As noted in Section 6B.2.1.2, around 1900 the steam turbine had developed to a point where it began to be used for central station power generation. Steam turbine systems use external combustion in a boiler to generate steam. The advantages of using turbine machinery with internal combustion led to numerous gas-turbine engine developments that did not fully mature until after 1945 as a result of the largely military-supported research and development effort on supercharged aircraft piston engines. Much of the technology of the aircraft development is used, after a modest time lag, in the industrial gas-turbine field.

In the early 1960's, the industrial gas-turbine market blossomed with its applications to natural-gas transmission-line pumping, the petrochemical industry, locomotive propulsion, and emergency and peaking electrical energy generation.

Although this type of power plant was introduced into the electric utility field in 1949, it was regarded as a curiosity until early in the 1960's when utilities recognized and accepted its usefulness in meeting their peak load demands. Its acceptance in the electric utility industry for this purpose has been substantial over the past ten years, so that almost 8% of installed generating capacity is now in gas-turbine power plants.



REGENERATIVE CYCLE GAS TURBINE

Figure 6B.4-1

6B.4.1.3 Present and Projected Applications

Today the simple-cycle gas-turbine prime mover is favored for new equipment to accommodate the peak portion of the electrical power demand. Fast start, low initial cost, and short delivery time are features desired for peak-load plants and are met by gas turbine units. An important variation of the simple-cycle system is the combined gas turbine and steam plant. Here the hot exhaust from the power turbine is used to generate steam in an unfired boiler. The steam is used in a conventional system to generate 50% more power without additional fuel (Figure 6B.4-2). The combined cycle thermal efficiency is comparable with that of a modern steam plant and is being used by some utilities for serving intermediate system loads. One forecast is that by 1980 the gas turbine and the combined gas turbine and steam power plant could be providing some 25% of the power requirements of the electric utility industry in meeting peak and intermediate load demands. Gas turbine cycles are expected to be used in high-temperature gas-cooled reactor (HTGR) and gas-cooled fast reactor (GCFR) systems.

6B.4.2 Technical Information

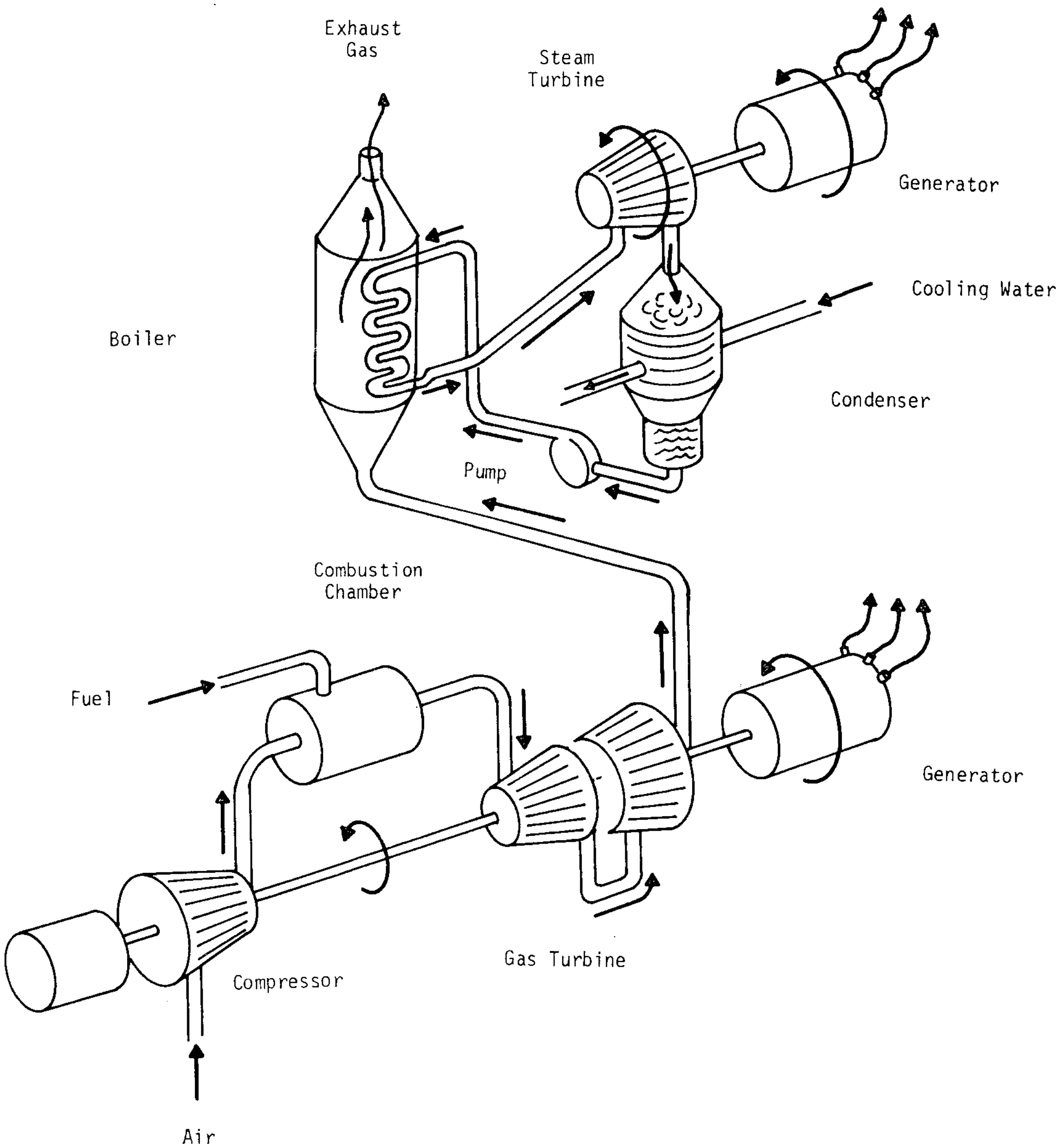
6B.4.2.1 Availability

Heavy-duty-type and aircraft-engine-derivative-type electric power gas turbines are currently available in sizes ranging from approximately 3 to 100 MWe when combined with a heat-recovery steam generator and a steam-turbine generating unit. Multiple units are employed to produce plant capacities up to 1000 MWe. For instance, such a plant might consist of four gas-turbines and their electrical-generator packages, plus one steam turbine with its electrical generator.

There are three major U.S. suppliers of large, heavy-duty, industrial-type gas turbines (50 MWe and greater) and three major suppliers for large, aircraft-engine-derivative systems. If, as expected, the combined cycle and its variants make substantial inroads into the midrange market, the short lead time advantage now offered by gas-turbine manufacturers (12 to 18 months) may well be lengthened. Alternatively, manufacturing capacity, not only for the gas turbine but also for electrical generators, regenerators, and heat-recovry boilers, will need to be expanded.

6B.4.2.2 Energy Source

One of the salient characteristics of a gas turbine is its requirement for a clean fuel so that the gas flow through the turbine is neither erosive (from particulates) nor corrosive (from vanadium, sodium, potassium, lead, and sulfur compounds).



COMBINED CYCLE GAS TURBINE

Figure 6B.4-2

Calcium is also troublesome, as it forms hard deposits. All of these elements are contained in residual fuel oils--the low-cost residue of the petroleum refining processes that produce the distillate fuel oils (diesel and kerosene) and gasoline. As a consequence of this, comparatively clean residual and crude fuel oils must be carefully selected, and these must then be treated further before fuel oil products can be used for gas-turbine operations. In addition, the growing need for our limited oil resources for other applications makes this energy source questionable for large-scale use in the electric power industry.

Gaseous fuels present no problems of this nature. Natural gas as distributed by utilities is an ideal fuel, but its scarcity also militates against use for electric power generation. Considerable attention is being given to the possibility of using high or low Btu gas derived from coal gasification, and there does not seem to be any technical problem in doing so. Coal gasification may well become an economical technique for removing sulfur. The gas turbine and the combined cycle plant might adapt very well to this type of fuel.

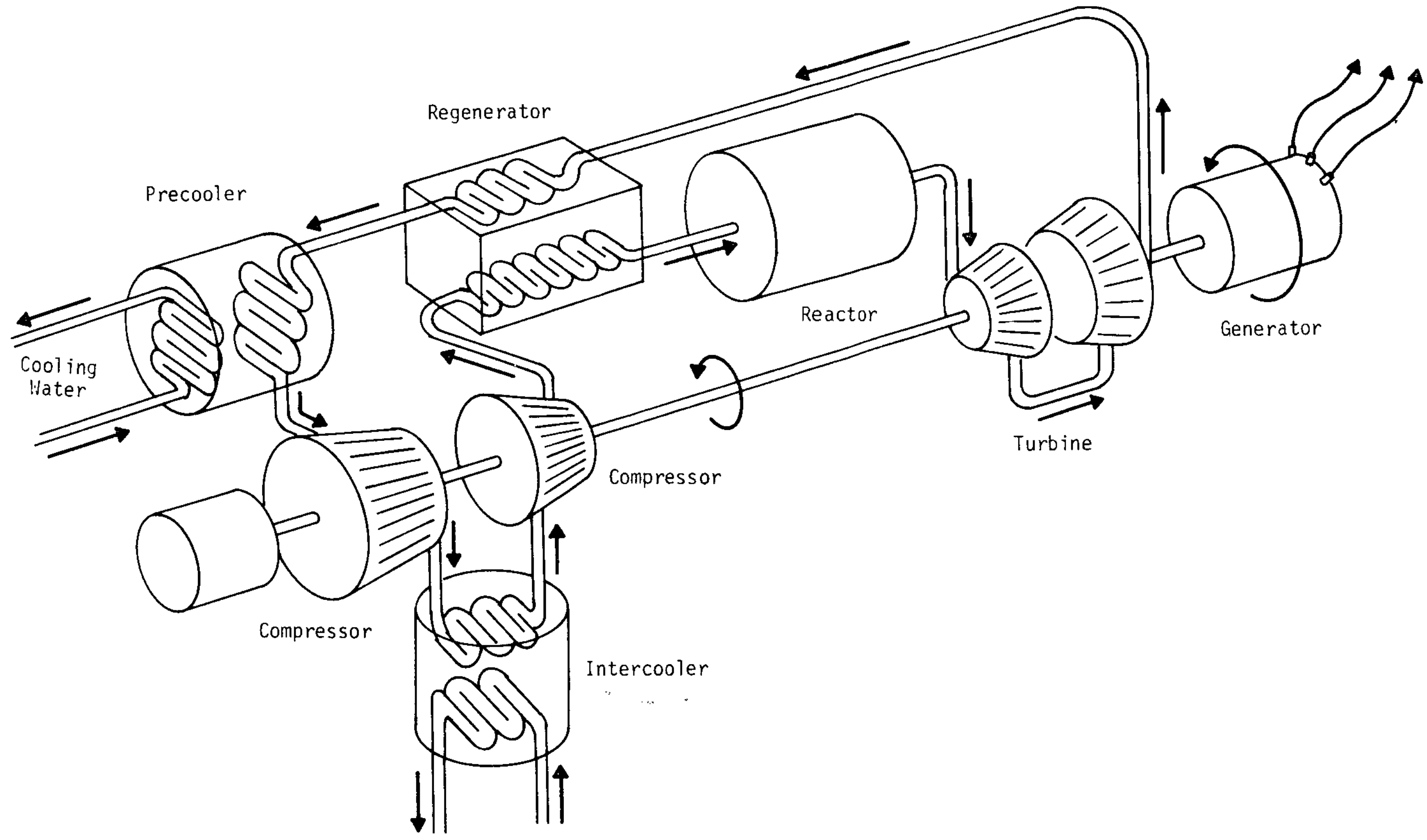
As discussed in Section 6A.1.2, high-temperature helium-gas-cooled thermal nuclear reactors coupled to steam-turbine converters are now being considered by the utilities as a viable alternative to water-cooled reactors, and a number of units have been ordered. As a result, increased emphasis may be placed on the closed-cycle helium-gas turbine rather than the steam turbine as the energy conversion system (Figure 6B.4-3).[1]

6B.4.2.3 Efficiency

Gas-turbine plants now available have the following efficiencies:

(1) simple cycle, 27%,
(2) combined cycle, 36-38%,
(3) regenerative cycle, 34%.

With currently available materials and turbine-cooling technology, commercial designs should be available in the 1975-1977 period having better thermal efficiencies, by a factor of 1.1 or more, which could make the combined cycle competitive with the best available conventional steam plants. By 1980, further evolutionary progress is expected to yield improvements resulting in a 1.2 multiplier on present-day thermal efficiency performance.



NUCLEAR CYCLE GAS TURBINE

Figure 6B.4-3

6B.4.2.4 Size Limitations

One great advantage of the gas-turbine cycle engine is that it lends itself to the concept of modular design and factory fabrication. The result is substantial economies in lead time and in costs for field erection. Another advantage of the modular concept is that good partload fuel economy can be realized by shutting down one or more units when only part of the total capacity is needed. Multiplicity of units also affords improved reliability and availability, as maintenance can be done to a single unit with only a partial reduction in capacity. These capabilities are highly desirable for plants used for the midload service range.

6B.4.2.5 State of the Art

The power obtained from the turbine components and the power required to drive the compressor are dependent on gas flow temperatures and component efficiencies. To achieve better fuel economics, the system should have a high turbine-inlet temperature and the flow path over the compressor and turbine blades should be designed to minimize losses.

The outstanding advantages of the gas turbine for aircraft propulsion has produced the research and development effort that led to the improved aerodynamics of flow path design, metal alloys allowing high turbine-inlet temperatures, and improved methods of cooling turbine blades and nozzles. The fallout of this technology has greatly improved the position of the gas turbine and has led to its acceptance for peak-load central-station power service.

Other important components of the industrial gas turbine and its variants are the heat exchangers for regeneration, steam generation, and other functions such as intercooling and precooling as needed by the closed cycle. Large regenerative heat exchangers for operation above 1000°F have not been built and pose difficult problems because operating conditions require materials that are expensive and difficult to fabricate.

In summary, the central-station-type gas-turbine engines available today represent advanced state-of-the-art designs evolved from well-funded aircraft-gas-turbine research and development. The heat-exchanger components, on the other hand, could benefit from an accelerated development effort.

6B.4.3 Research and Development

For central-station power units, research and development is required in the following areas:

(1) New-design combustion chamber--convincing service experience is needed to prove that oxides of nitrogen can be significantly reduced.

(2) Advanced technology--early design application is needed of available blade-cooling techniques and improved high-temperature materials.

(3) Exhaust heat boilers--improved designs for lower cost and lower bulk are required.

(4) Reliability--for intermediate-load operation more operating experience is required to show that gas turbines can operate at their design temperature for tens of thousands of hours without maintenance. (Some plants have operated 30,000 hrs without maintenance.)

(5) Regenerators--designs are needed for higher-temperature operation at a lower cost and bulk. More suppliers are needed for this component, as there is now only one manufacturer in this country of industrial-type regenerators. The top operating temperature that regenerates with conventional materials needs to be established. More long-term service is required to prove operating reliability.

In addition, the closed-cycle helium-gas turbine coupled with a thermal nuclear reactor requires resolution of the effect of fission products and fuel debris from a failed fuel element on turbine corrosion and maintenance. Turbine shaft seal development is also a major developmental area. This seal functions to prevent leakage of helium where the power turbine shaft passes through the turbine casing to drive the electrical generator. Also, the heat exchangers--the helium-to-helium regenerator, the intercooler, and the precooler--require substantial research to produce economical designs.

Further development of gas turbine technology has been recommended by both the FPC Task Force[2] and the AEC Subpanel VI.[3] This development would include advanced high-temperature gas turbine-steam cycles that could be fueled by low Btu coal gasification plants or fluidized-bed combustion systems and high-temperature closed-cycle gas turbine systems that could be used with gas-cooled nuclear reactor plants.

6B.4.4 Environmental Impacts

The site requirements for gas-turbine fossil-fuel plants are modest in acreage. The noise levels are low as the high-frequency noise typical of turbomachinery may be acoustically treated at low cost.

Stack gas pollutants are virtually nil insofar as carbon monoxide and hydrocarbons are concerned. As a low-sulfur, low-ash fuel is a requirement for the turbine operation, fly ash and sulfur dioxide emissions are also negligible. However, a present problem area is the stack effluent of oxides of nitrogen (NO and NO_2). The technique now used to treat the problem is to inject demineralized water into the combustion chamber, at a mass flow rate comparable to the fuel rate, for loads above 40% of rating. Most gas-turbine manufacturers feel that they will be able to offer combustion chambers that will reduce oxides of nitrogen without the added complexity of water injection.

A set of emission standards is needed (such as the maximum values applying to conventional steam plants) to provide realistic design targets for research to reduce the oxides of nitrogen.

Simple-cycle and regenerative-cycle plants, relative to the combined gas-turbine and steam-cycle plants, do not have an extensive requirement for cooling water. The combined gas-turbine steam cycle has cooling water requirements about 40% or less than those of a conventional steam plant.

6B.4.5 Costs and Benefits

Low initial cost is an area that has made gas turbine energy systems particularly attractive to utilities. The efficiency has been of lesser importance for peaking service, but whether this will hold in the future, because of the dwindling supply of clean fuel, is largely unknown. The relative station costs and performance levels of gas turbine plants are as follows:

	$/kW	Thermal efficiency (%)
(1) Simple Cycle	90	27
(2) Regeneration Cycle	100	34
(3) Combined Gas and Steam Turbine	150	37

The comparable fossil-fueled steam turbine plant figure (from Section 6A.2.1.7) is $180 per kilowatt for a plant without sophisticated environmental controls; this cost could escalate to over $300 per kilowatt when environmental controls are added. The efficiency of modern steam turbine plants is about 39%.

The cost advantages of the gas-turbine cycles arise primarily from the elimination of a fired, high-pressure boiler with its superheater, reheater, and regenerative feedwater heaters. These steam-generating components cost about $40 to 50 per kilowatt. Though a boiler is incorporated in the combined cycle, its cost is only about $15 to 20 per kilowatt, as it is an unfired heat exchanger operating at a low pressure (less than 1000 psi).

Further advantages of the gas turbine are lower construction costs, about $5 less per kilowatt, and lower interest and escalation charges by about $20 less per kilowatt, due in part to much shorter field erection times. Projections for the future indicate that the gas-turbine-plant advantage in base-line cost figures will increase further. This conclusion results from the fact that available technological improvements, which may be incorporated into the 1975-1980 designs, will increase specific power by 40% or more. The result is that a given size (and cost) of turbomachinery has a higher kilowatt rating. Moreover, there will be significant gains in thermal efficiency, although percentage-wise not as much as for the rating gain.

6B.4.6 Overall Assessment of Role in Energy Supply

The gas turbine is a highly flexible prime-mover concept. It can be tailored to higher-efficiency application (e.g., combined, regenerative, and helium-closed cycles) at the expense of initial capital costs or alternatively to a low first-cost cycle (e.g., the simple cycle and the water-injected variant) at the expense of lower efficiency with the associated higher fuel costs.

On the basis of present technology, the role of the gas-turbine prime mover as an electric power producer through 1990 should be largely in peaking and intermediate load operation, where it will contribute possibly as much as 30% of the power capability and about 15% of the total electrical energy production. Developments in gas turbine technology that improve efficiency might make this system more attractive for base-load service. Gasification of coal could enhance the gas turbine's position by making it a possible alternative for base-load service.

The helium closed-cycle gas turbine coupled to a high-temperature gas-cooled nuclear reactor appears to have attractive features for a base-load generating plant. Substantial research and development will be required to demonstrate this role.

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6B.5 BINARY CYCLES

6B.5.1 Introduction

As noted in Section 6B.2, a fossil-fueled steam turbine system cannot take full advantage of the high temperatures available because of metallurgical and economic limitations. In order to improve this situation, two or more heat engine cycles that cover different parts of the temperature range can be combined. A combination of two different cycles is commonly referred to as a binary cycle. When a second cycle is added to the high-temperature end of another cycle, it is called a topping cycle. The gas-turbine steam cycle shown in Section 6B.4 (Figure 6B.4-2) is one illustration of a topping cycle; two others (mercury and potassium) are discussed in this section.

On the other hand, when the second cycle is added to the low-temperature end, it is called a tailing (or bottoming) cycle. Various refrigerants have been considered as working fluids for use in steam turbine tailing cycles, but the main efforts have been concentrated on ammonia. Steam-ammonia cycles incorporate a loop using ammonia on the low-pressure side of a steam cycle. Two basic configurations are generally considered, one where the ammonia loop contains an ammonia turbine and one where it does not.

The ammonia tailing cycle provides a conceptual method for heat rejection with dry cooling towers while retaining an acceptably high system efficiency. This method permits the use of generating sites where cooling water is not available. The particular advantage of ammonia as a working fluid arises from its low specific volume at heat rejection temperatures, a trait that leads to material savings in heat rejection equipment, especially dry cooling towers.

Several studies have been carried out to identify the components and the characteristics of the steam-ammonia cycle although there has been no actual experimental work directed toward the use of this technique for large-scale power production. Preliminary cost estimates indicate a slight economic advantage for the binary bottoming cycles, but these estimates are based on studies and cost estimates of equipment that has not been designed or built. Although these tailing cycles may have some advantages over the single fluid cycle, they appear to be marginal.[1]

Further discussion is limited to liquid metal binary topping cycles.

6B.5.1.1 General Description

In Section 6B.2, electrical utilities were shown to generate most of their electrical energy in fossil-fuel-fired Rankine-cycle steam turbine plants. Some of the low melting-point metals, such as mercury (melting point -38°F), when vaporized, can be used, like steam, as the working fluid to drive a turbine. The principal advantage of "liquid metals" as the working substance in a power plant is their high boiling or vaporizing temperature at a modest boiler pressure. (For example, mercury boils at 907°F at 100 psia in contrast to water boiling at 662°F at 2400 psia.) Potassium, which boils at 1400°F at 1 atm, can also be considered as a working fluid. The lower boiling pressure allows, in principle, an acceptable boiler cost in spite of the higher boiling temperature. While the liquid metals possess advantages relative to water in the boiler portion of the plant, water has the advantage in the condenser. This difference results from the liquid-metal vapor densities being so low as to make the condenser (and low pressure end of the turbine) excessively large and costly. This difference can be resolved by combining a liquid-metal Rankine cycle with the water Rankine cycle. In this concept the metal vapor condenser, now operating at acceptable vapor densities, serves as a boiler for the water cycle. Thus, while each individual cycle is not of high thermal efficiency, the binary cycle has a high efficiency because the energy rejection from the high-temperature topping cycle is used again in the boiler of the lower temperature water cycle.

6B.5.1.2 History and Status

Between 1922 and 1950, the General Electric Company constructed a series of six fossil-fueled mercury and water binary cycle power plants for utility and industrial use. Mercury plants demonstrated long-life capability; the original South Meadow Station of the Hartford Electric Light Company operated from 1928 until 1947 when it was dismantled. During this interval, it accumulated more than 110,000 service hours, about 70% of the total life of the plant. Kearny, placed into service in 1933, achieved more than 86,000 service hours by 1950 and continued in operation past the 110,000-hr mark.[2-13]

Mercury topping cycles were not built after 1950. Steam power-plant operating conditions increased, resulting in efficiencies that exceeded those of the existing mercury plants. Moreover, steam-plant capacities grew substantially larger than those of the mercury plants, resulting in further economies. Finally, the price of mercury fluctuated enough to render construction of new mercury topping cycles with their large mercury inventory uncertain and risky. There does not appear to be much current interest in pursuing the mercury topping cycle for fossil-fueled power plant application.

During the 1960's, the technologies of several advanced power-conversion concepts were pursued for the space program, with the aim of providing electric power from a nuclear reactor. Among these concepts were mercury and potassium Rankine-cycle plants. Mercury-conversion systems and components, including turbines, were operated at 1500°F and above. The results of these relatively small power-rating space-application efforts have demonstrated the technical feasibility of mercury and potassium Rankine power-conversion systems operating at high temperature. Their use for topping plants for more efficient and much higher power-rating stationary power plants on earth is suggested as a space technology spinoff for industrial use.

There is no previous history of use of potassium topping cycles in utility power plants, but potassium topping cycles for central-station power have been studied as far back as the early 1960's. More recently, a potassium topping cycle has been proposed by Oak Ridge National Laboratory for use with the molten-salt nuclear reactor.[14] A three-fluid (i.e., ternary cycle) system involving a gas turbine in addition to the potassium and steam cycles has also been suggested. Alternative fossil-fuels considered for this system included coal, oil, and gas.[15,16] Others have also studied a potassium-steam binary cycle of more conventional design using coal as a fuel.

6B.5.1.3 Present and Projected Application

Binary power cycles, with a potassium topping cycle on a steam cycle, possess the potential of a higher energy-conversion efficiency than the single-fluid steam cycle. Such systems would probably produce lower-cost power in plants of large capacity rather than small and would operate more efficiently at design capacity than at part load. Consequently, binary-cycle plants should find application primarily as base-load plants.

The potassium topping cycle has potential for use above about 1400°F. At present, except for the HTGR, nuclear heat sources for the potassium cycle are nonexistent. Use of the potassium topping cycle with an HTGR has apparently not been investigated. However, the use of potassium-steam binary cycles with fossil-fueled heat sources for large, base-load plants has been studied. The need to develop high-temperature furnaces and boilers as part of a program to bring potassium topping cycles to fruition is recognized.

Because of the physical and thermodynamic properties of the mercury working fluid, mercury topping cycles require a heat source that will boil the mercury in the temperature range of about 900 to 1300°F. The LMFBR is expected to operate with a sodium outlet temperature of 1100°F or higher. A mercury-steam binary plant therefore might have some potential for use with the LMFBR and may offer certain design and operational advantages to the system, particularly with regard to eliminating sodium-water interfaces and slightly improving plant efficiency. These advantages would have to be balanced against potential cost disadvantages (see Section 6B.5.1.2) and the requirements for additional technological development in such areas as sodium-mercury heat exchangers.

6B.5.2 Technical Information

6B.5.2.1 Availability

Neither mercury nor potassium Rankine topping cycles are now being offered commercially. The mercury system was developed at one time, and the potassium system is under active investigation. Manufacturing facilities and background capability for the equipment in this type of system would be available from a number of well-established manufacturers.

There are no inherent limitations to the size of the mercury or potassium topping-cycle plants, because as is currently done in steam plants, capacity can be increased by using multiple units in a parallel-flow arrangement.

6B.5.2.2 Efficiency

As noted in Section 6B.5.1.3, the mercury binary cycle is a conversion system that might have the potential for eventual use with a system such as the LMFBR since the temperature regimes of both are similar. If the substantial development and economic problems of such a combined system were solved, net plant efficiencies of up to 46% might be achieved as compared with potential LMFBR single-cycle efficiencies of about 42%.

For a coal-fueled plant with a boiler efficiency of 90%, the thermal efficiency of a potassium-steam binary cycle is estimated to be 50 to 55% or more, over the range of turbine inlet temperatures of 1400 to 1800°F.

6B.5.2.3 State of the Technology

The most recent development effort on the mercury Rankine system was carried out in the NASA-funded SNAP-8 Power Conversion System program. The objective of this work was to demonstrate for space use a man-rated, reactor-heated, mercury-conversion system of 35 to 90 kWe capacity of high reliability and long life. Work was performed on four-stage axial-flow turbines, boilers, pumps, valves, and condensers with varying degrees of forces. The program was terminated in 1970 because of cut-backs in the space program.

During the 1960's, various agencies of the government were engaged in the development of the technology for potassium (and cesium) Rankine space power systems.

Several turbines were built and operated on potassium vapor. The largest of these were 250 and 340 hp. The turbine efficiencies were measured and found to be about 75%, confirming design predictions. The blades and discs were, for the most part, fabricated of nickel-based alloys. Potassium boilers, condensers, and pumps in relatively small sizes have been successfully tested.

6B.5.3 Research and Development Required

6B.5.3.1 Mercury Cycle

The application of a mercury--steam binary cycle to the LMFBR may require the use of tantalum or an equivalent refractory metal for a thin liner in the tubes of the boiler; otherwise, the use of tantalum will be prohibitively expensive. Bimetallic tubing size and length are presently limited because of inadequate fabrication equipment. To obtain the sizes and lengths of bimetallic tubing required for a commercial power plant, the existing fabrication equipment will have to be upgraded or techniques to make reliable bimetallic tube-to-tube joints will have to be developed. In addition, other joining techniques, involving the tantalum liner and the boiler shell or tube headers, will have to be developed and proven.

Boilers designed for use in the Systems for Nuclear Auxiliary Power (SNAP) program incorporated the use of long-length, small-diameter mercury flow passages at the inlet. Use of the passages was based, in part, on the nonwetting behavior of mercury encountered in the early phases of the program. An alternative boiler design, based on mercury acting as a wetting fluid and not involving small-diameter passages, was tested and proven equally satisfactory. Thus, two approaches to boiler design have been successfully demonstrated. Selection of one of these approaches, followed by the construction and test of a portion or module of the full-scale boiler, would be needed.

The development of the mercury condenser/steam generator will also require the testing of a large-scale module. Although water will not react with mercury, it can cause oxidation of tantalum in the boiler. Consequently, instrumentation must be included to rapidly detect leaks of oxygen (air) and water throughout the system.

The shaft seal of the mercury turbine at the exhaust end must limit the introduction of oxygen (air), lubricating oil, and other contaminants into the mercury loop to prevent corrosion in the boiler. At the inlet end the shaft seal must be designed to prevent leakage of mercury to the surroundings. A design study of the shaft seal followed by construction and testing is indicated. As the prototype turbine will involve a scale-up in the range of 3 to 10 times the rating of previous mercury turbines, some design developments may be necessary. The successful completion of the foregoing boiler, condenser/steam generator, and turbine development would set the stage for the design of a demonstration LMFBR mercury--steam binary cycle plant.

6B.5.3.2 Potassium Cycle

Scale-up of the key components of the potassium--steam binary cycle is required before construction of a pilot plant can be considerd. A large-scale model of both the potassium boiler and the potassium condenser/steam generator would have to be performance tested and operated long enough to ensure confidence in design and materials of construction.

As the scale-up from current research and development experience for the turbine rating is in the range of 300- to 1000-fold, turbine blade manufacturing techniques using appropriate alloys must be developed for the very large blade sizes required. Similarly the turbine seal, which must exclude oxygen (air) from the potassium loop, must also be scaled up successfully.

Oak Ridge National Laboratory, under a grant from the National Science Foundation, has begun the construction of a potassium boiler module. This is a several-megawatt-capacity unit designed to operate at the 1550°F level.

The FPC Task Force[17] and the AEC Subpanel VI[18] have recommended that both alkali metal topping cycles and ammonia (or organic fluid) bottoming cycles be developed. The topping cycles are important because of their potential for increased efficiency and the bottoming cycles because of their adaptability to both air heat-rejection systems and low-temperature (geothermal) heat sources.

6B.5.4 Environmental Impacts

The impact on the environment of a mercury--steam binary cycle power plant would be to reduce thermal discharges and the consumption of fuels relative to a conventional steam power plant. The extent of these benefits would depend on the improvement in efficiency brought about by the mercury--steam binary cycle. The design of such a power plant would have to incorporate features to restrict the release of mercury to the environment to safe levels.

Potassium--steam binary cycle power plants should have similar effects upon the environment. The reduction of fossil-fuel consumption due to higher efficiency automatically reduces the quantity of most of the air pollutants produced per unit of electrical energy generated. Likewise, the waste heat discharged by the plant will be considerably curtailed.

The accidental discharge of large quantities of potassium to the environment would be harmful to vegetation and animal life in the immediate area of the plant. Runoff of potassium wastes into groundwater, streams, lakes, or oceans could be detrimental. At low concentrations, potassium will not be hazardous since it is a normal constituent of foods. The use of suitable scrubbing equipment would have to be developed to prevent the release of sizable quantities of potassium from a power plant.

6B.5.5 Costs and Benefits

No meaningful information exists on either the costs of mercury topping cycle that uses an LMFBR heat source or potassium topping cycle for fossil-fuel plants. Clearly, because of the increased complexity, the plant capital costs will be higher than a conventional steam plant but these could be offset by higher plant efficiency. Detailed plant and equipment design studies are needed to develop more reliable cost data.

6B.5.6 Overall Assessment of Role in Energy Supply

The major advantage of the binary cycles using mercury or potassium with steam is that of increased conversion efficiency. The benefits that stem from an increase in efficiency (such as reductions in fuel consumption, waste-heat release, and production of pollutants) will apply to both fossil-fired and LMFBR plants. There may be operational advantages for use of mercury topping with the LMFBR, as noted in Section 6B.5.1.3. The disadvantages (higher capital and maintenance costs and increased complexity of the plant and its operation) will also be applicable to both. The extent to which the advantages will outweigh the disadvantages is unknown and can be determined only by systematic programs involving a continuing evaluation of costs, development of scaled-up key components, operation of a pilot plant, and, finally, the design and operation of a demonstration power plant. A technology base exists for binary cycles resulting from previous experience with mercury-topping cycles on fossil-fired steam plants and from the space power efforts on potassium--steam binary cycles conducted over the past decade, for units of small capacity.

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6B.6 FUEL CELLS

6B.6.1 Introduction

6B.6.1.1 General Description

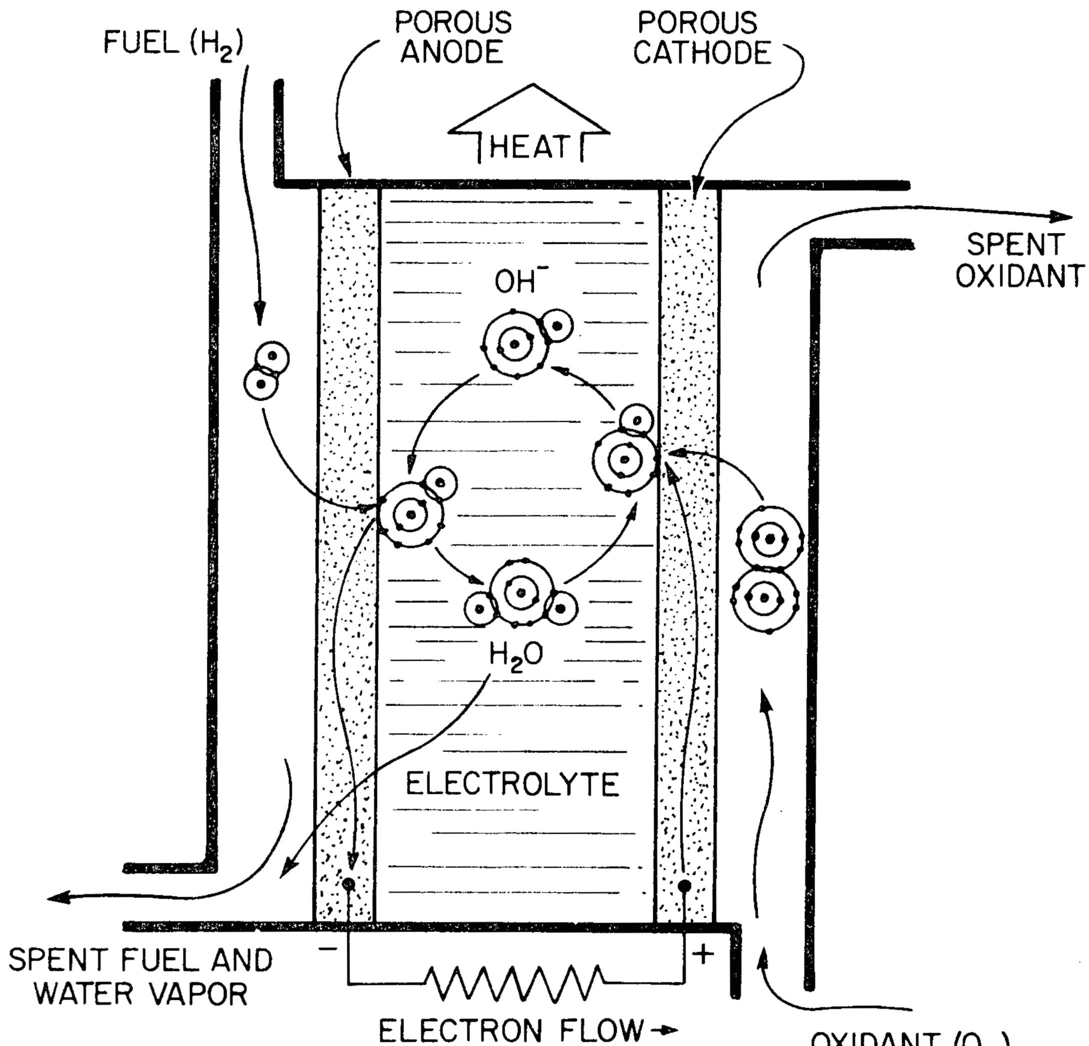
The fuel cell is a device that produces useful electrical energy from the controlled electrochemical oxidation of fuel. The reactants, fuel and oxidant, are supplied to the electrochemical cell, or cell stack, from reservoirs that, in many cases, are refillable.

The basic components of a simple hydrogen--oxygen fuel cell are the electrodes (anode and cathode) and an electrolyte; the electrolyte can be either acidic or basic. The reactants are normally consumed only when the external circuit is completed, allowing electrons to flow and the electrochemical reaction to occur. The result is good fuel efficiency even with low or intermittent loads. When the external circuit is completed, an oxidation reaction, yielding electrons, takes place at the anode and a reduction reaction, requiring electrons, occurs at the cathode. The electrodes provide electrochemical-reaction sites and also act as conductors for electron flow to the external circuit. In the example illustrated (Figure 6B.6-1), charge is transferred within the cell by migration of hydroxyl ions from cathode to anode. Continuous operation necessitates the removal of heat, water, and any inert material that enters the cell with the reactants, and reaction kinetics are usually enhanced by the incorporation of a catalyst such as platinum on the high surface area electrode surfaces. Power is produced as long as fuel and oxidant are supplied to the fuel cell and the external electrical circuit is closed allowing current to flow.

6B.6.1.2 History and Status

The first demonstration of what is now known as a fuel cell was reported by Sir William Grove in 1839.[1] In Grove's experiment, hydrogen and oxygen were reacted on platinum electrodes in a dilute sulfuric acid electrolyte, producing electricity, water, and heat.

Modern hydrogen--oxygen fuel-cell activity dates from the work of F. Bacon in England in the late 1930's.[2-4] In 1959, Allis-Chalmers Manufacturing Company demonstrated a 20-kWe hydrogen--oxygen fuel-cell-powered tractor and two years later demonstrated a forklift truck powered by a hydrogen--oxygen cell system. In late 1966, General Motors demonstrated a delivery van powered by hydrogen--oxygen fuel cells developed by Union Carbide Corporation. The reactants were stored as liquids at cryogenic temperatures, and the system had a peak power output of 160 kWe.



ELECTROCHEMICAL OXIDATION OF HYDROGEN IN A FUEL CELL

Figure 6B.6-1

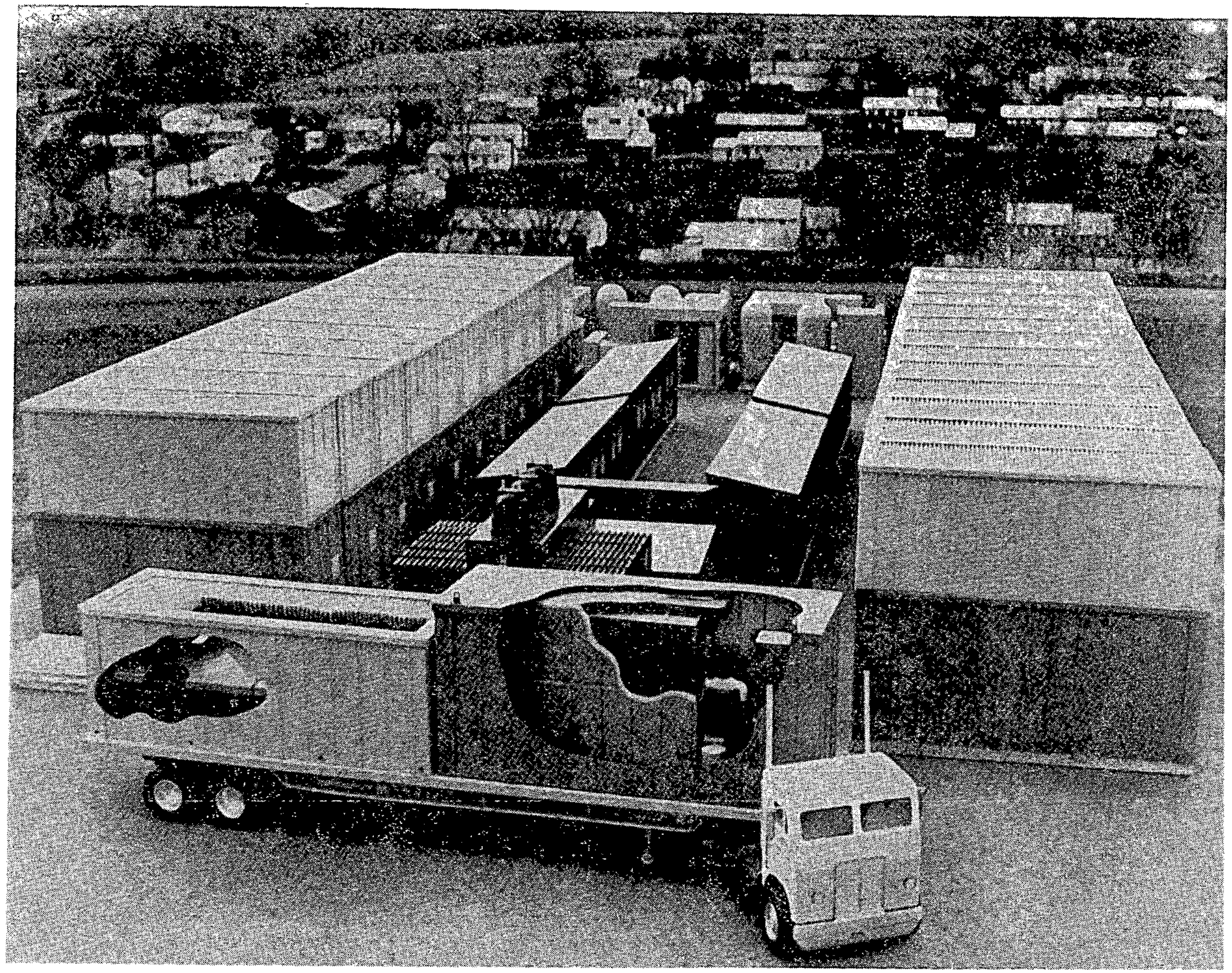
Space power requirements resulted in the first large-scale application of fuel cells. The technology of Bacon's hydrogen-oxygen cell incorporating a molten potassium-hydroxide electrolyte was used by Pratt & Whitney Division of United Aircraft (P&W) to develop the fuel cell system for the Apollo program of the National Aeronautics and Space Administration. Gemini space missions also used hydrogen-oxygen systems for electric power. This fuel cell system, manufactured by General Electric, uses an acidic ion exchange membrane as a fixed electrolyte and operates near ambient temperature.

In the 1960's, development of low-temperature fuel cells for direct oxidation of liquid fuels was extensively pursued. These systems use fuels such as decane, methanol, formic acid, and hydrazine.

Direct oxidation of carbonaceous fuels is difficult to achieve as efficiently as the oxidation of hydrogen. However, hydrocarbon fuels can be reacted with steam to produce a hydrogen-rich gas for consumption in fuel cells. Such systems have been investigated in the last decade by various industrial groups in the U.S. and Europe.

For the indirect oxidation of carbonaceous fuels, steam reformer systems used with either high- or low-temperature fuel cells have shown good performance, and several systems are in advanced stages of development. The major effort in this area started in 1967 with the first phase of what has become a six-year, $50 million program. This effort, presently sponsored by 31 gas utilities that make up the Team to Advance Research for Gas Energy Transformation (TARGET) group, has the goal of developing fuel-cell systems using reformed natural gas (methane) as fuel. The developmental work is being done by P&W, who in May 1971 demonstrated a 12.5-kWe system supplying all of the electrical energy to a home in Connecticut. This was the first of 60 test installations of various capacities planned, about 50 of which have been installed as of June 1, 1974. More than 4000 hr of automatic operation have been demonstrated with this system before refurbishing has been required.

Pratt & Whitney, in December 1973, announced a $42 million cooperative program with nine electric utilities to develop a 26,000-kW fuel cell. A model of the installation proposed for development is shown in Figure 6B.6-2. This level of power is sufficient to provide electricity for a community of about 20,000 people, and the manufacturer has estimated that deliveries of these units could begin as early as 1978. The application is dispersed power generation, as with the TARGET program, but in this case the unit of power is larger. The fuel will likely be distillate oils at first, with heavier oils coming later on.[5]



MODEL OF PROPOSED P&W 26,000-kWe FUEL-CELL INSTALLATION

<u>Figure 6B.6-2</u>

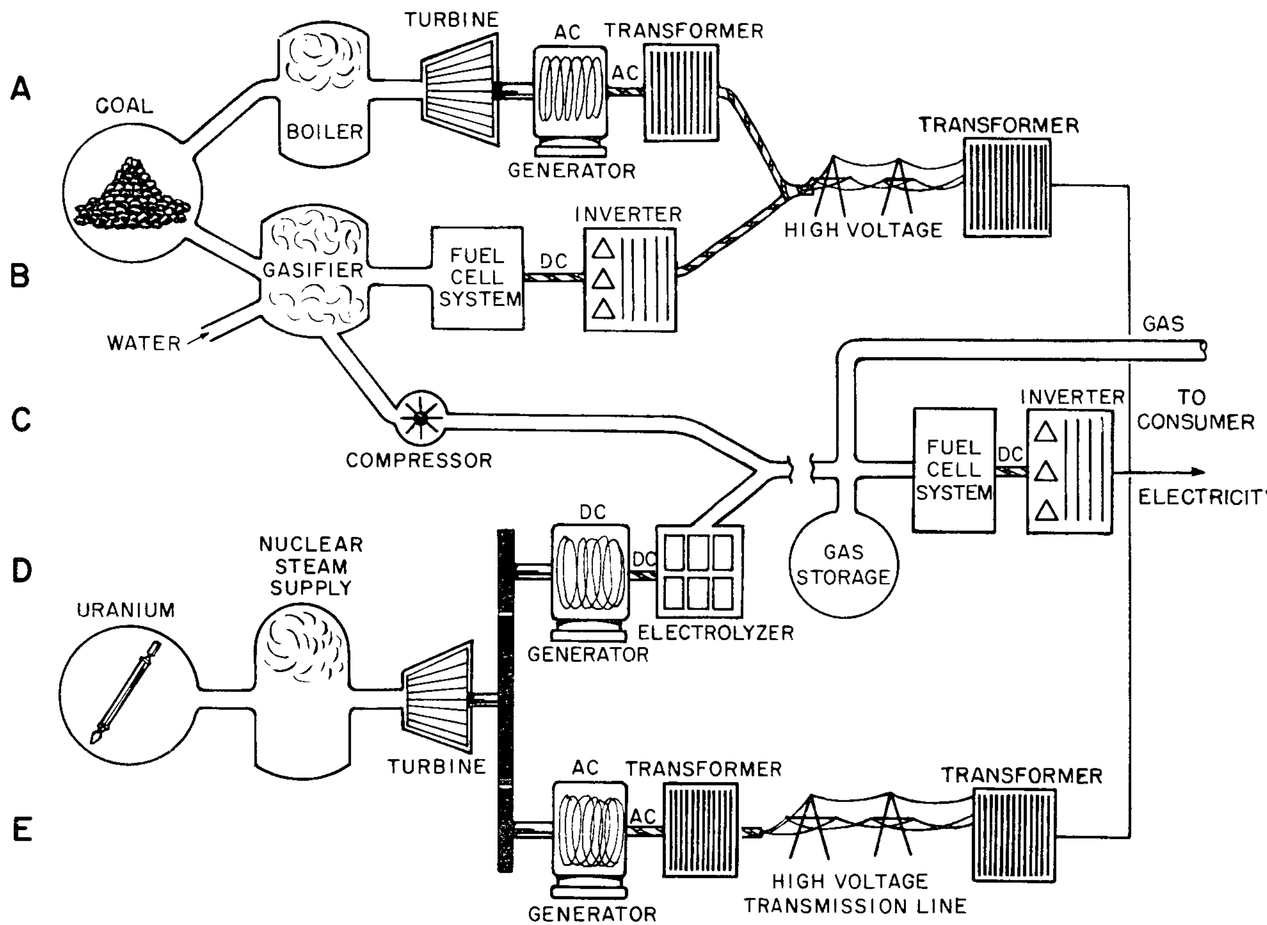
6B.6.1.3 Present and Projected Application

Attention is now being given to fuel cell systems to generate large blocks of electrical power. Two routes are being followed: one for central-station application and the other for dispersed generation of electrical power in residential or small community sites or at electrical substations. Work on the central-station application is still in the laboratory and system study phase; practical field hardware has not yet been built. However, Westinghouse Electric Corporation, as recently as 1970, was engaged in development work for the Office of Coal Research and had developed a preliminary design for a 100-kWe system based on gasification of coal and a high-temperature (1870°F) zirconia electrolyte fuel cell.[6] At the present time, work on this system is suspended.

As mentioned previously, P&W has a major program for dispersed generation using natural gas reformers and low-temperature (<250°F) fuel cells of the phosphoric acid and potassium hydroxide electrolyte types.[7] The Institute of Gas Technology has been doing complementary work using low-temperature phosphoric acid and higher-temperature (2200°F) molten carbonate electrolyte cells. All the above fuel cells will also operate on the fuel formed from coal gasification. This work has been sponsored by segments of the gas industry, American Gas Association, and TARGET and most recently by the Edison Electric Institute (EEI).

Energy system concepts using the thermal and electric output of nuclear reactors to produce hydrogen from the dissociation of water are currently under investigation. Fuel cells for dispersed generation of electric power are an integral part of these systems.[8]

The various energy-system concepts discussed above are shown in Figure 6B.6-3. Systems A and E illustrate the more-conventional central-station applications based on fossil-fueled steam boilers and nuclear steam supply systems. System B shows a fuel cell system replacement for a conventional central-station steam plant, while System C shows relocation of the fuel cell system to distribution substations. This provides for higher systems reliability and greater responsiveness to load changes through on-site gaseous fuel storage. System D illustrates the nuclear-powered equivalent of System C. Note that no compressor is required as the electrolyzer is capable of producing high-pressure gas. Systems C and D can provide gas directly to those consumers requiring reducing atmospheres or gaseous fuels for heating. The concepts shown in Systems B and D can supply dc energy directly to major industrial users and the distributed generation concept of System C can be extended to include a local dc distribution system.



COAL AND URANIUM ENERGY SYSTEMS

Figure 6B.6-3

6B.6.2 Technical Information

6B.6.2.1 Availability

Although fuel cell systems have been manufactured on a limited production basis for space application, only five organizations are presently capable of producing such systems in quantity: P&W, GE, Westinghouse, UCC, and Alsthom. None are actively marketing commercial systems of significant size. Pratt & Whitney is conducting extensive field tests of its 12.5-kWe reformed natural gas system.

Several fuel cell power-generation systems in the 10- to 20-kWe range have been constructed and operated. The modular construction of fuel cells and power conditioning equipment allows a nearly direct proportional scaling into the multi-MWe range. No control stability or complexity problems are introduced in paralleling fuel cell banks to construct large systems. In fact, overall system reliability is improved through load sharing in multistack systems and as a result of the capability to replace modular units on a programmed basis.

6B.6.2.2 Energy Sources

The fuel cells currently considered for central-station use oxidize either carbon monoxide or hydrogen. Finely powdered coal and various hydrocarbons are reformed to provide the hydrogen-rich fuel used in these fuel cells.

Three synthetic fuels have been proposed for use in nuclear-fuel-cell energy systems: hydrogen (produced by electrolysis of water), methane, and methanol. Both methane and methanol are produced by reacting hydrogen with carbon dioxide obtained by fractional distillation of air.

The other fuels that have been used in experimental cells, such as hydrazine, formic acid, sodium, lithium, and ammonia, are too costly for use in central-station energy generation.

6B.6.2.3 Efficiency

The theoretical maximum efficiency of a fuel cell is a function of the fuel and oxidant used. Where systems are integrated, as with a reformer, the theoretical efficiency is based on the primary feed material rather than on the fuel that is electrochemically oxidized. Projected reference efficiency limits based on laboratory investigations and systems studies are given in Table 6B.6-1.

Table 6B.6-1

FUEL CELL EFFICIENCIES

Fuel	Cell Voltage	Theoretical Cell Efficiency	Projected System Efficiency, 1980
Hydrogen	1.23	0.83	0.65
Methane	1.06	0.92	0.30 - 0.55
Coal	1.02	1.00	0.70

The areas of uncertainty result from lack of detailed engineering studies and extensive testing of large systems.

Gross efficiency is the product of the theoretical maximum efficiency and the ratio of the operating voltage to the theoretical voltage. For hydrogen-fueled cells, this efficiency today is 0.54 to 0.61. The small amount of unreacted fuel purged from the cells to eliminate inert material is neglected.

Because of extensive heat- and mass-transfer interactions, subsystem efficiencies cannot be multiplied to determine the overall efficiency of integrated fuel cell power system. The present published efficiency of conversion of chemical energy from natural gas fuel to ac electrical energy in the 12.5-kWe P&W-TARGET system is 40 to 45%. The large central-station version of this system is projected to have an overall efficiency of near 55%. The Westinghouse high-temperature system concept was estimated to be able to operate at a projected efficiency of 58% for the 100-kWe size and near 70% for 1000 MWe based upon dc output.

6B.6.2.4 Size Limitation

Several fuel cell power-generation systems in the 10- to 20-kWe range have been constructed and operated. The modular construction of fuel cells and power-conditioning equipment allows a nearly direct proportional scaling into the multi-MWe range. Plumbing, wiring, and fault-isolation equipment requirements are also nearly proportional to the system power capability. Fuel conditioning and control equipment have a scaling factor of 0.9. Systems can be demonstrated in small sizes, and full-scale systems can then be produced by conventional engineering techniques. Systems using fuel-reforming or high-temperature cells are significantly more efficient in large sizes (>100 kWe) due to the reduction in external surface area per unit volume.

6B.6.2.5 State of the Art

Although there have been many successful programs resulting in numerous fuel cell systems for specialized applications, there remain dominant uncertainties with respect to commercial power applications. These uncertainities stem from a lack of:

(1) detailed engineering design of low-cost systems;
(2) detailed design of fuel cells for high-volume production and long life;
(3) demonstration of the costs, lifetimes, efficiencies, and operational parameters of the projected systems.

6B.6.2.5.1 High-Temperature Fuel Cell System

The fuel cell system considered by the Westinghouse Electric Company for central-station power production uses high-temperature materials in the construction of the fuel cell. A porous nickel anode, a stabilized zirconia electrolyte, and a porous, tin-doped, indium-oxide cathode are deposited on a 0.5-in.-diam porous, stabilized, zirconia tube with appropriate cell interconnections.

The total system consists of fuel cell battery tubes assembled into banks, a coal gasifier, and ancillary equipment. Cell banks which operate at 1850°F are physically located in the fluidized-bed coal gasifier for maximum heat recovery.

6B.6.2.5.2 Low-Temperature Fuel Cell Power Systems

The fuel cell used in a system proposed for dispersed generation of electrical power is of the plate and frame type. Simple components produced in high volume are assembled into series stacks and either bolted or bonded together. Flow passages, a porous catalyzed nickel anode, an electrolyte-saturated matrix, and a porous catalyzed cathode make up the unit cell. Phosphoric acid is used as the electrolyte by P&W, with platinum-rhodium alloy as the anodic catalyst and platinum as the cathodic catalyst.

In the P&W-TARGET system, the cells operate at about 230°F. This system burns the effluent from the fuel cells to provide heat to reform hydrocarbons, such as natural gas, yielding a hydrogen--carbon-dioxide mixture. (Heat produced in the cells is also used to preheat the water used in the reforming reaction.) If given proper pretreatment, pure hydrogen can be used directly in the cells as can the fuel gas from coal gasification.

6B.6.3 Research and Development

In spite of having no moving parts, fuel cells do wear out. Redistribution of catalyst, with a resulting reduction of effective reaction surface area, is the most dominant degradation mechanism. There is also a finite solubility of catalyst in the electrolyte, which further reduces the active surface area. A secondary life-limiting phenomenon is corrosion of seal and current-collection components.

Erosion and blockage of ducts and manifolds are also seen in extended life tests. If fuel cells are to be economically applied to central-station power generation, the useful cell lifetimes must be extended beyond the 3000 to 20,000 hr presently available.

The fuel cell unit design must be amenable to high-volume production techniques, because thousands of cells per system will be required for electric generating systems in the multi-MWe range.

Fuel cell systems will not be applied, to any significant extent, to central-station power generation until economic advantages have been realistically demonstrated. To do so will require development of engineering experience and cost reductions in the specific areas listed below:

Fuel Source	Requirements
Oil	Reliable information on fuel cell lifetime under conditions representative of large power-generating systems (100 kWe or larger).
	Fuel cell materials and construction that result in minimizing cost.
	Large-capacity low-cost silicon-controlled rectifiers (SCR) that can be used to construct less-expensive dc-ac inverters.
	Complete integration of power-generating systems to reduce capital and operating costs, simplify controls, and minimize heat losses.
Coal	Detailed engineering design studies.
	Reliable information on materials corrosion resistance.
	Process control for reduction of ash-carbon content.

Natural Gas	The development of less-expensive catalysts and the reduction in the amount of catalyst required.
	Extension of fuel cell lifetime.
Hydrogen	A source of low-cost hydrogen.

The FPC Task Force[9] and the AEC Subpanel VI[10] have identified a high-priority requirement for research and development on fuel cell systems. Progress for this high potential payoff, but high-risk, area of technology has been hampered by lack of funding and a demonstration of adequate system life, and acceptable capital cost is urgently needed.

6B.6.4 Environmental Impacts

Central-station systems using fuel cells will produce chemical pollutants similar to those obtained by conventional combustion of the same fuels. The fuel cell, however, is particularly sensitive to the same pollutants, primarily sulfur, now causing concern in conventional steam-turbine-generator plants. This sensitivity will require extensive fuel pretreatment to eliminate contaminants prior to electrochemical oxidation. For an equivalent electrical power output, the higher operating efficiency of fuel cell systems will result in a reduction of the total quantity of fuel required and a reduction in the quantity of material discharged in the emission of nitrogen oxides because of the reduced temperatures to which the air streams are exposed. Waste-heat rejection is not a significant problem with fuel cell power systems since most of the waste heat is used in the fuel gasification or reforming process. Excess heat is rejected to the atmosphere, and cooling water is not required.

Large numbers of low-temperature fuel cells could have some impact on the catalyst material market and on the natural reserves. However, the catalyst is not consumed except for processing losses, and the total quantity available will be relatively unchanged. The total effect of this utilization of catalyst materials is unknown. (This is a problem common with certain pollution-control equipment being considered for internal combustion-engine-powered automobiles.)

Increased utilization of dispersed generation of electrical power, made possible by the high efficiency of relatively small fuel cell systems, should have a positive effect on the environment, particularly in urban areas. Gas transmission by buried pipeline requires less land for an equivalent amount of energy transmitted; however, the total environmental impact of buried pipelines has not been thoroughly evaluated.

The remote locations envisaged for fuel-processing plants and the chemical removal of sulfur at these plants should result in a positive environmental effect.

6B.6.5 Costs and Benefits

Since no large fuel cell power systems have been built, an estimate of the costs is somewhat speculative. Costs, however, have been projected for the coal-fired high-temperature system by taking into account research and development progress to date and comparing unit costs of various elements of the cost breakdown with similar items in a coal-fired steam-turbine power plant. By assuming that the cost of electricity produced from a coal-fueled fuel cell system is equal to that from a steam-turbine system, the allowable capital costs for the fuel cell system can be projected.

The result of these assumptions and calculations is to suggest that a coal-fueled fuel cell system can produce competitively priced electricity if it can be built for a total capital cost of $294 to 374 per kilowatt electrical. The three critical items are the fuel cell, power inverters, and spare parts. Each of these has projected cost ranges that will allow reaching the cost target.

The key item is the cost of the fuel cells. The cost range allocated, $60 to 80 per kilowatt electrical, corresponds to a manufactured cost of $7.00 to 9.30 per pound based on the materials requirements. Total materials costs for these thin-film solid-electrolyte fuel cell assemblies have been estimated to be about $21 per kilowatt electrical ($2.45 per pound), leaving an allowable margin for manufacturing and assembly of $39 to 59 per kilowatt electrical ($4.55 to 6.85 per pound). These allowable manufacturing costs show reasonably good agreement with independent direct estimates.

The major projected advantage of fossil-fueled fuel cell systems for central-station power generation is that they operate at a higher conversion efficiency than is possible with any system presently in use. This higher efficiency results in a lower rate of fossil-fuel reserve depletion, reduced air pollution, and no thermal pollution of natural bodies of water. Projected economics of central-station fuel cell power systems show equivalent capital costs and lower operating costs. For dispersed generation of electrical power using fuel cells, the capability for gaseous fuel storage at the point of usage allows a degree of freedom not found in present electric distribution systems. Coupling a hydrogen fuel cell system to a nuclear-powered hydrogen production facility offers several additional potential advantages:

(1) Improved load factor for the nuclear plant because it is producing a storable fuel.

(2) Enhanced hydrogen supply for use in the chemical and metallurgical process industries as well as for heat in homes and industrial plants, compared with that currently available from hydrocarbon sources.

(3) Pollution free generation of electricity at points of use.

6B.6.6 Overall Assessment of Role in Energy Supply

The state of technology of fuel cells and reformer systems has expanded in the 1960's; it is probably sufficient for the needs of initial prototype fuel cell demonstration plants. As mentioned in Section 6B.6.1.2, P&W is currently undergoing a field test of over fifty 2.5-kWe units, but these units are expensive and have a life about one-tenth of that required to make them a viable commercial option. Further, they require natural gas (already in short supply) as their energy source. The P&W 26,000-kWe fuel cells being developed with the cooperation of nine utilities also depend on fossil fuels in this application, namely distillate and heavier oils. It should be pointed out that these developments, while promising more efficient use of fossil fuels for electrical generation, do not provide a system for utilizing new energy sources and, therefore, will not appreciably relieve the energy crisis. When the constraints of economics and operating lifetime are imposed, the feasibility of fuel cell systems is undetermined for central-station or dispersed-power generation. Continued research and development will be required to establish the role of fuel cells in these applications.

Fuel cells using the more elementary gaseous fuels--hydrogen, carbon monoxide, and methane--will probably dominate for the predictable future. Continuing poor performance in the direct electrochemical oxidation of longer-chain hydrocarbons has resulted in less emphasis in this area. Because of the availability of large coal and uranium reserves, principal emphasis will be on fuels that can be readily produced by gasification of coal or from nuclear-reaction processes. However, both applications require the successful development of relatively high development-risk technologies that must be established on both a technological and economic basis: fuel cells and coal gasification or fuel cell and hydrogen production by nuclear/electrical, nuclear/thermal, or nuclear/electrothermal means.

This energy conversion system seems to be compatible with planning that centers around the near-term use of coal and long-term use of nuclear energy. It is also a key factor in a hydrogen energy economy as proposed by many and has a positive environmental impact.

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6B.7 BATTERIES

6B.7.1 Introduction

6B.7.1.1 General Description

The battery is a device that produces useful electrical energy from the controlled electrochemical oxidation of fuel. The reactants, fuel and oxidant, are supplied in fixed amounts associated with individual cells (in contrast to fuel cells which can have the fuel replenished from an outside supply). The individual cells may be connected electrically, either in series or parallel, to achieve desired voltage and current levels. This combination of cells is called a battery.

Cells of batteries are described as being either primary or secondary cells. Primary cells are those that are charged with chemical reactants and used once--either until the reactants are depleted or until the voltage of the cell decreases to an unacceptable level--and then are discarded or recycled to the manufacturer. The standard flashlight battery is a type of primary cell.

Secondary cells are composed of reactants and designed in a manner such that electrical recharge (by reversal of current with some other power source) is possible when voltage has declined to an unacceptable level. The standard automobile battery is a familiar example of a series of three (6 volts) or six (12 volts) secondary cells. Secondary batteries (sometimes called storage batteries since they can convert electrical energy to chemical energy which can be stored and then reconverted to electrical energy on demand) are the most promising for utility energy storage.

The basic components of a simple secondary cell are the electrodes (anode and cathode), an electrolyte, a separator, and a case. Schematically, the secondary battery is similar to the fuel cell (Figure 6B.6-1) with the electrode compartments replaced with fixed quantities of chemical reactants. A porous separator is used to hold the electrolyte in place and provide for physical separation of the anode and cathode. Power production is essentially similar to that of the fuel cell except that there is no continuous resupply of fuel and removal of reactant products.

6B.7.1.2 History and Status

The first experiments of electrochemistry are attributed to Davey and Volta at the beginning of the 19th Century. Plante's studies of electrolytic polarization, beginning around 1859, led to the real start of the development of secondary cells. After 1880 the development of secondary cells advanced at a rapid pace. The principal systems developed until the mid-20th century were limited to the lead/sulfuric acid/lead oxide, nickel/potassium hydroxide/iron, and nickel/potassium hydroxide/cadmium cells.

Increased interest in batteries as off-peak energy storage devices for use in the electric utility system has developed since the mid-1960's when sodium/sulfur and lithium/chalcogen cells were first publicly announced. A number of organizations are doing research and development on these high-temperature batteries for bulk energy storage. Since much of this is company-sponsored, the total level of effort is sometimes difficult to determine. Organizations doing research on batteries primarily for transportation are judged to be competent for development activities looking toward bulk storage systems as well. The principal work under way on lithium/sulfur and sodium/sulfur batteries is shown in Table 6B.7-1, but it is recognized that the organizations may also be competent to work on other battery technologies.

Table 6B.7-1

ORGANIZATIONS PERFORMING RESEARCH AND DEVELOPMENT ON LITHIUM/SULFUR AND SODIUM/SULFUR BATTERIES

Organization	Type of Cell	Goals
Argonne National Laboratory	Lithium/Sulfur	Bulk energy storage, propulsion
Atomics International	Lithium/Sulfur	Bulk energy storage
General Motors	Lithium/Sulfur	Transportation
Ford Motor Co.	Sodium/Sulfur	Transportation
TRW Systems, Inc.	Sodium/Sulfur	Bulk energy storage, transportation
General Electric	Sodium/Sulfur	Bulk energy storage, transportation
Dow Chemical Co.	Sodium/Sulfur (glass electrolyte)	

6B.7.1.3 Present and Projected Applications

There are no present applications of high-temperature batteries--all are in the developmental stage. Storage batteries, primarily the lead/sulfuric acid/lead oxide and nickel/potassium hydroxide/cadmium types, are used in emergency, standby, and minor peaking applications in a variety of industries.

The Electric Research Council 1971 report of research and development goals[1] considered the development of bulk storage batteries to be important to the future of the electric utility industry because they could offer utilities improved generation, substation, and transmission utilization plus fast response to increased load growth, minimal siting restrictions, and reduction in licensing delays.

Three major conclusions from this preliminary study on energy storage are:

(1) Energy storage units should be developed for two functions: first, as a device to shave peak loads, and second, as a power source during outages. In order to fulfill both purposes, a high ratio of emergency output to normal output is desired.
(2) Energy storage close to the load is especially attractive because it reduces the transmission capacity required to accommodate peak loads.
(3) The likelihood of attaining success with both the lithium/sulfur and the sodium/sulfur technologies is judged to be very high. Preliminary research extending over several years on each system supports this view.

The successful development of electrically rechargeable batteries capable of storing 200 W-hr/kg of battery weight, and capable of delivering up to 200 W/kg of battery weight could have a great impact on the economy of the U.S. and the world. A number of approaches to such a battery have been investigated; however, only those cells operating at elevated temperatures (330 to 600°C) have shown indications of being able to meet energy density, power density, life, cycle capability, and cost objectives.

6B.7.2 Technical Information

6B.7.2.1 Availability

No high-temperature battery systems have yet been developed commercially.

A review of worldwide activities has indicated the existence of at least 20 high-temperature battery efforts in the world, involving about 150 investigators, approximately 70 of whom are in the United States.[2] Only a few systems are being investigated, the main ones being sodium/beta alumina/sulfur and lithium/molten salt/iron sulfides. The two main areas of potential application are electric vehicle propulsion and off-peak energy storage.

In nearly all cases, the program is in the laboratory stage, studying cells of 10- to 200-cm^2 active area, with lifetimes of 100 to 1000 cycles. It is likely that a few 10- to 20-kW demonstration batteries will exist by 1977.

6B.7.2.2 Energy Source

The energy source for the storage application is electrical which can be derived from any means available.

6B.7.2.3 Efficiency

The efficiency of a secondary cell, rather than being a thermodynamic efficiency, would be a turn-around efficiency. The important feature in storage is how much energy can be retrieved as compared to the amount initially invested. For the cells under consideration this turn-around efficiency is about 75% excluding ac-dc conversion equipment, or an overall efficiency of 60%. To get the total efficiency, neglecting transmission and distribution losses, this 60% would have to be multiplied by the generating plant efficiency. Thus, for a modern steam plant with 40% efficiency, the total efficiency for generation and battery energy storage would be 24%.

6B.7.2.4 Size Limitations

From a practical point of view, there is no size limitation other than that determined by the particular application. The unit cell size will probably be small, $\sim$1.0 A-hr/cm^3. The battery or battery bank will be optimized for a particular application. Energy storage facilities in the range of 10 to 100 MWhr are considered to be most likely.

No problems are anticipated in paralleling batteries to construct large systems. In fact, overall systems reliability is improved through load sharing and the ability to replace units of the modular systems on a programmed basis.

6B.7.2.5 State of the Art

In general, high-temperature secondary cells and batteries are still in the laboratory stages of development. Argonne National Laboratory (ANL) has reported on the operation of single sealed cells having capacities in the range of 100 to 130 Whr per kilogram of active materials and lifetimes of up to 1400 hr. Activities are under way for building batteries of up to about 35 kWhr for tests starting in 1977. None of these cells or batteries have yet been optimized for long life and low cost. All of these are significant challenges. It will probably require at least two years for the development of a reliable (hundreds of cycles), light-weight (100 to 150 Whr/kg, 100 W/kg) prototype battery, if appropriate effort is devoted to the task.

The lithium/sulfur battery is being pursued by ANL (with AEC funding) and by Atomics International (AI) (with partial support from the Electric Power Research Institute) for off-peak energy storage applications. The status presented is that for the program at ANL. Candidate materials and components for a prototype cell have been screened, and a reference design has been established. The positive electrode for this cell is iron sulfide; the negative electrode is a solid lithium-aluminum alloy; the electrolyte is a lithium chloride-potassium chloride molten salt mixture; and the interelectrode separators are made of a boron-nitride cloth. The 13-cm-diam cell will weigh about 2 lb and is designed to store 150 Whr (75 Whr/lb). Engineering size cells are being developed for tests.

The sodium/sulfur cell is being developed by several companies, including Ford Motor Company, General Electric, and TRW, Inc. The status report is based on effort at Ford, since that organization has made the largest effort to date in the United States. Laboratory cells have been built, using a ceramic tubular electrolyte (beta alumina), and a demonstration battery has been built and tested. The battery consisted of 24 tube cells connected to give four parallel sets of six cells in series. The battery was designed for 250 W and was tested to 300 W. Its performance indicated a peak power of 490 W for short durations. A reversible capacity of 15 A-hr at approximately 11 V was measured, compared to the battery's theoretical capacity of 20 A-hr. Excluding insulation and packaging weight, the battery weighed 4-1/4 lb. The energy storage capacity of about 38 Whr/lb was 2 or 3 times as high as that of a lead-acid battery. However, many tasks, some of them basic, remain before a practical low-cost battery with sufficient lifetime and reliability can be built.

6B.7.3 Research and Development

The most promising electrochemical systems are the sodium/sulfur cell (with solid electrolyte) and the lithium/sulfur cell (with fused salt electrolyte). It is likely that at least one of these developments will be technically successful and economically attractive.

6B.7.3.1 Sodium/Sulfur

The key research and development problems relate to the ceramic electrolyte (powder synthesis and characterization; extrusion of tubing; isostatic pressing; sintering, grain growth, and control of microstructure; mechanical characteristics; electrical characteristics), the sulfur electrode melt composition, dynamic properties and coupled reactions, thermodynamic studies, proous electrode design, metal corrosion, and cell performance (role of impurities). Engineering studies are needed related to the integration of batteries into power systems.

A 12-V sodium/sulfur battery consisting of 24 tube cells connected to give four parallel sets of six cells in series has been operated at a power level of 300 W. This has demonstrated feasibility of the concept.

6B.7.3.2 Lithium/Sulfur

The key research and development problems are related to developing a low-cost interelectrode separator that is resistant to the cell environment and developing an electrical feedthrough that is resistant to the cell environment. Argonne National Laboratory has recently fabricated full-size sealed cells. These cells are being tested, and a prototype cell of improved design will be built and tested. Subsequently, a 10-kWhr battery and then a 35-kWhr battery module will be built. The module would then be incorporated into a large-scale battery. Program goals are directed toward increasing cell life and development of cell components which are more economical.

The importance of bulk electric storage batteries has also been reemphasized by the recent FPC Task Force.[3] Although lithium/sulfur and sodium/sulfur batteries are the most promising, the task force felt that low-temperature molten salt and aqueous batteries may prove viable for the near term.

6B.7.4 Environmental Impacts

Battery energy storage is most attractive and flexible in terms of siting considerations. There are no emissions, and resource conservation is favored by the use (as capital, not expendable) of abundant elements such as lithium, sodium, and sulfur.

High-temperature battery systems will have some heat loss to the surrounding atmosphere, but this will be minimized, inherently, by designs configured to optimize performance.

6

The use of storage batteries is applicable to all electrical power systems--fossil, nuclear, solar, etc. The impact on transmission systems is great because with the use of distributed storage they can be designed for 100% utilization. Storage batteries would always operate at full capacity since the load swings would be accommodated at the user end of the transmission line.

6B.7.5 Costs and Benefits

Materials costs for batteries, based on current concepts of materials to be incorporated, are easily estimated. Because of the relatively early state of current development, the estimates may be unreliable, but Argonne National Laboratory has estimated a total cost of $15 per kilowatt-hour for a lithium/sulfur battery of 1300-kWhr capacity. This is about equal to the total battery cost that could be afforded for a system that is competitive with other methods of supplying peak power.

The use of secondary batteries to store electrical energy generated during daily off-peak periods of delivery for use during peak periods will allow greater employment of low-cost nuclear systems because of decreased variation in load on the utility generating and transmission facilities.

6B.7.6 Overall Assessment of Energy Supply Role

In order for batteries to be economically competitive with alternative methods of providing power during peak demand periods, a capital cost in the range of $12 to $15 per kilowatt-hour of energy storage capability will be required. Most existing battery systems appear to be incapable of meeting this economic goal. The most likely candidates are the elevated-temperature cells now under development. Present cost projections as seen in Section 6B.7.5 are at the upper end of the desired range.

Battery systems used to store electrical energy probably have a place in the utility network similar to that of pumped storage. Their operational advantages, including reduction in requirements for peaking capacity, urban siting near load centers, more efficient use of transmission lines, and absence of atmospheric pollution would make them attractive, and the costs that could be borne would depend upon the specific applications.

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6B.8 THERMOELECTRIC CONVERTERS

6B.8.1 Introduction

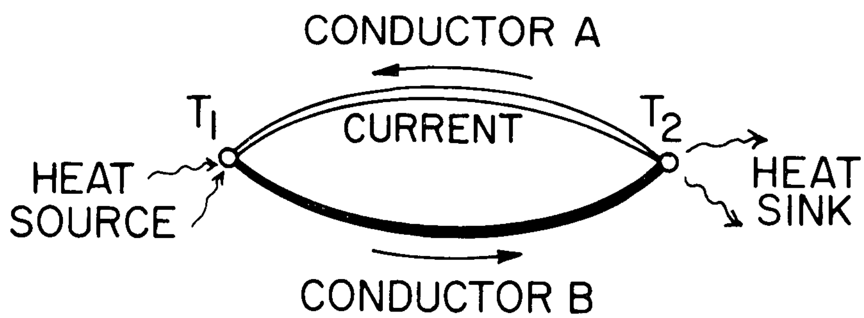
6B.8.1.1 General Description

A thermocouple is a device consisting of two dissimilar conductors joined together to form two junctions and a closed electrical circuit. As long as the temperatures of the two junctions are not equal, a current will flow in the circuit. This effect was discovered in 1822 by T. J. Seebeck.[1] The Seebeck effect suggests the potential for direct conversion of heat to electricity without the use of moving parts. (See Figure 6B.8-1.)

Since a device that utilizes the Seebeck effect is a heat engine, it is subject to the usual laws of thermodynamics and its maximum efficiency is the Carnot efficiency. However, losses always limit a practical device to efficiencies that are some fraction of the Carnot efficiency. For a thermoelectric generator with common metal junctions, and even with a temperature difference of several hundreds of degrees (between hot and cold junctions), this fraction of Carnot efficiency is about 0.1%. For the best metal junction, one formed of antimony and bismuth operating below their melting points, the efficiency is about 1%. To be considered as a replacement for a Rankine cycle (conventional steam cycle) plant, the efficiency must be nearer to 50% of Carnot.[2] It is obvious that materials other than the common metals must be used if thermoelectric power generation is to be economically feasible for large-scale applications. A number of materials, elemental and compound, are of interest. In certain cases these materials are semiconductors. Many compounds have been studied but only tellurides of Pb, Bi, Ag, Ge, Sb, and Sn [e.g., PbTe, Bi_2Te_3, GeTe·AgSbTe (TAGS), PbSnTe, BiSbTe] and SiGe have been used extensively in practical devices. These materials have potential efficiencies in the range of 11 to 27%.[3] The efficiency of practical devices will be lower.

6B.8.1.2 History and Status

A study by Rayleigh in 1885 and one by Altenkirch in 1909 made important contributions to the field of thermoelectricity. In 1929, A. F. Ioffe outlined the advantages of the thermoelectric generator (TEG) using semiconductors and calculated that their efficiency could reach 2.5 to 4%. In 1940, Maslakovets described a thermoelement made of PbS that had an efficiency of about 3%. Other important work was done in 1953 by Justi and by Goldsmid and Douglas.[4]



SIMPLE THERMOCOUPLE

Figure 6B.8-1

There were a few practical applications of thermoelectricity made during the period of 1930 to 1957. Based on Ioffe's suggestions, the Russians produced reliable sources of power for small radio transmitters during World War II. During the same period, engineers in the heating-gas industry were also experimenting with semiconductor thermoelectric materials in an effort to find a better device to operate automatic safety controls on gas-fired heaters.[5]

Prompted by the U.S. Navy's initial interest (and later, 1958, AEC/ANPO) in thermoelectric devices and the subsequent improvements in semiconductor technology and semiconductor devices, there was renewed interest in this field after 1957. A conservative estimation is that about $30 million of government and industrial funds were spent on thermoelectric research and development between 1957 and 1963.[5]

Before 1958, only three U.S. corporations were involved to any degree in thermoelectric development, but between 1958 and 1963 as many as 64 companies were participating. Unfortunately, the expected breakthroughs in new materials did not develop, and by 1971 only five U.S. companies remained in the thermoelectric business.[5]

At present, the search for materials continues. In 1957, the best thermoelectric materials were bismuth-telluride (Bi_2Te_3) and lead-telluride (PbTe). Silicon-germanium (SiGe) alloys made their appearance as excellent high-temperature materials in the early 1960's. These three compounds are still considered as the more important thermoelectric materials with SiGe being studied and used in units for long-lived space missions.[6] Due to materials limitations, which are related primarily to efficiency, little work has been done on the application of thermoelectric power generation to central station plants.[7]

6B.8.1.3 Present and Projected Application

Currently, the use of thermoelectric power generation is restricted to applications for which efficiency is not the primary consideration. These applications are based on a minimum mass for a given energy output and are limited to space applications and specialized terrestrial uses (e.g., remote monitoring stations, beacons, and navigation buoys).

Several thermoelectric power systems are included in the U.S. Space Nuclear Auxiliary Power (SNAP) program. These systems are of two kinds, the difference being whether the heat is supplied by a decaying radioisotope or directly from a nuclear reactor. The largest space power supply of this type being considered requires a 100-kWt reactor to provide heat for a 5-kWe thermoelectric generator.

Although some terrestrial applications use radioisotopes as the heat source, most use propane burner sources with either direct flame heating or catalytic bed heating.

A radioisotope thermoelectric device in the microwatt range is used as the power source for a new type heart pacemaker that is implanted in humans.

6B.8.2 Technical Information

6B.8.2.1 Availability

Several companies in the U.S. are currently engaged in commercial sales of thermoelectric devices. There seem to be no intrinsic problems with the manufacture of large numbers of devices using present-day materials. These materials have been available for a long time, and problems of joining, element design, etc. have all been fairly well worked out. However, new materials that may become available, with higher figures of merit, may reintroduce these same problems. Also, in the event that nuclear reactors are used as the heat source, irradiation damage to the thermoelements may severely reduce performance over long exposure periods.

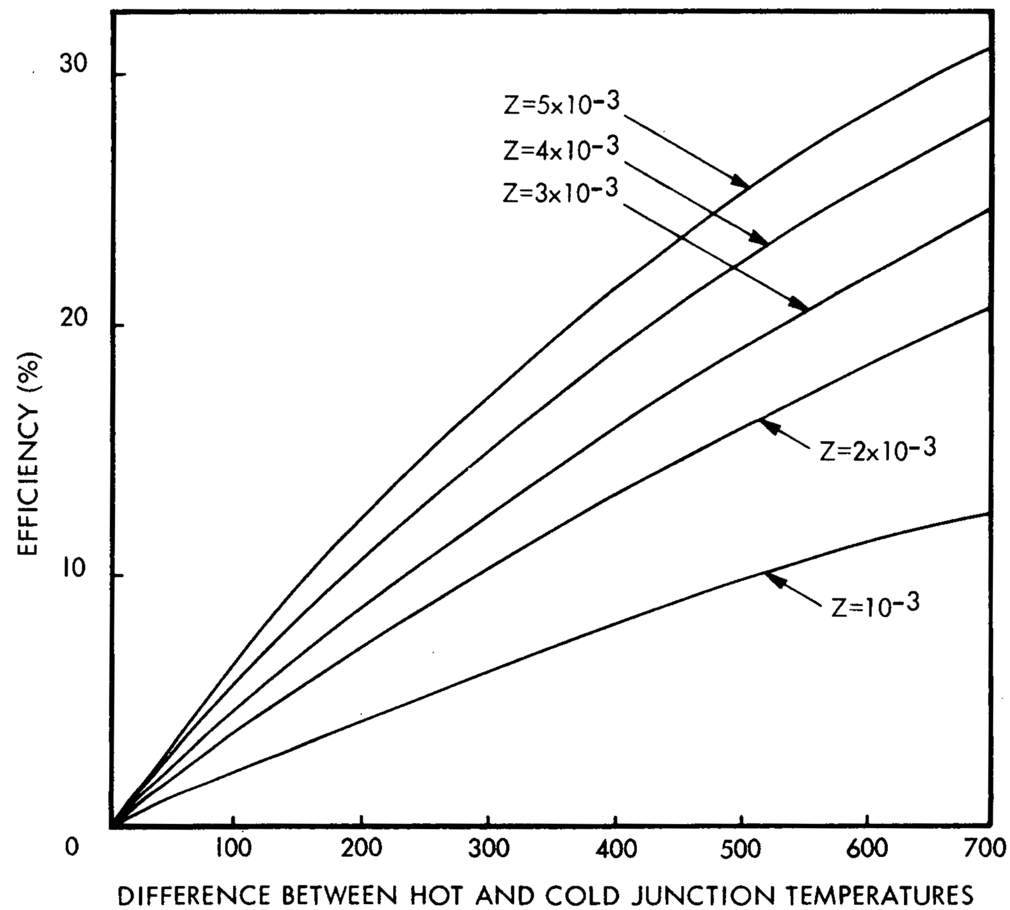
6B.8.2.2 Energy Source

Thermoelectric power systems have been built and operated using several energy sources. These include fossil fuels, radioisotopes, solar energy, and nuclear reactors.[8,9]

6B.8.2.3 Efficiency

Table 6B.8-1 lists several materials in use in thermoelectric devices as well as some of the parameters pertinent to efficiency calculations. The product ZT_m (T_m is the mean operating temperature and Z is a term called the figure of merit) will determine the percent of Carnot efficiency obtainable. The efficiency obtainable from an operating couple is found using the information in Table 6B.8-1 and Figure 6B.8-2. No material listed, operating with a sink temperature of 27°C and a source at the maximum allowable temperature, can approach an efficiency of 20%.

The efficiencies shown in Figure 6B.8-2 have been calculated for ideal conditions. Some representative numbers for actual devices as taken from Table 6B.8-1 show the severity of the materials and engineering limitations for TEGs. A number of TEGs



EFFICIENCY OF A THERMOELECTRIC GENERATOR

Figure 6B.8-2

Table 6B.8-1

THERMOELECTRIC MATERIALS[a]

Materials	Melting Point (°C)	Type	Z_{max} (figure of merit)	Temp. For Z_{max} (°C)	Max. Operating Temp. (°C)
Bi_2Te_3	575	n or p	2×10^{-3}	27	177
$BiSb_4Te_{7,5}$	-	p	3.3×10^{-3}	27	177
Bi_2Te_2Se	-	n	2.3×10^{-3}	27	327
PbTe	904	n or p	1.2×10^{-3}	27	627
GeTe(+Bi)	725	p	1.6×10^{-3}	527	627
ZnSb	546	p	1.2×10^{-3}	227	327
$AgSbTe_2$	576	p	1.8×10^{-3}	427	627
InAs(+P)	940	n	6×10^{-4}	627	827
CeS(+Ba)	-	n	8×10^{-4}	927	1027
Cu_8Te_3S	930	-	1.5×10^{-3}	827	-
Ge-Si	-	n	9×10^{-4}	627	927
Ge-Si	-	p	6×10^{-4}	627	927

[a]D. A. Wright, "Thermoelectric Generation," in Direct Generation of Electricity, K. H. Spring (ed.), Academic Press, New York, 1965.

used primarily for space applications (where efficiency is not necessarily the most important consideration) have efficiencies of less than 6% and most are in the 4 to 5% range. TEGs for terrestrial applications have efficiencies generally in the range of 4 to 6%.

Recognizing the reduction in efficiency in a real device, figures of merit above 5×10^{-3} are necessary (see Figure 6B.8-2) to attain overall system efficiencies of about 10%. Whether or not this Z is obtainable is open to serious question. A paper published in 1967 by Ure, a well-known worker in the field of thermoelectricity, states that a ZT of about 2 to 2.5 seems to be an upper limit.[10] To obtain a ZT of 2.5, operating between 27°C and 727°C, a material would need a Z of 3.84×10^{-3}. The efficiency would be about 28%. With a Z of 5×10^{-3} and operation between the same temperatures, the efficiency would be 32%.

6B.8.2.4 Size Limitations

A thermoelement is inherently a low-power device. By appropriate series/parallel electrical arrangements, higher power outputs can be obtained. This modular system lends itself to the construction of high-power systems, but still has a very low output for its size and weight.

A 150-We solar-powered TEG would use 480 couples, with a weight of 1.62 lb for a power density of 94 We/lb for the elements alone. In the actual generator, this drops to 11.3 We/lb.[8] A radioisotope thermoelectric generator for use in a Transit navigational spacecraft, TRIAD I, has a power density of 1.2 We/lb for the total assembly. For the thermoelectric panels, the power density is about 6 We/lb.[6]

6B.8.2.5 State of the Art

Extensive effort has been devoted to the development of thermoelectric materials with a high figure of merit, especially those materials that operate at higher temperatures and efficiency. Silicon-germanium alloys are considered as especially promising for operating temperatures near 1000°C, and these materials are under active investigation.[6]

The techniques of joining the couples to the metal plates to form junctions and terminals are fairly well established, although these joining techniques are more art than science. Each new combination of materials introduces new problems that must be solved before the thermoelectric material can be used in a practical generator. Additional problems are often introduced by the brittle nature of most of the useful materials.

6B.8.3 Research and Development

As has been pointed out, materials of higher figure of merit than now available must be developed. A second problem is inherent in the low-unit power output. At 1 We/couple (which seems to be a practical working size), a 1000-MWe power station would require 10^9 couples. Unless the output per couple can be increased significantly, the sheer number of interconnections and redundancy necessary for high reliability might be prohibitively expensive.

More effort is required in the basic materials area to achieve a high figure of merit. These efforts should include investigations directed at verifying or disproving Ure's estimate of 2 to 2.5×10^{-3} for an upper limit to ZT_m.[10] Without a substantial improvement in Z (or ZT_m), no amount of engineering will bring the overall system efficiency to a value high enough for economic consideration for central station electrical power production. An improvement in the Seebeck coefficient would not only improve Z but also increase the voltage output per couple. The AEC Subpanel VI[11] recommends that a relatively low level of materials research be continued.

6B.8.4 Environmental Impacts

Since a TEG is a thermal-conversion device with no moving parts, the only pollution results from the heat source. Naturally, being a thermal engine governed by the laws of thermodynamics, heat will be rejected to the surroundings.

The low efficiency of the TEG means more thermal energy must be rejected to the environment. Conversely, for the same useful power emitted, more fuel is consumed. With existing low efficiencies, energy sources will be depleted at a faster rate than is now the case. For central station plants this is unacceptable.

6B.8.5 Costs and Benefits

Present costs for small fossil-fueled TEG systems are about $25,000 to 30,000 per kilowatt electrical. This cost is more than 50 times the cost of a large conventional power plant. There is no large obvious reduction in unit cost that can be projected for increasing plant size since many small elements are required and the high unit cost still prevails. Mass production techniques applied to TEGs would, however, tend to reduce unit costs below what they are today.

An example of the cost of a thermoelectric generator can be found in the catalog of an established supplier of thermoelectric devices.[12] A 20-We TEG that operates between 125 and 25°C requires 26 modules, each containing 31 couples. Since the cost of each module is $60 (1971 catalog price), the cost of the TEG is $78 per watt. More recently, different suppliers offering other types of thermoelectric devices have quoted prices in the range of $40 per watt. There do not appear to be any benefits accruing from TEG for commercial electric power generation.

6B.8.6 Overall Assessment of Role in Energy Supply

The main benefit of the thermoelectric generator is that it has no moving parts which will tend to increase its reliability and long life. The modular construction of a TEG allows a variety of power levels to be easily obtained for a given basic couple.

The low efficiency and low power output per couple, together with high unit costs, will probably limit the application of TEGs to small special-purpose power sources.

The present economics are unacceptable for central-station power application and the low efficiency would create severe drain on our energy resources.

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6B.9 THERMIONIC CONVERTERS

6B.9.1 Introduction

6B.9.1.1 General Description

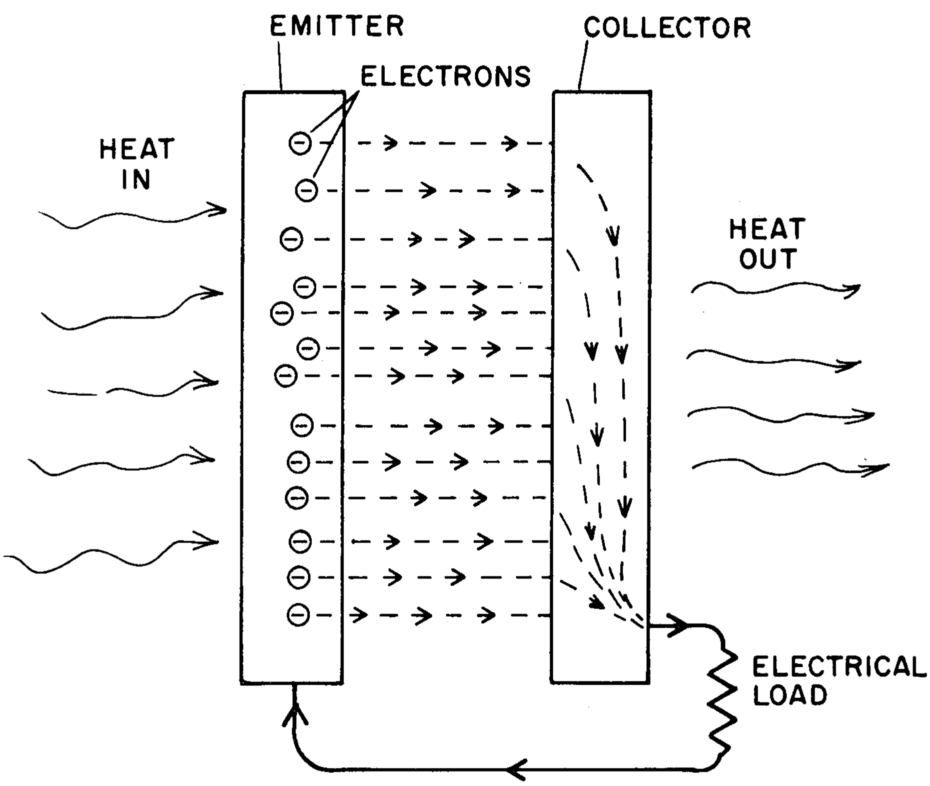
The principle of operation of thermionic devices is based on the emission of electrons from metals at high temperatures. This phenomenon was first investigated by Thomas Edison and was subsequently used as the basis of the conventional vacuum tube.

A thermionic converter is a device that contains an electron emitter and collector in a sealed envelope at reduced pressure. The emitter is heated, increasing the energy of the free electrons in the metal and causing them to travel at higher speed. This increased kinetic energy allows the electrons to escape from the open surface of the hot emitter and to move through an intervening space to the cooler electron collector. With no external circuit connections, a potential difference (voltage) will develop between the collector and emitter. When connected to an external circuit, the potential difference will cause a current to flow. (See Figure 6B.9-1.) In a thermionic converter with reasonable spacing between emitter and collector, some of the emitted electrons have insufficient energy to reach the collector; so they form an "electron cloud" (or space charge) which tends to repel subsequent electrons and hence limit the available current. In order to achieve reasonable power density, a low-pressure ionized vapor (usually cesium) is introduced to neutralize the space charge.

6B.9.1.2 History and Status

Although it has been known for 200 years that a negatively charged metallic body loses its charge more rapidly when heated, the phenomenon of thermionic emission wwas not studied intensively or put to practical use until efficient sources of electrons were needed for radio communication. The modern beginnings of the study of thermionic phenomena are usually attributed to Edison who discovered the emission of electrons into a vacuum in about 1883.

The first suggestion that a thermionic converter could be used to change thermal energy to electricity appears to have been made by Schlichter in 1915.[1] In his 1956 doctoral dissertation at MIT, Hatsopoulos described two types of thermionic converters, and his suggestions sparked serious experimental work around the world.[2] Soon afterward, experimental converters that produced electricity were built in several laboratories, and, in April 1959, electrical energy was converted directly from nuclear energy by a group at the Los Alamos Scientific Laboratory.[1]



SCHEMATIC OF A THERMIONIC ENERGY CONVERTER

Figure 6B.9-1

The bulk of the U.S. effort in thermionic energy conversion is in the area of nuclear-powered devices.[3-5] Nearly all concepts utilize what has become known as the flashlight-type fuel-element design. In this concept, a number of nuclear-fueled thermionic cells are placed in a thermionic fuel element (TFE) in the same manner as a flashlight is loaded with cylindrical batteries. The development of this TFE, a joint AEC/NASA effort, was directed at the 100-kWe level for space nuclear electric propulsion applications. This effort was effectively terminated in February 1973, and only a small research effort aimed at increasing the efficiency of the thermionic process remains in effect in the United States as of the beginning of 1974.

Two other countries have active thermionic energy conversion programs. The Soviet Union has operated at least two reactors containing thermionic devices. TOPAZ I became operational in 1970 and produced 5 to 10 kWe for more than 1000 hr.[6] In 1971, experiments were begun with TOPAZ II to check the reproducibility of characteristics obtained during the test of TOPAZ I. TOPAZ III is understood to have started operating in the fall of 1972.

The Federal Republic of Germany has operated a smaller (partial-length) TFE for 1700 hr and is considering the construction of a thermionic reactor in the 20- to 100-kWe range for space applications. France has started fabrication of a full-length TFE for Diogene I, a 10-kWe thermionic reactor, which will become operational in 1974 and will be used for underwater applications.[3]

6B.9.1.3 Present and Projected Applications

Thermionic converters have several potential applications ranging from a cardiac pacemaker that operates in the 0.1-mWe range[7] to a modified (topping) thermodynamic cycle for a central-station power plant that operates at 1000 MWe.[8] Thermionic devices, which are coupled with nuclear heat sources, are especially attractive for long-range and long-duration space applications because of their basic simplicity, the absence of moving parts, and their relatively higher efficiency as compared with other space power generators.

Interest in the thermionic device as a topping unit for conventional central-station power plants rests on its potential for increasing overall plant efficiency. Furnace temperatures which are not normally usable in conventional boilers and steam turbines, because of metallurgical limitations, can be effectively used with thermionic converters to increase the overall efficiency of the cycle. An analysis carried out for the Tennessee Valley Authority (TVA) Bull Run coal-fired plant shows that thermionic topping might result in an increase of station output from 914 to 1139 MWe and a gain in plant efficiency from 41.3 to 50.6%.[8]

6B.9.2 Technical Information

6B.9.2.1 Availability

All work to date is of a developmental nature. Full-length TFE irradiation tests reached the 7000-hr endurance level by January 1973 before the program was terminated. Reactors using TFEs of this design are not applicable to central power stations for economic reasons. Central power stations utilizing thermionic converter and furnace concepts have been considered. These are being examined from economic and technical standpoints.

6B.9.2.2 Energy Source

Thermionic converter systems can be used with thermal inputs from any source, including solar and nuclear power. However, from the standpoint of central-station power application, the major interest in thermionic conversion is as a topping unit for fossil-fueled plants. Thermionic converters are most efficient at high temperature, and they match the heat-source properties of a fossil-fueled plant well. Central-station nuclear power reactors are not suitable for thermionic applications since it is not practical to incorporate these conversion systems within the core of the reactor, and neither the water-cooled nor the sodium-cooled reactors operate at high enough coolant temperature to consider locating the thermionic converter outside of the reactor.

6B.9.2.3 Efficiency

The theoretical efficiency of a thermionic converter is limited by emitter and collector temperatures. As in any heat engine, the theoretical efficiency is seldom attained.

The efficiency of the radionuclide-powered ISOMITE batteries is less than 1%.[7] The efficiency of a proposed 5-kWe semiportable power supply was estimated to be about 10%.[9] A thermionic power supply utilizing solar energy had achieved 12.5% efficiency by 1964.[10] The TFE efficiencies[11] range from 10 to 16%, and the thermionic converters proposed for use in the fossil-fueled steam plant topping cycle would operate at an efficiency up to perhaps as high as 25 to 35%.[8]

6B.9.2.4 Size Limitations

Power systems that utilize thermionic converters will consist of individual units connected in series and parallel combinations to produce the voltage and current requirements for the various applications. Construction will be modular, and the unit size selected will depend on a number of considerations. Thermionic module size in the Bull Run application was set at 22 MWe.[8] Consideration is currently being given to applications in modified fossil-fueled central-station boilers with plant electrical capacities in the hundreds-of-MWe range.

6B.9.2.5 State of the Art

Although, in concept, the thermionic converter is a relatively simple device, building long-lived efficient thermionic converters is no easy task. The electrodes must operate in close proximity to one another and at high temperature so that the level of power generated is sufficient for practical applications. Also, the high operating temperature leads to high efficiencies. For example, the emitter may operate at 1880°F and the collector at 918°F. Under these conditions the theoretical efficiency is 41%; however, practical devices will never achieve this ideal efficiency. A high potential efficiency, as well as the feature of having no moving parts, makes thermionic energy conversion worthy of further consideration as a topping system with more conventional power cycles.[12]

With the exception of the concept developed for application to the TVA Bull Run coal plant, little has been done, until recently, in evaluating thermionic power systems applied to central station power, particularly not to coal-fired plants designed to meet EPA pollution standards. Present program efforts are focusing on these applications again. The state of the art is primarily based on the AEC/NASA program. Based on this work, thermionic devices are technically feasible but need further development to extend their lifetime.

6B.9.3 Research and Development

The experimental work of the 1960's identified most of the problem areas in converter design and operation except those of the economics of central-station power application. The cesium environment and high operating temperatures can cause emitter vaporization, thermal warping, insulator shorting, and seal failures. For space applications, the main problems were concerned with achieving the following:

(1) lifetime of at least 5 years;

(2) reproducible and stable thermionic converter performance;
(3) demonstration that any electrical arcing that might occur is not destructive to the cell and will not result in excessive power losses;
(4) qualification to expected shock and vibration environments;
(5) simplification of fabrication methods and lower costs.

The use of chemical vapor deposition as a technique for cladding converter emitters with tungsten has been successful in establishing stable long-term performance. Adoption of fine-grained high-density alumina with niobium skirts brazed with a V-60/Nb-40 alloy may eliminate the insulator problems.[13] Finally, the introduction of oxygen into the converter may reduce operating temperatures and improve the overall performance.[14] Both lower-cost materials and fabrication methods are required. For topping cycles, research is focused on achieving high efficiency and lower costs at lower and more practical operating temperature ranges. The AEC Subpanel VI[15] recommended a continuing modest level of support in thermionic diode development applicable to fossil-fueled power plants.

6B.9.4 Environmental Impacts

The operation of a thermionic generator produces no additional pollutants other than those normally present from the particular heat source used. It is important to note, however, that the use of thermionic topping in conventional central station power plants would increase the overall plant efficiency. The topping device, in principle, utilizes all the heat supplied to it with 100% efficiency because its rejected heat is at a temperature above the normal steam-cycle operating temperature. Thus, the increase in overall plant efficiency results in less thermal energy rejected to the surroudings for the equivalent electrical power production.

There are no new known environmental effects introduced with a thermionic converter system. With the higher efficiency projected for a thermionic system, the pollutants normally produced by the energy source being used will be diminished for equivalent amounts of electrical energy generated.

6B.9.5 Costs and Benefits

With the exception of certain terrestrial and hydrospace applications, the cost of thermionic converters for producing power has not been assessed. The value of a thermionic converter for a fossil-fueled plant can be estimated based on the incremental efficiency produced by a topping cycle operating with no degradation of the steam plant performance. Using a capital cost of $300 per kilowatt-electrical and a fuel cost of 50¢ per million Btu for a coal-fired steam plant, the purchase price for each of the thermionic modules could be as high as 15¢/We and still be economically competitive. Present costs for these devices are considerably higher than this, and current research is directed at achieving significant cost reductions.

The increase in plant efficiency and the apparent ease in incorporating the thermionic modules in the boiler unit of a fossil-fueled plant would suggest that this is a fruitful route to follow.

6B.9.6 Overall Assessment of Role in Energy Supply

A thermionic energy conversion system has the potential to improve fossil-fueled plant efficiency from the present 40% to possibly 50%. The system should be particularly adaptable to coal plants in which the combustion chamber temperature is well above the normal working temperature of the steam turbine. Insufficient studies are available to establish requirements of thermionic power systems as applied to new coal plants that will meet EPA standards. At present, low-cost, reliable converters have not been developed, and thermionic topping cycles for coal-fired steam-turbine power plants cannot be justified on an economical basis.

The AEC-NASA programs have demonstrated the technical feasibility of in-core, nuclear-heated thermionic fuel elements, but only for space power systems. These space reactor concepts are prohibitively complex and expensive for use with a commercial central-station power plant.

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6B.10 MAGNETOHYDRODYNAMICS

6B.10.1 Introduction

6B.10.1.1 General Description

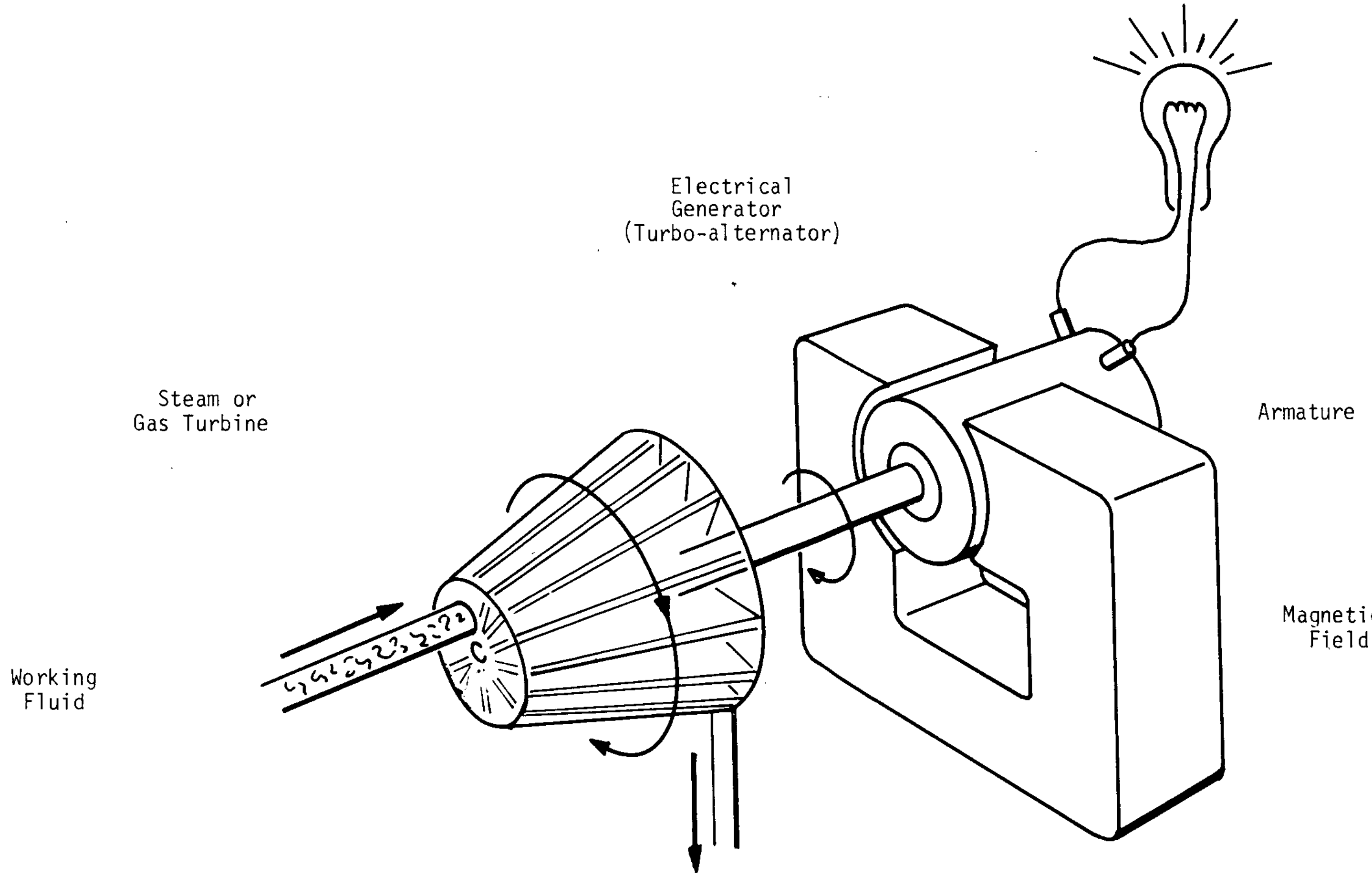
The magnetohydrodynamic (MHD) generator produces electrical energy directly from thermal energy; it is a heat engine that combines the features of the turbine and the generator of the conventional steam plant and has the potential for conversion efficiencies in the range of 50 to 60%.

In an MHD generator the rotating wire conductor of the conventional generator armature (Figure 6B.10-1) is replaced by an electrically conductive fluid (Figure 6B.10-2). As the working fluid flows through the magnetic field, a voltage drop is induced across the stream causing an electrical current to flow between the electrodes. The electrodes of the MHD generator are generally two opposite walls of a rectangular duct to which electrical leads are attached (the adjacent side walls are electrical insulators). The MHD working fluid can be either a plasma (e.g., ionized gas) in an open- or closed-cycle system or a homogeneous mixture of a liquid metal and an inert gas in a closed-cycle system.

In the open-cycle plasma system, fossil fuel is burned at a sufficiently high temperature so that the product gases are ionized. Electrical conductivity is further enhanced by "seeding" the gas with readily ionized material (i.e., salts of potassium or cesium). The conductive gas is expanded through an MHD generator, thereby producing electricity. The exiting hot gases are further used to generate steam that is used in a conventional steam-turbine energy system. "Seed" must be extracted from exhaust gases for reuse.

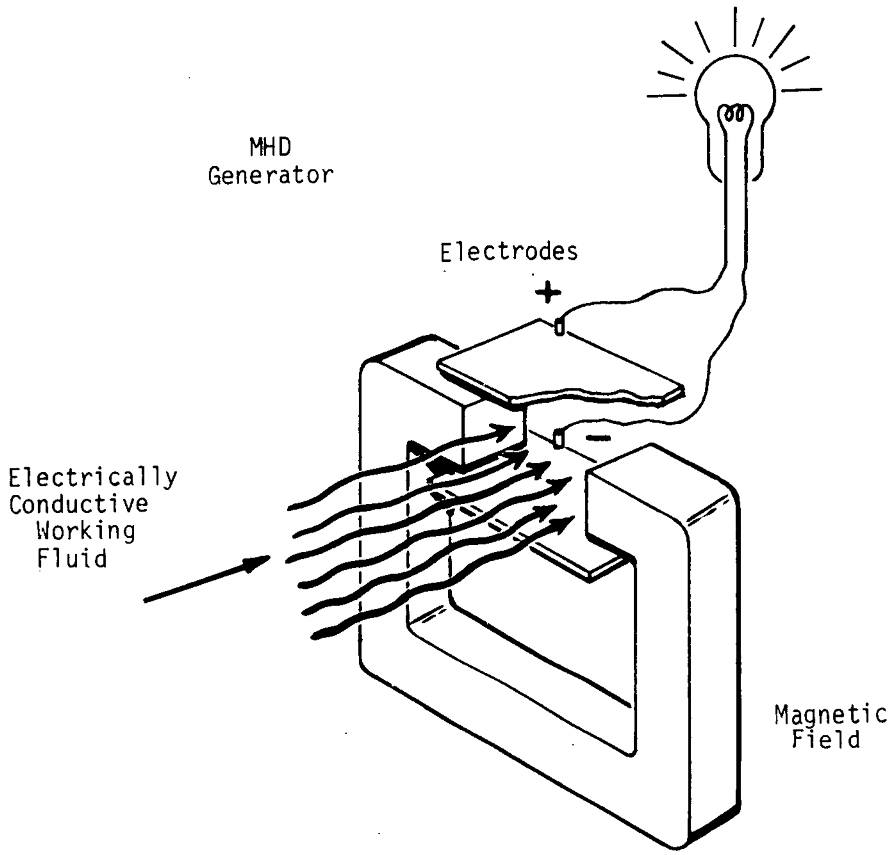
The closed-cycle plasma system utilizes a seeded noble gas heated by an indirect heat source (i.e., nuclear or fossil through a heat exchanger). The hot gas expands through an MHD generator, thereby producing electricity. The cooler gas is compressed for reheating. Regenerative exchange is normally used prior to the compressor, and reject heat can be pumped directly to the atmosphere.

In the liquid metal MHD concept, there are two fluid circuits, the liquid metal and an inert gas. The liquid metal is heated by a fossil or nuclear heat source, and then the inert gas is dispersed into the liquid metal. As the gas expands due to being heated by the liquid metal, the two fluids accelerate through the MHD generator--the liquid metal providing the moving conductor capability. At the exit of the MHD generator, the two fluids are separated. The liquid metal is



TURBINE GENERATOR ELECTRICAL SYSTEM

Figure 6B.10-1



MHD GENERATOR ELECTRICAL SYSTEM

Figure 6B.10-2

reheated, and the gas is cooled and recompressed, ready for mixing. Reject heat from the gas circuit can be used to generate steam for further use or be dumped to the atmosphere.

6B.10.1.2 History and Status

Patents related to MHD generators began to appear in about 1910, but the first attempt to construct a large plasma generator was not made until the early 1940's.[1] This program was unsuccessful and further work was shelved until the 1950's when work on nuclear fusion led to a better understanding of plasma phenomena. This work has resulted in an increased level of interest in MHD over the past decade.[2]

The space programs sponsored by the U.S. and the U.S.S.R. have generated much of the materials technology that made building demonstration units possible. However, the two countries have chosen different routes in the development of open-cycle plasma MHD power plants. The U.S. has developed the various system components required separately. For example, several generators have been built to deliver relatively large amounts of power (18 to 32 MWe) for short periods of time (several minutes). At the same time, a variety of electrode configurations have been tested for relatively long periods of time at low power levels. The U.S.S.R. has approached the problem by building a complete power plant designed to deliver 75 MWe to the Moscow grid (25 MWe from the MHD generator and 50 MWe from a steam-turbine system). Operation at the full-design output of the MHD generator is expected in 1975, and in the meantime, this system will be used to test components as they are developed.[3]

Research on liquid metal MHD systems has been conducted on a much smaller scale than for plasma systems. Much of this work has been done with eutectic mixtures of sodium and potassium (NaK) at room temperatures. Generator efficiencies up to 75% have been measured for a liquid metal MHD generator with a measured output of about 1 kWe. Tests of larger generators of 5 to 50 kWe are currently under way or being planned. In addition, several generators have been tested or are planned to be tested at temperatures in excess of 1000°F.[4]

6B.10.1.3 Present and Projected Application

A number of laboratory and pilot-plant scale plasma MHD generators have produced significant amounts of power (several MWe) for short time periods; however, large-scale power production remains to be demonstrated. Work is currently under way in several laboratories around the world to bring these concepts to fruition. The technology generated in this work is applicable to central-station power generation, but MHD will probably find its initial application as a topping cycle for conventional fossil-fueled steam power plants. As the state of the art evolves, MHD systems could generate electrical power in central-station power plants from either fossil-fired or advanced nuclear heat sources.

6B.10.2 Technical Information

6B.10.2.1 Availability

All MHD power generation system concepts are in the developmental stage. The construction and startup of new experimental MHD generator facilities in the last few years illustrate significant advances in both sophistication and understanding of the operation of MHD generators. Advocates of this system believe that none of the known problems present an insurmountable barrier to bringing MHD central-station power generation to fruition, and they optimistically estimate that either one or all three MHD power systems could be made commercially available by the 1980's if sufficient funding were available. This, of course, will depend upon the rate at which the known, and any currently unrecognized, technical problems can be solved.

6B.10.2.2 Energy Source

Magnetohydrodynamics power generators of various designs are under study which would be capable of operating over a range of heat-source temperatures from 1000 to 5000°F using either fossil or nuclear fuels. The normal combustion of coal produces a gaseous effluent at a temperature of ~2600°F. With O_2 enrichment, this temperature can be increased to 5000°F. Also currently under way are programs to burn coal in fluidized beds at reduced temperatures of 1600°F to reduce the levels of SO_2 and NO_2 pollutants produced.

The open-cycle plasma system is capable of producing electrical power from high-temperature fossil-fueled heat sources operating over the range of 4000 to 5000°F. The closed-cycle plasma system could generate electricity from the advanced HTGR or a fossil-fueled heat source operating over the range of 2300 to 3500°F. Finally, the two-phase liquid metal MHD system appears to be compatible with thermal energy sources operating over the range of 1000 to 2000°F.[5]

6B.10.2.3 Efficiency

Magnetohydrodynamics power systems have higher potential efficiencies than conventional steam and other expansion-type energy-conversion devices. First-generation open-cycle MHD power plants would operate with an MHD topping cycle on a conventional steam plant and could be expected to give overall plant efficiencies in the range of 46 to 50%. These power plants are projected to have an ultimate efficiency in the range of 55 to 60%.[6]

The closed-cycle plasma MHD system appears capable of plant efficiencies in excess of 60% for heat-source temperatures of 2900°F. The two-phase liquid metal MHD power systems are predicted to have overall efficiencies competitive with those of modern steam systems when operating at the same maximum cycle temperature and should have efficiencies approaching 50% at 1600°F.[7]

Proponents envisage that a high-performance all-MHD binary power cycle is possible utilizing the open-cycle plasma and the two-phase liquid metal MHD concepts. In such a system an open-cycle plasma MHD generator obtains thermal energy from a fossil-fueled heat source and rejects waste heat to a two-phase liquid metal MHD generator. This dual cycle is projected to have efficiencies in excess of 60% for a maximum cycle temperature of 5000°F.

6B.10.2.4 Size Limitations

Magnetohydrodynamics generators become more efficient as their size increases, because friction effects and heat losses become less significant as the MHD ducts become larger (i.e., as the surface-to-volume ratio decreases). In contrast to turbines in which forces acting on surfaces are involved in the energy-conversion process, MHD energy conversion is a consequence of a body (volumetric) force. Thus, large MHD generators should be easier to design and construct and less expensive to operate than small ones. The size limitations for MHD central-station power plants will be dependent on the limitations of supporting equipment such as pumps, heat exchangers, and the like.

6B.10.2.5 State of the Art

Significant advances have been made in the past ten years towards the goal of bringing the MHD concept to fruition in central-station power plants.[2] In this period the open-cycle plasma system has received considerably more attention than the other two concepts. This has resulted in improved understanding of the main phenomena in the open-cycle MHD channel so that generator designs can be made and the projected performance of the MHD duct can be bracketed. The required performances of the major components for base-load applications are being approached in the case of the liquid metal MHD system. Preliminary studies, using the projected generator enthalpy extraction and efficiencies, indicate that the future open-cycle plasma MHD power systems will be an economically viable means of base-load power generation provided the extensive research and development required (see Section 7.3) can be successfully performed.

The construction and startup of experimental plants in several countries, including the 25-MWe pilot plant in the U.S.S.R., represent significant milestones in the development of open-cycle plasma MHD. The emphasis of the present work is on increasing the service life of the electrodes, walls, and certain other components to ensure reliable operation of the MHD base-load power station during a predetermined service life.

The closed-cycle MHD generator has been shown to be feasible, and sufficient experimental and theoretical background exists to permit extrapolation to large sizes with confidence (isentropic efficiencies up to 70% and enthalpy extraction up to 36%). An enthalpy extraction of 10% has recently been attained. These results demonstrated that, after successful scaling-up to a thermal output of 1000 MW is achieved, a closed-cycle MHD generator should achieve a performance acceptable for large electric power plants.[8]

Because the working conditions of the closed-cycle MHD nonequilibrium duct are much less severe than for the open-cycle system because of a cleaner gas stream and lower temperatures, fewer difficulties are anticipated in the development of long-life ducts. The prospects of the closed-cycle plasma MHD systems for base-load power generation depends upon the development of a suitable heat source.

Extensive analytical studies of two-phase liquid metal MHD cycles have been made with detailed mathematical models of all components to show that these systems do have the potential for efficient production of electrical power. However, accurate models of the MHD components (i.e., mixer, generator, and separator) can only be developed by extensive experimental studies. The MHD generator tests at Argonne National Laboratories have shown that more than 80% of the end losses that would exist if there were an abrupt termination of the magnetic field can be eliminated. A program is currently under way to test a mixer-generator-separator system at 1000°F. These experiments should document the performance of the two-phase liquid metal MHD generator and, if successful, provide sufficient information for the design and construction of a high-temperature pilot plant.[5]

6B.10.3 Research and Development

Open-cycle plasma MHD power plants would have to operate with a highly erosive and corrosive working fluid at extremely high temperatures. Experimental studies thus far performed have not achieved the required performance levels of the various components. Thus, the major components of a plasma system require additional development to achieve the performance levels required for an efficient plant. The most important of these requirements are:

(1) Materials that will operate for extended periods in the high-temperature, erosive environment.
(2) A high-efficiency coal combustor capable of handling coals having 10% or more ash.
(3) A plasma generator that can extract 20 to 25% of the total enthalpy of the combustion products; thus far only 8% has been achieved, but scaling laws indicate that increasing the generator size should help achieve this goal. Additional study of the aforementioned generator problems is required.
(4) A scrubber that can remove 99.9% of the seed from the spent combustion gases; thus far, 99% removal has been achieved.
(5) An overall isentropic generator efficiency of at least 70%, while only 40% has been demonstrated. This goal should also be attained by increasing the generator size.
(6) A diffuser efficiency of 70 to 80%, while 35% has been reported.
(7) Superconducting magnets to produce the field strengths desired.
(8) The stack gases must be cleaned to acceptable levels; recent results indicate that present-day technology should be able to meet EPA standards.
(9) Finally, long-term tests must be undertaken to demonstrate component longevity once the required performance levels have been demonstrated.

The closed-cycle plasma system has basic problems of enthalpy extraction, generator and diffuser efficiency similar to open-cycle plasma systems. Recent results on the generator problems have been encouraging.

Most of the components in the liquid metal MHD system are conventional (e.g., gas-gas and gas-liquid heat exchangers and compressors) and require little or no additional development to meet performance requirements. Additional development is required on liquid metal pumps and the primary heat exchanger as well as the development of appropriate insulators and conductors for the generator walls which are compatible with the liquid metals. Much progress has been made on the problem of keeping the variation of the relative velocities between the two phases at a small value. This is necessary to ensure high efficiencies for the generator.

The FPC Task Force and AEC Subpanel VI both concluded that MHD systems offer sufficient potential to warrant their inclusion in a balanced energy research and development program. Because the open-cycle MHD system is closer to development than the closed-cycle plasma system, the task force suggested that the open-cycle system be followed through a 300- to 500-MW commercial demonstration. The potential for closed-cycle systems was considered less promising unless a means could be found that would assure a nuclear heat source with sufficiently high operating temperature.

6B.10.4 Environmental Impacts

The effluent problems associated with MHD power plants are those associated with the energy source (i.e., fossil fuel or nuclear fuel). All of the MHD concepts have the potential to reduce thermal discharges and conserve fuel supplies when compared with the pure steam power plants, because they are projected to have improved conversion efficiencies. The total quantity of thermal emissions will be reduced in inverse proportion to the improvement in efficiency.

The open-cycle MHD system is estimated to meet or exceed the EPA requirements for SO_2 and NO_x in effluent stack gases at costs that are predicted to be below those of conventional power plants when 2% sulfur coal is burned. Seed material must be removed and recovered from effluent gases for environmental as well as economic reasons. The seed materials being considered are alkali metal salts, and to release these to the environment as finely divided particulate would be undesirable. Furthermore, the cost of these materials dictates that they must be recycled for economic operation.[9]

Fossil-fueled heat sources for closed-cycle MHD systems possess the same pollution problems encountered with conventional steam plants. It is envisaged that the fluidized-bed combustor could burn high-sulfur coal to supply thermal energy for the liquid metal MHD systems without producing high NO_2 and SO_x levels in the stack gases. In addition, because the two-phase liquid metal MHD system operates on a Brayton-type (gas turbine) cycle, it possesses the potential to be effectively coupled to dry cooling towers without paying a significant economic penalty.

6B.10.5 Costs and Benefits

Although the technical feasibility of MHD power plants has been demonstrated, the concept is still in the developmental stage, and thus very little information has been developed on the projected economic benefits to accrue from central-station MHD power plants. The higher efficiencies projected for the various MHD systems must provide sufficient fuel cost savings to compensate for the capital costs of the MHD systems. Most of the economic studies carried out have been for open-cycle plasma-steam systems. The first generation open-cycle MHD topping systems for electrical generating plants may conceivably compete successfully with conventional steam stations in areas of high fuel costs. Future nuclear power plants would have an economic advantage over open-cycle fossil-fueled MHD power plants only in areas where fossil fuel is relatively expensive.[10]

At the present stage of development of closed-cycle plasma MHD technology, obtaining an absolutely reliable economic evaluation for central-station power applications is not possible. Some comparisons have been made between nuclear closed-cycle MHD and nuclear gas-turbine plants of the future as well as existing steam-turbine power systems. The results are not conclusive as there is not enough information on the efficiency, capital costs, and reliability of closed-cycle MHD.[11]

The results of economic studies carried out in the U.S.S.R. and the Federal Republic of Germany show that a fossil-fueled steam plant produces electricity that is more expensive than the projected costs for closed-cycle MHD and gas-turbine systems of the same capacity used in conjunction with a steam bottoming cycle. These results are based on a theoretical generator-channel model that has been proved in small-scale experimental facilities.[11]

There has been an insufficient effort in regard to in-depth conceptual plant designs and economic evaluations to make any definitive statements concerning the economics of liquid metal MHD. The major potential benefit of MHD generators is improved conversion efficiency.

6B.10.6 Overall Assessment of Role in Energy Supply

Magnetohydrodynamics generators and systems are still in a very formulative stage of research and development, and much work is still required. The fundamental characteristics of the generator are still not well understood, and the materials problems could be extremely significant. The prospect of high conversion efficiency and the ability to use the elevated temperatures available from the combustion of fossil fuels are particularly attractive.

While the economic aspects of MHD have not been studied in sufficient detail, preliminary analysis of open-cycle plasma MHD systems indicates that future nuclear power plants may have an economic advantage over open-cycle fossil-fueled MHD plants only in areas where fossil fuel is relatively expensive. The two-phase liquid metal MHD system has the potential to effectively employ a variety of advanced heat sources currently under development in the United States. These sources include the LMFBR, the HTGR, the fusion reactor, and the fluidized-bed combustor.

REFERENCES FOR SECTION 6B.10

1. Karlovitz et al., U.S. Patent 2,210,918, August 13, 1940.
2. "MHD Electrical Power Generation--1972 Status Report," At. Energy Rev. 10(3): 304-361 (1972).
3. Ibid., pp. 304-337.
4. Ibid., pp. 351-361.
5. W. E. Amend et al., "Liquid Metal MHD for Central Stations," Proceedings of the American Power Conference, Chicago, Ill., May 1973.
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7. W. E. Amend et al., "Analysis of Liquid-Metal MHD Power Cycles for Central Station Power Generation," Proceedings of the 12th Symposium on Engineering Aspects of MHD, Argonne, Ill., March 1972.
8. "MHD Electrical Power Generation--1972 Status Report," At. Energy Rev. 10(3): 345-346 (1972).
9. Ibid., pp. 332-334.
10. Ibid., pp. 329-335.
11. Ibid., pp. 347-350.

6B.11 SUMMARY

The devices discussed in this section have been or are under current investigation for fossil or nuclear electric power generation application. Comparison of these devices is shown in Table 6B.11-1.

Steam-turbine systems (that sometimes use topping cycles) also may have application to systems that use other energy sources (e.g., fusion or solar). Turbine systems using low boiling working fluids such as freon and isobutane are being strongly considered for use with geothermal energy sources. The principal environmental benefit of alternative conversion devices is derived from increased conversion efficiency, which reduces the amount of rejected heat and waste products and, in addition, conserves the energy source.

The importance of improved energy conversion and storage devices has recently been reemphasized in Dr. Dixy Lee Ray's report "The Nation's Energy Future."[1] Although each of the systems discussed in Section 6B has not been treated in Dr. Ray's report, the most promising systems for near-term development have been identified and a relative priority established by the recommended 5-year (1975 to 1979) level of research and development funding. The recommendations of AEC Subpanel VI[2] (which was one of 16 panels that provided basic information to Dr. Ray) are shown for comparative purposes. These figures represent maximum funding for accelerated development of each indicated option. Adjustments were made to provide total program balance within a total 5-year program guideline of $10 billion. The following items were specifically detailed.

Conversion System	Recommended Funding (in millions)		
	Dr. Ray	Subpanel VI	
	5 years	5 years	Total
High-Temperature Gas Turbines	$315.0	625.0	1000.0
Potassium Topping Cycle	90.0	102.2	110.0
Fuel Cells	80.0	131.8	250.8
Storage	50.9		
Advanced Concepts and Enabling Technology (MHD and thermionic)	30.0		
MHD		206.0	652.0
Enabling Technology		79.0	181.0

Table 6B.11-1

ENERGY CONVERSION DEVICE SUMMARY

Device	Availability	System Efficiency	Application	Remarks
Steam Turbines	Commercially available	35 to 41%	Predominantly fossil and nuclear central-station base-load	High reliability systems at modest efficiency. Present efficiency cannot be significantly improved for direct cycle.
Internal Combustion engines	Commercially available	35%	Small central station and peaking	Fossil fuel only. Application limited to small plants except for emergency and peaking purposes at large stations.
Gas Turbines	Commercially available and ASUD[a]	27 to 38%	Direct cycle for peaking; topping cycle for fossil, central station	High-temperature turbines under development for better cycle efficiency (up to 45%). Good application to gas-cooled nuclear plants.
Binary Cycles	ASUD	Up to 55%	Potassium topping cycle for fossil central station	Basic technology available. Development of large plants within seven years possible. Mercury binary might have application to LMFBR.
Fuel Cells	ASUD	Up to 70%	Central station or dispersed generation--energy storage features	Applicable to fossil and nuclear central-station power plant and hydrogen economy. Fossil central station may take five to ten years to develop; dispersed generation--five years.
Batteries	ASUD	60% (turnaround)	Energy storage for load leveling and reliability	Has potential for improving electric power systems. Prospects for development within five years are good.
Magnetohydrodynamics	ASUD	Up to 50%	Direct or topping cycle for central station	Potential for improving efficiency of central-station power plants but development may require ten years or more.
Thermionic Devices	ASUD	Up to 50%	Topping cycle on fossil or nuclear central station	Has potential for fossil application if proper devices can be developed--probably five to ten years. Little potential for nuclear application.
Thermoelectric Devices	Suitable materials being sought	6%	Low power only	Poor efficiency makes unsuitable for central-station consideration.

[a]ASUD - Advanced Systems Under Development

REFERENCES FOR SECTION 6B.11

1. Dr. Dixy Lee Ray, "The Nation's Energy Future," A Report to the President of the United States, USAEC Report WASH-1281, December 1, 1973.

2. R. E. English et al., Subpanel VI, "Conversion Techniques," National Aeronautics and Space Administration, Cleveland, Ohio, October 27, 1973.

SECTION 6C

CONSERVATION OF ENERGY

6C.1 INTRODUCTION

6C.1.1 Background

Energy conservation measures are particularly attractive, because their application could measurably extend our available energy resources as well as proportionately reduce the environmental damage inherent in energy usage. Fossil fuels, which form the bulk of the Nation's current energy resources, are finite, and increasing amounts of major components of these resources--oil and gas--must be imported. By slowing the growth rate of energy demand and by increasing the amount of usable energy produced from each unit of fuel used, the availability of these finite supplies can be stretched. Another result would be to reduce our dependence on foreign energy supplies with the consequent balance of payment and national defense implications.[1]

Thus, there are both direct and indirect benefits to be obtained from conservation of energy. These benefits must, however, be balanced against the economic and other costs of implementing specific conservation measures. The net energy conservation must be considered in the context of the whole energy production system, rather than the gross savings of some particular conservation measure considered independently of its own consequences. For example, the costs of mining aluminum ore, the electricity required to produce aluminum metal, and the production costs of fabricating aluminum storm windows and doors must be considered in determining the net savings achieved from reduced heating losses.

Whether or not conservation measures eventually do provide some degree of relief to the energy supply versus demand situation, clearly there is now a considerable amount of interest in implementing energy conservation, perhaps even to the extent of establishing it as a national goal. Several letters commenting on the Draft LMFBR Program Environmental Statement indicated interest in this idea.* For example, Dr. J. T. Edsall** of Harvard University noted in his letter of April 21, 1974:

> We should also institute a far reaching program of energy conservation, and efficiency in the use of energy.

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*Comment Letters 7, p. 19; 42, pp. 42-46; 19, p. 5; 16, p. 2; 24, p. 2; 38b, pp. 10-16.
**Comment Letter 16, p. 2.

Mr. J. Legakes, in an April 24, 1974 letter,* suggested that:

> Enormous energy savings can be made with better insulating of homes and buildings and other conservation practices. All government buildings, schools, supermarkets, shopping centers and the like could greatly reduce waste lighting and heating, as they have during the recent "crisis."

The Natural Resources Defense Council discussed energy conservation at some length in its letter** of April 29, 1974. The Council concluded that energy conservation is a matter of national policy and suggested several means by which energy savings may be obtained, such as better insulation in buildings, the use of more efficient heating and cooling equipment, and improvements in transportation patterns and vehicles.

The AEC is in agreement with the opinions expressed by these letters and supports a vigorous energy conservation program. However, there are various uncertainties regarding the eventual success of widespread conservation practices, and several views have been expressed to the effect that conservation should not be relied upon as a long-term solution.† These matters are discussed in Section 6C.7.

6C.1.2 Elements of Conservation

In a broad sense, conservation of energy as an option for reducing the requirement for alternative energy sources is not represented solely by reduction in the production and consumption of energy. It can also be interpreted to include expansion in the utilization of readily available and environmentally acceptable energy sources with concomitant reduction in the use of scarce or environmentally adverse resources. Both characteristics (i.e., readily available and environmentally acceptable) must be present if this procedure is to be acceptable. An example of a substitution that did not meet both these criteria, and therefore is being abandoned, has been the use of environmentally acceptable oil and gas in place of high-sulfur coal. The limited availability of oil and gas and the competing demand for their finite supplies have forced the Nation to look elsewhere for the solution to the environmental problems of high-sulfur coal (which happens to meet the criteria of being readily available). Flue gas desulfurization and coal gasification are being considered in this instance.

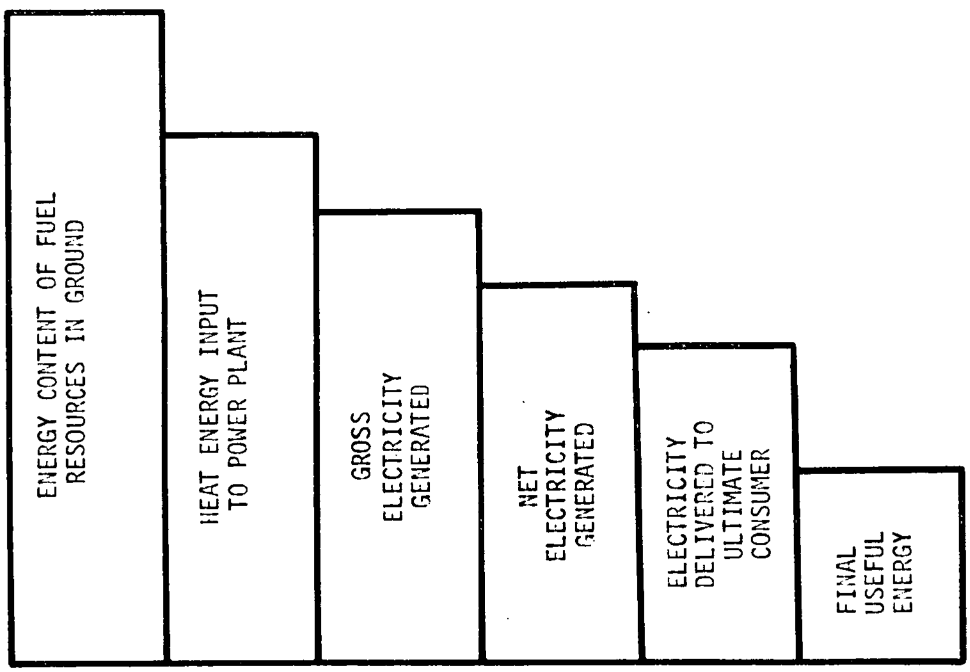
In addition to the procedures discussed above, actions taken to make beneficial use of energy that would otherwise be wasted (e.g., waste heat) are examples of

*Comment Letter 24, p. 2.
**Comment Letter 38b, pp. 10-16
†See, for example, written testimony by Mr. Jack Moore at the Public Hearing on the LMFBR Program, April 26, 1974, p. 4.

energy conservation, because the use of this otherwise wasted energy would eliminate the need to produce the energy from other sources.

Inasmuch as the projected application of the LMFBR is for the production of electricity, the discussion in this section will be directed primarily to electric power as it relates to the several categories of energy conservation described above; that is, the discussion will consider the practice of conserving energy as a substitute for producing power from the several types of power plants or sources previously discussed in this section.

The extent of environmental impact associated with production and consumption of electricity depends on a number of factors: the methods and efficiency of extraction of the basic energy resources needed for power generation; the methods and efficiency of power generation that, in turn, determine the quantity of energy resources needed; the quantity of power generated; and the quantity of power consumed. The following schematic drawing illustrates these categories:



Conservation of energy would result from dropping the height of each of the bars in relation to the bar on its right and also from lowering the last bar on the right through reduction in use of electricity.

With the exception of new energy sources (e.g., oil shale, tar sands, geothermal, solar, fusion power) and improved energy conversion devices (such as MHD and fuel cells), all of which are discussed elsewhere in this Statement, this section examines and quantifies, insofar as is feasible, the principal options for conservation of energy in each of the categories illustrated above. Comments are also made on the environmental, economic, social, resources, and manpower implications of the energy conservation measures considered. These factors are examined in conjunction with the energy conservation recommendations of several recent studies, among them a five-year, $10-billion Federal energy research and development program[2] that has been proposed to regain and maintain the Nation's energy self-sufficiency.

Also discussed in Section 6C.6 (Utilization of Energy) are several approaches to energy conservation resulting from studies performed by government agencies and private organizations. These studies address the magnitude of the energy reductions that might be achieved if conservation measures are successful, and they also examine the uncertainties bearing on the achievement of these savings. These uncertainties include the extent to which conservation research will be funded, the rate and degree of success in developing energy conserving processes and equipment, the extent to which the public utilizes these practices and accepts the accompanying changes in lifestyle, etc. Finally, the amount of electricity that may be saved by conservation measures is examined as an alternative to the construction of additional power plants or to the development of other energy sources such as the LMFBR. This section shows that energy conservation alone cannot now be considered as a reliable alternative to LMFBR development. Nevertheless, there is a place and a need for both energy conservation and new energy sources in the solution to current and future energy supply problems, and the conclusion is reached that both approaches should be pursued to the maximum extent feasible.

6C.2 EXTRACTION OF ENERGY RESOURCES

The United States possesses great resources of coal and uranium (assuming the successful development of a breeder reactor) and substantial, though inadequate, resources of oil. Historically, extraction of these resources has been incomplete in varying degrees. Improvement in extraction efficiency would relieve pressure on other fuels and on import requirements. Furthermore, more complete extraction of resources could be accomplished with only moderate additional impact on the environment.

The principal potential means for broadening the base of extraction of fuels from current sources are stimulation of petroleum and natural gas production and increased production from underground coal mines and from uranium deposits. These potential means are discussed below. An increase in the efficiency of extraction of fuels does not affect the amount of electricity that must be generated, but it may reduce the need for new power plants based on other technologies, such as the LMFBR.

6C.2.1 Stimulation of Petroleum and Natural Gas Production

The role of oil and gas is so pervasive in the Nation's energy economy that the recovery of more oil and gas from domestic fields is worthy of serious attention. Secondary and tertiary recovery methods in existing fields and release of gas from tight geological formations offer promise for immediate and short-term payoff. Scrupulous attention to environmental risks must, of course, be ensured. Work could proceed in parallel with improved extraction techniques on methods to prevent environmental damage (such as oil spills and well blowouts) and to clean up after accidents that do occur.

With current technology, the efficiency of extraction of oil is only about 30 to 35%. Thus, of the approximately 425 billion bbl of oil discovered in the U.S. to date, about 290 billion bbl remain in the ground. Every 1% increase in this recovery rate would represent an additional 4 billion bbl of proven U.S. reserves, an amount equal to about two-thirds of current annual consumption. The development of improved extraction techniques would make available a substantial amount of oil for transportation needs, space heating, chemical feedstocks, and other applications. Importation of crude oil and demands on coal, gas, and nuclear sources could correspondingly be reduced.

Oil recovery efficiency has been improving at the rate of about 1/2 of 1% per year. At this rate, during the next 20 years between 25 and 30 billion bbl of recoverable reserves from known discoveries could be added to domestic supplies.[3] If this improvement rate is to continue, new technology will need to be developed, and present technology must be fully utilized. The National Petroleum Council has expressed the belief that a recovery rate of 50 to 60% will ultimately be achieved.

The most significant methods of stimulating recovery are fluid injection (air, gas, water, steam, miscible fluids), earth fracturing by hydraulic pressure, in-situ combustion (to reduce oil viscosity and promote flow), and chemical explosives. Nearly one million wells have been hydraulically fractured, but there is a lack of adequate knowledge of fracture characteristics and the means to make optimum use of them. The use of nuclear explosives for oil stimulation is a possibility that has not as yet been undertaken commercially in this country.

Although in-situ combustion has not been emphasized as much as some of the other recovery methods, it appears to offer considerable promise. It may find wide application in heavy-oil reservoirs.[3]

Under the program to increase production of oil and natural gas as outlined in ref. 2, combinations of four methods for secondary and tertiary recovery of oil would be tested in approximately 20 experiments that would include about 15 reservoir types. These experiments would determine optimum methods applicable to particular reservoirs. A total of $70.4 million would be budgeted over the next five years for secondary and tertiary recovery activities. Seven experiments are planned in three different reservoirs to determine the potential of massive hydraulic fracturing and chemical explosive fracturing for stimulation of low-permeability formations of oil and natural gas. One further nuclear stimulation demonstration is also planned. The program is designed to determine which stimulation technique or combination of techniques is most suitable for given reservoir characteristics. A program totaling $96.3 million for developing stimulation techniques is recommended.[2]

Potential adverse environmental effects of the several recovery stimulation methods include inadequate disposal of brine produced with the oil, oil blowouts and seeps, saline water intrusion into fresh water subsurface zones, contamination of surface streams or lakes by injected water exiting to the surface, earth motion from explosives, and residual radioactivity from possible use of nuclear explosives. The refining and combustion of the additional oil produced would result in the release of sulfur and nitrogen oxides and of hydrocarbons into the atmosphere.

Offsetting this release would be the reduction in effluents represented by elimination of the need to consume fuels that would be replaced by the added oil and lessening of the potential for oil spills from import tankers.

A favorable environmental aspect of stimulated production from domestic oil wells is that the added production would be achieved with no significant increase in the impact caused by servicing roads, surface utilities and equipment, and workers accommodations, although some additional works associated with the stimulation methods would be required.

Present projections of the use of oil in the United States already assume a continuing increase in extraction efficiency. Thus, if there is to be a still greater utilization of domestic oil resources, research and development efforts will have to be intensified beyond the current level of about $50 million per year. The program outlined in ref. 2 entails a total expenditure of $310 million over the next five years to increase the production of both oil and natural gas; it also includes $127.8 million for development of in-situ retorting of oil shale and $15.5 million for development of advanced drilling techniques. "The Nation's Energy Future"[2] includes funding of $70.0 million for improving the current capabilities of resource assessment for petroleum and natural gas.

Improving the efficiency of oil extraction is not the same as increasing the rate of oil extraction from a well. However, the life of oil fields would be extended and more oil could be obtained from a given field if extraction efficiency were improved. Thus, by some given year, cumulative improvement in extraction efficiency may be presumed to have brought about a higher national production rate because certain fields that otherwise would have been exhausted would still be in production. How much of an impact an intensified improvement in extraction efficiency would have is difficult to predict with reasonable assurance of accuracy, but estimates show that if the methods proposed in ref. 2 are implemented, secondary and tertiary recovery could increase the production in operating fields by 200 million bbl/year by 1985. Improved methods for stimulating the flow of oil in low permeability reservoirs could result in the recovery of an additional 70 million bbl of oil by that year, and successful development of the equipment and procedures for faster, deeper, and more economical drilling could result in the discovery and recovery of 500 million bbl of oil by 1985.

Less-certain predictions to the year 2000 estimate that the improved extraction techniques discussed herein (not including oil shale development, the possible results of which are even more uncertain) could result in an increase in annual oil production of perhaps 5%, or 0.5 million bbl/day (assuming domestic production at that time would otherwise be 10 million bbl/day.) If all of this increase were applied to the production of electrical power, about 20 generating plants of 1000 MWe each could be fueled. In practice, the additional oil produced would probably be used for household, commercial, industrial, and transportation needs as well. The Interior Department projects that in the year 2000 about 7% of petroleum consumption will be for electricity production.[4] At this ratio, the application of the increased oil production to power generation would yield the equivalent of one or two large generating units, or about 1/10 of 1% of the projected national generating capacity for that year. Therefore, the benefits of improving oil extraction efficiency, while of some importance, will apparently not have substantial impact on the electricity supply situation.

Natural gas is obtained either from straight gas wells or from combination oil and gas wells. Gross U.S. production in 1971 was 18.9 trillion ft^3 from straight wells and 5.2 trillion ft^3 from combination wells.[5]

The previous discussion of stimulation of production from oil wells is applicable, also, to combination wells. Similarly, the activities just described for improving the recovery efficiency for oil contain program elements applicable to increasing the production of natural gas.[2]

The principal method used for stimulating straight gas wells is induced hydraulic fracturing. As with fracturing of oil reservoirs, more understanding of the characteristics of earth fractures is needed if the full potential of gas stimulation is to be achieved. Sample field tests have been made to investigate the feasibility of using chemical explosives to stimulate low-permeability gas-bearing formations. Results range from no improvement to a 14-fold increase in flow rate.

The concept of nuclear-explosive stimulation of natural-gas wells is to use the rock-breaking power of the explosive to create chimneys of broken rock with diverging fractures serving as enlarged wellbores. Three Government-industry experiments have been conducted. All three have demonstrated technical feasibility. Gas-recovery rates from the first two experiments are about 7 or 8 times those of unstimulated wells in the same areas,[3] and the third experiment is in the early stages of evaluation. Two environmental impacts for consideration with respect to nuclear explosives stimulation are ground motion and residual radioactivity.

Careful design of the explosive, knowledge of the subsurface region, and control methods to dispose of tritiated water will be necessary.[3]

A 1973 report of the Department of the Interior ("Final Environmental Statement for the Prototype Oil Shale Leasing Program"[6]) includes a detailed discussion of nuclear stimulation of natural gas reservoirs (pp. V-87 to V-96). Potential reserves are described as follows:

> The resource potential of the tight gas sands in the Rocky Mountain region is nearly 600 trillion cubic feet (tcf) of natural gas; the corresponding technically recoverable potential reserves have been estimated to be 300 tcf. Most of the resources amenable to nuclear stimulation are in the Green River, Piceance, and Uinta Basins. The potential reserves from these three basins correspond to about 300 x 10^{15} Btu or, on an energy equivalent basis, to about 50 billion barrels of oil. The rate of recovery is important when considering the reserve potential. One possible schedule being considered by AEC estimates that the annual production from full commercial development will be at just less than 100 Bcf the first year and level out at about 3.4 tcf. This would cause the basins to be drained in about 80 years.

In view of the increasingly tight present and future supply of natural gas in relation to potential demand from the various consuming sectors, the burning of gas for the generation of electrical power is anticipated to drop steadily, both in actual quantities and in proportion to other uses. Gas will be looked upon as a more valuable fuel for household, commercial, and industrial uses and for chemical feedstock. The Department of the Interior projects the U.S. consumption of natural gas for power production and the total gas consumption to be as follows:[4]

	Trillions of Cubic Feet			
	1975	1980	1985	2000
Power	3.7	3.5	3.3	2.6
Total	24.5	26.2	27.5	33.0

The program for increasing the recovery efficiency of natural gas as described in "The Nation's Energy Future"[2] includes estimates that if secondary and tertiary recovery techniques are implemented as proposed, they could result in the production of an additional 700 billion ft^3 of natural gas per year by 1985. Improved methods for stimulating the flow of natural gas in low permeability reservoirs could result in the recovery of an additional 2.6 trillion ft^3 of natural gas per year by 1985, and the development of improved drilling methods could yield the discovery and recovery of an additional 2.5 trillion ft^3 annually by that time.

Considering primarily the "conservation" elements of a recovery efficiency improvement program (i.e., disregarding future potential discoveries) and extending the analysis to the year 2000, an assessment of the effects of this program would be as follows. As mentioned above, nuclear stimulation of natural gas from tight sands could result in an eventual recovery rate of about 3.4 trillion ft^3/year. For purposes of analysis, an additional 2.6 trillion ft^3 is assumed from other methods of stimulation, including secondary and tertiary recovery techniques, for a total of 6 trillion ft^3 of additional natural gas available from domestic sources in the year 2000. If all of this quantity were consumed for electrical power production, it could fuel about 100 generating units of 1000 MWe each, at an average capacity factor of 70%. However, if the ratio of gas used for power production to gas used for other purposes in the year 2000 were that shown in the table above, then the remaining gas could fuel only about eight 1000-MWe power plants, or about 1/2 of 1% of the Nation's total anticipated generating capacity at that time.

All indications are that the demand for gas in future years will greatly exceed the supply. Therefore, increased production through stimulation of gas wells will probably supplement, but not replace, production from other sources, such as imported LNG and gasification of coal.

6C.2.2 Increased Production from Coal Mines

As of January 1, 1967, known or proved recoverable reserves of coal in the U.S. were about 390 billion tons[7] (within 1000 ft of the surface and with a cutoff of 28-in. seam thickness for bituminous and anthracite and 5 ft for subbituminous and lignite). Production and losses since that date represent only a small fraction of the total. Estimates in 1967 of total ultimately recoverable resources (including proved reserves) were about 1605 billion tons.[8] This figure was based on an assumption of 50% recoverability from a total in the ground of 3210 billion tons. Later estimates by the Bureau of Mines, however, show that advances in technology will increase national average recoverability to as much as 60 to 63.5%.[9] Another source states that in the production of coal by underground methods, the generally accepted recovery rate is 50%.[10]

Coal production is currently about evenly divided between underground and surface mining. However, the trend toward surface mining has been strongly upward in recent years and downward for underground mining, mainly because of the relatively high economic cost of the latter.

Different methods of surface mining include area stripping, contour stripping, and auger mining.[3] (See Section 6A.2.1 for further discussion of coal resources and mining methods.)

Area stripping is performed in flat or slightly rolling terrain (central and western U.S.) where the coal beds are continuous over large areas and are often near the surface. Recovery averages about 80% but can be as high as 90%. There is essentially no prospect of increasing this recovery percentage.

Contour stripping is employed in the narrow valleys of the Appalachian Region. Bench cuts are made parallel to the ridges. The extent of recovery of coal from available resources varies over a wide range and is influenced by the steepness of the slopes. The depth of the bench cut is limited by the resultant height of the highwall which, in turn, is determined by the slope. Contour strip mines are usually small and short-lived. In view of the above circumstances, general improvement in recovery rates from contour strip mining will probably not take place in the foreseeable future.

About 3% of current coal production is from auger mining. Coal is removed from exposed coalbeds with horizontal augers (rotating, spiral cutting tools from 18 in. to 7 ft in diameter) that penetrate to depths[3] of about 200 ft. As with contour mining, the rate of recovery from auger mining is variable, depending largely on the ground slope and size of coalbeds. Recovery ranges up to 50% but is more usually 20 to 25%. There may be some improvement in this rate with industrial development of advanced equipment, but the terrain limitations in Appalachia and the anticipated continued minor role of auger mining in that region as compared with nationwide production would indicate that improved recovery would have a relatively insignificant impact.

Underground coal mining techniques employed are room and pillar, longwall, and shortwall. In room and pillar mining, pillars of coal are left in place in the mined areas to provide support for the overlying rock and soil. Because of these pillars and of unminable coal lying under towns, lakes, and highways or around gas and oil wells, the average national recovery rate has been no more than 50 to 60%.

One approach to increasing productivity is to change to a different mining system, such as the longwall method.[11] Developed in Europe, the longwall method has met with limited acceptance in the United States. Only about 2.5% of the total U.S. underground production is mined by longwall equipment.

The longwall method resembles a carpenter's plane or a milling machine, and it comes closer to being a truly continuous technique than any other developed for coal mining. To prepare for "longwalling," a block of coal (called a panel) up to 1500 ft wide and as long as 7500 ft is developed by driving tunnels on all four sides. One of these tunnels will serve as the beginning of the working "face." The roof of this tunnel is supported by a long line of hydraulically operated steel roof supports called "chocks." On the floor and against the face of coal, a chain conveyor is installed. Straddling the conveyor, and able to move back and forth across the face, is the machine that does the job of cutting away the coal. This machine can be a device with fixed cutting blades called a "plow," or it can be a machine equipped with rotating drums, armed with an array of teeth, called a "shear." In either case, the machine moves across the face of coal, and, as it gnaws, the cut coal drops to the conveyor below and moves continuously away. The chain conveyor dumps its load on a belt at the end of the longwall, and a continuous stream of coal begins its journey out of the mine.

After the plow or shear has cut a foot or more into the coal face, the hydraulic roof supports are moved into the newly mined space, and the roof of the original tunnel, now left unsupported, collapses. Since this collapse is intended, there is no need for roof bolts. Thus, the face of the longwall moves as the machines mine all the coal that is exposed, with a yield approaching 85 to 90% of the coal in the original panel.

One of the deterrents to the adoption of the longwall method is the substantial investment that must be made in equipment and development work before the mining process can begin. Longwall mining equipment costs are on the order of 2-1/2 to 3-1/2 times the costs of continuous mining equipment of similar capacity. Investments as large as $1.5 million are required for the longwall equipment for a 400-ft face (and some systems involve a face of 1500 ft or more). A considerable portion of this cost is for the hydraulic chocks, called "shields." These shields are massive creatures of steel that cost many thousands of dollars each. Each one supports a roof area of 3 ft by 10 ft. The 400-ft face would require 133 shields. Not all mining companies can tackle a commitment of this size.

Shortwall mining is described in ref. 3 as follows:

> 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.

Longwall mining accounts for only a small portion of U.S. production today,[12] although it is growing as shown in Table 6C.2-1.

Table 6C.2-1

PRODUCTION FROM LONGWALL MINING

(thousands of tons)

1966	2251
1967	3232
1968	4633
1969	6344
1970	7132

Source: "Bituminous Coal Data, 1971," National Coal Association, Washington, D.C., 1972.

The long-term trend of methods of coal mining is uncertain. Strip mining is under fire because of adverse environmental impacts. Underground mining is becoming increasingly expensive and skilled labor more difficult to attract. For purposes of discussion, the assumption is made that expanded adoption of longwall and shortwall mining and the establishment of standard procedures for the reclamation of stripped areas will be such that by the year 2000, coal production will be equally divided between surface and underground mining.

There is one further possible breakthrough in underground mining technology that would maintain the efficient production obtained in strip mining and, at the same time, eliminate much of the adverse environmental impact associated with strip mining. This mining technique is described in ref. 3 as follows:

> ...thick bedded seams of coal, for which no satisfactory underground mining method has yet been devised, might be successfully block caved by repeatedly undercutting and caving a block of coal with the augers that are now successfully and economically used in surface mining. Ninety percent or better extraction should be achieved and coal measure [type] rocks are sufficiently resilient so that the gradual and controlled subsidence should not disturb overlying rock and water tables and would scarcely be noticeable on the surface. If the concept were to be successfully demonstrated, large scale production could be achieved in a competitive range with surface mining but with minimum impact on the environment.

The energy research and development program described in ref. 2 includes among its goals the development and demonstration of more productive, safe, and low environmental-impact coal mining technology to the point where the mining industry can rapidly incorporate this technology in greatly expanded future operations. A total of $325 million would be spent over the next five years towards this objective, which could lead to the substitution of coal for oil and gas in various applications, including power production. Program elements would include development and demonstration of surface mining and of reclamation systems and equipment that would permit surface mining in the western and Appalachian coal fields at minimum cost and environmental impact. Particular attention will be paid to demonstration projects to assess the efficacy of the best present technology and to identify and resolve indicated deficiencies.

The underground coal mining program will develop and conduct demonstrations of equipment systems for high-speed horizontal mine development, improved longwall mining, continuous-materials handling systems, improved roof-control systems, commercial extraction of methane from virgin coal and slag areas, and novel mining concepts. Technology for environmental protection associated with underground mining, including control of subsidence phenomena, control of chemical mine drainage effluents, and acceptable methods of waste disposal will be demonstrated. Work on the mining of oil shale (see Section 6A.2.3) would also be covered under this program.

To attain energy self-sufficiency, U.S. coal mining capability will have to at least triple in this century. In the near term, over 600 million tons/year of additional coal production capacity will be required by 1985.[2] Coal requirements for the production of electricity in the year 2000 are projected by another source to be 755 million tons.[4] (An additional 308 million tons are forecast as applied to the production of synthetic gas.) Under the assumptions adopted, 378 million tons each would be extracted from surface and underground sources. As discussed earlier, little improvement in the efficiency of surface extraction can be expected. However, shortwall and longwall underground mining recover 80% to 95% of the coal in place as contrasted to 50% to 60% for room-and-pillar mining. On the assumption that shortwall and longwall mining will expand to 50% of underground mining by the year 2000 (189 million tons), extraction of 189 million tons from 216 million tons of basic resource (87.5% recovery) would be possible, as contrasted to 344 million tons (55% recovery) needed for the room-and-pillar mining--a conservation of 128 million tons. Examining this possibility from another viewpoint, if, by the year 2000, advantage is taken of the high recovery rate of longwall and shortwall mining by increasing production from the same quantity of coal in the ground as needed for room-and-pillar mining (344 million tons), then 301 million tons could be recovered--an increase of 122 million tons. At 92% coal-processing efficiency and 99% transportation efficiency,[13] 102 million tons would be available for burning under power plant boilers. At 0.9 lb of coal per kilowatt hour,[14] this rate would permit the gross generation of 230 billion kWhr, or about 2% of the total power generation projected for the year 2000. (Plants of higher efficiency requiring less than 0.9 lb of coal per kWhr, as projected for the year 2000, would, of course, produce more electricity for the same amount of coal.) At an average 70% plant capacity factor, about 37 billion kW of generating capacity would be provided. Reference 4 projects a total generating capacity of 1880 million kW in the year 2000.

Potentially adverse environmental aspects of increasing coal production by shortwall and longwall mining would include added probabilities of subsidence, increased amounts of solid wastes from coal processing, greater acid water runoffs from processing, gaseous and particulate effluents from power plant stacks, and fly ash from the furnaces.

Conversely, impact on the environment would be lessened to the extent that other fuels, replaced by the increased coal, would not be mined and consumed for the generation of electricity.

6C.2.3 Increased Production from Uranium Deposits

Because the cost of power from converter reactors varies with the cost of mining and milling uranium (0.06 to 0.08 mills/kWhr increase for each $1 per pound rise in the cost of U_3O_8), whereas the cost of power from breeder reactors is insensitive to uranium costs, a major objective of the national program to bring the breeder to commercial application is to sever dependence on the limited reserves of low-cost uranium. In the interim, current practices in extraction of uranium from the lower-cost deposits frequently result in the loss of higher-cost ores located in the same ore body. If the benefit of currently estimated reserves and potential sources is to be fully achieved, measures for conserving lower-grade ores, as higher-grade ores are extracted, must be found and implemented.

6C.2.3.1 Uranium Resources and Mining Practice

Uranium resources on January 1, 1973, were estimated by cost of production as shown in Table 6C.2-2.

Table 6C.2-2

URANIUM RESOURCES (U_3O_8)

Cost ($ lb U_3O_8)	Reserves (tons)	Potential (tons)	Total (tons)
$8 subtotal	273,000	450,000	723,000
$8 to 10	64,000	250,000	314,000
$10 subtotal	337,000	700,000	1,037,000
$10 to 15	183,000	300,000	483,000
$15 subtotal	520,000	1,000,000	1,520,000
$15 to 30	180,000	700,000	880,000
$30 subtotal	700,000	1,700,000	2,400,000

Recovery of uranium in the mining and milling processes is high, leaving relatively little room for improvement. (Milling recovers about 95% of the resource.) However, variations in grade of the ore in a given deposit are common, as depicted in Figure 6A.1-3. Thus, much of the higher-cost uranium resources listed above are in the same deposits with the $8 per pound U_3O_8. Thus, when deposits are mined to an $8 cutoff and then shut down, the low-grade material left behind may be recoverable only at greatly increased cost or not at all.

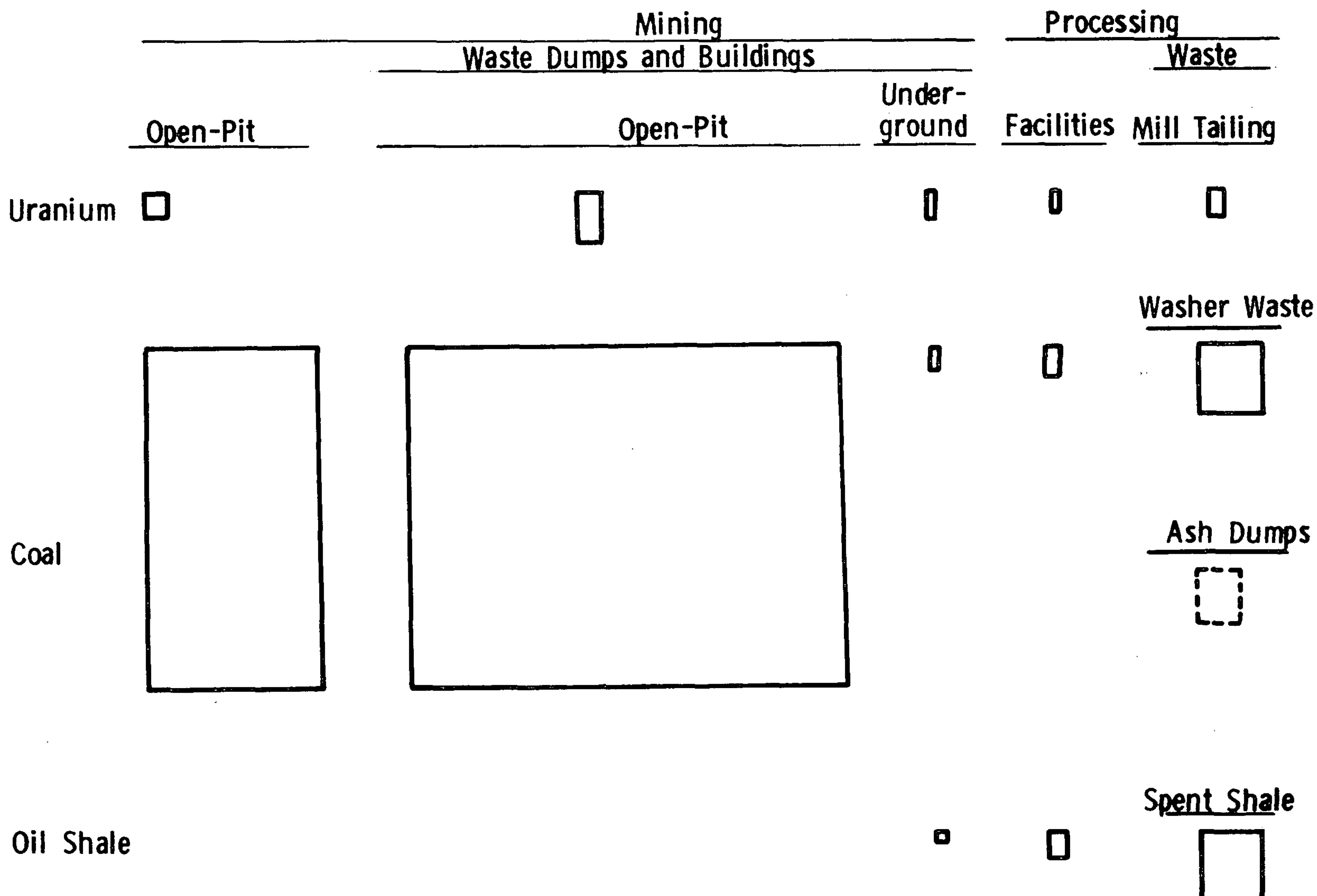
6C.2.3.2 Mining Methods

In the United States, uranium deposits are principally irregularly tabular ore bodies in sandstone beds and veins in crystalline rocks.

About 55% of the reserves will be mined by underground methods, while 45% are sufficiently shallow to be open-pit mined. As drilling extends into areas where uranium is more deeply buried, greater portions will be mined by underground methods. Deposits mineable at $8 per pound U_3O_8 have been found to depths of 4000 ft.

Open-pit mining consists of removing the overlying rock with large earth-moving equipment to expose the ore horizon and mining the ore with power shovels or backhoes. Sixty percent of 1972 production was by this method. Open-pit mining is usually done in steps with waste rock backfilled into mined-out areas.

Underground mining is usually accomplished by vertical shafts, ore-body development from drifts below the ore, and ore extraction by room-and-pillar methods. Rock in mine roofs is held up by roof bolts or steel jacks until the ore pillars can be



RELATIVE LAND AREA DISTURBED BY PRODUCTION OF ENERGY FUEL
FOR A 1000-MWe PLANT

Figure 6C.2-1

removed. When the ore pillars are removed, adjacent lower-grade ore is no longer mineable due to collapse of the mine roof.

6C.2.3.3 Percentage Extraction

Open-pit mining removes virtually all of the ore within the selected pit area. Lower-grade ore from the pit is often stacked for possible future treatment, but lower-grade ore adjacent to, or in the vicinity of, the pit is left unmined--making its future recovery a less economic proposition.

Underground mining practices recover 80 to 90% of the uranium ore. Sometimes the ore removed may exceed estimates, because development frequently discovers uranium not included in original estimates. Recovery can be improved with new mining technology, chiefly by lowering mining cost and thereby increasing the quantity of ore available at acceptable cost.

6C.2.3.4 Impact of Uranium Mining on the Environment

The area disturbed by production of uranium for a 1000-MWe LWR with plutonium recycle for 30 years using 53% of requirements from open pits and 47% from underground mines is estimated at 210 to 290 acres. Disturbed ground includes area within confines of the pit, waste dumps, and buildings; open-pit operations account for most of the disturbed area. An additional 80 acres would be disturbed by the treatment plant.

Figure 6C.2-1 compares the relative acreage disturbed by uranium production under current practice with that for coal and oil shale produced to fuel a comparable power plant. A large proportion of the areas of disturbance can be restored and put to other uses after mining is completed.

As the demand for uranium increases with the growth of nuclear power and with the concomitant reduction in reserves of low-cost ore, the economic forces of the marketplace will provide incentive for mining companies to extract the more expensive ores, probably as high as $30 per pound. (Note that $30 per pound U_3O_8 is an AEC estimate of production cost, not price. A price of $30 per pound would raise the power cost over present levels by about 1.5 mills/kWhr.) However, as mentioned above, a considerable quantity of the higher-cost ore associated with lower-cost ore that has been mined will not be recoverable or will be recoverable only at greatly increased cost. Conservation of a significant portion of this otherwise wasted resource would require not only improved mining technology but also near-term incentives to mine and store lower-grade ore for future use or to preserve the capability for future mining of the lower-grade ore.

In Figure 6C.2-2, projections show that up to 1990 about 170,000 tons of the currently known reserves of uranium in the $8 to $15 range will be lost by the mining of $8 cut-off uranium.

For purposes of estimating the potential for conservation, assumptions are made that: (1) all reserves plus potential $8 cut-off uranium (723,000 tons) will be mined by 1990, with prospective losses of $8 to $15 resources proportional to those shown in Figure 6C.2-2, and (2) improved mining technology plus the establishment of incentives to extract the higher-cost ore will result in the "saving" of one-third of the uranium in the $8 to $15 range that would otherwise have been lost to use. The resulting amount saved is about 145,000 tons of U_3O_8 by the year 1990.

In an LWR, a ton of uranium mined will provide the fuel for the generation of about 36 million kWhr. Thus, the 145,000 tons of potential resources savings could have the capability of producing nearly 5.2 trillion kWhr in LWRs, or the output of about twenty-eight 1000-MWe units operating at an average 70% capacity factor for 30 years.

6C.2.4 Summation of Potential for Improving Efficiency of Extraction of Energy Resources

The preceding discussion has developed the hypothesis that if all available steps are taken in a timely fashion to improve the efficiency of extraction of energy resources, the resulting annual increase by the year 2000 in the availability for electricity production of each of the fuels* could be approximately as follows:

Oil: 13 million bbl

Gas: 1/2 trillion ft^3

Coal: 102 million tons

Uranium: 3300 tons**

Application of each of the above quantities as fuel for power plants operating at an average of 70% capacity factor and 36% thermal efficiency would represent the following additional generating capacity:

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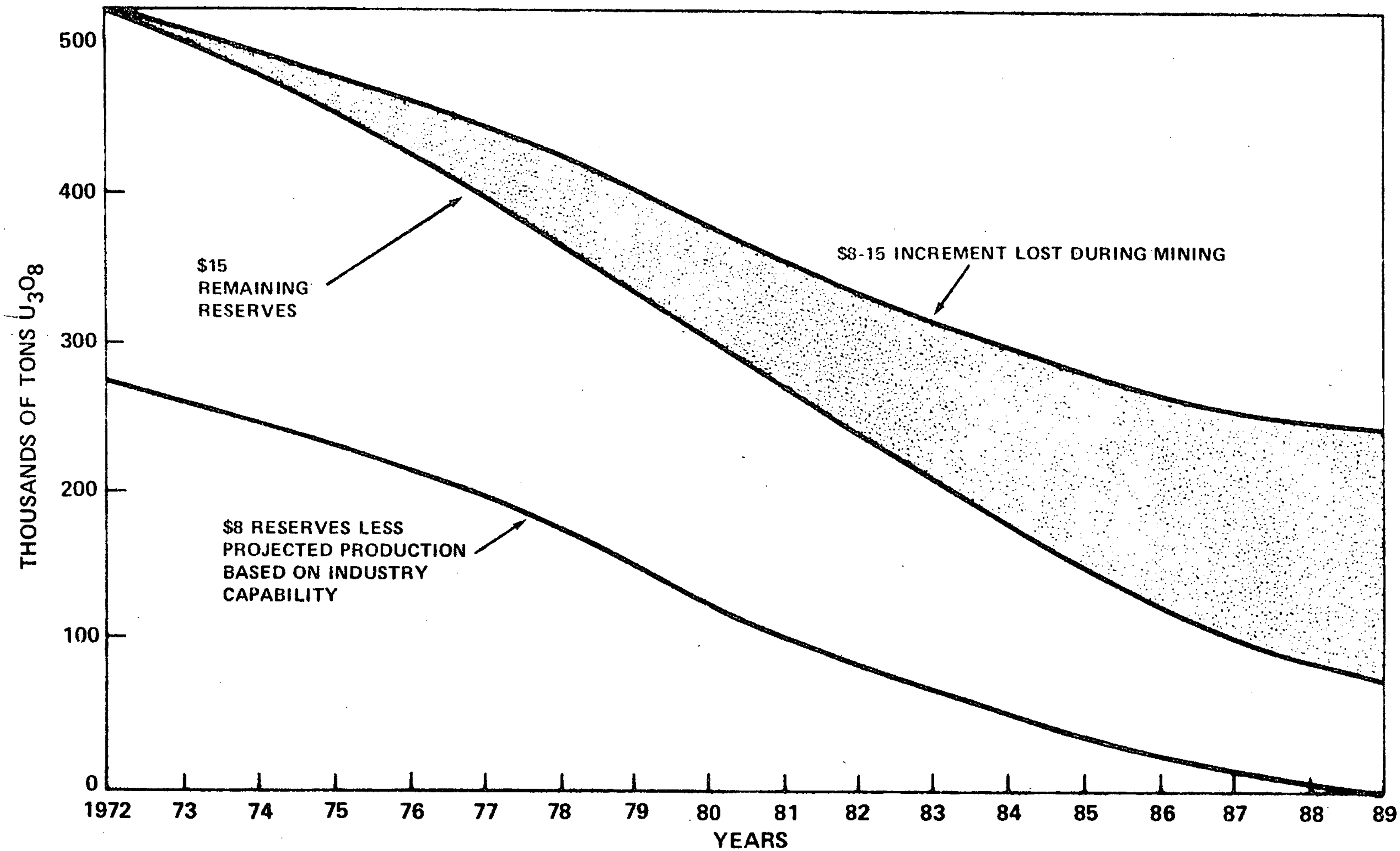
*Using the proportional application for electricity production as projected by the Interior Department in ref. 4; total added availability would be about 14 times as much for oil and 13 times for gas.

**The 145,000 added tons of U_3O_8 extracted to the year 1990, extended over 30 years of power plant life.



DEPLETION OF $15 RESERVES AS $8 RESERVES ARE MINED OUT

Figure 6C.2-2

	MWe
Oil	1,300
Gas	8,900
Coal	43,800
Uranium	28,000
Total	82,000

To put this 82,000 MW in perspective, comparison may be made with the forecast in Table 6C.2-3.[15]

Table 6C.2-3

INSTALLED U.S. GENERATING CAPACITY FOR THE YEAR 2000 (MWe)

Nuclear	1,090,000
Non-Nuclear	930,000
Total Nuclear and Non-Nuclear	2,020,000

Therefore, the projected savings from a successful program in increasing the efficiency of resource extraction would result in "producing" about 4% of the installed U.S. generating capacity projected for the year 2000. This increased fuel availability would require substantial investment in improving extraction efficiencies, and it would result in various environmental impacts above or beyond those associated with current resource extraction methods (such as possible contamination of surface streams by water injected into oil wells, radiological and other effects of nuclear explosives that may be used in the stimulation of natural gas wells, increased ground subsidence over coal mines). Any decisions on implementing increased resource extraction methods would have to balance the potential payoff in fuel availability against the economic and environmental costs associated with each method.

6C.3 POWER PLANT ENERGY CONVERSION EFFICIENCIES

6C.3.1 Fossil-Fuel Fired Steam-Electric Plants

As noted in Section 6A.2, the efficiency of a turbine generator generally increases with increase in the temperature of the steam supplied to the turbine. An increase in generator efficiency results in more electricity being produced for the same amount of fuel (or the need to use less fuel to produce the needed amount of electricity) and is, therefore, an obviously desirable characteristic. However, the necessary associated costs of temperature- and corrosion-resistant materials also go up as temperature (and therefore efficiency) increases. The current economic balance between efficiency and materials cost is about 1000°F steam at 3500 psig pressure and with 1000°F reheat. A modern oil-burning unit using these steam characteristics can be expected to convert about 37.5% of the heating value of the fuel to electrical energy reliably and economically at current fuel costs. The corresponding efficiency for a modern coal-burning unit is about 39%. The efficiencies would be raised about 1.5% if the main and reheat temperatures were increased to 1100°F. The technology for this process does exist, and a few units are in service. Decisions to add more units at 1100°F will depend largely on future trends of fuel costs and materials costs.

An efficiency as high as 44% could theoretically be obtained if using main and reheat steam at 1400°F temperatures were practical. Various exotic alloys have been tested in trial installations up to 1200°F, but none of these tests have been continued for a long enough period to demonstrate acceptable stability. Considerable further research and development on corrosion- and erosion-resistant materials, on the dissociation of steam at high temperatures (physical breakdown into hydrogen and oxygen molecules), and on the harmful effects of steam dissociation on pipe and tube materials will be necessary. Additional time will then be needed to meet learning, production, and construction requirements.

Another method for improving the energy conversion efficiency of steam-electric plants is steam reheat. Today's power plants normally reheat the steam partway through the turbine. A second reheat could add about 2% to the efficiency, and a third reheat could add another 1%. Each additional reheat would involve higher capital costs and more complicated installations with resultant risk of reduced reliability. For example, the pressure would have to be increased from 3500 psig to about 5500 psig and heavier-walled vessels, pipes, and tubes would have to be used.

The Interior Department projects that 2840 billion net kWhr of electricity will be generated in the year 2000 by fossil-fuel-burning plants with a total capacity of 820,000 MW.[4] To predict what portion of this capacity will be from plants incorporating some or all of the advanced steam improvements described in this section is, of course, purely speculative. However, to develop an approximate estimate, the assumption is made that 80% of the generation (or 2270 billion kWhr) will be from large, base-loaded units, that 50% of this (or 1135 billion kWhr) will be from units of recent enough installation to be able to utilize the results of research and commercial development necessary for the high steam temperatures and pressures, and that the average increase in efficiency of these units will be 5%. Under these assumptions for the same heat energy input, the advance-design fossil plants would generate 1190 billion kWhr, or an increase of 55 billion kWhr. This increase is about 1/2 of 1% of the total electricity projected to be generated in the year 2000. Thus, improvements in conversion efficiency of the type discussed above will not be of major impact in meeting future electricity requirements. Also important is the installation of higher-efficiency equipment which would mean a greater demand for exotic alloying materials, higher capital costs, and the possibility of reduced reliability of operation.

Favorable environmental impact aspects from efficiency improvements would include reduced waste-heat discharge because of the higher plant efficiencies and reduced use of steam-electric plants not equipped with the high-efficiency turbine generators.

The effect on manpower requirements should be minor with some increase, however, for the production of metals for the heavier-walled vessels, pipes, and tubes and for the shop fabrication of more complex equipment.

6C.3.2 Nuclear-Fueled Steam-Electric Plants

The probability of significant improvement in the thermal efficiency of LWR power plants is low, primarily because the steam temperatures are necessarily limited to the present low levels (about 600°F) that are in turn dictated by physical limits on the operating temperature of the fuel-element cladding material (Zircaloy). Other cladding materials (such as stainless steel) could withstand higher temperatures but would cause reduced neutron utilization.

However, additional reheat stages will possibly be added to some future LWR plants with a resultant modest increase in efficiency accompanied by added investment costs and potential for reduced reliability. The relative stability of fuel costs for LWRs as contrasted to the fossil fuels weakens the incentive of utilities to add reheat stages.

If, for the purpose of analysis, the assumption is made that added reheat stages will be incorporated to the extent that the average efficiency of LWR will be increased 1% to 2% by the year 2000, then for the same heat energy input an additional 49 billion kWhr, or about 1/2 of 1% of total generation, would be generated by LWRs in that year. This figure is derived by using the projection of 5470 billion kWhr of nuclear generation in 2000,[4] assuming 60% is from LWRs, and adding 1.5%. Nevertheless, as in the case of fossil-fueled plants, improvements in energy conversion efficiency are not expected to contribute significantly to meeting electricity demands.

6C.3.3 Utilization of Waste Heat from Power Plants

On the average, about two-thirds of the total energy output of thermal-electric power plants is released to the environment as waste heat. By-product utilization of this waste heat would bring about not only some reduction in thermal impact on the environment, but also some improvement in the electrical conversion efficiency through a net increase in energy use.

In 1971, waste heat from thermal power plants totalled nearly 10,000 trillion Btu, the energy equivalent of 1.7 billion bbl of oil. By the year 2000, without beneficial uses, projections indicate that the total will be in the range of 45,000 to 60,000 trillion Btu,[4,16] or the equivalent of 7.5 to 10 billion bbl of oil. These quantities will represent 20% to 30% of the Nation's total gross input of energy.

Possible uses of waste heat from power plants fall into the following general categories:

(1) Agriculture (open field cultivation, greenhouses, animal shelters)
(2) Aquaculture (shell and fin fish)
(3) Space heating and conditioning (including snow and ice melting)
(4) Low temperature industrial process applications (including distillation of sewage plant effluent and materials drying).

While the underlying principles are known and technology exists for most of the potential applications, there has been only minor implementation for a variety of reasons, including the following:

(1) Economic restraints. For example, the capital investment required for a given project may outweigh the benefit of low-cost energy.

(2) Seasonal aspects. The power plant may discharge waste water at a relatively high temperature in the summer months when the user does not need it and at a low temperature in the winter when heat is required.

(3) Scheduling. The user may not be able to do without the heated water when the power plant is in a scheduled or unscheduled shutdown. To compensate, provision needs to be made for switching to an additional unit at the power station, to an auxiliary heat supply at the user site, or both.

(4) Siting. Because of loss of waste water heat in transit, most operations need to be conducted adjacent to or in close proximity to the energy source. In many instances, location of the power plant near a potential user may not be feasible.

(5) Heat quantities involved. For the most part, the quantity of heat used or needed for an individual application is only a small fraction of the heat rejected at a typical central station power plant.

(6) Quality of heat involved. The use of thermal energies for space heating, ice removal or prevention, and industrial process applications is generally at higher temperatures than the 100°F or below normally associated with waste heat.[17] To compensate, higher investment and operating expenditures would generally be needed.

(7) Utility restraints. To permit productive use of waste heat, changes may be required in the regulations that specify how a utility may function as an operating company.[6] Complications with rate schedules may arise.[18]

(8) Coordination requirements. For a major potential use of waste heat, such as for an urban energy center, coordination of planning and implementation among numerous entities must be achieved to a very substantial degree.

Rising fuel costs and intensified public concern with thermal pollution are apt to incite increased efforts to apply power-plant condenser-cooling water to useful applications in spite of the problems enumerated above. Just how widespread this utilization will be is impossible to predict with any confidence because of the complexity of interrelations among affected parties and the diversity of potential users. Opinions vary from pessimistic to mildly optimistic. A related indeterminate factor is the extent to which this waste heat will be used to replace energy that would otherwise be generated from some other source, as opposed to using the waste heat as a source of energy for an application or process that otherwise would not be employed. The relative amount of "replacement" versus "new" uses for waste heat is difficult to predict. Some understanding of the questions involved may be obtained from the following discussion of some potential waste heat applications. The coverage is necessarily brief because of limitations of space, but a number of documents have been published on the subject, some of which are included in the references listed at the end of this section.[17-25]

6C.3.3.1 Agriculture

6C.3.3.1.1 Open-Field Cultivation

> Thermal effluents from power plants potentially can be used in open-field agriculture to promote rapid plant growth, improve crop quality, extend the growing season, and prevent damage due to temperature extremes. Water, used for both irrigation and heating, can be applied through nozzles (spray irrigation) or through subsurface porous pipes. With these systems the farm acts as a large, direct-contact heat exchanger for the power plant, while the utility provides irrigation water to the farmer.[19]

This application has two significant advantages. Temporary interruptions in water flow due to power plant shutdowns can usually be tolerated, and the capital investment required is relatively modest. Potential problem areas include: (1) economic risks due to undemonstrated techniques and crop yields on large farms over extended operating times, (2) possible side effects relative to plant disease and pest control, (3) the limited number of power stations located in rural areas where inadequate rainfall requires irrigation or where soil warming features could be advantageously used, (4) potential radioactive contamination from use of water from nuclear plants, (5) unavailability of heated water for frost control during periods of power plant shutdown, (6) equating the quantity of water that could be beneficially utilized with the quantity discharged, (7) water consumption through evaporation and transpiration (though this problem would be weighed against the alternative choice of cooling towers), and (8) legal restrictions resulting from the combination of power production and irrigation.[19]

Irrigation water volume requirements vary widely depending on the time of year, the crops being grown, and the geographical location. For the United States, the maximum would be about 10.6 in. during the month of July for such crops as cotton, peanuts, soybeans, sorghum, and beans.[20] Assuming a 20% deep percolation and evaporation loss, the amount of water required from the power plant would thus peak at about 12,000 gpd per acre. Since the condenser cooling water circulation through a 1000-MWe steam-electric generating unit is about 1 to 1-1/2 billion gpd, as much as 80,000 to 120,000 acres would be needed to fully utilize the waste water from the unit. Power requirements for pumping would be about 204,000 horsepower[20] or the equivalent of 152 MWe.

Where soil heating is applied, a 1000-MWe plant, utilizing a closed-cycle cooling system with a 500-acre evaporative cooling basin, is estimated to provide the soil heat for a 5000-acre farm.[19] The FPC projects that 160,000 MWe of steam-electric generating capacity (fossil and nuclear) will be added in the western part of the U.S. during the period 1971 to 1990.[21] If the assumption is made that 10% of the new plants will be at sites in proximity to extensive agricultural areas and, further, that these areas require soil heat, then there would be a potential for the application of power plant water discharge to about 80,000 acres of farmland.

6C.3.3.1.2 Greenhouses

The principal incentive for the use of power plant condensate in greenhouses would be a reduction in energy costs to the grower. Benefits to the power plant operator (abatement of thermal pollution by means of a substitute heat rejection system and a market for waste heat) would be limited by the size of the greenhouse installation.

Estimates of the heat consumption in greenhouses range from 11,000 Btu/min per acre[19] to 80,000 Btu/min per acre.[22] For a median value of 45,000 with the assumption that one-fourth of the heat in the condenser cooling water will be absorbed in the greenhouse before the water is discharged to a cooling tower, cooling pond, or the original source, then 250 acres of greenhouses could use the cooling water from 400 MWe of generating capacity (6824 Btu of waste heat in the water per kWhr generated). The capital investment for the greenhouses would approximate $25 million.[19] One percent of the projected steam-electric generating capacity of about 1,600,000 MW by the year 2000 could thus accommodate 10,000 acres of greenhouses. About 7000 acres of greenhouses are in production today in the U.S.

Provisions would be needed for disposition of waste heat during summer months. Alternatives include full utilization of the power plant standard cooling system, cooling of the greenhouses by the use of evaporative pads, and open-field irrigation if siting circumstances permit the proximity of large fields and if irrigation is needed.

The following additional comments are found in ref. 19:

> There are many unanswered questions concerning the use of waste heat from power plants. Chemicals such as chromates used for water treatment in the cooling water system might affect the plants in a greenhouse. Similarly, the pollen from the greenhouse could possibly affect the cooling system. The determination of whether such effects will occur requires experimental studies. In the case of nuclear plants the real and imagined hazards of radioactivity must be considered, and public acceptance of products produced in such greenhouse complexes would have to be analyzed. Potential sources of activity in the cooling water would have to be considered and measuring devices installed to continuously monitor the water for radioactivity.

The most difficult questions to resolve appear to be those of institutional arrangements necessary for the financing and operating of such an enterprise in conjunction with the operating of a power plant. The organization and training of the greenhouse operating teams, agreements with the utility on shutdown schedules, provision for auxiliary heat supply, and protection of the power plant coolants from loss or fouling are several of the important problems. If risk insurance is common to greenhouse operation, the degree to which it might be affected by coupling to a power plant for heat would have to be determined.

All of these questions point to the necessity of conducting research or studies to resolve uncertainties which now exist. Although engineering questions can be resolved fairly easily, these and the biological and economic questions require demonstration projects with crops in a greenhouse facility.

6C.3.3.1.3 Animal Shelters

A well-established fact is that knowledgeable control of temperature, humidity, and ventilation can significantly increase the feed efficiency (lb gain/lb feed) and growth rate of the smaller farm animals.[19] Waste heat from power plants can be used for animal shelter temperature control (heating in winter, evaporative pad cooling in summer), although this idea has been tested only in experimental and research projects to date.

The waste heat from a 1000-MWe plant is sufficient to brood almost one billion broilers annually or farrow and finish about 10 million hogs. Because a typical broiler operation currently produces about 50,000 birds a year and a large hog operation produces about 5000 pigs a year, the potential for conservation of energy in this application apparently is very minor. However, there are advantageous prospects of reducing user feed and fuel costs, increasing food production, and reducing or dispersing, to some extent, the environmental impact of power plant thermal effluents.

There are also some problems associated with the use of condenser cooling water for animal shelter temperature control that would have to be thoroughly investigated before a commitment could be made to large-scale waste heat applications.

6C.3.3.2 Aquaculture

Webster defines aquaculture as, "The culture of sea, lake, and river foodstuffs, such as fish, oysters, seaweed, etc." Among the needs for successful aquaculture are temperature control, nutritious but inexpensive feed, fish waste control, and adequate oxygen supply.[19]

Thermal aquaculture involves the use of heated effluents to maintain optimal temperatures for growth and to produce high yields. In recent years power plant coolant water has been applied to aquaculture in a few instances (oyster culture on Long Island, lobsters in Maine, catfish in Texas and Tennessee, shrimp in Florida, and a variety of species in Japan). Much more experimental and demonstration data are needed to form a firm basis for commercial expansion. The potential depends not only on technical feasibility but also on market conditions. For example, the current U.S. per capita fish consumption of 10 lb/year (as contrasted to Japan's 100 lb/year) might increase as a result of the development of a new aquacultural industry based on advanced technology. Projections[19] show that by the year 2000 as much as 2% of heat effluents from U.S power plants may be applied to thermal aquaculture (assuming 10% of the total 10 lb/year per capita consumption will be supplied by thermal aquaculture). Corresponding land requirements would be about 15,000 acres (20,000 lb of live product per acre-year).

The use of power plant effluents for aquaculture could present the following problems:

(1) To assure reliability of heat supply, backup sources should be available in the event of power unit outages. Capability to switch rapidly from one source to the other is essential to prevent sudden temperature changes.
(2) Uncorrected chlorination in the coolant water might have toxic effects.
(3) At temperatures over 100°F, copper concentrations might occur in the discharge water.
(4) Water used from nuclear plants must be free of radioactivity.
(5) Provision must be made for treatment of fish wastes.
(6) Legal and regulatory requirements (with respect to water rights) and discharge of heated water must be met.

With respect to conservation of energy, the principal favorable feature of using power plant effluents for thermal aquaculture would be the elimination of the need to supply the necessary large quantities of heat from other sources. Power would be required, however, for pumping purposes and for fish farm utility services.

Thermal aquaculture will not diminish the amount of waste heat to be rejected from a power plant. The amount of heat finally returned to the water source would, however, be reduced to the extent of absorption in fish ponds, tanks, or troughs and of dispersion to the air during channel flow. Also, reduction in adverse environmental impact would take place through elimination of mining, processing, transportation, and use of such fuels as would have been used to generate heat for thermal aquaculture if power plant waste heat were not used.

6C.3.3.3 Urban Use

Energy in the form of heat may be applied to urban requirements in several major categories, such as space heating, water heating, air conditioning, sewage treatment, and industrial process steam consumption.

Heat supplied by an electric power plant can be waste heat or low-temperature heat. Waste heat is the heat contained in the condenser cooling water and is normally at temperatures below 100°F. Low-temperature heat occurs in steam obtained from either an "extraction" turbine or a "back-pressure" turbine. In an extraction turbine, a portion of the steam is removed at some point along the turbine after the steam has generated considerable electricity. With a back-pressure turbine, all of the steam is extracted after it has reached some desired temperature and before its full energy has been used for the production of electricity. Typical temperatures of extraction of back-pressure steam put to beneficial use would be in the range of 200 to 300°F. Although the efficiency of electricity production would be reduced by the extraction of steam, overall efficiency of energy use would be improved. Thermal and air pollution would be reduced, and fuel would be conserved.

For urban needs the potential for beneficial uses of waste heat from power plants appears to be quite limited in comparison with the potential for the use of low-temperature heat. Because modern power plants utilize all the energy that can be economically extracted from the fuel, the heat released to the environment from these plants is only a few degrees (10 to 30°F) above ambient temperatures. The ability to use heat effectively is a function of the temperature difference that is available, and when the difference is small, taking practical advantage of the heat is usually expensive and difficult.

A possible application would be district space heating and air conditioning by conveying the heated water through a piping system to residential and commercial buildings. Because the temperature is relatively low, substantial flow volume would be required, which would, in turn, necessitate larger piping capacity and pumping power than for an equivalent system using low-temperature steam. Heavy insulation would also be needed to minimize temperature loss with increasing distance from the power plant. The practicality of going to higher temperatures is illustrated by the district heating installation in the City of Vasteras, Sweden,[23] where the water emerges from the plant at 175 to 265°F and returns at 130 to 150°F; the geothermal system at Reykjavik, Iceland, with water at 194°F; and the Montreal Airport at 375 to 400°F.[24] The heating of secondary sewage treatment plants during the winter with waste heat from steam-electric plants is now being seriously considered for accelerating the process.[23]

There are a number of additional potential beneficial urban uses of power plant waste heat which, however, represent relatively minor or short-term energy usage and high capital costs. These include city street and sidewalk snow and ice removal, airport de-fogging, and airport de-icing. For example, the thermal discharge from a 1000-MWe plant could de-ice over two square miles of runway.[24]

With respect to the beneficial urban use of low-temperature steam from power plants, the potential applications are all those described above for waste heat plus at least two significant additions - industrial processing and the distillation of sewage. The objectives of distilling sewage would be twofold - demineralization and (if needed) enhancement of usable water supply. A model design[25] indicates a heat requirement of 1.2 million Btu/hr and a power need of 6 MWe for a distillation plant to supplement the natural water supply for a city of one million people. If, for purposes of arriving at an approximate projection of the potential impact, the assumption is made that by 2000 an urban population of 150,000,000 will be served by such distillation plants, then the total heat energy input would be about 180 million Btu/hr, or (at 8000 hr operation per year) the equivalent of 240,000 bbl of oil per year. More significant than the relatively modest conservation of fuel would be the contribution to the preservation of the quality of surface waters by the removal or reduction from sewage effluent of mineral contaminants such as ammonia, nitrates, and phosphates. The concentrated solid waste resulting from distillation can be incinerated for heat recovery or possibly used as fertilizer.[25] Considerably more research is needed, however, to overcome potential difficulties such as fouling of waste demineralization processes by organics or the control of ammonia and other volatiles.

Energy applied to industrial processes can be in the form of direct heat, process steam, or electricity. The production of process steam accounts for about 41% of industrial fuel consumption or 17% of total national fuel consumption.[26] To obtain a significant portion of this steam from the turbines of electric power plants rather than by direct combustion of fossil fuels under boilers at the industrial facilities would result in a considerable overall net saving of energy. For example, consider the hypothetical case of a turbine fully utilized for electricity production with a thermal efficiency of 40%. If an equivalent extraction turbine is used instead, with the point of extraction being selected so that the removed steam would have energy equal to 35% of the heat input to the turbine, the thermal efficiency of electrical production would drop from 40% to 35%, but the overall efficiency of energy use would be about 70% (35% plus 35%) rather than 40%. Similarly, with a back-pressure turbine designed for 250°F exit steam, the electrical efficiency would drop to 30% but the overall efficiency of energy use could be as high as 100%, depending on how effectively the exit steam is used.

The Interior Department projects a total energy input to the industrial sector in the year 2000 to be 58,000 trillion Btu (42,000 trillion Btu if electricity is excluded).[13] Assuming that the current 41% share for process steam will also pertain in 2000, there would be a theoretical maximum potential for the application of low-temperature steam from central station power plants to as much as 24,000 trillion Btu of industrial processing, or the equivalent of about 4 billion bbl of oil. The feasible level of application will be considerably less due to a number of factors, including the following:

(1) The steam source needs to be near the user. Losses in transit require higher initial steam pressures and temperatures, as well as increased capital investment in piping with greater distances. However, as the cost of fossil fuels increases, the incentive for capital investment in low-temperature steam lines will increase.

(2) Most individual industrial plant process steam requirements are in quantities that are minor compared to the steam production capability of a modern power plant. One of the few exceptions is the Midland Nuclear Plant, currently under construction, which is planned to deliver 4 million lb of process steam per hour to the adjoining Dow Chemical Company and, in addition, to produce 1300 MWe of power from two units. These units, without extraction of steam, would have the capability of producing 1600 MWe of power. Thus, the supply of process steam to meet the needs of one of the Nation's largest chemical complexes is equivalent to only 300 MWe of electric power supply.

(3) Most industrial process steam use is concentrated in a few industries. Estimates of the percentage breakdown of industrial process steam usage in 1980 are:[25]

	Percentage
Chemicals and allied products	39
Petroleum refinery and related industries	22
Paper and allied products	18
Food and kindred products	13
Other industries	8

(4) The petroleum refinery and related industries for the most part utilize internally produced fuel for processing requirements. One outstanding exception is the linkage for the past 15 years between the Linden Generating Station of Public Service Electric and Gas Company and the Baywater Refinery of Exxon. Designed to achieve improved economy of operation by providing extraction steam for refinery purposes, the system offers the equally valuable gain of raising the reported heat efficiency of the generation cycle from 39% to 54%. This increase is equivalent to reducing the waste heat burden on the environment by 25%.[18] A similar situation of internal fuel generation occurs to a lesser degree in the paper and allied products industry.

With increasing incentive to use extraction steam in view of rising fuel costs, industry, by the year 2000, might be obtaining as much as 10% of its process steam from power plants, in spite of the restrictions listed above. The actual degree of utilization is, of course, impossible to project with confidence. However, use of only 10% would still have the energy equivalent of more than 1 million bbl of oil per day. Partially offsetting this gain would be the need for more power plant capacity and the consumption of more power plant fuel to compensate for reduction in efficiency.

Advantages accruing to a utility as a result of furnishing process steam would be additional income (Consolidated Edison Company of New York reported $83 million total steam sales in 1972) and disposal of waste heat. A principal advantage to the user would be lower-cost energy. The public would benefit through conservation of fuel resources and less thermal impact on the environment. A significant reduction in the use of electricity is anticipated since there are few examples in industry of process steam being substitutional for electric heat.

6C.4 GROSS VS NET GENERATION OF ELECTRICITY

6C.4.1 Steam-Driven Auxiliary Equipment

An electric power plant generates more electricity (gross production) than it sends out over the transmission line (net production). The difference is the power required to run plant auxiliary equipment or for other in-house needs. If reduction of auxiliary electric power consumption proves feasible in the 1990's and later, an added amount of useful electricity could be sent out over the lines without increasing gross production, and the need for gross generation of power from LMFBRs (or other types of power plants) could be reduced by a like amount.

The efficiency of large turbine units can be improved by using steam instead of electricity to drive large power plant auxiliaries, such as pumps, fans, and air compressors. Power plant designers for some time have been using steam turbines to drive boiler feed pumps on large units. As an example of the possible further use of steam auxiliary drives, the efficiency of a 1000-MWe unit utilizing 3500-psig, 1000°F steam can be improved about 1/3 of 1% by using steam rather than electric motors to drive the forced-draft fans.[13] By employing steam drive to the extent technically feasible for other items of equipment as well, the overall plant efficiency could be improved by approximately 1/2 of 1%. Net generation from steam plants (fossil and nuclear) in the year 2000[12] is projected to be about 8 trillion kWhr of which about 80%, or 6.4 trillion kWhr, would be from base-load plants. A 1/2 of 1% improvement in efficiency would thus save about 32 billion kWhr, equivalent to the output of about five 1000-MWe units.

Adverse environmental aspects associated with expanded steam drive include those resulting from the mining, processing, fabrication, transportation, and installation of the steam piping required. These effects would have to be balanced against the beneficial environmental results associated with the need to burn less fuel (either fossil or nuclear) to produce a net amount of electricity, if auxiliary electric consumption in power plants were reduced.

6C.4.2 Energy Demands for Pollution Abatement and Environmental Control

Actions taken to preserve or improve the quality of the environment and to hold in check potential pollution of the land, water, and atmosphere will, in some instances, require added energy (mostly electrical) and therefore increased consumption of fuel resources. This subsection will first develop an estimate of the quantity of additional energy that will be required and, second, explore the extent to which this energy might be conserved through alternative approaches, less stringent standards, or tradeoffs by such measures as recycling of materials.

An obvious method of conserving a substantial portion of the energy required for environmental control would be limitation, voluntary or otherwise, in the total amount of energy consumed for this purpose. One survey[27] showed that in 1971 a group of large industrial and commercial users of electricity used 8.8 billion kWhr for pollution control. This use represented 7.3% of their total annual electrical requirements in that year. By 1977, this figure is expected to rise to about 10% of annual needs.

The 1970 FPC National Power Survey[21] forecast of growth in electrical generating capacity reflected to some extent consideration of power needs for environmental protection, but the acceleration of concern with the environment that has occurred since the survey was made will result in the need for more capacity than was projected. Among the factors that will contribute to the increase are the following:

(1) Control of air and water pollution from electric generating plants, power to operate control equipment and reduced plant efficiency.
(2) Electrical energy demands for widespread sewage disposal improvement.
(3) Electrical energy demands for meeting water pollution control standards in industrial processes.
(4) Where apartment buildings, commercial establishments, and factories are now using direct combustion of fossil fuels for space heating and process heating, a significant number may convert to electricity because of restrictions on the emission of particulates and the oxides of sulfur and nitrogen.

In the transportation sector, additional significant use of electrical energy may occur in place of the direct combustion of fossil fuels, with the dual objectives of conserving scarce resources and of attaining better control over environmental pollution by concentrating power generation in relatively few central station plants rather than burning fuel in a multitude of small units. Such applications could include the successful development and utilization of battery-powered automobiles and trucks, electrification of railroads, and the installation of additional metropolitan area rail rapid transit systems.

The amounts of electricity that will be required for the likely and possible applications listed above and the potential for reducing these energy needs for pollution control purposes are discussed below.

6C.4.2.1 Electric Generation Plants

To satisfy the environmental standards for a new 1,000-MWe generating plant[10] will require on the average an estimated increase of about 7.1% in the gross total energy input over the energy input for the same plant without particulate cleanup, sulfur oxide removal, and with once-through cooling. This difference is based on a heat rate (without environmental controls) of 9500 Btu/kWhr, an estimated additional energy input of 600 Btu/kWhr for environmental controls (mechanical draft tower, two-stage scrubber for 85% SO_2 removal, and a 99% efficient electrostatic precipitator), and the equivalent of about 60 Btu/kWhr to represent the energy required to manufacture the equipment used to control pollution. No increase in energy has been assigned to nitrogen oxide removal or disposal of any solid wastes that might be created. A second and less optimistic estimate of pollution control requirements* reports that the sulfur removal systems currently being advocated will add at least 20% to production costs. This estimate concluded that if experience to date is an indicator, sulfur removal will be achieved only at an enormous penalty in plant efficiency, in much higher operating costs, and perhaps most important, in the total quality of the environment.

The Department of the Interior projects[4] an energy input of 25,200 trillion Btu for fuel burning power plants in the year 2000. On the basis of the values given in the preceding paragraph, about 1800 trillion Btu of this total would be applied to onsite environmental control. With a heat rate in the range of 8900 to 10,200 Btu/kWhr (depending on progress made in improving plant thermal efficiency) the equivalent electric power production in the year 2000 for environmental control would thus be about 180 to 200 billion kWhr or the output of 27 to 30 generating units of 1000 MWe each, operating at a 75% plant factor.

The projected energy input for nuclear plants in the year 2000 is 49,230 trillion Btu from a mix of LWRs, HTGRs, and fast breeder reactors.[4] Because the combustion

*Testimony of Thomas A. Steele, Manager, Environmental Department, Dairyland Power Cooperative Co., before the Senate Public Works Committee on The Clean Air Act, May 13, 1974.

process is not involved, no energy for particulate or oxide removal would be needed. Assuming an average thermal efficiency (without environmental controls) of 36% or 9500-Btu/kWhr heat rate, the additional energy input requirements with a mechanical-draft cooling tower and equipment to limit release of radioactive effluents would be about 350 Btu/kWhr or 4%. Thus, the added electric power production in the year 2000 for environmental control at nuclear plants would be about 200 billion kWhr or the equivalent of the output of thirty 1000-MWe units operating at a 75% plant factor.

The above discussion shows that conservation of energy by reducing energy needs for power plant environmental control could be achieved in two principal ways. One would be to increase the proportion of power generated by nuclear plants and decrease that generated by fossil-fueled plants. For each 1000-MWe capacity switch there would be an annual saving of about 210 million kWhr. The second conservation measure would obviously result from a relaxation of standards established for atmospheric and water effluent limits. The reductio ad absurdum would be the elimination of all controls, thus saving up to 400 billion kWhr in the year 2000. Whatever relaxation, if any, that is actually placed into effect would be the result of social, political, technical, and economic considerations stemming from such factors as scarcity of certain fuel resources and escalating fuel costs.

6C.4.2.2 Sewage Disposal Improvement

During the next decade, anywhere from $10 billion to $80 billion will be spent on the construction of improved sewage disposal facilities. The requirements for electrical power for these facilities will depend on the methods of waste treatment adopted. Current sewage treatment methods use about 50% of their electricity requirements for pollution control purposes. A survey by the Edison Electric Institute (EEI) indicated that sewage disposal used about 1 billion kWhr in 1971 and 1.3 billion in 1972, and EEI projects use of about 3.6 billion kWhr annually by 1977. Subsequently, greatly increased facilities installation could bring the annual requirements by 1990 to as much as 40 billion kWhr and by the year 2000 to 50 billion kWhr. The potential for reducing these requirements is difficult to assess but would, as in the case of electrical power plants, be dependent upon technical and economic factors in the development of more efficient equipment and on social and political attitudes toward modification of pollution standards.

6C.4.2.3 Industrial Water Pollution Control

As noted above, the EEI surveys in 1971 and 1972 indicated that about 7% of current industry electric power use is strictly for pollution control, but this figure does not reflect future increases that may result from recently enacted water-quality legislation. Reference 4 projects industrial use of electrical power in 2000 will be 4.6 trillion kWhr. The anticipated 10% application to pollution control, if continued, would require at that time 0.46 trillion kWhr. However, conformance to the new water pollution control standards may increase this figure by as much as 50% to a total of up to 0.7 trillion kWhr. This total would represent the output of over 100 1000-MWe units operating at 75% plant factor. Again, the benefits of conservation could be substantial, but the likelihood of their achievement and possible magnitude are at this time difficult to predict.

6C.4.2.4 Conversion of Direct Fuel Burning to Purchased Electricity

There is no readily apparent method of determining what might be a reasonable additional capacity figure to represent the future requirements in this category, either from usage of electricity rather than direct combustion of fossil fuels for space heating in buildings or from the transportation sector, where a similar shift of fuels may be contemplated for vehicular transportation. The pressures towards use of centrally generated electricity as a less polluting source of energy will be countered to some extent by the fact that it is a much less efficient means of energy utilization. For example, for every Btu of gas burned in a home for space heating, about 2 Btu of gas (or coal, oil, nuclear) would have to be burned to produce electricity for transmission to a home and used in an electrical resistance heater to produce the same heating value as the gas. With fuel costs increasing significantly, the relative environmental and economic characteristics of different fuel utilization mechanisms takes on a different meaning. This fact, coupled with potential future changes in the technical feasibility of powering vehicles by electricity on a large scale, indicates that in the future fuel utilization and economics would take on added importance relative to environmental characteristics, thereby apparently lessening any shift toward conversion to centrally generated electric heat rather than direct combustion of fossil fuels.

6C.5 TRANSMISSION AND DISTRIBUTION

In discussing the conservation of resources as affected by the planning and operation of electric utility transmission and distribution systems, note that the opportunities for savings in this sector are not large relative to those in other parts of the overall electric utility system. A total of 1465 billion net kWhr of electric energy was generated and received by the privately owned class A and B electric utilities in the U.S. in 1971.[28] Of this, 103.3 billion kWhr was lost in transmission and distribution (not counting distribution losses for 209 billion kWhr sold at wholesale). Assuming 4% distribution losses for the wholesale energy, the total of transmission and distribution losses on the systems of these class A and B utilities is about 7.6% of total net energy generated and received or 8.3% of the total energy utilized. These losses are about evenly split between the transmission and distribution systems.

The 8% or so of transmission/and distribution losses is small relative to the 60% or greater losses experienced in the energy-conversion (generation plant) stage of electric utility system operation. However, about 27,000 MW of utility power were generated solely to cover the transmission and distribution losses associated with meeting the 337,000-MW 1973 U.S. summer peak load; efforts to reduce these losses merit attention.

Losses in transmission and distribution systems consist of load losses and no-load losses. The load losses occur as heat produced by current flow through the electrical resistance of the line conductors and are proportional to the resistance and to the square of the current (I^2R). These losses constitute the principal losses in transmission systems. In cables, load losses can also occur due to currents induced in cable shields and metallic conduits. No-load losses occur whenever there is voltage on the transmission and distribution systems and consist of magnetizing losses in transformers, shunt reactors, and other iron core equipment; dielectric losses in capacitors and cables; and corona losses due to high potential ionization of the insulating medium.

6C.5.1 Transmission Systems

The primary function of the transmission system is to transport bulk electric energy from generation stations to the main substations serving load areas. The transmission system consists of (1) overhead transmission lines and underground cables operated at 69,000 volts (69 kV) or higher; (2) terminal equipment consisting of high voltage transformers, converters, switchgear, lightning arrestors, inductive reactors, and capacitors and (3) control and metering systems, including meters, relays, communications equipment, and computers. In addition to providing transmission within individual utility service areas, transmission systems also generally interconnect adjacent electric utility systems to achieve better operating economics and reliability of service.

At present, overhead transmission predominates in the U.S. Less than 1% of the Nation's electric power transmission lines are installed underground.[29] Largely responsible for this situation is the fact that the installed costs of underground cable are 5 to 20 times greater than those of overhead lines,[30] depending on circuit voltage and area conditions. This situation is likely to continue through the rest of this decade, with some small percentage gain in cable installations, principally for extending high power capacity transmission into metropolitan load centers.[31] The greatest increase in transmission circuit capability during the 1970's is expected to occur in extra-high-voltage overhead lines (345 kV to 765 kV), as shown in Figure 6C.5-1.[29]

New technological approaches to transmitting electric energy, namely high-voltage direct-current overhead lines and compressed gas cable, have been introduced in the last few years but are not expected to make any significant impact in this decade. These innovative technologies are discussed later.

There are a number of methods for reducing transmission losses, principal among which are the raising of transmission voltages, the reduction of line currents, and the reduction of line resistances. Involved in developing these options are: extra-high and ultra-high voltage alternating-current (AC) transmission systems; high-voltage direct-current systems; various innovative cable systems, including cryogenic systems; and power system control. The status and prospects of these are discussed in turn.

Several of these methods are cited as being justified of research and development support in the national energy research and development program outlined in ref. 2. The goal of these program elements would be to conserve energy by developing more efficient and reliable means of transmitting and distributing energy to meet future demands in a safe, environmentally acceptable way. Approximately $80 million would be spent on energy transmission and distribution in the next five years under this program, specific elements of which are discussed in the following sections.

6C.5.1.1 High Voltage AC Systems

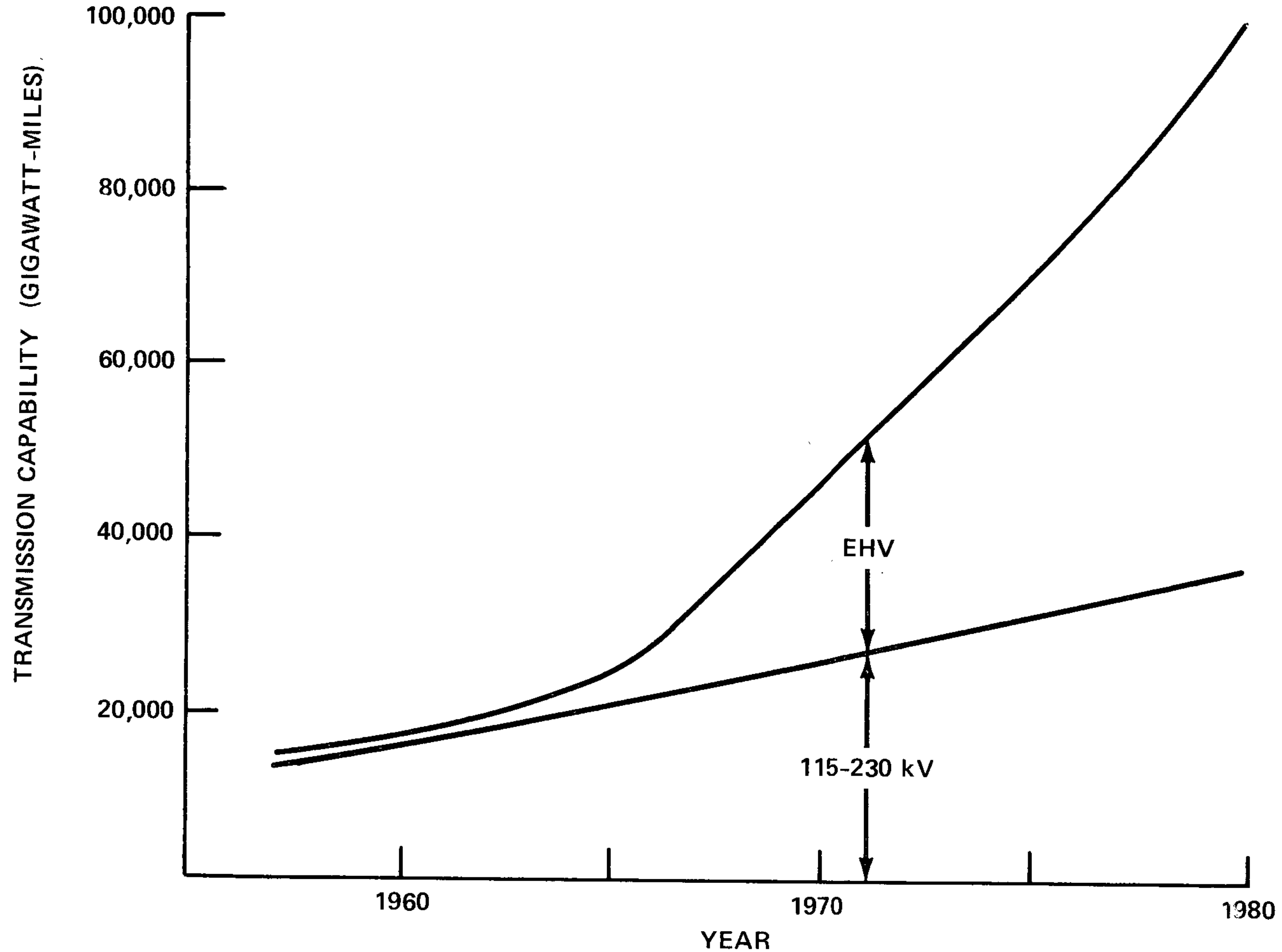
The relationship between overhead transmission-line voltage and line losses is shown in Figure 6C.5-2.[32] Obviously, the trend to extra-high-voltage (345 to 765 kV) overhead transmission lines will assist appreciably in reducing transmission losses. The magnitude of this trend per transmission voltage and circuit capability in gigawatt*-miles (GW-miles) is shown in Table 6C.5-1. If the circuit capability in gigawatt-miles for each voltage in the table is multiplied by the corresponding relative loss from Figure 6C.5-2 and the products summed for a particular year, the result is a measure of the transmission losses that could be expected for that year for full loading of the in-service circuit capability of that year. Dividing the result by the total in-service circuit capability for that year of the voltages considered yields the specific loss of transmission for that year. Comparison of the specific loss for one year with that of the preceding year gives a measure of the reduction in overhead transmission losses to be expected from the trend to higher voltages shown in Table 6C.5-1. The results of such a comparison are shown in Table 6C.5-2.

Table 6C.5-2 shows the gains in more efficient transmission as voltages are raised are not great; the saving in losses totals 35 billion kWhr over the seven-year period 1974-80. This amount of electrical energy could be generated over that time by a baseload generating unit rated at approximately 760 MW. As the incremental gains in loss reduction are expected to be less with voltage rises into the ultra-high range (Figure 6C.5-2), the gains in overhead AC transmission efficiency are not expected to have significant impact on conservation of energy. High voltage lines will be installed primarily to transmit greater blocks of power economically within land usage constraints.

I^2R losses for a given length of line can be reduced by increasing the size of the conductor, thereby reducing its resistance. Reduction in conductor resistance reduces I^2R losses proportionately for transmission of a given amount of power. However, increasing conductor size is practiced primarily to increase circuit power capability, as in the reconductoring of existing lines, rather than to reduce losses and is not expected to result in smaller losses per unit of power transmitted.

I^2R losses in AC transmission lines can be reduced by increasing the power factor of the line. In this case synchronous condensers or banks of static capacitors are installed in the system primarily to supply the nonpower currents required by the

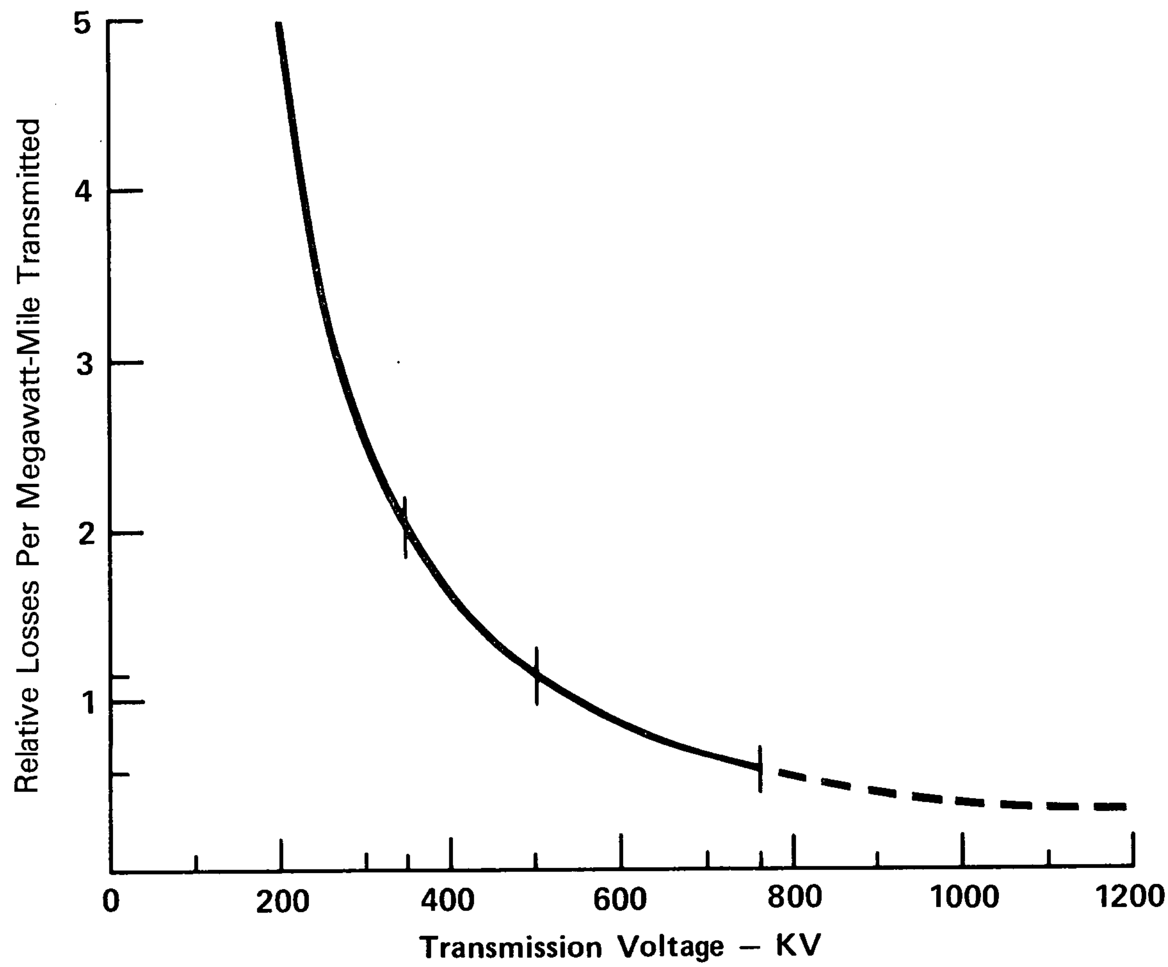
*Gigawatt = 1000 megawatts.



NO. E: EHV=EXTRA HIGH VOL E

TRANSMISSION CAPABILITY

Figure 6C.5-1



TYPICAL TRANSMISSION LOSSES

Figure 6C.5-2

Table 6C.5-1

OVERHEAD TRANSMISSION CIRCUIT CAPABILITY IN-SERVICE, IN GIGAWATT-MILES[a]

(Survey Sample Adjusted to National Totals)

Year	AC (kV)					800-kV DC	Total	Difference (GW-miles)
	115-161	230	345	500	765			
1957	9,791	3,969	968	0	0	0	14,728	702
1958	10,226	4,303	1,240	0	0	0	15,769	1,041
1959	10,487	4,579	1,289	0	0	0	16,805	586
1960	10,842	4,931	1,534	0	0	0	17,807	1,002
1961	11,310	5,658	1,694	0	0	0	18,862	1,355
1962	11,650	6,166	2,159	0	0	0	19,975	1,313
1963	12,121	6,657	2,772	0	0	0	21,530	1,575
1964	12,398	7,472	2,977	0	0	0	22,847	1,297
1965	12,753	7,845	3,023	766	0	0	24,984	2,437
1966	13,089	8,812	4,471	2,086	0	0	28,458	3,474
1967	13,482	9,511	5,471	4,699	0	0	33,463	4,705
1968	13,847	10,162	6,533	7,291	0	440	38,273	5,110
1969	14,221	10,744	8,344	8,020	165	879	42,484	4,211
1970	14,533	11,183	9,816	9,506	978	1,343	47,419	4,985
1971	14,895	11,823	11,192	11,018	1,743	1,343	52,014	4,595
1972	15,347	12,576	12,779	12,751	2,573	1,343	57,369	5,355
1973	15,741	13,290	14,023	14,186	2,905	1,343	61,488	4,119
1974	16,157	14,170	15,499	16,027	3,443	1,343	66,639	5,151
1975	16,500	14,978	17,227	17,410	3,593	1,343	71,051	4,412
1976	16,776	15,883	18,802	18,797	4,000	1,343	75,691	4,550
1977	17,085	16,540	20,456	20,640	5,963	1,343	82,029	6,428
1978	17,401	17,379	21,808	22,054	6,996	1,343	86,983	4,954
1979	17,685	17,934	22,476	26,218	8,538	1,343	94,244	7,261
1980	17,997	18,561	23,838	28,967	9,520	1,343	100,226	5,982

[a]Source: "Third Biennial Survey of Power Equipment Requirements of the U.S. Electric Utility Industry, 1971-80," National Electrical Manufacturer's Association, 1972.

Table 6C.5-2

PROJECTED ENERGY CONSERVATION THROUGH HIGHER OVERHEAD TRANSMISSION VOLTAGES FOR THE PERIOD 1974-1980

Year	Loss Reduction (%)[a]	Utility Generation (kWhr)[b]	Savings in Losses (kWhr) total from 1/1/74
1974	1.39	2000×10^9	7.77×10^9
1975	0.47	2140×10^9	2.40×10^9
1976	0.47	2290×10^9	2.15×10^9
1977	2.84	2450×10^9	11.12×10^9
1978	0.98	2620×10^9	3.09×10^9
1979	2.96	2800×10^9	6.64×10^9
1980	1.52	3000×10^9	1.82×10^9
TOTAL			34.89×10^9

[a] Loss reduction per gigawatt-mile compared with previous year.
[b] Projected at 7.0% annual rate of increase over 1747 billion kWhr generated by U.S. electric utilities in 1972 (Federal Power Commission).

transmission line and the electrical loads connected to it, thereby decreasing the nonpower currents that otherwise would have to be supplied by the generators and reducing line currents and losses in the process. Power factor correction is already employed extensively for other more urgent purposes, such as increased power loading of generators and lines, system voltage regulation, and reduced investment in system facilities. This correction is expected to keep pace with increases in transmission facilities and is not expected to be an option for conserving energy.

Another way to reduce transmission losses is to shorten transmission lines. Shortening the lines physically is dependent on system planning, particularly the selection of suitable generation sites. In such planning, concern about system losses is usually secondary to economic, environmental, reliability, and public acceptance considerations.

Generation in most U.S. electric utility systems is fairly well dispersed to match load center locations, so that the opportunity is small for shortening lines and reducing losses in future bulk power system expansion relative to the present situation. An appreciation of the effect on transmission system losses of the opposite situation--long lines from large mine-mouth generating stations to distant load centers--is afforded by the data in Table 6C.5-3. This table, taken from the North Central Power Study, shows how system losses increase from 3.3% for 3000 MW to 6.66% for 43,000 MW transmitted from a single generation site to load centers varying from 200 to 815 miles distant.

Table 6C.5-3

ENERGY INPUT AND SYSTEM LOSSES

Generation Capacity (MW)	Energy Generated (MW-years/year)	System Loss (MW)	System Loss (%)	System Losses (MW-years/year)
EAST				
3,000	2,550	100	3.30	76
10,000	9,100	511	5.11	435
20,000	18,400	1,266	6.33	1,100
40,000	36,800	2,704	6.76	2,360
43,000[a]	36,500	2,864	6.66	2,500
WEST				
1,000	850	9	0.90	7
3,000	2,745	36	1.20	31
10,000	9,200	183	1.83	159

[a]Energy for pumping was obtained from the generating complex during offpeak periods and would be about 1000 MW-years/year.

Electrical losses of lines can be reduced by the introduction of series capacitors in the lines to counteract their inductance. This action tends to shift power away from low-capacity, high-loss lines in the network into the more efficient, higher voltage lines having the series capacitor compensation, with consequent reduction in total network losses.[32] Utilities are planning to double present series capacitor installations over the 1973-1980 period.[29] To estimate how much this may reduce losses without computer studies of the systems involved is not feasible; however, the effect is not expected to be significant in terms of national energy requirements.

The no-load losses of transmission lines, principally corona losses, are small compared to I^2R losses. Corona losses become worse on AC overhead lines during rainy conditions but on the average are still only on the order of a few percent of line load losses. Corona losses are generally higher for ultra-high voltage lines than for lower voltage transmission, and this factor is significant in the economics for selecting optimum transmission voltage.

Economic dispatch of electric energy in bulk power systems is being implemented widely in U.S. electric utilities. The output of the generators on the system is scheduled in such a way as to minimize the overall cost of delivering electric energy to the consumer. As cost is directly related to fuel consumption, including energy generated to supply transmission losses, the effect is to minimize fuel consumption in generation-transmission systems.

Although placing transmission lines underground is not expected to be extensive in the near future because of economic reasons, cable systems are a means of saving on transmission energy losses. Conventional high pressure, oil-filled pipe-type high-voltage cables are very efficient conductors of electric energy. Over a distance of 10 km, for instance, the total losses (I^2R losses and dielectric losses) at full-load current amount to as little as 0.2 to 0.3% of the power transmitted.[33] Because very few cables carry full load continuously and because the conductor loss is proportional to the square of the transmitted power, cable losses are generally even less than the percentages mentioned. This low loss is enforced on the conventional self-cooled cable systems by the difficulties encountered in dissipating the heat (losses) generated in the cable to the surrounding soil and eventually to the atmosphere.

The main opportunity for new application of transmission cables should be their extension through high-density suburban and urban areas to feed new loads. For this service, conventional self-cooled high-pressure oil-filled cables at 345 kV (paper insulation) and 500 kV (synthetic insulation) would have permissible total losses about two-thirds those of overhead lines of the same voltage rating and equivalent conductor sizes.

If 75% of the new load between 1973 and 1980 is assumed to be supplied from urban main substations and 50% of this is supplied equally over new 345-kV and 500-kV high-pressure oil-filled cables averaging 10 miles in length, the saving in transmission losses in 1980 would be only about 30 MW compared to serving the new urban load only by overhead lines. In the following decades, the requirements for placing lines underground probably will be met with the advanced cable systems discussed later.

Despite what appears to be only limited potential for direct conservation of energy through improvements in high-voltage AC transmission technology, some research in this area is justified, as noted in ref. 2. Thus, under the proposed program, new or improved technology for AC (and DC) bulk power transmission systems would be developed to provide the capability to double the present capacity (with further eventual increase to 4 to 10 times present capacity) economically and without environmental degradation. The need for this capability is underscored by the projection that current technology applied to the anticipated need for electric power in 1985 and 2000 would result in a doubling and quadrupling, respectively, of power lines and auxiliary facilities. The research objectives, if attained, would allow the transmission and distribution of the power with fewer, higher capacity lines. Program elements during the next five years would include prototype 1100-kV AC overhead transmission lines and a 100-MW DC terminal demonstration project. While these activities would, as noted above, be implemented primarily for other than energy conservation objectives, some spin-off advantages in this regard may be expected.

6C.5.1.2 High Voltage, Direct Current Systems

High-voltage direct-current (HVDC) systems are receiving increased attention for both overhead and underground transmission because of their ability to transport more electric energy per unit width of right-of-way (greater energy density) than with an equivalent AC line.[34] Because of the absence of AC reactive (nonpower) currents and the resistance-increasing skin-effect experienced with AC transmission, the I^2R load losses of HVDC systems are less than that of extra-high-voltage AC lines for transmission of a given amount of power, as are the no-load losses due to the practical elimination of AC-induced dielectric losses. If HVDC and extra-high voltage overhead lines are built with the same insulation level and conductor size and operated at voltages that produce equivalent electrical stressing of the insulating medium (500-kV AC vs 800-kV DC, for instance) the HVDC-line losses would be about 65% of the AC-line losses for transmission of a given amount of power.[32] This advantage in line losses will be partially offset, however, by losses in the HVDC conversion terminals, which are on the order of 4-1/2 times those resulting from AC transformation. At the comparison voltage levels mentioned (500-kV AC vs 800-kV DC), the HVDC overhead line would have to exceed 300 to 400 miles in length before its losses, including those of the conversion equipment at its terminals, would be less than those of an extra-high-voltage AC line with voltage transformation at its terminals.

The economics of HVDC systems favor its use instead of extra-high-voltage AC systems for large amounts of power transmitted over long distances--in excess of 300 to 400 miles for overhead lines and 30 to 50 miles for underground cables.[34] These distances correspond to distant generation sites (hydro stations, mine-mouth thermal plants, and nuclear power parks), where HVDC overhead lines might be used, and long runs through populated or natural beauty areas, where underground DC transmission might be appropriate. The future proliferation of such distant generation is problematic and the magnitude of underground DC transmission into heavy load areas may be small compared with that of AC transmission. The choice of AC vs DC will be made on a case-by-case basis. To know at present how extensively HVDC systems will be introduced into U.S. systems and what the effect might be on transmission losses is difficult.

6C.5.1.3 Innovative Underground Transmission

Research and development is being conducted on new means of transmitting bulk electric energy underground so as to increase circuit capabilities and operate at voltages compatible with overhead systems while achieving better economics. Principal among these approaches are forced cooling of conventional high-pressure oil-filled cables, compressed-gas cable systems, cryogenic cable systems (both cryoresistive and superconducting), and microwave (waveguide) systems.

During the 1980's, there is likely to be increasing demand for higher capability circuits (up to 5000 MW by 1990) to carry electric power into suburban and urban load centers. Forced cooling of conventional cable and compressed gas and cryoresistive cable systems will probably share this application. Beyond 1990 the need will grow for even greater circuit capabilities, perhaps 10,000 MW and greater,[30] with the ability to transmit electric energy with very low loss for considerable distances, perhaps hundreds of miles. Superconducting cable would be expected to fill this role.

The choice of cable system for each underground application would most likely be determined more by consideration of economics, space and routing requirements, and reliability than by losses. Operating parameters[30,35,36] of the various types of innovative systems are shown in Table 6C.5-4. Note that losses are greater for forced-cooled cables and for the microwave systems than losses of naturally cooled conventional cables. Therefore, the only saving in electric energy losses to be expected would be from substitution of superconducting cable systems for others after 1990 or so.

A projection of energy conservation using superconducting cables for the period 1990-2000 is shown in Table 6C.5-5.[35] Based on the relative energy dissipations indicated in Table 6C.5-4, about 700,000 MWhr would be saved if the underground circuit additions over the period 1990-2000 were in superconducting AC cable rather

Table 6C.5-4

POWER LOSSES IN UNDERGROUND POWER SYSTEMS

System	Maximum Rating Power (MVA)	Power Loss (% per mile)
High-pressure, Oil-filled Cables (345 kV)		
Naturally cooled	450[a]	3.1×10^{-2}
Forced-cooled	1,020[b]	4.3×10^{-2}
Compressed-Gas Cable (500 kV)		
Naturally cooled	2,200[b]	1.3×10^{-2}
Forced-cooled	6,500[b]	4.5×10^{-2}
Cryoresistive Cable		
Nitrogen cooled (500 kV)	3,500[c]	5.6×10^{-2}
Hydrogen cooled (500 kV)	3,500[c]	4.3×10^{-2}
Superconducting Cable		
AC	3,000[a]	5×10^{-3}
DC	10,000[b]	4.5×10^{-4}
Microwave (waveguide)	10,000[b]	6×10^{-2}

[a]Source: "Cryogenic Transmission," Task Force on Technical Aspects (E. B. Forsyth, Chairman) of the Technical Advisory Committee on Conservation of Energy, Federal Power Commission, for updating of 1970 National Power Survey, Table 1, p. 12.

[b]Source: A. D. Little, Inc., "Underground Power Transmission," Electric Research Council, October 1971, Table 4.1, p. 4.5.

[c]Source: "Resistive Cryogenic Cable," Phase B Report, General Electric Co., for EEI Project RP 78-6, May 1970, Table 4, p. 30.

than conventional self-cooled cable. This savings is equivalent to the 10-year output of a generator rated at approximately 10 MW. The saving would be less if the superconducting cable were selected to replace compressed-gas cable. Nevertheless, for economic and aesthetic reasons as well as conservation goals, underground transmission is generally considered worthy of further investigation and support. "The Nation's Energy Future"[2] therefore proposes the development of underground transmission systems capable of matching future overhead systems in both power capacity and voltage with as low a cost differential between overhead and underground as possible. specific activities to be pursued under this program within the next five years include developing and completing four improved types of underground cables for commercial use and conducting model tests

Table 6C.5-5

PROJECTED ENERGY CONSERVATION USING SUPERCONDUCTING CABLES FOR THE PERIOD 1990-2000

Year	U.S. Generation Capacity (MW)	Power Plant Construction (MW/year)	Circuit-Miles of Underground Transmission Added per Year	Total Circuit miles of Underground Transmission	Total Circuit Miles of Superconducting Underground Transmission	Total Energy Conserved by Year 2000 in Superconducting Circuits[a] (MWhr)
1990	1.0×10^6	7×10^4	800	10,000	0	
1995	1.4×10^6	1.0×10^5	1000	14,000	100	
2000	1.7×10^6	1.3×10^5	1200	20,000	300	7×10^5

[a]Based on 2000-MVA capacity and 65% load factor.

on superconducting cables. If successful, these efforts may result in the underground transmission of a substantial portion of the electrical power produced toward the last decade of this century.

6C.5.2 Distribution Systems

The distribution system takes the electric energy from the transmission system (at the low voltage side of the latter's bulk-power receiving substations) and transports it to points of utilization. The typical U.S. distribution system consists of subtransmission lines (usually ranging from 69 to 138 kV), primary distribution substations, primary distribution lines (2.4 to 34.5 kV), distribution transformers, secondary distribution lines (120 to 240 V), and service lines to residential and commercial customers. Large commercial and industrial customers usually are supplied at primary distribution or even subtransmission voltages.

Distribution systems may be constructed as overhead systems, underground systems, or, as is usually the case today, a combination of both. The trend is toward putting more lines underground, particularly for the primary and secondary distribution systems feeding suburban loads.[37] For many years, these systems have been designed to operate with minimum losses consistent with the economic use of material and within environmental and mechanical limitations. Some of the research and development on underground transmission systems as described above in Section 6C.5.1.3 would be applicable also to underground distribution systems and may be expected to improve the technology for the latter.

Losses in distribution systems consist of load losses and no-load losses, as explained previously. The proportions of these losses within the overall system are approximately as follows:

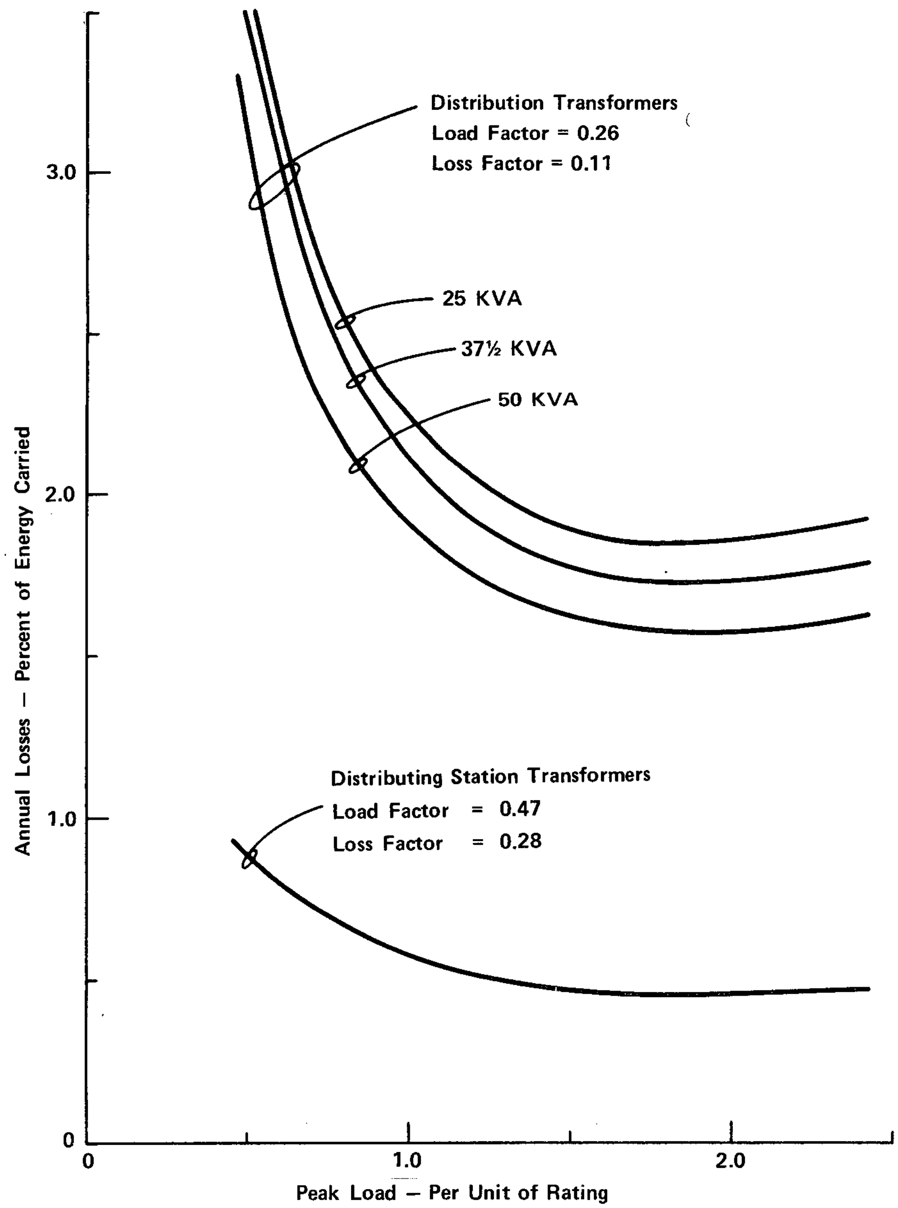
(1)	Subtransmission System	0.48%
(2)	Distribution Substations	0.47%
(3)	Primary Distribution System	0.82%
(4)	Distribution Transformers	2.04%
(5)	Secondary Distribution System	0.15%
(6)	Service Lines to Customers	0.03%
	Total Distribution (Approximately 4.0%)	3.99%

Obviously, the greatest losses occur in the distribution transformers, followed by the primary distribution lines feeding these transformers.

Losses in distribution transformers can be reduced by optimizing their loading. The relationship of transformer losses to transformer loading is shown in Figure 6C.5-3 for transformers of present designs.[38] The losses are higher for lightly loaded transformers because in that range their approximately constant no-load losses are higher per unit of load. The optimum range for loading transformers from the point of view of losses would be from about 160% to 200% for distribution transformers and 140% to 230% for primary distribution station transformers. Transformers are usually loaded up to the lower end of these ranges to prevent excessive system voltage drops and shortening of transformer service life. However, to emphasize energy conservation, consideration could be given to increasing transformer loading when it is below the optimum for losses.[37]

A measure of the conservation of energy that could be achieved by optimizing the loading of distribution transformers is estimated as follows. In 1985, peak loading of distribution transformers is assumed to average 120% of unit rating.[38] In Figure 6C.5-3, this value corresponds to annual losses for a 50-kVA transformer of 1.75% of energy carried. Assume further that the loading of the distribution transformers on the system is progressively increased after 1975 at 5.79% per annum until 160% average peak loading is achieved by 1991, after which the loading is held at this point to achieve near minimum transformer energy losses. At 160% 160% peak loading, the annual losses for the 50-kVA transformer of Figure 6C.5-3 are 1.59%, 0.16% lower than for 120% peak loading. If the annual reductions in 50-kVA distribution transformer losses are taken as the average for U.S. systems that can be achieved by the increased loading assumed and these reductions are multiplied by the corresponding annual electric energy projected to be carried by all distribution transformers in the U.S., the loss savings shown in Table 6C.5-6 are the result. The total savings in distribution transformer losses for the years 1986 through 2000 would be almost 65 billion kWhr. By the year 2000 the annual saving in losses would be approximately equivalent to the generating capacity of an 1100-MWe turbine generator. Notwithstanding the above discussion, it has been suggested that most utilities already maintain average transformer loadings at about 160%. In such instances, the estimates of energy savings that can be achieved by "optimizing" the loading of distribution transformers as reported above will be too high, and a lesser savings, if any, will result.

The only significant losses in overhead primary distribution power lines are the load losses. They may be reduced by decreasing the current or the resistance.



TRANSFORMER ENERGY LOSSES

Figure 6C.5-3

Table 6C.5-6

SAVINGS IN DISTRIBUTION TRANSFORMER ENERGY LOSSES

Year	Transformer Peak Load (%)	Loss Saving (%)	Distributed Energy[a] (Residential and Commercial) (billions of kWhr)	Saving in Losses (billions of kWhr)	Saving in Capacity[b] (MW)
1985	120.0		1820		
1986	126.9	0.04	1925	0.77	127
1987	134.2	0.07	2036	1.43	237
1988	142.0	0.11	2154	2.37	392
1989	150.2	0.13	2279	2.96	490
1990	158.9	0.16	2411	3.86	639
1991	160.0	0.16	2551	4.08	675
1992	160.0	0.16	2699	4.32	715
1993	160.0	0.16	2855	4.57	756
1994	160.0	0.16	3020	4.83	799
1995	160.0	0.16	3195	5.11	845
1996	160.0	0.16	3380	5.41	895
1997	160.0	0.16	3576	5.72	946
1998	160.0	0.16	3783	6.05	1001
1999	160.0	0.16	4002	6.40	1059
2000	160.0	0.16	4235	6.78	1122
			Total	64.66	

[a]Assumes 50% of total U.S. utility electric energy sales. These sales are assumed to increase at a yearly compounded rate of 5.79%.

[b]At 75% plant capacity factor and 8% losses in transmission and distribution systems.

As indicated in the discussion of transmission systems, current in a power line can be reduced by increasing the line voltage or by raising the system power factor. For distribution of a given amount of power, the saving in line losses will be proportional to the square of the reduction in line current. However, primarily to maximize the power capability of distribution lines and improve system economics, utilities have been converting to higher distribution voltages[37] and have installed many power factor correction capacitors to raise distribution system power factors. A secondary benefit has been a reduction in distribution line losses. To achieve the primary benefits stated, utilities will continue to raise the voltage of individual distribution lines and install more capacitors, with consequent reduction in line losses; such action will not constitute an independent option for conservation of energy.

Reduction in conductor resistance reduces load losses proportionately. For distribution circuits, this reduction can be achieved by changing the conductor material or increasing the conductor size. In recent years, aluminum has been the material most used for conductors in distribution systems, based on physical characteristics and economics. Other materials are available but are not expected to challenge aluminum's position. For distribution purposes, the practical way to reduce the resistance is to increase the conductor size. Conductor size normally is based on system economics considering projected load increases, provision for load transfer during line outages, maximum-allowable voltage drop, and installation and loss costs and is limited by current-carrying capacity and ecological and mechanical considerations. The effect of these factors has resulted in a conductor size generally larger than that necessary to carry the normal load, with the result that resistance losses in existing distribution systems tend to be relatively low and installing still larger conductors will further reduce energy losses only to a limited degree.[38]

6C.6 UTILIZATION OF ENERGY

Conservation of energy at the point of end-use has until recent years received little attention in comparison with that given to conservation in energy supply and conversion processes. Whereas research and development on more efficient ways to generate electricity or to burn fossil fuels has been extensive, programs to conserve energy in the manufacture of goods and the provision of services for residences and commercial buildings have been relatively insignificant until recently, despite the magnitude of the potential for energy savings.

Energy economics in the United States have been largely responsible for this inattention to conservation of energy in its end uses. Until very recently the gross national product has been wedded to cheap, abundant energy. Electricity, for instance, over the last several decades became an increasingly better bargain for the production of goods and services, and only in the last several years has its price trended upwards, largely due to fuel and equipment costs related to minimizing environmental impacts. This availability of energy that was inexpensive relative to other components of production cost discouraged investment in more energy-efficient buildings, equipment, and processes. Where energy was in essentially unlimited supply at low prices, the trade-offs in economic justification favored low initial investment rather than more efficient, less costly operation. Now, with rising energy costs and sometimes limited supplies of fuels, purchasers are becoming increasingly aware of the lifetime operating costs and energy consumption of the products purchased, as well as their initial costs. Technological and managerial steps to foster more efficient utilization of energy at the points of end-use will reduce operating costs and extend fuel availability.

6C.6.1 Approaches to Energy Conservation

This section on utilization of energy examines several studies that have been performed on approaches to energy conservation (most of which emphasize conservation in end use), looks at some of the more fruitful areas for achieving substantial energy savings, and establishes the basis for the conclusions on energy conservation which follow.

Energy consumption by end-use in the United States as determined in one authoritative study[39] is shown in Table 6C.6-1. During the interval 1960-1968, the Nation's annual consumption of total energy increased from 43.1 to 60.5 quadrillion Btu at a growth rate (compounded) of 4.3% per year. The annual growth rate in electricity usage during this period was approximately 6%. The industrial sector accounted for the greatest use of energy, 41.2% of the national total in 1968, while the commercial

Table 6C.6-1

ENERGY CONSUMPTION IN THE UNITED STATES BY END-USE
1960-1968
(Trillions of Btu and Percent per Year)

Sector and End Use	Consumption 1960	Consumption 1968	Annual Rate of Growth (%)	Percent of National Total 1960	Percent of National Total 1968
Residential					
Space heating	4,848	6,675	4.1	11.3	11.0
Water heating	1,159	1,736	5.2	2.7	2.9
Cooling	556	637	1.7	1.3	1.1
Clothes drying	93	208	10.6	0.2	0.3
Refrigeration	569	692	8.2	0.9	1.1
Air conditioning	134	427	15.6	0.3	0.7
Other	809	1,241	5.5	1.9	2.1
Total	7,968	11,616	4.8	18.6	19.2
Commercial					
Space heating	3,111	4,182	3.8	7.2	6.9
Water heating	544	653	2.3	1.3	1.1
Cooking	98	139	4.5	0.2	0.2
Refrigeration	534	670	2.9	1.2	1.1
Air conditioning	576	1,113	8.6	1.3	1.8
Feedstock	734	984	3.7	1.7	1.6
Other	145	1,025	28.0	0.3	1.7
Total	5,742	8,766	5.4	13.2	14.4
Industrial					
Process steam	7,646	10,132	3.6	17.8	16.7
Electric drive	3,170	4,794	5.3	7.4	7.9
Electrolytic processes	486	705	4.8	1.1	1.2
Direct heat	5,550	6,929	2.8	12.9	11.5
Feedstock	1,370	2,202	6.1	3.2	3.6
Other	118	198	6.7	0.3	0.3
Total	18,340	24,960	3.9	42.7	41.2
Transportation					
Fuel	10,873	15,038	4.1	25.2	24.9
Raw materials	141	146	0.4	0.3	0.3
Total	11,014	15,184	4.1	25.5	25.2
National total	43,064	60,526	4.3	100.0	100.0

Note: Electric utility consumption has been allocated to each end use.
Source: Stanford Research Institute, using Bureau of Mines and other sources.

sector, the smallest, used only 14.4%. However, the latter was the fastest growing, at 5.4% annually, while the former was the slowest growing, at 3.9%.

A relatively small number of energy applications constitute the greatest market for energy in the U.S., as indicated for 1968 in Table 6C.6-2. The twelve applications shown account for all but approximately 3% of total U.S. energy consumption. Their relative shares of the energy market are not changing rapidly despite the somewhat slower growth rates of the larger applications. Industrial uses, transportation, and space heating constitute for the foreseeable future the largest targets for conservation in the utilization of energy.

A number of recent studies have been dedicated to examining ways in which the consumption of energy can be reduced. Among these is the study published in October 1972[40] by the former Office of Emergency Preparedness (OEP). The objective of this study was the suggestion of programs that would either improve the efficiency with which energy is consumed or minimize its consumption, while providing the same or similar services to the consumer. The conservation measures suggested deal primarily with the utilization of energy in the major consuming sectors: industrial, transportation, residential, and commercial.

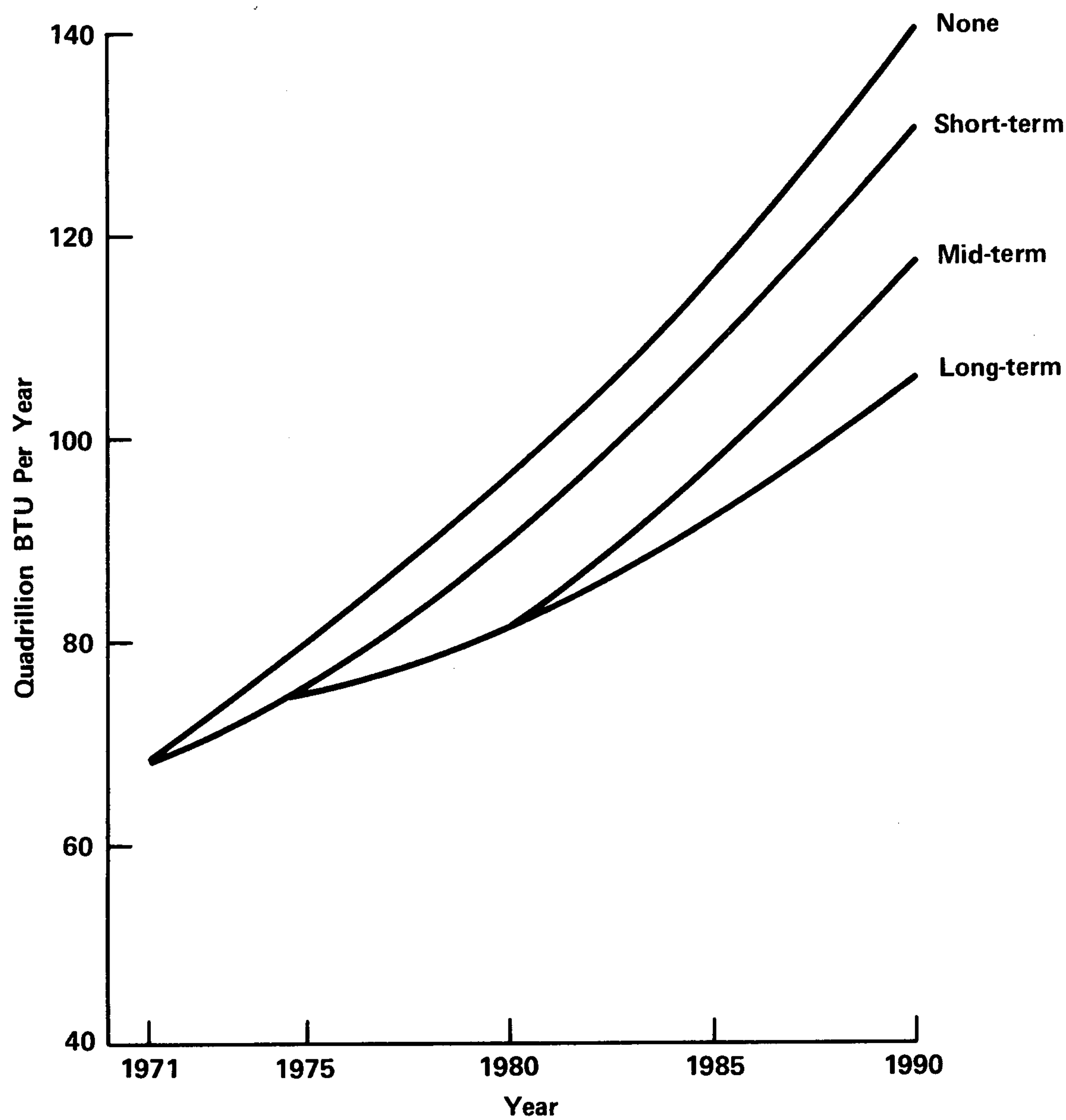
The study concludes that full implementation of the measures suggested could reduce projected U.S. total energy demand in 1980 of 96 quadrillion Btu by 15 to 17% and the 1990 demand of 140 quadrillion Btu by 23 to 25%. Implementation of the program would reduce the annual growth rate in electricity consumption from 6% to 4 1/2%. Graphical representation of idealized projections of total U.S. energy consumption based on putting the suggested energy conservation measures into practice is shown in Figure 6C.6-1.

The most significant energy conservation measures suggested to achieve these reductions are the installation of improved insulation in new and old homes, the use of more efficient space heating and cooling equipment, the introduction of more efficient industrial processes and equipment, and the shift to more efficient modes of transportation. The possible energy savings corresponding to implementation of these measures are listed by sector and end-use in Table 6C.6-3, which is a compilation of the potential savings reported in the OEP Study. Note that the savings indicated in the table are expressed in terms of primary source energy inputs before conversion to the energy forms ultimately utilized. Thus, when divided by the average electric generating plant conversion rate of 9000 Btu/kWhr projected for 1990, the 32 to 35 quadrillion Btu savings estimated possible for that year are equivalent to an electric generation of 3560 to 3890 billion kWhr, which in turn is equivalent to 540 to 590 GW of baseload generating capacity.

Table 6C.6-2

SIGNIFICANT END-USES OF ENERGY IN THE U.S.
(1968)

Applications	Percent of Total Uses
Transportation (fuel; excludes lubes and greases)	24.9
Space Heating (residential, commercial)	17.9
Process Steam (industrial)	16.7
Direct Heat (industrial)	11.5
Electric Drive (industrial)	7.9
Feedstocks, Raw Materials (commercial, industrial, transportation)	5.5
Water Heating (residential, commercial)	4.0
Air Conditioning (residential, commercial)	2.5
Refrigeration (residential, commercial)	2.2
Lighting (residential, commercial)	1.5
Cooking (residential, commercial)	1.3
Electrolytic Processes (industrial)	1.2
Total	97.1



IDEALIZED PROJECTIONS OF ENERGY CONSUMPTION BASED ON SUGGESTED CONSERVATION MEASURES

Figure 6C.6-1

Table 6C.6-3

POSSIBLE ANNUAL ENERGY SAVINGS
BY SECTOR AND END USE

Sector and End-Use	Savings in Gross Energy Input (10^{15} Btu) 1980	1990
Industrial	4.5 to 6.4	9.0 to 12.0
Process Steam	included above	
Direct Heat	included above	
Electric Drive	included above	
Electrolytic Processes	included above	
Other	included above	
Residential	3.6	15.0
Space Heating	2.2	
Water Heating	0.25	
Air Conditioning	0.50	
Refrigeration	0.10	
Cooling	0.05	
Other, Including Lighting	0.50	
Commercial[a]	1.5	
Transportation	4.8	8.0
Total	14.4 to 16.3 (15-17%)[d]	32.0 to 35.0 (23-25%)
Equivalent Generation[b] (10^9 kWhr)	1440 to 1630	3560 to 3890
Equivalent Baseload Generating Capacity[c] (GW)	220 to 250	540 to 590

[a]Commercial end-uses.

[b]At the electric utility generation bus, assuming average plant heat rates of 10,000 Btu/kWhr in 1980, 9000 Btu/kWhr in 1990, and 8000 Btu/kWhr in 2000.

[c]At 75% generating plant capacity factor.

[d]Percentage savings refer to the total projections of U.S. energy consumption in 1980 of 96 x 10^{15} Btu, in 1990 of 140 x 10^{15} Btu, and in 2000 of 190 x 10^{15} Btu considered in "The Nation's Energy Future," USAEC Report WASH-1281, December 1973.

Another view of the savings that may be achieved by reducing end-use consumption of energy is presented in a study by the Ford Foundation's Energy Policy Project.[41] This study considered several alternative futures, or scenarios, each based on different assumptions regarding the energy growth patterns our society might adopt for the years ahead, and the policies and consequences that each would entail. These futures, which are summarized below, were not presented as predictions, but as tools for rigorous thinking. No one scenario was advocated over another.

The first scenario, called historical growth, assumed that the use of energy will continue to grow much as it has in the past. This scenario assumes that the Nation will not deliberately impose any policies that might affect our ingrained habits of energy use, but will make a strong effort to develop supplies at a rapid pace to match rising demand.

In this scenario, the use of energy will continue to increase at about 3.4% per year, the average rate of the past 20 years, and would amount to 185 quadrillion Btu in the year 2000. The scenario assumes no deliberate conservation policies and would require the aggressive development of all possible supplies--off-shore oil and gas, coal, oil, shale, and nuclear power. High energy prices or government subsidies will be needed, as well as other policies favoring expansion of energy supplies, but oil imports could be kept to a modest level and the remaining increases in production obtained from domestic resources, possibly at a high environmental cost.[42]

The second scenario, or "technical fix," offers the option of reducing energy demand substantially below historical growth rates. This reduction is accomplished by making consumption efficiency, rather than increased supply, the focal point of energy policy.

The scenario under discussion was developed by applying economically feasible energy-saving "technical fixes" to the end uses of energy in the historical growth scenario. As a result, energy demand grows at half the 3.4% rate in the historical growth scenario, but the standard of living is not reduced and lifestyles are not changed significantly. In this scenario, the use of energy will increase at only half the historical rate, amounting to 118 quadrillion Btu in the year 2000. The scenario assumes sweeping application of energy-saving technologies and other conservation policies designed to reduce demand, but also assumes that economic growth would not be affected and that consumer choices would not be restricted. Major savings would come from the use of heat pumps and better insulation; smaller, more efficient cars; and more efficient production of process steam in industry. In consequence, only one major domestic source of energy would have to be aggressively developed. (Again, no preference is expressed; several options are explored.) The resulting flexibility could be used to severely limit, for environmental or security reasons, the role of nuclear energy, of coal, or of imported fuels in the national energy mix. Adjustments in tax and subsidy policies, federal research and development efforts, and new regulatory policies will all be needed.

The third scenario, titled zero energy growth, is different. It represents, according to the study, a real break with our accustomed way of doing things. Under this approach, the use of energy will grow only slightly, leveling off at about 100 quadrillion Btu/year in 2000. The scenario assumes widespread concern with the social and environmental costs of energy growth, adoption of an "enough is best" ethic, and a switch to production of more durable items. Cities and transportation systems would be redesigned, and economic growth, although not stopped, would be concentrated in the provision of services rather than in manufacturing. While some changes in lifestyle are foreseen in this scenario, it does not assume austerity--air conditioners, automobiles, and other appliances would be available to all consumers. The report does not spell out the full list of policies to accomplish this goal, but it does suggest that high prices and government actions to maintain full employment will be needed. Further discussion of the effects on society and likelihood of implementation of a conservation program, such as zero energy growth, that would have significant impact on lifestyles in this nation, is provided later in Section 6C.7, wherein the views of several persons who commented on the Draft Statement in "support" of lifestyle changes are addressed. Several views indicating that lifestyle changes will not be broadly accepted are also discussed in that section.

An important point to be noted with regard to the term zero energy growth is that the term "energy" refers to total overall consumption of all forms of energy, not just electricity. Even if zero total energy growth were to be achieved, the demand for electricity is likely to still increase, as economic and environmental factors tend to increase the fraction of our energy consumption which is in the form of electricity. Also in this respect, the areas of energy usage with the greatest potential for savings, e.g., space heating and transportation, are among those which rely less heavily on electricity, and thus are not prime targets for reduced electricity usage.

Yet another view of how conservation measures in end use of energy may be used to achieve a better balance between energy supply and demand is that expressed in the

Half and Half Plan by the Council on Environmental Quality.[43] The major elements of this plan are:

(1) The target for <u>gross</u> energy consumption in the year 2000 should be 121 quadrillion Btu, an increase of 49 quadrillion Btu over the 1972 consumption of 72 quadrillion Btu. This increase represents an annual growth rate of 1.8%.

(2) This target is based on growth in net per capita energy consumption of 0.7% per year and on a continuing conservation effort that would, through improved efficiency and elimination of waste, save energy at a rate of 0.7% per year. This program--half growth and half conservation--would provide an effective increase in usable energy of 1.4% per year, equal to the average rate of growth experienced from 1947 to 1972.

The implications for energy demand from implementation of the Half and Half Plan are:

(1) In terms of increased inputs, per capita net energy consumption in the year 2000 would be 25% above present per capita levels in the residential and commercial sector, 35% above present per capita levels in the industrial sector, and 10% above present per capita levels in the transportation sector.

(2) In terms of effective energy, this increase would be supplemented by energy saved through energy conservation in the residential and commercial sector (through such means as more efficient appliances, better insulation, and more energy-conscious architectural design), in the industrial sector (through more recycling of materials and more energy-conscious process design), and in the transportation sector (through smaller, more efficient cars, increased use of mass transit, and more rational land use).

In addition to emphasizing energy conservation, the Half and Half Plan recognizes that part of the burden of providing a balance between energy demand and supply must fall on the energy supply process. In this respect, the Plan cites the following implications for energy supply:

(1) Major reliance must be placed on coal and nuclear fission. Coal will increase from 12.6 quadrillion Btu in 1971 to 33.4 quadrillion Btu in 2000; nuclear power from 0.4 to 35 quadrillion Btu.

(2) Over 42% of total energy inputs will be used to produce electricity. This action will result in substantial conversion losses--as much as 30.7 quadrillion Btu in 2000.

(3) Limited petroleum resources must increasingly be reserved for transportation uses.

(4) Major research and development should be carried out on new energy resources such as nuclear fusion and solar and geothermal energy. Even with a major effort, however, the CEQ believes that we cannot reasonably expect to meet more than 3% of our total needs from these new sources by the year 2000.

In summary, the Plan includes several proposals for national action:

(1) A long-term national program to conserve energy must be undertaken and given high priority. This program should include research and analysis to identify opportunities for energy conservation and to develop patterns of incentive and regulation which will encourage more efficient and less wasteful use of energy supplies.

(2) Planning for the development of energy supplies must be undertaken on a long-term basis and be premised on an effective national energy conservation program.

(3) Previous major advertising campaigns to promote the use of energy must be replaced with campaigns to promote conservation of energy.

A somewhat broader approach to strategies for reducing national energy demand is presented in a report on Energy Conservation Strategies by the Environmental Protection Agency.[44] This report holds that rate revisions and internalization of environmental costs to users are two basic measures for promoting reduced usage of energy. Its basic finding is that if the government should wish to take an activist position on behalf of energy conservation, a market-based strategy appears attractive. Large amounts of energy go for uses that could be eliminated at very little cost; such energy savings would not call for changes in lifestyle, cessation of national growth, or significant economic dislocations. If such low-priority energy uses (or wastes) are not eliminated, maintenance (much less improvement) of environmental quality will become far more difficult. Thus, the process of allocating environmental costs to energy suppliers (and through them to users) is part of the solution to the energy problem, not part of the problem itself. In more detail, a number of the specific areas where such savings are economically viable have been identified, and additional government actions, if any, which might be taken to ensure a sound market if this approach should be adopted, have been considered.

More specifically, the EPA report cites the following strategies as worthy of further investigation and/or implementation:

(1) Overall
  Dual strategy, using both market and regulation
  Broad research on energy use and conservation
(2) Review and revision of energy-wasteful Government policies
  Discriminatory pricing
  Highway and aviation subsidies
  Depletion allowances
(3) Internalization of environmental costs to users
  Sulfur emissions tax
  Auto emissions tax
  General costs of compliance
(4) Assisting market with selective actions
  Insulate new dwellings (regulation and labeling)
  Insulate old dwellings (subsidy or labeling)
  Control trends to energy-wasteful products, processes
  Improve automobile energy efficiency

The potential savings by 1990, assuming successful implementation of the above strategies, would be as follows:

22% of residential/commercial - -	8 QBtu* or 6%
34% of industrial - - - - - - - -	24 QBtu or 17%
27% of transportation - - - - - -	9 QBtu or 7%
National- - - - - - - - -	41 QBtu or 30%

The nationally projected savings of 30% by 1990 are not inconsistent with the conclusions of other conservation studies as reported in this section.

A further national overview of the role of conservation in balancing energy supply and demand is provided in several publications of the Federal Energy Administration (FEA), which has the responsibility of establishing overall government policy regarding energy conservation.[45,46] The FEA, in outlining the program for achieving U.S. energy independence by 1980,[46] has cited a series of major conservation programs

*Quadrillion British thermal units.

designed to create an energy conservation ethic and to reduce the growth rate in energy consumption from 3.6% to 2% per year. These programs, which are similar to those discussed in more detail later in this section, include improved efficiency in household and commercial heating, reduction in energy use by appliances, changes in transportation modes and patterns, industrial conservation, and changes in pricing policies. This last mechanism includes significant increases in the prices of all forms of energy between 1974 and 1985 and change in the peak-load pricing for electricity, thereby shifting industrial schedules so as to reduce the percentage increase in electricity demand.

One other comprehensive study of the savings that may be achieved by reducing end-use consumption of energy and improving the management of our energy resources and policies is provided in "The Nation's Energy Future,"[2] which outlines a five-year, $210-million program aimed at achieving these goals. This report, prepared by an interagency government panel, established two principal areas for reduced consumption--end-use conservation and improved management. Under the former task, the program goal would be to conserve energy and energy fuels by reducing the rate of growth in consumption and to achieve this reduction while maintaining an acceptable standard of living and environment, under conditions of minimal social and economic dislocation. The goal of improved management would be to conserve energy, energy sources, and energy research and development resources by providing analytic tools for comparative analyses of alternative energy strategies that will assist energy policy makers and energy research and development policy decision makers in establishing policies.

More specifically, the objectives of the program in end-use conservation are as follows:

(1) To maximize specific energy efficiency in buildings by developing and demonstrating improved design, construction techniques and practices, operational methods and maintenance practices, and use of materials that require less energy for production.

(2) To reduce energy consumption in industrial processes by developing and demonstrating improved design, construction techniques and practices, operational methods and maintenance practices, and use of materials that require less energy for production.

(3) To increase the energy efficiency of transportation systems by developing and demonstrating more efficient utilization of alternative modes, patterns of traffic flow, coordination of systems to urban growth patterns, and use of local regulations.

(4) To demonstrate the energy efficiencies to be derived from integrated utility services from a single plant.

(5) To develop appropriate information and data, with cross-energy-sector applications, for analysis of the implications of demographic trends, land use alternatives, and new technologies in terms of their impact on energy demands.

The objectives of improved management are:

(1) Develop and maintain an adequate base of information and data on and improve existing and develop new quantitative models of the U.S. energy system in order to provide the analytical tools required for analyses of alternative energy policies or management concepts.

(2) Conduct assessments, including evaluation of environmental, economic, and social factors, of emerging energy technologies and integrate the results of those assessments into evolving national energy policies and strategies.

(3) Develop evaluation criteria for the selection of energy research and development strategy alternatives and identify the trade offs implicit to these alternatives.

(4) Develop recommendations for systematic management of energy research and development including identification of total resource needs and the allocation of those resources among competing programs, taking into consideration the appropriate roles for Federal and private funding.

If these activities are successful, the report estimates several areas in which reduced consumption would be achieved. In end-use conservation, potential savings are analyzed as follows:

(1) The potential savings available through the application of conservation measures are obviously very large and difficult to predict. A 20% savings by 2000 is a conservative estimate. If 30% of the existing buildings in the United States are modified so that their heating and cooling loads are reduced 40% and 30%, respectively, a savings of 3% of the present total annual energy used will be realized.

(2) If 50% of the new buildings built each year incorporate energy conservation design features that result in a 40% savings in consumption, a total savings of 15% of the present U.S. consumption would be realized at the end of 10 years.

(3) Ultimately a 30% reduction in primary fuel requirements for industrial thermal processes is a realistic goal, through improved thermal processes and waste energy utilization.

(4) Improved transportation efficiency, especially improved auto occupancy and improved management of freight, could reduce projected transportation demand by about 5% by 1978 and 10% by the year 2000.

(5) Market analysis shows that modular integrated utility systems (combinations of various utility services in a single facility) can be utilized to service 16% of all new construction. Based on this estimate, energy requirements for space heating, hot water, air conditioning, and electricity in new construction can be reduced 35% by 1986--a reduction of 8.5% of total energy requirements for residential utilities.

Further insight into the projections and conclusions in The Nation's Energy Future is to be gained from consideration of the report of the Subpanel XII, Conservation,[47] which provided the input on which "The Nation's Energy Future" was based. The goal of a national program in energy conservation, as seen by the subpanel, would be to decrease overall growth rate of demand for energy and specific fuels consonant with maintenance of a socially acceptable standard of living and environmental quality, under conditions of minimum social and economic dislocations. The subpanel noted that the greatest opportunities for effecting significant conservation of energy in this regard would be in the end-use (utilization) phase and therefore focused their attention in this area. (As may be seen from the other conservation studies reviewed in this section, this conclusion is shared by most, if not all, organizations evaluating energy conservation and is also the focus of the conservation discussion in this Environmental Statement.) The subpanel also noted, however, that diverse approaches must be used to achieve the projected savings in end-usage of energy. Current research programs in several government agencies strongly focus on technological opportunities (such as improved insulation in new houses), as will be discussed in detail in Sections 6C.6.2.1 through 6C.6.2.6. On the other hand, studies sponsored by the National Science Foundation, Council on Environmental Quality, Environmental Protection Agency, and the Energy Policy Project of the Ford Foundation, most of which have been discussed in this section, emphasize systems analysis, socioeconomic and institutional research, and policy studies. Obviously, there is merit in both approaches, and both will be needed to achieve the necessary savings.

With regard to research on and expertise in energy conservation, Subpanel XII found that these are currently minimal and can be expanded only at a finite rate. The limitation to funding seems to be a shortage of available experts, rather than the scope of conservation opportunities. The subpanel also found that estimates of potential conservation methods need a firmer basis before massive investment in development. They did note, however, that the required research, while highly complex, is less costly than the kind of research required for new supply technology.

The recommendations and conclusions of Subpanel XII are especially noteworthy in that they represented a broad overview of all other conservation studies completed up to that time (late 1973) and an attempt to set the direction for a national research and development program in energy conservation. The Subpanel outlines three research and development approaches to achieving conservation goals and described them as minimum, orderly, and maximum programs in terms of the funding and effort that would be devoted to each. These programs amounted to 5, 7, and 10%, respectively, of the overall $10-billion, five-year effort on energy research examined in "The Nation's Energy Future." These levels of funding were believed capable of facilitating respective reductions in energy demand of 15, 30, and 40% of the predicted total demand in the year 2000. The subpanel also expressed the opinion that even the 10% level, if allocated only to end-use energy conservation, could be considered as the minimum appropriate effort in this area. However, the Subpanel pointed out that the allocation to end-use studies is currently about 2% of total energy research and development, up from less than 1% a year ago.

As to the meaning and impact of the three proposed programs, the subpanel reported as noted above that the minimal conservation program is designed to conserve roughly 15% of the energy assumed to be used in the year 2000 and takes account of implementation lags during the intervening years. This level of conservation corresponds to implementation of those savings measures that would be cost-effective at 1973 energy costs, using technology that is either available or easily forseeable. With the exception of a moderate decrease in the demand for industrial process heat, all of the savings result from changes in the efficiency of various processes, rather than from any forces acting directly on demand. For this reason, such a program would minimize the second-order impacts of demand shifts as they are reflected through the rest of the economy. In general, the efficiency changes would be embodied in alterations of capital equipment which had not yet been installed in 1973, rather than in massive changes to existing capital stocks or in substitution of drastically different products requiring different inputs and generating significantly different pollutants.

Such a program would be expected to have a very favorable impact on both resource use and on the environment, because the saved energy is just the marginal energy that would otherwise be the most costly, in terms of both resources and maintenance of environmental quality, for the Nation to provide. The minimal target conservation program, combined with emission controls on new energy converters, could allow, according to the subpanel, for approximate maintenance of present air quality; but even this program would require considerable private and public investment (for emission controls), and environmental improvement would be much more costly.

The subpanel's orderly (or adequate) conservation program is designed to conserve roughly 30% of the energy assumed to be used in the year 2000. This level corresponds to the approximate level of conservation that would be cost-effective at likely energy prices in the year 2000, if those prices reflect the cost of adequate environmental protection and are also adjusted to reflect a moderate (10%) premium for scarcity. The subpanel chose to model this program by adding to the minimum program a series of reductions in final demand, most of which reflect various product or process changes that would become cost-effective at such a set of prices. The subpanel did not visualize such measures as gasoline rationing (or prohibitive taxation, beyond moderate environmental charges) or forced changes in consumer life-styles such as deliberately keeping houses less comfortable. The adequate program will, in the subpanel's opinion, probably have the impact of permitting the Nation to achieve either full self-sufficiency or a high level of environmental restoration without massive expenditures for energy supplies and without massive governmental interference in consumer choices.

The maximum conservation program is designed to reduce the "adequate" program by yet another 15%, so that consumption of energy would be down 40% from projections of use in the system for the year 2000. The subpanel modeled this program through added constraints on demand, this time interfering with consumers' market choices so as to force reductions of industrial electricity and process heat, restrictions on auto travel, and a small level of discomfort in dwellings. The subpanel noted that such a program appears to coincide with a worst-case need to become self-sufficient even in the presence of environmental constraints. The strains such a program would place on the economy give some measure of the urgency of research on either the expansion of domestic energy supplies or the development of higher-level technology for energy conservation.

One final report that should be considered in assessing potential reduction in end usage of energy as a result of conservation practices is "Nuclear Power Growth, 1974-2000,"[48] which was prepared independently of the above studies by the AEC Office of Planning and Analysis. This report offers forecasts of energy consumption and electric generating capacity at various future dates as a means of planning AEC activities in uranium enrichment services, plutonium recycle, and other activities. These forecasts are presented in Table 6C.6-4 for the year 2000 in terms of four separate cases representing various assumptions as to the growth of energy usage, the rate of economic growth, the extent to which conservation measures are implemented, and other factors. These forecasts are made not to predict precise points in the future, but rather to predict a range of values within which the future is likely to be. Of greatest interest for purposes of this discussion is the extent to which conservation of energy is utilized and how this affects total energy consumption in each case.

Table 6C.6-4

FORECASTS OF ENERGY CONSUMPTION IN GENERATING CAPACITY
IN THE UNITED STATES IN THE YEAR 2000

	Case A	Case B	Case C	Case D
Energy Consumed, Million Btu per capita	499	719	737	642
Total Energy Consumption,[a] quadrillion Btu	135	195	200	174
Fraction of Energy Used for Electric Generation	0.51	0.50	0.54	0.50
Total Electric Generating Capacity per capita, kW	5.81	8.19	9.22	7.45
Total Electric Generating Capacity, Thousands of MW	1575	2200	2500	2020

[a]Based on an assumed population in the year 2000 of 271 million persons.

Case B represents a projection of energy growth that assumes a continuation of the past relationship between energy consumption and gross national product, together with a further increase in the importance of electricity as a secondary energy source. On this basis, total energy consumption was projected to increase at a 3.6% annual compound rate. Thus, while per capita energy use is expected to grow, this projection also implies that the declining long-term trend in energy inputs required to produce a dollar of output will continue. Furthermore, the projection indicates that the share of total primary energy required by the year 2000 for electricity generation will nearly double, as it has for a similar time period in the past.

Case B inherently assumes that factors historically important in shifting the pattern of energy use in favor of electricity will influence future demand. Electricity is expected to remain a useful, convenient, and inexpensive form of energy relative to available substitutes. Technological innovation will proceed so that the rate of introduction of devices, processes, and other end uses for electricity will not change from past experience.

Case C may be characterized as being based on a continuation of the same general long-term historical trend in total energy consumption as Case B but with a different means utilized to satisfy demand. In this case electricity is assumed to remain cheap relative to oil and natural gas, but energy prices on the whole are not assumed to change significantly relative to other commodities. As a result, a more rapid shift to electricity is expected to occur where technically feasible. Specifically, the case assumes that all new houses added beyond 1977 are all-electric homes, that electricity is substituted for heating and cooling in the commercial sector and in certain industrial end-uses particularly for process heat, and further that electric vehicles and electric transportation constitute an important fraction of transportation needs by the end of the century.

Case D considers the situation where total consumption of all forms of energy is reduced through conservation measures, but where these measures are not so stringent as to limit improvements in standard of living or economic development. In this view, all end-use energy demands are met, but fewer energy resources are consumed because higher energy prices relative to other commodities cause industrial and other energy consumers to improve the efficiency with which they use energy.

Efficiency improvements are expected to take place primarily in space heating and air-conditioning uses, in industrial process heating and steel making, as well as in both private and public transportation modes. Average increases of 10% in utilization efficiencies for these end uses in 1985 and 20% for the year 2000 result in annual savings in total energy consumption of 10% per year compared with Case B. This difference is equivalent to an annual savings of 20 quadrillion Btu by the year 2000. These factors reduce electrical energy requirements as well as total energy consumption.

Case A is characterized by a slower rate of economic growth owing to a decreased emphasis on the production of goods, coupled with higher energy prices relative to other commodities. Maximum efforts are made to conserve energy by increasing utilization efficiencies in all sectors including residential and commercial space heating and cooling, air and ground transportation (oil), in steel making (coal), aluminum production (electricity), and industrial process heat. Actual reductions in demand also occur in several sectors, notably in petrochemical requirements and process heat use, as a result of a slower rate of economic growth. High energy costs result in less demand for heating and cooling in homes through adjustments in temperature and expenditures for more household insulation. Internalization of pollution control costs, coupled with electric rate structure revisions to discourage peak use, are expected to affect electricity consumption. Similarly, the high energy costs assumed in this case will cause shifts away from inefficient transportation modes such as private vehicles and airplanes and increase the use of buses and railways. This combination of factors reduces total energy consumption in the year 2000 by 30% from the projection in Case B.

From the several conservation studies that have been examined above, there are evidently many opportunities for conservation in the utilization of energy in industry, commerce, and residences. This expectation is broadly reflected in the energy savings shown in Table 6C.6-3. In addition, the transportation and building sectors hold substantial potential for energy reductions. The following discussion deals with some of the means for achieving the savings discussed above in each of these sectors, including some quantitative estimates of their magnitude. Due to the nature of the actions and processes to be examined, the discussion will be from the viewpoint of total energy conservation, rather than from only projected electricity savings.

6C.6.2 Conservation Actions

6C.6.2.1 Industry

The industrial processes listed in Table 6C.6-1--process steam, direct heat, electric drive, and electrolytic processes--accounted for 37.3% of the Nation's energy consumption in 1968. Of this, the industrial thermal processes alone, process steam and direct heat, total 28.2% of U.S. energy requirements, about the same as that required to support all residential and commercial services.

The average heat transfer efficiency of individual equipment used in direct heat or process steam operations is not high--approximately 30%. The heat transfer efficiency of heat treating furnaces is also about 30%, due to the loss of approximately 50% of combustion heat in the stack gases.[49] The overall efficiency of thermal processing plants (e.g., heat treating facilities, paper mills, glass factories) is even lower than the nominal efficiencies of the individual devices, sometimes as low as 5%,[50] because plants are not commonly operated as systems making optimal use of energy. For example, computer control of fuel management in hot strip steel mill operations to govern such things as the startup and shutdown of furnaces and their idling temperatures can reduce furnace fuel requirements by 25%.

Substantial conservation of energy should be possible through design of equipment that consumes less energy for a given productive output and the application of control for more efficient management of systems and processes.

Recommendation of specific measures for more effective energy utilization in industry is more difficult than in the case of residential and commercial heating, for example, because of the many and varied processes employed in industry. Also, industrial process research is almost always proprietary. However, certain examples can be mentioned where application of new technology would conserve significant amounts of energy. For example, gas-fired vacuum furnaces have recently been developed for industry; and, together with well-designed vacuum insulation, heat pipe technology, and modern heat transfer and combustion techniques, these furnaces operate with 25% of the total fuel consumption of previous vacuum furnaces.[51]

The application of fluidized-bed processing* to cement kilns and similar apparatus offers the prospect of considerable savings in industrial fuel utilization (cement production accounts for about 2% of U.S. fuel consumption). Recent advances in design of fluidized-bed equipment may increase the heat transfer efficiency to approximately 50%, instead of the present 30%. In addition, the time for completion of the reaction time in the kiln may be reduced substantially, with consequent improvement in the productivity of cement making.[49]

The heat pipe, a device that permits rapid and highly controllable heat transfer over long distances with minimal drop in temperature, can be applied to reduce fuel requirements. Heat pipes can be used as heat sources for vacuum furnaces, and

*In a fluidized-bed, a stream of fluid (usually gas) is forced up through a bed of small particles. The fluid drag on the particles overcomes the gravity force, and the entire bed of particles can be made to flow and to exhibit other mechanical properties similar to those of a true fluid. In thermal reactors, the hot gaseous products of combustion may be used to fluidize a bed. With the hot fluid surrounding individual particles, heat transfer to the solid takes place efficiently and rapidly.

prospects appear good for their application to glass furnaces. Heat pipes could also be used to extract heat from stack gases, thereby using heat that would otherwise be wasted.[49]

Various other methods and processes are being found to conserve energy as industry actively pursues a conservation ethic. U.S. Steel, for example, reports that a ton of steel is made today with 15% less energy than was required a year ago.[52] Much of this saving is the result of new furnaces and casting machinery that improve efficiency. A carpet company in Georgia estimates that company efforts to increase boiler efficiency, burn waste material, and recirculate heat it once pumped out a smokestack will result in overall savings of $450,000 per year. By reusing hot air from huge dryers, this company already has cut by 31% its gas consumption, and a 40% reduction is expected when the energy-conservation program is completed.

Raytheon, a diversified electronics manufacturer, found one way to save energy in large open tanks containing hot liquids by floating plastic spheres--similar to table-tennis balls--on top of the liquid. The balls keep in the heat while still allowing access to the vats for measurements and processing. In addition, Raytheon has a 131-step campaign under way to save energy at its 45 U.S. facilities. During the winter, this campaign cut use of heating oil by 30% below last year's level and electrical consumption by 20%.

One reason industry has pursued conservation measures so aggressively is cost. Even with these cuts in the usage of energy, many firms will still pay more for energy in 1974 than in 1973.

The growing realization that fuel costs are likely to continue rising has stimulated a brisk business for a division of a nationally known chemical corporation. Its Energy Management Services office is selling the company's expertise on how to reduce all types of fuel consumption. More than 70 of the Nation's largest corporations have hired this company to study their energy utilization. The service is offered only to companies with an annual fuel bill of more than half a million dollars.[52]

Other internal industry conservation efforts used by various firms include recycling of materials and waste heat (see Section 6C.3.3), burning as fuel materials previously wasted, and improved maintenance (leading to lowered energy losses) on energy-intensive equipment such as boilers.

One source[50] has estimated that approximately 30% of the energy used in industrial processes could be saved through the application of existing techniques and that the use of these techniques would be economically justifiable at present fuel prices. Other sources might suggest that this figure is too high and that a more probable value would be 20% when the costs of making the changes are taken into account. In either event, as fossil fuel prices increase, the employment of these techniques becomes increasingly attractive. The development of more efficient devices and processes and the application of better waste heat management may be expected to yield savings exceeding the 20% or 30% mentioned.

6C.6.2.2 Commerce

In some respects commercial conservation practices may be considered as extensions of those discussed above for industry or of these discussed later for residences. However, there are a few measures that may be considered to belong primarily in the marketplace, and these are briefly reviewed below.

The establishment of "energy management" programs by businesses is one means for bringing the need for conservation to the attention of large numbers of people and for identifying areas in which substantial energy savings may be achieved. Energy management, as proposed by the Department of Commerce,[53] is the application of the same basic techniques to the use of energy resources that one would apply to administration, finance, marketing, purchasing, or production in any soundly run business endeavor. Implementation of energy management programs in business may take various forms, such as the appointment of a top-level energy coordinator to spearhead the company conservation program throughout the corporate structure. A line staff of full- or part-time people to implement proposed conservation measures, supported by top management, is in many instances believed to be an economical use of manpower. Other approaches include the establishment of energy consultant groups for all corporate affairs and the use of energy audits on much the same basis that financial audits are conducted. The goal of such exercises, of course, is to firmly establish the conservation ethic and to reduce the usage of energy to a minimum.

Other ways in which business decision can be translated into energy savings include the use of recycled materials when available rather than virgin materials (which may require up to 20 times more energy to produce), the use of natural materials rather than synthetics, the use of materials requiring less maintenance, and planning of new facilities such as stores and offices to consider their energy requirements. The benefits to be achieved show up in cost savings, as well as in reductions in energy usage.

6C.6.2.3 Residential Applications

The consumer is bombarded almost daily with exhortations to reduce his energy usage, and these suggestions are often coupled with projections of the savings that will occur from their implementation. There can be little doubt that such measures are beginning to be effective; several utilities have reported reduced demand for electricity in the first few months of 1974 of up to 5% over earlier projections. While not all these reductions can be attributed to residential usage, consumers are clearly using less electricity as well as other forms of energy. Whether or not this trend will continue is a matter of speculation and is examined further in Section 6C.7.

What are the specific measures that can be employed? The list is almost endless, but a few of the more obvious or attractive measures, many of which are also applicable to other sectors of the economy, are as follows:[54-56]

(1) Heating and cooling

In winter, lower thermostats to 68° during the day and 60° at night.

In summer, set air conditioning at 78°.

Install shades, vertical louvers, or awnings over windows facing south and west for summertime shading.

Draw draperies and shades in sunny windows in summer; keep them open in winter.

Close off unoccupied rooms, and turn off the heat or air conditioning.

Run air-conditioning equipment only on really hot days. Open windows for fresh air cooling instead of using the unit's fan.

Clean air-conditioning filters at least once a month.

Use ventilating fans intermittently and only as needed.

Use exhaust fans to pull heat and moisture released in kitchens and laundries directly to the outside.

Keep outside doors closed during heating and cooling seasons.

Service the oil burner once a year, preferably each fall.

Clean or replace the filter in hot air heating system monthly.

(2) Lighting

Remove one bulb permanently. Replace it with a burned-out bulb for safety. Replace half of the others with bulbs of the next lower wattage.

Concentrate lighting in the reading and working areas of the home; reduce lighting in other areas.

Use higher lumen/watt light sources--a fluorescent lamp, for instance, is three times as efficient in energy use as an incandescent bulb.

Use fluorescent lights for kitchen, bathroom, and yard lighting. A single long tube is more energy-efficient and economical than two shorter bulbs.

Do not use long-life incandescent lamps; they're more energy-consuming and less efficient than ordinary bulbs.

Use one large bulb rather than several smaller ones. One 100-watt incandescent lamp, for example, produces more light than two 60-watt lamps.

Turn off all lights when they are not needed.

Keep lamps and lighting fixtures clean.

Never use artificial lights strictly for decorative effects.

(3) All Living Spaces

Use light colors for walls, rugs, draperies, and upholstery to reduce the amount of artificial lighting required.

Unplug quick-on television sets when they are not in use. Even when the screen is black, these sets use energy.

Turn off all radio and television sets when not in use.

Use manual wind clocks rather than electrical clocks, or reduce use to just one electric clock in a convenient location.

(4) Kitchen and Laundry

Set water heater at 100 °F. Higher temperatures are not necessary, and the lower setting will reduce hot water heating bills.

Use clothes washers and dryers only when they are fully loaded, more frequently only if they have small load attachments. If every household cut its frequency of use in half, the Nation could save the equivalent of 140,000 bbl of oil per day.

Wash clothes in cold water with cold water detergents. If everyone stopped laundering in hot water, the national fuel savings could amount to some 160,000 bbl of oil per day. A household's dollar saving could be about 4% in gas or electric bills.

Wash dishes by hand instead of in the dishwasher. National savings in fuel could be 30,000 bbl of oil per day.

Buy manual rather than automatic defrost refrigerator/freezers. Automatic defrost refrigerators/freezers consume about 50% more energy than the manual models.

Reduce energy consumption in cooking. Use pans that cover the heating element so that more heat enters the pot and less is lost to the surrounding air, and cover them whenever possible.

When using the oven, plan all-oven-cooked meals to make the most use of the single heat source.

Do as much household cleaning as possible with cold water rather than hot.

Use manual rather than electrical appliances whenever possible.

(5) The Workshop, the Yard, and the Garden

Maintain electrical tools in top operating shape, clean and properly lubricated.

Keep cutting edges sharp. A sharp bit or saw cuts more quickly and uses less power. Oil on bits and cutting compounds on saws also reduces power required.

Use hand tools in workshop.

Remember to turn off shop lights, soldering irons, glue-pots, and all bench heating devices as quickly as possible.

When buying power tools, purchase the machine with the lowest adequate horse power for the work it will do.

Save all workshop wood cuttings and burnable yard wood for fireplace.

Use hand lawn mowers, pruners, and clippers in place of powered equipment in the yard and garden.

Do not allow gasoline-powered yard equipment to idle for long periods. Turn them off and restart when ready to resume operation.

Use a natural compost from yard cuttings. Manufactured fertilizers use petroleum source elements.

(6) The House Itself

Caulk and weatherstrip doors and windows. This inexpensive measure, which the homeowner himself could do, would reduce the family's fuel bill by at least 10%. If every householder followed this advice, 580,000 bbl of fuel oil could be saved each winter day.

Install storm windows or plastic sheet protection. If the estimated 18 million homes without window insulation were treated this way, the Nation's fuel oil demand would drop the equivalent of 200,000 bbl/day each winter season.

Insulate the attic. A do-it-yourselfer could install mineral wool, fiberglass, or cellulose insulation in the attic for about $100.00, reducing his heating bill by about 20% or more. If 15 million homes with inadequate attic insulation were upgraded this way, about 400,000 bbl of heating oil would be saved each winter day.

Install central air-conditioning systems rather than window units.

When buying new water heaters, select a unit with high energy efficiency and with thick insulation on the shell.

Shut off furnace pilot lights in summer.

Ventilate the attic with louvered window panels or wind-powered roof ventilators rather than motor-driven attic fans.

Install a screen outside north or west doorways to shield them from the wind.

Install a vestibule or a second set of doors at lobby entrances to reduce loss of heated or cooled air.

Select light colored roofing.

Plant deciduous trees and vines on south and west sides of homes to provide protective shade against summer sun.

When buying a home, ask for a decription of the insulation installed and for data on the efficiency of space heating, air conditioning, and water heating plants or have an independent engineer advise you about the efficiency of the equipment provided.

(7) New Home Planning

Limit window areas to 10% of the floor area or less.

Install windows that open so that natural ventilation can be used to maintain comfortable indoor temperatures in moderate weather. Use heat reflecting, heat absorbing, or double-pane glass.

Design new homes to make maximum use of natural light throughout the year.

Insulate walls and roof.

While all these residential energy conservation measures are desirable, it is obvious that some of them will be more effective than others in achieving significant energy savings. As a general rule, the most substantial sources of saving are in home heating, automobile travel, and personal use of hot water. Of these, the biggest energy economies can be realized by changing the utlilization patterns of the family car, which is not a major user of electricity. Thus, it is again seen that reduction in total energy usage can show a disproportionately lesser reduction in electricity usage, i.e., the potentials for energy conservation and for electricity conservation are substantially different.

6C.6.2.4 Thermal Performance of Structures

Energy is consumed in buildings principally for space heating and cooling and water heating. As shown in Table 6C.6-1, these services for residences and commercial buildings required 24.4% of U.S. energy consumption in 1968.

Heat losses or gains in buildings are due to inadequate insulation, excessive ventilation, high air infiltration rates, and excessive fenestration.[51] A measure of the improvement considered possible through improved thermal insulation and control of air infiltration are the newly implemented FHA minimum property standards (1972) that require heat losses to be less than 1000 Btu per 1000 ft^3-degree day in comparison to the FHA standards of 1965 that permitted heat losses of 2000 Btu per 1000 ft^3-degree day. Few buildings are designed to exceed the performance levels of the FHA 1972 standards, and therefore it is reasonable to assume that most of the residential buildings in use today may consume approximately 40% more energy for heating and air conditioning than they would had they been insulated and sealed in accordance with present-day minimum property standards. Sample fuel observations indicate that the situation is not significantly different for existing commercial buildings.[51]

Future standards for insulation, ventilation, and infiltration may offer even greater potential for saving energy. To reduce heating losses from buildings to approximately 700 Btu per 1000 ft^3-degree day is considered technically and economically feasible through better insulation. If implementation of this standard were achieved, total energy requirements of buildings could be reduced by more than 50% through well-designed insulation and careful control of ventilation.

The choice of heating system can also affect energy conservation. The end-use efficiency of fuel use for electric resistance heating in the home is essentially 100%, but when the energy conversion efficiency at the electric generating plant, averaging about 33%, and the electric system transmission and distribution efficiency of about 91% are considered, the overall efficiency of electric heating is approximately 30%.[57] The end-use efficiency of gas- or oil-burning home-heating systems is on the order of 50%. The latter figure might fluctuate somewhat due to the extent of losses in delivering the fuel to residences and commercial buildings as opposed to bulk deliveries to central generating stations, but the overall efficiency of gas or oil heating still would be much higher than that for electric resistance heating.

The use of electrical heat pumps could just about equalize the overall efficiencies of electric, gas, and oil heating systems, due to the fact that the heat pump delivers about two units of heat energy for each unit of electric energy it consumes.[57] Heat pumps are not initially expensive when installed in conjunction with central air conditioning, but they have caused high maintenance costs due to equipment failure. Extensive programs by manufacturers to improve component reliability could result in their greater market acceptance and a saving in energy consumption over electric resistance heating.

Air conditioning ranks third in the residential and commercial end uses listed in Table 6C.6-2, representing 2.5% of total U.S. energy consumption, but it is important beyond its ranking because it is a large contributor to summer peak loads on electric utility systems, which in turn determine system generating capacity.

Room air conditioners were installed in over 29 million American homes in 1972, which represents a market saturation of about 44%.[57] Strong growth in sales is expected to continue. As there is considerable range in the efficiency of room air conditioners, from about 4.7 to 12.2 Btu/watt-hr, sale of the more efficient units could contribute significantly to energy conservation.

An estimate of the impact of more efficient room air conditioners on energy consumption is available from Table 6C.6-5, which is taken from a recent study.[58] By examination of Figure 6C.6-2 and consideration of the fact that low-efficiency machines generally have lower selling prices and, as a result, appear to be better bargains to the casual shopper, a present-day average efficiency of 6 Btu/watt-hr can be assumed. An improved average efficiency of 10 Btu/watt-hr appears to be attainable without any technological breakthrough--this level is well below the maximum efficiency available today. Such an improvement would result in a cumulative saving of electricity consumption over the eight-year period of 212 billion kWhr. This savings is equivalent to 2.4 times the 1970 total electricity sales of the Tennessee Valley Authority or 6.5 times the 1970 sales of the Consolidated Edison Company. The 1980 connected load of the room air conditioners sold during the eight-year period would be 145,000 MW with an efficiency of 6 Btu/watt-hr, or 87,000 MW with an efficiency of 10 Btu/watt-hr. Although not all of the air conditioners would ever be operating at the same time, this 58,000-MW reduction in connected load due to the efficiency improvement would surely result in an appreciable reduction in installed generating capacity requirements for the Nation's utilities.

Hot water heating required 4% of total U.S. energy consumption in 1968. Once the water was used, its remaining heat went down the drain. If some of this energy were recovered through heat exchangers, to supplement space heating requirements for instance, a substantial saving in fuel would result. Solar water heaters could be employed, as they are in a number of countries. One source[51] estimates they could provide a relief of 2% or more of total national energy requirements.

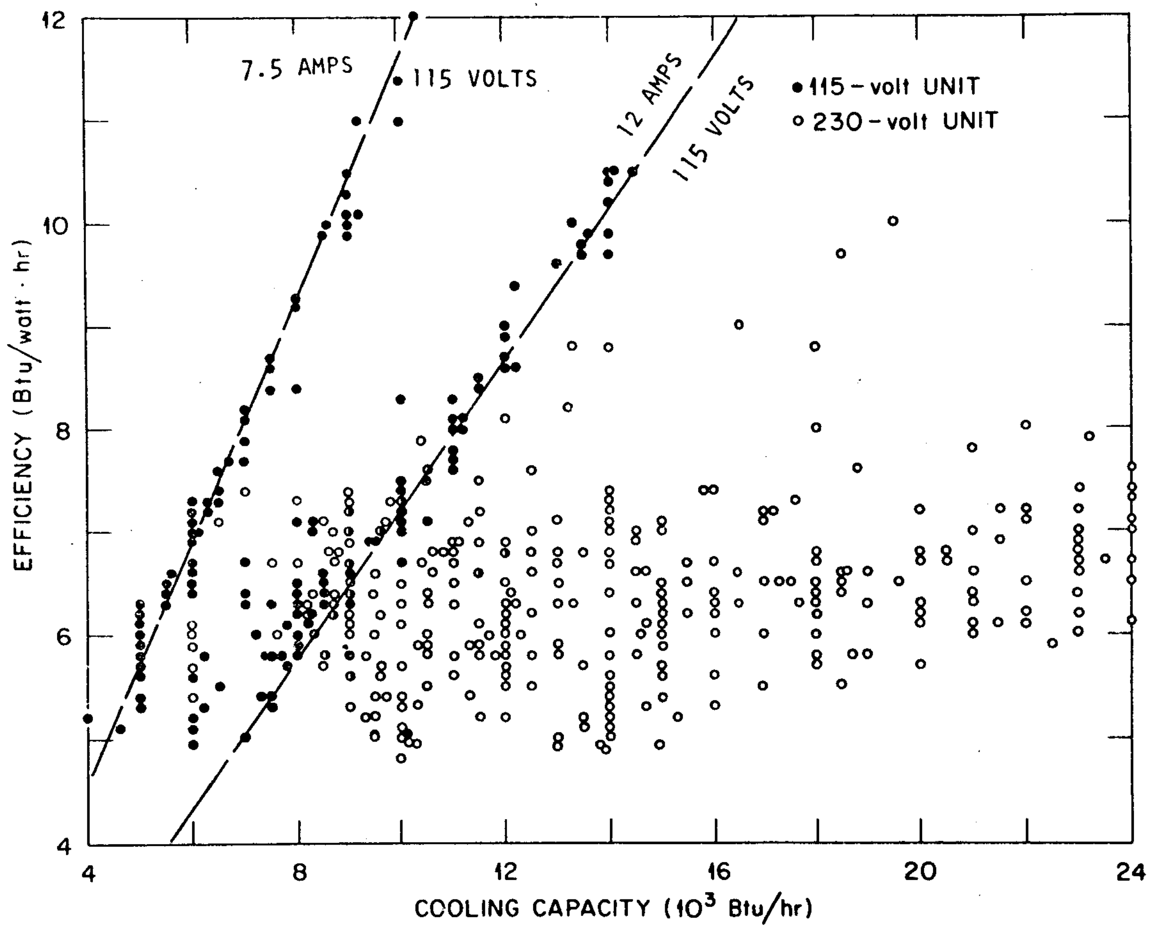
Table 6C.6-5

ESTIMATED AIR CONDITIONER SHIPMENTS, COOLING CAPACITY, AND AMOUNT OF COOLING (1973-1980)

Year	Shipments (millions)	Capacity Shipped (10^9 Btu)	Annual Cooling (10^{12} Btu)	Cumulative Cooling (10^{12} Btu/year)
1973	7.25	84.1	74.5	74.5
1974	7.77	90.1	79.8	154.3
1975	8.33	96.6	85.6	239.9
1976	8.93	103.6	91.8	331.7
1977	9.57	111.0	98.4	430.1
1978	10.25	118.9	105.3	535.4
1979	10.99	127.5	113.0	648.4
1980	11.78	136.6	121.0	769.4
	Total cooling for 8-year period			3183.7

Total power consumed:

At efficiency of 6 Btu/watt-hr, 530.6×10^9 kWhr.
At efficiency of 8 Btu/watt-hr, 398.0×10^9 kWhr.
At efficiency of 10 Btu/watt-hr, 318.4×10^9 kWhr.
At efficiency of 12 Btu/watt-hr, 265.3×10^9 kWhr.



EFFICIENCY OF ROOM AIR CONDITIONERS

Figure 6C.6-2

6C.6.2.5 Transportation

Transportation uses 25% of the Nation's energy. Of this total, automobiles and trucks use over three-fourths, while aircraft use another 8%. The remaining 17% is used by railroads, buses, waterways, pipelines, and other forms of transportation. More passenger-miles are traveled each year, and we continually use faster and more convenient transport modes that are also more energy-intensive. For example, there is now about one automobile for every two people in the United States. The two-car family is a way of life, and three- and four-car families are no longer uncommon. Freight transport has also become more energy-intensive. In the last 20 years, air and truck transport volume has grown dramatically, while more energy efficient but slower or less convenient rail and waterborne freight has increased only slightly.[1]

Transportation provides examples of energy being traded for convenience, comfort, and time savings. The energy efficiencies of vehicles for transporting people vary greatly. The fastest form of transportation, the airplane, is also one of the most profligate in terms of energy used per passenger-mile. On the ground, the automobile, the most flexible and ubiquitous vehicle, uses much more energy per passenger-mile than its competitors, the urban transit bus, the intercity bus, the passenger train, rapid transit, and commuter trains. This high rate of energy consumption per passenger-mile, coupled with our extensive use of cars, has led to their using 13% of all energy.[1]

Table 6C.6-6[57] shows approximate values for energy consumption and average revenue in 1970 for passenger and freight transport. The range in energy efficiency among modes is large. Over the last decade or so, the trend in transportation on the whole has been in the direction of use of less energy-efficient means and declines in the energy efficiency of individual modes. Trucks have been taking away intercity freight business from the more energy-efficient railroads; buses and railroads have been losing passenger traffic to more energy-intensive aircraft and automobiles. (Recent petroleum product shortages have shown signs of arresting these trends.) Lower energy efficiency of specific transportation modes has been the result of such things as the air-conditioning of automobiles, heavier automobiles--partly in response to recently required safety provisions, larger engines, and engine emission controls (emission controls currently being installed and projected are estimated to result in an additional gasoline consumption by 1980 of the order of 2 million bbl/day.)[59]

Table 6C.6-6

ENERGY AND PRICE DATA FOR TRANSPORT

Intercity Freight Transport

Mode	Energy (Btu/ton-mile)	Price (cents/ton-mile)
Pipeline	450	0.27
Railroad	670	1.4
Waterway	680	0.30
Truck	2,800	7.5
Airplane	42,000	21.9

Passenger Transport

Mode	Energy (Btu/passenger-mile)	Price (cents/passenger-mile)
	Intercity[a]	
Bus	1,600	3.6
Railroad	2,900	4.0
Automobile	3,400	4.0
Airplane	8,400	6.0
	Urban[b]	
Mass Transit	3,800	8.3
Automobile	8,100	9.6

[a]Load factors (percentage of transport capacity utilized) for intercity travel are about: bus, 45%, railroad, 35%; automobile, 48%; and airplane, 50%.

[b]Load factors for urban travel are about: mass transit, 20%; automobile, 28%.

A number of actions have been suggested to increase energy efficiency, improve the balance between transportation modes, and reduce the overall demand for transportation. These actions include incentives for the use of smaller automobiles (savings approaching 3 million bbl/day by 1985 are possible here), subsidized mass transit systems, and improved traffic flow through priority lanes for buses and car pools and traffic metering systems. If half of the intercity air traffic and one-quarter of the intercity automobile traffic could be shifted to passenger trains--requiring almost a 100-fold increase in railroad passenger-miles--and if railroads could operate at 70% capacity instead of the present 25%, about 11 billion gal of fuel could be saved annually. The figure is over 8% of all energy used for transportation in 1971.[1] Longer range recommendations encompass new transportation technology and urban design. The latter includes the development of urban clusters that would reduce drastically the need for low energy-efficiency transportation.[59]

A measure of the order of energy savings possible by a shift of transportation to the more efficient modes already available is given in Table 6C.6-7. The traffic shown in this table is that for 1970 in the U.S. The actual dispersion of traffic for 1970 among the various modes is indicated as well as a hypothetical rearrangement of the traffic to effectuate energy savings. In the hypothetical scenario, half the freight traffic actually carried by truck and airplane is assumed to have been carried by rail; half the intercity passenger traffic carried by airplane and one-third the traffic carried by car are assumed to have been carried by bus and train; and half the urban automobile traffic is assumed to have been carried by bus. The load factors (percentage of transport capacity utilized) and prices are assumed to be the same for both calculations. The hypothetical scenario requires only 77% as much energy to move the same traffic as for the actual case. The saving of 2.8 quadrillion Btu is equal to approximately 4% of the U.S. energy requirement for 1970.

6C.6.2.6 Other Conservation Measures

The conservation measures discussed above are those that appear most readily adaptable into our technical, economic and social structure. Most of the measures involve little or only moderate inconvenience; a few, such as improving the balance between transportation modes, would require careful long-range planning and substantial changes (not necessarily for the worse) in our approach to getting from one place to another. All these measures, however, can be considered part of an integrated, orderly approach to decreasing the usage of energy. On the other hand, one may also postulate conservation measures whose implementation would not be quite so orderly and which could involve varying degrees of disruption to our normal

Table 6C.6-7

ACTUAL AND HYPOTHETICAL ENERGY CONSUMPTION PATTERNS FOR TRANSPORTATION IN 1970

	Total Traffic	Percentage of Total Traffic: Air	Truck	Rail	Waterway and Pipeline	Auto	Bus[a]	Total Energy (10^{12} Btu)	Total Cost (10^9 \$)
				Intercity Freight Traffic					
Actual	2210[b]	0.2	19	35	46			2,400	45
Hypothetical	2210	0.1	9	44	46			1,900	33
				Intercity Passenger Traffic					
Actual	1120[c]	10		1		87	2	4,399	47
Hypothetical	1120	5		12		58	25	3,500	45
				Urban Passenger Traffic					
Actual	710[c]					97	3	5,700	68
Hypothetical	710					49	51	4,200	63
				Totals					
Actual								12,400	160
Hypothetical								9,600	141

[a]Intercity bus or urban mass transit.

[b]Billion ton-miles

[c]Billion passenger-miles

industrial, commercial, and residential activities. Several such measures were considered in a staff study by the Interior Department's Office of Energy Conservation, as part of an exercise in identifying potential energy conservation measures on a broader scale.[60] This study highlighted 300 ways for saving energy, and, although the authors noted that few of the measures had been thoroughly evaluated as of the time of publication (late 1973), most of them are similar to those discussed above in this environmental statement, e.g., space heating and cooling, improved insulation in buildings. Of the measures that could involve some disruption of normal activities, only ten were so identified, under the category of "suitable for implementation during an emergency." These measures are listed below to indicate what may be the "outer limits" of conservation practices:

(1) Shut down primary aluminum plants, using instead aluminum taken from stockpiles.
(2) Wash dishes by hand in lieu of using a dishwasher.
(3) Dilute natural gas with air to reduce consumption in pilot lights, yard lights, and other uses.
(4) Remove emission controls from all vehicles.
(5) Stop use of auto air conditioning on existing cars.
(6) Lighten weight of existing cars by removing spare tire and jack and bumpers.
(7) Permit burning of oil or gas only when solid fuels are unavailable.
(8) Reduce voltage of electrical power systems during periods of excessively high demand.
(9) Reduce frequency of electrical power systems.
(10) Shut down AEC gaseous diffusion plants (which are very large users of electricity).

The study does not estimate the energy savings that might be obtained through implementation of these measures, either individually or as a group, nor does it address the resulting economic or social consequences, which might range from moderate to substantial.

6C.6.2.7 Research and Development

The very substantial potential for achieving significant reductions in the end usage of energy through implementation of the measures discussed in the several sections above clearly justifies the undertaking of a research and development program to facilitate and accelerate these savings. A broad framework for conservation research has been set forth in "The Nation's Energy Future," as discussed above, and several elements of this program have already been integrated into the Government's energy research and development activities for fiscal years 1974 and 1975. For example, the Federal Energy Administration announced in May 1974 the undertaking of nine research, development, and demonstration contracts in energy conservation representing an expenditure of more than $1 million. The purpose of this program is "to build the technical, economic, and institutional base essential to achieving our comprehensive, long range energy conservation goals."[61]

These studies will focus on end use of energy and conservation opportunities in industry, buildings (residential and commercial), and transportation. Studies will be carried out by FEA's Office of Energy Conservation, other Government agencies, and private groups. They will include evaluation of the energy characteristics of mobile homes, design of a seven-story energy-conserving office building, installation of an electric heat pump in a 20-year-old house, study of the fuel conservation aspects of a high-speed rail-transit line, development of an information exchange on energy research needs, and related activities. Additional studies are also planned by FEA and other Government agencies. Further insight into the likelihood of success of these activities and their eventual effect on energy demand is provided in the following section.

6C.7 SUMMARY

The preceding discussions show that a wide variety of energy conservation measures are known to exist, and many of them are worthy of immediate implementation. However, their potential for significantly alleviating current fuel shortages or becoming, individually or as a group, a viable alternative to the LMFBR is mixed. A number of potential conservation measures, while attractive in theory, do not appear likely to offer major relief to fuel scarcities and in themselves may lead to significant economic or environmental penalties. Other conservation methods are worth pursuing and should be implemented where practical. The relative advantages and disadvantages of the conservation measures discussed in this section are summarized below, along with various views as to their potential for reducing total energy and electricity demand, their possible effects on lifestyles, and their overall potential as an alternative to the development of new energy sources such as the LMFBR.

Improvements in methods of resource extraction for coal, oil, gas, and uranium could, if implemented, result in the availability of additional fuel to such extent that if the additional fuel were all allocated to the production of electricity (which is unlikely), it could support an additional generating capacity of 82,000 MWe annually by the year 2000 (see Section 6C.2.4). This amount is about 4% of the installed U.S. generating capacity projected for that time period. This increased fuel availability would require substantial investment in improving extraction efficiencies and would result in various environmental impacts beyond those associated with current resource extraction methods, such as possible contamination of surface streams by water injected into oil wells, radiological and other effects of nuclear explosives that may be used in the stimulation of natural gas wells, and increased ground subsidence over coal mines. Any decisions on implementing increased resource extraction methods would have to balance the potential payoff in fuel availability against the economic and environmental costs associated with each method.

Potential improvements in power plant conversion efficiencies using current technology for fossil- and nuclear-fueled plants appear to be limited and are not expected to change significantly the amount of usable energy that may be extracted from power plant fuels. (This discussion does not apply to basic changes in technology, such as MHD power generation, as discussed in Section 6B.) Some improvements in conversion efficiency may come about due to future changes in current technology, such as the development of high temperature alloys. However, due to economic considerations and the small potential payoff (see Sections 6C.3.1

and 6C.3.2), conversion efficiency improvements are expected to be the result of improvements or changes in technology, rather than to provide the impetus or incentive for them.

Utilization of waste heat from power plants is generally considered a fertile untapped area for energy conservation, but as noted in Section 6C.3.3 its full potential may never be realized due to a variety of technical and economic reasons. Further, the extent to which waste heat utilization may actually replace some other energy source is difficult to quantify. Nevertheless, both economic and environmental advantages would appear to exist in the utilization of waste heat in certain specific applications, and this utilization would appear to be a viable conservation measure in such instances.

Minor improvements in the ratio of net vs gross generation of electricity could be obtained through the use of steam rather than electricity to drive plant auxiliary equipment. A significant improvement in this ratio might be obtained through a reduction in the energy devoted to pollution control in the production of electricity as well as other goods and services. The anticipated use of 10% of electricity by industrial and commercial users for the operation of pollution control equipment by 1977 represents a substantial resource use. Any changes in the relative amount of energy devoted to pollution control that might be proposed as a means of alleviating fuel shortages or as an alternative to development of the LMFBR would have significant social as well as environmental and economic consequences. They would merit wide discussion on a national basis by all concerned elements of government, industry, and the public.

The amount of energy that might be saved by conserving energy through reducing losses in the transmission of bulk electric energy from generating plants to the distribution system is not large. The principal methods that could be employed, such as raising transmission voltages or reducing resistance, result in only minor efficiency gains; the countrywide savings that could accrue from raising of voltages in the 240 kV and above range over the period 1974-80 has been estimated to be equivalent to the output of one 760-MWe baseload generating plant. The use of nearer term innovative underground transmission methods is not expected to lead to significant energy conservation. Only the installation of superconducting cable systems, not likely before the late 1980's, would result in an appreciable reduction in transmission losses underground. This reduction is estimated to be only on the order of the output of one baseload 10-MWe generator if all underground circuit additions over the period 1990-2000 were in superconducting AC cable rather than conventional cable. Thus, the transmission of electricity does not appear to be a promising area for large savings from conservation measures.

The situation with regard to distribution systems is similar. The major potential in this area is in optimizing the loading of distribution transformers; this is shown in Section 6C.5.2 to result in a total annual savings by the year 2000 equivalent to the generation of one baseload 1100-MWe power plant. While not insignificant on an absolute basis, this generating capacity is only a minute fraction of the installed generating capacity that will exist by the year 2000.

Conservation of energy at the point of end use has only recently begun to receive wide attention. Contrasted to the several measures discussed above (improvements in resource extraction, in power plant conversion efficiencies, and other factors), whose total contributions might result in savings equivalent to approximately 5% of U.S. generating capacity in the year 2000, end-use conservation can result in very substantial and worthwhile energy savings and could appreciably lower U.S. demand for both electricity and total energy usage in the years to come. The "technical" means by which these savings may be achieved are known and include the installation of improved insulation in buildings, the use of more efficient space heating and cooling equipment, the introduction of more efficient industrial processes and equipment, the shift to more efficient modes of transportation, and the various other measures discussed in this section. Not quite so clear, however, is the magnitude of the energy reductions that may be achieved from implementation of these measures. The principal issues bearing on this question that are still the subject of debate include the extent to which various conservation measures will be technically successful, the date and rate of introduction of conservation practices, the extent to which people utilize these practices and accept accompanying changes (where applicable) in their lifestyles, the extent to which energy conservation should be "enforced" by government regulation or pricing policies, the extent to which research and development in energy conservation will be supported--as well as be successful (which in turn bears on the degree of technical success that can be achieved by conservation measures), and related matters of policy, economics, and planning.

A number of studies have been conducted by government agencies and private organizations (as reviewed earlier in this section) which attempt to estimate the results of a national commitment to energy conservation in terms of energy savings. These studies are based on a variety of assumptions and end dates and lend different weight to the several policy, technical, and planning variables just noted. To run a strict comparison between the energy savings projected by the several studies for specific future dates is therefore difficult, if not impossible. However, an examination of their broad conclusions is instructive, while recognizing that, on the basis of their differing assumptions, none of them may prove to be accurate or, on the other hand, they all may prove to be correct in varying degrees.

The Office of Emergency Preparedness study was undertaken in 1972 with the objective of suggesting programs that would either improve the efficiency with which energy is consumed or minimize its consumption, while providing the same or similar services to the consumer. The conservation measures suggested dealt primarily with energy utilization in the major consuming sectors. The study concluded that full implementation of the measures suggested could reduce projected U.S. energy demand in 1980 (96 quadrillion Btu) by 15 to 17% and 1990 demand (140 QBtu) by 23 to 25%.

The Ford Foundation's Energy Policy Project examined three "levels" of conservation. The first level (little or no conservation) was based on the historical energy growth rate in total energy usage of about 3.4% per year. This scenario would result in the use of 180 quadrillion Btu in the year 2000. The second scenario halved this growth rate through the application of a vigorous conservation program but without reducing the Nation's standard of living or significantly changing life-styles. Under this approach, energy usage would amount to 118 quadrillion Btu in the year 2000, a savings of 36% over the historical pattern. The third scenario is one of zero energy growth, in which energy usage would level off at 100 quadrillion Btu in the year 2000, resulting in a savings of 46%. Although this scenario does not, according to its proponents, involve austerity, it does require some significant changes in lifestyle, including redesign of cities and transportation systems.

Since the Ford Foundation study yields results only in terms of total energy usage, it is not clear what the corresponding reductions in electricity usage would be in these scenarios. However, as discussed previously, reductions in electricity usage would clearly be less than those for total energy. Zero energy growth is not equivalent to zero electricity growth.

The Council on Environmental Quality's Half and Half Plan also proposes a vigorous conservation program, coupled with well-defined energy supply and usage goals. The target for gross energy consumption in the year 2000 under this plan would be 121

QBtu, representing an average annual growth rate of 1.8%. Many similarities may be noted between this approach and that in the Ford Foundation's second scenario (technical fix).

The study of energy conservation strategies by the Environmental Protection Agency places more emphasis than the previous studies on government policies and regulation as incentives to achieving energy conservation. It concludes that national savings of 41 QBtu by 1990 or 30% of energy usage otherwise projected (135 QBtu) for that year could be achieved by implementation of the suggested strategies.

The Federal Energy Administration suggests that reduction of the current and projected 3.6% annual growth rate in energy usage to 2.0% is possible without hindering an adequate national growth rate. The bulk of these savings will come in transportation, household, and industrial uses. This reduced energy growth rate will be necessary to achieve U.S. energy self-sufficiency by 1980 through Project Independence. The FEA proposal does not extrapolate this approach to yield energy usage figures for future dates such as 1990 or 2000 as in the other studies, but if the suggested annual growth rate of 2.0% is achieved, energy usage in the year 2000 might be about 30% less than that projected based on historical growth patterns.

An interagency government panel reported to the President in December 1973 (see The Nation's Energy Future[2]) that, with minimal social and economic dislocation, a 20% energy savings by the year 2000 would be a conservative estimate. A number of conservation activities, including research and development in resource recovery, industrial processes, energy management, and other areas, would have to be implemented if this program is to be successful.

The AEC's staff forecast[15] suggested that where conservation measures are employed to the assumed extent (such that improvements in standard of living or economic development would not be limited), a savings in total energy consumption of 10% per year could be achieved by the year 2000 as compared to the historical trend (174 QBtu in that case vs 195 QBtu historical). Under the combined impact of maximum conservation efforts, higher energy prices and slower rate of economic growth, total energy consumption by the year 2000 could be reduced as much as 30% from the historical pattern, down to 135 QBtu. These values are meant to be used as forecasts rather than as firm calculated values.

What, then, may be concluded from these several studies as to the extent to which conservation measures may reduce projected energy demands? Although as noted above

Table 6C.7-1

APPROXIMATE COMPARISON OF ENERGY SAVINGS RESULTING FROM IMPLEMENTATION OF PROPOSED CONSERVATION MEASURES

Office of Emergency Preparedness	23-25% by 1990
Ford Foundation - Energy Policy Project	36% by 2000 (technical fix scenario)
Council on Environmental Quality	35% by 2000
Environmental Protection Agency	30% by 1990
Federal Energy Administration	30% by 2000[a]
Nation's Energy Future	at least 20% by 2000
AEC, Office of Planning and Analysis	10-30% by 2000

[a]Based on extrapolation of annual 2% growth rate.

an accurate direct comparison of these studies' conclusions is not possible without substantial qualification, such a comparison is presented in Table 6C.7-1 as a rough estimate of what might be achieved. A general consensus of these studies is that a vigorous conservation program could, if successful, reduce total energy consumption by about 30% by the year 2000.

As indicated previously, a 30% reduction in projected total energy demand in the year 2000 may not necessarily result in a proportionate reduction in electrical energy demand. This is so because many of the projected conservation measures are in areas in which electricity does not now play a major factor, and the extent to which they may play a larger factor in the year 2000 cannot be stated with certainty. Some of the energy conservation measures will result in increased future requirements for electrical power. To take one illustrative example, conservation of oil by encouraging more efficient transportation methods could result in increased electrical power demand to power electric trains for mass transportation and ultimately for electric automobiles for personal use. From the mid-1970's til the year 2000, the additional usage of electricity for transportation and other purposes such as space heating will result in an increasing role for electricity in our total energy usage patterns. By the year 2000, it is reasonable to assume that many applications of electrical power may have become saturated and that future reductions in total energy usage may then become more closely proportional to reductions in electricity usage.

It should also be noted that the specific conservation measures discussed in

Section 6, as opposed to across-the-board improvements in efficiencies, may result in a different energy usage mix than the standard mix assumed. That is, it is likely that specific conservation measures may lead to a larger share of the total energy market for electrical energy than the 50% share usually projected by the year 2000.*

Should energy conservation then be established as a national goal? Several letters commenting on the Draft LMFBR Program Environmental Statement (see quotations in Section 6C.1) indicated that this should be the case. They concluded that energy conservation is a matter of national policy and suggested various means by which energy savings may be obtained. The Natural Resources Defense Council, in their letter,** indicated that conservation practices could result in electricity demand being reduced by as much as 40% of the historical projection by the year 2020. This conclusion is not inconsistent with the "findings" summarized in Table 6C.7-1.

The Atomic Energy Commission, as noted earlier, is in agreement with the opinions favoring energy conservation expressed by these letters and supports a vigorous energy conservation program.

Several remarks were also made in the comment letters that conservation measures that would require changes in our lifestyles should be considered in the environmental statement. For example, the April 24, 1974, letter from the Mid-America Coalition for Energy Alternatives*** suggested that

> The real conservation question is by-passed--namely, can we learn to live less energy-intensively, thus stopping the continued growth of per capita energy consumption.

More specifically, an April 22, 1974, letter,† from M. T. Carter et al. noted:

> The discussion is nevertheless limited in that changes necessitating serious adaptations in our national lifestyle are not included. Certainly, it would be difficult if not impossible to quantify such changes in the manner that other conservation measures in the section were quantified as to possible savings, and some changes might at this time be so repugnant to sectors of the public that the possibilities of implementation in the near future are slight. However, the same

*Although electricity generation now accounts for only about 25 to 30% of energy usage, this fraction is expected to rise to about 50% by the year 2000 as more homes are heated by electricity, as more transportation systems become electrified, etc.

**Comment Letter 38b, pp. 10-16.

***Comment Letter 22, p. 15.

†Comment Letter 19, p. 3.

> changes in lifestyle which we may now reject might someday be considered desirable or needed, and a section on conservation as an Alternative Technology Option in the DES provides an excellent opportunity to begin to enumerate changes in our lifestyle which might now seem radical.
>
> While we may now recoil from the major changes in our lifestyle which would be indicated by such situations as exemplified above, it is nonetheless reasonable that we consider, as a significant conservation measure, the alteration of the lifestyle to which we have become accustomed. The LMFBR Program DES does not probe conservation measures having such a major impact on our lives - a discussion of this sort might prove useful.

The AEC recognizes that such measures do have a place in conservation planning, and many of these measures that require changes in lifestyles are now clearly part of some of the conservation studies and programs reviewed in this environmental statement. For example, the Ford Foundation study's scenarios include a zero energy growth situation that would require major changes, such as redesign of cities and transportation systems. The AEC Office of Planning and Analysis study (Case A) considers higher energy costs as a means of discouraging energy use, and the Environmental Protection Agency study referenced also examines "forced" savings. Various degrees of restrictions in personal choices and lack of availability of "conveniences," such as shifts to smaller cars and reduction in air conditioning are an inherent part of several of the conservation proposals reviewed.

Will such restrictions be accepted and complied with by the public? The EPA report addresses this issue:

> Current emphasis is on energy conservation through "voluntary" programs. The American consumer seems to be quite willing to cooperate in such programs in the short run, when he believes the purpose is valid. However, he seems unwilling to make economically unsound choices for any great length of time; and he seems very quick and willing to make economically prudent choices. He has more common sense than to ask for higher prices, but doesn't seem to be clamoring for especially low energy prices any more. For these reasons, it behooves policy-makers to give careful consideration to the means by which the "voluntary" actions which are needed can be converted into economically rational actions on the part of consumers. (p. 3)

This point was further discussed by Mr. J. W. Simpson, President, Power Systems, Westinghouse Electric Corporation,[62] in a recent speech:

> The fact is that energy wastage is not nearly so high as some might believe, and a seemingly sizable reduction of, say, 20% would really do little to defer the depletion date for oil and gas. Truly deep cuts can only be made by mandating substantial reductions in our standard of living. I see no evidence that people in this country are willing to accept a permanent decline in living standards -- especially if it is unnecessary.

Recent developments such as the lack of compliance by many motorists with reduced highway speed limits would seem to support this statement.

The AEC believes that conservation measures requiring changes in lifestyles should indeed be considered as part of any major program in energy conservation. Whether or not such measures would be successful (both technically and in their acceptance by the public) can now only be guessed at. Some of the suggested changes in lifestyle actually involve only slight inconvenience or hardships, while some of the major concepts proposed in this area would involve substantial restructuring of our economy and perhaps even our landscapes. Obviously the decisions that will have to be made regarding energy conservation measures must include consideration of potential changes in lifestyle as well as technical, economic, political, environmental, and social aspects of our energy supply vs demand situation in future times.

Another point that has been raised in the review of the Draft Environmental Statement has been that of the impact of electricity cost on electricity usage. For example, the April 26, 1974, letter* from Dr. C. Kepford suggested that the Statement consider:

> ...the influence of utility company rate structures and promotional practices on consumption patterns assumes that consuming patterns originate from a spontaneous demand with the public. This is an utter falsehood.

In a similar vein, testimony offered by the Scientists Institute for Public Information at the April 25, 1974, public hearing held on the Draft Statement noted:

> ...it is a basic error to extrapolate historical patterns of electrical demand growth without taking cognizance of how this fundamentally new economic fact (price elasticity) will affect demand for electricity in the future. Furthermore, it is now the policy of this Administration, as enunciated by the President and the Federal Energy Office, to encourage energy conservation by allowing energy prices to rise, and even by increasing them with added taxes.

*Comment Letter 25, p. 31.

The AEC recognizes the influence that energy price will have on energy usage, and this influence has indeed been reflected in the cost-benefit discussion in this Environmental Statement and in some of the conservation studies reviewed in this section (on which the projected energy savings reported herein have been based). In particular, energy pricing is a major element of the conservation strategies discussed in the EPA report and was also considered in several of the cases examined in the AEC Office of Planning and Analysis report. There can be little doubt that higher energy prices will tend to drive energy usage down; this effect is already being observed to some extent. Whether or not the public will welcome or accept such pricing policies as "incentives" to conserve energy is, as in the case of potential changes in lifestyles, a political and social matter as well as an economic one. In addition, as energy costs increase, not all energy sources are affected to the same extent; that is, the relative costs of different types of energy will change, and this change will also affect their relative usage. For example, as the cost of diesel oil has increased substantially, at least one railroad is giving serious thought to using electricity on a large portion of its system. Thus, an increase in energy costs might lead to more rather than less use of electricity.

As indicated above, several of the comment letters on the Draft Statement supported conservation of energy as an alternative to the development of the LMFBR. Various conservation measures and strategies were proposed in these letters, most of which concluded, as did the April 29, 1974, letter* from the Natural Resources Defense Council, that:

> Energy conservation is a matter of national policy. It cannot be ignored.

However, although the benefits of energy conservation are apparent to almost everyone, several voices have been raised to the effect that conservation is not the complete or final answer to the energy crisis. For example, in his address[62] before the American Nuclear Society noted above, J. W. Simpson stated:

> Some feel that energy conservation can solve our problem. Without question, the use of improved insulation, smaller cars, more efficient appliances, recycling of materials, and similar efforts can help to some degree and should be aggressively pursued. However, it is wishful thinking that conservation alone can solve the long-term problem.

*Comment Letter 38b, p. 13.

Mr. Simpson went on to note, with regard to a reduced usage of energy, that:

> ... even if Americans were willing to accept reduced living standards this would not really change the world energy problem. Per capita GNP and energy use patterns attest that most of the world exists in terrible poverty, with truly compelling needs for improved living standards. The problem is to bring these nations toward the U.S. level, not drag the U.S. downward. Even if we reduced U.S. living standards, this would produce surprisingly little help for the rest of the world. In fact, if U.S. citizens returned to living of our colonial days and transferred all our energy resources overseas, the time to exhaustion of world oil and gas supplies would be extended less than one decade!

In a similar vein, Mr. Jack Moore of Southern California Edison Company observed in his prepared statement at the April 26, 1974, public hearing:

> Conservation measures such as improved equipment efficiencies and reduced energy demand can go only so far in alleviating the problems due to fuel shortages. Curtailing the energy usage of existing consumers provides only a temporary relief from shortages. A healthy economic environment and improving living standards for the less privileged in the future will depend not on reduced usage, but on the development of available energy resources as yet untapped within the present economic framework.*

In an even more direct manner, Mr. Carl Bagge, President of the National Coal Association, in a May 1974 speech before the Portland Cement Association,[63] warned the Federal government against too great a reliance on energy conservation in achieving energy self-sufficiency:

> Conservation is a most important tool. But while conservation looks like the easiest way out on paper, it is difficult to mandate through administrative hearings or acts of Congress.

Mr. Bagge said he could easily imagine Congress passing a law that requires all cars to get 25 miles per gallon by 1985, "but I hate to imagine what would happen when Detroit had to shut down production lines because the best its biggest cars could do is 23.7 miles per gallon."

> We've been down this route before with highly technical clean air and water standards that paid close heed to political climates but ignored the simple economic and technological facts of life. I hope sincerely that this time the federal establishment sets realistic goals for its program of attaining energy self-sufficiency and then set a judicious course to achieve it.

*Transcript of public hearings on the LMFBR Program, p. 4.

> Conservation will, of course, be a part of this program, ... But reasonable men must agree that it can be but a secondary part of the program unless the nation is willing to scrap much of its existing industrial base, which is the nation's largest consumer of energy.

This is true because a massive energy conservation program would require the early retirement of existing industrial equipment and its replacement with modern energy-efficient designs, according to Mr. Bagge.

> Let's face facts. What we need is more energy, not less. And the best way to produce more energy is providing incentives and removing the traps and snares that stand in the way of attaining this goal.

Finally, Mr. Milton Levenson of the Electric Power Research Institute observed in his testimony* at the April 26, 1974 public hearing:

> There appears to be no acceptable alternative to the expansion of electric power generation. Even with the most conservative projections of population growth during the next 30 years we expect a 30 percent to 40 percent increase in the nation's total population. During the past half century the total energy consumption per capita in the U.S. has roughly doubled, with a good part of that increase occurring in the last decade. Even with the most effective attempts at energy conservation and increased efficiency in end uses, it would be optimistic to project less than a doubling in the per capita energy consumption during the next half century. The economic welfare and social goals of our population are such that any lower projection seems unlikely. Historically electricity consumption has grown much more rapidly than total energy consumption, primarily because of the convenience and safety for the consumer of this particular energy form. ... While it is difficult to predict how fast future electricity demand will grow relative to total energy consumption, the factors which have made it desirable in the past will probably continue to make it more so in the future. The key point is that increasing electricity production will remain a prime demand of our society.

*Transcript of public hearing on the LMFBR Program, p. 255.

6C.8 CONCLUSIONS

There are numerous strategies, policies, and technical measures by which energy usage may be reduced from its current levels or by which future projected energy demand levels may be reduced. The greatest potential for achieving substantial energy savings is in the various end uses. A rough consensus of several of the more recent and authoritative energy conservation studies would indicate that, with a vigorous conservation program, the use of electricity and other forms of energy could be reduced by about 30% from those levels now projected for the year 2000. The achievement of these savings, however, presupposes various degrees of success in the following respects:

(1) Governmental bodies will encourage and financially support to a much greater extent than in the past research and development into mechanisms and processes for conserving energy.

(2) Improved energy conservation measures will be developed and prove successful in practice over the years in reducing energy usage to the projected extent.

(3) Industry and the public will accept the considerably higher energy prices inherent in some of the conservation strategies and measures proposed.

(4) The public will accept the moderate to severe inconveniences and changes in lifestyle that would inevitably accompany a number of the proposed conservation measures.

Acting on the assumption that energy conservation is indeed pursued and proven successful over an extended period of time such that the anticipated energy reductions are achieved and noting that the resulting electricity savings are approximately equivalent to that which otherwise would have to be produced by the LMFBR, the Natural Resources Defense Council suggests in their April 29, 1974, letter* that the need for the LMFBR may be eliminated. The AEC submits that this argument is over-simplified. Although energy conservation is necessary and desirable, and should be pursued to the maximum feasible extent, there is no assurance at this time that future energy demand will be substantially reduced by conservation practices. This belief is based on the questions regarding acceptability of changes in lifestyles, technical achievement, and costs as discussed above and is reinforced by the viewpoints of Simpson, Moore, and Bagge. For these reasons, a national program of energy conservation, however desirable, is no more assured of success in reducing energy demand by a fixed amount than any of the other alternative

*Comment Letter 38b, p. 16.

options discussed in this Environmental Statement are assured of increasing the energy supply. The AEC, therefore, believes that failure to develop promising technologies such as the LMFBR in the expectation that they may not be needed due to possibly lessened future energy requirements from a successful conservation program would be unwise. The AEC believes that appropriate energy supply options should be developed and also that conservation measures should be encouraged and supported. In this manner, our energy requirements may be both held to reasonable levels and met in an economic and environmentally acceptable manner.

In conclusion, the AEC feels that while the final place of energy conservation as an alternative to energy production technologies is not yet completely determined, as discussed in this Environmental Statement, those conservation measures that meet all necessary criteria should be made a part of our energy use patterns as soon as practicable.

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