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TECHNOLOGY CHARACTERIZATIONS ENVIRONMENTAL INFORMATION HANDBOOK

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TECHNOLOGY CHARACTERIZATIONS

Environmental Information Handbook

U.S. Department of Energy
Assistant Secretary for Environment
Office of Environmental Assessments

June 1980

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FOREWORD

The business of the public sector is to make governmental policy decisions and to implement those already made. These activities demand considerable amounts of time and resources. Furthermore, they require the gathering and analyses of large amounts of information for successful operation and completion. Policy debates, often conducted in a hurried atmosphere, initiate an immediate requirement for new analytical information for a particular issue under consideration. When a new subject is begun, the previously developed information is set aside to be used later for similar discussions. Even then, the users tend to be the same people who were familiar with the prior data base.

Information developed in this manner is generally not available to the open literature. This is true not because of any desire for secrecy, but because it takes time and resources to organize information for purposes other than policy decision inputs. The inclination is usually lacking in the bureaucracy to take the additional time and spend the resources to transform information for other uses or even to initially develop it in a format for additional possible applications. Furthermore, there is often the suspicion that public sector information from a mission agency is not apt to be totally unbiased, and this can result in tacit dismissal.

The Environmental Handbook Series is designed to overcome the deficiency of information utility and transfer. Each of the works in this series will bring together information in an area and format that is useful to both public and private sector needs. It is meant to serve as a basic reference document that will stand for a period of time and help to enrich decisionmaking and research in the interface of energy and the environment.

Further, the production of summary documents, such as in this Handbook, helps to more sharply focus the adversarial nature of policy debates. By making explicit the information base available and by exposing it to peer review prior to input into policy deliberations, an organization insures the credibility of the data, or has a basis for not using it. The policy debate then narrows considerably as the quality of the technical detail is substantiated.

This particular handbook deals with environmental characterization data for the energy technologies and presents the data in a format for use by DOE policy analysts. This treatment includes not only the actual information base, but also a Preface which explains the present concept, the historical growth of the program, and the new direction for improved utility. The information base, itself, is constantly being enhanced and is republished periodically as necessary.

The development and maintenance of the Environmental Characterization Information Base is the responsibility of the Technology Assessments Division. Assistance was provided by The Mitre Corporation in the preparation of the summary information sheets, and by the Aerospace Corporation in the development of the draft Environmental Information Characterization Report (Appendix A). Special acknowledgement goes to Albert E. Fry, consultant, for assistance provided in the preparation of the Preface.

Peter W. House, Director
Office of Environmental Assessments
Office of Environment

PREFACE

Environmental Information Requirements for Energy Technologies

The availability of quality energy-related environmental information for use by the Department of Energy is essential for evaluating alternative energy policies and technology strategies, and for carrying out responsibilities assigned by the Congress. Environmental information is required for two different purposes. First, the Department conducts strategic energy policy and planning analyses which forecast the future levels of U.S. energy consumption and supply as well as the shares to be provided of the various fuels by the competing energy technologies. Second, the Department plays a leading role in the development and advocacy of specific new energy technologies. Simply stated, energy planners are seeking to determine how much energy will be required and produced domestically, and how much of this domestic share will be produced from the various energy sources. Strategic energy planning should include an assessment of the environmental implications of the various energy generating technologies. The relative success or failure of the competing energy technologies depends upon economic, engineering and environmental considerations. These considerations are inseparable since engineering design modifications and the implementation of additional control technologies can reduce pollution residuals at some added cost, efficiency and safety of the energy technologies involved.

The Department also needs environmental information for other program requirements ranging from the preparation of Environmental Impact Statements to working with the Environmental Protection Agency in the development of environmental regulations for emerging energy technologies. Department of Energy environmental information is often used by State and Local planners, by public interest groups, and by the business community in the process of formulating industrial policy. However, the first two purposes identified are representative of the Department of Energy's needs in this area and also provide a focus for identifying certain inherent problems with the information.

To conduct strategic energy policy and planning analyses, national or regional energy models are usually employed. Given existing resource and time limitations, collection of accurate and current information for each individual energy facility is costly. Energy analysts are forced to rely on limited information for existing or hypothetical facilities for estimating the environmental impacts. For example, the analyst may rely on real data from existing plants collected by the Environmental Protection Agency or State environmental control agencies, or, based on existing and proposed environmental regulations, the analyst may develop a representative model of future plants and extrapolate existing data to fit the representative model. No real plant will match this model plant precisely since site specific conditions, coal type, system components, engineering design, environmental control technology and other factors may vary somewhat from the model in reality. Over a reasonable sample size this representative plant works very well. But for a single site specific plant there will be variations from the expected information. The problem of ascribing data to hypothetical facilities is heightened when dealing with new emerging technologies, which are usually dependent upon a limited number of prototype or demonstration facilities and may not reflect future reality.

The description of most model process systems with the related data can always be improved since more resources enable the analysts to perform a more comprehensive study, and apply more quality control. Data elements in particular, always require continuous validation and updating. A problem facing every information manager is the determination of which information requirements can be satisfied within given budgetary constraints. For analyses required to support the development of emerging new energy technologies, the level of specificity of environmental information desired is very high. The program manager needs assurance that information is generated from an engineering design or operation which most accurately reflects the program manager's current projection of the specific energy technology to be carried through to commercialization. The fewer the number of existing facilities, the more difficult it is to develop a representative model plant. If the analyst attempts to average a wide range of estimates, the decision makers find that the information is no longer useful.

In summary, environmental characterization information needs to meet both the general requirements of the strategic energy policy planner and the more specific requirements of the managers of developing technologies. Additionally, the information should be documented, verifiable, consistent, current and available in a format applicable to the diverse users inside and outside the Department.

Evolution of the Activity

The conception of the Environmental Characterization Information activity began with information requirements for the Strategic Environmental Assessment System (SEAS). SEAS, a mathematical model for assessing environmental impacts on a national scale, was originally developed by the Washington Environmental Research Center of EPA. Subsequently, use of this model was incorporated into the analyses conducted by the Energy Research and Development Administration (ERDA) Assistant Administrator for Environment and Safety. SEAS contains extensive environmental data files which were drawn initially from a wide range of sources such as the EPA National Emissions Data System, the EPA New Source Performance Standards and Effluent Guidelines, Hittman Associates "Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use" (Contract for CEQ), the EPA "Cost of Clean Air" and "Cost of Clean Water," and the EPA "Industry Studies."

Subsequently, additional data from the Bureau of Mines, Federal Power Commission, Federal Energy Administration, Brookhaven National Laboratory and from ERDA's Market Oriented Program Planning Study (MOPPS) were added to the SEAS data bases. The data developed were normalized to 10^{12} Btu of energy output for use by the model. These extensive environmental data bases, despite existing inadequacies, comprised the most complete data set of environmental characterization information available to ERDA and subsequently to the Department of Energy.

In 1977, with contractual assistance from the MITRE Corporation, Consad, Inc., Control Data Corporation, and International Research and Technology, Inc., SEAS was used by ERDA to produce the information for the first Annual Environmental Analysis Report which provided a national and regional analysis of President Carter's first National Energy Plan. Distributed widely, the report became an important element in the energy policy debate which followed. In 1978, the Office of Technology Impacts, under the DOE Assistant Secretary for Environment, accelerated the validation and updating of the data in SEAS. As an integral part of this activity, a series of documents gradually evolved which presented comprehensive environmental data on the environmental pollution potential of the various energy technologies.

The first step was the production of summary data sheets for a set of energy technologies. These summary sheets were generated in a format which reflected SEAS requirements. The first volume, "Environmental Data for Energy Technology Policy Analysis," was published in January 1979, with a supplement adding several new technologies appearing in August 1979.

In January 1980, a revision entitled, "Environmental Data/Energy Technology Characterizations" was issued. Approximately one-half of the data summary sheets had undergone considerable revision with improved quality control and data source documentation. In addition, supplemental publications for each major energy fuel source (coal, nuclear, petroleum, solar, etc.) have since been prepared to explain the methods used to develop the summary volume. The chapters in each supplementary volume, relating specifically to the organization of the summary, begin with a brief description of standard characteristics, size, availability, mode of operation, and place in the fuel cycle. Next, major legislative and/or technological factors influencing the commercial operation of the activity are identified as well as coefficients for resources consumed, residuals produced, and economic information. The data summary sheets presented in subsequent pages of this publication complete the major revision begun in January.

Present Limitations

The purpose of the present activity is to present environmental characterization information in a useful format for environmental policy and planning analyses relating to energy technology development and deployment. The information should represent the best available data on resource requirements and environmental effects for each principal energy technology considered.

Evaluation of the present information base has revealed inherent weaknesses. Some data are inconsistent with the base model description, some are based on faulty assumptions or outdated engineering designs, some data have been entered incorrectly into the system, and some elements have been derived from studies of questionable validity. As a result, approximations have been made by analysts. Also, missing data are prevalent, particularly for coal conversion and other new technologies. While approximations assuming reasonably valid and consistent information are ordinarily adequate for general environmental policy and planning activities, this approach is not adequate for site specific analyses. If one is concerned with the distribution of plants across the country, then the information can be used to develop estimates of the total loadings in a particular geographic region, representing the total environmental impact for that region.

Although aggregations of the residuals can be computed in this way resulting in an understanding of the changes or rates of changes of total pollutants in the environment, problems remain. The information in "Environmental/Energy Data Characterizations" is not realistically representative of specific operations nor realistic in terms of being able to identify the need for particular control equipment that might have modified these systems. In many cases, the hypothetical plant on which the characterization is based is an average of several installations which may have used different technological bases. The energy systems used to develop the model plant vary in character and raw material input requirements. The hypothetical basis is ineffective for real world analyses.

While the net result of the present effort has significantly improved information, certain deficiencies in consistency and reliability remain. Because the data have been derived from multiple sources, the numbers represent outcomes of engineering analyses which have been developed using different criteria. The residuals computed for a particular type of technology are sometimes derived from the analyses of two or more specific engineering systems, each behaving differently and discharging different levels of residuals. Moreover, in addition to not using standard criteria for base system selection, certain parameters have been derived by calculations which do not have a clear relationship to a specific engineering system. Consequently, the environmental residual coefficients combined in the summary volume as a single value are not always consistent in representing actual residuals output. Failure to apply standard criteria from component to component within the process results in certain of the environmental residual coefficients being noncomparable to other coefficients within the same technology or the other technologies.

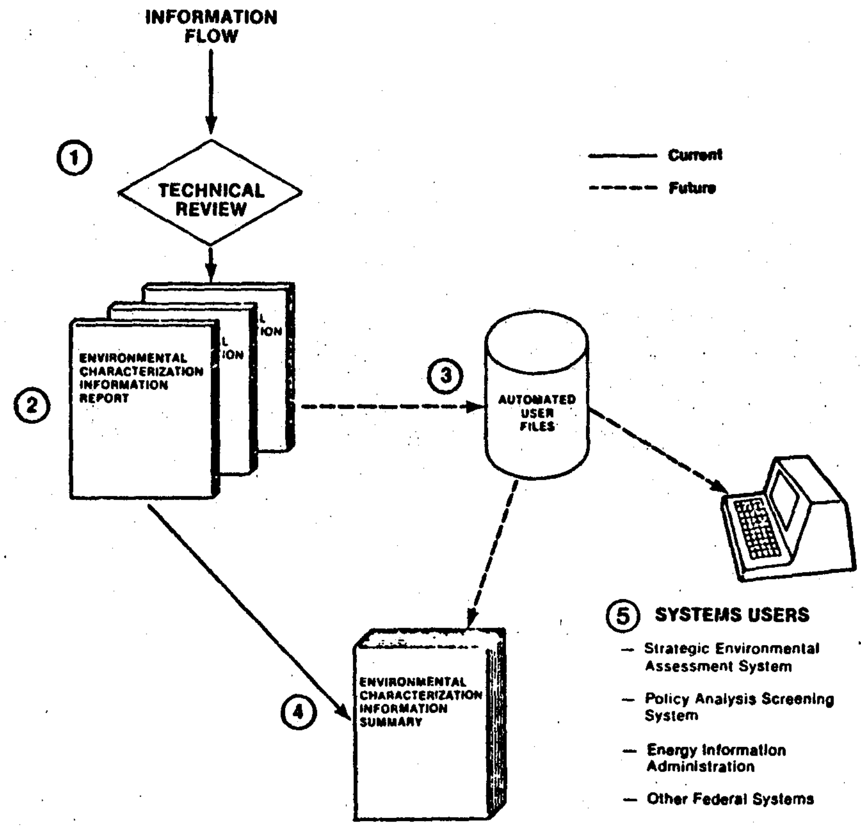
Because work has continued on the development of engineering systems, specific information has become available over time on new energy technologies. In particular, operating data from pilot operations and more detailed designs have become available. This presents a unique opportunity to take the next logical step to improve the information base by substituting this new engineering specific environmental data. In cases where actual data based on engineering operations is not yet available, computations and energy balances can be made to provide information about the unit operation and steps within the overall process. A more accurate and detailed set of information including operating parameters, resources, and environmental pollutants under specific conditions of energy generation and operation of facilities would result. This would provide the user not only with better information for decision making at the policy level, planning, and identification of environmental control requirements, but also with information which identifies the need for specific environmental R&D and control technology data. It would also provide DOE with specific environmental information for the analysis of systems being developed at particular sites. The value of this information for environmental impact assessment to satisfy NEPA requirements would be an important example. All these considerations point to the need for a new programmatic approach.

Future Direction

The development of a new approach will significantly alter the present process. Instead of environmental information flowing from the SEAS data base to the information file, the process will be reversed. Environmental characterization information will be derived through a detailed engineering analysis of a specific energy technology process, and developed through an Environmental Characterization Information Report. The process specific data sheets will be pulled together in a summary volume for all technologies. This new information will be available to augment SEAS as appropriate. The next section will outline the proposed changes in the system and describe the Energy Characterization Information Report concept.

If environmental characterization information is to effectively serve planning and analyses by the Department and other users, the information contained in the file must be at a level of quality that will ensure its acceptance and use. As noted above, the Office of Technology Impacts has determined, after objective appraisal, that the quality of information must be improved. The improvements will be directed at enhancing several important quality attributes of the information; its representative character, its inherent consistency and validity, and its currency. Users of the information will be able to track or replicate the data independently. This means that all initial calculations or subsequent revisions will be explicitly documented. Accordingly, the Office of Environment is establishing a revised approach for conducting these related activities, as described in Figure 1.

(Figure 1 is shown on the next page.)



ENVIRONMENTAL CHARACTERIZATION INFORMATION PROGRAM

All information developed through the new approach will be subjected to technical review 1 conducted by the appropriate technology specialist from the Office of Technology Impacts consulting with recognized experts in the related fields. The activity to develop the information and present it for technical is the central element in this new system. The final presentation of the characterization information will be the report 2 . Each report will be technology specific. Basic information developed in the report will be used for updating the automated information base 3 and for preparing the summary volume 4 which encompasses all of the energy technologies. The automated information base can be used to transfer the data automatically to other Departmental users 5 as appropriate.

A report will be prepared for each specific energy base system. It will represent one or typical elements of an energy fuel cycle. The basis for the characterization information in the report will be a specified energy technology system typical of systems in current operation or under development for eventual commercialization. Since it is not feasible to produce a characterization for every possible system variant, the selection will insure, as availability permits, that the energy technology system chosen for characterization is representative of actual systems and broadly representative of a segment of the overall energy supply or conservation system. By associating the characterization information with actual systems, the credibility of the information will be enhanced for systems of that type. There are components of an emerging energy technology system which equate to actual functioning systems and for these components the information represented will be accurate and can be used for purposes of predicting how a particular segment of a new system might function in the future. The representation can be regarded as highly reliable because it is closely based upon real or as near to real system data as is obtainable.

In the Environmental Characterization Information Report, the analysis of resource requirements, environmental residual coefficients, and certain impacts will be carried out for each major component and environmental point-of-interest in the system. The system will be graphically portrayed with all environmental points-of-interest identified and related to the narrative discussion in the text.

The assumptions and methods used to derive the information will be clearly shown. Information will be taken either directly from the technical literature (if its validity and usefulness is confirmed by qualified experts) or extrapolated by computation or by suitable estimating technique from such information. In instances where information is not available directly, a valid estimating method may be employed and will be documented. For those components of the process that are not fully developed, the best available experimental information will be used.

The results of this new approach, to managing the selection, review and presentation of the information, should represent a significant step forward in providing useful information for environmental analyses and planning. The fundamental advantages for adopting this approach are several:

- a baseline will have been established for focusing continuing review, and update of environmental information,
- the baseline will provide a common reference point for individual users to extrapolate from with respect to their specific situations,
- the user will have assurance that all information in the file has been subjected to expert review,
- the user will have an accessible, easy to understand, and well documented presentation showing the derivation of information for each environmental point-of-interest in the system,
- standard criteria for environmental information development will be used, and,
- availability and relevancy to other Departmental programs will be enhanced.

To illustrate the new approach, a draft prototype Environmental Characterization Information Report has been developed for a new coal-fired power plant burning typical Eastern United States bituminous coal. The prototype Report is in Appendix A.

In this instance, the best available characterization of both the technology and its associated impacts were developed for each step and module in a specific engineering design. For each component step or module, computations were carried out based upon the best information available in order to specify what the environmental characterization of that particular module would be and to put the results in terms and dimensions convenient to the user. The information is expressed in conventional engineering units, metric units, and in terms compatible with computer modeling requirements. Coefficients are expressed for a variety of parameters of interest:

Resources	Environmental Residuals
Coal Consumption	Air Pollutants
Water Consumption	Water Contaminants
Raw Materials	Trace Metals
Land	Solid Wastes
	Heat Losses

Further development of the prototype will include information relevant to capital costs, pollution control costs, manpower requirements, more occupational health and safety factors, and other parameters as needed. The information will be uniformly presented in all Environmental Characterization Information Reports. Priority will be given to emerging technologies which are the primary focus of DOE's energy policy analyses. Ultimately, as resources permit, a complete library of these reports will be developed comprising about 50-60 energy technology systems of interest. Initially, the program will focus on those conventional and emerging energy systems that are critical to National energy policy in the near and intermediate term. Subsequently, second and third generation technologies for use in the 1990 era will also be addressed. These will be evolving documents and will be revised as appropriate.

Summary

In conclusion, this revised activity is designed to overcome discrete deficiencies in the present system. The new approach emphasizes realistic representation and expert verification. Information sources, calculations, or data manipulations will be documented. Users of the information will be able to trace the source of the data and have confidence in its credibility.

Environmental Characterization Information Reports will represent a significant advance in specificity, reliability and comprehensive untility over earlier presentations of environmental/energy technology data.

TABLE OF CONTENTS

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TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

Preceding page blank

TABLE OF CONTENTS (concluded)

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INTRODUCTION

Revised sections of this publication also include new summary sheets for the solar, oil, and gas technologies. Assumptions and methods used to derive the total of summarized information are available as additional volumes. The total library of documentation includes the following:

Summary (Handbook)
Nuclear
Coal
Petroleum
Natural Gas
Synthetic Fuels
Hydroelectricity

Backup documentation for the solar technologies is available through a variety of reports published under the Technology Assessment of Solar Energy Project. The reports are referenced in this volume on the applicable pages.

The information summarized in this Handbook represents the current status of data development and verification performed by technology specialists in the Technology Assessments Division, Office of Environment. If there are any questions regarding the information presented herein, please contact the technology specialists listed below for further discussions.

Nuclear Energy:	W. Neill Thomasson	353-4327
Coal:	William G. Wilson	353-4414
Synthetic Fuels from Coal:	Bipin C. Almaula	353-4401
Petroleum and Natural Gas:	George J. Rotariu	353-5865
Oil Shale:	George J. Rotariu	353-5865
Solar Energy:	Gregory J. D'Alessio	353-5141
Geothermal:	Robert P. Blaunstein	353-5849
Hydroelectricity:	Robert P. Blaunstein	353-5849
Conservation:	David O. Moses	353-4665

Comments or questions dealing with the scope or objectives of this program should be addressed to the EV Program Manager, Nevaire M. Serrajian, Mail Station E-201, Germantown (telephone 353-4658).

Notes on the Format

The specific energy systems for which environmental/technology characterization information is provided are grouped as follows:

- Nuclear Energy
- Coal
- Petroleum
- Gas
- Synthetic Fuels
- Solar Energy
- Geothermal Energy
- Hydroelectricity

Information for each energy system is presented in a uniform three-column format with one system per page. Because of extensive information on some systems, continuation pages have been included.

The first column "Energy System" provides the basic technical information for the system or process. Included are the following:

- Size of a typical plant or operating system, which includes typical operating capacities, yields, efficiencies and annual production capacities.
- Description of the process and its mode of operation.
- Principal components of the system.
- Major environmental concerns.

The second column presents information for the resources expended in the operation of the energy system. Included are raw materials or feedstock (the "fuel") needed, land, water, other materials, costs and personnel needs. Because the different energy systems vary widely in size, all resources information is given for a hypothetical energy system or plant of one trillion (10^{12}) Btu production capacity.

The third column presents information on environmental residuals and energy products. The residuals listed include air pollutants, water pollutants, radiation, and solid wastes. In cases where the technology is not sufficiently advanced to provide quantitative information, the anticipated pollutants are listed to indicate their existence. Again, because the different energy systems vary widely in size, all residuals and products information is given for a hypothetical energy system or plant of one trillion (10^{12}) Btu production capacity.

Nuclear Energy

Open Pit Uranium Mining

ENERGY SYSTEM:

SIZE
- typical mine size of 3.28×10^5 tons/year supports 4.8 model LWRs
- 4,600 tons produce 10^{12} Btu/year
- 0.8 capacity factor
- recovery efficiency 80%
- 20 year lifetime

DESCRIPTION
- Open pit mining accounted for about 48% of ore production during 1976. It is done when the ore body lies under relatively friable material at depths up to several hundred feet.

COMPONENTS
- large open excavation
- large piles of earth and rock overburden
- network of operating roads and yards
- flow of mine water pumped into local surface drainage or holding ponds
- shops
- warehouses
- office and changehouse structure
- assortment of heavy earth moving equipment
- blasting
- drill rigs 3 years lifetime

ENVIRONMENTAL CONCERNS
- air emissions from heavy earth moving equipment and blasting
- disposal of mine drainage water
- barren rock and earth overburden containing uranium and its daughter products
- uranium bearing dusts and radon and its daughter emissions from mining operations
- dissolved and suspended uranium and its daughter products in mine drainage water
- reclamation of land
- aesthetic considerations
- trace metal contaminants
- mine tailings disposition
- accident risks - flooding, fire and washout, blasting, heavy equipment accidents and pit wall failure

RESOURCES USED:
(Per 10^{12} Btu Produced)

ENERGY	
electricity	11.5 MWh(e)
diesel fuel, oil, and grease	12,700 gallons(e)

LAND	Acres(d)
temporarily committed	2.5
undisturbed area	1.8
disturbed area	0.7
permanently committed	0.1
total	2.6

WATER	Acre-Ft.(e)
discharged to ground	17.3

MATERIALS	Tons(1)(d)
concrete	0.16
total steel & castings	32.40
copper, brass & bronze	0.40
aluminum & castings	0.19
manganese	0.15
chromium	0.07
nickel	0.002
cast iron	1.35

COSTS	Dollars (1978)(4)(d)
construction	
manpower	110,000
materials	22,000
equipment	66,000
other construction	64,000
(land rights)	(66,000)
(escalation during construction)	(33,000)
(interest during construction)	(99,000)
(working capital)	(55,000)
total	264,000
operation & maintenance	198,000

PERSONNEL	Workers(d)
construction (4 years)	1.0
operation	3.5

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons
particulates	0.27(e)
SO_2	0.43(e)
NO_x	0.25(e)
hydrocarbons	0.02(e)
CO	0.001(e)

WATER POLLUTANTS	Tons
suspended solids	NA
dissolved solids	NA
trace elements	NA

SOLID WASTE	Tons
overburden moved	1.4×10^5 (e)

RADIATION	Curies
Air	
radon and radon daughters	negligible(2) (NRC presently reconsidering emission rate)

ENERGY PRODUCT	Tons(3)
uranium ore	4,600(e)

(1) Selected materials and equipment items.
(2) Negligible because it is rapidly diluted in the atmosphere and has a very short half-life, but some of the daughter elements are long-lived.
(3) The amount of ore mined is adjusted to account for a 9% loss of material in the milling stage because the mill requires a total throughput of 4,200 tons of ore at 0.2% U_3O_8 per 10^{12} Btu output.
(4) Items in parentheses are not included in total.

SOURCE: (a) U.S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle (Wash. 1248), 1974.
(b) University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
(c) U.S. Department of Energy, Environmental Development Plan - Uranium Mining, Milling, and Conversion, DOE/EDP-0058, 1979.
(d) Bechtel Corporation, Energy Supply Planning Model, 1978.
(e) U.S. Environmental Protection Agency, Energy from the West - Energy Resource Development Systems Report, Volume IV: Uranium, EPA-600/7-79-060d, 1979.

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Uranium Milling

ENERGY SYSTEM:

SIZE
- typical mill size of 1,060 tons/year of Uranium concentrate (U_3O_8) support 5.3 model Light Water Reactors (LWRs)
- 12.31 tons yellowcake (75% U_3O_8) produce 10^{12} Btu output
- 0.8 capacity factor
- recovery efficiency 91%
- 22 year lifetime

DESCRIPTION
- Milling operations extract uranium from the ore and concentrate it into a semi-refined product called "yellowcake", using both mechanical and chemical processes.

COMPONENTS
- ore storage and blending area
- crushing and sampling building
- mill building containing grinding equipment
- acid or alkaline leach tanks (sulfuric acid or sodium carbonate or bicarbonate are typical)
- solvent extraction building
- thickeners
- tailings retention system of about 250 acres
- sewage treatment system
- several ancillary buildings for office and maintenance purposes

ENVIRONMENTAL CONCERNS
- emissions of sulfuric acid fumes, kerosene vapors, and dusts from uranium mill processes
- low level radiological pollutant releases, including uranium and uranium daughter products from milling operations
- liquid and solid chemical and radiological waste discharges to retention ponds
- heat dissipation may cause dense fogging conditions near site
- water availability
- toxic metals - impacts on groundwater quality
- long-term management of uranium mill tailings piles
- accident risks - fires, heavy equipment, tailings pond dike failure
- radon releases

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	**Tons**[a]
uranium ore	4,400
ENERGY	
electricity	113 MWh[a]
natural gas	2.9×10^6 scf[a]
LAND	**Acres**[a]
temporarily committed	0.02
undisturbed area	0.01
disturbed area	0.01
permanently committed (limited use)	0.10
total	0.12
WATER	**Acre-Ft.**[a]
process water	8.3
MATERIALS (1)	**Tons**[e]
concrete	95.20
total steel & castings	32.80
copper, brass & bronze	0.32
aluminum & castings	0.63
manganese	0.15
chromium	0.03
nickel	0.01
cast iron	0.47
pumps & drivers (1000 HP)	0.05
COSTS	**Dollars (1978)**[e]
construction (3)	
manpower	50,000
materials	20,000
equipment	50,000
other construction	30,000
(land rights)	(200)
(escalation during construction)	(6,000)
(interest during construction)	(9,000)
total	150,000
operation & maintenance	120,000
PERSONNEL	**Workers**[e]
construction (2.3 years)	0.7
operation	2.7

RESIDUALS AND PRODUCTS. (2)
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	**Tons**
particulates	2.30[c]
SO_2	1.70[a]
NO_x (40% from natural gas use)	0.73[a]
hydrocarbons	0.06[a]
CO	0.01[a]
WATER POLLUTANTS	**Tons**[a]
tailings solutions	11,000
other pollutants	NA
SOLID WASTE	**Tons**[a]
tailings	4,170
RADIATION	
Air	**Curies**
Rn-222	61.5 (NRC presently reconsidering emission rate)[d]
Ra-226	8.3×10^{-4}[a]
Th-230	8.3×10^{-4}[a]
U-natural	1.2×10^{-3}[a]
WATER	**Curies**[a]
U & daughters	8.3×10^{-2}
SOLID WASTE	**Curies**[a]
U & daughters (buried)	25.0
HEAT	**Btu's**[a]
heat discharged to air	2.9×10^9
ENERGY PRODUCT	**Tons**[a]
yellowcake (75% U_3O_8)	11.2
U_3O_8 (purified)	8.4

(1) Selected materials and equipment items.
(2) Residuals are a function of the leaching process; sulfuric acid leaching is assumed.
(3) Terms in parentheses are not included in total.

SOURCES: (a) U.S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle (Wash. 1248), 1974.
(b) U.S. Department of Energy, Environmental Development Plan - Uranium Mining, Milling and Conversion, DOE/EDP-0058, 1979.
(c) U.S. Environmental Protection Agency, Energy from the West - Energy Resource Development Systems Report, Volume IV: Uranium, EPA-600/7-79-060d, 1979.
(d) U.S. Nuclear Regulatory Commission, Draft Generic Environmental Impact Statement on Uranium Milling, NUREG-0511, 1979.
(e) Bechtel Corporation, Energy Supply Planning Model, 1978.

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Uranium Hexafluoride Conversion

ENERGY SYSTEM:

SIZE
- 5,300 tons/year
- supports 27.5 model Light Water Reactors (LWRs)
- 8.4 tons produce 10^{12} Btu output
- 0.8 capacity factor
- recovery efficiency 100%
- 30 year lifetime

DESCRIPTION
- Uranium hexafluoride (UF_6) conversion converts the U_3O_8 (yellowcake) concentrate to a volatile UF_6 compound for enrichment by the gaseous diffusion process. UF_6 conversion can be done by either the dry or wet hydrofluor process.

COMPONENTS

Dry Hydrofluor Process
- pre-process handling, weighing, sampling and storage
- reduction-roasting of Uranium concentrate (U_3O_8) with cracked ammonia (N_2 & H_2) to form UO_2
- hydrofluorination - F_2 reacted with UF_4 to form UF_6 crude product
- cold trap - removal of molybdenum and vanadium impurities
- distillation - fractional distillation purifies the UF_6 product
- waste ponds

Wet Chemical Solvent Extraction Process
- pre-process handling, weighing, sampling and storage
- digestion in hot nitric acid
- countercurrent solvent extraction with TBP in benzene
- reextraction of uranium as uranyl nitrate solution
- calcination to UO_3
- reduction - UO_3 reduced to UO_2 with cracked ammonia
- hydrofluorination, fluorination, and cold trap same as dry process
- waste ponds

ENVIRONMENTAL CONCERNS
- emissions of off-gases from UF_6 preparation, e.g., fluorides and oxides of nitrogen
- liquid waste from the two waste streams which require holding for future reprocessing or burial
- solid chemical effluents from hydrofluor process
- release of radium to nearby river and disposal of radioactive sludge
- heat dissipation from UF_6 production
- water availability
- accident risks - fires in solvent extraction, failure or rupture of UF_6 cylinder, raffinate pond failure, uranium nitrate hexahydrate evaporator failure, and HF release from a storage tank

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons[(a)]
yellowcake at 75% U_3O_8	11.2
U_3O_8 (purified)	8.4

ENERGY	
electricity	71 Mwh[(a)]
natural gas	0.83×10^6 scf[(a)]

LAND	Acres[(a)]
temporarily committed	0.10
undisturbed area	0.09
disturbed area	0.01
permanently committed	0.001
total	0.10

WATER	Acre Ft.[(a)]
discharged to air	0.42
discharged to water bodies	2.94
total	3.36

MATERIALS[(1)]	Tons[(c)]
concrete	395.00
total steel & castings	12.50
copper, brass & bronze	0.19
aluminum & castings	0.06
manganese	0.06
chromium	0.06
nickel	0.02
cast iron	0.15
pumps & drivers (1000 HP)	0.01
heat exchangers (1000 ft² surface)	0.05
non-nuclear pressure vessel	0.33

COSTS	Dollars (1978)[(c)]
construction[(2)]	
manpower	20,000
materials	9,000
equipment	20,000
other construction	10,000
(land rights)	(300)
(escalation during construction)	(5,000)
(interest during construction)	(10,000)
(working capital)	(10,000)
total	59,000
operation & maintenance	24,000

PERSONNEL	Workers[(c)]
construction (3 years)	0.3
operation	0.4

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons[(a)]
SO_2	1.30
NO_x	0.48
hydrocarbons	0.04
CO	0.01
F^-	0.005

WATER POLLUTANTS	Tons[(a)]
F^-	1.20
SO_4^-	0.21
NO_3^-	0.01
Cl^-	0.01
Na^+	0.16
NH_3^+	0.07
Fe	0.002

SOLID WASTE	Tons[(a)]
solid chemical effluents (non-volatile ash containing Fe, Co, Mg, Cu, F^-)	1.8

RADIATION	
Air	Curies[(a)]
uranium	6.2×10^{-6}
radon and daughters	NA
WATER	Curies[(a)]
Ra-226	1.4×10^{-4}
Th-230	6.3×10^{-5}
uranium	1.8×10^{-3}
SOLID WASTE	Curies[(a)]
low and intermediate level (buried)	3.6×10^{-2}

HEAT	Btus
heat discharged to air	0.83×10^9

ENERGY PRODUCT	Tons[(a)]
UF_6	8.4

(1) Selected materials and equipment items.
(2) Costs in parentheses are not included in total.

SOURCES: (a) U. S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle (Wash. 1248), 1974.
(b) U.S. Department of Energy, Environmental Development Plan - Uranium Mining, Milling, and Conversion, DOE/EDP-0058, 1979.
(c) Bechtel Corporation, Energy Supply Planning Model, 1978.

Uranium Enrichment Gaseous Diffusion

ENERGY SYSTEM:

SIZE
- 12,000 tons/year
- supports 91 model Light Water Reactors (LWRs)
- 8.4 tons UF_6 produce 10^{12} Btu output
- 0.8 capacity factor
- recovery efficiency 65.4%
- 20 year lifetime

DESCRIPTION
- Gaseous diffusion enrichment is accomplished by passing the volatile Uranium hexafluoride (UF_6) compound through porous barriers and cascades to produce the product material 4 percent ^{235}U.

COMPONENTS
- buildings - process, auxiliaries and support, warehouse and storage
- roadways and parking lots
- storage yards - UF_6
- electric switchyards
- steam plant
- recirculation water system
- fire protection water system
- water (chemical treatment) plant
- nitrogen plant
- dry air plant
- tails storage - UF_6
- setting neutralization ponds
- waste burial grounds
- fluorine production

ENVIRONMENTAL CONCERNS
- recycle fission products
- air emissions from coal-fired stations for electricity generation, especially particulates, SO_x, and NO_x
- heating dissipation causing misting and fogging conditions
- emissions of fluorides and its compounds, nitrogen oxides, and sulfur
- liquid effluent containing calcium, chloride, sodium, and sulfate ions
- small quantities of uranium and other radionuclides in gaseous and liquid effluent releases
- water availability
- waste storage
- setting neutralization ponds
- accident risks - fires, explosion, criticality and unintentional UF_6 releases
- transuranics and fission product contamination of process equipment and environmental releases in processing recycle fuel.

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons[a]
UF_6	8.4

ENERGY	MWh[a]
electricity	1.3×10^6

LAND	Acres[a]
temporarily committed	0.04
undisturbed area	0.03
disturbed area	0.01
permanently committed	0.0
total	0.04

WATER	Acre-Ft.[a]
discharged to air (at GDP)	10.7
discharged to water bodies (at GDP)	0.8
discharged to water bodies (at power plants)	1,407

MATERIALS[1]	Tons[c]
concrete	762.00
total steel & castings	330.00
copper, brass & bronze	11.70
aluminum & castings	7.50
manganese	1.80
chromium	2.30
nickel	0.41
cast iron	26.50
steam turbogenerators (MWe)	0.24
pumps & drivers (1000 HP)	0.27
axial compressor (1000 HP)	3.80
centrifuge compressor & driver	0.01
heat exchangers (1000 ft^2)	3.60

COSTS	Dollars (1978)[c]
construction[3]	
manpower	630,000
materials	270,000
equipment	1,070,000
other construction	490,000
land rights	10,000
(escalation during construction)	(820,000)
(interest during construction)	(1,270,000)
(working capital)	(680,000)
total	2,470,000
operation & maintenance	350,000

PERSONNEL	Workers[c]
construction (8 years)	2.8
operation	1.0

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons[a]
particulates	51.8
SO_2	197.0
NO_x	51.8
hydrocarbons	0.5
CO	1.3
F^-	0.02

WATER POLLUTANTS	Tons[a]
Ca^{++}	0.3
Cl^-	0.4
Na^+	0.4
$SO_4^=$	0.3
Fe	0.02
NO_3^-	0.12

RADIATION

AIR	Curies
uranium	8.3×10^{-5} (a)
radon and daughters	NA
Tc-99m	NA
Pu-239	2.5×10^{-13} (b)
Np-237	1.3×10^{-10} (b)
Tc-99	3.4×10^{-4} (b)
Ru-106	4.6×10^{-6} (b)
Zr-Nb-95	9.5×10^{-7} (b)
Cs-137	7.0×10^{-8} (b)
Ce-144	7.0×10^{-8} (b)
Other fission products	7.0×10^{-8} (b)

WATER	Curies
uranium	4.3×10^{-4} (a)
Pu-239	3.1×10^{-12} (b)
Np-237	2.5×10^{-9} (b)
Ru-106	5.8×10^{-5} (b)
Zr-Nb-95	1.3×10^{-5} (b)
Cs-137	9.5×10^{-7} (b)
Ce-144	9.5×10^{-7} (b)
Tc-99	4.4×10^{-3} (b)

HEAT	Btus[a]
heat discharged to water	103×10^9
heat discharged to air	31×10^9

ENERGY PRODUCT	Tons[a]
enriched ^{235}U in UF_6	5.40

BY-PRODUCTS[2]	Tons
^{235}U in tails	0.01

(1) Selected materials and equipment items.
(2) This value represents the amount of U-235 (0.25%) contained in the UF_6 depleted tails assay.
(3) Costs in parentheses are not included in total.

SOURCES: (a) U.S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle (Wash. 1248), 1974.
(b) U.S. Energy Research and Development Administration, Draft Environmental Statement-Expansion of U.S. Uranium Enrichment Capacity, ERDA-1543, 1975.
(c) Bechtel Corporation, Energy Supply and Planning Model, 1978.

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Uranium Enrichment Gas Centrifuge

ENERGY SYSTEM:

SIZE
- 10,000 tons/year
- supports 75 model Light Water Reactors (LWRs)
- 8.4 tons UF_6 produce 10^{12} Btu output
- 0.8 capacity factor
- recovery efficiency 63.4%
- 20 year lifetime

DESCRIPTION
- Gas centrifuge enrichment is similar to gaseous diffusion except for the substitution of centrifuges for the system of compressors and barrier materials.

COMPONENTS
- production facilities
- feed, product, and tails withdrawal systems
- recycle/assembly plant
- facility for equipment decontamination and uranium recovery
- steam plant
- miscellaneous support facilities
- laboratories
- air plant
- recirculating water system
- sanitary water system
- firewater system
- sanitary sewage system
- storm drainage
- holding ponds
- burial grounds
- heat dissipation system
- toll enrichment facility

ENVIRONMENTAL CONCERNS
- gaseous emissions from coal-fired station for heating, process steam and electrical power generation, i.e., particulates, CO, water vapor, SO_x, NO_x
- small quantities of CO, HC, and aldehydes from stack effluent
- fly ash and slurry discharges to holding ponds
- waste from uranium recovery facility discharged to holding pond
- radioactive emissions
- water availability
- accident risks - critically accidents, UF_6 releases, fires, and centrifuge failure

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons[c]
UF_6	8.4

ENERGY	
coal (heating and process steam)	36.7 tons[b]
gasoline and diesel fuel	114 gallons[b]
electricity	1.1×10^3 MWh[b]

LAND	Acres[b]
temporarily committed	
to plant	0.45
disturbed area	0.25
undisturbed area	0.20
committed to landfill disposal (year 2000)	
uranium-contaminated material	0.01
uncontaminated material	0.001
total	0.46

WATER	Acre-Ft.[b]
discharged to air	
cooling towers	0.44
steam plant	0.05
discharged to water	
enrichment plant operations	0.91
sanitary waste	0.12
total required	1.32
(additional reserve for fire protection)	(0.005)

MATERIALS[1]	Tons[2][b]
concrete[3]	329.00
steel[3]	151.00
aluminum	14.00
copper	2.70
zinc	0.12
transformer cooling oil	0.18
paving materials[3]	0.70
miscellaneous metal products	0.63

COSTS	Dollars (1975)[b]
construction	
centrifuge plant	1,900,000
(land rights)	(444)
rotor fabrication plant	63,500
(land rights)	(32)
total	1,963,500
operation & maintenance	260,000

PERSONNEL	Workers[b]
construction (7 years)[4]	2.8
operation	1.0

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS[5]	Tons[b]
particulates	0.02
SO_2	0.44
NO_x	0.37
hydrocarbons	negligible
CO	0.01

WATER POLLUTANTS[6]

Condensate	Tons[b]
water	2.03
HNO_3	negligible
U	trace
$Al(NO_3)_3$	trace

Aqueous Waste	Tons[b]
water	0.31
HNO_3	0.05
$Al(NO_3)_3$	0.06
F^-	negligible
U	negligible

Noncondensable Gases	Tons[b]
NO_x	0.001
U	trace

RADIATION

Air	Curies[b]
uranium (total isotopes)	3.1×10^{-5}

(since no recycled feed material will be processed by gas centrifuge, values for Pu-239, Np-237, Tc-99, Ru-106, Zr-Nb-95, Cs-137, Ce-144, and other fission products are shown only for gaseous diffusion)

Water	Curies[b]
uranium (total isotopes)	3.3×10^{-6}

(since no recycle feed material will be processed by gas centrifuge, values for Pu-239, Np-237, Ru-106, Zr-Nb-95, Cs-137, Ce-144, and Tc-99 are shown only for gaseous diffusion)

HEAT	Btus
heat dissipated from steam plant	0.2×10^9

ENERGY PRODUCT	Tons[c]
enriched ^{235}U in UF_6	5.49

BY-PRODUCT[7]	Tons[c]
^{235}U in tails	0.01

(1) Bulk materials data taken from ERDA 1,543 reported for 10 plants, p. 8.1-4.
(2) Selected materials and equipment items.
(3) Materials for and included for auxiliary rotor fabrication plant.
(4) This total includes 0.2 workers per year for construction of the rotor fabrication plant which requires about 4.75 years for design and construction.
(5) From coal-fired plant.
(6) From uranium recovery facility.
(7) This value represents the amount of U.235 (0.25%) contained in the depleted UF_6 tails assay.

SOURCES:
(a) U.S. Energy Research and Development Administration, Draft Environmental Statement-Portsmouth Gaseous Diffusion Plant Expansion, Piketon, Ohio, ERDA-1549, 1976.
(b) U.S. Energy Research and Development Administration, Draft Environmental Statement-Expansion of U.S. Uranium Enrichment Capacity, ERDA-1543, 1975.
(c) U.S. Atomic Energy Commission, Environmental Survey of the Uranium Fuel Cycle (WASH-1248), 1974.

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Fuel Fabrication Plant

ENERGY SYSTEM:

SIZE
- 990 tons/year supports 36 model Light Water Reactors (LWRs)
- 3.49 tons produce 10^{12} Btu output
- 0.8 capacity factor
- conversion efficiency 100%
- 30 year lifetime

DESCRIPTION
- Fuel fabrication is accomplished by chemical conversion of UF_6 to UO_2 and mechanical processing including pellet production and fuel element fabrication loaded in zircaloy or stainless steel tubes, fitted with end caps and welded.

COMPONENTS

UO_2 Powder Processing
- vaporization of UF_6 in steam or electrically heated cabinet
- hydrolysis - reacting UF_6 with H_2O to form UO_2F_2 solution
- precipitation - ammonium hydroxide to convert UO_2F_2 to ammonium diuranate (ADU)
- centrifuge or filtration - concentrate ADU slurries
- calcination - ADU is calcined by heating
- reduction - ADU reduced to UO_2 powder in a reducing atmosphere (hydrogen)

Mechanical Processing
- pretreatment of UO_2 powder by comminution, compaction and granulation to obtain desired particle size
- pelletizing
- sintering of pellets in a reducing atmosphere
- grinding to finished dimensions
- washing and drying the pellets
- loading pellets into fuel rods and welding the end caps
- assemble fuel rods to form finished fuel elements

Scrap Recovery/Off-Specification Material
- dissolution of uranium in nitric acid to form uranyl nitrate
- purification of uranium through solvent extraction
- reconversion of uranium to return to UO_2 production

ENVIRONMENTAL CONCERNS
- emissions from coal-fired power plant for electricity generation
- fluorides emission from fabrication plant
- nitrogen compounds in liquid effluents from NH_4OH in UO_2 production and nitric acid recovery of scrap
- heat dissipation into environment
- radioactive contaminated CaF_2 (solid waste) retained onsite
- accident risks - rupture of UF_6 cylinder releasing U and HF, furnace explosion releasing U, and criticality accident

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons[a]
enriched 235U in UF_6	3.49

ENERGY	[a]
electricity	71 MWh
natural gas	1.5×10^5 scf[a]

LAND	Acres[a]
temporarily committed	0.01
undisturbed area	0.01
disturbed area	0.002
permanently committed	0.0
total	0.01

WATER	Acre-Ft.[a]
discharged to water	0.67

MATERIALS(1)	Tons(2)[b]
concrete	74.70 - 444.0
total steel & castings	12.00 - 45.00
copper, brass & bronze	0.59 - 5.20
aluminum & castings	0.27 - 1.43
manganese	0.08 - 0.21
chromium	0.10 - 0.15
nickel	0.02 - 0.03
cast iron	0.49 - 0.90
steam turbines (1000 HP)	0.01 - 0.00
pumps & drivers (1000 HP)	0.01 - 0.04
heat exchangers (1000 ft²)	0.00 - 0.03

COSTS	Dollars(1978)(2)[b]
construction	
manpower	60,000 - 220,000
materials	10,000 - 60,000
equipment	80,000 - 260,000
other construction	20,000 - 60,000
(land rights)	(400 - 1,000)
(escalation during construction)	(20,000 - 50,000)
(interest during construction)	(30,000 - 50,000)
(working capital)	(30,000 - 180,000)
total	170,000 - 600,000
operation & maintenance	180,000 - 260,000

PERSONNEL	Workers[b]
construction (3&2 years)	0.7 - 3.8(3)
operation	1.6 - 3.4

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons[a]
SO_2	1.10
NO_x	0.28
hydrocarbons	negligible
CO	0.01
F⁻	negligible

WATER POLLUTANTS	Tons[a]
N as NH_3	0.44
N as NO_3	1.10
fluoride	0.19

SOLID WASTE	Tons[a]
CaF_2	1.36

RADIATION

Gases	Curies[a]
uranium	8.5×10^{-6}

Liquids	Curies[a]
uranium	8.5×10^{-4}
Th-234	4.2×10^{-4}

SOLID WASTE	Curies[a]
uranium (buried)	9.6×10^{-3}

HEAT	Btus[a]
heat dissipated	0.4×10^9

ENERGY PRODUCT	Tons[a]
uranium (UO_2) fuel elements	1.6

(1) Selected material and equipment items.
(2) These values represent no Pu and Pu recycle, 1st and 2nd, respectively. Costs in parentheses are not included in total.
(3) Three years are required if there is no Pu recycle, two years if there is Pu recycle.

SOURCES: (a) U.S. Atomic Energy Commission, *Environmental Survey of the Uranium Fuel Cycle (Wash. 1248)*, 1975.
(b) Bechtel Corporation, *Energy Supply Planning Model*, 1978.

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Light Water Reactor Nonradiological Effluents

ENERGY SYSTEM

SIZE
- 1,000 MWe Light Water Reactor (LWR)
- produces 21×10^{12} Btu
- 0.7 capacity factor
- conversion efficiency 33%
- 30 year lifetime

DESCRIPTION
- Light Water Reactors (LWR) consist of two types: pressurized-water reactor (PWR) which heats water without allowing it to boil and the boiling water reactor (BWR).

COMPONENTS*
- containment structure
- reactor vessel
- fuel assemblies within reactor core
- steam separator
- turbine generator
- cooling water condenser
- liquid waste system
- cooling towers
- PWR has a dual cooling system using steam generators
- BWR has only a primary cooling system
- spent fuel storage
- waste treatment systems
- auxiliary ventilation control systems
- engineered safety features

ENVIRONMENTAL CONCERNS
- airborne chemical effluents from cooling tower drift releases
- gaseous radioactive releases from power facilities (Kr-85, Kr-87, Kr-88, H-3, I-131, Xe-133)
- liquid chemical effluents from cooling systems
- liquid radioactive releases from power facilities (H-3, Co-60, Sr-89, Sr-90, Ru-106, Cs-134, Cs-137, I-131, Mn-54, Fe-59, Ce-144, La-Ba-140)
- land use
- availability of water
- spent fuel transport, storage, and disposition
- thermal effluents
- cooling water chemical effluents
- transmission lines (corridor effect on wildlife systems)
- aesthetics (cooling towers and transmission lines)
- decontamination and decommissioning at end of plant useful life
- accident risks - steam line break, rod ejection, loss of coolant, steam generator tube rupture, other transients, failure of off-gas system, and waste tanks

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons(a)
uranium (UO_2) fuel elements	1.6
LAND	Acres(b)
permanently committed	3.9
WATER	Acre-Ft(b)
losses from evaporation, drift	720
discharged to water bodies	72
MATERIALS	Tons**(c)
concrete	24,500.00
total steel & castings	3,450.00
copper, brass & bronze	104.00
aluminum & castings	31.30
manganese	18.00
chromium	20.80
nickel	3.50
cast iron	39.20
steam turbogenerator (MWe)	47.80
steam turbines (1000 HP)	1.00
pumps & drivers (1000 HP)	4.80
heat exchangers (1000 ft^2)	14.80
nuclear steam supply systems	47.80
COSTS	Dollars (1978)(c)
construction	
manpower	8,080,000
materials	3,230,000
equipment	7,980,000
other construction	6,280,000
(land rights)	(150,000)
general plant	700,000
(escalation during construction)	(11,990,000)
(interest during construction)	(13,550,000)
(working capital)	(4,150,000)
total	26,270,000
operation & maintenance	710,000
PERSONNEL	Workers(c)
construction (9 years)	29.0
operation	5.7

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons(b)
particulates	NA
chromates	8.6×10^{-1}
zinc	1.7×10^{-6}
chlorides	3.7×10^{-3}
WATER POLLUTANTS	Tons(b)
BOD	1.0×10^{-1}
chlorine	1.2
phosphate	1.8
boron	14.4
chromates	1.0×10^{-1}
acids	3.6
organics	2.9
SOLID WASTE	Tons
total	NA
HEAT	Btus
heat dissipated	2×10^{12}
ENERGY PRODUCT	Kw-hrs
electricity	2.93×10^{8}

*LWRs consist of a 2:1 mix of PWRs and BWRs
**Selected materials and equipment items

Note: Values reported in AEAR were derived from Bisselle, C.A., *Strategic Environmental Assessment System: Radiation Residuals*, MTR-6511, 1973.

SOURCES:
(a) U.S. Atomic Energy Commission, *Environmental Survey of the Uranium Fuel Cycle (Wash. 1248)*, 1974.
(b) The MITRE Corporation, *Annual Environmental Analysis Report (AEAR)*, 1977.
(c) Bechtel Corporation, *Energy Supply Planning Model*, 1978.
(d) U.S. Environmental Protection Agency, *Assessment of Carbon-14 Control Technology and Costs for the LWR Fuel Cycle*, EPA 520/4-77-013, 1977.

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Light Water Reactor Radiological Effluents

Note: All coefficients listed below are per 10^{12} Btu produced.

Radiation Air	PWR* Curies	BWR** Curies
Ar-37	6.83×10^{-1}	NA
Ar-41	8.06×10^{-1}	3.25×10^{1}
Kr-83m	2.37×10^{-2}	9.60×10^{2}
Kr-85	3.90	1.66×10^{3}
Kr-85m	2.77	5.31×10^{2}
Kr-87	7.00×10^{-1}	1.57×10^{3}
Kr-88	2.70	1.56×10^{3}
Xe-131m	3.77×10^{-1}	1.50×10^{1}
Xe-133	4.08×10^{2}	1.52×10^{3}
Xe-133m	6.95	1.72×10^{2}
Xe-135	4.30×10^{1}	2.09×10^{3}
Xe-135m	4.21	3.62×10^{2}
Xe-137	1.16×10^{-5}	NA
Xe-138	2.07×10^{-1}	2.07×10^{3}
I-131	5.28×10^{-3}	5.54×10^{-2}
I-132	2.16×10^{-3}	NA
I-133	2.00×10^{-3}	3.31×10^{-1}
I-134	4.73×10^{-4}	NA
I-135	7.42×10^{-3}	3.59×10^{-1}
Br-82	4.02×10^{-6}	NA
C-14	1.64×10^{-1}	3.0×10^{-1}
Co-57	6.03×10^{-8}	NA

Air	PWR* Curies	BWR** Curies
Co-58	8.90×10^{-4}	1.31×10^{-4}
Co-60	1.46×10^{-4}	1.34×10^{-3}
Sr-89	3.63×10^{-5}	1.17×10^{-2}
Sr-90	6.31×10^{-6}	2.48×10^{-4}
Sr-91	3.78×10^{-4}	NA
Zr-95	3.41×10^{-7}	1.91×10^{-4}
Nb-95	5.41×10^{-7}	9.28×10^{-5}
Zr-97	8.17×10^{-6}	NA
Cs-134	4.06×10^{-5}	2.54×10^{-4}
Cs-136	7.81×10^{-7}	2.47×10^{-5}
Cs-137	2.31×10^{-4}	5.43×10^{-4}
Cs-138	1.11×10^{-3}	NA
Ba-131	1.33×10^{-7}	NA
Ba-133	1.33×10^{-7}	NA
Ba-139	6.61×10^{-8}	NA
Ba-140	7.80×10^{-5}	1.87×10^{-2}
La-140	7.80×10^{-5}	2.23×10^{-3}
H-3	7.42	6.27
Cr-51	7.38×10^{-4}	4.75×10^{-4}
Mn-54	6.78×10^{-5}	2.34×10^{-4}
Mn-56	3.13×10^{-6}	NA

Air	PWR* Curies	BWR** Curies
Rb-88	1.91×10^{-2}	5.52×10^{-7}
Mo-99	3.16×10^{-7}	2.09×10^{-4}
Tc-99m	7.99×10^{-3}	3.10×10^{-6}
Ce-139	8.32×10^{-7}	NA
Ce-141	2.16×10^{-7}	3.06×10^{-4}
Ce-144	2.26×10^{-7}	1.14×10^{-3}
Ag-108m	3.66×10^{-8}	NA
Ag-110m	1.29×10^{-6}	1.89×10^{-4}
Np-239	4.54×10^{-7}	1.66×10^{-5}
Na-24	2.29×10^{-5}	5.92×10^{-6}
Ru-103	7.36×10^{-7}	7.47×10^{-5}
Sn-123m	9.55×10^{-7}	NA
Cd-109	1.64×10^{-7}	NA
Cd-115	3.41×10^{-5}	NA
Cu-64	5.01×10^{-6}	NA
Ni-65	1.47×10^{-7}	NA
Te-132	1.80×10^{-6}	NA
Sb-124	2.86×10^{-5}	NA
Fe-59	NA	1.77×10^{-4}
Zn-65	NA	6.06×10^{-5}
As-76	NA	1.47×10^{-5}

Water	PWR* Curies	BWR** Curies
Ar-41	1.17×10^{-4}	NA
Kr-85	2.18×10^{-4}	NA
Kr-85m	6.15×10^{-3}	NA
Kr-87	1.12×10^{-4}	NA
Kr-88	3.38×10^{-5}	NA
Xe-131m	6.80×10^{-3}	NA
Xe-133	1.08	9.52×10^{-3}
Xe-133m	6.72×10^{-3}	NA
Xe-135	1.28×10^{-1}	1.44×10^{-2}
XE-135m	7.32×10^{-4}	NA
I-131	9.64×10^{-2}	1.29×10^{-2}
I-132	4.66×10^{-3}	5.28×10^{-3}
I-133	2.17×10^{-2}	8.34×10^{-3}
I-134	3.80×10^{-3}	NA
I-135	1.10×10^{-2}	1.39×10^{-3}
Be-7	1.01×10^{-3}	NA
Co-57	3.86×10^{-4}	NA
Co-58	6.31×10^{-2}	2.22×10^{-3}
Co-60	2.28×10^{-2}	1.50×10^{-2}
Fe-59	1.17×10^{-3}	2.05×10^{-3}
Na-24	5.97×10^{-2}	1.64×10^{-2}
Cr-51	1.39×10^{-2}	2.34×10^{-3}
Mn-54	6.91×10^{-3}	1.63×10^{-2}
Mn-56	1.08×10^{-3}	1.52×10^{-4}
Cu-64	2.02×10^{-4}	NA

Water	PWR* Curies	BWR** Curies
Zn-65	6.71×10^{-4}	3.29×10^{-3}
Se-75	1.10×10^{-5}	NA
Sr-85	3.09×10^{-5}	NA
Sr-89	1.91×10^{-3}	1.65×10^{-2}
Sr-90	4.43×10^{-4}	4.09×10^{-4}
Sr-91	1.20×10^{-5}	1.37×10^{-7}
Sr-92	2.86×10^{-5}	NA
Zr-95	1.07×10^{-3}	1.80×10^{-3}
Nb-95	1.29×10^{-3}	6.61×10^{-4}
Zr-97	3.94×10^{-5}	NA
Nb-97	2.72×10^{-4}	NA
Mo-99	4.22×10^{-3}	4.46×10^{-3}
Ru-103	2.40×10^{-3}	2.60×10^{-4}
Rh-106	1.72×10^{-6}	NA
Ag-108m	3.60×10^{-7}	NA
Ag-110m	5.28×10^{-3}	3.25×10^{-5}
Cs-134	4.08×10^{-2}	4.75×10^{-2}
Cs-136	5.38×10^{-4}	1.07×10^{-3}
Cs-137	5.28×10^{-2}	6.91×10^{-2}
Cs-138	9.27×10^{-7}	NA
Ba-133	6.27×10^{-6}	NA
Ba-139	7.72×10^{-6}	NA
Ba-140	1.07×10^{-3}	5.68×10^{-3}
La-140	9.93×10^{-4}	8.23×10^{-3}
Ce-134	4.09×10^{-5}	NA

Water	PWR* Curies	BWR** Curies
Ce-139	6.09×10^{-5}	NA
Ce-141	1.26×10^{-3}	3.25×10^{-4}
Ce-144	1.40×10^{-3}	NA
W-187	1.41×10^{-4}	NA
Np-239	1.69×10^{-4}	7.18×10^{-3}
H-3	2.11×10^{1}	1.14
C-14	7.53×10^{-4}	NA
Ni-65	4.15×10^{-7}	NA
Rb-88	6.66×10^{-4}	NA
Tc-99m	8.37×10^{-4}	1.43×10^{-2}
Cd-109	1.39×10^{-4}	NA
Cd-115	9.37×10^{-5}	NA
Cd-115m	1.23×10^{-5}	NA
Y-92	2.66×10^{-8}	NA
In-113m	1.13×10^{-5}	NA
Sn-113	3.54×10^{-5}	NA
Sn-117m	6.34×10^{-4}	NA
Sn-125m	3.41×10^{-4}	NA
Au-198	7.57×10^{-6}	NA
Ni-63	1.47×10^{-3}	NA
Sb-124	7.18×10^{-4}	NA
F-18	1.16×10^{-2}	NA
Ti-51	3.62×10^{-4}	NA
As-76	NA	1.36×10^{-4}
Y-90	NA	1.65×10^{-3}

Solid Waste	Curies	Curies
Total	48.7	79.0

*These residuals represent a weighted average for PWRs in operation during 1976. Representative reactors include: Babcox and Wilcox-Arkansas 1, Oconee 1, 2 & 3, Rancho Seco, and Three Mile Island 1; Combustion Engineering-Calvert Cliffs, Millstone Point 2, Palisades, and Fort Calhoun; and Westinghouse-Indian Point, Surry 1 & 2, Trojan, and Zion 1 & 2.

**These residuals represent a weight average for BWRs in operation during 1976. Representative reactors include: General Electric - Browns Ferry 1, 2 & 3, Dresden 2 & 3, Millstone Point 1, Peach Bottom 2 & 3, and Quad Cities 1 & 2.

SOURCE: U.S. Nuclear Regulatory Commission, Radioactive Materials Released From Nuclear Power Plants (1976), NUREG-0367, 1978.

U.S. Environmental Protection Agency, Assessment of Carbon-14 Control Technology and Costs for the LWR Fuel Cycle, EPA 520/4-77-013, 1977.

ENERGY SYSTEM:

SIZE
- 1,160 MWe High Temperature Gas Reactor (HTGR) plant
- produces 24.3 x 10^{12} Btu
- 0.7 capacity factor
- conversion efficiency 39%
- 30 year lifetime

DESCRIPTION
- High Temperature Gas Reactors (HTGRs) use helium as a coolant and heat transfer medium, instead of water as used in the Light Water Reactor (LWR). The use of helium allows high efficiencies of 40 percent. The HTGR uses Th-232, U-233, and U-235 fuels.

COMPONENTS
- containment structure
- fuel microspheres contained in reactor core
- helium circulator
- steam generator
- prestressed concrete reactor vessel (PCRV)
- turbine generator
- water cooling condenser
- cooling towers
- helium purification system
- gaseous waste system
- liquid waste system
- gas purification system

ENVIRONMENTAL CONCERNS
- reactor core components contaminated with graphite dust films of "plateout" radioactivity
- contaminated control rod drive following plant refueling and tritium diffuses into secondary coolant system
- airborne releases of small quantities of fission product and activation gases, halogens (mostly iodine), tritium, and particulate material
- water availability and quality
- thermal dissipation causing fogging and icing - site dependent
- transmission lines
- liquid radioactive waste discharges
- accident risks - radwaste system failure, fission products releases from primary to secondary system, refueling, spent fuel handling, loss of coolant

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL(1)	Tons(b)
U-235	0.0274
thorium	0.372

ENERGY	MWh
electricity	NA

LAND	Acres(b)
permanently committed	
plant site	1.1
railroad-spur	0.2
temporarily committed	
plant site	1.8
transmission line	0.2
undisturbed area	
plant site	4.0
total	7.3

WATER	Acre-Ft.(b)
input to process	1000
discharged	
- to air	465
- to water bodies	535

MATERIALS	Tons(2)(c)
concrete	17,000.00
total steel & castings	5,340.00
copper, brass & bronze	82.40
aluminum & castings	27.40
manganese	26.60
chromium	36.20
nickel	5.00
cast iron	126.00
steam turbogenerator (MWe)	47.80
steam turbine (1000 HP)	1.80
pumps & drivers (1000 HP)	3.18
heat exchangers (1000 ft^2)	8.80
nuclear steam supply systems	47.80

COSTS	Dollars (1978)(c)
construction	
manpower	7,860,000
materials	2,930,000
equipment	10,570,000
other construction	6,370,000
(land rights)	(160,000)
general plant	760,000
(escalation during construction)	(13,000,000)
(interest during construction)	(14,690,000)
(working capital)	(4,490,000)
total	28,490,000
operation & maintenance	550,000

PERSONNEL	Workers(c)
construction (9 years)	28.7
operation	4.6

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons(b)
water vapor	548 x 10^3
other	NA

WATER POLLUTANTS	Tons(b)	WATER POLLUTANTS	Tons(b)
Na^+	13.1	Pb^{2+}	0.08
K^+	7.0	Cl^-	20.6
Mg^{2+}	16.3	NO_2^-	0.19
Ca^{2+}	57.2	NO_3^-	11.4
Fe^{2+}	0.1	HCO_3^-	93.3
Mn^{2+}	0.6	SO_4^{2-}	127.2
Cu^{2+}	0.08	PO_4^{3-}	0.36
Zn^{2+}	0.06	SiO_2	8.5
Cd^{2+}	0.04	TDS	354.0

SOLID WASTE	Cubic Ft.(3)(a)
total	90

RADIATION

Air	Curies(b)	Air	Curies(b)
H-3	3.2	Xe-133	0.32
Kr-83m	0.14	I-134	3.6 x 10^{-6}
Kr-85m	0.25	Xe-135m	0.14
Kr-85	151.0	Xe-135	0.25
Kr-87	0.32	I-136	1.1 x 10^{-3}
Kr-88	0.51	Xe-137	0.04
Kr-89	0.11	Xe-138	0.07
Kr-90	0.04		
C-14	NA		

(Noble gas values less than 0.04 and iodine values less than 3.6 x 10^{-9} omitted)

Water	Curies(b)	Water	Curies(b)
H-3	NA	Te-129m	7.2 x 10^{-6}
Fe-55	1.4 x 10^{-6}	Te-129	7.2 x 10^{-6}
Se-83m	2.2 x 10^{-6}	Te-131	1.1 x 10^{-6}
Se-84	5.4 x 10^{-6}	I-132	7.2 x 10^{-7}
Br-84	1.8 x 10^{-6}	Te-133m	1.4 x 10^{-6}
Br-85	7.2 x 10^{-6}	Te-133	1.1 x 10^{-6}
Rb-88	1.4 x 10^{-15}	Te-134	1.8 x 10^{-6}
Rb-89	3.6 x 10^{-6}	I-134	1.8 x 10^{-6}
Sr-89	3.6 x 10^{-6}	Cs-136	6.5 x 10^{-6}
Rb-90	8.7 x 10^{-6}	I-136	5.4 x 10^{-6}
Sr-90	3.3 x 10^{-5}	Cs-137	1.3 x 10^{-3}
Y-90	2.6 x 10^{-6}	B-137m	1.2 x 10^{-3}
Rb-91	7.2 x 10^{-6}	Cs-138	1.4 x 10^{-6}
Y-91	7.2 x 10^{-6}	Ce-139	1.1 x 10^{-6}
Sr-94	7.2 x 10^{-7}	Ce-140	3.6 x 10^{-6}
Te-127m	5.8 x 10^{-6}	Sm-151	1.4 x 10^{-6}
Te-127	5.8 x 10^{-6}		

SOLID WASTE	Curies(b)
reflector blocks	216
low-specific-activity waste	32
titanium sponge (H-3)	432

HEAT	Btus(b)
heat dissipated from steam plant	1.5 x 10^{12}

ENERGY PRODUCT	MWh
electricity	2.93 x 10^8

(1) Initial fuel loading only Th-232 and U-235. The Th-232 in the reactor converts to U-233 which is recycled for use as fuel.
(2) Selected materials and equipment items.
(3) Weight not available.

SOURCES: (a) University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
(b) U.S. Nuclear Regulatory Commission, Final Environmental Statement - Fulton Generating Station Units 1 and 2, 1975.
(c) Bechtel Corporation, Energy Supply Planning Model, 1978.

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Light Water Breeder Reactor

ENERGY SYSTEM:

SIZE
- 1,000 MWe Light Water Breeder Reactor (LWBR)
- produces 21 x 10^{12} Btus/year
- 0.7 capacity factor
- conversion efficiency 30%
- 30 year lifetime

DESCRIPTION
- Light Water Breeder Reactor (LWBR) employs a technology similar to Light Water Reactor (LWR), it also breeds additional nuclear fuel using thorium oxide.

COMPONENTS
- containment structure
- reactor vessel
- pressurizer
- heaters
- steam generator
- turbine generator
- reactor coolant loops
- LWBR reactor core
- gaseous waste system
- liquid waste system
- plant ventilation control systems
- fuel handling system concerns

ENVIRONMENTAL CONCERNS
- emissions of airborne chemical and radioactive effluents to the atmosphere
- emissions of liquid chemical and radioactive effluents
- heat dissipation
- availability of water
- land used
- thermal impacts
- accident risks - radwaste system failure, fission products releases from primary to secondary system, refueling, spent fuel handling, loss of coolant, steam generator tube rupture and other transients.

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL (Prebreeder)	Tons(1)(a)
U-233	0.2
U-238	1.6
thorium	3.7

FUEL (Breeder)	Tons(1)(a)
uranium-fissile(3)	0.1
other uranium(3)	0.03
thorium (4)	4.9

ENERGY	Gallons(a)
diesel fuel	1,905

LAND	Acres(a)
temporarily committed	23.3
undisturbed area	21.0
disturbed area	2.3
permanently committed	0.1
total	23.4

WATER	Acre-Ft.
discharged to air	720
discharged to water bodies	72

MATERIALS	Tons(2)(b)
concrete	24,500
total steel & castings	3,430
copper, brass & bronze	104
aluminum & castings	31.3
manganese	18.0
chromium	20.8
nickel	3.5
cast iron	39.2
steam turbogenerator (MWe)	47.8
steam turbines (1000 HP)	1.0
pumps & drivers (1000 HP)	4.8
heat exchangers (1000 ft^2)	14.8
nuclear steam supply systems	47.8

COSTS	Dollars (1978)(2)(b)
construction	
manpower	8,080,000
materials	3,230,000
equipment	7,980,000
other construction	6,280,000
(land rights)	(150,000)
general plant	708,000
(escalation during construction)	(11,990,000)
(interest during construction)	(13,350,000)
(working capital)	(4,150,000)
total	26,270,000
operation & maintenance	710,000

PERSONNEL	Workers(1)(b)
construction (9 years)	29.0
operation	5.7

RESOURCES AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons(a)
particulates	0.01
SO_2	0.04
NO_x	0.08
hydrocarbons	negligible
CO	negligible
aldehydes	negligible

WATER POLLUTANTS	Tons(a)
sulfate and sulfide	37.5
chloride	0.04

SOLID WASTE	Tons(a)
total	NA

RADIATION	Curies(a)
Air	
H-3	32.4(1)
C-14	0.2(1)
Kr-85	37.7(1)
Iodine (all isotopes)	4.8 x 10^{-3}
other fission products	147.4(1)
Water	Curies(a)
H-3	12.9(1)

HEAT	Btus
heat dissipated	2 x 10^{12}

ENERGY PRODUCT	KWh
electricity	2.93 x 10^{8}

(1) These values represent the upper limit when a range of two values was reported.
(2) Estimates based on light water reactor costs, selected materials and equipment items, and manpower. Construction cost items in parentheses are not included in total.
(3) Uranium isotopes grown from irradiation of uranium 233.
(4) Does not include small amount of thorium from recycle of reflector. This is estimated to be less than 0.33 to 0.13 ton thorium per year.

SOURCES: (a) U.S. Energy Research and Development Administration, Final Environmental Statement-Light Water Breeder Reactor Program, Vols. 1-5, ERDA-1541.
(b) Bechtel Corporation, Energy Supply Planning Model, 1978.

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Coal

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ENERGY SYSTEM:

SIZE
- 20-year mine life
- 4 million tons per year
- 102.8×10^{12} Btu per year equivalent
- Eastern area mine, Northern Appalachian district

DESCRIPTION
- In the East, modified area mining is generally used in areas where the terrain is gentle (5° to 10° slope) and the overburden does not exceed about 100 feet. Typically, the thickness of the coal bed averages six feet and the efficiency of removal is about 80 percent (in terms of Btu recovered). Blasting with light charge is frequently needed to improve the mining. Overburden from each successive cut is placed in the previous one. Regrading to approximate the original land form is undertaken. Topsoil is replaced and revegetation is begun. Coal is transported to an offsite coal preparation plant.

COMPONENTS	**Quantity**
• power shovels	2
• trucks	7
• front end loaders	2
• scrapers	4
• coal shovel	2
• drilling equipment	4
• graders	2
• cable handler & reel	2
• bulldozers	8

ENVIRONMENTAL CONCERNS
- aesthetics
- acidic mine drainage contamination of surface and groundwater
- blasting damage and noise pollution
- vehicular emissions
- fugitive dust
- erosion
- altered land use

RESOURCES USED:
(Per 10^{12} Btu Produced)

RESOURCE DEPLETION	
in-place coal	48,638 tons
energy content	12,850 Btu/lb
COAL ANALYSIS	**% (by weight)**
moisture	5.9
volatile matter	34.1
fixed carbon	52.4
ash	9.6
sulfur	2.1
nitrogen	1.1
ENERGY	
diesel fuel	4.0×10^{9} Btu
electricity	5.9×10^{5} kWh
LAND	**Acres**
fixed	0.3
incremental	6.1
WATER	**Acre-Feet**
consumption	1.7
COSTS	**Dollars (1977)**
construction	
total construction cost	1.24×10^{6}
other investments and fees	0.48×10^{6}
operation	
general mining cost	0.44×10^{6}
reclamation and sediment control	3×10^{3}
PERSONNEL	**Workers**
construction	
non-manual, technical	1.0
non-manual, non-technical	0.2
manual	6.7
operation	
non-manual, technical	0.8
non-manual, non-technical	1.1
manual	2.6

RESIDUALS (Per 10^{12} Btu Produced)	**GROSS** (tons)	**NET** (tons)
AIR POLLUTANTS		
particulates(1)	0.06	0.02
SO_2	0.1	0.1
NO_2	1.5	1.5
hydrocarbons	0.2	0.2
CO	0.9	0.9
WATER POLLUTANTS		
Total Dissolved Solids	35.6	20.8
Iron	0.4	0.0004
Manganese	0.4	0.1
Aluminum	0.6	0.03
Zinc	0.02	0.002
Nickel	0.006	0.002
Total Suspended Solids	4.8	0.4
Iron	0.02	0.004
Ammonia	0.06	0.02
Sulfate	16.1	19.3
SOLID WASTE(2)		
overburden removal	435	0
runoff treatment	390	0

ENERGY PRODUCT
raw coal - 38,910 tons

(1) Assumes a 60% reduction in fugitive dust emissions through dust suppression.
(2) Assumes all solid waste is returned to mining pits.

SOURCES: The MITRE Corporation, Annual Environmental Analysis Report, 1977.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
TRW, Mesa Environmental Data Book, Volume IV, 1978.
Hittman Associates, Inc., Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume I, 1974.
Bechtel Corporation, Energy Supply Planning Model, 1978.
Bureau of Mines, Basic Estimated Capital Investment and Operating Costs for Coal Strip Mines, 1976.
Energy and Environmental Analysis, Coal and Profitability, 1979.
Bureau of Land Management, Federal Coal Management Program, Final Environmental Statement, 1979.

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ENERGY SYSTEM:

SIZE
- 6 million tons per year
- 1.1×10^{14} Btu per year equivalent
- 30 year mine life
- Western area mine, Powder River Basin

DESCRIPTION
- In Wyoming and Montana, the two states which will account for most of the increase in production in the West, area strip mining is the dominant surface mining technique. After segregating the topsoil for subsequent reclamation purposes, and after blasting, the overburden (averaging 70 feet) is removed in long parallel cuts. The now exposed and blasted coal seam (averaging 25-30 feet) is removed (89 percent efficiency in terms of Btu recovered). With the exception of the first cut, overburden from each cut is placed in the previous one. Coal is loaded into trucks for transport to a coal cleaning area. Reclamation consists of grading the spoil, replacing the topsoil and initiating revegetation.

COMPONENTS	Quantity
• trucks	11
• front end loaders	2
• scrapers	8
• draglines	2
• bulldozers	12
• drilling equipment	6
• graders	2
• coal shovel	2
• cable handler and reel	2

ENVIRONMENTAL CONCERNS
- fugitive dust and vehicular emissions
- reclamation
- alkaline mine drainage
- erosion
- noise
- aesthetics
- altered land use

RESOURCES USED:
(Per 10^{12} Btu Produced)

RESOURCE DEPLETION	
total in-place coal	39,448 tons
heat content	9,430 Btu/lb

COAL ANALYSIS	% (by weight)
moisture	21.5
volatile matter	34.5
fixed carbon	30.6
ash	4.4
sulfur	0.4
nitrogen	1.2

ENERGY	
fuel	0.8×10^9 Btu
electricity	1.1×10^3 MWh

LAND	Acres
fixed	0.4
incremental	1.8

WATER	Acre-Feet
consumption	3.0

COSTS	Dollars (1977)
construction	
total construction cost	1.32×10^6
other investments and fees	0.23×10^6
operation	
general mining cost	0.38×10^6
reclamation and sediment control	2×10^3

PERSONNEL	Workers
construction	
non-manual, technical	1.1
non-manual, non-technical	0.2
manual	2.2
operation	
non-manual, technical	0.7
non-manual, non-technical	0.9
manual	1.9

RESIDUALS (Per 10^{12} Btu Produced)	GROSS (Tons)	NET (Tons)
AIR POLLUTANTS		
Particulates(1)	0.2	0.08
SO_x	0.2	0.2
NO_x	2.0	2.0
hydrocarbons	0.2	0.2
CO	1.2	1.2
WATER POLLUTANTS		
Total Dissolved Solids	90.9	23.9
Iron	0.005	0.005
Manganese	0.02	0.02
Aluminum	0.006	0.006
Zinc	0.005	0.005
Nickel	0.001	0.001
Total Suspended Solids	3.0	2.3
Iron	0.002	0.02
Ammonia	0.1	0.2
Sulfate	42.1	37.7
SOLID WASTE(2)		
overburden removal	743	0
runoff treatment	NA	0

ENERGY PRODUCT
raw coal - 52,910 tons

(1) Assuming 60% reduction in fugitive dust emissions through dust suppression.
(2) Assumes all solid waste is returned to mining pits.

SOURCES: The MITRE Corporation, Annual Environmental Analysis Report, 1977.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
TRW, Base Environmental Data Book, Volume IV, 1978.
Hittman Associates, Inc., Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume I, 1974.
Bechtel Corporation, Energy Supply Planning Model, 1978.
Bureau of Mines, Basic Estimated Capital Investment and Operating Costs for Coal Strip Mines, 1976.
Energy and Environmental Analysis, Coal and Profitability, 1979.
Bureau of Land Management, Federal Coal Management Program, Final Environmental Statement, 1979.

Underground Coal Mining - Eastern

ENERGY SYSTEM:

SIZE
- 2 million tons per year
- 51.6×10^{12} Btu per year equivalent
- 30 year mine life

DESCRIPTION
- The mining involves driving main entries with production entries normal to the main entry on the right and left. As mining advances on one side of the main entry, rooms are excavated in the five foot coal seam. The strata above the seam is supported by pillars of coal. After an entire section is mined, part of the coal in the pillar is recovered (overall, about 57 percent recovery is possible) as a return to the main entry is made. With a mechanized continuous miner, many of the mining operations performed in the same section are executed simultaneously. An electric powered continuous miner either bores, digs or rips the coal from the working face. Coal is then loaded into a ratio feeder at the tail piece of a unit belt conveyor.

COMPONENTS	Quantity
• mainline belt conveyor	1
• roof bolting machines	13
• ventilating fan	1
• continuous mining machines	11
• loading machines	11
• shuttle car	22
• ratio feeder	11
• rock duster	12
• supply motor	5
• mainline power center	5
• section rectifier	11
• auxiliary fan	13
• section belt power center	7

ENVIRONMENTAL CONCERNS
- solid waste disposal
- runoff from waste piles
- acid mine drainage
- subsidence of surface area
- noise

RESOURCES USED:
(Per 10^{12} Btu Produced)

RESOURCE DEPLETION	
total in-place coal	68,264 tons
energy content	12,030 Btu/lb
COAL ANALYSIS	**% (by weight)**
moisture	3.9
volatile matter	34.1
fixed carbon	52.4
ash	9.6
sulfur	2.1
nitrogen	1.1
ENERGY	**MWh**
electricity	7.2×10^3
LAND	**Acres**
fixed	0.3
incremental	11.7
WATER	**Acre-Feet**
consumption	2.3
COSTS	**Dollars (1977)**
construction	
manpower	1.7×10^5
material	1.1×10^5
equipment	3.8×10^5
other investments and fees	7.1×10^5
operation	
manpower	4.9×10^5
material	0.8×10^5
equipment	1.4×10^5
other costs	3.6×10^5
PERSONNEL	**Workers**
construction	
non-manual, technical	1.3
non-manual, non-technical	0.1
manual	4.3
operation	
non-manual, technical	3.9
non-manual, non-technical	5.2
manual	12.4

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
Air emissions from equipment are not considered a problem in underground extraction since most equipment is electric powered.

	GROSS (Tons)	NET (Tons)
particulates	negligible	
SO_2	negligible	
NO_x	negligible	
hydrocarbons	negligible	
CO	negligible	
aldehydes	negligible	
WATER POLLUTANTS		
Total Dissolved Solids	396.4	392.8
Iron	22.4	0.02
Manganese	0.6	0.2
Aluminum	3.6	1.7
Zinc	0.1	0.02
Nickel	0.06	0.02
Strontium	0.2	0.2
Chloride	0.6	12.7
Fluoride	0.1	0.1
Calcium carbonate*	101.7	136.3
Total Suspended Solids	19.0	1.7
Iron	7.0	0.2
Ammonia	1.0	0.3
Sulfate	197.0	174.9
SOLID WASTE		
from sinking the mine shaft	38.4	38.6
from treating mine water runoff	0	2,090
from extraction process	NA	NA

ENERGY PRODUCT
raw coal - 38,910 tons

*Calcium carbonate net emissions are greater than calcium carbonate gross emissions because calcium carbonate is added to waste water as part of the treatment process.

SOURCES: The MITRE Corporation, Annual Environmental Analysis Report, 1977.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
TRW, Hoge Environmental Data Book, Volume IV, 1978.
Hittman Associates, Inc., Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume I, 1974.
Bechtel Corporation, Energy Supply Planning Model, 1978.
Bureau of Mines, Basic Estimated Capital Investment and Operating Costs for Coal Strip Mines, 1976.
Bureau of Land Management, Federal Coal Management Program, Final Environmental Statement, 1979.

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Coal Beneficiation

ENERGY SYSTEM:

SIZE
- Process 2,857,000 tons of run-of-mine (ROM) coal each year to produce 2 million tons of clean coal
- Hourly capacity 950 tons of ROM coal
- Operates 3,000 hours per year, representing ten shifts per week, 230 days per year
- 30 year plant life
- 87.3% efficiency (in terms of Btus)
- yield by weight is 70%

DESCRIPTION
- Coal beneficiation is a process for upgrading coal prior to its use for metallurgical or utility purposes. The purpose of beneficiation is to remove impurities (i.e. ash and/or sulfur) from raw coal. The degree of beneficiation depends on the type of coal and its ultimate use. The system described on this summary sheet (level E per Phillips et al.) is a relatively intense procedure. It removes more sulfur and ash than most other types of beneficiation, and it is also more costly. The resultant cleaned coal would be used for metallurgical purposes.

COMPONENTS
- scalping screen
- crusher
- rotary breaker
- vibrator screens
- jigs
- dewatering equipment
- thickeners
- filters
- concentrating tables or hydroclones
- flotation circuits
- thermal drying

ENVIRONMENTAL CONCERNS
- particulate emissions
- solid waste disposal
- surface water contamination from settling pond overflow and/or refuse pile runoff
- possible ground water contamination from settling pond leaching
- noise

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons
run-of-mine (ROM) or raw coal (assuming one ton of ROM coal has an energy content of 22 million Btus per ton)	51,945
ENERGY(1)	
electricity	2.0×10^5 kWh
oil	5.9×10^6 Btu
LAND	Acres(2)
washing plant	0.2
loading facility	1.8
settling pond	2.3
WATER	Acre-Ft.
consumption	3.7
COSTS	Dollars (1976)
construction	6.3×10^5
operation and maintenance	3.2×10^5
PERSONNEL	Workers
construction (1 year)	8.1
operation and maintenance	1.5

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons (Gross)	Tons (Net)(3)
particulates	51	0.9
SO_2	2.7	0.005
NO_x	1.5	0.6
hydrocarbons	1.1	0.2
CO	5.4	0.2
WATER POLLUTANTS	Tons (Gross)	Tons (Net)(3)
total dissolved solids	143	33
iron	0.2	0.007
manganese	0.2	0.03
aluminum	1.1	0.04
zinc	0.06	0.005
nickel	0.01	0.003
total suspended solids	5,070	0.6
iron	4.4	0.06
ammonia	0.2	0.05
sulfates	90	18
SOLID WASTE	Tons (Gross)	Tons (Net)(3)
primary breaking	0	0
coarse cleaning(5)	2	2
raw-coal sizing	0	0
primary cleaning	10,157	10,157
froth flotation	5,341	5,341
thermal drying	0	0
breaking and sizing	2	2
total	15,502	15,502

HEAT
little or none

NOISE
Noise may affect workers involved in cleaning coal, but there should be little or no adverse impact on receptors near beneficiation plants.

ENERGY PRODUCT
cleaned coal

(1) These figures were calculated assuming an energy content of 12,000 btu/lb of coal (Hittman, 1974). They are national averages (assuming an energy efficiency of 91.3%) and do not apply to elaborate (i.e., level E) beneficiation in particular.
(2) These coefficients may be subject to error since the data source presented only the fixed amount of land used without specifying the plant's annual output of coal. In calculating these coefficients, it was assumed here that plant output was the same as that specified in the "size" section of this sheet.
(3) These figures are weighted national averages based upon regional coefficients projected by SEAS for 1979. The regional coefficients were weighted in terms of Btus used. Each of the coefficients shown on this sheet is equal to total national tons of residual divided by total national Btu output. These figures include residuals from refuse piles and the beneficiation process itself. They assumed that 80% of coal preparation plants are closed cycle and that all refuse is treated. An efficiency of 90% (in Btus) was assumed.
(4) Based on national averages in Hittman.

SOURCES: Phillips, Peter and Paul DeRienzo, "Assessing the Economics of Steam Coal Preparation", Coal Mining and Processing, September, 1977.
DOE and EPA, Engineering/Economic Analysis of Coal Preparation with SO_2 Cleanup Processes, 1978.
Hittman Associates, Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, 1974.
The MITRE Corporation, Annual Environmental Analysis Report, 1977.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
Schmidt, Richard A., Coal in America, 1979.
McGraw Hill Mining Information Services, Keystone Coal Industry Manual, 1977.
Bureau of Land Management, Federal Coal Management Program, Final Environmental Statement, 1979.

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This page has been revised. Please refer to Appendix A, pages A-2 and A-3 for the revised information.

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ENERGY SYSTEM:

SIZE
- 300 MWe
- 3,312 tons coal feed/day
- heat rate 10,000 Btu/kWh
- thermal efficiency 34%
- capacity factor 55% (national average)
- annual energy production 8.2×10^{12} Btu/year
- 30 year life

DESCRIPTION
- Current NSPS
  - particulates 0.1 lb/10^6 Btu (coal input)
  - sulfur oxides 1.2 lb/10^6 Btu (coal input)
- Revised NSPS
  - particulates 0.03 lb/10^6 Btu (coal input)
  - sulfur oxides reduction varies between 70% and 90% based on sulfur content and Btu content per pound of coal.

COMPONENTS
- coal
- coal crushing/conveying system
- coal pulverizing
- p.f. boiler
- turbine
- generator
- feed water treatment
- air preheater
- economizer
- flue gas desulfurization(1)
- settling ponds
- electrostatic precipitator (ESP)
- cooling towers

ENVIRONMENTAL CONCERNS
- NO_x emissions
- potential leachate of trace elements from ash/sludge
- water use (in certain areas)
- SO_2 emissions from plants

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL
coal: Western Rocky Mountain Province, [illegible]; heat content, 10,000 Btu/lb

COAL ANALYSIS	% (by weight)
sulfur	0.6
ash	7.7

ENERGY(2) (requirements for pollution control devices)	
electrostatic precipitator	0.09
cooling towers	4.5

LAND	Acres/Year
plant site, permanent	32.6
waste disposal area, temporary	5.9

WATER	Acre-Ft./Year
total	154.3

COSTS	Dollars
construction	NA
operation & maintenance	NA

PERSONNEL	Workers
construction	NA
operation & maintenance	0.51

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS (Tons)

	Gross	Plant Under NSPS Net	Plant Under Revised NSPS Net
particulate	9824.0	147.0	44.0
SO_2	1670.0	1670.0	382.0
NO_x	1318.0	1025.0	464.0
hydrocarbons	22.0	22.0	22.0
CO	73.0	73.0	73.0
arsenic	0.14	0.007	0.007
beryllium	0.06	0.001	0.001
cadmium	0.04	0.001	0.001
fluorine	7.3	0.56	0.56
lead	0.58	0.05	0.05
mercury	0.005	0.005	0.005
selenium	0.14	0.04	0.04
manganese	2.5	0.14	0.14

WATER POLLUTANTS	Tons
BOD	1.41
COD	137.16
total suspended solids	0.33
total dissolved solids	873.53
aluminium	0.30
chromium	0.01
non-ferrous metals	110.79
zinc	0.05
sulfates	41.10
nickel	3.62
nutrients	
nitrates	1.07
ammonia	0.06
phosphorus	0.17
surfactants	0.30

SOLID WASTE (dry weight tons)

	Without Scrubbers	With Non-Regenerative Lime Scrubbers (Revised NSPS)
scrubber sludge	0	2311.0
boiler ash	2441.1	2441.1
ESP ash	8735.2	8735.2

HEAT	Btus
stack loss	0.53×10^{12}
cooling towers	1.41×10^{12}

ENERGY PRODUCT(3)	kWh
electricity per 10^{12} Btu output	2.93×10^8

(1) Will probably only occur under NSPS.
(2) Excludes requirements for conformance with NSPS, i.e., for an FGD system.
(3) For each Btu of electricity generated, 0.53 of energy is lost out of the stack, and 1.4 Btu of energy is lost through the cooling towers.

SOURCES: U.S. Department of Energy, *Materials-Process Analysis of Coal Process Technology - Final Report for Project Phase II*, 1977.
The MITRE Corporation, *Annual Environmental Analysis Report*, 1977.
U.S. Environmental Protection Agency, *Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source*, 1974.

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Atmospheric Fluidized Bed Combustion - Bituminous Coal

ENERGY SYSTEM:

<u>SIZE</u>:
- 878.66 MWe gross plant output
- 814.26 MWe net plant output or 2.779×10^9 Btu/hour
- 15.8×10^{12} Btu/year at 65% capacity factor
- power plant efficiency 33.8%
- plant life 20 years

<u>DESCRIPTION</u>
- This process is based on the combustion of small pieces of coal suspended by a continuous flow of air. This suspended mass of coal is somewhat similar to a fluid in its characteristics. A limestone sorbent added directly to the combustion allows the control of SO_2 emissions. The fluidized-bed therefore achieves SO_2 control without the use of a conventional limestone flue gas scrubber. Fluidized-beds also emit less NO_x than conventional boilers. Fluidized-bed combustion can be applied to a wide range of boiler sizes.

<u>COMPONENTS</u>
- main fluidized-bed boiler
- 83-85% SO_2 removal efficiency
- AFBC steam generator
- steam turbine system
- carbon burn-up cell
- cyclones
- fabric filter or electrostatic precipitator (ESP)
- cooling tower
- generator and transformers

<u>ENVIRONMENTAL CONCERNS</u>
- solid waste disposal
- particulate emissions control

RESOURCES USED:
(Per net 10^{12} Btu_e Produced)

<u>FUEL</u>	
coal: bituminous, Illinois No. 6	329,506 tons
energy content	10,700 Btu/lb
<u>COAL ANALYSIS</u>	<u>% (by weight)</u>
sulfur	3.9
ash	9.6
<u>LAND</u>	<u>Acres</u>(1)
main plant site	7.2
disposal area	8.4
total	15.6
<u>WATER</u>	
consumptive use	180 (1,2)
<u>SORBENT MATERIAL</u>	<u>Tons</u>
limestone	33,285
<u>COSTS</u>	<u>Dollars (1980)</u>(3)
construction (5.5 years)	32,714,550
operation & maintenance	3,428,000

<u>PERSONNEL</u>
approximately same value as conventional power station of equivalent capacity

RESIDUALS AND PRODUCTS:
(Per net 10^{12} Btu_e Produced)

<u>AIR POLLUTANTS</u>	<u>Tons</u>	<u>NSPS</u>(3)
particulates	130	
SO_2	1,435	
NO_x	364	
hydrocarbons	13	
CO	56	

<u>WATER POLLUTANTS</u>
same values as conventional power station of equivalent capacity

<u>SOLID WASTE</u>	<u>Tons</u>
dry weight	42,778
<u>ENERGY PRODUCT</u>	<u>kWh</u>
base load electric power	2.93×10^8

(1) Data values represent the life-cycle values per 10^{12} Btu divided by annual energy output; i.e. 7.2 acres/10^{12} Btu annually or 7.2 ÷ 20 = 0.36 acres/10^{12} Btu.
(2) Generally the same as a conventional plant of equivalent capacity except that the latter uses approximately five percent of total water use for a wet sulfur dioxide scrubber.
(3) Standards for FBC have yet to be promulgated.

SOURCES: Vance, J.T., <u>Utility Boiler Design/Cost Comparison Fluidized-Bed Combustion vs. Flue Gas Desulfurization</u>, (EPA-600/7-77-126), 1977.
Fluidized Combustion Company, <u>Preliminary Design and Cost Estimate for an Atmospheric Fluidized-Bed Steam Generator</u>, Tennessee Valley Authority, 1974.

Atmospheric Fluidized Bed Combustion - Western Subbituminous Coal

ENERGY SYSTEM:

SIZE:
- 600 MWe nominal rating
- 568.215 MWe gross plant output
- 535.905 MWe net plant output
- 1.029×10^9 Btu per hour
- 95% (on stream operation)
- 15.22×10^{12} Btu/year
- net plant efficiency of 34.42%
- plant life 20 years

DESCRIPTION
- This process is based on the combustion of small pieces of coal suspended by a continuous flow of air. This suspended mass of coal is somewhat similar to a fluid in its characteristics. A limestone sorbent added directly to the combustion allows the control of SO_2 emissions. The fluidized-bed therefore achieves SO_2 control without the use of a conventional limestone flue gas scrubber. Fluidized-beds also emit less NO_x than conventional boilers. Fluidized-bed combustion can be applied to a wide range of coals and boiler sizes.

COMPONENTS
- main fluidized-bed boiler
- AFBC steam generator
- steam turbine system
- carbon burn-up cell
- cyclones
- fabric filter, more than 99% efficient
- cooling tower
- generator and transformers

ENVIRONMENTAL CONCERNS
- solid waste disposal
- particulate emissions control

RESOURCES USED:
(Per Net 10^{12} Btu_e Produced)

FUEL	Tons
coal: Western subbituminous, Powder River, Wyoming, HHV 8053 Btu/lb	≈180,683

COAL ULTIMATE ANALYSIS	% (by weight)
carbon	47.0
hydrogen	6.5
nitrogen	0.7
oxygen	37.1
sulfur	0.9
ash	7.8

LAND(1)	Acres
total land use	29.1
site only	20.4

WATER	10^6 Gallons
consumptive use	190(3)

SORBENT MATERIAL	Tons
limestone	12,829

COSTS	Dollars (Mid 1977)
construction	18,300,000(1)
operation & maintenance	356,110

PERSONNEL
approximately same value as conventional power station of equivalent capacity

RESIDUALS AND PRODUCTS:
(Per Net 10^{12} Btu_e Produced)

AIR POLLUTANTS	Tons	NSPS(4)
particulates	146	
SO_2	1,737(2)	
NO_x	582	
hydrocarbons, CO	less than conventional power station of equivalent capacity at 85% removal	

WATER POLLUTANTS
approximately same values as conventional power station of equivalent capacity

SOLID WASTE	Tons
dry weight	23,796

ENERGY PRODUCT	kWh
base load electric power	2.93×10^8

(1) Data values represent life-cycle values per 10^{12} Btu divided by annual energy output; i.e. 35.1 acres/10^{12} Btu annually or 35.1 ÷ 20 = 1.46 acres/10^{12} Btu.
(2) Operating at 46% efficiency of sulfur removal. At 85% efficiency, the SO_2 emission would be 483 tons/10^{12} Btu. This plant is designed to meet a SO_2 emission standard of 1.2 lbs SO_2/MM Btu.
(3) Generally, the same as conventional power plant of equivalent capacity except that the latter uses approximately three percent of total water use for a wet sulfur oxide scrubber.
(4) Standards for FBC have yet to be promulgated.

SOURCES: Bradley, W.J. et al., Conceptual Design of an Atmospheric Fluidized-Bed (AFBC) Electric Power Generating Plant-Interim Report, U.S. Department of Energy, 1978.
Stone and Webster Engineering Corporation, Technical Notes for the Conceptual Design for an Atmospheric Fluidized-Bed Direct Combustion Power Generating Plant, U.S. Department of Energy, 1978.

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Magnetohydrodynamic System

ENERGY SYSTEM:

SIZE
- 1,993 MWe gross output
- 1,932 MWe net output
- plant efficiency 49.8%
- load factor 65%
- 37.5×10^{12} Btus net output per year

DESCRIPTION
- Generation of base load electric power using magnetohydrodynamics. Seed material (Potassium) is mixed with a finely ground coal and ionized at a high temperature and passed through a magnetic field to generate electricity.

COMPONENTS
- pulverized coal burner (2 stage combustors)
- MHD generators
- seed recovery system
- steam bottoming cycle

ENVIRONMENTAL CONCERNS
- particulate emissions
- potential for NO_x emissions

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons
coal: Illinois No. 6 (bituminous)	95,090
LAND	Acres
total(1)	47.3
WATER	Acre-Feet
consumptive	306
COSTS	Dollars (1975)
construction(2)	37,000,000
operation & maintenance(3)	1,000,000
PERSONNEL	Workers
construction	NA
operation & maintenance	NA

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons
particulates	30
SO_2	500
NO_x	300

WATER POLLUTANTS
Blowdown from cooling and steam system. Similar to emission from an electric power station.

SOLID WASTE	Tons
furnace wastes	7,600
fly ash	1,340
ENERGY PRODUCT	kWh
electrical energy	2.93×10^8
OTHER PRODUCT	Tons
sulfur	3,100

NA = Not Available from cited source.

(1) Represents total land required for the plant, divided by annual energy output, measured in trillion Btu.
(2) Represents construction costs, divided by annual energy output, measured in trillion Btu.
(3) Includes fuel cost but excludes recovery of capital.

SOURCE: General Electric Company, Study of Advanced Energy Conversion Techniques for Utility Applications Using Coal or Coal Derived Fuels, 1976.

Coal-Oil Mixture Retrofit Boiler

ENERGY SYSTEM:

SIZE
- 300 MW_e
- 55% capacity factor
- 35% thermal efficiency
- 9800 Btu/kWhr heat rate
- 5×10^{12} Btu/yr net energy output
- Operates 20 hr. per day, 312 days per year
- No. 6 fuel oil
- Appalachian Bituminous coal

DESCRIPTION [a]

- Recently constructed oil-designed boilers are a favorable target for coal-oil mixture (COM) conversion. These units generally require certain modifications. Use of wear-resistant alloys and enlarging orifices are necessary to prevent deterioration and to ensure a compatible viscosity range. Existing fuel train pumps may have to be replaced with wear-resistant rotary gears or progressive cavity-type pumps; valves will also need to be replaced with full-bore, ball-type units for control. Additional sootblower capacity may be required to control the builup of residue. Additional particulate and sulfur oxide controls will be needed to control emissions. The capacity of the bottom ash removal system may need augmentation. Assuming that the COM is purchased from a central COM preparation plant, the existing oil unloading facility can be used to unload COM. However, an independent COM storage and handling system will be needed to achieve dual fuel capacity (so that oil can be burned periodically to minimize the effect of derating).

MAJOR EQUIPMENT COMPONENTS
- COM pumping system
- Electrostatic precipitator (ESP)
- Sootblower
- Bottom ash hopper and handling system
- Flue gas desulfurization (FGD)

ENVIRONMENTAL CONCERNS [b]
- Air pollution (sulfur oxides, nitrogen oxides, particulates, carbon monoxide, hydrocarbons, and hazardous trace substances)
- Ash disposal
- Leachates
- Spills/Leaks

RESOURCES USED:
(Per 10^{12} Btu Output)

FUEL
50% coal-oil mix by weight
4.8×10^{5} barrels
Cost - \$$6.57 \times 10^{6}$ [c]

FUEL ANALYSIS
Heating value - 15,930 Btu/lb
Density - 8.82 lb/gal
Sulfur - 1.5%
Ash - 3%

ENERGY [d]	Btu
Fuel train	NA
FGD (limestone wet scrubber)	4.0×10^{10}
ESP	3.0×10^{9}
NO_x control	6.0×10^{9}
Soot control and ash handling	site specific

LAND	Acres
Waste disposal (landfill)	site specific

WATER [b]	Acre-Feet
Consumption	271

COST	1980 Dollars
Retrofit [c]	6.94 x 10[illegible]
Annual operating & maintenance [e]	9.0×10^{5}

PERSONNEL	No. of Workers
Construction (retrofit)	NA
Operating and maintenance (total) [f]*	16.2
nonmanual, technical	2.4
nonmanual, nontechnical	2.8
manual	11.0

RESIDUALS AND PRODUCT:
(Per 10^{12} Btu Output)

AIR POLLUTANTS (tons) [g]	Gross	NSPS Net
Particulates	1968	144
Sulfur oxides	2527	1297
Nitrogren oxides	961	648
Carbon monoxide	38	40
Hydrocarbons	17	18

WATER POLLUTANTS NA

SOLID WASTE (tons) [b]	Gross	Net
Spent sorbent and sodium bicarbonate	NA	NA
Ash	NA	NA
Total	NA	NA

ENERGY PRODUCT	kWhr
Electricity	2.93×10^{8}

*Assume O/M manpower levels are similar to that used by a similarly sized oil-fired power plant.

SOURCES:
(a) Pruce, Leslie M., 1980. COMs: Boiler Fuel of the Future? Power, Vol. No. 2, p. 110.
(b) Brown, Richard (editor), 1979. Health and Environmental Effects of Coal Technologies. Prepared for Federal Interagency Committee on Health and Environmental Effects of Energy Technologies, Report No. DOE/HEW/EPA-04.
(c) George, Thomas J., T.C. Campbell, and Perry D. Bergman, 1979. Coal-Oil Mixtures: A Good Idea from DOE. Coal Mining and Processing, Vol. 16, No. 3, p. 71.
(d) DOE/EPA, 1977. Energy Consumption of Environmental Controls: Fossil Fuel, Steam Electric Generating Industry.
(e) Foo, O.K., et al., 1980. Market Assessment and Financial Analysis of COM Conversion. The MITRE Corporation (to be published).
(f) Bechtel Corporation, 1978. Energy Supply and Planning Model. San Francisco, California.
(g) U.S. Environmental Protection Agency, 1975. Compilation of Air Pollutant Emission Factors. EPA Publication No. AP/42.

Central Coal-Oil Mixture Preparation Plant

ENERGY SYSTEM:

SIZE[a]
- 33 million barrels (6.26×10^6 ton) per year of a 50/50 mixture of coal-oil
- 194.7×10^{12} Btu per year
- Operates 20 hours per day
- 312 days per year
- 20 year plant life
- No. 6 fuel oil
- Appalachian bituminous coal

DESCRIPTION[a]
- When a large central preparation/distribution COM facility is built, it is most likely to also include an elaborate coal beneficiation capability. Coarsely beneficiated coal would be delivered by a unit train to a rotary car dump and then moved to a transfer house. From the transfer house, the coal is either brought to a live or dead storage stockpile through a stacker/reclaimer or it is introduced to the coal-oil mixture or the coal beneficiation circuit through a 24-hour capacity process surge silo. Coal in the COM circuit is first passed through hoppers which have a 6-hour holdup. From the hoppers, the coal is moved through a pulverizer (e.g., a vertical roll mill) which reduces the coal to 90 percent through 200 mesh. Cyclone separator feeders then transmit the coal for mixing with oil. Either continuous or batch mixing may be employed. (Batch mixing appears the most likely for the initial facilities.) Batch mixing consists of filling a tank to a specified level with oil and then blending in coal until a second level is reached which represents the desired mixture. It is assumed that the COM is delivered to market through existing No. 6 fuel oil distribution systems.

MAJOR COMPONENTS[1], [a]

Battery Unit	No. of Units
Rotary Car Dump	1
Stacker/Reclaimer	1
Coal Stockpile	2
Process Surge Silo/Hopper	1
Pulverizer	3
Mixing Tank	3
Oil/COM Storage Tank (180,000 bbl)	25

ENVIRONMENTAL CONCERNS[b]
- Evaporate losses from oil storage and transfer operations
- Fugitive dust
- Runoff
- Noise
- Leaks/Spills

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL[a]
Coal:
Coarsely beneficiated Appalachian bituminous
Operating Amount - 1.6×10^4 T[2]
Oil:
No. 6 Fuel Oil
Operating Amount - 9.4×10^4 barrels

FUEL ANALYSIS[a]
Coal
- Level C beneficiated
- Heating Value - 13,060 Btu/lb
- 2% sulfur, maximum
- \$27/ton[3]

Oil
- Heating Value - 18,800 Btu/lb
- 1% sulfur
- \$18.00/barrel[3]
- Density - 8.1 lb/gal

OPERATING ENERGY[a]	
Electricity	4.3×10^5 kWhr
LAND[c]	
Fixed land[4]	1.34 acres
WATER	
Consumptive use	Negligible
COSTS[4], [c]	1978 Dollars
Total investment requirements	6.40×10^5
total plant cost, insurance	4.16×10^5
taxes, interest, and working capital	2.24×10^5
Total operating cost	9.00×10^4
raw materials and utilities	1.42×10^4
direct labor	0.42×10^4
plant maintenance (materials and manpower)	1.85×10^4
overhead	2.12×10^4
taxes, insurance, and depreciation	3.19×10^4
PERSONNEL	Workers
Construction total[c]	1.54
nonmanual, technical[5]	0.28
nonmanual, nontechnical[5]	0.04
manual[5]	1.22
Operation, Maintenance and Supervision[a]	0.64

RESIDUALS AND PRODUCT:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	
Fugitive dust	NA[6]
Hydrocarbons	NA[6]
WATER POLLUTANTS	NA
SOLID WASTE	Negligible

ENERGY PRODUCT[a]
50% oil - 50% coal (by weight)
Heating value - 15,930 Btu/lb
Density - 370.4 lb/barrel
Cost - $\$1.67 \times 10^6$ @ 12% DCF with 60% equity and 3% interest on debt
Amount - 3.15×10^4 Tons

(1) The COM facility is assessed without a coal beneficiation circuit.

(2) Assumes a coal throughput of 10,000 T/day.

(3) Costs are based on DOE Monthly Energy Review January 1980.

(4) Assumes that land required for the COM facility would be about that needed for a similarly sized petroleum bulk station and nominal (11.5 acres for 60,000 T) coal storage needs.

(5) Assume construction manpower needs would be about that needed for a similarly sized petroleum bulk station.

(6) Fugitive dust and evaporative losses are highly dependent on site specific events and operating modes. For example, factors affecting the rate of hydrocarbon emissions include: true vapor pressure of the liquid stored, temperature changes in the tanks, height of the vapor space, tank diameter, schedule of tank filling and emptying, mechanical condition of tank and seals, and type of tank and type of paint applied to outer surface.

SOURCES: (a) George, T. J. (1978). "A Commercial Coal-Oil Prepdration Facility: Concepts and Economics Assuming a 50 Percent Mixture (33 Million Barrels per year)," U.S. Department of Energy, Morgantown, WV. Process Evaluation Office, Report No. FE/EES-79/2.
(b) Brown, R. (ed.) (1979). "Health and Environmental Effects of Coal Technologies. Prepared by The MITRE Corporation for the Federal Interagency Committee on Health and Environmental Effects of Energy Technologies. MITRE Report No. MTR-79W0015901.
(c) Bechtel Corporation (1978). Energy Supply and Planning Model. San Francisco, California.

Eastern Coal Unit Train

ENERGY SYSTEM:

SIZE
- one unit train carries 10,500 tons of coal per trip
- unit train consists of 105 freight cars each carrying 100 tons of coal
- four diesel locomotives of 3,000 HP each
- ten spare freight cars are reserved for each unit train
- each unit train is assumed to make 90 round trips per year. Each trip is 700 miles (1126 km) one way
- 99.75% of the coal loaded on a unit train is successfully delivered to its destination—0.25% inefficiency accounts for losses in handling and wind losses in transportation
- 30 year lifetime of cars

DESCRIPTION
- Unit trains consist of equipment dedicated to transportation of coal from a single origin to a single destination. The unit train described in this summary runs on diesel fuel (99% of all rail ton-miles in the U.S. are by diesel; 1% are on electrically-powered trains)

COMPONENTS
- freight cars
- locomotives
- cabooses

ENVIRONMENTAL CONCERNS
- air pollution
- railroad crossing hazard
- noise

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	
coal transported	38,911 tons
energy content	12,850 Btu/lb

ENERGY	Btus
diesel	0.95×10^{10}

LAND(1)

MATERIALS(2)	Tons
aluminum	1.87
brass & bronze (castings)	0.75
chromium	0.10
copper	2.58
iron	NA
manganese	1.33
nickel	0.02
steel	105

COSTS	Dollars (1978)
construction(2)(3)(4)	
electrical equipment	50,000
miscellaneous equipment	274,000
other constructor expenses	9,000
total	334,000
operation and maintenance(5)	
ancillary energy (diesel)	39,000
other	258,000
total	297,000

PERSONNEL	Workers
construction (1 year)	NA
operation & maintenance	5.16

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Transported)

AIR POLLUTANTS(6)	Tons
particulates(7)	102.9
SO_2	3.7
NO_x	3.2
hydrocarbons	2.5
CO	3.4
aldehydes, etc.	0.6

NOISE
Noise inside diesel locomotives ranges at least as high as 112 decibels (dBA). 100 feet from a moving train, noise may be approximately 95 dBA, while at 1000 feet the noise level may be about 75dBA. Locomotive whistle noise at 1000 feet from a train has been recorded at 85 dBA, dropping below 70 dBA at 1300 feet. The amount of noise generated is affected by train speed, the number of cars in a train, track condition and topography. Welding of tracks help reduce noise, and man-made barriers can obstruct or dissipate sound emissions. Federal design noise levels range from 55 dBA (maximum desirable for residences) to 75 dBA.

ENERGY PRODUCT	Tons
transported coal	38,911

(1) Land use value has been excluded, as it cannot be exclusively associated with coal transportation.
(2) These figures do not include materials (construction costs) for tracks, loading facilities and unloading facilities.
(3) This represents the costs of construction, divided by the annual volume transported.
(4) Total construction costs shown here do not include labor.
(5) O&M costs include tracks, but exclude loading facilities and unloading facilities.
(6) Removal efficiency 0 percent.
(7) Includes particulates from locomotives and fugitive emissions.

SOURCES: Hittman Associates, Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume 1, 1974.
Bechtel Corporation, Energy and Supply Planning Model, 1978.
International Research & Technology Corporation, TECNET, 1979.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
C. Harris, C., Handbook of Noise Control, 1957.
PEDCo, Inc., Environmental Assessment of Coal Transportation, 1978

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Western Coal Unit Train

ENERGY SYSTEM:

SIZE
- One unit train carries 10,000 tons of coal per trip.
- Unit train consists of 100 freight cars each carrying 100 tons of coal.
- Four diesel locomotives of 3,000 HP each
- Ten spare freight cars are reserved for each unit train.
- Each unit train is assumed to make 90 round trips per year. Each trip is 700 miles (1126km) one way.
- 99.75% of the coal loaded on a unit train is successfully delivered to its destination—0.25% inefficiency accounts for losses in handling and wind losses in transportation.
- 30 year lifetime of cars

DESCRIPTION
- Unit trains consist of equipment dedicated to transportation of coal from a single origin to a single destination. The unit train described in this summary runs on diesel fuel (99% of all rail ton-miles in the U.S. are by diesel; 1% are on electrically-powered trains).

COMPONENTS
- freight cars
- locomotives
- caboose

ENVIRONMENTAL CONCERNS
- air pollution (particulates)
- railroad crossing hazard
- noise

RESOURCES USED:
(Per 10^{12} Btu Transported)

PRODUCT	
coal transported	53,040 tons
energy content	9,430 Btu/lb
ENERGY	Btus
diesel	1.38×10^{10}
LAND(1)	NA
MATERIALS(2)	Tons
aluminum	2.54
brass & bronze (castings)	1.02
chromium	0.13
copper	3.51
iron	NA
manganese	1.80
nickel	0.03
steel	251.33
COSTS	Dollars (1978)
construction(2)(3)(4)	
electrical equipment	60,000
miscellaneous equipment	372,000
other constructor expenses	13,000
total	654,000
operation and maintenance(5)	
ancillary energy(1) (diesel)	53,000
other	351,000
total	405,000
PERSONNEL	Workers
construction (1 year)	NA
operation & maintenance	7.02

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Transported)

AIR POLLUTANTS(6)	Tons
particulates	[illegible](7)
SO_2	5.0
NO_x	4.4
hydrocarbons	3.6
CO	4.6
aldehydes, etc.	0.8

NOISE
Noise inside diesel locomotives ranges at least as high as 112 decibels (dBA). 100 feet from a moving train, noise may be approximately 95 dBA, while at 1000 feet the noise level may be about 75 dBA. Locomotive whistle noise at 1000 feet from a train has been recorded at 85 dBA, dropping below 70 dBA at 1300 feet. The amount of noise generated is affected by train speed, the number of cars in a train, track condition and topography. Welding of tracks help reduce noise, and man-made barriers can obstruct or dissipate sound emissions. Federal design noise levels range from 55 dBA (maximum desirable for residences) to 75 dBA.

ENERGY PRODUCT	Tons
transported coal	52,910

(1) Land use value has been excluded as it cannot be exclusively associated with coal transportation.
(2) These figures do not include materials (construction costs) for tracks, loading facilities and unloading facilities.
(3) This represents the costs of construction, divided by the annual volume transported.
(4) Total construction costs shown here do not include labor.
(5) O&M costs include tracks, but exclude loading facilities and unloading facilities.
(6) Uncontrolled.
(7) Includes particulates from locomotives and fugitive emissions.

SOURCES: Hittman Associates, Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume 1, 1974.
Bechtel Corporation, Energy Supply Planning Model, 1978.
International Research & Technology Corporation, TECNET, 1978.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
C. Harris, Ed., Handbook of Noise Control, 1957.
PEDCo, Inc., Environmental Assessment of Coal Transportation, 1978.

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Eastern Coal Conventional Train

ENERGY SYSTEM:

SIZE
- One conventional train carries 1 ton of coal per trip.
- A conventional train is assumed to consist of 85 freight cars, each of which carries 85 tons of freight. 17 of these freight cars carry coal. The other 68 cars carry non-coal products.
- Each conventional train is assumed to make 20 round trips per year. Each trip is 300 miles (483 Km) one-way.
- 99.75% of the coal loaded on a conventional train is successfully delivered to its destination—0.25% inefficiency accounts for losses in handling and wind losses in transportation.
- 30 year lifetime of cars

DESCRIPTION
- Conventional trains transport several commodities simultaneously. Only one of these products is coal. The conventional train described in this summary runs on diesel fuel (99% of all rail ton-miles in the U.S. are by diesel; 1% are by electrically-powered trains).

COMPONENTS
- freight cars containing coal
- freight cars containing other products (all coefficients shown on this summary sheet are pro-rated to include freight cars containing non-coal products)

ENVIRONMENTAL CONCERNS
- air pollution (particulates)
- noise pollution, particularly in populated areas
- railroad crossing hazards

RESOURCES USED:
(Per 10^{12} Btu Transported)

PRODUCT	
coal transported	39,000 tons
energy content	12,830 Btu/lb
ENERGY	**Btus**[1]
diesel	1.08×10^{10}
LAND[1]	NA
MATERIALS[2]	**Tons**
aluminum	5.84
brass & bronze	3.33
chromium	0.40
copper	9.76
iron	NA
manganese	6.02
nickel	0.09
steel	844
COSTS	**Dollars (1978)**
construction[2][3][4]	
electrical equipment	138,000
miscellaneous equipment	1,136,000
other constructor expenses	38,000
total	1,313,000
operation and maintenance[5]	
ancillary energy (diesel)	31,000
other	854,000
total	885,000
PERSONNEL	**Workers**
construction	NA
operation & maintenance	3.91

RESIDUALS & PRODUCTS:
(Per 10^{12} Btu Transported)

AIR POLLUTANTS[6]	**Tons**[7]
particulates	101.7
SO_2	2.6
NO_x	2.9
hydrocarbons	2.0
CO	2.7
aldehydes, etc.	0.5

NOISE
Noise inside diesel locomotives ranges at least as high as 112 decibels (dBA). 100 feet from a moving train, noise may be approximately 95 dBA, while at 1000 feet the noise level may be about 75 dBA. Locomotive whistle noise at 1000 feet from a train has been recorded at 85 dBA, dropping below 70 dBA at 1,300 feet.

The amount of noise generated is affected by train speed, the number of cars in a train, track condition, and topography. Welding of tracks helps reduce noise, and man-made barriers can obstruct or dissipate sound emissions. Federal design noise levels range from 55 dBA (maximum desirable for residences) to 75 dBA (open land).

ENERGY PRODUCT	**Tons**
transported coal	38,911

(1) Land use value has been excluded as it cannot be exclusively associated with coal transportation.
(2) These figures do not include materials (construction costs) for tracks, loading facilities and unloading facilities.
(3) This represents the costs of construction, divided by the annual volume transported.
(4) Total construction costs shown here do not include labor.
(5) O&M costs include tracks, but exclude loading facilities, and unloading facilities.
(6) Uncontrolled.
(7) Includes particulates from locomotives and fugitive emissions.

SOURCES: Bechtel Corporation, Energy Supply Planning Model, Volume I, 1975, and revisions, 1978
Hittman Associates, Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume I, 1974.
International Research & Technology Corporation, TECNET, 1978.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
Cyril Harris, ed., Handbook of Noise Control, 1956.
PEDCo, Inc., Environmental Assessment of Coal Transportation, 1978.

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Western Coal Conventional Train

ENERGY SYSTEM:

SIZE
- One conventional train carries 1,445 tons of coal per trip.
- A conventional train is assumed to consist of 85 freight cars, each of which carries 85 tons of freight. 17 of these freight cars carry coal. The other 68 cars carry non-coal products.
- Each conventional train is assumed to make 20 round trips per year. Each trip is 300 miles (483 Km) one way.
- 30 year lifetime of cars
- 99.75% efficiency; 0.25% losses are due to loading, unloading, and windage during transit.

DESCRIPTION
- Conventional trains transport several commodities simultaneously. Only one of these products is coal. The conventional train described in this summary runs on diesel fuel (99% of all rail ton-miles in the U.S. are by diesel; 1% are by electrically-powered trains).

COMPONENTS
- freight cars containing coal
- freight cars containing other products (all coefficients shown on this summary sheet are pro-rated to exclude freight cars containing non-coal products)
- locomotives
- caboose
- tracks
- loading and unloading facilities
- yard facilities, including switch-yard buildings

ENVIRONMENTAL CONCERNS
- air pollution (particulates,
- noise pollution, particularly in populated areas
- railroad crossing hazards

RESOURCES USED:
(Per 10^{12} Btu Transported)

PRODUCT	
coal transported	53,040 tons
energy content	9,450 Btu/lb
ENERGY	Btus
diesel	1.67×10^{10}
LAND[1]	NA
MATERIALS[2]	Tons
aluminum	7.67
brass & bronze	4.52
chromium	0.54
copper	13.27
iron	NA
manganese	8.18
nickel	0.12
steel	11.47
COSTS	Dollars (1978)
construction[2][3][4]	
electrical equipment	188,000
miscellaneous equipment	1,548,000
other constructor expenses	52,000
total	1,785,000
operation & maintenance[5]	
ancillary energy (diesel)	43,000
other	1,161,000
total	1,204,000
PERSONNEL	Workers
construction	NA
operation & maintenance	5.32

RESIDUALS & PRODUCTS:
(Per 10^{12} Btu Transported)

AIR POLLUTANTS[6]	Tons
particulates	138.4[7]
SO_2	3.5
NO_x	4.0
hydrocarbons	2.7
CO	3.7
aldehydes, etc.	0.6

NOISE

Noise inside diesel locomotives ranges at least as high as 112 decibels (dBA). 100 feet from a moving train, noise may be approximately 95 dBA, while at 1000 feet the noise level may be about 75 dBA. Locomotive whistle noise at 1000 feet from a train has been recorded at 85 dBA, dropping below 70 dBA at 1300 feet.

The amount of noise generated is affected by train speed, the number of cars in a train, track condition and topography. Welding of tracks helps reduce noise, and man-made barriers can obstruct or dissipate sound emissions. Federal design noise levels range from 55 dBA (maximum desirable for residences) to 75 dBA (open land).

ENERGY PRODUCT	Tons
transported coal	52,910

(1) Land use value has been excluded as it cannot be exclusively associated with coal transportation.
(2) These figures do not include materials (construction costs) for tracks, loading facilities and unloading facilities.
(3) This represents costs of construction, divided by the annual volume transported.
(4) Total construction costs shown here do not include labor.
(5) O&M costs include tracks, but exclude loading facilities, and unloading facilities.
(6) Uncontrolled.
(7) Includes particulates from locomotives and fugitive emissions.

SOURCES: Bechtel Corporation, Energy Supply Planning Model. Volume I, 1975, and revisions, 1978.
Hittman Associates, Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume I, 1974.
International Research & Technology Corporation, TECNET, 1978.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
Cyril Harris, ed., Handbook of Noise Control, 1957.
PEDCo, Inc. Environmental Assessment of Coal Transportation, 1978.

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Barge Transportation - Eastern Coal

ENERGY SYSTEM:

SIZE
- A barge tow consists of fifteen barges, each with a capacity of 1,400 tons of coal. The barge tow is propelled by a single diesel-powered 4200 horsepower towboat.

DESCRIPTION
- Expected lifetime of barges is 30 years.
- Average speed is estimated to be 9 mph (14.4 kph), average haul distance is estimated to be 190 miles (one way), and an estimated 116 round trips are made annually. Approximately 3 weeks per year are reserved for maintenance and miscellaneous delays.
- Annual throughput of eastern coal (12850 Btu/lb) is approximately 62.4 x 10^{12} Btu.
- TSP losses negligible due to low transit speeds and small exposure area of coal-piles on barge.

COMPONENTS
- 15 steel barges, each with 1400 ton capacity
- 1 - 4,200 horsepower diesel-powered towboat
- loading and unloading facilities
- commercial navigation facilities (channels, aids to navigation, locks, dams, etc.)

MAJOR ENVIRONMENTAL PROBLEMS
- Waterway traffic congestion
- Shoreline erosion due to towboat wake
- Potential water quality degradation from diesel fuel and coal spillage

RESOURCES USED:
(Per 10^{12} Btu of Annual Throughput)

FUEL	
Coal	30911 tons
Energy content	12850 Btu/lb
ENERGY	
Diesel fuel	4.53 x 10^{9} Btu consumed per 10^{12} Btu moved
MATERIALS	**Tons**
Carbon steel	60.2
Alloy steel	0.7
Stainless steel	0.1
Total Steel	61.0
Copper	0.3
Aluminum	0.6
Manganese	0.5
Chromium	0.1
Cast Iron	1.7
COSTS	**1978 Dollars (x 10^6)**
Capital	
Construction Costs	0.1
Operating Costs (excludes fuel)	
labor	0.011
materials	0.011
taxes	0.003
Total	0.025
PERSONNEL	**Workers/Yr**
Construction (man years)	N/A
Operation and Maintenance	0.5

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Annual Throughput)

AIR POLLUTANTS	**Tons**
Particulates[(a)]	0.55
SO_x	0.32
NO_x	7.71
Hydrocarbons	0.62
CO	1.68
ENERGY PRODUCT	**Tons**
Transported coal	30911

(a) Particulates from diesel fuel combustion. Windage losses of coal dust are estimated to be negligible.

SOURCES: Bechtel Corporation, "Energy Supply Planning Model," Vol. 1, 1975, and revisions, 1978.
PEDCo, Inc., "Environmental Assessment of Coal Transportation," 1978.
U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors, 3rd Edition," AP-42, 1978.

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Barge Transportation - Western Coal

ENERGY SYSTEM:

__SIZE__
- A barge tow consists of 15 barges, each with a capacity of 1,400 tons. Total capacity of each tow is 21,000 tons of coal per trip. The 15 barges are propelled by a single 4,200 horsepower diesel-fueled towboat.

__DESCRIPTION__
- Expected lifetime of barges is 30 years.
- Assuming an average speed of 9 mph (14.4 kph), average haul distance if 400 miles (640 km) one way, average load/unload time (total) of 10 hours, one day layover per trip, and 21 days scheduled maintenance per year results in a total of 67.2 trips per year
- Energy transported is equal to 26.7 x 10^{12} Btu/year.
- TSP losses (windage) are estimated to be negligible due to low speeds, small exposed surface area and high moisture content of western coal.

__COMPONENTS__
- 15 steel barges, each with 1400 ton capacity
- 1 - 4,200 horsepower diesel powered towboat
- loading and unloading facilities
- commercial navigation facilities (channels, aids to navigation, locks, dams, etc.)

__MAJOR ENVIRONMENTAL PROBLEMS__
- Waterway traffic congestion
- Shoreline erosion due to towboat wake
- Potential water quality degradation from spillage of diesel fuel and/or coal

RESOURCES USED:
(Per 10^{12} Btu throughput)

__ENERGY TRANSPORTED__	
Coal	32,911 tons
Energy content	9450 Btu/lb
__FUEL__	
Diesel fuel	1.30 x 10^{10} Btu consumed per 10^{12} Btu of coal transported
__MATERIAL__	__Tons__
Carbon steel	141.3
Alloy steel	1.6
Stainless steel	0.3
Total steel	143.2
Copper	1.1
Aluminum	1.3
Manganese	1.1
Chromium	0.1
Cast iron	3.9
__COSTS__	__1978 Dollars x 10^6__
Capital Costs	
Construction cost	0.200
Operating Costs (excluding fuel)	
Labor	0.026
materials	0.023
taxes	0.007
Total	0.056
__PERSONNEL__	
Construction (man years)	N/A
Operation & Maintenance	1.20

RESIDUALS AND PRODUCTS.
(Per 10^{12} Btu of annual throughput)

__AIR POLLUTANTS__	__Tons__
Particulates(a)	1.37
SO_x	1.47
NO_x	22.03
Hydrocarbon	1.76
CO	4.79

__ENERGY PRODUCT__	
Transported coal	32,911 tons

NOTE: THIS PRESENTATION IS BASED UPON ESTIMATES OF HOW BARGE TRANSPORTATION COULD DEVELOP IN THE WEST.

(a) Particulates are from diesel fuel combustion. Windage losses estimated to be negligible.

SOURCES: Bechtel Corporation, "Energy Supply Planning Model.", Vol. 1, 1975, and revisions, 1978.
PEDCo, Inc., "Environmental Assessment of Coal Transportation," 1978.
U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors, 3rd Edition," AP-42, 1978.

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Coal Transportation by Truck - Eastern Coal

ENERGY SYSTEM:

SIZE
- One over-the-road tractor trailer has a net carrying capacity of 25 tons per trip. Due to the economics of coal transportation by truck, the economically feasible maximum one way distance per trip is limited to 100 miles.
- Each truck is assumed to operate 240 days per year, 10 hours per day and have an average speed of 20 miles per hour, with a round trip distance of 60 miles. Accordingly, each coal truck makes a projected 800 round trips per year and results in a total of 1.2×10^6 net ton miles annually.
- Expected life of each truck is seven years.
- Annual energy throughput estimated to be 0.51×10^{12} Btu.

DESCRIPTION
- Over the road transportation of coal represents a small segment of the coal transportation sector. Due to distance constraints, minimal truck transport of coal is anticipated in western coal supply regions.

COMPONENTS
- 25 ton tractor-trailer trucks
- Loading and unloading facilities

MAJOR ENVIRONMENTAL PROBLEMS
- Air emissions from diesel fuel combustion
- Noise
- Increased traffic levels on secondary roads
- Road damage caused by overweight trucks
- Fugitive dust emissions (coal dust)

RESOURCES USED:
(Per 10^{12} Btu of Energy Delivered Annually)

FUEL	
Coal	38,946 tons
Energy Content	12,850 Btu/lb
ENERGY	Btus
Diesel Fuel[a]	3.13×10^9 Btu
MATERIALS	Tons
Carbon steel	22.6
Cast iron	0.6
Structural steel	3.8
Steel plate <1.5" thick	3.2
COSTS	(1976 Dollars x 10^6)
Construction	0.15
Operation and maintenance (excluding fuel)	0.19
PERSONNEL	
Construction	N/A
Operation and maintenance	4.9

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Transported Annually)

AIR POLLUTANTS	Tons
TSP	35.16[b]
SO_x	0.29[c]
NO_x	1.87
CO	2.95
HC	0.47
Aldehydes	0.03
Organic Acids	0.03

NOISE
The major sources of noise from trucks are from the engine, exhaust, and tires. Mufflers can reduce exhaust noise from 100 dBa to 90 dBa.

ENERGY PRODUCT	
Transported coal	38911 tons

[a] Based upon a 3.5 mpg (loaded), 5 mpg (unloaded) composite average. PEDCo (1978). This is equivalent to 22,700 gallons per 10^{12} Btu of annual throughput.

[b] Based on fugitive dust losses at 0.09% of coal loaded and U.S. EPA 1980 model year heavy diesel truck allowable emission levels.

[c] Based on 1980 model year heavy diesel truck allowable emission levels.

SOURCES: Bechtel Corporation, "Energy Supply Planning Model,", Vol. I, 1975, and revisions, 1978.
PEDCo, Inc., "Environmental Assessment of Coal Transportation," 1978.
U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors, Third Edition,", AP-42, 1978.

Slurry Pipeline

ENERGY SYSTEM:

SIZE
- 1,355 mile pipeline with a 100 foot right-of-way (this based on the slurry pipeline between proposed ETSI, Inc., Wyoming and Arkansas
- annual capacity is 25.0×10^{6} tons of coal (472.5×10^{12} Btus)
- 90% efficiency losses due to reduction of coal heating value because of its slurry water content (5)
- 38 inch diameter pipe
- ratio of solids to water (in terms of volume) is approximately 50-50 ± 5%

DESCRIPTION
- Slurry pipelines transport pulverized coal suspended in water or oil. The system described in this sheet uses water to transport coal. Pipelines using oil to move coal are under study. Coal moved by slurry pipeline must be processed to obtain the proper particle size. Pumping stations, dewatering facilities and (in some cases) storage facilities are also required.

COMPONENTS
- pipeline
- pumping stations
- dewatering facilities
- slurry preparation facility

ENVIRONMENTAL CONCERNS
- substantial water requirements
- disposal of waste water at end-of-line (water may be passed through power plant cooling system prior to discharge)

RESOURCES USED:
(Per 10^{12} Btu Transported Annually)

FUEL	
coal transported	52,910 tons
energy content	9,450 Btu/lb
ENERGY	kWh
electricity	1.2×10^{7}
LAND (1)(2)	Acres
pipeline, right-of-way	35.4
pumping stations	1.79
dewatering facilities	0.11
slurry preparation facility	0.11
WATER	Acre-Ft.
consumptive	38.87 (3)
MATERIALS (4)	Tons
aluminum	1.34
brass & bronze	0.40
chromium	0.30
concrete	3,016.93
copper	4.43
iron	NA
manganese	9.62
nickel	0.03
steel	1,285.98
COSTS	Dollars (1978)
construction (4)	
pipeline (1,355 miles)	2,100,000
coal slurry preparation	380,000
dewatering	15,000
total	2,640,000
operation & maintenance	180,000
PERSONNEL	Workers
construction (3)	12.3
operation & maintenance	0.00226

RESIDUALS & PRODUCTS:
(Per 10^{12} Btu Transported Annually)

AIR POLLUTANTS
The amount of any pollutant emitted, if any, is unknown.

WATER POLLUTANTS
After coal slurry has been dewatered, waste water containing suspended coal particles remains to be disposed of. With an open system, disposal of the waste water could cause problems. These could be mitigated by evaporating the water in ponds, or passage through power plant cooling system prior to treatment and discharge.

ENERGY PRODUCT

transported coal	52,910 tons
energy content	9,260 Btu/lb

(1) Land use value represents land committed to use for the facility divided by annual throughput.
(2) Based on Bechtel figures for a 38-inch pipeline system with a capacity of 25 million tons/year, and scaled up from 150 miles to 1,355 miles, and assumes a 100 foot right-of-way.
(3) Based upon 1×10^{12} Btu = 52,910 tons of Western subbituminous coal.
(4) This represents total construction value divided by annual throughput.
(5) This efficiency refers to the diminution in the energy content of the coal from entry to exit at the pipeline.

SOURCES: Hittman Associates, Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume I, 1976.
Bechtel Corporation, Energy Supply Planning Model, 1978.
University of Oklahoma, Energy Alternatives, May, 1975.
U.S. House of Representatives Committee on Science & Technology, Oversight Hearings - Coal Slurry Pipeline Research & Development, 1976.
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High Voltage Transmission

ENERGY SYSTEM:

SIZE
- 345 KV AC line, 300 miles long
- right-of-way (ROW) width-130 ft. (16 acres/mile)
- single circuit, 3 conductors
- serves 600 MW of power plant capacity
- 65% capacity factor
- 82% efficiency
- total annual input is 11.7 x 10^{12} Btus (3.4 x 10^9 kWh)
- total annual output is 9.6 x 10^{12} Btus (2.8 x 10^9 kWh)

DESCRIPTION
- 345 KV lines are considered high voltage transmission and are more energy efficient than the more common 230 KV lines. The conductors are made of stranded aluminum while the ground wires are steel.

COMPONENTS
- conductors
- conductor towers and insulators
- land for ROW

ENVIRONMENTAL CONCERNS
- corona discharge, which may result in radio and TV interference (especially in areas of fringe reception), audible noise, and production of ozone and NO_x
- electric and magnetic fields, which may result in fuel ignition by spark discharges, induced electric shock interference with cardiac pacemakers.
- land usage (however, most ROW land can be put to other uses e.g., agriculture)
- fuel ignition by spark discharges

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	kWh
electricity (1)	3.54 x 10^8 (equivalent to 1.21 x 10^{12} Btu)

MATERIALS (2)	Tons
concrete (including cement)	3610
steel	2520
copper	90.9
aluminum	430
manganese	17.6
chromium	1.86
nickel	0.0229
cast iron	10.4

LAND	Acres
right-of-way (may be simultaneously used for other purposes)	447.6

COSTS	Dollars (1978)
construction (2 years)	
labor	
non-manual technical labor	830,000
non-manual non-technical labor	168,000
manual labor	4,320,000
materials	
primary non-ferrous metals	1,540,000
fabricated structural products	2,920,000
other materials	530,000
equipment	1,100,000
other construction costs	4,600,000
total construction	16,100,000
operation and maintenance	
operation	none
maintenance	
labor	16,800
material	4,480
equipment	833
total operation and maintenance	22,100

PERSONNEL	Workers First Year	Workers Second Year
construction (2 years)		
non-manual technical labor		
civil engineers	3.9	2.6
electrical engineers	7.9	5.1
mechanical engineers	1.3	0.83
designers and draftsmen	5.3	3.5
supervisors and managers	1.0	0.63
non-manual non-technical labor	4.2	4.2
manual labor		
iron workers	16.6	49.7
linemen	13.1	39.4
truck drivers	2.7	8.0
operation and maintenance		
operation	none	
maintenance	0.75	

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
A small amount of chemical oxidants, including some NO_x but mainly ozone, may be generated by the corona of transmission lines.

NOISE
The corona may cause some audible noise, particularly in foul weather. Noise generated will be barely audible, however, will not be loud enough to cause any hearing damage.

ELECTROMAGNETIC FIELDS
Electric and magnetic fields from 345 KV lines may interfere with a few of the most sensitive types of cardiac pacemakers. Single circuit 345 KV lines have maximum field strengths of 4.3 to 8 KV/meter at three feet above the ground. For field strengths of 6 KV/m or more, annoying transient spark discharges may occur in some circumstances.

ENERGY PRODUCT	kWh
electricity	2.93 x 10^8

(1) Total electrical input to line to get 10^{12} Btu out at 82% efficiency.
(2) This is not an exhaustive list of all materials required.

SOURCES: Bechtel Corporation, Energy Supply Planning Model, Volume 1975 and revisions 1978.
Miller, Morton and Gary Kaufman, "High Voltage Overhead," Environment Magazine, Jan/Feb, 1978.
Tell, R.A. et al., An Examination of Electric Fields Under EHV Overhead Transmission Lines, EPA, 1977.
General Electric Company, Assessment of Energy Parks vs. Dispersed Electric Power Generating Facilities, Final Report, Volume I, 1975.
MITRE Corporation, Resource and Land Investigations (RALI) Program: Considerations in Evaluating Utility Line Proposals, MTR-6948, 1975.

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ENERGY SYSTEM:

SIZE
- 500 KV AC line, 500 miles long
- right-of-way (ROW) width-175 ft.(1) (21 acres/mile)
- single circuit, 3 conductors
- serves 1200 MW of power plant capacity
- 65% capacity factor
- 90% efficiency (resulting from an energy loss of approximately 2% for every 100 miles of transmission line)
- total annual input is 23.3 x 10^{12} Btus (6.8 x 10^9 kWh)
- total annual output is 20.8 x 10^{12} Btus (6.1 x 10^9 kWh)

DESCRIPTION
- 500 KV lines are considered high voltage transmission and are considerably more efficient than the standard 230 KV lines. The conductors are made of stranded aluminum while the ground wires are steel.

COMPONENTS
- conductors
- conductor towers and insulators
- land for right-of-way

ENVIRONMENTAL CONCERNS
- corona discharge, which may result in radio and TV interference (especially in areas of fringe reception), audible noise, and production of ozone and NO_x
- electric and magnetic fields, which may result in fuel ignition by spark discharges, induced electric shocks, interference with cardiac pacemakers
- land usage (however, most ROW land can be put to other uses e.g., agriculture)
- adverse health effects close to line
- fuel ignition by spark discharges

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	kWh
electricity(1)	3.28 x 10^8 (equivalent to 1.12 x 10^{12} Btu)

MATERIALS (2)	Tons
concrete (including cement)	1,832
steel	1,687
copper	127
aluminum	534
manganese	11
chromium	3
nickel	0.1
cast iron	6

LAND(1)	Acres
right-of-way (may be simultaneously used for other purposes)	509.9

COSTS	Dollars (1978)
construction (2 years)(1)	
labor	
non-manual technical labor	610,000
non-manual non-technical labor	130,000
manual labor	2,690,000
materials	
primary non-ferrous metal	1,820,000
fabricated structural products	1,610,000
other materials	410,000
equipment	
electrical equipment	630,000
other equipment	620,000
other construction costs	[illegible]
total	11,310,000
operation and maintenance	
operation	none
maintenance	
labor	13,740
material	3,046
equipment	1,210
total	17,900

PERSONNEL	Workers First Year	Workers Second Year
construction		
non-manual technical labor		
civil engineers	2.0	1.9
electrical engineers	5.6	3.7
mechanical engineers	1.0	0.7
designers & draftsmen	3.6	2.5
supervisors & managers	0.7	0.4
non-manual non-technical labor	3.0	3.0
manual labor		
electricians	1.2	3.4
iron workers	9.2	27.6
linemen	0.1	24.2
truck drivers & laborers	1.8	5.2
operation & maintenance		
operation	none	
maintenance	0.6	

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
A small amount of chemical oxidants, including some NO_x but mainly ozone, may be generated by the corona of transmission lines.

NOISE
The corona may cause some audible noise, particularly in foul weather. Noise generated will not be loud enough to cause hearing damage, however.

ELECTROMAGNETIC FIELDS
Electric and magnetic fields from 500 KV lines will probably interfere with some cardiac pacemakers. Single-circuit 500 KV AC lines have maximum field strengths of 6 to 7 KV/meter at three feet above the ground. This is strong enough to result in annoying transient spark discharges under some circumstances.

ENERGY PRODUCT	kWh
electricity	2.93 x 10^8

(1) Total electrical input to line to get 10^{12} Btu out at 90% efficiency.
(2) This is not an exhaustive list of all materials required.

SOURCES: Bechtel Corporation, "Energy Supply Planning Model", Volume I, 1975, and revisions, 1978.
Morton Miller and Gary Kaufman, "High Voltage Overhead", Environment Magazine, Jan/Feb- 1978.
R.A. Tell, et. al., "An Examination of Electric Fields Under EHV Overhead Transmission Lines", EPA, 1977.
General Electric Company, Assessment of Energy Parks vs. Dispersed Electric Power Generating Facilities, Volume I, 1975.
The MITRE Corporation, Resource and Land Investigations (RALI) Program: Considerations in Evaluating Utility Line Proposals, MTR-6948, 1975.

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Petroleum

The following should be recognized as limitations of the information provided on the summary sheets of this section:

1. The impacts and costs of oil and gas operations vary widely over the period of development. Typically capital costs will be concentrated in the initial phases of development while operation and maintenance costs and impacts will be spread over a longer period of time. Annualizing costs and impacts over the life cycle of a project ignores the actual pattern in which they occur.

2. The figures presented in the data sheets apply to specific representative cases. The variation around these cases may be quite extensive. Some costs, such as platforms, will vary geometrically rather than arithmetically. Thus, an 18-well platform in 400 feet of water will be much more than twice as expensive than one in 200 feet. Unless production per platform changes in exactly the same proportion, the numbers provided in the data sheets may be unrealistic.

3. The data sheets also do not consider changes in the underlying conditions determining the economic limit for oil and gas development. The rapid escalation of crude oil prices and changes in price/cost relationships will bring formerly uneconomic projects into production. These projects will generally have unit cost characteristics which are very different from the "representative" projects shown on the data sheets. It is likely that for these new projects the costs per 10^{12} Btu produced will be much higher. The estimates of environmental impact also do not include the fact that many of the new projects will have improved environmental control systems which are not yet defined. For example, new steam Enhanced Oil Recovery projects will be required to have air emission levels which are much lower than the national averages shown on the data sheets.

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Onshore Oil Exploration - Lower 48 States

ENERGY SYSTEM:

SIZE
- 100,000 barrels per field per day ultimate average primary production
- 36.5 x 10^6 barrels per field per year
- 27.24% success ratio
- 20 successful wells, 53 unsuccessful wells
- four years before initial production begins
- 5.8 x 10^6 Btu's per barrel
- 212 x 10^{12} Btus per year ultimate production
- 30% oil reservoir recovery efficiency

DESCRIPTION
- Regional Surveys
  - Research libraries and state or Federal geology offices for information on rock formations and outcrops
  - Obtain any previous stratigraphic drilling records
  - Examine satellite imagery for potential regions
- Local surveys by geophysicist
  - Magnetometer; sedimentary rocks - low magnetic properties
  - Gravimeter; dense rock increases gravitational pull
  - Seismograph; distance shock waves travel to various strata recorded
- Stratigraphic core tests to examine strata for arrangement and possible traces of oil, gas or fossils
- Secure lease, obtain drilling permits and pay annual rental fee
- Site access; site preparation
- Water availability secured through wells or temporary water lines
- Assemble rig; drill to desired depth
- Conduct logging (electric, etc) analysis as to potential productivity
- If considered profitable, remainder of well cased and Christmas tree installed; if not, well plugged with cement and crimped below ground

COMPONENTS
- Geophysical surveying equipment/satellite imagery
- Bulldozer, backhoe and dump truck
- Temporary water lines
- Rotary drill rig: hoisting, rotary and fluid circulation systems; drill string and bits
- Steeling casing and cement
- Geophysical logging and analysis equipment
- Possible production tubing and Christmas tree

ENVIRONMENTAL CONCERNS
- Possible fracturing or connection of underground aquifers of varying qualities
- Air emissions from drilling rigs and site preparation equipment
- Soil erosion losses and decreased fertility resulting from site access and preparation and possible aquatic sedimentation in nearby streams
- Possible blowout or accidental drill pond release

RESOURCES USED:
(Per 10^{12} Btu Produced)

RESOURCE DEPLETION OF OIL FIELD RESERVOIR	none
ENERGY(1)	Gallons
Diesel fuel for exploration drilling	7,900
LAND(1)	Acres
Temporarily committed	2.00
Permanently committed	0.24
WATER(1)	Acre-Ft.
drilling fluid	0.0067
MATERIALS(1)	Tons
casing and tubing	8.0
surface and subsurface equipment	7.3
steel tonnage/rig	86.1
cement	20.7
COSTS(1)	Dollars - 1978
exploratory drilling	
53 dry holes	25,550
20 oil wells	16,438

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS(1)	Tons
NO_x	3.30
CO	0.71
HC	0.26
SO_x	0.22
Particulates	0.23
WATER POLLUTANTS(1)	Tons
Circulating mud system water loss	minimal
Eroded construction site sediments	site specific
Organics	0.14 - 3.86
Dissolved Solids	neg. - 2,989
SOLID WASTE(1)	Tons
Drill cuttings, barite, bentonite, and phosphate	13

Note: Please refer to the qualification statements at the beginning of this section on Petroleum.

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(1) Data values represent total life cycle values divided by ultimate average annual energy output normalized to 10^{12} Btu; i.e., for exploratory drilling fuel requirements = 1,675,350 gallons of diesel fuel (for 73 wells) ÷ 212 (212 x 10^{12} Btu = ultimate annual production) = 7,900 gallons of fuel/10^{12} Btu ultimate production.

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U.S. Department of Energy, 1978. Working Draft Environmental Impact Statement, Eastern Gas Shale Project and Possible Ensuing Commercialization of the Devonian Gas Shale Resource. Washington, D.C.
U.S. Department of Interior, 1977. Final Environmental Statement, 1977 Outer Continental Shelf Oil and Gas Lease Sale Offshore the North Atlantic Statements Bureau of Land Management.
U.S. Environmental Protection Agency, 1978. AP-42. Supplement No. 8 for Compilation of Air Pollutant Emission Factors. Third Edition. Office of Air Quality Planning and Standards. Research Triangle Park, North Carolina.

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Offshore Oil Exploration - Lower 48 States

ENERGY SYSTEM:

SIZE
- 4,000 barrels per platform per day[14] average ultimate primary production
- 1,460,000 barrels per platform per year average ultimate primary production[14]
- 15.4% total offshore exploratory success ratio[11]
- 18 successful wells per platform ultimate size[15]
- five exploratory wells drilled; two successful wells and three dry holes[6]
- Average drilling depth 9,500 feet; many of the wells are deviated[12,13]
- 1/3 year of exploratory drilling, then a 2-3 year layover while the development plan is finalized and the production platform constructed, towed to position and installed[6]
- 5.8×10^6 Btus per barrel
- 8.47×10^{12} Btus per platform per year
- 40% oil reservoir offshore recovery efficiency[17]

DESCRIPTION[1,2,4]
- Exploratory permit obtained
- Regional surveys performed
  - Magnetometer; air or ship-borne measurements of changes in earth's magnetic field
  - Gravimeter; variations in gravitational pull of various rock types
  - Natural oil seeps
  - Satellite and infrared imagery
- Local surveys
  - Seismic survey in which reflected and refracted sound waves help elucidate subsurface structures and strata
  - Bottom sampling and coring (500-1000 ft. max); permit required
- Exploratory drilling
  - Obtain lease
  - Rent a drill barge, drill ship, jack-up, semi-submersible or submersible depending on water depth, climatic conditions, seafloor configuration and availability
  - Transport drilling apparatus to location and set up to drill
  - Drill to desired depth, and set and cement casing
  - Log and analyze the well for commercial production
  - If productive, finish casing well, perforate the casing, fracture or acidize if necessary, and install production tubing and temporary Christmas tree
  - If not productive, plug with cement and crimp casing 15-ft below seafloor

RESOURCES USED:
(Per 10^{12} Btu Produced)

RESOURCE DEPLETION OF OIL FIELD RESERVOIR	none
ENERGY	**Btu x 10^9**
Exploratory drilling fuel (five wells - 25,940 bbl)[a]	17.765
WATER SURFACE AREA LAND USE[a][9]	**Acres**
Jack-ups and drill ships	0.24 - 0.59
Semi-submersible	19.1
If one mile fishing buffer included in permit	237.4
WATER[a][7,18]	**Barrels**
Drilling mud water (fresh or salt) for five wells	77.4
Fresh water requirement for workers	3,513.8
COSTS[b]	**Dollars - 1978**
Cantilever jack-up rig example costs	
Shipyard furnished components	
Hull, cantilever, spud legs	1,833,600
Electromechanical self-elevating system	556,300
Crew quarters and heliport	147,000
Cranes, winches, safety equipment, and other	268,700
Owner-furnished components	
Drawworks	65,500
Prime movers	65,000
Traveling block and derrick	47,200
Other equipment such as mud systems, pipe, casing, and safety equipment	658,100
Total Cost	3,441,400
Drilling Costs[a] - two successful wells	413,300
- three unsuccessful wells	490,000
Rig Rental Rate (125 days)	
Shallow water rigs	236,250 - 325,000
Deep water rigs	368,750 - 516,250
PERSONNEL[a][7,9]	**Workers**
Exploratory drilling - jack-up	9.9 - 10.3
OCCUPATIONAL SAFETY[c][16]	**Number**
Blowouts	.0010
Fatalities	.0001
Injuries	.0008
Fire and Explosions	.0050
Fatalities	.0008
Injuries	.0032
Miscellaneous Accidents	.0026
Fatalities	.0023
Injuries	.0009

RESIDUALS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS[a]	**Tons**
NO_x	38.26
CO	8.28
Exhaust Hydrocarbons	3.06
Particulates	2.73
SO_x	2.54
WATER POLLUTANTS	
Components of drilling muds listed under solid waste	
Brines during well testing	negligible
SOLID WASTE[a][9]	**Tons**
Drill cuttings - 9,500 foot wells	825.3
Drilling Muds	
Barite ($BaSO_4$)	137.9
Bentonite and Attapulgite Clay	19.5
Caustic Soda	6.2
Aromatic Detergent	0.9
Organic Polymers	1.2
Ferrachrome Lignosulfonate	7.7
Total Drilling Muds	193.3

Note: Please refer to the qualification statements at the beginning of this section on Petroleum.

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Offshore Oil Exploration - Lower 48 States (Concluded)

ENERGY SYSTEM:

RESOURCES USED: (Per 10^{12} Btu Produced)

RESIDUALS: (Per 10^{12} Btu Produced)

COMPONENTS[1,2,4]

- Geophysical surveying equipment/satellite imagery, boats and planes
- A drilling barge, drill ship, jack-up, semi-submersible or submersible
- Rotary drill rig: hoisting, rotary and fluid circulation systems
- Drill string and bits and water pumping system
- Steel casing and cement
- Geophysical logging and analysis equipment
- Possible production tubing and Christmas tree

ENVIRONMENTAL CONCERNS

- Oil spills/blowouts
  - -Open ocean, temporary impact; nearshore bay or estuary severe impact[9]
  - -Chronic leakage around platform localized impact[9]
  - -Tanker ballast and tanker lane water pollution could be substantial[10]
- Water pollution caused by possible formation brine discharges released during drilling and pumping, and the disposal of exploratory drilling muds which are only used once[10,9]
- Fire
- Air emissions from drilling and electric power generation motors

Note: Please refer to the qualification statements at the beginning of this section on Petroleum.

(a) Data values represent total exploratory values divided by the expected average annual output normalized to 10^{12} Btu; i.e., exploratory drilling fuel requirement (5 wells) = 25,940 bbl of diesel fuel x 5.8×10^6 Btu/bbl = 1.505×10^{11} Btu ÷ (8.47×10^{12} Btu average annual production) = 17.765×10^9 Btus of fuel/10^{12} Btu produced. (Note that annualizing ignores the actual pattern on which costs and impacts occur.)

(b) Example exploratory rig costs are shown to illustrate the capital outlay for the exploratory rig owners. Since many exploratory wells would be drilled for a large number of drilling projects with the same rig, the rig rental rate is included as a more realistic exploratory cost.

(c) These values encompass injuries and fatalities which occurred during exploration, development and production of offshore facilities between 1970-1977.

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(3) Tubb, Maretta, 1979. "1979-80 Director of Marine Drilling Rigs". Ocean Industry. 14:19-176.

(4) Weaver, L.K., H.F. Pierce, and C.J. Jirik, 1972. Offshore Petroleum Studies. Composition of the Offshore U.S. Petroleum Industry and Estimated Costs of Producing Petroleum in the Gulf of Mexico. Information Circular 8557. Bureau of Mines, U.S. Department of the Interior.

(5) Lawson, Robert G. and W.D. Moore, 1979. "Offshore Drilling: Record Activity, Fewer New Rigs". Oil and Gas Journal. 77:151-157.

(6) Matheny, Shannon L., 1979. "Shell Group is Rapidly Developing Cognac Field". Oil and Gas Journal. 77:160-165.

(7) Ocean Industry, 1979. "Facts and Forecasts". Ocean Industry. Volume 14:35-91.

(8) Council on Environmental Quality, 1974. OCS Oil and Gas. Volume I. U.S. Government Printing Office, Washington, D.C.

(9) U.S. Department of the Interior, 1977. Mineral Yearbook. Volume I. Metals, Minerals and Fuels. Bureau of Mines. U.S. Gov Printing Office, Washington, D.C.

(10) Clark, John and Charles Terrell, 1978a. Environmental Planning for Offshore Oil and Gas. Volume III. Effects on Living and Habitats. U.S. Fish and Wildlife Service, Biological Services Program. FWS/OBS-77/14.

(11) American Petroleum Institute, 1978. Basic Petroleum Data Book. Petroleum Industry Statistics, Washington, D.C.

(12) American Petroleum Institute, 1979. 1977 Joint Association Survey on Drilling Costs. Washington, D.C.

(13) DeGloyer and MacNaughton, 1978. Twentieth Century Petroleum Statistics. Dallas, Texas.

(14) International Oil Scouts Association, 1978. International Oil and Gas Development. Part II. Volume 47. Austin, Texas.

(15) Cashman, Margaret D., 1977. "Offshore Construction Report". Ocean Industry. Volume 12, No. 7: 74-82.

(16) U.S. Geological Survey, 1978. Outer Continental Shelf Statistics 1953-1977. Conservation Division/Geological Survey - Department of Interior. Washington, D.C.

(17) University of Oklahoma, 1975. Energy Alternatives: A Comparative Analysis. U.S. Government Printing Office, Washington, D.C.

(18) U.S. Department of Interior, 1973. Draft Environmental Statement - Proposed 1974 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Louisiana. OCS Shale No. 33 DES 73-69. Bureau of Land Management.

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Onshore Primary Oil Extraction - Lower 48 States

ENERGY SYSTEM:

SIZE:
- 100,000 barrels per field per day average primary production
- 36.5×10^6 barrels per field per year
- 67.18% success ratio
- 400 producing wells - 250 barrels per well per day
- 193 dry holes
- seven years for all drilling and facility construction to be completed
- 26 year average well life expectancy
- 5.8×10^6 Btu's per barrel
- 212×10^{12} Btu's produced per year
- 30% oil reservoir recovery efficiency

DESCRIPTION
- After exploratory drilling completed, the wells tested, and the data analysed, a production plan has to be developed and a lease obtained.
- Drilling is carried out according to the production plan and to the desired depth, and the plan is modified if higher or lower pay zones come in or if dry holes are obtained.
- Set and cement casing; log and analyze the strata.
- If productive, finish casing the bottom of the hole, perforate the casing, fracture or acidize if necessary, and install production tubing and Christmas tree.
- If not productive, plug with cement and crimp casing below ground.
- After development drilling is complete, disassemble drilling equipment and install gathering pipeline to transport oil from the well site to the field processing facility for gas-water-oil separation.

COMPONENTS
- Site access and site preparation equipment; bulldozer, backhoe and dump truck
- Temporary water lines
- Rotary drill rig; hoisting, rotary and fluid circulation systems
- Drilling string and bits
- Steel casing and cement
- Geophysical logging and analysis equipment
- Possible production tubing and Christmas tree

ENVIRONMENTAL CONCERNS
- Possible fracturing or connection of underground aquifers of varying qualities
- Air emissions from drilling rigs and site preparation equipment
- Oil spills or blowouts
  - Dry land, relatively easily contained and cleaned up - localized impact
  - In or near wetland environments, difficult to contain and clean up - could be substantial impact
- Soil erosional losses and decreased fertility resulting from site access and preparation, and subsequently, possible aquatic sedimentation in nearby water bodies
- Possible accidental drill pond release

RESOURCES USED:
(Per 10^{12} Btu Produced based on LVB):

RESOURCE DEPLETION	
Average possible yearly depletion of crude	574,700 barrels
Oil reservoir recovery efficiency	30 percent

ENERGY	Btu's x 10^9
Diesel fuel for development drilling (1)	7.55
Operation	
Prime Mover Electric Pumps (2)	6.32
Heater Treater Separators (2)	0.84

LAND	Acres
permanently committed	9.43

WATER (1)	Acre-Ft.
drilling fluid	0.7482

MATERIALS (1)	Tons
refined products	3,301.9
concrete (mixed)	94.3
pipe and tubing	339.6
oil country tubular goods	2,641.5
reinforcing bars	18.9
pumps and drivers	15.1

COSTS (1)	Dollars - 1978
Wood Products	56,000
Chemical & Petroleum Products	924,000
Stone and Clay	364,000
Steel and Iron	2,493,000
Non-ferrous Metals	28,000
Fabricated Products	476,000
Materials Total	4,342,000
Construction & Oil Field Equipment	3,754,000
Welding and General Industrial Equipment	315,000
Electrical and Fabricated Plate Products	364,000
Miscellaneous	1,037,000
Equipment Subtotal	5,470,000
Labor, Overhead & Profit	4,475,000
Total Capital Construction Cost	14,286,000
OPERATION/MAINTENANCE (2)	
Metal Products and Machinery	35,000
Electrical Equipment and Instruments	14,000
Transportation and Miscellaneous	77,000
Total Operation and Maintenance	126,000

PERSONNEL	Workers
construction (3)	13.2
operation/maintenance (2)	9.7

OCCUPATIONAL SAFETY (4)	Per Year
deaths	0.002
injuries	0.233
workdays lost	33.745

RESIDUALS
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons
Site access, site preparation, development drilling, & gathering pipeline system[1]	
NO_x	23.2
CO	5.0
HC	1.9
SO_x	1.6
Particulates	1.6
Annual emissions during production[2]	
NO_x	18.6
CO	0.5
HC	10.6
SO_x	13.6
Particulates	3.5

WATER POLLUTANTS	Tons
circulating mud system water loss	minimal
eroded construction site sediments	

SOLID WASTE (1)	Tons
drilling cutting, barite, bentonite and phosphate	94.6

ULTIMATE AVERAGE FIELD PRODUCTION	
crude oil	172,400 barrels
heat content	5.8×10^6 Btu/b

Onshore Primary Oil Extraction—Lower 48 States (Concluded)

(1) Data values represent total life cycle values divided by average annual energy output normalized to 10^{12} Btus.
i.e., development drilling fluid energy requirement = 285,316 bbl ÷ 212 (average annual energy production in trillion Btu)
x 5.62 x 10^{6} Btu/bbl = 7.55 x 10^{9} Btu/10^{12} Btu produced.
(2) Data values represent annual values divided by average annual energy output normalized to 10^{12} Btu.
(3) Average number of construction workers (7 year period) divided by average annual energy output normalized to 10^{12} Btu.
(4) Data are obtained from information on oil and gas production (University of Oklahoma, 1979).

SOURCES:

American Gas Association, 1969. Gas Engineers Handbook. Industrial Press Inc. New York, N.Y.
American Petroleum Institute, 1977. Facts About Oil. API. Washington, D.C.
DeGloyer and MacNaughton, 1978. Twentieth Century Petroleum Statistics. Dallas, Texas.
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U.S. Department of the Interior, 1977. Final Environmental Statement. 1977 Outer Continental Shelf Oil and Gas Lease Sale Offshore the North Atlantic States. Bureau of Land Management.
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Offshore Oil Extraction - Lower 48 States

ENERGY SYSTEM:

SIZE
- 4,000 barrels per platform per day average primary production[15]
- 1,460,000 barrels per platform per year average primary production[15]
- 76.3% development well success ratio[11]
- 18 development wells would be drilled to efficiently tap the reservoir; six dry holes would also be expected. Subsequent to the exploratory drilling, 16 successful oil wells and three dry holes would be drilled during the development phase.[11]
- 18 months to complete drilling. Partial production could begin before this time has elapsed.
- Average drilling depth 9,500 feet (TVD); many of the wells are deviated[12,14]
- 15-20 year well life expectancy[4]
- 5.8×10^6 Btus per barrel
- 8.47×10^{12} Btus per platform per year
- 40% offshore oil reservoir recovery efficiency[21]

DESCRIPTION[1,2,4,5,6]

- After exploratory drilling is completed, the wells tested, and the data analyzed, a production plan has to be developed and a lease obtained.
- Production platform ordered, fabricated, towed to position, and assembled.
- Directional drilling is carried out according to production plan and to the desired depth, and the plan is modified if higher or lower pay zones come in or if dry holes are obtained.
- Set and cement casing; log and analyze the strata.
- If productive, finish casing the bottom of the hole, perforate the casing, fracture or acidize if necessary, and install production tubing and Christmas tree or subsea completion apparatus.
- If not productive, plug with cement and crimp casing 15 ft below seafloor or use for reinjection of formation water.
- When development drilling is completed, the drilling equipment is disassembled and the production/processing equipment is installed on the same platform.
- Process the oil mixture for sand knock out and water and gas separation.
- Pump onshore if the find is substantial and pumping economical; otherwise, store on-site for tanker pickup.

COMPONENTS[1,2,4,5,6]
- A permanent drilling and production platform
- Rotary drill rig: hoisting, rotary, and fluid circulation systems
- Drill string and bits, and water pumping systems
- Steel casing and cement
- Geophysical logging and analysis equipment
- Production tubing and Christmas tree
- On site separation and processing equipment

ENVIRONMENTAL CONCERNS
- Oil spills/blowouts
  - Open ocean, temporary effect; nearshore, bay or estuary - severe effect[9]
  - Chronic leakage around platform - localized
  - Tanker ballast and tanker lane water pollution could be substantial
- Water pollution caused by formation brine discharges if not reinjected or processed[10,9]
- Fires
- Air emissions from drilling and electric power generation equipment

RESOURCES USED:
(Per 10^{12} Btu Produced):

RESOURCE DEPLETION	
Average potential depletion of crude	431,000 barrels
Oil reservoir recovery efficiency	40 percent
ENERGY	Btu x 10^9
Development drilling (16 successful wells + 3 dry holes)[a]	67.508
Operation and Maintenance[b]	
Prime mover pumps	1.053
Heater treater (5% brine)	6.326
Other production and support requirements	14.822
WATER SURFACE AREA LAND USE[a]	Acres
Drilling platform	0.24 - 0.39
If one mile fishing buffer included in permit	237.4
WATER	Barrels
Drilling mud water (fresh or salt) - 19 wells[a]	293.8
Fresh water requirement for workers[b]	1,973.3
MATERIALS	
Concrete	NA
Barite and bentonite	NA
Steel	NA
Copper, aluminum, manganese, nickel, and chromium	NA
Iron, steel, aluminum and brass castings	NA
Structural steel and steel plates	NA
Pipe, tubular goods, and valves	NA
COSTS	Dollars (1978)
Platform[a]	
Labor	717,500
Materials for 4,000-ton steel platform	830,500
Offshore installation cost	217,200
Heliport and living quarters	81,500
Cranes/survival capsule generators	78,200
Water system/instruments/corrosion control	49,400
Other - computerized equipment, oil and gas treating, separators, heat exchangers, firefighting equipment, barge bumpers, valves, derrick barges tugs, etc.	877,100
Drilling 16 successful oil wells[a]	3,306,200
Three dry holes[a]	490,000
Annual operating costs[b]	
Labor, supervision, and payroll overhead	63,800
Food and transportation	48,500
Surface equipment and operating supplies	10,000
Workover	64,500
Communications/Administrative/Insurance	55,000
PERSONNEL	Workers
Development drilling and production equipment installation(a)	5.3 - 7.7
Production(b)	1.9
OCCUPATIONAL SAFETY[c]	Number of Accidents or Workers
Blowouts	.0010
Fatalities	.0001
Injuries	.0008
Fire and explosions	.0050
Fatalities	.0008
Injuries	.0032
Miscellaneous accidents	.0026
Fatalities	.0023
Injuries	.0009

RESIDUALS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons
Development drilling[a]	
NO_x	145.40
CO	31.47
Exhaust Hydrocarbons	11.63
Particulates	10.38
SO_x	9.67
Production[b]	
NO_x	31.92
CO	6.91
Exhaust Hydrocarbons	2.55
Particulates	2.28
SO_x	2.12
WATER POLLUTANTS[d]	Tons
Cadmium	0.024095
Cyanide	0.00354
Mercury	0.00018
Total organic carbon (including oil)	146.340
Total suspended solids	25.847
Total dissolved solids	38,977.0
Chlorides	21,615.0
Oil spills	NA
SOLID WASTE[a]	Tons
Drill cuttings - 9,500 foot wells	3,236.0
Drilling muds	
Barite ($BaSO_4$)	450.0
Bentonite and Attapulgite Clay	55.5
Caustic Soda (NaOH)	17.7
Aromatic Detergent	3.5
Organic Polymers	3.6
Ferrochrome Lignosulfonate	21.9
Total Drilling Muds	551.0
ULTIMATE AVERAGE FIELD PRODUCTION	
Crude oil(a)	172,400 barrels
Heat content	5.8×10^6 Btu/bbl

SEE SUCCEEDING PAGE FOR FOOTNOTES

Note: Please refer to the qualification statements at the beginning of this section on Petroleum.

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Offshore Oil Extraction - Lower 48 States (Concluded)

(a) Data values represent total life cycle values divided by average annual energy output normalized to 10^{12} Btu; i.e., development drilling fuel requirement (19 wells) = 98,365 bbl. of diesel fuel x 5.8 x 10^6 Btu/bbl = 5.7179 x 10^{11} ÷ 8.47 (8.47 x 10^{12} Btu average annual production) = 67.508 x 10^9 Btu's of fuel/10^{12} Btu produced. (Note that annualizing ignores the actual pattern on which costs and impacts occur.)
(b) Data values represent annual values divided by average annual energy output normalized to 10^{12} Btu.
(c) These values encompass injuries and fatalities which occurred during exploration, development and production of offshore facilities between 1970-1977.
(d) Data values represent annual raw unprocessed water pollutants from average Gulf Coast brine concentrations and average brine production per platform, all normalized to 10^{12} Btu.

SOURCES: (1) Kash, Don E., I.L. White, K.H. Bergey, M.A. Chartock., M.D. Devine, R.L. Leonard, S.N. Salomon and H.W. Young, 1973. Energy Under the Oceans, A Technology Assessment of Outer Continental Shelf Oil and Gas Operations. University of Oklahoma, Norman, Oklahoma.
(2) Clark, John, Jeffrey Zinn and Charles Terrell, 1978. Environmental Planning for Offshore Oil and Gas. Volume I. Recovery Technology. U.S. Fish and Wildlife Service, Biological Services Program. FWS/OBS-77/12.
(3) Tubb, Maretta, 1979. "Directory of Marine Drilling Rigs". Ocean Industry (9/79) 14:19-176.
(4) Weaver, L.K., H.F. Pierce and C.J. Jirik, 1972. Offshore Petroleum Studies. Composition of the Offshore U.S. Petroleum Industry and Estimated Costs of Producing Petroleum in the Gulf of Mexico. Information Circular 8557. Bureau of Mines. U.S. Department of the Interior.
(5) Lawson, Robert C. and W.D. Moore, 1979. "Offshore Drilling: Record Activity, Fewer New-Rigs". Oil and Gas Journal. 77-:151-157.
(6) Matheny, Shannon L., 1979. "Shell Group in Rapidly Developing Cognac Field". Oil and Gas Journal. 77:160-165.
(7) Ocean Industry, 1979. "Facts and Forecasts". Ocean Industry. Vol. 14:35-91.
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(9) U.S. Departmentof the Interior, 1977. Final Environmental Statement. 1977 Outer Continental Shelf Oil and Gas Lease Sale Offshore the North Atlantic States. Volume 2 of 5. Bureau of Land Management.
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(11) American Petroleum Institute, 1978. Basic Petroleum Data Book. Petroleum Industry Statistics. Washington. D.C.
(12) American Petroleum Institute, 1979. 1977 Joint Association Survey of Drilling Costs. Washington. D.C.
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(14) DeGolyer and MacNaughton, 1978. Twentieth Century Petroleum Statistics. Dallas, Texas.
(15) International Oil Scouts Association, 1978. International Oil and Gas Development. Part II. Volume 47. Austin, Texas
(16) U.S. Geological Survey, 1978. Outer Continental Shelf Statistics 1975-1977. Conservation Division/Geological Survey, Department of the Interior. Washington, D.C.
(17) U.S. Department of Energy, 1979. Cost and Indexes for Domestic Oilfield Equipment and Production Operations 1978. DOE/EIA-0185. Order No. 495.
(18) U.S. Department of Commerce, 1979. Survey of Current Business. Volume 59, No. 11. Bureau of Economic Analysis.
(19) Bechtel Corporation, 1978. The Energy Supply Planning Model. 1978 Computer Printout and Update. San Francisco, California.
(20) U.S. Environmental Protection Agency, 1975. Development Document for Interior Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Segment of the Oil and Gas Extraction Point Source Category. EPA 440/1-75/055. Group II. Washington, D.C.
(21) University of Oklahoma, 1975. Energy Alternatives: A Comparative Analysis. U.S. Government Printing Office, Washington, D.C.

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ENERGY SYSTEM:

SIZE:
- Daily production of enhanced oil recovery 32,650 barrels per day[1]
- Average heat content 6.3 x 10^6 Btu/bbl
- Annual nominal product heat content 84.7 x 10^{12} Btu
- Number of wells 1,302[1]
- Field size 3,434 acres
- Plant availability 70%
- Lifetime 15 years
- Recovery efficiency 10% of OOIP[4]
- Representative oil field Kern River, California (Getty)[1]

DESCRIPTION
- Steam drive is a thermal enhanced oil recovery method where steam is continuously injected through special wells. Due to changes in viscosity and volume (expansion) of oil and possible permeability of rock oil is displaced by water originated from condensed steam. The recovered oil, water, gas mixture is treated in a separation unit.

COMPONENTS
- drill rig
- pipe and tubing
- pumps and drivers
- water softeners
- steam boilers
- lines and wellhead insulation
- water knock out tanks (separators)

ENVIRONMENTAL CONCERNS
- air emissions from boilers and heaters (separators)
- fugitive emissions from well heads, oil/water separators, valves, pumps, and storage tanks
- oil and grease spills
- releases of HC and H_2S during oil production
- potential subsidence and seismic activities

RESOURCES USED:
(Per 10^{12} Btu Produced)

RESOURCE DEPLETION	
crude oil	150,700 barrels
average heat content	6.3 x 10^6 Btu/bbl
LAND*	**Acres**
permanently committed oil field site[1]	61.6
WATER	**Acre-Ft.**
process steam[4]	102.5
MATERIALS	**Tons**
total construction costs*[3]	
concrete	1,504
total steel	921
oil country tubular goods	460
COSTS	**Dollars (1978)**
total construction costs*[3]	4.4 x 10^6
manpower	1.12 x 10^6
materials	.97 x 10^6
equipment	1.98 x 10^6
other	0.35 x 10^6
total capital costs*[3]	5.97 x 10^6
operation and maintenance[3]	1.13 x 10^6
PERSONNEL	**Workers**
construction* (2 years)[3]	3.3
operation[3]	9.2

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS (see text)	**Tons**
particulates[4]	23
SO_2[4]	207
NO_x[2,4]	71
HC	2.8
CO[4]	4.3
WATER POLLUTANTS	**Tons**
HC[4]	0.8 - 3.9
SOLID WASTE	**Tons**
sludge (waste water treatment)	quantity is process and site specific
sludge (SO_2 scrubbers)	quantity is process and site specific
PRODUCT	
crude oil	150,700 bbl
average heat content	6.3 x 10^6 Btu/bbl

*Total plant land, construction cost, materials, or man power divided by the annual output in trillion Btu (70% availability rate).

SOURCES:
(1) Noran, D., "Growth Marks Enhanced Oil Recovery". Oil and Gas Journal, 1978.
(2) Battelle Pacific Northwest Laboratory, Tertiary Oil Recovery: Potential Application and Constraints, 1978
(3) Bechtel Corporation, Energy Supply Planning Model, 1975.
(4) U.S. Environmental Protection Agency, Energy From the West: Energy Resource Development Systems Report Volume V: Oil and Natural Gas, EPA-600/7-79-060e, 1979.

Note: The project selected for analysis is the largest project in operation, thus, factors based on this project may not provide average estimates.

Note: Please refer to the qualification statements at the beginning of this section on Petroleum.

ENERGY SYSTEM:

(a)(c)(d)

SIZE
- 800 MWe output
- thermal efficiency 34.7%
- heat rate 9,800 Btu/kWh
- capacity factor 55%
- equipment lifetime 35 years
- net electrical energy produced 13.13 x 10^{12} BTU/year

DESCRIPTION:
- Oil-fired steam electric power plants generate electricity using the same basic unit processes as the other fossil fueled power stations, i.e. coal and natural gas. The chemical energy in the fuel oil is converted to heat energy in the steam generator and again converted to mechanical energy in the turbine. This energy is finally transformed to electrical energy by the generator.

COMPONENTS:
- fuel oil handling, storage and feed system
- steam generator (boiler)
- steam turbine
- generator
- environmental control system - ESP, SO_2 scrubber
- boiler fed water treatment system
- condenser
- water cooling system
- waste water treatment system
- ash removal system
- sludge dewatering system
- solid waste disposal system

ENVIRONMENTAL PROBLEMS:
- air emissions - particulates, SO_2, NO_x
- chemical effluents in wastewater
- thermal discharge
- solid waste disposal
- release of toxic substances
- water use

RESOURCES USED:
(Per 10^{12} Btu equivalent electricity produced)

FUEL (h)	
residual oil No. 6	409,300 barrels
heat content	146,000 Btu/gallon
OIL ANALYSIS (h)	**% by weight**
carbon	85.6 - 88.4
hydrogen	10.3 - 12.0
sulfur	0.2 - 4.0 (2.0)
oxygen	0.6 - 1.0
nitrogen	0.3 - 0.5
moisture	0.2
ash	0.05 - 1.0 (0.3)
ENERGY (i) (requirements for pollution control devices)	**% energy generated**
FGD	3.5 - 6.0
mechanical collectors	0.2 - 0.9
ESP	0.3
combustion modifications (NO_x)	0 - 0.6
waste water treatment plant	0.1
evaporative cooling towers	
mechanical draft	2.5
noise control	<0.1
LAND (g)	**Acres**
fixed area	
plant area	8-12 (6)
evaporative cooling towers,	
mechanical draft	0.6 - 1.4
natural draft	0.1 - 0.4
	Acres/Year
incremental area	
surface storage piles	0.3
landfill	highly variable
evaporation ponds	NA
WATER (g)	**Acre-Ft./Year**
once-through	330
evaporative cooling towers	
mechanical draft	<330
natural draft	<330
COSTS (d)	**Dollars (1978)**
construction	
labor	$5,360,000
materials	1,570,000
equipment	6,530,000
other construction	3,970,000
land & land rights	90,000
general plant	480,000
total	18,000,000
operation and maintenance	
labor	240,000
materials	97,000
equipment	72,300
utilities	73,400
annual operating cost	483,000

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu equivalent electricity produced)

AIR POLLUTANTS (e)(h)	Gross	Revised NSPS
TSP	436	43
particulates/arsenic	0.00063	
particulates/beryllium	0.00769	
particulates/cadmium	0.108	
particulates/lead	0.00154	
particulates/mercury	0.00063	
particulates/nickel	2.00	
particulates/manganese	0.00063	
particulates/chromium	0.0236	
particulates/copper	0.0236	
particulates/vanadium	0.0455	
SO_x**	3270	327
NO_x	433	
HC^{**}	9.88	
CO	49.3	

WATER POLLUTANTS (f)	Open Cycle (Tons)	Closed Cycle (Tons)
alkalinity	26.9	27.3
acidity	32.4	0
BOD	0.307	5.16
COD	34.6	38.7
TSS	69.2	69.2
TDS	109	385
ammonia	0.0743	0.0743
nitrate	0.605	0.605
phosphorus	0.0443	0.0443
sulfate	204	268
chloride	32.6	58.7
aluminum	9.06	1.16
chromium	0.0313	0.0313
copper	0.417	0.417
iron	0.463	0.463
magnesium	6.19	69.9
nickel	4.37	4.37
zinc	0.487	0.0426
sodium	83.1	83.1
surfactants	135	135
antimony	0.00334 - 0.0216	
arsenic	0.00723 - 0.00134	
benzene	0.0000174 - 0.000836	
beryllium		
cadmium	0.000122 - 0.0139	
chloroform	< 0.0000346	
cyanogens	< 0.302	
lead	0.00948 - 0.000200	
mercury	0.00000677 - 0.000507	
phenol	0.0220	
selenium	0.0136 - 0.0220	
toluene	0.0040 - 0.000122	

Note: Please refer to the qualification statements at the beginning of this section on Petroleum.

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Oil-Fired Steam Electric Power Plant (Concluded)

ENERGY SYSTEM

RESOURCES USED:
(Per 10^{12} Btu equivalent electricity produced)

PERSONNEL [a]	Workers/Year First Year	Second Year	Third Year	Fourth Year	Fifth Year
construction					
nonmanual technical	1.6	4.9	6.8	4.7	2.5
nonmanual nontechnical	0.8	2.4	3.3	2.3	1.2
manual	0	20.5	47.9	7.9	20.5
total	2.4	27.8	58.0	14.9	24.2

	Workers/Year
operation and maintenance	
nonmanual technical	2.4
nonmanual nontechnical	2.3
manual	5.8
total	11.0

OCCUPATIONAL SAFETY [e]	Workers/Year
deaths	0.00181
injuries	0.173
mandays lost	7.20

RESIDUALS AND PRODUCTS:
(per 10^{12} Btu equivalent electricity produced)

SOLID WASTE (Tons)[h]	Without Scrubbers	With Non-Regenerative limestone scrubbers**
scrubber sludge (60% water 40% dry solids)	0	16,000
fly ash (100% dry solids)	370	370
total solid waste	370	16,370

HEAT [c]	Btu/Year
stack loss	0.40×10^{12}
cooling water loss + miscellaneous station losses	1.46×10^{12}

ENERGY PRODUCT	KW-hrs.
electricity	2.93×10^{8}

ENVIRONMENTAL CONTROL COSTS[d]	Dollars (1978)*
capital costs -	
central treatment plant	$ [illegible]
ash transport treatment	[illegible]
area runoff treatment	18,000
condenser cooling water treatment (or)	9,300
cooling tower blowdown treatment	4,300
cooling system	
once-through (or)	[illegible],300
evaporative cooling towers	
mechanical draft (or)	[illegible]
natural draft	1,[illegible],000
flue gas desulfurization system	[illegible]
ESP	[illegible] - [illegible]
operation and maintenance costs-	
central treatment plant	[illegible]
ash transport treatment	[illegible]
area runoff treatment	[illegible]
condenser cooling water treatment (or)	1,[illegible]
cooling tower blowdown treatment	[illegible]
cooling system	
once-through (or)	[illegible]
evaporative cooling towers	
mechanical draft (or)	[illegible]
natural draft	[illegible]
flue gas desulfurization system	632,000

*Costs applicable to new equipment, not retrofit cases.
**Assumes 2.0 percent sulfur, 90% removal efficiency.

SOURCES: (a) EPA Development Document for Proposed Effluent Limitation Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category, March 1974 and October 1974.
(b) EPA, Technical Report for Revision of Steam Electric Effluent Limitations Guidelines, September 1978.
(c) Teknekron, Water Pollution Control for the Steam Electric Power Industry, Vol. I, 1975.
(d) Bechtel Corporation, "Energy Supply Planning Model," 1978.
(e) EPA, Compilation of Air Pollutant Emission Factors, 1977.
(f) Hittman, Trace Toxic Pollutant Coefficients for Energy Supply and Conversions, 1977.
(g) University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
(h) Federal Register, Vol. 44, No. 113, Rules and Regulations, 1979.
(i) Code of Federal Regulations, Title 40, Part 400 to end.)
(j) DOC/EPA, Energy Consumption of Environmental Controls: Fossil Fuel, Stream Electric Generating Industry, 1977.
(k) Petroleum Refinery Engineering, W.L. Nelson, McGraw-Hill, 1958.
(l) Hittman, Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, 1974.

Note: Please refer to the qualification statements at the beginning of this section on Petroleum.

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Crude Oil Storage in Salt Dome Caverns

ENERGY SYSTEM:[a]

SIZE
- 60 million barrels
- Energy Storage: 336×10^{12} Btu

DESCRIPTION[a]
- The salt dome caverns are created by leaching with water; the resulting brine is discharged into a large body of water such as the Gulf of Mexico in an environmentally acceptable manner. These caverns are provided with a cemented casing to protect subsurface water quality and with pipelines to handle water/brine and crude oil.

MAJOR COMPONENTS[a]
- salt dome caverns
- a major body of water nearby
- water withdrawal and brine discharge system
- crude oil delivery and handling system

ENVIRONMENTAL CONCERNS[a]
- discharge of brine and its impact on environment/ecology
- risk of oil spills and associated hazards
- hydrocarbon emissions
- fugitive dust during construction
- emissions from construction vehicles

RESOURCE REQUIREMENTS:
(Per 10^{12} Btu Energy Stored)

ENERGY REQUIREMENT	
electrical power to operate pumps	negligible

LAND USE REQUIREMENT[b]	Acre
pipelines, site facilities and brine disposal	1.6
pipelines right of way	0.8

WATER REQUIREMENT[b]	Acre-Ft.
initial leaching operation 56,250,000 gallons	173
each pumping (crude withdrawal) operation	24

COSTS[a]	Dollars (1976)
construction of total system	230,000
operation and maintenance	not available

PERSONNEL[b]	Man-Years
construction	0.6
operation and maintenance	not available

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Energy Stored)

RESIDUALS IN AIR	Tons
hydrocarbons[b]	2.27

RESIDUALS IN WATER	Tons
hydrocarbons	not available

QUANTITY OF BRINE DISCHARGED	Acre-Ft.
initial leaching operation	196
each crude oil filling operation	21

SOLID WASTE
negligible during operation

HEAT DISSIPATED
negligible

ENERGY PRODUCT	Barrels
crude oil quantity stored	178,572

SOURCES: (a) Petroleum Storage for National Security, 1975. National Petroleum Council, Washington, D.C.
(b) Strategic Petroleum Reserve, 1977. Supplement Final Environmental Impact Statement. West Hackberry Salt Dome. NTIS, PB-265-796.

Note: Please refer to the qualification statements at the beginning of this section on Petroleum.

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Natural Gas

The following should be recognized as limitations of the information provided on the summary sheets of this section:

1. The impacts and costs of oil and gas operations vary widely over the period of development. Typically capital costs will be concentrated in the initial phases of development while operation and maintenance costs and impacts will be spread over a longer period of time. Annualizing costs and impacts over the life cycle of a project ignores the actual pattern in which they occur.

2. The figures presented in the data sheets apply to specific representative cases. The variation around these cases may be quite extensive. Some costs, such as platforms, will vary geometrically rather than arithmetically. Thus, an 18-well platform in 400 feet of water will be much more than twice as expensive than one in 200 feet. Unless production per platform changes in exactly the same proportion, the numbers provided in the data sheets may be unrealistic.

3. The data sheets also do not consider changes in the underlying conditions determining the economic limit for oil and gas development. The rapid escalation of crude oil prices and changes in price/cost relationships will bring formerly uneconomic projects into production. These projects will generally have unit cost characteristics which are very different from the "representative" projects shown on the data sheets. It is likely that for these new projects the costs per 10^{12} Btu produced will be much higher. The estimates of environmental impact also do not include the fact that many of the new projects will have improved environmental control systems which are not yet defined. For example, new steam Enhanced Oil Recovery projects will be required to have air emission levels which are much lower than the national averages shown on the data sheets.

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Onshore Gas Exploration - Lower 48 States

ENERGY SYSTEM:

SIZE (1,3,4,6,7,6,7,8)
- 30.6 x 10^6 cu ft gas per well field per day average ultimate production (1,3,7)
- 10.811 x 10^9 cu ft gas per field per year average ultimate production (1,3,7)
- [illegible] success ratio (2)
- 130 successful wells per field ultimate size (2)
- Twenty-eight exploratory wells drilled; 6 successful and 22 unsuccessful wells drilled (2)
- One to one and a half years of drilling and analysis before a decision is made on production
- Average drilling depth 5,000 ft (6)
- Well life expectancy 15-25 years (3)
- 1000 Btus per average cubic foot of gas
- 70 percent (50-90%) gas reservoir recovery efficiency (8)
- 10.811 x 10^{12} Btus per field per year ultimate production

DESCRIPTION
- Regional surveys (4)
  - Research libraries and state or Federal geology offices for information on rock formations and outcrops
  - Obtain any previous stratigraphic drilling records
  - Examine satellite imagery for potential regions
- Local surveys by geophysicist (4)
  - Magnetometer; sedimentary rocks - low magnetic properties
  - Gravimeter; dense rock increases gravitational pull
  - Seismograph; distance shock waves travel to various strata recorded
- Stratigraphic core tests to examine strata for arrangement and possible traces of oil, gas or fossils (4)
- Secure lease, obtain drilling permits and pay annual rental fee (4)
- Site access; site preparation (1)
- Water availability secured through wells or temporary water lines (1)
- Conduct logging analysis to determine potential productivity (1)
- If considered profitable, remainder of well cased and Christmas tree installed; if not, well plugged with cement and crimped below ground (1)

COMPONENTS
- Geophysical surveying equipment/satellite imagery
- Bulldozer, backhoe and dump truck
- Temporary water lines
- Rotary drill rig: hoisting, rotary and fluid circulation systems; drill string and bits
- Steel casing and cement
- Geophysical logging and analysis equipment
- Possible production tubing and Christmas tree

ENVIRONMENTAL CONCERNS
- Possible fracturing or connection of underground aquifers of varying qualities
- Air emissions from drilling rigs and site preparation equipment
- Soil erosion losses and decreased fertility resulting from site access and preparation and possible aquatic sedimentation in nearby streams
- Possible blowout, fire or accidental drill pond release

RESOURCES USED:
(Per 10^{12} Btu Produced)

RESOURCE DEPLETION OF OIL FIELD RESERVOIR	None
ENERGY (9,10,11,12,6)	Btu x 10^9
Exploratory drilling fuel (28 wells - 24,750 bbl diesel)[a]	13.278
Gas processing fuel requirement	None
LAND (13)	Acres
Well pads and access roadways[a]	7.54
WATER (13)	Barrels
Drilling mud fluid (28 wells)[a]	16,510
MATERIALS	N/A[b]
COSTS (6)[b]	
Drilling costs	
6 successful gas wells[a]	88,730
22 unsuccessful dry holes[a]	223,930
PERSONNEL (12,11)	Man-Days
Construction and drilling requirements (28 wells)[a]	
Site access	30.8
Site preparation	51.6
Well drilling	660.4
Perforation and cleaning (6 successful wells)	12.1
Site cleanup	25.9
OCCUPATIONAL SAFETY (15)[c]	Number
Fatalities	0.000061
Injuries	0.004
Man-days lost	0.13

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS (14,12,11,10)[a]	Tons
Exploratory drilling/site prep	
NO_x	23.8
CO	5.2
HC	1.9
SO_x	1.6
Particulates	1.7
WATER POLLUTANTS	
Brines during well testing	Negligible
SOLID WASTE[d]	Tons
Drill cuttings (28-5000 ft wells)[a]	619.7

Note: Please refer to the qualification statements at the beginning of this section on Natural Gas.

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Onshore Gas Exploration - Lower 48 States (Concluded)

[a] Data values represent total exploratory values divided by the expected average annual output normalized to 10^{12} Btu; i.e., exploratory drilling fuel requirement for 20-5000 ft wells = 24,750 bbl of diesel fuel x 5.8 x 10^6 Btu/bbl = 1.4355 x 10^{11} Btu ÷ 10.811 (10.811 x 10^{12} Btu average annual production) = 13.278 x 10^9 Btus of fuel/10^{12} Btu produced.

[b] Material and cost data for onshore gas is derived from the Bechtel Corporation (1978) study; however, they did not separate their exploratory material and cost data from their development material and cost data and, consequently, the exploratory values are a portion of those listed under the extraction/production phase. Sample drilling costs are included for informational purposes only as they would also be included in the extraction/production phase.

[c] These values are industry values which have been previously normalized to 10^{12} Btu.

[d] Calculated assuming the following bore hole sizes: 18 inches for 100 ft, 12 3/4 inches for 1800 ft, and 8 3/4 inches for 1100 ft and an average rock density for limestones, clays, and shales of approximately 2.5 grams per cubic centimeter.

SOURCES:

(1) University of Oklahoma, 1979. "Energy From the West: Energy Resource Development Systems Report." Volume V. Oil and Natural Gas. Science and Public Policy Program/University of Oklahoma. U.S. Environmental Protection Agency, EPA-600/7-79-060e, Washington, D.C.
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(5) American Gas Association, 1979. Gas Facts 1978 Data. American Gas Association Department of Statistics, Arlington, Virginia.
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Offshore Gas Exploration - Lower 48 States

ENERGY SYSTEM:

SIZE[2,4,8,13,14,15,16,17]

- 88,722,000 cubic feet of gas per platform per day average ultimate conventional production[16]
- 3.2384 x 10^{10} cubic feet of gas per platform per year average ultimate conventional production[16]
- 13.4% exploratory well success ratio[13]
- five exploratory wells drilled: two successful wells and three dry holes [6]
- 1/3 year of exploratory drilling, then a 2-3 year layover while the development plan is finalized, and the production platform constructed, towed to position and installed[6]
- Average total vertical depth (TVD) 9,600 feet; many of the wells are deviated[14,2]
- 1,000 Btus per cubic foot of gas
- 32.384 x 10^{12} Btus per platform per year average ultimate conventional production
- 50-90 percent gas reservoir recovery efficiency[17]

DESCRIPTION[1,3,4,7,8,9]

- Exploratory permit must be obtained
- Regional surveys made
  - Magnetometer; air or ship-borne measurements of changes in earth's magnetic field
  - Gravimeter; variations in gravitational pull of various rock types
  - Natural oil seeps
  - Satellite and infrared imagery
- Local surveys made
  - Seismic survey in which reflected and refracted sound waves help elucidate subsurface structures and strata
  - Bottom sampling and coring (500-1000 ft. max); permit required
- Exploratory drilling activities performed
  - Obtain lease
  - Rent a drill barge, drill ship, jack-up, semi-submersible or submersible depending on water depth, climatic conditions, seafloor configuration, and availability
  - Transport drilling apparatus to location and set up to drill
  - Drill to desired depth, and set and cement casing
  - Log and analyze the well for commercial production
  - If productive, finish casing well, perforate the casing, fracture or acidize if necessary, and install production tubing and temporary Christmas tree
  - If not productive, plug with cement and crimp casing 15-ft below seafloor

COMPONENTS[3,4,6]

- Geophysical surveying equipment/satellite imagery, boats and planes
- A drilling barge, drill ship, jack-up, semi-submersible or submersible
- Rotary drill rig: hoisting, rotary and fluid circulation systems
- Drill string and bits, and water pumping system
- Steel casing and cement
- Geophysical logging and analysis equipment
- Possible production tubing and Christmas tree

ENVIRONMENTAL CONCERNS

- Possible blowouts and fires
- Water pollution from formation brine, discharges released during drilling and pumping operations (if not reinjected), and the disposal of exploratory drilling muds which are only used once[11,12]
- Air emissions from drilling and electric power generation motors

RESOURCES USED:
(Per 10^{12} Btu Production Potential)

RESOURCE DEPLETION OF GAS FIELD RESERVOIR	negligible
ENERGY[3,4,8,22,23]	Btu x 10^9
Exploratory drilling fuel - five wells[a]	4.646
WATER SURFACE AREA LAND USE[a][11]	Acres
Jack-ups and drill ships	.052 - .154
Semi-submersible	5.00
If one mile fishing buffer included in permit	62.10
WATER[a][9,20]	Barrels
Drilling mud water (fresh or salt) for five wells	20.2
Fresh water requirement for workers	919.0
COSTS[a,b][9,14,18]	Dollars -1978
(These are cantilever jack-up rig example costs)	
Shipyard furnished components	
Hull, cantilever and spud legs	$ 479,600
Electromechanical self-elevating system	145,500
Crew quarters and heliport	38,400
Cranes, winches, safety equipment and other	70,300
Owner furnished components	
Drawworks	16,900
Prime movers	17,000
Traveling block and derrick	12,400
Other equipment such as mud system, pipe, casing and safety equipment	119,800
Total Cost	$ 899,900
Rig Rental Rate (125 days)	
Shallow water rigs	$61,800 -$84,900
Deep water rigs	$96,500 -$135,000
Drilling Cost - two successful gas wells[14,18]	$106,700
- three dry holes	$128,200
PERSONNEL[a][9,11]	Workers
Exploratory drilling - jack-up rig	2.39 -2.69
OCCUPATIONAL SAFETY[c][19]	Number of Accidents of Workers
Blowouts	.0010
Fatalities	.0001
Injuries	.0008
Fires and Explosions	.0050
Fatalities	.0008
Injuries	.0032
Miscellaneous Accidents	.0026
Fatalities	.0023
Injuries	.0009

RESIDUALS:
(Per 10^{12} Produced)

AIR POLLUTANTS[a][3,4,8,21,22,23]	Tons
Exploratory drilling	
NO_x	10.01
CO_x	2.17
Exhaust Hydrocarbons	8.80
SO_x	0.67
Particulates	0.72
WATER POLLUTANTS	
Brines during well testing (Components of the drilling muds are listed under solid waste)	negligible
SOLID WASTE[a][11]	Tons
Drill cuttings - 9,600 foot wells	215.85
Drilling muds	
Barite ($BaSO_4$)	41.30
Bentonite and Attapulgite Clays	5.10
Caustic Soda (NaOH)	1.62
Aromatic Detergent	0.23
Organic Polymers	0.31
Ferrochrome Lignosulfonate	2.01
Total Drilling Muds	50.57

Note: Please refer to the qualification statements at the beginning of this section on Natural Gas.

Offshore Gas Exploration - Lower 48 States (Concluded)

(a) Data values represent total exploratory values divided by the expected average annual output normalized to 10^{12} Btu; i.e., exploratory drilling fuel requirement (3 wells) x 25,946 bbl of diesel fuel x 5.8 x 10^{6} Btu/bbl ÷ 32.384 (32.834 x 10^{12} Btu average annual production) = 4.646 x 10^{6} Btus of fuel/10^{12} Btus produced. (Note that annualizing ignores the actual pattern on which costs and impacts occur.)
(b) Example exploratory rig costs are shown to illustrate the capital outlay for the exploratory rig owners. Since many exploratory wells would be drilled for a large number of drilling projects with the same rig, the rig rental rate is included as a more realistic exploratory cost.
(c) These values encompass injuries and fatalities which occurred during exploration, development, and production of offshore facilities between 1970-1977.

SOURCES: (1) University of Oklahoma, 1979. "Energy From the West: Energy Resource Development Systems Report." Volume V. Oil and Natural Gas. Science and Public Policy Program/University of Oklahoma. U.S. Environmental Protection Agency, EPA-600/7-79-060e, Washington, D.C.
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(20) U.S. Department of Interior, 1973. Draft Environmental Statement - Proposed 1974 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Louisiana. OCS Sale No. 33 DES 73-60. Bureau of Land Management.
(21) U.S. Environmental Protection Agency, 1978. AP-42. Supplement No. 8 for Compilation of Air Pollutant Emission Factors. Third Edition. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.
(22) Salisbury, J. Kenneth (Ed.), 1967. Kent's Mechanical Engineers' Handbook - Power Volume. Wiley Engineering Handbook Series. John Wiley & Sons, Inc., London, England.
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Onshore Gas Extraction - Lower 48 States

ENERGY SYSTEM:

SIZE (1,5,7,2,6,3,8,4)

- 29.6 x 10^6 cu. ft. gas per well field per day average production (1,5,7)
- 10.811 x 10^9 cu. ft. gas per well field per year average production (1,5,7)
- 67.18% success ratio (2)
- 2.47 x 10^5 cu. ft. per well per day (5)
- 120 wells would be drilled to efficiently tap the reservoir; 60 dry holes would also be expected. Subsequent to the exploratory drilling, 114 successful gas wells and 38 unsuccessful dry holes would be drilled during the development stage (2)
- 5 years for all drilling and facility construction to be completed (1)
- Average drilling depth 5,000 ft. (6)
- Well life expectancy 15–25 years (3)
- 1000 Btus per average cubic foot of gas
- 70 percent (50-90%) gas reservoir recovery efficiency (8)
- 10.811 x 10^{12} Btus per field per year

DESCRIPTION (1,4)

- After exploratory drilling completed, the wells tested and the data analysed, a production plan has to be developed and a lease obtained.
- Drilling is carried out according to the production plan and to the desired depth, and the plan is modified if higher or lower pay zones come in or if dry holes are obtained.
- Set and cement casing; log and analyze the strata.
- If productive, finish casing the bottom of the hole, perforate the casing, fracture or acidize if necessary, and install production tubing and Christmas tree.
- If not productive, plug with cement and crimp casing below the ground.
- After development drilling complete, disassemble drilling equipment and install gathering pipeline to transport gas from the well site to the field processing facility for gas-water separation and treatment.

COMPONENTS

- Site access and site preparation equipment; bulldozer, backhoe and dump truck
- Temporary water lines
- Rotary drill rig: hoisting, rotary and fluid circulation systems
- Drill string and bits
- Steel casing and cement
- Geophysical logging and analysis equipment
- Possible production tubing and Christmas tree
- Gas processing facility

ENVIRONMENTAL CONCERNS

- Possible fracturing or connection of underground aquifers of varying qualities
- Air emissions from drilling rigs and site preparation equipment
- Soil erosional losses and decreased fertility resulting from site access and preparation, and subsequently possible aquatic sedimentation in nearby waterbodies
- Possible blowout, fire or accidental drill mud release

RESOURCES USED:
(Per 10^{12} Btu Produced)

RESOURCE DEPLETION	
Average potential yearly depletion of gas	15.444 x 10^9 cu fc
Gas reservoir recovery efficiency (8)	70 (50-90) percent

ENERGY (9,10,6,11,12,13)	Btu x 10^9
Development drilling fuel (114 successful wells plus 38 dry holes - 134,370 bbl diesel)[a]	72.088
Gas Processing Energy Requirement (10)[b]	
Sweet gas	309.19
Sour Gas	980-1363.0

LAND (14)	Acres
Temporary requirement[a]	47.36
Permanent requirement[b]	38.93

WATER (14)	Barrels
Drilling mud fluid (152 wells)[a]	88,630

MATERIALS (7)[a]	Tons
Concrete/cement	4116.2
Bentonite/barite	246.0
Steel	1563.0
Copper, aluminum, manganese & other metals	33.7
Steel casings and steel plate	61.4
Pipe, tubular goods, and valves	1392.1
Drill bits, pumps, compressors and heat exchangers	57.3

COSTS (7)	1978 Dollars
Manpower	1,703,600
Materials (concrete, clay, steel, metals, etc.)	1,743,500
Equipment (electrical, instrumentation, drilling)	1,212,700
Other costs and services (land, construction start-up, interest, etc.)	6,052,200
Total Construction & Drilling Costs[a]	10,712,000
Manpower	111,900
Materials (chemicals, petroleum products, steel & other metals)	20,400
Equipment & fabricated plate products	25,100
Other (rents, royalties, taxes and services)	329,200
Annual Operating Cost[b]	486,600

PERSONNEL (7)	Workers
Technical Manpower	7.40
Non-manual, non-technical manpower	1.39
Manual manpower	34.69
Total Construction Manpower[a]	43.48
Technical Manpower	1.13
Non-manual, non-technical manpower	1.02
Manual manpower	2.68
Total Annual Manpower[b]	4.83

OCCUPATIONAL SAFETY (18)[c]	Number
Fatalities	0.0000052
Injuries	0.003
Man-days lost	0.030

RESIDUALS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS (10,15,16,12,13,11)	Tons
Development drilling/site access & preparation/gathering pipeline system construction[a]	
NO_x	130.5
CO	28.7
HC	10.6
SO_x	9.0
Particulates	9.3
Annual production emissions[b]	
NO_x	84.7
CO	1.9
HC	0.6
SO_x	1424.6
Particulates	1.9

WATER POLLUTANTS (17)	Tons
Natural gas processing plants[b]	
BOD	1.71
COD	11.20
Oil & Grease	34.27
Chromium	0.09
Zinc	0.03
TDS	456.95
Chloride	85.68
Sulfate	68.54

SOLID WASTE[a]	Tons
Drill cuttings (152-5000 ft. wells)[a]	3864

AVERAGE FIELD PRODUCTION	
Natural Gas	1 x 10^9 cu.ft.
Heat Content	1000 Btu/scf

Note: Please refer to the qualification statements at the beginning of this section on Natural Gas.

[a]Base values represent <u>total life cycle values</u> divided by <u>average annual</u> energy output normalized to 10^{12} Btu; i.e., development drilling fuel requirement (133-5000 ft wells) = 134,376 bbl diesel fuel x 5.8 x 10^6 Btu/bbl = 7.7935 x 10^{11} Btu ÷ 10.811 (10.811 x 10^{12} Btu average annual production) = 72.088 x 10^9 Btu of fuel/10^{12} Btu produced. (Note that annualizing ignores the actual pattern on which costs and impacts occur.)

[b]Base values represent <u>annual values</u> divided by <u>average annual</u> energy output normalized to 10^{12} Btu.

[c]These values are industry values which have been previously normalized to 10^{12} Btu.

[d]Calculated assuming the following bore hole sizes: 18 inches for 100 ft, 12 3/4 inches for 1800 ft, and 8 3/4 inches for 3100 ft and an average rock density for limestones, clays and shales of approximately 2.5 grams per cubic centimeter.

SOURCES:

(1) University of Oklahoma, 1979. "Energy From the West: Energy Resource Development Systems Report." Volume V. Oil and Natural Gas. Science and Public Policy Program/University of Oklahoma. U.S. Environmental Protection Agency, EPA-600/7-79-060e, Washington, D.C.

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(4) American Petroleum Institute, 1977. Facts About Oil. Washington, D. C.

(5) American Gas Association, 1979. Gas Facts 1978 Data. American Gas Association Department of Statistics, Arlington, Virginia.

(6) American Petroleum Institute, 1979. 1977 Joint Association Survey on Drilling Costs. Washington, D. C.

(7) Bechtel Corporation, 1978. The Energy Supply Planning Model. San Francisco, California.

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Offshore Gas Extraction - Lower 48 States

ENERGY SYSTEM:

SIZE[2,6,8,13,14,15,16,17]

- 86,722,000 cu. ft. of gas per platform per day average conventional production[16]
- 3.2104 x 10^{10} cu. ft. of gas per platform per year average conventional production[16]
- 76.3% development well success ratio[13]
- 18 development wells would be drilled to efficiently tap the reservoir; six dry holes would also be expected. Subsequent to the exploratory drilling, 16 successful oil wells and three dry holes would be drilled during the development phase.
- 3 1/2 years total development drilling time[6,8]
- Average total vertical drilling depth (TVD) 9,600 ft.; many of the wells are deviated[14]
- 15-25 year well life expectancy[16]
- 1000 Btus per cu. ft. of gas
- 32,104 x 10^{12} Btus per platform per year average conventional production
- 50-90 percent gas reservoir recovery efficiency[17]

DESCRIPTION[1,3,4,7,8,9]

- After exploratory drilling completed, the wells tested, and the data analyzed, a production plan has to be developed and a lease obtained
- Production platform ordered, fabricated, towed to position, and assembled
- Directional drilling is carried out according to production plan and to the desired depth, and the plan is modified if higher or lower pay zones come in or if dry holes are obtained
- Set and cement casing; log and analyze the strata
- If productive, finish casing the bottom of the hole, perforate the casing, fracture or acidize if necessary, and install production tubing and Christmas tree or subsea completion apparatus
- If not productive, plug with cement and crimp casing 15 ft. below seafloor or use for reinjection of formation water
- After development drilling complete, disassemble drilling equipment and install production/processing equipment on the same platform
- Process the gas for water, hydrogen sulfide, and higher hydrocarbons and pump it onshore thru pipelines

COMPONENTS [3,4,6]

- A permanent drilling and production platform
- Rotary drill rig: hoisting, rotary and fluid circulation systems
- Drill string and bits, and water pumping system
- Steel casing and cement
- Geophysical logging and analysis equipment
- Production tubing and Christmas tree
- On-site separation and processing equipment

ENVIRONMENTAL CONCERNS

- Possible blowouts and fires
- Water pollution from formation brine, discharges released during drilling and pumping operations (if not reinjected)[11,12]
- Air emissions from drilling and electric power generation motors

RESOURCES USED:
(Per 10^{12} Btu Produced)

RESOURCE DEPLETION OF GAS FIELD RESERVOIR	
Average potential yearly depletion of gas	1.429 x 10^9 cu.ft.
Gas reservoir recovery efficiency[17]	70 (50-90) percent

ENERGY[5,6,8,18,19,24,25]	Btu x 10^9
Development drilling (16 successful wells + 3 dry holes)[a,b]	17.657
Operation and maintenance[c][18,19]	
Gas turbine (300hp) for electrical/mechanical use	1.091

WATER SURFACE AREA LAND USE[a][11]	Acres
Drilling platform	.062 - .154
If one mile fishing buffer included in permit	62.10

WATER[9,23]	Barrels
Drilling mud water (fresh or salt) for nineteen wells[a]	76.8
Fresh water requirement for workers[c]	515.3

COSTS[9,14,20,21]	Dollars - 1978
Platform[a]	
Labor	$187,600
Materials - 6000 ton steel platform	222,400
Offshore installation cost	54,800
Heliport and living quarters	21,300
Cranes/survival capsule/generators	20,500
Water system/instruments/corrosion control	13,800
Other - compression equipment, oil and gas treating equipment, heat exchangers, fire fighting equipment, barge bumpers, valves, derrick barges, tugs, etc.	229,400
Total - platform costs	$751,000
Drilling costs - 16 successful gas wells[a,b][14,20]	$853,500
- 3 dry holes	128,200
Total drilling costs	$981,700
Annual operating costs[c][18,20,21]	
Labor, supervision & payroll overhead	$ 16,700
Food and transportation	12,700
Surface equipment and operating supplies	2,700
Workover	16,900
Communications/administrative/insurance	14,400
Total annual operating costs	$ 63,400

PERSONNEL[9,11]	Workers
Development drilling and production equipment installation[a]	1.39 - 2.01
Production[c]	0.49

OCCUPATIONAL SAFETY[d][22]	Number
Blowouts	.0010
Fatalities	.0001
Injuries	.0008
Fires and Explosions	.0050
Fatalities	.0008
Injuries	.0032
Miscellaneous Accidents	.0026
Fatalities	.0023
Injuries	.0009

RESIDUALS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS[5,6,8,9,18,24,25,26]	Tons
Development drilling[a]	
NO_x	38.03
CO	8.23
Exhaust hydrocarbons	3.04
SO_x	2.53
Particulates	2.72
Annual estimate during production[c]	
NO_x	0.1519
CO	0.0627
Exhaust hydrocarbons	0.0098
SO_x	0.0003
Particulates	N/A

WATER POLLUTANTS[a][27]	Tons
Cadmium	0.00629
Cyanide	0.00093
Mercury	0.00005
Total organic carbon	38.313
Total suspended solids	6.7544
Total dissolved solids	10,178.0
Chlorides	5,644.0

SOLID WASTE[a][11]	Tons
Drill cuttings - 9,600 foot wells	820.22
Drilling muds	
Barite	117.69
Bentonitic and Attapulgite Clay	14.52
Caustic soda (NaOH)	4.62
Aromatic detergent	0.66
Organic polymers	0.88
Ferrochrome lignosulfonate	5.72
Total drilling muds	144.09

AVERAGE FIELD PRODUCTION	
Natural gas	1.0 x 10^9 cu. ft.
Heat content	1000 Btu/scf

Note: Please refer to the qualification statements at the beginning of this section on Natural Gas.

Offshore Gas Extraction - Lower 48 States (Concluded)

(a) Data values indicate total life cycle values divided by average annual energy output normalized to 10^{12} Btu; i.e., development drilling fuel requirement (19 wells) = 96,565 bbl. of diesel fuel x 5.8 x 10^6 Btu/bbl ÷ 32.304 (32.304×10^{12} Btu average annual production) = 17.657 x 10^9 Btu of fuel/10^{12} Btus produced.
(b) Fuel requirements for development drilling include only those wells drilled during development (16 successful plus three unsuccessful); exploratory drilling fuel requirements are accounted for during the exploratory phase. Drilling costs are determined in a similar manner.
(c) Data values represent annual values divided by average annual energy output normalized to 10^{12} Btus.
(d) These values encompass injuries and fatalities which occurred during exploration, development, and production of offshore facilities between 1970-1977.
(e) Data values indicate annual raw unprocessed water pollutants from average Gulf Coast brine concentrations and average brine production per platform, all normalized to 10^{12} Btu. Values for water produced from gas wells were determined from data combining both oil and gas wells.

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ENERGY SYSTEM:

SIZE:[a][d]
- 250 million scf/D of clean gas output
- >1,000 Btu/scf
- operates 328 days per year
- 90% plant availability
- plant efficiency 87 to 92%
- plant life 30 years

DESCRIPTION[a]
- Raw natural gas contains gases and liquids which have to be removed before the natural gas can be placed in the transmission line. These gases and liquids can include water, hydrogen sulfide, carbon dioxide, nitrogen, and various hydrocarbons such as ethane, propane, butane, and heavier. The purification process incorporates those systems such as dehydration, desulfurization, and carbon dioxide removal (gas sweetening), and natural gas liquids (NGL) separation required to provide a natural gas product suitable for pipeline distribution.

COMPONENTS[a]
- Major equipment consists of contactors, stills, reboilers, heaters, condensers, pumps and compressors, plus auxiliary hardware associated with the following processing systems. These processes, which may be utilized either separately or in combination, include the following:
  - Dehydration - can be accomplished by compression, treatment with drying substances such as diethylene glycol, absorption, and refrigeration.
  - Desulfurization - raw gas is usually scrubbed with some sort of aqueous amine solution such as, mono, di or triethanolamine. Additional processes such as the Claus Process may be added to recover sulfur from the hydrogen sulfide off-gas.
  - Natural Gas Liquids Separation - two of the major processes used are refrigerated absorption and low temperature distillation.

ENVIRONMENTAL CONCERNS
- Vent gas from Claus Plant (may require tail gas clean-up facility if emissions exceed applicable regulations).
- Stripper solution vents.
- Condensate stripper bottoms diposal.
- Relief valve and vent emissions.
- Make-up water requirements.

RESOURCES USED:
(Per 10^{12} Btu of clean natural gas produced)

FUEL[d]
Sour raw gas requiring sulfur removal and separation of natural gas liquids, i.e. propane, butane, etc. The quantity of raw gas consumed to produce 10^{12} Btu of clean natural gas is determined by the overall process efficiency (87 to 92%), and the heating values and quantities of by-products produced (sulfur, propane, butane, etc.)

ENERGY	
electricity	NA
LAND[3]	
plant	0.275 acres
WATER[1][3][c]	
boiler make-up	5.0 acre-ft.
COSTS	**Dollars**
construction	NA
operation and maintenance	NA
PERSONNEL	**Workers/Year**
construction	NA
operation and maintenance	NA

RESIDUALS AND PRODUCTS:
(per 10^{12} Btu of clean natural gas produced)

AIR POLLUTANTS[b][e][f]	**Tons**
Particulates	0.162
NO_x	40.9
SO_2	0.0054
HC	0.36
CO	0.0036
Aldehydes	0.027

BY-PRODUCT	**Tons**
sulfur	NA
natural gas liquids - propane, butance, etc.	NA

ENERGY PRODUCT[a]	
clean natural gas	250 million scf/D
heating value[2]	1,011 to 1,093 Btu/scf
gas consumption[2]	**% Volume**
· methane	81 to 94
· ethane	2.5 to 7.0
· propane	0.7 to 2.8
· butane	0.2 to 0.6
· pentane	0.03 to 0.64
· CO_2	0.4 to 1.0
· N_2	0 to 9.2

Note: Please refer to the qualification statements at the beginning of this section on Natural Gas.

(1) Estimated from source (c).
(2) Synthesized from source (a).
(3) Values are annualized per trillion Btu.

SOURCES:
(a) Chemical Process Industries, R.N. Shreve and J.A. Brink, Jr., McGraw-Hill, 1977.
(b) Teknekron, Inc. (Thomas H. Pigford, et al.) Fuel Cycles for Electrical Power Generation. Phase I Toward Comprehensive Standards the Electric Power Case (NTIS #PB 258 523). Office of Research and Monitoring - Environmental Protection Agency, January 1973.
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(e) University of Oklahoma, Energy Alternatives: A Comparative Analysis, (U.S. GPO #041--011-00025-4), (Washington, D.C.: Council on Environmental Quality, May 1975).
(f) Harry Butcher and Tom Lahre, "Natural Gas Processing," Compilation of Air Pollutant Emission Factors, Third Edition, (AP-42 Part B). Research Triangle Park, N.C: U.S. Environmental Protection Agency - Office of Air and Waste Management, August, 1977, pp. 9.2-3.

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Gas-Fired Steam Electric Power Plant

ENERGY SYSTEM:

SIZE
- 800 MWe
- thermal efficiency 34.0%
- heat rate 10,000 Btu/kWh
- capacity factor 55%
- equipment lifetime 35 years
- annual net electrical energy production 13.15 x 10^{12} Btu/year

DESCRIPTION
- Gas-fired steam electric power plants generate electricity using the steam produced in the boiler, with heat from natural gas combustion

COMPONENTS
- water purification system
- boiler
- condenser
- condenser cooling water system once through (or) cooling towers
- steam turbine
- generator
- central waste treatment plant
- air preheater
- economizer

ENVIRONMENTAL CONCERNS
- air emissions - NO_x
- chemical waste water effluents
- availability of water
- thermal discharge

RESOURCES USED:
(Per 10^{12} Btu equivalent electric power generated)

FUEL	
natural gas	2.87 x 10^9 cu.ft.
heat content	1,024 Btu/cu.ft.

Gas Analysis (by volume)	%
CH_4	81.8
C_2H_6	14.0
N_2	3.1
CO_2	1.0
O_2	0.1
S (as H_2S)	0.01

ENERGY (Requirements for pollution control devices)	% Energy Generated
combustion modifications	<0.6
central waste treatment plant	0.1
evaporative cooling towers	2.5
noise control	<0.1

LAND	Acres[3]
fixed area	
plant area	6
evaporative cooling towers	0.1-1.6

WATER	Withdrawal[8] (Acre-ft/yr.)	Consumption[a] (Acre-ft/yr)
once-through	56,000	250
evaporative cooling towers	2,000	800

COSTS	Dollars(1978)[3]
construction	
labor	$3,350,000
materials	420,000
equipment	4,610,000
other construction	2,330,000
land & land rights	55,000
general plant	295,000
total	$11,060,000
operation and maintenance	
labor	$183,000
materials	66,300
equipment	73,500
utilities	72,500
annual operating cost	$395,300

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu equivalent electric power generated)

		Tons	
AIR POLLUTANTS[a]	Gross	NSPS	Revised NSPS
TSP	71.8 - 21.32	14?	44.1
SO_2	0.861	1,176	1,176[2]
NO_x	1000	294	294
HC(as CH_4)	1.43	-	-
CO	24.6	-	-
gases & mists	-	-	-
CO_2	-	-	

WATER POLLUTANTS[a]	Open cycle Gross Tons	Closed cycle Gross Tons
alkalinity	26.0	26.4
acidity	52.4	0
BOD	0.396	5.16
COD	33.4	37.5
TSS	69.1	69.1
TDS	64.6	341
ammonia	0.0740	0.0740
nitrate	0.594	0.594
phosphorus	0.0229	0.0229
sulfate	278	263
chloride	20.7	47.9
aluminum	9.87	1.13
chromium	0.0316	0.0316
copper	0.0440	0.0440
iron	0.662	0.662
magnesium	6.08	69.7
nickel	4.37	4.37
zinc	0.400	0.405
sodium	83.1	83.1
surfactants	135	135
oil & grease	0.00208	0.00208

TRACE TOXIC ELEMENTS[f]	Gross Tons
antimony	0.000482
arsenic	0.00
benzene	0.00
beryllium	0.00
cadium	0.00
chloroform	0.0000347
cyanogene	0.00644
lead	0.00
mercury	0.0000124
phenol	0.00
selenium	0.000347
toluene	0.00104

Note: Please refer to the qualification statements at the beginning of this section on Natural Gas.

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Gas-Fired Steam Electric Power Plant (Concluded)

ENERGY SYSTEM:

RESOURCES USED:
(Per 10^{11} Btu equivalent electric power generated)

pollution abatement costs(b)				
capital costs				
central treatment plant	$27,000			
area runoff treatment	18,000			
condenser cooling water treatment	8,500			
(or)				
cooling tower blowdown treatment	6,000			
cooling system				
once-through (or)	301,000			
evaporative cooling towers				
mechanical draft	753,000			
(or)				
natural draft	1,190,000			
operation and maintenance				
central treatment plant	18,300			
area runoff treatment	700			
condenser cooling water treatment	1,000			
(or)				
cooling tower blowdown treatment	1,000			
cooling system				
once-through (or)	1,000			
evaporative cooling towers				
mechanical draft	4,000			
(or)				
natural draft	2,000			
PERSONNEL(d)	Workers/Year			
	First Year	Second Year	Third Year	Fourth Year
construction				
nonmanual technical	1.5	5.9	3.2	2.2
nonmanual nontechnical	0.6	2.6	2.3	1.0
manual	0	3.3	41.8	25.1
construction manpower total	2.1	11.8	47.3	28.3
	Workers/Year			
operation & maintenance				
nonmanual technical	1.9			
nonmanual nontechnical	2.0			
manual	4.3			
operation and maintenance manpower total	8.2			
OCCUPATIONAL SAFETY(f)	Workers/Year			
deaths	0.00175			
injuries	0.387			
man-days lost	6.94			

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu equivalent electric power generation)

SOLID WASTE	negligible
HEAT	Btu
stack loss	0.41×10^{12}
cooling water loss + miscellaneous station losses	1.53×10^{12}
ENERGY PRODUCT	kW-hrs.
electricity	2.93×10^{8}

(1) Costs applicable to new equipment items, not retrofit cases.
(2) Ceiling 1176 tons/10^{12} Btu; requires 90% reduction, requirement waived if SO_2 emission is less than 294 tons/10^{12} Btu.
(3) Values are annualized per trillion Btu.

SOURCES:
(a) EPA, Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generation Point Source Category, March 1974 and October 1974.
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(h) EPA, Compilation of Air Pollutant Emission Factors, 3rd Edition, Supplements 1 to 9, July 1979.

Note: Please refer to the qualification statements at the beginning of this section on Natural Gas.

Underground Natural Gas Storage

ENERGY SYSTEM:

SIZE
- 30 wells, 5000 underground acres
- 60 x 10^9 SCF annual deliverability
- 1020 Btus per SCF
- 61.2 x 10^{12} Btus annual deliverability
- 62 x 10^9 SCF annual recharge
- 96.77% efficiency[(a)]
- 365 operating days per year
- 30 year life

DESCRIPTION
- System consists of 30 wells drilled in a depleted gas field. The system is charged annually in the summer and gas is withdrawn in the winter. Working capacity (annual deliverability) is 60 x 10^9 SCF and 2 x 10^9 SCF is used as fuel or lost per year. Additional facilities include compressors, metering facilities, scrubbing and dehydration equipment, and 30 miles of 30 inch connecting pipeline.

COMPONENTS
- Depleted underground gas reservoir
- Wells
- Metering facilities
- Gas processing facilities
- 30 inch diameter pipeline

ENVIRONMENTAL CONCERNS
- NO_x emissions from the compressor stations
- Land disturbance during construction
- Aquifer contamination from defective gas well casings

RESOURCES USED:
(Per 10^{12} Btu Produced)

ENERGY	
Field use in compressors	.024 x 10^{12}(b) Btus
lost	.009 x 10^{12} Btus

LAND	Acres
Surface land occupied	0.327
Underground lease	81.700

WATER	
Water used for drinking, sanitary use and potential firefighting on site.	Negligible

MATERIALS	Tons
Concrete (includes cement)	31.314
Bentonite (in drilling mud)	5.719
Barite (in drilling mud)	3.260
Steel	442.569
Copper	1.303
Aluminum	0.477
Manganese	3.323
Chrome	0.041
Nickel	0.071
Cast iron	6.049

COST	Thousand Dollars (1978)
Construction-Total	1552.00
labor	597.00
materials	420.00
equipment	391.00
other construction costs	144.00
Operation and Maintenance-Total	15.25
labor	1.03
materials	0.83
equipment	3.48
other construction costs	9.90

PERSONNEL	Man Years		
Construction (3-Years)	Year 1	Year 2	Year 3
non-manual technical	0.515	0.686	0.515
non-manual non-technical	0.114	0.229	0.229
manual	1.307	5.536	5.229
Operation and Maintenance			
non-manual technical		0.01157	
non-manual non-technical		0.00845	
manual		0.02337	

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS[(b)]	Tons
Particulates	N/A
SO_x	0.1809
NO_x	136.98
HC	9.447
CO	3.915

WATER POLLUTANTS
Construction activities may temporarily increase stream sediment loadings. Potential exists for contamination of local aquifers through defective gas well casings.

SOLID WASTE
It is assumed that new wells will be drilled for gas injection and withdrawal. Negligible amounts of solid waste will be produced.

NOISE
Noise during operation would be restricted to compressor stations. Would probably be less than 60 dBA at property boundary.

ENERGY PRODUCT
980.392 x 10^6 SCF natural gas
(1 x 10^{12} Btus)

Note: Please refer to the qualification statements at the beginning of this section on Natural Gas.

(a) Assumes 62 x 10^9 SCF into facility per year and 60 x 10^9 SCF delivered from storage.

(b) Assumes 66,000 HP of compression in use continually. In actual fact, compressor requirements will vary depending on seasonal load and specific characteristics of the system.

SOURCES: Bechtel Corporation, 1978. Energy Supply Planning Model. San Francisco, California.
Federal Power Commission, 1977. Final Environmental Impact Statement for the TAPCO Project. Tenneco Pipeline Company, et al. Docket No. CP 77-100 et al. Washington, D.C.
Katz, D.L., D. Cornell, R. Kobayashi, F.H. Poettmann, J.A. Vary, J.R. Elenbaas, and C.F. Weinaug. Handbook of Natural Gas Engineering. McGraw-Hill, New York.
U.S. Environmental Protection Agency, 1977. Compilation of Air Pollutant Emission Factors. Office of Air and Waste Management, Research Triangle Park, North Carolina.

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Natural Gas Transmission Pipeline

ENERGY SYSTEM:

SIZE:
- 30 inch outside diameter pipeline
- 600 mile length
- 600 MM f per day capacity, 88% load factor[a]
- 0.53856×10^{12} Btus per day input
- 96.904% efficiency
- 100% availability
- 0.52189×10^{12} Btus per day output (88% load factor)
- 190.488×10^{12} Btus per year output (88% load factor)
- 20 year economic life

DESCRIPTION:[b]
- A 600 mile underground steel pipeline constructed of 30" 0.0 x 0.625" API 5LX60 pipe and operating at 1200 psig maximum allowable pressure. Natural gas is driven by six centrifugal compressors located at 100 mile intervals. The compressors are diven by gas turbines fueled by the natural gas in the pipeline. A metering station is located at each end of the pipeline.

COMPONENTS:
- Underground steel pipeline
- Compressor stations
- Metering stations

ENVIRONMENTAL CONCERNS
- NO_x emissions from the compressor stations
- Land disturbance during construction, particularly to streams and rivers

RESOURCES USED:
(Per 10^{12} Btus Produced)

FUEL

natural gas	1.0117×10^9 SCF Input
energy content	1020 Btus per SCF
fuel gas consumed	3.13×10^7 SCF ($.03193 \times 10^{12}$ Btus)

COMPOSITION (Percent)[d]	On-Shore Okla Texas	Off Shore Louisiana Gulf
methane	71.51	96.65
ethane	7.00	2.05
propane	4.40	0.47
butanes	0.99	0.17
pentanes	0.02	0.05
hexanes and higher	0	0.31
nitrogen	15.5	0
carbon dioxide	0	0.30
helium	0.58	0

MATERIAL

steel	1643.25 tons (82.16 tons)[c]

LAND

total land disturbed	43.35 acres (2.167 acres)[c]
permanent land affected	19.56 acres (0.978 acres)

WATER

temporary Use (hydrostatic testing)	0.5589×10^6 gallons (2.79×10^4 gallons)[c]
well capacity at compressor stations	0.331×10^6 gallons[g]

LABOR

construction	83.00 man-months (4.15 man-months)[c]
operation	0.21 man-years

COSTS

construction	$1.468 million ($73.4 thousand)[c]

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btus Produced)

AIR POLLUTANTS	Tons[e]
particulates	NA
NO_x	4.001
CO	1.518
HC	0.2759
SO_x	0.0055

WATER POLLUTANTS
Construction activities, particularly stream crossings, may temporarily increase stream sediment loadings. Normal operation should not affect water quality.

SOLID WASTE
None

NOISE[f]
Noise during construction of pipeline and compressor stations could resulting in sound levels of 90 dBA along edge of right of-way. Instantaneous sound levels of 121 dBA could occur during blasting. Noise during operation would be restricted to compressor stations and would be less than 60 dBA at boundary of property.

AESTHETICS
Aesthetic quality of landscape, particularly in forested areas, will be altered for the life time of the pipeline.

ENERGY PRODUCT
980.392×10^6 SCF natural gas (1×10^{12} Btus)

SOURCES:
(a) Federal Power Commission, 1973. National Gas Survey, Vol. III, Transmission. Washington, D.C.
(b) Characteristics of the natural gas transmission line are based on a Federal Power Commission import application filing by Tennessee Atlantic Pipeline, FPC Docket No. CP77-100 et al.
(c) For a one time commitment of resources, the first numbers represents resources used per annual 10^{12} Btus, the value in parenthesis indicates the resources used per 10^{12} Btu over the 20 year economic life of the project.
(d) Segeler, C.G. ed. 1964. Gas Engineers Handbook. Industrial Press, New York.
(e) Derived from: U.S. Environmental Protection Agency, 1977. Compilation of Air Pollutant Emission Factors. Office of Air and Waste Management, Research Triangle Park, North Carolina.
(f) Federal Power Commission, 1977. Final Environmental Impact Statement for the TAPCO Project. Tenneco Atlantic Pipeline Company, et al. Docket No. CP77-100 et al. Washington, D.C.
(g) Well capacity represents the annual total capacity of 20 gallons per minute of the wells, at six compressor stations per 10^{12} Btus produced. It is not anticipated that any of these wells would operate at capacity for any length of time.

Note: Please refer to the qualification statements at the beginning of this section on Natural Gas.

LNG Tanker

ENERGY SYSTEM:

SIZE
- 125,000 cubic meter capacity (2.6 BCF) tanker
- 95.3% availability (348 days)
- 95.0% efficiency (percent of cargo delivered)
- 12 roundtrips per year (26 days at sea, 3 days in port)
- 20 knots service speed, 12,000 nautical mile roundtrip
- 350 metric tons (827.4 cubic meters) "heel" on return voyage[(a)]
- 31.053 x 10^{12} Btus delivered per year (1020 Btus per cubic foot gas)
- 25 year service life[(c)]

DESCRIPTION
- A 63,460 deadweight ton tanker with five 25,000 cubic meter insulated cryogenic tanks to hold liquefied methane at -260°F. Ship length, 289; beam, 41; design draft, 11; maximum shaft horsepower, 40,000; 35 crew accomodations; service speed, 20 knots. Ship is double hulled with one propeller.

COMPONENTS
- LNG Tanker[(b)]

ENVIRONMENTAL CONCERNS
- Potential risk to crew and coastal populations in event of pool fire or vapor ignition following LNG spill. Risks range from negligible to equivalent to natural events such as hurricanes tornadoes, and lightning.

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL (1020 Btus per SCF natural gas)[(d)]	
Boil-off burned to power tanker	29.5 x 10^9 Btu
Fuel oil to power tanker	27.6 x 10^9 Btu
Boil-off vented	7.72 x 10^9 Btu

LAND[(b)]
None

WATER	Gallons
Seawater to cool shipboard LNG boil-off condensors	984.25 x 10^6

MATERIALS	Tons
steel	1092.513 (43.7)[(c)]
copper	8.602 (0.344)[(c)]
aluminum	3.575 (0.143)[(c)]
manganese	9.274 (0.371)[(c)]
chromium	34.004 (1.360)[(c)]
nickel	16.864 (0.675)[(c)]
cast iron	3.691 (0.148)[(c)]

COST	Thousand Dollars (1978)	
Construction total	6440	(257.6)[(c)]
labor	3220	(128.8)[(c)]
equipment and materials	3220	(128.8)[(c)]
Operation total	879	
labor	22.54	
maintenance, provisions	856.60	

PERSONNEL	Man Years
Construction (3 years)	77.287 (3.092)[(c)]
Operations	1.127

RESIDUALS AND PRODUCTS
(Per 10^{12} Btu Produced)

Air Pollutants	Tons
Particulates	2.438
SO_x	7.424
NO_x	5.842
HC	0.324
CO	0.405
Methane vented	164.52

WATER POLLUTANTS
Water stream from shipboard LNG boil-off condensers would be 5.9°F above ambient at sea and 7.4° above ambient in port.

SOLID WASTE
None anticipated

NOISE
NA

ENERGY PRODUCT - Liquid Natural Gas
1 x 10^{12} Btus
19.569 x 10^3 metric tons LNG
980.392 x 10^6 SCF natural gas

(a) The "heel" on a ballasted ship is a residual volume retained in the LNG tanks to keep them cold.

(b) Analysis is restricted to the ship component only. Shore-based support facilities must be considered separately.

(c) For a one-time commitment of resources, the first number represents resources used per annual 10^{12} Btus delivered by the tanker, the value in parenthesis indicates the resources used per 10^{12} Btus delivered over the entire 25 year service life of the tanker.

(d) Fuel use calculations assume the ship burns 2/3 boil-off gas and 1/3 oil while loaded, 1/3 boil-off gas and 2/3 oil while ballasted, and all boil-off while in port. Calculations also assume engines run at .75 load factor while steaming and .15 load factor in port, in both cases at 33 percent efficiency.

SOURCES: Federal Power Commission, 1977. TAPCO Project, Final Environmental Impact Statement, Docket No. CP 77-100 et al. Washington, D.C.
Bliss, C., P. Clifford, G. Goldgraben, E. Graf-Webster, K. Krickenberger, H. Mahar, and N. Zimmerman. 1976. Accidents and Unscheduled Events Associated with Non-Nuclear Energy Resources and Technology. The MITRE Corporation, M76-68, McLean, Virginia.
Agouris, T., 1975. A Case History: Economics of an LNG Project. Ocean Industry, March 1975.
U.S. Department of Energy, 1978. Western LNG Project, Final Environmental Impact Statement, Docket No. CP75-140, Federal Energy Regulatory Commission, Washington, D.C.
McCowan, John, 1979. Office of Shipbuilding Cost, U.S. Maritime Administration. Personal Communication.
Gallagher, J.M. et al., 1978. Resource Requirements, Impacts, and Potential Constraints Associated with Various Energy Futures. Bechtel Corporation, Inc., August 1978, San Francisco, California.

Note: Please refer to the qualification statements at the beginning of this section on Natural Gas.

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Synthetic Fuels

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Solvent Refined Coal II

ENERGY SYSTEM:

SIZE Fuel Input[a]
- 31,533 TPD ROM coal
- 8.09 x 10^11 Btu/day (HHV)

Product Output[a]
- 43,341 BPD SRC fuel oil
- 16,082 BPD fuel oil
- 4,654 BPD Naphtha
- 467 TPD sulfur
- 70 TPD ammonia
- 37 TPD phenols
- 5.18 x 10^11 Btu/day total product output
- 170 x 10^12 Btu annual total product output

Plant Characteristics
- 64% plant efficiency (HHV)
- 30 years plant life[a]
- 90% on stream factor[a]

DESCRIPTION:
- Pulverized, dried coal is slurried with a process derived oil. After the addition of hydrogen, the pressurized coal/oil/hydrogen mixture is preheated and then pumped into the reactor (2000 psi, 850°F) for the actual liquefaction reaction. The reactor effluent is let down separating the gaseous products from the slurry. The product gases are cleaned, recycled (hydrogen) or burned (fuel gas) for in-plant power/heat. Some liquid product is recycled, the rest is separated from the heavy bottom slurry by distillation. The heavy bottom is gasified for hydrogen production.

COMPONENTS:
- coal pulverizers/dryers
- hydrogen plant (Texaco partial oxidation unit)
- preheaters
- tubular plug flow reactor
- product recovery units (flash separators, atmospheric and vacuum distillation units)
- gas processing units (scrubbers, sulfur recovery, etc.)

ENVIRONMENTAL CONCERNS
- air emissions
- water pollution from runoff and leachates
- solid waste
- occupational hazards and health effects
- noise pollution
- odor

RESOURCES USED:
(Per 10^12 Btu Produced)

COAL	**Tons**
ROM bituminous coal	63,980

COAL (ROM) PROXIMATE ANALYSIS[a]	**% (by weight)**
	--
moisture	2.7
ash	7.13
volatiles	38.47
fixed carbon	51.70
sulfur content[a]	3.38
heating value (ROM)[a]	12,821 Btu/lb (HHV)

LAND[a]	**Acre**
plant facilities	2.1
solid waste disposal	NA

CONSUMPTIVE WATER USE	**Acre-Ft.**
potable water	1.46
boiler feed water make-up	19.51
process water	30.22
waste water	5.67
utility water	2.32
cooling water	126.14
Total	185.32
recovered water	37.31
Total make-up water (river)	148.01

COSTS	**Dollars - 1975**
construction[d]	9,050,000
operation	1,920,000

PERSONNEL	**Workers**
construction[d]	NA
operation and maintenance	5.7

RESIDUALS AND PRODUCTS:
(Per 10^12 Btu Produced)

AIR POLLUTANTS[a]	**Tons**
particulates	1.6
SO_2	22.0
NO_x	30.1
hydrocarbons	3.0
CO	1.6
arsenic	1.0×10^{-4}
cadmium	1.7×10^{-4}
mercury	2.9×10^{-3}
zinc	1.3×10^{-3}
chromium	2.7×10^{-3}
nickel	3.9×10^{-4}
lead	6.2×10^{-4}
polynuclear organic material	1.3×10^{-9}

WATER POLLUTANTS
no direct discharge to any watercourse

SOLID WASTE[a]	**Tons**
dry ton equivalent	6,348

ENERGY PRODUCT[1]	
syncrude (SRC II) (energy content = 6.7 x 10^6 Btu/bbl)	149,254

*The data presented are based on a conceptual design of a commercial facility. The data will be updated when more current data become available. The data should not be used directly for comparison with other coal liquefaction processes.

(1) Representative values selected for analysis purposes.

SOURCES: (a) Rittman Associates, Inc., Standard of Practice Manual for Solvent Refined Coal Liquefaction Process, 1978.
(b) Rittman Associates, Inc., Environmental Assessment of Coal Liquefaction, 1978.
(c) TRW, Characterizations and Data in the Area of Coal Base Environmental Data Book, Volume IV, 1978.
(d) Flash and Pryor, Boiler Fuel and Building Blocks, 1978.

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H-Coal (1)

ENERGY SYSTEM:

SIZE:

Fuel Input
- 27,836 TPD ROM coal
- 25,000 TPD dry coal
- .66 x 10^{12} (.637 x 10^{12}) Btu/day HHV(LHV)

Product/Output
- 36,432 BPD syncrude
- 24,686 BPD naphtha
- .368 x 10^{12} Btu/day liquid product yield (LHV)
- 1,192 TPD sulfur
- 234.6 TPD ammonia
- 23.7 TPD phenols
- 1.36 x 10^{10} Btu/day (1,960 MWh/day) electric power (sold)
- 127.4 x 10^{12} Btu total annual product output

Plant Characteristics
- 60.0% (61.4%) plant efficiency LHV(HHV)
- 20 years plant life
- 91.3% (8,000 hr/year) on stream factor
- 405 acres plant size
- 1,150 M$(1975) total capital costs

DESCRIPTION
- Dried, pulverized coal is slurried with recycled oil, mixed with hydrogen, preheated and pumped into an ebullating bed reactor with a colbalt-molybdenum catalyst. Gases, vapors and liquid (slurry) are separated by condensation (flash), distillation (atmospheric and vacuum) and hydrocyclone units. The concentrated bottom slurry can be used for hydrogen production.

COMPONENTS
- Coal preparation (4 Loesche mills for crushing, drying classifying)
- Hydrogen Plant (Texaco partial oxidation unit)
- Preheaters
- Ebullating Bed Reactors
- Product Recovery Units (separators, atmospheric and vacuum distillation units)
- Gas Processing Units (scrubbing, sulfur recovery, etc)

ENVIRONMENTAL CONCERNS
- air emissions
- solid waste
- water pollution from runoff and leaching
- occupational hazards and health effects
- noise
- odor

RESOURCES USED:
(Per 10^{12} Btu Produced based on LHV):

FUEL	
coal: bituminous ROM	72,831 tons
energy content	11,900 Btu/lb HHV
	11,443 Btu/lb LHV

COAL ANALYSIS ROM (Illinois No. 6)	**% (by weight)**
moisture	10.0
carbon	63.48
hydrogen	4.81
nitrogen	.86
sulfur	4.45
oxygen	7.28
ash	9.12

LAND(3)	**Acres**
plant facility	3.1
solid waste disposal (returned to mine)	0

CONSUMPTIVE WATER USE	**Acre-Ft.**
potable water	1.46
boiler feed water make up	19.51
process water	30.22
waste water	5.67
utility water	2.32
cooling water	126.14
Total	185.32
recovered water	37.31
Total make up water (river)	148.01

COSTS	**Dollars - 1975**
construction(4)	9,020,000
operation	1,920,000

PERSONNEL	**Workers**
construction(4)	NA
operation and maintenance	5.7

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	**Tons**
particulates(5)	4.6
SO_2 (max.)	72
NO_x (2,5)	40.9
hydrocarbons(5)	0.6
CO	NA

WATER POLLUTANTS	**Tons**
no direct discharge into any water source	0

SOLID WASTE	
dry ton equivalent	7,354

PRODUCTS	
syncrude	95,356 barrels
naphtha	64,578 barrels
ammonia	614 tons
sulfur	3,119 tons
phenols	62 tons
electric power	5,120 MWh

(1) The data presented are based on a conceptual design of a commercial facility. The data will be updated when more current data become available. The data should not be used directly for comparison with other coal liquefaction processes.
(2) Including power generation.
(3) This represents land committed to use over the lifetime of the plant, divided by the annual output of the plant, expressed in trillion Btu.
(4) This represents total cost or manpower, divided by the annual output of the plant, expressed in trillion Btu.
(5) These data not available from Fluor, for comparison data from TRW, Characterizations and Data in the Area of Coal Mass Environmental Data Book, Volume IV, 1976 are added.

SOURCE: Fluor Engineers and Constructors, Inc. , 1976. H-Coal, Commercial Evaluation. FE-2002-12.

Lurgi Process - Lignite Coal

ENERGY SYSTEM:

SIZE
- 275 x 10^6 SCFD output (stream day)
- plant fuel efficiency = 67.3%
- 91% plant availability
- North Dakota lignite, 7,230 Btu/lb
- 27,272 tons coal feed to gasifier
- 997 Btu/scf energy content of SNG
- 0.274 x 10^{12} Btu/day output
- 91.03 x 10^{12} Btu/year output
- 135 MWe auxiliary power required
- 30 year plant life

DESCRIPTION
- The Lurgi gasifier is used to produce substitute natural gas from lignite coal. The Lurgi process converts coal particles into a gas in a fixed-bed gasifier. The raw gas is processed and purified to yield an output product gas that is equivalent to natural gas in heating value. The Lurgi plant is capable of using any coal as its input raw material. (Fines are not currently gasified).

COMPONENTS
- coal crusher
- Lurgi gasifier
- shift converter
- Stretford gas clean-up
- tubewall methanator
- oxygen plant
- limestone scrubber
- mineral pulverizer
- stack
- waste water treatment
- landfill

ENVIRONMENTAL CONCERNS
- solid waste disposal
- criteria pollutants from boiler
- large water demand

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	
North Dakota lignite	99,333 tons
energy content	7,320 Btu/lb

COAL ANALYSIS (ROM)	% (by weight)
water	35.98
volatile material	27.21
fixed carbon	29.39
ash	7.42
sulfur	1.26

LAND	Acres
plant site (gasification)	5.9*
disposal (mine mouth)	0

WATER	Acre-Ft.
consumptive (gasification only)	19.3**

POWER	
utility	500 MWe

COSTS	Dollars
construction	
coal crusher	NA
Lurgi gasifier	NA
oxygen plant	NA
limestone scrubber	NA
other equipment	NA
operation & maintenance	NA

PERSONNEL**	Workers
construction (9 years)	8.7
operation (30 years)	7.0

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS		Tons
particulates	gasifier and auxiliaries	30.2
SO_2		264.3
NO_x		641.9
hydrocarbons		NA
CO		NA

WASTE WATER	Barrels
surface disposal	0
deep well disposal	8,800

SOLID WASTE	Tons
ash (gasifier)	6,435

BY-PRODUCTS (1)	Barrels
tar	16,712
tar oil	6,150
naphtha	3,460
phenol	5,106
sulfur	3,835

ENERGY PRODUCT	Cubic Feet
high Btu gas (997 Btu/cubic foot)	1.00 x 10^9 scf

*535 acres required for the 91.03 x 10^{12} Btu/year plant. 5.9 acres are required for a 10^{12} Btu plant (535 ÷ 91.03 = 5.9).
**12.904 MGD are required for the 91.03 x 10^{12} Btu/year plant, 192.3 acre-feet per 10^{12} Btu.

(1) Consumed by plant to generate steam.

SOURCE: U.S. Department of the Interior, Final Environmental Impact Statement for the ANG Coal Gasification Company (ANGCGC) North Dakota Project, 1978.

Lurgi Process - Western Subbituminous Coal

ENERGY SYSTEM:

SIZE:
- 288 x 10^6 SCFD output
- 0.275 x 10^{12} Btu/day output
- 934 Btu/cf heat content
- 4,992 T/day coal feed rate to auxiliaries
- 34,396 T/day coal feed rate to gasifiers
- 8,320 Btu/lb western subbituminous coal
- plant synthetic gas efficiency = 56.5%
- 90% plant availability
- 90.25 x 10^{12} Btu/year
- 30 year plant life

DESCRIPTION
- The Lurgi gasifier is used to produce substitute natural gas from bituminous coal. The Lurgi process converts coal particles into a gas in a fixed-bed gasifier. The raw gas is processed and purified to yield an output product gas that is equivalent to natural gas in heating value. The Lurgi plant is capable of using any coal as its input raw material. (Fines are not currently gasified).

COMPONENTS
- coal crusher
- Lurgi coal gasifiers
- shift converter
- Stretford gas clean-up
- tube-wall methanator
- oxygen plant
- on-site utilities plant
- limestone scrubber
- mineral pulverizer
- landfill
- waste water treatment
- stack

ENVIRONMENTAL CONCERNS
- solid waste disposal
- criteria pollutants from boiler
- large water demand

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	
Western Subbituminous coal	
gasifier feed	88,204 tons
auxiliaries feed	18,153 tons
energy content	8,320 Btu/lb

COAL ANALYSIS	% (by weight)
fixed carbon	33.20
volatile material	28.08
sulfur	0.74
H_2O	16.96
ash	20.77

LAND	Acres
plant site (permanent	10.64*
disposal (mine mouth)	0

WATER	Acre-Ft.
consumptive	105.6**

COSTS	Dollars (1976)
construction	
coal crusher	NA
Lurgi gasifiers	NA
oxygen plant	NA
limestone scrubber	NA
other equipment	NA
operation & maintenance	NA

PERSONNEL	Workers/Year
construction (3 years)	20.1
operation (30 years)	10.9

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons
particulates	NA
SO_2	26.2
NO_x	26.8
hydrocarbons	NA
CO	NA
CO_2	64,916

WASTE WATER	Barrels
surface disposal	0
mine burial	6,349

SOLID WASTE	Tons
ash	20,090

ENERGY PRODUCT	Cubic Feet
high Btu gas (934 Btu/cf)	1.047 x 10^9

BY-PRODUCTS	Tons
tar	3,876
tar oil	2,120
ammonia	4,669
phenol	495
sulfur	681
naphtha	873

*960 acres are required for the 90.25 x 10^{12} Btu/year plant. 10.64 acres are required for a 10^{12} Btu plant (960 ÷ 90.25 = 10.64).
**9,482 acre-feet/year are required for the 90.25 x 10^{12} Btu/year plant. 105.6 acre-feet/year are required for a 10^{12} plant (9,482 ÷ 90.25 = 105.6).

SOURCE: U.S. Department of the Interior, Final Environmental Statement for the El Paso Coal Gasification Project, San Juan County, New Mexico, 1977.

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In-Situ Coal Gasification

ENERGY SYSTEM:

SIZE
- 250×10^6 scf of SNG equivalent per day
- 126 Btu/scf heat content(1)
- $.250 \times 10^{12}$ Btu/day fuel gas output
- operates 328.5 days per year
- 90% plant availability
- overall energy efficiency 51%
- plant life 30 years

DESCRIPTION
- In-situ processing steps consist of pregasification, followed by gasification and production. Pregasification prepares the coal bed by linking definable points in the coal seam such as the inlet and outlet bore holes. The implaced fracture providing the link between inlet and outlet of the bore increases the permeability of the coal bed. This fracture may be accomplished by hydraulic fracturing or explosives. Gasification introduces air into the coal seam which upon contact with the coal produces, hydrogen, carbon monoxide, carbon dioxide, water vapor and methane. The product gases are brought to the surface, cleaned and distributed.

COMPONENTS
- drilling equipment
- compressor
- explosives
- gas cleaning and heat recovery equipment

ENVIRONMENTAL CONCERNS
- fugitive air emissions
- water pollution
- subsidence
- noise pollution

RESOURCES USED:
(Per 10^{12} Btu of Fuel Gas Produced)

FUEL	
coal (dry)	99,200 tons

ENERGY	Btus
diesel fuel for air compression and mobile equipment	0.33×10^{12}
utilities	0.015×10^{12}

COAL
subbituminous coal (Hanna field)
-HHV (dry) 10,285 Btu/lb

Proximate Analysis	% (by weight)
fixed carbon	43
volatile matter	40
moisture	7
ash	10
sulfur	1

LAND (5)	Acres
plant facilities	0.24
subsidence (area affected)	1.54

WATER(2)	Acre-Ft.
total requirements	108

COSTS	Dollars
construction	NA
operation & maintenance	NA

PERSONNEL	Workers
construction	NA
operation & maintenance	NA

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu of Fuel Gas Produced)

AIR POLLUTANTS(3)	Tons
particulates	14
SO_2	NA
NO_2	NA
hydrocarbons	160
CO	75

WATER POLLUTANTS
There is zero process discharge. Possibility of underground pollution due to leachates

BY-PRODUCT	
sulfur	993 tons(4)
liquid hydrocarbons (tars)	0.05×10^{12} Btus
sensible heat	0.15×10^{12} Btus

ENERGY PRODUCT	
Low Btu gas	7.94×10^9 scf
HHV	126 Btu/scf(1)

Composition	% (by weight)
H_2	16.0
CO	6.3
N_2	53.2
CO_2	19.2
CH_4	3.9
Other	1.4

(1) Subsequent tests have reported product gas heating values of 175 Btu/scf.
(2) This value represents total water requirements and does not consider water already present in coal seam.
(3) Estimated fugitive emissions from vehicular traffic and high pressure equipment.
(4) Assuming 98.2% sulfur recovery.
(5) Represents total land affected, divided by the annual energy output measured in trillion Btus. For example, 20 acres ÷ 81.125 = 0.24 acres/10^{12} Btu.

SOURCE: The Environmental Protection Agency, In-Situ Gasification: Status of Technology Environmental Impact, EPA-600/7-77045, 1977.

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Surface Oil Shale Mining

ENERGY SYSTEM:

SIZE
- 73,700 tons of raw shale per day
- 0.413 x 10^{12} Btu/day
- 2,800 Btu/pound of raw shale
- 30 gallons/ton shale oil content
- mine operates 328.5 days/year
- 24.2 x 10^{6} tons of shale mined/year
- total annual output is 136.67 x 10^{12} Btu
- mine life is 30 years

DESCRIPTION
- In surface mining, the overburden is removed exposing the underlying shale. Shale is mined using the bench technique. Shale is fractured through drilling and blasting and transported by trucks to primary crushing site.

COMPONENTS
- drilling equipment
- excavation equipment (cranes)
- crushers
- trucks

ENVIRONMENTAL CONCERNS
- air quality deterioration
- noise
- water requirement
- contamination of underground water supplies with saline mine water

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons
raw unmined shale	178,450

ENERGY	
electricity for operating drilling equipment and trucks	NA

COMPOSITION	% (by weight)
organic material	17.1
water	1.4
inorganic material	81.5

LAND(1)	Acres
mine development	0.8
disposal of permanent overburden	7.4
storage of spent shale	1.1
disposal of spent shale	1.1

WATER	Acres-Feet
mining and crushing	2.6 (2.2 - 3.3)

COSTS	Dollars (1978)
construction(2)	
manpower	226,033
materials	28,809
equipment	339,649
other cost	14,797
total	609,288
operation & maintenance	NA

PERSONNEL	Workers
construction	NA
operation & maintenance	NA

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons
particulates	21.79
SO_2	0.21
NO_x	2.95
hydrocarbons	1.44
CO	1.80

WATER POLLUTANTS
probability of saline contamination of underground water by mine water

SOLID WASTE
negligible (see Processing)

ENERGY PRODUCT	Tons
mined shale rock	178,450

(1) This represents land committed to use over the lifetime of the plant, divided by the annual output of the plant, expressed in trillion Btu.
(2) This represents total cost of constructing the plant, divided by the annual output of the plant, expressed in trillion Btu.

SOURCES: Environmental Protection Agency, Monitoring Environmental Impacts of the Coal and Oil Shale Industries, 600/7-77-015, February 1977.
Cameron Engineers Incorporated, Synthetic Fuels Handbook, 1975.
Department of Energy, Draft Environmental Impact Statement for the (updated) Prototype Oil Shale Leasing Program, 1979.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
Bechtel Corporation, Energy Supply Planning Model, 1978.

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ENERGY SYSTEM:

SIZE
- 73,700 tons of raw shale per day
- 0.443×10^{12} Btu/day
- 2,800 Btu/pound of raw shale
- 30 gallons/ton shale oil content
- mine operates 328.5 days/year
- 24.2×10^{6} tons of shale mined/year
- total annual output is 135.67×10^{12} Btu
- mine life is 30 years

DESCRIPTION
- Underground mining uses room and pillar technique. The oil shale deposit is entered through a tunnel dug into the side of a valley where an outcrop appears. Pillars are left in place to provide roof support at appropriate intervals. Extraction is also accomplished by drilling and blasting. The broken shale is transported to portable crusher for primary crushing.

COMPONENTS
- drilling equipment
- excavation equipment (cranes)
- crushers
- trucks

ENVIRONMENTAL CONCERNS
- air quality deterioration
- noise
- water requirement
- contamination of underground water supplies with saline mine water

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Tons
raw unmined shale	178,430

ENERGY	
electricity for operating drilling equipment and trucks	NA

COMPOSITION	% (by weight)
organic material	17.1
water	1.4
inorganic material	81.5

LAND(1)	Acres
mine development	3.15
crushing	2.93

WATER	Acre-Feet
mining and crushing	2.8 (2.3 - 3.3)

COSTS	Dollars (1978)
construction(2)	
manpower	164,224
materials	43,249
equipment	254,842
other cost	82,341
total	544,655
operation & maintenance	NA

PERSONNEL	Workers
construction	484
operation & maintenance	NA

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons
particulates	1.46
SO_2	0.012
NO_x	0.17
hydrocarbons	0.019
CO	0.10

WATER POLLUTANTS
probability of saline contamination of underground water with mine water

SOLID WASTE
negligible (see Processing)

ENERGY PRODUCT	Tons
mined shale rock	178,430

(1) This represents land committed to use over the lifetime of the plant, divided by the annual output of the plant, expressed in trillion Btu.
(2) This represents total cost of constructing the plant, divided by the annual output of the plant, expressed in trillion Btu.

SOURCES: Environmental Protection Agency, Monitoring Environmental Impacts of the Coal and Oil Shale Industries, 600/7-77-015, February, 1977.
Cameron Engineers Incorporated, Synthetic Fuels Handbook, 1975.
Department of Energy, Draft Environmental Impact Statement for the (updated) Prototype Oil Shale Leasing Program, 1979.
University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
Bechtel Corporation, Energy Supply Planning Model, 1978

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TOSCO II Shale Retorting

ENERGY SYSTEM:

SIZE
- 50,000 bbls/day of crude shale oil
- 16.43 x 10^6 barrels of oil/year
- .29 x 10^{12} Btu/day
- 5.6 x 10^6 Btu/barrel
- operates 328.5 days/year
- total annual output 95.27 x 10^{12} Btu
- plant life 30 years
- plant efficiency (thermal) 67%

DESCRIPTION
- Heated ceramic balls are fed into a horizontal rotating cylindrical retort and mixed with crushed shale (1/2 inch diameter). Pyrolysis occurs at 900°F. Shale oil steam and gases are emitted from one end of the retort and are collected and fed into a fractionater for product recovery. The ceramic balls are recycled to a vertical ball heater where reheating for further use occurs.

COMPONENTS
- horizontal cylindrical retort
- fractionator and coker
- naphtha hydrofiner
- gas oil hydrofiner
- hydrogen plant
- by-product recovery

ENVIRONMENTAL CONCERNS
- air quality deterioration
- health effects due to hydrocarbons
- modifications to biological environment
- deterioration of water quality due to leachates and runoff
- solid waste disposal
- socio-economic problems due to high influx of personnel in previously sparsely populated areas

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL[b]	
raw shale	230,000 tons
oil content	35 gallons/tons

COMPOSITION[a]	% (by weight)
oil	11.8
water	1.4
spent shale	84.9
gas	2.0

LAND[1]	Acres
retorting, upgrading and offsite facilities	3.36
expansion, water containment and greenbelt	3.42

WATER[b]	Acre-Feet
cooling towers	15.8
waste heat boilers	14.5
water treatment plant	0.4
processed shale	21.3
dust control on shale ash	3.9
moisture evaporator	7.8
dust scrubbers	10.4
revegetation	1.1
fire and drinking	2.4
total	77.7

COSTS[2]	Dollars (1975)
construction	
manpower	1,640,000
materials	671,000
equipment	1,655,000
other cost	337,000
total	4,303,000
operation & maintenance	NA

PERSONNEL	Workers
construction	2.1
operation & maintenance	11.5

RESIDUALS AND PRODUCTS:
(Per 10^{12} Produced)

AIR POLLUTANTS[b]	Tons
particulates	19.6
SO_2	11.6
NO_x	63.3
hydrocarbons	11.2
CO	2.7

WATER POLLUTANTS
assume zero direct discharge to any water-course

SOLID WASTE[b]	Tons
spent shale	190,000

ENERGY PRODUCT[b]	Barrels
refined shale oil	172,400 barrels
heat content	5.6 x 10^6 Btu/barrel

(1) Land use value represents land committed to use for the facility, divided by annual production, measured in trillion Btu.
(2) Costs are total costs for plant construction, divided by annual output, measured in trillion Btu.

SOURCES:
(a) Environmental Protection Agency, Monitoring Environmental Impacts of the Coal and Oil Shale Industries, 600/7-77-015, February 1977.
(b) University of Denver, Denver Research Institute. An Engineering Analysis Report on the TOSCO II Shale Process, March 1977.
(c) University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
(d) Bechtel Corporation, Energy Supply Planning Model, 1978.
(e) Cameron Engineers Incorporated, Synthetic Fuels Handbook, 1975.

Modified In-Situ Shale Retorting

ENERGY SYSTEM:

SIZE
- 34,200 tons of raw shale mined/day[e]
- 102,600 tons of raw shale retorted in-situ/day[e]
- shale oil content 25 gallons/ton[d]
- 50,000 bbl/day
- .29 x 10^{12} Btu/day
- 95.3 x 10^{12} Btu/year
- operates 328.5 days/year
- plant life 30 years
- thermal efficiency 61% overall[d]

DESCRIPTION
- In modified in-situ approximately 15-20% of the deposit is mined using conventional mining techniques in the ground and fractured using either chemical, hydraulic, or electric means. Prior to fracturing of the deposit, parallel wells (productions and injection) are drilled on two opposing sides of the deposit. A retorting fluid (hot steam or gas) is injected within the formation. After ignition, retorting takes place and the oil mist, gas and steam produced are forced to the surface through the production wells. Liquid gathered at the base of the combustion zone is later pumped out. The products are refined using techniques similar to surface refining.

COMPONENTS
- underground retort created from blasting procedure
- fractionator and coker
- naphtha hydrofiner
- gas oil hydrofiner
- hydrogen plant
- by-product

ENVIRONMENTAL CONCERNS
- air quality deterioration
- health effects due to hydrocarbons
- modifications to biological environment
- deterioration of water quality due to leachates and runoff
- solid waste disposal
- socio-economic problems due to high influx of personnel in previously sparsely populated areas

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL[c,d]	
mined shale	117,900 tons
unmined shale	353,800 tons
oil content	25 gallons/ton

COMPOSITION[a]	% (by weight)
organic material	NA
water	NA
inorganic material	NA
spent shale	NA

LAND[c]	Acres
permanent disposal	207-310/Year
surface facilities	363
active well area	863/Year

WATER[c]	Acre-Ft.
retorting and upgrading	(22.2)*
power generation	26.4
revegetation	0.9
steam injection	28.9
miscellaneous	4.4
total	36.4

COSTS[b]	Dollars (1978)
construction	13,400,000
operation & maintenance	NA

PERSONNEL[b]	Workers
construction	38.6
operation & maintenance	NA

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS[d,e]	Tons
particulates	39.6
SO_2	6.21
NO_x	33.7
hydrocarbons	0.51
CO	10.0

WATER POLLUTANTS
There is assumed a zero direct discharge of effluent into any water course.

SOLID WASTE[d]	Tons
spent shale	99,000

ENERGY PRODUCT	Barrels
refined shale oil	172,400

*Approximately one barrel of water/barrel of oil is produced during retorting by the release of interstitial water and the combustion of hydrocarbons.

SOURCES:
(a) Cameron Engineers, Incorporated, Synthetic Fuels Handbook, 1975.
(b) MERES Data Group, Environmental Characterizations for Energy Technologies and End Uses, Revision 1, 1978.
(c) Department of Energy, Draft Environmental Impact Statement for the (updated) Prototype Oil Shale Leasing Program, 1979.
(d) Environmental Protection Agency, A Preliminary Assessment of the Environmental Impacts from Oil Shale Development, 600/7-77-060, July 1977.
(e) Ashland Oil, Inc., Tenneco & Occidental Oil Shale, Inc., Modifications to Detailed Development Plan, Oil Shale Tract C-b, February, 1977.

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REPORT SYSTEM:

SIZE
- 132,100 tons of raw shale/day (inground)
- 30 gallons/ton shale oil content
- .29 x 10^{12} Btu/day
- 50,000 Bbl/day
- 16.41 x 10^6 barrels of oil/year
- operates 328.5 days/year
- total annual output 95.12 x 10^{12} Btu
- thermal efficiency 53%

DESCRIPTION
- In-situ processing retorts the shale in the ground. This method fractures the shale using either chemical, hydraulic, or electrical means. Prior to fracturing of the deposit, parallel wells (production and injection) are drilled on two opposing sides of the deposit. A retorting fluid (hot steam or gas) is injected within the formation. After ignition, retorting takes place and the oil mist, gas, and steam produced are forced to the surface through the production wells. Liquid gathered at the base of the combustion zone is later pumped out. The products are refined using techniques similar to surface refining.

COMPONENTS
- underground retort created from blasting procedure
- fractionator and coker
- naphtha hydrofiner
- gas oil hydrofiner
- hydrogen plant
- by-product recovery

ENVIRONMENTAL CONCERNS
- air quality deterioration
- health effects due to hydrocarbons
- modifications to biological environment
- deterioration of water quality due to leachates and runoff
- solid waste disposal
- socioeconomic problems due to high influx of personnel in previously sparsely populated areas

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	
unmined shale	455,500 tons
oil content	30 gallons/ton
COMPOSITION[b]	% (by weight)
organic material	NA
water	NA
inorganic material	NA
spent shale	NA
LAND[f]	Acres
surface facilities, permanent	345
active well area, temporary	862
WATER[f]	Acre-Ft.
retorting & upgrading	(22.2)*
onsite power generation	24.4
steam injection	28.9
miscellaneous	4.4
total	35.5
COSTS[e]	Dollars (1978)
construction	
manpower	1,895,000
materials	602,000
equipment	2,300,000
other cost	583,000
total	5,390,000
operation & maintenance	NA
PERSONNEL	Workers
construction	NA
operation & maintenance	NA

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS[a]	Tons
particulates	31.3
SO_2	102.7
NO_x	21.4
hydrocarbons	4.4
CO	25.0
WATER POLLUTANTS[a]	
No direct discharge to any water body	
SOLID WASTE[a]	Tons
spent shale	negligible
ENERGY PRODUCT	Barrels
refined shale oil	172,400

*Approximately one barrel of water/barrel of oil is produced during retorting by the release of interstitial water and the combustion of hydrocarbons.

SOURCES (a) Environmental Protection Agency, Monitoring Environmental Impacts of the Coal and Oil Shale Industries, 600/7-77-015, February, 1977.
(b) Cameron Engineers, Incorporated, Synthetic Fuels Handbook, 1975.
(c) Environmental Protection Agency, A Preliminary Assessment of the Environmental Impacts from Oil Shale Development, 600/7-77-069, July 1977.
(d) University of Oklahoma, Energy Alternatives: A Comparative Analysis, 1975.
(e) Bechtel Corporation, Energy Supply Planning Model, 1978.
(f) Department of Energy, Draft Environmental Impact Statement for the (updated) Prototype Oil Shale Leasing Program, 1979.

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Solar Energy

Solar Heating and Cooling of Building Systems

UNIT ENERGY SYSTEM:

SIZE
- provides 75% of the load for a 2000 ft^2 single family house
- 30 ft^2 collector area (flat plate)
- 80 gallon storage tank
- 7.0×10^6 Btu/yr in Denver

DESCRIPTION
- Solar energy is absorbed onto the collector panels and transferred to storage via a water/glycol working fluid which is pumped through the collector panel and a heat exchanger in a storage tank. Cold water enters the storage tank and is heated by contact with the heat exchanger. Warm water enters a second tank where an auxiliary heat source maintains the water at some desired temperature. Lifetime of the system is assumed to be 20 years.

COMPONENTS
- flat plate solar collectors
- copper piping
- copper heat exchanger
- pump
- hot water tanks (2)
- urethane insulation (2 inches)
- conventional water heater element (electric, natural gas-fired)

ENVIRONMENTAL CONCERNS
- possible accidental spillage or leakage of working fluid
- hazard potential of toxic working fluid
- collector overheating or fire
- fluid disposal

RESOURCES USED:
(Number of Unit Systems to Yield 10^{12} Btu/yr; N = 142,857)

FUEL
(Per 10^{12} Btu Produced)
solar insolation
ancillary power requirement - 7.2×10^6 kWh
conventional fuel required to cover 25% of the load

MATERIALS
(10^3 tons per N units)

steel	26.6
glass	5.8
urethane	3.9
copper	2.1
coolant	5.8

LAND
negligible

WATER
82 acre-ft per 10^{12} Btu produced

COSTS
$1,234 (1977$) per unit
$176.3 × 10^6 (1977$) per N units

PERSONNEL
Data not available

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
none

WATER POLLUTANTS
COD* 632 tons

SOLID WASTE
none

WASTEHEAT
none

ENERGY PRODUCT
10^{12} Btu thermal

*Chemical Oxygen Demand assuming ultimate disposal of all working fluid in water.

SOURCE: Los Alamos Scientific Laboratory, 1979. The Characterization and Assessment of Selected Solar Thermal Energy Systems for Residential and Process Heat Applications. LA-7993-TASE. Los Alamos, New Mexico. Technology Assessment of Solar Energy (TASE) Project, Solar Technology Assessment Program, Technology Assessments Division, OTI, EV, DOE.

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Residential/Commercial Heating—Active System

UNIT ENERGY SYSTEM:

SIZE
- provides 75% of the load
- 500 ft^2 collector (flat plate)
- 900 gallons storage
- 47.5×10^6 Btu/yr produced in Denver**

DESCRIPTION
- An array of flat plate collectors absorbs solar thermal energy and transfers it to storage via solution of water and glycol alcohol. The heated water in the tank is pumped through a heat exchanger in the house to provide space heating. Lifetime of the system is assumed to be 20 years.

COMPONENTS
- solar collector panels (double-glazed)
- storage tank
- copper heat exchangers (2)
- pumps (2)
- valves (2)
- vents
- system controls
- urethane insulation

ENVIRONMENTAL CONCERNS
- possible accidental spillage and leakage of working fluid
- hazard potential of toxic working fluid
- collector overheating or fire
- fluid disposal

RESOURCES USED:
(Number of Unit Systems to Yield 10^{12} Btu/yr; N = 21,053)

FUEL
(Per 10^{12} Btu Produced)
solar insolation
ancillary power requirement - 10.61×10^6 kWh
conventional fuel required to cover 25% of the load

MATERIALS
(10^3 tons per N units)

steel	40.5
glass	8.4
urethane	3.9
copper	1.7
coolant	0.4

LAND
negligible

WATER
226 acre-ft per 10^{12} Btu produced

COSTS
$11,823 (1977$) per unit
$248.9 x 10^6 (1977$) per N units

PERSONNEL
Data not available

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
none

WATER POLLUTANTS
COD* 774 tons

SOLID WASTE
none

WASTEHEAT
none

ENERGY PRODUCT
10^{12} Btu thermal

*Chemical Oxygen Demand assuming ultimate disposal of all working fluid in water.

** Based on an assumed 6 month heating season

SOURCE: Los Alamos Scientific Laboratory, 1979. The Characterization and Assessment of Selected Solar Thermal Energy Systems for Residential and Process Heat Applications, LA-7993-TASE, Los Alamos, New Mexico. Technology Assessment of Solar Energy (TASE) Project, Solar Technology Assessment Program, Technology Assessments Division, OTI, EV, DOE.

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Residential Heating and Cooling—Active System

UNIT ENERGY SYSTEM:

<u>SIZE</u>
- provides 75% of the heating and cooling load
- 500 ft^2 collector area (flat plate)
- 900 gallons storage
- 71 x 10^6 Btu/yr in Denver **

<u>DESCRIPTION</u>
- An array of flat plate collectors absorbs solar thermal energy and transfers it to storage via a solution of water and glycol alcohol. The heated water in the tank is pumped through a heat exchanger in the house to provide space heating, or is pumped through an absorption-type refrigerator. Lifetime of the system is assumed to be 20 years.

<u>COMPONENTS</u>
- solar collector panels (double-glazed)
- storage tank
- copper heat exchangers (2)
- one-inch diameter copper piping (100 feet)
- pumps (2)
- valves (2)
- absorption-type refrigerator
- vents
- system controls
- urethane

<u>ENVIRONMENTAL CONCERNS</u>
- possible accidental spillage or leakage of working fluid
- hazard potential of toxic working fluid
- collector overheating or fire
- fluid disposal

RESOURCES USED:
(Number of Unit Systems to Yield 10^{12} Btu/yr; N = 14,085)

<u>FUEL</u>
(Per 10^{12} Btu Produced)
solar insolation
ancillary power requirement - 7.1 x 10^6 KWh
conventional fuel to cover 25% of the load

<u>MATERIALS</u>

(10^3 tons per N units)	
steel	30.6
glass	5.7
urethane	2.6
copper	1.8
coolant (ethyl glycol)	5.6

<u>LAND</u>
negligible (roof mounted)

<u>WATER</u>
173 acre-ft. per 10^{12} Btu produced

<u>COSTS</u>
$23,458 (1977$) per unit
$330.4 x 10^6 (1977$) per N units

<u>PERSONNEL</u>
Data not available

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

<u>AIR POLLUTANTS</u>
none

<u>WATER POLLUTANTS</u>
COD* 1130 tons

<u>SOLID WASTE</u>
none

<u>WASTEHEAT</u>
none

<u>ENERGY PRODUCT</u>
10^{12} Btu thermal
(heating and cooling)

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*Chemical Oxygen Demand assuming ultimate disposal of all working fluid in water.

** Based on an assumed 8 month operating season

SOURCE: Los Alamos Scientific Laboratory, 1979. <u>The Characterizations and Assessment of Selected Solar Thermal Energy Systems for Residential and Process Heat Applications</u>. LA-7995-TASE. Los Alamos, New Mexico. Technology Assessment of Solar Energy (TASE) Project, Solar Technology Assessment Program, Technology Assessments Division, OTI, EV, DOE.

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UNIT ENERGY SYSTEM:

SIZE
- provides 75% of the heating load
- 500 ft^2 concrete wall
- 47.5×10^6 Btu/yr in Denver*

DESCRIPTION
- During sunlight hours, solar radiation penetrates the covering glass and is absorbed by the concrete wall. The concrete radiates heat, which circulates by natural convection to heat interior living space. At night, an insulating drape is deployed between the two panes of covering glass to reduce heat loss. Lifetime of the system is assumed to be 20 years.

COMPONENTS
- high density concrete wall (18 inches thick)
- glazing (two 1/8 inch thick sheets)
- insulating drape

ENVIRONMENTAL CONCERNS
- none

RESOURCES USED:
(Number of Unit Systems to Yield 10^{12} Btu/yr; N = 21,053)

FUEL
(Per 10^{12} Btu Produced)
solar insolation
no ancillary energy required

MATERIALS
(10^3 tons per N units)

glass	8.4
concrete	1170
insulation	1.0

LAND
negligible

WATER
negligible

COSTS
\$6,600 (1977\$) per unit
$\$138.9 \times 10^6$ (1977\$) per N units

PERSONNEL
Data not available.

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
none

WATER POLLUTANTS
none

SOLID WASTE
none

WASTEHEAT
none

ENERGY PRODUCT
10^{12} Btu thermal

* Based on an assumed 6 month heating season

SOURCE: Los Alamos Scientific Laboratory, 1979. The Characterization and Assessment of Selected Solar Thermal Energy Systems for Residential and Process Heat Applications. LA-7993-TASE. Los Alamos, New Mexico. Technology Assessment of Solar Energy (TASE) Project, Solar Technology Assessment Program, Technology Assessments Division, OTI, EV, DOE.

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Solar Agricultural and Industrial Process Heat Systems

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Low Temperature Solar AIPH

UNIT ENERGY SYSTEM:

SIZE
- provides 30-100°C low temperature industrial process heat
- 900 gallon storage tank
- 500 ft^2 collector area (flat plate)
- 65 x 10^6 Btu/yr in Indianapolis

DESCRIPTION
- Solar energy is absorbed onto nonreflective surfaces of collector panels. Thermal energy is transferred from collectors to storage, using a closed water/glycol loop and a copper heat exchanger immersed in the storage tank. Fluid in the storage tank is then pumped through a second heat exchanger to produce low temperature process heat. Lifetime of the system is assumed to be 20 years.

COMPONENTS
- flat plate solar collector
- 900 gallon storage tank
- 2 copper heat exchangers
- 100 ft. of 1 in. diameter copper piping
- 2 pumps
- 2 valves
- expansion tanks
- vents
- system controls

ENVIRONMENTAL CONCERNS
- leakage or spillage of system fluid
- product contamination
- fluid disposal

RESOURCES USED:
(Number of Unit Systems to Yield 10^{12} Btu/yr: N =15,355)

FUEL
(Per 10^{12} Btu Produced)
solar insolation
ancillary energy requirement - data not available

MATERIALS
(10^3 tons per N units)

steel	16
glass	3.32
urethane	1.54
copper	0.66
coolant	4.1

LAND
negligible

WATER
133 acre-ft. per 10^{12} Btu produced

COSTS
Data not available

PERSONNEL
Data not available

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
none

WATER POLLUTANTS
COD* 645 tons

SOLID WASTE
none

WASTEHEAT
data not available

ENERGY PRODUCT
10^{12} Btu thermal

*Chemical Oxygen Demand assuming ultimate disposal of all working fluid in water.

SOURCE: Los Alamos Laboratory, 1979. The Characterization and Assessment of Selected Solar Thermal Energy Systems for Residential and Process Heat Applications. LA-7995-TASE. Los Alamos, New Mexico. Technology Assessment of Solar Energy (TASE) Project, Solar Technology Assessment Program, Technology Assessments Division, OTI, EV. DOE.

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Medium Temperature Solar AIPH

UNIT ENERGY SYSTEM:

SIZE:
- provides 140-300°C medium temperature industrial process heat
- 500 sq ft** concentrating collector area
- 900 gallon storage tank
- 102.5 x 10^6 Btu/yr in Madison, Wisconsin

DESCRIPTION
- Sunlight strikes parabolic reflector surfaces and is reflected/concentrated onto the absorber surface at the vertex. Therminol 66 is pumped through the vertex to transfer heat to storage. Lifetime of the system is assumed to be 20 years.

COMPONENTS
- concentrating collectors tracking-type (compound parabolic)
- timing mechanisms
- 900 gallon storage tank
- 2 copper heat exchangers
- 100 ft. of 1-inch diameter copper piping
- 2 pumps
- 2 valves
- expansion tanks
- vents
- system controls

ENVIRONMENTAL CONCERNS
- leakage or spillage of system fluid
- product contamination
- fluid disposal

RESOURCES USED:
(Number of Unit Systems to Yield 10^{12} Btu/yr; # = 9,756)

FUEL
(Per 10^{12} Btu Produced)
solar insolation
ancillary energy requirement - data not available

MATERIALS
(10^3 tons per # units)

steel	38.5
glass	3.9
aluminum	3.41
urethane	2.92
coolant	[data not available]

LAND
24 acres per # units

WATER
192 acre-ft. per 10^{12} Btu produced

COSTS
Data not available

PERSONNEL
Data not available

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
none

WATER POLLUTANTS
COD* 674 tons

SOLID WASTE
none

WASTEHEAT
none

ENERGY PRODUCT
10^{12} Btu thermal

*Chemical Oxygen Demand assuming ultimate disposal of all working fluid in water.

**Collector size is normalized to 500 ft^2. Depending upon specific application, more than one module may be required; i.e., 1,268 unit systems would be needed to provide 50% of the medium temperature (100-300°C) process heat load for a 200,000 tons/year pulp mill.

SOURCE: Los Alamos Scientific Laboratory, 1979. The Characterization and Assessment of Selected Thermal Energy Systems for Residential and Process Heat Applications. LA-7995-TASE. Los Alamos, New Mexico. Technology Assessment of Solar Energy (TASE) Project, Solar Technology Assessment Program, Technology Assessments Division, OTI, EV, DOE.

Photovoltaic Energy Systems

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Residential Photovoltaic System

UNIT ENERGY SYSTEM:

SIZE
- supplies power to 1,507 ft^2 home in Phoenix
- collector area 904 ft^2
- 16,420 kWh/yr (after losses)

DESCRIPTION
- Sunlight striking the photovoltaic cells induces a dc electrical current which is fed either to battery storage or is converted into alternating current and supplied for immediate use in the home.

COMPONENTS
- array of silicon-based photovoltaic cells
- battery storage subsystem
- inverter

ENVIRONMENTAL CONCERNS
- release of toxic gases during system operation or malfunction
- solid waste disposal
- inhalation of toxic gases and dusts by PV industry workers

RESOURCES USED:
(Number of Unit Systems to Yield 10^{12} Btu/yr; N = 17,849)

FUEL
(Per 10^{12} Btu Produced)
solar insolation
ancillary power requirement - data not available

MATERIALS
(Tons per N unit)

plastic	20.02×10^3
silicon	6.16×10^3
aluminum	33.8
silver	27.7
tantalum pentoxide	2.7
solder (60/40 tin/lead)	1.74×10^2
lead	3.16×10^4
antimony	7.35×10^2
polypropylene	2.55×10^3
sulfuric acid	8.89×10^3
steel	4.43×10^3
copper	1.2×10^3
zinc	5.89
porcelain	2.56
varnish	55.1
glass	5.89

LAND
minimal

WATER
258.8 acre ft per 10^{12} Btu produced

COSTS
Data not available

PERSONNEL
Data not available

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
none

WATER POLLUTANTS
none

SOLID WASTE
none

WASTEHEAT
data not available

ENERGY PRODUCT
2.93×10^8 kWh

SOURCE: Los Alamos Scientific Laboratory, 1979. Decentralized Solar Photovoltaic Energy Systems, LA-7866-TASE. Los Alamos, New Mexico. Technology Assessment of Solar Energy (TASE) Project, Solar Technology Assessment Program, Technology Assessments Division, OTI, EV, DOE.

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Solar Photovoltaic Power Plant (Central Utility)

ENERGY SYSTEM:

SIZE
- factory rated power is [illegible] MW
- reflectors and favorable location lead to 100 MW peak field performance
- power conditioning efficiency of 92%
- capacity factor 0.3 due to availability of solar energy
- availability of 0.9
- no storage system
- field consists of [illegible] arrays; each producing 48,700 KWh/year
- field produces 0.841 x 10^{12} Btu/year

DESCRIPTION
- A flat panel array consisting of single-crystal silicon photovoltaic cells with 16% in-panel efficiency converts solar energy to electricity. The system employs a reflector to increase performance. Power conditioning equipment is designed to be capable of delivering peak array power.

COMPONENTS
- solar arrays
- reflecting surfaces
- inverters/converters
- transformers
- medium voltage cabling

ENVIRONMENTAL CONCERNS
- potential for a variety of chemical releases during manufacture of cells
- thermal releases and changes parameter changes over large land areas, possibly producing local weather changes
- glare from solar arrays
- large land area used, [illegible] ecological disruptions and competition with other land uses
- lack of sufficient quantitative information about potential [illegible]

RESOURCES USED:
(Per 10^{12} Btu Produced)
(Number of Unit Systems to Yield 10^{12} Btu/yr; N=1.19)

FUEL	**Btu's**
incident solar radiation	6.79×10^{12}
MATERIALS*	**Tons**
concrete	
silicon	Not Available
steel	
LAND	**Acres**
site	230
WATER	
for cleaning only	
COSTS**	**Dollars (1976)**
construction	
field or arrays	97,000,000
power conditioning and facility	19,000,000
total	116,000,000
operation and maintenance	1,860,000
PERSONNEL	**Workers/Year**
construction (peak)	900
operation and maintenance	10

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	
no normal releases	
releases from damaged cells	
silicon (relatively inert)	negligible
WATER POLLUTANTS	
solvents/detergents (released during washing once every 3-5 months) sodium phosphate	2-3 oz/5 gallons of water
vegetation suppressants	
pesticides	
HEAT	
thermal releases from collectors to atmosphere	
reduction in net solar input to land area	
changed reflectivity, absorptivity, emissivity of land area	
concentrated solar radiation on collectors producing glare	
shading of land	
ENERGY PRODUCT	**Kw-Hrs**
electricity	2.93×10^{8}

*Data for other materials not [illegible].
**Costs are for 1985 construction, [illegible] assume large decrease from present costs.

SOURCES: The MITRE Corporation, Systems Descriptions and Engineering Costs for Solar-Related Technologies, Vol. VIII, June 207.
U.S. Energy Research and Development Administration, Environmental Development Plan, Photovoltaic Energy Conversion, 1977.

Wind Energy Conversion Systems

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Residential/Commercial Wind Energy Conversion System

UNIT ENERGY SYSTEM:

SIZE
- provides electric power to residences or commercial buildings
- 15 KW_e rated capacity*
- 22% capacity factor
- 28,908 KWh/yr

DESCRIPTION
- The machine begins producing electricity when wind speed reaches 8 mph. At 26 mph, the system reaches maximum rated output and at 50 mph, the machine stops generating to protect itself from damage. Lifetime of the system is assumed to be 30 years.

COMPONENTS
- 3 bladed rotor (25 ft in diameter)
- self-excited generator
- small tower
- Gemini synchronous inverter
- battery storage

ENVIRONMENTAL CONCERNS
- safety hazards associated with mechanical stress
- electromagnetic interference
- noise
- aesthetics

RESOURCES USED:
(Number of Unit Systems to Yield 10^{12} Btu/yr; N = 10,130

FUEL
(Per 10^{12} Btu Produced)
wind energy
ancillary power requirement - data not available

MATERIALS
(10^3 tons per N units)

steel	67.23
concrete	1.45
copper	186.1

LAND
68.02 acre per N units

WATER
negligible

COSTS
Data not available

PERSONNEL
Data not available

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
none

WATER POLLUTANTS
none

SOLID WASTE
none

WASTEHEAT
none

ENERGY PRODUCT
2.93×10^8 KWh

*Low Wind Regime (12-15 MPH at 10 Meters)

SOURCE: Los Alamos Scientific Laboratory, 1979. Technology Assessment of Wind Energy Conversion Systems. LA-8044-TASE. Technology Assessment of Solar Energy (TASE) Project, Solar Technology Assessment Program, Technology Assessments Division, OTI, EV, DOE.

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Wind Energy Conversion System—Electric Utility Application

UNIT ENERGY SYSTEM:

SIZE
- power to utility grid
- 1.5 MWe rated capacity
- capacity factor .38, .33, and .22 for high, moderate and low wind regimes
- annual output depending on wind: ranges 4.99 GWh to 2.89 GWh/yr depending on wind regime.

DESCRIPTION
- Wind energy turns the rotor to produce shaft horsepower. The machine operates at constant speed by varying the pitch of its rotor blades. Lifetime of the system is assumed to be 30 years.

COMPONENTS
- rotor assembly
- tower
- generator
- an energy storage subsystem may also be included
- step-up gears

ENVIRONMENTAL CONCERNS
- safety hazards associated with mechanical stress
- electromagnetic interference
- noise
- aesthetics

RESOURCES USED:
(Number of Unit Systems to Yield 10^{12} Btu/yr; N = 101)

FUEL
(Per 10^{12} Btu Produced)
wind energy
ancillary energy requirement - data not available

MATERIALS
(10^3 tons per N units)

	Low Wind	Med.Wind	High Wind
steel	17.6	9.33	5.64
copper	0.135	0.092	0.079
concrete	55.38	31.5	21.75
fiberglass	1.936	0.942	0.498

LAND
50.5

WATER
negligible

COSTS
Data not available

PERSONNEL
Data not available

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
none

WATER POLLUTANTS
none

SOLID WASTE
none

WASTEHEAT
none

ENERGY PRODUCT
2.93 x 10^8 kWh

SOURCE: Los Alamos Scientific Laboratory, 1978. Technology Assessment of Wind Energy Conversion Systems. Los Alamos, New Mexico. Technology Assessment of Solar Energy (TASE) Project, Solar Technology Assessment Program, Technology Assessments Division, OTI, EV, DOE.

Solar Thermal Power Systems

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Solar Thermal Power Plant (Central Facility)

ENERGY SYSTEM:

SIZE
- provides power to utility grid
- 100 MWe plant
- net overall plant efficiency 0.234
- 0.5 capacity factor
- 0.9 availability
- 450 Langleys average daily solar radiation
- 1.50×10^{12} Btu/year energy output
- 7.65×10^{6} sq. ft. total reflector area
- 1.3 magnification factor
- 22,500 heliostats, 3 receiver towers 750' high
- 420 MWhe storage system with superheated steam transport
- 30 year plant life

DESCRIPTION
- The central receiver is composed of a field of tracking heliostats (mirrors) which are controlled to reflect incoming direct solar rays to a common absorber (receiver) elevated above the field by a central tower. The energy, in the form of heat, is transferred from the absorber to a working fluid, which in turn is the source of heat for a thermodynamic cycle producing electricity. A storage system retains a portion of the collected energy to be used in cloudy periods, at night, or to delay production of maximum power.

COMPONENTS
- heliostats (mirrors) and tracking control
- tower receiver and heat transport
- thermal storage
- turbogenerator
- cooling tower
- land, buildings, and ancillary equipment

MAJOR ENVIRONMENTAL PROBLEMS
- handling and disposal of system fluids and wastes (boiler blowdown) leading to water contamination
- heliostat reflection (safety)
- alteration of the microclimate
- large quantities of land used
- ecological impacts of heliostat fields

RESOURCES USED:
(per 10^{12} Btu Produced)
(Number of Unit Systems to Yield 10^{12} Btu/yr; N = 0.667)

FUEL	Btu
incident solar radiation	4.27×10^{12}
LAND	Acres
collector field, buildings, waste treatment areas, rail and road connections	670
WATER	Acre-Ft.
consumed by process	
makeup water (boiler)	19
heliostat washing	1.4
MATERIALS	Tons
aluminum	1,300 - 3,400
concrete	100,000 - 170,000
copper	340 - 670
exotics (chrome/titanium)	70 - 130
glass	3,300 - 6,700
insulation	1,300 - 2,700
plastic	300 - 1,300
silver	0.7 - 3.3
steel	33,000 - 47,000

WORKING/STORAGE FLUIDS
possible candidates are:
- liquid sodium
- sodium hydroxide
- hydrocarbon oils
- eutectic salts (sodium or potassium nitrates/nitrites)

COSTS	Dollars (1976)
construction	
collector	39,000,000
receiver	4,100,000
tower	9,100,000
storage	15,900,000
cooling tower	4,000,000
turbogenerator	8,700,000
master control	5,300,000
plant, structures	8,300,000
total	95,400,000
operation and maintenance	1,000,000 - 1,900,000
PERSONNEL	Workers/Year
construction (over 2-3 yrs.)	570 - 850
operation and maintenance	
full-time	30
part-time	20

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
no normal releases
possible releases during fire or system rupture of working/storage fluids (dependent on fluid composition)
- nitrogen oxides
- sodium monoxide/peroxide
- sodium hydroxide mists or dusts

WATER POLLUTANTS
no normal releases
accidental or emergency release of system fluids and wastes, as well as periodic system flushing may cause toxic releases, dependent on fluid composition
- hydrocarbon oils
- corrosion inhibitors
  - chromate, borate, nitrate, nitrite, sulfate, sulphite, arsenate, and benzoate salts, triazole, silicate, phosphate compounds
- pH controllers
- bactericides
  - chlorinated phenols
- freeze protectants
  - glycols

maintenance related releases
- herbicides
- chemical dust suppressors

boiler blowdown — 19 Acre-Ft.

HEAT
concentrated solar radiation producing
- glare
- fire

reduction of net solar input to land
localized changes in thermal parameters - albedo, energy balance, moisture balance, low-level wind flow patterns, air/surface temperatures, shading of land
thermal releases from cooler tower 1.5×10^{12} Btu

ENERGY PRODUCT	Kw-hrs
electricity	2.95×10^{8}

SOURCES: U.S. Energy Research and Development Administration, Environmental Development Plan, Solar Thermal Power Systems, 1977.
The MITRE Corporation, Systems Description and Engineering Costs for Solar-Related Technologies, Volume V, 1977.
The MITRE Corporation, Annual Environmental Analysis Report, 1977.

Ocean Thermal Energy Conversion

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Ocean Thermal Energy Conversion

UNIT ENERGY SYSTEM:

SIZE
- 400 MWe, 40°F ΔT
  30°F ΔT (Gulf design point)
- capacity factor — 0.73-0.90
- efficiency factor: 0.03
- power loss
  AC : 0.3%/mi + 2% power conditioning loss
  DC : 0.01%/mi + 2% power conditioning loss
- offshore distance and transmission mode (AC or DC)
  AC : 3-30 miles
  DC : 30-200 miles
- annual production : 8.4×10^{12}-10.4×10^{12} Btu
- 30 years plant amortization life

DESCRIPTION
- The OTEC system uses the ocean temperature differential between the surface and depth up to 1000 meters to drive a simple Rankine cycle and produce electricity. Power is transmitted to shore by either AC or DC cables depending on distance. The data is based on the ship platform/coldwater pipe concept of Lockheed and Westinghouse design titanium shell and tube heat exchangers and 50 MWe power modules from PSD-1 studies.
- Assumes ultimate power system based on a 3600 MWe (8 plant) complexes.
- Performance is site-dependent.

COMPONENTS
- platform
- cold water pipe
- mooring system
- riser cable
- undersea cable
- shore station
- tie point
- heat exchangers
- turbine-generators
- sea water pumps
- piping and distribution
- ammonia pumps
- controls
- auxiliary systems
- biofouling control

MAJOR ENVIRONMENTAL PROBLEMS
- changes in oceanic properties
  - environmental effects of ocean water-mass displacement
  - destruction of marine eco-system by impingement/entrainment of biota
  - local climate alteration
- chemical pollution
  - ecological effects of biocide discharges
  - ecological effects of working fluid leaks
  - marine food chain contamination from metal corrosion
- ecological impacts associated with the operations of a manned platform
  - artificial reef
  - life-support system discharges
- international/institutional aspects of environmental laws and agreements
- secondary effects
  - site selection
  - environmental/ecological impacts of OTEC construction and operations
  - worker safety

RESOURCES USED:
(Per 10^{12} Btu Produced)
(Number of Unit Systems to Yield 10^{12} Btu/yr; N = 0.119)

SEAWATER		
warm	$1.3-1.6 \times 10^{11}$	cf/yr
cold	$1.3-1.6 \times 10^{11}$	cf/yr

WORKING FLUIDS
ammonia

initial inventory	770-950 tons
makeup	10 tons per year

LAND
shore station 20 acres

MATERIALS	Tons
concrete	45,000-56,000
steel	7,500- 9,200
titanium	980- 1,210
copper	490- 605
lead	190- 230
rubberized nylon	600- 750

COSTS	Dollars (1976)
construction (5 years)	230-290
operation and maintenance	16-20
engineering/ technical	Not Available

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
no releases

CIRCULATED SEAWATER		
warm	$1.3-1.6 \times 10^{11}$	cf
cold	$1.3-1.6 \times 10^{11}$	cf

WATER POLLUTANTS	
free chlorine	1,700-2,000 tons
ammonia	negligible
oil and grease	negligible
nutrients	negligible
metals	negligible

ENERGY PRODUCT	KW-hrs.
electricity	2.93×10^{8}

SOURCES: B. Abelson, OTEC Power System Performance Model, MITRE Corporation, MTR 7924, August, 1978.
Doty Associates, Critique of OTEC Phase II Commercial Applications Study Cost Estimates, Doty Associates Technical Report Number 189, May 31, 1978.
General Electric Corporation, Development, Design and Testimony of OTEC, Power System Development II, Briefing Document, March 8, 1978.
W.E. Jacobsen and R.W. Manley, OTEC Commercialization Analysis, MITRE Corporation, MTR 7963, January, 1979.
Lockheed Missile and Space Company, Interim Design Briefing, PSD II, March 7, 1979.
Lockheed Missile and Space Company, OTEC Power System Development, Phase I - Preliminary Design Report, LMSC-D630248.
TRW Incorporated, OTEC Power System Development, Phase I, October 1978.
TRW Incorporated, OTEC PSD II Utilizing UCC/Linde Enhanced Plate Type Heat Exchanger, March 6, 1979.
Westinghouse Incorporated, OTEC Power System Development, Phase I, October, 1978.
Personal Communication: Lloyd Lewis, Department of Energy, April, 1979.

Biomass Energy Systems

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Wood-Fired Steam Electric Plant

UNIT ENERGY SYSTEM:

SIZE
- 56 MWe or 1.34×10^{12} Btu/yr at 80% availability factor
- conversion efficiency .315
- annual fuel requirement 2.5×10^5 dry ton equivalent
- plant lifetime of 30 years

DESCRIPTION
- wood-fired steam electric plant using a spreader stoker furnace to produce 392,000 MW hrs/yr.

COMPONENTS
- steam generating equipment (i.e., boilers)
- draft system
- wood fuel equipment
- ash handling system
- emission control equipment (i.e., precipitator)
- turbine generator equipment
- condenser water system
- cooling tower system
- switchgear
- protective equipment
- electric structure and wire contingency
- miscellaneous plant equipment

MAJOR ENVIRONMENTAL PROBLEMS
- particulate residue
- stack emissions

RESOURCES USED:
(Per 10^{12} Btu Produced)
(Number of Unit Systems to Yield 10^{12} Btu/yr; N = 0.746)

FUEL	Dry Tons
wood	
(assuming 8500 Btu/lb or 3.2×10^{12} Btu/yr)	1.87×10^5
(1 dry ton is equivalent to 2 tons of wood if moisture is included)	

LAND	Acres
storage/plant site	74.6
landfill for boiler residue	.48

WATER	Acre-Ft.
water consumption	547.8

COSTS*	Dollars (1967)
construction	
(front end and site preparation)	(1,660,000)
water treatment plant	240,000
cooling towers	830,000
general construction	3,560,000
equipment	22,450,000
engineering	6,300,000
(commissioning and contingency)	(4,940,000)
total	37,980,000
operation and maintenance	2,730,000
fuel cost	3,175,000-7,937,000

PERSONNEL	Workers
construction	Not Available
operation and maintenance	22.4

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS	Tons
particulates**	641.5
SO_2	280.5
NO_x	1870
hydrocarbons	374
CO	374

WATER POLLUTANTS	Tons
total dissolved solids	NA

SOLID WASTE	Tons
boiler residue (boiler ash, clinkers captured fly ash)	1866

HEAT	Btu's
stack loss	Not Available
cooling tower	Not Available

ENERGY PRODUCT	Kw-hrs.
electricity	2.93×10^8

*Includes cost of electrostatic precipitator
**Assumes 90% removal efficiency

SOURCES: The MITRE Corporation, Annual Environmental Assessment Report, 1977.
The MITRE Corporation, Silviculture Biomass Farms, Conversion Processes and Costs, Volume V, 1977.

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Geothermal Energy

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Geothermal—Vapor Dominated System

ENERGY SYSTEM:

SIZE
- 110 MWe
- 15% conversion factor
- 75% capacity factor
- produces 2.47×10^{12} Btu per year
- unit 12 of Pacific Gas and Electric Geysers generating system

DESCRIPTION
- Steam is purchased from the Geysers field and is used to drive a turbine generator with condensate water used for cooling. No abatement procedures are used at the generating plant; however, the steam distribution system includes a centrifugal axial separator. Furthermore H_2S abatement measures are planned for implementation beginning with unit 13.

COMPONENTS
- production wells
- gathering system
- steam distribution system
- turbine-generator
- condensers
- heat rejection system
- gas ejector system
- electrical system and controls
- waste purification

ENVIRONMENTAL CONCERNS
- hydrogen sulfide (H_2S) is toxic, has odor - but control technologies are available
- high noise levels
- disposal of excess steam
- emissions highly site, reservoir, and time dependent
- conflicts with existing community lifestyles

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	
steam	6.7×10^{12} Btu's
LAND[1]	
permanent	31.2 - 62.4 acres
undisturbed	249.6 - 280.8 acres
WATER	Acre-Feet
water vapor input	1,960
water vapor discharged to air	1,640
water reinjected to wells	320
COSTS[2]	Dollars
construction (1978)[1]	21,180,000
operation and maintenance (1976)	175,000
annual cost of steam (1978)	3,807,000-5,272,000
abatement costs[3] (1976)	
peroxide system	
capital	401,000-490,000
operation and maintenance	126,000-434,000
ozone system	
capital	710,000-1,560,000
operation and maintenance	129,000-211,000
geothermal field construction	NA
geothermal field operation and maintenance	NA
PERSONNEL	Workers
construction (man-years)	
generating plant	57.43
well-field	NA
total	NA
operation and maintenance	
generating plant	NA
well-field	NA
total	4.97

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS[4]	Tons	(6)
carbon dioxide	250-26,000	(11,160)
ammonia	16- 1,800	(660)
methane	13- 1,300	(660)
hydrogen sulfide	5- 1,500	(764)
arsenic	NA	(8×10^{-4})
boron	NA	(1.7)
mercury	NA	(5×10^{-5})
hydrogen	6-120	(83)
water vapor	NA	(2.9×10^{6})
nitrogen, argon	4-410	

WATER POLLUTANTS[5]	Tons	
carbonates	81-210	(249)
ammonia	62-106	(84)
SO_2	NA	(1.2)
sulfate	87-260	(76.2)
sulfur	NA	(4.9)
nitrate	<0.04	(0.06)
chloride	<2	(2.0)
calcium	NA	(3.1)
magnesium	NA	(0.6)
silicon	NA	(2.2)
boron	44-89	(10.0)
total solids from evaporation	NA	(107.7)
organics and volatile solids	NA	(120.0)
water	NA	(≈320 acres-feet)

RADIATION[4]	
Air	Curies
Rn-222	41
HEAT	Btu's
waste heat (discharged to air)	5.4×10^{12}
NOISE	Decibels(A)
well drilling	75-80 at 50 feet
mud drilling (60 days/well)	85-120 at 25 feet
air drilling (30 days/well)	
well cleaning; open well (3-6 days)	118 at 50 feet
well testing: open well (14 days)	118 at 50 feet
rock muffler	89 at 50 feet
well bleeding (variable)	65-86 at 5 feet
well blowouts (infrequent)	118 at 50 feet
construction of plant	
construction operations (1-2 years)	70-90 at 50 feet
plant operation (20-30 years)	
muffled steam line vent (intermittent)	90 at 100 feet
jet gas ejector (continuous)	84-117 at 5-10 feet
steam line separator (continuous)	80 at 25 feet
steam line breaks (brief, infrequent)	100 at 50 feet
cooling tower (continuous)	80-90 at 5-10 feet
turbine generator building (continuous)	70 outside
ENERGY	
electricity	2.93×10^{8} kWh

(1) Data values represent life-cycle values divided by annual energy output, measured in 10^{12} Btu.
(2) Construction and operation and maintenance costs are for the plant only.
(3) Costs projected to achieve 99% H_2S abatement at the Geysers. To be installed on all units beginning with unit 14. Does not include cost of retrofitting.
(4) Site specific for the Geysers field. Assumes no abatement measures.
(5) No treatment involved, reinjected through wells.
(6) Values in parentheses indicate actual emissions from the Geysers field operations as presented in Caratas, 1977.

SOURCES: Personal communication with D. J. Cosnette of Pacific Gas and Electric, Comments of Dr. Lynn Anspaugh, Lawrence Livermore Labs, 1978.
Ronald DiPippo, Geothermal Power Plants of the United States-A Technical Survey of Existing and Planned Installations, Brown University, 1978.
The MITRE Corporation, Environmental Research Needs for Geothermal Resources Development, Volume I, MTR-7419, D. Caratas, 1977.
U.S. Environmental Protection Agency, Western Energy Resources and the Environment: Geothermal Energy, EPA-600/9-77-010, May 1977.

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Geothermal-Flash Injection System

ENERGY SYSTEM:

SIZE:(1)
- 50 MWe (net) power output
- 10.1 x 10^6 lb/hr brine flow rate (feed) to plant at 330°F/115 psia
- 13 production wells
- 6 reinjection wells
- 8.60 x 10^6 lb/hr brine/cooling water flowrate reinjected at 230°F/115 psia
- 10 acres plant site
- 30 years plant life
- .75 capacity factor
- 1.121 x 10^{12} Btu annual power output
- 8-11% thermal conversion efficiency for 375°F brine(2)

DESCRIPTION
- Geothermal brine is drawn through production wells and transported to the power plant. Steam is produced from the brine by reducing the brine pressure below its vapor pressure. This process, known as flashing, is performed twice. The excess brine is reinjected through reinjection wells. The noncondensable gas portion of the steam is treated with an H_2S scrubbing process and is released to the atmosphere (estimated H_2S removal of 99%). Condensate steam is used for cooling with excess condensate employed for continuous blowdown and reinjected with the excess brine.

COMPONENTS
- production wells and islands
- reinjection wells and islands
- distribution system
- steam system
- brine system
- cooling system
- H_2S scrubber

ENVIRONMENTAL CONCERNS
- releases of noncondensable gases
- high noise levels
- potential groundwater contamination
- land subsidence
- increased seismic activity
- alteration of runoff patterns
- habitat disruption
- all factors are highly site specific

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL		
geothermal brine, 330°F, 115 psia(1)	(1)	2.950 x 10^7 tons
LAND(a)		
wells and islands	(2)	3.57 acres
plant site	(2)	8.9 acres
CHEMICALS		Tons
alkali for scrubber		NA

COSTS(b)(1)	Dollars (1976)
well field(a)	
surface equipment	5,352,000
wells	7,136,000
engineering services	1,070,000
Subtotal	13,558,000
plant construction(a)	
turbine-generator	5,986,000-9,064,000
other mechanical	4,585,000
piping and instrumentation	4,112,000
electrical	2,828,000
civil/structural	3,381,000
engineering services	2,426,000-2,881,000
Subtotal	23,318,000-26,851,000
Total(a)	36,876,000-40,409,000
well field operation and maintenance	1,320,000
plant operation and maintenance	466,000-537,000
Total	1,786,000-1,857,000

PERSONNEL	Workers
field construction	NA
field operation	NA
plant construction	NA
plant operation	NA

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS(3)	Tons
hydrogen sulfide(c)	19.4
ammonia	90.0
methane	500
carbon dioxide	35,300
arsenic	NA
boron	NA
mercury	0.1
hydrogen	NA
nitrogen, argon	NA
water vapor	4.3 x 10^6

WATER POLLUTANTS(d)(3)	Tons
carbonates	NA
ammonia	NA
SO_4	NA
sulfate	NA
sulfur	NA
nitrate	NA
chloride	NA
calcium	NA
magnesium	NA
silicon	NA
boron	NA
dissolved solids	NA
water (tower blowdown)	1.76 x 10^5
total brine	2.53 x 10^7
total suspended solids(e)	NA
nutrients(e)	NA

RADIATION(3)	
Air	Curies
Rn-222	7.3
other radionuclides	NA

NOISE(4)	Decibels
well construction	intermittent high intensity
well operation	intermittent high intensity
plant construction	medium intensity
plant operation	low intensity

ENERGY PRODUCT	MWh
electricity	2.93 x 10^8

NOTE: Allowance for contingency is not included in costs.

(a) Data values represent life-cycle values divided by annual energy output, measured in 10^{12} Btu.
(b) Capital costs include installation, personnel, etc.
(c) Without sulfur removal system
(d) Reinjection
(e) Construction related, result of altered runoff patterns.

SOURCES: (1) Bechtel Corporation, Advanced Design and Economic Considerations for Commercial Power Plants at Heber and Niland California, 1977.
(2) Brush, D. L., 1977. "Potential Growth of Electric Power Production from Imperial Valley Geothermal Resources," UCRL-52232.
(3) Knox, J. B., and R. C. Orphan, ed., Program Report - FY 1977, Atmospheric and Geophysical Sciences Division Physics Department, UCRL-51444-77, Lawrence Livermore Labs, 1977.
(4) Environmental Protection Agency, Western Energy Resources and The Environment: Geothermal Energy, 1977.

Hydroelectricity

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Large Hydroelectric Plant

ENERGY SYSTEM:

SIZE
- 300 MWe plant (composed of three 66.7 MWe generators)
- 56% capacity factor
- lifetime 60 years
- an earth filled dam (containing 15 million cubic yards of earth)
- produces 3.349×10^{12} Btu per year
- 82.6% efficiency

DESCRIPTION
- Conventional hydroelectric plants are assumed to be run-of-river plants: a dam is placed across a river, generating base load power more or less continuously throughout the year. The amount of energy produced by this type of plant is dependent on the site's characteristics and the daily, weekly, or seasonal fluctuations of river flow. In 1976 the developed conventional capacity of hydroelectric power was 57,000 MWe. It is projected to increase some 40 percent to 79,300 MWe by 1995.

COMPONENTS
- dam
- spillways
- intakes
- powerhouse
  - conduits
  - hydraulic structures
  - turbines
  - electrical equipment

ENVIRONMENTAL CONCERNS
- inundation of existing habitats created by impoundments of water
- formation of a deep pool of water creating physical, chemical, and biological changes to the environment
- creation of biologically impoverished zone caused by the fluctuations of the reservoir's water level
- alterations of downstream habitats
- modification of animal movement patterns
- imposition of additional sources of stress and mortality to fish and wildlife
- conflicts of land and water use
- dam safety and potential effects of dam failure

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Btus
kinetic energy of water	1.2×10^{12}
LAND (1)	Acres
acres occupied	119.43
MATERIALS	Tons
concrete	44,789
total steel & castings	6,210
copper, brass & bronze	86
aluminum & castings	45
manganese	25
chromium	6
nickel	1
cast iron	138
COSTS	Dollars (1978)
construction (1)	
manpower	11,490,000
materials	6,140,000
equipment	11,530,000
plant	850,000
land & land rights	(7,234,000)
other construction	3,890,000
total	31,900,000
operation & maintenance	
manpower	110,000
materials	20,000
equipment	80,000
total	210,000
PERSONNEL	Workers
construction (4.75 years)	74.95
operation	5.02

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

AIR POLLUTANTS
no normal releases

WATER POLLUTANTS
Water quality and quantity may be altered up and down stream with potential changes in dissolved gases, temperature, and water levels.

HEAT
no normal releases

ENERGY PRODUCT	kWh
electricity	2.93×10^{8}

(1) Data values represent life-cycle values divided by annual energy output, measured in 10^{12} Btu.

SOURCES: Bechtel National Incorporated, Resource Requirements, Impacts, and Potential Constraints Associated with Various Energy Futures, 1978.
The MITRE Corporation, Features of Hydroelectric Facilities and Their Impact on Fish and Wildlife Resources, 1977.
Federal Power Commission, Hydroelectric Power Resources of the United States, 1976.
Creager, W.P. and J.D. Justin, Hydroelectric Handbook.

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Small Hydroelectric Plant

ENERGY SYSTEM:

SIZE
- 4 Mwe plant
- .35 capacity factor for new plants and .37 for retrofits.
- lifetime 50 years
- 93% efficiency
- produces .04 x 10^{12} Btu/year

DESCRIPTION
- Small hydroelectric plants have less than, or equal to 15 MWe of capacity, fed by dams with heights no more than 65 feet, and impounding less than 500 acres. It is estimated that by the year 2000, 23360 MWe of low head hydro could be in existence, contributed by three major types of sources: 15% from presently existing plants; 60% from installed power at existing nonhydro dams, and 25% from installed hydro power and new dams.

COMPONENTS
- dam
- penstock
- hydraulic turbine
- generator
- transformer
- other miscellaneous structures & equipment

ENVIRONMENTAL CONCERNS(1)
- effects on aquatic and semiaquatic organisms
- releases of impounded chemicals
- conflicts of land and water use
- dam safety and potential effects of dam failure.

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	Acre-Feet
water	1.98 x 10^7
ENERGY	MWe
electricity	NA
LAND	Acres
acres occupied	NA

COSTS

	Dollars (1977) Installed Power at Existing Non-hydro Dams	Installed Hydro-power at New Dams
construction(2)		
design	13,350,000	11,300,000
structures	19,370,000	20,700,000
dam & spillway	21,360,000	90,360,000
equipment	38,180,000	41,420,000
roads, railways, bridges, etc.	270,000	1,800,000
land & land rights	(2,140,000)	(22,590,000)
total	92,660,000	186,440,000
operation and maintenance (1972 dollars)	1,430,000	1,350,000

PERSONNEL	Workers
construction	NA
operation and maintenance	NA

RESIDUALS AND PRODUCTS:
(Per 10^{12} Btu Produced)

WATER POLLUTION
Water quality and quantity may be altered up and down stream with potential changes in dissolved gases, temperature, and water levels.

ENERGY PRODUCT	Kwh
electricity	2.93 x 10^8

(1) As compared to other sources of electricity, the environmental effects of low head hydro are minor.
(2) Costs are total costs for plant construction, divided by annual energy output, measured in trillion Btus.

SOURCES: The MITRE Corporation, Small-Scale Hydroelectric Preliminary Program Plan, 1978.
Bureau of Reclamation, U.S. Army Engineers, Identification of Selected Small-Scale Dams Suitable for Hydroelectric Power Development, 1978.
U.S. Department of Energy. Environmental Readiness Document - Small Scale Low Head Hydro , In Press.
Jelen, F.C., Cost and Optimization Engineering, McGraw-Hill, New York, 1970.

Pumped Storage System

ENERGY SYSTEM:

SIZE
- 1000 MWe pumped storage plant (composed of four 250 MW pumps and drivers)
- 13% capacity factor
- lifetime 60 years
- two earth-filled dams
- produces 3.89×10^{12} Btu per year
- 70% efficiency

DESCRIPTION
- Pumped storage plants can be thought of as large batteries which store energy (in the form of water) during low demand periods and release that energy during periods of peak demand. Excess energy, usually from base load facilities, is used to make the reversible units act as motors, pumping the water to the upper reservoir. These units then become turbine generators for power production when the water is released during periods of high demand. In 1976, the developed pumped storage capacity in the U.S. was 9,700 MWe. It is projected to increase some 285 percent to 37,300 MWe by 1995.

COMPONENTS
- dam
- spillways
- intakes
- powerhouse
  - conduits
  - hydraulic structures
  - reversible pump turbines
  - electrical equipment

ENVIRONMENTAL CONCERNS
- inundation of existing habitats created by impoundments of water
- formation of a deep pool of water creating physical, chemical, and biological changes to the environment
- creation of a biologically impoverished zone caused by the fluctuations of the reservoir's water level
- alterations of downstream habitats
- modification of animal movement patterns
- imposition of additional sources of stress and mortality to fish and wildlife
- conflicts of land and water use
- dam safety and potential effects of dam failure

RESOURCES USED:
(Per 10^{12} Btu Produced)

FUEL	**Btus**
off-peak base load electricity	1.43×10^{12}
LAND(1)	**Acres**
acres occupied	514.13
MATERIALS(2)	**Tons**
concrete	151,157
total steel & castings	16,110
copper, brass & bronze	191
aluminum & castings	125
manganese	82
chromium	14
nickel	3
cast iron	335
COSTS	**Dollars (1978)**
construction(3)	
manpower	26,630,000
materials	15,760,000
equipment	22,440,000
plant	2,040,000
land & land rights	(7,797,000)
other construction	9,340,000
total	76,210,000
operation & maintenance	
manpower	186,000
materials	18,000
equipment	166,000
total	370,000
PERSONNEL	**Workers**
construction (6.5 years)	127.16
operation & maintenance	8.49

RESIDUALS AND PRODUCTS
(per 10^{12} Btu Produced)

AIR POLLUTANTS
no normal release

WATER POLLUTANTS
Water quality and quantity may be altered up and down stream with potential changes in dissolved gases, temperature, and water levels.

HEAT
no normal release

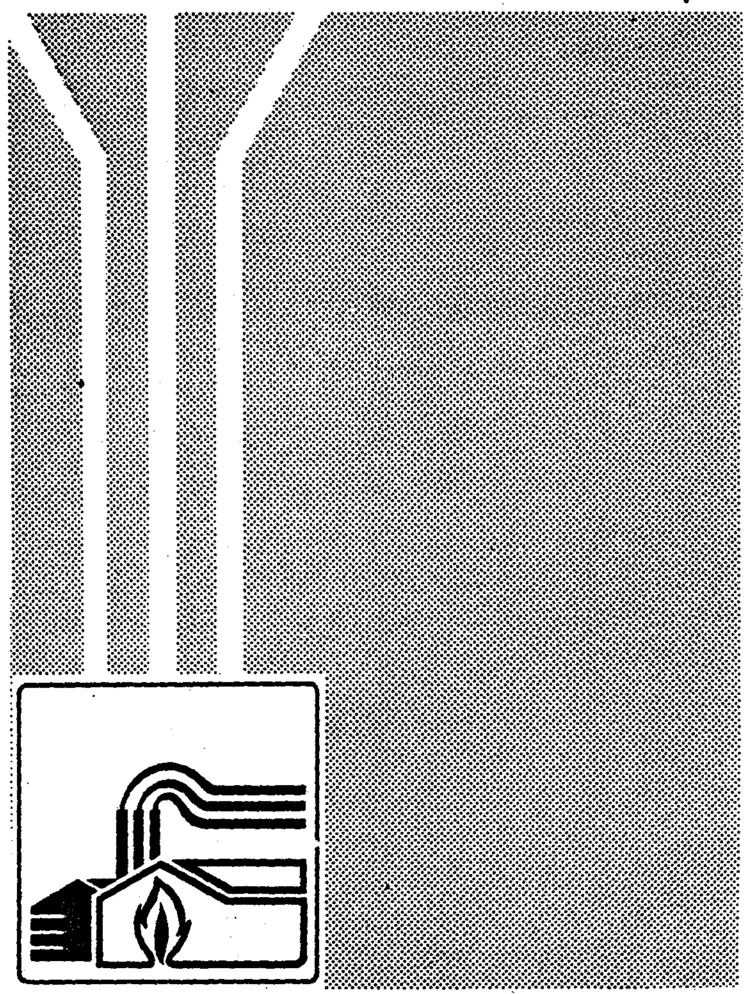
ENERGY PRODUCT	**Kwh**
electricity	2.93×10^{8}

(1) Plus replacement of water lost by evaporation and seepage.
(2) Selected materials and equipment items.
(3) Data values represent life-cycle values divided by annual energy output, measured in 10^{12} Btu.

SOURCES: Bechtel National Incorporated, Resource Requirements, Impacts, and Potential Constraints Associated with Various Energy Futures, 1978.
The MITRE Corporation, Features of Hydroelectric Facilities and Their Impact on Fish and Wildlife Resources, 1977.
U.S. Federal Power Commission, Hydroelectric Power Resources of the United States, 1976.

APPENDIX A

Coal - Fired Power Plant
(Eastern Coal)
Environmental Characterization Information Report



Draft
June 1980

William G. Wilson: Technical Project Officer
U.S. Department of Energy
Assistant Secretary for Environment
Office of Environmental Assessments

FOREWORD

This Environmental Characterization Information Report (ECIR) is a synthesis of environmental data and information relevant to a coal-fired power plant that burns eastern coal. It is prototypical of a set of ECIRs that will be developed for a range of fossil, solar, geothermal, nuclear, and conservation energy systems. The ECIRs are designed to have several related purposes: to communicate to all potential users environmental data and information characteristic of an energy system; to present an organized data and information base for application in manual and computer-based analytical systems; and to provide the medium for facilitating development, maintenance, and critical review of the data and information base. The set of ECIRs is designed to replace the general technical backup volumes formerly supplied with "Environmental Data Energy Technology Characterizations," Summary, January 1980.

Responsibility for the contents and development of an ECIR is assigned to individual technology specialists in the Technology Assessments Division. In this endeavor, we expect to draw upon the technical support and assistance of qualified experts familiar with the energy systems. Technical comments regarding this ECIR should be directed to Mr. William G. Wilson, (301) 353-4414. Suggestions or recommendations for improving the ECIR concept should be addressed to me.

Dario R. Monti
Director, Technology Assessments Division
Office of Technology Impacts

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ACKNOWLEDGMENTS

Many people assisted in the development of this prototype Environmental Characterization Information Report (ECIR), and to these people, acknowledgment is made:

Dr. Arnold J. Goldberg, Chief, Fossil Technologies Branch, Technology Assessments Division, for technical and planning advice.

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Mr. Robert Bee, Mr. Kenneth Stephens, Dr. Lawrence Weinberger, and others, The Aerospace Corporation, for technical support and assistance in developing the structure of the ECIR.

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CONTENTS

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Page

I. SUMMARY

This Environmental Characterization Information Report (ECIR) for Coal-Fired Power Plants (Eastern Coal) has been prepared from the latest available environmental and technical information collected from a number of sources. The typical plant chosen for characterization is a 500-MWe nameplate rating pulverized-coal plant with an electrostatic precipitator, wet scrubber, and a wet-mechanical-draft cooling tower. It is a mine-mouth facility, with its own coal preparation plant.

The process, plant operating parameters, resources needed, and the environmental residuals and products associated with the power plant are presented in this secton in the summary table (Table 1). Annual resource usage and pollutant discharges are shown in English and metric units, assuming an annual plant capacity factor of 80 percent. While this capacity factor is representative of the reliability of generating units of this size, it does not consider unscheduled shutdowns for repairs of the plant and associated environmental control equipment or factors independent of the plant itself, e.g., reserve requirements.

In addition to annual quantities, the summary table gives quantities in terms of 10^{12} Btu of electric energy produced. These figures are provided to allow comparison between different energy processes and to facilitate application of the information in computer models.

The supporting information and calculation procedures for the data are given in Section II. Twenty-three environmental points of interest are discussed individually, giving a brief description of the pollutants or resources involved, standards to be met, example calculations showing the derivation of quantities, scaling laws and extrapolation methods to adjust to other conditions, and a bibliography of cited references. Specific environmental regulations are discussed in the individual sections. The calculations of allowable emission levels are based on current Federal regulations applicable to new plants. For information on similar sized plants operating under previous Federal regulations, see Appendix A. For information on impending regulations, see Reference 1.

Section III discusses the overall physical requirements of the plant for land and water. A glossary of terms, cost information, and a trace element analysis are included as appendixes to this report. Data pertaining to additional subjects such as construction resources will be covered in a later version of this ECIR.

<u>Reference</u>

1. U.S. Department of Energy, Office of Technology Impacts, Office of Environment, "Environmental Issues Briefing Book for Policy Analysis Division," original issue April 1979 (compiled by the Mitre Corporation).

TABLE 1. SUMMARY SHEET

COAL-FIRED POWER PLANT (EASTERN BITUMINOUS COAL)

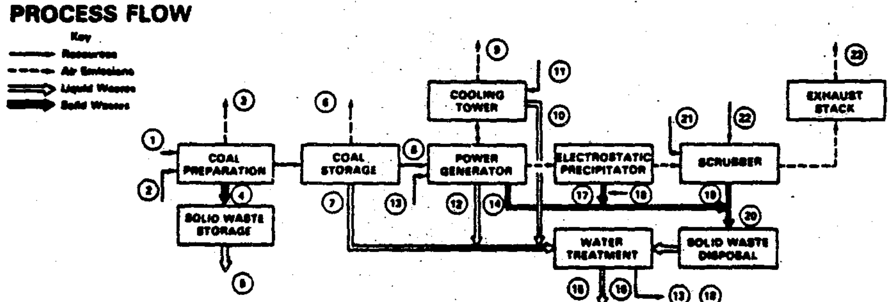
ENERGY SYSTEM DESCRIPTION

Mine-Mouth Conventional Steam Electric Power Plant Using Typical Eastern Bituminous Coal; No Cogeneration; Electrostatic Precipitator for Particulate Control; Wet Lime/Limestone Scrubber for SO_2 Control; On-Site Solid Waste Disposal; and On-Site Water Treatment for Recirculation to Minimize Discharge. New Plant Subject to Current Regulations.

PLANT OPERATING PARAMETERS

Power Output to Grid:	500 MWe
Annual Capacity Factor:	80% (assumed)
Overall Plant Efficiency:	35%
Annual Energy Production:	12×10^{12} Btu (3.5×10^6 MW-hrs)
Plant Lifetime:	30 yrs

PROCESS FLOW



NOTE Code Numbers are same as "Environmental Points of Interest" Described in Section II

RESOURCES USED

Code No.	Resource	Quantities Used Annual Usage* English Units	Annual Usage* Metric Units	Per 10^{12} Btu Energy Produced	Remarks
	<u>Fuel</u>				
1	Run-of-min Eastern bituminous coal	1.96×10^6 tons	1.77×10^6 tonne	0.16×10^6 tons	High-sulfur coal (3.3% S)
8	Coal feed to boiler	1.43×10^6 tons	1.3×10^6 tonne	0.12×10^6 tons	
	<u>Water</u>				
2	Coal preparation makeup water	$19\text{-}45 \times 10^6$ gal	$57\text{-}170 \times 10^6$ l	$1.25\text{-}3.75 \times 10^6$ gal	Quality not critical
11, 13	Power plant makeup water	2.2×10^9 gal	8.3×10^9 l	0.18×10^9 gal	
16, 21	Environmental cleaning makeup water	3.2×10^7 gal	12×10^7 l	0.27×10^7 gal	
	<u>Raw Materials for Processing</u>				
22	Limestone to scrubber	146×10^3 tons	132×10^3 tonne	12.2×10^3 tons	
	<u>Land</u>				
4	Land for coal preparation solid waste storage (see Section III)	16 acres	6.5 ha	1.3 acres	Sufficient land needed for a 30 yr life
20	Land for power plant and environmental solid waste disposal (see Section III)	12.3 acres	5 ha	1.03 acres	
	<u>Personnel</u>				
	Power Plant	135 person-yr		11.3 person-yr	
	Preparation Plant	20 person-yr		1.7 person-yr	
	<u>Raw Materials for Construction</u>	To Be Added			
	<u>Facility Costs</u>	To Be Added			
	<u>Control Costs</u>	To Be Added			

*Based on the assumed 80% capacity factor

TABLE 1. (Continued)

COAL-FIRED POWER PLANT (EASTERN BITUMINOUS COAL)

ENVIRONMENTAL RESIDUALS & PRODUCTS

Code No.	Residual or Product	Quantities Released: Annual Levels* English Units	Quantities Released: Annual Levels* Metric Units	Per 10^{12} Btu Energy Produced	Regulatory Compliance Levels
	Air Pollutants				
③,⑥	Fugitive dust from coal preparation and storage		Not quantifiable		
[illegible]	Post-Control Flue Gas Constituents				
	Sulfur Dioxide (SO_2)	10.2×10^3 tons	9.3×10^3 te	850 tons	0.6 lb/10^6 Btu
	Oxides of Nitrogen (NO_x)	10.2×10^3 tons	9.3×10^3 te	850 tons	0.6 lb/10^6 Btu
	Total Suspended Particulates (TSP)	500 tons	455 te	42 tons	0.03 lb/10^6 Btu
	Nonmethane Hydrocarbons (HC)	220 tons	200 te	18 tons	Not established
	Carbon Monoxide (CO)	720 tons	655 te	60 tons	
	Carbon Dioxide (CO_2)	3.7×10^6 tons	3.4×10^6 te	0.3×10^6 tons	↓
	Arsenic (As)	225 lb	102 kg	18.8 lb	
	Beryllium (Be)	9.3 lb	4.2 kg	0.8 lb	
	Cadmium (Cd)	4.1 lb	1.9 kg	0.4 lb	
	Manganese (Mn)	161 lb	74 kg	13.4 lb	
	Lead (Pb)	114 lb	52 kg	9.5 lb	
	Selenium (Se)	56 lb	25 kg	4.7 lb	
	Water Pollutants				
⑧	Airborne water from cooling tower drift and evaporation	2×10^9 gal	7.6×10^9 l	0.17×10^9 gal	
⑤	Surface run-off from coal preparation solid waste storage		Not quantifiable		
⑪	Excess water runoff from treatment/recycling holding ponds				
	Total Suspended Solids (TSS)		30 mg/l**		30 mg/l***
	Oil and Greases		15.2 mg/l		None
	Copper		0.009 mg/l		1 mg/l***
	Iron		0.009 mg/l		1 mg/l***
	Chlorine		3 0.11 mg/l		None
	Solid Waste				
④	Solid wastes from coal preparation (to storage)	0 525 $\times 10^6$ tons	0.48×10^6 te	0.04×10^6 tons	
⑭	Bottom ash from boiler (dry)	25×10^3 tons	22.8×10^3 te	2.1×10^3 tons	
⑰	Collected flyash (dry) from precipitator	100×10^3 tons	91×10^3 te	8.3×10^3 tons	
⑱	Limestone scrubber sludge (dry)	193×10^3 tons	175×10^3 te	16×10^3 tons	
	Heat				
⑧	Total heat losses to air	34×10^{12} Btu	10×10^6 MW-hr	2.8×10^{12} Btu	

Symbols and abbreviations are discussed in the acronyms and abbreviations section.

*Based on the assumed 80% capacity factor

**Estimated maximum concentrations for a 30-day average for a typical plant

***Kentucky water quality standards

OCCUPATIONAL SAFETY AND HEALTH

	Preparation Plant: Annual	Preparation Plant: Per 10^{12} Btu	Power Plant: Annual	Power Plant: Per 10^{12} Btu
Deaths	0.0033-0.0053	0.0003-0.0004	0-0.11	0-0.0095
Injuries	1.9-3.1	0.16-0.26	1.9-2.3	0.16-0.19

II. PROCESS DESCRIPTION AND ENVIRONMENTAL POINTS OF INTEREST

To identify current trends in coal-fired power plant design, the features of 43 modern plants were examined.[1] On the basis of the observed trends, and through discussions with power engineers, a typical plant was chosen for characterization. This composite plant is a 500-MWe pulverized-coal plant with an electrostatic precipitator to control particulate emissions; a wet lime/limestone scrubber for flue gas desulfurization; and a wet, mechanical draft cooling tower. The plant was assumed to be a mine-mouth facility with its own coal preparation plant.

The net station heat rate of 9760 Btu/kWh, which corresponds to an overall efficiency of 35 percent, was taken from an actual 500-MWe plant with similar controls and design features.[2] The coal used in the analysis is an eastern bituminous coal with a heat value of 12,000 Btu/lb, 3.3 percent sulfur, and 8.8 percent ash.[3]

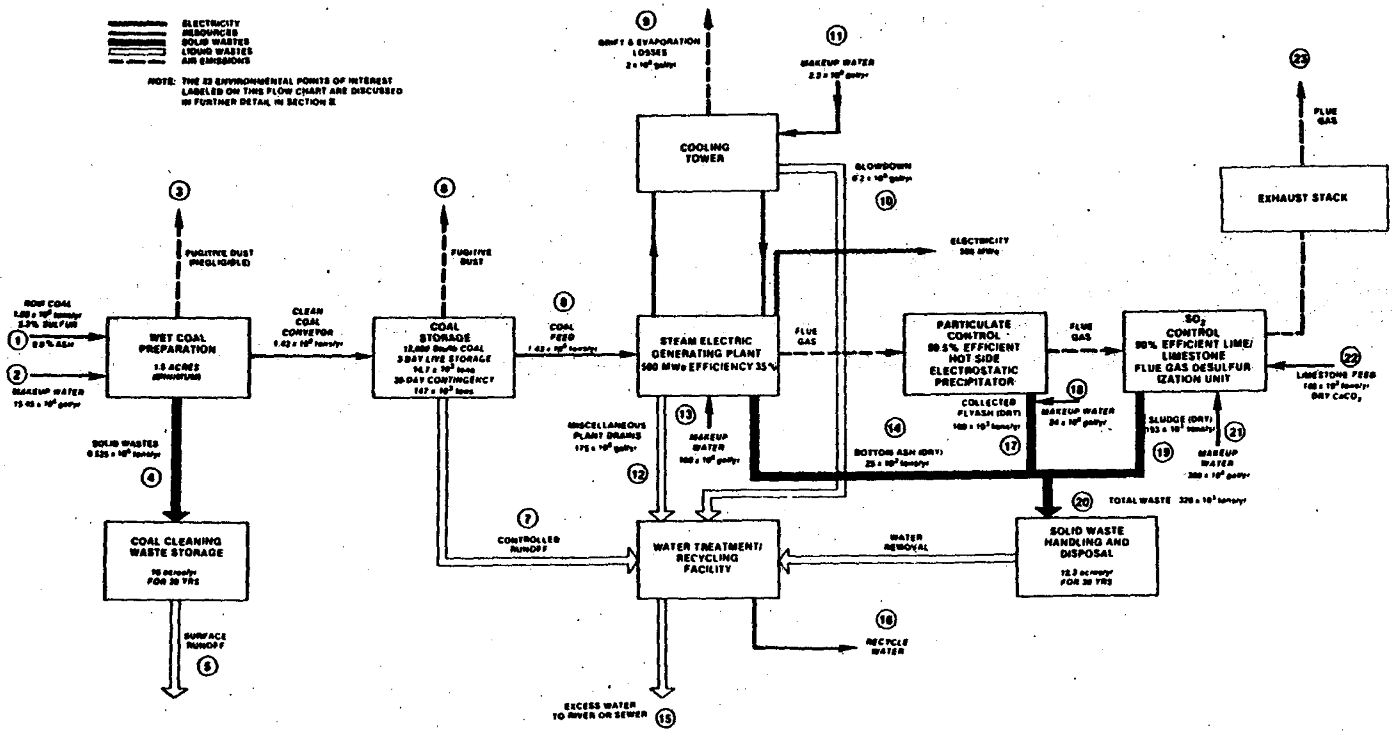
The use of an eastern high-sulfur coal for electrical generation is shown in Figure 1. Twenty-three environmental points of interest have been identified in Figure 1 and are discussed in the following sections. Items ① through ⑤ deal with coal preparation, ⑥ and ⑦ deal with onsite coal storage, ⑧ through ⑬ deal with the generating plant itself, and ⑭ through ㉓ deal with pollution controls.

Cost information for the plant is given in Appendix B.

References

1. J.J. O'Connor, ed., Power, 1978 Plant Design Issue, Vol. 122, No. 11, November 1978.
2. Final Environmental Impact Statement, Spurlock Station, Unit No. 2 and Associated Transmission, USDA-REA-EIS-76-4F, Chapter I, November 1976.
3. G.K. Nielsen, ed., 1978 Keystone Coal Industry Coal Manual, Kentucky #11 Coal, McGraw-Hill, New York, New York, 1978.

FIGURE 1.
PROCESS FLOW CHART WITH ENVIRONMENTAL POINTS OF INTEREST COAL-FIRED POWER PLANT — EASTERN BITUMINOUS COAL — 80% CAPACITY FACTOR



① Run-of-Mine Coal to Coal Preparation

The amount of run-of-mine (ROM) coal to the coal preparation plant is 1.96 x 10^6 tons/yr.

The ROM coal is assumed to be extracted from an underground eastern mine (drift mine operating in thin seam (<40 inches thick) bituminous coal).[1,2] The mined material is assumed to contain rock, slate, and other refuse normally associated with underground mining. The material has moisture, some of which occurs naturally, and some of which is added by in-mine sprays for dust control. The material is carried to the surface preparation plant by conveyor and to the out-of-mine sections, which are enclosed. No Federal regulations apply to the characteristics of the mined material.

To determine the quantity of ROM coal entering the preparation plant, the heat rate, the proposed operating power level of the power plant, and the operating characteristics of the coal preparation plant must be known. The typical power plant design used in this ECIR has a heat rate of 9760 Btu/kWh, and the generating plant operating level is 500 MWe. The coal preparation plant can operate effectively between 20 percent and 30 percent rejection rates.[2] It is assumed that the rejection rate for this coal in this preparation plant has been found empirically to be 27 percent. This typical operating point was established through review of similar circuit operation and accumulated operating experience.[3]

The calculations are as follows:

$$\begin{aligned}\text{Required heat input} &= (\text{Station power output})(\text{net station heat rate})(\text{hr/day}) \\ &= (5.0 \times 10^5\ \text{kWh/hr})(9760\ \text{Btu/kWh})(24\ \text{hr/day}) \\ &= 117 \times 10^9\ \text{Btu/day}\end{aligned}$$

Using the coal cleaning plant operating point of 27 percent rejection, the cleaned coal will have an energy content of 12,000 Btu/lb. Therefore,

$$\begin{aligned}\text{ROM coal into the preparation plant} &= \frac{(\text{heat input})}{(\text{coal heat content})(1 - \text{rejection rate})} \\ &= \frac{(117 \times 10^9\ \text{Btu/day})}{(12.0 \times 10^3\ \text{Btu/lb})(2 \times 10^3\ \text{lb/ton})(1 - 0.27)} \\ &= 6.7 \times 10^3\ \text{tons/day}\end{aligned}$$

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On a yearly basis,

ROM coal into the preparation plant =
(6.7 x 10^3 tons/day)(0.8 capacity factor)(365 days/yr)
= 1.96 x 10^6 tons/yr

The amount of ROM coal input for any preparation plant and power plant combination can be calculated for any coal by applying the plant's known heat rate, the typical preparation plant rejection rate, and cleaned coal Btu content to the above formulas.

References

1. G.K. Nielsen, ed., 1978 Keystone Coal Industry Coal Manual, Kentucky #11 Coal, McGraw-Hill, New York, New York, 1978, p. 505 and pp. 920-921.
2. S.M. Cassidy, "Elements of Practical Coal Mining," Society of Mining Engineers, New York, New York, 1973, pp. 346-356.
3. P.J. Phillips and P.P. DeRienzo, "Assessing the Economics of Steam," Coal Preparation, Coal Mining and Processing, September 1977, p. 75.

② Makeup Water to Coal Preparation

The required makeup water for the coal preparation plant ranges from 15×10^6 gal/yr to 45×10^6 gal/yr.

The coal preparation plant assumed in this system design consists of crushing, washing, and sizing/screening operations, all of which are conducted in the presence of moisture (wet circuit). The system is designed to dewater the coal prior to delivery using screen and hydrocyclone separators and to recirculate the water in the system through a thickener to remove suspended solids. Some water will leave the plant as surface moisture on the clean coal and the rejected refuse material and must be made up by moisture arriving on the surface of the input ROM coal or from a makeup water source. The quality of this makeup water is not critical, and it may come from any of a number of sources such as wells, streams, or mine dewatering.

Because the surface moisture on the input coal is not highly controlled, the makeup requirement will be variable. In general, however, some makeup water will be required.[1]

While the makeup water requirement will vary with the preparation plant capacity, it is not necessarily directly scalable and will depend on empirical experience with a particular preparation circuit and ROM coal.[2] However, this value will not generally exceed 20 gal/ton of ROM coal processed, which equals 40×10^6 gal/yr at an 80-percent capacity factor.

References

1. S.M. Cassidy, "Elements of Practical Coal Mining," Society of Mining Engineers, New York, New York, 1973, p. 435.
2. Personal Communication, Mr. William Ostarello, Roberts and Schaefer Co. Engineers and Contractors, Chicago, Illinois, (312)-236-7292.

③ Fugitive Dust From Coal Preparation

Fugitive or stack particulate emissions from the coal preparation plant are negligible because no thermal drying or onsite open coal storage is employed.

Because the entire preparation facility is enclosed and the preparation circuit is operated in a wet mode, there is little opportunity for fugitive dust emissions from the plant.[1] Typical enclosed silo type coal storage would add little to these emissions if used. Exposed pile storage (seldom used in the east) could be the source of windblown dust if no dust control measures such as compacting, water sprays, or surface coatings are used.

If thermal drying of coal were used in this plant design, either to facilitate dry processing or for shipment preparation, dust emissions to the environment would occur. The uncontrolled emissions from three popular coal drying systems range from 15 to 25 pounds of dust per ton of coal processed. The emissions to the atmosphere could be reduced to less than .075 pound per ton using cyclones followed by wet scrubbing.[1]

The low-level fugitive dust emission characteristics of total wet circuit processing plants are generally applicable to all plant sizes. The emissions factors for thermal drying are directly applicable to any size of processing unit.[1]

Reference

1. U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Third Edition, including supplements 1-7, PB 275-525, August 1977, pp. 346-347.

④ Solid Waste From Coal Preparation

The solid wastes discharged by the coal preparation plant amount to 0.525 x 10^6 tons/yr.

Solid waste discharged from the preparation plant consists of approximately 93 percent rock, slate, and shale; 2 percent coal fines rejected in the cleaning process; and 5 percent pyritic material.[1,2] The exact composition of this material will vary widely from coal to coal and as site mining conditions change, but the coal content will be kept to a minimum.[2] Analyzed samples of contemporary coal preparation plant waste piles show concentrations of pyritic material ranging from 7.7 percent for fines (the size fraction in which pyrites would be expected to concentrate) to 3.1 percent in course rewash refuse.[2]

The calculation is as follows:

Coal preparation waste = (Rejection rate)(ROM coal feed rate)

For the typical plant,

Coal preparation waste = (0.27)(6.7 x 10^3 tons/day) = 1800 tons/day

On a yearly basis,

Coal preparation waste = (1800 tons/day)(0.8 capacity factor)(365 days/yr) = 0.525 x 10^6 tons/yr

This material is transported with associated moisture (10 to 15 percent) to nearby surface landfill where it will be compacted and rehabilitated through revegetation and stabilization techniques.[3] Such sites must be designated and permitted by state/local authorities. Section III discusses land requirements for solid waste disposal. Water control must be installed for both surface and subsurface drainage of the area.

The production of solid waste for a given coal and a given preparation plant is linearly scaleable for changes in plant coal use. As more rock or slate enters in the ROM coal, as in coal from thinner seams, the rock refuse fraction can be expected to rise accordingly, but the coal fines fraction and the pyritic material fraction can be expected to remain constant, based on the clean coal plant output.

References

1. U.S. Environmental Protection Agency, "Environmental Assessment of Coal Cleaning Processes: Technology Overview," EPA-600/7-79-073e, September 1979, p. 47.
2. C. Treworgy, Illinois Geological Survey, In House Studies of Processing Wastes, April 2, 1980.
3. Federal Register, "Surface Coal Mining and Reclamation Operations, Permanent Regulatory Program," Vol. 44, No. 50, March 13, 1979, pp. 15435-15439.

(5) Surface Runoff From Coal Preparation Waste Storage

Surface runoff for coal processing disposal sites is, in general, not quantifiable because it depends on rainfall and subsurface water quantities that may come in contact with the waste material.[1]

Runoff from coal cleaning refuse waste piles will originate from two sources: rainfall on the surface of the fill and subsurface water including moisture on the surface of the material. The requirement to cover with "topsoil" and revegetate and control drainage on the surface of the disposal area will, in general, isolate the rainfall and surface water from the waste material.[1,2] Subsurface water can more readily come in contact with the waste material and this contact can result in the dissolving of solids (forming, for example, sulfates); the acidification of the liquids; or the deposition of suspended solids in the liquid. It is possible that a properly designed and operated drainage system will result in acceptable water quality for discharge to surface waters. If this quality cannot be achieved, treatment of the drainage from the area may be necessary to meet local regulations for dissolved solids, suspended solids, and acidity.[3]

For this processing plant, the dry landfill method of disposal has been chosen. As the surface area of the fill increases, there will be a general increase in the opportunity for ingress of surface (rain) water and for intrusions of subsurface water. Neither of these sources can be accurately quantified.

References

1. U.S. Environmental Protection Agency, "Environmental Assessment of Coal Cleaning Processes: Technology Overview," EPA-600/7-79-073e, September 1979, p. 48.
2. Federal Register, "Surface Coal Mining and Reclamation Operations, Permanent Regulatory Program," Vol. 44, No. 50, March 13, 1979, pp. 15434-15436 and 15424-15430.
3. Personal Communication, Harry Chappel, Illinois Environmental Protection Agency, April 3, 1980.

(6) Fugitive Dust From Onsite Coal Storage

It is not possible to accurately quantify the fugitive dust emissions from the coal storage area. Wind erosion resulting in airborne dust should not be a significant air pollution source for active piles if dust control measures are maintained.

Coal fines are an inevitable[1,2] result of coal preparation and handling operations. Dust emissions from the storage areas, especially active storage, can be effectively controlled through the use of water sprays and surface compaction. In addition, oil, asphalt, or latex coatings can be applied to long-term storage piles to control dust emissions. It should also be noted that the surface of a properly compacted long-term storage pile will quickly lose the fines, which can become airborne, and the dust emissions will drop to a very low level unless the pile is physically disturbed.

The dust emissions from an open coal storage pile are not, in general, quantifiable. They are, however, proportional to the exposed surface of the coal pile and generally will increase with increases in surface wind velocity.[2]

References

1. T.H. Pigford et al., "Fuel Cycles for Electrical Power Generation," EEED-101 Teknekron, Inc., Berkeley, California, January 1973.
2. U.S. Environmental Protection Agency, "Survey of Fugitive Dust From Coal Mines," EPA-908/1-78-003, February 1978, pp. 2 and 56.

⑦ Controlled Runoff From Onsite Coal Storage

It is not possible to accurately quantify the liquid runoff from the coal storage areas because the source of this liquid is primarily rainfall and, to a lesser extent, the water sprays that may be used to control dust.[1]

Subsurface water is excluded from the area by a liner, usually clay or an impermeable membrane. Water that falls on the surface of the coal pile will either be lost to the air through evaporation or be drained to a peripheral drainage channel where it can be routed to the power plant water treatment system. This water may contain suspended solids and dissolved solids; be slightly acidic; and contain oil, if oil sprays are used in dust control. The receiving water treatment system is designed to handle such pollutants through settling, neutralization, oil removal, and blending to achieve acceptable water quality for either recycling uses in the system or discharge to surface water.

The quantity of runoff is generally proportional to the surface area of the coal storage pile and the relative quantity of precipitation at the site.

Reference

1. U.S. Environmental Protection Agency, "Environmental Assessments of Coal Cleaning Processes: Technology Overview," EPA-600/7-79-073e, September 1979, pp. 44 and 45.

⑧ Coal Feed to Generating Plant

The amount of prepared coal required for the typical plant assumed in this ECIR is 1.43 x 10⁶ tons/yr.

To determine how much coal is required to run any given power plant, the following information is needed:

- Net power delivered to the transmission grid (P) in MWe
- Net station heat rate ($\dot{Q}$) in Btu/kWh
- Heat content of coal, as fired (Q) in Btu/lb

The power delivered to the grid is known for a given plant (i.e., the nominal rating of 500 MWe, 1000 MWe, etc.)

The net station heat rate ($\dot{Q}$), which varies from plant to plant, is a measure of the amount of heat (Btu) that must be fed into the boiler to get 1 kWh of electricity out to the grid. Net power delivered to the grid equals total power generated minus power required to operate plant auxiliaries, including environmental control equipment. The actual overall plant heat rate is listed in the plant's major documents, such as the Environmental Impact Statement or the Power Plant Design Report.

The heat content of coal (Q) as fired is a parameter given in the coal analysis.

Using the above definitons, the coal required on a daily basis is as follows:

$$\frac{(P)(\dot{Q})}{Q}\left[\left(\frac{1 \times 10^3 \text{ kWe}}{\text{MWe}}\right)\left(\frac{1}{2 \times 10^3}\frac{\text{ton}}{\text{lb}}\right)\left(2.4 \times 10 \frac{\text{hr}}{\text{day}}\right)\right] = 12\ P\dot{Q}/Q \text{ tons/day}$$

In the typical plant,

P = 500 MWe
$\dot{Q}$ = 9760 Btu/kWh
Q = 12,000 Btu/lb

Thus, for the typical plant,

$$\text{Coal feed rate} = 12\ P\dot{Q}/Q \text{ tons/day}$$

$$\text{Coal feed rate} = \frac{12\ (500 \text{ MWe})(9760 \text{ Btu/kWh})}{12{,}000 \text{ Btu/lb}}$$

$$= 4.9 \times 10^3 \text{ tons/day}$$

On a yearly basis,

Coal feed rate = (4.9 x 10^3 tons/day)(0.8 capacity factor)(365 days/yr)
= 1.43 x 10^6 tons/yr

The analysis for the coal used in this ECIR is as follows[1]:

Proximate Analysis (%)		Ultimate Analysis (%)	
ash	8.8	C	64.9
fixed C	44.3	O	8.7
volatile	38.7	H	4.6
moisture	8.2	N	1.5
		S	3.3
		ash	8.8
		moisture	8.2

Heat value 12,000 Btu/lb

In subsequent sections of this ECIR, values from this coal analysis are used to calculate the resources and residuals associated with operation of the plant, e.g., in item (14) the ash content of the coal is used to calculate the amount of bottom ash from combustion. If a coal different from the one shown in the above table were used, the values from the new coal analysis would be substituted in the equations.

In the calculations of environmental pollutants, it is assumed that 20 percent of the ash is emitted as bottom ash and that the remaining 80 percent is emitted from the boiler as fly ash.[2,3] It is also assumed that 10 percent of the sulfur is retained in the bottom ash and fly ash or removed as a result of pyrite removal in the coal pulverizer, and the remaining 90 percent is converted to sulfur dioxide.[4,5]

The energy content of the coal feed into the boilers is converted into electricity with an efficiency of 35 percent. The remainder of the energy is lost in the form of thermal energy according to the following table.[6]

	Percent of Input	Energy at 100-Percent Capacity (Btu/day)
Net Electrical Output	35	41×10^9
Heat Rejected to Condenser	50	58.5×10^9
Sensible Heat in Flue Gas	10.7	12.5×10^9
Internal Thermal Losses and Plant Consumption	4.3	5×10^9
Total Energy From 4.9×10^3 tons/day Coal Feed at 12,000 Btu/lb	100	117×10^9

These heat losses pose little environmental concern: the heat rejected directly to the atmosphere is negligible, the heat rejected to the main condenser is cooled by closed-cycle cooling towers, and heat rejected through the cooling tower blowdown line is dissipated into the atmosphere through water treatment/recycling facility holding ponds.

References

1. G.K. Nielsen, ed., 1978 Keystone Coal Industry Coal Manual, Kentucky #11 Coal, McGraw-Hill, New York, New York, 1978.
2. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
3. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
4. Personal Communication, Robert Statnick, (202) 426-2683, Senior Staff Engineer, Office of Energy, Minerals, and Industry, Office of Research and Development, U.S. Environmental Protection Agency, Washington, D.C, April 1980.
5. Personal Communication, Walter Stevenson, (919) 541-5477, Staff Scientist, Office of Air Quality, Planning, and Standards, U.S. Environmental Protection Agency, Raleigh-Durham, North Carolina, April 1980.
6. Teknekron, Inc., "Towards Comprehensive Standards: The Electric Power Case," EPA No. 68-01-0561, January 1973, p. 70.

⑨ Evaporative and Drift Losses From Wet Cooling Towers

Evaporative losses from the cooling towers into the atmosphere are approximately 2 x 10^9 gal/yr for a typical 500-MWe power plant operating at full load. Additionally, another 0.25 percent or 5 x 10^6 gal/yr will be lost in the form of drift if drift eliminators are not used.

The above values are based on the assumptions that 50 percent of the gross heat released from coal combustion is dissipated to the circulating water system and that the water heat of vaporization at standard conditions is 1050 Btu/lb water evaporated.[1,2,3] In general, the water requirements due to cooling tower evaporation are given by

$$W_{EVAP}, \text{ gal/day} = 2880 \text{ (percent heat rejected to circulating water system)} \dot{Q}P/\text{(water heat of vaporization)}$$

For the typical plant,

$$W_{EVAP} = (2880)(0.50)(9760 \text{ Btu/kWh})(500 \text{ MWe})/(1050 \text{ Btu/lb}) = 6.7 \times 10^6 \text{ gal/day}$$

On a yearly basis,

$$W_{EVAP} = (6.7 \times 10^6 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) = 2 \times 10^9 \text{ gal/yr}$$

Similarly, requirements due to cooling tower drift for the typical plant are

$$W_{DRIFT} = 0.0025\, W_{EVAP} = 0.0025\,(6.7 \times 10^6 \text{ gal/day}) = 16.8 \times 10^3 \text{ gal/day}$$

On a yearly basis,

$$W_{DRIFT} = (16.8 \times 10^3 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})$$
$$= 4.91 \times 10^6 \text{ gal/yr}$$

These cooling tower losses may interact with the local meteorology and cause visibility impairment, fogging, or icing conditions. There are no existing regulations limiting cooling tower losses to the atmosphere.

References

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 47-81.
2. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, pp. 61-105.
3. Power Handbook: Basic Power Facts Made Easy, Part One and Part Two, Power Magazine, 1975, p. 104.

(10) Cooling Tower Blowdown

Cooling tower blowdown represents approximately 10 percent of the evaporation losses.[1,2] For a typical plant, blowdown is 0.2 x 10⁹ gal/yr and goes to the water treatment/recycling facility to be reused as makeup water.

Blowdown water typically contain the following environmental residuals: biocides (e.g., chlorine), added for marine and biological growth control; corrosion inhibitors (e.g., chromates), a high concentration of total dissolved solids; and excess heat. Because these residuals are collected and controlled in the water treatment/recycling facility, there is no direct influence on the environment (see item (15)).

For any plant,

$$W_{BLOWDOWN} = 0.1\ W_{EVAP}$$

For the typical plant,

$$W_{BLOWDOWN} = 0.1\ (6.7 \times 10^6\ \text{gal/day})$$
$$W_{BLOWDOWN} = 0.7 \times 10^6\ \text{gal/day}$$

On a yearly basis,

$$W_{BLOWDOWN} = (0.7 \times 10^6\ \text{gal/day})(0.8\ \text{capacity factor})(365\ \text{days/yr}) = 0.2 \times 10^9\ \text{gal/yr}$$

References

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, p. 47.
2. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, p. 69.

(11) Cooling Tower Makeup

Approximately 2.2 x 10^9 gal/yr are needed to make up cooling tower losses due to drift, evaporation, and blowdown for a typical plant.

Cooling tower makeup is obtained by summing W_{EVAP} and W_{DRIFT} from item (9) and $W_{BLOWDOWN}$ from item (10) as follows:

$$W_{TOW} = W_{EVAP} + W_{DRIFT} + W_{BLOWDOWN}$$

For the typical plant,

$$W_{TOW} = (6.7)(10^6 \text{ gal/day} + 0.02)(10^6 \text{ gal/day} + 0.67)(10^6 \text{ gal/day})$$
$$= 7.4 \times 10^6 \text{ gal/day}$$

On a yearly basis,

$$W_{TOW} = (7.4 \times 10^6 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})$$
$$= 2.2 \times 10^9 \text{ gal/yr}$$

The above analysis is for a wet cooling system only. When water is expensive, however, (greater than about $0.80/$10^3$ gallons) or of limited availability, combined wet and dry cooling systems would be used. For such systems, the average annual water consumption is between 10 and 25 percent of the all wet system.[1]

Reference

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 47-81.

(12) Miscellaneous Plant Drains

The typical liquid waste flow from miscellaneous plant drains is 175 x 10^6 gal/yr, all of which goes to the water treatment/recycling facility.[1]

The liquid waste consists of various water streams used in maintaining plant operation (e.g., boiler blowdown and bearing cooling) and can be slightly contaminated with oil or chemicals. The waste figure given above was taken from an operating 500-MWe power plant.[1] Because the magnitude of the waste stream is not a linear function of plant power level, the waste from a power plant of a size other than 500 MWe should be obtained from an actual plant of that size. Such information is contained in the plant's Environmental Impact Statement.

The chemical nature of the waste stream as potentially released to the environment is discussed in item (15).

Reference

1. Environmental Analysis, Spurlock Station Unit No. 2, Docket No. 6500-05, July 1975, p. II-54.

(13) Makeup Water to Generating Plant

The makeup water to the generating plant is 180 x 10^6 gal/yr.

Makeup water is required for two purposes: for the operations discussed in item (12) and for handling bottom ash from the boiler.

Bottom ash is collected and quenched in water-filled hoppers before it is sluiced to a disposal site. The rate at which water is evaporated from the hopper, W_{VAP}, is a function of the ash specific heat, temperature drop, quenching rate, and water heat of vaporization, i.e.,

$$W_{VAP}, \text{gal/day} = 240 \text{ (ash fraction in coal)(coal feed rate)(bottom ash fraction)(bottom ash temperature change)(bottom ash specific heat)/(water heat of vaporization)}$$

For the typical plant, if it is assumed that

Ash removal temperature	= 1200° F
Ash quenched temperature	= 200° F
Ash specific heat	= 0.2 Btu/lb-° F
Water heat of vaporization	= 1.050 x 10^3 Btu/lb
Bottom ash fraction	= 0.2

then

$$W_{VAP} = 240\ (0.088)(4.9 \times 10^3 \text{ tons/day})(0.2)(1000°F)(0.2 \text{ Btu/lb-°F})/(1050 \text{ Btu/lb}) = 3.9 \times 10^3 \text{ gal/day}$$

On a yearly basis,

$$W_{VAP} = (3.9 \times 10^3 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) = 1.14 \times 10^6 \text{ gal/yr}$$

Of equal importance to the water evaporated is the amount of excess water needed for bottom ash handling and disposal, W_{HAD}. If the weight of water remaining in the quenched ash is 30 percent of the ash weight, then

$$W_{HAD}\text{, gal/day} = 72\ (\text{ash fraction in coal})(\text{coal feed rate})(\text{bottom ash fraction})$$

For the typical plant,

$$\begin{aligned} W_{HAD} &= 72\ (0.088)(4.9 \times 10^3\ \text{tons/day})(0.2) \\ &= 6.2 \times 10^3\ \text{gal/day} \end{aligned}$$

On a yearly basis,

$$\begin{aligned} W_{HAD} &= (6.2 \times 10^3\ \text{gal/day})(0.8\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 1.81 \times 10^6\ \text{gal/yr} \end{aligned}$$

The total water requirement for bottom ash disposal, W_{BA}, is therefore given as

$$W_{BA} = W_{VAP} + W_{HAD}$$

For the typical plant,

$$\begin{aligned} W_{BA} &= (3.9)(10^3\ \text{gal/day} + 6.2)(10^3\ \text{gal/day}) \\ &= 10.1 \times 10^3\ \text{gal/day} \end{aligned}$$

On a yearly basis,

$$W_{BA} = (10.1 \times 10^3 \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})$$
$$= 3 \times 10^6 \text{ gal/yr}$$
$$= 0.03 \times 10^8 \text{ gal/yr}$$

The majority of this water will be supplied from recycled water (see item (16)). Thus, the total makeup water requirement for the generating plant is the 1.75×10^8 gal/yr for general plant operations (see item (12)) plus the 0.03×10^8 gal/yr given above, or 1.78×10^8 gal/yr $\approx 180 \times 10^6$ gal/yr.

Reference

1. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, Chapter 8, August 24, 1976, p. 141.

(14) Bottom Ash From Coal Combustion

The amount of bottom ash generated is 25 x 10^3 tons/yr.

As described earlier, the quantity of ash in the coal assumed for this ECIR is 8.8 percent, and 20 percent of this ash becomes bottom ash.[1,2] Thus,

$$\text{Bottom ash} = (\text{ash fraction in coal})(\text{coal feed rate})(\text{bottom ash fraction})$$

For the typical plant:

$$\text{Bottom ash} = (0.088)(4.9 \times 10^3 \text{ tons/day})(0.20) = 86 \text{ tons/day}$$

On a yearly basis,

$$\text{Bottom ash} = (86 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) = 25 \times 10^3 \text{ tons/yr}$$

Bottom ash from a dry bottom pulverized coal boiler is collected and quenched in hoppers, located beneath the boiler, where it is sluiced with water to settling ponds or dewatering bins.[3]

<u>References</u>

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
2. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
3. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plant in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, p. 142.

(15) Excess Water to River or Sewer

Whenever the holding pond from the water treatment/recycling facility overflows during low demand periods, the excess water is directed to the area surface waters (lake or river) or to a sewer system.

The quantity and quality of the overflow is controlled to within standards established by either the Federal Government or the state based on National Pollutant Discharge Elimination System (NPDES) procedures and guidelines. Projections for the typical coal-fired 500-MWe power plant show that the maximum flow rate from the holding ponds under worst-case conditions is 26 x 10^6 gal/day.[4] The maximum daily average concentration of controlled residuals observed for 30 consecutive days and the amount of residuals that would be released at the maximum flow rate are as follows:[4]

Residual	Maximum Amount Released	Maximum Measured Concentration (mg/l)	Kentucky Water Quality Standards (mg/l)
Total Suspended Solids	3.3 tons/day	30	30
Oil and Greases	1.7 tons/day	15.2	None
Copper	2 lb/day	0.009	1
Iron	2 lb/day	0.009	1
Chlorine	24.2 lb/day	0.11	None

Where

$$\text{Maximum amount released per day} = (\text{Maximum flow rate})\left(\text{Maximum average 30-day concentration}\right)$$

The allowable concentrations of the pollutants shown above are specified by the appropriate state NPDES permitting authority[5] based on Federal regulations in the Clean Water Act, local pollutant regulations, and the water quality characteristics of the receiving water.

The 26 x 10^6 gal/day worst-case discharge is not characteristic of the expected flow. The actual flow would be considerably lower and would depend on site-specific conditions, such as precipitation.

References

1. Federal Water Pollution Control Act, P.L. 92-500 (as ammended), 1972.
2. Clean Water Act, P.L. 95-217, 1977.
3. U.S. Environmental Protection Agency, "A Guide to New Regulations for the NPDES Permit Program," C-1, June 1979.
4. Environmental Analysis, Spurlock Station Unit No. 2, Docket No. 6500-05, July 1975, p. II-55.
5. Personal Communication, Division of Water Quality, Kentucky Department of Natural Resources and Environmental Protection, (502) 564-2126.

(16) Recycle Water

Recycled water can be used for the solid waste handling requirement of 2.9 x 10^7 gal/yr.

Recycle water in this plant configuration is water that has been withdrawn from the plant water treatment system after settling, oil removal, and acidic neutralization. This water will contain varying degrees of dissolved solids as well as suspended particulates. In general, it will be of such quality that it could be discharged to surface waters.

The amount of water required in solid waste handling systems, assuming a 50-percent total solids mixture is given by

$$\text{Water required, gal/day} = 240\ [(\text{bottom ash, dry}) + (\text{fly ash, dry}) + (\text{scrubber sludge, dry}) - (\text{water in scrubber sludge})]$$

For the typical plant,

$$\text{Water required} = 240\ [86\ \text{tons/day} + 345\ \text{tons/day} + 660\ \text{tons/day} - 660\ \text{tons/day}] = 0.1 \times 10^6\ \text{tons/day}$$

On a yearly basis,

$$\text{Water required} = (0.1 \times 10^6\ \text{gal/day})(0.8\ \text{capacity factor})(365\ \text{days/yr}) = 2.9 \times 10^7\ \text{gal/yr}$$

The amount of recycle water required for ash handling is directly and linearly scalable with plant capacity for a given coal and scrubber operation and will increase linearly as the dry solids to be transferred increase.

Reference

1. Final Environmental Impact Statement, Spurlock Station Unit No. 2, and Associated Transmission, USDA-REA-EIS-76-4F, November 1976.

(17) Fly Ash From Particulate Control

The total amount of fly ash generated is 100×10^3 tons/yr.

Dry electrostatic precipitators are used to remove the coal fly ash from the flue gas. Eighty percent of the ash in the coal is emitted as fly ash,[1,2] or

$$\text{Fly ash} = (\text{ash fraction in coal})(\text{coal feed rate})(\text{fly ash fraction})$$

For the typical plant,

$$\begin{aligned}\text{Fly ash} &= (0.088)(4.9 \times 10^3 \text{ tons/day})(0.80)\\ &= 345 \text{ tons/day}\end{aligned}$$

On an annual basis,

$$\begin{aligned}\text{Fly ash} &= (345 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})\\ &= 100 \times 10^3 \text{ tons/yr}\end{aligned}$$

To meet the current NSPS of 0.03 $lb/10^6$ Btu, only 0.5 percent of this amount is emitted to the ambient atmosphere, and 99.5 percent is captured by the electrostatic precipitator.

From these precipitators, the collected ash is discharged into storage hoppers by rapping. The dry fly ash is transported by pneumatic conveying from the precipitator to the sluicing system, where it will become part of the bottom ash scrubber sludge mixture.[3]

A second particle control technology now in use and gaining in popularity is the baghouse. Although the technology has been applied to large utility boilers both in the East and in the West, it is more predominantly applied in the West to collect the high resistivity fly ash from western coals that is difficult to collect in an ESP[4] and to meet more stringent particulate emission standards imposed by some western states. Baghouses generally have higher collection efficiencies than ESPs (96 to 99.5 percent for ESPs versus >99 percent for baghouses in most cases) and are especially effective in the control of fine particles ($<3\mu$). If a baghouse is to be considered, the assumed collection efficiency of the unit can be directly substituted in the example given in place of the 99.5 percent removal efficiency assumed for the ESP. Although the removal efficiency is variable for both ESPs and baghouses, the individual utilities will generally operate the units to meet the standards that apply in each specific case.

<u>References</u>

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
2. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
3. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Porgram, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, p. 144.
4. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Matter Emission Standards," EPA-450/2-78-006a, July 1978 p. 4-1.

(18) Makeup Water for Fly Ash Transport

Water added to the captured fly ash to transport it to the disposal area is 24 x 10^6 gal/yr.

Dry electrostatic precipitators are used to remove the coal fly ash from the flue gas. In these precipitators, the collected ash is discharged into a sluicing system by rapping. The ash is then combined with recycle water until the mixture is at least 50-percent liquid by weight.[1] Note that the fly ash, bottom ash, and scrubber sludge are all individually fed into the sluicing system.

The amount of water required to transport the ash in the sluicing system is given as

$$\text{Water required, gal/day} = 240\ (\text{ash fraction in coal})(\text{coal feed rate})(\text{fly ash fraction})$$

For the typical plant,

$$\begin{aligned}\text{Water required} &= 240\ (0.088)(4.9 \times 10^3\ \text{tons/day})(0.8) \\ &= 83 \times 10^3\ \text{gal/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Water required} &= (83 \times 10^3\ \text{gal/day})(0.8\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 24 \times 10^6\ \text{gal/yr}\end{aligned}$$

Reference

1. Electric Power Research Institute, "FGD Sludge Disposal Manual," FP-977, January 1979, p. 4-7, Table 4-2.

(19) Sludge From SO_2 Control

The amount of scrubber sludge generated (on a dry basis) is 193 x 10^3 tons/yr.

The use of a limestone scrubber is assumed for SO_2 control based on the current number of such units in operation and their combined record of effectiveness and reliability. The operation of such units involves the creation and requirement for disposal of sludge (spent reactants mixed in the same ratio with water).

The quantity of sulfur in the coal used is 3.3 percent. Therefore, the quantity of sulfur entering the boiler is

$$\begin{aligned} S &= \text{(sulfur fraction in coal)(coal feed rate)} \\ &= 0.033\ (4.9 \times 10^3 \text{ tons/day}) \\ &= 162 \text{ tons/day} \end{aligned}$$

If it is assumed that a total of 10 percent of the sulfur is retained in the bottom ash and fly ash or removed as a result of pyrite removal in the coal pulverizer, and that the remainder of the sulfur is converted to SO_2, then

$$\begin{aligned} SO_2 &= 0.9\ \text{(sulfur entering boiler)(2)} \\ &= 0.9\ (162 \text{ tons/day})(2) \\ &= 292 \text{ tons/day} \end{aligned}$$

Thus, 292 tons/day of SO_2 enter the scrubber.[1-4] (Note: The factor "2" in this equation is used because every mole of sulfur requires 1 mole of oxygen to form 1 mole of SO_2.) As will be shown in item 22, the amount of dry limestone used is 500 tons/day, i.e., 1.25 times the stoichiometric requirement. This excess 25 percent of the stoichiometric requirement will become part of the sludge residue. It is generally accepted[5] that the spent slurry consists of 75 percent $CaSO_3 \cdot \frac{1}{2}H_2O$ and 25 percent $CaSO_4 \cdot 2H_2O$. As will be shown in item (23), the scrubber must operate at 88 percent efficiency to meet the standard. Consequently, the amount of scrubber sludge (dry basis) generated each day is

$$\begin{aligned} \text{Sludge} &= [0.25\ (100/64) + (140/64)]\text{(scrubber efficiency)}(SO_2 \text{ feed rate}) \\ &= [0.25\ (100/64) + (140/64)](0.88)(292 \text{ tons/day}) \\ &= 660 \text{ tons/day} \end{aligned}$$

On a yearly basis,

$$\text{Sludge} = (660 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) = 193 \times 10^3 \text{ tons/yr}$$

where

100/64 = limestone/SO_2 molecular weight ratio
140/64 = ($CaSO_3 \cdot ½H_2O$ and $CaSO_4 \cdot 2H_2O$) mixture/SO_2 molecular weight ratio

Based on current usage and projections of new installations, lime/limestone scrubbers are the most popular form of SO_2 control now available and are expected to remain so in the foreseeable future. Other SO_2 control systems have been demonstrated at utility scale, however. These include sodium carbonate scrubber systems, dual alkali scrubber systems, Wellman-Lord regenerative scrubber systems, magnesium oxide regenerative scrubber systems, and dry lime or alkali injection systems. Although these systems are now or have been in commercial operation, their overall number is small and for this reason have not been included in the detailed evaluation of control technology. The major points of environmental interest for these systems are generally the same as those for lime/limestone. The interest in these systems centers primarily on their potential for desirable modification or reduction in the waste (generally considered solid waste) streams from the process.

Although the current NSPS for SO_2 control excludes the use of low-sulfur coal alone to achieve compliance, low-sulfur coal can be used in combination with other SO_2 removal techniques to achieve a more desirable system from the standpoint of reliability, economics, or both. For those plants operating under the previous Federal NSPS, the use of low-sulfur coal is a viable option to achieve the 1.2 lb/10^6 Btu SO_2 emission limit. Older plants, not controlled by Federal regulations, may also use low-sulfur coal to comply with applicable state and local SO_2 standards.

References

1. Personal Communication, Robert Statnick, (202) 426-2683, Senior Staff Engineer, Office of Energy, Minerals, and Industry, Office of Research and Development, U.S. Environmental Protection Agency, Washington, D.C.
2. Communication, Walter Stevenson, (919) 541-5477, Staff Scientist, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Raleigh-Durham, North Carolina, April 1980.
3. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards," EPA-450/2-78-007a, July 1978.
4. U.S. Environmental Protection Agency, "Position Paper on Regulation of Atmospheric Sulfates," EPA-450/2-75-007, September 1975.
5. Aerospace Corporation, "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact, Vol. II. Technical Discussion," EPA-600/7-78-0446, March 1978.

(20) Solid Waste Handling

The typical plant and associated pollutant controls generate 320 x 10^3 tons/yr (dry basis) of solid sludge.

Waste streams entering the disposal site contain pyrites sluiced from the coal pulverizer and bottom ash sluiced from the boiler, fly ash sluiced from the electrostatic precipitator, and scrubber sludge underflow from a thickener located downstream of the scrubber. The scrubber wastes in the disposal site settle to approximately 50 percent solids. Excess water, i.e., from the settling of the scrubber sludge and unevaporated rainwater, is returned to the water treatment/recycle facility.

The wastes are contained in impoundments formed by the excavation of the disposal site. Sides of the impoundment are sloped and extend above grade level to complete the basin and form berms and dikes around the periphery of the site. A total depth of 30 feet of waste material is considered typical.

For the typical plant, determination of total solid wastes on a dry basis and required land area are as follows:

1. 86 tons/day bottom ash
   345 fly ash
   560 reacted limestone (75%:$CaSO_3 \cdot \frac{1}{2} H_2O$ & 25%:$CaSO_4 \cdot 2 H_2O$)[1]
   +100 unreacted limestone

   1100 tons/day (solids, dry) at 88.6 lb/ft^3

2. Adding sluicing water results in
   +1100 tons/day (sluicing water)

   2200 tons/day wet waste

3. To determine land required:[2]

$$\left(2200 \frac{\text{tons}}{\text{day}}\right)\left(2000 \frac{\text{lb}}{\text{ton}}\right)\left(\frac{1}{88.6} \frac{\text{ft}^3}{\text{lb}}\right)\left(\frac{1}{30} \text{ ft} \times \frac{1}{43{,}560} \frac{\text{acre}}{\text{ft}^2}\right)(1.1, \text{ impoundment size factor})\left(365 \frac{\text{days}}{\text{year}}\right) = 15.3 \frac{\text{acres}}{\text{year}}$$

4. This results in a land acreage requirement of

$$\left(15.3 \frac{\text{acres}}{\text{year}}\right)\left(30 \frac{\text{years}}{(\text{life})}\right) = 460 \text{ acres at 100 percent capacity factor}$$

On an annual basis,

$$\text{Sludge} = (1100\ \text{tons/day})(0.8\ \text{capacity factor})(365\ \text{days/yr}) = 320 \times 10^3\ \text{tons/yr}$$

and

$$\text{Land requirement} = (460\ \text{acres/yr})(0.8\ \text{capacity factor}) = 370\ \text{acres for 30 years, 30 feet deep}$$

Regardless of the solid waste treatment or stabilization method used, upon filling of the disposal impoundment, it is expected that a layer of soil will be placed over the wastes and will be graded and sloped to encourage rainwater runoff and to minimize seepage of rainwater through the wastes.

Three alternative sludge treatment and stabilization methods are available for disposal of the wastes: (1) Settling the wastes over an impervious layer and decauting of supernatant liquid; the impervious material can be clay or an elastomeric liner with a permeability coefficient of 10^{-7} cm/sec or less. (2) Reducing the leachability of the waste (to 10^{-5} to 10^{-7} cm/sec) by chemically treating the scrubber sludge-ash waste with lime, forming a solid material with low permeability characteristics and high load-bearing characteristics.[2] (3) Installing an underdrainage or dewatering system of perforated pipes in the soil immediately below the sludge-soil interface. Settling of the wastes up to 60 percent solids has been observed.[2] Further settling to 80 percent solids (with a correspondent reduction of waste volume and disposal land area) can be achieved if the scrubber sludge were oxidized to gypsum within the scrubber or in an oxidation tower downstream of the scrubber.

Decisions on the use of these alternatives will be based on site-specific considerations, including sludge and soil characteristics, land reclamation requirements, and cost factors.

<u>Radon Emanation From Solid Waste Storage</u>

Analysis of the ash produced by the combustion of bituminous coal has shown that a power plant solid waste burial site will emit approximately 2.23×10^{-4} Ci/day of radioactive radon-222 gas for every acre of covered solid waste disposed of. Over a 30-year plant lifetime, radon emissions will average 4.1×10^{-2} Ci/day for a typical 500-MWe plant, assuming that all of the solid wastes are buried with approximately 2 feet of earth cover at the power plant site and the plant operates at an average capacity factor of 80 percent.

Radon emanation from ash piles is a function of the surface area and depth of the buried waste and the depth of earth cover over the waste. Waste containing radium-226 (the parent nuclide of radon-222 gas) buried at a depth of 10 feet will emit approximately the same amount of radon gas as waste buried in deeper layers because of the self-shielding effect of the waste. Using data collected by the U.S. Geological Survey,[3] Goldman has shown that the annual radon-222 gas emissions from Appalachian coal ash waste with a radium-226 concentration of 3.48 pCi/gm would be 0.191 Ci/acre-yr assuming a 25-percent reduction due to a 2-foot earth cover.[4]

Using these data and adjusting for the higher radium-226 concentration assumed in item (23), a radon gas emanation rate factor of 5.69×10^{-4} Ci/day-acre is produced, assuming a 2-foot earth cover and an ash depth of at least 10 feet. This factor must be adjusted downward according to the amount of non-ash waste, e.g., scrubber sludge, in the solid waste piles.

Because radium-226 decays to radon-gas at a very slow rate (the half-life of radium-226 is over 1600 years), it can be assumed that, over the 30-year plant life, radon gas emanation is directly proportional to the waste pile surface area and the amount of ash containing radium-226 in the waste; therefore,

$$\text{Radon gas, Ci/day} = \left(\frac{\text{ash content in solid waste}}{\text{total solid waste disposed}}\right)\left(\text{surface area of waste piles, acres}\right)\left(5.69 \times 10^{-4}\ \text{Ci/day-acre}\right)$$

For the typical plant,

$$\text{Radon gas, Ci/day} = \left(\frac{\text{431 tons/day bottom and fly ash}}{\text{1100 tons/day total solid waste}}\right)\left(\text{surface area of waste piles}\right)\left(5.69 \times 10^{-4}\ \text{Ci/day-acre}\right)$$

(See item 20 for solid waste quantities)

$$= (2.23 \times 10^{-4}\ \text{Ci/day-acre})(\text{surface area of waste pile, acre})$$

For item (20), the total area necessary for the disposal of solid wastes at a depth of 30 feet over the 30-year lifetime for the typical 500-MWe plant, assuming an 80-percent capacity factor, is 370 acres. Therefore, the average daily radon emission from the burial site over the 30-year plant life is as follows:

$$\text{Radon gas} = \left(2.23 \times 10^{-4}\ \text{Ci/day-acre}\right)\left(\frac{370\ \text{acres}}{2}\right)$$
$$= 4.1 \times 10^{-2}\ \text{Ci/day}$$

The factor of 2 is used to compute the average area of the solid waste burial ground assuming a constant buildup at 10 acres/yr over 30 years (see item (20)).

Therefore, the annual average radon emission, assuming a 80-percent capacity factor, is

$$\text{Annual radon gas} = (4.1 \times 10^{-2}\ \text{Ci/day})(365\ \text{days/yr})$$
$$= 14.9\ \text{Ci/yr}$$

There are no current regulations controlling the release of radon from coal waste storage piles.

<u>References</u>

1. P.P. Leo and J. Rossoff, "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact," EPA-600/7-78-044b, Aerospace Corporation, March 1978.
2. R.B. Fling et al., "Disposal of Flue Gas Cleaning Wastes: EPA Shawnee Field Evaluation - Third Annual Report," EPA-600/7-80-011, Aerospace Corporation, January 1978.
3. V.E. Swanson, "Collection, Chemical Analysis, and Evaluation of Coal Samples," USGA Open File Report 76-468, 1975.
4. M.I. Goldman, "Energy: What About the Waste?" <u>Chemical Engineering Progress</u>, November 1979, p. 65.

(21) Makeup Water for SO_2 Control

The amount of makeup water required for flue gas desulfurization is 300 x 10^6 gal/yr.

For this analysis, a lime/limestone slurry is used in the scrubber, and it is assumed that the flue gas is saturated with water vapor upon leaving the scrubber. Typical conditions at this location are P = 15.056 psia and T = 102°F, which correspond to flue gas containing 0.127 mole water/mole dry gas. If the fractional weights of carbon (C), sulfur (S), hydrogen (H), oxygen (X), and water (W) in the coal are known, and 15 percent excess air is assumed, it can be shown that the makeup water requirement per unit weight of coal is given by the following relation:[1,2]

$$\frac{\text{lb makeup water}}{\text{lb coal}} = 12.8\left(\frac{C}{12} + \frac{S}{32}\right) + 10.5\left(\frac{H}{4} - \frac{X}{32}\right) - W - \frac{H}{9}$$

Using the coal feed rate obtained previously, the above equation can be modified to give the required daily water feed rate, W^1_{FGD}:

$$W^1_{FGD},\ \text{gal/day} = \left[12.8\left(\frac{C}{12} + \frac{S}{32}\right) + 10.5\left(\frac{H}{4} - \frac{X}{32}\right) - W - \frac{H}{9}\right]\left(2.88 \times 10^3\ \frac{PQ}{Q}\right)$$

In addition to leaving with the flue gas, there is also going to be some water leaving with the solid wastes, e.g., $CaSO_3 \cdot \frac{1}{2}H_2O$ and $CaSO_4 . 2H_2O$. It is to be noted that, for the purposes of these calculations, the amount of water of hydration is considered negligible. The amount of water leaving in the solid wastes is a function of the sulfur concentration of coal and the slurry concentration,[1,2] i.e.,

$$\frac{\text{lb makeup water}}{\text{lb sulfur}} = 5.9\left(\frac{1-m}{m}\right)$$

where

m = weight fraction of solids in waste

= (weight of solids)/(weight of solids plus water)

The above equation can similarly be modified to give the required daily water feed rate, W^2_{FGD}:

$$W^2_{FGD},\ \text{gal/day} = 1.7 \times 10^4\ \frac{PQ}{Q}\ S\left(\frac{1-m}{m}\right)$$

The total required daily water feed rate is therefore given as

$$W_{FGD} = W_{FGD}^{1} + W_{FGD}^{2}$$

For the typical plant, application of the above equations gives

$$W_{FGD}^{1} = 0.80 \times 10^{6} \text{ gal/day (vaporized)}$$
$$W_{FGD}^{2} = 0.23 \times 10^{6} \text{ gal/day (50 percent solids)}$$
$$W_{FGD} = 1.0 \times 10^{6} \text{ gal/day}$$

On an annual basis,

$$W_{FGD} = (1.0 \times 10^{6} \text{ gal/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) = 300 \times 10^{6} \text{ gal/yr}$$

References

1. R.F. Probstein and H. Gold, Water in Synthetic Fuel Production: The Technology and Alternatives, The MIT Press, 1978, pp. 40-44.
2. Water Purification Associates, "Final Report: An Assessment of Minimum Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," prepared for Science and Public Policy Program, University of Oklahoma, Contract No. 68-01-1916, August 24, 1976, pp. 110-120.

(22) Lime/Limestone Requirement for SO_2 Control

The amount of lime/limestone required for flue gas desulfurization is 146 x 10^3 tons of dry $CaCO_3$/yr. (The requirement is given solely in terms of limestone because of the relatively large economic penalty incurred if lime is purchased rather than obtained during calcination of limestone.)

For limestone scrubbing, absorbent utilization is generally 0.8[1] (i.e., the calcium-to-sulfur ratio is 1.25) and, as shown in item (23), Figure 2, the scrubber has to achieve 88-percent removal efficiency to satisfy the SO_2 emission standard. The limestone requirement is therefore given by

$$\begin{aligned}\text{Limestone} &= (1.25)(100/64)(SO_2 \text{ feed rate})(\text{scrubber efficiency}) \\ &= 1.25\ (100/64)(292 \text{ ton } SO_2/\text{day})(0.88) \\ &= 500 \text{ tons dry } CaCO_3/\text{day}\end{aligned}$$

where

100/64 = limestone/SO_2 molecular weight ratio.

On an annual basis,

$$\begin{aligned}\text{Limestone} &= (500 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) \\ &= 146 \times 10^3 \text{ tons/yr}\end{aligned}$$

Reference

1. Aerospace Corporation, "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact, Vol. II. Technical Discussion," EPA-600/7-78-044b, March 1978.

(23) Flue Gas

The pollutants and trace elements that are part of the flue gas emitted to the ambient atmosphere past control are as follows:

SO_2	10.2×10^3 tons/yr
NO_x	10.2×10^3 tons/yr
TSP	0.5×10^3 tons/yr
HC	0.22×10^3 tons/yr
CO	0.72×10^3 tons/yr
CO_2	3.7×10^6 tons/yr
As	225 lb/yr
Be	9.3 lb/yr
Cd	4.1 lb/yr
Mn	161 lb/yr
Pb	114 lb/yr
Se	56 lb/yr
Ra	3×10^{-3} Ci/yr (radioactive)

SO_2

The amount of SO_2 emitted to the ambient atmosphere is 0.6 lb/10^6 Btu. The current New Source Performance Standards for SO_2 regulation are summarized below.[1]

Uncontrolled Emissions (lb $SO_2/10^6$ Btu)	Percent Reduction	Controlled Emissions (lb $SO_2/10^6$ Btu)
> 12	> 90	1.2 maximum
12 to 6	90	1.2 → 0.6
6 to 2	90 → 70	0.6 (constant)
< 2	70	< 0.6

Basically, for steam coals burned by utilities with uncontrolled emissions exceeding 12 lb $SO_2/10^6$ Btu, SO_2 reductions exceeding 90 percent would be required to limit emissions to a maximum of 1.2 lb $SO_2/10^6$ Btu. For those coals whose uncontrolled emissions would range from 12 to 6 lb/10^6 Btu, a constant 90-percent removal is required, resulting in controlled emissions ranging from 1.2 lb $SO_2/10^6$ Btu to 0.6 lb/10^6 Btu. For coals with sulfur contents that would emit 6 to 2 lb $SO_2/10^6$ Btu, a variable removal rate between 90 and 70 percent is required to achieve a constant 0.6 lb $SO_2/10^6$ Btu. For example, at 6 lb $SO_2/10^6$ Btu, 90-percent removal is required; at

2 lb $SO_2/10^6$ Btu, 70 percent is required; and at 3 lb $SO_2/10^6$ Btu, 80 percent is needed. In all cases, it should be noted that the controlled emissions are 0.6 lb/10^6 Btu. If the uncontrolled emissions are less than 2 lb/10^6 Btu, 70 percent SO_2 is then required.

On a yearly basis, controlling SO_x and NO_x to 0.6 lb/10^6 Btu gives (at 80-percent capacity factor),

$$
\begin{aligned}
SO_x \text{ (and } NO_x) &= (0.6 \text{ lb}/10^6 \text{ Btu})(34 \times 10^{12} \text{ Btu/yr}) \\
&= 20.4 \times 10^6 \text{ lb/yr} \\
&= 10.2 \times 10^3 \text{ tons/yr}
\end{aligned}
$$

The SO_2 removal requirements for a 12,000 Btu/lb coal are illustrated in Figure 2. Seventy percent SO_2 removal is required up to a sulfur content of 1.2 percent. Between 3.6 and 7.2 percent, 90-percent removal is required. If the sulfur content is in the range between 1.2 and 3.6, different removal rates, as shown, are required to maintain the 0.6 lb $SO_2/10^6$ allowable. For the coal used in this ECIR (3.3 percent sulfur and 12,000 Btu/lb), an overall 89.1-percent SO_2 removal is needed. With a total of 10 percent sulfur removed as a result of pyrite removal in the coal pulverizer and as sulfur retained in the bottom ash and fly ash, the sulfur content as seen by the scrubber is 3.0 percent (3.3 - 0.1 x 3.3). The scrubber will therefore be required to remove 88 percent to achieve the overall 89.1-percent reduction.

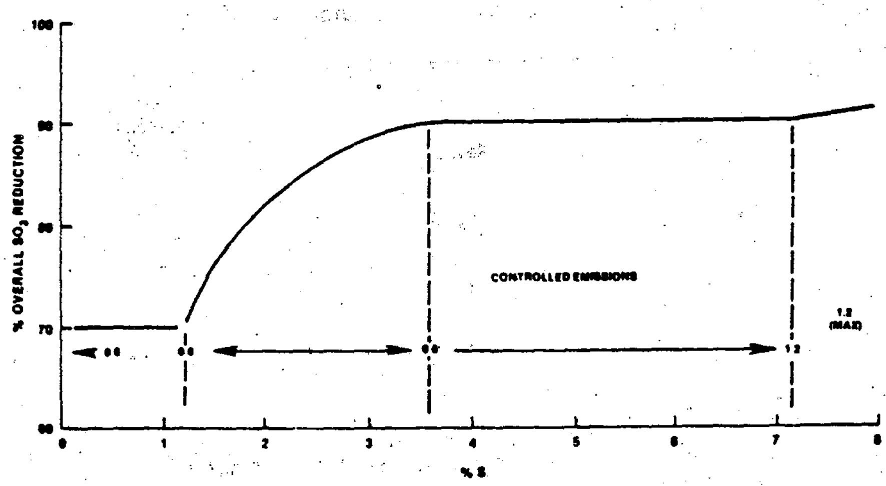

FIGURE 2. OVERALL SO_2 REDUCTION REQUIRED FOR A 12,000 Btu/lb COAL TO MEET CURRENT NSPS REGULATIONS

NO_x

The current New Source Performance Standard for NO_x regulations is[1] 0.6 lb/10^6 Btu.

The amount of NO_x emitted to the ambient atmosphere is 0.6 lb/10^6 Btu. The general way of achieving compliance with NO_x emissions is to employ combustion modification techniques.[2,4] The boiler manufacturer usually includes in his performance guarantee the provision that emissions of nitrogen oxides while firing coal shall be less than 0.6 lb/10^6 Btu.[3] Emissions of oxides of nitrogen are limited by low flame and furnace temperatures, by short residence time of the gases at high temperatures, and by reduced amounts of excess air present in the flame.

Particulates

The current New Source Performance Standard for particulate regulation is 0.03 lb/10^6 Btu.

The amount of particulates (i.e., fly ash that is not captured in the electrostatic precipitator) emitted to the ambient atmosphere is 0.03 lb/10^6 Btu. The amount of ash in the coal used in this ECIR is 8.8 percent. If 80 percent of the ash is emitted as fly ash and the electrostatic precipitator efficiency is 99.5 percent, the particulate emission to the atmosphere is given by

$$\text{Particulates} = (\text{ash fraction in coal})(\text{fly ash fraction})(\text{coal feed rate})(1-\text{electrostatic precipitator efficiency})$$

For the typical plant,

$$\begin{aligned}\text{Particulates} &= (0.088)(0.80)(4.9 \times 10^3 \text{ tons/day})(1-0.995)\\ &= 1.7 \text{ tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}\text{Particulates} &= (1.7 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})\\ &= 500 \text{ tons/yr}\end{aligned}$$

On a yearly basis, controlling particulates (TSP) to 0.03 lb/10^6 Btu gives (at 80-percent capacity factor),

$$\begin{aligned}\text{TSP} &= (0.03 \text{ lb}/10^6 \text{ Btu})(34 \times 10^{12} \text{ Btu/yr})\\ &= 1.02 \times 10^6 \text{ lb/yr}\\ &= 500 \text{ tons/yr}\end{aligned}$$

Carbon Monoxide and Hydrocarbons

There are no New Source Performance Standards for carbon monoxide (CO) or hydrocarbons (HC). The amounts of CO and HC emitted to the ambient atmosphere are 2.45 tons/day and 0.74 ton/day, respectively. The emission factors for CO and HC are 1 lb/ton coal burned and 0.3 lb/ton coal burned, respectively.[5] Hence, the daily emissions of these pollutants are given by

$$\text{CO, HC} = (\text{emission factor})(\text{coal feed rate})$$

For the typical plant,

$$\text{CO} = (1 \text{ lb/ton})(4.9 \times 10^3 \text{ tons/day})/2 \times 10^3 \text{ lb/ton}$$
$$= 2.45 \text{ tons/day}$$

$$\text{HC} = (0.3 \text{ lb/ton})(4.9 \times 10^3 \text{ tons/day})/2 \times 10^3 \text{ lb/ton}$$
$$= 0.74 \text{ ton/day}$$

On a yearly basis,

$$\text{CO} = (2.45 \text{ tons/day})(0.8 \text{ capacity factor})(365 \text{ days/yr})$$
$$= 720 \text{ tons/yr}$$

$$\text{HC} = (0.74 \text{ tons/yr})(0.8 \text{ capacity factor})(365 \text{ days/yr})$$
$$= 220 \text{ tons/yr}$$

An indication of the completeness of a combustion process is the concentration of carbon monoxide (and, to a lesser extent, hydrocarbon concentration). As such, pulverized coal-fired boilers have negligible emissions of carbon monoxide and hydrocarbons. Careful monitoring of excess air and temperature in the boiler ensures that the emissions of these pollutants are low.[6]

Trace Elements

Atmospheric emission rates for the trace elements are calculated as follows (Appendix C):

Element	lb/day at 100% capacity factor	lb/yr at 80% capacity factor
As	0.77	225
Be	0.03	9.3
Cd	0.01	4.1
Mn	0.55	161
Pb	0.39	114
Se	0.19	56

The trace elements are species found in small quantities in the raw coal. They become distributed among the bottom ash slag or the fly ash and flue gases. In the latter, some are emitted past the precipitator and enter the atmosphere. Because many trace elements exhibit preferential concentrations in the smaller particles emitted, about 5 percent of the initial concentrations of most trace elements are emitted to the ambient atmosphere.[7] Based on recent work at Lawrence Livermore Laboratory, a method was developed to calculate trace element emissions to the atmosphere. The generalized methodology, algorithm, and associated references for calculating trace element emissions are given in Appendix B.

Carbon Dioxide

The amount of CO_2 emitted to the ambient atmosphere is 12.5×10^3 tons/day. During the combustion of bituminous coal, 0.21 lb CO_2 are emitted to the atmosphere for every 10^3 Btu generated.[8] Hence,

$$(CO_2)_{COMB} = \text{(emission factor)(coal feed rate)(heat content of coal)}$$

For the typical plant,

$$\begin{aligned}(CO_2)_{COMB} &= (0.21\ \text{lb}/10^3\ \text{Btu})(4.9 \times 10^3\ \text{tons/day})(12 \times 10^3\ \text{Btu/lb}) \\ &= 12.3 \times 10^3\ \text{tons/day}\end{aligned}$$

Additionally, a small amount of CO_2 is released to the atmosphere from the limestone reaction with the SO_2.[9] This amount is estimated as follows:

$$\begin{aligned}(CO_2)_{LIMESTONE} &= \left(\begin{array}{c}\text{500 tons/day, limestone into} \\ \text{scrubber}\end{array}\right)\left(\frac{44}{100},\ \begin{array}{c}\text{molecular weight} \\ \text{of } SO_2/CaCO_3\end{array}\right) \\ &= 0.220 \times 10^3\ \text{tons/day}\end{aligned}$$

The total amount of CO_2 emitted to the atmosphere is given by

$$\begin{aligned}CO_2 &= (CO_2)_{COMB} + (CO_2)_{LIMESTONE} \\ &= 12.3 \times 10^3\ \text{tons/day} + 0.22 \times 10^3\ \text{tons/day} \\ &= 12.5 \times 10^3\ \text{tons/day}\end{aligned}$$

On a yearly basis,

$$\begin{aligned}CO_2 &= (12.5 \times 10^3\ \text{tons/day})(0.8\ \text{capacity factor})(365\ \text{days/yr}) \\ &= 3.7 \times 10^6\ \text{tons/yr}\end{aligned}$$

Radionuclides

Analysis of the fly ash produced by combustion of eastern bituminous coal has shown that a typical 500-MWe plant will discharge into the atmosphere approximately 10.35×10^{-6} Ci/day of radioactive radium.

Because over 80 percent of the trace radioactive particles in coal remain with the fly ash after combustion, removal of the fly ash by electrostatic precipitators is the most effective control technology available.[10] Samples from the combustion of six different batches of Appalachian coal were analyzed for its radium content by Eisenbud and Petrow with the following results:[10]

Concentration of Radioactive Elements in Fly Ash

Radium-226	3.8×10^{-12} Ci/gm	or	1.73×10^{-9} Ci/lb
Radium-228	2.4×10^{-12} Ci/gm		1.09×10^{-9} Ci/lb

Other trace radioactive elements are emitted, e.g., thorium and uranium, but pose a much smaller health hazard than radium.

Assuming the total activity released to the environment is through the fly ash escaping the electrostatic precipitators, the daily release of any radioactive isotope may be calculated as follows:

$$\text{Activity of isotope i, Ci/day} = (\text{concentration of isotope i in fly ash})(\text{fly-ash generated, tons/day})(2000 \text{ lbs/ton})(1-ESP_{EFFICIENCY})$$

For the typical plant,

$$\text{Radium-226} = (1.73 \times 10^{-9} \text{ Ci/lb})(367 \text{ tons/day})(2000 \text{ lbs/ton})(1-.995) = 6.35 \times 10^{-6} \text{ Ci/day}$$

$$\text{Radium-228} = (1.09 \times 10^{-9} \text{ Ci/lb})(367 \text{ tons/day})(2000 \text{ lbs/ton})(1-.995) = 4.00 \times 10^{-6} \text{ Ci/day}$$

Total radium activity emitted daily for the typical plant is therefore 10.35×10^{-6} Ci/day.

On a yearly basis,

$$\text{Radium} = (10.35 \times 10^{-6} \text{ Ci/day})(0.8 \text{ capacity factor})(365 \text{ days/yr}) = 3 \times 10^{-3} \text{ Ci/yr}$$

To date, there are no regulations that apply to the release of radioactive pollutants from coal-fired power plants.

References

1. Federal Register, Vol. 44, No. 113, 40 CFR Part 60, "New Sources Performance Standards; Electric Utility Steam Generating Units," June 11, 1979.

2. J. Ando, "NO_x Abatement for Stationary Sources in Japan," EPA-600/7-79-205, August 1979.
3. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed NO_x Emission Standards," EPA-450/2-78-005a, July 1978.
4. National Academy of Sciences, "Air Quality and Stationary Source Emission Control," prepared for the Committee on Public Works, U.S. Senate, Serial No. 94-4, 1975.
5. U.S. Environmental Protection Agency, "Compilation of Air Pollution Emission Factors," 2nd edition, EPA AP-42, 1975.
6. Final Environmental Impact Statement, Spurlock Station, Unit No. 2 and Associated Transmission, USDA-REA-EIS-76-4F, November 1976.
7. K.K. Bertin and E.D. Goldbert, Science, Vol. 183, p. 233, 1971.
8. U.S. Department of Energy, "CO_2 Emissions from Synthetic Fuels Energy Sources," August 8, 1979, p. 2, Table 1.
9. Aerospace Corporation, Estimation, April 1980.
10. M. Eisenbud and H.G. Petrow, "Radioactivity in the Atmospheric Effluents of Power Plants That Use Fossil Fuels," Science 144, April 17, 1964, p. 288

III. PHYSICAL REQUIREMENTS

Large amounts of land and water resources are required for a coal-fired power plant. The section on Water summarizes the requirements and uses of makeup water discussed in Section II. The section on Land discusses the land needed for plant siting and solid waste disposal.

Water

The maximum makeup water requirement estimated for the typical plant operating at 80-percent capacity factor is 2.7×10^9 gal/yr. Some of this water is recovered, treated in the water treatment facility, and recycled back to the plant (see Section II, item (16)). The remainder is obtained from local water sources and is lost primarily through evaporation and drift losses in the cooling towers, holding pond surface losses, and dust suppression systems. The major uses of makeup water are listed in Table 2.

Land

The sizes of actual power plant sites vary over a considerable range and depend on a number of factors such as utility preference, cost of land, onsite versus offsite waste disposal, plant location, and the power of the plant. Although there is not a strong link between site size and the particular features of the plant (such as MWe), broad relationships exist. For plants in the 500-MWe range, site sizes appear to vary from about 500 to 1000 acres. There are a number of older plants sited in urban areas with much smaller sites, but they should not be considered typical for new plants.

Because the land needed for buildings is a relatively small portion of the site, the bulk of the site is needed for coal storage, onsite waste disposal (ponds, etc.), and general working room. Solid waste disposal area for a plant similar to the typical plant was estimated at 370 acres (30-foot depth) for the 30-year lifetime of the plant (see Section II, item (20)).[1] A representative 500-MWe plant that does not have onsite solid waste disposal for the entire life of the plant has a site size of approximately 400 acres, excluding waste disposal.[2] Accordingly, 800 acres is a typical site size when lifetime waste disposal is included.

The typical plant was designed as a mine-mouth plant with its own coal preparation plant. The actual coal preparation facilities would require a minimum of 1.5 acres.[3] In addition, if the refuse from the preparation plant is kept aboveground, disposal area will be required. The preparation plant will generate 1800 tons/day of refuse (see Section II, item (4) for

Table 2. Makeup Water Demands for Major Plant Processes (at 80-Percent Capacity Factor)

Source	Environmental Point of Interest on Flow Chart	Estimated Quantity (gal/yr)
Cooling tower makeup	11	2.2×10^9
SO_x control	21	300×10^6
Generating plant makeup	13	180×10^6
Electrostatic precipitator fly ash transport	18	24×10^6
Total estimated makeup water demand	-	$\approx 2.7 \times 10^9$
Recovered Water for Recycling		
Controlled runoff from coal storage	7	Variable
Boiler blowdown and miscellaneous plant drains	12	175×10^6
Cooling tower blowdown	10	200×10^6
Water removed from solid waste handling system	20	Variable
Total estimated recycled water available for makeup	16	$\approx 29 \times 10^6$
Net makeup water requirements	-	2.67×10^9
Total estimated makeup water demand	-	2.7×10^9
Total estimated availability of recycled water	-	29×10^6

calculation). Assuming a density of 50 lb/ft^3, and a 30-foot depth, the land requirements for waste disposal are calculated as follows:

$$\text{Land requirements, acres/yr} = \frac{0.34\ (\text{solid waste disposal, tons/day})}{\text{depth of disposal site, ft}}$$

For the typical plant,

$$\text{Land} = \frac{0.34\ (1800\ \text{tons/day})}{30\ \text{ft}}$$
$$= 20.4\ \text{acres/yr (at 100-percent capacity factor)}$$
$$= (20.4)(0.8)$$
$$= 16\ \text{acres/yr (at 80-percent capacity factor)}$$

For the 30-year lifetime of the plant, the land required for coal preparation waste disposal is therefore approximately 500 acres.

References

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards," EPA-450/2-78-007a, pp. 6-18, July 1978.
2. Final Environmental Impact Statement, Spurlock Station Unit No. 2, and Associated Transmission, USDA-REA-EIS-76-4F, November 1976, p. 69.
3. Personal Communication, Phillip Halch, Roberts and Schaefer Engineers and Contractors, April 1980.

IV. PERSONNEL

Although the number of people required for the operation and planned maintenance of a power plant is highly dependent on the philosophy of the particular utility, certain standards are used. One such guideline is 0.089 persons/MWe for each shift.[1] This number, which includes support personnel and personnel for operating and maintaining pollution control equipment, equates to 45 persons per shift or 135 persons total per day for a 500-MWe plant.

In addition to the above requirement, personnel will be needed for the coal preparation plant. Although preparation plant staffing levels vary, discussions with power engineers revealed that 10 persons per shift or 20 persons total for the two preparation plant shifts would be a reasonable figure.

Reference

1. Personal Communication, John W. Holt, Jr., Power Plants Branch, Rural Electrification Administration, Washington, D.C., April 1980.

V. OCCUPATIONAL SAFETY AND HEALTH

Occupational safety and health implications of coal-fired power plants have been examined using actual death and injury statistics.[1] For coal processing plants, the report lists (per 10^8 tons processed) 1.7 to 2.7 deaths and 98 to 159 injuries. The corresponding figures for power plant workers (per 10^{12} Btu output) are 0 to 0.0095 deaths and 0.16 to 0.19 injuries.

For the plant assumed in this ECIR, the amount of coal processed is 1.96 x 10^6 tons/yr and 0.16 x 10^6 tons/10^{12} Btu. The output of the plant is 12 x 10^{12} Btu/yr. Thus, the projected deaths and injuries for the plant are as follows:

	Preparation Plant		Power Plant	
	Annual	Per 10^{12} Btu	Annual	Per 10^{12} Btu
Deaths	0.0033-0.0053	0.0003-0.0004	0-0.11	0-0.0095
Injuries	1.9-3.1	0.16-0.26	1.9-2.3	0.16-0.19

Reference

1. S.C. Morris, K.M. Novak, and L.D. Hamilton, "Health Effects of Coal in the National Energy Plan," Brookhaven National Laboratory, BNL-51043, April 1979, pp. 8-9.

APPENDIX A. AIR EMISSIONS UNDER VARIOUS REGULATORY AND CONTROL TECHNOLOGY ASSUMPTIONS

The air emissions calculated for the coal-fired power plant described in this document are based on current Federal NSPS for coal-fired power plants using bituminous coal and that commenced construction after September 18, 1978. The units coming on line now and for several years into the future are generally subject to the previous Federal NSPS. There are also many units now operating that were under constructon or operating prior to the effective date of the previous NSPS and are therefore not subject to any Federal NSPS. Although these plants are subject to Federal NSPS less stringent than the current regulation, they will in many instances be subject to more stringent state and local air emission regulations. In many instances, the new plants, subject to current Federal NSPS, will also be subject to more stringent state or local standards that will effectively establish the allowable air pollutant emission levels. Table A-1 provides a summary of air emissions under current NSPS and previous NSPS, as well as emissions from uncontrolled plants.

It should also be noted that under the previous NSPS and uncontrolled assumptions, coals having low-sulfur content could be used to reduce SO_2 emissions and to thus comply with the NSPS standard. The new NSPS do not allow the use of low-sulfur coal alone as an SO_2 control for new plants.

In addition to impacts on air emissions, the use of a limestone or lime scrubber generates a varying amount of solid waste (scrubber sludge). As SO_2 removal requirements increase, the amount of scrubber sludge will increase (see item (19), Sludge From SO_2 Control). Solid wastes will also be increased if a higher ash coal is selected (see item (17), Fly Ash From Particulate Control).

Table A-1. Air Emissions Under Various Regulatory Assumptions*

Federal Regulation	Firing Rate - 34 x 10^{12} Btu/yr: SO_2	NO_x	Particulate
Current NSPS As of 6/11/79	.6 lb/10^6 Btu 10.2 x 10^3 tons/yr	.6 lb/10^6 Btu 10.2 x 10^3 tons/yr	.03 lb/10^6 Btu .50 x 10^3 tons/yr
Previous NSPS 12/23/71 to 6/11/79	1.2 lb/10^6 Btu 20.4 x 10^3 tons/yr	.7 lb/10^6 Btu 11.9 x 10^3 tons/yr	.1 lb/10^6 Btu 1.7 x 10^3 tons/yr
Uncontrolled emissions	85 x 10^3 tons/yr	**"Normal firing" @ .82 lb/10^6 Btu 13.9 x 10^3 tons/yr	50% mechanical removal of fly ash 50 x 10^3 tons/yr

* Based on the plant assumed in this ECIR, using a coal with 3.3 percent sulfur content.

** U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed NO_x Emission Standards," EPA-450/2-78-005a, July 1978, p. 6-9.

APPENDIX B. COST INFORMATION

Obtaining an accurate estimate of the costs associated with any power plant is an ambitious undertaking and beyond the scope of this study. However, sufficient information is available to approximate the costs for the typical plant.

An extensive effort by the Department of Energy (DOE) and the Nuclear Regulatory Commission (NRC)[1] examined the total costs (capital, fuel, and operating and maintenance) for various plant types and sizes under a range of economic assumptions. The plant most similar to the typical plant in this Environmental Characterization Information Report (ECIR) is a 794-MWe plant burning high-sulfur coal. It, too, is a pulverized coal plant with electrostatic precipitator and flue gas scrubbers.

There is sufficient information in the study to determine approximate economies of scale with respect to plant size. When the data for the 794-MWe plant are converted to our 500-MWe plant size, the result for plant capital cost is $450/kW (1976 dollars) or $225,000,000. The DOE/NRC study provided an analysis that assumed an 8-percent escalation rate and a 1985 date for first operation. Under these assumptions, correcting for escalation, interest during construction, and contingency, the total (integrated) capital cost for the 500-MWe plant is $1270/kW, or $635,000,000. If the escalation rate were only 5 percent, the capital cost would be $1030/kW, or $514,000,000.

The study also calculated the total costs for the 1985 plant in mills/kWh (including capital, fuel, and operating and maintenance), assuming 8-percent escalation and a 12-percent discount rate, as well as the alternate economic assumptions of 5-percent escalation and 10-percent discount rate. As might be expected, this total cost will depend on the portion of time the plant actually operates (capacity factor). The total costs for the 500-MWe plant are as follows:

Capacity Factor (%)	Total Generating Costs (mills/kWh): 8% Escalation 12% Discount	5% Escalation 10% Discount
50	116.9	87.4
60	107.4	78.8
70	101.1	72.8
80	96.0	68.1

These cost figures include transportation of coal 900 miles from the eastern high-sulfur coal mines to a hypothetical northeastern coastal location. If coal transportation were not necessary, as in the case of the mine-mouth typical plant, the total generating costs would be reduced by 23.6 mills/kWh for the 8-percent escalation/12-percent discount case and 13.8 mills/kWh for the 5-percent escalation/10-percent discount case. Thus, the costs for the typical plant, excluding coal preparation, are as follows:

Capacity Factor (%)	Total Generating Costs (mills/kWh)	
	8% Escalation 12% Discount	5% Escalation 10% Discount
50	93.3	73.6
60	83.8	65.0
70	77.5	59.0
80	72.4	54.3

The capital cost for the coal preparation plant is estimated at $10.5 million in 1976 dollars, with operating and maintenance costs of $1.33/ton of coal.[2] This total cost for the coal preparation plant, which is not very sensitive to the capacity factor, is 5.8 mills/kWh for the 8-percent escalation/12-percent discount case and 3.9 mills/kWh for the 5-percent escalation and 10-percent discount case.

References

1. United Engineers and Constructors, Inc., "Total Generating Cost: Coal and Nuclear Plants," Vol. 8 in a Series of 8 Commercial Electric Power Cost Studies, NUREG-0248, COO-2477-12, February 1979.
2. J.F. Wilkinson, ed., "What's New in Preparation: Equipment, Processes, and Training," Coal Age, Vol. 85, No. 1, pp. 54-109, January 1980.

APPENDIX C. TRACE ELEMENT ANALYSIS

Trace elements are species that are found in small quantities in a mineral. During coal combustion, they become distributed among slag, fly ash, or gases and are emitted into the environment. Based on industrial experience with pulverized coal boilers, it is generally accepted that 80 percent of the ash present in coal is charged as fly ash, while only 20 percent is discharged as bottom ash.[1,2] Because many trace elements exhibit preferential concentrations in the smaller particles emitted from coal-fired power plants,[3,6] about 5 percent of the initial concentrations of most trace elements are emitted to the ambient atmosphere.[7] In addition, due to the nonhomogeneity of coal, the composition and concentration of combustion products will vary with coal. However, based on recent work conducted by Lawerence Livermore Laboratory, it is possible to calculate trace element emissions if certain system operating parameters and coal composition are known.[8] An explanation of how this is done follows.*

Needed information:

- Trace element concentrations in coal being fired (C_i, i=1, 2, ... n, $\mu g/g$)
- Coal feed rate (F, g/sec)
- Plant net power output (P, watts)
- Overall thermal efficiency (η_p)
- Electrostatic precipitator overall efficiency (η_{ESP})

Definitions:

plant total power input	= (plant net power output)/(overall thermal efficiency)
	= P/η_p
(consumption rate)$_i$	= (trace element i concentration in coal) (coal feed rate)/(plant total power input)**
	= $(C_i)(F)/P/\eta_p)$
ESP efficiency ratio	= (1-ESP overall efficiency)/(1-ESP overall efficiency used in LLL study)
	= $(1-\eta_{ESP})/(1-0.97)$

* There are other methodologies for determining trace element emissions; see, for example, Reference 9.

** Note: 1 watt = 1 joule/second.

(atmospheric emission rate)$_i$ = (stack emission of trace element i)/(plant total power input)

$(AER)_i$ = unknown to be determined

(penetration)$_i$ = (100%) (atmospheric emission rate)$_i$/(consumption rate)$_i$

= given in following Table C-1

Procedure:

1. When the needed information is obtained, determine

   - plant total power input
   - (consumption rate)$_i$
   - ESP efficiency ratio

2. Obtain (penetration)$_i$ from Table C-1

3. (atmospheric emission rate)$_i$ = (penetration)$_i$(consumption rate)$_i$ (ESP efficiency ratio)/100

$$(AER,\ \mu g/joule)_i = (penetration)_i\ [(C_i)(F)/(P/\eta_p),\ \mu g/joule]\ (1-\eta_{ESP})/[(1-0.97)]$$

For the typical plant a representative coal from Kentucky was chosen.[10] Trace element concentrations of this coal are listed as follows:

Element	Concentration ($\mu g/g$)
As	4.1
Be	2.2
Cd	0.1
Mn	21.0
Pb	4.3
Se	1.5

To find the atmospheric emission rates for the trace elements, the following information is used:

$P = 5 \times 10^8$ watt
$\eta_p = 35$ percent
$F = 5.15 \times 10^4$ g/sec
$\eta_{ESP} = 99.5$ percent

Table C-1. Penetration of Elements Contained in Particles Emitted From an ESP-Equipped Coal-Fired Generating Unit (%)

Element	ESP unit[a]	Element	ESP unit[a]
Al	1.1 ± 0.1	Mo	5.1 ± 1.2
As	11.5 ± 3.0	Mn	1.6 ± 0.5
Ba	4.0 ± 0.8	Na	1.55 ± 0.09
Be	0.9 ± 0.3	Pb	5.5 ± 1.1
Br	0.14 ± 0.08	Rb	1.3 ± 0.1
Ca	1.3 ± 0.2	Sb	7.7 ± 0.7
Cd	8.8 ± 3.0	Sc	1.46 ± 0.06
Ce	1.29 ± 0.09	Se	7.7 ± 0.8
Co	2.5 ± 0.3	Sr	2.0 ± 0.3
Cr	3.8 ± 0.3	Ta	1.3 ± 0.1
Cs	1.2 ± 0.2	Th	1.32 ± 0.08
Fe	1.32 ± 0.09	Ti	1.51 ± 0.03
Ga	4.4 ± 0.7	U	3.7 ± 0.4
In	5.4 ± 0.7	V	3.7 ± 0.6
K	1.0 ± 0.3	W	7.2 ± 2.2
La	1.29 ± 0.07	Zn	6.3 ± 0.8
Mg	1.2 ± 0.4	Zr	1.4 ± 0.3

[a] Number of samples was eight unless otherwise indicated.

The atmospheric emission rate for arsenic is therefore

$$(AER)_{As} = \left[\frac{(\text{penetration})_{As}\,(C_{As})(F)}{(P/np)}\right]\left[\frac{1-ESP}{1-0.97}\right]$$

$$= \left[\frac{(0.115)(4.1\ \mu g/g)(5.15 \times 10^4\ g/s)}{5 \times 10^8\ J/s\,/\,0.35}\right]\left[\frac{1-0.995}{1-0.97}\right]$$

$$= 2.83 \times 10^{-6}\ \mu g/J$$

On a daily basis,

$$(AER)_{As} = \frac{(2.83 \times 10^{-6}\ \mu g/J)(1.055 \times 10^3\ J/Btu)(0.117 \times 10^{12}\ Btu/day)(1 \times 10^{-6}\ g/\mu g)}{(4.54 \times 10^2\ g/lb)}$$

$$= 0.77\ lb/day$$

Daily atmospheric emission rates for the trace elements are as follows:

Element	lb/day at 100% capacity factor	lb/yr at 80% capacity factor
As	0.77	225
Be	0.03	9.3
Cd	0.01	4.1
Mn	0.55	161
Pb	0.39	114
Se	0.19	56

References

1. U.S. Environmental Protection Agency, "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Emission Standards," EPA-450/2-78-006a, July 1978, p. 3-14.
2. Teknekron, Inc., "Comprehensive Standards: The Power Generation Case," EPA No. 68-01-0561, March 1975, p. 91.
3. D.F.S. Natusch, J.R. Wallace, and C.A. Evans, Jr., Science, Vol. 183 No. 4121, pp. 202-4, 1974.
4. N.E. Bolton et al., "Trace Element Measurement at the Coal-Fired Allen Steam Plant, Progress Report, June 1971 - January 1973," ORNL-NSF-EP-43, March 1973.
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6. G.E. Gordon et al., "Study of the Emissions from Major Air Pollution Sources and Their Atmospheric Interactions," University of Maryland Department of Chemistry and Institute for Fluid Dynamics and Applied Mathematics, College Park, Maryland, 1974.
7. K.K. Bertine and E.D. Goldbert, Science, Vol. 173, No. 233, 1971.
8. J.M. Ondov, R.C. Ragaini, and A.H. Biermann, "Emissions and Particle-Size Distributions of Minor and Trace Elements at Two Western Coal-Fired Power Plants Equipped with Cold-Side Electrostatic Precipitators," Environmental Science and Technology, Vol. 13, pp. 946-953, 1979.
9. Radian Corporation, "Trace Elements of Fly Ash: Emissions from Coal Fired Steam Plants Equipped with Hotside and Coldside Electrostatic Precipitators for Particulate Control," EPA 908/4-78-008, December 1978, Final Report.
10. H.J. Gluskoter et al., "Trace Elements in Coal: Occurrence and Distribution," Illinois State Geological Survey, Circular 499, 1977.

GLOSSARY

Blowdown	Water that is periodically removed from either the cooling towers or the coal-fired boiler to prevent concentration of total dissolved solids.
Bottom ash	Noncombustible residues of coal combustion that are collected and removed from the boiler.
Capacity factor	The actual plant output in a year divided by the output that would be achieved if the plant were to operate at 100-percent power for 365 days/year.
Circulating water	Water supplied to the main condenser in the generating plant that is cooled by the cooling towers.
Cooling tower drift loss	Aerosols of water that are lost in the atmosphere from the cooling towers.
Cooling tower evaporation loss	Circulating water that is evaporated as a result of heat transferred from the circulating water system and lost in the atmosphere via the cooling towers.
Dead storage	Long-term storage in which the coal is typically compacted and sealed.
Discount rate	A factor in formulas used for analyzing the time value of money. Its magnitude depends on the cost of capital, financing schemes, etc.
Electrostatic precipitator	Environmental control device used to remove a high percentage of the fly ash in the flue gas.
Escalation	Increases in cost of equipment, materials, labor, etc., as a result of inflation.
Flue gas	Gases generated from the combustion of fossil fuel in the boiler.
Flue gas desulfurization scrubbers	Environmental control device used to remove a high percentage of the sulfur dioxide in the flue gas.
Fly ash	Noncombustible residues of coal combustion that are carried out of the boiler in the flue gas.
Fugitive emissions	Unintentional emissions, such as blowing dust from a coal pile.

Net station heat rate ($\dot{Q}$)	Amount of fuel input (in Btu) necessary to generate 1 kWh of electricity.
Pyritic material	Metallic compounds of sulfur naturally occurring in coal.
Recycle water	Water that is collected, treated, and reused at the power plant.
Run-of-mine coal	Coal as it comes from the mine prior to sizing or other preparation.
Sludge	Wet residue of lime/limestone and sulfur that is generated in the flue gas desulfurization unit.

ACRONYMS AND ABBREVIATIONS

A	ash content in coal
AER_i	atmospheric emission rate of trace element i
As	arsenic
Be	beryllium
Btu	British thermal unit
C	carbon
$CaSO_3$	limestone
Cd	cadmium
Ci	curie
C_i	concentration of trace element i
Cl	chlorine
CO	carbon monoxide
CO_2	carbon dioxide
Cu	copper
DOE	Department of Energy
ECIR	Environmental Characterization Information Report
η_p	overall thermal efficiency of plant
η_{ESP}	overall efficiency of electrostatic precipitator
EPA	Environmental Protection Agency
ESP	electrostatic precipitator
F	feed rate of coal
Fe	iron
FGD	flue gas desulfurization
g	gram
gal	gallon
H	hydrogen
ha	hectare
HC	hydrocarbons
J	joule
kg	kilogram
kWh	kilowatt-hour
l	liter
lb	pound
mg	milligram (10^{-3} gram)
µg	micrograms (10^{-6} grams)
Mn	manganese
MWe	megawatt - electrical
MWt	megawatt - thermal
NO_x	nitrogen oxides
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
O	oxygen
P	net power delivered to the transmission grid
Pb	lead
Q	heat content of coal
Q	net station heat rate
ROM	run-of-mine

s	second
S	sulfur
Se	selinium
SO_2	sulfur dioxide
te	tonne
TSP	total suspended particulates (air)
TSS	total suspended solids (water)
W_{BA}	total makeup water requirements for bottom ash handling
$W_{BLOWDOWN}$	amount of cooling tower blowdown
W_{DRIFT}	amount of drift loss from cooling tower
W_{EVAP}	amount of evaporation loss from cooling tower
W_{FGD}	makeup water for dust control of SO_2 scrubbers
W_{HAD}	amount of water needed for bottom ash handling and disposal
W_{TOW}	total makeup water requirements to the cooling towers
W_{VAP}	amount of evaporation loss from bottom ash hopper

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