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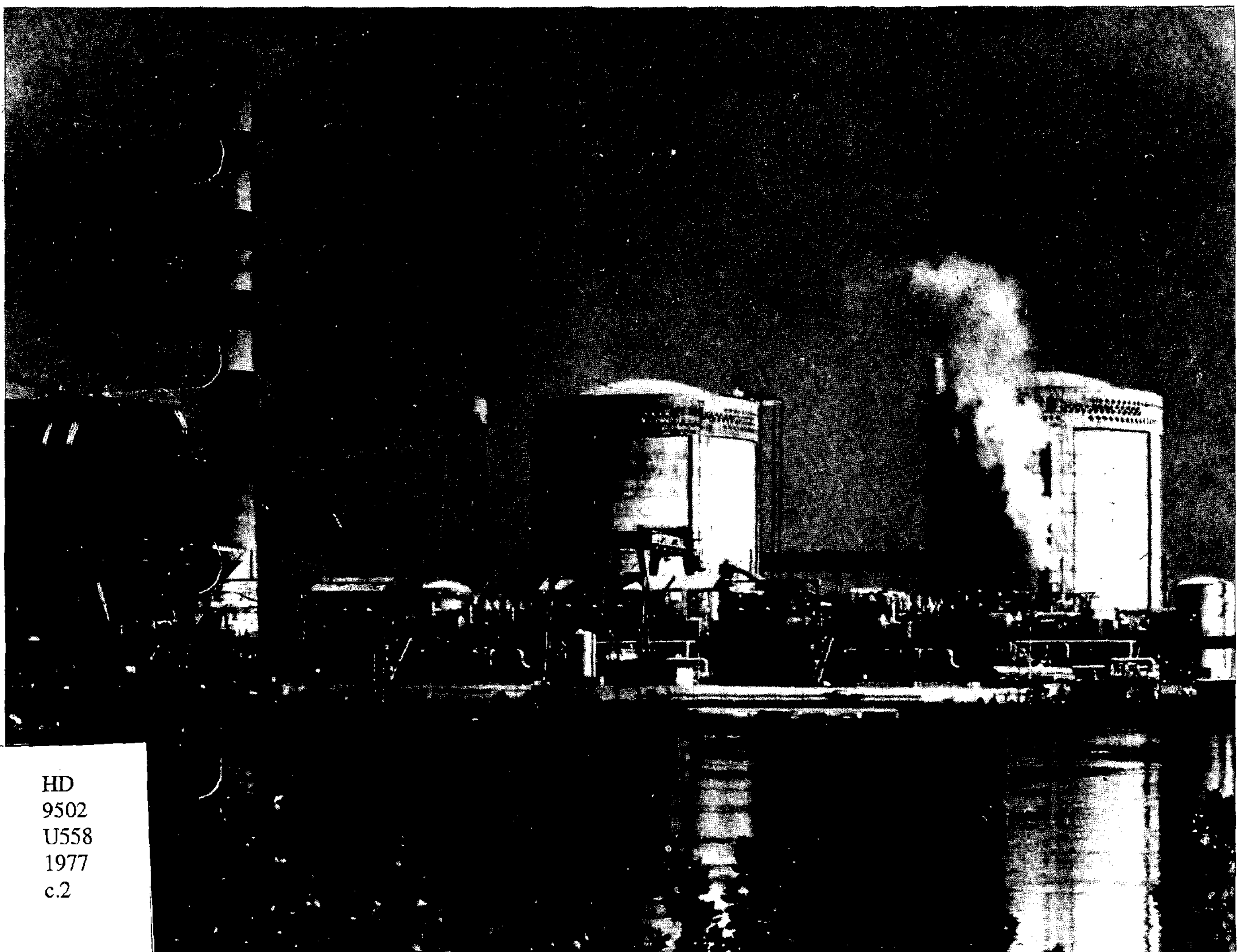
Energy Facility Siting In The Great Lakes Coastal Zone: Analysis And Policy Options

Great Lakes Basin Commission for
The Office Of Coastal Zone Management
National Oceanic And Atmospheric Administration
U. S. DEPARTMENT OF COMMERCE



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Prepared for
The Office of Coastal Zone Management
National Oceanic and Atmospheric Administration
U.S. DEPARTMENT OF COMMERCE

(Under Contract No. 6-35350)

And The Standing Committee on Coastal Zone Management, Great Lakes Basin Commission

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PREFACE

This study, Energy Facility Siting in the Great Lakes Coastal Zone: Analysis and Policy Options, can be described as fact-finding and brainstorming in nature. It is fact-finding in that it surveys existing state and federal policies affecting energy facilities siting, examines specific types of energy facilities and their dependence on coastal locations, and reviews projections of energy use and related facility requirements. For this portion of the report, tremendous amounts of information (over 150,000 pages of reports, documents and correspondence, as well as phone calls and interviews) were summarized and abstracted. The study is of a brainstorming nature in that the staff spent substantial time evolving institutional and technical options for the siting of energy facilities in the Great Lakes coastal zone.

The study was conducted by the Great Lakes Basin Commission staff over a period of four months, from July 6 through November 5, 1976. Guidance, suggestions, and review comments were provided throughout the study by the project's steering committee, technical advisors, and citizen advisors, by state coastal zone program managers, and by the Office of Coastal Zone Management. This assistance was gratefully received by the staff and was most important in helping the staff complete the study on time.

The draft report was reviewed by the project's steering committee, technical and citizen advisors, the state coastal zone management programs, and the Office of Coastal Zone Management. The review period ran from November 10 to December 7, 1976. Comments received after the closing date were also considered in the preparation of this final report.

In the course of the review, general comments criticized the report from two standpoints. First, some members of the energy industry indicated that the report is somewhat biased toward environmental concerns, whereas some environmentalists suggested that certain portions of the report are too biased in favor of the energy industry. It is the conclusion of the staff that the report takes a middle ground that will serve the concerns of the state coastal zone management programs well as they develop management plans to balance environmental and economic considerations.

Second, some comments suggested that the report is too long and includes information accessible elsewhere. (This is, in part, related to the broad scope of the study.) On the other hand, a considerable number of comments indicated that the report is very useful, because it synthesizes a tremendous amount of diverse but related information under one cover. The coastal zone management programs, to which the report is directed, are probably best served by this latter approach since their own resources are limited.

While a broad group of technical advisors from both the public and private sectors participated in the study through their review of and comment on preliminary material and the draft report, this should not be taken as an endorsement of this final report by them. They served only as information providers, advisors, and reactors.

ACKNOWLEDGEMENTS

The Office of Coastal Zone Management, National Oceanic and Atmospheric Administration, U.S. Department of Commerce, funded the Great Lakes Basin Commission to engage in this study on June 30, 1976, to provide assistance on a regional basis to aid the Great Lakes states' coastal zone management programs in the examination of energy facility siting and the development of related options. The Great Lakes Basin Commission and staff appreciated the opportunity to undertake this study for the Office of Coastal Zone Management and the eight Great Lakes states.

The staff received tremendous assistance from the Steering Committee and Technical Advisors of the study (listed in Appendices A and B). Their efforts are greatly appreciated. These people represent agencies and companies involved at all levels of energy planning. The fact that the staff was able to complete the study on time can in no small part be attributed to their efforts. In particular, the staff would like to acknowledge the expert assistance of the Argonne and Brookhaven National Laboratories, the Chicago regional office of the Federal Power Commission, Mr. Owen Lentz, Executive Manager of the East Central Area Reliability Coordination Agreement, and Mr. Julius Bleiweis, Executive Director of the Northeast Power Coordinating Council.

Chapter I

EXECUTIVE SUMMARY

Concerned about energy facility siting in the Great Lakes coastal zone and anticipating federal legislation to provide for planning of and amelioration of the impacts from energy facilities, the Great Lakes states coastal zone management programs requested that the Great Lakes Basin Commission undertake this study of energy facility siting and develop related policy options. The study was funded by the Office of Coastal Zone Management, U.S. Department of Commerce, and was conducted from July 6 to November 5, 1976.

The study examined the state and federal roles in energy facility siting in order to develop institutional and technical policy options which the Great Lakes states might employ to influence or control energy facility siting, primarily in their coastal zones. Coal-fired and nuclear power plants, fuel (coal and oil) transshipment and storage facilities, and refineries were described generally and their resource requirements examined. These resource requirements were then applied to four regional electrical energy facility scenarios to establish land, water, and fuel (coal) requirements for the period 1975-1995 for a range of annual electrical energy consumption growth rates from 3% to 8% for each of the Great Lakes states and their respective tier of counties bordering the Great Lakes. These projections suggested the possible pressures on the Great Lakes coastal zone for the development of energy facilities. This background provided the impetus for developing technical options for energy facility siting.

A. INSTITUTIONAL CONSIDERATIONS

Institutional considerations address the legal, organizational, and procedural aspects of energy facility siting and are distinguished from technical considerations. The analysis of institutional considerations provides a means for comparing and evaluating state energy facility siting programs and describes the federal role and the constraints it imposes on the states and the opportunities it provides.

1. FEDERAL ENERGY FACILITY SITING REGULATION

Several federal agencies exert a considerable amount of influence on energy facility siting. The Nuclear Regulatory Commission has licensing authority for nuclear power plants. The Federal Power Commission regulates the siting of non-federal hydroelectric power plants (including dams and pumped storage facilities) and the interstate sale of electricity and natural gas. The Environmental Protection Agency exerts a great deal of influence on energy facility siting by administering two federal acts. The Clean Air Act (CAA) established National Ambient Air Quality Standards (NAAQS) and performance standards for new stationary sources of pollution. These must be met by all energy facilities. The CAA also provides for the prevention of significant deterioration of air quality that exceeds the NAAQS. The Federal Water Pollution Control Act Amendments of 1972 provide for the regulation of water pollution from various sources, including energy facilities. In particular, regulations governing thermal discharges, cooling water intake structures, and certain chemical constituents are significant in energy facility siting decisions. The U.S. Coast Guard and the U.S. Army Corps of Engineers are concerned with discharges and physical obstructions to waterways, and the Federal Aviation Administration is concerned with similar infringements upon air traffic routes.

Two federal laws also affect energy facility siting: the National Environmental Policy Act of 1969 (NEPA), and the Coastal Zone Management Act of 1972 (CZMA) and its Amendments of 1976. The CZMA encourages states to develop plans for managing their coastal zones and provides funding for such planning and subsequent management. State plans, once approved, become formal documents requiring enforcement by the state, and all federal actions affecting the coastal zone must be consistent with these plans. In particular, the Great Lakes states, under the 1976 amendments, must develop a planning process for energy facilities located in or significantly affecting the coastal zone, and are eligible for grants to study and plan for any economic, social, or environmental consequences resulting from siting, construction, expansion, or operation of all types of energy facilities in or affecting the coastal zone. The states are also eligible for grants to assist them in preventing, reducing, or ameliorating the loss of valuable environmental or recreational resources resulting from the transportation, transfer, or storage of oil, natural gas, or coal in or through the coastal zone. The inclusion of these elements in the Great Lakes states coastal zone management programs provides the basis for energy facility siting programs for the Great Lakes coastal zone. This is particularly significant for the states that have not already established energy facility siting programs on a statewide basis. In recognition of the different institutional arrangements in each state, the Act provides latitude for the organization of the coastal zone energy facility planning process in each state. The National Environmental Policy Act requires environmental impact statements for all major federal activities (including issuance of licenses and permits) that significantly affect the environment. This promotes the environmental compatibility of all energy facility siting, both within and outside the coastal zone.

2. STATE ENERGY FACILITY SITING REGULATION

Of the eight Great Lakes states, New York, Ohio, Wisconsin and Minnesota have recently enacted legislation to regulate the siting of power plants and other energy facilities. Minnesota has placed siting responsibility with its Environmental Quality Council. The council has established criteria for the selection of suitable sites and is compiling an inventory of specific sites from which utilities may select. The Wisconsin statute serves to streamline the site certification process by concentrating responsibility for the various aspects of siting in the Department of Natural Resources and the Public Utilities Commission. Both New York and Ohio have established energy facility siting councils composed of the heads of several pertinent state agencies. All four states have established site certification application procedures and provide for the public disclosure of long-range utility plans, for public participation in the siting process and for mechanisms to finance the regulation of energy facility siting. However, none of these states address all types of energy facilities in their siting programs. The facilities that are not addressed in the siting programs are covered by applicable environmental protection programs.

The remaining four states (Illinois, Indiana, Michigan and Pennsylvania) rely on general programs for environmental protection, and public utility regulation for any control they exercise over facility siting. These states generally require that a utility obtain several permits from various state agencies. Emphasis in these states is on compliance of proposed energy facilities with applicable standards and guidelines for protection of air, water, and other resources. In general, the larger range of siting issues are not addressed in a comprehensive, coordinated manner. There are no provisions for the disclosure of long-range utility plans in these states, and opportunities for public participation are generally less than in the other four states.

Several coastal states outside the Great Lakes Region (Maine, Maryland, Massachusetts, Washington, Oregon, and California) were selected for investigation in this study because of their unique energy facility siting programs. The approaches used in these states include: regulation of any large land development project, maintenance of state-purchased energy facility land reserve, inclusion of all types of energy facilities in a siting program, and active encouragement of public participation in the siting process.

State officials and other interested persons are encouraged to carefully compare and evaluate the various state energy facility siting programs and the ways in which CZM considerations are incorporated. The following criteria are suggested by the staff, based on the review of extensive information concerning energy facility siting, for use in such an evaluation:

- The program should provide for the resolution of conflicts among interests and the identification of tradeoffs.
- The program should be accountable to the public and responsive to its needs and desires.
- The program should include an effective planning mechanism.
- The program should be coordinated with other energy and land use programs.
- Energy facility siting should provide for regional needs.
- The program should specifically address the protection of the environment, especially in the coastal zone.
- The program should facilitate provision of an adequate supply of energy.
- The program should be assured adequate funding and staffing.
- The program should be flexible and adaptable.
- The program should be politically feasible.
- The program should be as streamlined as possible.

B. TECHNICAL CONSIDERATIONS

1. ENVIRONMENTAL AND ECONOMIC FACTORS AFFECTING THE SITING OF ENERGY FACILITIES

Technical considerations--social, economic, and environmental--and their relationship to energy facility siting are reported in detail in the study. The facilities examined include fossil-fuel (coal-fired only) and nuclear power plants, fuel (coal and oil) transshipment and storage facilities, and refineries. General siting considerations affecting the location of these facilities include system planning, safety and reliability, engineering, environmental, institutional/regulatory, and economic. A generalized facility size was established for each facility type in order to present comparable resource requirements of the facilities. For both fossil-fuel (coal) and nuclear power plants, a 1,000 megawatt electrical output (MWe) capacity single unit plant was selected as the generalized facility. The efficiency and annual average capacity assumed for these two types of facilities are 38 percent and 65 percent respectively for fossil-fuel plants, and 32 percent and 65 percent respectively for nuclear plants. Refineries are not described in "generalized facility" terms because of their complex production systems reflecting particular product mixes. Fuel transshipment and storage facilities do not lend themselves to a generalized description because of their range in size and uses.

The generalized 1,000 MWe coal-fired power plant is assumed in this study to occupy from 145 to 2,500 acres, depending on the cooling system used, SO_x waste disposal method, and coal storage requirements. An average land requirement used for calculating future resource requirements is 525 acres. Water withdrawals can range from 9,300 gpm (21 cfs) to 800,000 gpm (1800 cfs), depending on the cooling system used: once-through, natural draft tower, mechanical draft tower, spray canal, or cooling pond.

Water consumed in the cooling process is also a major consideration in power plant location because the amount of water returned to a water body may be significantly less than the amount withdrawn, depending on the cooling system used. Generally, for a once-through cooling system, water withdrawal is larger (equaling the flow across the condenser), but the consumptive water use is much less than for closed-cycle systems.

For the generalized nuclear power plant, 1,335 acres is the average land area required. This figure is much higher than that for coal-fired plants, due in part to the requirement for an exclusion zone around the plant for the protection of people and property from potential radioactive emissions. Nuclear power plants require significantly more water than do similar sized fossil-fuel plants, due primarily to differences in thermal efficiency. A lower bound of 13,500 to 18,000 gpm (30 to 40 cfs) withdrawal rate with a consumptive use rate of about 11,225 gpm (25 cfs) is not unreasonable for an efficient closed-cycle system of 1000-MWe nuclear unit. A withdrawal rate of one million gpm (2230 cfs) for a once-through system with no significant consumptive loss provides an upper bound (assuming 15°F temperature rise across the condenser). Even if closed-cycle cooling were used for a nuclear or coal-fired plant of the generalized size (or larger), there are few river locations in the Great Lakes Basin which could provide a sufficient amount of water, given other environmental constraints. Thus, the water source for these facilities would have to be the Great Lakes.

Other major factors affecting power plant siting include: location with respect to population (important due to transmission line costs, and aesthetics, and for nuclear plants, due to safety and radiological considerations), transportation access, seismology and geology (particularly important for nuclear plants), hydrology, meteorology, ambient air quality (particularly important for fossil fuel plants), minimization of aquatic and terrestrial ecosystem impacts, and public acceptance. Additional construction and operation effects and activities of importance are described in the report (Chapter IV, Technical Considerations--Environmental and Economic Impact Analysis).

The evaluation and determination of an energy facility's coastal dependence or non-dependence must be conducted on a case-by-case basis to determine the importance of a shoreline location for a given proposed energy facility. For a power plant, a large number of considerations must be evaluated, including, but not limited to: land ownership, mode of fuel delivery, local meteorology and dispersion patterns, aesthetics, potential land use conflicts, and transmission line tie-in ability.

The coastal dependence of power plants can be summarized as follows:

- Facilities using once-through cooling must be located on or near the shoreline because of substantial costs of transporting water inland by pipeline.
- Facilities using closed-cycle cooling (while drawing water from the Great Lakes) are less dependent on locations on or near the shoreline than are facilities using once-through cooling, assuming all other factors to be approximately equal. Site conditions will determine the type of closed-cycle cooling system used. However, the further inland a facility is located, the greater are

the construction (capital) costs for water provision and blowdown pipelines.

- For facilities using closed-cycle cooling, the cost of locating on the shoreline versus the cost of locating inland are essentially trade-offs between construction and operation costs for transmission lines, facilities for water supply and cooling, facilities for delivery and handling of fuels and other supplies, and disposal of waste material.

- Nuclear facilities require very large and massive components, which in most cases rely on water access for delivery. However, rail or road corridors of adequate width and load carrying capacity can be utilized for delivery of these components. If these rail or road corridors are not available to potential inland sites, the location of nuclear facilities may be more dependent on shoreline or near shoreline locations. In any event, field assembly is becoming more common, thus possibly negating some of this shoreline-water access dependence. Otherwise, nuclear facility coastal dependence considerations would be those listed in the previous item.

The coastal dependence of fuel transshipment and storage facilities and refineries can be summarized as follows:

- Fuel (coal and oil) transshipment facilities (receiving or shipping their commodities by water) must locate near the shoreline, althrough the related storage areas do not have to be located on the shoreline. Storage area location is highly dependent on industrial needs, future transportation requirements, and onsite and offsite use of stored fuel.

- Refineries are not coastal dependent, but do need access to water for processing and cooling. Refinery siting dependence based on water supply and wastewater disposal considerations is decreasing due to increasing water recycling practices. Air cooling is also decreasing refinery dependence on easy water access. Refinery location decisions are increasingly becoming market oriented, with decisions being made on a national basis, due to the existence of the national product distribution pipeline.

Coal gasification and liquefaction facilities are not likely to be located in the Great Lakes Basin, with the possible exception of low-Btu gasification facilities which can be located at or near the site of use. Large goal gasification and liquefaction facilities will have mine-mouth locations due to the higher cost of transporting coal relative to the cost of transporting substitute or synthetic natural gas (SNG).

2. ENERGY CONSUMPTION AND MOVEMENT

The Great Lakes Basin and states are net importers of fuels. It is difficult to determine whether the Basin is a net importer or exporter of electricity since this depends on temporal factors. It appears however that the coastal counties in most states (except Illinois) are net exporters of electricity. Furthermore, significant intra-coastal county electrical flows occur, particularly in areas around Milwaukee, Detroit, Toledo, and Cleveland.

The combined planned and scheduled electrical energy generating capacity for the entire Great Lakes states area through the mid 1980's is 74,067 MWe, with 19,433 MWe--or 23 new plants or plant additions--to be located in the Great Lakes coastal counties in the states of New York, Ohio, Michigan, Indiana, and Wisconsin. New generating capacity is not planned or scheduled to be in service by 1984 in the coastal counties of Illinois, Minnesota or Pennsylvania. (A state-by-state analysis is presented in Chapter VI, Technical Considerations--Energy Consumption and Movement in the Great Lakes Region.) Of this 19,433 MWe of additional capacity by the mid-1980's, 28 percent will be coal-fired (Michigan, New York and Wisconsin), 12% will be oil-fired (Michigan and New York), and 60% will be nuclear (Michigan, New York, Ohio, and Indiana).

Regional scenarios of energy development (principally electrical energy generation) have been prepared. The scenarios are based on different fuel mix assumptions due to the present uncertain conditions. The four scenarios with their respective fuel mix assumptions are:

- Recent trends--50% coal, 35% nuclear, 15% oil, gas and hydroelectric
- High Coal--70% coal, 15% nuclear, 15% oil, gas, and hydroelectric
- High Nuclear--45% coal, 45% nuclear, 10% oil, gas, and hydroelectric
- New Technologies--40-50% coal, 20-35% nuclear, 15-20% new technologies (solar, wind, fluidized bed, etc.).

In developing regional resource requirements for land, water, and fuel (coal), these scenarios were applied to a range of electrical energy demand projections (3%/year, 5.5%/year, and 8%/year), an assumed mix of generating facilities (75% base load, 20% intermediate load, and 5% peak load), and an assumed capacity load factor (65%). The resource requirements of the generalized facilities (coal-fired and nuclear power plants) were then applied to these assumptions to evolve the regional resource requirements of energy development.

For the purposes of this study a 3 percent growth rate per year in electrical energy consumption was assumed to be a lower bound in projecting future power plant development given uncertain circumstances. Actual growth in the future may be considerably higher or somewhat lower. This 3% growth rate will describe the minimum amount of resources required to meet future electrical energy consumption, as shown in the following table:

ADDITIONAL RESOURCE REQUIREMENTS OF THE GREAT LAKES STATES, 1975-1995
SCENARIOS AT 3%/YEAR GROWTH RATE IN
ELECTRICAL ENERGY CONSUMPTION

Additional Requirements (1975-1995)	Scenarios		
	I	II	III
Nuclear (units)	70	24	104
land (acres)	46,725	16,020	69,420
water (gpd)			
once-through	$1,008 \times 10^8$	346×10^8	$1,498 \times 10^8$
closed-cycle	$1,512 \times 10^6$	518×10^6	$2,246 \times 10^6$
Coal (units)	40	96	12
land (acres)	16,000	38,400	4,800
fuel (millions of tons per year)	80	192	24
water (gpd)			
once-through	403×10^8	968×10^8	121×10^8
closed-cycle	576×10^6	$1,382 \times 10^6$	173×10^6

The requirements in Scenario IV, New Technologies, are assumed to be about 80% of those in Scenario I, Recent Trends, due to a postulated reduced dependence on more conventional generation technologies.

Assuming an 8%/year growth rate, Scenario I, Recent Trends, projects an additional 238 nuclear units and 185 coal units needed, with land requirements of 233,000 acres; water withdrawals of $5,292 \times 10^8$ gpd for once-through cooling or $7,805 \times 10^6$ gpd for closed-cycle cooling; and coal requirements of 370 million tons per year.

For the Great Lakes coastal counties, the following general projected resource requirements (assuming a 50% coal/50% nuclear mix for additional capacity between 1975 and 1995--an approximate average of the four scenarios) were developed on the basis of an analysis of the scenarios and each state's energy development:

ADDITIONAL RESOURCE REQUIREMENTS OF THE GREAT LAKES COASTAL COUNTIES, 1975-1995, ASSUMING A 3% GROWTH RATE IN ELECTRICAL ENERGY CONSUMPTION*

State	Additional Requirements					
	Generating Units*	Generating Capacity (MWe)	Land (Acres)	Water Withdrawals (gpm) Once-Through	Water Withdrawals (gpm) Closed Cycle	Coal (Millions of Tons per year)
Illinois	---	---	---	---	---	---
Indiana**	---	---	---	---	---	---
Michigan	11	11,000	5,870	$9.35x10^6$	137,500	11.0
Minnesota	1-2	1-2,000	1-2,000	$0.9-1.7x10^6$	12-25,000	2-4.0
New York	7	7,000	3,740	$5.95x10^6$	87,500	7.0
Ohio	4	4,000	2,135	$3.4x10^6$	50,000	4.0
Pennsylvania	---	---	---	---	---	---
Wisconsin	8	8,000	4,270	$6.8x10^6$	100,000	8.0

*Coal and nuclear units, assuming a 50% coal/50% nuclear mix, as noted above.

**Does not include Bailly nuclear unit, Porter County, on site already containing two coal-fired units.

If an 8% growth rate is assumed, the figures in the table above would increase by a factor ranging from 2.0 to 4.8, depending on the state being examined. This indicates that considerable pressure might be placed on the coastal counties of Great Lakes Basin for electrical energy generation facilities.

C. POLICY OPTIONS

The policy options developed for this report fall into two categories: institutional and technical. The institutional options are further classified into seven groups: siting policy, organizational arrangements, functional responsibilities, siting procedures, siting criteria, financial mechanisms, and intergovernmental relations. The technical options address the types of energy facility development that might be included or excluded from the coastal zone. Environmental, economic and social considerations are included in both sets of options.

1. INSTITUTIONAL OPTIONS

Institutional options were derived from the study of existing state programs and of various proposals for improving such programs. Options for siting policy describe several possible associations that the siting function may enter into with respect to other functions and programs. Emphasis in these options is on the possibilities for the primary orientation of the program. Options for organizational structure and arrangements focus on the composition of agencies responsible for handling siting and related issues. The options for functional responsibilities address the means for accomplishing some of the tasks associated with siting.

Options for siting procedures deal with the procedural requirements of siting regulation that may be employed to meet the energy facility siting goals, policies and objectives of the states. Options for siting criteria and standards are related to the options available to a siting program for the site selection process. Options for financial mechanisms offer the states several options to facilitate the planned development of energy. Options for intergovernmental relations involve options for interaction and coordination between federal and state agencies with responsibilities in energy facility siting.

2. TECHNICAL OPTIONS

The technical options related to energy facility siting and development with regard to the coastal zone have been arranged to provide a full range of policy choices which remain within the context of the Coastal Zone Management Act. The three major groupings of options were selected as they relate to jurisdictional decisions. They are:

- Exclusion of all new facility development in the coastal zone management area, including access to coastal waters and fuel transportation. This option, however, is precluded under the Coastal Zone Management Act.
- Exclusion of all new facility development in the coastal zone management area, but allowing access to coastal waters and fuel transportation.
- Inclusion of new facility development in the coastal zone management area.

Throughout the development of these options it was assumed that all present and anticipated environmental controls will be operative as a minimum requirement and that the presently stated guidelines of the Coastal Zone Management Act will be followed in the development of the state CZM programs. The first major option, that of excluding facility development including access to coastal waters and fuel transshipment, discusses economic and environmental implications arising from such a policy. This policy would significantly affect lake movement of fuel and shift a greater demand to inland modes of transportation. Many of the technical spin-offs of such a policy relate to the resultant shift in transportation and the development of energy production technologies requiring less water. The second major technical policy option excludes new facility development in the coastal zone management area but allows access to coastal waters, and fuel transshipment and product transmission through the coastal zone. It was felt that this option would be more realistic under the guidelines of the Coastal Zone Management Act because the exclusion of facilities from coastal resources would not be complete. A number of suboptions were developed within this policy examining various methods of implementation relating to fuel delivery, provision of cooling water, and development of corridors for transmission of products such as electricity and oil back into the coastal zone.

The final set of options considers inclusion of new facility development in the coastal zone management area. Suboptions address specification of critical areas, development areas, and buffer control zones; the encouragement of dispersed siting; limitations on expansion or reconstruction; location in proximity to existing power grids or near transshipment facilities; maintenance or increase of public access to the shoreline, permitting shoreline use for energy facilities; setback distance for energy facilities; permitting shoreline use only by those facilities absolutely requiring shoreline location; designation of coastal development priorities to energy facilities; priority use for facilities employing by-product utilization; multiple use/single site development; and specification of type and size of facility allowed to site in the coastal zone.

These options were developed to provide a broad range of policy choices that are feasible within present technical capabilities. The technical options were not constrained by existing policies, so it was possible to consider a number of innovative options that remain reasonable possibilities.

The energy growth rates used in this study do not affect the particular options that might be chosen from the range of options developed. The growth rate of energy consumption in each state or substate region would serve to suggest: how much emphasis a particular state should place on developing an energy facility siting program; how comprehensive that program could be in terms of facilities and fuels; what the areal extent of the program jurisdiction should be; which levels of government should be involved with the program; what involvement the coastal zone management program might have in such a program; and what authorities and sanctions should be vested in the program.

Chapter II

INTRODUCTION

In the Great Lakes Region, people have become increasingly concerned about the uses to which the coastal areas have been and will be put. Future energy development in the Great Lakes coastal zone is of substantial importance to these people and to their governments, acting as resource trustees and managers for present and future generations. In response to public concern and to the Coastal Zone Management Act of 1972, each of the Great Lakes states is developing a coastal zone management program charged to balance economic and environmental considerations affecting coastal areas and their waters.

The Coastal Zone Management Act recognizes both the economic and environmental significance of the coastal areas. It highlights the necessity of preserving certain areas from degradation and developing others. Growing concern about the impacts of energy development, particularly on the coastal areas, gave birth to the Coastal Zone Management Act Amendments of 1976. A major provision in these amendments grants funds to coastal states and local governments to offset the adverse economic and environmental effects of developing outer-continental-shelf oil and gas. Although this does not apply to the Great Lakes, other provisions in the amendments promote energy facilities study and planning, interstate coordination, and mitigation of impacts from the development of major fuel transportation and storage facilities. The energy facilities study and planning grants for which the Great Lakes state coastal zone management programs are eligible apply to study and planning for facilities in the coastal zone such as coal-fired and nuclear electrical generating facilities, refineries, fuel transshipment and storage facilities, and potential coal gasification and liquefaction plants.

A. STATE AND FEDERAL ACTIVITIES AFFECTING ENERGY FACILITY SITING

Many state and federal agencies are responsible for energy development and energy-related environmental programs in the Great Lakes Region. Each of the Great Lakes states has a public service or public utilities commission, which regulates the provision of electricity and gas and establishes rates for these energy sources. Some states also have commissions or boards with authority to monitor energy development and review proposed energy facilities. Each of the Great Lakes states has laws, regulations, policies, and/or programs affecting energy facility siting. New York and Ohio have had siting programs for several years. Minnesota and Wisconsin have recently developed similar programs. The remaining states are using other governmental mechanisms (described in Chapter III) to address energy facility siting. As stated previously, the coastal zone management programs of each state, established under the Coastal Zone Management Act of 1972 (P.L. 92-583), must establish programs that balance environmental and economic values in the management of their coastal resources. Energy development highlights the trade-offs that must be made and is an important factor in the development of these programs.

Several federal agencies are involved in the siting of energy facilities. The Nuclear Regulatory Commission is responsible for reviewing and licensing nuclear facilities. The Federal Power Commission licenses hydroelectric facilities and determines interstate gas rates. The Environmental Protection Agency monitors and regulates environmental pollutants from energy facilities as well as from other types of plants. The Corps of Engineers is concerned with energy facility structures placed in navigable waters. The Federal Energy Administration is responsible for establishing energy policies and the allocation of fuels. The Federal Aviation Administration oversees air transport of nuclear fuels. The Coast Guard is concerned with aids to navigation, adequate and safe navigation conditions, potential pollutants to the aquatic environment of navigable waters, and potential obstacles to navigation. Furthermore, the National Environmental Policy Act of 1969 specifies environmental considerations that must be taken in federally funded, assisted, or licensed programs and projects. This includes federal responsibilities in the area of energy facilities and energy facility siting.

B. CONCERN OF THE GREAT LAKES STATES COASTAL ZONE MANAGEMENT PROGRAMS ABOUT ENERGY FACILITIES SITING

The Great Lakes states coastal zone management programs participate on the Great Lakes Basin Commission's Standing Committee on Coastal Zone Management. This Committee was formed to address opportunities, problems, and concerns of mutual, interstate or regional interest relating to coastal zone management.

In late 1975, the states were anticipating the passage of Section 308(c) and (d)(4) of the Coastal Zone Management Act Amendments which would (and do) provide grants to the Great Lakes and other coastal states for amelioration of impacts from fuel transportation and storage facilities in the coastal zone and for energy facilities planning. This provision appeared in both the House and Senate versions of the bill. At a meeting in late 1975, the Great Lakes coastal zone programs caucused and identified energy facility siting as an area in which they felt they would like to have additional support in developing their programs. As a result, the Commission staff developed a proposal for the Standing Committee on Coastal Zone Management to study energy facility siting policies and programs as well as projections and trends of energy use in the Great Lakes Region. The Great Lakes states indicated that, as their programs were up for approval within the next 12 to 18 months, they required immediate input in this important area, and asked the staff to revise the proposal to focus specifically on energy facility siting policies at the state and federal level, future regional energy developments, and policy options for the siting of energy facilities in the Great Lakes coastal zone. They also requested that the study be shortened from nine to four months at considerably reduced funding. As a result, the staff prepared a new proposal, which was approved by the Standing Committee on Coastal Zone Management in April, 1976, and was funded for approximately $53,760 by the Office of Coastal Zone Management on June 30, 1976. The study began on July 6, 1976, and was conducted over a four month period.

C. DEVELOPMENT OF THE STUDY

The objectives of the study were the examination of energy trends and the coastal dependence of energy facilities and the development of a full range of policy options for the siting of energy facilities in the Great Lakes coastal zone. A by-product of the study was the development of a facility activity impact matrix which can be used by the Great Lakes coastal zone programs in evaluating future proposed facilities for the coastal zone. Also, scenarios were developed, based on a range of energy growth rates for the region. These scenarios present their assumptions and related energy developments along with resource requirements to 1995, thus indicating the likely pressures on the coastal zone for various types of facilities. Finally, state and federal policies and programs related to energy facility siting were reviewed and summarized, and a comparative analysis of these programs is presented.

Once the Standing Committee on Coastal Zone Management approved the proposal, it established a steering committee for the project. The steering committee was composed of representatives from the states of Wisconsin, Ohio, Pennsylvania, and Michigan, and from the federal agencies of the Department of the Interior, the Environmental Protection Agency, the Department of Transportation, and the Department of Commerce. Members of the steering committee are listed in Appendix B. The proposal also indicated that a group of technical advisors would be formed to advise the study staff on technical matters. The project manager asked the steering committee to identify persons who would be available and qualified to serve as technical advisors. Additional technical advisors were identified and added as the study proceeded. These persons are listed in Appendix C.

After the funding was approved for the study, the steering committee met, and the project manager presented a lengthy list of energy facilities which could be examined in the study. The steering committee reduced this list and ranked them according to their apparent importance to the Great Lakes coastal zone. The facilities to be examined, in order from first to third priority are: (1) electrical energy generation (fossil-fuel and nuclear); (2) fuel transshipment and storage; and (3) refining. Recognizing the time constraints on the study, the steering committee indicated that if all types of facilities could not be addressed, then the staff should address first those at the top of the list, namely, electrical generating facilities.

During the course of the study, state and federal agencies and utility companies and other industries having energy facilities were continually involved in the review of interim draft papers prepared by the project's staff. Furthermore, the technical advisors were consulted throughout the study and provided tremendous assistance to the staff. After the first two months of the study, the steering committee met to review its progress. On the advice of the project manager, the steering committee indicated that the focus during the study's last two months should be on electrical energy generation facilities and fuel transshipment and storage facilities.

D. STAFF ORGANIZATION AND FUNCTIONS

The principal areas of investigation in this study lent themselves to three major assignments: (1) analysis of institutions, policies, and programs concerned with energy facility siting; (2) analysis of coastal dependency and the economic and environmental considerations in the siting of facilities; and (3) analysis of the projections and trends and their relation to possible scenarios of energy development. Therefore, the staff was organized into three principal units: the policy unit, the coastal dependence unit; and the projections and trends unit. Two staff members served in the policy unit, three staff members in the coastal dependence unit, and two in the projections and trends unit. All persons were assigned according to their background and expertise. In addition, other Commission staff members were utilized in the study as technical advisors. Commission staff committed to the study are listed in Appendix D.

The policy unit reviewed, summarized and analyzed the state and federal policies, programs, legislation and regulations affecting energy facility siting in the Great Lakes Region. They also examined programs of coastal states outside the region. This unit also developed institutional policy options for the siting of energy facilities.

The coastal dependence unit developed a matrix and an analysis approach that can be utilized by the states in their assessment of proposed energy facilities. This unit also described in detail the major elements of the principal types of energy facilities addressed in the study and their associated resource requirements. Finally, it provided an analysis of the environmental impacts, both natural and cultural, associated with facility construction and operation and the major cost components of each facility type.

The projections and trends unit analyzed existing energy flows within the region, particularly with regard to electricity and coal, and examined projections and trends of future energy growth on the basis of its own analysis and with the assistance of the technical advisors. It also developed scenarios of energy development, given different rates of growth and various assumptions regarding fuel mix.

The coastal dependence unit and the projections and trends unit combined their efforts to report the implications on resource requirements of the various scenarios. In addition, these two units utilized their expertise to develop technical policy options for the siting of energy facilities in the Great Lakes coastal zone. These options incorporate the environmental and locational considerations that have been reported in the study.

E. LIMITATIONS OF THE STUDY

As previously indicated, the study focused only on electrical energy generating facilities (fossil-fuel and nuclear), fuel (coal and oil) transshipment and storage facilities, and refineries. Thus, the scope of the study is somewhat narrow and is restricted to conventional technologies.

For the electric generating facilities, a generalized facility size was used to discuss the possible effects on the resources of the coastal zone. The principal reasons for this approach were:

- The short time frame of the study did not lend itself to a discussion of range of facility size.
- More importantly, the study attempted to examine facilities of the size which were most likely to be constructed in the coastal zone.

A 1000-MW plant was selected for fossil-fuel and nuclear facilities. The other facility types investigated in this study did not lend themselves to a discussion of generalized facilities. The facility sizes for electrical generation mentioned above (or sizes very close to these) are cited in the literature and have been used in recent studies of facility types and their resource implications. Both larger and smaller facilities may be constructed depending on the particular requirements of the service area. The generalized facilities also enabled the staff to discuss from a general standpoint the possible resource requirements of future facilities and the resultant pressures on the Great Lakes coastal zone, a topic deemed very important to future management planning in the Great Lakes coastal zone with respect to energy facilities.

Throughout the report, figures for costs, land areas, water volumes, and other resources affected by the siting of energy facilities have been presented. This quantification has been provided wherever possible to give the users of this report a base of reference for future comparisons. Whenever possible, ranges of values for costs, land areas, or other resources were used to indicate not only the range of possible resource requirements but also to suggest that there are no "hard" or "firm" figures.

Most cost figures in this report use the years 1974 through 1976 as a base. This narrow range should give a good basis for comparison of facilities proposed in the future. Caution should be used when examining and using any of the figures cited in the report; the figures will change quickly due to inflation and site-specific or geographic considerations. Thus, these figures should be used to discuss the relative, not absolute, magnitudes of effects or resource requirements of the various facilities. In some cases, cost information was difficult to obtain; in other cases, it varied so widely as to be almost entirely inconsistent. After consultation with technical advisors, the staff did its best to determine an accurate estimate of these widely varying costs. Every attempt was made to obtain cost information from both government and industry sources so as not to bias the information in one direction or the other.

F. IMPORTANT FACTS AND DEFINITIONS

Several points concerning the study should be made clear.

- The Great Lakes states, through their coastal zone management programs, have asked the Great Lakes Basin Commission staff to examine from a regional standpoint the coastal dependency of energy facilities and the resource requirements and pressures on the coastal zone from future energy development.
- The results of the study are not binding, but only suggestive, and will be used by each Great Lake's state as it sees fit for the development of its own coastal zone management policies for the siting of energy facilities.
- The study examined the implications of coastal versus inland siting of energy facilities and projections related to future energy facilities development. The study was not undertaken with the intent of excluding facilities from the coastal zone, but rather to provide the coastal zone management programs with a general technical understanding of the relationships involved in

the siting of facilities. Furthermore, the Coastal Zone Management Act specifically directs the states not to exclude from consideration facilities or uses of the coastal zone which are of greater than local concern. This would certainly apply to energy facilities.

- The definition of energy facilities for the purposes of this study includes facilities for electrical energy generation (fossil-fuel and nuclear), fuel (coal and oil) transshipment and storage, and crude oil refining.

- The time period covered by the study is the next fifteen to twenty years - to 1995.

- In discussions of inland versus coastal locations for energy facilities, inland refers to a location generally one mile or more from the coastline, inland to a distance approximated by the inland boundaries of the Great Lakes states coastal counties. Coastal refers to general locations or sites on or near (less than one mile from) the shoreline of the Great Lakes.

- Coastal dependence refers to the determination of energy facility location with respect to the shoreline of the Great Lakes. The following general considerations aid this determination: system requirement, safety, engineering, environmental, institutional, and economic. This definition broadens the analysis beyond simple dependence on the coast into a more general examination of facility location.

Other definitions essential for understanding the report are:

- Coastal county--a county with frontage on one of the Great Lakes, their connecting channels, or the St. Lawrence River;

- Coastal zone--an area adjacent to the shoreline, generally much narrower and smaller in area than the tier of counties bordering the Great Lakes and connecting channels;

- Coastal zone management area--the area along the Great Lakes shoreline which is designated to come under the purview of the states' coastal zone management plans. The lakeward extent of the management area reaches to the international or state boundary, as appropriate. The landward extent of the management area is generally a narrow strip of land, defined differently by each state (some Great Lakes states have not yet firmly specified an inland management boundary). Some activities (uses of or affecting land, air, water, etc.) adjacent to or beyond the management area which affect or influence the management area might also come under the jurisdiction of a state's coastal zone management program.

G. POLICY OPTIONS AND THEIR APPLICATION

Institutional and technical policy options for the siting of energy facilities in the coastal zone were developed by the staff. The institutional options suggest possible institutional arrangements which might be used by the states and their coastal zone management programs to enable them to better manage the effects of energy facilities located in the coastal zone. Some institutional options envision major reorganization; others suggest the use of existing institutional arrangements. The situation in each state will dictate the kinds of institutional options it might employ in planning for and managing the effects of energy facilities sited in the coastal zone.

It should be noted that these options are only suggestions. This study and report have been undertaken with no intention of asserting that a particular state or program should adopt any of the options proposed. The Great Lakes states coastal zone management programs asked only that a full range of options be developed for their consideration. As the state CZM program staffs examine the options, they may identify additional options of a specific nature which could be incorporated into their programs, but, due to the brevity of the study, could not be developed for this report. Furthermore the selection of certain institutional options will necessarily preclude other institutional options.

The second group of options, the technical options, were developed on the basis of the technical, environmental, and economic research carried out for the study. These options range from complete exclusion of energy facilities from the coastal zone to the inclusion of energy facilities on shoreline locations. Some of these options may be unrealistic for some or all states. Some of the technical options are mutually exclusive. The implications of each option are described so that the state CZM programs will have an initial understanding of their respective opportunities and problems.

The energy growth rates used in this study do not affect the particular options that might be chosen from the range of options developed. The growth rate of energy consumption in each state or sub-state region would serve to suggest: how much emphasis a particular state might place on developing an energy facility siting program; how comprehensive that program might be in terms of facilities, fuels, and types of energy dealt with; what the areal extent of the program jurisdiction should be; which levels of government should be involved with the program; what involvement the coastal zone management program might have in such a program; and what authorities and sanctions should be vested in the program.

H. ADDITIONAL APPLICATION OF THE REPORT

The Great Lakes states coastal zone management programs can merge the information assembled in this report with information on energy requirements of future industrial, commercial and residential development in their respective coastal zones. Once these programs can estimate the expected energy demands of industry and per capita residential use on an area-by-area basis, they can then estimate the needed energy facilities and their related resource requirements. Having better locational information for these facilities than is presently available will permit more meaningful and informed coastal zone management plans and decisions.

The study focuses only on the Great Lakes coastal zone of the eight states of New York, Pennsylvania, Ohio, Michigan, Indiana, Illinois, Wisconsin, and Minnesota. Thus, the study does not address energy facility siting or associated policy options for the Hudson River mouth, Long Island Sound, and Atlantic Ocean portion of New York's coastal zone management program, nor the Delaware River-Chesapeake Bay estuary element of Pennsylvania's program. Although some of the information and policy options developed in this study could be useful in addressing resource management problems for these other areas, the states and their local levels of government will have to decide on the degree of applicability. With respect to projections of electrical energy consumption and associated resource requirements for the states of Pennsylvania and New York, only the northwest corner of Pennsylvania and upstate New York were considered. Maps of the Great Lakes basin and counties appear as Figures A and B.

Exact figures of energy facility cost and resource requirements are difficult, if not impossible, to arrive at. However, ranges of costs and resource requirements have been assembled in this report and are intended to be used to obtain a rough estimate of the magnitude of effects associated with energy facilities and to extrapolate estimates of future resource requirements of energy facilities and the possible pressures on the Great Lakes coastal zone.

The policy options in this report suggest possible approaches to the planning for and management of the effects of energy facility development in the coastal zone. This study provides input for one particular aspect of coastal

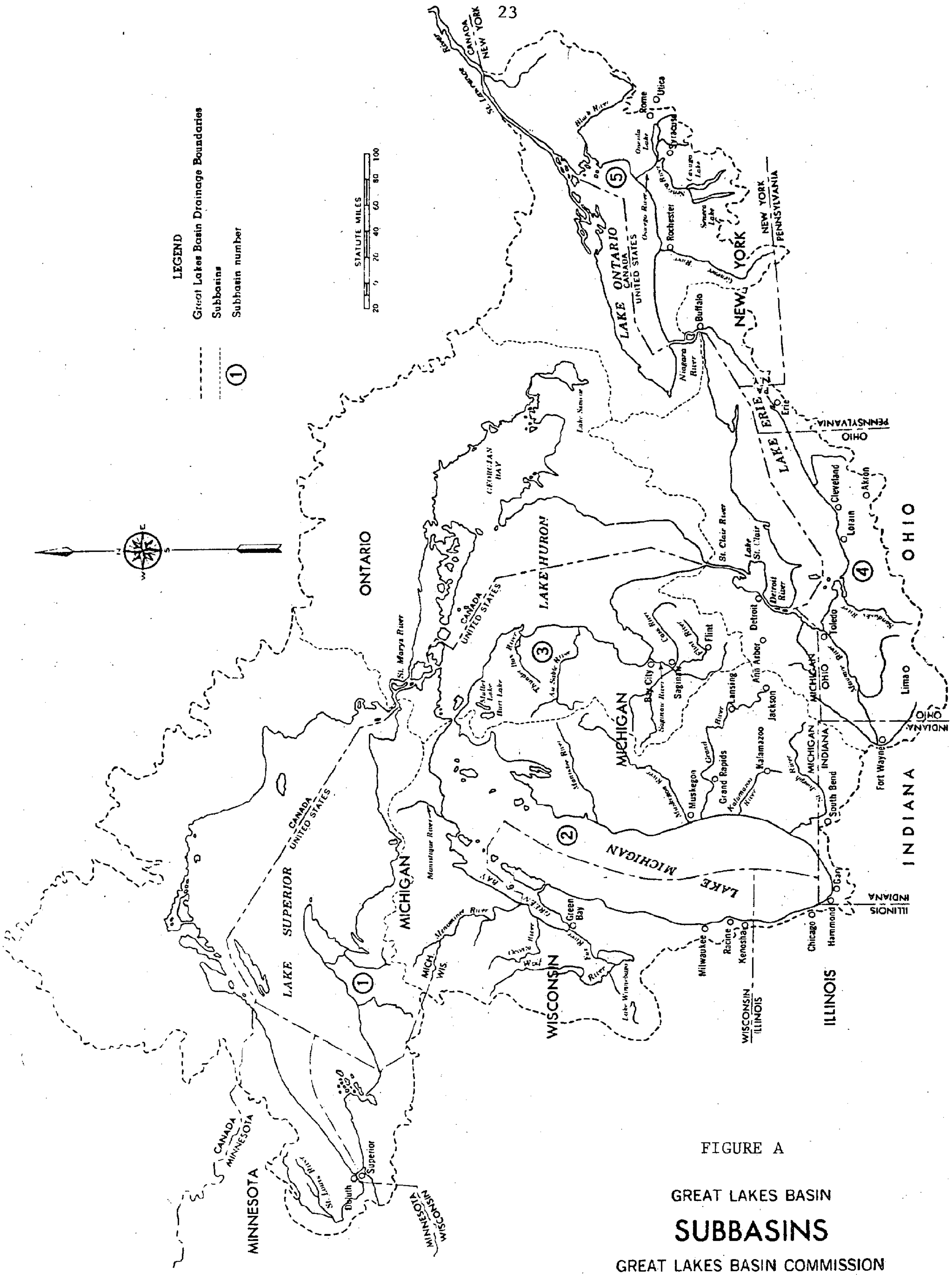

FIGURE A

GREAT LAKES BASIN

SUBBASINS

GREAT LAKES BASIN COMMISSION

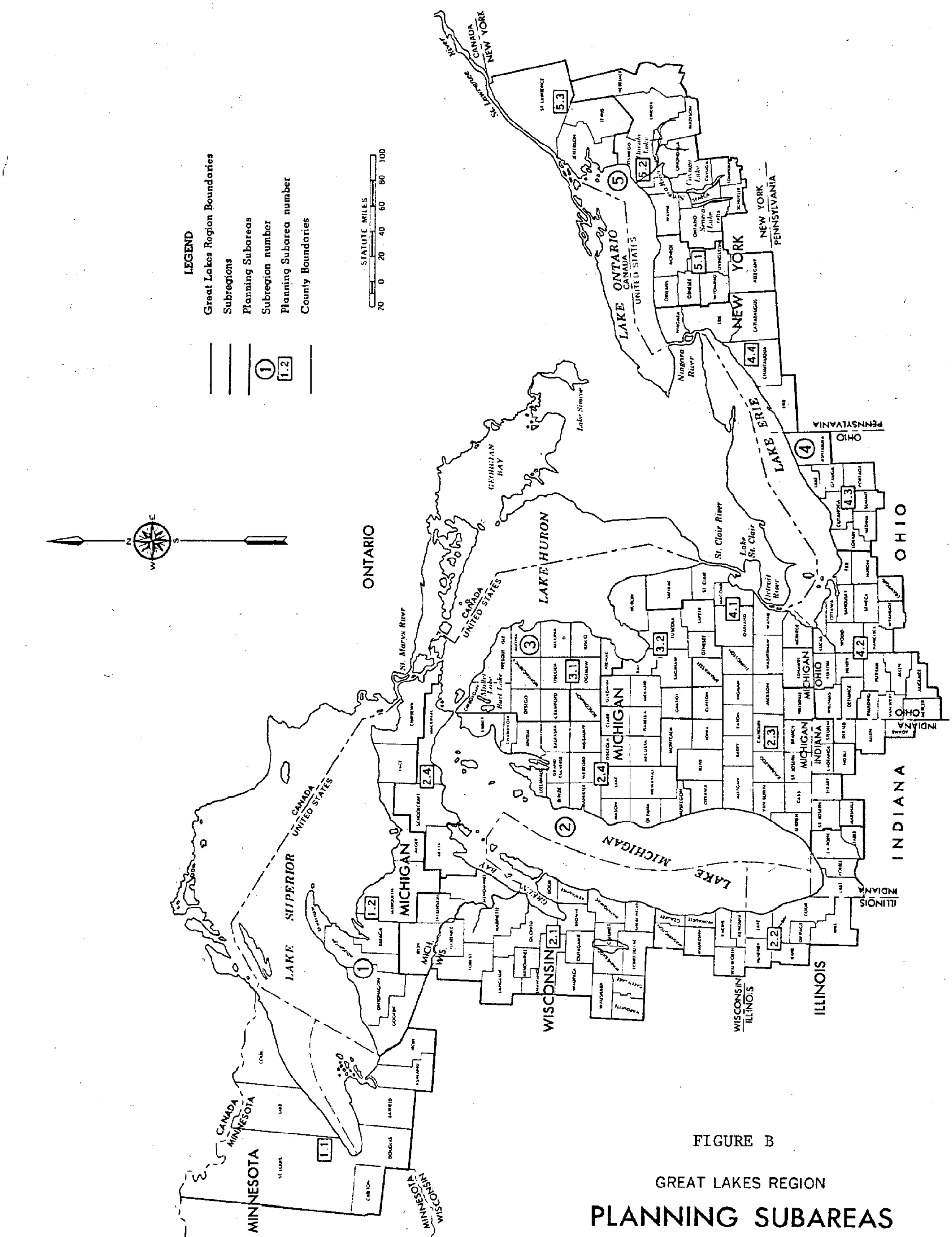

FIGURE B

GREAT LAKES REGION

PLANNING SUBAREAS

GREAT LAKES BASIN COMMISSION

zone management. Its relation to other elements of the CZM program will hopefully be resolved by the states. Thus, this report is intended to be a tool to assist the Great Lakes states coastal zone management programs and it is to them that it is directed. The report is not and never was intended to be a definitive treatise on energy facility siting in the Great Lakes coastal zone.

While a broad group of technical advisors from both the public and private sectors participated in the study by reviewing and commenting on preliminary material and the draft report, this should not be taken as their endorsement of this final report. They served only as advisors, reactors, and providers of information. So that this point is well understood, it is restated at appropriate places in the report.

Chapter III
INSTITUTIONAL CONSIDERATIONS

A. INTRODUCTION

1. PURPOSE

This chapter addresses the institutional (legal, organizational and procedural) aspects of energy facility siting, with emphasis on the Great Lakes states and their coastal zones. Institutional aspects are distinguished from technical aspects, which are covered in the next chapter. The study of existing institutions provides the means for comparing the various state programs and for developing options for the states to consider in the context of federal programs and requirements as well as other related state programs. In a broad sense, the institutions associated with energy facility siting are primarily concerned with the structure of government, the structure of the energy industry and the relationship between them.

2. SCOPE

The first section describes federal legislation and agencies that are deemed to have significant impacts on energy facility siting. The most direct federal involvement is found in the regulation of the siting of nuclear and certain hydroelectric facilities, though other significant federal involvement is possible, especially in the area of environmental protection. For example, the U.S. Environmental Protection Agency has retained authority over the issuance of water and air permits.

Subsequent sections describe the energy facility siting programs in the eight Great Lakes states and those in other coastal states that provide examples of unique and/or interesting approaches to the siting problem. Such features are emphasized in the descriptions.

The final section provides a set of criteria which interested persons may use to evaluate a state siting program. Several features of state programs are described, and a table is provided to show how these features are addressed by each of the states.

B. ENERGY FACILITY SITING REGULATION

1. FEDERAL

The Congress has recently considered, but has not passed, legislation that would specifically address energy facility siting. This leaves the federal government with a direct role in siting only in the case of hydroelectric generation and nuclear energy facilities. However, several federal laws and regulations affect siting less directly and involve a number of federal agencies in the process. The Coastal Zone Management Act of 1972 as amended is of central importance to this study and will be discussed first. Another federal statute, the National Environmental Policy Act of 1969, established a major federal program with widespread application and will thus be discussed separately. The remainder of the existing federal legislation that significantly affects or is related to the siting of the types of energy facilities under consideration in this study are discussed under the appropriate administrative agencies.

a. Coastal Zone Management Act

The Coastal Zone Management Act (CZMA) of 1972 (P.L. 92-583) created a comprehensive program to plan for and manage the nation's coastal areas. "The Act recognizes that the coastal zone is rich in a variety of natural, commercial, recreational, industrial, and esthetic resources of immediate and potential value to the present and future well-being of the nation" [632]. The Act responds to the problem that "present state and institutional arrangements for planning and regulating land and water uses in the coastal zone are often inadequate to deal with the competing demands and the urgent need to protect natural systems in the ecologically fragile area" [632].

Significant amendments to the Act (P.L. 94-370) were passed in 1976 that (among other things) expanded the program to provide for increased planning and management of energy development which affects the coastal zone.

The general institutional approach of the CZM program is one of providing federal technical and financial assistance to coastal states to encourage them to develop programs for the management of their coastal resources. The eight Great Lakes states are currently developing coastal zone management programs pursuant to the federal legislation. Of particular significance to this study are provisions for establishing an energy facility planning process within the CZM programs of each coastal state.

Subsection 305(b) of the Act as amended indicates that these programs must include:

> (1) an identification of the boundaries of the coastal zone subject to the management program;
> (2) a definition of what shall constitute permissible land and water uses within the coastal zone which have a direct and significant impact on the coastal waters;
> (3) an inventory and designation of areas of particular concern within the coastal zone;
> (4) an identification of the means by which the state proposes to exert control over the land and water uses referred to in paragraph (2), including a listing of relevant constitutional provisions, laws, regulations, and judicial decisions;
> (5) broad guidelines on priority of uses in particular areas, including specifically those uses of lowest priority;
> (6) a description of the organizational structure proposed to implement the management program, including the responsibilities of local, areawide, state, regional, and interstate agencies in the management process;
> (7) a definition of the term "beach" and a planning process for the protection of, and access to, public beaches and other public coastal areas of environmental, recreational, historical, esthetic, ecological, or cultural value;
> (8) a planning process for energy facilities likely to be located in, or which may significantly affect, the coastal zone, including, but not limited to, a process for anticipating and managing the impacts from such facilities;
> (9) a planning process for (A) assessing the effects of shoreline erosion (however caused), and (B) studying and evaluating ways to control, or lessen the impact of, such erosion, and to restore areas adversely affected by such erosion.

Although the Great Lakes states are at different stages in the development of their management programs, once they have defined the inland management boundary(s) of the coastal zone in their respective states and the programs are approved by the Secretary of Commerce and thus implemented, future activities and planning efforts must acknowledge whether they are in or significantly affect the coastal zone. If they are in or affect the coastal zone, the plans must receive the approval of the state's coastal zone management program and be certified as consistent with it. In the case of activities on federally owned lands, no final decision has yet been made concerning consistency requirements.

In determining the permissible land and water uses within the coastal zone, the states must evolve and apply an objective procedure which includes at a minimum:

> (1) a method for relating various specific land and water uses to impact upon coastal waters, including utilization of an operational definition of "direct and significant impact,"
> (2) an inventory of natural and manmade coastal resources,
> (3) an analysis or establishment of a method for analysis of the capability and suitability for each type of resource and application to existing, projected, or potential uses,
> (4) an analysis or establishment of a method for analysis of the environmental impact of reasonable resource utilizations [633].
>
> Based on the analyses [mentioned above] and applicable Federal, State and local policies and standards, the State(s) should define permissible uses as those which can be reasonably and safely supported by the resource, which are compatible with surrounding resource utilization and which have a tolerable impact upon the environment [633].

In the event that the states prohibit certain uses within the coastal zone, the reasons for the prohibition should be identified.

The states must include in their respective management programs an inventory and designation of areas of particular concern within the coastal zone, based on a review of natural and manmade coastal zone resources and uses, and upon consideration of state-established criteria. According to the rules and regulations implementing the Act, the factors considered in these designations must include at a minimum:

> (1) Areas of unique, scarce, fragile or vulnerable natural habitat, physical feature, historical significance, cultural value and scenic importance;
> (2) Areas of high natural productivity or essential habitat for living resources, including fish, wildlife and the various trophic levels in the food web critical to their well-being;
> (3) Areas of substantial recreational value and/or opportunity;
> (4) Areas where developments and facilities are dependent upon the utilization of, or access to, coastal waters;
> (5) Areas of unique geologic or topographic significance to industrial or commercial development;
> (6) Areas of urban concentration where shoreline utilization and water uses are highly competitive;
> (7) Areas of significant hazard if developed, due to storms, slides, floods, erosion, settlement, etc.; and
> (8) Areas needed to protect, maintain or replenish coastal lands or resources, including coastal flood plains, aquifer recharge areas, sand dunes, coral and other reefs, beaches, offshore sand deposits and mangrove stands [633].

The intent in specifying areas of particular concern is to convey some degree of statewide concern about them and then to incorporate them within the scope of the management programs. In this manner, the states will give these areas special attention in the development and implementation of policies and actions to manage areas of particular concern.

Of special relevance to this study and its policy options (described in Chapter VI) is the possible designation of: areas to be preserved, such as areas of unique, scarce or fragile natural habitat, historical significance, or aesthetic importance; areas of high natural productivity or essential habitat; and areas of substantial recreational value or opportunity. These areas should generally be avoided or affected minimally by energy facilities in their construction, expansion and/or operation. Another important factor to be considered in the siting of energy facilities is the designation of: areas of unique geologic or topographic significance (to industry or commerce), and areas of highly competitive uses for shoreline and water in and near urban concentrations. The possible designation of "energy resource areas" as areas of particular concern to the energy industry as well as to other industry, commerce, and the public are important for the future provision of energy to the coastal zone and areas inland. The concern for energy-related needs must be balanced with other land uses. This general approach is addressed in greater detail in Chapter VI. Finally, areas of significant hazard and areas needed to protect, maintain, or replenish coastal lands or resources must receive special attention in planning.

A significant facet of the coastal zone management programs that could affect energy facility siting is the development of policies or guidelines for establishing priorities in areas of particular concern for at least those permissible land and water uses discussed above. The guidelines for these priorities will describe the extent of state interest in the preservation, conservation, and orderly development of specific areas. Certain areas could receive high priority for development, and other areas, low priority for development, including energy facilities. Subsection 306(c)(9) of the Act further states that the coastal zone management agencies, in order to receive approval of their programs, must provide for "procedures whereby specific areas may be designated for the purpose of preserving or restoring them for their conservation, recreational, ecological or esthetic values." Thus, using the state procedures and criteria for preservation and restoration designation, these areas can be given a low priority for development, thereby essentially precluding development, including energy facilities, from those areas.

Additionally, in order to address the requirements of Subsection 306(e)(2), the management programs must provide evidence that "the state has developed and applied a method for determining uses of regional benefit and has established a method for assuring that local land and water use controls in the coastal zone do not unreasonably or arbitrarily restrict or exclude those uses of regional benefit" [633]. Through this requirement, local decisions concerning land and water use are prevented from arbitrarily excluding uses that are of importance to more than a single unit of government. However, the state may determine that certain land and water uses are of regional benefit under certain conditions or circumstances only. It must then establish standards and criteria for determining when these conditions exist. Complete exclusion or restrictions of these uses in the coastal zone cannot be made through local regulation unless they are based on "reasonable considerations of the suitability of the area for the uses or the carrying capacity of the area" [633]. Therefore, energy facilities may be permitted in some coastal areas but not in others. Furthermore, certain types or sizes of energy facilities may be permitted in certain locations whereas other types or other sizes of similar facilities may be precluded from the same locations.

In addition, Subsection 306(c)(8) of the Coastal Zone Management Act as amended includes a requirement that "the management program provides for adequate consideration of the national interest involved in planning for, and in the siting of, facilities (including energy facilities in, or which significantly affect, such state's coastal zone) which are necessary to meet requirements which are other than local in nature." In other words, <u>energy facilities may not be arbitrarily excluded from coastal zones if they are considered to be in the national interest</u>. Otherwise, the regulation of energy facility siting is (except as otherwise indicated) left to the discretion of each state.

Section 306(e) of the Act specified that the state management program must provide

> for any one or a combination of the following general techniques for control of land and water uses within the coastal zone:
> a. State establishment of criteria and standards for local implementation, subject to administrative review and enforcement of compliance;
> b. Direct state land and water use regulation; or
> c. State administrative review for consistency with the management program of all development plans, projects, or land and water use regulations, including exceptions thereto, proposed by any state or local authority or private developer,

> with power to approve or disapprove after public notice and an opportunity for hearings.

Thus, the state must, at the least, oversee local zoning practice in the coastal zone and enforce the provisions of the coastal zone program.

Due to the specific relationship established between coastal zone management and energy facility planning as a result of the 1976 amendments, the following sections of the Coastal Zone Management Act as amended are of particular relevance to this study:

- Subsection 305(b)(8), which requires each state program to include a planning process for energy facilities;
- Subsection 308(c), which makes grants available to states for the study of and planning for any economic, social, or environmental effects of energy facilities of all types in or significantly affecting the coastal zone;
- Subsection 308(d)(4), which provides for grants to coastal states to assist them in the prevention, reduction, or amelioration of unavoidable loss to the coastal zone of valuable environmental or recreational resources resulting from a coastal energy activity.

The coastal energy activities outlined in the amendments which apply, or potentially could apply, to the Great Lakes states are: (1) "any transportation, transfer, or storage of oil, natural gas, or coal"; and (2) "any transportation, conversion, treatment, transfer, or storage of liquified natural gas." Energy facilities (distinguished from coastal energy activities) refer to all types including but not limited to: electric generating plants; petroleum refineries and associated facilities; gasification plants; facilities used for transportation, conversion, treatment, transfer, or storage of liquified natural gas; uranium enrichment or nuclear fuel processing facilities; oil and gas facilities, including platforms, assembly plants, storage depots, tank farms, crew and supply bases, and refining complexes; facilities, including deepwater ports, for the transfer of petroleum; pipelines and transmission facilities; and terminals which are associated with the foregoing facilities.

Subsection 305(b)(8) of the 1976 amendments states that:

> The management program for each coastal state shall include...(a) planning process for energy facilities likely to be located in, or which may significantly affect, the coastal zone, including, but not limited to, a process for anticipating and managing the impacts from such facilities.

According to proposed rules published in the Federal Register on December 6, 1976 (Department of Commerce, National Oceanic and Atmospheric Administration [15 CFR Part 920] Coastal Zone Management Program Development Grants, pp. 53418-13425) [636], the planning process for energy facilities referred to in the Act should include:

> (1) A means of identifying energy facilities which are likely to be located in or which may significantly affect the coastal zone;
> (2) A procedure for assessing impacts for such facilities;
> (3) Development of State policies and other techniques for the management of energy facility impacts; and
> (4) A mechanism for coordination and/or cooperative working arrangements, as appropriate, between the State coastal management agency and other relevant State, Federal, and local agencies involved in energy facility planning [636].

To reiterate the intent of Subsection 305(b)(8), the planning process is to cover energy facilities, whatever their location, that significantly affect the coastal zone (outside the coastal zone but having major effects on it, or within the coastal zone), and whenever they might reasonably be expected to have effects (benefical or adverse, social, economic, or environmental) in the coastal zone.

In developing procedures for energy facilities impact assessment, states should include in their planning process assessment of the impacts from energy facilities that must be considered under Section 308 of the Act, the Coastal Energy Impact Program, (discussed further below) as applicable to the Great Lakes states. These impacts might include, but are not limited to, "increased population, changed employment patterns, changed demands for public facilities and services, local price inflation, changed patterns of tax or user fee revenues, effects on fishing revenues, effects on beaches and sand dunes, shoreline erosion, effects on air and water quality, and ecological effects."

With respect to the development of state policies and techniques for the management of energy facility impacts, the state coastal zone management programs are

> encouraged to develop, in cooperation with other appropriate agencies, procedures for assessing need/demand projections; for allocating these needs among coastal and inland locations; for identifying potential coastal impacts; and for determining site suitability of alternate locations for particular facilities [636].

(See "Policy Options Related to the Siting of Energy Facilities in the Great

Lakes Coastal Zone," Chapter VI.) Suitability analysis of particular sites could be accomplished with funds authorized under Subsection 308(c) of the Act as amended (see below). It should be recognized that the nature of the policies and techniques for managing energy facility impacts in or significantly affecting the coastal zone that are incorporated in the overall implementation program will depend in part on the type and extent of energy facility siting policies and techniques already in existence at the local, state, and federal levels.

With respect to developing mechanisms for coordination and cooperation between the state coastal zone management agency and other local, state, and federal agencies, the Act states that the states "should give particular attention to State and Federal agencies already involved in various aspects of energy planning. At a minimum, where interstate plans exist (as referred to in Subsection 306(c)(8) of the Act), these plans should be taken into consideration." The consideration of interstate energy plans or programs in the state coastal zone management programs will facilitate some regional consistency among the CZM programs in energy planning with respect to the management of resources and energy facility impacts in or affecting the coastal zone. The proposed rules for Program Development Grants also suggest that cooperative arrangements be made to use energy data, projections, estimates of facility needs, and policies developed by others, including government energy and utility agencies and energy industries. This report provides a substantial amount of material on these matters in the Great Lakes Basin.

Concerning energy facility environmental planning grants for which the Great Lakes states are eligible, Subsection 308(c) of the Act states that:

> The Secretary [of Commerce] shall make grants to any coastal state if the Secretary finds that the coastal zone of such state is being, or is likely to be, significantly affected by the siting, construction, expansion, or operation of new or expanded energy facilities. Such grants shall be used for the study of, and planning for (including, but not limited to, the application of the planning process included in a management program pursuant to Section 305(b)(8)), any economic, social, or environmental consequence which has occurred, is occurring, or is likely to occur in such state's coastal zone as a result of the siting, construction, expansion, or operation of such new or expanded energy facilities. The amount of any such grant shall not exceed 80 per centum of the cost of such study and planning.

The objectives of this subsection of the Act as applied to the Great Lakes states are (1) to aid the states in planning for the economic, social and environmental effects ensuing, or expected to result, from the siting or operation of new or expanded energy facilities in or that significantly affect the coastal zone, and (2) "to encourage rational, timely, and thorough planning for the management of energy facility siting and the impacts from energy resources development." According to the proposed rules (previously cited), energy facility siting and impact studies might include:

> (1) Collecting data and taking physical measurements;
> (2) Making projections of employment, population, public facility and public service needs and costs, and tax and user fee revenues;
> (3) Comparing the consequences of alternative energy facility types or sites;
> (4) Examining private industry or government siting policies; and
> (5) Conducting analyses required for coastal State or local government regulatory decisions, including licenses, leases, permits, and zoning ordinances [635].

In the Great Lakes states, planning for the management of energy facility siting and the amelioration of impacts from energy resources development might include, but not be limited to:

> (1) Devising methods of protecting recreational or environmental resources in the coastal zone...;
> (2) Devising strategies for recovering compensation from appropriate parties for any adverse impacts caused by the energy activity involved;
> (3) Preparing for the provision of new or improved public facilities and public services required as a result of new or expanded coastal energy activity...;
> (4) Designing and carrying out an equitable intrastate fund allocation process...; and
> (5) Devising strategies for the public purchase of land upon or near which energy-related development is to take place in order to capture the benefits of the increased value of such land or to contain such development [635].

The proposed rules indicate that an eligible coastal state may be allotted a proportion of the 308(c) moneys appropriated to the fund based on employment equivalencies for planned energy facilities listed with the Office of Coastal Zone Management. The proposed rules stipulate that the state agency(s) receiving these funds do(es) not necessarily have to be the agency responsible for coastal zone management, but must be designated by the Governor of the state to receive the funds and must certify that the uses of the funding assistance are compatible with the state's coastal zone management program. Certain limitations have been placed on the use of Subsection 308(c) funds under the proposed rules: (1) the funds cannot be used to "duplicate the development of the general planning process for coastal energy facilities required of management programs under [sub]section 305(b)(8)," and (2) the funds may not be applied to general studies or plans separated from existing, proposed or planned energy facilities [635].

Subsection 308(d)(4) of the Act states that:

> The Secretary [of Commerce] shall make grants to any coastal state to enable such state to prevent, reduce, or ameliorate any unavoidable loss in such state's coastal zone of any valuable environmental or recreational resource, if such loss results from coastal energy activity,...

A major objective of this provision is to "encourage payment of the full cost of those environmental and recreational losses resulting from coastal energy activity by the [individual, corporation or other organization] responsible for the loss" [635]. The grants are available only if there is no other means to recover the cost of amelioration, reduction or prevention of the unavoidable environmental or recreational loss from the individual, corporation, or organization causing the loss, or from another federal program. With respect to the Great Lakes states these grants would apply primarily to the costs of prevention, reduction, or amelioration of any unavoidable loss in the coastal zone of valuable environmental or recreational resources due to the transportation, transfer and storage of oil, natural gas, or coal.

The consistency requirements of the Act (Section 307) affect both state actions and the actions of all federal agencies conducting, supporting, or licensing activities in the coastal zone. Rules proposed (41 FR 42885) pursuant to Section 307 require that "[c]oastal zone management programs developed by the coastal states shall...give full consideration to federal consistency requirements and such consideration shall be reflected by procedures incorporated in the management program to: (1) review the consistency of federally conducted or supported activities including Federal development projects, (2) provide public notice and review of the certification of consistency statements developed by applicants for Federal licenses and permits, and (3) review the consistency of Federal assistance to applicant agencies."

State and local agencies applying for federal assistance under federal programs affecting the coastal zone must "indicate the views of the appropriate state or local agency as to the relationship of such activities to the approved management program for the coastal zone" [Section 307(d)]. Furthermore, the proposed rules require federal agencies to comply with the consistency policies and procedures of Section 307. "Federal agencies shall: (1) Develop procedures to provide State agencies with notification and an opportunity to review the consistency of Federally conducted or supported activities, including Federal development projects, (2) not grant Federal licenses or permits if the State agency objects to the applicant's certification, unless the objection is overridden by the Secretary [of Commerce], and (3) not grant federal assistance to applicant agencies if the State agency finds that the proposed activity is not consistent with the management program, unless the State agency objection is overridden by the Secretary [of Commerce]" [634].

On August 10, 1976, the Assistant Attorney General, Office of Legal Counsel, Department of Justice, issued an opinion concluding that, "The exclusionary clause [in the Act] excludes all lands owned by the United States from the definition of the Coastal Zone." OCZM believes (as stated in a draft position paper) that regardless of the fact that lands owned by the federal government are not to be included within the boundaries of a state's coastal zone, authority under the federal consistency provisions of the CZMA is still sufficient to require Federal land-holding agencies to conduct actions on such lands in conformance with approved state programs, when the proposed actions will have spill-over impacts in the coastal zone. For example, if a federal agency were to undertake an activity on federal lands which would directly affect an area adjacent to it in the coastal zone, then the agency would be required to proceed in a manner consistent to the maximum extent practicable with the state's program.

Thus, an approved state coastal zone management program becomes a legal document requiring consistency from federal activities directly affecting the coastal zone, including activities conducted, supported or licensed by federal agencies. Federal activities that affect the siting of energy facilities are outlined below.

Consistency with the state CZM program is assured through a variety of mechanisms. The program itself must be developed in consultation with the appropriate federal agencies. The approval process entails further federal agency review. Once the plan is approved, state and local applicants for federal funding or licensing must first obtain approval from the state CZM agency. Federal agencies receiving other applications also require that the applicant must certify "that the proposed activity complies with the state's approved program and that such activity will be conducted in a manner consistent with the program" [Section 307(c)(3) as amended].

The development of a single plan and program for management of the coastal zone of each state and the requirements for consistency therewith promote a unified approach to the management of the coastal zone. The consistency requirements further guarantee that energy facility siting will be considered in terms of alternative uses of coastal lands and the use of other lands in the vicinity of such facilities. The siting of individual energy facilities will be considered in terms of the siting of other energy facilities and will provide a measure of rationality and planning for the best means of supplying energy needs. The fact that all state plans and programs are reviewed and approved by a single (federal) agency (the Department of Commerce) helps insure consistency in management practices across state lines. The entire CZM program is expected to insure comprehensive, timely, and effective coastal zone planning and management through the integration of the planning and decision-making process.

The CZM energy facility planning approach as discussed above incorporates the determination of permissible land and water uses; the designation of areas of particular concern; the designation of areas to be preserved, conserved, restored, or generally avoided as well as areas for development; the development of priorities for permissible land and water uses; the considerations for uses of regional benefit and in the national interest; and the considerations for federal-state consistency. In addition, once a state has an approved energy facilities planning process, including a means of identifying energy facilities that would significantly affect the coastal zone (whether they be located on or near the shoreline or inland), a procedure for assessing energy facility impacts, state policies and techniques for managing energy facility impacts, and a mechanism for coordination and cooperation with other agencies involved in energy facility planning, it has what might be considered the nucleus of an energy facility siting program <u>for the state's coastal zone</u> and inland areas adjacent to it (and offshore or nearshore locations within state jurisdiction in the case of floating and/or anchored facilities) in which energy facilities that significantly affect the coastal zone might be located. For states that already have some form of an energy facility siting program (see below) which applies to the entire state, such a process will serve to give emphasis to the sensitive areas and resources possibly affected by and the potential impacts (positive and negative) from energy facilities to be located in or near the coastal zone of those states. The environmental planning grants (under Subsection 308(c) of the Act) permit the states to move one important step beyond energy facility siting programs examined in this report (below) by providing funds to study and plan for any economic, social, and environmental consequence resulting from the siting, construction, expansion, or operation of new or expanded energy facilities in or significantly affecting the coastal zone. Also, Subsection 308(d)(4) provides opportunity for remuneration for costs of environmental or recreational losses resulting from coastal energy activity.

Thus, the Coastal Zone Management Act as amended provides a comprehensive and basic framework for addressing energy facility siting in or affecting the Great Lakes coastal zone. This is particularly significant for states not already having state-wide energy facility siting programs. The policy options for energy facility siting described later in this report (Chapter VI) elaborate on the possibilities for further development of energy facility siting controls and programs by the Great Lakes states, given the Coastal Zone Management Act and its Amendments as a foundation.

Additionally, grants are available for interstate coordination and for research and technical assistance. The interstate grants (Sec. 309, as amended) are for "coordinating state coastal zone planning, policies and programs with respect to contiguous areas" [309(a)(1)]. The establishment of interstate compacts or temporary planning and coordinating entities is encouraged. Grants are available under Section 310, as amended, "to assist (coastal) states in carrying out research, studies and training required with respect to coastal zone management" [310(b)]. Grants are also available for acquiring, developing or operating estuarine sanctuaries and for "acquiring lands to provide access to public beaches and for other coastal areas of environmental, recreational, historical, aesthetic, ecological, or cultural value, and for the preservation of islands" [Sec. 315, as amended].

The coastal zone management plan developed by each state must be approved by the Secretary of Commerce before that state may begin receiving funds for the administration of its CZM program. Plan approval is contingent upon the factors noted above, as well as others included in the Act as amended and in the implementing rules and regulations.

b. National Environmental Policy Act

The National Environmental Policy Act (NEPA) is one of the most significant federal environmental statutes. The principal action-forcing provision is the detailed environmental statement that is required under Section 102(2)(c) of the Act for any major federal action significantly affecting the quality of the human environment. The purpose of the detailed statement is the identification and assessment of the environmental impacts of a proposed federal action before the action is taken. The five action review criteria include: (1) the potential environmental impacts of the action, (2) the unavoidable adverse impacts involved, (3) the irreversible commitments of resources caused by the action, (4) short-term considerations vis-a-vis long-term resource needs, and (5) alternatives to the proposed action. The lead federal agency is responsible for preparation of the EIS, although this is often delegated to a consultant, applicant, or to a state agency involved in the organizational arrangement associated with the federal action. Pursuant to regulations promulgated by the Council on Environmental Quality (which administers NEPA), federal agencies have established NEPA guidelines covering their respective actions. The following list indicates the lead federal agencies with NEPA responsibility for various types of energy facilities.

Facility	NEPA Responsibility
Hydroelectric generation facilities	Federal Power Commission
Nuclear fired steam electric generation facilities	Nuclear Regulatory Commission
Coal, oil, and gas fired steam electric generation facilities	U.S. Army Corps of Engineers, if Corps permit is required
Port and Terminal handling facilities	"
Petroleum refineries	U.S. Environmental Protection Agency--<u>but</u> only in those states in which EPA has retained authority over water (e.g., Illinois) and air discharge permits.
Any new source of air or water discharges	"

The major energy facility siting implications of NEPA revolve around the mandatory assessment of the environmental effects of a proposal involving a federal agency or role. The policies and procedural requirements contained in NEPA and in the associated administrative rules and regulations, as well as subsequent legal interpretations of the Act have established a mechanism for public involvement in energy facility siting proposals.

c. Nuclear Regulatory Commission (NRC)

(1) General

The Nuclear Regulatory Commission is a five-member commission established under the Energy Reorganization Act of 1974 to assume the regulatory functions of the Atomic Energy Commission. In addition to licensing the construction and operation of nuclear power plants, the Commission also oversees fuel fabrication facilities, fuel reprocessing plants and enrichment plants.

Under the Energy Reorganization Act, the NRC was authorized to undertake the Nuclear Energy Center Site Survey, which considers the possibility of (1) establishing nuclear energy centers (NEC's) containing up to forty nuclear power plants (1200 MWe each) on a single site; or (2) establishing fuel-cycle centers which would accommodate fuel fabrication and reprocessing, uranium enrichment and waste disposal; or (3) combinations of (1) and (2). This survey has been published [48 thru 54] and it concludes that, while the siting of up to twenty reactors on a single site can be feasible and practical, there is no great advantage or compelling need for such centers.

The NRC has three components: the Office of Nuclear Reactor Regulation, the Office Nuclear Material Safety and Safeguards, and the Office of Nuclear Regulatory REsearch. The Office of Nuclear Reactor Regulation reviews the safety of and safeguards for all nuclear facilities, materials and activities, including the monitoring of existing systems, the testing of new systems and recommendations for updating systems. They also have primary responsibility for the safe transportation of nonfissionable nuclear materials and for the licensing and regulation of liquid metal fast breeder reactors (LMFBR's).

The Office of Nuclear Material Safety and Safeguards sets standards, issues licenses, and enforces regulations for construction and operation of facilities which produce or use fissionable materials, including nuclear power plants, uranium milling and enrichment facilities, fuel fabrication and reprocessing plants, plutonium production facilities and radioactive waste treatment facilities. It is also responsible for the transportation and storage of fissionable materials and radioactive wastes, industrial security and safeguards, antitrust provisions of the Atomic Energy Act, liability coverage associated with nuclear power, and the financial stability of utilities dealing in nuclear power.

The Office of Nuclear Regulatory Research is charged with developing recommendations for research related to licensing and regulatory functions and with performing or contracting for such research.

Concerning nuclear radiation hazards, the role of the NRC preempts state efforts; i.e., no state may enact restrictions more limiting than those of the NRC (see Northern States Power Co. v. State of Minnesota). Section 274 of the Atomic Energy Act, enacted in 1959, provides for states to assume certain regulatory functions over small quantities of nuclear material, but this bears little or no relation to the area of energy production.

In the early months of the National Environmental Policy Act of 1969, the Atomic Energy Commission displayed great reluctance to consider factors other than those specifically related to the nuclear aspects of power plants in their licensing process. The change came with the Calvert Cliffs case (Calvert Cliffs Coordinating Committee, Inc. v. AEC, 449F.2d.1109 or 2ERC 1779) which determined that the AEC was required to comply with NEPA; i.e., that they must consider all environmental impacts before approving the construction or operation of a nuclear power plant. As a result, the NRC and several states duplicate efforts in environmental review. Attempts are being made to eliminate duplication and coordinate the state and federal efforts.

(2) Siting Procedures

The process employed by NRC for issuing permits for the construction of nuclear power plants consists of three separate functions that proceed simultaneously. These functions are: (1) safety, (2) environment and site suitability, and (3) antitrust. The first step in the process is the filing of an application for a construction permit by the utility and its acceptance by the NRC. Notice of the filing is published in the Federal Register and copies are distributed to appropriate state and local authorities and to a public document room in the vicinity of the proposed site. Also a notice of hearing is published in the Federal Register and in local newspapers.

For the environment and site suitability review, the NRC staff prepares a draft environmental statement (DES) which is reviewed by federal, state and local agencies and other interested persons. The comments received become part of the final environmental statement (FES). Both documents are made available to the general public. A public hearing follows the FES.

The safety review includes the preparation of a safety evaluation report (SER) by the NRC staff. Safety is the responsibility of the Advisory Committee on Reactor Safeguards (ACRS). After their review, the staff issues a supplement to the SER which discusses any action taken as a result of the review. A public hearing may then be held; possibly in conjunction with the environment and site suitability hearing. Hearings are conducted by the Atomic Safety and Licensing Board (ASLB) which is responsible for issuing the permit. Appeals go automatically to an Atomic Safety and Licensing Appeal Board and, if necessary, to the NRC commissioners.

Antitrust reviews are conducted by the NRC and the Attorney General. Antitrust hearings, if necessary, are separate from other hearings.

The process is essentially repeated for an operating license once the plant has been constructed. Public hearings are not mandatory here but may be held if requested by responsible parties. The operating license specifies conditions for operation. Continuous surveillance and periodic inspections are conducted by NRC.

The authority of the NRC does not diminish that of the U.S. Environmental Protection Agency or of the states on issues relating to applicable federal air and water pollution control legislation.

d. Environmental Protection Agency (EPA)

Of all the federal policies, programs, rules and regulations associated with the siting of energy facilities, those of the Environmental Protection Agency are probably the most complex and have the most far-reaching implications. Within the scope of the nationwide pollution control programs, the EPA has a major, if indirect, role in energy facility siting in the Great Lakes states. It is charged primarily with implementing the mandates of the Clean Air Act (PL 91-604 as amended) and the Federal Water Pollution Control Act (PL 92-500 as amended). Under these Acts, the EPA is directed to promulgate rules and regulations detailing performance standards, and with one exception, the states were given the primary enforcement responsibility. The states are required to implement management programs and adopt air and water quality standards that are at least as stringent as those stipulated by EPA. The EPA monitors state performance, and retains ultimate authority if necessary.

(1) Air Quality Program

The existing federal air quality policy and implementation program is derived from two major statutes: The Clean Air Act of 1967, and the Clean Air Act Amendments of 1970. Through these Acts the states have been given authority to and are required to establish enforcement programs to implement federal policy and standards. The major aspects of the air quality program that are relevant to this study include the following:

- The establishment of national ambient air quality standards (NAAQS) for a variety of pollutants.
- The establishment of performance standards for new stationary sources of pollution.
- The prevention of significant deterioration of air quality exceeding national ambient standards.
- State enforcement of federally mandated emission limitations, compliance schedules, and enforcement provisions.

(a) National ambient air quality standards (NAAQS)

Under Section 109(a)(1) of the Clean Air Act Amendments of 1970, the Administrator of EPA was directed to promulgate national primary and secondary ambient air quality standards for each air pollutant. Primary standards were established to protect health with an adequate margin of safety. Secondary standards are designed to protect the public welfare, including such things as property, from any known or anticipated adverse effects created by the presence of pollutants in the air (see Table 1 for NAAQS). All states were required to attain primary standards no later than May 31, 1975, and secondary standards within "a reasonable time." The Administrator may, under Sections 110(e) and 110(f), and upon request by the Governor of a state, postpone attainment of primary standards for a period of up to two years if certain criteria are satisfied. However, this is not to be interpreted as a continuous source of variance from attainment of the NAAQS in the future.

(b) New stationary source performance standards

Section 111 of the Clean Air Act directed the EPA to promulgate emission standards for new stationary sources of pollution. Included in these categories are fossil-fuel fired steam electric generating plants of greater than 250 million Btu/hr heat input. The major air pollutants generated by fossil-fuel fired steam electric generating plants are total suspended particulates, sulfur dioxide, and to a lesser extent, nitrogen dioxide. For these facilities, the following standards apply:

- Total suspended particulates [40 CRF 60.42]:

> ...no owner or operator...shall discharge or cause the discharge into the atmosphere of particulate matter which is:

TABLE 1

NATIONAL AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	Primary Standards	Secondary Standards
Particulates	Annual (G)	75 μg/m³	60 μg/m³
	24-Hour[a]	260 μg/m³	150 μg/m³
SO_2	Annual (A)	80 μg/m³	-
	24-Hour[a]	365 μg/m³	-
	3-Hour[a]		1300 μg/m³
CO	8-Hour[a]	10 mg/m³	10 mg/m³
	1-Hour[a]	40 mg/m³	40 mg/m³
NO_2	Annual (A)	100 μg/m³	100 μg/m³
Photochemical Oxidants	1-Hour[a]	160 μg/m³	160 μg/m³
Hydrocarbons	3-Hour[a] (6 to 9 a.m.)	160 μg/m³	160 μg/m³

[a]Not to be exceeded more than once a year.

(A) Arithmetic mean
(G) Geometric mean

(a) In excess of 0.10 lb. per million B.t.u. heat input (0.18 g. per million cal.) maximum 2-hour average.
(b) Greater than 20 percent opacity, except that 40 percent opacity shall be permissible for not more than 2 minutes in any hour.
(c) Where the presence of uncombined water is the only reason for failure to meet the requirements of paragraph (b) of this section, such failure shall not be a violation of this section.

- Sulfur dioxide [40 CFR 60.43]:

 ...no owner or operator...shall discharge or cause the discharge into the atmosphere of sulfur dioxide in excess of:
 (a) <u>0.80 lb. per million B.t.u.</u> heat input (1.4 g. per million cal.), maximum 2-hour average, when <u>liquid fossil fuel</u> is burned.
 (b) 1.2 lbs. per million B.t.u. heat input (2.2 g. per million cal.), maximum 2-hour average, when <u>solid fossil fuel</u> is burned.
 (c) Where different fossil fuels are burned simultaneously in any <u>combination</u>, the applicable standard shall be determined by proration. Compliance shall be determined using the following formula:

$$\frac{y(0.80) + z(1.2)}{x + y + z}$$

 where:

 x is the percent of total heat input derived from gaseous fossil fuel and,

 y is the percent of total heat input derived from liquid fossil fuel and,

 z is the percent of total heat input derived from solid fossil fuel.

- Nitrogen dioxide [40 CFR 60.44]:

 ...no owner or operator...shall discharge or cause the discharge into the atmosphere of nitrogen oxides in excess of:
 (a) 0.20 lb. per million B.t.u. heat input (0.36 g. per million cal.), maximum 2-hour average, expressed as NO_2, when gaseous fossil fuel is burned.
 (b) 0.30 lb. per million B.t.u. heat input (0.54 g. per million cal.), maximum 2-hour average, expressed as NO_2, when liquid fossil fuel is burned.
 (c) 0.70 lb. per million B.t.u. heat input (1.26 g. per million cal.), maximum 2-hour average, expressed as NO_2, when solid fossil fuel (except lignite) is burned.
 (d) When different fossil fuels are burned simultaneously in any combination the applicable standard shall be determined by proration. Compliance shall be determined by using the following formula:

$$\frac{x(0.20) + y(0.30) + z(0.70)}{x + y + z}$$

 where:

 x is the percent of total heat input derived from gaseous fossil fuel and,

 y is the percent of total heat input derived from liquid fossil fuel and,

 z is the percent of total heat input derived from solid fossil fuel.

(c) Prevention of significant deterioration

Another major component of the Clean Air Act, and one that is extremely important to the siting of energy facilities, is the prevention of significant deterioration (nondegradation) of air that is already clean. Pursuant to a 1973 U.S. Supreme Court decision, the EPA was required to promulgate regulations to insure nondegradation [459]. The approach taken was to establish increments of air quality which cannot be exceeded by any new source or combination of sources within a specific impact zone. In addition, three classes of areas were identified in which varying degrees of additional pollution are permitted. Class I areas are those where little or no degradation (i.e., little or no development) is permitted. In Class II areas, moderate degradation of existing air quality (i.e., some additional development) is allowed. In Class III areas, a substantial amount of deterioration of existing air quality is allowed, thus permitting concentrated or large scale development [459]. In no case will deterioration be permitted which violates the national primary and secondary ambient air quality standards. The allowable increments for sulfur dioxide and suspended particulates are shown in Table 2.

TABLE 2

ALLOWABLE INCREMENTS OF AIR QUALITY DETERIORATION (ug/m^3)

Pollutant	Class I	Class II	Class III
Sulfur Dioxide			
Annual	2	15	80
24-hour	5	100	365
3-hour	25	700	1300
Total Suspended Solids			
Annual	5	10	75
24-hour	10	30	150

Initially the EPA classified the entire U.S. (except those areas that already violate secondary standards) as a Class II area. The states may redesignate areas as either Class I or Class III, provided that certain public participation procedures are followed, subject to EPA approval.

(d) State implementation plans

Under Section 110, the states, through their respective EPA-approved state implementation plans (SIP), are the primary enforcement agencies of the Clean Air Act. In order to establish a control mechanism, the EPA designated a system of air quality control regions (AQCR). Each AQCR is typically composed of several counties, after involving two or more states. In the SIP's the states are required to establish and enforce for each AQCR, ambient air quality and emission standards that are at least as stringent as those stipulated above by EPA. The SIP must include (among other things) the specification of land use and transportation controls to insure the attainment of the federal primary and secondary ambient standards. In addition, states are required to institute preconstruction review procedures to insure that new sources of pollution, such as energy facilities, will meet primary and secondary ambient air quality standards.

(e) Energy Supply and Environmental Coordination Act of 1974

The Energy Supply and Environmental Coordination Act of 1974 (ESECA) amended Section 119 of the Clean Air Act by providing a short-term suspension of stationary-source fuel or emission limitations to permit the continued use of coal as a fuel source. This is not to be construed as a permanent variance.

Another major aspect of ESECA that is related to air quality is Section 4 of the Act, which mandated the review of all state implementation plans to determine whether revisions in performance standards can be made to permit the increased use of coal as a primary fuel source without jeopardizing the attainment of national primary and secondary ambient air quality standards.

Under Section 309 of the Clean Air Act, the Administrator of EPA is required to review and comment on the environmental impact of certain matters relating to the authority of the EPA under <u>all</u> applicable federal environmental protection legislation, dealing with air, water, toxic substances, etc. Matters included in this provision are (1) legislation proposed by any federal agency, (2) newly authorized federal construction projects and any major federal action covered by environmental impact statement requirements under Section 102(2)(c) of NEPA, and (3) proposed regulations published by any federal agency. If the EPA determines that the legislation, action, or regulation of concern is unsatisfactory from the standpoint of public health or welfare or environmental quality, formal notification of this finding is referred to the Council on Environmental Quality.

(f) Implications for energy facility siting

It is generally agreed that the federal air quality program will have significant implications for the siting of energy facilities. All facilities must meet new source performance standards using the best available control technology regardless of the site. In addition, no new source will be permitted which clearly violates national ambient air quality standards even if it meets the new source emission standards. Finally, existing clean air areas are protected by the non-degradation provisions, and emissions from new energy facilities must fall within the limits established for their areas, which are designated as Class I, II or III. Currently, the Environmental Protection Agency is administering the significant air quality deterioration program and has tentatively classified all areas as Class II. As the states incorporate this program into their planning process they can redesignate areas as Class I or III. Designation of an area as Class III would permit substantial new sources of air emissions, such as fossil-fuel fired power plants, provided the new source emission standards and ambient air quality standards are met.

For certain facilities, the costs of emission control equipment for new sources of emissions will vary according to the degree of air quality degradation permitted. In Class I areas, or in areas where the ambient air quality is approaching the national ambient standards, these costs will be considerably higher than Class II or III areas and may be prohibitive. On the other hand, designation of an area as Class III would require less sophisticated emission control technology and would encourage the siting of certain kinds of energy facilities that would have difficulty meeting the standards imposed in Class I or II areas.

(2) Water Quality Program

Another major federal program with significant implications for the siting of energy facilities is the clean water program, embodied for the most part in P.L. 92-500, the Federal Water Pollution Control Act Amendments of 1972, and also administered by the EPA. The approach taken is similar to that of the Clean Air Act. Goals, policies and minimum standards were established by the federal government, and the states are required to enforce standards at least as stringent as the federal standards through the state implementation plan (SIP) process. At the present time, all states in the Great Lakes Basin except Illinois are empowered by EPA to act as administrators of federal policy. The major aspects of the clean water program that are relevant to this study include:

- The establishment of effluent guidelines and standards for various pollutants for various categories of point sources of pollution.
- The control of thermal discharges.
- The control of intake structures.
- The National Pollutant Discharge Elimination System (NPDES) permit program.
- The State Implementation Plan Process.

(a) General policy

Congress included in its statement of policy in Section 101 of P.L 92-500 the following:

1. it is the national goal that the discharge of pollutants into the navigable waters be eliminated by 1985;
2. it is the national goal that wherever attainable, an interim goal of water quality which provides for the protection and propagation of fish, shellfish, and wildlife and provides for recreation in and on the water be achieved by July 1, 1983;
3. it is the national policy that the discharge of toxic pollutnats in toxic amounts be prohibited.

These goals and policies are the basis of the rules, regulations and standards that have been developed to control the discharges of waste from energy facilities and other sources into the nation's waters.

Another significant policy declaration was contained in Section 301, which mandated the application of the best practicable control technology currently available by July 1, 1977, to all point sources of water pollution. Furthermore, it required the application of the best available technology economically achievable by July 1, 1983. Effluent guidelines and standards have been promulgated to achieve these 1977 and 1983 goals.

(b) Effluent guidelines and standards

In order to implement clean water policies, effluent guidelines and standards were established for a variety of the typical sources of pollution. Among these point sources are steam-electric power generating facilities fired by coal, oil, gas, or nuclear fuels, and petroleum refineries.

On October 8, 1974, special procedures for permit issuance and effluent guidelines and standards were established for the various operational phases of coal, oil, gas, or nuclear-fired steam-electric facilities [624]. Parameters for which standards were set include heat, total suspended solids, pH, oil and grease, copper, iron, chlorine, zinc, chromium, and phosphate. Chlorine, used extensively to treat water discharged by power plants, is recognized by the EPA as a potentially significant source of water pollution [624]. Thus, effluent guidelines to protect aquatic organisms from the toxic effects of chlorine have been promulgated by EPA. The maximum permissible concentration of free available chlorine in water discharged from either once-through cooling systems or cooling towers is 0.5 mg/l, while the highest average concentration allowed is 0.2 mg/l, although EPA has recently been applying more stringent limitations on chlorine concentrations. Furthermore,

> Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the regional administrator or state, if the state has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination [624].

The results of recent research indicate that these short-term limitations may undergo modification in the near future.

In addition to regulating point discharges, standards are applied to the area runoff associated with these facilities, including that generated by the disturbance of the earth's surface during construction, and that generated by the storage of materials such as coal or ash.

The effluent guidelines dealing primarily with thermal discharges were recently remanded to the EPA by the Fourth Circuit Court of Appeals for revision. Those guidelines dealing with thermal discharges are particularly subject to revision. Thus, regulation of discharges from steam-electric generation facilities is in a state of flux. However, state water quality standards still apply.

(c) Control of thermal discharges by closed-cycle cooling

In recognition of the potentially significant adverse environmental implications of thermal discharges from electric generation facilities, the Congress gave special consideration to controlling this type of pollution in the development of P.L. 92-500. In promulgating administrative rules pursuant to the Act, the EPA determined that, for certain categories of electric generation units, closed-cycle evaporative cooling represents the best available technology economically achievable for controlling heated water discharges. Power plants covered by the closed-cycle cooling requirement include those units of 25 MWe capacity or larger placed into operation on or after January 1, 1974, and those units of 500 MWe capacity or larger placed into operation on or after operation on January 1, 1970 [624]. However, the EPA has also determined that, due to the time involved in converting to closed-cycle cooling and due to the necessity of insuring the reliability of electrical generation in the short term, once-through cooling (or at least no additional restraint on heated discharges) represents the best practicable control technology currently available. Thus, compliance with the closed-cycle cooling requirement will not take effect until 1977.

(d) Variance from thermal discharge limitations

Although Congress identified as an important objective the control of thermal discharges from power plants, it also acknowledged that, under certain circumstances, closed-cycle cooling would not be required to meet the objectives of P.L. 92-500. Under Section 316(a) of the Act, if an owner or operator of a facility that discharges heated water can demonstrate to the satisfaction of the Administrator of EPA or the state that the effluent standards are more stringent than necessary to maintain a balanced, indigenous population of shellfish, fish and wildlife in or on the receiving body of water of concern, the Administrator or the state may grant a variance from such requirements and impose alternative thermal discharge effluent limitations, provided that the continued existence of the aforementioned aquatic-oriented species will not be jeopardized.

In order to obtain a variance under Section 316(a) one must make application to the EPA or to the state, and demonstrate that at least one of the criteria listed below is satisfied. (These criteria are extracted from [627].)

- Absence of prior appreciable harm. Under this criterion it must be demonstrated that (1) no appreciable harm has resulted from the thermal component of the discharge (taking into account the interaction of such thermal component with other pollutants and the additive effect of other thermal sources) to a balanced, indigenous community of shellfish, fish and wildlife in and on the body of water into which the discharge has been made, or (2) despite the occurrence of such previous harm, the desired alternative effluent limitations (or appropriate modifications thereof) will nevertheless assure the protection and propagation of a balanced, indigenous community of shellfish, fish and wildlife in and on the body of water into which the discharge is made.

- Protection of representative, important species. A variance may be granted if it can be demonstrated that the discharge will assure the protection and propagation of representative, important species whose protection and propagation, if assured, will assure the protection and propagation of a balanced, indigenous community of shellfish, fish and wildlife in and on the body of water; unless unrebutted information received during the period provided for public comment or evidence introduced at any hearing held to consider the permit indicates:

  -that the species selected by the Regional Administrator are not representative, in terms of biological needs, of a balanced, indigenous community in the receiving water body; or
  -that the temperature requirements employed in calculating the proposed alternative effluent limitations are not adequate to assure the protection and propagation of those species in and on the receiving water body; or
  -that the temporal or spatial distribution of the mixing zone is excessively large or otherwise inconsistent with the purpose of section 316(a).
- Evidence provided by biological engineering and other data. Alternative effluent limitations can be imposed if the applicant can provide evidence supported by data, models, etc. that indicate that either of the first two criteria will be met or if such limitations will assure the protection and propagation of indigenous aquatic life [627].

A technical guidance manual has been issued by the EPA to guide the development of a 316(a) demonstration.

Several 316(a) demonstration studies in the Great Lakes Basin have been completed or are in progress, and variances from the closed-cycle cooling requirement are quite common. Most of the applications for 316(a) variances have been associated with requests either for approval of cooling systems currently employed in existing power plants, or of expansion of generating capacity at these facilities.

(e) Control of cooling water intake structures

Another major influence on energy facility siting contained in P.L. 92-500 is Section 316(b). According to this section any standard established to control point sources of pollution must require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. Section 316(b) is applicable to all existing as well as new cooling water intake structures.

The issues associated with the location, design, construction, and capacity of intake structures [316(b)] are often more complex than those related to 316(a) demonstrations and generally need to be evaluated in detail on a case-by-case basis. In support of this conclusion, the development document for intake structures, which is the official source of EPA guidance on these matters addresses this complexity:

> Owing to the highly site specific characteristics of available technology for the location, design, construction and capacity of cooling water intake structures for minimizing adverse environmental impact, no technology can be presently generally identified as the best technology available, even within broad categories of possible application. Within this context, a prerequisite to the identification of best technology available for any specific site should be a biological study and associated report to characterize the type, extent, distribution, and significant overall environmental relation of all aquatic organisms in the sphere of influence of the intake, and an evaluation of available technologies, to identify the site specific best technology available for the location, design, construction and capacity of cooling water intake structures for minimizing adverse environmental impact [628].

Although the Section 316(a) and 316(b) demonstrations are separate processes, there is a relationship between the type of cooling system employed and the location, design, capacity, and construction activity associated with the intake structure used with that system. Also, in a given situation, the environmental impacts of an existing or proposed intake structure may well be more significant than those associated with the cooling system employed, and the issues related to the intake structure may require more scrutiny by the EPA or the state.

(f) National pollutant discharge elimination system (NPDES)

The NPDES permit system was established under Section 402 of P.L. 92-500 and is the regulatory mechanism through which effluent guidelines and standards for energy facilities are enforced. All point source discharges into the nation's waters (with a few exceptions) must obtain an NPDES permit. Procedures have been established which insure public access to information, public hearings, and agency review. States are intended to be the enforcing agency of the NPDES program, but EPA can assume control if a state's approach is unacceptable.

(g) State implementation plan process (SIP)

Pursuant to Section 303(e) of P.L. 92-500, the states are designated the primary agencies of the clean water program, provided that they can demonstrate the initiative and capability for program administration. They are required to maintain ongoing comprehensive water quality management programs which implement federal policies and standards. The states may enforce standards that are more stringent than those of the federal government. They are required to designate all segments of their respective waters as either "water quality limited" or "effluent limited" segments. A segment is classified as "water quality limited" if it does not meet and/or is not expected to meet applicable water quality standards assigned to it even after the application of effluent guidelines and standards to the various uses of the water. A segment is classified as "effluent limited" if water quality is meeting and will continue to meet applicable standards or will meet such standards after the application of effluent guidelines and standards. All of the Great Lakes states except Illinois have been designated as the primary program administrators. The EPA currently administers the program in Illinois, but formal approval of the Illinois program by EPA is likely in the near future.

In setting standards, the states are required to consider and incorporate the following criteria (excerpted from [629]):

- Water quality standards shall specify appropriate beneficial water uses to be achieved or protected and the water quality criteria necessary to support those appropriate beneficial uses;
- Water quality standards shall be established taking into consideration their use and value for public water supplies; propagation of fish, shellfish, and wildlife; recreational purposes; and agricultural, industrial, and other purposes; and also taking into consideration their use and value for navigation;
- Water quality standards shall be such as to protect the public health or welfare, enhance the quality of water and serve the purposes of the Act [629].

Another major element of the SIP is the development of a statewide non-degradation policy and regulatory mechanism. The non-degradation policy must be consistent with these criteria:

- Existing in-stream beneficial water uses shall be maintained and protected. No further water quality degradation which would result in impairment of existing in-stream beneficial uses is allowable.
- Existing high quality waters which exceed those levels necessary to support propagation of fish, shellfish and wildlife and recreation in and on the water shall be maintained and protected unless the State chooses, after full satisfaction of the intergovernmental coordination and public participation provisions of the State's continuing planning process, to allow lower water quality as a result of necessary and justifiable economic or social development.

In such cases, the state must assure that the highest statutory and regulatory requirements for all new and existing point sources and feasible management or regulatory programs pursuant to Section 308 of the Act will be achieved.

- In those cases where potential water quality impairment associated with a thermal discharge is involved, the anti-degradation policy and implementing method shall be consistent with section 316 of the Act [629].

(h) Implications for energy facility siting

The federal and state water pollution control programs, created for the most part by P.L. 92-500, will exert a great deal of influence on energy facility siting in the Great Lakes Basin. However, one cannot conclude from the above discussions that existing federal water pollution control policy will either strongly encourage or discourage the siting of energy facilities in the coastal zone or inland. The influence on siting of the EPA or the authorized state agency in terms of water resources will depend largely on the existing conditions at the proposed site and the applicable water quality standards and guidelines in effect for that site.

In any event, water quality standards will be met by any new energy facility in the Great Lakes Basin. If specific site conditions dictate the employment of sophisticated technologies for cooling systems and of other practices to avoid unacceptable degradation of water resources, economic considerations become critical.

(i) Relationship between EPA programs and coastal zone management

There are some fundamental relationships between air and water quality and the use of the coastal zone, and several of the policies and provisions contained in the air and water pollution control programs and the CZM program have recognized the importance of these relationships. In developing policies and planning processes to guide the siting of energy facilities in the coastal zone, the Great Lakes states must give full consideration to the applicable provisions of the appropriate federal acts.

There exists a two way consistency between the Coastal Zone Management Act (CZMA) on the one hand, and the Clean Air Act and the Federal Water Pollution Control Act on the other. Section 307 of the CZMA established the requirement that any activity in a state's coastal zone involving participation of a federal agency must be consistent with the approved CZM program of that state. However, Section 307(f) of the CZMA also clearly states that it does not diminish the authority vested in the air and water pollution control programs:

> ...nothing in this [Act] shall in any way affect any requirement established by the Federal Water Pollution Control Act, as amended, or the Clean Air Act, as amended, or established by the Federal Government or by any state or local government pursuant to such Acts. Such requirements shall be incorporated in any program developed pursuant to this title and shall be the water pollution control and air pollution control requirements applicable to such programs.

Nothing in the state's CZM program may violate any standards promulgated under the authority of these Acts. Also, the state CZM agency cannot set air or water quality standards directly [630, 631].

One issue of particular interest in the siting of energy facilities in the coastal zone is the possibility that air or water pollution control standards might be used to encourage or discourage siting in particular areas of a state's coast. According to the EPA General Legal Counsel, states <u>may not</u> impose more stringent (or more lenient) limitations on the discharge of air or water pollutants merely because the discharge occurs in the coastal zone [630]. Thus, not only must CZM plans comply with applicable EPA air and water quality requirements, but these standards and guidelines provide the baseline for environmental protection in plan development.

As indicated above, the determination of consistency of actions with the approved state CZM plan must be based on a comprehensive framework of planning for coastal areas resources. The state CZM entity may not object to an action as being inconsistent with the CZM plan on the grounds that the effective effluent limitations and standards set by EPA or by that state (as empowered by EPA) are not sufficiently stringent [630].

Success of the CZM program depends largely on communication and coordination between the state CZM entity and agencies and interests at all levels of organization. Coordination between the CZM programs and those programs administered by the EPA is especially significant. In developing CZM plans and in establishing energy facility policies and planning processes, the states should coordinate activities with areawide wastewater management plans (P.L. 92-500, Section 208) and Level B river basin plans (P.L. 92-500, Section 209, and the Water Resources Planning Act of 1965, P.L. 89-80). Also, existing policies for prevention of significant deterioration of air quality, and the zones classified by these policies, as well as any air quality maintenance areas would have to be incorporated into the CZM plan.

e. Federal Power Commission

The Federal Power Commission (FPC) has sole regulatory authority over the siting of all nonfederal hydroelectric generating facilities on lands and waters subject to federal jurisdiction. The Federal Power Commission was created by Congress in 1920 to administer the Federal Water Power Act, now Part I of the Federal Power Act. In 1930, the FPC was reorganized by Congress as an independent agency. The kinds of energy facilities under FPC jurisdiction include electric generating plants using water from impoundments and from pumped storage. Since these facilities are of relatively low priority to the study, the role of the FPC will not be examined in detail.

The licensing procedure employed by the FPC involves five steps; preliminary permit to investigate (optional), application for license, FPC review, possible hearing and final determination, and construction and operation. Any person or entity may apply for a preliminary permit to investigate a potential hydroelectric power site for up to three years. A public hearing may be held at this point if sufficient public interest is expressed. The application for a license includes the following considerations: the extent of water and land rights, the lands owned, the right to sell power within the State, the effect of a project's operation on water use and quality, the recreation possibilities of the site area, the impact on fish and wildlife, the project's achievement of the comprehensive development of the waterway, the evidence of project's optimum utilization of its power resources, the preservation of scenic and aesthetic values, and general environmental considerations.

Review of the application by FPC involves notification in the Federal Register and in local newspapers, consultation by applicant with the U.S. Fish and Wildlife Service, Bureau of Outdoor Recreation and appropriate state agencies. One of the major evaluation criteria is the effect of the proposal on the overall regional energy system. Following application review, a hearing may or may not be held by the FPC and should it be held, the hearing examiner renders an initial decision that is reviewed and either supported or rejected by the commission. Finally, the FPC monitors construction and compliance with the terms of the license.

In addition to its licensing authority over hydroelectric facilities, the FPC proposes in Docket No. RM76-38 to amend sections of the Regulations of the Federal Power Act and the Natural Gas Act to comply with the requirements of Section 307(c)(3) of the Coastal Zone Management Act. The Coastal Zone

Management Act affects the regulatory responsibilities of the FPC in the following areas:

- Licensing of hydroelectric projects under Section 4(e) and 15 of the Federal Power Act;
- Ordering interconnection of electric transmission facilities under Section 202 of the Federal Power Act;
- Authorizing international transmission of electricity under Section 202(e) of the Federal Power Act and Executive Order No. 10485;
- Authorizing import or export of natural gas under Section 3 of the Natural Gas Act; and
- Certification under Section 7 of the Natural Gas Act.

f. U.S. Army Corps of Engineers

The involvement of the U.S. Army Corps of Engineers in energy facility siting is primarily associated with construction activities in navigable waters of the United States. Under authority of Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. 403) each utility and corporation must obtain a permit from the Corps for any energy facility-related construction activity in navigable water, including intake and outfall pipes, bulkheads, piers, and other structures. Since permits issued for such facilities often constitute a major federal action significantly affecting the quality of the human environment, an environmental impact statement must be prepared in accordance with NEPA. Due to the fact that Section 10 permits are often the only major federal involvement in fossil-fueled electric generating plants and refineries, the Corps is the lead agency under NEPA for such facilities. Nuclear plants must also obtain permits for construction in navigable waters, but the Corps has no other involvement in these facilities beyond granting permits. Other kinds of energy facilities, such as port and terminal facilities, in the Great Lakes coastal zone have also been covered by NEPA under the Section 10 permit program [158, 199].

Although the Corps has no authority or mandate to engage in the full range of energy facility siting regulation, it is required to consider nonnavigational aspects of proposals covered by the Section 10 permit system [456]. This judicial interpretation was based on the mandates of NEPA and the Fish and Wildlife Coordination Act (16 U.S.C. 661 et seq., as amended), the latter of which requires the Corps to consult with the U.S. Fish and Wildlife Service and the head of the appropriate state fish and wildlife department with regard to Section 10 permit applications [456].

g. Federal Aviation Administration (FAA)

The FAA is concerned with all hazards to aircraft. Tall structures such as meteorological towers or cooling towers must be lighted in accordance with FAA recommendations. Any structure over 200 feet tall (generally any cooling tower or smoke stack) requires notification of the FAA. If the proposed structure falls within the restricted zone around an airport as described in Federal Avaiation Regulation 77, the request for permission to construct is routed to various airlines and the airport management for comment. If a hazard is determined, the FAA will seek to have permission to construct denied by the appropriate state or federal agency. Such hazards are generally considered in the planning of facilities and FAA involvement is rarely necessary.

h. Coast Guard (CG)

The Coast Guard is responsible for investigating oil pollution incidents, for assessing penalties for violations of Section 311 of the Federal Water Pollution Control Act, and for oil removal in coastal waters. Coastal waters in the Great Lakes are generally the lakes, bays, marshes, and rivers inland to the point where commercial navigation does not exist. The Coast Guard would necessarily become involved in a nuclear incident which threatened those who use the Great Lakes through issuing warnings by radio, vessel and aircraft or by conducting any other action the Coast Guard is qualified to perform. The Coast Guard is also concerned with hazards to navigation. Lights must be placed on structures in a navigable waterway, according to Coast Guard regulations. Such hazards may include dikes or submerged intake structures associated with an energy facility. Decisions as to which structures are to be lighted are at the discretion of the Coast Guard. Permits for such construction are under the purview of the Corps of Engineers (see Sect. f. above)

i. Federal Energy Administration (FEA)

The Federal Energy Administration (FEA), created by the Federal Energy Administration Act of 1974, has very little to do with the siting of energy facilities. The enabling Act deals with general energy considerations and does not specifically address energy facility siting [462].

Under Section 10 of the Energy Supply and Environmental Coordination Act of 1974 (ESECA) the FEA is directed to weigh the environmental effects of the use of coal in existing power plants against the savings of petroleum and natural fuels that could be achieved by converting to coal. Following this analysis, the FEA Administrator must issue orders requiring conversion from oil or gas to coal, where desirable, by plants that have the conversion capability. Section 119(b) of the Clean Air Act was amended by ESECA to permit the continuing use of coal by facilities that have converted.

Another ESECA provision directs the FEA Administrator to require that all new fossil-fuel electric generation plants be designed and constructed to allow the burning of coal as the primary fuel source. Enforcement of this provision, as well as the decision to convert an oil- or gas-fired power plant to a coal-fired plant, is contingent upon the availability of coal, the adequacy of the coal transportation system, and the maintenance and reliability of power service [463].

2. GREAT LAKES STATES

This section describes energy facility siting regulations in the eight Great Lakes states. The regulatory processes are discussed in terms of their general approach to the issue, requirements for disclosure of long-range plans and forecasts by applicants for site certification, provisions for public participation in the siting process, the procedure by which sites are certified, provisions for the acquisition of sites, and provisions for financing the siting regulation process.

An exception to this outline is found in the description of the program in New York state. It was felt that a detailed description of some aspects of the New York program would provide an interesting example of a comprehensive, substantive program for regulating power plant siting.

a. Illinois

(1) General Approach

Illinois has not established special policies or procedures that relate to the siting of energy facilities. Utilities are regulated by the Illinois Commerce Commission, which has recently extended its area of concern beyond cost, safety and reliability considerations. The Illinois Pollution Control Board has authority to determine and implement environmental quality standards and through this responsibility has a major impact on the location and operation of energy facilities. The Illinois Environmental Protection Agency is also involved, as are several other state agencies to some extent. Local governments retain control over siting through zoning and building codes, and several local authorities may also be involved. Electric and natural gas utilities and oil and gas pipelines are subject to Commission regulation, except those owned or operated by a political subdivision or municipal corporation. Electric cooperatives are subject to limited jurisdiction.

(2) Long Range Plans and Forecasts

Long range plans and forecasts are not required in Illinois.

(3) Public Participation

The Illinois Commerce Commission holds public hearings on all power plant licensing cases.

(4) Certification Procedures

The Illinois Commerce Commission is responsible for issuing both a "Certificate of Convenience and Necessity" and a "Section 50 Order" which permits a utility to construct, operate and maintain a facility. The hearings on the certificate and the order are open to the public.

Permits must also be obtained from several other state and local agencies. The state Environmental Protection Agency administers the permit and certification programs for air and water pollution control. Power plants must have permits for any permanent fuel combustion equipment and for thermal, chemical and sewage discharges. Other state agencies with license or permit functions associated with energy facility siting are listed in Table 3.

Local governments retain control over local zoning and building codes, and have direct impact on facility siting. Other local authorities who may require permits include the building inspector, the county or township road authority, the fire department, and the local health authority. Furthermore, there are over twenty kinds of local agencies exercising regulatory authority over water use, many of which enjoy permit granting authority.

(5) Site Acquisition

The Section 50 Order issued by the Illinois Commerce Commission usually includes explicit authority to acquire private property by eminent domain.

(6) Financing

There are no specific provisions for funding the work associated with energy facility siting regulation in Illinois.

TABLE 3

MAJOR PERMITS REQUIRED FOR POWER PLANT SITING IN ILLINOIS

AGENCY	LICENSE OR PERMIT	AUTHORITY
Dept. of Public Works and Bldgs. Division of Waterways	Construction permit or intake and discharge flumes	Ill. Rev. Stat. Ch. 19 Sect. 52 et. seq. (1969)
Dept. of Mines	Permit to drill water wells	Ill. Rev. Stat. Ch. 104 Sect. 62 et.seq. (1969)
Illinois EPA	Permit to discharge sanitary waste during construction	Ill. Rev. Stat. Ch. 111-1/2 Sect.1001 et.seq. (1970 Supp.)
do.	Permit to install auxillary boiler heating systems.	do.
Commerce Commission	Certificate of Public Convenience and Necessity authorizing and directing construction facilities	Ill. Rev. Stat. Ch. 111-2/3 Sects. 50 and 55 (1969)
Dept. of Highways	Permit for transmission lines to cross highways	Ill. Rev. Stat. Ch. 121 Sect. 1-101 et. seq. (1969)
Dept. of Aeronautics	Permit to construct meteorological survey tower.	
Dept. of Public Health	Special license for radiation installation	Ill. Rev. Stat. Ch. 111-1/2 Sect. 211, et. seq.

b. Indiana

(1) General Approach

Indiana does not have a comprehensive program for energy facility siting. Responsibility for approving a power plant is divided among several agencies within the Department of Natural Resources, the Stream Pollution Control Board, the Air Pollution Control Board, the Environmental Management Board, and the Public Service Commission (PSC). However, regulation of siting is largely indirect through these several regulatory agencies. The power of eminent domain resides with the utilities for acquisition of power plant sites and transmission line corridors.

(2) Long Range Plans and Forecasts

There are no provisions for utility disclosure of long range plans or forecasts in Indiana.

(3) Public Participation

Meetings of regulatory bodies are open to the public. A pollution control board or other regulatory bodies may choose to hold public hearings. State citizens who oppose a permit granted by a regulatory body have been granted standing under a 1971 state law. Citizens may initiate agency review and/or judicial review of the permit.

(4) Certification Procedure

Facility certification is under the purview of the PSC. Environmental considerations are the responsibility of the DNR and the Environmental Management Board. Both a construction permit and an operating permit are required from both the Stream Pollution Control Board and the Air Pollution Control Board, agencies within the Environmental Management Board. Permits are required from the DNR for any construction in the floodway of a river, for water withdrawal from a navigable stream or from Lake Michigan, and for inter-basin diversions. Site selection is the prerogative of each utility within these constraints.

(5) Site Acquisition

Utilities have the right to exercise eminent domain to acquire sites for their facilities.

(6) Financing

The Stream Pollution Control Board charges a fee for outfall permits. If the discharge is less than 50,000 gallons per day the fee is $10.00. If the discharge is greater than 50,000 gallons per day the fee is $100.00 for the first outfall and $50.00 for each additional outfall.

In addition, if plant construction requires the removal of sand and gravel or other minerals from the bed of Lake Michigan, a yearly fee of $50.00 is assessed by the Department of Natural Resources plus a charge of $.10 per cubic yard of sand and gravel removed from, or filled over in Lake Michigan.

c. Michigan

(1) General Approach

The State of Michigan presently has no legislation directly governing the siting of energy facilities. The regulatory framework that is currently employed is best described as traditional utility regulation. Most of the factors related to the geographic siting of energy facilities in Michigan are addressed at the local level through land use control techniques such as zoning, and building codes. However, a considerable degree of state authority is exerted over facility certification through the implementation of various environmental protection and natural resource management programs. The thrust of this general approach is to influence siting indirectly by insuring compliance with various environmental protection policies. In brief, emphasis in the existing regulatory mechanism is placed on facility certification instead of alternative site evaluation and selection.

A number of statutes exert at least some influence on the siting of energy facilities in Michigan. The Shorelands Management and Protection Act of 1970, which predated the Federal Coastal Zone Management Act of 1972, calls for the control of environmental and high risk erosion areas situated within 1000 feet of the ordinary high water mark of the Great Lakes. Flood hazard areas are also covered and are not limited to the 1000 feet criterion. Authority for implementation of this program rests primarily at the local level. The Michigan CZM Program is being built primarily around this state Act.

Another element of environmental policy in Michigan that affects energy facility siting in the coastal zone is the Great Lakes Submerged Lands Act. This Act established a permit program for construction activities in navigable waters that is somewhat similar to the permit system required by Section 10 of the Rivers and Harbors Act of 1899, administered by the Corps of Engineers.

A statute that could influence energy facility siting in inland areas is the Michigan Natural Rivers Act of 1970. Under this Act, segments of the state's rivers that meet certain criteria may be designated as areas that warrant statewide concern and management. This Act provides for mandatory local zoning of corridors of the rivers included in the program. It is unlikely that an energy facility would be sited in close proximity to a river included in this program.

(2) Long Range Plans and Forecasts

At present, no formal mechanism exists for a state role in long range energy facility planning and demand forecasting. Traditionally, this has been performed by the private sector. Recently, the Public Service Commission has requested that the electric utilities voluntarily disclose the details of their projected capital improvement expenditures over the next ten years for electric generating plant expansion and for air and water pollution control equipment installation. Disclosure of this information allows at least some evaluation of planned site locations. Cooperation by the utilities has aided this process. However, public involvement in the early stages of alternative site evaluation and selection remains limited.

The Michigan Energy Administration has recently begun to look at a broad range of problems and needs associated with future energy production in Michigan.

(3) Public Participation

Public involvement in energy facility siting decisions occurs primarily in the public hearings concerning permit and license applications required by state and local governments. State requirements are outlined in the next section. Hearings are also held on the utility rate regulation process administered by the Public Service Commission. In the event that an environmental impact statement were prepared on a proposed siting pursuant to Michigan's environmental impact review program (as discussed below), hearings would be held and public input would be solicited.

(4) Site Certification

Michigan does not have widespread authority to override local governments in siting decisions. Thus, energy companies must obtain all necessary clearances at the local level as well as at the state and federal levels. In accordance with existing State of Michigan and U.S. federal legislation, a number of permits are required to site an energy facility. The Environmental Protection Branch of the Michigan Department of Natural Resources is in charge of implementing environmental protection policies through the enforcement of the permit requirements. Table 4 lists the principal permit programs that apply to energy facilities in Michigan.

TABLE 4

MAJOR PERMITS REQUIRED FOR POWER PLANT SITING IN MICHIGAN

Agency	Permit Required	Authority
Water Resources Commission	Nation Pollutant Discharge Elimination System (NPDES) permits for all point source discharges to surface waters	Mich. Act 245, P.A. 1929, as amended
Water Resources Commission	Permit for all discharges to groundwater	Mich. Act 245, P.A. 1929, as amended
Water Resources	Soil erosion and sedimentation control permit	Act 347, P.A. 1972
Water Resources Commission	Permit to erect a structure in or alter the flow of navigable water (similar to Corps of Engineers Section 10 permit)	Act 247, P.A. 1955
Water Resources Commission	Permit to physically alter inland lakes and streams.	Act 346, P.A. 1972
Air Pollution Control Commission	Permit to install source of air emissions	Act 348, P.A. 1965 as amended
Air Pollution Control Commission	Permit to operate source of air emissions	Act 348, P.A. 1965, as amended
Resource Recovery Commission	Permit to dispose solid wastes	Act 366, P.A. 1974

As mentioned above, Michigan has adopted a statewide process of environmental impact assessment. This process, which was created by Executive Order 1974-4, is applied to major state actions that significantly affect the quality of the human environment. Although this process has not been routinely applied to energy facilities, coverage could be extended to include these facilities since the state licenses or permits that are invariably required could be defined as major state actions requiring an environmental assessment.

(5) Site Acquisition

The acquisition of sites for energy facilities is usually accomplished by the private sector through voluntary purchase on the market. Although the electric utilities have the authority to exercise the power of eminent domain for site acquisition, subject to approval by the Public Service Commission, this authority is rarely used.

(6) Financing

The existing energy facility siting regulatory mechanism is funded through the normal budgetary process. Modest fees must be submitted with some of the permit applications to cover certain costs.

(7) Power Authority Proposal

A recent study of electric power generation in Michigan warrants attention in this discussion. In 1975 Governor Milliken issued Executive Order 1975-4 which established the Governor's Advisory Commission on Electric Power Alternatives. In his charge to the commission the Governor identified some of the major institutional problems associated with the provision of an adequate supply of electric power:

> Traditional regulatory practices simply will not be adequate to solve the enormous and complex problems of the electric utility industry in Michigan. The process does not react fast enough to provide sufficient relief given the rapid pace of developments in the national economy. In addition, regulation may create disincentives to economic efficiency. Yet, even though the system has been and will continue to be strengthened, it does not provide regulators with sufficient control to rectify the problems.
>
> The State of Michigan must act now to examine other alternatives to the existing regulatory structure. The state must insure the availability of an adequate supply of power at an affordable price. The financial condition of Michigan's major utilities must be improved or the state will in the very near future be faced with:

a--the indefinite deferral of all major construction;
b--the termination of environmental and safety programs;
c--the inability to serve new residential, commercial, and industrial customers;
d--the deterioration of existing service [457].

Specifically, the Commission was directed to:

> a. examine the general trends in the rates of growth of the demand for electric energy both in the nation and in Michigan; ...assess the accuracy of utility industry and state government projections of such electric energy demand growth; ...and
> b. examine all of the feasible alternatives that will provide the consumers of Michigan with an adequate supply of electric power, ...specifically including establishing a Michigan Power Authority to engage in the financing, construction and operation of new generating or other facilities, establishing a program of insurance and guarantees on the state level to bring about the lower cost of financing electric utility debt, and urging some form of federal financing support [emphasis added] [457].

The final report of the Commission was issued in August, 1976. The foremost recommendation was the establishment of the Michigan Power Authority (MPA). The recommendations of the commission address many of the problems and needs identified throughout this study, and the reader is referred to the Final Report of the [Michigan] Governor's Advisory Commission on Electric Power Alternatives [457] for further information on this concept.

d. Minnesota

(1) General Approach

The Minnesota Power Plant Siting Act was passed in May, 1973 to provide for the siting of power plants and the routing of transmission lines under authority of the Environmental Quality Council (EQC). The state also has an Energy Agency created in March, 1974, which has authority to issue certificates of need for energy facilities. The Environmental Quality Council is composed of the heads of seven state agencies (including Energy), a representative of the Governor's Office, and four public members appointed by the Governor. The council has additional responsibilities under the Subdivided Lands, Critical Areas and the Environmental Policy Acts. Local zoning and land use control regulation are preempted by EQC site approval. Aggrieved parties may appeal council decisions in district court.

(2) Long-Range Plans and Forecasts

Public utilities, either individually or in concert, must submit biennial forecasts covering the subsequent 15-year period. The forecasts must include: tentative descriptions of size, type and general location of power plants and transmission lines; a statement of projected demand for electricity and the underlying assumptions used in its calculation; an estimation of capacity required to meet this demand; and a description of the relationship of each utility to each other and to power pools.

Annual five-year plans for facility development must also be submitted by utilities. These plans are to include identification of a tentative site and at least one alternative, with a preliminary indication of the potential impact of planned facilities on the existing environment and how such impacts may be avoided or minimized.

(3) Public Participation

There are four members of the public on the 12-person EQC, and the siting Act includes several provisions for additional public input. The process begins with identifying the criteria to be used for selecting suibable sites and corridors for electric power facilities. Public hearings are required for the development of these criteria. An annual public hearing is also held in order afford interested persons an opportunity to express their views regarding the inventory of potential sites or any other aspect of the council's activities, duties or policies.

The Act stipulates that the council appoint advisory committees comprised of a majority of public representatives. Such committees include representatives of the utilities, the regional council, and any county or municipality which is host to a proposed site. The Act requires additional public participation beyond public hearings and advisory committees, but is not specific as to the nature of this participation.

(4) Certification Procedure

Pursuant to the Power Plant Siting Act, a set of criteria has been developed to establish an inventory of potential sites for the generation and distribution of electric power. The actual inventory of sites is in the final stages of development at this writing and will be available in the near future.

Utilities must either select tentative sites from this inventory in its annual facility plan or, if selecting a non-inventory site, set forth reasons for this departure and make an evaluation of the site or route using the established criteria.

Applications for sites and routes are made in a form and manner prescribed by the council. The council conducts both studies and hearings on the application and designates a suitable site or corridor for each facility. Such designation is made in accordance with the established site selection criteria and standards. An approved site or corridor receives a certificate of site compatibility. Time limits of one year for power plants and 180 days for transmission line corridors are provided. The study and evaluation process includes assessments of environmental impact, direct and indirect economic impact, potential beneficial uses of waste energy (heat), and an evaluation of alternatives and irreversible commitments of resources.

The process is not a single-phase operation, because the EQC is responsible only for site certification. Utilities must also obtain permits from other agencies as in the past. Thus, the public service commissions and environmental protection agencies retain responsibility for issuing permits and certificates for power plant construction and operation.

(5) Site Acquisition

The Act provides for the continuance of utilities' rights of eminent domain.

(6) Financing

An application fee of $500 to $1000 for each $1 million of estimated investment and a minimum fee of $5000 are used to cover the cost of site-specific studies. An annual levy based on both kilowatt-hour and dollar sales of electricity is used to finance the general work of the council, including baseline studies, criteria development, inventory preparation and general environmental studies.

e. New York

(1) General Approach

The State of New York has established a specific regulatory mechanism to deal with the siting of steam electric generation facilities of greater than

50 MWe capacity. This includes coal, oil and nuclear-fueled plants. Article VIII of the Public Service Law created the New York State Board on Electric Generation Siting and the Environment. The board was placed in the Department of Public Services and is composed of the chairman of the Public Service Commission (who is also chairman of the board), the heads of the Departments of Environmental Conservation, Commerce, and Health, and citizens appointed by the Governor on an ad hoc basis from the areas of the proposed sites. The board has considerable authority to implement the various state laws that apply to the siting of electric generation facilities. All aspects of site and facility approval are administered by the board. In the final analysis, all necessary approvals and review processes are incorporated into the Certificate of Environmental Compatibility and Public Need, which must be obtained before a facility of 50 MWe or greater can be sited.

(2) Long-Range Planning

Under the authority of Section 149-b of the New York Public Service Law each electric utility must submit an annual long-range plan which includes:

- a forecast of demand for the next ten years, specifying anticipated load duration, including peak loads;
- identification of generating capacity to be utilized in meeting such demands, including capacity to be provided by others on a contractual basis;
- an inventory of all major facilities operated by members of the New York Power Pool, including the dates for completion, operation and retirement;
- an inventory of land owned and held for future use as a major steam electric generating facility site;
- anticipated expenditures for research in the areas of generation and transmission of electricity and abatement and control of pollution during the next year;
- such additional information as the commission may by regulation require to carry out the purposes of this section.

Subchapter E-1 of Chapter I of <u>The Rules of Procedure</u> outline the "additional information" required by the PSC for long-range planning. The utilities are required to notify a wide range of public and private organizations and individuals of the filing of the annual report. Following notification, the PSC holds one or more public hearings on the annual plan. The annual plan contains four major sections: power demand and energy requirements, generation facilities, transmission facilities, and research and development.

Each plan must document the summer and winter peak loads in the service area of concern for the previous 10 years and must provide estimates for the current year and for each of the 20 years subsequent to the year of filing. In addition, information is also required on the energy requirements for the time frame mentioned above for such uses as residential, small light and power, large light and power, corporate uses, street and highway lighting, railroads and railways, and other public uses.

The plan must also contain a documentation of the methodology used to estimate peak loads and energy requirements, including a description of the economic and demographic assumptions employed in peak load and energy requirement forecasts.

Finally, data used in the forecasts must accompany the annual plan, and each utility is required to describe present and planned future efforts with regard to encouraging energy conservation or to stimulating demand.

Under the generation facilities section utilities are required to specify in detail the existing and projected generation capacity of their respective systems. This section requires a projected timetable of plant completion, including the approximate date of application of any permit or license required under state or federal law. A summary must be presented of each New York State environmental law, rule, regulation or standard of less than statewide applicability pertaining to any facility proposed within ten years of the year in which the plan is filed.

For each facility proposed within 10 years of the plan of concern, utilities must provide an estimate of the capital cost of environmental control facilities and a description of the major design constraints posed by environmental standards or site-specific conditions.

In terms of site inventory, information is required with regard to:

- the size and location of the site
- any applicable land use standards as contained in zoning regulations and master plans
- the changes in land use that would result from construction at the proposed site
- the probable environmental suitability of the site for the type of generating facility proposed.

Finally, the plan must discuss how the availability of environmentally suitable sites, the location of load centers, the configuration of the state bulk transmission facilities, and the final costs of delivered power have influenced the selection of each proposed site.

(3) Public Participation

Public involvement in the decision-making process is provided by a variety of means, including public disclosure of long-range plans by utilities, procedural requirements insuring notification of the filing of an application for a certificate, and public hearings conducted on long-range plans for site development. In addition, local interests are represented on the board as ad hoc members from the judicial district of the proposed site.

(4) Site Certification

In New York the certification of the site and of the facility is handled by means of the application and approval processes associated with the Certificate of Environmental Compatibility and Public Need. All permits and licenses related to compliance with environmental protection legislation are handled through the board and are included as part of the application for the certificate. Under the authority of Section 149-a of Article VIII of the Public Service Law, the board preempts all other state and local authorities in siting-related matters by effectively incorporating these legal requirements in the certification process.

The decision-making process surrounding site approval is characterized by a formal, legal adversary proceeding, at which the various interests present testimony on matters related to the proposal of concern. The extensive information obtained in applying for the certificate supplies much of the basis for the evaluation of the proposal. The findings of the board, which may constitute approval, approval with conditions, or disapproval of the proposed siting, are based on the following criteria:

- the public need for the facility and basis thereof
- the nature of the probable environmental impact, including a specification of the predictable adverse effect on the normal environment and ecology, public health and safety, aesthetics, scenic, historic and recreational value, forest and parks, air and water quality, fish and other marine life, and wildlife

- that the facility represents the minimum adverse environmental impact, considering the state of available technology, the nature and economics of the various alternatives, the interests of the state with respect to aesthetics, preservation of historic sites, forest and parks, fish and wildlife, and other pertinent considerations

- that the facility is compatible with the public health and safety

- that the facility will not discharge any effluent in contravention of the standards adopted by the Department of Environmental Conservation or, in case no classification has been made of the receiving waters that the facility will not discharge any effluent that will be unduly injurious to the propagation and protection of fish and wildlife, the industrial development of the state, and public health and public enjoyment of the receiving waters.

- that the facility is designed to operate in compliance with applicable state and local laws and regulations issued thereunder concerning, among other matters, the environment, public health and safety, all of which shall be binding upon the applicant. However, the board may refuse to apply any local ordinance, law, or resolution which it finds unreasonably restrictive in view of the existing technology or the needs of or costs to consumers whether located inside or outside of such municipality. The board shall provide the municipality an opportunity to present evidence in support of such ordinance, law, resolution, regulation, or other local actin issued thereunder

- that the facility is consistent with long-range planning objectives for electric power supply in the state.

- that the facility will serve the public interest, convenience, and necessity, provided, however, that determination of necessity for a facility made by the Power Authority of the State of New York pursuant to Section 1005 of the Public Authorities Law shall be conclusive on the board; and

- that the facility is in the public interest, considering the evidence in support of such ordinance, law, resolution, regulation, or other local action issued thereunder.

Regulations implementing Article VIII of the New York Public Service Law require that at least two locations (primary and alternate) be evaluated in detail for the proposed facility, or that, in addition to the primary location for the proposed facility, an alternate facility at an alternate site must also be evaluated in detail.

(5) Guidelines for Application for Certificate

The rules and regulations governing the Certificate of Environmental Compatibility and Public Need are highly detailed and cover an extremely broad range of factors related to the siting of electric generation facilities.

Each of these categories is broken down into subsections. No attempt will be made here to provide an in-depth review of these regulations. The points most relevant to this study will be described to the extent possible according to the headings that appear in the guidelines.

(a) General requirements

Provisions are made in this section to insure that the applicant and the board are fully aware of all federal, state and local laws, rules, regulations, standards applicable to any apsect of the proposed site.

(b) Public need and engineering design

The data relevant to demand and supply forecasts as determined in the most recent long-range electric system plan are incorporated in the certificate application to document the need for the proposed facility. Also included is information on engineering design, transmission facilities, costs of initial investment, and costs of generation of electricity.

(c) Air quality and meteorology

Under this section, the applicant is required to submit information on meteorological conditions at the proposed site. Data are collected for suspended particulates, sulfur dioxide, nitrogen dioxide, and other contaminants likely to be discharged by the facility. Data are also collected for other meteorological parameters to establish a framework within which to predict impacts of the proposed facility on air quality.

(d) Aquatic ecology

In order to assess the effects of the proposal on aquatic ecosystems, the applicant is required to collect data for a period of not less than 12 consecutive months, ending not more than 6 months prior to the date of application. These data are in addition to any data collected by the U.S. Fish and Wildlife Service and the New York Department of Environmental Conservation. The design, operation, and maintenance aspects of the facility are then evaluated in terms of the ecological relationships that are likely to be impacted by the proposal. The impact areas include:

- physical disruption of bottom sediments
- discharge of thermally enriched water
- scheduled or unscheduled shutdown
- significant change in dissolved oxygen
- major change in local current patterns or water movement
- significant buildup of a toxic material in the sediment
- impingement or entrainment of any significant life form.

(e) Environmental noise

Noise impacts are evaluated in a fashion similar to that of air impacts. Present conditions are determined; construction, operation, and maintenance activities are specified; and the associated effects are predicted.

(f) Geology and seismology

This section was unavailable for review.

(g) Land use and aesthetics

Land use effects are treated in the same manner as air and noise effects. The categories of land use effects that must be discussed include the following social and economic impacts:

- the total number of employees and the associated payroll for each year of the construction phase and the total number of employees and associated payroll by annual salary levels for the first two years of operation;
- the number of persons to be employed from the local labor market;
- the probable impact, if any, of the use of the site and any associated influx of employees upon the sufficiency of police, fire, health, and other public services, as well as housing, educational, and recreational facilities;
- the estimated annual amount of municipal or special district property taxes and any municipal or special district user charges;
- the impact of any change in access to any land as a result of the construction, operation, or maintenance of the proposed facility;
- if there is any plan for using the site area for other than the proposed facility, the impact of the preemption of that plan by the proposed facility; and

- the impact on adjacent land uses, including existing patterns of land use and zoning in the locality.

(6) Site acquisition

State involvement in site acquisition is limited to requiring that electric utilities disclose ownership of or interests in prospective future sites. Site acquisition is usually achieved through voluntary negotiation.

(7) Financing

Applicants are required to submit an application fee of $25,000 to the board which may be distributed to the local jurisdictions affected by the proposed siting if they can demonstrate a need for the funds. These funds are intended to defray expenses incurred by local interests in providing expert testimony in their behalf at the formal hearing. Unused funds are returned to the applicant.

f. Ohio

(1) General Approach

The State of Ohio has modeled its power plant siting program after that of New York. Although some differences exist, the general approaches are the same. The regulatory mechanism has been fashioned into a one-stop process. The Ohio Power Siting Commission (PSC) is the lead agency through which the process operates and is composed of the heads of the Departments of Environmental Protection, Health, Economic and Community Development, and the Chairman of the Public Utilities Commission. In addition, an engineer appointed from the general public also serves on the PSC. It is noteworthy that in Ohio, as opposed to New York, the responsibilities for natural resource management and environmental protection are performed by separate agencies, the Ohio Department of Natural Resources (ODNR) and the Ohio Environmental Protection Agency (OEPA). Although ODNR is not represented directly by membership on the PSC, it is extensively involved in the review process of site proposals.

Covered by this program are electric generating facilities, including oil, coal, and nuclear power plants of greater than 50 MWe capacity, electricity transmission lines of greater than 125 kV capacity, gas transmission lines and associated facilities capable of transporting gas at greater than 125 pounds per square inch.

In order to site a facility of the type covered, a utility must first obtain a Certificate of Environmental Compatibility and Public Need from the OPSC. All permit and license requirements are incorporated in the certificate application process.

(2) Long-Range Planning

Chapter 4906.15 of the Ohio Revised Code establishes the requirement that utilities prepare annual forecasts of electric power and natural gas demand and supply. The PSC has promulgated detailed guidelines for these forecasts. The electric generating and transmission facilities forecast is composed of three parts: (1) electric power demand forecast, (2) resource forecasts and site inventories for electric generating plants and (3) resource forecasts and site inventories for transmission facilities. The regulations include an appendix which outlines various forecasting methodologies which may be employed by the utilities. The time frame that must be employed for data analysis includes:

- the past five years' actual historical data
- the current year forecast (both actual and projected)
- a ten-year forecast of loads, both in terms of energy and peak demands, as appropriate.

(a) Demand forecast

The utilities must provide the following:

- a description of the extent to which the reporting utility coordinates its load forecasts with those of other systems, such as affiliations in a holding company group, associated systems in a power pool or other coordinating organization, or other neighboring systems
- a description of the manner in which such forecasts are coordinated and of any problems experienced in this coordination
- a brief description of any computer modeling, demand forecasting, polls, survey or data gathering activities engaged in during the past year (exclusive of normal operations), including cost data, manpower requirements and significant findings.

In order to facilitate the analysis of forecasts, Ohio has established 11 service districts, and 15 planning regions for the state. Some elements of the demand forecasts are linked to this breakdown. The output of the demand forecast is composed of five parts:

- a forecast of the energy demand in the utility's service area
- a forecast of system energy demand in Ohio by industrial sectors only
- a separate ten-year forecast of energy demand for that part of each state planning region included in the reporting utility's service area
- a forecast of system peak demand levels for winter and summer seasons
- a forecast of annual peak loads for each major load center.

Another requirement of the annual ten-year forecast is the documentation of the approach used in the forecast, the major factors of which are the methodology, the data base, and the assumptions employed. Particular attention is paid to the use of assumptions in the forecasts, and those related to the following points must be covered:

- relative prices and availability of alternatives to the use of electric energy
- pricing policy, including:
  - alternative rate structures
  - promotion of consumption or conservation
  - predicted future price behavior
  - impact of price changes on quantity demanded.
- growth in the economy
- advertising policy assumed
- availability and potential development of primary energy sources (coal, oil, hydro, nuclear, solar, wind, etc.) used in generating electricity
- other assumptions critical to forecast techniques or company operating procedures.

(b) Resource forecasts and site inventories for electric generating plants

This section of the overall forecast is intended to provide documentation of estimated future resource requirements and of the prospective sites under consideration by the reporting utility. The major items that must be addressed are outlined below:

- a description of the generating capacity of the existing system
- a ten-year resource plan which identifies the requirements of new facility construction to meet projected loads (broken down on an annual basis)

- a description of the rationale for planned expansion
- an inventory of prospective sites for generating plants that are subject to the certification process.

With regard to this last item, utilities must provide a detailed site description, ecological data, a description of likely socio-economic impacts, and a brief discussion of alternate sites.

(3) Site Certification

In the Ohio program site certification and environmental certification of the facility are combined into one process. The OPSC administers all state and local laws, permits and licenses that apply to a proposed energy facility covered by the program. The OPSC preempts the authority of all other state and local agencies and units of government in the regulation of siting.

As required by Section 4 of Chapter 4906 of the Ohio Revised Code, utilities must obtain a Certificate of Environmental Compatibility and Public Need before siting an electric generating facility. In reviewing an application for a certificate the OPSC must determine:

- "the basis of the need for the facility
- the nature of the probable environmental impact
- that the facility represents the minimum adverse environmental impact, considering the state of available technology and the nature and economics of the various alternatives, and other pertinent considerations
- in the case of an electric transmission line, that such facility is consistent with regional plans for expansion of the electric power grid of the electric systems serving this state and interconnected utility systems; and that such facilities will serve the interests of electric system economy and reliability
- that the facility will comply with Chapters 3704., 3734., and 6111. of the Revised Code and all regulations and standards adopted thereunder
- that the facility will serve the public interest, convenience, and necessity." (ORC, Section 4906.10)

The Rules and Regulations of the OPSC include an extensive section on the completion of an application for a certificate. The relevant points under each major heading of this section of the guidelines will be covered.

(a) Justification of need

This discussion must include a description of the relationship of the proposed site to the most recent ten-year forecast and an analysis of the alternatives considered. This section also provides for a project schedule which describes the time staging of the procedural requirements and of plant construction.

(b) Technical data

In order to fully evaluate the proposal, certain detailed information is required. In terms of the site itself, data must be collected on geography and topography, geology and seismology, and hydrology. Also required are data on site layout and preparation, and on generating, cooling and emission control equipment to be employed.

(c) Environmental data

This section of the certificate includes a detailed environmental assessment of the proposed site. As used in this context, "environmental" generally refers to the pollution-related aspects of environmental impacts. The data requirements are listed in detail, and the general assessment headings include air, water, and solid waste, radioactive emissions, noise, and resources.

(d) Social and ecological impact of the proposed generating facility

The major headings under this section include health and safety impacts, ecological impacts, impacts on resources, economics, land use and community development, and cultural effects.

(e) Permit requirements

As mentioned above, the various permits and licenses that must be obtained by the applicant in order to site an electric generation facility are incorporated into the application process for the certificate. A list of the major permits is given in Table 5.

(4) Public Participation

The Ohio program provides a variety of opportunities for public involvement. All information submitted to the OPSC by the electric utilities (except proprietary information) is available for public review. Widespread notification is made of applications for certificates. In addition, the annual ten-year forecast report meetings, the pre-application review conference (if held), the formal hearing on the certificate, and other meetings of a non-proprietary nature are all open to the public.

TABLE 5

MAJOR PERMITS REQUIRED FOR POWER PLANT SITING IN OHIO

Resource	Agency	Permit Required	Authority
Air	Ohio EPA	Permit to install source of air emissions	Ohio Revised Code, Chapter 3704.03
Air	Ohio EPA	Permit to operate source of air emissions	Ohio Revised Code, Chapter 3704.03
Water	Ohio EPA	Permits for all discharges into receiving waters	Ohio Revised Code, Chapter 6111.03 (NPDES permit)
Solid Waste	Ohio EPA	Permit to dispose of solid wastes	Ohio Revised Code Chapter 3734

(5) Certification Procedure

A well-defined application and review procedure has been developed for electric generating facility siting in Ohio. The procedural guidelines will be described briefly according to the major topical headings.

(a) Letter of intent

In order to provide adequate lead time for the evaluation of the proposed siting and to insure the proper course of action, the Ohio Power Siting Commission requires that a letter of intent be filed at least one year in advance of the filing of an application for a Certificate of Environmental Compatibility and Public Need. In the letter, the utility may request waivers from certain OPSC rules and regulations. The OPSC must respond to the letter of intent within sixty days, making any appropriate comments.

(b) Pre-application conference

The purpose of this conference is to identify environmental, social, and public factors that could result in disapproval of a specific site, before significant time and monetary resources have been expended. The pre-application hearing is also open to the public, and may be held before or after the filing of the letter of intent.

(c) Filing of application

The next major step is the filing of the application for the certificate with the OPSC, which then has 60 days to determine the completeness of the application. During this period, appropriate state agencies, principally the ODNR and the OEPA, review the application. Major substantive factors that do not appear to be addressed in the application are identified at this point. The utility then responds to these comments and resubmits its application, after which the OPSC has 60 to 90 days to circulate the application for review and schedule a public hearing, at which the formal, legal proceedings take place. During this period, review comments by the ODNR, the OEPA, the PUCO and other agencies are solicited by OPSC. The OPSC has established specific certificate evaluation procedures and guidelines, which specify the statutory authority of the review, the particular agency and staff member responsible for the review, and the primary focus of the review. The results of this substantive review form the basis of the testimony presented at the formal hearing. At this point, the certificate is either approved, approved with conditions, or denied.

(6) Site Acquisition

The State of Ohio is not involved in the acquisition of prospective sites for energy facilities. The private sector acquires sites primarily through voluntary negotiation with landowners.

(7) Financing

Ohio has established a financial mechanism to offset the costs of various aspects of the program including review, analysis, evaluation, investigation, monitoring, enforcement, etc.

The application fee for a power plant is determined by the following formula:

- the product of \$1.10 times the maximum kilowatt electric generating capacity as determined by the name plate rating, <u>plus</u>
- ten percent of the amount determined above, <u>times</u>
- the difference between the anticipated year of expiration of the period of initial operation and the anticipated year of commencement of construction.

g. Pennsylvania

(1) General Policy Approach

At present, Pennsylvania does not have legislation that specifically addresses energy facility siting. The regulations and standards of the environmental protection and natural resource management policies form the basis for the existing, indirect regulation of siting. The concept of local control of land use is deeply imbedded in Pennsylvania, and this will continue to play a major role in future policy development.

In 1970 Pennsylvania passed legislation establishing the Department of Environmental Resources and charging it with the development of statewide environmental master plan. The Environmental Quality Board is the policy making body of the DER and is in charge of master plan development. The chairman of the Public Utility Commission is also a member of the board. The approach taken in the master plan is the identification, policy development, and management of environmental areas of critical state importance. The general categories identified as priority areas include:

- prime agricultural soils
- watersheds with high quality streams
- floodplains
- coal resources
- areas with limited water supply
- clean air resource areas
- open space in metropolitan areas
- geologic areas with development constraints.

These categories generally reflect a land capability approach to environmental planning. The policies developed for the general critical areas will significantly influence the siting of electric generating facilities as well as other types of energy facilities.

(2) Site Certification

Site certification and facility certification are handled under separate mechanisms in Pennsylvania. With respect to site certification, no state approval is required if a proposed electric generating facility site has been zoned for such a use or if a variance has been granted by the appropriate local governmental jurisdiction. Under existing law, the Pennsylvania Public Utility Commission (PUC) can preempt local regulations and can grant the conditional power of eminent domain to utilities. If the proposed site has not been given local approval, the utility can apply to the PUC for intervention. If the PUC determines that the proposal is needed to maintain an adequate supply of electricity, it can grant a Certificate of Necessity for the proposal. This gives the utility the power of eminent domain to acquire the site and transmission line rights-of-way.

With regard to certification of the facility, Pennsylvania has established environmental protection legislation for air and water pollution, soil erosion and sedimentation, and solid waste disposal. The Department of Environmental Resources (DER) is the principal agency in charge of the environmental protection programs. Table 6 lists the major permit requirements for energy facilities in Pennsylvania.

TABLE 6

MAJOR PERMITS REQUIRED FOR POWER PLANT SITING IN PENNSYLVANIA

Resource	Agency	Permit Required	Authority
Air	DER Bureau of Air Quality Control	Permit to install source of air emissions	Penn. Air Pollution Control Act
Air	"	Permit to operate source of air emissions	"
Water	Bureau of Water Quality Management	Industrial waste discharge permit	Penn. Clean Streams Act of 1937, as amended.
Water	U.S.E.P.A. (Authority not as yet delegated to Penn. DER)	National Pollutant Discharge Elimination System (NPDES) permit	Section 402, P.L. 92-500
Water/Soil	Bureau of Water Quality Management	Soil erosion control permit for earth changes greater than 25 acres	Penn. Clean Streams Act of 1937, as amended
Solid Waste	Bureau of Land Protection	Permit to dispose of solid waste	Penn. Solid Waste Management Act

The specific requirements under each permit vary according to the type of facility and site under consideration. The DER has established regional offices to coordinate these permit systems and to expedite procedural matters.

(3) Long-Range Planning

Long-range planning for electric generating plants and other kinds of energy facilities is performed by private corporations. The PUC does require that electric utilities demonstrate that an adequate supply of reasonably priced electricity will be available in the future. Thus, some knowledge is gained of possible future sites, but detailed disclosure of specific plans is not required.

(4) Site Acquisition

The normal site acquisition procedure is one of voluntary purchase by private corporations. Negotiation usually is sufficient for acquisition. The PUC has the authority to grant the power of eminent domain to electric utilities for land acquisition. Although condemnation is used occasionally for acquisition of transmission line rights-of-way, it is rarely used for large tracts of land for future sites.

(5) Public Involvement

Public involvement in the siting decision process in Pennsylvania is provided mainly through public hearings conducted on the various environmental protection permit applications mentioned above.

(6) Financing

There do not appear to be any financial mechanisms established to facilitate or implement the energy facility siting process in Pennsylvania.

h. Wisconsin

(1) General Approach

The Wisconsin legislature enacted a power plant siting bill in September 1975 which provides for the siting of large power plants (over 300 MWe) and high voltage transmission lines. The Act does not create a new agency but rather assigns responsibilities to existing agencies, especially to the Public Service Commission (PSC) and Department of Natural Resources (DNR). Local ordinances which preclude or inhibit installation and utilization of facilities covered by the Act are preempted. The Act provides for judicial review of any decision by the PSC regarding the advance plan or the certification of facilities.

(2) Long-Range Plans and Forecasts

Biennial plans are required of the utilities and may be submitted individually or in concert. The plans are to include a general description of facilities and locations planned for the succeeding ten-year period, identification of possible alternatives and reasons for selecting the proposed facilities and locations, a detailed projection of electric energy demand and the basis thereof, identification of planned research projects, and identification of programs to discourage inefficient and excessive power use.

The utility plans are to be submitted to the PSC with copies to seven other state agencies and any concerned regional planning commission. These agencies are allowed 180 days in which to comment on the plans. Copies are also sent to cities, counties and libraries in proximity to proposed sites and to those who request copies. Local governments and members of the public may also submit written comments within 180 days. A hearing on the plan will also be held within 180 days within the vicinity of the site proposed to be constructed in the following three years. At least thirty days prior to the hearing, the PSC must prepare a single environmental assessment on all plans submitted by the utilities.

Within eighteen months of its filing, each plan must either be approved or disapproved by the commission. Approval is based on four criteria: provides adequate supply, is in the public interest, is coordinated with other long-range plans and policies, and provides programs for discouraging inefficient and excessive power use.

(3) Public Participation

At least one public hearing is to be held on each utility plan. Several public hearings are also held in the vicinity of a proposed site after the application for Certificate of Public Convenience and Necessity has been filed. The public is provided access to copies of the utility's plans through county libraries and is invited to make written comment on the plans.

(4) Certification Procedure

At least 120 days before filing an application for a certificate, a utility must notify the PSC and the DNR of its intention to file and provide an engineering plan showing the location of the proposed facility accompanied by a description of the facility including anticipated effects on air and water quality. Within 60 days of such notification the DNR provides the applicant with a list of all permits and approvals required for the construction or operation of the facility indicating which of these would be required prior to issuance of the certificate. An optional permit procedure allows the utility to obtain a single permit from the DNR covering all permits and approvals issued by that agency.

The certificate is required prior to commencement of construction. Time limits of eighteen months for power plants and six months for transmission lines are specified for the approval process. The process is to include "as many hearings...as practicable." Approval of the certificate is based on: compliance with the most recent advance plan, necessity to meet demand, consideration of alternatives, environmental considerations, and conformance with orderly land use and regional development plans. The PSC issues the certificates.

(5) Site Acquisition

Utilities in Wisconsin have the power of eminent domain, but the Siting Act restricts the use of this power. A utility may condemn a limited interest in real property or appurtenant personal property for purposes of feasibility tests and studies under certain restrictions. A utility may not acquire real or appurtenant personal property by condemnation until a Certificate of Public Convenience and Necessity has been issued for the site.

(6) Financing

The Act does not provide for the funding of siting regulation procedures.

3. OTHER COASTAL STATES

This section briefly describes energy facility siting programs in selected coastal states outside the Great Lakes Region. States were selected for the uniqueness of their approach to the question of energy facility siting. All six states have recently enacted legislation to deal directly with this issue. California has the only program that specifically relates energy facility siting to coastal zone management.

a. California

(1) General Approach

The California Energy Resources Conservation and Development Act of May 1974 provides that state with one of the most comprehensive energy programs in the country. The Act establishes the Energy Resources Conservation and Development Commission (ERCDC), which is comprised of five governor appointees confirmed by the senate, two non-voting, ex-officio members, the secretary of the state Resources Agency and the president of the Public Utilities Commission. Conflict of interest provisions are specified in the Act. The commission is charged with power plant siting and certification, energy resources conservation, and research/development programs to deal with supply, consumption and conservation of energy. The commission has sole responsibility for site certification except in the coastal zone, where prior approval from the state Coastal Zone Conservation Commission is also required.

(2) Long-Range Plans and Forecasts

Utilities must prepare biennial 5-, 10-, and 20-year forecasts of demand, estimated savings through greater efficiency, alternative ways to meet increases in demand, siting needs, and the potential for increasing capacity at existing sites. The forecasts are to be widely disseminated with comments invited from all quarters. The Public Utilities Commission submits an independent evaluation of each forecast during the four-month review period, after which the ERCDC issues a preliminary statewide report on the forecasts. After more review and another public hearing, the forecast is incorporated into the biennial report. The report concerns overall energy needs, developments, policies and practices. It includes a list of possible sites to meet the 10-year need for electricity and a 20-year projection of the likely environmental, economic and social impacts of continuing present trends, with recommendations for reducing demand, conserving energy, and developing potential energy sources.

(3) Public Participation

Public participation is not only permitted, it is actively sought out. An Office of the Public Advisor has been established to insure dissemination of information to the public and the notification of interested parties and the general public with regard to public hearings and other commission actions. This appears to be a unique attempt to facilitate public particiation and insure an open and thorough decision-making process.

(4) Certification Procedure

A utility proposing to construct a power plant in California must first submit a notice of intent to file an application for site certification to the Energy Resource Conservation and Development Commission (ERCDC). The notice of intent is to include identification of three alternative sites, a description of the facility proposed for each site, a preliminary statement of the relative economic, technological, and environmental advantages and disadvantages of each alternative, and a statement of need and information showing compatibility with the most recent biennial report. Of the three alternative sites, at least one must be outside the coastal zone. The notice of intent may also describe phased development for a site.

Copies of the intent notice are widely disseminated. The ERCDC then requests comments from appropriate agencies, including the Public Utilities Commission, from whom a certification of public convenience and necessity may also be required, and the Coastal Zone Conservation Commission, from whom prior approval is required for facilities in the coastal zone.

Public hearings are begun in the county of the proposed sites in the interval from 60 to 90 days after the filing of a notice of intent. Hearings are to conclude within 90 days of commencement. Within 90 days after the conclusion of hearings, the council issues a preliminary report on the notice of intent. Thirty days are provided for distribution of the preliminary report and another 60 days for written responses thereto. Within 120 days of the issuance of the preliminary report, the final report is to be prepared and distributed. Public hearings on the final report are to commence within 30 days of its release and conclude in another 30 days.

Among other things, approval of the notice of intent requires that at least two of the three alternative sites and related facility proposals be found acceptable. Approval of the permit with only one acceptable site is possible under certain conditions. If no acceptable site is found, but the need for a power plant established, the commission may designate a feasible site and related facility, if so requested by the applicant.

The above process may proceed simultaneously with the processing of an application for a Certificate of Public Convenience and Necessity by the Public Utilities Commission.

At least 18 months before the planned commencement of construction, a utility must file for certification of a site and related facility found acceptable under the process described above. An environmental impact report is then prepared, with the commission acting as lead agency except where the Coastal Zone Conservation Commission has jurisdiction. A new round of agency review and public hearings is initiated with a final decision due within 18 months of the filing for certification. Sites in the coastal zone will not be certified until a permit is issued by the appropriate (regional or state) coastal zone commission.

(5) Site Acquisition

Utilities have the power of condemnation. The utility may also be required to acquire development rights in a buffer zone to insure that maximum population densities in the area of the plant would not be exceeded. Maximum population densities may be established by the commission to protect public health and safety. For a nuclear facility such population densities may be determined by the Nuclear Regulatory Commission (as successor to the AEC).

(6) Funding

A surcharge of one-tenth of a mill per kilowatt-hour of electric power produced, subject to annual revision, is used to finance the operation of the Energy Resource Conservation and Development Commission. In addition, the filing of a notice of intent requires submission of a fee of 1¢ per kilowatt of net electric capacity of the largest proposed alternative within the range of $1,000 minimum to $25,000 maximum total. Applications for other types of facilities (e.g., transmission lines) must be accompanied by a $5,000 fee.

b. Maine

(1) General Approach

Due to increasing pressures to locate petroleum refineries in the coastal zone, and for other reasons, the State of Maine has developed its principal state land use control program around the siting of large-scale facilities involving more than 20 acres of land or water. This includes all energy facilities which meet the size criterion. Although Maine does not specifically address energy facility siting as a separate issue, it does administer (as do some Great Lakes states) a complex set of fairly broad programs for environmental protection and natural resource management, and these influence energy facility siting and/or the coastal zone. Included in this set are programs for the siting of major developments (including energy facilities), long-range energy planning, oil and gas conservation and development control, air and water pollution control, public utility regulation, the protection of coastal wetlands, the alteration of rivers and streams, shoreland zoning with jurisdiction up to 250 feet from coastal waters, the protection of critical areas of scenic, scientific, or historical value, and state land use planning and regulation in unorganized territories of the state. Maine is currently developing a coastal zone management plan but has not as yet adopted policies specific to the siting of energy facilities in the coastal zone.

Local autonomy in land use and development decisions is deeply ingrained, and coastal zone management in the State of Maine has encountered considerable local opposition [456].

(2) Long-Range Plans and Forecasts

Under the Energy Resources Act the state Office of Energy Resources (OER) is engaged in independent, long-range energy planning. The OER provides technical advice on energy matters to the Board of Environmental Protection. There do not appear to be any action forcing provisions which relate energy facility site approval to long-range plans and forecasts prepared by the state. The private sector prepares its own plans and forecasts for future energy development, and these plans are more influential than state plans.

(3) Public Participation

In Maine an applicant must possess all the necessary state and local permits and licenses in order to apply for a permit under the Site Location of

Development Act. Public participation in the siting decision process begins with the public hearings held on these various permit and license requirements. In addition, the prehearing conference and the formal decision hearing are also open to the public. Project-related files of the Board of Environmental Protection are open to public inspection.

(4) Certification Procedure

The certification of a site for any type energy facility revolves around the permit system established by the Maine Site Location of Development Act. Site approval and environmental certification of the facility are combined into one comprehensive application process. For petroleum refineries, port and terminal handling facilities, and very small electric generating facilities for the site location permit is essentially all that is required at the state level. For electric generating facilities of 1,000 kW capacity or larger, the Maine Public Utilities Commission must also approve the proposal by granting a Certificate of Public Convenience and Necessity.

The process begins with the filing of an application for a site location permit for a power plant, refinery, or other energy facility. At this point the applicant must possess all the necessary local licenses and permits, as well as proof of ownership of the site. Although the board does require that local conditions be met, it retains the authority to override local approval. All final approvals on the state level are handled by the board. The information requirements of these permits are consolidated into one application form.

Following notification by a developer, the state has 30 days to hold a public hearing on the proposal. The board may hold a prehearing conference to expedite the conduct of the hearing. At the formal hearing, appropriate state agencies present testimony. The burden of proof is on the developer to satisfy the following criteria:

- Financial capacity. The developer must have the financial capacity and technical ability to meet air and water pollution control standards and make adequate provision for solid waste disposal, the control of offensive odors and the securing and maintenance of sufficient and healthful water supplies.
- Traffic movement. The developer must make adequate provision for traffic movement of all types out of or into the development area.
- No adverse effect on the natural environment. The developer must make adequate provision for fitting the development harmoniously into the existing

natural environment and ascertaining that the development will not adversely affect existing uses, scenic character, or natural resources in the municipality or in neighboring municipalities.

- Soil types. The proposed development must be built on soil types suitable to the nature of the undertaking [508].

(5) Site Acquisition

Site acquisition is the responsibility of the energy corporations. With regard to electric generating facilities, the utilities may exercise the power of eminent domain, subject to approval by the PUC. The applicant for a site location permit must demonstrate that the proposed site has been acquired, before the permit can be issued.

(6) Financing

Maine's site location permit program is financed through the normal state budgetary process and does not entail application fees or production surcharges.

c. Maryland

(1) General Policy Approach

The State of Maryland has developed a centralized program to regulate the siting of all electric generating facilities. Some elements of this program are considerably different from those adopted by other states, while other elements are fairly commonly applied. The scope of this program is limited to electric generating facilities. The siting of other types of energy facilities is handled under separate regulatory mechanisms with a lower degree of state involvement.

The Maryland program has pioneered what is generally referred to as the one-stop decision process. In this particular approach, input by the state agencies responsible for economic, health, environmental, and planning considerations is incorporated into a single, final decision by the Maryland Public Service Commission. The overall program is basically composed of four subprograms dealing with site evaluation, site acquisition, monitoring, and research. The basic thrust of the program is to predict the impact of proposed generating facilities, to assess the impacts of existing facilities, and to acquire alternative sites for utilities unable to find suitable sites on their own.

The Maryland Department of Natural Resources also plays a major role in the power plant siting program by conducting environmental impact assessments and suitability analyses of alternative site proposals. Other major elements of the Maryland program include preemption of local authority in siting matters, requirements for long-range plans and forecasts, and a comprehensive application procedure for site approval.

(2) Long-Range Plans and Forecasts

Like other states having established active state-level roles in the regulation of electric generating facilities, Maryland requires all electric utilities to prepare, on an annual basis, ten-year plans specifying future resource requirements and proposed, potential sites for new facilities. The Public Service Commission compiles and evaluates the various ten-year plans and identifies proposed future site locations. Following the filing of the plan with the PUC, the DNR is notified of the proposed sites outlined in the ten-year plan. The DNR then conducts a detailed environmental assessment of the sites. The general assessment criteria applied to the sites are essentially the same as those outlined in the National Environmental Policy Act of 1969. If the DNR determines that a proposed site is unsuitable, the Public Service Commission must delete this site from the ten-year plan. If it is found that a site is likely to result in a violation of applicable federal or state environmental standards, the site must be declared unsuitable. This implies that prospective sites are evaluated with sufficient detail to determine compliance with air and water pollution standards.

(3) Public Participation

Maryland requires public disclosure of the annually updated long-range plans and forecasts prepared by the electric utilities. Public hearings are held on all Certifications of Public Convenience and Necessity and all associated materials are available for public inspection. Although public hearings are not required at other points in the process, they may be held at the discretion of state officials.

(4) Site Certification

Following the preliminary screening of sites outlined in a particular ten-year plan, the DNR conducts detailed assessments of sites deemed suitable.

This amounts to the preparation of a formal environmental impact statement on the site. The final EIS on the site must be published at least two years prior to the proposed date of construction as outlined in the ten-year plan. At this point, the formal application procedure for approval of a specific site begins.

The principal means of formal site approval is the Certificate of Public Convenience and Necessity. The certification process is handled by the Public Service Commission with the technical advice and recommendations of the Department of Natural Resources. Within 60 days after an application has been filed with the commission, the DNR is notified of the application and is directed to complete any additional study and investigation necessary, including, but not limited to, the necessity for dredging and filling at the plant site and the water requirements of the facility. At some point following the filing of the application, the PSC establishes a date for the formal administrative hearing. Following the testimony presented at the hearing, all interested parties are given 15 days within which to modify, affirm, or amend their initial recommendations. The final decision on the application must be made by the PSC within 90 days after the hearing. Due to the extensive preliminary evaluations of alternative sites, the amount of information required in the certificate application is somewhat reduced.

The monitoring program is designed to provide feedback to the overall energy facility siting program. As part of this program, the DNR issues, on a biennial basis, a cumulative environmental impact statement of all power plants currently operating in the state.

(5) Site Acquisition

This phase of the power plant siting process is one of the more interesting elements of the Maryland program. The state is actively engaged in the acquisition of sites determined suitable. Within two years of the date on which the prospective site is identified by the state, a detailed environmental assessment is prepared and the site is either accepted or rejected. If accepted, the site is acquired by the state through voluntary agreement or by condemnation.

The electric utilities may also acquire prospective power plant sites, although such sites must undergo the same environmental assessment as those owned by the state. The inventory of suitable state-owned sites serves as a source of alternatives from which the utilities may lease or purchase sites in the event that their own sites are unsuitable.

(6) Financing

In order to administer the program, Maryland established the Environmental Trust Fund. The fund, administered by the Secretary of Natural Resources, is derived from a one- to three-tenths mill per kWh surcharge on electricity generated within the state. The electric utilities are specifically authorized to add the full surcharge to customers' bills. The fund is used to administer the program and to acquire prospective sites.

d. Massachusetts

(1) General Policy Approach

Massachusetts has adopted one of the most comprehensive energy facility siting regulatory programs in the nation. The program includes electric generating facilities of 100 MW or more capacity, facilities for manufacturing or storing gas, and facilities for refining or storing petroleum. The organization responsible for implementing energy siting policies is the Energy Facility Siting Council. The council is composed of the secretaries of the Departments of Environmental Affairs, Consumers Affairs, Manpower Affairs, and Administration and Finance, and five governor appointees: one representing conservation and protection of the environment, one professional engineer, and one each knowledgeable of electricity, gas, and oil industries, respectively.

The siting regulatory process is fairly centralized and can best be described as a one-stop process. The council has authority to preempt other state and local requirements.

(2) Long-Range Plans and Forecasts

All electric utilities are required every five years to submit a long-range electric power forecast covering the subsequent ten-year period. In addition, updates and revisions must be filed every year. In preparing the ten-year forecasts the utility must provide the following information:

- A description of all existing agreements with other electric companies for joint planning or joint forecasting of electric power needs and the purchase or sale of electric power or reserve capacity.
- A forecast of the electric power needs for its market area, taking into account wholesale bulk power sales or purchases or other co-operative arrangements with other utilities and electric energy policies as adopted by the

commonwealth.

- A description of actions planned to be taken by the company which will affect its capacity to meet such needs, including:
  - expansion, reduction, or removal of existing facilities
  - construction or acquisition of additional facilities
  - description of alternatives to planned action such as:
    - other methods of generating
    - other site locations
    - other sources of electrical power
    - no additional electric power.
  - a description of environmental impact of each proposed facility.

In this regard, the council shall, after public notice and a period for comment, be empowered to issue and revise its own list of guidelines providing a minimum of data for initial review of impacts on land use, water resources, air quality, solid waste, radiation, and noise.

Within six months of submittal of the plan, a public hearing is held, and the council accepts or rejects the plan in whole or in part within one year of filing. In making this decision the council insures that the following conditions are fulfilled:

- All information relating to current activities, agreements and policies as adopted by the commonwealth is substantially accurate and complete.
- Projections of demand for electric power and of the capacities for existing and proposed facilities are based on substantially accurate historical information and reasonable statistical projection methods.
- Projections relating to service area, facility use and pooling arrangements are consistent with such forecasts of other companies subject to this chapter as may have already been approved, and reasonable projections of activities of other companies in the New England area.
- Plans for expansion and construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth.

(3) Public Participation

Public hearings are held on all long-range forecasts and in localities where prospective electric generating sites are identified in the plans. Public disclosure of this information is required. In addition, at least two hearings are held on each notice of intention to construct and operate an energy facility. Hearings may also be held on applications for Certificates of Environmental Impact and Public Need.

(4) Certification Procedure

The principal mechanism for siting certification in Massachusetts is the notice of intention. This process applies to all types of energy facilities covered by the program. At least two years prior to the expected commencement date of construction the applicant must file a notice of intention with the council. Separate and distinct from the notice of intention is the process for the Certificate of Environmental Impact and Public Need. Any energy company may petition the council for a certificate if one of the following conditions exist:

> The applicant is prevented from building a facility because it cannot meet standards imposed by a state or local agency with commercially available equipment.
> There has been an undue delay imposed on the applicant by state or local agencies.
> There are inconsistencies among resource-use permits issued by state or local agencies.
> There are nonregulatory issues or conditions imposed by state or local agencies such as aesthetics, recreation, etc.
> There are disapprovals, conditions, or denials by local governments [508].

Information required in the application includes:

- A description of the location of the facility to be constructed or operated thereon.

- A summary of the studies which the applicant has made of the environmental impact of the facility, and a statement of the reasons for the choice of the location.

- A copy of the long-range plan approved by the council in proof of the need for the facility to meet the energy requirements of the applicant's market area, taking into account wholesale bulk power sales or purchase or other co-operative arrangements with other utilities and electric energy policies as adopted by the commonwealth.

- A statement setting forth the need of the applicant for the certificate, including:

  - all licenses, permits and other regulatory approvals required by law for the construction or operation of the facility which have been granted.

- indication of the good faith effort made by the applicant to obtain from state agencies and local governments the licenses, permits and other regulatory approvals required by law for construction or operation of the facility.
- indication as to the inability, if any, of the applicant to comply with any law, ordinance, by-law, rule and regulation affecting the construction or operation of the facility.
- indication as to the applicant's inability to proceed with the construction or operation of the facility by reason of the denial, delay, or imposition of a burdensome condition in issuing specified licenses, permits or approvals.

Only those council members with interest or expertise in a particular type of facility may participate in decisions affecting that particular type of energy facility. For instance, the oil and gas industry representatives may not vote on decisions concerning electric generating facilities.

(5) Site Acquisition

Electric and gas utilities can employ the power of eminent domain, subject to approval by the Department of Public Utilities, to acquire land for sites, but, in general, site acquisition is achieved through voluntary purchase agreements.

(6) Financing

Massachusetts employs an application fee of $25,000 maximum for each certificate application. For each forecast or supplement thereto the electric utility industry is also assessed a total of $400,000 which is broken down according to the proportion of electric energy generated by each utility. A similar proportional assessment is levied on gas companies based on a total industry assessment of $125,000 annually. Finally, each notice of intention to construct an oil facility must be accompanied by a filing fee graduated in accordance with the expected capital investment in the facility to a maximum of $400,000. Revenues are employed for program administration.

e. <u>Oregon</u>

(1) General Approach

On June 30, 1975, the Energy Facility Siting Council replaced the Nuclear and Thermal Energy Council, which had been in operation four years. The Energy Facility Siting Council consists of seven public members appointed by the governor subject to senate confirmation. The powers and duties of the council include:

- preparation and execution of studies, investigations, research and programs relating to all aspects of site selection
- designation of areas within the state suitable or unsuitable for various types of energy facilities
- establishment of standards and promulgation of rules that applicants for site certificates must meet.

The council is responsible for siting power plants, transmission lines, solar collectors and pipelines above specified minimum sizes.

Oregon also has a Department of Energy whose duties include:

- collection and dissemination of information and data on energy resources, including an annual forecast
- education of the public regarding energy problems and means of conservation
- coordination of energy research.

In addition to these agencies, there is an Energy Policy Review Committee consisting of nine members appointed by the governor, the president of the senate and the speaker of the house. The Committee's functions are primarily to review programs, rules and reports and to make recommendations on all aspects of energy policy.

(2) Long-Range Plans and Forecasts

The Department of Energy issues an annual forecast of the energy situation as it affects Oregon. The forecast is to include estimates of energy demand, resource availability and the impacts of conservation, new technology and future construction. The forecast covers the five years as well as the tenth and twentieth years following issuance of the forecast.

Information and data for the forecasts are to be supplied by all producers, suppliers and major consumers of energy resources and by political subdivisions of the state. Subpoena power may be employed to obtain information, but data must be kept confidential and presented in such a way as to conceal the source if so requested.

A preliminary forecast is required of the department by July 1. Public hearings must be scheduled within 45 days and the final forecast must be issued by January 1.

The site certification process includes a provision for a notice of intent to file an application for a site certificate. This notice of intent to file must be filed at least twelve months prior to the filing of the application for a site certificate and must identify the proposed site.

(3) Public Participation

The Department of Energy holds public hearings on the annual long-range forecast as described in Section (2) above. Preliminary forecasts are made available to anyone who requests one at a fee not to exceed the cost. The final forecast is included in the annual report of the Energy Council to the governor and the legislative assembly.

Upon receipt of a site application, the Siting Council holds public hearings in the affected area and elsewhere as it deems necessary. Any person may appear and present testimony at the hearings. The recommendation of the council is subject to judicial appeal. Public hearings are also held prior to determining whether areas are suitable or unsuitable for energy facilities.

The Energy Facility Siting Council is comprised of general public members. Appointment to the council is denied to anyone with pecuniary interest in energy facilities, and employment by an owner or operator of an energy facility is prohibited for two years subsequent to council membership.

The council must designate the local governing body (of the city or county host to a proposed site) as a special advisory group and may appoint additional advisory groups as it deems necessary.

(4) Certification Procedure

The Energy Facility Siting Council is charged with advance designation of sites as suitable or unsuitable for thermal power plants (nuclear and fossil) larger than 200 MW, geothermal power plants, and any additional energy facility type for which the council determines such designations necessary.

The first step in site certification is the notice of intent to file an application for a site certificate, which must precede the application itself by at least twelve months and include identification of the site. The Energy Facility Siting Council gives public notice that the intent has been filed.

Copies of both the notice of intent and the application for site certificate are sent for comment and recommendation to twelve state agencies and to any affected city or county. A time limit for response is set by the council. The council may commission an independent study of any aspect of the proposed facility to be funded from the application fee.

Public hearings are held in the affected area and elsewhere as necessary. Following the hearings and the receipt of any authorized studies, the council may reject, recommend, or recommend with conditions the application for a site certificate. Time limits from the filing of an application to final council action are specified as follows: 24 months for a thermal power plant, except combustion turbine types for which the limit is 9 months; 6 months for most expansions of energy facilities; and 12 months for other energy facility construction. The governor has thirty days in which to execute the certificate.

The site certificate is executed by the governor and the applicant and includes authorization both to construct and operate the proposed facility, subject to any conditions which may be specified in the certificate. Local regulation is preempted by the state. State agencies are to issue the appropriate permits, licenses and certificates subject only to conditions of the site certificate, though the individual agencies continue to exercise enforcement authority.

(5) Site Acquisition

The siting legislation does not provide any special means of site acquisition. The Siting Council is charged with designating areas of the state as suitable or unsuitable for use as sites for various types of energy facilities. Applications are not accepted for sites in unsuitable areas. Public utilities have the power of eminent domain for the purchase of sites.

(6) Financing

A $5,000 fee is required with each notice of an intent to file for a site certificate. This will be credited against any subsequent fees. Site certificate applications require fees of 5¢ per kW of planned maximum net electric capacity or $1,000 for each $1 million of estimated capital investment in any other proposed facility or addition. In addition, thermal power plants must pay an annual fee of 2.5¢ per kW of maximum net capacity authorized by the site certificate. Other energy facilities are assessed $300 for each $1 million of estimated capital investment. Furthermore, the state's gas and electric utilities are assessed a total of $300,000 annually on a proportional basis.

Funds from application fees are used solely for conducting studies with respect to the proposed site. Unused funds must be returned to the applicant. The annual assessments are used for the operations of the Department of Energy and the Siting Council.

f. Washington

(1) General Approach

The energy facility siting program in Washington is among the most comprehensive in that it provides for the siting of pipelines, refineries, oil ports, and transmission corridors, in addition to power plants. Responsibility for this program lies with the Energy Facility Site Evaluation Council which is composed of the administrators, or their designees, of fourteen state agencies and an ad hoc member appointed by the county legislative body with jurisdiction over the proposed site. The director of the state Energy Office serves as non-voting chairman of the council. The decisions of the council serve as recommendations to the governor, who has final authority to approve or reject site applications.

The state Energy Office is responsible for energy resource data collection, analysis and dissemination; the coordination of research and other activities; advice to and support of state agencies on energy matters; and guidelines for conservation plans. The director of the Energy Office is appointed by the governor with the consent of the senate.

(2) Long-Range Plans and Forecasts

The state Energy Office has responsibility for producing analyses of projections and/or forecasts of energy supply and demand. The legislation does not specify a time interval to be covered by such analyses or a frequency for their production, but they are to be prepared "as necessary for development of recommendations with respect to the timing of construction of additional facilities and other energy programs." There are no provisions for public disclosure of plans/forecasts; in fact, the law shows concern only for protecting the confidentiality of information, if so requested.

(3) Public Participation

The Energy Facility Site Evaluation Council holds hearings on proposed site locations.

(4) Certification Procedure

The Energy Facility Site Evaluation Council receives all applications for site certification. The council then commissions its own independent consultant study to measure the consequences of the proposed facility on the environment. Within 12 months of the receipt of an application, the council must report its recommendation to the governor as to the approval or disapproval of the application. If the application is approved by the governor, the council has 30 days thereafter to compose and submit a certification agreement for execution by the governor and applicant.

(5) Site Acquisition

Utilities do not have the power of eminent domain in Washington. Sites or options thereon are generally purchased prior to commencement of the application process.

(6) Financing

A fee of $25,000 must accompany each site application. This fee is used to fund the environmental impact study and any unused portion is returned to the applicant. Studies whose cost exceeds the fee must be approved and paid for by the applicant.

4. COMPARATIVE ANALYSIS OF STATE PROGRAMS

This section provides the means for comparing and evaluating the state energy facility siting programs previously described (Sections 2 and 3). While no critical evaluation of individual programs will be undertaken here, such efforts by appropriate state personnel and interested citizens are encouraged. The material in this section may provide the basis for such an evaluation.

a. Selected Features of State Programs

Table 7 summarizes the descriptions of 14 state energy facility siting programs. The 21 features listed are divided into six general categories: the state's general approach to siting; provisions for long-range plans and forecasts; provisions for public participation in the siting process; selected features of the actual site certification process; the various means by which site selection is achieved; and different methods of financing the siting program. The individual features under each of these categories are described below.

TABLE 7 FEATURES OF STATE ENERGY FACILITY SITING PROGRAMS

	General					Plans and Forecasts			
	Principal Agency	Types of Facilities	Local Preempt.	Relation to CZM	Conserv. Program	Public Discl.	Time Frame	Approval Process	Document. of Method.
Illinois	Commerce Commission	---	No	---	---	No	---	---	---
Indiana	PUC	---	By Em. Domain	---	---	No	---	---	---
Michigan	DNR/PSC	---	No	Unspec.	None	No	---	---	---
Minnesota	Environmental Quality Council	PP (50 MW) TL (200 kv)	Yes	Regional Zoning Preempted	Energy Agency	Yes	P=5 Biennial F=15	None	Utility
New York	Board on Electric Generation and Siting	PP (50 MW)	Yes	Unspec.	Utilities must describe	Yes	P=10	Public Hrngs.	Assumptions and data
Ohio	Power Siting Commission	PP (50 MW) Gas & Elec. Trans.	Yes	Unspec.	Utilities must show impact	Yes	P=10	Public Hrngs.	Method, Assumpt. and data
Pennsylvania	Dept. of Envr. Resources/ PUC	---	Conditional	---	None	No	---	---	---
Wisconsin	DNR/PUC	PP (300 MW) TL (100 kv)	Yes	Unspec.	Utilties must describe	Yes	Biennial P=10	Public Hrngs. Agency Review	No
California	Energy Resource Conservation & Dev. Comm.	PP (50 MW) TL	Yes	---	Cons. Div. within ERCDC	Yes	Biennial F=5,10 20	Public Hrngs. State Approval	State Specifies
Maine	Dept. of Envr. Protect.	All EF over 20 ac.	Yes	Unspec.	---	No	---	---	---
Maryland	PSC/DNR	All PP TL (69 kv)	Yes	Unspec.	---	Yes	P=10	Eval. of Sites in Plan	No
Massachusetts	Energy Facilities Siting Council	PP (100 MW) TL (69 kv) ST (500 kbbl) Others	Yes	Unspec.	---	Yes	P=10	Public Hrngs. Council Votes	No
Oregon	Energy Facility Siting Council	PP (25 MW) TL (230 kv) geotherm. PL, Solar	Yes	None	Dept. of Energy	Yes	P=5,10 20 F=1-5, 10,20	Public Hrngs. State Compiles	No
Washington	Energy Fac. Site Eval. Council	All EF	No	Shoreline Permits Preempted	State Energy Office	No	As Necess.	Energy Office Prepares	No

KEY: PP = Power Plants; TL = Transmission Lines; EF = Energy Facilities; ST = Storage Tanks; PL = Pipelines; OR = Oil Refineries; P = Plans; F = Forecasts

TABLE 7 (Continued)

Public Participation			Site Certification				Site Selection		Financing	
Agency Members	Access to Info	Public Hrngs.	One Stop	Time[1] Limits	Envr. Assess.	Alternate Sites	Site Select.	Site Acquis.	Applic. Fee	Annual Fee
---	---	Facility Certific.	No	---	---	---	Private Sector	Cond. Em. Domain	---	---
---	---	No	No	---	---	---	Private Sector	Em. Domain	---	---
---	Notice of Envr. Permit Applic.	Air Water Permits Etc.	No	---	By Exec. Order	---	Private Sector	Em. Domain	---	---
7S 1G 4PM	Yes	Criteria, Inventory, Site Certific.	Yes	PP (1 yr) TL (180)	EQC Staff	One Alt.	State Site Inventory	Em. Domain	$500/ $ million ($5000 min.)	Based on kwh + $ sales
4S 1A	Plans, Applic. for Cert.	LR Plan Pre-applic. Application	Yes	Hrng. 6-7 mos after applic.	DER as part of applic.	One Alt.	Site Suitability Criteria	Private Sector	$25,000	---
4S 1G	Plans, Applic., for Cert.	LR Plan Pre-applic. Application	Yes	2-5 yrs.	PSC/ DNR/ EPA	Four Total	Site Suitability Criteria	Private Sector	Formula for PP	---
---	Notice of Envr. Pre Applic.	Hrngs. on Envr. Permits	No	---	No Formal Requirement	---	Private Sector	Conditional Em. Domain	---	---
---	LR Plan	Plan, Site Certif.	2-Stop DNR/PUC	sm. PP + TL (150) lg. PP (480)	DNR	No	Private Sector	Conditional Em. Domain	---	---
5PM	Office of Public Advisor	Plans & Forecasts, Site Certific.	Yes Except CZ	18 mo.	Siting Agency (ERCDC)	Three Total, One Inland	Private Sector	Em. Domain	10 mills/ kw capac. ($1000 to $25,000)	.1 mill/ kwh
10PM 1S	Notice of Permit Applic.	Pre-applic. hrng, siting hrng.	Yes	Hrng. 30 da. after applic.	Part of Permit Applic.	No	Private Sector	Em. Domain	---	---
PSC Members	LR Plans EIS Sites Applic.	Applic. Conference	Yes	2 yrs. minimum	DNR	Yes	Site Inventory & Utility	By State and Utility	---	.1 - .3 mills/ kwh
4S 2PM 3G	LR Plan Notice of Intent Applic.	LR Plan Notice of Intent Applic.	Yes	PP (6 mo.) OR (1-2 yr)	Dept. of Envir. Affairs	No	Site Suitability Criteria	Em. Domain	$25,000 for PP, Complex for EF	Complex Fee on Plans & Forecasts
7PM	LR Plans	P+F Suitable Areas, Site Cert.	Yes w/ Governor	PP(24 mo) Other EF (6-12 mo)	Indep. Study Possible	No	State Desig. Suitable Regions	Condit. Em. Domain	50 mills/ kw 1% of invest.	25 mills/ kw $300/$ million
14S	Not Specif.	Site Cert.	No Local & Governor	12 mo. + 60 da. + 30 da.	Indep. Private Consult.	No	Private Sector	No Em. Domain	$10,000	---

S = State Agency Heads
PM = Public Member (Appointed by Governor)
G = Other Governor Appointee
A = Ad Hoc Member

[1] Days, unless indicated otherwise.

(1) General

These features describe the methods which each state employs to accomplish energy facility siting.

(a) Principal agency

This column lists the one or two agencies with primary responsibility for energy facility siting. Common abbreviations are used.

(b) Types of facilities

This column indicates the types of facilities regulated by the state siting agency. A blank indicates that any regulation of siting is simply a part of the utility regulation process and not addressed specifically by the state. Minimum sizes are indicated for power plants (PP), transmission lines (TL), and petroleum storage tanks (ST) where appropriate. Oregon includes pipelines (PL), geothermal facilities and solar collectors among its regulated facilities.

(c) Local preemption

This column indicates whether or not local zoning laws are preempted by the state in energy facility siting. In Indiana, the utilities' power of eminent domain supersedes local zoning and utilities are generally unrestricted in their site selection. In Pennsylvania, the commonwealth may grant eminent domain powers that override local zoning restrictions.

(d) Relation to CZM

This column specifies what, if any, relationship exists between the regulation of energy facility siting and the management of the coastal zone. At present, only California provides for coordination between the agencies responsible for coastal zone management and energy facility siting. This is expected to change as other coastal states develop their coastal zone management programs.

(e) Conservation program

One approach to the regulation of siting involves efforts by the state to reduce the demand for sites by reducing the demand for energy. The state itself may assume an active role in conservation or it may require that industry implement conservation programs.

(2) Long-Range Plans and Forecasts

The construction plans and demand forecasts of the energy industry are important to the siting process. The states have various ways of handling plans and forecasts.

(a) Public disclosure

This column indicates whether or not industry plans and forecasts are made public. Such plans and forecasts are generally required of those industries whose siting is regulated by the state. The law in Washington allows the state siting council to obtain information from the industries but does not provide for public disclosure of that information.

(b) Time frame

The period to be covered by the required plans (P) and forecasts (F) is indicated. Forecasts are often included as part of a plan where only the latter is indicated. Plans/forecasts are to be submitted annually unless otherwise indicated.

(c) Approval process

The means for approving plans/forecasts is indicated in this column. Approval implies that the plan will assume a formal role in the regulation of siting, such as a requirement for subsequent siting proposals to conform with the plan.

(d) Documentation of methodology

This column indicates the means by which the forecast methodology is documented. The state either requires that the forecaster describe his methodology, including the data and assumptions employed, or the state may specify the methodology to be employed.

(3) Public Participation

The states provide a variety of devices for involving the public in the siting process. The previous section (Plans and Forecasts) implies some public role in the states with regard to disclosure of long-range plans and the requirement for public hearings on the approval of plans. Additional public participation is indicated in this section.

(a) Siting agency members

This column shows the composition of the state energy facility siting council. The council usually includes public members appointed by the governor (PM) or representatives of state agencies (S). Other governor appointees (G) represent special interests, and New York provides an ad hoc member (A) to represent the locality in which a site is being considered for approval.

(b) Access to information

This column indicates the provisions for keeping the public informed on various aspects of the siting process.

(c) Public hearings

This column indicates whether public hearings are held, and if so, for which aspects of the siting procedure they are held.

(4) Site Certification

This section is comprised of selected features of the actual site certification process.

(a) One-stop siting process

An affirmative response here means that a single agency has responsibility for site certification. Facility certification may be performed separately by the public utilities commission, the department of natural resources, or the environmental protection department.

(b) Time limits

This column indicates the period of time alloted for the site certification process from the receipt of the application through final approval. Other time frames are specified where appropriate. This time may be different for power plants (PP), transmission lines (TL), oil refineries (OR), or other energy facilities (EF).

(c) Environmental assessment

The entity responsible for the assessment of environmental impacts on proposed sites is listed in this column.

(d) Alternate sites

This column indicates requirements for the proposal and consideration of alternate sites as opposed to an application for approval of a single site.

(5) Site Selection

This category is divided into two components; site selection and site acquisition.

(a) Site selection

This heading refers to the choice of a site or sites to be proposed for construction of an energy facility. The private sector (utility, etc.) is usually free to find and propose sites, but some states have chosen to enter the process at this early stage. The state may establish criteria for the selection of sites or take a more active role in the process.

(b) Site acquisition

Eminent domain is generally provided to regulated utilities while other energy industries must purchase sites on the open market. Eminent domain powers may be conditioned upon site certification.

(6) Financing

The two common methods for financing the energy facility siting program are the application fee and the annual fee.

(a) Application fee

This is a fee assessed with each application for site approval. The fee may be based on the proposed capacity or cost of the facility.

(b) Annual fee

The annual fee is used to finance general agency functions and is often based on annual electricity production, either in terms of kilowatt-hours or dollar value or both.

(b) <u>Evaluation Criteria</u>

This section will suggest a set of criteria by which siting regulation programs may be evaluated. These criteria have been drawn together from a variety of sources. Most of them, rather than specifically addressing energy facility siting, focus on some aspect of public sector decision making.

(1) Resolution of Conflicts of Interest

The program should prvide for the resolution of conflicts among all interests. Government should seek to identify and provide for the public interest, which in this case may be considered to consist of several special interests, including the assurance of a reliable supply of energy and the protection of the environment. There are also components of the public interest concerned with economic matters (e.g., low utility rates, return on investment by utilities, etc.) and environmental sub-interests related to the coastal zone. These interests and others must all be considered together and balanced against one another in the siting of energy facilities.

Conflicts have arisen over the use of different types of fuels due to the inherent interrelationships among the various forms of energy and predictions of scarcity, both real and artificial (e.g., an oil embargo) of certain forms. The production of electricity may entail the use of fuels better used for other purposes, and electricity itself becomes a form of energy that is interchangeable to some degree with various fuels. The issue of energy use as opposed to conservation is also one that states may choose to address.

(2) Accountability to the Public

Those responsible for energy facility siting regulation should be accountable to the public and responsive to public needs and desires. Maximum accountability is achieved through direct popular election, though this method may be unacceptable for other reasons. Provisions to assure accountability of appointed decision-makers include the accountability of the appointer and restrictions on the previous or subsequent employment of decision-makers by those regulated. An open decision process is also essential.

Open decision making also promotes responsiveness. The process should afford meaningful public input at public hearings and through workshops, advisory councils, and, perhaps, representation on the decision-making board. Responsiveness is further enhanced by public access to information in a timely fashion.

(3) Effective Planning Mechanism

The process should include an effective planning mechanism. To plan effectively, decision makers require both information and the authority to implement plans. Information includes the long-range plans and forecasts of energy suppliers and independent (state) data collections and analysis for economic and environmental impacts. Effective planning requires knowledge of how each energy facility will fit into the ultimate energy scenario for the state at some future date. The effect of today's decisions on limiting future choices must be considered.

(4) Coordination with Other Programs

The facility siting program should be coordinated with other energy and land use programs. Facility siting should account for the inherent interrelationships and interchangeability among all forms of energy. An overall energy policy which addresses alternative uses of fuels, innovative technologies, and conservation should be developed at the state level and coordinated with facility siting. Siting should also be coordinated with programs affecting land use in critical areas or the coastal zone or general programs for the siting of large facilities.

(5) Regional Needs

Energy facility siting should provide for regional needs. The site certification process should preempt local zoning and other local land use authority in order to assure a more rational program based on issues other than local in nature. Energy facilities require consideration of regional, state, interstate and national needs and resources.

(6) Environmental Protection

The siting process should specifically address protection of the environment, especially the coastal zone. Protection of unique and fragile ecosystems should be a primary concern in energy facility siting. The coastal zone is a small portion of total land area but is subjected to the greatest developmental pressures. The unique ecological, recreational, and aesthetic aspects of the coastal zone require special consideration and protection in any program for energy facility siting.

(7) Energy Supply

The siting process should facilitate provision of an adequate supply of energy. The process should commence sufficiently in advance of planned construction to preclude delay in the availability of new sources of energy. Time limits should be established for the various phases of the process. "Generic" issues common to several facilities or sites should be resolved in advance of the siting process to obviate repeated consideration and arbitrary decisions.

(8) Funding

The energy facility siting program should be adequately funded. The effectiveness of the program should not be constrained by a lack of resources. A permanent staff should provide information on environmental, economic, and other issues to promote consistency and expertise in the siting process.

5. IMPLICATIONS FOR POLICY OPTIONS

The existing institutional arrangements governing energy facility siting in the Great Lakes Basin have several significant implications for the kinds and ranges of options that can realistically be implemented by the states. At the federal level, the policies and performance standards of the Clear Air Act and the Federal Water Polluction Control Act are of fundamental importance to siting. Options available to the states with regard to federally established environmental protection standards are subject to a one-way flexibility; the states cannot institute standards less stringent than those mandated by the U.S. EPA. The Coastal Zone Management Act of 1972 as amended, which is ultimately administered by the states, contains several provisions of primary concern to this study. Most of these provisions, however, have not been sufficiently studied to justify definitive statements as to their influence or value. Other federal agencies concerned with energy facility siting operate under their own legislative mandates and policies. However, under Section 307 of the CZM Act, these agencies are required to insure and demonstrate that their actions are "consistent" with approved Great Lakes State CZM programs. Consideration must also be given to the siting of facilities that are in the national interest. Thus, it behooves the states to consider a broad range of alternative institutional mechanisms with which to implement policies for the siting of energy facilities in the coastal zone.

The preceding overview of state regulation of energy facility siting indicates that an extremely wide range of factors is at play in determining the overall regulatory climate. The policies, programs, legal authorities, and social institutions that operate within each state will ultimately determine those options that are easily implementable, those that will require significant changes in the existing institutional framework, and those options that are simply not feasible. The wide variety of approaches to energy facility siting regulation exhibited by the Great Lakes states, coupled with the fact that is unrealistic to restrict energy facility siting regulation to the coastal zone management program, dictate that the range of options for institutional arangements developed later in this report should be broad in scope.

In view of these considerations, an attempt will be made, to the extent practicable, to tailor institutional options to the specific policies, programs, legal and organizational arrangements, discussed above. However, it is clear from the preceding institutional overview that the feasibility or attractiveness of any set of options will vary a great deal from state to state. A detailed analysis of the implications of each option as applied to each of the Great Lakes states requires an intimate familiarity with the situation current in these states, and is beyond the scope of this report. Rather, it is intended that the institutional options presented will provide a broad-based framework of consideration from which skilled, informed individuals at the state level will select elements for indepth analysis.

One very significant implication underscored by this institutional overview clear to all those involved in energy facility siting, is that there is a pressing need to design regulatory processes that are streamlined, operate efficiently and are capable of insuring decisive action on proposals within well-defined time periods. However, no process can be successful in the long run unless adequate measures are incorporated to insure consideration of the full range of public and private concerns for energy facility siting and management of coastal area resources.

One final point should be addressed in this discussion. The primary focus of this study is the siting of energy facilities in the coastal zone. Thus, policy initiatives in this area by coastal states are of particular interest. A concerted effort was made to identify such initiatives in the states analyzed in this overview. In addition, several other coastal states were contacted for this purpose. The conclusion that can be drawn is that, in general, the adoption of policies by coastal states to guide the siting of energy facilities in the coastal zone is at an early state of development. Several state CZM programs are currently engaged in this activity, but have not as yet produced material useful to this study.

Chapter IV

TECHNICAL CONSIDERATIONS

A. ENVIRONMENTAL AND ECONOMIC FACTORS AFFECTING THE SITING OF ENERGY FACILITIES, AND ANALYSIS OF COASTAL DEPENDENCE OF FACILITIES

1. INTRODUCTION

a. Purpose

This section reviews the technical factors, both environmental and economic, which determine the eventual location of energy facilities, and summarizes the impacts associated with these facilities once they are sited. Also, it is the intent of this section to determine the degree to which these facilities are dependent on coastal resources and locations, based on the technical factors mentioned above. These findings will then provide the basis for the development of technical policy options for the future siting of energy facilities in the coastal zone.

b. Scope

The energy facilities which have been considered for this report are those involved with electrical energy generation, fuel transshipment and storage, and fuel production. Specifically, they are fossil-fuel (coal) and nuclear generating plants, coal and oil transshipment and storage facilities, and petroleum refineries. Emerging technologies which may significantly affect these facilities within the time frame of this report (15-20 years) have been included with the facility descriptions.

c. Study Approach

The coastal dependence analysis is carried out in several phases. Considerations associated with the site selection process for energy facilities are outlined in general. The facilities are individually described and their specific siting requirements and considerations summarized. Next, the environmental and economic impacts associated with the construction, operation and maintenance of each of the facilities is reviewed. A facility cost analysis follows which highlights the relative costs of the essential components of each facility and indicates how these costs may vary with location.

Following these three sections of background information and analysis is a discussion of those factors determined to be most significant with regard to the question of coastal dependence. In conjuction with this discussion is the presentation of a case study that attempts to relate the identified coastal dependent factors to the final siting decision for a proposed (and approved) energy facility. Finally, the implications of this coastal dependence discussion are summarized as they may relate to the technical policy options which the coastal zone management programs of the eight Great Lakes states may consider in the formulation of their individual energy facility siting policies.

d. Definition of Coastal Dependency

In determining the relative dependence of an energy facility on a coastal location, it is important to understand what is meant by the term coastal dependence. To provide latitude for analysis and consideration, yet remain within the confines of the study objective, the following definition was adopted.

> The determination of energy facility location with respect to the lake shore as expressed through the following general considerations; system requirements, safety, engineering, environmental, institutional, and economic.

This definition broadens the analysis beyond simple dependency into a more general facility location examination. By maintaining reference to the lakeshore, however, the intent of coastal zone management, and the role of the state coastal zone programs may be more readily addressed.

2. GENERAL SITING CONSIDERATIONS

A review of procedures for siting energy facilities has resulted in the selection of six general considerations which appear to be applicable, in a broad sense, in the planning and location of all of the selected energy facilities addressed in this report. The ordering of the considerations should not imply a priority rating, as the considerations will vary in their importance depending on the facility (e.g., safety will be a higher consideration for the siting of a nuclear plant than for the location of a shipping port). Nevertheless, certain facets of each of the six considerations will contribute to the eventual selection of any energy facility site [174].

a. System Planning

Included in system planning are considerations given to territorial responsibilities of public utilities, geographical locations of projected load, coordination with system transmission plans, and location with respect to the fuel source and transportation routes. Production and/or storage capacity of the proposed facility is coordinated with these systems considerations in order to meet demand requirements.

b. Safety and Reliability

Safety considerations include the location of population centers and associated population distribution and density, seismological and geological restrictions on foundation locations, and potential lake or riverine flooding. As stated above, safety considerations are applied most heavily to siting of nuclear energy facilities to reduce potential radiation threats. In addition, safety considerations are applied to fossil-fuel plants, refineries, and gasification and liquefaction plants, with regard to air and water emissions and the resultant health and safety of the population centers. Lake and river flooding are important safety and reliability considerations in the siting of plants. Likewise, geological and seismological factors are both safety and reliability considerations.

c. Engineering

Engineering considerations are numerous and extremely site- and facility-specific in their application to overall siting criteria. However, several general aspects of engineering feasibility may be applied to the siting of energy facilities. These would include water supply, accessibility to transportation routes, soil and/or bedrock conditions, topography, and facilities design. Water supply and coal delivery are the most important of the engineering considerations in the siting of energy production facilities. Water supply is a determinant of the cooling method alternatives that may be considered.

d. Environmental

Perhaps the most recently developed and most important considerations in terms of their widespread applicability are the variety of factors which fall into the environmental category. Enacted primarily via the provisions of the Environmental Policy Act of 1969, environmental siting criteria have come to the forefront of considerations in the overall site selection procedure for energy facilities. Among these considerations are the dedicated lands, environmentally sensitive areas, surface and groundwater hydrology, meteorology, aesthetics, and public attitudes. Associated with these are the various air and water quality considerations which must be investigated regardless of the type of energy facility. Thus, consideration must be given to present and potential land uses and the potential land uses and the potential environmental impacts of a proposed facility.

e. Institutional/Regulatory

Siting considerations within this category refer to all of the regulatory requirements which must be met in both the siting procedure and the final site selection and facility construction and operation. These include all local (where applicable), state, and federal regulations and requirements applying to enviornmental standards, water resources, land use, transmission and transportation routes, economic development, and activity-specific policies.

f. Economics

There are three primary cost considerations to be weighted when looking at the economics of energy facilities: the cost of system planning considerations, the cost of engineering considerations, and the cost of environmental and social considerations [174]. These may be very site specific. The system planning costs include factors such as transportation routes, access to the site, and the transmission line location. Engineering costs are concerned with excavating, building, and operating the facility. In this report, costs related to different cooling systems and transmission lines will be evaluated. Environmental costs are concerned with mitigation of air, water, and land quality problems, while social costs and benefits are concerned with sociological effects, land values, fiscal effects, local economic effects, and public acceptance.

3. FACILITY DESCRIPTIONS AND SITING REQUIREMENTS

a. Fossil-Fuel (Coal) Power Plants

(1) Description

The facilities considered in this section are base load electrical power generating plants that burn fossil-fuels to generate steam. Because it is likely that the majority of future fossil-fuel power plants in the Great Lakes Basin will use coal as their primary heat source, discussion is limited to such facilities. In developing the siting consideration presented below, it has been assumed that present technology will be employed in the design and operation of new plants built in the time frame of this study. A discussion of how new technologies might affect these considerations is included at the end of this section.

The analysis of the fossil-fuel power plant is based on a 1,000 megawatt electrical output (MWe)* capacity coal-fired unit with a plant life of 35 years. It is further assumed that this unit operates at 38 percent efficiency with a capacity factor of 65 percent on an annual basis. It is recognized that the present trend is toward multiple-unit complexes with total outputs in the range of 1000 to 2000 MWe, with some as large as 3200 MWe (e.g., the Monroe facility operated by Detroit Edison). While the site requirements are developed for only one such unit, problems related to scaling the facility up are also addressed.

Figure 1 shows a simplified schematic diagram of a fossil-fueled generating system [222]. In actuality, a modern steam-electric plant is much more complex than Figure 1 suggests, "with a number of steam cycles operating at different temperatures and pressures and driving several high and low pressure turbines mounted on the same shaft as the generator" [451; p.54]. For the purposes of this study however, the information in Figure 1 will be sufficient.

(2) Site Requirements

In addition to the general site selection criteria discussed previously there are several specific site requirements considered in choosing a site for a major new coal-fired power plant. These are discussed below, with quantitative estimates of resources (land and water primarily) required given where appropriate and available.

(a) Land requirements

The amount of land required for a coal-fired power plant depends on

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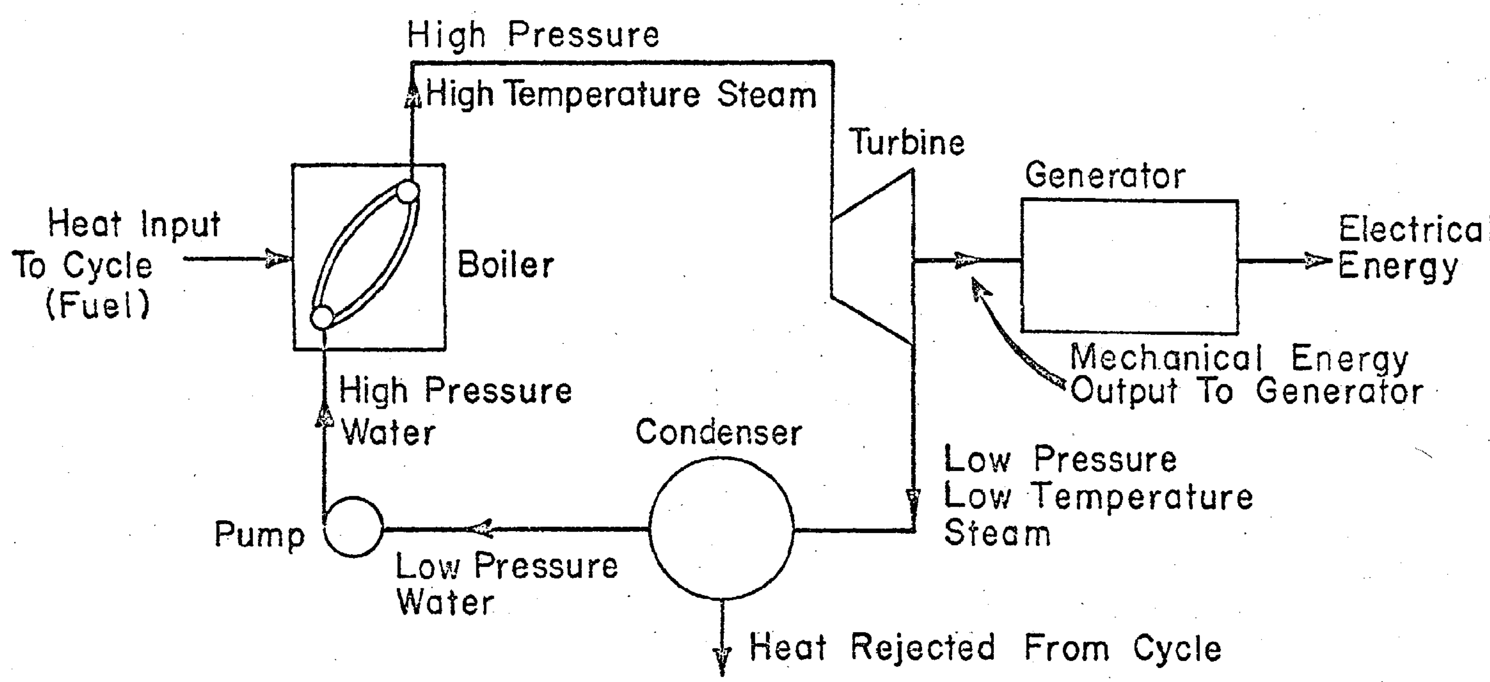
* MWe refers to the electrical output capacity of the facility. This is distinguished from MWt, the thermal energy equivalent, which represents the total energy produced by the combustion of the fuel. The 1000 MWe figure assumed for a fossil-fueled power plant would be a very large facility by today's standards (a single unit plant may be 800 MWe). The selection of 1000 MWe should not be seen as advocating a larger unit size for coal-fired plants. It was selected for convenience and comparative purposes only.

FIGURE 1

SCHEMATIC OF A FOSSIL FUEL (COAL) POWER PLANT



[Source - 222]

several factors: onsite requirements for fuel handling and storage, setting (urban or rural), solid waste disposal techniques, cooling system type, possible multiple use of parts of the site, and ultimate plant capacity [203, 451].

Land required for the actual powerhouse (boilers, turbines, generators, and condensers) itself is quite small, amounting to less than 5 acres for the 1000 MWe facility considered here. In addition parking lots, office space, and emission control devices require approximately 5 acres, bringing the total to about 10 acres (estimated from information in 451).

An important determinant of site size is the fuel handling and storage system. Generally, there are two coal storage areas, one that provides the feed to the combustion chamber, the other holding a larger reserve supply to allow the plant to operate through fuel supply interruptions. While reserve requirements vary, in the Great Lakes Region, a six-month reserve supply is generally maintained to allow for winter disruption of the shipping season [526, 539]. Facilities not dependent on lake-borne coal deliveries also maintain reserve supplies, but may be enough for only 90 days of operation [203, 451]. Six-month and 90-day reserves for a 1000 MWe facility would require about 50 acres and 25 acres respectively. The size of this coal storage area will vary with plant size, so that a multiple unit facility would require proportionately more land for storage. A linear relationship between plant size and storage area can be assumed if pile heights remain constant (e.g., a 2000 MWe plant would require twice the storage area of a 1000 MWe plant).

Ash disposal is another major factor in determining the site size required for a coal-fired plant. Coal burned in large plants in the Great Lakes Region had an average ash content of 11 percent in 1973 [192]. Estimates based on a 3000 MWe facility indicate that 300-400 acres would be required for ash disposal, assuming a 35-year plant life and an average pile depth of 25 feet [first cited in 442]. This gives an incremental requirement of 0.0033 acres/year/MWe for ash disposal. For the 1000 MWe facility considered in this study, a total of 100 acres to 130 acres would be needed over the life of the plant.

The above discussion does not take into account the potential for fly ash recovery and reuse. A study [cited in 451] by the Edison Electric Institute indicated that 17.4 percent of the fly ash generated nationally was reused. Possible uses include backfilling mines, neutralization of acid mine water, use in automobile tires and cement, and construction fill [451].

Another solid waste disposal requirement is additional land for sulfur dioxide control wastes. If a throwaway system (a system in which the adsorptive material is used only once, such as limestone scrubbing) were used, the land required for waste disposal would be increased by 100 to 200 percent [442]. Also, additional land for limestone receiving and storage would be needed.

The final important consideration in determining the land required for a coal-fired power plant is the cooling system used. A 1000 MWe plant of the type considered here would reject 3.62×10^9 Btu/hr of waste heat on an annual basis. Of this, 90 percent (3.26×10^9 Btu/hr) is dissipated to the cooling water through the condenser, with the remaining 10 percent lost up the stack. The acreage required for each of the cooling system alternatives considered here for a 1000 MWe plant are [from 203]:

• Once-through	1 acre
• Natural Draft Tower	10 acres
• Mechanical Draft Tower	45 acres
• Spray Canal	100 acres
• Pond	2,000 acres

Transmission lines (on-site) and switchyards will add about 10 acres more to the total land required.

Based on the information presented above, a 1000 MWe coal-fired power plant will occupy from 145 to almost 2,500 acres depending on the cooling system used, SO_x waste disposal, and coal reserve size. "Typical" configurations and their site sizes are given below:

- Once-through cooling, 6-month coal supply (50 acres) onsite ash (120 acres) and SO_x waste (200 acres) disposal. . . . . 395 acres

- Natural draft cooling towers, 6-month coal supply, onsite ash and SO_x disposal. . . . . 405 acres

- Mechanical draft towers, 90-day coal supply, 20% ash utilization (removed from site), no SO_x waste disposal. . . . . 190 acres

- Spray canal cooling, 6-month coal supply, onsite ash and SO_x waste disposal . . . . . . 495 acres

These figures do not take into account multiple use areas, buffer zones to shield the plant from general view, transmission line rights-of-way, or anything else beyond the factors discussed above. However, they do compare well with figures prepared for a conventional plant both with and without SO_x scrubbing systems--640 and 435 acres, respectively [222].

(b) Location with respect to population

Unlike the case for nuclear facilities, there is no explicit exclusion or isolation requirement for coal-fired power plants. They can, therefore, be located near to population concentrations and, in fact, have been so in most cases in the past to meet system requirements and to take advantage of reduced transmission costs. However, while there may not be specific regulations regarding isolation, it should be apparent from the above discussion regarding land requirements that in many cases such isolation is necessary; the expense of procuring storage land in urban areas might offset the savings of reduced transmission distances. In addition, public health problems related to air quality may force plants to locate away from metropolitan areas (see Section IV.A.4.C.1). Finally, aesthetic considerations and other factors that influence public acceptance may necessitate isolating new facilities from large population centers.

(c) Water requirements

As mentioned above, a 1000 MWe coal-fired power plant with the operating characteristics assumed here (65% plant capacity, 38% efficiency) would reject 3.62×10^9 Btu/hr. annually. The purpose of the cooling system is to absorb a large part of this excess heat and dissipate it to a large receiving body (the atmosphere, a river, lake, or ocean). There are three basic elements common to all systems [441]:

- An intake for supplying cooling water to the power plant
- A condenser where turbine exhaust steam is condensed at low temperature and low pressure while transferring waste heat to the cooling water
- A device for transferring this waste heat to the atmosphere (and finally to the ultimate sink--outer space).

The amount of water that must flow through the condenser is determined by the amount of heat rejected by the plant and by the temperature rise desired in the cooling water. Figure 1 [from 441] shows the relationship between these factors. Based on the fossil fuel plant characteristics shown in Figure 2, a 1000-MWe plant would require the following cooling water flow rates for the accompanying temperature rise:

Temperature Rise (Δt)	Flow (cfs)
30°F	600
20°	900
10°	1,800

As these figures show, the flow across the condenser rises in direct proportion to the decrease in Δt.

As discussed in the section on Land Requirements, five alternative cooling methods are considered for this report: once-through or open-cycle; natural draft wet cooling towers; mechanical draft wet towers; spray canals; and cooling ponds. The last four systems are termed closed-cycle because most of the cooling water is recycled through the system in a loop configuration. Not considered explicitly in this study were the combination systems, which utilize an off-stream device, such as a cooling tower, to cool the water prior to returning it to the source waterbody. These three cooling configurations are shown in Figure 3. In addition, Figure 4 shows simplified cross-sectional views of three of the closed-cycle devices: natural draft towers, mechanical draft towers, and spray canals.

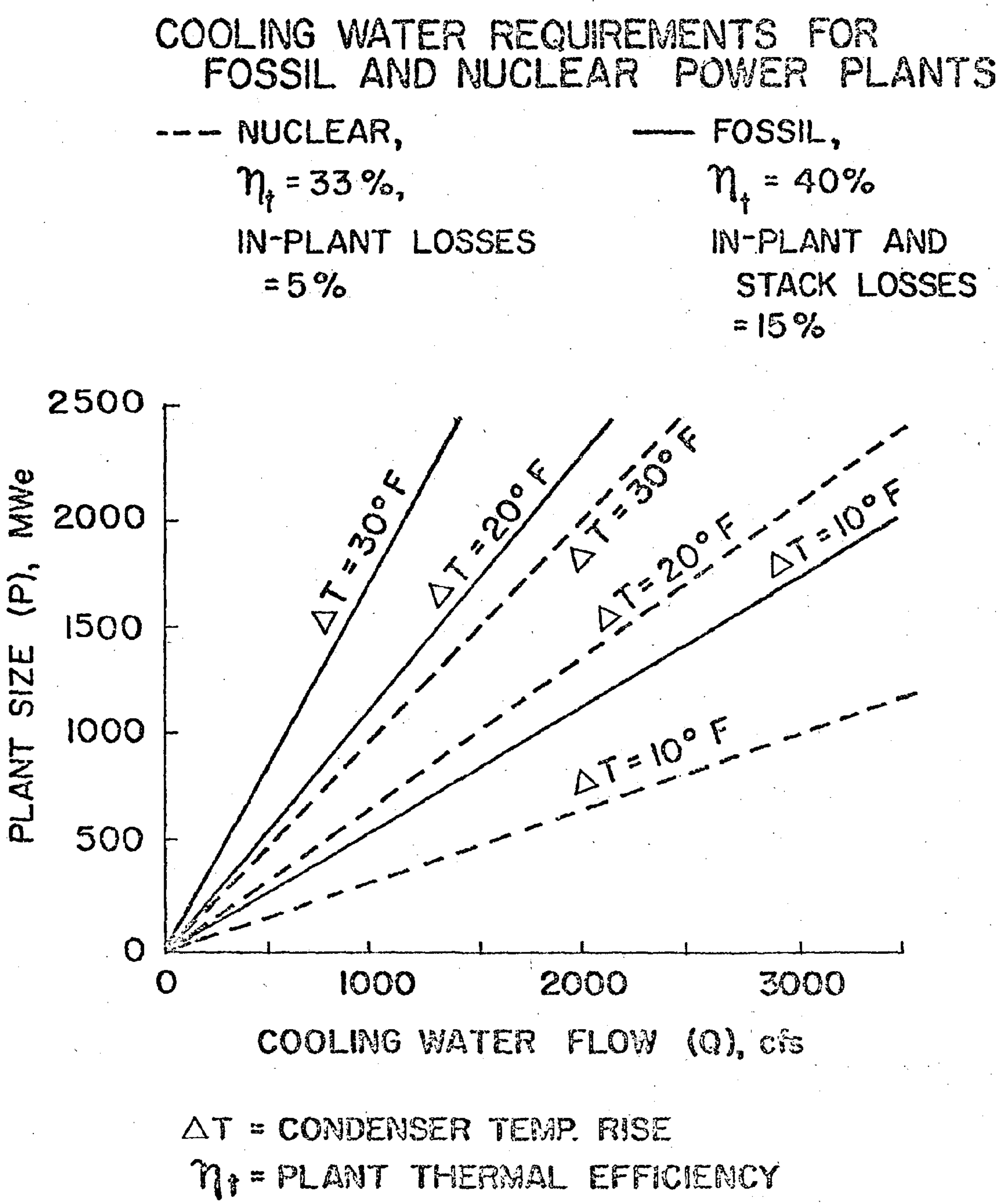
Two water use requirements are important for the plant cooling system: total withdrawal and amount consumed. In a once-through system, consumption is quite small, but withdrawals must equal the flow across the condenser, generally 1000 cfs (450,000 gpm) or more. In closed-cycle systems, the consumption is more significant, although withdrawals are limited. The figures in Table 8 show representative values for evaporative losses for a 1000-MWe fossil-fuel plant.

Makeup water for evaporative losses is only a portion of the water requirement for a closed-cycle system. Another important consideration is blowdown water replacement. Blowdown is that portion of the cooling water removed to prevent an undesirable buildup of dissolved and suspended solids.

> The blowdown (B) is a function of the available makeup (B+D+Ev) water quality and is related to evaporation (Ev) and drift [water lost in droplet form] (D) in the following manner:
>
> $$C = (B+Ev+D)/(B+D)$$
>
> In this equation, C = cycles of concentration: the number of times the concentration of any constituent is multiplied from its original value in the makeup of water [441; pp. 24-25].

FIGURE 2

COOLING WATER REQUIREMENTS
FOR FOSSIL AND NUCLEAR POWER PLANTS



[Source - 441]

FIGURE 3

ALTERNATIVE COOLING SYSTEM CONFIGURATIONS

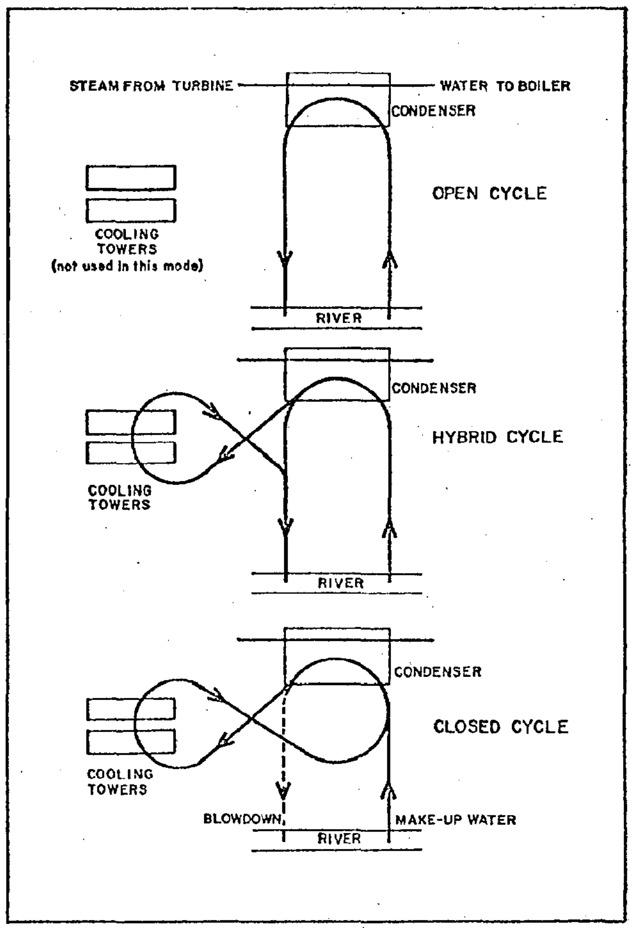


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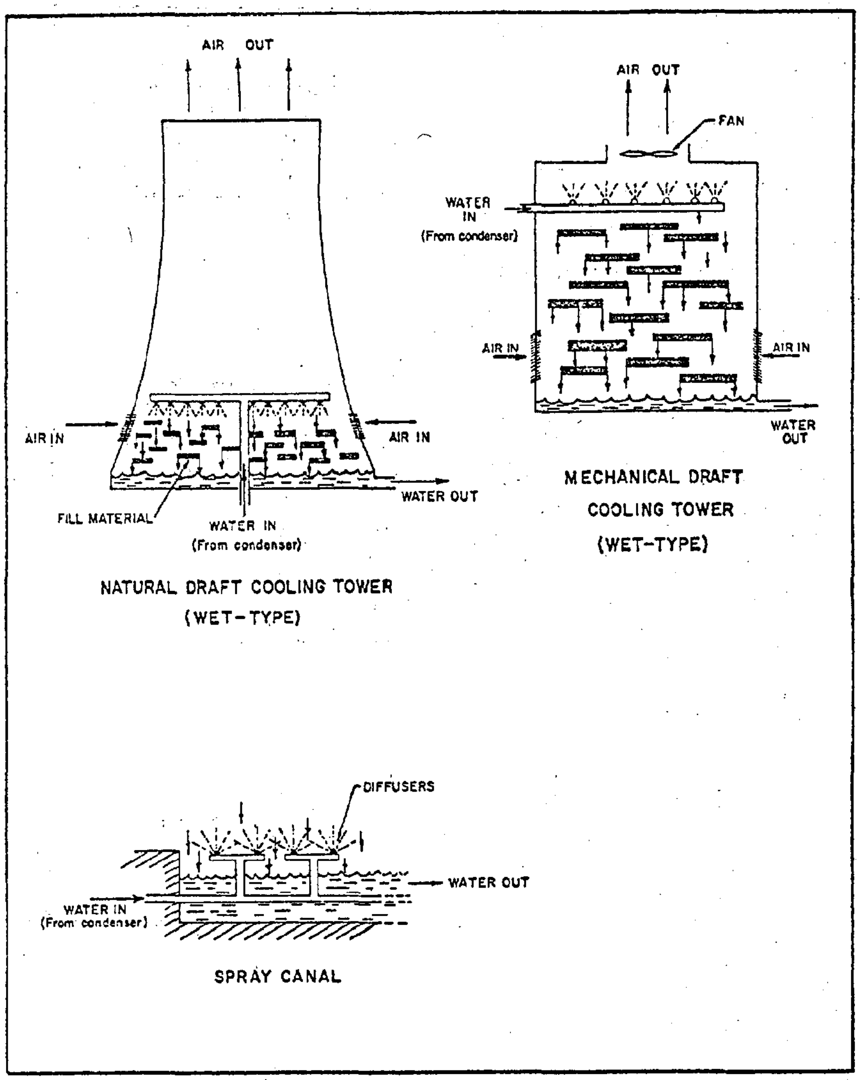
FIGURE 4

CROSS-SECTIONAL VIEWS OF
THREE COOLING DEVICES



[Source - 451]

TABLE 8

COOLING WATER EVAPORATIVE LOSSES

COOLING SYSTEM	EVAPORATIVE LOSS GPM	EVAPORATIVE LOSS CFS
Once-Through	390[1]	0.9[1]
	0[3]	0[3]
Natural Draft Tower	630[1]	1.4[1]
	3502[2]	7.8[2]
	950[3]	2.1[3]
Mechanical Draft Tower	630[1]	1.4[1]
	3800[2]	8.5[2]
	950[3]	2.1[3]
Spray Canal	3700[2]	8.2[2]
Pond	472[1]	1.1[1]
	5250[2]	11.7[2]
	1410[3]	3.1[3]

1 [78]
2 [203]
3 [222]

As C increases, blowdown makeup decreases. The values below are representative of this relationship (based on Ev = 21.4 cfs and D = 0.05 cfs):

C	B (cfs)
1.2	107
2	21.4
5	5.3
10	2.3
20	1.1

[441; p.27]

In summary, water withdrawals can range from approximately 9,300 gpm (21 cfs) to 800,000 gpm (1,800 cfs), depending on the temperature rise and cooling system used [203]. Site selection depends on a water supply adequate for normal plant generations as well for long-term low-flow conditions. For once-through systems, plants are limited to locations where large quantities of lake water are economically available. There are few river locations in the basin adequate for even closed-cycle plants.

(d) Transportation access

Transportation access requirements for coal-fired power plants relate primarily to fuel delivery and, in some cases, waste disposal, if disposal is off-site. However, it is also important during the construction phases for movement of workers, heavy equipment, and materials to the site.

Coal deliveries to the plant are generally made either by rail or water (ship or barge). Because a modern 1000-MWe plant may require 8,000 to 10,000 tons of coal per day, delivery by truck, except at minemouth plants, is usually done only to supplement rail receipts. For the scale of facilities discussed in this report, trucks cannot provide sufficient deliveries to make them the primary suppliers.

Another delivery system not considered to be a major factor in future coal movement to plants in the Great Lakes Basin is the slurry pipeline. While coal slurry pipelines can be used to move large volumes of coal over long distances,* the easy availability of cost-competitive alternatives in the basin makes the development of such a system unlikely.

The most common rail delivery system is a dead-end line into the plant with 75-120-car-unit trains (100 tons per car) used to move the coal from the mine to the plant [221]. Approximately 200 trainloads per year would be required, or one every day-and-a-half for this study's generalized 1000-MWe coal-fired plant. By designing the unloading facilities around the train configuration it is possible to reduce operating costs as well as provide a continuous supply of coal. In addition, the reduced turnaround time means lower freight rates, important in the economics of large coal plants [221].

Receipt of coal via water borne carriers requires a site with harbor access. A naturally deep harbor in which extensive dredging can be avoided is ideal, although suitable harbors can be developed if necessary.

Barges with capacities in the range of 500 to 3,000 tons draw up to 12 feet of water. A 1000-MWe plant should have "harbor, docking, and unloading facilities capable of handling 3 to 7 barges per day" [221; p.13]. Gravel-filled sheet pile cells with barge unloading cranes on 80-100-foot centers providing 600-1,000-foot long docks are generally used [221].

Movement of coal by lake vessel is an important alternative in the

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* At present, the largest planned slurry pipeline will deliver 330 tons of pulverized coal slurry per hour over a distance of 275 miles.

Great Lakes basin. For example, the proposed Belle River plant (Detroit Edison) would receive western coal from Superior, Wisconsin by lake vessel; "these freighters will have a capacity of 45,000-60,000 tons and unload at a rate of approximately 7,000 tons per hour" [526; p.47]. These large carriers, requiring drafts up to 26 feet, can provide large volumes of coal per delivery, reducing the need for a constant stream of coal to the site. In addition, many of these vessels are self-unloaders, obviating the need for extensive dockside works (see the section of Coal Transshipment and Storage Facilities for a more complete description).

It is desirable to provide dual access by rail and water. There are two important reasons for this. First, there may be some uncertainty as to the long-term (over the life of the plant) source of coal as environmental and economic conditions change. Second, there is a need to protect against possible work stoppages in one mode that could cause fuel shortages. Thus, while either mode may provide sufficient delivery capacity for the facilities considered here, it is desirable to maintain options for both.

It is also desirable to locate near the existing bulk transmission system. The existence of a major network of EHV and UHV (765#V) transmission lines constrains, to some extent, the location of major new generating facilities. The desire to reduce costs while maintaining a high levels of reliability and flexibility makes tie-ins to the existing system generally preferable to the construction of major new carriers. There are, of course, exceptions when system expansions are desired or when current capacity is reached.

(e) Seismology and geology

There are no special geologic of seismological requirements for the siting of coal-fired plants other than that a satisfactory foundation for the plant structure be available and that there should be no active faults.

(f) Hydrology and meteorology

The most important meteorological requirements relate to the dispersion of air pollutants generated by the facility. It is important that account be taken of prevailing winds and that the facility be sited so that particulates and other pollutants will not be blown to nearby population concentrations.

The most important hydrological requirements are related to the cooling system requirements. Generally, for consumptive uses of stream water, the average withdrawal rate should be no greater than one-third of the 10-year-7-day low flow. In addition, the thermal effluent receiving body should be capable of rapidly dispersing the heated return flow. Finally, the receiving body must be able to adequately dilute and disperse the blowdown effluent.

Other hydrological requirements relate to the protection of surface and ground-water resources against contamination from other sources: leachates and runoff from the coal storage and waste disposal areas, storm runoff from the plant in general, and sanitary wastes from the plant water supply system.

(3) Environmental and Other Considerations

In addition to the resource requirements discussed above, there are several additional factors that enter into a facility siting decision. One such factor is the availability of sites previously acquired by the utility. Major utilities keep an inventory of facility sites purchased in the past for future plant development. Then, as new capacity additions are required, the utility will look first at these sites to determine which, if any, are suited to the proposed addition. It is important to remember that many of these sites were purchased ten or more years in the past, when site selection criteria and plant design were somewhat different than today. Thus, it is likely that some of these available sites might not be suitable by today's standards.

Another factor that is especially important in siting fossil-fuel plants is ambient air quality. The construction of new base load capacity will be limited only to those areas where ambient conditions with the new facility meet national standards.*

Overall environmental impact of the facility will also influence the location decision process. A site will be selected that minimizes impacts on aquatic and terrestrial ecosystems. This includes avoiding (or preserving) fragile habitats, locating away from sensitive areas, etc. Clearly, this policy has not been followed in all cases in the past. However, as environmental reporting and analysis standards became more defined and stringent, these considerations will become more important. One result of this effort has been the increase in multiple purpose site planning by the utilities, providing public access to certain areas of the site for recreational activities (this is more common on nuclear power plant sites).

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* See discussion of EPA for details of air pollution control program, Chapter III.

A final consideration is public acceptance of the proposed facility. This aspect of the facility planning process is becoming more and more important. To a large extent, the mitigation of public opposition is tied to the environmental sensitivity demonstrated in selecting the site and preparing the site plan. Opposition can also be reduced by public involvement in the site selection process. Many of the policy options described in this study are designed to minimize this opposition, resulting in a better, more holistic facility siting process.

(4) Emerging Technologies

Within the time span of this study (15-20 years) there are not expected to be any major new technological breakthroughs in the generation of electricity from fossil fuels. Those technological advances that do occur will be based on presently demonstrated technology applied to large-scale operations. Even then, these changes would not be seen until the mid-1980's.*

Areas in which changes can be expected to occur in the near- to mid-term are fuel combustion, power conversion, and air quality control. Fuel combustion technology is related to the manner in which the fuel (coal, in this case) is burned. Power conversion is related to the manner in which the energy released by the combustion process is used to generate electricity. Air quality control refers to the alternative techniques available to reduce air emissions (primarily sulfur dioxide) from the combustion process. Any given change in technology may affect all three areas. For ease of discussion they have been grouped as follows:

Fuel combustion	fluidized bed low Btu coal gasification combined coal-solid wastes

* See Scenario Four, Applied Emerging Technologies, in Chapter V.

A completely new technology that may be available in the next 20-50 years is the fuel cell generator. The fuel cell is a sandwich-like device with two electrodes separated by an electrolyte. A fuel (low Btu synthetic natural as, for example), is fed to one, and an oxidizer to the other. A DC current is produced by the resultant oxidation reaction. Efficiencies near 70 percent are projected for a 1000-MWe central station unit using one process currently under development [222]. Such a unit would produce chemical pollutants similar to those produced by conventional processes, except that NO_x emmissions would be reduced due to the lower operating temperatures. "However, the fuel cell is particularly sensitive to pollutants, such as sulfur, now causing concern in conventional steam turbine plants. Thus, the pollutants must be removed prior to the fuel cell system" [222; pp.12-33].

Power conversion	combined cycle generation
Air quality control	(too numerous to identify individual processes)

Although the above list does not include all potentially important technological advances, it is a representative sample of what is available.

(a) Fuel combustion

(i) Fluidized bed combustion

The following description [222; pp.12-18] summarizes this process and its advantages:

> A fluidized bed boiler involves passing air upward through a grid plate supporting a (several foot) thick bed of granular, noncumbustible material such as coal, ash, or lime. The air fluidizes the granular particulates and, with the relatively small amount of air used to inject the fuel (usually coal but possibly residual oil), serves as the combustion air. The heat transfer surfaces or boiler tubes can be embedded in the fluidized bed directly because combustion takes place at temperatures (approximately 1,500°F.) that will not damage the tubes.
>
> The fluidized bed boiler has two basic advantages: the ability to burn high-sulfur coal with low-sulfur dioxide (SO_2), particulate, and to some extent, NO_x emissions; high heat release and heat transfer coefficients that can drastically reduce boiler size, weight and cost. This means that fluidized bed boilers can be built as factory-assembled, packaged units, shipped to sites, and arrayed as required. These factors will considerably reduce construction times for new power plants.

A study by the Battelle Columbus Lab [545] estimated that a 600-MWe unit (operating at atmospheric pressure) might be one-half to two-thirds the size of a conventional boiler unit. Pressurized units (up to 10 atmospheres) might be even smaller. Data developed by Hittman Associates [cited in 222] indicate an even greater reduction in land required. Other potential advantages [545] include: lower capital costs (10-20 percent reduction) and operating costs (5-15 percent reduction), possibly higher supercritical steam conditions (1,200°F. at 4,000 pisg), and reductions in ash fouling, high temperature corrosion and thermal discharges.

The major disadvantage perceived at this time is the disposal of large volumes of spent bed material (limestone or dolomote). However, because this is a problem shared with other new (and existing) technologies, it may not be significant.

(ii) Low Btu coal gasification

A large part of the present energy research effort is directed toward perfecting methods of converting coal to a substitute natural gas (SNG). Many of the methods presently under study are described in Reference 222. Of concern here are those methods which can be used to produce a low Btu gas (heat value of 100-300 Btu per 1,000 standard cubic feet). Because it is generally not economical to transport such low quality gas [203] it must be produced at the point of its use. In this context we are concerned with a combined coal gasification/electrical power generating plant. The gas produced by the gasification process can then generate electricity by using gas-fired boilers, combined cycle turbines, or gas turbines. (See references 203, 222, 545, and 400 for detailed descriptions of the various processes and their associated resource requirements and environmental impacts.)

(iii) Combined coal-solid waste combustion

A potential source of fuel in the future may be found in solid wastes. Because the energy value of such material is so low (generally 4,000-4,500 Btu/lb. as compared to 9,000-12,000 Btu/lb. for coal) the potential of 100 percent solid waste-fueled plants is quite low, especially for the size considered here.* However, it may be possible to utilize a mixture of coal and "clean" solid wastes (non-combustibles removed prior to burning). One report [545] indicates that use of wastes to provide 10-20 percent of the total energy input would not interfere with boiler operation.** Potential problems relate to chloride corrosion in the boiler/generation system and potential leaching of incinerator solid wastes.

(b) Power conversion

The only method considered for this phase of the power generating system

* A 1000-MWe power plant using only solid waste would require 24,000 tons/day based on the figures given above.

** The Union Electric Company of Missouri has completed a demonstration program and has decided to go ahead with a program to convert its plants for burning a 90 percent coal, 10 percent refuse mixture [Communication with NPCC].

is the use of combined cycle power plant. While there are several types of combined cycle units presently under development, a typical configuration using gas and steam turbines is shown in Figure 5. It is essentially a combination of a standard gas turbine (similar to jet engine) powered by hot gas (SNG) which is then used to heat water in a boiler to power a conventional steam turbine. It is estimated that a system like this could achieve an efficiency of 40-42 percent in the near future [222]. The Battelle Lab's report [545] projects efficiencies of up to 50 percent.

(c) Air quality control

One of the major technological problems faced by utilities in expanding their coal-fired generating capacity is meeting national air quality and stationary new source performance standards, especially with respect to sulfur dioxide emissions. In response to this problem, a great deal of research has been carried out on sulfur dioxide removal systems. Unless the present regulatory posture is substantially altered, it can be expected that one or more or these systems will be used in the near future as new plants come on line.*

Of the many sulfur dioxide removal methods presently under development, "the most effective appear to be 'scrubbing' processes in which the stack gas is passed over or through a material that reacts with SO_2 to form a compound" [222; pp.12-13]. There are two ways to deal with the resultant compound: dumping it at a disposal site, which changes an air quality problem to one of solid waste handling and disposal "throw away" method; or conversion to a useful sulfur product with possible recycling of the absorptive material. This latter method involves the added expense of installing a costly sulfur recovery plant.

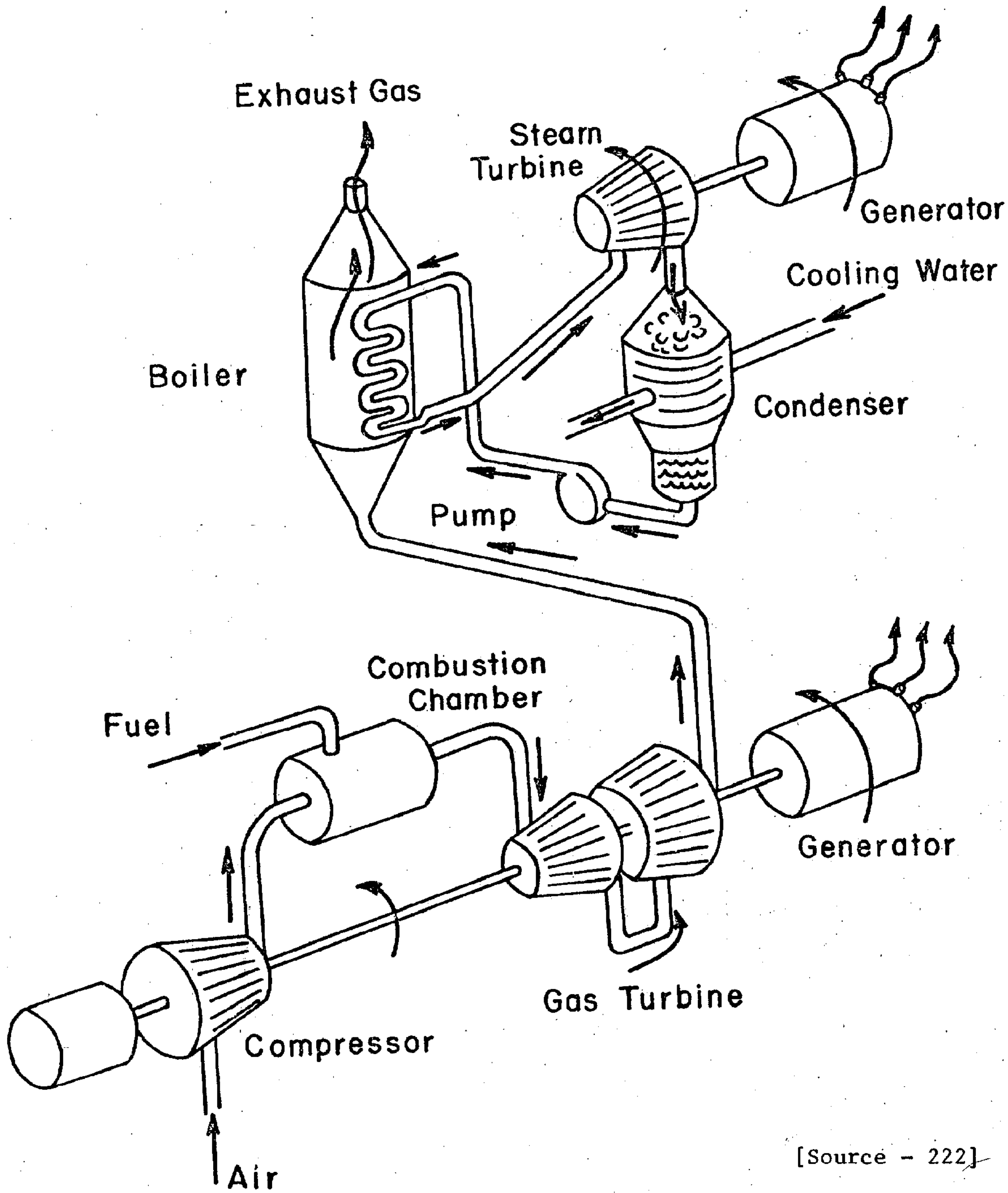
Figure 6 illustrates three sulfur removal methods using lime or limestone as the reacting material. Present indications are that the electric utility industry favors lime and limestone throwaway processes for several reasons: "relative simplicity, relatively low investment, and freedom from the problems of marketing and making a by-product" [222; pp.12-13]. The three methods in Figure 6 are:

- Introduction of limestone directly into the scrubber. This is the simplest route and seems to be the one favored by the power industry at present. The main drawback is that limestone is not as

* Alternative sulfur control technologies not discussed in this report are the techniques of coal cleaning and beneficiation used to remove sulfur and ash prior to combustion.

FIGURE 5

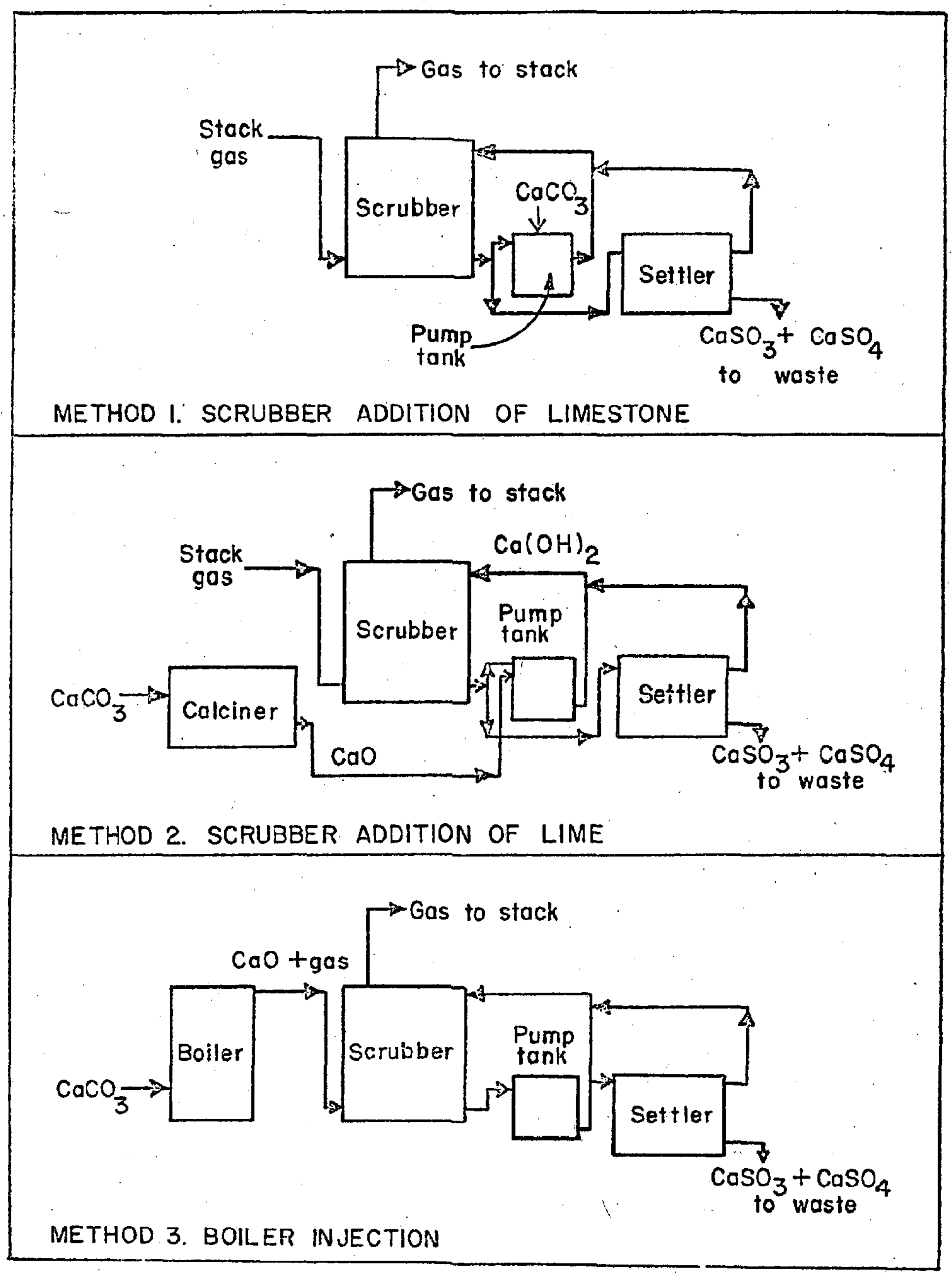
SCHEMATIC DIAGRAM OF A COMBINED CYCLE GAS-STEAM GENERATING PLANT



[Source - 222]

FIGURE 6

SIMPLIFIED DIAGRAMS OF THREE LIMESTONE/LIME STACK GAS DESULFURIZATION TECHNIQUES



[Source-222]

reactive as lime, which makes it necessary to use more limestone, install a larger scrubber, recirculate more slurry, grind the limestone finer, or otherwise offset the lower reactivity.

- Introduction of lime into the scrubber. Scrubbing efficiency can be improved by first calcining the limestone to lime (CaO) and introducing the lime into the scrubber. However, the cost is increased greatly over that for limestone slurry scrubbing, since a lime kiln installation is expensive to build and operate. Use of lime also increases the problem of deposit formation in the scrubber (scaling).

- Introduction of limestone into the boiler. The cost of calcination can be reduced in power plants by injecting the limestone into a boiler furnace. The gas then carries the lime into the scrubber. Problems include possibility of boiler fouling, danger of over-burning and inactivating the lime, and increased scaling in the scrubber when the lime enters with the gas [222; pp.12-13].

Table 9 summarizes the status (as of January 1976) of the present and projected development (by megawatt capacity) of flue gas desulfurization (FGD) systems in the U.S. By the end of 1976, approximately 10,000 MWe of FGD is expected to be installed. The efficiencies for removal of SO_2 range from approximately 40-90 percent and particulate removal efficiencies generally are above 99 percent for those units designed for particulate removal. Most systems are being designed to operate at 80-90 percent efficiency [336].

TABLE 9

STATUS, NUMBER AND CAPACITY OF FLUE GAS DESULFURIZATION SYSTEMS

Status	No. of units	MW
Operational	21	3,796
Under construction	20	7,026
Planned		
Contract awarded	10	3,761
Letter of intent	10	3,911
Requesting/evaluating bids	7	3,837
Considering only FGD systems	40	19,797
Total	108	42,128

[336]

The major resource requirement related to power plant siting that will change if these techniques are used is the amount of land required. As discussed earlier, the amount of land needed for throwaway system waste disposal can be up to 200 acres beyond the normal plant requirements. In addition, facilities will be needed for scrubber material (limestone) delivery and storage at the site. If deliveries are made by water, this may increase the desirability of coastal locations. Presumably, the same considerations as those related to fuel delivery would be important.

b. Nuclear Power Plants

(1) Description

Nuclear power plants on-line at this time or planned for construction in the next ten years are almost uniformly light water-reactors (LWR). Figure 7 shows diagrams of the two common LWR types presently in use. In the boiling water reactor (BWR) water is converted to high temperature/high pressure steam (545°F./1,000 psi) by the core and is used directly to drive the turbine. The pressurized water reactor (PWR), on the other hand, has two heated water systems. Heat is picked up from the core by the primary system (600°F./2,250 psi) and is transferred to the secondary system via a heat exchanger (the steam generator). Steam carried in the secondary system is then used to drive the turbine/generator system.

For purposes of comparison, a 1000-MWe nuclear power plant has been selected as the unit of analysis. It has been assumed that this plant operates at an efficiency of 32 percent with an average annual plant capacity of 65 percent. Average operating life is assumed to be 30-35 years.

Use of a 1000-MWe plant size does not take into account the potential for multiple-unit facilities with combined nameplate capacities of 3000 MWe and above.* Because this clustering of 2-4 units on one site seems to be the present trend, it is important to recognize this practice and examine its effect on the resources required. Efforts will be made, therefore, to indicate how resource requirements change as capacity is raised above 1000 MWe.

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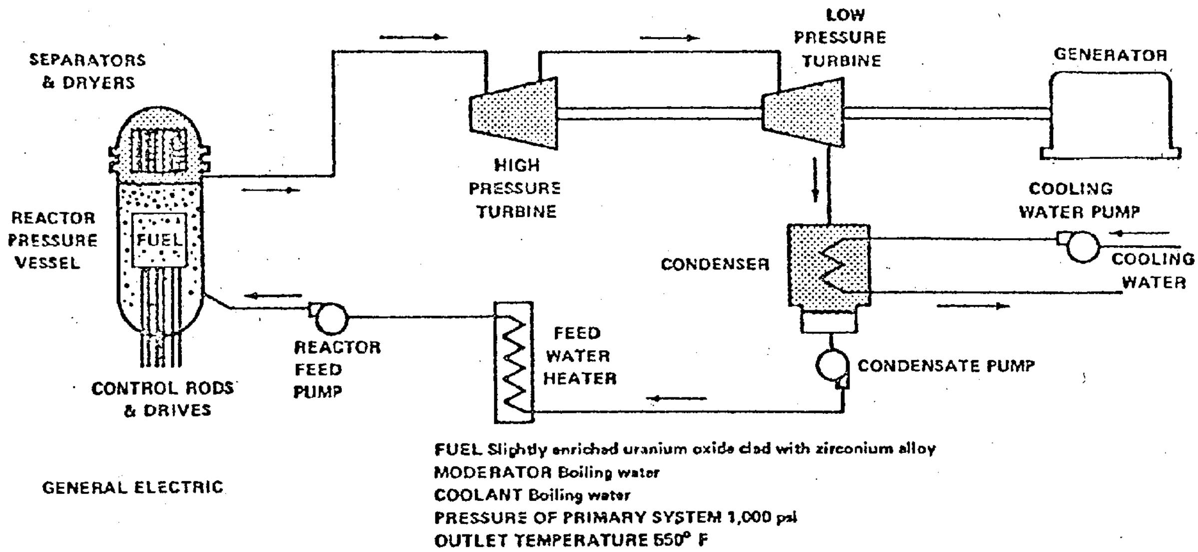
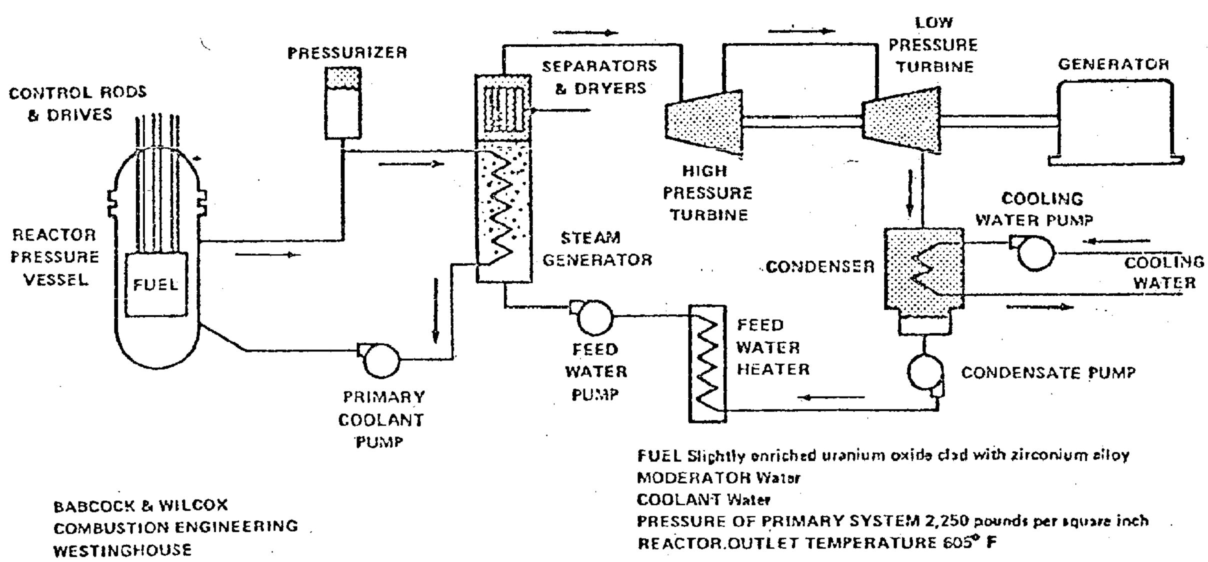
* Nameplate capacity is the power production at 100 percent output; actual output is nameplate capacity multiplied by load factor, generally about 65 percent of this (as assumed above).

FIGURE 7



Boiling Water Reactor Power Plant



Pressurized Water Reactor Power Plant

[Source - 203]

(2) Site Requirements

(a) Land requirements

An analysis of 75 existing and proposed nuclear power plant sites shows a size range from 84 acres to 30,000 acres, with an average of 2,730 acres [data in 208]. Further analysis of the same data indicates that the average station size (including power house, reactor, and related buildings, cooling structures, but not including ponds or canals and onsite switching and transmission equipment) is 135 acres, or roughly 5 percent of the total site area. Excluding those facilities using cooling ponds or canals for cooling the average total site and station sizes are 1,335 acres and 123 acres, respectively. This indicates that, even without cooling systems requiring a large land commitment (i.e., ponds and canals), nuclear sites are much larger than strict generating requirements dictate.

A large part of this additional land requirement is for the provision of an exclusion zone, within which the operating utility has "authority to determine all activities including exclusion or removal of personnel and property from the area" [442; p.20]. This requirement will be dealt with more fully in the next section.

Because the conversion efficiency of a nuclear power plant is 32 percent, as compared to 38 percent for fossil fuel plants, the total heat rejection per kilowatt hour is substantially higher. In addition, while 10 percent of the thermal waste produced by a fossil plant is lost up the stock, essentially all goes into the cooling water system from a nuclear plant. Thus, total heat rejected by the nuclear facility considered here would be 4.71×10^9 Btu/hr, as compared to 3.26×10^9 Btu/hr for a similar size fossil fuel plant.

This higher heat rejection rate results in an increase in cooling system requirements, both in terms of flow across the condenser [discussed in Water requirements, Section IV.A.3.b(2)(a)] and land required for the system components. Table 10 lists the land required for cooling systems of both nuclear and fossil fuel plants. As can be seen from these figures, a nuclear plant requires 50 percent more land for its cooling system than does a similar capacity fossil fuel plant.

There are several additional considerations which determine the size of the site required. For example, additional land may be needed to provide adequate noise buffering, especially in the case of mechanical draft cooling towers. Another important consideration is the necessity to limit the potential impact of water vapor plumes from the cooling system. Although this aspect of plant siting is not specifically subject to federal or state regulation, it must be considered by the utilities in their site selection procedure and envrionmental report preparation.*

There are other considerations that are not included above. For example, multiple use areas for controlled public access to shoreline areas and cooling ponds, farming and grazing, and use of other inactive areas on the site.

In moving from a single 1000-MWe plant to a multiple unit facility of 2000-4000 MWe, several factors related to total land required will increase. First, it is important to note that the exclusion zone requirement is <u>not</u> based on total plant capacity and will not change for a given site as that capacity is increased. Land requirements that may change include those for cooling, noise abatement, plume dispersion, and the plant itself. The degree of this change is not known and probably is site-specific.

Based on the material given above, it is difficult to postulate a "typical" site size for nuclear facilities. Given the figures for the various components that determine site size, a range from 320-3,500 acres would seem reasonable.** Multiple unit sites could range up to 10,000 acres if cooling ponds were used.

(b) Location with respect to population

As mentioned in the previous section, there have been regulations promulgated by the AEC, now administered by the NRC, regarding the location of nuclear power plants with respect to population. In general, "long standing policy of the Atomic Energy Commission [now Nuclear Regulatory Commission] has encouraged siting nuclear power plants away from densely populated areas..." [207]. Title 10 CFR Part 100 (Statement of Consideration, Reactor Site Criteria, published in the Federal Register, April 12, 1962] specifies a three-tiered system of population-related locational criteria that must be met in

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* Off-site effects of water vapor plumes are also considered by utilities in selecting fossil fuel plant sites, although environmental reports are not required.

An exception to this is New York State, which regards cooling tower drift as a settleable particulate, subject to numerical regulatory criteria.

** Assumes a minimum exclusion area radius of 0.4 miles [570] and a plant size of 100 acres. The only explicit variable is cooling system size.

siting a nuclear facility. The three criteria, illustrated in Figure 8, are:

- An exclusion area, which is that area surrounding the reactor in which the reactor licensee must have the authority to determine all activities including exclusion or removal or personnel and property from the area. Activities unrelated to operation of the reactor may be permitted in an exclusion area under appropriate limitations, but the licensee must be in a position to clear the area promptly in the event of an emergency. For example, the area may be traversed by a highway, railroad, or waterway, provided these are not so close to the facility as to interfere with normal operations of the facility and provided appropriate and effective arrangements are made to control traffic on the highway, railroad, or waterway in case of emergency.

- A low population zone, immediately surrounding the exclusion area in which the total number of residents and the population density are small enough to provide a reasonable probability that appropriate protective measures could be taken in their behalf in the event of a serious accident. AEC's regulations do not specify a permissible population density or total population within this zone because the situation varies from case to case. Whether a specific number of people can, for example, be evacuated from a specific area, or instructed to take shelter, on a timely basis will depend on many factors such as location, number and size of highways, scope and extent of advance planning, and distribution of residents within the area.

- A population center distance, which is the distance from the reactor to the nearest boundary of a densely populated center containing more than about 25,000 residents.

[442; p.20]

(c) Water requirements

Because of the significantly higher heat rejection rate, the cooling water requirements for a nuclear power plant are substantially higher than those of a fossil fuel plant of similar capacity. Table 11 compares the flow required across the condenser for the fossil fuel and nuclear plants considered here for different temperature rises. As can be seen, flow requirements are two-thirds higher for nuclear plants for a given temperature rise.

Estimated water consumption rates for cooling system alternatives have been compiled from various sources and are shown in Table 12. Because of the wide range of values and a lack of uniformity in assumptions among sources, it is difficult to estimate an average consumptive rate for any given cooling alternative. A range of 0-30 cfs would not seem unreasonable.

There are, of course, other water requirements for a nuclear facility

TABLE 10

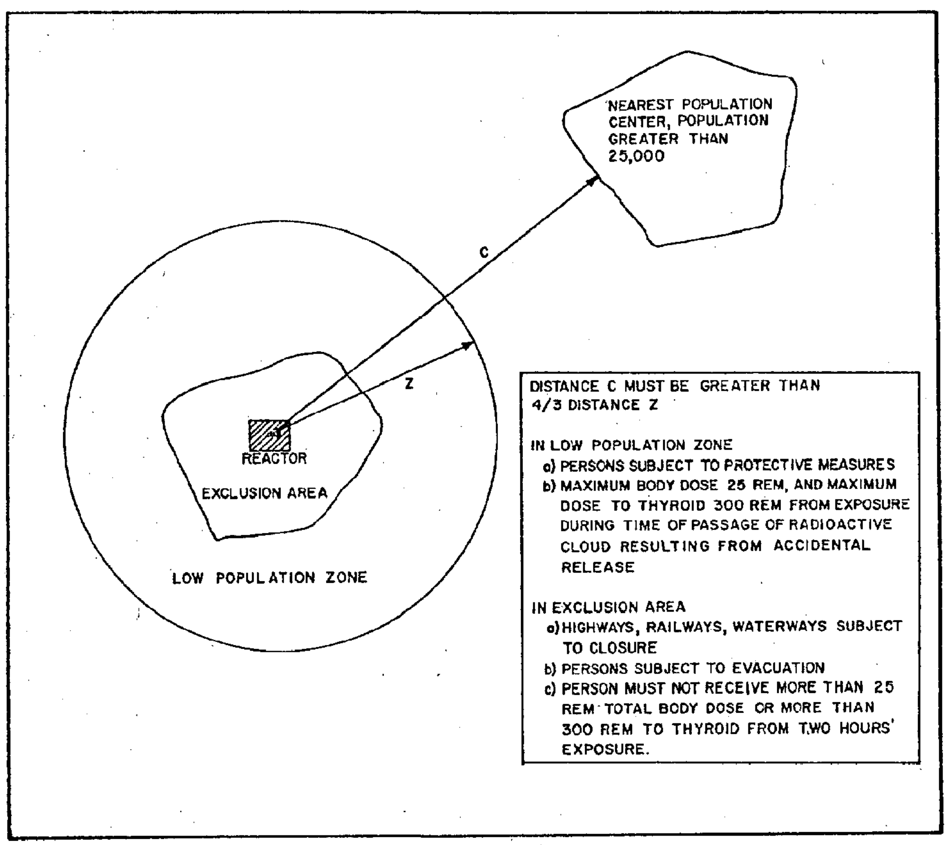
COOLING SYSTEM LAND REQUIREMENTS

	Nuclear	Fossil Fuel
Once-Through	1	1
Natural Draft Cooling Towers	15	10
Mechanical Draft Cooling Towers	68	45
Spray Canals	150	100
Cooling Ponds	3000	2000

[Source - 203]

FIGURE 8

DEFINITION OF EXCLUSION AREA LOW POPULATION ZONE AND NEAREST POPULATION CENTER



[Source 451]

TABLE 11

REQUIRED COOLING WATER FLOW RATES*

	Change in Temperature (°F)					
	30		20		10	
	gpm	cfs	gpm	cfs	gpm	cfs
Fossil Fuel	269,400	600	404,100	900	808,200	1800
Nuclear	449,000	1000	673,500	1500	1,347,000	3000

* Figures from Figure 2

beyond cooling.* An example of a water flow system through a nuclear facility, proposed Enrico Fermi Units (1075 MWe), is given in Figure 9 and Table 12 [from 551]. As can be seen, these other flows are not significant when compared to cooling needs. Total withdrawals are 22,545 gpm (50.2 cfs) on an annual average basis, with a total consumptive loss of 11,610 gpm (25.9 cfs).

In summary, nuclear power facilities require significantly more water than do similar sized fossil fuel plants, due primarily to differences in thermal efficiency. A lower bound of 13,470 to 17, 960 gpm (30-40 cfs) withdrawal rate with a consumptive rate of about 11,225 gpm (25 cfs) is not unreasonable for an efficient closed-cycle system. A withdrawal rate of one million gpm (2,230 cfs) for a once-through system with some consumptive loss provides an upper bound (assuming a 15°F temperature rise across the condenser).

The above discussion is based on a single unit 1000-MWe reactor. For each additional unit added, the water requirements given above should be increased by a similar amount. This does not take into account possible water use economies of scale that may be available, although it does provide a reasonable rule of thumb.

(d) Transportation access

Good transportation access to a nuclear facility site is required for movement of fuel and wastes, and delivery of large components during the construction phase. Unlike the case of a coal-fired plant, large volumes of fuel are not required on a continuous basis; figures from the Fermi 2 unit are shown in Table 13. In addition, nuclear waste materials (primarily spent fuel) must be

* The same is true, of course, for fossil-fuel plants, although it was not discussed at that point.

TABLE 12

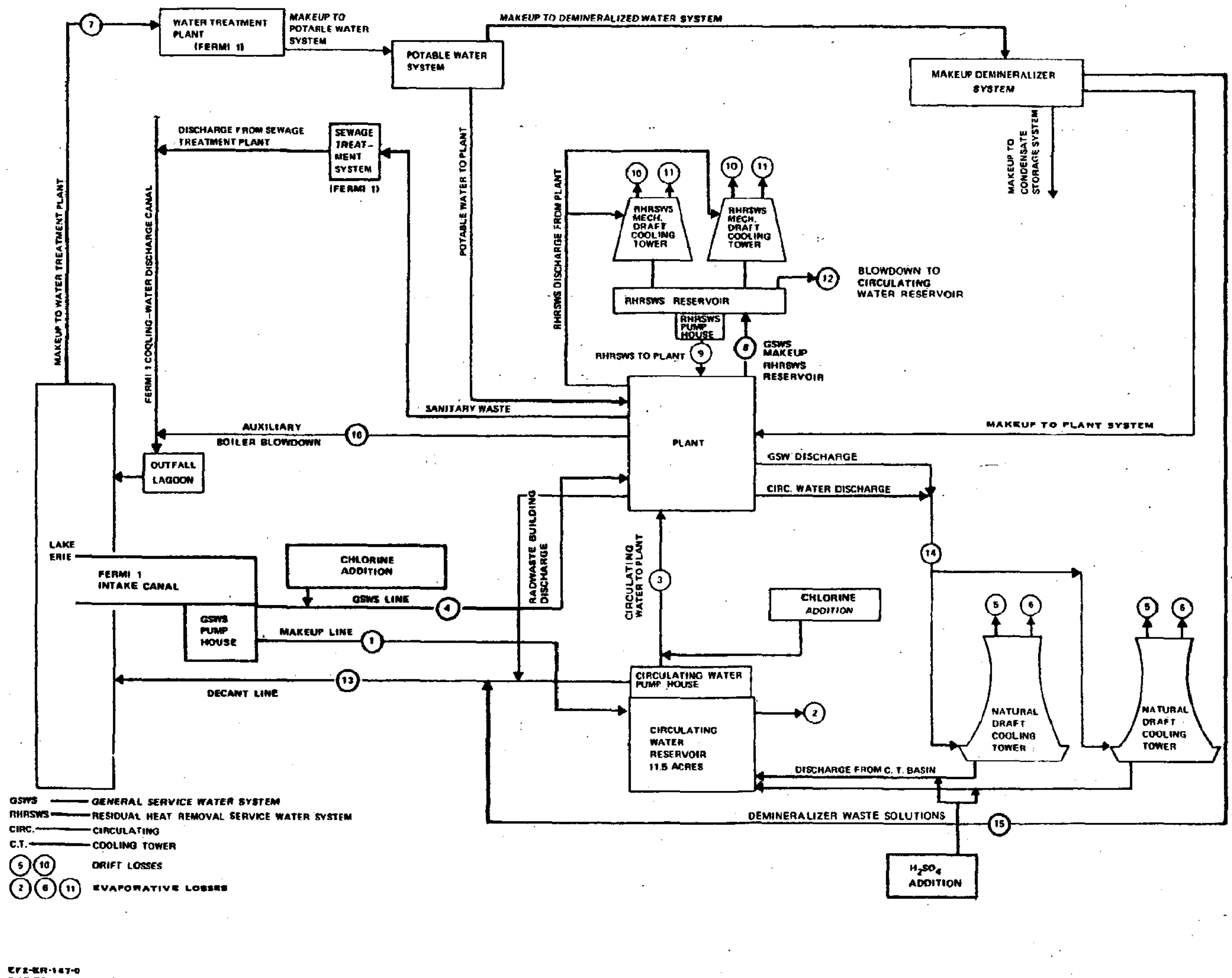
NUCLEAR POWER PLANT CONSUMPTIVE WATER USE

	gpm	cfs
Once-Through	4520[1]	10.1[1]
	3590[2]	8[2]
	5840[3]	13[3]
	0[4]	0[4]
Natural Draft Tower	7240[1]	16.1[1]
	8530[3]	19[3]
	12030[4]	26.8[4]
Mechanical Draft Tower	7240[1]	16.1[1]
	12570[2]	28[2]
	8530[3]	19[3]
	12030[4]	26.8[4]
Spray Canal	11670[2]	26[2]
Cooling Pond	5440[1]	12.1[1]
	6290[2]	14[2]
	9880[3]	22[3]
	17740[4]	39.5[4]

1 [78]
2 [207]
3 [51], assumes 1200 MWe
4 [222]

FIGURE 9

FERMI 2 (DETROIT EDISON) WATER USE SYSTEM



ENRICO FERMI ATOMIC POWER PLANT
UNIT 2
ENVIRONMENTAL REPORT

PLANT WATER USE
(SHEET 1 OF 2)

[Source 551]

TABLE 13

KEY TO FIGURE 9

FLOWS OF MAJOR PLANT STREAMS

Point:	Average Flows Under Full Power Operation, gpm: Minimum Monthly Avg.	Maximum Monthly Avg.	Annual Average [a]	Average Shutdown Flow, gpm
(1) Required reservoir makeup in addition to GSWS flow	0	7,900	3,580	
(2) Reservoir evaporation rate	110	150	130	110 - 150
(3) Condenser cooling flow [b]	840,000	840,000	840,000	0
(4) GSWS flow	12,000	27,000	18,950	10,000 - 12,000 [c]
(5) Drift loss from cooling towers [c]	900	900	900	0
(6) Evaporation loss from cooling towers	8,740	12,220	10,580	0
(7) Makeup to water treatment plant	12	17	15	12 - 17
(8) Makeup to RHRSWS [c]	0	0	0	430
(9) RHRSWS flow to plant [c]	0	0	0	9,000
(10) Drift loss from RHRSWS cooling towers [c]	0	0	0	20
(11) Evaporation from RHRSWS cooling towers [c]	0	0	0	220
(12) Blowdown from RHRSWS [c]	0	0	0	200
(13) Blowdown from circulating water reservoir	10,000	12,200	10,900	10,000 [c]
(14) Total flow to cooling towers [c]	900,000	900,000	900,000	0
(15) Ion exchange regenerant waste flow	0.7	0.7	0.7	0.7
(16) Blowdown from auxiliary boilers	<1	1	0.8	1

(a) Calculated at 100% plant capacity. Expected plant capacity factor is 80%.
(b) Rated flow.
(c) Approximate.

EF2-ER-148-0
8-15-74

[Source 551]

removed from the plant site for reprocessing or disposal; figures on expected waste shipments from Fermi 2 are also included in Table 14. However, while the annual tonnage of materials moved may be relatively small, the potential (and realized) problems can be quite significant, especially with regard to waste transport:

> Shipment of spent fuel from the reactor to nuclear fuel reprocessing plants is the most complicated and expensive shipment in the nuclear fuel cycle. The large amount of shielding needed for a shipping cask designed to carry a single pressurized water reactor (PWR) fuel element brings the cask's empty weight to about 50,000 pounds. The tractor, trailer, and clask will have a gross vehicle weight in excess of the 73,000 pound highway limit which most states impose. Thus, special overweight permits will be required in many cases for shipment of spent fuel by truck. On the other hand, rail transported shipping casks are envisioned which will carry seven elements per cask and will have a loaded weight close to 200,000 pounds. However, not all reactor sites have rail facilities immediately available at the fuel storage area and some reactor sites equipped with rail facilities cannot obtain rail service because local railroads have refused to transport fuel [203; p.127].

Because of the potential for long-term catastrophic impacts if an accident should occur during transit, it is important that safe routes be guaranteed over the life of the plant. Careful consideration of the long-term implications of an accident (such as a container leak) should be made before a transit plan is approved for a specific facility, especially if all or part of the route involves waterborne movement [625].

The second aspect of nuclear facility siting concerned with transportation access is related to the delivery of construction material and major plant components:

> The site should preferably be convenient to either bodies of water or rail or road corridors of sufficient width and load-carrying capacity to enable the delivery of construction materials and equipment amd major reactor and turbine components without unacceptable disruption of the surrounding environment [207; p.107].

Many of the plant components are very large and massive, so that "water access is espcially desirable for deliver of large shop-fabricated and assembled reactor vessels, although field assembly is becoming more common" [442: p.8]. For example,

> For a PWR the reactor pressure vessel itself may be a steel container 17 feet in diameter and 42 feet long with 9-inch thick walls and a weight of 450 tons...The turbine-generator train may

TABLE 14

EXPECTED FUEL AND WASTE SHIPMENTS FOR FERMI 2

FRESH FUEL

Year	Load	Assemblies Per Year	Truckloads Per Year	Enrichment (Wt% U)	Total Wt. U (KG)
1977	1 (1st Core)	764	24	1.90	142,000
1980	2 (1st reload)	276	9	2.61	51,300
1981	3	208	7	2.61	38,700
1982	4	176	6	2.61	32,700
1983	5	180	6	2.61	33,500
1984[a]	6	188	6	2.61	34,900

(a) and annually thereafter

SPENT FUEL

Year	Shipment Number	Total Assemblies	Truckloads Per Year	Total Wt. U (KG)	Ave. Burnup (MWD/MTU)
1980	1	276	138	50,400	12,000
1981	2	208	104	37,700	18,200
1982	3	176	88	31,800	22,000
1983	4	180	90	32,400	23,500
1984[a]	5	188	94	33,700	26,700

(a) and annually thereafter

> be as much as 18 feet in diameter by 200 feet long and weigh 3,900 tons. This component, too, must be shipped to the site in major segments weighing up to 500 tons [207; pp.107-108].

(e) Seismology and geology

Specific regulations have been published regarding seismic and geological protection and assessment of risk for nuclear power facilities ("Design Bases for Protection Against Natural Phenomena," U.S.A.E.C. 10CFR, 50, Appendix A, and "Seismic and Geological Siting Criteria for Nuclear Plants, "U.S.A.E.C., 10 CRF 100, Appendix A).

> Natural disasters such as earthquakes, volcanic activities, landslides, floodings, and tsunamis are potentially so catastrophic that their possible occurrence at any site could be considered as sufficient cause to exclude the site from further consideration" [207; p.14].

However, sites subject to flooding, <u>but properly protected</u>, can and have been used. Site characteristics related to soil stability and topography must also be considered. In general, however, slope instability will not "pose any direct hazard to a nuclear power plant that has been well engineered to the environment" [207; p.15]. Also,

> Areas of actual or potential surface or subsurface subsidence, uplift, or collapse that can result in such phenomena as ground-water withdrawal or recharge, mineral extraction, cavernous or karst terrain, and regional warping should be avoided [207; p.17].

Finally, the potential for site inundation by seiches should be considered carefully before siting of a nuclear facility.

(f) Hydrology and meteorology

Among the factors important in determining "the magnitude of the radioactive dose received by individuals and the population within 50 miles are... meteorology, and hydrology of the site and its surrounding environs" [203; p.125].

Criteria related to the hydrological and meteorological conditions of a potential nuclear power plant site have been published [see, for example, 207] and in some instances codified into the federal regulatory structure.

The most significant meteorological concerns are related to the potential problem of plume formation from a closed-cycle cooling device. As a general rule, the plume from a natural draft tower will rarely extend to the ground, but rather will merge with existing clouds or evaporate before reaching ground level. On the other hand, plumes from mechanical cooling towers, ponds, and spray canals are more likely to cause ground-level fog [207].

Specific consideration should be given to the site dispersion climatology during the site selection and evaluation process:

> A site should provide atmospheric dispersion of radioactive effluents and wate heat sufficient to protect the surrounding environment [207; p. 21].

Specific annual average atmospheric dilution factors have been suggested by the AEC [207; p.2]]. It is also recommended that specific consideration be given to the cumulative effect of "wind trajectories passing over several scattered heat sources" [207; p.22] on localities near the proposed site.

More specific recommendations are made with regard to shoreline sites:

> If cooling tower plumes or other atmospheric emissions could deleteriously affect the residential, recreational, or other human resources, then shoreline sites which have low over-water diffusion rates and high over-land turbulent mixing should be avoided. This especially applies to shorelines where there are cold currents [207; p.25].

Two important factors have been identified in evaluating a shoreline site: the change in atmospheric stability that occurs at the land-air interface, and the change in wind trajectory that occurs when air moves from the smooth surface of the water to the irregular land surface.

The major concerns related to plume dispersion are potential increases in fog and ice formation in the area surrounding the plant site. Plumes are formed when the effluent from the water-saturated cooling device fails to mix effectively with the drier ambient air. The degree of plume formation and stability is determined primarily by air mixing (mechanical and convective), temperature, humidity, and ambient air pressure.

> At sites where the prevailing atmospheric conditions are less favorable for the dissipation of visible water droplet plumes, visibility hazards to transportation and navigation may result. In particular, environmental hazards may occur where water droplet plumes from cooling towers or ponds result in fog formation over corridors of land, sea, or air transportation.
>
> Additional hazards caused by icing may result in areas under the influence of cooling towers if ambient air or surface temperatures below freezing are prevalent [207; p.31].

As mentioned before, fewer fogging and icing problems can be expected from natural draft towers than from other closed-cycle devices.

In the Great Lakes Region, there are several important hydrological aspects of a potential site than must be considered. There must be assurance of a long-term uninterrupted water supply in amounts sufficient to meet the plant's needs. Careful consideration must be given to future development in the plant locality which could change the quantity of water available either for in-plant use or as a receiving body for thermal and chemical effluents. For streams in the Great Lakes Basin supplying principal consumptive requirements, "the consumptive withdrawal should not exceed 50 percent of the lowest monthly mean flow of record unless reservoir capacity is included" [207; p.40]. In addition, water withdrawals must be related to regional withdrawal agreements, where applicable.

With respect to ground-water resources, the AEC has stated:

> Protection of groundwater [sic] supplies is needed for the qualification of a site as suitable for a nuclear power plant. If groundwater is used by the plant, the sustained yield of the groundwater system should not be exceeded, i.e., groundwater mining would require special evaluation.
>
> The location and use of groundwater at the potential site must be considered in the selection process if any discharge of water to the groundwater system, planned or inadvertent, may occur [207; p.43].

Statutory requirements related to water quality are defined in sections 401 and 402 of P.L. 92-500. All water effluents discharged from a nuclear power plant must conform to the limitations established under P.L. 92-500. Thus, "designs associated with site options should in all cases minimize the discharge of any materials which contribute to lowering of water quality" [207; p.51].

There are several other important requirements in site selection decisions:

> "Potential sites on waterbodies subject to heavy icing and blockage need special consideration in order to assure continuity of water supply. Because ice can impact upon structures, causing plugging or structural failures, this factor should also be considered in the selection of a site [207; p.54].
>
> The site must accomodate a power plant design such that the mixing of all heated or otherwise thermally modified discharges to receiving waters can be carried out within the formal mixing zones established by applicable Federal or State regulations [207; p.57]. Waterbodies which are stratified at any time of the year need

special consideration of their vertical mixing characteristics if they are to be used for cooling water" [207; p.59].

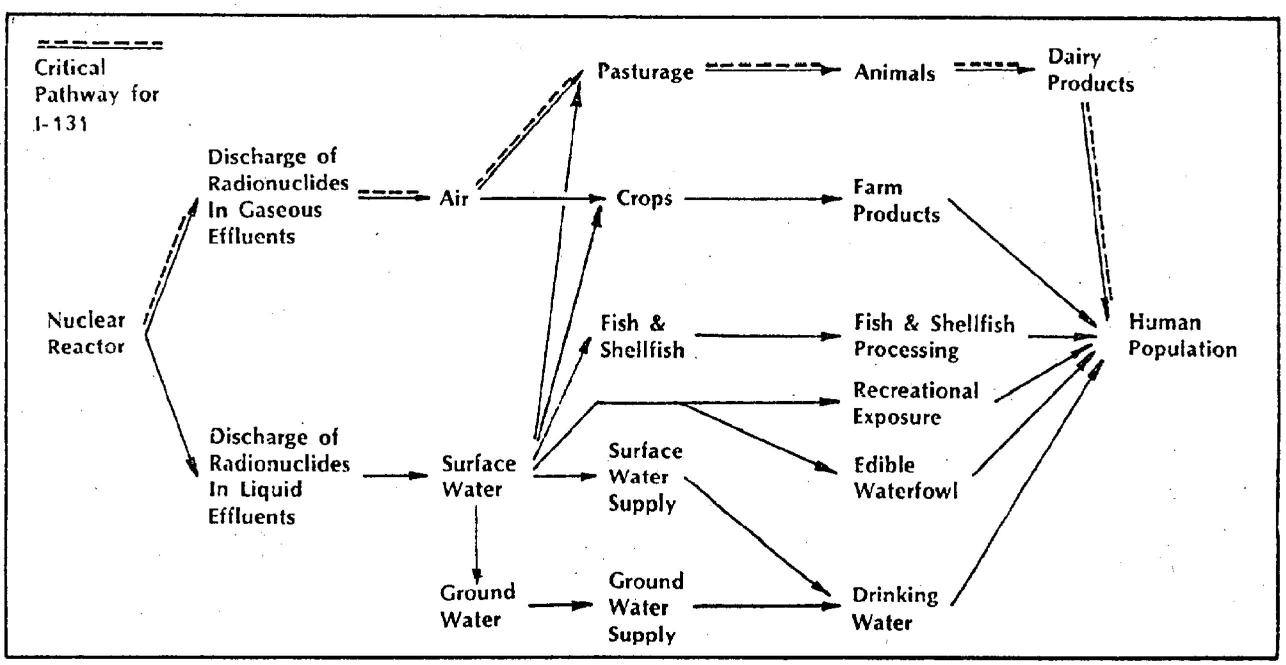
(3) Environmental and Other Considerations

There are a number of further considerations that must be included in a site selection and evaluation process. A general consideration is the total impact of construction and operation on the terrestrial and aquatic ecosystems in the vicinity of the site. While there are several important specific aspects to this problem (see discussion below) the overall degree of disruption and change engendered by the plant must be explicitly discussed. The importance of these impacts will, of course, depend on the importance (as measured by scarcity, system function, etc.) of the ecosystems disrupted and the degree of the impact.

Related to this is the question of the long-term effect of low-level radioactive emissions on the plant and animal (including human) populations in the plant vicinity. All nuclear power facilities produce some radioactive effluents, both gaseous and liquid, that are released into the environment. The major concern is that these emissions will be taken up by plants and animals and will become concentrated through the food chain (see Figure 10). The generic issue of long-term low-level emission affects are unresolved and are presently under study.

FIGURE 10

PATHWAYS OF RADIATION THROUGH THE ENVIRONMENT



[Source - 451]

While this report has not dealt with the nuclear fuel cycle and the problems of waste handling and storage, these factors are important in the general decision to authorize or encourage the development of nuclear power plants. Resolution of problems in these areas is paramount if a major commitment to nuclear energy is to be made. Consideration of these problems must be a part of the decision to permit the continued shift to a higher nuclear share in the electric power fuel mix.

One problem that has not been dealt with extensively to date concerns the eventual decommissioning of nuclear power plants. With a life expectancy of 30-35 years, utilities and the public at large will have to face this problem in the near future and consideration should be given to it now. One report [551] stated that a mothballed period of up to 50 years would be required before "all areas of the plant site will be available for unrestricted access" [551; p.59-62]. This means that at least a portion of the site would be committed to the facility for 80 years or more, a long period in terms of land use change and socioeconomic development.

Another consideration is whether there is a need for continuous cooling of the reactor throughout the period prior to final decommissioning. If there is, then consideration should be given to providing sufficient cooling water to meet this requirement. If a closed-cycle system is used then potential problems with maintenance of the system through this period of inactivity should be dealt with.

As with the other facility types dealt with in this study, perhaps the most important determinant of siting and site requirements is public opinion. However, in the case of nuclear power plants, the public acceptance factor is even more significant as there are basic questions being asked about the desirability of using it at all, as evidenced by the many recent State nuclear power referenda.

(4) Emerging Technologies

There are two principal technological alternatives to the light water reactors presently in use: the high temperature gas-cooled reactor (HTGR), and the liquid metal fast breeder reactor (LMFBR). Only the HTGR is considered to be feasible (i.e., potentially applicable as a major producer in the commercial electrical energy market) during the period covered by this study. While the

LMFBR may see some commercial use by the end of the study period, there are too many technological and political problems with it to make widespread use feasible.

The HTGR was available commercially for a period although it has seen only limited use. Research and development on the process is continuing.

Figure 11 shows a cross-sectional view of the major components of a typical HTGR generating system. As opposed to the LWR system, the HTGR uses helium as a coolant and heat transfer medium. Because helium can be heated to higher temperatures and pressures than water, HTGR can achieve efficiencies of 40 percent. The fuel, a mixture of uranium 235 and thorium 232, is formed into microspheres and embedded in a matrix of graphite blocks. While large quantities of thorium are not available today (primarily due to a lack of demand), economically recoverable reserves are thought to be available in sufficient quantities to supply a 100,000-MWe capacity for 400 years [222]

HTGR proponents claim significant safety advantages over available LWR systems [222]. First, loss of the helium coolant does not represent as severe a problem as does the loss of the coolant water in a LWR, because the graphite core can absorb substantial amounts of heat. Second, the use of a prestressed concrete reactor vessel (PCRV) adds to the overall safety of the reactor by eliminating the worry of a primary pipe rupture. Third, the use of small, coated fuel pellets instead of large fuel rods reduces the amount of radioactive material released to the coolant should a fuel pellet rupture. Finally, the graphite core reduces the chance of a major core meltdown.

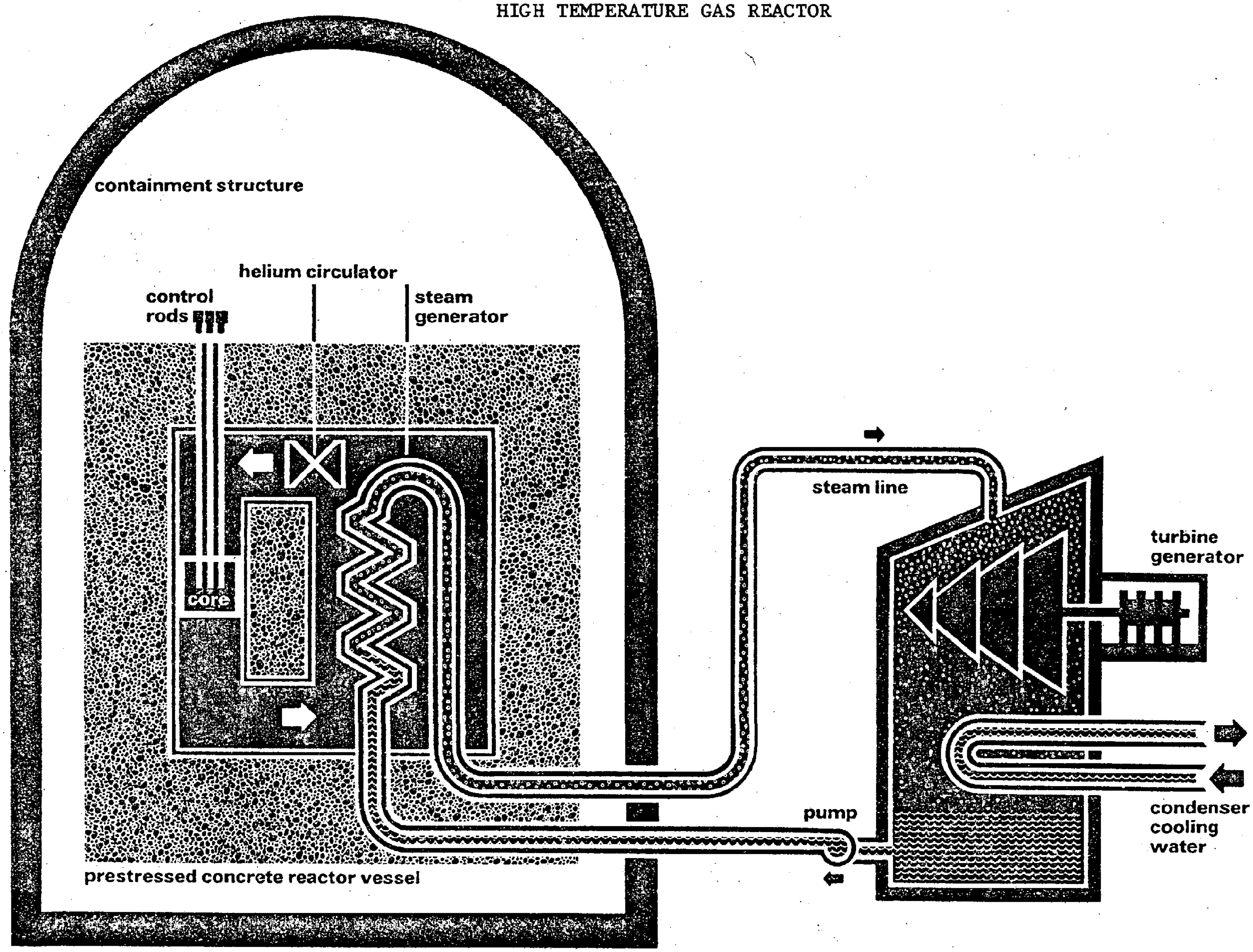
Use of a direct-cycle system in which the helium is expanded through the turbine could raise HTGR efficiencies to 50 percent.

c. Fuel Transshipment and Storage Facilities

Ports and terminals are being considered as energy facilities insofar as they relate to the transshipment and/or storage of fuels and materials associated with power plants, conversion facilities, and refineries. Because this category is represented by a wide variety of facilities, it serves no useful purpose to attempt to establish a generalized definition of any one facility. However, these facilities may be classified according to the type of fuels or materials which they handle, e.g., coal, oil, or nuclear fuels and wastes. Furthermore, the six general siting considerations established at the outset of this report may be expanded as they apply to ports and terminals. These facilities include harbors, associated storage areas, and combination rail-harbor

FIGURE 11

HIGH TEMPERATURE GAS REACTOR



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transshipment facilities.

(1) Facility Types

(a) Coal

Development or expansion of coal handling and storage facilities depends directly on projected increases of coal utilization within the Great Lakes Basin and changes in mode of transportation. Furthermore, increased use of low sulfur western coal has necessitated a change in coal traffic flow on the Great Lakes and corresponding development of new storage and handling facilities. The general considerations associated with the development or expansion of these facilities are demonstrated in such specific cases as the coal transshipment facility at the Duluth-Superior harbor and the unloading facility at Marquette, Michigan.

In the case of the Duluth-Superior facility, a detailed report [391] was published outlining the site selection process and the impacts associated with the final propsed site. Paramount in the location analysis was the need for multimodal transshipment capabilities (e.g., ship and rail); rail lines capable of supporting unit train transport; and potential for adequate docking facilities for large lake freighters. Furthermore, relative proximity to coal source and load center was a major consideration.

After selection of the location at Superior, Wisconsin, attention was shifted to defining the impacts of the proposed facility and designing controls to reduce or preclude any negative impacts. The impacts most directly associated with the construction and operation of such a coal transshipment facility are the effects of coal dust on ambient air and water quality. During the process of moving coal from unit train, to storage pile, to conveyor belt, to ship, large amounts of coal dust may be generated and controls must be implemented to reduce the amount of dust which escapes into the air or water. Some controls include wetting down the coal with special suppressants, and the use of restricting bag chutes on the conveyor systems.

Other impacts are those generally associated with construction and operation of a major facility. These include dredging, dredge spoil, and land alteration impacts on surrounding air and water quality. Also, magnitudes of community disruption, noise, and aesthetic impacts are considered in the assessment of the Superior facility development.

The coal unloading facility at Marquette, Michigan [299] is designed to supply coal directly to the Presque Isle generating station at Marquette. Its development was related directly to projected increases in coal requirements by the power plant and a desire to modernize the existing facility. This modernization included the elimination of a short haul rail line and overall decrease in personnel requirements due to automation. According to the environmental impact statement:

> Consideration of siting the proposed unloading facility must acknowledge the presence of existing facilities in the vicinity of the site. The immediate environs surrounding the Presque Isle site are presently committed to industrial use. Since the site west of Lake Shore Boulevard has already been dedicated to power generation, the unloading facility can be considered a reasonable adjunct to this enterprise [299].

From the above two examples and others, it is possible to summarize the general resource requirements and the major impacts which are specific to this type of facility.

Of primary concern is the availability of land adjacent to existing rail and harbor facilities. Acreage requirements for coal storage and related handling equipment vary greatly depending on the configuration of the coal pile and the length of reserve time required. Based on figures from specifications in project reports [391, 203, 299, 526] and communications with coal dock personnel, an approximate figure of 35,000-40,000 tons per acre is reasonable for a coal storage land-requirement, assuming a 40-50-foot pile height. This figure can vary greatly depending on the customer-pile relationships and the type of mechanical stacking equipment employed.

Major impacts of coal handling facilities as evidenced in the previous discussions include disruption of communities during construction, increase in noise levels as a result of heavy equipment use, health and cleaning problems associated with coal dust as a result of coal handling, water quality problems associated with runoff from coal piles, and removal of land from multiple use for storage.

(b) Oil

Oil storage facilities are utilized at almost all the major ports on the Great Lakes [535]. This includes both crude oil and refined products storage and related transshipment facilities. Future development of storage and handling capacity is expected to take place primarily in the form of expansion at existing facilities. This, of course, is highly dependent on decisions regarding potential future development of major pipelines capable of bringing crude oil into the Great Lakes Basin from sources in the West.

Considerations of particular importance to the siting of new facilities or expansion of existing facilities which store or handle oil are primarily in the areas of systems requirements and environmental concerns. Presently, most storage facilities contain refined petroleum products and are situated at Great Lakes ports to facilitate ship loading, which in turn insures a wide variety of distribution points without the restrictions of a permanent pipeline. Crude oil on the other hand is routed by pipeline directly to the regining facility. (In 1974, crude oil represented only .2 percent of the petroleum products shipped on the Lakes [536]). A discussion of the crude oil-refinery relationship is contained in the following section.

Storage and handling facilities are located with regard to existing and potential product distribution systems. Consequently, most oil storage tank farms are located at Great Lakes ports, particularly those ports which have refining capacity and, thus, short distance product transport capacity. From a systems planning standpoint, the location of storage facilities at ports and utilization of the extensive shipping network provides for the widest distribution of refined products.

A review of some of the important environmental considerations associated with the development or expansion of an oil storage and handling facility is provided by the Lakehead Pipe Line Company for their proposed Refined Products Terminal in Superior, Wisconsin [158].

As might be expected, the primary concern regarding the facility is safeguarding against potential spills in storage and handling. This would include tank construction, pipeline integrity, and any special precautions required for the loading manifold (pipeline-ship hookup). Clay dikes surrounding the oil storage tanks are proposed in order to insure control of potential spills in the case of tank leaks. The negative effects of oil on water quality and aquatic ecology are well documented; consequently drainage controls and leak security are important considerations. Other considerations for oil storage facilities are those associated with hydrocarbon emissions from storage tanks. Ambient air quality may in some cases prohibit further expansion of oil storage capacity, if this expansion is projected to raise hydrocarbon levels above acceptable standards. Emissions during vessel loading are a particular problem.

(c) Nuclear fuel

The scope of this study did not allow a complete investigation of the nuclear fuel cycle, nor of the controversial issue of nuclear waste disposal. However, because of the extent of planned nuclear power development in the Great Lakes states, it is necessary to comment at least on handling and storage of the fuels required by these plants and the waste generated from them.

Because of the comparatively small volume of fuel required by nuclear power plants, transshipment and storage facilities such as those associated with coal and oil are not a necessary component in the fuel delivery system of nuclear plants. Arrangements for delivery of nuclear fuel involve truck transport from the fuel processing plant directly to the power plant site [379]. Transport and/or storage of wastes remain uncertain at this writing but are anticipated to involve either truck or rail transfer from the generating plant directly to a disposal site or fuel reprocessing center. Consequently, without dismissing the safety and disposal problems associated with nuclear fuels, the role of nuclear fuel transshipment facilities is small or non-existent.

(2) General Considerations

(a) Systems requirements

Expansion of harbor or harbor-rail facilities necessarily depends on comparable expansion or development in power production or changing emphasis in transporation modes. In addition to new facilities, existing developments, such as harbors, docks, and rails, provide areas for continued expansion. Other systems considerations are the relative distances and related transportation costs between proposed storage or handling facilities and ultimate usage locations.

(b) Safety

The considerations within this category apply primarily to the environmental aspects associated with the storage and handling of fuels. These would include the affects of spills or leaks of radioactive fuels or wastes, the affect of coal dust and other particulate matter associated with coal storage and handling, and the problems with hydrocarbon emissions from oil storage tanks.

(c) Engineering

Development or expansion of storage and/or handling facilities entail many engineering considerations similar to those discussed for other energy facilities. Most important of these are the feasibility of the land-water interface and the design of harbor breakwaters and docks. Likewise, consideration must be given to foundation stability and soil properties. Finally, pollution abatement and control is an important consideration when associated with the preceding and following sections.

(d) Environmental

Determining site locations for development or expansion of fuel storage and handling systems relies heavily on the potential environmental impacts of the facility: possible water pollution from runoff, spills, and ship activity; air pollution from emissions, hydrocarbon leaks, and coal dust; increase in ambient noise levels due to unloading operations and related industrial activity; aesthetic considerations such as visual impacts of coal piles, tanks, stacks, dust, and railways; decreases in nearby residential land values due to industrial development; and disruption of terrestiral and aquatic ecology.

(e) Institutional

Regulating and permitting procedures by state and federal agencies must be met in some phases of siting of storage and handling facilties. These would include filing of environmental impact reports with the proper administrative body, application for construction permits with agencies such as the Corps of Engineers or state departments of natural resources, and meeting various state and federal air and water quality standards. In addition, specific safety regulations regarding the storage and/or handling of radioactive wastes would be a special consideration for the placement of these particular facilities.

(f) Economics

Costs of the above considerations are a major determinant of the location and mode of storage and handling facility to be constructed. The costs of land acquisition, construction, and operation will vary depending on the type of facility planned and the kind of fuel to be considered. Likewise, pollution control and abatement costs are dependent on the materials and the areas in which they are handled but are major considerations in the planning phase.

d. Refineries

(1) Description

Present petroleum refining facilities in the Great Lakes Basin range from small, less than 10 mbd (1 mbd = 1,000 barrels per day), to plants with capacities greater than 350 mbd.* At the present time, there are no new refineries under construction in the Basin although several existing facilities are being expanded. The largest expansion identified at this time is one of 27.5 MBD. The only new "grassroots" refinery being considered in the Basin would be a 200 MBD facility at Oswego, New York, although no decision has been made as yet as to whether or not it will be constructed. Further discussion of present and future refinery activity in the Great Lakes Basin can be found in Section IV.B., "Energy Consumption and Movement in the Great Lakes Region."

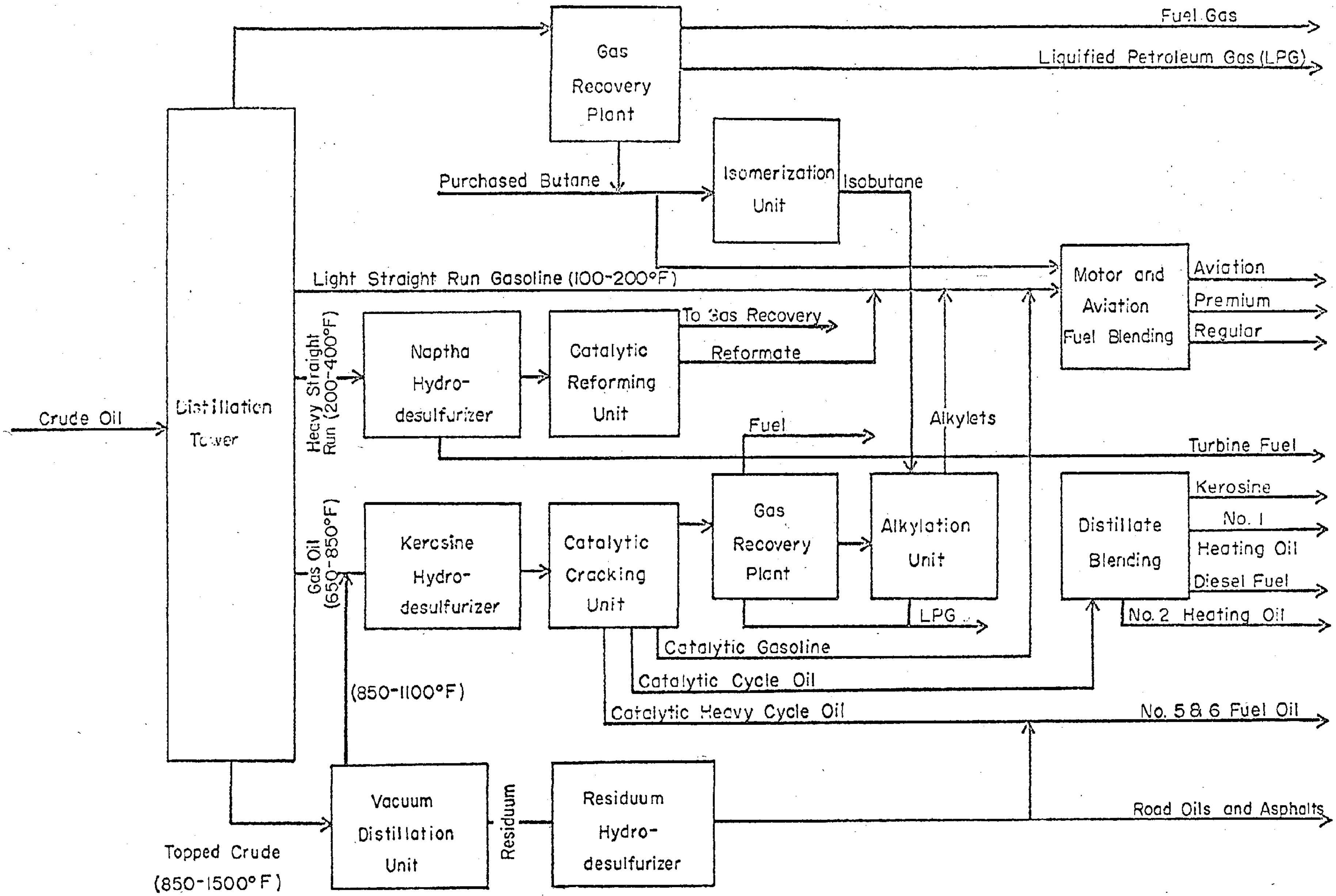
Refineries are by nature very complex systems with many components. As such, it is difficult to characterize a "typical" configuration, size and product mix. Generally, complexity and associated resource requirements increase with product mix diversity. As will be discussed below, refineries specializing in one or more of the four "standard" products (gasoline, jet fuel, diesel fuel, and fuel oil) are relatively simple and require less area than a diversified refinery producing a wide range of products and petro-chemical feedstocks [292]. Contact with several of the refineries in the Basin has indicated that they produce a broad spectrum of products with little evidence or regional specialization.

Figure 12 shows some of the major components and feedstock flow patterns used in modern refineries. The configuration of these components and flow rates will vary from refinery to refinery, depending on crude oil supply source and product mix. For a more complete discussion of these components, including their potential environmental impacts, the reader is referred to 370. In addition, reference 135 provides concise descriptions of several refinery configurations.

(2) Site Requirements

General siting considerations for refineries can be broken into two groups: economic criteria and environmental criteria [292]. While both will be

* For the purpose of this discussion, no distinction has been made between barrels per calendar day (annual capacity divided by 365) and barrels per stream day (annual capacity divided by the days the refinery is actually in operation). Generally, calendar day capacity is about 95 percent of stream day capacity.



MAJOR COMPONENTS OF A REFINERY
FIGURE 12

discussed at greater length below, some general observations can be made at this time. The two most important economic criteria are availability of crude oil and access to product markets. The most important environmental criteria considered in the Great Lakes Basin region relate to air and water quality regulations. Also important are problems related to visual intrusion (aesthetics) and socio-economic impacts to the local area.

(a) Land requirements

Estimates of land required for refineries of varying sizes and complexities are shown below in Table 15. Because major Great Lakes refineries would generally fall into the "diversified" class, the acreage estimates given for that class are the most important for this study.

TABLE 15

REFINERY LAND REQUIREMENTS (ACRES)

	COMPLEXITY		
CAPACITY (MBD)	SIMPLE[1]	MAJOR PRODUCT[2]	DIVERSIFIED[3]
100	700[6]	800[6]	1860-2105[4] 1000[6]
200	1400[6]	1600[6]	3720-4210[4] 1800[7] 1400[8] 2000[6]
250	1750[6]	2000[6]	4650-5265[4] 1000[5] 2500[6]

1 Gasoline and fuel oil [292]
2 Gasoline, fuel oil, jet fuel, and diesel fuel [292]
3 Wide range of distillates
4 Reference 222 - Room for expansion buffers. Accurate within a factor of 2.
5 Reference 505 (New Eng. Vol.II)
6 Reference 292 - Includes doubling, 60 day storage
7 Reference 370 - Includes doubling, buffers
8 Reference 285 - 15 days storage

In a report on refinery siting considerations [370], estimates for land required for 200 mbd account for 1.27-3.73 percent of the total facility cost (estimates based on 1973 dollar costs). As a result

> ...refineries have an incentive to buy as much land as possible for use as a green belt and for storage. The green belt is important for aesthetic reasons and so that emissions measured at the fenceline meet standards [370; p.13].

If it is assumed that future refineries would allow sufficient space to double production capacity as well as provide a green belt to isolate the plant from surrounding land uses, "average" site sizes might be:

100 mbd	1,500 acres
200 mbd	2,200 acres
250 mbd	2,700 acres

(b) Location with respect to population

When selecting a site for a refinery, there are two countervailing forces considered. One is the necessity of being located close to the finished product market or distribution system to reduce transportation costs. The second is to meet environmental criteria related to reduced air quality impacts, aesthetic and noise impacts, etc. As indicated above, companies are balancing these two criteria by locating on large sites in which it is possible to isolate the plant from the surrounding population. How these two forces balance in a given plant location decision depends on the specifics of the situation and cannot be generalized.

(c) Water requirements

Water use by a refinery can be partitioned into process water used in producing the distillates (usually an insignificant fraction of total consumption) and cooling water. The amount of cooling water required will depend on the component configuration and the extent to which air cooling is used. Typical values are given in Table 16.

Reductions in water consumption for cooling are possible using a higher level of air cooling. However, it would increase capital costs and the land required as well as the level of noise produced [505]. Even without a total shift to air cooling, however, refinery dependence on easy water access has been decreasing. This conclusion is best summarized as follows:

TABLE 16

REFINERY COOLING WATER REQUIREMENTS

CAPACITY (MBD)	WATER REQUIRED MGD	CFS
100	4/3[1] 5-10[2]	6.2/4.6 7.3-15.5
200	8/6[1]	12.4/9.3
250	10/7.5[1] 4.5-5.4[3]	15.5/11.6 7.0-8.4

[1] Estimated 1985/2000 make-up requirements [285]
[2] [292], 40-50% air cooling
[3] [506], 40% of total flow consumed

Historically, siting was dependent upon water supply and waste-water disposal considerations, but this dependence is weakening as water makeup and discharge both decrease with increasing water recycling practices [370; p.63].

(d) Transportation access

As indicated above, the two most important economic criteria considered in refinery siting are crude oil supply and product distribution. In terms of crude oil supply to the plant, there are two principal modes available in the Great Lakes Basin: tankers and pipeline. The extension of the nationwide crude oil pipeline system into the Great Lakes Region has made it unlikely that future refineries will be dependent on tanker-supplied crude oil. This conclusion was reached in a study of the Great Lakes transportation system [147], which stated that, "consideration of oil and gas in relation to the Grat Lakes shipping does not involve to any significant degree either crude or products as cargoes to, from, or within the Lakes." Support for this conclusion came by contacting several of the refineries in the Great Lakes Basin; most crude was received by pipelines from either the southern U.S. or Canada.

The product distribution question is somewhat more complicated. Because product transport is more expensive than crude oil movement, this may lead to a situation in which refineries are located close to their potential product markets, with crude oil supplied by pipeline or tanker. In this way, crude oil source is less determinative of site location than is product market location [370]. This view of the site selection process can be summarized as follows:

> Petroleum refining is rapidly becoming "market oriented" rather than "raw material" oriented. This trend stems from the general concession that transportation of crude to the refinery is less costly than transportation of products to the market....Therefore, it is very likely that new refineries will be located in the vicinity of the large metropolitan markets such as the East Coast, along the Great Lakes, the West Coast, and the Gulf Coast [370; pp.53-54] (emphasis added).

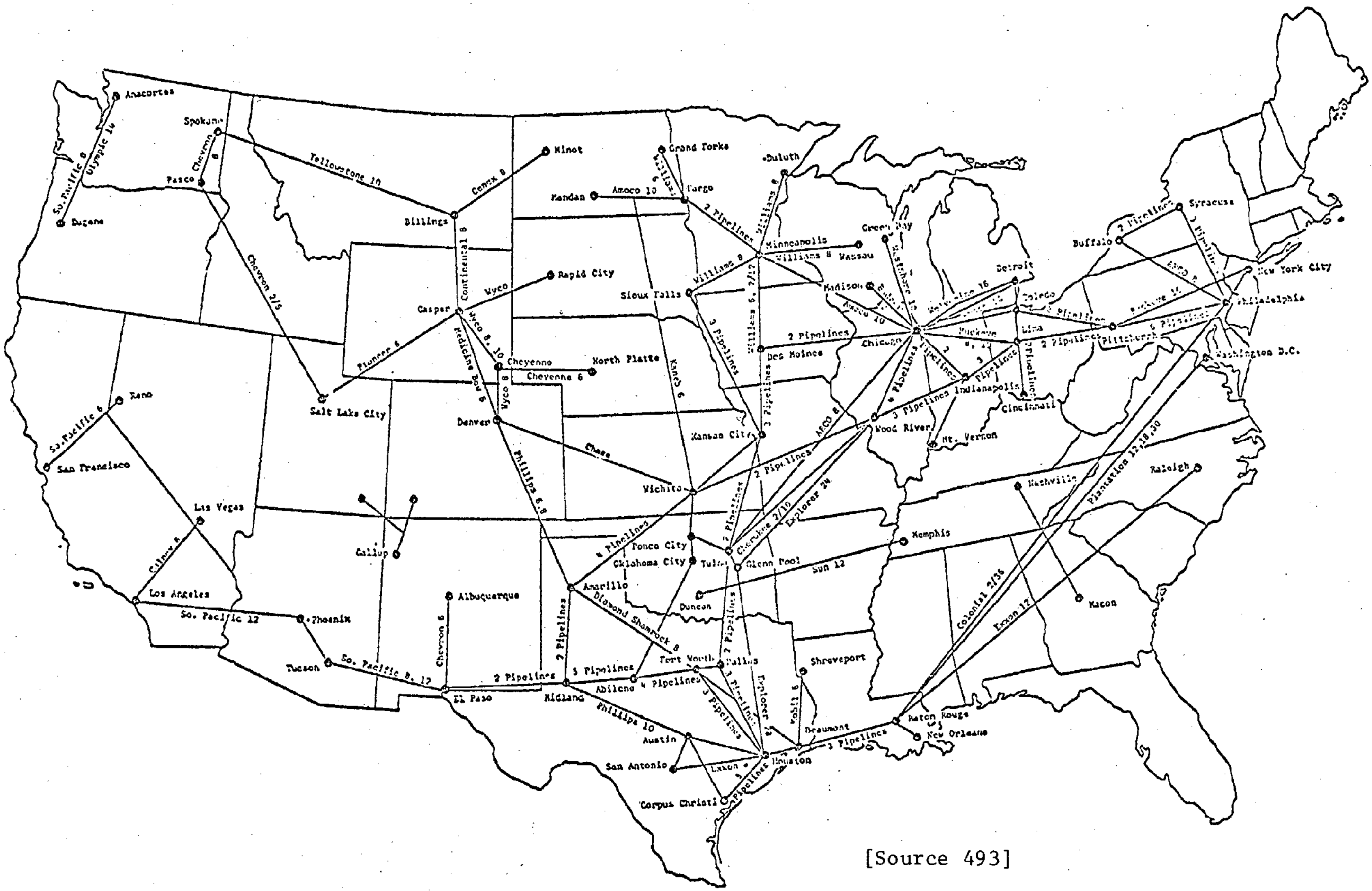
Under this view, one would expect to see major new refining capacity, either as new plants or large-scale expansions of existing facilities, come into being in the Great Lakes region in the near to mid-term future.

There are, however, certain constraints that modify this market-oriented site selection model. Some of these constraints were discussed previously: land and water availability in the quantities required. Others, related to long-term protection from natural disasters, are discussed briefly in subsequent sections. Constraints related to potential environmental and public-acceptance problems will also be discussed in the section, "Environmental and Other Considerations."

Of particular importance to this study is that most of the large refineries in the Basin are connected to a regional/national product pipeline system (see Figure 13). For this reason, refineries do not have to be located in the vicinity of their potential product market. Instead, the national refinery system can respond to regional demands and ship products to the points where they are needed. The existence of this demand-responsive system obviates the need for locating refineries in each product market area. Indications at this time are that major new refining capacity will be located outside of the Basin (most likely on the Gulf Coast) and the products moved through this system to the Great Lakes market. Thus, refineries are not expected to be a major concern in the future energy facility siting in the Great Lakes region.

(e) Seismology and geology

Requirements for refineries are much the same as those for coal-fired



[Source 493]

FIGURE 13

MAJOR NATIONAL PRODUCT PIPELINE SYSTEM

generating plants--i.e., they be located in areas with suitable foundation conditions outside of areas with active faults or other types of geologic hazards.

(f) Hydrology and meteorology

As is the case with the coal-fired power generating facilities, refineries should be located outside of areas prone to flooding and where plant operation will not adversely affect surface and ground-water quality.

(3) Environmental and Other Considerations

There are several further criteria to be considered in the siting of new fuel processing facilities. The most important relative to the Great Lakes Basin are those concerned with environmental quality. In particular, air pollution emission standards may prove to be the most restrictive in terms of limiting new plant construction (and possible expansion of existing plants).* While most air quality problems can be solved, reducing hydrocarbon emissions to the levels specified in the national standards presents major technological difficulties. This problem has been highlighted in several reports dealing with refinery siting [506, 285, and 370], indicating "the need for careful attention to hydrocarbon emissions in refinery siting decisions" [506; pp.II-50]. However, care must be taken to assess refinery effluent impacts with respect to existing water quality conditions in the receiving stream. Also, low-flow conditions of the receiving waters must be considered in a refinery siting decision. Finally, the state water quality control agencies should be contacted since states have the right to impose water quality standards more stringent than those established at the federal level.

The final site selection consideration discussed here, public acceptance, is perhaps the most important of all. It has become increasingly obvious in the past couple of years that public sentiment can be the final determinant of where new refining capacity will ultimately be located. An excellent example of this is the case of the Olympic refinery (400 mbd) proposal for Durham, New Hampshire that was rejected by local residents in 1974 [505]. Thus, it is important that public opinions and attitudes be assessed early in the site selection process. In addition, the issues causing greatest concern, air and water quality degradation, aesthetics, conflicting land use, etc, must be addressed directly at the

* See discussion of EPA for details of air pollution control program, Chapter III.

outset. (Some of these impacts are discussed in a subsequent section.)

(4) Summary

The process of selecting a site for a major new refinery is complex, superceding simple regional boundaries. Because the U.S. refinery system is tied together via an extensive crude oil supply and product shipment pipeline system, the decision of where to locate a new facility is made at the national level, in conjunction with various regional considerations related to crude oil supply and environmental quality limitations.

4. ENVIRONMENTAL AND ECONOMIC IMPACT ANALYSIS

a. Introduction

This section presents both a discussion of the environmental and economic impacts of the energy facility types considered in this report and a framework within which these impacts can be organized. Because of the specific nature of the data required, this framework cannot be used to perform a regionwide general facility analysis. Rather, it has been included to provide the coastal zone management programs with a concise framework within which they can evaluate proposed energy facilities. In addition, it provides a useful summary of the major facility activities as well as the potentially affected environments. Finally, it has been used as a guideline in development the accompanying text material.

(1) Framework Approach

For each facility type, there is a general discussion on potential impacts to both the natural and cultural environments. Following this, there is an activity impact matrix specific to each facility type. On this matrix, activities associated with a given facility are listed on the left-hand side and are cross-referenced with potentially affected environments. There is a separate matrix for each of the major facility types:

- Fossil-Fuel (Coal Power Plants
- Nuclear Power Plants
- Coal Transshipment and Storage Facilities
- Oil Transshipment and Storage Facilities
- Refineries

The degree of impact would be indicated by a numerical entry at the intersection of the appropriate activity and environment. An impact scale of -3 (major negative impact) to +3 (major benefit) is suggested. There would also be a special entry for those potential impacts that are inherently immeasurable. It is important to emphasize again that this system will not and cannot be used in a regionwide analysis. It is, instead, intended to be used by the states in evaluating specific facility proposals.

(2) Facility Activities

The energy facilities considered in this study have been characterized in terms of activities associated with them. For the purposes of this report, an activity is defined as follows:

Activity--The major actions associated with the construction and operation of major energy facilities.

These activities have been further subdivided into one or more impact vectors, which are defined as follows:

- Impact vectors--Those aspects of an activity which may result in a significant change in the existing environment. In some cases, they represent actions, such as ground clearing and reshaping, equipment use, channelization, and shoreline modification, etc. Others are the result of an activity, such as influx of temporary work force, wastewater discharge, thermal effluents, etc. It is important to note that they are not potential impacts themselves but rather are elements of facility operation or construction that may cause impacts on certain aspects of the natural and cultural environment.

The following material presents definitions of all activities and impact vectors used in the five facility-type matrices.

(a) All facilities

Construction--That activity associated with the actual development of the energy facility. It is common to all facility types and is found on each matrix.

- Ground clearing and reshaping--Those operations involving a physical disruption of the ground surface, including stripping of vegetation, grading, excavation, road building, and site restoration.
- Equipment use--Those impacts directly attributable to the use of construction equipment, such as noise, dust, air pollution, etc.

• Channelization, shoreline modification, and other water-related activities--All construction activities associated with the water, including channelization of harbors for moving heavy equipment and material to the site, construction of breakwalls, jetties, and other shore protection devices, construction of docks and terminals for fuel and product transshipment, and the construction of water intake and outlet structures.

• Material movement to site--Those impacts related to the movement of construction materials to the facility site, e.g., disruption of local traffic patterns, deterioration of roads, dust, and noise.

• Influx of temporary work force--The impacts of moving a large (1,000-3,000-person) work force into a local community during the construction of a major facility. These impacts may be expressed in terms of increased demand for housing, increased local business activity, increased local inflation, increased demand for public services, etc.

• Public service requirements--The impact that construction of a major new energy facility would have on levels of public services required in the local area (independent of those above), including public safety (fire, police, and medical protection), water supply and wastewater treatment facilities, government services, etc.

• Land committed to facility--The impact of the lost opportunities for potential uses of the land committed to the development of major energy facilities (several hundred to several thousand acres).

• Other--Facility or site specific construction activities, specified on a case-by-case basis.

(b) Nuclear power plant operation

Reactor Operation--Those impacts associated with the production of power from a nuclear reactor facility. This does not include those impacts generated by the cooling system, by fuel and waste handling, or by the transmission of the electric power.

• Rad emissions--Those impacts generated by the emission of radionuclides to the air and water. While a portion of these radionuclide emissions are associated with the cooling system, they have been included here to provide for the more general case of overall plant operation.

• Wastewater discharge--Those wastewater effluents not associated with the cooling system nor containing radionuclide emissions (e.g., stormwater runoff, sanitary sewage, and other non-process water uses).

- Human service requirements--The long-term employment and public service requirements of operating a nuclear power plant facility. This includes plant operating personnel, public safety requirements (possibly including disaster training for police, fire, and medical personnel), increased government services, etc.

- Accidents--The potential for major disaster occurrences (e.g., core meltdowns and radioactive gas emissions). Because of the potentially catastrophic nature of such an event, its impacts are immeasurable. This category has been included primarily to emphasize that such events should be considered when judging a proposed nuclear facility.

Fuel and Waste Handling--Both an activity and an impact vector. For the purposes of this study, consideration of fuel and waste handling problems has been limited to those aspects directly related to the energy facility site; it is beyond the scope of the present project to consider problems related to waste reprocessing and ultimate disposal. While such problems are not explicitly discussed in this report, they must be considered as part of an overall site approval process.

Cooling--Those impact vectors directly related to the operation of the facility cooling system.

- Thermal effluent--Those environmental impacts related to the release of heated water from the cooling system into the environment.

- Chemical additions--The impact of the various chemicals, such as chlorine, added to the cooling waters to prevent fouling, scale formation, etc.

- Blowdown water--That fraction of the cooling water removed to prevent the build-up of an undesirable levels of dissolved solids in the cooling water system. It does not include water removed from the boiler-turbine system.

- Makeup water requirement--The impacts resulting from cooling system consumptive water use.

- Fog/drift--The impacts of the production of a visible water vapor plume (fog) and the deposition of dissolved solid material on the ground surface (drift).

- Entrapment/impingement--The physical impact or damage that the cooling water intake has on aquatic organisms (primarily plankton and fish).

- Visual intrusion--Those impacts associated with the physical presence of a major structure as they relate to the surrounding environment.

Transmission--Those impacts related to the transmission of electrical energy via EHV and UHV transmission lines. Also included are those impacts of maintaining these large bulk transmission systems.

- Visual intrusion--(See previous definition.)
- Disruption of human activities--Those impacts related to a limitation on the use of land or the movement of people across it. Examples are the fractionation of property by rights-of-way, and the limitation of the use of lands within a right-of-way.
- Natural system disruption--Those impacts affecting the ecology of an area. They may be reflected in changes in the species diversity of the plant and/or animal communities in and around the area of interest.
- Electric field effects--Potential impacts of high energy electric fields, especially those associated with UHV (765 KV and larger) transmission lines. Examples of these potential impacts include radio noise (RN), television interference (TVI), audible noise (AN), induced voltages, and production of ozone near the lines.

(c) Fossil fuel (coal-fired) power plant operation

Fuel Transshipment and Storage--The receiving, movement over short distances, and storage of coal at fossil fuel power plants.

- Noise-- The impacts of noise generated for a given activity.
- Particulates-- The impacts of fine solid materials given off to the atmosphere during fuel processing and storage or combustion.
- Leachates and runoff--The impact of material leaching and washing off of stored coal and surface wash from plant site in general.
- Visual instrusion--(See previous definition.)
- Human activity disruption--(See previous definition.)
- Equipment use--Impacts associated with the use of fuel-handling equipment.

Plant Operation--That activity directly related to the operation of a fossil fuel power plant to produce electricity.

- Wastewater discharge--(See previous definition.)
- Particulates--(See previous definition.)
- SO_x emissions--The impacts of sulfur emissions from plant operation and fuel processing.

- NO_x emissions--The impacts of nitrogen oxide emissions from fuel processing or combustion.
- Human service requirements--(See previous definition.)
- Accidents--(See previous definition.)

Cooling--(See previous activity and impact vector definitions.)

Waste Handling and Storage--An activity associated with the disposal and storage of waste from fuel combustion or processing. This may include fly-ash and spent sulfur dioxide control materials (limestone, dolomite, etc.). Impact vectors included under this activity have been satisfactorily defined previously.

- Leachates and runoff--
- Particulates--
- Visual intrusion-- (See previous definitions.)
- Human activity disruption--
- Natural system disruption--

Transmission--(See previous activity and impact vector definitions.)

(d) Fuel transshipment and storage facilities

General--Activities common to both coal and oil transshipment facilities.

- Harbor maintenance--The impact of additional harbor maintenance required to service fuel transshipment and storage facilities, including such operations as dredging, dredge spoils disposal, breakwater construction, etc.
- Waterborne material movement--The impacts of additional harbor traffic related to the development of a fuel transshipment and storage facility. It only deals with impacts in the harbor area, not on the lakes in general.
- Overland material movement--Impacts of material movement in the vicinity of the facility. It does not include impacts of the movement of material from the point of extraction to the facility.

Coal Facilities--Those impact vectors specific to coal transshipment and storage facilities. All impact vectors included under this activity have been defined previously.

- Human service requirements--
- Particulates--
- Leachates and runoff-- (See previous definitions.)
- Visual intrusion--
- Human activity disruption--
- Equipment use--

Oil Facilities--Those impact vectors specific to oil transshipment and storage facilities.

- Hydrocarbon emissions--Those impacts associated with the dispersion of hydrocarbon vapors into the atmosphere.
- Leaks and spills--Those impacts that occur through the release of small amounts of oil into the environment.
- Visual intrusion--(See previous definition.)
- Human activity disruption--(See previous definition.)
- Accidents--(See previous definition.)

(e) Refineries

Crude Oil Receiving and Storage--Those impact vectors related to the movement of crude oil from its arrival point (e.g., pipeline, tanker terminal, or rail terminal) to the refinery complex and its storage onsite. All impact vectors included in this activity have been defined previously.

- Hydrocarbon emissions--
- Leaks and spills--
- Visual intrusion-- (See previous definitions.)
- Human activity disruption--
- Accidents--

Plant Operation--Those impact vectors related to fuel processing at a refinery. (The following have been previously defined.)

- SO_x emissions--
- NO_x emissions--
- Particulates--
- Hydrocarbon emissions--
- Other emissions--Impacts associated with the emission of other refinery residuals to the atmosphere, including aldehydes, carbon monoxide, and ammonia.
- Leaks and spills--(See previous definition.)
- Solid wastes--Impacts stemming from handling and disposal of refinery waste materials, such as sludges and biological solids.
- Cooling water consumption--(See Makeup Water Requirement.)
- Process Water Consumption--Water consumed in processing crude oil and feedstocks independent of the cooling system requirements.

- Wastewater effluents--(See previous definition.)
- Visual intrusion--(See previous definition.)
- Accidents--(See previous definition.)

Product Storage and Shipping--The activity with the impact vectors related to the storage of refinery products and their transfer into a shipment system (truck, train, pipe, or ship). All associated impact vectors have been defined previously.

- Hydrocarbon emissions--
- Leaks and spills--
- Visual intrusion-- (See previous definitions.)
- Human activity disruption--
- Accidents--

(3) Impacted Environments

The environments potentially impacted by the activities associated with the construction and operation of energy facilities may be conveniently divided into two major categories: natural and cultural. The natural environment in this analysis refers to the existing physical, chemical, and biological characteristics of a site or area which may be altered by a proposed activity. The cultural environment may be distinguished from the natural by emphasizing the attributes, uses, and alterations of the environment associated with human development. These may be divided into the social, economic, and physical aspects of the human environment.

(a) Natural

(i) Physical and chemical characteristics

Dividing the environment into its three major components, terrestrial, hydrological, and atmospheric, it is possible to describe the existing conditions and suggest how those conditions may be affected by a proposed activity. Under terrestrial are included the existing soil characteristics defined in terms of quantity and composition and landforms which define the natural topography.

The hydrological category includes both the quantity and quality aspects of the surface and ground-water systems. It is necessary to define the existing characteristics of water supply and water quality in order to determine the potential impact of a proposed activity, such as the development of a cooling system and the associated additional demand for water. Changes in water quality that result from this activity are potentially important impacts and should be accounted for in an impact analysis. Examples of such physical and chemical quality changes would include alterations in temperature due to thermal discharges from cooling systems and increases in chloride content as a result of chemical treatment.

The atmospheric category includes the local meteorology of a proposed site and the ambient air quality associated with the area. Because of the importance of the meteorology to local circulation patterns and affected land uses (e.g., agricultural), any potential impacts from energy facility activities should be outlined prior to implementation. Likewise, any alterations in air quality, beneficial or detrimental, which may result from a proposed activity should be noted in an environmental impact assessment. An example of this would be the increase in hydrocarbon levels associated with the emplacement of a new oil refinery.

(ii) Biological conditions

The natural biological conditions can be divided into the terrestrial and aquatic ecology of a given area.

The terrestrial ecology can be categorized in terms of the vegetation and the wildlife which characterize an area or site for a proposed energy facility. Because of the complex interrelationships within these categories, it is important to outline any potential alterations or disruptions in the vegetation and wildlife communities as a result of activities associated with the construction and operation phases of a proposed facility.

Likewise, impacts on aquatic life, such as disruption of benthic communities due to dredging, entrainment, and impingement of nektonic communities by water intake systems, and alteration of planktonic life due to thermal changes, are all potentially significant and should be addressed in an overall assessment.

(b) Cultural

The cultural environment refers to the attributes, uses, and alterations of the natural environment associated with human development. These can be categorized into social, economic, and physical headings.

(i) Social

Included in the social division of the cultural environment are the unquantifiable aspects associated with aesthetics and human interest and the potentially sensitive areas of public health.

Aesthetics and human interest refer to the prevalent values assigned to natural features such as scenic views and vistas, wilderness qualities, landscape design, unique physical features (e.g., sand dunes), parks and reserves, rare and unique species and ecosystems, and historical or archeological sites. It is possible that activities associated with the development of energy facilities may create, enhance, alter, reduce, or destroy those features to which value or interest is attached in a particular area and this impact should be noted.

Factors related to public health which may be affected by a specified activity include ambient noise levels, quality and quantity of drinking water, air quality, and safety. In this case, safety refers to the degree to which public well-being may be affected in the event of a major accident such as radiation leaks, fires, or terrorist attack on the facility.

(ii) Economic

Included in the economic section are those areas of the cultural environment related to the framework within which the human community functions: employment, housing, infrastructure, land value, and local economy.

Impacts on employment can be divided into short-term effects related to the construction of a facility and any long-term effects due to increases or decreases in the maintenance and operation staff. Other possible impacts on employment are the indirect or multiplier effects associated with the increased demand on related goods and services, and the decrease in employment associated with new automated technologies.

Housing supply and demand in an area are directly affected by the influx or workers associated with a construction project on the short term and permanent staff on the long term. In order to meet housing requirements, this impact must be assessed during the planning stages.

Infrastructure refers to the existing transportation network, waste disposal systems, utilities, and public services that are required for support of a population in a given area. Changes in these requirements as a result of the development of an energy facility should be planned for and are thus included in the impact assessment. Safety services in this section refer to police, medical, and fire services.

Land values may change as a result of energy facility development and related activities. These land values are divided into residential, agricultural, commercial, and industrial categories and are considered with regard to their proximity to the proposed facility. In other words, it is possible that residential land values adjacent to a proposed refinery would decrease for its present use, whereas, the value of residential land somewhat removed from the facility would increase due to added demand from added employees.

Finally, the local economy of an area may be affected by a proposed energy facility in terms of changes in governmental budgetary or fiscal effects, and positive or negative impacts on local business activity.

(iii) Physical

Physical aspects of the cultural environment include the existing and potential land and water uses assigned by humans to the natural environment. Also included are the recreational values of the natural environment.

Land and water uses have been divided into wilderness and open space, wetlands, forests, grazing, agriculture, residential, commercial, industrial, and designated lands (i.e., state and federal lands). Impacts of energy facility development differ greatly depending on the existing land use of the area under consideration. This is exemplified in the decision of whether to develop on agricultural land, precluding further agricultural use of that land, or to develop on land already used by industry. The impacts on land use and potential alterations in land use are extremely important in an overall assessment of environmental impact.

Recreational value assigned to a natural area increases or decreases as a result of an energy facility development. Such a change in value should be recognized at the outset. Recreational categories include hunting, fishing, boating, swimming, and camping.

(4) Application

The material that follows provides a general survey of the types of natural and cultural impacts that may accompany the construction and operation of a major new energy facility. Because it deals with general energy facility types rather than with specifically proposed projects, it cannot reach the level of detail necessary in actual project evaluation. It will, however, focus attention on certain aspects of each facility type that should be addressed in such an evaluation.

The matrices accompanying each discussion are intended to be used as guides in developing a facility siting evaluation process. As such, they can be used in several ways. The activities and environments listed on the matrices could be used as guidelines in developing the elements of such a process. In addition, the matrices themselves could be used as a part of the evaluation process. This could be done in one, or both, of two ways. They could be used by the state site review agency or agencies in evaluating specific energy facility siting proposals. Alternatively, they could be used by utilities and companies in developing reports on the environmental and economic impacts of their proposed projects. Ideally, the state agencies and the companies would use the same framework to facilitate a more comprehensive and free-flowing procedure.

Before the analysis of major facility operation impacts, there is a general discussion of construction activity impacts common to all.

b. Energy Facility Construction

Because most construction activities are common to all of the facilities considered here, discussion of their impacts has been grouped into this one section. Where differences do exist, e.g., in period of construction, size of labor force employed, and overall project scale, they will be highlighted and discussed separately. In general, power generating facilities of both types require the longer time (7-10 years) and a larger labor force (peak of more than 2,000 persons) for construction than transshipment facilities, which require the less than 2 years and 100-200 persons. The discussion will first address impacts to the natural environment and then examine cultural impacts.

(1) Natural Environment

Construction activities represent a major disruption of the local environment that can result in significant changes in the surrounding air and water quality. While details as to what those impacts would be and how extensively they would change the existing environment will vary from site to site, a certain amount of generalization is possible. In a report published by the EPA [599], three classes of construction-related pollutants were identified: sediment, chemical, and biological. Of these, very little is known in a quantitative way concerning chemical and biological pollutants. The principal biological pollutants are associated with poor sanitary conditions at the site as well as soil organisms released through the physical disturbance of the earth. The major chemical pollutants associated with construction activities are petroleum products (the largest group), pesticides, fertilizers, synthetic organic materials, heavy metals, additives used to maintain desirable soil characteristics (including lime, fly ash, asphalt, phosphoric acid, salt, and calcium chloride), and construction chemicals (glues, solvents, sealants, etc.)

Several studies have looked at the effect of construction activities on erosion rates and sediment loads. One study in the Washington D.C. area found that, while lands under natural conditions contributed sediment at a rate of less than 70 metric tons/km^2/yr, land under development contributed 354 to 42,350 metric tons/km^2/yr [cited in 599]. Other studies have demonstrated similar results: a study in northern Virginia showed that construction activities representing only 6 percent (72.5 ha) of the surface area of a watershed contributed 94 percent of the 33,500 metric tons of sediment transported from the basin during a 3-4 year period of record [cited in 599].

In a report prepared for the Atomic Industrial Forum [173], four phases in the facility construction process were identified:

- Preconstruction--Those activities which closely follow site selection, including site inventory, environmental monitoring, and implementation of temporary impact controls.
- Site Work--Site clearing and construction of temporary buildings, access routes (roads, railroad spurs, and channels and docks) and associated facilities.
- Permanent Facilities--Activities associated with construction of facility components.
- Project Closeout--Removal of temporary buildings and final landscaping.

The principal pollutants and potential impacts associated with each are listed in Table 17 [from 203].

The distribution and magnitude of these impacts varies with the type of facility being constructed. For example, impacts on the aquatic ecosystem, particularly the benthos, might be greater in the development of a new fuel transshipment facility for which major harbor and channel modification may be necessary. In similar fashion, water quality impacts stemming from erosion of

TABLE 17 POTENTIAL ENVIRONMENTAL IMPACTS RESULTING FROM CONSTRUCTION PRACTICES

Construction Phase	Construction Practice	Primary Pollutants	Potential Environmental Impacts
1. Preconstruction	a. Site inventory		Short-term and nominal
	(1) Vehicular traffic	Dust, noise, sediment	Dust, sediment, and tree injury
	(2) Test pits		Tree root injury, sediment
	b. Environmental monitoring	Visual	Negligible if properly done
	c. Temporary controls		Short-term and nominal
	(1) Stormwater		Vegetation, water quality
	(2) Erosion & sediment	Sediment spoil, nutrients, solid waste	Vegetation, water quality
	(3) Vegetative		Fertilizers in excess
	(4) Dust		Negligible if properly done
2. Site Work	a. Clearing and demolition		Short-term
	(1) Clearing	Dust, sediment, noise, solid wastes, wood wastes	Decrease in the area of protective tree, shrub, and ground covers, stripping of topsoil; increased soil erosion, sedimentation, and stormwater runoff; increased stream water temperatures; modification of stream banks and channels, water quality
	(2) Demolition		Increased dust, noise, solid wastes
	b. Temporary facilities		Long-term
	(1) Shops & storage sheds	Gases, odors, fumes, particulates, dust, deicing chemicals, noise petroleum products, waste water, solid wastes, aerosols, pesticides	Increased surface areas impervious to water infiltration, increased water runoff, petroleum products
	(2) Access roads & parking lots		Increased surface areas impervious to water infiltration, increased water runoff, generation of dust on unpaved areas
	(3) Utility trenches & backfills		Increased visual impacts, soil erosion, and sedimentation for short periods
	(4) Sanitary facilities		Increased visual impacts, solid wastes
	(5) Fences		Barriers to animal migration
	(6) Laydown areas		Visual impacts, increased runoff
	(7) Concrete batch plant	Sediment, dust	Increased visual impacts; disposal of wastewater, increased dust and noise
	(8) Temporary and permanent pest control (termites, weeds, insects)		Non-degradable or slowly degradable pesticides are accumulated by plants and animals, then passed up the food chain to man. Degradable pesticides having short biological half-lives are preferred for use
	c. Earthwork	Dust, noise, sediment, debris, wood wastes, solid wastes, pesticides, particulates, bituminous products, soil conditioner chemicals	Long-term
	(1) Excavation		Stripping, soil stockpiling, and site grading; increased erosion, sedimentation, and runoff, soil compaction; increased in soil levels of potentially hazardous materials; side effects on living plants and animals, and the incorporation of decomposition products into food chains, water quality
	(2) Grading		
	(3) Trenching		
	(4) Soil treatment		
	d. Site drainage		Long-term
	(1) Foundation drainage		Decrease in the volume of underground water for short and long time periods, increased stream flow volumes and velocities, downstream damages, water quality
	(2) Dewatering	Sediment	
	(3) Well points		
	(4) Stream channel relocation		
	e. Landscaping		
	(1) Temporary seeding	Nutrients, pesticides	Decreased soil erosion and overland flow of stormwater, stabilization of exposed cut and fill slopes, increased water infiltration and underground storage of water, minimize visual impacts
	(2) Permanent seeding and sodding		
3. Permanent Facilities	a. Transmission lines & heavy traffic areas	Sediment, dust, noise, particulates	Long-term
	(1) Parking lots		Stormwater runoff, petroleum products
	(2) Switchyard		Visual impacts, sediment, runoff
	(3) Railroad spur line		Stormwater runoff
	b. Buildings		Long-term
	(1) Warehouses		Impervious surfaces, stormwater runoff, solid wastes, spillages
	(2) Sanitary waste treatment	Solid wastes	Odors, discharges, bacteria, viruses
	(3) Cooling towers		Visual impacts
	c. Related facilities		Long-term
	(1) Reactor intake & discharge channel		Shoreline changes, bottom topography changes, fish migration, benthic fauna changes
	(2) Water supply & treatment		Waste discharges, water quality
	(3) Stormwater drainage	Sediment, trace elements, noise, caustic chemical wastes, sediment spoil, flocculants, particulates, fumes, solid wastes	Sediment, water quality
	(4) Wastewater treatment		Sediment, water quality, trace elements
	(5) Dams & impoundments		Dredging, shoreline erosion
	(6) Breakwaters, jetties, etc.		Circulation patterns in the waterway
	(7) Fuel handling equipment		Spillages, fire, and visual impacts
	(8) Oil storage tanks, controls, & piping		Visual impacts
	(9) Conveying systems (cranes, hoists, chutes)		Visual impacts
	(10) Waste handling equipment (incinerators, wood chippers, trash compactors)		Noise, and visual impacts
	d. Security fencing		Long-term
	(1) Access road	Sediments, wood wastes	Increased runoff
	(2) Fencing		Barriers to animal movements
4. Project Closeout	a. Removal of temporary offices & shops		Short-term
	(1) Demolition	Noise, dust, solid wastes	Noise, solid waste, dust
	(2) Relocation		Stormwater, runoff, traffic blockages, soil compaction
	b. Site restoration		Short-term
	(1) Finish grading		Sediment, dust soil compaction
	(2) Topsoiling	Sediment, dust	Erosion, sediment
	(3) Fertilizing		Nutrient runoff, water quality
	(4) Sediment controls		Vegetation
	c. Preliminary start-up		Short-term
	(1) Cleaning	Nuetients, petroleum products	Water quality, oils, phosphate and other nutrients
	(2) Flushing		

excavated and cleared soil might be greatest for a nuclear facility construction site because of the longer construction periods involved. The impacts associated with a given construction activity must be evaluated in light of the specific conditions of the site under consideration and the actions proposed by the developer. A list of factors having a bearing on these impacts include:

- Resistance of the surface and subsurface soils to erosion by gravity, water, and wind
- Chemical and physical properties of the soils and parent materials
- Topography and size of the jobsite
- Distribution and frequency of rainfall
- Care used in trapping sediment and collecting liquid wastes
- Area and time duration of exposure of cleared and excavated portions of the jobsite
- Number of people and machines linked with each jobsite at successive stages of the construction effort [173; p.4].

(2) Cultural Environment

The impacts of construction on the cultural environment in the vicinity of a proposed energy facility can be severe as evidenced in the Alaskan Pipeline experience. While it is unlikely that impacts of such magnitude would be experienced in the Great Lakes Region, certain elements of development-induced cultural system change must be considered.

Tables 18 through 21 present employment profiles for each of the facility types considered. The different facility types show considerable variation in terms of construction time, peak construction employment, and operating employment requirements. Because of its small construction manpower requirements, it is not likely that the development of a new fuel transshipment facility would cause any significant cultural system impacts. On the other hand, the large work forces and relatively long construction periods with high levels of employment for power plants and refineries create the potential for some local social impact. The magnitude of this impact depends on existing socioeconomic conditions and must be evaluted on a case-by-case basis.

Cultural impacts during the construction and pre-operational stages of major facilties development arise from three major sources: influx of a large construction work force, the movement of construction materials through the

TABLE 18

WORK FORCE PROFILE: NUCLEAR POWER PLANTS*

	PROPOSED POWER PLANT INFORMATION								HYPOTHETICAL AVERAGE (2200MWe)	
	Belefonte (2430MWe)		McGuire (2360MWe)		River Bend (1870MWe)		Susquehanna (2100MWe)			
Year	Construction	Operation	Construction	Operation	Construction	Operation	Construction	Operation	Construction	Operation
1	850	0	850	0	100	0	300	0	418	0
2	1500	0	1537	0	350	0	1800	0	1232	0
3	2150	0	1810	0	1200	0	2300	0	1980	0
4	2240	30	1634	0	2100	0	2500	0	2200	0
5	1660	155	950	30	2000	0	2400	0	1914	0
6	630	170	200	170	1650	0	1500	0	1254	35
7	0	170	0	200	1000	30	800	0	396	105
8	0	170	0	200	300	70	250	20	0	140
9	0	170	0	200	0	100	100	60	0	140
10+	0	170	0	200	0	100	0	77	0	140

* [390]

TABLE 19

WORK FORCE PROFILE: FOSSIL FUEL (COAL) POWER PLANTS

	PROPOSED POWER PLANT INFORMATION						BECHTEL ESTIMATES[3] (800MWe)	
	Colstrip 3 & 4[1] (700MWe)		Tombigbee 2 & 3[1] (420MWe)		Pleasant Prairie 1 & 2[2] (1234MWe)			
Year	Construction	Operation	Construction	Operation	Construction	Operation	Construction	Operation
1	270	0	180	0	48	0	40	0
2	1418	0	972	0	155	0	420	0
3	1418	0	972	0	566	0	864	0
4	270	173	180	112	1131	0	814	0
5	0	693	0	450	578	0	360	109
6	0	693	0	450	845	0	0	109
7	0	693	0	450	81	120	0	109
8+	0	693	0	450	0	120	0	109

1 [390]

2 [573], Unit 1 completed in year 5, Unit 2 in year 7.

3 [541], probable error less than 25%.

TABLE 20

WORK FORCE PROFILE: REFINERIES

Year	250 MBD[1]				200 MBD[3]	
	Low Fuel Oil		High Fuel Oil		Low Fuel Oil	
	Construction[1]	Operation[2]	Construction[1]	Operation[2]	Construction	Operation
1	2180	0	1800	0	521	0
2	2180	0	1800	0	2536	0
3	2180	0	1800	0	3272	0
4	0	435	0	410	1257	0
5+	0	435	0	410	0	551

1 [506]

2 [505]

3 [541], probable error generally less than 25%.

TABLE 21

WORK FORCE PROFILE: FUEL TRANSSHIPMENT FACILITIES

	COAL		OIL
	Superior, Wisconsin[1] (8 million tons/yr)	Marquette, Michigan[2] (12 million tons/yr)	Superior, Wisconsin[3] (6.2 million barrels/yr)
Construction Period (months)	20	12	12
Construction Employment	100	-	150 - 200
Operating Employment	50	2[4]	8 - 12

1 [391]

2 [299]

3 [158]

4 Based on operator time requirements.

local area, and the presence of the facility itself.* Of these, the potential for the greatest cultural system damage is associated with the first, while the greatest potential benefits stem from the third. Of course, the magnitudes of the costs and benefits associated with each will vary from case to case.

(a) Influx of work force

For a construction project of the magnitude considered here, there will be 1,000-3,000 workers employed at the site for periods of up to five years. It is doubtful that a mix of the skilled tradesmen in the quantities required could be found locally unless the site were near a major metropolitan area. In other cases, a large fraction of the work force would have to come in from outside of the local area and either commute (daily or for the week days, leaving on weekends) or move into the local area for the duration of the project. Construction workers generally are willing to commute long distances to job sites, with 50-100 miles each way not uncommon [451]. Figure 14 shows those areas within 75 miles of major metropolitan areas (SMSAs with 1970 populations of 500,000 persons or more) in the Basin where daily commuting may be possible for a large portion of the work force. While it may not present a complete picture of "local work force availability," Figure 14 does at least indicate that the southern, more heavily developed portion of the Basin may generally be less susceptible to the types of impacts associated with heavy in-migrations of construction workers.

The reader is cautioned about drawing conclusions from Figure 14 and the brief dicussion of it that go beyond the material presented. In reality, the problem of a commuting versus transient resident work force is much more complex, depending on many factors, some site-dependent, others supralocal. One factor that must be considered is the attractiveness of the site community in terms of inducing workers to move from their present locations to the local area. For example, if the workers were being drawn primarily from large metropolitan areas of great cultural diversity (shopping, entertainment, recreation, schools, etc.) that a rural job site could not offer, then it might be that those that could commute would do so. If however, the site were in an area similar to those

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* For the purpose of this discussion, the physical presence of the facility itself, regardless of its operational status, will be considered under construction impacts. Impacts and residuals stemming directly from the operation of the plant are discussed in later sections.

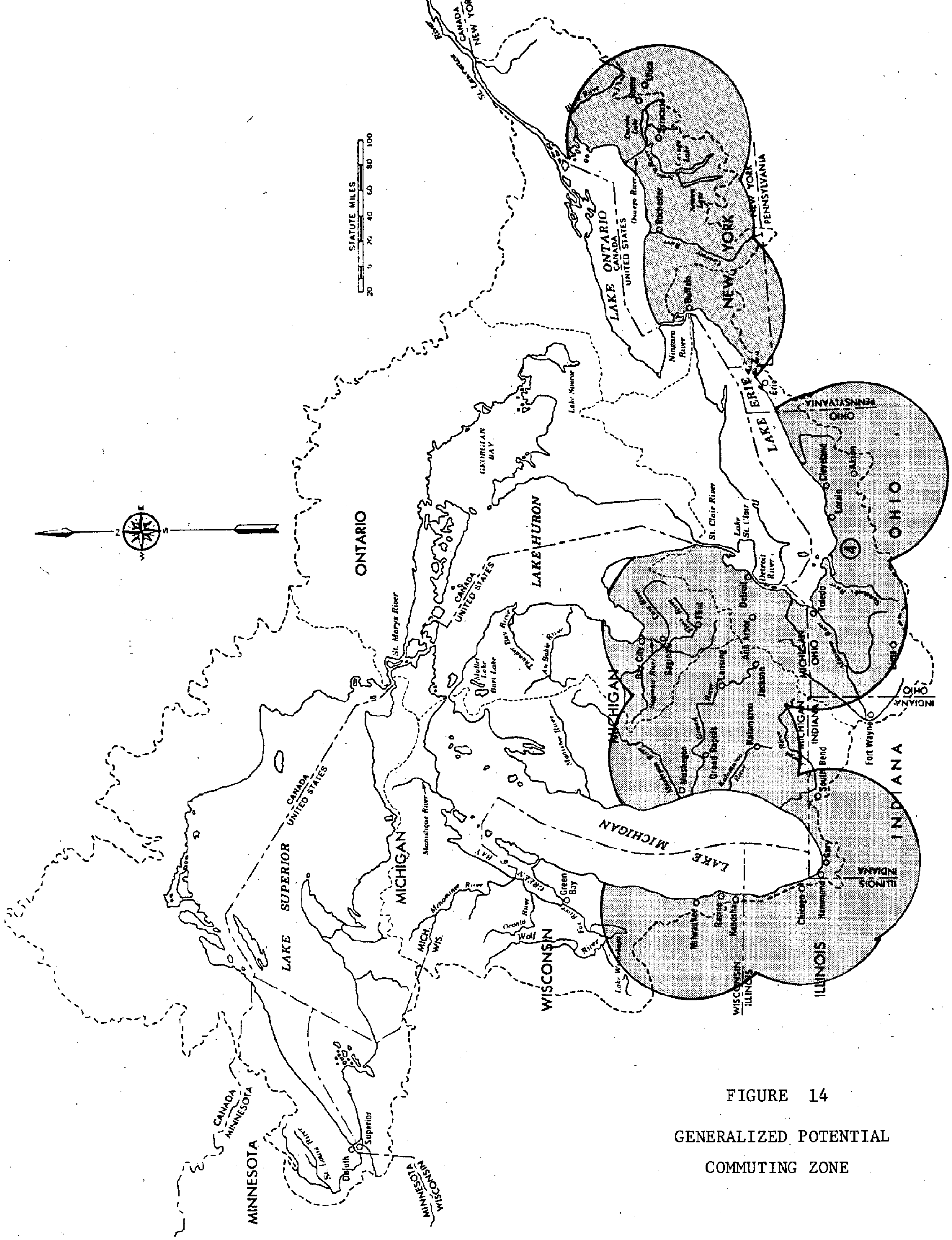

FIGURE 14

GENERALIZED POTENTIAL

COMMUTING ZONE

in which the potential work force lived at present, there may be more in-migration to the local community.

Another factor is that the contractor and subcontractors may bring a portion of the labor force in with them, especially for the managerial and highly skilled engineering positions [451]. Thus, if non-local construction firms were used, it is likely that at least a portion of the work force would be brought in form outside of the area.

Labor union practices are also important in determining the geographic origin of the construction work force [451]. How jobs are distributed to members of the various craft locals will influence the mix of commuting versus resident workers:

> It was found to be a general rule that the location of the union had much to do with the housing and commuting patterns of the work force. For instance...more people commuted to the job site from Leominster and Fitchburg [Massachusetts], a distance of roughly one hour by good road, than might have been expected. The cause of the heavy commuting was the fact that most of the carpenters working on the site were from the Fitchburg-Leominster area [and] nearly all the field employees commuting from that area were, and are, carpenters [451; p.175].

Another factor that should be considered is the condition of the local (i.e, commuting) construction labor market. If unemployment among the skilled trades is high, then more local commuting might be expected. If, on the other hand, the available labor force is fully employed, then immigration from other regions may provide a large percentage of the needed workers.

There are three patterns of work force entry to the local area: daily commuting, Monday-Friday commuting (where the worker stays in the area during the week and travels to a permanent home over the weekend), and relocation to the local area for the duration of the project. In general, the first case, a daily commuting force, "generates minimal fiscal, social, or political impacts on a host community" [hypothesis advanced in 600]. In a study of the cultural system impacts of two nuclear facility construction projects (Pilgrim I in Plymouth, Massachusetts and Millstone I in Waterford, Connecticut) in which daily commuting was common, the following conclusions were drawn:

> Social, political, and economic impacts upon the towns of Waterford and Plymouth during construction of their respective nuclear plants have been minimal. The only impact of any magnitude identified retrospectively is construction worker traffic.

> Most construction workers in the case of Pilgrim I and Millstone I and II commuted to the site from their existing place of residence within the metropolitan areas rather than relocate closer to the site or within the host community. As a result, little impact on commercial activity was noted in either community during construction.
>
> In both Plymouth and Waterford, little interaction took place between construction worker crews and local townspeople. What interaction did take place was primarily in local grocery stores and taverns.
>
> Speeding by construction workers appeared to be a problem in Waterford and Plymouth. In Waterford, a police officer had to be stationed at the entrance to the construction site each night in order to control speeding onto secondary town roads [600; pp.9-10].

In the case of Monday-Friday commuting by the project workers, the potential impacts may be somewhat more important, depending on local socio-economic conditions. During the week, the workers would require housing, food, and recreation in the local area. However, they would probably not spend a large portion of their wages locally, preferring instead to send most of it to their families for living expenses elsewhere. This means that service industry requirements would be minimal. Also, because the workers do not relocate their families into the local area, impacts on the schools and other family-related systems would be insignificant.

This is not to say, however, that Monday-Friday commuters may not cause significant local impacts. The need for housing, especially of a "boarding house" type, for the workers during the week may cause changes in the local housing mix and price structure. Conversions of large single dwellings into multiple units may increase availability to offset this demand.* Existing rental housing may be diverted away from those who would normally rent it as well. Rents may rise as the demand increases, especially as local landlords see an opportunity to increase profits at the expense of the construction workers (whose median income may be considerably higher than the local norm). Because of this, low-income residents of the area may be forced into lower quality housing than they could afford prior to the project. Finally, the housing mix established as a response to the project will exist after construction has ceased, which may leave the local communities with an overabundance of poor

* A secondary impact may be an increase in building code violations and the need for an expanded inspection and enforcement program.

quality rental units [451]. Also, rents may fall once the work force leaves the area, causing significant local income effects.

There will also be impacts felt in other sectors of the local economy. Food sales may increase, both at markets and restaurants and cafes. Tavern and bar sales may also increase [451]. As in the case of housing, market demand-response expansion and inflation may occur in these areas during the construction period followed by a sharp decline once the project ends. It is not likely that there would be significant increases in the durable goods market.

There are, of course, many factors operating to mitigate these potential problems. For one, the magnitude of these problems will depend on the local economic and social structure. It would be reasonable to assume that, in general, a large metropolitan area would be better able to absorb the work force without significant change than would a rural town or small city. Care must be taken not to over generalize, however, and to examine the economy of the proposed site localities in detail to determine how important these effects might be. For example, the impacts, particularly with respect to housing, may be considerably less in areas oriented to a seasonal tourist economy, where excess capacity may be available for rent.* Also, areas with stagnant or declining populations may have an excess supply of housing available and, thus, be more able to absorb the influx of workers.

In addition, the construction workers may not locate in one area but rather, spread out into surrounding localties. This avoids a concentration of the impacts of this phase (subject to the qualifications discussed with respect to local fiscal effects below).

In some cases, a substantial portion of the work force may relocate into the locality of the project. The impacts of such an immigration can be significant, subject to the caveats discussed above. Demand for housing in this case will be shifted away from the "boarding house" market, into family dwellings. This may cause a decrease in availability of rental units and a limited increase in new home starts. An important source of housing for construction worker families is the mobile home sector [451]. Because rapid development of mobile home parks can bring problems with public service support and conflict with existing residents (especially in areas of limited experience with this form of

---

* Owners may also prefer to rent to construction workers on a year-round basis, rather than depend on temporary tourist occupancy.

housing), the expansion of these facilities should be carefully planned and integrated into the local system.

An overview of the local response to the demand for new housing has been summarized as follows:

> Recent population trends and the age structure of the local population are important: in an area which is stagnant or declining in population, and which has relatively few younger people, rooms or larger parts of existing houses may be in great supply and obviate the need for other sources. An area which is growing rapidly and has many young families is more likely to meet some demand with permanent housing, because such housing is likely to be saleable or rentable after construction ceases.
>
> The availability of sites for mobile home parks, the importance of tourism (and, thus, the abundance of motels and inns), and the attitudes of owners toward conversion and renting space to strangers are all relevant factors. The general amenities and quality of public services will also influence choices of workers, especially those bringing families. Thus, the sources of supply of housing which are easily expanded in particularly favored communities will weigh heavily in determining the mix for the whole region [451; p.179].

In addition to demand for new housing and associated services, there will also be a general increase in local business activity. As in the case of the weekend commuting, food and food service sales will increase, although to a greater extent in this instance. There will also be increases in other sectors, including both durables and nondurables as family-oriented demand rises.

As a net result, more of the consturction payroll will be spent locally, generating secondary income benefits. The size of this income multiplier effect, as it is called, is determined primarily by two important factors, the marginal propensity to spend locally (c), and the fraction of sales that becomes local income (h).* The general formula is:

$$\text{multiplier} = \frac{1}{1-(c)(h)}$$

The larger the value of the multiplier, the greater the secondary income benefits.

The marginal propensity to spend locally is simply the fraction of total income spent on locally provided goods and services. As such, it depends on the

* This concise explanation of a potentially complex concept is taken from reference 451.

mix of goods available locally, relative prices between local and imported goods, the availability of imports, and the type of goods and services desired.

Finally, movement of families into a locality for the term of the project could have impacts on other services, such as schools, sewers, health care, police, churches, etc. The school system especially could be adversely affected, as enrollment increases, but only for a short period (2-7 years). Because the crowding is only temporary, new additions may not be warranted. This does, of course, depend on the enrollment in the system relative to capacity before the project begins.

(b) Movement of material through the local area

In addition to a movement of workers to the site of a new energy facility there is also a large-scale movement of material:

> All plants require substantial amounts of materials to be moved to the plant site. The most important of these are the concrete required for buildings and dams; steel for concrete reinforcing and for structural frameworks; and large pieces of equipment, such as turbines, parts of boilers, pipes, etc. These materials can be moved to the construction site by any one of three ways, by truck, by rail, or by barge, depending upon how accessible the site is to each of the modes and where the materials are being shipped from. In general, the greater the dependence on highway transportation, the greater the impact on the surrounding communities [451; p.130].*

The major transportation-related problems are local system congestion (both by worker traffic and material delivery to the site), increased risk of accidents, and deterioration of the roadbed, curbs, and bridges.

There may also be local improvements to the transportation system brought about by the project. For example, relocation and improvement of existing roadways could provide improved access for the local residents after the construction period has ended.

Related to the movement of construction materials through the local area is the local purchase of materials to be used at the site. If the area is highly industrialized and produces structural steel, piping, equipment, or other materials, then a significant share may be bought locally. However, if the area is rural with little heavy industry, then the locally purchased material will

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* See discussion of Transportation Access Requirements in description of nuclear power plants.

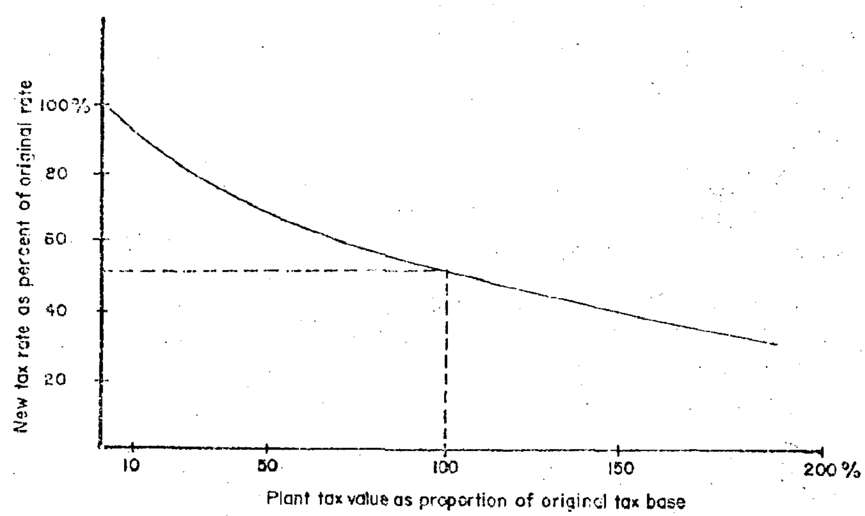
most likely be limited to sand and gravel.

(c) Impacts of the facility's presence

The presence of a major new energy facility, even prior to its operation, can produce significant changes in the local socioeconomic system. One of the most obvious of these impacts is the addition to the local tax base. A new facility valued at several hundred million to more than one billion dollars will pay several million dollars per year in property taxes upon completion.* Assuming that total tax revenue to the local jurisdictions remains constant, this would mean a tax reduction for all other property owners. The size of this reduction depends, of course, on the tax value of the plant relative to the total local tax base. Figure 15 illustrates the range of effects that a new plant might have on the tax rate as its share of the tax base changes.

FIGURE 15

EFFECT OF A MAJOR NEW FACILITY
ON THE LOCAL TAX BASE



[Source - 451]

* It will also produce property tax revenue throughout the period of construction in proportion "to the total amount expended by the utility on investment to date" [451; p.194].

In a case study of two towns within which nuclear generating plants provided 50-60 percent of the local tax base, workers from Oak Ridge National Laboratory found the following:

> The major impact of the nuclear plant in both Plymouth and Waterford is the large increase in tax base provided by the operating reactor.
>
> One option chosen by both communities has been to lower (or stabilize) the existing tax rates while currently using the additional revenues to significantly increase public services and facilities.
>
> Both communities have taken some steps to professionalize administration of services through hiring new staff and creating some new positions in local government. In both communities, new departments of public works have been established and town planners have been hired to control future land use development. In Plymouth, a town manager has been hired to oversee local affairs [600; p.10].

In addition, to direct tax benefits from the new facility, there will be some secondary tax revenue gains. For example, new housing for construction and operating employees will expand the facility tax base. Also, market value of commercial property may increase in expectation of higher profits [451]. Finally, there may be added benefits in cases where local communities can levy sales and income taxes, especially during the construction period.

These benefits do not accrue without offsetting costs, however. The Oak Ridge study cited above also has identified a number of problems created by the new facilities:

> External relationships of the two communities have been altered by the presence of the nuclear power plant, principally because of the augmented tax base. The presence of the nuclear power plant may create new tensions or exacerbate existing tensions.
>
> Efforts have been initiated in both states to redistribute the utility tax payments so that a larger proportion will go to other jurisdictions and/or the state.
>
> Neighboring towns have, in varying degrees, become resentful or antagonistic over the favored status and resources of the host community. The transportation of nuclear waste through neighboring towns in both Plymouth and Waterford has caused some concern and has resulted in challenge of the legality of the transfer of that waste.
>
> The sudden population growth occurring in Plymouth since 1968 (the beginning of the nuclear plant construction) was intensified by construction and operation of Pilgrim I, but growth would have occurred soon because of regional growth patterns

> and proximity to Boston. Growth was one consequence of the lowered tax rate in Plymouth [600; pp.11-12].

While these conclusions are based on the study of a specific situation, they do highlight a problem that may be true in the general case. That is, while tax revenue (especially property tax revenues) generated by the facility accrues primarily to the host jursidiction, the costs may be shared with several surrounding communities.

There are other problems related to local fiscal effects as well. For example, the actual assessment and taxing procedure may be very complex, causing problems for local officials. There are sometimes problems with deciding what portion of the facility is taxable, how to tax transmission line easements, how the presence of the plant or construction activities affect neighboring property values, etc. [451]. Resolution of problems such as these may be beyond the capability of local administrators.

Another problem is that plannning and implementation of programs to mitigate adverse impacts, especially during the construction phase, must be done before the project begins. Tax revenue to finance these programs, however, is not available until after construction has begun (see Table 22). This lag effect can produce dislocations in the local fiscal picture.

TABLE 22

TAX PAYMENTS DURING CONSTRUCTION

OF THE JIM BRIDGER POWER PLANT

Tax Year	Property Taxes ($)
1972	$ 37,000
1973	490,000
1974	1,285,000
1975	3,000,000
1976	4,000,000
1977+	5,000,000

[Source - 451]

Another source of monetary benefits is the interst paid on the bonds to construct the facility. However, it is likely that these monies will be spread out among a large group outside of the local area and, hence, will not add directly to local income.

In addition to monetary costs and benefits, the presence of a large energy facility will have other impacts of both a local and regional scale. In many cases, at least a portion of the land used for such a facility will be unavailable for other uses for at least 30-40 years. The long-term commitment of a site of the size considered here (range of 300 to approximately 3,000 acres) will affect development patterns on a local and, perhaps, a regional scale. In addition, potential uses displaced by the facility must be considered, especially in terms of alternative sites available to them. This analysis should also include possible uses of water resources that may be preempted in the long term.

Related to this is the problem of potential land use conflicts that may arise, both in terms of existing development patterns and future changes. A large facility does not exist in a vacuum and must be related to the socioeconomic matrix within which it is located. Included in this is the problem of aesthetic disruption and visual intrusions which may be considered to be a measure of harmony between human artifacts and the existing environment. Natural draft cooling towers, tall stacks, and large distillation and cracking towers can significantly degrade the quality of surrounding environment.

(d) Summary

The evaluation of facility impacts during the construction and preoperational stages is a complex and confusing task. The discussion presented above covered only part of the picture, giving major highlights without filling in the many gaps and details needed to do a complete analysis. Table 23 presents a list of potential construction phase problems. Used in conjunction with the facility activity impact matrices, it should present at least a starting point in evaluating the cultural impacts engendered in the construction of a new facility.

c. Operating Impacts

The major impacts caused by the operation and maintenance of a large energy facility are related to the production, storage, and release of residuals to the water, air, and land. In contrast to the construction phase impacts

TABLE 23

CONSTRUCTION IMPACT SUMMARY

ACTIVITY	ITEM OF ACTIVITY	COMMUNITY FUNCTION PRACTICE, OR VALUE	IDENTIFICATION OF POTENTIAL PRIMARY CONDITION CHANGES, NUISANCES, AND BENEFITS	IDENTIFICATION OF MAJOR ENVIRONMENTAL AND SOCIOECONOMIC IMPACTS
I. Work Force	A. Services	1. Lodging 2. Transportation 3. Schools & churches 4. Utilities 5. Medical 6. Police & fire 7. Recreational 8. Commerical 9. Postal	CHANGES IN: Need for housing, schools, water supply, medical, postal, and police services. NUISANCES: Disposal of garbage and solid wastes, increased peak traffic loads, and overloading of telephone system. BENEFITS: Increased taxes and income for public utilities; expansion of medical services, postal, and food services.	Schools; recreational use of waterways, playgrounds, and open space; increased circulation of money; increased traffic loads.
	B. Social Aspects	1. Labor force 2. Employment 3. Cultural patterns	CHANGES IN: Mix of professional and technical workers, influx of skilled labor, family life pressures. NUISANCES: Population density, pressure on existing local wage rates, relocation of homes, and changes in property ownership. BENEFITS: Increased employment opportunities for skilled and unskilled workers.	Relocation of homes and property; increased employment opportunities.
II. Overall Development	A. Business	1. Agricultural 2. Commercial 3. Industrial 4. Mineral 5. Forestry 6. Recreational	CHANGES IN: Size of certain business establishments; land use, zoning and sewerage ordinances; demand for recreation, entertainment, and other lesiure-time activities. NUISANCES: *Periodic* crowding of commercial parking areas, picnic, and recreational areas; solid waste disposal, sediment and other pollutants related to new business construction. BENEFITS: Increased spending for food, drugs, heating fuel, gasoline, lumber, leisure time activities, and rentals.	Demand for recreation, entertainment, and food.
	B. Aesthetics and Human Interest	1. Scenic views 2. Wilderness areas 3. Unique physical features 4. Parks and reservoirs 5. Open space 6. Monuments and landmarks 7. Rare and unique species of plants, mammals, & birds 8. Historical and archaeological	CHANGES IN: Accessibility and relative security of wilderness areas, landmarks, and rare and unique species. NUISANCES: Visual pollution, emotional clashes, adversary encounters, litigation, time delays due to public opposition BENEFITS: Public discussion and decision making.	Public attitudes and historic conflicts.
	C. Transportation	1. Truck and rail deliveries of heavy equipment and construction materials 2. Heavy construction equipment	CHANGES IN: Traffic volume, required fuel supplies. NUISANCES: Increased demands on locals to provide fuels and lubricants: load limits on roads and small bridges necessitating delivery route changes; low underpasses requiring alternate highway and railroad routes: oversized loads causing tree damage: increased noise and exhaust emissions. BENEFITS: New bridges and/or roads to accomodate increased load weights, creation of docking and rail-head unloading facilities, increased job opportunities for locals to provide fuels and road and vehicle maintenance	Increased traffic flow

[Source - 173]

which are primarily related to the cultural environment, those produced by plant operations tend to be more closely tied to the natural environment. This is not to say, however, that they do not affect the cultural system, but rather that their impacts are generally channeled through the natural system. For example, changes in air quality caused by plant emissions could lead to public health problems and reductions in land values close to the plant site.

In many cases, the linkages between these natural system changes and resultant changes in the cultural system are poorly understood. This is especially true where those changes require long periods of time to accumulate and become measurable. As a result, a discussion of the environmental impacts caused by facility operation must deal primarily with identifying the residuals produced rather than the effects of those residuals on the natural and cultural environments.

(1) Fossil Fuel (Coal-Fired) Power Plants

Table 24 presents a general summary of the types of impacts associated with the major activities in the power generation fuel cycle,* while Figure 16 diagrams the major impacts specifically related to the operation of a coal-fired power plant. The discussion below is organized by major activity types as defined previously and shown in Figure 16. For a discussion of the impacts related to fuel transshipment and storage, the reader is referred to the section on Coal Transshipment and Storage Facilities.

(a) Plant operation

Table 25 presents estimates of the air-borne effluents produced by a 1,000-MWe plant both with and without emission controls. While this type of information may not indicate the effect of these emissions on the environment, it does at least provide guidelines as to the scale of the problem.

The impacts and interactions of these air-borne residuals on the environment are generally not understood at this time. Of the major pollutants listed in Table 25, the one most easily controlled at present is particulate matter. Current control technology allows collection efficiencies greater than 99 percent [546, 222, 451, and others]. For this reason, the most visible effects of

* The entire fuel cycle has been included here to provide the reader with a broad perspective of the impact picture. Only those activities directly related to this report are discussed further.

TABLE 24

SUMMARY OF FUEL CYCLE IMPACTS

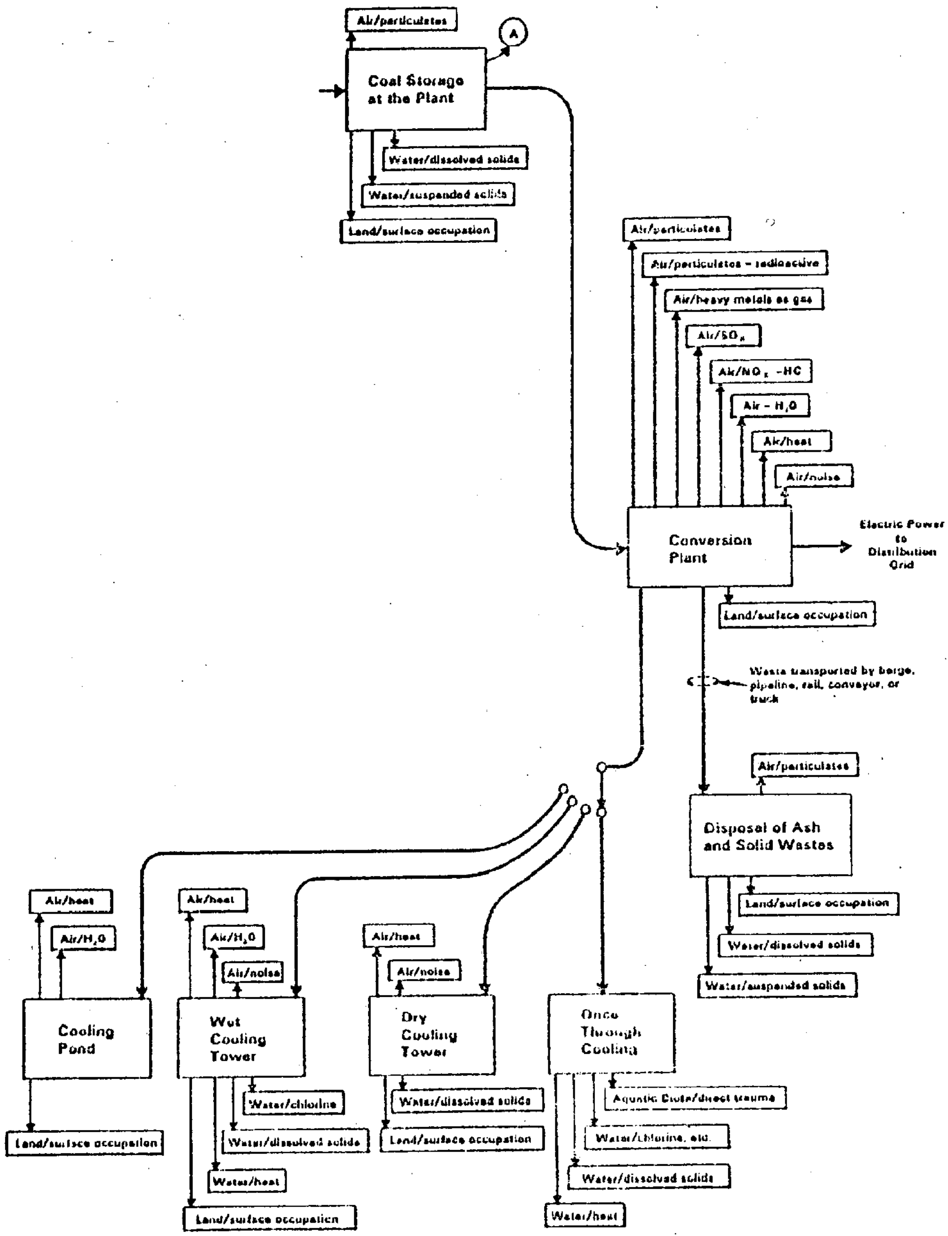
FUEL CYCLE ACTIVITY	WATER	AIR	LAND	BIOTA
Extraction	siltation, pH changes	particulate emissions	soil erosion	disruption of habitat altered successional patterns, toxic compounds, radiological impact
Transport	accidental releases	particulate and gaseous emissions,	right-of-way	disruption of habitat toxic compounds radiological impact
Preparation	effluents, heat rejection	particulate and gaseous emissions, heat rejection	solid wastes, physical plant siting	disruption of habitat toxic compounds radiological impact
*Conversion	thermal discharges, toxic compounds consumptive water use	particulate and gaseous emissions	solid wastes, physical plant siting	disruption of habitat toxic compounds, radiological impact
*Transmission			right-of-way maintenance	alteration of habitat, disruption of landscape homogeniety, biocides
*Disposal	heat rejection	gaseous emissions, heat rejection	dedication of repository land	releases of toxicants, radiological impact

* Discussed further in text

[Source - 501]

FIGURE 16

DIAGRAMATIC SUMMARY OF
COAL-FIRED POWER PLANT ENVIRONMENTAL IMPACTS



(A) Indicates significant numbers of direct human deaths from accidents.

[Source - 501]

TABLE 25

SUMMARY OF COAL-FIRED POWER PLANT AIR EMISSIONS

Description	Primary Efficiency	Nitrogen Oxides (10^3 tons)	Sulfur Oxides (10^3 tons)	Particulates (10^3 tons)	Thermal (10^{12} Btu's)	Solid (10^3 tons)
Coal: Conventional steam No controls [1]	38	21.8	119.2	48.5	31.1	298
Eastern Coal: Conventional Boiler with wet limestone scrubbing	35	19.2	16.0	3.2	0	955
Eastern Coal: Conventional Boiler with magnesium oxide scrubbing [2]	35	19.2	16.0	3.2	0	410
Western Coal: Conventional Boiler with wet limestone scrubbing [2]	35	25.0	5.1	2.2	0	487
Physically Cleaned Eastern Coal: Conventional Boiler with wet limestone scrubbing [2]	35	17.6	6.4	1.4	0	417
Coal: Steam plant with controls [1]	38	23.2	19.1	2.6	0	1,009

1 Based on data developed by Hittman [400 and 401]

2 Based on data from Battelle [545]

particulate emissions, thick, dark smoke, and deposition of dirt on surrounding property, can be eliminated.

While the overall removal efficiency may be high, the ability to control the fine particulates (<1μ) is markedly lower. Recent studies have indicated that trace metals (such as arsenic, beryllium, cadmium, maganese, mercury, nickel, and vanadium) have a high affinity to this fine fraction [546]. Table 26 shows estimates of emission rates for these trace elements. The toxicity of many of these elements has been documented and there is some concern regarding the long-term effects of chronic, low-level exposure.

TABLE 26

TRACE ELEMENT EMISSIONS OF A COAL-FIRED POWER PLANT (1000MWe)

	lbs/ton of coal burned[1]	tons/yr[2]
Arsenic	0.003	5
Beryllium	0.0003	0.4
Cadmium	0.001	0.001
Manganese	0.080	
Mercury	0.0004	5
Nickel	0.003	0.5
Vanadium	0.0005	
Lead		0.2

[1] [546] [2] [203]

Also of increasing concern is the emission of trace radioactive materials in particulate form, primarily as uranium and thorium and their associated daughter products [203]. While comparison with nuclear plant emissions is difficult because of the large number of variables involved, one study has indicated that they fall "intermediate between the annual dose from PWR and BWR nuclear plants" [cited in 203; p.174].

Other effects associated with particulate emissions include the following:

- Action as a catalytic agent in reactions involving SO_x and/or NO_x (discussed below)

- Vehicle for carrying toxic materials deep into the respiratory tract
- Reduction of direct sunlight
- Reduced visibility
- Interference with plant physiology
- Adverse effects on animals eating plant materials with particulates on them [203]

The principal oxides of nitrogen released to the atmosphere during the combustion process are NO (nitric oxide) and NO_2 (nitrogen dioxide). Most of the NO_x produced in the boiler is NO, a portion of which is converted to NO_2 upon reaction with oxygen in the atmosphere via a photo-chemical reaction [203]. The effects of NO_x in the environment are just now becoming clear. They are "now recognized as prime contributors to the eye-irritating smog characteristic of Los Angeles area" [451; p.115]. Other studies [cited in 203] indicate serious health effects:

> At ambient concentrations, NO_2 presents a direct threat to general health, while NO does not...except in its ability to be converted to NO_2...
>
> Nitrogen dioxide exhibits primary toxicity to the lungs, and levels above about 100 ppm are lethal to most animals. Repeated exposure to NO_2 in sub-lethal doses has resulted in early pulmonary emphysema-type lesions in the experimental animals. Long-term exposure to NO_2 concentration that does not cause acute inflammatory responses may have a significant role in the development of chronic lung disease... Other effects of atmospheric NO_x are corrosion damage and crop reduction...[203; p.172].

In general, research and development of NO_x control systems for power plants have been quite limited, primarily because the automobile is presently the major contributor to air-borne oxides of nitrogen.

As discussed previously,* air pollution control efforts by the electric utilities have concentrated on the reduction of sulfur emissions (SO_x) from the combustion process. The main species of SO_x formed in the combustion chamber is SO_2 (sulfur dioxide). In general, SO_2 by itself does not exhibit any major deleterious effects [521]. However, once in the atmosphere, the SO_2 participates in a number of chemical reactions resulting in several products, each capable of some degree of environmental damage. The processes by which these conversions take place "are complex and incompletely understood" [521; pp.xxii-xxiii].

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* See discussion of Emerging Technology in Fossil Fuel Power Plant.

When SO_2 is emitted to the atmosphere, a fraction of it is oxidized to form H_2SO_4 (sulfuric acid). While the reaction normally occurs relatively slowly (0.1 percent per hour), it is greatly accelerated by the presence of other air contaminants (trace metal ions, hydrocarbons, and nitrogen oxides). Once formed, the sulfuric acid may then react with trace metal ions (found in conjunction with the five particulates discussed above) to form particulate sulfates. Even in the absence of this oxidation reaction, the SO_2 may dissolve in water vapor, forming the weakly acidic surfurous acid (H_2SO_3).*

The effects of SO_2 and its by-products can be observed throughout the natural and cultural environments.

> The major impact of airborne SO_2 is probably on vegetation. These effects are due to the direct effect of acid formed on the surface of leaves in combination with moisture and to SO_2 gas penetrating into the plant tissues..." [498; p.29].

In terms of its impact on man, SO_2 is primarily a pulmonary irritant:

> Massive acute doses can result in severe respiratory reactions, chronic low level exposure may lead to chronic obstructive lung disease. The secondary reaction products of SO_2 in the body may result in additional potentially systemic effects" [498; p.30].

The synergistic effect of SO_2 and fine particulates may be potentially more serious due to the formation of sulfates and the ability of the particulate material to carry them deeper into the respiratory tract [498 and 521]. "Animal studies and the recent...epidemiological studies indicate that sulfate aerosols are the form of airborne sulfur primarily affecting man's health" [498; p.32]. However, the health effect findings are not completely clear:

> First, the chemical form of the sulfates that are associated with increased mortality and morbidity has not yet been clearly identified. Second, there have been few direct epidemiological studies linking excess mortality to sulfates. Rather sulfate concentrations were usually estimated based on correlations with particulates and sulfur dioxide (a correlation which has been shown to be low) and these estimates were related to health effects... Finally, case studies (e.g., London) tend to indicate that attainment and maintenance of ambient standards for SO_2 and particulates will protect public health [393; p.A-7].

In addition, sulfur emissions can affect materials as an acid increasing corrosion and deterioration of "painted surfaces, metals, building materials, and

* See [521] for a more complete description of these reaction sequences.

fabrics" [498; p.31]. They also can reduce visibility at high concentrations.

Appendix E contains a list of the observed effects of the three major air contaminants associated with fossil fuel power plant operation (particulates, NO_2, and SO_2), taken from a report prepared for the Michigan Public Service Commission [393]. While they are not the only important pollutants associated with plant operations, they are the ones for which standards currently exist and, thus, should be highlighted. However, consideration of a much broader range of pollutants, including the secondary products of these three, should be a part of a site selection and/or certification procedure.

Wastewater effluents other than those associated with the cooling system arise from several sources: main steam boiler blowdown, demineralizer regeneration wastes, floor drains, sanitary wastes, and ash sluicing water. Most of these waste streams are relatively small compared to cooling water return flow. (Even a closed-cycle system blowdown flow can be several thousand gallons per minute.) Some are subject to standard treatment practices (e.g., sanitary waste treatment and the use of ash settling ponds to significantly reduce suspended solid loads in ash sluicing water).

The impact of these effluents will depend on the volume of flows, treatment received, the discharge structure configuration, the nature of the chemicals, and the assimilative capacities of the receiving waters.

> The impact of these chemicals on human populations is generally not direct, because natural processes of dilution and chemical reactions reduce the concentrations to negligible levels at the point where water is withdrawn for human uses [203; p.156].

Specific details of potential impacts on the aquatic ecology are difficult to quantify because of the wide variety of variables and the complexity of interactions (most not yet understood) involved.

Leaching of toxic materials from the ash storage pile may represent a serious threat to the quality of the ground-water supply.

Direct cultural system impacts arising from the operation of a coal-fired power plant are not nearly as significant as those possible during the construction phase. As indicated in Table 12, the operational work force for proposed plants ranges from 120-693 persons. Estimates from other sources indicate a somewhat smaller range: 150-300 [203], approximately 160 [451], and 120 [526]. Unlike the construction force, however, the operating personnel will become part of the permanent residential base in the local communities:

> ...the induced effect on local business and employment in other industries will be substantially greater than the effects of the same number of construction employees. They will tend to spend a greater proportion of their income in the area, and their housing needs will be more permanent and substantial. This means the property tax collections per employee will be higher, but of course their demands on public services will also be higher. They and their families are much more likely to take active roles in the community, especially as they have above-average education and income. In a sparsely populated region, the addition of even 50 or so such families may make an important difference in social and cultural life, and the work of civic, charitable, and fraternal organizations [451; p.177].

(b) Cooling system operation

Presently, one of the activities of concern related to the operation of a power plant (both fossil fueled and nuclear) is the dissipation of waste heat via the condenser cooling system. The potential impacts, particularly to the aquatic ecology, may be significant and must be considered in a facility evaluation procedure. Discussion as to what these impacts are has been grouped by cooling system type below.

(i) Once-through cooling

Once-through cooling systems have a minimal impact on the air and local meteorology, as most of the waste heat is carried to the receiving body. Likewise, they have the smallest land requirement and require no major structures that may conflict with the surrounding landscape.

It is the potential impact on the aquatic ecology that has generated the most opposition to the continued use of once-through cooling. These impacts are:

> ...attributed to (a) the mechanical and thermal shock to small entrained organisms that pass through the cooling system pumps and condensers, (b) the effects of increased water temperature on the biota in the receiving waters, (c) the entrapment and impingement of fish on the intake screens, (d) the toxic effect of chemicals introduced into the cooling water, and (e) the effects of erosion and changing of ambient currents in the receiving water. Because once-through cooling systems utilize large volumes of water from the receiving body (rivers or lakes), they have the potential for producing significant biological impacts [203; p.191].

The entrainment and subsequent passage through the condenser system of large numbers of small organisms is considered by some to be the leading environmental hazard of once-through cooling systems [380]. While there are few studies available to show the magnitude of the problem in the Great Lakes, indications are that it may be significant:

> In addition to the losses of fish caused by impingement on the 3/8-inch mesh traveling screens within power plant cooling systems on the Great Lakes, substantially larger numbers of fish 0.3-2.5 inches long are lost when they are drawn into these plants and pass through the traveling screens (rather than being impinged). ...Edsall and Yocum estimated a potential entrainment of several million fish fry per day at two power plants in southeastern Lake Michigan. Their estimate was based on the abundance of fish fry in the lake near the cooling water intakes and the cooling water use rates at the two power plants. Intensive studies of the kinds and numbers of fish eggs and fry being entrained at plants on the Great Lakes and their connecting waterways are now underway. Preliminary results of one such study being conducted at the Detroit Edison plant on Lake Erie near Monroe, Michigan, indicate that more than 300 million fish larvae may have passed through that plant during April-August 1973. The fate of these larvae was not determined, but the data indicate that some may have disintegrated during passage through the plant, and the mortality among the remainder must almost certainly have been high [617; p.458].

While the importance of entrainment has recently become apparent, the significance of thermal loadings has been discounted by some: "Thermal pollution is not the leading adverse environmental threat from power plants, as commonly has been believed" [380; p.v]. However, there is still a large body of evidence that thermal effluents can and do cause significant damage (see reviews of findings in 203 and 617). In general, most effects seem to be sublethal, involving changes in species composition, fish movement through the area, and spawning habits. Other temperature-induced effects include increased incidence of gas bubble disease, synergistic chemical reactions, and oxygen depletion.

Related to the discharge of thermal effluents are the effects of entrainment of fish in the discharge plume.

> This form of entrainment had also been overlooked until recently, but the available information suggests that the number of fish fry that are entrained in this manner may be several times greater than the number entrained at the cooling system intake and passed through the plant. This is especially prevalent at plants with high velocity discharges specifically designed to lower the effluent temperature by rapid dilution of the effluent with the cooler lake (receiving) water. Studies have not been done to determine the fate of fry entrained in this manner at

> Great Lakes power plants, but mortality could occur from heat shock, chlorine intoxication, predation, or from hydraulic mauling received during entrainment. Various investigators have found that one major effect of such sublethal exposure of fish to elevated temperature is a reduction in the ability of exposed fish to avoid predation [611; p.459].

Impingement on the trash rack and mesh screens of the water intake structure may also cause fish kills. Examples from studies on impingement problems in the Great Lakes include the following:

- About 92,000 pounds of gizzard shad at the Lambton plant on the St. Clair River in 6 weeks during December 1971-January 1972
- 82,187 pounds (nearly 1.1 million individuals) at the Detroit Edison Company's plant on Lake Erie near Monroe, Michigan between April 1972 and March 1973, when the plant was operating at less than maximum capacity
- 36,631 pounds (584,687 fish) at the Consumers Power Company's Palisades plant on Lake Michigan between July 1972 and June 1973, when the plant was operating at about 68 percent of its total capacity
- An estimated 1.2 million fish (no weight data given) at the Waukegan, Illinois plant on Lake Michigan between June 1972 and June 1973
- 150,000 pounds of fish at the Pickering Plant on Lake Ontario in April-June 1973
- 659,000 fish (weight unavailable) at the Nine Mile Point plant generating unit number one on Lake Ontario during intermittent sampling from January to December 1973, representing an estimated total of about 5 million fish at unit one for that period
- About 67,950 pounds (929,000 fish) at the Zion plant near Zion, Illinois, on Lake Michigan during September-December 1973 and March-June 1974, when the monthly cooling water flow averaged only about 45 percent of the maximum capacity [611; p.458].

Of course, the significance of the entrapment and impingement problem cannot be judged unless its effects are viewed relative to the Great Lakes Fishery as a whole.

Water used in a plant cooling system requires the addition of chemicals to prevent biological fouling and retard corrosion. Chemicals used include:

> chromates, zinc, phosphates, and silicates for corrosion control; chlorine, hypochlorite, chlorophenols, quaternary amines, and organometallic compounds for bacterial growth control; acids and alkalis for pH control necessary to prevent scale formation;

lignintannins, polyacrylamides, polyethylene amines, and other polyelectrolytes to reduce silt deposition [203; p.205].

When released to the aquatic environment, these chemicals and/or their reaction products can have toxic effects, especially on organisms near the outfall. While discharges are normally kept below established toxicity levels, there may be adverse effects due to:

- Possible synergistic effects of the higher water temperatures in a cooling water discharge
- Possible synergistic and/or cumulative effects of other chemicals already present in the water and in the tissues of the organism
- Presence of untested species or individuals more sensitive to a particular chemical than the tested individuals
- Possible chronic and long-term sublethal effects that may not manifest themselves until later in the life cycle of the organism [203; p.205].

These effects may be more serious with closed-cycle systems because of the increased amounts of chemicals used and the small amount of water available for dilution.

(ii) Natural draft cooling towers

The use of a natural draft tower creates potential adverse effects on the local meteorology through increased fogging (and icing during the winter months).* However, this is less likely to be a problem than if mechanical draft towers are used.

Related to the problem of fogging is that of drift: water lost in droplet form by means of which salts are deposited over a wide area downwind from the tower. While drift rates are low (0.002 percent of the circulating flow rate for natural draft towers), these deposits may be detrimental to the biota and agriculture.

One concern related to the use of cooling towers at fossil fuel plants is the possibility of synergistic effects between the most vapor plume and the stack emissions. In particular, reactions with SO_2 in the stack gas could produce a sulfuric acid mist. But studies have not indicated that this is a serious problem [203].

Land requirements for a natural draft cooling tower are greater than for

* See section on Hydrology and Meteorology in description of Nuclear Power Plants.

a once-through system but are less than that of the other closed-cycle systems.*

The most obvious impact of a natural draft cooling tower is its presence in the surrounding landscape. Because they are up to 500 feet tall and 400 feet in diameter, it is difficult to make them unobtrusive. Of course, the degree of intrusion will depend on the character of the surrounding area and the way in which people view the two in juxtaposition.

Finally, natural draft towers could have adverse effects on migratory birds if located in a major flyway [614].

(iii) Mechanical draft cooling towers

The potential for fogging and icing problems is much greater with mechanical draft towers than with natural draft towers. This is because the mechanical towers are much lower (60 feet versus 500 feet), making inversion penetration less likely. Also, the plume is less concentrated and cools faster than the larger natural draft plume. The potential for drift problems is somewhat higher as 0.005 percent of the circulating flow is lost in this form [203].

Land requirements are somewhat higher than for natural draft towers due to the need for multiple units and spacing between them to prevent recirculation.

Because of their low profiles, mechanical draft towers themselves do not present the aesthetic problems associated with natural draft units. However, the increased propensity for fogging and icing could cause significant visual impacts. Also, noise caused by the fans can be an important problem during operation.

(iv) Cooling ponds

Occasional fogging and icing problems may be associated with the use of cooling ponds, although not to the extent of cooling towers. There are no drift problems.

The major problem associated with the use of cooling ponds in the large land requirement: greater than 1,000 acres for the size of facility considered here. Creation of a water surface this large may require the impoundment on a river, which could have significant natural and cultural impacts.

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* See Land Requirements in the Fossil Fuel Power Plant description.

(v) Spray Canals

The potential for fogging and icing problems is somewhat higher for spray canals than for cooling poinds, although it may be more localized than that of mechanical draft towers. Also, while there may be some drift produced, it is ejected at such a low altitude (10-15 feet) that it would most likely not be a problem outside of the plant site.

Land area requirements for a spray canal system are larger than that for a cooling tower of either type but much smaller than that for a cooling pond.

(vi) Summary of cooling system impacts

The above discussion has touched only briefly on the problems related to cooling system operation, especially with respect to the impacts on the aquatic environment. While the discussion of these impacts was included in the section on once-through cooling, it is important to remember that all cooling systems will affect the source and receiving waters to some degree.

(c) Waste handling and storage

As discussed in the facility description section, a coal-fired power plant requires approximately 100 acres for ash disposal over its operational lifetime. The impacts associated with the handling and storage of these waste materials are primarily related to the release of potentially degrading and toxic materials to the environment and the disruption of human and natural systems.

As discussed in the plant operation section, toxic materials present in the fuel tend to become concentrated in the ash. These substances (primarily heavy metals and radioactive isotopes) find their way into the environment by several pathways: particulate material blown off the waste piles, dissolved and suspended fine particulates in the ash sluicing water, leachates and runoff from the storage area into the ground and surface waters.

The movement of waste material between the boiler and the disposal site may have an impact on traffic movement around the facility if the two sites are physically separated. Also, the presence of the disposal area could have aesthetic impacts if it is visible from off-site locations. Finally, the ash disposal area will displace the natural biota of the site.

(d) Transmission lines

The impacts of an Extra High Voltage (EHV-345 and 765 kV) transmission line arise primarily from two sources: disruption of the natural and cultural environments by the presence of the right-of-way and its associated structures, and induced electric field effects caused by the flow of energy through the line.

The presence of a transmission line right-of-way can cause several changes in the local natural environment. The clearing and subsequent revegetation of the right-of-way create a new habitat, leading to increased species diversity. At the same time, however, the application of herbicides as a part of the right-of-way maintenance procedure may have detrimental effects on both the terrestrial and aquatic ecosystems, if proper application procedures are not followed. Also, piles of slash left along the right-of-way may provide breeding grounds for harmful insects and plant pathogens.

Crossing of property lines by the right-of-way may result in fractionation of property and disruption of certain activities, such as agriculture. This will not be a significant problem if less than fee-simple ownership of the right-of-way (i.e., an easement) is acquired, since the actual structures require little area and the owner would be able to keep most of the land in its former use.

A right-of-way may also provide an access route into or through an area where none had existed previously. This may have a positive or negative effect, depending on whether or not such access is desirable.

One of the major problems associated with transmission lines is that they can be aesthetically disruptive. This is especially a problem in cases where the right-of-way crosses a high-visibility area, such as a hilltop or a scenic vista. It can also create aesthetic, and sometimes physical, disruption when it crosses a recreation area. The degree of disruption will vary from case-to-case and should be evaluated carefully in site selection and/or approval decision.

The second class of effects associated with EHV transmission lines is that related to the electric field generated by the flow of energy through the lines. Available environmental reports prepared by the utilities [378 and 608] indicate that these effects are limited and not significant, although there is some controversy regarding this point [602].

CONSTRUCTION		GROUND CLEARING AND RESHAPING
		EQUIPMENT USE
		CHANNELIZATION, SHORELINE MODIFICATI AND OTHER WATER-RELATED ACTIVITIES
		MATERIAL MOVEMENT TO SITE
		INFLUX OF TEMPORARY WORK FORCE
		PUBLIC SERVICE REQUIREMENTS
		LAND COMMITTED TO FACILITY
		OTHER
FOSSIL FUEL (COAL) POWER PLANT OPERATION	FUEL TRANSSHIPMENT AND STORAGE	NOISE
		PARTICULATES
		LEACHATES AND RUNOFF
		VISUAL INTRUSION
		HUMAN ACTIVITY DISRUPTION
		EQUIPMENT USE
	PLANT OPERATION	WASTEWATER DISCHARGE
		PARTICULATES
		SO_x
		NO_x
		HUMAN SERVICE REQUIREMENTS
		ACCIDENTS
	COOLING	THERMAL EFFLUENT
		CHEMICAL ADDITIONS
		BLOWDOWN WATER
		MAKE-UP WATER REQUIREMENTS
		FOG/ICING/DRIFT
		ENTRAPMENT/IMPINGEMENT
		VISUAL INTRUSION
	WASTE HANDLING AND STORAGE	LEACHATES AND RUNOFF
		PARTICULATES
		VISUAL INTRUSION
		HUMAN ACTIVITY DISRUPTION
		NATURAL SYSTEM DISRUPTION
	TRANSMISSION	VISUAL INTRUSION
		HUMAN ACTIVITY DISRUPTION
		NATURAL SYSTEM DISRUPTION
		ELECTRIC FIELD EFFECTS

Because EHV transmission lines use air as an insulator, there is a constant discharge to the atmosphere, termed "corona discharge." The magnitude of this discharge depends primarily on the size and spacing of the conductors and ambient weather conditions, especially humidity. Proper design can reduce the problems caused by corona discharge, but cannot eliminate them.

There are four potential problems related to the effects of corona discharge: audible noise (AN), television and radio interference (TVI and RI, respectively), ozone production, and electrostatic induction.

Generally, these problems are worse during wet or humid weather. Right-of-way selection and line design should be carried out in such a way as to minimize these effects.

Figure 17 summarizes the impact vectors and environments potentially affected by the construction and operation of a fossil-fuel power plant.

(2) Nuclear Power Plants

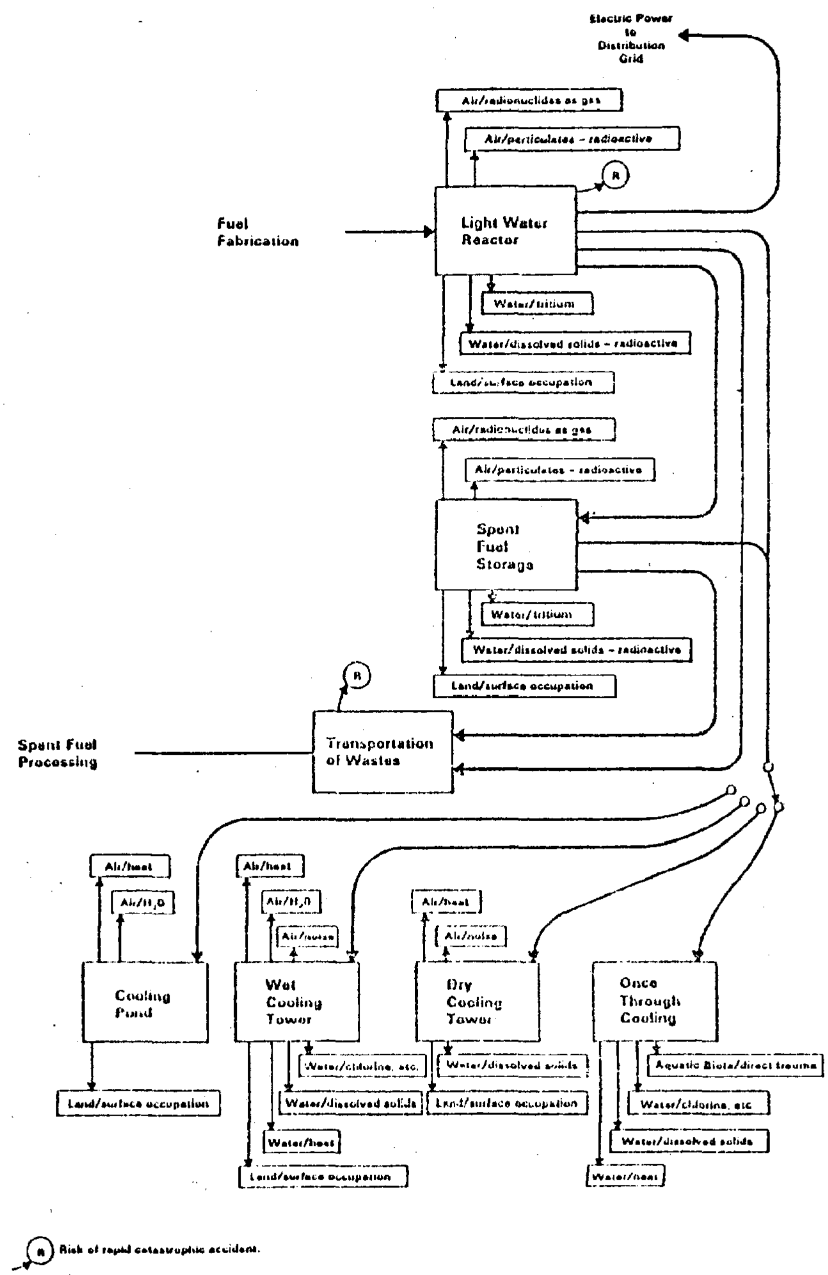
The types of impacts and general environments affected by the operation of a nuclear power plant are shown in Figure 18. This discussion will concentrate on impacts related to reactor operation, specifically sources of radionuclide release to the environment. It will also touch briefly on human service requirements, and accidents. Impacts related to cooling system operation and electricity transmission have been covered adequately in the previous section and will not be repeated here.

> The principal sources of radioactive materials are the fission products which are produced in the fuel elements as a by-product of normal operation. The quantity formed is small in terms of mass, amounting to a few kilograms per day in a large power plant. Under normal operation, more than 99 percent of fission products remain in the reactor core where they were formed. Small quantities which leak from the fuel elements, however, are ultimately released from the plant radioactive waste processing system to the environment. In addition to the fission products, other sources of radioactivity are leakage of radioactive materials from control rods, activation of impurities in the reactor coolant, activation of corrosion products from structural materials, and tramp uranium which adheres to the outside of the fuel rods during the manufacturing process [203; p.23].

There are four types of radioactive waste materials (radwastes) that must be dealt with: gaseous, liquid, ventilation exhaust air, and solids. All four are produced by both reactor types now in use: the boiling water reactor

FIGURE 18

DIAGRAMATIC SUMMARY OF
NUCLEAR POWER PLANT ENVIRONMENTAL IMPACTS



and pressurized water reactor. However, the mix of these wastes varies with reactor type, BWR's producing more gaseous radwaste (radgas) and PWR's producing higher levels of liquid radwaste.

(a) Boiling water reactor wastes

The principal source of radgas in both reactor types is the degassing of the primary coolant. Much of this gas is a result of air inleakage at the condenser. In a BWR, additional gaseous wastes are generated by fission and activation products and radiolytic decomposition products (hydrogen and oxygen). Also, radgas emissions may arise from leakages around the turbine gland seals, especially in older plants (new plants having eliminated this waste source).

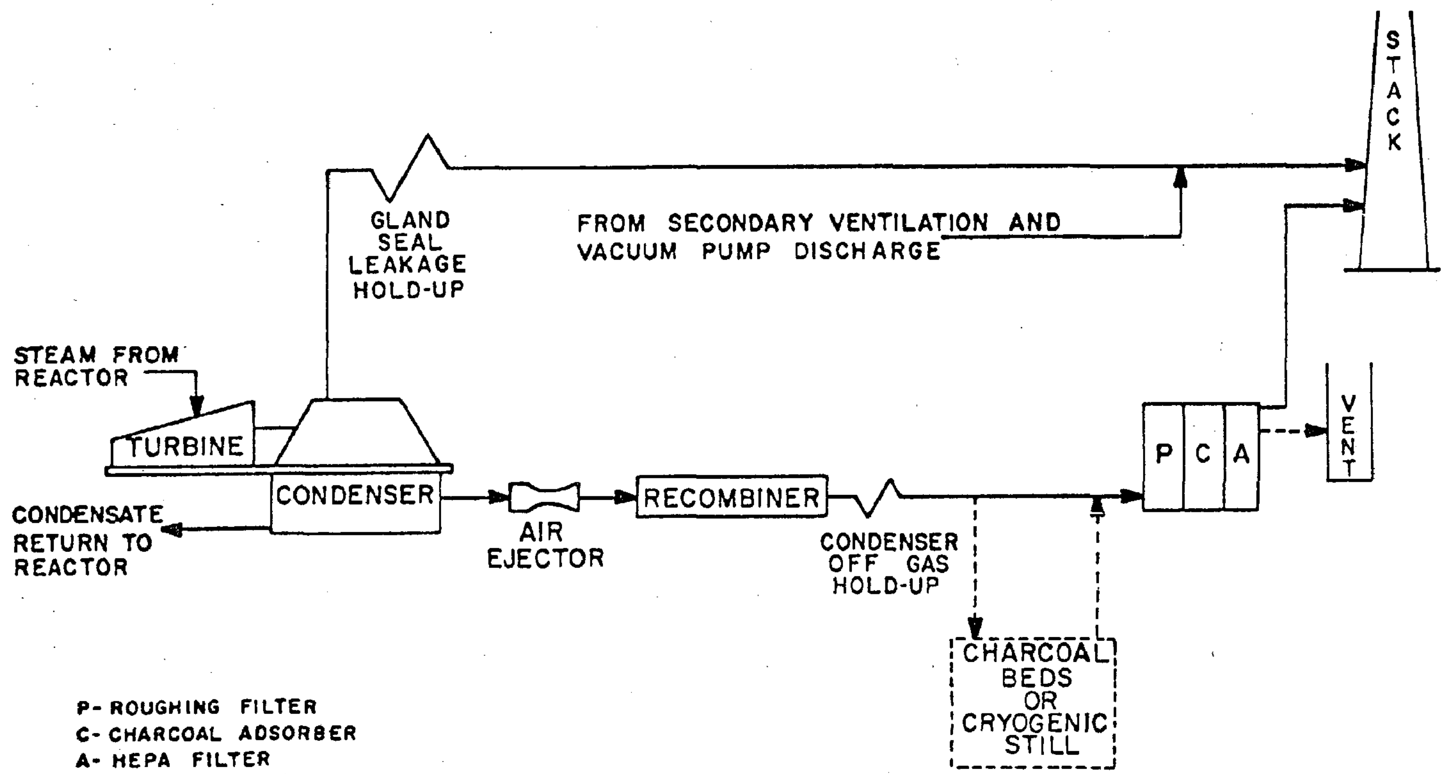
Most of these gaseous wastes are removed at the turbine condenser through an air ejector. These effluents contain nitrogen-13 (an activation product), noble gas isotopes, krypton and xenon (fission products), halogens (mostly iodine), and tritium. In addition, there are some radioactive particulates and solid decay products associated with the gaseous wastes.

Treatment consists primarily of delay (30-60 minutes) to allow the short-lived isotopes to decay and filtration through high efficiency particulate (HEPA) filters prior to venting through the station's stack [203 and 546]. Alternatively, cryogenic distillation may be used to liquify and remove the noble gas fission products [546]. A charcoal absorber system can also be used to provide up to 10 hours of delay to reduce the amount of xenon and krypton, the two principal radioactive species. Figure 19 shows a simplified radgas control system schematic while Table 27 summarizes the principal isotope emissions based on varying delay times.

There are four major types of liquid radwastes from a nuclear power facility of either type: high purity wastes, which are radioactive but low in normal chemical impurities (e.g., primary coolant leaks and equipment drains); low purity wastes with varying levels of radioactivity, such as floor drains; chemical wastes; and detergent wastes with low levels of radioactivity [203 and 546]. "These waste streams are segregated according to origin so that liquids of near coolant quality may be treated and reused..." [546; p.167]. Following treatment, the liquid waste discharges are then bled into the cooling water discharge flow at such a rate to meet government emission standards. Figure 20 and Table 27 show a typical BWR liquid radwaste treatment system and effluent activity levels, respectively.

FIGURE 19

BWR RADGAS CONTROL SYSTEM



P- ROUGHING FILTER
C- CHARCOAL ADSORBER
A- HEPA FILTER

[Source - 203]

TABLE 27

ANNUAL LIQUID EFFLUENT ACTIVITY FOR A 1000 MWe REACTOR

Principle Isotopes	BWR (Curies/year)	PWR (Curies/year)
Rb-88	--	0.39
Sr-89	0.64	--
Y-90	0.14	--
Y-91	0.31	--
I-131	1.71	0.47
Te-132	--	0.96
I-133	0.20	0.11
Cs-134	0.36	0.41
Cs-136	--	0.20
Cs-137	0.27	0.28
Cs-138	--	0.27
Ba-140	0.93	--
Ba-137m	--	0.26
La-140	0.71	--
Fe-55	0.26	--
Co-58	0.60	0.33
Mn-56	--	0.84
Other liquid activity	1.0	0.78
Total (excluding tritium)	7.1	5.3
Tritium	20.0	350

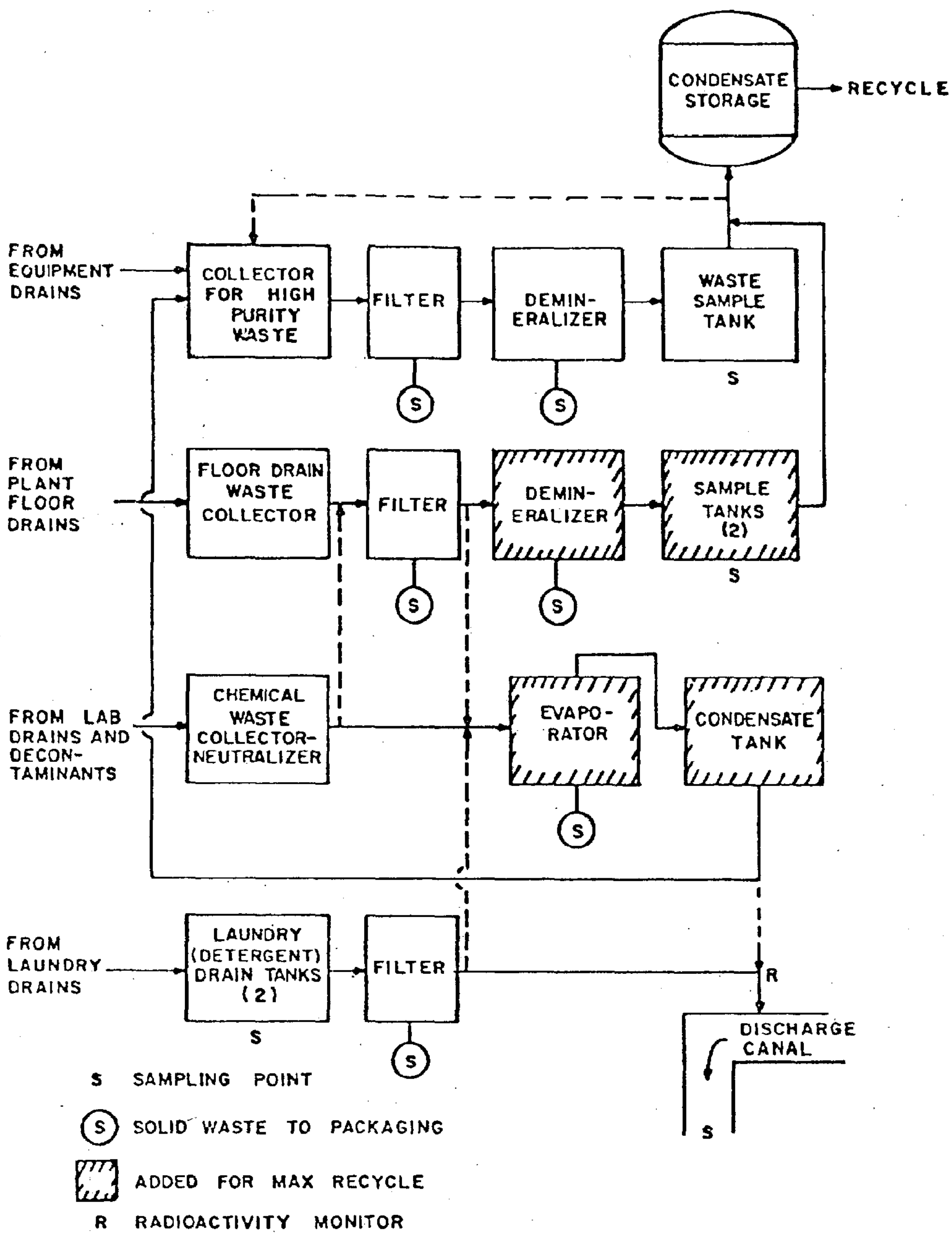
[Source - 203]

Solid radwastes are similar for both BWR's and PWR's, consisting of three general types: wet, such as spent resins and evaporator concentrates; dry compressible, such as rags, clothing, and plastic; and dry noncompressible, such as equipment [546]. The wet wastes are solidified and kept on-site for a period to permit the decay of short-lived radionuclides. Ultimate disposal for all forms is burial at an approved site. It is estimated that total solid waste activity from a 1000-MWe reactor amounts to 2,500-5,000 curies* per year [203].

* See Table 21 for definition.

FIGURE 20

BWR LIQUID WASTE SYSTEM



[Source - 203]

(b) Pressurized water reactor wastes

The major source of PWR radgas is in the primary coolant system, although "radioactive gases will exhaust from the main condenser air ejector when steam generator leakage from primary to secondary system occurs" [546; p.190].

> During operation of PWR, radioactive materials released to the atmosphere in gaseous effluents are similar to those released from a BWR and include low concentrations of the fission product noble gases (krypton and xenon), halogens (mostly iodines), and tritium contained in water vapor and particulate material [203; p.26].

However, the activity levels of these emissions is typically much lower for a PWR, due to the considerably larger delay prior to release (45-60 days); see Table 28. A schematic of a PWR radgas control system is shown in Figure 21.

As Table 28 indicates, liquid radwastes are similar for both PWR and BWR plants with the exception of tritium. This greater than tenfold difference in tritium emissions arises

> primarily from the use of boron soluble poison in the PWR coolant for supplementary control. Boron undergoes a neutron capture reaction to generate tritium which has a relatively long half-life (12.3 years). Since tritiated water is chemically identifical with ordinary water, separation is very difficult and to date impractical. The lower tritium releases in later model PWR's have been largely achieved by water management schemes which store more of the tritium in the plant water inventory [203; p.34].

As discussed above, PWR solid radwastes are similar to those from a BWR facility.

(c) Environmental impacts of emissions

Figure 22 shows the major pathways of radiation through the environment and ultimately to the human population. Under normal operating conditions, all nuclear plants (and, as discussed earlier, most fossil fuel plants) emit traces of radioactive substances to the environment in both liquid and gaseous form.* Concern with the effects of these emissions, especially over the long term, is one of the major points of controversy in the nuclear power debate. The brief discussion below cannot answer any of these questions (nor can any other document) but it will highlight some of the issues.

---

* Radioactive solids (except for fine particulates that may pass through the HEPA filters) are not considered to be an emission for the purposes of this report, although their handling and disposal (storage) do present significant problems.

TABLE 28

ESTIMATED ANNUAL RADGAS EFFLUENTS
FROM A 1000-MWe REACTOR

Nuclide	Half-Life	Release Rate, curies*/year 1/		
		30 min. delay 2/	1 day delay 3/	60 day delay 4/
^{83m}Kr	1.86 hr.	90,000	13	0
^{85}Kr	10.76 yr.	250	250	250
^{85m}Kr	4.4 hr.	160,000	3,900	0
^{87}Kr	1.3 hr.	480,000	1.5	0
^{88}Kr	2.8 hr.	510,000	1,500	0
^{89}Kr	3.2 min.	11,000	0	0
Total Kr activity		1,250,000 (approx.)	5,650	250
			15 day delay 3/	
^{131m}Xe	11.9 day	375	150	10
^{133}Xe	5.27 day	160,000	22,000	50
^{133m}Xe	2.3 day	6,000	50	0
^{135}Xe	9.2 hr.	540,000	0	0
^{135m}Xe	15.6 min.	260,000	0	0
^{137}Xe	3.8 min.	28,000	0	0
^{138}Xe	14 min.	780,000	0	0
Total Xe activity		1,800,000 (approx.)	22,200	60

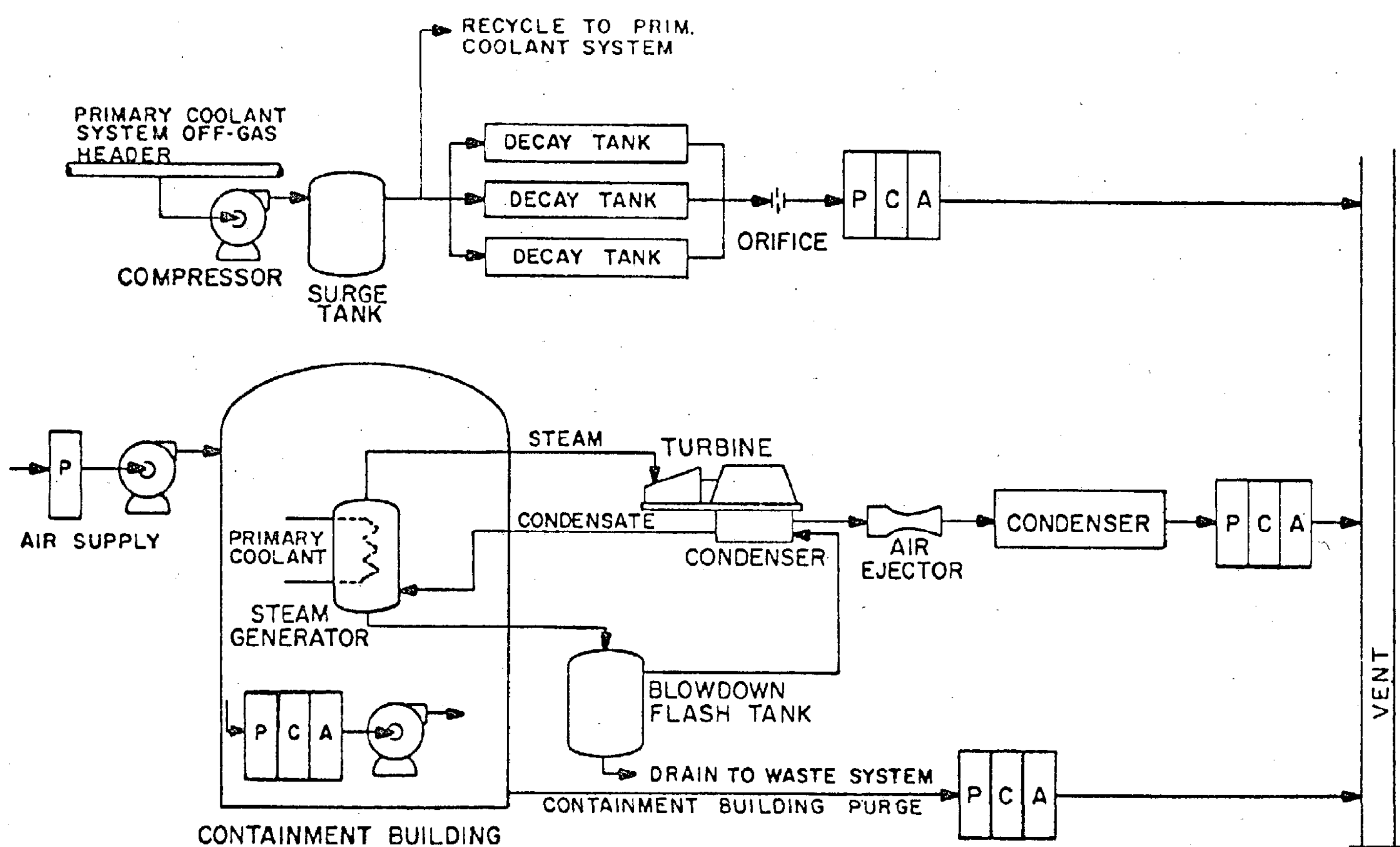
1/ Assumes operation with 0.2% clad defects.
2/ Typical holdup time in BWR's built to date.
3/ Typical holdup times for BWR's using charcoal beds.
4/ Typical holdup times in PWR's are between 45 and 60 days and accordingly would be between the 1 and 60 day values.

* A curie is a measure of radioactivity, specifically "a quantity of any radioactive nuclide in which 3.7 x 10^{10} disintegrations occur per second." (Webster's New Collegiate Dictionary)

[Source - 203]

FIGURE 21

PWR RADGAS CONTROL SYSTEM

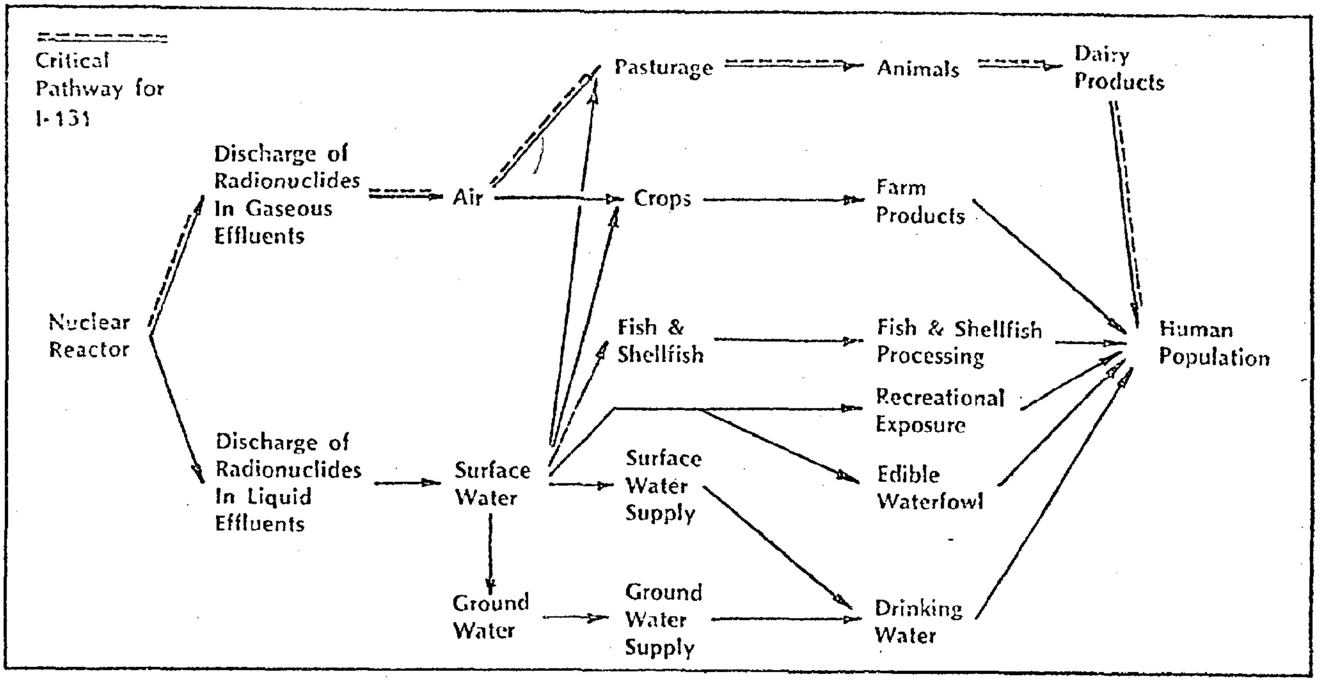


P-ROUGHING FILTER
C-CHARCOAL ADSORBER
A-HEPA FILTER

[Source - 203]

FIGURE 22

PATHWAYS OF RADIATION THROUGH THE ENVIRONMENT



[Source - 451]

No radioactive materials normally emitted by a nuclear power facility must exceed standards administered by the NRC. At present, the regulations (10 CFR 50 Appendix I) specify that air emissions cannot exceed one percent of the normal background level of activity.* Furthermore, the maximum annual whole body dose to an unprotected individual is restricted to 5 millirems.**

- Estimated annual total quantity of radioactive material, except tritium, should not exceed 5 curies.
- Estimated annual average concentration of radioactive material prior to dilution in a natural body of water, except tritium, should not exceed 2×10^{-5} microcuries per liter.
- Estimated annual average concentrations of tritium prior to dilution in a natural body of water should not exceed 5×10^{-3} microcuries per liter.

---

* On a similar basis, SO_2 and NO_2 emission standards are 10,000 percent and 400 percent of natural background levels.

** A measure of radiation dosage. For comparative purposes, the average dose per year from natural background sources is 135 millirems.

• Radioactive material above background must not result in an exposure rate such that a hypothetical individual, continuously present in the open at the site boundary, incurs an annual exposure to the whole body or any organ in excess of 5 millirems [203; p.155].

A major factor in calculating the effective dose rate from airborne radioactive material is the dispersion pattern upon release from the stack. Estimated maximum individual doses are shown in Table 29, based on a person residing permanently at the plant site boundary closest to the plant. Doses for individuals further from the plant would be lower, the amount dependent on wind patterns and other dispersion factors.

TABLE 29

MAXIMUM ESTIMATED WHOLE BODY DOSE AT SITE BOUNDARY FOR A 1000 MWe PLANT

	Dose Rate (millirem/year)		
		BWR	
Holdup Time (days)	PWR	300 ft. Stack Discharge	Roof Vent Discharge
0	40	--	--
30 (min.)	--	500	--
1	--	8	420
3	--	2	110
9	--	0.8	45
15*	4.5	--	--
25	--	0.1	6
30	0.9	--	--
45**	0.45	0.01	0.7
60	0.36	0.005	0.3
90	0.34	--	--

* Typical design hold-up time for BWR's currently coming into service

** Typical design hold-up time for PWR's currently coming into service

As Figure 22 indicates, direct whole body exposure is not the only route to human (and other natural system component) contamination. For example, iodine-131 is passed to man via an air-pasture-animal-dairy product pathway. Once consumed, it concentrates in the thyroid gland. Knowledge of this and other pathways of airborne emissions is incomplete and worthy of considerable future research. The problem has been summarized:

> The true impact on the population of these very low doses from nuclear power stations has not been accurately quantified to date. The difficulty arises from the enormous amount of data which would be required to detect a statistically significant effect from incremental doses that are only a few percent above the normal background radiation exposure. Even if one accepts the "linear dose theory," which implies that damage is proportional to dose down to essentially zero exposure, with no threshold, the evidence suggests that the additional impacts are small indeed [203; p.153].

The pathways of radioactive materials released to the aquatic environment have been succinctly described in material presented in reference 603:

> Upon introduction into an aquatic environment, radioactive wastes can: (1) remain in solution or in suspension; (2) precipitate and settle to the bottom; or (3) be taken up by plants and animals. Immediately upon introduction of radioactive materials into the water, certain factors interact to dilute and disperse these materials, while simultaneously other factors tend to concentrate the radioactivity. Among those factors that dilute and disperse radioactivity are currents, turbulent diffusion, isotopic dilution, and biological transport. Radioactivity is concentrated biologically by uptake directly from the water and passage through food webs, chemically and physically by adsorption, ion exchange, coprecipitation, flocculation, and sedimentation.
>
> Radioactive wastes in the aquatic environment may be cycled through water, sediment, and the biota. Each radionuclide tends to take a characteristic route and has its own rate of movement from component to component prior to coming to rest in a temporary reservoir, one of the three components of the ecosystems. Isotopes can move from the water to the sediments or to the biota. In effect, the sediments and biota compete for the isotopes in the water. Even though in some instances, sediments are initially successful in removing large quantities of radionuclides from water, and thus, preventing their immediate uptake by the biota, this sediment-associated radioactivity may later affect many benthic species by exposing them to radiation. Also, any radioactivity leached from the sediments back to the water again becomes available for uptake by the biota. Even before the radioactivity is leached from the sediment, it may become available to the biota due to a variation in the strength of the bonds between the different

> radionuclides and the sediment particles. Loosely bound radionuclides can be 'stripped' from particles of sediment and utilized by bottom feeding organisms.
>
> Plants and animals, to be of any significance in the cycling of radionuclides in the aquatic environment, must accumulate the radionuclide, retain it, be eaten by another organism, and be digestible. However, even if an organism accumulates and retains a radionuclide and is not eaten before it dies, the radionuclide will enter the "biological cycle" through organisms that decompose the dead organic material into its elemental components. Plants and animals that become radioactive in this biological cycle can pose a health hazard when eaten by man.
>
> Aquatic life may receive radiation from radionuclides present in the water and substrate and also from radionuclides that may accumulate within their tissues. Humans can acquire radionuclides via many pathways, but among the most important are drinking water or edible fish and shellfish that have concentrated nuclides from the water. In order to prevent unacceptable doses of radiation from reaching humans, fish, and other important organisms, the concentrations of radionuclides in water, both fresh and marine, must be restricted [603].

As indicated above, the levels of exposure are too close to background levels to be assessed easily, "although all indications are that the effect is vanishingly small" [203; p.155].

As indicated in Table 18 in the discussion on construction impacts, the operating work force requirements for a major nuclear power facility are relatively small, ranging from 77-200 at the proposed plants listed. Other sources indicate that a single unit facility with a capacity of 750-1000 MWe will have less than 100 full-time employees, while a plant with two units "will have much less than double" that number of employees [451]. Based on this, it would seem that the long-term socioeconomic impacts of immigration would be on par or slightly less than those of a similar capacity fossil fuel plant.

A potential impact "unique to nuclear power plants evolves from perceived danger of radiation" [601; p.2]. This concern would be articulated via local opposition to the construction of a facility and tension during the operational phase. In a study of this problem in the Northeast, researchers from Oak Ridge National Laboratory found that:

> Residents, in general, are unconcerned about the nuclear plant in their community unless it has an accident or radioactive spill.

> Intervenors [opposition leaders] in both communities are few; those who do intervene or are vocal about nuclear power face opposition from the majority of local residents.
>
> Communities appear to adopt an "out of sight, out of mind" attitude toward the facility [600; pp.11-12].

While these results apply only to the specific communities involved and should not be generalized, they do at least provide an indication of what local sentiment might be. Opinion research studies in the area of a proposed facility should be a part of the evaluation procedure.

One of the most controversial issues related to the future use of nuclear power plants is the potential for catastrophic accidents, core meltdowns with a release of primary coolant to the atmosphere.* The utilities and suppliers point to redundant emergency control systems, conservative engineering standards, and a nuclear safety record of hundreds of reactor-years of operation without a major accident. Critics point out that much of that experience has been with low-power naval reactors and that several mishaps have pointed out flaws in design, construction, and operation. Finally, they make the point that the magnitude of destruction associated with an accident presents risks too large to take, even if the probability is extremely small. There is no answer to the controversy and it is not the purpose of this report to go beyond suggesting that the states should consider it as a part of an energy facility siting program.

The activity-impact evaluation matrix in Figure 23 summarizes the activities associated with the construction and operation of a nuclear power facility and the environments potentially affected by them.

(3) Coal Transshipment Facilities

Impacts related specifically to the operation and maintenance of coal transshipment facilities fall into the major categories of natural environment disruption and intrusion on cultural aesthetics. In addition to these negative impacts are the positive effects on local and regional economy and employment and the value of the service performed by the facility when completed. Consequently, the natural/cultural division of environments provide a workable base

---

* Other major issues include safe disposal of high-level wastes, protection against sabotage and terrorist activites (including stealing plutonium), and transport of hazardous materials.

Phase	Action	Natural – Physical & Chemical Characteristics – Terrestrial – Soil	Terrestrial – Land Forms	Hydrological – Surface Water – Quantity	Surface Water – Qual. – Physical	Surface Water – Qual. – Chemical	Ground Water – Quantity	Ground Water – Qual. – Physical	Ground Water – Qual. – Chemical	Atmospheric – Local Meteorology	Atmospheric – Quality – Physical	Atmospheric – Quality – Chemical	Biological Conditions – Terrestrial Ecology – Vegetation	Terrestrial Ecology – Wildlife	Aquatic Ecology – Benthic	Aquatic Ecology – Nektonic	Aquatic Ecology – Planktonic
Construction	Ground clearing and reshaping																
Construction	Equipment use																
Construction	Channelization, shoreline modification, and other water-related activities																
Construction	Material movement to site																
Construction	Influx of temporary work force																
Construction	Public service requirements																
Construction	Land committed to facility																
Construction	Other																
Operation – Reactor Operation	Rad emissions																
Operation – Reactor Operation	Wastewater discharge																
Operation – Reactor Operation	Human service requirements																
Operation – Reactor Operation	Accidents																
Operation	Fuel and waste handling																
Operation – Cooling	Thermal effluent																
Operation – Cooling	Chemical additions																
Operation – Cooling	Blowdown water																
Operation – Cooling	Make-up water requirements																
Operation – Cooling	Fog/icing/drift																
Operation – Cooling	Entrapment/impingement																
Operation – Cooling	Visual intrusion																
Operation – Transmission	Visual intrusion																
Operation – Transmission	Human activity disruption																
Operation – Transmission	Natural system disruption																
Operation – Transmission	Electric field effects																

Phase	Action	Cultural – Social – Aesthetics and Human Interest – Views & Vistas	Wilderness Qualities	Landscape Designs	Unique Physical Features	Parks & Reserves	Rare & Unique Species & Ecosystems	Historical or Archeological Sites	Public Health – Ambient Noise Levels	Public Health – Drinking Water	Public Health – Air Quality	Public Health – Safety	Economic – Employment – Short Term	Employment – Long Term	Housing – Short Term	Housing – Long Term	Infrastructure – Transportation Network	Infrastructure – Waste Disposal	Infrastructure – Utilities	Infrastructure – Government Services	Infrastructure – Safety Services	Land Value – Residential – Adjacent	Residential – Remote	Agricultural – Adjacent	Agricultural – Remote	Commercial – Adjacent	Commercial – Remote	Industrial – Adjacent	Industrial – Remote	Local Economy – Government Fiscal Effects	Local Economy – Business Activity
Construction	Ground clearing and reshaping																														
Construction	Equipment use																														
Construction	Channelization, shoreline modification, and other water-related activities																														
Construction	Material movement to site																														
Construction	Influx of temporary work force																														
Construction	Public service requirements																														
Construction	Land committed to facility																														
Construction	Other																														
Operation – Reactor Operation	Rad emissions																														
Operation – Reactor Operation	Wastewater discharge																														
Operation – Reactor Operation	Human service requirements																														
Operation – Reactor Operation	Accidents																														
Operation	Fuel and waste handling																														
Operation – Cooling	Thermal effluent																														
Operation – Cooling	Chemical additions																														
Operation – Cooling	Blowdown water																														
Operation – Cooling	Make-up water requirements																														
Operation – Cooling	Fog/icing/drift																														
Operation – Cooling	Entrapment/impingement																														
Operation – Cooling	Visual intrusion																														
Operation – Transmission	Visual intrusion																														
Operation – Transmission	Human activity disruption																														
Operation – Transmission	Natural system disruption																														
Operation – Transmission	Electric field effects																														

Phase	Action	Cultural – Physical – Land and Water Use – Wilderness and Open Spaces	Wetlands	Forests	Grazing	Agriculture	Residential	Commercial	Industrial	Designated Lands	Recreation – Hunting	Fishing	Boating	Swimming	Camping	Hiking
Construction	Ground clearing and reshaping															
Construction	Equipment use															
Construction	Channelization, shoreline modification, and other water-related activities															
Construction	Material movement to site															
Construction	Influx of temporary work force															
Construction	Public service requirements															
Construction	Land committed to facility															
Construction	Other															
Operation – Reactor Operation	Rad emissions															
Operation – Reactor Operation	Wastewater discharge															
Operation – Reactor Operation	Human service requirements															
Operation – Reactor Operation	Accidents															
Operation	Fuel and waste handling															
Operation – Cooling	Thermal effluent															
Operation – Cooling	Chemical additions															
Operation – Cooling	Blowdown water															
Operation – Cooling	Make-up water requirements															
Operation – Cooling	Fog/icing/drift															
Operation – Cooling	Entrapment/impingement															
Operation – Cooling	Visual intrusion															
Operation – Transmission	Visual intrusion															
Operation – Transmission	Human activity disruption															
Operation – Transmission	Natural system disruption															
Operation – Transmission	Electric field effects															

FIGURE 23

NUCLEAR POWER PLANTS

from which the specific impacts of a coal transshipment facility may be considered.

(a) Natural

Coal dust emissions and their associated effects are the most significant negative impacts related to the operation of coal handling and storage facilities. The two most important impacts of these coal dust emissions relate to the terrestrial and aquatic ecologies. Because of the presence in coal of trace elements such as cadmium, mercury, lead, and arsenic, problems may develop when these heavy metals are taken up from the soils and sediments by terrestrial and aquatic plants [391]. Ingestion of these plants by terrestrial and aquatic life introduces these trace elements to the food chain and in some cases, may reach toxic levels through a cumulative process.

Coal dust fallout may increase turbidity levels of surrounding water bodies as well. This may result in an overall decrease in the zone of photosynthetic activity and, thus, reduce productivity [391].

Similar impacts result from runoff and leachates associated with coal stockpile drainage. In the case where large stockpiles of coal are maintained during the off-shipping season, large volumes of coal are exposed to snow and rain and subsequent runoff. In addition, liquid suppressants are sometimes used to wet down the coal piles to control dust, resulting in additional infiltration of the pile by liquids.

The result of this drainage is two-fold. First, the surface runoff is capable of washing coal dust from the pile and carrying it into existing drainage canals or storm sewers, eventually introducing the dust to the receiving water body. The effects of this are explained above. Secondly, the water which percolates through the coal pile may take into solution those trace elements mentioned previously and introduce this resulting leachate to the ground-water system. Because of the persistence of these heavy metals, well water quality and even surface water quality may be impacted.

Harbor maintenance in the form of dredging and disposal of these dredge spoils is particular to coal transshipment facilties and has a potentially significant impact on both water quality and aquatic and terrestrial ecology. Mechanical disruption and displacement of bottom sediments may result in increased turbidity and the release of gases and nutrients to the water column which were previously tied up in the bottom sediments.

Noise from operation of heavy equipment such as rail traffic, stackers, conveyors, bulldozers, ship loaders, and ship machinery may have an impact on the wildlife community within the vicinity of the facility. This may result in both behavioral and physiological changes such as alterations in migratory patterns and sexual function [391].

(b) Cultural

Impacts of a coal transshipment facility on the cultural environment of the area result primarily from the physical presence of the facility and the activities associated with its operation.

From a social standpoint, the visual intrusions which result from the creation of large coal stockpiles approaching 50 feet in height may represent a serious alteration of the previous view. This aesthetic impact is difficult to quantify but may be reflected indirectly in public attitudes toward the facility and in changes of land value around the facility. Other aesthetic impacts may result from high noise levels due to equipment use. Public health may be affected by a coal transshipment facility operation in two ways: noise levels due to equipment use may occasionally exceed hearing damage levels resulting in hearing impairment in the vicinity of the facility; likewise, effects of coal dust on water quality (discussed in the previous section) may affect drinking water supplies, threatening water potability.

Economic impacts of a coal transshipment facility are reflected in long-term employment for operation, taxes on earnings, property taxes, and employment in associated rail and ship transport. These are all generally positive impacts, which are felt most strongly at the local level. The magnitude of economic benefit will depend on the scope of the project. A new facility will create many more jobs than the expansion of an existing facility, but this number is still small by comparison with electric generating plant figures (see Table 21). Likewise, the extent of economic impact is highly dependent on the economic health of the area in question.

From a physical standpoint, changes in land use and recreational value may result in cases where the facilities are developed on previously nonindustrial sites. This is unlikely because most coal transshipment facilities have been developed at existing harbors and expansion of these facilties is generally contiguous to the existing facility. In the case of specific sites, such as Conneaut Harbor, Ohio, expansion of coal storage facilities may result in a

		NATURAL										
		PHYSICAL & CHEMICAL CHARACTERISTICS										
		TERRESTRIAL		HYDROLOGICAL						ATMOSPHERIC		
				SURFACE WATER			GROUND WATER				QUALITY	
					QUAL.			QUAL.				
		SOIL	LAND FORMS	QUANTITY	PHYSICAL	CHEMICAL	QUANTITY	PHYSICAL	CHEMICAL	LOCAL METEOROLOGY	PHYSICAL	CHEMICAL
CONSTRUCTION	GROUND CLEARING AND RESHAPING											
	EQUIPMENT USE											
	CHANNELIZATION, SHORELINE MODIFICATION, AND OTHER WATER-RELATED ACTIVITIES											
	MATERIAL MOVEMENT TO SITE											
	INFLUX OF TEMPORARY WORK FORCE											
	PUBLIC SERVICE REQUIREMENTS											
	LAND COMMITTED TO FACILITY											
	OTHER											
FUEL TRANSSHIPMENT AND STORAGE FACILITIES	HARBOR MAINTENANCE											
	WATERBORNE MATERIAL MOVEMENT											
	OVERLAND MATERIAL MOVEMENT											
	HUMAN SERVICE REQUIREMENTS											
	PARTICULATES											
	LEACHATES AND RUNOFF											
	VISUAL INTRUSION											
	HUMAN ACTIVITY DISRUPTION											
	EQUIPMENT USE											

		NATURAL					CULTURAL										
		BIOLOGICAL CONDITIONS					SOCIAL										
		TERRESTRIAL ECOLOGY		AQUATIC ECOLOGY			AESTHETICS AND HUMAN INTEREST							PUBLIC HEALTH			
		VEGETATION	WILDLIFE	BENTHIC	NEKTONIC	PLANKTONIC	VIEWS & VISTAS	WILDERNESS QUALITIES	LANDSCAPE DESIGNS	UNIQUE PHYSICAL FEATURES	PARKS & RESERVES	RARE & UNIQUE SPECIES & ECOSYSTEMS	HISTORICAL OR ARCHEOLOGICAL SITES	AMBIENT NOISE LEVELS	DRINKING WATER	AIR QUALITY	SAFETY
CONSTRUCTION	GROUND CLEARING AND RESHAPING																
	EQUIPMENT USE																
	CHANNELIZATION, SHORELINE MODIFICATION, AND OTHER WATER-RELATED ACTIVITIES																
	MATERIAL MOVEMENT TO SITE																
	INFLUX OF TEMPORARY WORK FORCE																
	PUBLIC SERVICE REQUIREMENTS																
	LAND COMMITTED TO FACILITY																
	OTHER																
FUEL TRANSSHIPMENT AND STORAGE FACILITIES	HARBOR MAINTENANCE																
	WATERBORNE MATERIAL MOVEMENT																
	OVERLAND MATERIAL MOVEMENT																
	HUMAN SERVICE REQUIREMENTS																
	PARTICULATES																
	LEACHATES AND RUNOFF																
	VISUAL INTRUSION																
	HUMAN ACTIVITY DISRUPTION																
	EQUIPMENT USE																

		CULTURAL																		
		ECONOMIC																		
		EMPLOYMENT		HOUSING		INFRASTRUCTURE					LAND VALUE								LOCAL ECONOMY	
											RESIDENTIAL		AGRICULTURAL		COMMERCIAL		INDUSTRIAL			
		SHORT TERM	LONG TERM	SHORT TERM	LONG TERM	TRANSPORTATION NETWORK	WASTE DISPOSAL	UTILITIES	GOVERNMENT SERVICES	SAFETY SERVICES	ADJACENT	REMOTE	ADJACENT	REMOTE	ADJACENT	REMOTE	ADJACENT	REMOTE	GOVERNMENT FISCAL EFFECTS	BUSINESS ACTIVITY
CONSTRUCTION	GROUND CLEARING AND RESHAPING																			
	EQUIPMENT USE																			
	CHANNELIZATION, SHORELINE MODIFICATION, AND OTHER WATER-RELATED ACTIVITIES																			
	MATERIAL MOVEMENT TO SITE																			
	INFLUX OF TEMPORARY WORK FORCE																			
	PUBLIC SERVICE REQUIREMENTS																			
	LAND COMMITTED TO FACILITY																			
	OTHER																			
FUEL TRANSSHIPMENT AND STORAGE FACILITIES	HARBOR MAINTENANCE																			
	WATERBORNE MATERIAL MOVEMENT																			
	OVERLAND MATERIAL MOVEMENT																			
	HUMAN SERVICE REQUIREMENTS																			
	PARTICULATES																			
	LEACHATES AND RUNOFF																			
	VISUAL INTRUSION																			
	HUMAN ACTIVITY DISRUPTION																			
	EQUIPMENT USE																			

		CULTURAL														
		PHYSICAL														
		LAND AND WATER USE									RECREATION					
		WILDERNESS AND OPEN SPACES	WETLANDS	FORESTS	GRAZING	AGRICULTURE	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	DESIGNATED LANDS	HUNTING	FISHING	BOATING	SWIMMING	CAMPING	HIKING
CONSTRUCTION	GROUND CLEARING AND RESHAPING															
	EQUIPMENT USE															
	CHANNELIZATION, SHORELINE MODIFICATION, AND OTHER WATER-RELATED ACTIVITIES															
	MATERIAL MOVEMENT TO SITE															
	INFLUX OF TEMPORARY WORK FORCE															
	PUBLIC SERVICE REQUIREMENTS															
	LAND COMMITTED TO FACILITY															
	OTHER															
FUEL TRANSSHIPMENT AND STORAGE FACILITIES	HARBOR MAINTENANCE															
	WATERBORNE MATERIAL MOVEMENT															
	OVERLAND MATERIAL MOVEMENT															
	HUMAN SERVICE REQUIREMENTS															
	PARTICULATES															
	LEACHATES AND RUNOFF															
	VISUAL INTRUSION															
	HUMAN ACTIVITY DISRUPTION															
	EQUIPMENT USE															

COAL TRANSSHIPMENT FACILITIES

Figure 24

change of land use due to the rural nature of the area. In these cases, the impact of committing undeveloped open lands to a single use (coal storage) is significant especially in the coastal zone where land utilization and public access are important questions.

Finally, community disruption in the form of traffic flow alterations and tie-ups is a potentially significant impact of a coal transshipment facility. In the case of the coal facility at Superior Harbor, Wisconsin [391], major consideration was given to the effects of unit train operation in and about the facility and how it would be reflected in traffic disruption. These effects include increased necessity for traffic rerouting, construction of bridges and bypasses, and expansion of existing roads or railways. A graphic summary of activities and environments assembled in the form of a matrix, which may be used for a more specified case analysis, is provided in Figure 24.

(4) Oil Transshipment and Storage

Operation and maintenance impacts associated with oil transshipment and storage facilities include the effects on the natural environment of oil spills and hydrocarbon emissions and effects on the cultural environment in terms of aesthetics and safety.

(a) Natural

The most significant and specific impacts of an oil transshipment and storage facility on the natural environment are those associated with hydrocarbon emissions and potential leaks and spills of oil. Hydrocarbon emissions escaping during both storage and loading processes adversely affect air quality by reducing visibility in contributing to a photochemical smog effect [158] and by adding significantly to the ambient odors. Also, as discussed in the facilities description section, refined products transshipment is most common on the Great Lakes and it is these petroleum products whose aromatic hydrocarbons are most toxic [292].

Effects of oil leaks and spills on the natural environment range from adverse impacts on water quality to health effects on wildlife. Figure 25 shows the manner in which an oil spill may be taken in the aquatic environment. In the case of transshipment facilities on the Great Lakes, these spills will most likely occur at or near the water's edge. Depending on the viscosity of the spilled oil, impacts on the land range from few for high viscosity products

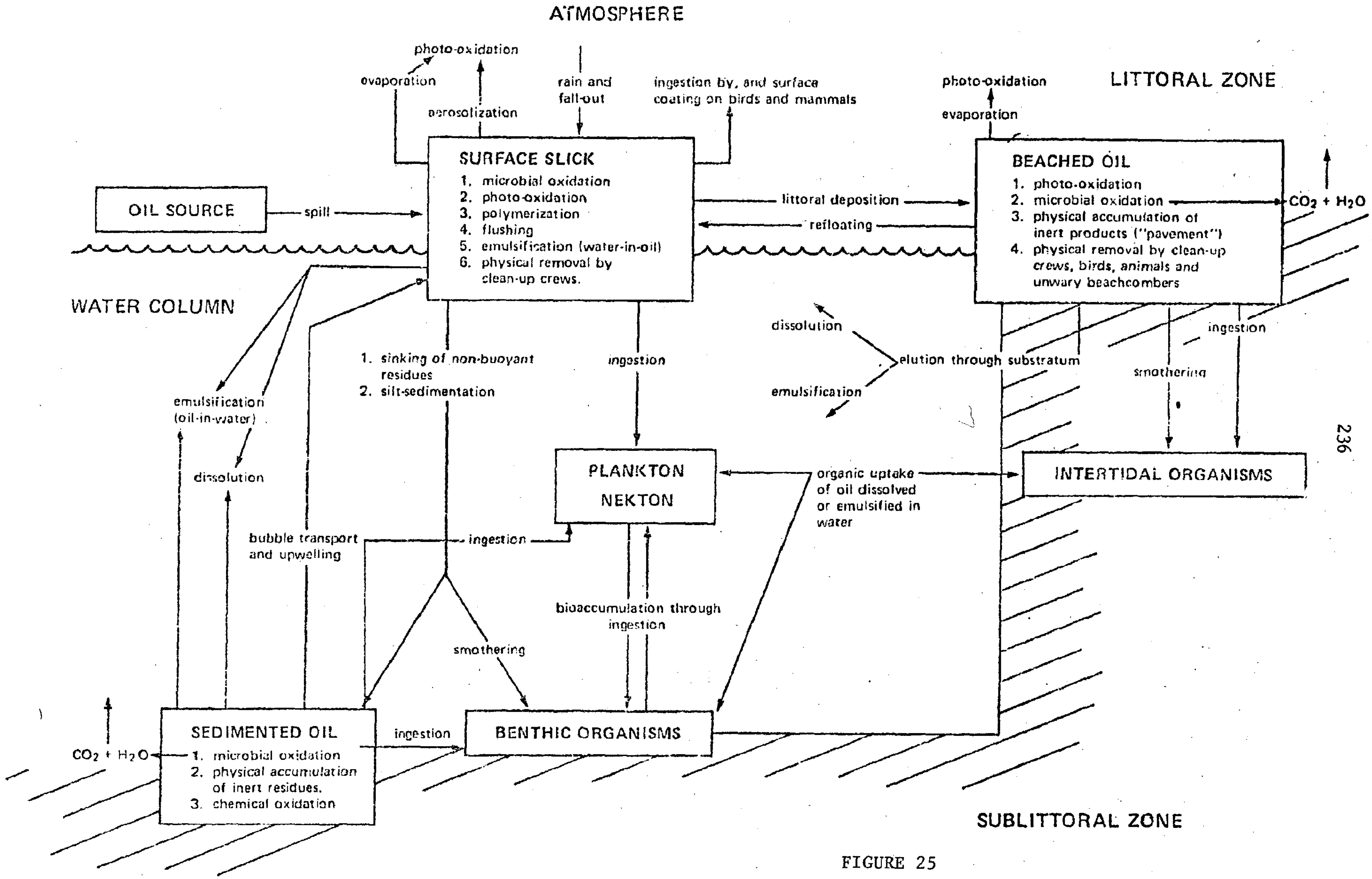


FIGURE 25

FATE OF OIL IN THE MARINE ENVIRONMENT [292] to significant for low viscosity products (such as gasoline), which are more difficult to recover [158]. Impacts on water quality are intensified by the high solubility of refined prducts and the subsequent toxic impacts on aquatic ecology. In the cases where oil products are emulsified in the water column, threats to drinking water derived from wells may result.

Impacts on biota include toxicity of volatile hydrocarbons and smothering by the heavier fractions of refined products. Effects of oil spills are felt most severely in nearshore areas, and shoreline communities are thought to suffer pronounced detrimental effects [158]. Benthic organisms, aquatic vegetation, and sea and shorebirds are all significantly affected by the range of petroleum distillates that may be spilled from a storage facility. The effects are numerous and underscore the necessity for strict safeguards against leaks and spills.

In addition to the potential for leaks and hydrocarbon emissions, there are harbor maintenance impacts similar to those described in the proceeding coal transshipment section. These dredging impacts are significant in the case of oil transshipment facilities because the sediments in the berthing areas are likely to have higher amounts of petroleum distillates due to leaks. When these materials are dredged up, the hydrocarbons may be released into the water, or the dredge spoil may have a higher toxicity and present special problems for disposal. Finally, hydrocarbons and other chemicals may be discharged from ballast tanks of ships during the loading of refined products. Their effects further degrade water quality in the harbor areas.

(b) Cultural

Cultural impacts of oil transshipment facilities lie primarily in the aesthetic intrusion and safety categories.

Because of the organoleptic impacts of hydrocarbon emissions and oil leaks and spills, public attitude is the area most severely affected by these facilties. Odors from these emissions are generally disagreeable and their indirect effects may be seen in changes of land value in the vicinity of the facility. In the case of spills or leaks, drinking water quality may be negatively affected in an extreme case if ground or surface water infiltration by low viscosity distillates.

The probability of major accidents is low, but the magnitude is extremely high. In the event of a major spill, human service requirements for oil spill contingency plans must be met. These include personnel trained in oil containment and clean-up techniques, and the various paraphenalia, such as booms and skimmers used in the clean-up process. Likewise, the potential for major fires exists and local fire fighting services must be prepared for special procedures for petroleum fires.

Economic benefits from these facilities are reflected primarily in tax revenues to the local area. Personnel requirements for maintenance and operation are low or negligible and therefore, do not significantly affect employment or housing.

(5) Refineries

The problems associated with crude oil and product transshipment were described in the preceding section. This discussion will focus only on those activities related directly to crude oil refining: air and water emissions, solid wastes, visual intrusion, and human service requirements. Because expansion of the present Great Lakes refinery capacity is unlikely and "standard" refinery characterization so difficult, this discussion will be as brief as possible, touching only on major issues.

(a) Air quality impacts

The principal air emissions produced during refinery operation are SO_x, NO_x, particulates, and hydrocarbons. In addition, a wide range of organic and inorganic materials are produced in various quantities: olefins, aldehydes, ammonia, hydrogen sulfide, carbon monoxide and others. Table 30 shows estimated emission rates for a variety of refinery sizes and product mixes.

The technology is presently available to meet national air emission standards for all major pollutants with the exception of hydrocarbons [506, 370, and 222]. Measuring the impact of these hydrocarbon emissions is difficult, however:

> Current federal standards are based on total hydrocarbon emissions. One of the major problems in measuring hydrocarbon impacts is the difficulty in discriminating among "reactive" hydrocarbons and inert forms. Reactivity is critical to the formation of photochemical oxidants, which constitute the major hydrocarbon-related air quality problem. At present, there is no adequate basis for distinguishing between reactive and nonreactive hydrocarbons; the subject is being studied by the federal government [506; pp.II-80].

NATURAL

		Physical & Chemical Characteristics: Terrestrial: Soil	Terrestrial: Land Forms	Hydrological: Surface Water: Quantity	Surface Water: Qual.: Physical	Surface Water: Qual.: Chemical	Ground Water: Quantity	Ground Water: Qual.: Physical	Ground Water: Qual.: Chemical	Atmospheric: Local Meteorology	Atmospheric: Quality: Physical	Atmospheric: Quality: Chemical	Biological Conditions: Terrestrial Ecology: Vegetation	Terrestrial Ecology: Wildlife	Aquatic Ecology: Benthic	Aquatic Ecology: Nektonic	Aquatic Ecology: Planktonic
CONSTRUCTION	GROUND CLEARING AND RESHAPING																
	EQUIPMENT USE																
	CHANNELIZATION, SHORELINE MODIFICATION, AND OTHER WATER-RELATED ACTIVITIES																
	MATERIAL MOVEMENT TO SITE																
	INFLUX OF TEMPORARY WORK FORCE																
	PUBLIC SERVICE REQUIREMENTS																
	LAND COMMITTED TO FACILITY																
	OTHER																
FUEL TRANSSHIPMENT AND STORAGE FACILITIES	HARBOR MAINTENANCE																
	WATERBORNE MATERIAL MOVEMENT																
	OVERLAND MATERIAL MOVEMENT																
	HUMAN SERVICE REQUIREMENTS																
	HYDROCARBON EMISSIONS																
	LEAKS AND SPILLS																
	VISUAL INTRUSION																
	HUMAN ACTIVITY DISRUPTION																
	ACCIDENTS																

CULTURAL — SOCIAL

		Aesthetics and Human Interest: Views & Vistas	Wilderness Qualities	Landscape Designs	Unique Physical Features	Parks & Reserves	Rare & Unique Species & Ecosystems	Historical or Archeological Sites	Public Health: Ambient Noise Levels	Drinking Water	Air Quality	Safety
CONSTRUCTION	GROUND CLEARING AND RESHAPING											
	EQUIPMENT USE											
	CHANNELIZATION, SHORELINE MODIFICATION, AND OTHER WATER-RELATED ACTIVITIES											
	MATERIAL MOVEMENT TO SITE											
	INFLUX OF TEMPORARY WORK FORCE											
	PUBLIC SERVICE REQUIREMENTS											
	LAND COMMITTED TO FACILITY											
	OTHER											
FUEL TRANSSHIPMENT AND STORAGE FACILITIES	HARBOR MAINTENANCE											
	WATERBORNE MATERIAL MOVEMENT											
	OVERLAND MATERIAL MOVEMENT											
	HUMAN SERVICE REQUIREMENTS											
	HYDROCARBON EMISSIONS											
	LEAKS AND SPILLS											
	VISUAL INTRUSION											
	HUMAN ACTIVITY DISRUPTION											
	ACCIDENTS											

CULTURAL — ECONOMIC

		Employment: Short Term	Employment: Long Term	Housing: Short Term	Housing: Long Term	Infrastructure: Transportation Network	Waste Disposal	Utilities	Government Services	Safety Services	Land Value: Residential: Adjacent	Residential: Remote	Agricultural: Adjacent	Agricultural: Remote	Commercial: Adjacent	Commercial: Remote	Industrial: Adjacent	Industrial: Remote	Local Economy: Government Fiscal Effects	Business Activity
CONSTRUCTION	GROUND CLEARING AND RESHAPING																			
	EQUIPMENT USE																			
	CHANNELIZATION, SHORELINE MODIFICATION, AND OTHER WATER-RELATED ACTIVITIES																			
	MATERIAL MOVEMENT TO SITE																			
	INFLUX OF TEMPORARY WORK FORCE																			
	PUBLIC SERVICE REQUIREMENTS																			
	LAND COMMITTED TO FACILITY																			
	OTHER																			
FUEL TRANSSHIPMENT AND STORAGE FACILITIES	HARBOR MAINTENANCE																			
	WATERBORNE MATERIAL MOVEMENT																			
	OVERLAND MATERIAL MOVEMENT																			
	HUMAN SERVICE REQUIREMENTS																			
	HYDROCARBON EMISSIONS																			
	LEAKS AND SPILLS																			
	VISUAL INTRUSION																			
	HUMAN ACTIVITY DISRUPTION																			
	ACCIDENTS																			

CULTURAL — PHYSICAL

		Land and Water Use: Wilderness and Open Spaces	Wetlands	Forests	Grazing	Agriculture	Residential	Commercial	Industrial	Designated Lands	Recreation: Hunting	Fishing	Boating	Swimming	Camping	Hiking
CONSTRUCTION	GROUND CLEARING AND RESHAPING															
	EQUIPMENT USE															
	CHANNELIZATION, SHORELINE MODIFICATION, AND OTHER WATER-RELATED ACTIVITIES															
	MATERIAL MOVEMENT TO SITE															
	INFLUX OF TEMPORARY WORK FORCE															
	PUBLIC SERVICE REQUIREMENTS															
	LAND COMMITTED TO FACILITY															
	OTHER															
FUEL TRANSSHIPMENT AND STORAGE FACILITIES	HARBOR MAINTENANCE															
	WATERBORNE MATERIAL MOVEMENT															
	OVERLAND MATERIAL MOVEMENT															
	HUMAN SERVICE REQUIREMENTS															
	HYDROCARBON EMISSIONS															
	LEAKS AND SPILLS															
	VISUAL INTRUSION															
	HUMAN ACTIVITY DISRUPTION															
	ACCIDENTS															

OIL TRANSSHIPMENT FACILITIES

Figure 26

TABLE 30

ESTIMATED REFINERY AIR EMISSIONS

(1000 lbs/day)

	SO_2	CO	NO_x	HC	Particulates
250 MBD, Low Fuel Oil[1]	97.8	5.6	42.1	90.1	20.8
250 MBD, High Fuel Oil[1]	84.0	5.7	35.1	91.9	17.2
100 MBD, uncontrolled[2]	274.3[3]	698.2	26.1	265.1	10.4
100 MBD, controlled[4]	24.0[3]	0.2	22.5	27.0	3.1
180 MBD[5]	102.6	4.7	63.2	62.4	23.1

1 [506]
2 [222], without emission controls
3 SO_x
4 [222], with emission controls
5 [370]

(b) Aquatic impacts

Water-related impacts of refinery operations arise from two sources: withdrawal and consumption, and effluents added to the receiving waters. As was indicated in the refinery description discussion, the dependence on water supply and wastewater disposal has decreased as water recycling within the facilities has increased. Water requirements (Table 16) are relative small, generally less than 10 mgd (15 cfs). Estimates of withdrawals and consumption for a 250-mbd facility are:

	Withdrawal	Consumption
low fuel oil	13.2 mgd	5.4
high fuel oil	10.5 mgd	4.5

[Source - 506]

Waterborne effluents discharged by a refinery include both organic and inorganic materials. Table 31 presents estimates of pollutant concentrations in the water return flow from typical refinery configurations.

TABLE 31

ESTIMATED WATERBORNE EFFLUENT CONCENTRATIONS (ppm)

	BODs	COD	SS	Oil	Phenols	Ammonia	Total P
250 MBD Low Fuel Oil, Present Controls[1]	43.22	291.72	27.60	12.96	0.28	42.05	
250 MBD Low Fuel Oil, Advanced controls[1]	13.68	74.43	13.68	2.64	0.06	16.71	
250 MBD High Fuel Oil, Present Controls[1]	30.49	206.48	19.69	9.12	0.19	29.44	
250 MBD High Fuel Oil, Advanced Controls[1]	9.75	52.82	9.75	1.92	0.04	11.76	
180 MBD[2]	15	80	10	2	0.1	2	2

[1] [506]

[2] [370], best available controls

The impact of these effluents depends on the water quality and volume (flow) of the receiving waters. For large rivers and lakes, very few problems are anticipated using existing technology [370 and 506]. An analysis of the effects of a new refinery on a large river in New England concluded:

> The effluents from "new source" [existing control technology] 250-mbd refineries appear to pose very few water quality problems in a large river, when considered independent of actual receiving water quality above the point of discharge. (If the receiving stream immediately above the refinery discharge already contains high concentrations of contaminants, even minor incremental loading may contribute to poor water quality.) The 250-mbd "new source" refineries would probably remove biochemical oxygen demand (BOD), suspended solids (TSS), and chemical oxygen demand (COD), in greater amounts than they would contribute to most large New England rivers, thereby improving certain aspects of water quality. The concentrations of phenolics in the receiving waters would approach or slightly exceed Massachusetts standards [0.001 ppm], but would be well within the EPA recommended criteria [0.1 ppm]. Ammonia concentrations would exceed the EPA criteria [0.02 ppm], but not those of Massachusetts [0.5 ppm]. ...In summary, the 250-mbd refinery modules with "new source" wastewater treatment technology would appear to pose several minor but no major water quality problems in a large clean river [506; pp.II-50].

	NATURAL: Physical & Chemical Characteristics – Terrestrial: SOIL	Terrestrial: LAND FORMS	Hydrological – Surface Water: QUANTITY	Surface Water – Qual.: PHYSICAL	Surface Water – Qual.: CHEMICAL	Hydrological – Ground Water: QUANTITY	Ground Water – Qual.: PHYSICAL	Ground Water – Qual.: CHEMICAL	Atmospheric: LOCAL METEOROLOGY	Atmospheric – Quality: PHYSICAL	Atmospheric – Quality: CHEMICAL	Biological Conditions – Terrestrial Ecology: VEGETATION	Terrestrial Ecology: WILDLIFE	Aquatic Ecology: BENTHIC	Aquatic Ecology: NEKTONIC	Aquatic Ecology: PLANKTONIC
CONSTRUCTION: GROUND CLEARING AND RESHAPING																
CONSTRUCTION: EQUIPMENT USE																
CONSTRUCTION: CHANNELIZATION, SHORELINE MODIFICATION, AND OTHER WATER-RELATED ACTIVITIES																
CONSTRUCTION: MATERIAL MOVEMENT TO SITE																
CONSTRUCTION: INFLUX OF TEMPORARY WORK FORCE																
CONSTRUCTION: PUBLIC SERVICE REQUIREMENTS																
CONSTRUCTION: LAND COMMITTED TO FACILITY																
CONSTRUCTION: OTHER																
REFINERY OPERATION – CRUDE OIL RECEIVING AND STORAGE: HYDROCARBON EMISSIONS																
CRUDE OIL RECEIVING AND STORAGE: LEAKS AND SPILLS																
CRUDE OIL RECEIVING AND STORAGE: VISUAL INTRUSION																
CRUDE OIL RECEIVING AND STORAGE: HUMAN ACTIVITY DISRUPTION																
CRUDE OIL RECEIVING AND STORAGE: ACCIDENTS																
PLANT OPERATION: SO_x EMISSIONS																
PLANT OPERATION: NO_x EMISSIONS																
PLANT OPERATION: PARTICULATES																
PLANT OPERATION: HYDROCARBON EMISSIONS																
PLANT OPERATION: OTHER EMISSIONS																
PLANT OPERATION: LEAKS AND SPILLS																
PLANT OPERATION: SOLID WASTE																
PLANT OPERATION: COOLING WATER CONSUMPTION																
PLANT OPERATION: PROCESS WATER CONSUMPTION																
PLANT OPERATION: WASTEWATER EFFLUENTS																
PLANT OPERATION: VISUAL INTRUSION																
PLANT OPERATION: ACCIDENTS																
PRODUCT STORAGE AND SHIPPING: HYDROCARBON EMISSIONS																
PRODUCT STORAGE AND SHIPPING: LEAKS AND SPILLS																
PRODUCT STORAGE AND SHIPPING: VISUAL INTRUSION																
PRODUCT STORAGE AND SHIPPING: HUMAN ACTIVITY DISRUPTION																
PRODUCT STORAGE AND SHIPPING: ACCIDENTS																

	CULTURAL: Social – Aesthetics and Human Interest: VIEWS & VISTAS	WILDERNESS QUALITIES	LANDSCAPE DESIGNS	UNIQUE PHYSICAL FEATURES	PARKS & RESERVES	RARE & UNIQUE SPECIES & ECOSYSTEMS	HISTORICAL OR ARCHEOLOGICAL SITES	Public Health: AMBIENT NOISE LEVELS	DRINKING WATER	AIR QUALITY	SAFETY
CONSTRUCTION: GROUND CLEARING AND RESHAPING											
CONSTRUCTION: EQUIPMENT USE											
CONSTRUCTION: CHANNELIZATION, SHORELINE MODIFICATION, AND OTHER WATER-RELATED ACTIVITIES											
CONSTRUCTION: MATERIAL MOVEMENT TO SITE											
CONSTRUCTION: INFLUX OF TEMPORARY WORK FORCE											
CONSTRUCTION: PUBLIC SERVICE REQUIREMENTS											
CONSTRUCTION: LAND COMMITTED TO FACILITY											
CONSTRUCTION: OTHER											
REFINERY OPERATION – CRUDE OIL RECEIVING AND STORAGE: HYDROCARBON EMISSIONS											
CRUDE OIL RECEIVING AND STORAGE: LEAKS AND SPILLS											
CRUDE OIL RECEIVING AND STORAGE: VISUAL INTRUSION											
CRUDE OIL RECEIVING AND STORAGE: HUMAN ACTIVITY DISRUPTION											
CRUDE OIL RECEIVING AND STORAGE: ACCIDENTS											
PLANT OPERATION: SO_x EMISSIONS											
PLANT OPERATION: NO_x EMISSIONS											
PLANT OPERATION: PARTICULATES											
PLANT OPERATION: HYDROCARBON EMISSIONS											
PLANT OPERATION: OTHER EMISSIONS											
PLANT OPERATION: LEAKS AND SPILLS											
PLANT OPERATION: SOLID WASTE											
PLANT OPERATION: COOLING WATER CONSUMPTION											
PLANT OPERATION: PROCESS WATER CONSUMPTION											
PLANT OPERATION: WASTEWATER EFFLUENTS											
PLANT OPERATION: VISUAL INTRUSION											
PLANT OPERATION: ACCIDENTS											
PRODUCT STORAGE AND SHIPPING: HYDROCARBON EMISSIONS											
PRODUCT STORAGE AND SHIPPING: LEAKS AND SPILLS											
PRODUCT STORAGE AND SHIPPING: VISUAL INTRUSION											
PRODUCT STORAGE AND SHIPPING: HUMAN ACTIVITY DISRUPTION											
PRODUCT STORAGE AND SHIPPING: ACCIDENTS											

	CULTURAL: Economic – Employment: SHORT TERM	Employment: LONG TERM	Housing: SHORT TERM	Housing: LONG TERM	Infrastructure: TRANSPORTATION NETWORK	WASTE DISPOSAL	UTILITIES	GOVERNMENT SERVICES	SAFETY SERVICES	Land Value – Residential: ADJACENT	Residential: REMOTE	Agricultural: ADJACENT	Agricultural: REMOTE	Commercial: ADJACENT	Commercial: REMOTE	Industrial: ADJACENT	Industrial: REMOTE	Local Economy: GOVERNMENT FISCAL EFFECTS	BUSINESS ACTIVITY
CONSTRUCTION: GROUND CLEARING AND RESHAPING																			
CONSTRUCTION: EQUIPMENT USE																			
CONSTRUCTION: CHANNELIZATION, SHORELINE MODIFICATION, AND OTHER WATER-RELATED ACTIVITIES																			
CONSTRUCTION: MATERIAL MOVEMENT TO SITE																			
CONSTRUCTION: INFLUX OF TEMPORARY WORK FORCE																			
CONSTRUCTION: PUBLIC SERVICE REQUIREMENTS																			
CONSTRUCTION: LAND COMMITTED TO FACILITY																			
CONSTRUCTION: OTHER																			
REFINERY OPERATION – CRUDE OIL RECEIVING AND STORAGE: HYDROCARBON EMISSIONS																			
CRUDE OIL RECEIVING AND STORAGE: LEAKS AND SPILLS																			
CRUDE OIL RECEIVING AND STORAGE: VISUAL INTRUSION																			
CRUDE OIL RECEIVING AND STORAGE: HUMAN ACTIVITY DISRUPTION																			
CRUDE OIL RECEIVING AND STORAGE: ACCIDENTS																			
PLANT OPERATION: SO_x EMISSIONS																			
PLANT OPERATION: NO_x EMISSIONS																			
PLANT OPERATION: PARTICULATES																			
PLANT OPERATION: HYDROCARBON EMISSIONS																			
PLANT OPERATION: OTHER EMISSIONS																			
PLANT OPERATION: LEAKS AND SPILLS																			
PLANT OPERATION: SOLID WASTE																			
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PLANT OPERATION: PROCESS WATER CONSUMPTION																			
PLANT OPERATION: WASTEWATER EFFLUENTS																			
PLANT OPERATION: VISUAL INTRUSION																			
PLANT OPERATION: ACCIDENTS																			
PRODUCT STORAGE AND SHIPPING: HYDROCARBON EMISSIONS																			
PRODUCT STORAGE AND SHIPPING: LEAKS AND SPILLS																			
PRODUCT STORAGE AND SHIPPING: VISUAL INTRUSION																			
PRODUCT STORAGE AND SHIPPING: HUMAN ACTIVITY DISRUPTION																			
PRODUCT STORAGE AND SHIPPING: ACCIDENTS																			

	CULTURAL: Physical – Land and Water Use: WILDERNESS AND OPEN SPACES	WETLANDS	FORESTS	GRAZING	AGRICULTURE	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	DESIGNATED LANDS	Recreation: HUNTING	FISHING	BOATING	SWIMMING	CAMPING	HIKING
CONSTRUCTION: GROUND CLEARING AND RESHAPING															
CONSTRUCTION: EQUIPMENT USE															
CONSTRUCTION: CHANNELIZATION, SHORELINE MODIFICATION, AND OTHER WATER-RELATED ACTIVITIES															
CONSTRUCTION: MATERIAL MOVEMENT TO SITE															
CONSTRUCTION: INFLUX OF TEMPORARY WORK FORCE															
CONSTRUCTION: PUBLIC SERVICE REQUIREMENTS															
CONSTRUCTION: LAND COMMITTED TO FACILITY															
CONSTRUCTION: OTHER															
REFINERY OPERATION – CRUDE OIL RECEIVING AND STORAGE: HYDROCARBON EMISSIONS															
CRUDE OIL RECEIVING AND STORAGE: LEAKS AND SPILLS															
CRUDE OIL RECEIVING AND STORAGE: VISUAL INTRUSION															
CRUDE OIL RECEIVING AND STORAGE: HUMAN ACTIVITY DISRUPTION															
CRUDE OIL RECEIVING AND STORAGE: ACCIDENTS															
PLANT OPERATION: SO_x EMISSIONS															
PLANT OPERATION: NO_x EMISSIONS															
PLANT OPERATION: PARTICULATES															
PLANT OPERATION: HYDROCARBON EMISSIONS															
PLANT OPERATION: OTHER EMISSIONS															
PLANT OPERATION: LEAKS AND SPILLS															
PLANT OPERATION: SOLID WASTE															
PLANT OPERATION: COOLING WATER CONSUMPTION															
PLANT OPERATION: PROCESS WATER CONSUMPTION															
PLANT OPERATION: WASTEWATER EFFLUENTS															
PLANT OPERATION: VISUAL INTRUSION															
PLANT OPERATION: ACCIDENTS															
PRODUCT STORAGE AND SHIPPING: HYDROCARBON EMISSIONS															
PRODUCT STORAGE AND SHIPPING: LEAKS AND SPILLS															
PRODUCT STORAGE AND SHIPPING: VISUAL INTRUSION															
PRODUCT STORAGE AND SHIPPING: HUMAN ACTIVITY DISRUPTION															
PRODUCT STORAGE AND SHIPPING: ACCIDENTS															

REFINERIES

Figure 27

(c) Cultural impacts

Of all facilities examined in this study, refineries require the largest operational work force. As shown in Table 20, the estimated employment during the operational phase varies from 410-550 persons for a 200-250-mbd facility. Furthermore, because average refinery wages are higher-than-average for the economy as a whole [506; pp.I-29], the indirect employment and income gains to the local and regional economy could be significant. Also, the tendency for associated petrochemical plants to locate near large refineries could bring in significant numbers of new jobs and income.

An important consideration is the land committed to the facility on a long-term basis, especially concerning the uses displaced by it. As the discussion of refinery land requirements indicates, a facility of the size considered here would require from 1,500-2,700 acres, a substantial committment of land on a local and even regional scale.

Other concerns of a site-specific nature are related to aesthetics, noise, and public safety hazards.

The accompanying activity impact matrix for refineries (Figure 27) can be used to evaluate potential impacts of a proposed refinery.

5. FACILITY COST ANALYSIS

a. Introduction

The economics of site location depend on the variations of costs and prices over space and time that arise through differences in resource and product availability and distribution. Some of the basic economic factors that are considered when examining and comparing energy facility locations are the availability and cost of capital, infrastructure, labor, transportation, facilities, and the natural resources necessary for production and waste disposal, such as air, water, and land.

The following factors are related to the determination of power plant location in the coastal zone:

- The cost of transporting fuel from its origin to the energy facility and of onsite fuel storage.
- The cost of a cooling system (including transporting water from source to plant).
- The cost of product storage and distribution to consumers and the relationship of distribution to the distance of consumers from the facility.
- The opportunity cost of using land on the coast for energy facilities rather than alternative uses.
- The cost of environmental controls, including air and water quality controls and transportation and storage of solid wastes.

Energy facility siting requires tradeoffs among these factors. Table 32 is an example of such tradeoffs developed by the Rand Corporation for power plants located in California. Caution should be exercised in using these figures because of their regional specificity. However, this chart does show some of the tradeoffs that can be important in siting power plants. These tradeoffs are of the type that must be made in comparing coastal and inland sites.

b. Fossil-Fuel (Coal) Power Plants

(1) Fuel Transportation and Storage

The three major coal-producing areas which serve the Great Lakes Region are: the Eastern Province, the Interior Province, and the Northern Great Plains Province (Montana, Wyoming, North Dakota, and South Dakota). These areas are shown in Figure 28 [222].

Table 32

MISCELLANEOUS COST COMPARISONS

INLAND COOLING VS. ONCE-THROUGH WITH SET-BACK

- Wet cooling towers[a] ≈ 2 mi of set-back
- Dry cooling towers ≈ 6 mi of set-back

WATER CONVEYANCING VS. TRANSMISSION

- 1 mi of water conveyancing ≈ 1 mi of transmission lines

WATER COST VS. WATER CONVEYANCING COST

- Water cost at $100/acre-ft ≈ 18 mi of water conveyancing

DRY COOLING TOWERS VS. TRANSMISSION

- Nuclear: dry cooling tower ≈ 240 mi of transmission lines
- Fossil-fuel: dry cooling tower ≈ 170 mi of transmission lines

WET COOLING TOWERS VS. TRANSMISSION

- Nuclear: wet cooling tower ≈ 70 mi of transmission lines
- Fossil-fuel: wet cooling tower[a] ≈ 60 mi of transmission lines

[149]

[a] No water or water conveyancing costs included

There is a great deal of variation in the heat content of coal, depending upon its origin. Western coal contains 7,800 to 8,800 Btu per pound, with an average of 8,300 Btu per pound, although some coal has up to 13,000 Btu per pound [316]; Illinois and Indiana coal ranges from 10,500 to 13,000 [213] Btu per pound, with an average of 12,000 Btu per pound; and Appalachian coal varies from 10,000 to 13,000 Btu per pound, with an average of about 12,000 Btu per pound.

The Great Lakes Basin has four major coal transportation routes. Coal is transported by unit train from the Appalachian area to Lake Erie ports and shipped from there to other United States and Canadian Great Lakes ports (51% of the coal shipped out of Lake Erie ports went to Canada in 1975). The second

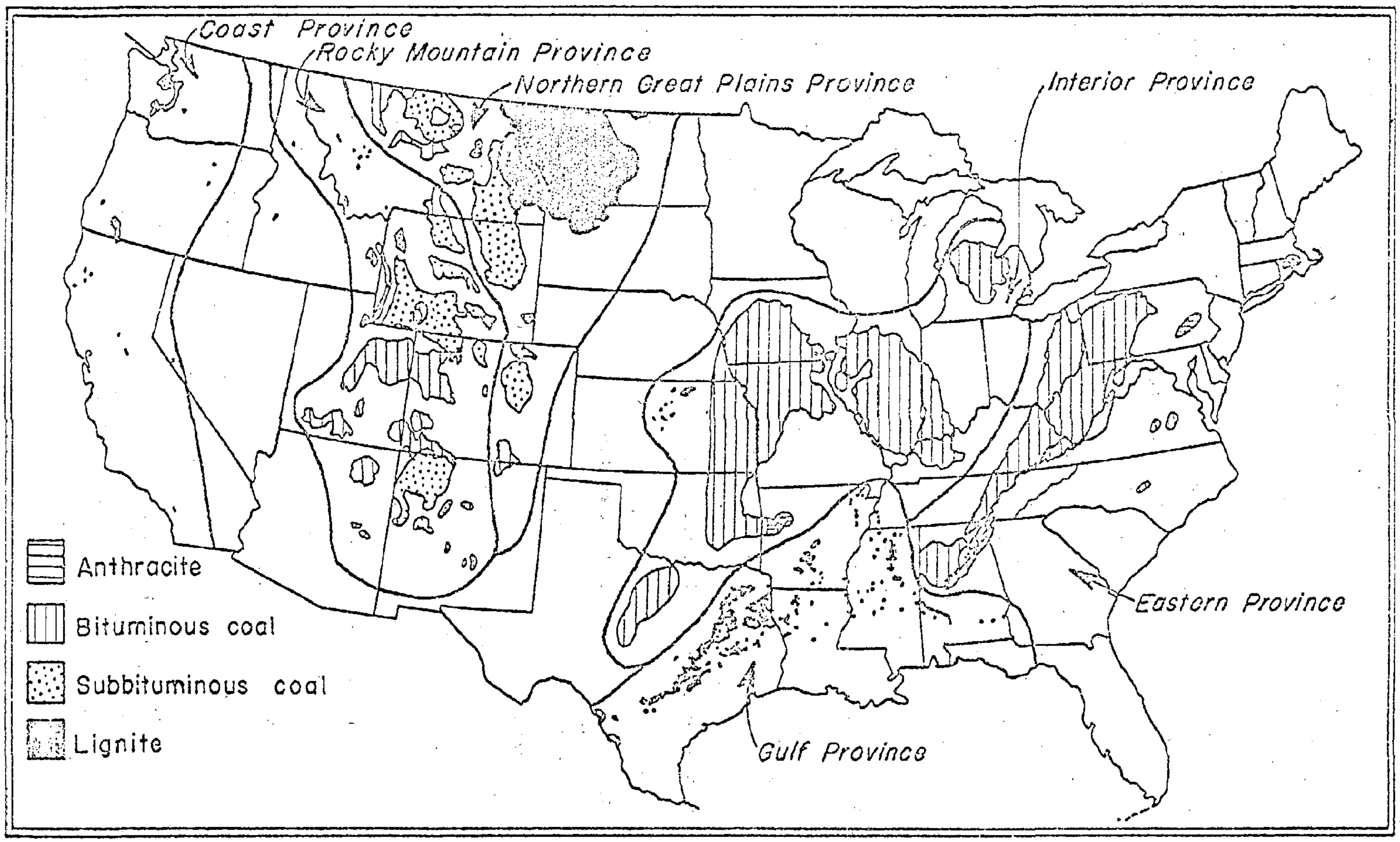

Figure 28 - Distribution of United States Coal Resources

Source: BLM, 1974: I-47

route is from Illinois and Indiana coal fields by unit train to the Chicago area and the lower part of Wisconsin along Lake Michigan. The third and most recently developed route is from the west by unit train to the Lake Superior ports of Duluth and Superior. Currently, coal from the Superior coal dock facility is shipped to ports on the St. Clair River at the southern end of Lake Huron. Western coal may soon be shipped as far as Buffalo. The fourth route, also developed recently, is by unit train from the west to Minnesota, Wisconsin, Illinois, and Ohio.

The costs of transportation are important considerations in the future location of the coal-fired power plants in the Great Lakes Basin. Coal delivered by unit train is less dependent upon coastal siting than coal delivered by ship or barge. Locations east of Chicago probably would not receive western coal by unit train because the cost of receiving that coal would increase substantially, due to problems and costs of transferring the coal to lines of other railroad companies.

Important economic parameters that affect the cost of shipments are volume, distance, capacity, speed, return trip cargo, and mode. Delivery of coal can be less expensive per mile if there is a return cargo, if it is delivered by unit rather than conventional train, if there are higher volumes, and if the cargo travels longer distances (although short routes with high volumes can be less expensive in some cases than longer routes). It should be noted that these factors will change with the location of the receiving site.

A comparison of slurry pipeline and unit train costs per mile (shown in Table 33) illustrates that their costs are closely competitive. Shipping coal on the lakes is less expensive per mile than other modes, but shipping distances are generally greater on water than on land.

(a) Western coal

A comparison between railroad unit train delivery and a combined unit train-ship delivery of coal presented in Table 34 shows that it is economically feasible to deliver coal by unit train-ship from the western coal regions to Detroit. Although not indicated by Table 34, it is also economically competitive to deliver coal to Buffalo by this method. (Power companies serving the western New York area are considering this possibility.) The estimated cost of transporting coal to Buffalo by unit train-ship combination is \$11.19 per ton; to Cleveland, \$10.36 per ton.

TABLE 33
COSTS OF COAL TRANSPORTATION
(1972 ESTIMATES)

Type	Costs (dollars per 10^{12} Btu's transported)			Distance Assumed (miles)	Cost per Ton-Mile (cents per ton-mile)
	Fixed	Operating	Total		
Unit Train	5,100	79,800	84,900	300	0.7
Conventional Train	9,240	145,000	154,000	300	1.3
River Barge	4,850	35,600	40,400	300	0.3
Slurry Pipeline	48,500	20,800	69,300	273	0.6
Ship**					.5*

Source: (Hittman, 1974, Vol. I, Tables 1 and 2 and associated footnotes.)
* Personal communication, Argonne National Laboratory. [218]
** 1976 Dollar Figures.

Slurry pipeline is another mode of transportation that can be used to deliver large quantities of coal. The estimates by Hittman Associates (218) show unit train and slurry pipeline are economically competitive with each other under certain conditions. Slurry pipeline is much more specialized and requires high initial capital outlay. It is considered a serious alternative only when:

- No other transport exists.
- Volumes between origins and destinations are large and steady.
- Pipeline transport offers a more direct route (especially over rugged terrain).
- The solid coal is reduced to a slurry of fine particles during part of its normal processing.
- Water for transport is readily and cheaply available.

If one assumes new rail branch-line construction rather than transport by existing lines, costs per ton-mile for pipelines are competitive under the following conditions for solids:

Tons per year (in thousands)	Competitive with Railroads Over:
500	All distances
1,000	Distances over 70 miles
2,000	Distances over 150 miles
5,000	Distances over 250 miles
10,000	About the same over 300 miles

[312]

Table 34

Transportation Costs (April 1974 Dollars)
Per Ton of Delivered Coal

Midwestern Point (D=Distance in Miles)[1]	1974	1978	1982
	Powder River Basin		
Chicago (D=1172)	\$ 8.08 (9.20)[2]	\$ 9.10 (10.36)	\$10.24 (11.76)
Detroit (D=1444)	9.96 (9.78)	11.21 (11.01)	12.63 (12.39)
Milwaukee (D=1257)	8.66	9.77	11.00
Indianapolis (D=1266)	8.74	9.84	11.07
Cincinnati (D=1304)	9.14 (9.67)	10.14 (10.88)	11.37 (12.25)
Cleveland (D=1512)	10.43	10.77	13.21
	Hanna Basin		
Chicago (D=1128)	7.78	8.76	9.87
Detroit (D=1400)	9.66	10.87	12.24
Milwaukee (D=1213)	8.37	9.42	10.60
Indianapolis (D=1273)	8.78	9.90	11.14
Cincinnati (D=1361)	9.40 (10.24)	10.58	11.89 (12.99)
Cleveland (D=1468)	10.13	10.92	12.84
	Uinta		
Chicago (D=1477)	10.20	11.47	12.91
Detroit (D=1749)	12.07	13.59	15.30
Milwaukee (D=1562)	10.78	12.13	13.66
Indianapolis (D=1585)	10.94	12.32	13.85
Cincinnati (D=1612)	11.30 (11.58)	12.53 (13.03)	14.09 (14.67)
Cleveland (D=1817)	12.54	14.11	15.89

[1] Railroad distance measured from the Handy Railroad Atlas of the U.S. (Rand McNally)
[2] Numbers in parenthesis correspond to rail water routes

*Argonne National Laboratory has indicated that these figures have increased three to four dollars a ton.

It is difficult to obtain land for construction of slurry pipelines without the power of eminent domain. Most states do not have laws granting land condemnation power for slurry pipelines. Capital construction costs are 70% [312] of the total costs of slurry pipeline operation and construction.

Slurry pipelines transport a single substance (coal) from a single point. There is a tremendous risk in building such a specialized line due to changes in the fuel transportation patterns, coal gasification costs, or costs of desulfurization. One slurry pipeline in Ohio has not shipped coal since 1958. The purpose of this pipeline was to reduce coal shipping cost by offering competition to railroads. However, the railroads proved to be a more adaptable transportation mode and were more economically desirable.

In the Great Lakes Basin the most likely destination for a slurry pipeline from the western United States, from an economic standpoint, would probably be the Chicago area. Such a facility would probably not be dependent on coastal locations, unless the coal slurry were transshipped to water carriers. The uncertainty of origin and type of fuels that will be used in the U.S. in the future and competition from railroad and barge lines will likely restrict any possible development of slurry pipelines to the Midwest.

The location of power plants at western coal mines and transmission of electricity to the Midwest is an exceedingly expensive option, due to the high cost of building transmission lines compared to using existing railroads for coal shipment [307].

In summary, the most likely mode of transportation from the western coal region in the next 5 years is unit train, or a combination of unit train and ship. Power plants west of Lake Michigan are not as coastal dependent with respect to deliveries of coal from the western United States as are plants that must receive western or Appalachian coal transported by a combined unit train-lake carrier movement.

(b) Eastern coal

Obviously, since Appalachian and Illinois basin coal is transported shorter distances (50 to 400 miles) than western coal (900 to 1,400 miles) to reach the Great Lakes Region [550], eastern coal transportation costs are lower. Coal from these regions is transported by unit train to power plants in the Great Lakes Region.

The typical costs for transporting coal from the Appalachian field to the Great Lakes range from 2.50 to 4.00 dollars per ton in 1973 dollars. These costs depend upon the origin and destination of coal. The cost of transporting southern Illinois coal to the city of Chicago is approximately $2.00 per ton,* and to the State of Wisconsin is approximately $4.50 per ton in 1976 dollars.** The costs vary by contract, type of delivery, distance, and other regional considerations.

(c) Short distance hauling

Power facilities located at inland sites near but not on the coast may receive fuels from water ports. In this situation, the additional cost of transporting the fuel is reflected in the cost of locating the facility inland as opposed to on the coast. The total cost of the coal may be less if it is transported to the plant entirely by railroad. In this case, the incremental cost of locating the facility inland (as opposed to on the coast) may be less than it would be if the coal were transported by water and then from the port to an inland location.

There are a number of ways to transport coal over short distances, truck, conveyor, slurry pipeline, train, and barge being the most common.

Trucks, although commonly used at mines, have limitations in the coastal zone. Economic considerations require use of large trucks which are generally undesirable or illegal for street use. Off-street use of large mine trucks requires an access road with approximately 53 feet of right-of-way or 6.4 acres per mile from the harbor to the power facility [400].

Conveyor belts can transport coal and wastes along a fixed route on an access strip. Conveyors require approximately 30 feet of right-of-way or 3.64 acres of land per mile [400].

Pneumatic slurry pipeline is a new technology for transporting coal. The pipeline would require a right-of-way of approximately 62.5 feet, but could be buried [400]. For new technologies such as this, costs are subject to change more rapidly than in existing and proven technologies.

Unit train transportation of coal for short distrances is expensive because of high loading and unloading costs in addition to other slowdowns and

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* Personal Communication, Commonwealth Edison

** Personal Communication, Wisconsin Electric Power Company delays incurred by using a long train over a short distance. According to one industry source, it would be virtually impossible from an economic standpoint to move a unit train 15 miles or less. Rail transportation lends itself to longer hauls.

Barge transportation of coal from ports and terminals inland is limited to special areas with water access and inland dock facilities.

Table 35 presents a cost comparison among methods used for short distance transportation of coal. Although the estimates are not all for the same base year, the costs listed are indicative of the relative differences between modes. The cost estimates indicate the following order of transport modes by cost per ton-mile for a 5-mile distance, from lowest cost to highest: slurry (water) pipeline, truck, unit train, and conveyor belt. The (updated) 1974 cost estimates for unit train and conveyor belt transport of coal suggest that the two modes are about equal in cost over the 5-mile distance.

Table 35

SHORT HAUL COAL TRANSPORTATION COSTS

MODE	YEAR	MILES	TONNAGE PER DAY	COST PER TON-MILE (Cents)
Trucking	1972 (estimates)	5-10		4.5 (A)
	(July '74) updated	5		4.7 (B)
Conveyor Belts	1972 (estimates)	5		7.6 (A)
	(July '74) updated	5		5.4 (B)
Unit Train	(July '74) updated	5		5.4 (B)
Slurry Pipeline (Pneumatic)	May 1975	4.5	(above 2000 tons)	1-2¢ (estimates) (C)
Slurry Pipeline	(July '74) updated	5		1.2 excluding grinding equip. (B)

(A) [222]
(B) [211]
(C) [218]

*Personal communication, Chessie System.

However, additional considerations change the relative ranking of the alternatives. Unit trains would probably not be used to transport coal from a coal unloading dock to an inland electrical generating or storage facility located 15 miles or less from the dock because of loading costs and delays. Additionally, large trucks presently used to transport coal at mine sites would probably not be used for the short haul of coal from docking facilities to inland sites over public roads and highways due to the weight of the trucks and environmental concerns such as noise and coal dust. Thus, conveyor belts and slurry pipelines are the primary modes that would be used to transport coal from shoreline coal unloading docks to inland sites over distances of 15 miles or less [211, 218, 222]. Additional costs must be considered for slurry pipelines for grinding the coal for slurry pipeline use and dewatering the coal slurry (if pneumatic lines are not used) after movement to destination. Therefore, conveyor belt transport is the mode most likely to be used for the short haul transportation of coal from a shoreline dock to an inland facility.

(2) Cooling Systems

(a) Cooling system types

A major determinant in the location of coal power plants is the cost of providing a sink for waste heat. Water is the primary natural resource used as a heat sink, although air can also be used in some cases. Costs vary for providing water and cooling systems to coastal and inland locations.

There are five basic types of cooling systems used for fossil-fueled and nuclear steam-electric plants: 1) once-through cooling, 2) wet cooling towers (mechanical and natural draft), 3) cooling ponds, 4) spray channels, and 5) dry towers.

A nuclear power plant requires 50 percent more cooling water than a coal plant of the same capacity, due to the difference in heat rejection rates to the cooling water and stack losses. This difference for coal power plants is 67% of that for nuclear power plants. As a result, coal-fired plant cooling systems cost less than systems used on nuclear plants of the same generating capacity [211, 149]. As a rule of thumb, the cost of the cooling system for nuclear power plants is assumed to be 50 percent more than that of a coal-fired plant. For this study's generalized facilities it is 45 percent.

There are two major costs to consider in analyzing cooling systems: 1) capital costs (costs of building the system) and 2) operation and maintenance costs. Once-through cooling systems are used as a standard or base against which to compare other cooling systems. Table 36 shows that there is a loss in plant efficiency and plant capacity and an increase in auxillary power consumption when other systems are used. These losses and increased power consumption are reflected in higher operation and maintenance costs.

TABLE 36

COOLING SYSTEM EFFICIENCIES FOR 800 MW COAL-FIRED PLANTS

	Once Thru	Wet Mechanical	Natural	Dry (Mech)
Lost Capacity (Due to Higher Back Press)	Base	1%	1%	9%
Loss in Efficiency[1] (Increased Heat Rate)	Base	1%	1%	10%
Auxillary Power[1] (Consumption)	Base	0.5%	0.25%	1.25%
Land Requirements[2] (Acres)	-	3-5	2-3	5-7

Source: [149]

[1] Based on various reports, and manufacturer's information

[2] These land requirements are for comparative purposes only, not to calculate total station land needs.

The capital costs in Table 37 were compiled for various cooling systems from an Atomic Energy Commission report on power plant costs [308]. Historically, once-through cooling has been the least expensive cooling method.

Table 37

ESTIMATED COSTS OF TWO-UNIT [1300 MW(e) EACH] COAL FIRED PLANT WITH ALTERNATIVE COOLING SYSTEMS

	Without Abatement	With SO_2	Increased Costs Above Once-through Cooling Costs	
Once-Through Cooling				
Capital Costs[a]	945	1150	Base	Base
Dollars per kilowatt[b]	363	442	Base	Base
Wet Natural Draft Cooling Towers				
Capital costs	983	1194	38+	44+
Dollars per kilowatt	378	459	15+	17+
Mechanical Draft Cooling Towers[c]				
Capital costs	958	1164	13+	14+
Dollars per kilowatt	368	448	5+	6+

Source: [308]

[a] Capital costs in millions of dollars (mid-1974 dollars)

[b] Capital costs in dollars per kilowatt of plant capacity

The cost figures in Table 38 compare alternative cooling systems for nuclear power plants [51]. The figures are updated to 1975 dollars from 1973 dollars in the manner explained below the table and are based on a lower heat rejection rate for coal-fired plants than for nuclear plants. The entry entitled "Evaluated Present Worth of Cooling System, Millions of Dollars" presents the capital costs for the various systems and the entry entitled "Increase in Generation Cost, Mills per Kilowatt-Hour" gives the operation and maintenance costs.

From a capital cost standpoint, once-through cooling is the least expensive plant cooling system. At present, however, closed-cycle cooling is required unless a utility company can prove, on the basis of meeting certain criteria presecribed by the U.S. Environmental Protection Agency (see Section III.B.1.d.), that its once-through cooling system will not cause serious environmental damage, and thereby receive a variance from this requirement. The data for closed-cycle cooling systems show that wet natural draft towers, wet mechanical draft towers, and spray canals are all economically competitive cooling systems, and the ultimate choice is dependent on site conditions. Environmental impact statements for nuclear and coal-fired plants show a wide variation in the costs of cooling systems. The reports [51, 181, 203, 235, 279, 308, 312, 149] do, however, indicate that wet mechanical draft towers are currently the least costly closed-cycle cooling system. Wet natural draft cooling towers are closely competitive to wet mechanical draft, but are restricted in use due to geological and atmospheric considerations. Recent experience with spray canals shows that operation and maintenance costs have been much higher than reported in the Nuclear Regulatory Commission's Nuclear Energy Center Site Survey [48-54].

(b) Cooling water supply

A power plant located inland but near the coast could have water transported to it by pipeline from the Great Lakes. Supplying water for a 1,000 MWe power plant with a once-through cooling system would require a pipe ten to twenty feet in diameter. An evaporative cooling system would only require a one to three-foot pipe. The exact diameter of the pipe needed depends upon many factors, such as the velocity of the water, the hydraulic resistance of the pipe, and the volume of water required to ensure proper heat exchange.

The operation and maintenance costs of supplying water by pipeline depend on pumping costs, which are a function of the height the water is pumped,

Table 38

COMPARISON OF COSTS AND EFFECTS ON NET CAPABILITY FOR
1200-MWe NUCLEAR GENERATING UNIT
(Figures in 1975 Dollars)

		Evaporative Cooling				Dry Cooling	
	Once-Through	Mech. Draft	Natural Draft	Pond	Spray Canal	Mech. Draft	Natural Draft
Plant Capability at Design Conditions, Megawatts	1,200	1,177	1,170	1,159	1,156	1,022	1,029
Pumping Power Requirements, Megawatts	3.3	6.6	7.0	4.5	8.0	3.5	3.8
Fan Power Requirements, Megawatts	--	3.5		--	--	14.9	--
* Cooling System Capital Investment, Millions of Dollars[a]	14.9	19.5	21.1	35.9	18.1	33.2	40.7
* Evaluated Present Worth of Cooling System, Millions of Dollars[b]	34.4	65.1	64.7	94.8	70.1	210.9	202.5
* Increase in Generation Cost, Mills per Kilowatt-hour[c]	Base	.397	.397	.794	.464	2.307	2.197

*The above dollar figures were approximated from 1973 cost data to 1975 cost data by multiplying by the factors indicated below.

[a] 1973 Cooling System Capital x 1.2

[b] 1973 Evaluated Present Worth x 1.3

[c] 1973 Generation Cost x 1.6

These corrections are approximate based on NECSS study assumptions of: (1) 30 year unit life; (2) 10% discount rate; (3) 15 mill value of replacement power; (4) 20% increase in capital cost; (5) 70% capacity factor.

The above chart and dollar figures were developed and adapted from a Nuclear Regulatory Agency Commission report [51], and from Nuclear Regulatory Commission staff.

the distance from the water source, the type of power plant, and the type of cooling system. Table 39 shows how operation costs vary by distance from water source and height that the water is raised. The cost of operation increases drastically with the distance and height that the water must be pumped. In general, power plants with once-through cooling will be used when the elevation of the site does not significantly increase operating costs. The operating costs for conveying water for closed-cycle cooling will not generally affect the selection of a site. In the Wisconsin Electric Power Company Environmental Report on the Pleasant Prairie Power Plant [552], three of the potential sites located along Lake Michigan would not have used once-through cooling systems due to the height to which the water would have had to have been pumped and the distance from the plant to the end of the pipe in the water.

Table 39

OPERATION COSTS FOR WATER CONVEYANCE BY PIPELINE, BY DISTANCE, AND BY TYPE OF FACILITY FOR A 1000 MWe PLANT (Mills/kWh)

	COAL			NUCLEAR		
(HEIGHT WATER IS CONVEYED)	3 FT.	50 FT.	100 FT.	3 FT.	50 FT.	100 FT.
DISTANCE FROM WATER SUPPLY			CLOSED CYCLE COOLING			
1,000 Feet	.0024	.0168	.0315	.0031	.0219	.0419
1 Mile	.0089	.0230	.0380	.0112	.0300	.0500
5 Miles	.0409	.0550	.0700	.0512	.0700	.0900
			ONCE-THROUGH COOLING			
1,000 Feet	.0776	.4536	.8536	.0993	.5693	1.069
1 Mile	.3070	.6830	1.083	.3960	.8660	1.366
5 Miles	1.439	1.815	2.215	1.860	2.180	2.830

NOTE: 1972 dollars are projected to 1985 dollars at 3% for operation costs. The differential between nuclear and coal operation cost for water conveyance are due to the higher BTU/Kwh for nuclear power plants. Figures are from formulas derived by a Rand Corporation Report Electrical Generating Cost Model For Comparison of California Power Plant Siting Alternatives, Rand Corporation, 1973, p.24.

Capital costs for pipelines vary directly with the diameter of the pipe, length of pipe, type of cooling system, and cost of land. Both evaporative cooling and once-through cooling systems require intake and outfall pipes. Table 40 shows the cost of pipelines for different cooling systems.

TABLE 40

WATER PIPELINE COSTS

COOLING SYSTEM	NUMBER OF 1000 MW POWER PLANT UNITS	CAPITAL COSTS PER MILE	YEAR OF DOLLAR
Evaporative Cooling System	1	$158,400	1985 from 1972 3/ at 5% inflation
	2 units (1234 MW)	1,020,000 5/	1974
	4 units (4800 MW)	1,071,428	1973 1/
	1	223,214 4/	1973
Once-Through cooling System	2	20,000,000	1976 2/
	1	10,000,000 6/	
	1	9,963,360	1985 estimated from 1972 3/

1/ Communication, Detroit Edison

2/ Communication, Commonwealth Edison

3/ 1985 dollars estimated at inflation rate of 5% per year. [311]

4/ The proportion of cost for a 1000 MW unit of the 4800 MW - 4 unit costs. Cost for 1 pipeline would be much higher than the figures indicate, but it is assumed that if power plants were located inland from the coast, then more than one plant would be built to take advantage of these economies of scale.

5/ The average cost per mile derived from cost data for a five-mile pipeline. [573, 574]

6/ The proportion of cost for a pipeline serving a 1000 MW unit of a 2000 MW-2 unit plant. The cost for one pipeline would be much higher than this figure indicates, but it is assumed that if the power plant were located inland, then more than one unit would be constructed to take advantage of economies of scale.

In general, once-through cooling would not be used for a facility located two or more miles inland. For example, cooling system costs for a 1200 MWe coal-fired power plant with a once-through cooling system located two miles inland are shown in Table 41 to be approximately the same as those of a plant with a closed-cycle cooling system, because of the rapidly increasing operation and maintenance costs of the former system. Costs for specific sites vary depending upon site characteristics.

Table 41

COST OF PROVIDING WATER TO A COAL-FIRED POWER PLANT WITH 1200 MW CAPACITY SITED TWO MILES INLAND

ONCE-THROUGH COOLING		
Pipeline Costs		
	A. Capital	$20,000,000 [(a)]
	B. Operation	0.5279 Mills Kwh [(b)(d)]
CLOSED CYCLE COOLING (MECHANICAL DRAFT)		
Pipeline Costs		
	A. Capital	$500,000 - $2,000,000 [(e)]
	B. Operation	0.0153 Mills Kwh [(b)(d)]
The cost of the Mechanical Draft System which is more than the Once-through Cooling System.		
	C. Capital	$30,700,000
	D. Operation and Maintenance	0.397 Mills Kwh [(c)(d)]

(a) 1976 dollars

(b) 1975 dollars - adjusted at 3% per year from 1985 dollars to 1973 dollars, and increased at 9.3% per year to 1975.

(c) 1975 dollars

(d) Pumping costs assume 3 ft. per mile which maximizes the use of once-through cooling.

(e) 1974 dollars

If a variance to current Environmental Protection requirements is not obtained or if once-through cooling cannot be used, the principal cost of locating a power plant that uses Great Lakes water one mile inland from the shoreline would then be the cost of conveying water for an evaporative cooling system, or about $250,000 to $1,000,000 per mile. "This is not to say that such variances cannot be obtained at a reasonable expenditure of time and resources by the utility. Section 316[a] (of the Federal Water Pollution Control Act Amendments of 1972) exemptions to the closed cycle cooling requirements have been granted to Great Lakes stations."*

If a given site would qualify for a 316[a] exemption, the differential

* Communication, Commonwealth Edison

cost of locating inland would be the cost of conveying water for a once-through cooling system up to a distance of two miles. This cost is approximately $10,000,000 per mile and 0.307 to 0.396 mills per kwh, assuming a 3 foot change in elevation. When a closed-cycle cooling system has to be used, the differential cost is that of using a closed-cycle system versus a once-through cooling system. This cost is $30 to $45 million for the differential in capital costs of the systems, 0.397 to 0.517 mills per kwh for the differential in operation and maintenance costs of the two systems, and $250,000 to $1,000,000 per mile for the water pipeline costs. In any event, economics have a strong bearing on the type and design of cooling systems.

(3) Electrical Transmission System

The electricity produced by power plants is consumed at load centers which are primarily in the urbanized areas of the Basin. The cost of transmitting the electricity to the load centers from the power plant is primarily dependent upon the cost of the transmission facilities. These costs encompass transmission lines, their associated terminals, substations, and step-down transformers at major load centers. In recent years the location of power plants in relation to regional and instrastate transmission lines has been coordinated to minimize costs and increase electrical reliability.* Power generated in urban-metropolitan coastal areas is generally consumed within the coastal zone.

There is no simple relationship between a transmission facility's cost and distance of power plants from the load centers.* In specific cases, the cost may be increased or decreased by locating a power facility inland rather than on the coast. It is important to consider the location of existing load centers and transmission lines when examining an inland location for a power plant. If the transmission lines have been placed inland for environmental, social, or economic reasons, it may be less expensive to locate the power plant inland. If no such lines exist, it probably would be more economical to locate on the coast. There are more potential inland sites near load centers (urban areas).

The cost of transmission facilities varies widely.

Estimating unit cost is made difficult by 1)regional differences in line construction cost due both to labor rates and the type of

*Communication, Detroit Edison

terrain; 2) differences in design at the same voltage rate; and 3) rapidly escalating costs [236].

Two lines of the same voltage level and length may have substantial differences in cost because one may have to follow an irregular right-of-way, requiring installation of costly angle structures and dead end towers, in contrast to lower cost tangent towers which can be used on straight rights-of-way.*

As is indicated in Table 42 the "capacity of a transmission line at any voltage is a function of the length of the line and its location in the bulk power network."* Figure 29 graphically presents the variations in power capacity with voltage and line length.

Transmission lines, like other structures, have increased in cost at disproportionately higher inflation rates than the average price indexes. Overhead 765 kV lines are projected in various studies to cost in 1975 dollars between $200,000 and $500,000 per mile, excluding land costs. It was estimated in the Nuclear Energy Center Site Survey (1975) that it would cost about $400,000 per mile on the average for the west and east central regions of the United States and $500,000 per mile for the eastern regions of the United States for a 765 kV line [51].

In summary, there is no apparent relationship between transmission line cost and proximity to load centers. Specific site characteristics will determine the cost of locating inland versus locating on the coast, and no trends have been found at this time.

(4) Land

The value of land is a function of the availability of land offering a similar mix of resources, and not necessarily a function of the amount of land needed for energy facilities. The coastal zone has unique characteristics and features, whose value has often been assumed to be greater than that of an equal sized inland property. The value of these unique characteristics and features result from various demands on the coastal zone, many of which are in competition with one another, such as recreation, tourism, water supply, and multimodal transportation (ship and train). The value placed on this land due to its cultural, psychological, and aesthetic resources is greater than the value that these physical uses would indicate. For example, a house located on a lot on the coast near West Olive, Michigan costs $60,000 [549]. The cost

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*Communication, East Central Area Reliability Agreement

TABLE 42

Costs and Power Carrying Capabilities of Overhead Transmission Circuits

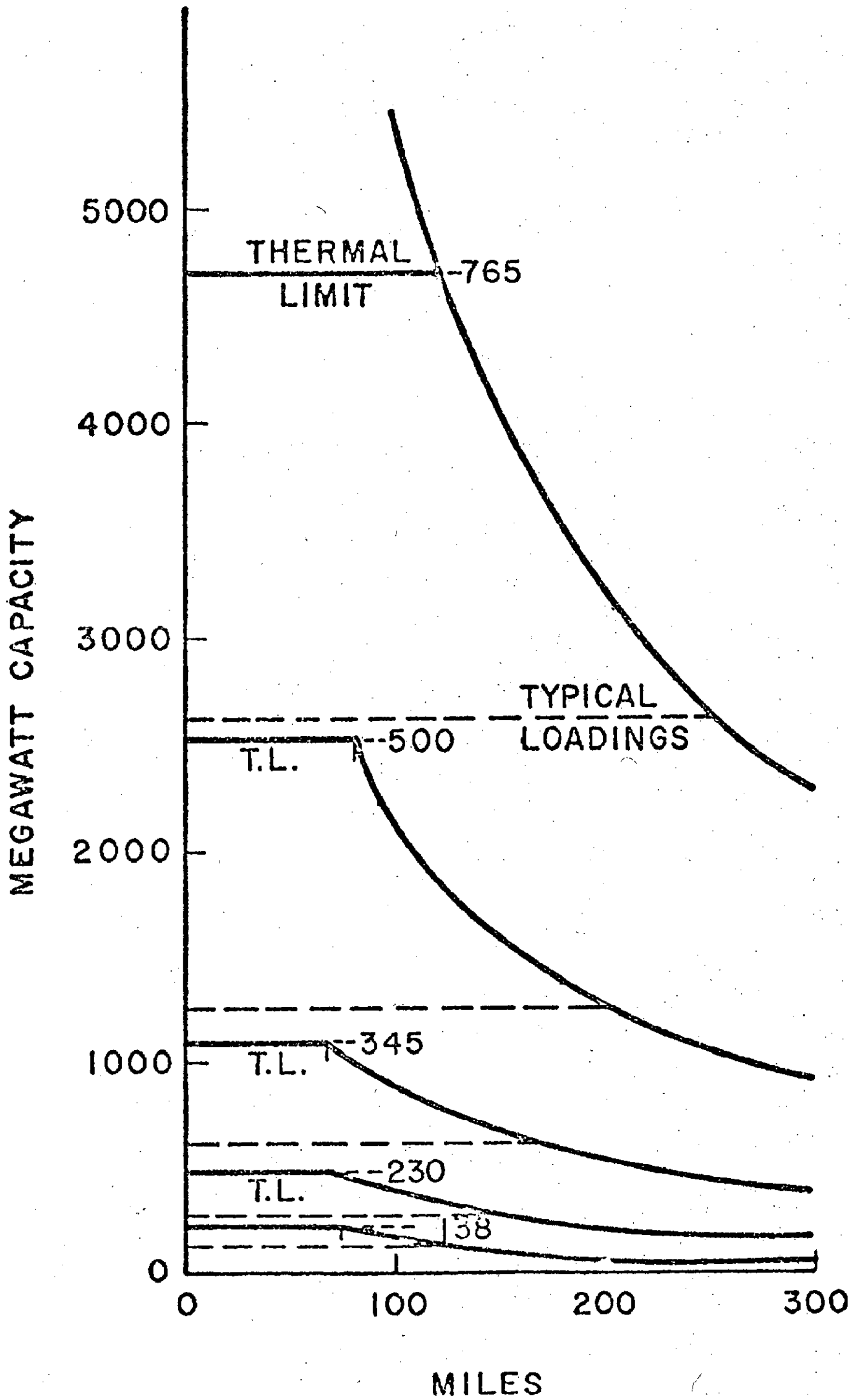
Costs are estimated as of January, 1974*

		345kV	500kV	765kV
1.	Voltage: Nominal	345kV	500kV	765kV
	Maximum	362kV	550kV	800kV
2.	Capacity: 50 Mile	1000MW	2400MW	5500MW
	250 Mile	625MW	1500MW	3300MW
3.	Land: Route Width	150 ft.	175 ft.	200 ft.
	Acres/Mile	18	21	25
4.	Line Cost: Million $/Mile East	0.081	0.151	0.236
	West	0.059	0.113	0.206
	Central	0.051	0.059	0.102
5.	Terminal Cost: Million $/Line (excluding transformers)			
	50 mile	3.175	4.900	8.700
	250 mile	4.415	6.475	13.500
6.	Incremental Terminal Cost (Park less dispersed) Million $/Line			
	50 mile	-	0	5.525
	250 mile	-	1.575	10.325
7.	Transformer $/MW			
	Generator Step Up	1900	1900	1900
	Step Down (Auto)	2600	2600	2600
8.	Power Losses: Percent of yearly energy delivered per 100 miles	1.0%	1.0%	1.0%

* CAUTION: As of April 1975 these costs, which were derived from industry reported values in the early 1970's, appear to be ½ or 1/3 of their present values.

FIGURE 29

TRANSMISSION LINE CAPACITIES



of the lot was $30,000 of which $5,000 was simple land value (similar to inland land costs) and $25,000 was aesthetic value [549]. The implications of these figures are that coastal property is more valuable than non-coastal property primarily because of its unique aesthetic resources. The benefits from this land realized by the public for aesthetic, recreational, or psychological reasons versus the benefits gained by public and private uses for ports and terminals, power plant siting, and cooling water are important resource management considerations.

In summary, although difficult to estimate, the value of coastal land is generally assumed to be greater than non-coastal land.

(5) Environmental Controls

(a) Air

The major air pollutants from the coal-fired power plants are SO_2 (sulfur dioxide), NO_2 (nitrogen dioxides), and suspended particulates. The National Ambient Air Quality Standards and New Stationary Source Performance Standards place restrictions on the emission of these air pollutants. The major technological problem for coal-fired power plants has been meeting the SO_2 standards and auxiliary to this, particulate emission standards.

Two primary ways to meet the sulfur dioxide emission standards in the near future are flue gas desulfurization and use of low sulfur coal. In the future, fluidized-bed boilers and coal gasification may be important. Flue gas desulfurization technology is now in operation on several demonstration coal-fired power plants; however, the technology has not proven to be reliable in all cases. There are several types of flue gas desulfurization systems: wet limestone, dry limestone, magnesium oxide, catalytic oxidation, double alkali, and citrate systems, among others.

Environmental Protection Agency information in Table 43 shows the latest estimates of cost for different flue gas sulfur control technologies, arranged by size of power plant. The Table shows that the cost is between 2.7 and 4.2 mills per kilowatt-hour for limestone flue gas desulfurization, currently the least expensive of the technologies [336].

The other major method of controlling sulfur emissions is through the use of low sulfur coal. There are two sources of low sulfur coal: the western states and the Kentucky-West Virginia region. Most of of the West Virginia and

Table 43

SUMMARY OF TOTAL AVERAGE ANNUAL REVENUE REQUIREMENTS OF FIVE LEADING FLUE GAS DESULFURIZATION PROCESSES

1978 Cost Basis

Case	Years life	Total average annual revenue requirements[a,b] Limestone M $	Limestone Mills/kWh	Lime M $	Lime Mills/kWh	Magnesia M $	Magnesia Mills/kWh	Sodium M $	Sodium Mills/kWh	Cat-Ox M $	Cat-Ox Mills/kWh
Coal-fired power unit											
90% SO_2 removal; onsite solids disposal											
200 MW, new, 3.5% S	30	5,883	4.20	6,362	4.54	7,036	5.03	9,238	6.60	6,000	4.29
200 MW, existing, 3.5% S	20	5,686	4.06	7,150	5.11	7,257	5.18	10,868	7.76	8,263	5.90
500 MW, existing, 3.5% S	25	11,854	3.39	14,528	4.15	14,052	4.01	22,189	6.34	17,765	5.08
500 MW, new, 2.0% S	30	10,625	3.04	11,145	3.18	11,572	3.31	14,549	4.16	12,681	3.62
500 MW, new, 3.5% S	30	11,937	3.41	12,758	3.65	14,082	4.02	18,782	5.37	12,766	3.65
500 MW, new, 5.0% S	30	13,105	3.74	14,377	4.11	16,448	4.70	22,858	6.53	12,844	3.67
1,000 MW, existing, 3.5% S	25	19,711	2.82	23,819	3.40	23,169	3.31	38,813	5.54	31,138	4.45
1,000 MW, new, 3.5% S	30	19,163	2.74	20,570	2.94	22,789	3.26	31,186	4.46	20,534	2.93
80% SO_2 removal; onsite solids disposal											
500 MW, new, 3.5% S	30	11,319	3.23	12,206	3.49	13,406	3.83	17,425	4.98	-	-
90% SO_2 removal; onsite solids disposal (existing unit without existing particulate collection facilities)											
500 MW, existing, 3.5% S	25	14,376	4.11	14,826	4.24	16,639	4.75	24,995	7.14	19,480	5.57

[a] Power unit on-stream time, 7,000 hr/yr. Midwest plant location, 1978 revenue requirements. Investment and revenue requirements for disposal of flyash excluded.

[b] These revenue requirements reflect capital investments shown in Table 1 (updated); byproduct credit and sludge fixation costs excluded.

Kentucky low sulfur coal is used for metallurgic processes although some has been used in the Midwest by power plants.

The cost of western low sulfur coal, the major source of low sulfur coal for the Midwest utility market, is projected to increase at 3% per year between 1975 and 1980. After 1980, the price is expected to remain relatively constant.* The cost of transporting coal has been a major component of this increased cost. This cost has roughly increased three to four dollars a ton more than the figures reported in the coal transportation section (Section IV.B.2.a).* The cost of flue gas desulfurization, on the other hand, has recently stabilized and is not expected to increase as rapidly as in the past.

The price of western coal depends upon several parameters; the cost of transportation, profit margins on low sulfur coal, whether air pollution standards are enforced on time and without variances, the capability of mining and transportation facilities to expand, and others.

An Argonne National Laboratory study on the differential in cost between low sulfur coal and flue gas desulfurization found it to be less than one mill per kwh, with low sulfur coal being slightly cheaper. Due to this small variation in the cost differential between the two major sulfur controls, the method which will be used depends upon site characteristics affecting the transportation, origin, and destination of coal, duration of contracts, and company policy.

There is an interrelationship between the cost of SO_2 removal and particulate removal. For example, the use of certain low sulfur coal will increase the emissions of particulates, and the cost of particulate removal.

Another method for reducing sulfur emissions is physical and chemical coal desulfurization. When used with medium sulfur content coal, the resulting fuel can meet existing standards. The availability of medium sulfur coal restricts the use of this method (14% of the United States reserves) [219].

(b) Waste disposal

Coal-fired power plants produce large quantities of solid waste; out of a ton of coal delivered to the plant, 10 to 30 percent is residual waste, mainly in the form of fly ash. Coal with an ash content of 15 percent would produce approximately 40 tons of waste per hour or approximately 250,000 tons a

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* Communication, Argonne National Laboratory

year for a 1000 MWe power plant. A large land area (100-133 acres) filled to a depth of 25 feet is necessary for disposal of the waste over a 35-year useful life for a 1000 MWe plant [221].* In recent years, fly ash has been sold as filling material on local markets for asphalt and structural fills or embankments.** In the United States in 1974, 16.3% of the fly ash was sold at prices ranging from two dollars a ton to as much as six dollars a ton, depending on the market supply and demand and the region.** In the future, scarce metals such as magnesium, chromium, titanium, and vanadium may be extracted from the ash.**

A power plant located near the coast may transport the waste to an inland location for disposal. The mode of transporting the waste inland varies, but tenerally pipelines or trucks are used. "The tariffs currently approved by the Michigan Public Service Commission for transporting fly ash are 69¢/ton for up to five miles and $1.32/ton for distances up to 5-20 miles."*** The transportation cost is only one of the costs associated with transporting the waste to an offsite location. The other is the incremental cost (the extra cost above onsite disposal costs) for extra onsite or offsite preparation, disposal, and storage of waste.

"Annualized costs for waste disposal, a difficult problem, ranged from $1.00 to $7.00 a ton, and $3.00 a ton is used" [432]. Information from Detroit Edison shows the total cost of transporting fly ash wastes and disposing of them offsite to be as follows:

A. Dry storage in silos and trucking to offsite disposal area. Assume sufficient silo capacity for three-day storage.

   Levelized Annual Cost: $3.96 per ton, 5 miles to disposal site
   $5.02 per ton, 20 miles to disposal site

B. Flyash from hoppers mixed with water and pumped to small onsite reservoir. Dewatered sludge removed and trucked to off-disposal area every two years.

   $2.64 per ton, 5 miles to disposal site
   $3.71 per ton, 20 miles to disposal site

C. Flyash from hoppers mixed with water and pumped directly to permanent disposal site.

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* Figures were reduced from a 3000 MWe plant, which would require 300-400 acres.

** Electric World, May 1, 1976; Volume 185, Number 9.

*** Communication, Detroit Edison.

Levelized Annual Cost: \$2.53 per ton, 5 miles to disposal site
\$3.32 per ton, 20 miles to disposal site

> It should be noted that these costs are actually costs per ton of fly ash produced. The increased tonnage of ash-water mixtures or any additional costs due to lime/sulfur slurries have not been estimated.*

The differential cost per ton of disposing the fly ash offsite as opposed to onsite is the cost per ton of offsite disposal (as in the chart above) minus the onsite disposal cost per ton. The major costs contributing to this difference are those for transportation, onsite equipment, cost of disposal site, and site preparation.* The cost of onsite disposal of fly ash varies from site to site and depends upon land costs, selling price and alternative uses for fly ash, and transportation and storage costs.

If limestone scrubbers are used for the removal of SO_2, residual waste volumes will be expanded by one to two times the present amount each year [231]. Special problems will be encountered in disposing of the sludge from limestone scrubbers. Sulfur removed from the gas can be sold at up to \$15.00 per ton [432]. "The EPA has estimated that sludge for a 1000 MWe coal-fired power plant [assuming three percent sulfur, 12 percent fly ash, 6,400 hours/year operation] will require 269 acres for solid waste disposal or 377 acres necessary including fly ash" [432]. "As a rough guide, EPA believes that if the cost of sludge disposal exceeds \$4.00 to \$6.00 a ton [wet basis], a regenerable process which covers a useful byproduct will be more economical than a nonregenerable process" [432]. In many instances, the preliminary data which EPA compiled on disposal waste indicated that offsite disposal is cheaper than onsite disposal [432]. In reality, the costs associated with offsite disposal depends upon specific site factors and regional conditions.

In summary, waste disposal with limestone scrubbing could be a major problem in terms of land required. There is no obvious pattern related to the extra cost associated with offsite disposal as opposed to onsite disposal.

c. Nuclear Power Plants

(1) Fuel Transportation and Storage

While the cost of transporting fuel can have a major effect on the location of a coal-fired power plant, this same factor has but a minor effect on

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* Communication, Detroit Edison.

the location of a nuclear power plant [50].

The cost of transporting nuclear fuel is approximately $4.00 to $5.00 per kilogram of uranuim, or only one to two percent of the total cost of fuel.

Table 44 shows that the transportation requirements for nuclear power plants are low over the entire nuclear fuel cycle.

The implications of risk and impact on coastal waters from the transportation of nuclear materials is out of the scope of this report; however, the implications are extremely important and deserve further examination.

TABLE 44

ANNUAL SHIPMENTS OF RADIOACTIVE MATERIALS TO AND FROM AN OFFSHORE NUCLEAR POWER STATION (One 1100-MWe Pressurized Water Reactor)

Operation	Approximate number of shipments per year	
	Barge	Land
Fresh (unirradiated) fuel[a]		
1. Fuel fabrication plant to shore transfer point		6 trucks[b]
2. Shore transfer point to offshore power plant	1 to 2 barges[c]	
Spent (irradiated) fuel[a]		
1. Offshore power plant to shore transfer point	2 to 5 barges[c]	
2. Shore transfer point to fuel reprocessing facility		60 trucks or 10 rail cars
Solid radioactive wastes		
1. Offshore power plant to shore transfer point	2 to 5 barges[c]	
2. Shore transfer point to licensed radioactive waste disposal facility		46 trucks or 11 rail cars

[a]The shipment of empty casks for fresh and spent fuel will require essentially the same number of shipments as the number of loaded casks indicated in the table. However, the radioactivity hazard will be negligible.

[b]Initial loading of reactor requires about 18 truckloads of unirradiated fuel. Shipment of unirradiated fuel by rail is usually ruled out because of length of transit time.

[c]Number depends on capacity of barge. [562]

(2) Cooling Systems

A major determinant in the location of nuclear power plants is the cost of providing a cooling medium. Water is the primary natural resource used as a cooling medium, although air can also be used. There are different costs involved in providing cooling water to coastal and inland locations.

As was the case with coal-fired plants, both capital (costs of building and of the components of the system) and operation and maintenance costs must be considered. The use of more sophisticated cooling systems results in greater losses in efficiency and capacity, and increased auxiliary power consumption than the use of once-through cooling. Table 45 shows that the efficiencies for nuclear power plants vary with the cooling method. Table 46

TABLE 45

COOLING MODE EFFECTS ON NUCLEAR PLANT EFFICIENCY

Cooling Mode	Typical Nuclear Plant Efficiency
Evaporative Natural Draft Tower	32.7
Evaporative Mechanical Draft Tower	32.6
Cooling Pond	32.8
Once Through (River)	32.9
Dry Tower - Mechanical Draft	28.1
Dry Tower - Natural Draft	28.6

Source: [149]

Table 46

COOLING MODE EFFECTS ON FOSSIL/NUCLEAR PLANT OPERATION

	FOSSIL/HTGR - 800 MW				BWR/PWR - 1000 MW			
	Once Thru	Wet Mechanical	Wet Natural	Dry (Mech)	Once Thru	Wet Mechanical	Wet Natural	Dry (Mech)
Lost Capacity								
(Due to Higher Back Press)	Base	1%	1%	9%	Base	1%	1%	15%-PWR 17%-BWR
Loss in Efficiency(1)								
(Increased Heat Rate)	Base	1%	1%	10%	Base	1%	1%	15%-PWR 17%-BWR
Auxiliary Power(1)								
Consumption	Base	0.5%	0.25%	1.25%	Base	0.8%	0.4%	2%
Land Requirement(2)								
(Acres)	-	3-5	2-3	5-7	-	5-7	3-5	7-10

(1) Based on various reports, studies, and manufacturer's information

(2) These land requirements are for comparative purposes only, not to calculate total station land needs.

[149]

shows losses in efficiency and capacity and the increase in auxiliary power consumption due to various cooling systems. These losses are reflected in higher operation and maintenance costs.

The capital costs in Table 47 were compiled for various cooling systems from an Atomic Energy Commission report [308]. Historically, as shown in the table, once-through cooling has been the least expensive cooling method.

The cost figures given in Table 48 show comparisons among alternative

TABLE 47

ESTIMATED COSTS OF TWO-UNIT [1300MWe EACH] LWR PLANT
WITH ALTERNATIVE COOLING SYSTEMS

(Cooling Systems Cost in Brackets for One-Unit [1300 MWe]
LWR Power Plant with Alternative Cooling Systems)

		Increased Capital Costs Above Once-Through Cooling
Once-Through Cooling		
Capital costs[a]	1410	BASE
Dollars per kilowatt[b]	542	BASE
Wet Natural Draft Cooling Towers		
Capital costs	1434 [722]	24+
Dollars per kilowatt	551 [556]	11+
Wet Mechanical Draft Cooling Towers		
Capital costs	1406	-4
Dollars per kilowatt	541	-1

[a] Capital costs millions of dollars mid-1974 dollars for a plant finished in 1981
[b] Capital costs in dollars per kilowatt of plant capacity

[308]

cooling systems for nuclear power plants [51]. The figures in the table are updated to 1975 dollars from 1973 dollars in the manner explained at the bottom of the table. The line indicating "Evaluated Present Worth of Cooling Systems, Millions of Dollars" shows the capital costs and "Increase in Generation Costs, Mills per Kilowatt-hour" is the operation and maintenance costs.

Once-through cooling is the least expensive system but currently is not used on new plants unless a variance is granted under Section 316(a) of the Federal Water Pollution Control Act Amendments of 1972.

As the data shows, wet natural draft towers, wet mechanical draft towers, and spray canals are all competitive alternative cooling systems depending upon the site location. Further discussion of this subject is presented under Section IV.A.5.b.(2) of this report.

(3) Electrical Transmission Systems

No discernable differences between electrical transmission lines for nuclear power plants versus coal power plants could be detected. For discussion see Section IV.A.5.b.3.

TABLE 48

COMPARISON OF COSTS AND EFFECTS ON NET CAPABILITY FOR 1200-MWe NUCLEAR GENERATING UNIT USING ALTERNATIVE COOLING SYSTEMS (1973 COST DATA)

		Evaporative Cooling				Dry Cooling	
	Once-Through	Mech. Draft	Natural Draft	Pond	Spray Canal	Mech. Draft	Natural Draft
Plant Capability at Design Conditions, Megawatts	1,200	1,177	1,170	1,159	1,156	1,022	1,029
Pumping Power Requirements, Megawatts	4.8	9.5	10.2	6.5	11.6	5.1	5.5
Fan Power Requirements, Megawatts	-	5.0	-	-	-	21.6	-
Cooling System Capital Investment, Millions of Dollars[a]	18.0 21.6	23.6 28.32	25.5 30.6	43.4 52.08	21.8 26.16	40.1 48.12	49.1 58.92
Evaluated Present Worth of Cooling System, Millions of Dollars[b]	38.3 49.79	72.6 94.38	72.1 93.73	105.7 137.41	78.1 101.53	235.2 305.76	225.8 293.54
Increase in Generation Cost, Mills per Kilowatt-hour[c]	Base	0.36 .576	0.36 .576	0.72 1.152	0.42 .672	2.09 3.344	1.99 3.184

Note: For approximate correction to January 1975 costs multiply by factors as indicated.

[a]Cooling System Capital x 1.2.

[b]Evaluated Present Worth x 1.3.

[c]Generation Cost x 1.6

[51]

These corrections are approximate based on NECSS study assumptions of: (1) 30 year unit life; (2) 10% discount rate; (3) 15 mill value of replacement power; (4) 20% increase in capital cost; (5) 70% capacity factor.

(4) Land

No discernable differences between land or land value for nuclear power plants versus coal power plants could be detected. For discussion, see Section IV.A.5.b.4.

(5) Environmental Controls

"It is recognized that there exist a number of controversial issues regarding the safety-environmental-public health aspects of nuclear power plants and accompanying fuel cycle operations" [148]. This section is concerned only with the cost of environmental controls which affect site location and resource utilization in respect to the coastal waters.

The cost of controlling accidental releases of radioactive material into the coastal waters or land through plant operation and fuel transshipment would not affect the location of a nuclear facility [50, 148].

Radioactive material is stored on the site of a nuclear power plant. Irridated spent fuel elements require the strictest containment due to their extreme toxicity and radioactivity. The storage of such material is not a significant cost in locating a power plant [148].

The irridated spent fuel elements may, in the future, be transported to regional reprocessing plants. These reprocessing plants may receive shipments by truck, railroad, or barge.*

It is beyond the scope of this report to consider risks and impacts of these activities on the coastal zone or waters. However, it is recommended that future research be conducted on the impact of these activities on the coastal zone and waters, especially in respect to possible barge shipment of irridated spent fuel to reprocessing plants.*

In summary, while an initial evaluation indicates the costs associated with nuclear power plants' environmental safety are not a significant factor in determining site location, more detailed research on both impacts and costs in relation to coastal waters would be beneficial.

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* Role of Transportation in the Nuclear Fuel Cycle, Energy Research and Development Administration presented at the July meeting of Michigan Environmental Review Board.

d. Fuel Transshipment and Storage Facilities

(1) Introduction

In the following discussion, only coal transshipment and storage facilities are considered, because the potential magnitude of their possible effects on the Great Lakes coastal zone is the greatest. The capacity of coal transshipment and storage facilities in the Basin varies from 2,000 tons of coal per year to as large as 20 million tons of coal per year.

This section examines the cost of a fuel transshipment and storage facility where the storage pile is inland from the port. The cost of transporting coal inland by conveyor belt for the distance of five miles is 5.4 cents per ton mile.* The cost of moving 5.6 million tons of coal per year (the amount needed for two 1000 MWe power plants) one mile is $302,400. It is unlikely that coal would be transported only one mile inland to a storage area, due to the high cost of handling for short transport. It is more reasonable to assume that coal would be transported longer distances.

(2) Land

Coal may be transported inland to conserve the use of coastal properties. In general, a coal transshipment and storage facility maintains a 90-day supply; this varies depending upon the accessibility of the facility to incoming coal during the winter. The amount of land required to store a 90-day supply of coal (1,400,000 tons for two 1000 MWe power plants) at 30-40,000 tons/acre is 30-40 acres. Approximately one to two acres would be necessary for transient storage. A transient storage area at the port is necessary because it is uneconomical for a conveyor belt several miles long to have a transport capacity equal to the rate at which a barge or ship may be unloaded.

In summary, transporting coal inland saves only about 28-38 acres of coastal land for a facility with a capacity of 5.6 million tons per year.

e. Refineries

As was indicated in the discussion of refinery site requirements and considerations in Section IV.A.3, the economics of refinery location is a complex issue that must be considered at a national level. For example, an

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* The cost data is based on the analysis in Coal Fuel Transportation and Storage (Section IV.A.5.b.1.)

analysis [in 312 based on material from 370] compares costs of supplying refined products to the east coast from refineries located on the east coast, the Gulf Coast, and offshore (i.e., outside of the U.S., such as the Carribbean). As the figures in Table 49 show, the cost of refined products on the east coast (Petroleum Administration for Defense, PAD, District I), is lowest if the crude oil is refined outside of the United States and shipped to the market area. While this is only one example, it does indicate that an evaluation of refinery economics must be done at a supraregional scale.

f. Facility Cost Discussion

This section is a summary of previous economic material on coal-fired power plants, nuclear power plants, ports and terminals, and refineries. Table 50 is a matrix summary of economic material compiled in the previous sections. The assumptions of the cost data are listed in the footnotes. It is important when using this material to review the footnotes, and to keep the material in context by reviewing the section where it originated.

The first column titled "Land" reflects the average amount of land that coal-fired plants, nuclear power plants, and refineries occupy. The categories for the different cooling systems under nuclear and coal-fired power plants show the average amoung of land different cooling systems occupy.

The "Plant" column reflects plant capital costs for the different facilities. It is important to note the size and capacity of the nuclear and coal-fired power plants as they differ from our idealized 1000 MWe power plant.

The "Cooling System" column indicates two sections--water provision and plant system. The water provision section indicates that both capital and operation and maintenance costs for conveying water to a closed-cycle cooling system are less expensive than to a once-through cooling system. The plant system indicates that both capital and operation and maintenance costs are more expensive for closed-cycle cooling than once-through cooling. The cost of locating a power plant inland versus on the coast depends upon many site-specific factors and different configurations of the components of the cooling systems.

The fuel column is divided into three sections: short haul transportation, long haul transportation, and storage. The short haul transportation section indicates that the cost of moving coal one mile inland from a fuel transshipment and storage facility is not exceedingly expensive. The long

(continued on page 277)

TABLE 49

COST OF SUPPLYING REFINED PRODUCTS TO THE EAST COAST FROM ONSHORE AND OFFSHORE REFINERIES

($/bbl of product in 1985)

Cost Component	Origin of Supply		
	Onshore		
	EAST COAST	GULF COAST	Offshore[a]
Crude oil in Persian Gulf[b]	2.65	2.63	2.69
Transportation and terminaling[c]	1.28	1.21	1.00
Duty	0.11	0.11	0.29
Operating costs	0.48	0.45	0.38
Product transportation	---	0.51	0.27
Interest on working capital	0.08	0.08	0.10
Marketing expense	0.05	0.05	---
Income taxes[d]	0.52	0.05	0.05
Return on refinery investment[e]	0.90	0.79	0.90
Total (15% DCF[f] rate of return)	6.07[g]	6.28	5.68
Total (10% DCF rate of return)	5.58	5.85	5.42

[a]The tabulation of costs shown in this table for an offshore refinery is not based on any particular location, nor are there currently any offshore refineries making the assumed "balanced" District I slate of products. Current offshore refineries are of the hydroskimming type, feeding mixtures of low-sulfur and high-sulfur crude, primarily producing fuel oil for the U.S. market. Consequently, these costs are not intended to display actual circumstances of current offshore conditions.

[b]Prices of crude oil in the Persian Gulf are the same. Figures in the table differ because they are expressed in dollars per barrel of product, and product yields vary from location to location. Costs include butane purchases and exclude cost of acquiring import quota.

[c]Shipping at Worldscale 70 rates. Oil moves to District I by vlcc to a Caribbean terminal and thence by barge to the United States. District III uses vlccs and a man-made deepwater port.

[d]Forty-eight percent tax rate onshore and zero offshore. It is assumed that a refiner offshore will make full use of tax concessions.

[e]Fifteen percent rate of return. Return is related to estimated refinery investments. Offshore refinery investment included a power plant, which onshore refineries do not have.

[f]Discounted cash flow.

[g]Costs are in 1972 dollars.

[SOURCE - 312]

TABLE 50

IV 4a(3) FACILITY-COST MATRIX (VI)
For Facilities 1 Mile Inland

FACILITIES	LAND VI	VI PLANT	COOLING SYSTEM: WATER PROVISION: Capital Cost	COOLING SYSTEM: WATER PROVISION: Operating and Maintenance	COOLING SYSTEM: PLANT SYSTEM: Capital Cost	COOLING SYSTEM: PLANT SYSTEM: Operating and Maintenance	FUEL: Short Haul Trans. (Per Year)	FUEL: Long Haul Trans. (Per Year) VI	FUEL: Storage VI	PRODUCT DISTRIBUTION VI	ENVIRONMENTAL CONTROLS VI: Air	ENVIRONMENTAL CONTROLS VI: Water	ENVIRONMENTAL CONTROLS VI: Solid	ENVIRONMENTAL CONTROLS VI: Other
	(1) V	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(10)		(12)	(11)	(13)	
	I	II	III	IV	II	IV	III	II	I	III	IV		II	
COAL POWER PLANTS:	145-2000													
Once-Through	>1	945	10,000	.317	34.4	0	151.2	5.6-28	25	116,667+	2.7	---	2.50	---
Nat. Draft Tower	10		250-1,000	.0089	64.7	.397	151.2	5.6-28	15-20	116,667+	–	---	–	---
Mech. Draft Tower	45		250-1,000	.0089	65.1	.397	151.2	5.6-28	15-20	116,667+	5.2	---	1.75	---
Spray Canal	100		250-1,000	.0089	70.1	.462	151.2	5.6-28	15-20	116,667+	"	---	"	---
Cooling Pond	2000		250-1,000	.0089	94.8	.794	151.2	5.6-28	15-20	116,667+	"	---	"	---
NUCLEAR POWER PLANTS:	I (84-30,500 1,100Ave)	II	III	IV	II	IV		III (9)		III (11)				
Once-Through	>1	1410	10,000	.396	49.8	0	---	234	---	116,667+	---	---	---	---
Nat. Draft Tower	10		250-1,000	.0112	86.5	.576	---	234	---	116,667+	---	---	---	---
Mech. Draft Tower	45		250-1,000	.0112	94.4	.576	---	234	---	116,667+	---	---	---	---
Spray Canal	130		250-1,000	.0112	93.7	.672	---	234	---	116,667+	---	---	---	---
Cooling Pond	2600		250-1,000	.0112	126.9	1.152	---	234	---	116,667+	---	---	---	---
REFINERY	I (16) 1,500 - 2,700	II (17) 200 - 815		VIII (20) 33 - 82.6						VII 1.24	II (18) .4-3.4	II (18) 8.9-22.3		II (19) 1.1-2.75
(COAL) FUEL TRANS-SHIPMENT & STORAGE	---	---	---	---	---	---	III (15) 302	---	I (14) 35-45	---	---	---	---	---

I Figures in acres
II Figures in millions of dollars
III Figures in thousand of dollars
IV Figures in mills per kwh
V Footnotes on following pg. for numbers in ( ) brackets
VI This factor would not be substantially affected by location on coast or one mile inland
VII Dollars per barrel [312]
VIII Total plant, million \$/yr.

Footnotes for Table 50.

1 The figures for land requirements include the requirements for different cooling systems except for cooling ponds. The land requirements for cooling ponds and spray canals for coal-fired power plants were adapted from nuclear power plant requirements at the lower Btu/kWh heat rejection rate (77% of a nuclear power plant) for coal-fired power plants. The other cooling systems, it is assumed, would not use appreciably more land for fossil-fuels than for nuclear.

2 These figures represent different plant capital costs in millions of dollars for a two unit [1300 MWe each] power plant. These costs are from a different source than the cooling system costs and are in mid-1974 present value dollars. These figures do not include fuel costs, operation and maintenance costs, or sulfur dioxide controls [308].

3 The capital costs are presented in 1976 present value dollars for conveying water one mile inland for a 1000 MWe plant. See section on Water Supply (Section IV.A.b.(2)(b)), for detailed limitations on use of figures. The capital costs for water supply do not consider the type of facilities which could be used on the coast versus inland and should be used with caution.

4 The operation and maintenance costs are in mills per kilowatt hour in 1985 dollars projected from 1972 dollars for a 1000 MWe plant, assuming a height increase of 3 feet for one mile inland distance.

5 The capital cost figures are represented in 1975 present value dollars for a 1200 MWe plant. The coal-fired power plant figures are adapted from the nuclear figures by using the lower heat rejection, 77% of a nuclear power plant, for a coal-fired power plant.

6 The operation and maintenance costs are in 1975 dollars in mills per kWh. See section on Cooling Systems [Section IV.A.b.(2)], for limitations on use of figures.

7 The figures in the short haul transportation of fuel for coal assume a 1000 MWe plant using 2,800,000 tons of coal per year: the amount of western coal a power plant would use in a year. The short haul transportation figures assume moving coal one mile using conveyor belts at 5.4¢ per ton mile. Coal would not be moved just one mile at this cost due to high handling costs.

8 The long haul transportation figures assume moving 2,800,000 tons of coal a distance ranging from 250 miles to 1400 miles, assuming approximately seven miles per ton per mile.

9 The cost figures for transporting nuclear fuel for a 1000 MWe nuclear plant assumes the cost of 46,800 KgU of fuel per year is between $4.50 to $5.54 per KgU or an approximately average of $5.00 per KgU in 1976 dollars.

10 The land acreage needed for storage at a coal power plant assumes 90-day supply of coal and 30-40,000 tons/acre.

11 The cost figures are for a 1000 MWe plant assuming a quarter of the cost of a 765 kV line with a 4000 MWe line capacity in 1976 dollars.

12 The cost for sulfur dioxide controls, the principal air pollution control, are figured from costs that range between 2.7 to 4.2 mills per kWh.

13 The costs for fly ash disposal, the principal solid environmental control, are figured from a volume of 250,000 tons a year fly ash wastes for a 1000 MWe plant at one to seven dollars a ton disposal costs. The costs and volume will increase one to two times if limestone desulfurization processes are used.

14 The figures for land requirements for fuel transshipment and storage are for the principal use of these facilities--coal. The land requirements are only the area necessary for storing 1,400,000 tons of coal.

15 This cost figure for short haul transportation of coal is based upon 5.4 cents per ton per mile, and 5.6 million tons of coal transported per year. Coal would not be moved just one mile at this cost due to high handling costs.

16 Depends on capacity. Figures given are from refinery description section.

17 Based on minimum and maximum figures found in literature and size varies from 100 to 250 MBD.

18 Based on figures from [370] cited in [312].

19 Noise and light control.

20 @ $1.052/bbl [312] -- encompasses estimates in [506].

(continued from page 273) haul transportation section indicates that the cost of transporting coal fuels versus nuclear is many times more expensive on a per unit basis. The cost of transporting coal can have a significant effect on the location of a coal-fired power plant. Refinery site location costs, though no figures are listed, are significantly affected by existing pipeline location. New refineries will locate near existing or proposed crude oil pipelines. The storage section indicates the approximate number of acres the facilities require for oil storage.

The "Product Distribution" column indicates the cost to power plants and refineries for distributing their product, electricity and oil, to customers. The cost of product distribution from power plants is an important site location factor, but not necessarily a coastal dependent factor. The cost of product distribution from refineries is not an important factor in determining site location.

The "Environmental Controls" column reflects the cost to facilities for air, water, solids, noise, and light controls. The important environmental control in relation to site location is air. The air quality can affect both the location of refineries and coal power plants due to the ambient air quality. Refinery location can also be affected by light and noise intrusion, especially in relation to residential communities.

In summary, this section has highlighted those factors which affect site location and coastal dependency. These important general factors affecting site location are often mitigated by specific site location factors. The specific site location factors, as is shown in the Pleasant Prairie Case Study, in Section IV.6, and the discussion of coastal dependency can be more important in determining site location in respect to the coast than general site location factors.

6. DISCUSSION OF COASTAL DEPENDENCE AND CASE STUDY

At the outset of this discussion on the environmental and economic factors affecting the siting of energy facilities the following definition of "coastal dependence" was adopted:

> The determination of energy facility location with respect to the lakeshore is expressed through the following general considerations: system requirements, safety, engineering, environmental, institutional, and economic.

The breadth of this definition indicates that the analysis must go beyond simple evaluation of factors related to coastal locations, to a more general examination of facility location. Retaining the lakeshore as a reference point, however, puts the analysis into a coastal-versus-inland framework. This definition thus provides sufficient latitude to identify the trade-offs between coastal and inland site locations.

This analysis will provide a discussion of the general and specific factors related to both coastal and inland sites, highlighted by examples from a specific facility proposal. In selecting the facility to be used as an example, the following criteria were important: (1) it should be one of the facility types considered in this study, (2) it should be representative of the approximate size of facilities considered in this study, and (3) coastal and inland location alternatives should have been considered. The facility selected, the Pleasant Prairie Power Plant (Wisconsin Electric Power Company) near Kenosha, Wisconsin, provides the perfect example for this type of analysis. It is a coal-fired plant with an electric output of 1,160 MWe. Furthermore, sites both on Lake Michigan and inland were considered during the site selection process. A brief description of the facility is given below. The material used to highlight the discussion of coastal dependent and nondependent factors was abstracted from the Environmental Report, Pleasant Prairie Power Plant, Units 1 and 2 [552 and 553].

a. Pleasant Prairie Description

In February, 1975, the Wisconsin Electric Power Company submitted an environmental report describing its proposed Pleasant Prairie Power Plant Units 1 and 2, to be built near the town of Pleasant Prairie, approximately four miles southwest of Kenosha, Wisconsin. In the report, information was provided on the proposed plant and site and its environment, the expected environmental impact of the project was assessed, and a comparative assessment was made of six alternative sites. The facility is presently under construction.

The plant will consist of two identical generating units, each of which includes a coal-fired boiler, steam turbine and generator, and associated equipment. The two steam generators will use low sulfur pulverized coal at a rate of approximately 380 tons per hour per unit on a normal full load basis. The expected net capacity of the plant will be 1,160 MWe, although actual output will vary with ambient temperature and relative humidity. The total capital investment in the plant and facilities will be $432,672,000, with annual operating expenses estimated to be $42,830,000.

As of 1975, the Wisconsin Electric Power Company had not selected a coal supplier for the plant. However, it is determined that coal will be received at the Pleasant Prairie site by unit train from Wyoming coal fields, approximately 1,150 miles away.

The main cooling water system will consist of two mechanical draft cooling towers rejecting approximately 6.8×10^9 Btu/hr to the atmosphere. The system will circulate a total of 400,000 gpm across the condensers for both units. Makeup water for this sytem will be received via pipe from Lake Michigan (approximately 4.5 miles east of the site) at a nominal rate of approximately 8,660 gpm.

Particulate material will be controlled through the use of electrostatic precipitators designed for overall collection efficiencies of at least 99.3 percent. The collected fly ash will be moved pneumatically to silos for temporary storage before movement to an onsite disposal area. Because the plant will use low sulfur western coal it is not expected that sulfur dioxide emissions will be a major problem. In addition, nitrogen oxides and carbon monoxides are also expected to meet emission standards. To aid in the dispersion of these effluents a stack at least 450 feet high will be used.

The Pleasant Prairie site incorporates an area of approximately 425 acres, of which the principal plant facility will require 210 acres. Figure 30 depicts the arrangement of the plant and the locations of the related facilities. Figure 31 shows the proposed intake and discharge pipe corridor leading to Lake Michigan from the site.

The six alternative sites considered for this plant include: (a) the Haven site located at former Camp Haven Military Reservation in the northeastern portion of Sheboygan County; (b) the Port Washington site located southwest of the company's existing Port Washington Power Plant in Ozaukee County on Lake Michigan; (c) the Milwaukee Harbor site situated just north of the mouth of the

Milwaukee River on existing lake fill; (d) the Lakeside site located between South Lake Drive and Lake Michigan in the City of St. Francis (an existing power plant owned by the company is located just south of this site); (e) the Oak Creek site located in the southeastern part of Milwaukee County just north of the company's existing Oak Creek Power Plant on Lake Michigan; and (f) the Kenosha site located just south of the City of Kenosha municipal boundary. Figure 32 shows all of these sites, including the selected Pleasant Prairie site.

In a comparison of the alternative sites, factors considered included the following: (1) proximity and suitability of both rail and road facilities during construction and operation of the plant; (2) potential for congestion of service roads; (3) surrounding land use; (4) proximity to population concentrations, and; (5) other factors discussed in the environmental report. In addition, sites were evaluated on a combined economic, engineering and environmental basis. Critical factors for evaluation and comparison included site characteristics, cooling method, and fuel supply provisions.

b. Discussion of Coastal Dependence

Because this study deals with the problem of site selction on a nonsite-specific basis, it is impossible to identify those factors favoring a coastal site over an inland site or vice versa. Instead, at the level of this analysis there is a continuum of coastal dependence or nondependence, running from those factors that can be generalized for all sites as being coastal-related to those factors which may, on a site-specific case-by-case basis, involve important coastal versus inland site trade-offs.

The most obvious factor tying major energy facilities, especially electrical generating facilities, to the coast is the need for large volumes of water to dissipate the great amounts of waste heat. In the past when once-through cooling was used almost exclusively, a coastal location could result in tremendous cost savings: figures developed for this report indicate that the capital cost alone for a once-through cooling system could be up to $10 million per mile to move water to an inland site for a 1000 MWe plant. In addition, the operating and maintenance cost would be enormous. One estimate of this is 0.307 mills/kWh/mi (assuming a difference in elevation of 3 feet between water intake in the plant). With the increased use of closed-cycle cooling systems, however, this dependency on the coast has been lessened considerably. The capital costs for supplying water to a plant with a closed-cycle system range from only $250,000 to $1 million per mile. Operating and maintenance cost are estimated to be

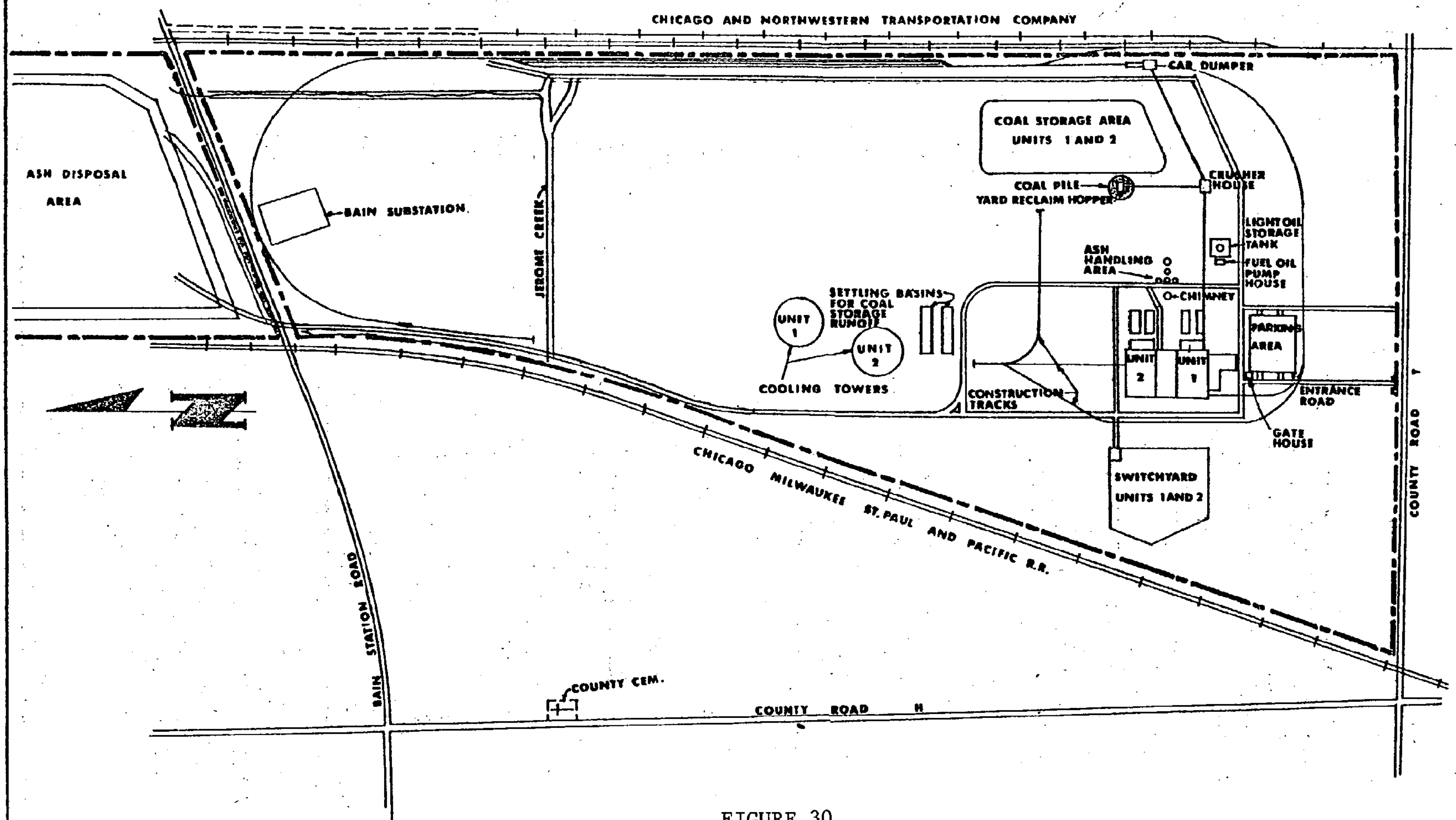


FIGURE 30

SCALE: 400 0 400 800 1200

SOURCE: SARGENT AND LUNDY

Wisconsin Electric

PLEASANT PRAIRIE POWER PLANT

PRELIMINARY PLANT LAYOUT

[SOURCE 552]

LEGEND

SITE BOUNDARY

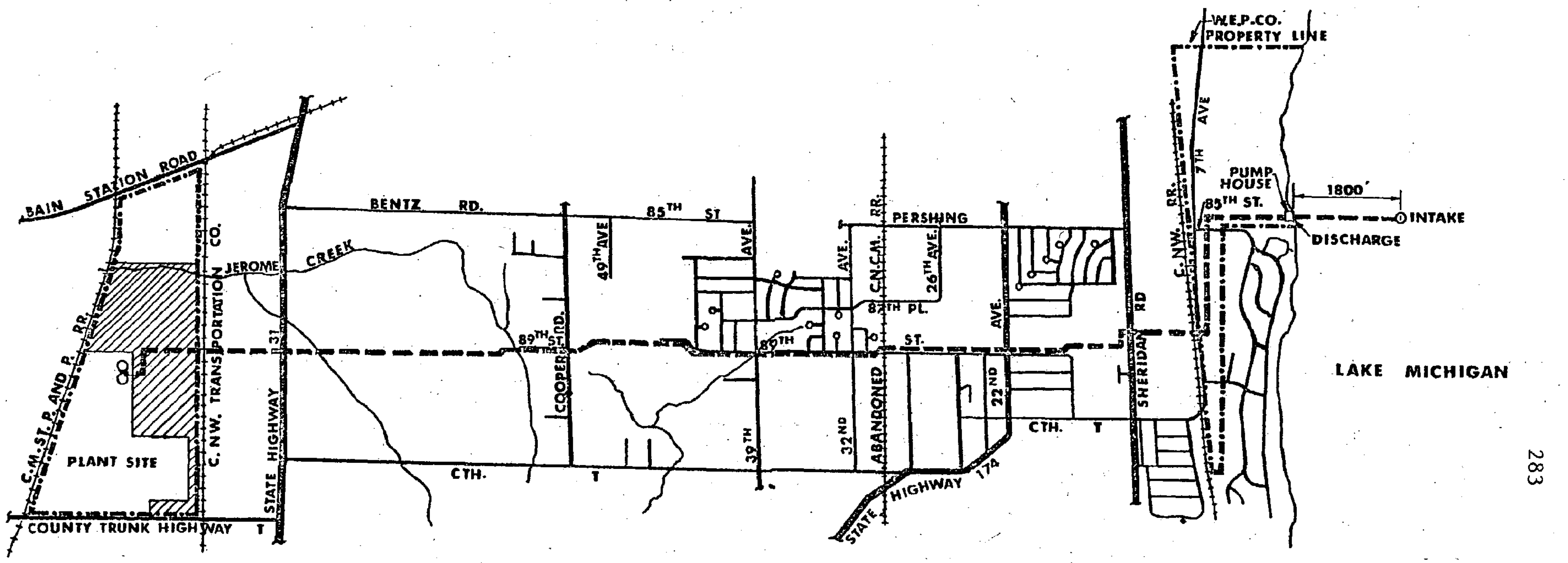


FIGURE 31

PROPOSED INTAKE/DISCHARGE CORRIDOR

[SOURCE - 552]

SCALE: 0 1/4 1/2 1 MILE

SOURCE: S.E.W.R.P.C., CITY OF KENOSHA

Wisconsin Electric

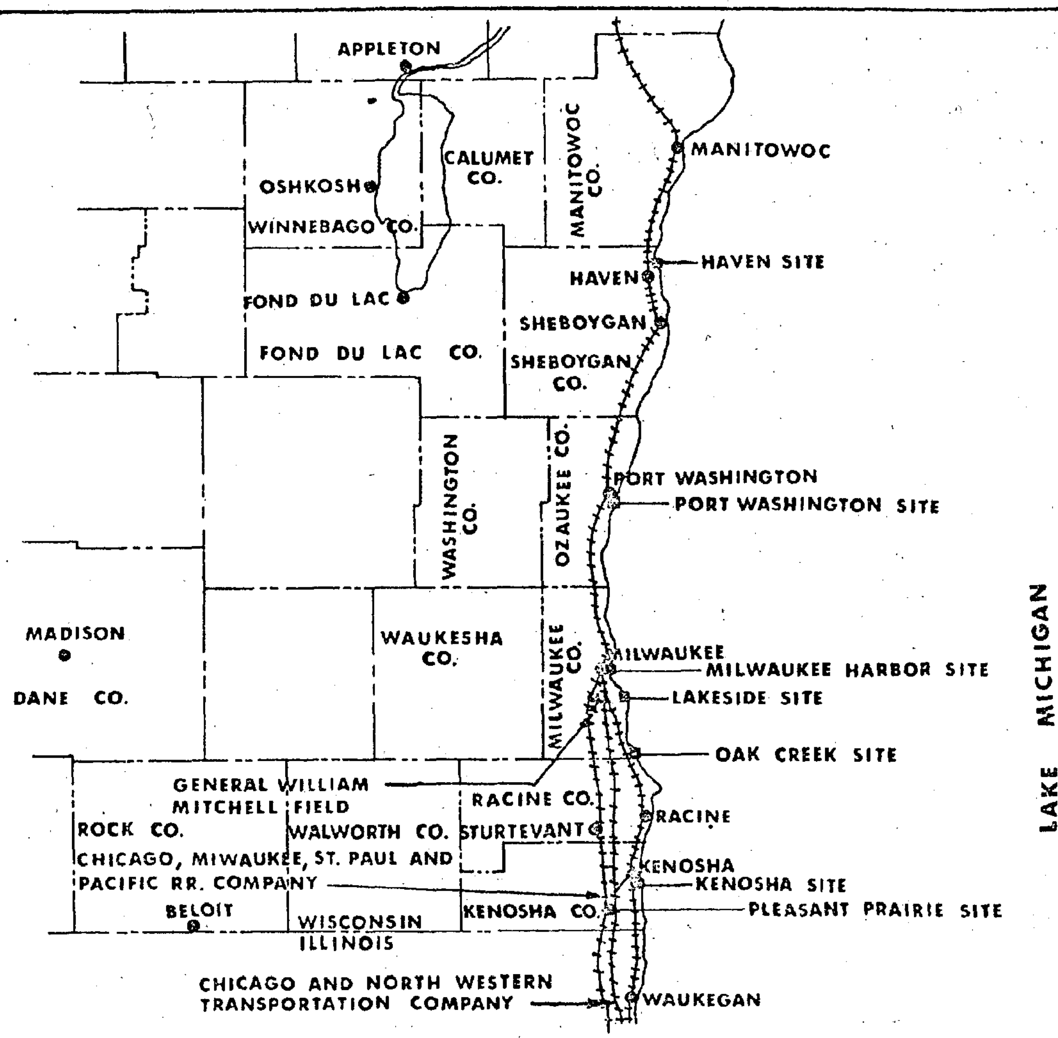
PLEASANT PRAIRIE POWER PLANT

LEGEND

PIPE LINE CORRIDOR

SITE BOUNDRY LINE

PROPERTY NOT OWNED BY W.E.P.CO.



ALTERNATIVE SITE LOCATIONS

N

FIGURE 32

PLEASANT PRAIRIE POWER PLANT

Wisconsin Electric

[SOURCE - 552]

0.0153 mills/kWh/mi. This reduction in cooling water supply costs for inland sites allows the utilities and companies much more freedom in their site selection procedure. This is not to say, of course, that an inland site with a closed-cycle system will maintain its water supply more economically than a coastal site with once-through cooling; in most cases the latter would be much less expensive in the long run. What it does mean, however, is that the companies will be able to take advantage of other possible benefits of inland locations.

In the Pleasant Prairie example the following site alternative combinations were considered:

- Both once-through and mechanical draft cooling towers were considered for the Kenosha, Oak Creek, and Haven sites.
- Once-through cooling exclusively was considered for the Port Washington, Lakeside, and Milwaukee Harbor sites.
- Mechanical draft cooling exclusively was considered for the Pleasant Prairie site.

While an acceptable arrangement could be developed for each of the sites using the systems mentioned above, there were substantial construction and operating cost differences between the systems and among the sites. For example, minimum construction cost would be incurred at the Haven, Oak Creek and Kenosha sites, utilizing mechanical draft cooling towers. All schemes utilizing a once-through system would be considerably more expensive ($2.5 to $7.8 million, depending primarily on the length of the cooling water intake and blowdown discharge lines required). The Pleasant Prairie site would incur additional construction costs of $5.5 million for the five-mile cooling water makeup pipeline from Lake Michigan to the site. While construction costs for the mechanical draft towers are significantly lower than for the once-through cooling arrangements the annual operating costs of approximately $850,000 per year would be considerably higher.

Although long run costs for cooling water supply to the Pleasant Prairie site would be higher than for the other locations, use of a closed-cycle system allowed the Wisconsin Electric Power Company to take advantage of other significant Pleasant Prairie site benefits. Specifically, the Pleasant Prairie site would incur minimum costs in tying into the existing transmission system, for which the other sites would incur considerable costs. In addition, Pleasant Prairie was the only site at which adequate rail transportation access was already available. The Pleasant Prairie site had additional benefits not found at the other locations (some of these are discussed below).

Another factor important in many, if not all, facility location decisions is the location of properties owned in part or wholly by the companies. For example, in most environmental reports regarding proposed facilities reviewed during the course of this study, it was found that alternative sites were generally owned by the utilities. In similar fashion, fuel transshipment facilities and refinery expansions are generally constructed adjacent to existing facilities. This is primarily a reflection of the long range planning engaged in by the major energy suppliers. However, it can result in a definite bias toward coastal locations purchased by the companies in the past when once-through cooling was used almost without exception. This observation is borne out by the following citation from the Pleasant Prairie Environmental Report:

> With the exception of Pleasant Prairie, all of the candidate sites were located on Lake Michigan...All sites are owned by the Applicant with the exception of the Milwaukee Harbor site and small parcels at some of the other sites [552; p.6.3-1].

A factor of considerable importance, especially in the siting of fossil-fuel power plants, is the location of fuel delivery routes and transshipment points. As was indicated in the discussion of transportation access in the fossil-fuel facility description [Section IV.A.5.b.(1)], it is desirable to have a location offering fuel delivery options; a coastal site served by both lake carrier and railroads would meet that requirement. There are many locations in the Great Lakes Region where delivery by lake vessel or barge is far more economical than by unit train. For a 1000 MWe coal-fired plant using 2.8 million tons of coal per year it would cost approximately $150,000 per mile per year to transport coal inland, in addition to the handling and land costs for port and terminal storage. Cost savings for fuel supply (in addition to water supply) in such a case would tend to favor a coastal location.

While fuel delivery via lake carrier or barge may not be an important consideration in the case of nuclear facilities, delivery of major facility components might very well be. As was discussed in the transportation access section in the nuclear plant description [Section IV.A.c.(1)], ease in delivery of large reactor and turbine components may favor locations with water access.

In the Pleasant Prairie example, the opposite situation was found. Coal receipt was to be exclusively by unit train from the western United States, and the Pleasant Prairie location offered the least expensive alternative with respect to fuel supply. This cost savings was able to partially offset the increased cost of cooling water supply, illustrating the advantages of coastal nondependency.

Two important factors were identified in the discussion of the hydrological and meteorological site requirements for nuclear plants related to shoreline sites: (1) the change in atmospheric stability that occurs at the land-air interface, and (2) the change in wind trajectory experienced when air moves from the smooth surface of the water to the irregular land surface. These concerns highlight the fact that local coastal meteorology may be an important factor in determining whether or not a facility should be located on or near the lakeshore. This consideration was further addressed with respect to coastal meteorology as it affects the dispersion of emissions from fossil fuel plants.

> The influence of the lakes on meteorological patterns plays an important role in determining nitrogen oxide and hydrocarbon impacts on the air quality onshore. For example, Milwaukee has experienced high oxidant air pollution reading at times when emission activity was low. One theory is that the daytime nitrogen oxide and hydrocarbon emissions are blown out over Lake Michigan by a land breeze, photochemically reacted to form oxidants, and blown back to the shore with the evening lake breeze. There are only sketchy experimental data to verify this hypothesis. Nevertheless, the lakes do play a significant role in determining the transport of pollutants [546; p.80].

The Pleasant Prairie report provides a perfect example of these types of concerns. With respect to air quality, the Haven site was the most desirable, being located in an area which had no other major sources of pollution. In this regard, the Pleasant Prairie site ranked second and was located further away from local and metropolitan emissions than the other sites available. Concerning meteorology and climatology, all the sites are located in a region characterized by favorable large scale dispersion patterns. The Pleasant Prairie site, however, appeared to be the most acceptable in this respect because it was further inland, with frequency and intensity of lake effects being less than at the other sites. Therefore, "the potential for fumigation of stack emission and for ground level fogging and icing due to the cooling tower emissions during onshore winds will be less than for the lake shore sites" [552; p.6.3-6].

A second concern related to local shoreline meteorology is the potential effect of the facility on the local climate. For example, in some areas (e.g., Erie County, Pennsylvania, and southwestern Michigan) the presence of the lakes creates a climate uniquely suited to specialized agricultural crops, such as fruits, by extending and stabilizing local growing seasons. The presence of a major energy facility, especially one fitted with a closed-cycle cooling system, could possibly change these conditions. The potential for such changes would have to be evaluated.

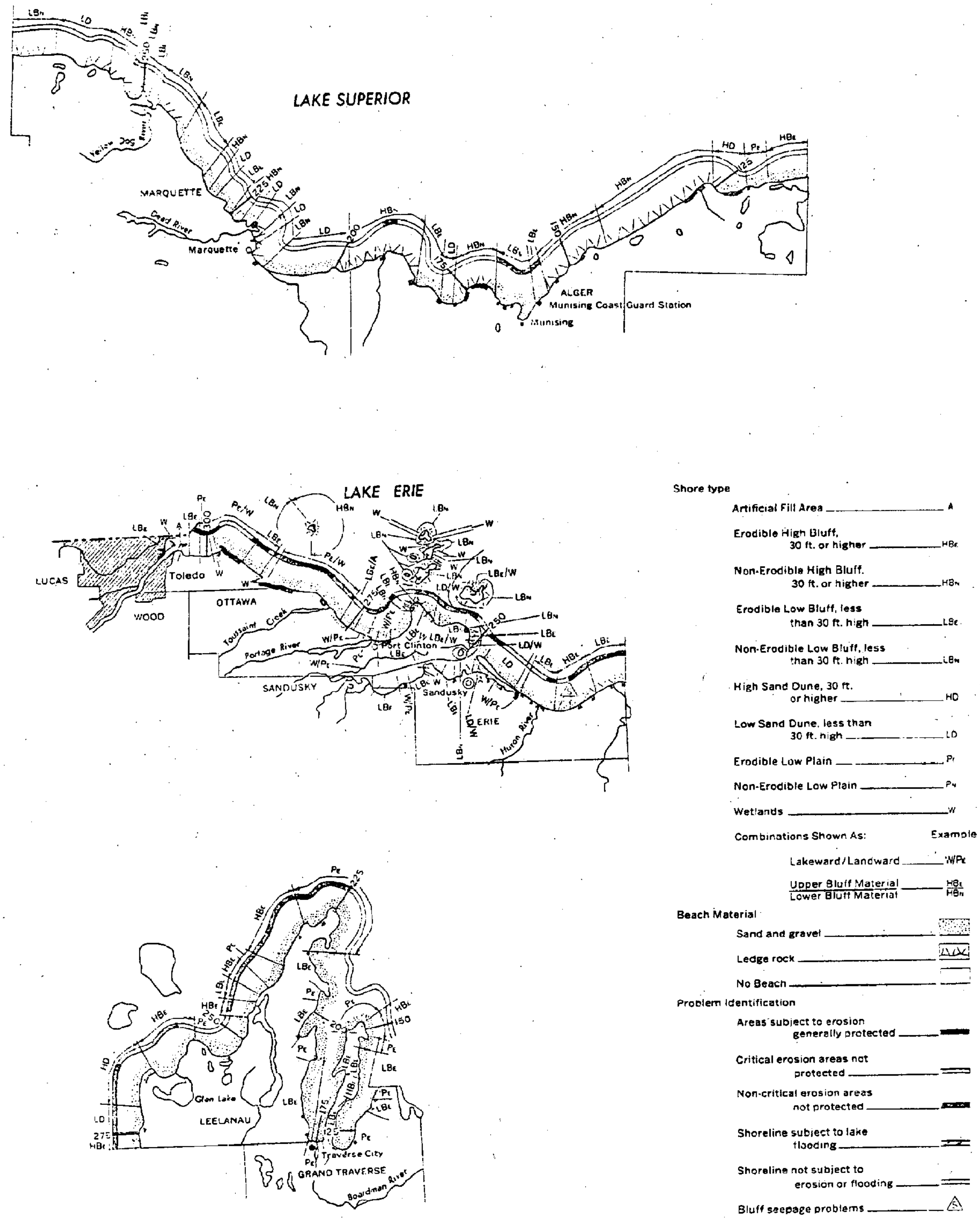
The aesthetic impact of a coastally located energy facility can be great. While this may not be true for all locations (e.g., highly industrialized areas such as Gary, Indiana, and Lackawana, New York) there most certainly are many areas along the Great Lakes shoreline which would be severely disrupted by the presence of such a facility. While there may also be aesthetically unique areas inland from the coast, it is more likely that such areas would be of limited extent along the coast. This would indicate a desirability to locate facilities away from these unique shoreline areas when possible.

There are a series of coastal-related factors that may tend to favor inland locations to allow savings in construction costs. Examples of these are areas subject to flooding during periods of high lake levels, coastal reaches subject to high rates of erosion requiring expensive (and sometimes ineffective) erosion control structures, areas requiring significant bluff restructuring, sites requiring significant fill, and sites requiring special foundations. As the shoreline segment maps in Figure 33 indicate, the Great Lakes coast is highly variable and these factors must be evaluated on a site-by-site basis. It is sufficient to say, however, that there are many areas in the Great Lakes Basin where inland locations may be preferable to near-shore locations to avoid such problems.

Several of these considerations were brought out in the selection of the Pleasant Prairie site. The comparisons of site preparation costs included: special structures required, earth work, demolition, and associated costs. The only major difference among the sites was in the amount of earth work required. The Haven, Milwaukee Harbor, and Pleasant Prairie sites required a minimum amount of earth work and thus showed the minimum cost. Two Oak Creek alternatives and the Kenosha site would have required major grading and use of borrow material with associated costs of approximately $400,000. The Port Washington, Lakeside, and a third Oak Creek alternative required landfill and extensive restructuring of bluffs. Costs associated with these activities were estimated at approximately $5 to $6 million above the minimum site preparation costs. In addition, the Haven, Oak Creek, Kenosha, and Pleasant Prairie sites could utilize mat foundations. The Port Washington, Milwaukee Harbor, Lakeside, and a variation of the Oak Creek site would use landfill and thus would require pile foundations at an additional cost of approximately $4.4 million. Thus, the lower construction costs associated with the inland site tended to favor the selection of Pleasant Prairie.

FIGURE 33

EXAMPLES OF GREAT LAKES SHORELINE TYPES



[SOURCE - 607]

Just as there are a wide variety of shoreline characteristics that influence construction costs, there are also many landforms and habitats which make portions of the coast unique. Examples include the rocky cliffs along portions of the Lake Superior shoreline, the sand dunes along eastern Lake Michigan, and the areas of coastal wetlands. In many cases these features may be quite rare and limited in their extent. For example, there are only 57 miles of coastal wetlands in the entire Great Lakes Region, amounting to only 1.5 percent of the total shoreline mileage [436]. In some cases the protection of these rare and unique landforms and habitats may require the inland siting of energy facilities. This may become especially true when the state coastal zone management programs begin to designate areas of particular concern.

Not only should potential conflicts with the land in its natural state be avoided, but also conflicts with various land uses. The Great Lakes shoreline is and will continue to be put to many uses by people from both within and outside of the region. Some of these uses, such as lake fishing, swimming, and boating, require the use of the lake. Others, while not absolutely requiring a lakeshore location can be greatly enhanced by one, such as second home development, picnicking, hiking, nature study, etc. Displacement of these uses by committing large tracts of land to energy facilities for long periods of time can result in long-term social costs and lost resources. The need to look at these alternative land use conflicts has been alluded to at several points in the discussion of energy facility impacts. The desirability of avoiding such conflicts may indicate a preference for inland locations for large energy facilities. Because the amount of shoreline is immutably fixed, it is important that uses of it should be assigned priorities, with those not requiring a coastal location sited inland when possible.

c. Summary

This discussion of the coastal dependence or nondependence of energy facilities in the Great Lakes Region has necessarily been conducted at a very general level. Because of this it has identified only one generally applicable example of a trade-off that must be made between coastal and non-coastal locations: the supply of water for the main cooling system. There are however, a large number of other considerations that should be evaluated on a site-by-site basis to determine the importance of a shoreline location for a proposed power plant: utility land ownership, mode of fuel delivery, local meteorology and dispersion patterns, aesthetics, potential construction problems, unique landforms and habitats, and potential land use conflicts. The use of the Pleasant Prairie example has served to illustrate that none of these factors can be considered in a vacuum. A similar evaluation of another plant in a different area of the Basin could show a strong coastal dependence. The trade-offs and relative economies associated with each must be evaluated so an overall picture of the coastal dependency of a given facility can be developed.

7. CONCLUSIONS AND IMPLICATIONS FOR POLICY OPTIONS

The preceding descriptions and discussions of energy facilities and their associated siting requirements and environmental and economic impacts have been provided to determine the degree to which these facilities are dependent on coastal resources, and to highlight those siting factors which appear to be most coastal dependent. The discussion of coastal dependence which directly precedes this section attempts to outline those technical considerations and environmental impacts which most heavily depend on or affect coastal resources. These coastal dependent factors are further clarified by relating them to a case study reporting the actual coastal and non-coastal factors considered in the siting of a fossil-fuel power plant.

Briefly, the following factors and considerations have been highlighted in the foregoing discussion as the most coastal dependent in relation to the siting of energy facilities in the Great Lakes Basin:

- The Great Lakes coastal zone provides resources and opportunities for many uses. Inevitably, the development of some of these uses must necessarily exclude or displace others.
- Unique landforms and habitats presently exist in Great Lakes coastal areas.
- Aesthetic considerations such as scenic coastal vistas are unique to the Great Lakes coastal zone.
- Special construction constraints such as bluff reshaping and shore protection are associated only with the lakeshore.
- Coastal meteorology and related dispersive capability are special siting considerations on a site-specific basis.
- Many utilities presently own land along the coast for future development of energy facilities.

- The Great Lakes represent a large and easily accessible source of water for cooling purposes.

- Access to waterborne transport of fuels and materials is necessarily related to the Great Lakes ports and terminals.

The following general conclusions can be cited with respect to the coastal dependence of power plants:

- Facilities using once-through cooling must be located on or near the shoreline because of the substantial costs of transporting cooling water inland via pipeline.

- Facilities using closed-cycle cooling are less dependent on locations on or near the shoreline than are facilities using once-through cooling, assuming all other factors to be approximately equal for sites being compared. Site conditions will determine the type of closed-cycle cooling system used. However, the further inland a facility is located, the greater are the construction (capital) costs for water provision and blowdown pipelines.

- For power plants using closed-cycle cooling, the cost of locating on the shoreline versus the cost of locating inland are essentially trade-offs among the construction and operation costs of such necessities as transmission lines, water supply and cooling facilities, facilities for delivery and handling of fuels and other supplies, and disposal of waste material.

- Nuclear facilities require very large and massive components, which in most cases are delivered via water transportation. However, rail or road corridors of adequate width and load-carrying capacity can be utilized for delivery of these components. If these rail or road corridors are not available to potential sites, the location of nuclear facilities may be more dependent on shoreline or near-shoreline locations. However, field assembly is becoming more common, thus possibly negating some of this shoreline dependence. Other nuclear facility coastal dependence considerations are the same as in the preceding item.

The coastal dependence of fuel transshipment and storage facilities and refineries can be summarized as follows:

- Fuel (coal and oil) transshipment and storage facilities that receive or ship their commodities by water must locate near the shoreline, although storage areas do not have to be located on the shoreline. Storage area location is highly dependent on industrial needs, future transportation requirements, and onsite and offsite use of stored fuel.

• Refineries are not coastal dependent, but do need access to water for processing and cooling. Dependence on easily accessible water is decreasing due to increasing water recycling practices. Air cooling is also reducing refinery dependence on easy water access. Refinery location decisions are increasingly becoming market oriented, with decisions being made on a national basis, due to the existence of the national product distribution pipeline.

Finally, coal gasification and liquefaction facilities are not likely to be located in the Great Lakes Basin, with the possible exception of low-Btu gasification facilities, which can be located at or near the site of use. Large coal gasification and liquefaction facilities will be located near mine mouth locations due to the high cost of transporting coal compared to substitute natural gas.

The implications of this report on technical considerations for the development of policy options relating to energy facility siting in the coastal zone are many and varied. In a general sense, however, it is possible to say that no one factor absolutely ties a given energy facility to a coastal site. Furthermore, it is evident from the discussion of technical considerations and the case study that there are a number of technical options which may be generated for future siting considerations. These options are predicated on the conclusion that energy facilities are not coastal dependent per se, and that it is possible that they be sited inland from the coast while maintaining certain degrees of access to coastal resources. The technical policy options and implications developed in Section VI.C are based on this tenet of nondependency.

At this point, a concluding statement on facility siting should be made. The entire preceding section dealt with technical considerations affecting siting of energy facilities. It should be noted that there are other possible (or even probable) considerations of a nontechnical nature which may affect the final site selection process. More specifically, these considerations relate to politico-economic decisions based on expediency and profit motivation. To ignore the existence of these nontechnical considerations in the site selection process would be naive; to assess their magnitude in relation to coastal siting would be impossible.

B. ENERGY CONSUMPTION AND MOVEMENT IN THE GREAT LAKES REGION

1. INTRODUCTION

Rational planning for the future necessitates a sound knowledge of the present. The following information was collected for the purpose of providing that knowledge. This section presents collected data on the present energy situation pertinent to the Great Lakes coastal zone.

An attempt was made to concentrate on those aspects of supply, transportation and utilization of energy that relate to electric power generation and the coastal zone. Electric generating facilities and fuel transshipment points are discussed both in the context of present capacities and locations and of planned and scheduled facilities.

A major portion of this section attempts to address the question of the future relationship between energy facilities and the coastal zone. This discussion focuses on the relationship between electric generating facilities and potential fuel mixes. Further, the problems associated with determining future demand levels for electric energy are discussed in the context of how various demand growth rates may affect siting of electric generating facilities. Finally, a number of potential fuel mixes and growth rates were postulated in the attempt to determine possible future resource requirements and pressures on the coastal zone.

2. ENERGY DEMAND

a. Fuels for Power Production

The Great Lakes Region is one of the most highly industrialized and energy consumptive regions in the world. Its development is in large measure facilitated by the ease of commodity transportation on the lakes and the wealth of fuel resources within the eight states bordering the Great Lakes. Energy production in the Great Lakes states reflects the unique resource capabilities of the region.

An average of over ninety percent of the fossil-fuel electrical generating facilities are coal fired in seven of the eight Great Lakes states. This section will therefore focus on the origin, transportation and end use of coal, although other fuels will be discussed also. The discussion will assume a regional and state perspective with special emphasis on activity in the coastal zone.

(1) Origin of Fuels

The Great Lakes Basin states are net importers of energy. Each state consumes more energy from coal, oil and natural gas than it can produce. Even the major coal- and oil-producing states of Pennsylvania and Illinois consume over twice as much fuel as they produce [618]. Thus, the Great Lakes Region must depend heavily on fuels from elsewhere.

(a) Coal

The United States has an abundant supply of coal. The estimated reserve base for the country is 434 billion short tons. This is an estimate of the identified resources deemed suitable for mining by 1974 methods [19]. At the present consumption rate of approximately 600 million tons per year this resource could last six or seven centuries.

There are three primary coal supply regions: the Appalachian, Illinois and Western basins.

The preponderance of coal consumed in the Great Lakes states is produced in the Appalachian and Illinois coal fields. These two major fields supply most of the region's needs for coal for power production. Pennsylvania and Ohio supply almost 40% of the coal used by electric utilities in the Great Lakes states. Illinois, Kentucky and Indiana follow in order behind these states. Combined, the five states provided 76% of the total coal supplied to the Great Lakes utilities in 1975 [547].

FIVE LARGEST COAL PRODUCING STATES
FOR ELECTRIC UTILITY USE
IN THE GREAT LAKES STATES

State	1975 (1000 Tons)	1975 Percent of Great Lakes States Total
Pennsylvania	38,093	19.5
Ohio	37,533	19.2
Illinois	31,201	16.0
Kentucky	22,933	11.8
Indiana	20,172	10.3
TOTAL	149,932	76.8

SOURCE [547]

Recently, air quality standards have forced utilities to purchase a lower sulfur coal than commonly found in the eastern fields. The purchase of a considerably lower sulfur coal from the Western basin, primarily Montana and Wyoming, has increased considerably in the region. Between 1974 and 1975 there was a 58.3% increase in western coal destined for states in the East Northcentral Region (Wisconsin, Illinois, Indiana, Ohio and Michigan). Ninety-five percent of the western coal shipped to the Great Lakes states was produced in Montana or Wyoming. Most of this fuel was surface mined and of sub-bituminous grade [547]. Table 51 presents the major state sources of coal to electric utilities in the Great Lakes states.

TABLE 51

ORIGIN AND DESTINATION OF COAL DELIVERIES

TO ELECTRIC UTILITIES IN 1975

(Deliveries in 1000 tons)

	ORIGIN										
	EASTERN				MIDWEST		WESTERN				
DESTINATION	KENTUCKY	OHIO	W. VA.	PA.	ILL.	IND.	MONT.	WYO.	COLO	UTAH	Percent Total Coal From All States
Illinois	1,182.1	9.1	0.3	-	21,218.1	379.3	9,310.5	1,866.3	10.3	20.0	$\frac{33,996.0}{33,999.3}$ = 99%
Indiana	5,045.5	0.9	75.0	-	3,134.6	18,896.4	819.0	2,841.4	1.6	130.3	$\frac{30,944.7}{30,968.1}$ = 99%
Michigan	5,778.7	8,362.3	5,116.6	691.0	274.5	82.2	1,056.0	-	-	-	$\frac{21,361.3}{21,361.8}$ = 99%
Minnesota	98.3	0.4	3.0	-	1,717.3	-	6,205.1	2.2	3.0	60.9	$\frac{8,090.2}{8,797.4}$ = 92%
New York	524.0	-	839.7	4,591.6	-	-	-	-	5.0	-	$\frac{5,960.3}{5,970.8}$ = 99%
Ohio	7,151.9	29,113.6	6,540.6	2,168.2	-	29.6	-	937.7	1.9	362.4	$\frac{46,305.9}{46,860.3}$ = 99%
Pennsylvania	1,080.4	20.3	4,216.2	30,070.3	-	-	-	-	-	-	$\frac{35,387.2}{35,448.9}$ = 99%
Wisconsin	2,072.6	26.6	4.6	572.4	4,856.9	784.6	2,161.2	1,052.8	20.2	-	$\frac{11,551.9}{11,552.5}$ = 99%
TOTAL	22,933.5	37,533.2	16,796.0	38,093.5	31,201.4	20,172.1	19,551.8	6,700.4	316.5	573.6	$\frac{194,659.1}{194,959.1}$ = 99%

SOURCE: [547]

NOTE: Does not include anthracite and imported coal.

The coal resources in this country have been extensively surveyed. The magnitude of remaining deposits provides a stable base for fossil fuel-fired electricity generation. The quantity of this fuel is not at issue. Concern centers rather on environmental and health risks involved in coal utilization. These factors will to a large extent determine the coal type recovered for future use.

(b) Oil and natural gas

All the Great Lakes states except New York have a fossil-fuel mix percentage for electrical generation lower in oil and natural gas than the rest of the country. These seven states used about 5% oil and 3% gas for power. The national figures in 1975 were 18.9% oil and 19.8% gas for the generation of electricity [547]. Further analysis of these statistics is contained in the discussion of fuel mixes.

Most of the sources for oil and natural gas are distant from the Great Lakes Region. A network of pipelines carries oil and gas into the region from the south, central, and Gulf states. Canada also supplies oil to the region from fields in Alberta. With Canadian demand increasing, this source will soon be terminated to the Great Lakes states. The Great Lakes states are relatively minor producers of oil and natural gas, contributing about 3% of the U.S. oil production and 2% of the national gas production [24]. The region must therefore import substantial quantities of oil and gas. An examination of production and consumption figures in the eight states for oil and natural gas reveals that the states supply about 4% of their annual consumption [618]. Figures 34 and 35 show the major sources of natural gas and oil for the Great Lakes Basin states.

FIGURE 34

SOURCES OF NATURAL GAS SUPPLY TO THE GREAT LAKES BASIN STATES

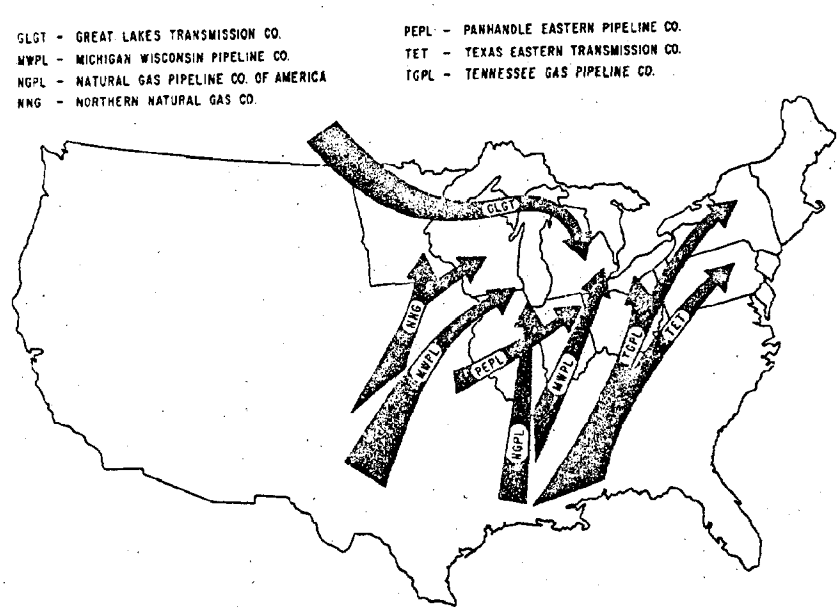
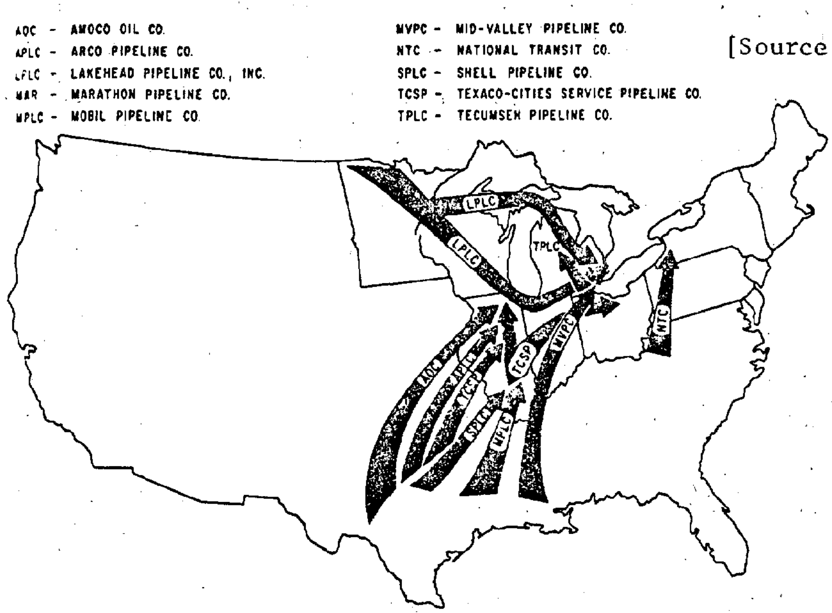


FIGURE 35

SOURCES OF CRUDE OIL SUPPLY TO THE GREAT LAKES BASIN



[Source 618]

Future long-term supplies of Alaskan oil to the Great Lakes region are presently under consideration. Three major long-term options have emerged for transport of the oil.

- Trans-Provincial Pipeline--Alaskan crude transported by tanker from Valdez, Alaska, would be delivered to a new deepwater port at Kitimat, British Columbia. The oil then would be transferred to a 30-inch pipeline and would move 830 miles to Edmonton, Alberta. In Edmonton the oil would move into existing pipelines. The Trans-Provincial Pipeline would utilize the Interprovincial/Lakehead Pipeline system presently serving the Great Lakes Region. The proposal is projected for an initial total capacity of 300,000 barrels per day with an eventual capacity of 650,000 barrels per day [490].

- Northern Tier Pipeline--This proposed line would cross the northern tier of states from a deepwater facility in Port Angeles, Washington, to Clearbrook, Minnesota. This 40- to 42-inch line would stretch 1500 miles and connect with Minnesota and Lakehead pipelines in Clearbrook, Minnesota. Initial operational capacity is projected as 600,000 barrels per day with an eventual capacity of 800,000 to 1,200,000 barrels per day [490].

• Williams Pipeline Company--This expansion involves construction of a 500-mile pipeline from Oklahoma to Iowa. The proposed 24-inch line would receive oil from existing pipelines connected to a new deepwater facility in Texas. The Williams line could also connect to a proposed pipeline from Long Beach, California. The new system could provide an additional 350,000 barrels per day of crude oil from Oklahoma to Minneapolis, Minnesota [490].

The availability of oil in the future relies on the rate of new discoveries and the economic incentives arranged to promote further exploration. Development of coal liquefaction technologies may also affect the supply of liquid fossil fuels.

Additional sources of natural gas to the Great Lakes states may also arrive from Alaska. Proven natural gas reserves in the North Slope are estimated at 22.5 trillion cubic feet. The proposed Artic Gas system would transport gas through 5,551 miles of buried pipeline overland from northern Alaska through northern and western Canada to three ultimate destinations within the 48 contiguous United States. One of these destinations would be Delmont, Pennsylvania, where an estimated 1.5 billion cfd could be delivered.

The other major alternative, the El Paso Alaska system, would move gas south from the Prudhoe Bay area by pipeline to a port on the southern Alaskan coast. There the gas would be converted to liquified natural gas (LNG) and shipped via cryogenic tanker along the northern Pacific coast to a delivery point on the California coast. The LNG would then be regasified and would be distributed through the gas pipeline network. The El Paso Alaska system would provide gas to the Great Lakes Region by rerouting northward the gas previously required on the west coast [257].

(2) Great Lakes States Production and Reserves

Oil, natural gas and coal are produced in the states bordering the Great Lakes. Peat, a potential fuel found in the Great Lakes Region, is not presently used as a fuel for power production. The four southernmost Great Lakes states, Illinois, Indiana, Ohio and Pennsylvania, yield most of the gas, and oil and virtually all the coal produced in the Great Lakes states. A summary of fuel production and reserve capacity by state follows.

• Illinois--Illinois has a recoverable reserve of coal greater than the combined reserve of the remaining seven Great Lakes states [19]. Deposits underlie 65% of the state and are found in 86 of its 102 counties [5]. Illinois holds

15.1% of the country's total coal reserves, or 65 billion tons. This plentiful resource, which has a high heating value ranging from 10,500 to 13,000 Btu's per pound, accounts for 16.6% of the nation's potential energy reserve from coal [4]. Illinois coal production, although on the decline, contributed 9.6% of the total U.S. coal production in 1974 [327]. The state mined 58,215,000 short tons that year compared to an average 64,197,000 tons/year between 1966 and 1970 [585]. The decline in coal production is in many ways symptomatic of the quality of Illinois coal. Much of this coal has a 3 to 5% range in sulfur content, which exceeds the standards set by the Environmental Protection Agency [4]. The Federal Power Commission in 1973 estimated that more than 85% of the coal now being burned by Illinois electric utilities would be prohibited when sulfur emission standards are enforced [3]. This valuable resource therefore grows increasingly impractical for power generation and depends on the development of efficient technology for sulfur removal.

Illinois also has substantial reserves of oil and natural gas. Illinois oil production was 26,080,000 bbl of crude in 1975 [319], which was the highest for the eight Great Lakes states. The state had an estimated reserve in 1974 of 162.3 million barrels, which among the Great Lakes states was second only to Michigan [24].

Natural gas production was 2,840 million cubic feet in 1973, with reserves in total gas of 380,525 million cubic feet [586]. Illinois is developing the use of underground caverns for storing liquified petroleum gases. The Illinois Great Lakes Basin counties of Will and Dupage presently store 46,000 bbl of LP gas and 250,000 bbl of propane and butane [3].

Peat, which is not sold as a fuel for power production, is the only fuel mined in the coastal zone [317].

- Indiana--The mineral industry survey for Indiana in 1975 reports that

> Mineral fuels accounted for about 58% of the estimated value of Indiana's mineral production in 1975, 15% higher than in 1974. Coal, which alone accounted for nearly half of the total value of all mineral output, increased an estimated 5% in quantity and 19% in value. Output of both petroleum and natural gas declined sharply in 1975, continuing a downward trend which has occurred annually since 1965 [320].

In 1975, Indiana produced 24.8 million short tons of bituminous and lignite coal [320]. The state had a demonstrated coal reserve in 1974 of 10.6 billion tons. Sixty-four percent of this reserve has a sulfur content greater than three percent, which makes it environmentally unfavorable. No coal is mined in the Indiana coastal counties.

Crude petroleum production in Indiana in 1975 was 4.6 million barrels, a decrease of 287,000 bbl from 1974 production [403]. Reserves of Indiana crude oil were 29.6 million barrels in 1974 [24]. A small amount of the oil produced in 1974 came from the coastal county of LaPorte, which produced 3,389 barrels [321].

Production of natural gas in Indiana has declined also. Production fell from 176 million cubic feet in 1974 to 126 mmcf in 1975 [320]. Though reserves of natural gas are estimated at 5,308 mmcf, 50% of this reserve is in nonproducing reservoirs [24].

- Michigan--Michigan produced no coal in 1974 [327]. Coal fields are found beneath 20% of the state, but the resource is thinly distributed, yielding an identified coal reserve base of only 119 million tons [19].

Michigan's petroleum production in 1975 increased 6.3 million barrels from the previous year, yielding a total of 24,413,000 bbl [319]. Petroleum was produced in the coastal counties of Allegan, Antrim, Arenac, Bay, Grand Traverse, Huron, Macomb, Mason, Monroe, Muskegon, Oceana, Ottawa, Presque Isle, St. Clair, Tuscola, VanBuren, and Wayne. These counties produced 1,757,000 barrels in 1975, which accounted for about 14% of the total state petroleum production [317]. Michigan's oil reserve of 164.1 million barrels is the largest of the eight Great Lakes states.

Natural gas production in Michigan in 1975 was 102 billion cubic feet which was an increase of 32 billion cubic feet over 1974 [75]. Natural gas was produced in the coastal counties of Allegan, Grand Traverse, Macomb, Ottawa, and St. Clair (also natural gas liquids) in 1972 [319]. Michigan exceeded the remaining Great Lakes states in production and reserves of natural gas in 1974. Total reserves were estimated at 1,041 billion cubic feet [24].

Michigan produced 1.1 million barrels of natural gas liquids in 1973. Of this total 65% was liquified petroleum (LP) gas and 35% was natural gasoline. Proved reserves of this resource totaled 25 million barrels in 1973, which was an increase of 6 million barrels over the previous year's estimate [586].

Overall, Michigan is able to produce approximately 10% of its needs for oil and gas, so must still import the majority of its energy [75].

- Minnesota--Minnesota claims 50% of the nation's known supply of peat. Peat, the only potential mineral fuel Minnesota produces, was used primarily for potting purposes [317].

• New York--New York's mineral fuel production is restricted to natural gas and petroleum. Negligible coal resources are estimated to cover 10 square miles of New York's total area of 49,576 square miles [19]. In 1975 New York produced 890,000 barrels of crude petroleum, which was a decrease of 6,000 barrels from 1974 [319]. The state showed crude oil reserves of 6,667 mbbl in 1974 [24]. Chautauqua County was the sole New York Great Lakes coastal county to produce oil. In 1973 this county had 43% (41 wells) of New York's proved oil field wells [586].

Natural gas production in New York was 4.5 million cubic feet in 1973. This represented a 23% increase over production in the previous year [586]. The estimate of natural gas reserves in New York was 87.1 billion cubic feet. The coastal counties of Cayuga, Chautauqua, Erie and Monroe produced natural gas. Erie and Chautauqua Counties had 87% (21 wells) of New York's proved natural gas field wells in 1973 [586].

• Ohio--Ohio coal production in 1974 was 45.4 million short tons, which accounted for 7.5% of the national coal production [327]. In terms of value, bituminous coal is the state's principal mineral commodity, contributing $338.8 million to the economy in 1973 [586].

There was a demonstrated coal reserve in Ohio of 21 billion tons [19]. Of this reserve 60% has sulfur content greater than 3.0% [327]. Most of the future production of coal in Ohio will depend on recovery from underground mines. An estimated 80% of the recoverable coal reserve in Ohio is located in beds suited to underground mining [19]. No coal is extracted in Ohio's coastal counties.

Ohio ranked third among the Great Lakes states in oil production. The state produced 11,704,000 barrels of crude petroleum in 1975 which was an increase of 2.6 million barrels over production in 1974 [319]. All coastal counties in Ohio are considered either oil or gas producing counties. In 1975 twenty-five new producing wells were drilled in Ashtabula County. Eight of the wells produced natural gas, two produced oil, and fifteen produced both oil and natural gas. Of the five new wells drilled in Lorain County in 1975, four were dry and one produced gas [325]. Total oil reserves within the state amounted to 87.3 million barrels. Total natural gas production in 1974 was 94.3 billion cubic feet [10] with gas reserves totaling 1,238.6 billion cubic feet [24].

• Pennsylvania--Pennsylvania is the largest coal producing state in the Great Lakes Region. In 1974, the state produced 80.5 million short tons of coal, which was 13.3% of the total U.S. production [327]. Coal deposits cover 15,000 square miles or approximately one-third of the state. The demonstrated coal reserve base in Pennsylvania is 31.0 billion tons. Approximately 95% of this reserve is recoverable by underground mining methods. Seventy-eight percent of the total underground and surface bituminous coal reserve has a sulfur content less than 3%. Twenty-four percent or 7.3 million tons of the coal has less than 1% sulfur. Anthracite, a high quality coal, is found primarily in Pennsylvania. This high Btu coal has an average sulfur content of 0.75%, which is favorable for compliance with air quality standards [586]. Anthracite reserves are smaller and more difficult to recover than bituminous coal. In 1973 anthracite production was 6.8 million short tons or 8.2% of the total coal production in the state. Being higher quality coal, anthracite contributed over 10% of the total value from coal in Pennsylvania that year [586]. Erie County, Pennsylvania's only Great Lakes coastal county, has no reserves of coal.

Crude petroleum production in 1975 was 3,910,000 barrels, an increase of 432,000 barrels over 1974 production figures [319]. Proved reserves were estimated at 35.5 million barrels [24]. Erie County had five crude oil wells in 1974, which produced an insignificant 257 barrels [14].

Natural gas production was 82.7 billion cubic feet in 1974, which was a 5% increase over the previous year. Gas reserves were estimated at 878.5 billion cubic feet [24]. Erie County produced 64 mmcf of natural gas in 1974 [14].

- Wisconsin--As of 1976, Wisconsin has no known or projected production or reserves of oil, natural gas or coal.

Although producers of coal, oil and natural gas, the Great Lakes states are net importers of energy. The role each state will assume in production of these fuels is contingent upon a multiplicity of factors relating to recovery technologies, costs, availability, demand and fuel quality. Reserves of the mineral fuels available in the Great Lakes states are located primarily in Michigan, Illinois, Pennsylvania and Ohio. Michigan and Ohio hold 70% of the natural gas reserves. This reserve is insignificant relative to gas consumption in the region. The 2,279.8 billion cubic feet of natural gas reserves in Michigan and Ohio would supply about one-tenth of the yearly demand of the Great Lakes states, which in 1972 consumed approximately 22,614 billion cubic feet of gas [618]. The situation is similar for oil. Michigan and Indiana have 67% of the reserves, or 326.5 million barrels of oil. Consumption in 1972 was 1,752 million barrels of oil, which was five times the total reserves of the two states [618].

Therefore, production of oil and natural gas in the Great Lakes states can meet only a minor portion of the demands.

Coal, which is the major fuel for the generation of electricity in the basin, remains in extensive reserve in Pennsylvania, Ohio, Indiana and Illinois. Pennsylvania and Illinois hold more than 75% of the demonstrated coal reserve among these four states. The Pennsylvania-Illinois reserve of 96.6 billion tons contributes substantially to the demands in the Great Lakes Region. The future recovery of coal from the Great Lakes states hinges increasingly on the question of sulfur content. Great Lakes coal will retain its traditional share of the market only if the cost of removing sulfur is competitive with the cost of delivering low sulfur western coal to the region. Great Lakes states coal production also faces higher mining costs as 85% of the demonstrated reserve would be recovered from underground mines.

The Great Lakes states produce no fuels for nuclear power generation. The states of Wyoming, New Mexico, Texas, and Utah are the principle U.S. producers of uranium, listed in order of quantity produced [586]. Hydroelectric power, which contributes substantially to the generation of electricity, is assumed to remain fairly constant because of the environmental cost of creating reservoirs and because the major sites in proximity to load centers have been developed.

(3) Present Fuel Mix

The Great Lakes states consume approximately 46% of the Btu's produced by coal for fossil-fuels plants in the country. The eight states also consume 27% and 4%, respectively, of the national supplies of oil and natural gas used for power production [547]. Table 52 describes the relative percentages of coal, oil and natural gas used for steam-electric plants in 1975. This table shows that 82.8 percent of the total Btu's produced by fossil-fuel facilities in the eight states were generated by coal.

The fuel mix for New York is a reversal of the mix for the other seven states. In 1975, New York used oil for 77% of its electric generation needs. This percentage does not properly reflect the fuel mix in the New York Great Lakes coastal zone. Coal-fired power plants account for about 70% of the power produced by fossil-fueled plants in the upstate coastal counties of New York [289]. The state figures on fuel mix are generally more representative of the dependence on oil in and around the New York City area.

TABLE 52

PRIMARY ENERGY PURCHASE DATA FOR STEAM-ELECTRIC PLANTS DURING THE TWELVE MONTHS OF 1975

STATE	TOTAL BTU (BILLIONS)				PERCENT OF TOTAL BTU			AVERAGE PRICE, ¢ PER 10^6 BTU		
	COAL	OIL	GAS	TOTAL	COAL	OIL	GAS	COAL	OIL	GAS
ILLINOIS	688,793.7	44,970.2	29,438.0	763,201.9	90.3	5.9	3.9	75.4	153.5	113.1
INDIANA	657,428.4	8,867.3	10,053.2	676,349.0	97.2	1.3	1.5	59.2	214.1	81.7
MICHIGAN	505,464.0	95,488.7	32,820.4	633,773.2	79.8	15.1	5.2	92.3	209.1	127.7
MINNESOTA	157,825.9	4,872.4	15,173.7	177,872.0	88.7	2.7	8.5	62.3	196.0	63.9
NEW YORK	143,624.5	526,724.0	13,146.1	683,494.6	21.0	77.1	1.9	117.7	194.3	87.4
OHIO	1,027,147.5	8,304.9	3,630.5	1,039,082.8	98.9	0.8	0.3	95.2	224.1	122.6
PENNSYLVANIA	864,484.7	79,199.4	11.7	943,695.7	91.6	8.4	0.0	95.5	210.9	146.7
WISCONSIN	245,320.5	2,856.6	13,751.5	261,928.5	93.7	1.1	5.3	86.4	189.9	81.5
GREAT LAKES STATES TOTAL	4,290,089.3	771,283.4	118,025.0	5,179,397.6	82.8	14.9	2.3	85.3	196.0	101.9

[Source: "Annual Summary of Cost and Quality of Steam-Electric Plant fuels 1975" Federal Power Commission]

The fossil-fuel mix figures for the seven remaining Great Lakes states reliably portray the general situation in the coastal counties. This is especially true in Michigan in which 38 of the 45 fossil-fuel plants are located in the coastal counties. Many of the plants in the Illinois-Indiana coastal zone are designated as coal/gas-fired. The gas used is a relatively small amount however, generally supplying fuel for peaking units or as start-up fuel for the large coal-fired boilers. The percentage of gas used in the coastal counties of this area does not greatly differ from the states' fuel mix consumption figure. An examination of kilowatts produced in the coastal counties of Illinois and Indiana show that approximately 4% of the fossil-fuel electrical generating capacity is provided by natural gas. Therefore a substantially accurate extrapolation concerning fuel mix in the coastal counties can be derived from review of the statewide mix.

The present fuel mix of the Great Lakes states depends on enormous quantities of coal. Ohio, Pennsylvania, Illinois and Indiana are the four largest coal consuming states for electric generation in the nation [547]. Oil and natural gas are minor sources of fuel in the region. In absolute terms though, the Great Lakes Region provides a substantial market for the national consumption of oil and natural gas.

Problems with the availability and price of natural gas make this fuel increasing unreliable as a primary fuel for power generation. Demands for space heating and industrial applications further remove natural gas from consideration as a primary fuel for electric production.

Petroleum, another versatile fuel, will most likely continue to decline in importance as a base load fuel for power production. The cost of petroleum is growing increasingly prohibitive, but petroleum still has certain environmental advantages over coal-fired plants and generally requires lower initial capital costs for plant construction.

Being more limited in its applications than oil or gas, coal will continue to be the primary fuel for power generation. New technologies which utilize coal (i.e., fluidized bed, liquefaction and gasification, etc.) are aimed at reducing many of the detrimental effects of coal-fired generation.

A developing trend suggests that electricity will take up much of the slack left by reduced use of oil and natural gas due to the end use versatility of electricity. However, the continuation of any such trend is very dependent on the progress made in acceptable means of utilizing coal for power production.

This issue hinges on the problem of sulfur. Changes in the amount of coal used depend on the development of efficient desulfurization technologies either before or after combustion.

Hydro-electric power currently comprises 5% of the region's generating capacity and is not expected to increase to any degree in the future. This type of generation is centered primarily in New York where it meets approximately 24% of the current state power needs [466].

The utilities have planned to increase nuclear capacity rapidly over the next twenty years to the point where it will comprise some 30-35% of the total generating capacity. The continuation of this trend is predicated upon the resolution of many serious problems currently plaguing the nuclear industry. These factors would include the availability of fuel, a reduced construction period, a greater public acceptance, and a solution to the problem of nuclear fuel waste disposal. Some seven or eight nuclear generating facilities in the Great Lakes Region have been hard hit by plant cancellations and deferrals. Those deferrals, combined with the rising costs and long lead times for construction of nuclear facilities, indicate a continued heavy reliance on coal over the next ten years or so.

Nuclear facilities have grown rapidly and now contribute 12% of the power generated in the region. The future development of nuclear generating capabilities will depend on the industry's ability to surmount the problems mentioned above. The relative price and availability of the major fuels for electrical power generation will play a major role in determining their future use.

TABLE 53

1975 Fuel Mix by Fuel Type for Power Generation (percent B.T.U. contributed by State)

State	Oil	Gas	Coal	Hydro	Nuclear
Illinois	8%	4%	63%	.1%	24%
Indiana	3%	2%	93%	1%	0%
Michigan	10%	6%	72%	1%	10%
Minnesota	3%	12%	63%	2%	19%
New York	39%	5%	15%	24%	17%
Ohio	4%	2%	94%	0%	0%
Penn.	14%	1%	74%	1%	9%
Wisconsin	1%	9%	57%	1%	28%
Regional Weighted Average	13%	4%	66%	5%	12%

Source: FPC, NRC, FEA

(4) Cost and Use By State and Region

The cost of primary fuels has increased greatly since the early 1970's. The most significant price increases have affected users of nuclear fuels and residual oil for power generation. The relatively greater increase in the price of these two fuels compared to coal indicate coal's favorable cost position. However, the costs of transportation and insuring environmentally sound use of coal are expected to rise in the future. For many reasons the price of all primary fuels for power production are expected to rise in the future, with coal prices possibly rising least of all. The price in 1975 for the four primary fuels in the Great Lakes states was:

Coal	85¢/10^6 Btu	
Nuclear	55¢/10^6 Btu*	
Oil	196¢/10^6 Btu	
Gas	102¢/10^6 Btu	

*Based upon U_3O_8 at twenty dollars/pound.

The costs of transportation and extraction will play an increasingly larger role in the future price of electricity.

(5) Transport of Fuels for Power Production

The movement and distribution patterns of fuels for power production in the Great Lakes Region evolve through complex interactions among the transportation mode, commodity, and the commodity's origin. Fuel movement and routing are subject to constant change. Competition between fuel carriers insures a high degree of flexibility in the transportation pattern. It is through the existence of such a network that fuels used in the Great Lakes Region can originate from such diverse areas of the country as the Louisiana Gulf Coast or the North Slope of Alaska.

Historically, coal, oil and natural gas have been transported by rail, waterway, truck or pipeline throughout the Great Lakes states.

The railway system is comprised of more than 200,000 miles of track, with the greatest concentration existing in the eastern half of the country. Coal, as a high bulk commodity, is well suited to transport by rail. Railroads haul 78% of the coal and less than 3% of the oil and gas in the country [364]. Recent innovations, particularly the advent of unit trains, have substantially lowered the costs of hauling large volumes of coal. Approximately 20% of all coal mined in the United States presently moves by unit train [147]. The unit train "consists of a dedicated set of haulage equipment loaded at one origin, unloaded at one destination each trip, and moving in both directions on a predetermined schedule. The unit train combines three principle factors: design efficiency, equipment balance, and intensive use. To achieve the lowest possible transportation costs, all elements of the operation must be in balance; the loading, haulage, and unloading facilities must be designed and scheduled for intensive use but not to a degree that would bring intolerable maintenance costs; the haulage capacity must be in balance with supply, with the consumer's needs, and with amortization requirements" [310].

TABLE 54

STEAM-ELECTRIC FUEL FIGURES

MARCH 1975-FEBRUARY 1976

	New York	Penn.	Ill.	Indiana	Mich.	Ohio	Wis.	Minn.	TOTAL
1975 oil delivery	86,128	13,105	7,365	1,530	15,879	1,373	471	773	126,624 x 10^3 bbl
Avg. cost/bbl	$11.48	$12.74	$12.16	$12.41	$12.36	$13.90	$11.24	$12.35	
Number of reporting plants	22	31	15	13	14	25	8	10	160
Percent of total BTU	77.1%	8.8%	5.4%	1.2%	14.6%	1.2%	1.2%	2.4%	14.6%
1975 coal delivery	5,972	36,733.3	33,499	30,968	21,361	46,860	11,552	8,797	196,242 x 10^3 tons
Avg. cost/ton	$28.31	$22.45	$15.28	$12.57	$21.84	$20.86	$18.35	$11.18	
Number of reporting plants	10	27	25	26	25	35	18	17	183
Percent of total BTU	21%	91.1%	90.6%	97.4%	80.1%	94.1%	94.1%	89.6%	83.1%
Gas									2.3%
Total energy used for power plants in bbl x 10^3 (equivalent)	110,016	160,037	143,361	124,402	101,323	188,818	46,679	35,965	911,000

Compiled from FPC data.

Unit trains in the Great Lakes Region have primarily hauled coal to the consumer directly from the mine. Unit train rates were developed through major long-term contracts for all rail coal movement from mine to consumer. Railroads have been unwilling to offer such rates to ports and terminals. Rail companies would naturally prefer to contract for coal movement to the final destination rather than short-hauling for transshipment to lake carrier. The Lake Carriers Association recently received a favorable ruling concerning the establishment of unit train rates to the Lake Erie ports. Additional litigation on this matter is expected. Unit train transportation is not excluded from all ports on the Great Lakes. Of notable exception is the transshipment facility in Superior, Wisconsin. Unit trains 100 cars in length are loaded in Montana and hauled 800 miles east to deliver 10,000 tons of western coal to the coal transshipment facility at Superior. Operations of this sort represent a significant improvement in the historical transportation of coal by rail.

Rail transport of coal, traditionally parochial in nature, is expanding to markets well beyond the regions of production. Efficient utilization of rail transportation on this scale relies on rapid turnaround time in loading and unloading as well as stable and well constructed road beds capable of withstanding the stresses of 10,000-ton unit trains.

The shipment of coal by rail accounts for 57% of the total coal movements for electric utilities in the Great Lakes states. The two largest coal consuming states in the country, Ohio and Pennsylvania, move 34% and 36% of their coal for electricity by rail [604]. The rail network, although extensive in these states, competes with the inland movement by barge and truck to utilities. However, it should be stressed that these competing modes of transportation occur largely outside the Great Lakes Basin. Some of the largest coal mines are located near the Monongahela and Ohio Rivers, which assume a large portion of the coal traffic by barge. Economical movement by truck is generally restricted to the regions of coal production located well inland of the coastal counties. Therefore, the rail system, unencumbered by the geographical and economic restraints affecting river or truck transportation, primarily serves the coal demands of the Pennsylvania and Ohio utilities located in the coastal counties along Lake Erie.

Illinois and Indiana are also large producers of coal. The percentage of rail transport for electric utilities is considerably greater in these midwestern states than in Ohio and Pennsylvania. Indiana and Illinois move better than two-thirds of the coal used for electric power generation by rail. This traffic supplies fuel for the enormous industrial and residential power demands in the Lake Michigan coastal counties of Illinois and Indiana. More than half of the coal moved by rail for electric utilities is produced within the states' borders. Recently the influx of low sulfur western coal has taken a larger share of the coal movement by rail. Thirty-eight percent of the rail movement to Illinois originated in Montana and approximately 15% of Indiana's coal for electric power generation was produced in Wyoming. As demands for low sulfur coal increase, rail traffic can be expected to realize an even greater share of the coal transportation market in Indiana and Illinois.

The four northernmost Great Lakes states of Minnesota, Wisconsin, Michigan and New York are north of the bituminous border that runs through Illinois, Indiana, Ohio and Pennsylvania. The northernmost states must import virtually all their fuel supply for electric power generation. The transportation sector, particularly the railroad industry, benefits from this situation. This is especially true in Minnesota and New York, whose geographic location have historically precluded extensive coal traffic on the Great Lakes. In 1975 over 80% of the coal used by utilities in Minnesota was transported by rail. All but 15% of this coal was mined in Montana. New York similarly received approximately 80% of the coal delivered to utilities by rail. This coal was mined primarily in eastern Pennsylvania and West Virginia. Although the percentages for rail traffic are high in these two states it should be noted that the total tonnage of coal consumed by utilities in New York and Minnesota are the lowest of the Great Lakes states. Combined, these states consume only about 8% of all coal use for electric power production in the Great Lakes states. Michigan and Wisconsin consume more than twice the coal used in New York and Minnesota. Here again rail transportation is the dominant method of coal movement. These states, however, are well suited for coal transport by lake vessel. Consequently, rail shipments to Michigan and Wisconsin constitute a slightly smaller portion of the total coal movement than in Minnesota and New York. In 1975, Wisconsin received 66% of its coal for electric utilities by rail. Most of this coal originated in Illinois and Kentucky. Almost 30% of this fuel was mined in Montana or Wyoming and transported by rail. Eastbound rail movement from Montana and Wyoming can be expected to increase in the near future. Two planned power facilities in Wisconsin's Lake Michigan coastal counties, Edgewater and Prairie View, anticipate delivery of western coal by unit train. Although Michigan has more shoreline than the remaining seven Great Lakes states, rail movement comprised

71% of the total coal shipments in 1975. More than 80% of this rail movement originated in Ohio and West Virginia. The dominant position of rail over water transportation in Michigan can be partially attributed to the locations of the major load centers in the southern portion of the state. The growth of unit train movement directly to utilities in the Detroit area has affected the traditional short haul by lake vessel from the coal loading ports on Lake Erie.

Railroads, as previously mentioned, prefer to control the commodity's transportation from mine to consumer. They are not, however, interested in totally displacing the coal commerce of the lake carriers. Each major coal shipping port is serviced by a particular rail company which delivers coal to the facility. An extensive rail network supplies the lake ports with coal for transshipment to the waterways. Other rail companies not directly serving the ports may do so indirectly by delivery to a number of inland "turnover points" where coal is transferred to the rail company serving a port for final delivery. The Louisville and Nashville Railroad Company indirectly serves many of the Lake Erie coal ports in this manner.

This symbiotic relationship with railroads is necessary for economical coal movement by lake carrier. Michigan and Wisconsin are the only Great Lakes states that receive appreciable tonnages of coal by lake vessel. In 1975, Michigan received 29% of the coal for electric power generation from Great Lakes vessels. Approximately 40% of the lake traffic to Michigan originated in West Virginia and Kentucky and was transshipped via the Lake Erie ports [604]. The coal destined for Wisconsin ports primarily originated in the midwestern coal fields of Illinois, Indiana and Kentucky and moved onto the lakes through the port at South Chicago. This movement of coal has diminished almost by half over the last ten years.

Western coal, notably from Montana, is presently taking a larger share of the coal movement on the Great Lakes. Originating from a new transshipment facility in Superior, Wisconsin, western low sulfur coal traffic on the Great Lakes represents a reversal of the traditional patterns of movement by lake carriers. Historically, iron ore and coal have been complementary commodities for dry bulk transportation on the Great Lakes. Vessels hauling iron ore downbound from Lake Superior to Lake Erie could reload with coal for the return upbound passage.

The advent of western coal movement on the lakes complicates this traditional commodity exchange flow. The additional coal traffic from Lake

Superior has spurred construction of new bulk cargo vessels. The dimensions of new vessels on the Great Lakes are increasing with the capacity of the locks to accommodate them. The completion of the Poe Lock at Sault Ste. Marie in 1970 increased the limitations on vessel dimensions to 1,000 feet length and 105 feet beam. This development permits construction of vessels with a carrying capacity over 56,000 tons or approximately twice as much as any prior lakers [251]. Although the number of commercial vessels on the Great Lakes has decreased by one-half since 1960, the increased capacity of vessels presently on the lakes has compensated for this decline so that there is a total decrease in carrying capacity of only 10% [290].

The extension of the shipping season on the Great Lakes may also have a minor impact on the waterborne movement of coal. Coal is generally stockpiled on site in quantities sufficient for the demand over the winter months. The beneficiaries of an extension in the shipping season would most likely be the smaller, older shoreline plants located primarily on the western shores of Lakes Michigan and Huron. These utilities with smaller storage facilities must presently supplement winter stockpiles with deliveries by rail. With season extension the percentage increase in coal tonnage shipped on the Lakes would be less than 5% [243].

Lake vessels also transport crude petroleum and petroleum products. The development of an extensive pipeline network throughout the region has substantially reduced tanker transport of these liquid fuels. Petroleum, a minor fuel commodity for electric power generation in the coastal counties of the Great Lakes, can be expected to continue to decline in movement on the Lakes with additional pipeline construction in the region. The heavy fixed investment and economies of scale are cited as reasons for the favorable share of the market assumed by pipeline transportation [147]. The possible movement of oil onto the lakes by ocean-going tanker is restricted by the limitations of the St. Lawrence Seaway and the connecting channels of the lakes.

On a much smaller scale there is barge movement of oil on the lakes for power production. Specifically, the oil-fired energy facilities in Oswego, New York, receive oil by barge. Originating from oil storage facilities in Montreal, barges supplied the Niagara-Mohawk Oswego facilities with approximately 4.5 million barrels in 1975. Coal is also transported by barge. The Commonwealth Edison Company uses barges to deliver four to five million tons of coal per year to electric facilities in and around Chicago. Low sulfur western coal is transported by rail to a transshipment point on the Illinois River near Peoria. Barges move up river delivering 1,250 to 1,450 tons of coal per barge. The Commonwealth Edison Company has long been committed to this method of coal transportation and anticipates continued use of barges for fuel transport.

Movement of crude oil by pipeline is routed from Duluth-Superior through Michigan to Sarnia, Ontario, and another line from the same origin runs parallel to the western shore of Lake Michigan around the southern end of the Lake and across Michigan to Sarnia. Additional supplies of crude are delivered from the Gulf region to the major refining facilities along the Illinois and Indiana region of Lake Michigan. Refined products from refineries throughout the Great Lakes states are transported via a major refined products pipeline network concentrated in the major industrial load centers throughout the Great Lakes Region. Pipelines can also carry a coal slurry. Finely pulverized coal can be mixed with water and pumped through a pipeline at about three and one-half miles per hour. At the destination point coal is removed from the water by a filter. A coal slurry pipeline once delivered coal to the Cleveland area. Completed in 1958, operations ceased in 1963 when railroads lowered their rates to compete with the line. Future development of coal slurry pipelines is presently constrained by the inability to acquire legal rights-of-way across private property, particularly railroad property. These pipelines also require considerable quantities of water for the slurry mix. Availability of water is a major limiting factor to the development of slurry lines.

b. Electricity

(1) Power

Use of electricity is growing faster than use of any other form of energy in the United States. While the national average growth of energy consumption was 4.8% per year from 1961-1972, the growth in electrical energy consumption grew at an annual average rate of 7.3%, or doubled approximately in 10 years. [576]. A continuation of this rate would require approximately an eight-fold increase in the present generating capacity, transmission capability and fuel requirements by the year 2000. Improved efficiencies would slightly reduce the magnitude of this increase. Though the amount of fuel would necessarily increase proportionately, the mixture of fuel types used for power production has and will continue to change.

TABLE 55

U.S. DISTRIBUTION OF ENERGY CONSUMPTION BY FUEL AND BY SECTOR

Fuel	1968	1973
Coal	22%	18%
Petroleum	44.2%	46%
Nuclear	.2%	1%
Hydro	1.3%	4%
Natural Gas	32.3%	31%

[576]

Broken down further by sector use (1968) Office of the Secretary of Transportation report, relative importance of energy source:

Sector	Coal %	Gas %	Pet. %	Elec. %	Total
Commercial	8.3	26.8	49.2	15.7	100
Industrial	26.2	43.3	20.9	9.6	100
Transport	.1	4.0	95.8	.1	100
Residential	---	50.1	34.8	15.1	100

For the period 1971-1975 annual growth in net electricity produced varied from a high of 8.6% during 1971-1972 to a low of 0.4% for the 1973-1974. The average for the 5-year period was 5.1%, with the growth rate during 1974-1975 being 2.6%. These are national electricity production figures which should not be confused with the increase in installed generating capacity, which (over the 5-year period) increased at an average annual rate of 8.2%. These statistics reflect fairly accurately the conditions of the eight Great Lakes states.

Nationwide, the production of electricity accounted for over 25% of the primary energy consumed annually. The electric utility sector's demand for energy is growing faster than that of any other sector, at approximately 8% per year (pre-1973). Since the Arab oil embargo of 1973, the utility sector's demand for energy has lessened in response decreased consumption of electricity, due to such factors as the increased cost of power and the depressed state of the economy. As will be seen further on in the study, assessing future demand for electricity is a most difficult task. The historical growth rate of approximately 7% is no longer assumed to be the case in the post-1973 world of higher energy prices, capital shortages, conservation measures, and economic misfortunes.

The economic growth of an area will often indicate a rapid rise in the demand for electricity. Similarly, the growth in population and its electric energy consumption habits will greatly influence the demand for electric power.

TABLE 56

CONTRIBUTION OF EACH FUEL TO THE UTILITY SECTOR

U.S.

	10^6kwh prod.	Coal	Oil	Gas	Nuc.	Hydro.
1960	_	57.3%	9.5	26.1	-	7.1
1973	1,859,120	45.7%	16.8	18.3	4.5	14.6
1974	1,854,847	44.5%	16.1	17.2	6.0	16.1
1975	1,908,784	44.6%	15.1	15.7	8.7	15.7

Electric use growth rate (1973)	
Residential	8.2
Commercial	9.6
Industrial	5.8
Transportation	---

Electricity demand by sector (1973) (% used)	
Residential	32%
Commercial	22%
Industrial	42%
Other uses	4%

(2) Population

Historically, population has been growing at a rate of 15% per decade, and for the last few years the U.S. population has been growing at an annual rate of just under 2% [U.S. 1975 statistical abstract]. In comparison, the power generating capability in the U.S. since 1955 has been growing at an annual rate of approximately 7%. This indicates to some degree the increasing consumption of energy per capita in the U.S. Tables 57 and 58 indicate the growth in energy consumption that has taken place in the last few decades.

TABLE 57

PER CAPITA POWER GENERATION

Year	Population (10^6 people)	Kilowatt-hours per capita	Installed Kw per capita	Total Power Generated* (10^9 Kw-hr)
1955	164	3853	0.44	633
1960	180	4718	0.53	849
1965	194	5969	0.68	1157
1970	205	8100	0.93	1660
1975 (est)	221	10450	1.19	2310
1980 (est)	231	14000	1.60	3300

[U.S. Statistical Abstract]

TABLE 58

TOTAL AND PER CAPITA ENERGY CONSUMPTION

	Total 10^{12}B.T.U.)	Per Capita (10^6B.T.U.)
1920	19,782	182
1930	22,288	181
1940	19,107	181
1950	34,153	226
1955	39,956	243
1960	44,816	249
1965	53,969	278
1970	67,143	330
1974	73,121	346

[U.S. Statistical Abstract, 1975]

The preceding tables illustrate the growth in energy consumption in the U.S. As population growth begins to level off in the future, demand for energy can be expected to continue increasing, although at a reduced rate.

The projected population of the U.S. as of July, 1976, is 211,909,000. At the same time the populations of the states within the Great Lakes Region were:

N.Y.	18,111,000
Penn.	11,835,000
Ind.	5,330,000
Ill.	11,131,000
Ohio	10,737,000
Minn.	3,917,000
Wisc.	4,566,000
Mich.	9,098,000
	74,725,000

The Great Lakes states contain 35.27% of the total U.S. population. Of the states in the Great Lakes Region, the coastal zones (figures by counties) comprise 26% or 19,415,897 of the total population of the eight Great Lakes states. Table 59 shows the population of the states' coastal zones as of July, 1975.

TABLE 59

GREAT LAKES STATES POPULATION BY COASTAL ZONE

	Number of Counties	Coastal Zone Population	Total State Population	Percent Population in Coastal Zone
N.Y.	10	2,696,600	18,111,000	14.89
Penn.	1	273,780	11,835,000	2.31
Ind.	3	749,000	5,330,000	14.03
Ill.	2	5,765,700	11,131,200	51.8
Ohio	8	2,855,700	10,737,000	26.6
Minn	3	233,500		6.34
Wisc.	15	1,928,400	4,566,000	42.23
Mich.	41	4,898,200	9,098,000	53.83

[U.S. Census Bureau]

Major changes in the populations of the eight Great Lakes states do not appear likely. What does appear to be happening within the states is the continued growth, in both numbers and density, of the various Standard Metropolitan Statistical Areas around the large cities. The growth of these areas has implications for the concentrating of the utility's load centers. This concentration of population and load centers around the large metropolitan areas will affect the siting of facilities and the flow of electric power in and out of the Great Lakes coastal zone.

(3) Power Flows in the Great Lakes Coastal Counties

The relationship of electical power flows moving in and out of the coastal counties is a major consideration in attempting to assess the importance of electric generating facilities in the future. Power flows in and out of the coastal counties are not constant with respect to both direction and amounts. Further, once electricity leaves the generating unit it is virtually impossible to determine its final destination.

Electric power flows within the coastal counties of Lake Michigan are easily defined on a large scale. On the simplest level, power generated in rural coastal counties flows inland from the coast, whereas power generated in urban-metropolitan coastal areas is generally consumed within the coastal counties. Beyond these simple observations, electrical energy flows vary according to region and are a function of a particular power pool's varying requirements.

The Michigan Electric Power Pool (a combination of Detroit Edison and Consumers Power Co.) regulates electrical flows throughout the state, constantly monitoring loads, costs of power generation, and related factors in the effort to provide the lowest cost, most efficiently derived electric power.* Given that power flows within the state are not the same on any two days, attempts to specify coastal counties' electrical energy flows are impractical. However, what can be determined is the direction of average flows for large cities near the coast.

Generally, electric power flows into cities such as Detroit, Chicago, and Cleveland. The Chicago area has more than 5 million people living in its two

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* Communication, Michigan Electric Power Pool.

coastal counties and only four coastal power generating units. The Chicago metropolitan region is the load center for Commonwealth Edison, whose service area extends over most of northern Illinois. For the Chicago region there is a constant need to bring electricity into the coastal counties, predominantly from the south and west.* With the difficulty of obtaining sufficient coastal properties within the Commonwealth Edison Service Area and transmission rights-of-way in the metropolitan area, additions to generating capacity which involve new coastal sites would seem unlikely, so there will be a continued reliance on noncoastal zone electric power supplies.

The Detroit Edison Company, with a service area of 7,600 square miles, is an example of a utility with its primary load center and a high percentage of generating capacity located in the coastal zone.** The generating facilities located within the Detroit metropolitan coastal counties produce power less efficiently than those located on the St. Clair River and Lake Erie, so that on light load days only 10% of Detroit's power is generated within the metropolitan area, the other 90% coming from the north and south. On heavy load days, only 75% of Detroit's power comes from these areas, because the output from the inefficient Detroit plants is increased. The St. Clair River, Detroit River, and Lake Erie generating facilities are largely located in the coastal zone, making intracoastal power flows predominant in the eastern Michigan area.

With a service area of 1,700 square miles, Cleveland Electric Illuminating Company has both a very concentrated load center and, by comparison to Detroit Edison and Consolidated Edison, a concentrated service area. The Cleveland municipal plant has the ability to generate 90% of the portion of the needs in its service areas. However, there are three generating facilities that produce with greater efficiency and at lower cost most of the metropolitan area's needs.*** Cleveland Electric Illuminating Company's generating facilities are closer to its load center than either Detroit Edison or Commonwealth Edison, with the major plants located close to Lake Erie. As with Detroit Edison, the power which Cleveland Electric Illuminating Company generates is consumed within the coastal zone.

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* Communication, Commonwealth Edison.

** Communication, Detroit Edison.

*** Communication, Cleveland Electric Illuminating Company.

The Milwaukee metropolitan area is the largest consumer served by the Wisconsin Electric Power Company. The area's industrial sector uses approximately two-thirds of the power produced by the utility. This high percentage reflects the heavy industrialization of the Milwaukee area. The electric power is generated on the coast, with much of this within the Milwaukee metropolitan area.* The remainder of the Milwaukee base load is generated in the coastal zone north of Milwaukee at the Point Beach plant (this assumes the Oak Creek plant to be in the Milwaukee metropolitan area). The power flows for Milwaukee are intracoastal.

More power is produced within the coastal zone of New York than is consumed locally. The inland location of many New York population centers, combined with the difficulty of siting power facilities in many parts of the state, suggests the reason for intensive energy facility siting in the coastal zone. Generally, power flows from west to east in New York State. Areas such as Oswego are rapidly becoming major energy exporting centers. The number of power plants and transmission facilities existing and being planned suggests the importance of the coastal zone in supplying inland areas with large blocks of power [449]. (For example, utilities such as Long Island Lighting Company and Orange and Rockland Utilities, Inc. are joining in construction of Oswego area power facilities.)** The Niagara Falls-Buffalo area produces large amounts of power, but due to heavy industrialization, exports smaller quantities of electricity to more eastern areas.

The variations that have developed in electrical energy produced in the coastal zone and its end use are the result of the needs of the regional power pools, availability of facility sites and transmission line rights-of-way, and location of fuel and water resources.

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* Communication, Wisconsin Electric Power Co.

** Communication, New York Power Pool.

3. EXISTING ENERGY SUPPLY FACILITIES

a. Electrical Generation

(1) Types by State and Region

The types of generating facilities in the Great Lakes Region are currently reflected in the region's fuel mix, described in Section IV.B.2.a.(3). The average capacities of the different types of facilities varies. Modern nuclear facilities average between 900-1000 MW each whereas most coal-fired units are around 600 to 800 MW. The majority of hydroelectric and gas facilities are quite small and are often used for peaking purposes.

The locational requirements for the different generating types varies considerably according to fuel types. Hydroelectric facilities have the most obvious restrictions as to where they may site. These restrictions suggest a limited future role for hydroelectric power. The possible exception to this would be a further development of pumped storage facilities, but these also have very stringent locational restrictions.

A primary siting consideration for fossil-fuel plants is the location of existing or planned fuel transportation. In the past few years environmental considerations have become a major factor in determining the location of a fossil-fuel generating plant. Air quality regulations are especially pertinent to coal-fired facilities. In addition to environmental and fuel considerations, fossil-fuel plants have and will continue to locate where water is available.

The location of nuclear facilities has been dictated by two primary considerations: (1) availability of water, and (2) availability of enough land for the required zone of exclusion. Fuel transportation is not a major consideration in the location of nuclear facilities.

There does not appear to have been a preference of one fuel type over another in locating in the coastal zone. Recent trends, however, suggest that a higher percentage of nuclear facilities have and will be located in the coastal counties. Future preference for locating in the coastal zone will be dictated by the following considerations: (1) water availability, (2) access to fuel transport routes, (3) environmental quality standards, and (4) land in sufficient quantities for exclusion areas. The following shows a rough breakdown of the quantity of each state's generating capacity.

Table 60 POWER GENERATION BY STATE

ILLINOIS

Elec. produced 94,480 GWh

Installed gen. cap. 25,942 MW [F.P.C. News June 4 - 12/31/75]

Gen. cap. in C.Z. 3267.25 MW [322]

% of total cap. in C.Z. 12.5%

Future scheduled or planned gen. cap. 16,880 (planned through 1984)

Planned expansion in C.Z. - None

WISCONSIN

Elec. produced 35,063 GWh

Installed gen. cap. 8,881 NRC

Gen. cap. in C.Z. 5574.3 MW

% of total cap. in C.Z. 59.6%

Future scheduled or planned gen. cap. 5333 MW

Planned expansion in C.Z. 1,560 MW

MICHIGAN

Elec. produced 72,074 GWh

Installed gen. cap. 18,926 MW

Gen. cap. in C.Z. 17229 MW

% of total cap. in C.Z. 73%

Future scheduled or planned gen. cap. 10232 MW

Planned expansion in C.Z. 9557 MW (include D.C. Cook unit 2)

OHIO

Elec. produced 105,665 GWh

Installed gen. cap. 25,225 MW

Gen. cap. in C.Z. 5514.4 MW

% of total cap. in C.Z. 21%

Future scheduled or planned cap. 10,077 MW

Planned expansion in C.Z. 5,300 MW

INDIANA

Elec. produced 65,421 GWh

Installed gen. cap. 13,315 MW

Total cap. in C.Z. 2,918.956 MW

% of total cap. in C.Z. 20.4%

Future scheduled or planned gen. cap. 6,516 MW

Planned expansion in C.Z. 685 MW (nuclear) (indef.)

MINNESOTA

Elec. produced 28,289 GWh [F.P.C.]

Installed gen. cap. 6,707 MW

Gen. cap in C.Z. 324.329 MW

% gen. cap. in C.Z. 5%

Future scheduled or planned gen. cap. 2,820 MW

Planned expansion in C.Z. - None.

PENNSYLVANIA

Elec. produced 111,762 GWh

Installed gen. cap. 28,770 MW

Gen. cap. in C.Z. 118 MW [322]

% of total cap. in C.Z. .4%

Future scheduled or planned gen. cap. 13,120 MW

Planned expansion in C.Z. 800 MW

NEW YORK

Elec. produced 109,521 GWh

Installed gen. cap. 29,500 MW [F.P.C. Jan. 1, 1976]

Gen. cap. in C.Z. 7,968 MW

% of total cap. in C.Z. 27%

Future scheduled or planned gen. cap. 15,829 MW [F.P.C. Jan. 1, 1976]

Planned expansion in C.Z. (1100 Nuc) 3,950 MW

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(2) Electrical Transmission

With the development of the electric reliability councils during the mid-1960's the electrical transmission network within the Great Lakes Region has become increasingly reliable. A primary function of these councils is to promote the comprehensive planning of both generating facilities and transmission networks. The reliability councils have helped to coordinate overall design of the transmission grid for the purpose of balancing power flows between load centers and the generating units, the sharing of power between utilities, and the overall efficient operation of the region's generating capacity. Further, inter-utility buying and selling of power has been encouraged by the development of a comprehensive transmission network. One benefit of pooling power is the reduction in generating capacity needed by an individual utility to compensate for emergency generating outages or days of extra heavy load.

The development of power pools such as the Michigan Power Pool or CAPCO was predicated upon the ideas of sharing and coordinating resources and providing the least expensive power possible. The practices of the utilities and power pools have become very complex, such that at any given time it is nearly impossible to determine the destination of locally generated power. With the development of inter-utility electric reliability councils and power pools, the siting of new generating units is no longer heavily dependent upon proximity to large load centers. To assure transmission line stability and interregional power reliability, some new generating units may locate outside of the general proximity of large load centers.

The development of a comprehensive and efficient transmission network has increased the flexibility in energy facility siting. The D.C. Cook nuclear facility, located in Michigan and owned by the Indiana and Michigan Power Company, is a good example of a generating unit able to locate hundreds of miles from the load areas it serves, due to the availability of an efficient long distance transmission network. Cooling water from Lake Michigan was the primary reason for the selection of the Michigan site, while the EHV (345 and 765 kV) transmission network made it economically feasible to serve the widely dispersed demands of the American Electric Power grid.

The bulk transmission system of the region is predominantly comprised of 345 kilovolt (kV) lines. The use of high voltage transmission lines allows large transfers of power at a very high efficiency. The overall efficiency of the electric transmission network is lowered each time the power is stepped down to a lower capacity line, so it is beneficial to transmit power along the higher voltage power lines over long distances. Future transmission network plans call for the development of 765 kV transmission lines which will allow the transfer of more power at a higher efficiency than that of the 345 kV lines. The 765 kV network presently operating in the Great Lakes Region is currently transmitting the power generated at the D.C. Cook facility to the southwestern Ohio region. The trend in transmission lines is towards larger, more efficient lines. A continued emphasis is being placed on reliability and coordination of the entire generating-transmission system.

b. Fuel Transshipment and Storage

(1) Facility Type and Size

Ports on the Great Lakes have shown a pattern of growth and development towards efficient and rapid handling of bulk commodities. Rapid growth in many phases of transportation, particularly those concerned with the handling of bulk commodities, forced the gradual disappearance of the old general cargo facility. Typically located close to the downtown metropolitan area, these ports became obsolete due to increasing demands for extensive land areas, access to major rail facilities, waterfront dockage capable of accommodating larger vessels, and closer proximity to outlying industrial complexes.

Bulk cargo terminals are designed specifically to handle materials such as grain, ore, coal and oil efficiently and quickly. Fuels, coal and petroleum products account for a significant portion of the bulk commodity trade on the lakes.

(a) Coal

In 1974 the 35 million tons of coal shipped on the Great Lakes accounted for about 17% of the total foreign and domestic freight shipped on the lakes. This was the third largest single commodity handled that year. Coal is shipped from three primary regions on the Great Lakes: southern Lake Erie, south Chicago, and Superior, Wisconsin. Together these ports shipped over 95% of the total lake coal traffic in 1975 [290].

The Lake Erie coal ports of Toledo, Sandusky, Lorain, Conneaut, and Ashtabula transship coal originating in West Virginia, Pennsylvania and Ohio. The combined tonnage of coal shipped from these ports was over 33 million tons, or 85% of all coal shipments on the Great Lakes in 1975 [290]. This massive commodity shipment is partially counterbalanced by receipts of iron ore from mines in the upper Great Lakes for use in the iron and steel industries located along the Ohio River and its tributaries. The ports developed as the gateways for coal demanded by northern utilities and industries and iron ore demanded by foundries in Ohio and Pennsylvania.

A brief survey of the ports follows.

- Toledo--The port of Toledo typically handles more coal traffic than the remaining four major facilities on Lake Erie. Coal shipments in 1975 increased 11% from 1974 to 14.6 million tons [290]. This was a reversal of the previous four-year downward trend. Four of the six coal piers are served by the Chessie System while the Baltimore & Ohio and Penn Central service the remaining piers.

The port has no coal storage areas employing direct rail-to-ship transfer. The combined unloading speed for the six piers is 15,900 tons per hour.

- Sandusky--This port is served by the Norfolk and Western Railroad. Its unloading equipment can handle 3,500 tons per hour. In 1975 Sandusky shipped 4.3 million tons of coal. This was a slight increase over coal shipments in 1974 but less than the tonnage figures for the 1972 and 1973 shipping seasons. Storage capacity is 910,000 tons.
- Lorain--Lorain is the smallest of the Lake Erie coal ports. Served by the Chessie System, the port has lost more than half its coal traffic since 1973. In 1975, Lorain shipped 1,264,954 tons. The port uses very little of the approximately 80 acres available for storage. It can load coal at a speed of 2,700 tons per hour.
- Ashtabula--Comparable to Sandusky in coal traffic volume, Ashtabula coal shipping was up approximately 400,000 tons over 1974. Penn Central serves this port, which is capable of loading 8,000 tons per hour. Total coal storage capacity is presently 1.4 million tons.
- Conneaut--Conneaut ranks second in coal tonnage shipped from Lake Erie ports. Between 1974 and 1975 this port increased tonnage shipped almost 20% to 8.3 million tons. Conneaut has direct rail connections with the Bessemer and Lake Erie Railroad. It can store 4 million tons and has a loading speed of 10,000 tons per hour.

Four million tons, or 10% of the total coal shipments on the Great Lakes in 1975 were shipped out of the South Chicago port facility. This facility is the major coal shipment area on Lake Michigan. In 1975, 3,943,165 tons were shipped from this port. The facility is served by the Belt Railway Company of Chicago and is a transshipment point for coal mined in western Kentucky, Indiana and southern and central Illinois. Coal shipments from this facility have steadily declined to essentially half of what they were in 1967. The port can load two vessels simultaneously at a total of 5,000 tons per hour.

A new port in Superior, Wisconsin, presently competes with the South Chicago and Lake Erie ports. Superior has become the third major coal shipping port due to the attractiveness of low sulfur western coal. The new Superior Transshipment Terminal presently receives coal from Burlington Northern Railroad unit trains. The unit trains consist of 100 cars each hauling 100 tons. Coal is loaded in Montana and travels 800 miles east to the Superior coal facility. This terminal has the capacity to transship 14 million tons annually. The facility is designed for an eventual expansion to 20 million tons throughout. Coal is unloaded from the train, transported by inclined conveyor to a 1,200 foot long elevated truss which evenly stockpiles the coal beneath it. The storage area has capacity for 7 million tons. Coal is reclaimed by four rotary plow feeders beneath the stockpile which feed the coal to a 96-inch conveyor capable of moving 11,000 tons per hour. This conveyor feeds the shiploader, which is the largest in the world in terms of volume handled per unit time [605]. In 1976 Superior harbor will ship 2.2 million tons. By 1980 it is expected that throughput will increase to 8 million tons.

Table 61 shows the tonnage of coal shipped and received at the major Great Lakes ports in 1974. The ports and terminals that receive and store coal are typically comprised of many private facilities designed to accommodate the fuel needs of a specific factory or power plant. For example, the 6.5 million tons received in Detroit in 1974 is the combined total for 23 separate coal facilities reported to exist at the Detroit Harbor. Twelve are situated along the Detroit River; nine are located on the Rouge River and two are on the Short Cut Canal. The combined storage capacity of these facilities is 5 million tons [584].

Table 61 shows that coal received in Chicago does not arrive via the Great Lakes. The waterborne movement of coal to Chicago is handled primarily by barge traffic up the inland waterway system connecting the Great Lakes with the Mississippi River Basin. There are 17 facilities that handle coal in the Port of Chicago. Eleven facilities report a total storage area of 68.7 acres. The remaining six facilities have a combined coal storage capacity of 2,360,000 tons [583].

The existence of the many private coal unloading and storage facilities within a port indicates that industry has found there are positive economic and environmental benefits to the direct control of coal deliveries. Offsite unloading and storage results in increased costs from additional handling to transport the coal to the site of consumption and added environmental impacts. For example, the Upper Peninsula Generating Company in Marquette had no storage facility at the plant site until recently. Coal was held for the company at the Marquette Dock Company, four miles away, and transported by rail to the power plant. The intermediate transportation of coal was costly and restrictive. The company anticipated expansion of generating capacity, so it constructed a new coal facility, located approximately 600 feet from the plant to receive coal directly from self-unloading vessels. The harbor has a storage capacity of 500,000 tons

Table 61

MAJOR COAL SHIPPING OR RECEIVING PORTS, 1974
(Thousands of Short Tons)

	Foreign			Domestic		
	Total	Overseas	Canadian	Coastwise	Lakewise	Internal
U.S. Receiving Ports						
Port of Detroit	6,571	-	1	-	6,570	-
Port of Chicago	5,024	-	-	-	1	5,023
St. Clair River, Mich.	3,046	-	-	-	3,046	-
Muskegon, Mich.	1,919	-	-	-	1,919	-
Green Bay, Wis.	1,606	-	-	-	1,606	-
Marquette, Mich.	909	-	-	-	909	-
Duluth-Superior	892	-	-	-	892	-
Milwaukee, Wis.	890	-	-	-	890	-
Total	20,857	0	1	0	15,833	5,023
Percent of Total	100%	-	-	-	76%	24%
U.S. Shipping Ports						
Toledo, Ohio	12,732	-	2,911	-	9,821	-
Conneaut, Ohio	6,719	-	4,699	-	2,020	-
Port of Chicago	4,150	2	37	-	4,113	-
Ashtabula, Ohio	4,186	-	3,017	-	1,169	-
Sandusky, Ohio	4,059	60	2,257	-	1,742	-
Lorain, Ohio	2,015	-	-	-	2,015	-
Duluth-Superior	821	12	13	-	796	-
Total	34,682	72	12,934	0	21,676	0
Percent of Total	100%	0.3	37.2	-	62.5%	-

Sources: Waterborne Commerce of the United States, Part 3, Waterways & Harbors, Great Lakes, 1974.

and is designed for eventual expansion to accommodate three new generating units in Marquette. This new development is but one of the numerous and highly site-specific coal unloading facilities that exist throughout the Great Lakes system. Greenwood's Guide to Great Lakes Shipping lists 90 such facilities.
Storage capacity at these coal unloading docks ranges from 2.5 million to 5 thousand tons. Most of the facilities are owned by electric utilities or steel and cement industries.

A fairly recent design feature that has become commonplace among the coal receipt docks is coal delivery from self-unloading vessels. The development of the self-unloading vessel has eliminated the need for much of the expensive unloading equipment that previously dominated coal unloading sites. A self-unloading vessel has hoppers with a V-shaped bottom located in the hold of the ship, which allow the coal to be dumped onto a conveyor belt located in a tunnel at the bottom of the ship. Bucket elevators then life the coal out of the hold to another system of conveyors which swing out from either side of the ship and dump the coal directly onshore. These ships can carry 35,000 tons and unload at a rate of 3,600 tons per hour. Once in storage the coal is then fed mechanically or by bulldozer to a belt conveyor feeding the plant [566].

(b) Oil

Oil is another major fuel commodity transported on the lakes. In 1975, shipments of petroleum products totaled 11,545,789 net tons, which is approximately equal to 86,600,000 barrels. This represents a 9% decrease from 1974 and a 23% decrease from shipments in 1973 [290]. The development of pipeline facilities around the lakes has accelerated the decline in transport of petroleum products by lake carrier. The network of pipelines and the physical limitations of the Great Lakes-St. Lawrence Seaway System have substantially restricted movement of crude petroleum through the ports. In 1974, less than one percent of the petroleum moved on the lakes was crude petroleum. Refined products, particularly distillate and residual fuel oil and gasoline, are the major liquid fuels carried by lake tankers.

Table 62 lists the major shipping and receiving ports for petroleum products. Commodities considered in developing this table were crude petroleum, crude tar, oil, gas products, gasoline, jet fuel, kerosene, distillate fuel oil, residual fuel oil, coke, petroleum coke and liquefied gases.

The bulk of products refined in the U.S. destined to be transported by lake vessel originates from the Indiana Harbor area of Lake Michigan. In 1974 Indiana Harbor was the shipping terminal for 77.3% of the gasoline, 81.3% of the jet fuel, 70.4% of the kerosene, 70.6% of the distillate fuel and 40.0% of the residual fuel oil shipped on the Great Lakes [536]. This facility is served by one of the largest refineries on the Great Lakes, Amoco's Whiting refinery, which has a capacity to process 360,000 barrels of crude petroleum per day. There are eight major transshipment facilities located in Indiana Harbor. The

433 storage tanks in the harbor have a combined capacity of approximately 15 million barrels [607]. Movement of refined products on the lakes through this facility has remained fairly constant over the last 10 years. Crude petroleum, a minor commodity which was not handled in the harbor in 1974, is primarily refined in the area for shipment as a refined product. The other major petroleum shipping ports in 1974 were Chicago (10%) and Toledo (12%), which together with Indiana Harbor (61%) handled over 80% of the petroleum products shipped on the Great Lakes.

Table 62

MAJOR PETROLEUM SHIPPING OR RECEIVING PORTS, 1974

(Thousands of Short Tons)

		Foreign		Domestic		
	Total	Overseas	Canadian	Coastwise	Lakewise	Internal
U.S. Receiving Ports						
Port of Chicago	3,776	-	7	-	682	3,087
Oswego Harbor	721	-	710	-	-	11
Indiana Harbor	550	-	-	-	442	108
Milwaukee Harbor	534	-	6	-	522	6
Port of Detroit	314	-	210	4	100	0
Total	5,895	-	933	4	1,746	3,212
Percent of Total	100	-	15.8	0.1	29.6	54.5
U.S. Shipping Ports						
Indiana Harbor	3,325	-	-	-	3,325	-
Port of Chicago	1,111	-	-	-	556	555
Toledo Harbor	649	-	7	-	642	-
Port of Buffalo	244	-	12	-	227	5
Port of Detroit	201	-	3	-	198	-
Total	5,530	-	22	-	4,948	560
Percent of Total	100	-	0.5	-	89.4	10.1

Source: Waterborne Commerce of the United States, Part 3, Waterways & Harbors, Great Lakes, 1974

The Port of Chicago is the major receiving port on the Great Lakes. Eighty percent of the petroleum traffic in this port occurs internally and reflects movement by barge in and around the facilities on the Chicago Sanitary and Ship Canal and Calumet River.

In 1974 1.1 million tons of Canadian petroleum products were received by U.S. ports. Most of this was residual fuel oil (913,779 tons). Of that amount 78% was received at Oswego, New York, and 10% was handled in Detroit.

(2) Capacity

There is a subtle but important distinction to be made between port capacity and port capability. The distinction reflects the difference between historic performance (capability) and estimated potential performance (capacity). Capacity is in many respects an unrealistic term when applied to port activities. Though often used, the term is often misunderstood. Capacity implies an upper limit to the quantity of cargo throughput and storage. The nature of port operation tends to preclude such absolute characterization. Port capacity is not a simple function of the loading/unloading speed. The constraints of ship scheduling, rail movements, traffic interruptions and delays each contribute to a port's capacity to handle cargo. Additionally, the activity of a port can be deceptive. Ports are designed to accommodate the reasonable seasonal and intermittent peaks in demand. Therefore a certain amount of inactivity is programmed into the function of a port and doesn't necessarily indicate the capacity is in excess of need [251]. Consequently, capacity is a constantly fluctuating value dependent not only on the space and equipment at the port but also on the coordination, availability, and transshipment limitations of the various shipping and receiving modes of transportation. The U.S. National Academy of Science [548] points out:

> It would be possible, of course, to design a port facility so that its capacity would be fully utilized at all times. Under this situation, variations in demand would have to be accommodated by delaying ships, forcing them to wait at anchorage until vessels that arrived previously had been serviced. Also, cargo awaiting ships would be delayed or would be routed through a competing port. Although this approach to port operations would maximize the cargo handled at a port for a given set of facilities, an economic analysis incorporating both vessel cost and port facility costs would show that such an extreme case of port operations would represent a highly uneconomic use of resources. Conversely, designing a port so that vessels are never forced to wait also represents an uneconomic use of resources. As for any service

operation, the least total cost is obtained by minimizing the sum of the costs of service facility construction and operation and the costs of ship and cargo delays. This results in a level of service at which vessels are infrequently forced to wait during peak periods.

Determination of such an economic optimum point requires a complex and detailed analysis of each port. While queuing theory and other concepts can be employed for the study of individual facilities or elements in a port, the interconnections among these facilities and elements are so complex that a sophisticated time-oriented simulation procedure may be necessary to determine fully the effects of modifications in facilities or changes in operating costs of physical facilities requires simulations using as inputs varying numbers of berths, entrance channel configurations, storage capacities, and operating policies and procedures. Such analyses to determine the economic balance for a port are, of course, costly and time consuming, especially in the larger and more complex ports.

The scope of this study precludes a detailed evaluation of the capacities of the Great Lakes ports insofar as those capacities are determined through the realization of a complex and largely site-specific analysis of the economic and physical parameters of the port. In recognition of the variables associated with port capacity, this study highlights the historic port transshipment capability.

The study briefly reviews the peak bulk throughput figures for the major fuel handling regions in the last ten years. A ten year time frame was chosen because it was felt that a decade would provide an adequate range of yearly cargo fluctuations with the least complications in equipment retirement and facility modification. This approach is felt to offer the most reasonable measure of the Great Lakes ports' existing potential for fuel transshipment. The approach is conservative but appears realistic in terms of near future coal and oil movement on the lakes.

Coal shipments from the major coal ports of Lake Erie have declined 30% within the last decade. This decline is marked by an overall decrease of 13.9 million tons since 1966. In that year 47.2 million tons of coal were shipped from Lake Erie ports. The year 1966 will serve as the high volume benchmark for total shipments of coal from Lake Erie. Over seventy percent of this total in 1966 originated from the port of Toledo. This port has witnessed a decline of 19.1 million tons of coal shipments since 1966. Toledo has the present capability to more than double its coal throughput. Of the four remaining major coal ports on Lake Erie only Lorain is regarded as presently operating considerably below previous levels of coal throughput. This port has had a nearly threefold decline in coal traffic since 1973. In that year Lorain shipped 3.6 million tons of coal. In 1975 shipments had decreased to approximately 1.3 million tons. This port, which primarily handles coal for electric power generation, plays an increasingly minor role in the total Lake Erie coal traffic, contributing about four percent to the combined coal shipments from Lake Erie in 1975 [290].

The ports of Sandusky, Ashtabula, and Conneaut are presently running either near or above peak levels of the last decade. Sandusky and Ashtabula both presently ship approximately four and one-half million tons of coal and are considered by their respective port officials to be operating comfortably within the port limitations and foresee no major expansions necessary. Conneaut is the only major Lake Erie port presently considering an extensive expansion of facilities and storage.

In conclusion, Toledo could presently contribute an additional 20 million tons of coal traffic to the system. Revitalization of smaller facilities such as Lorain with additional growth in throughput from Sandusky, Ashtabula and Conneaut could add substantially to this figure. Thus, in general terms, the ports of Lake Erie are capable of nearly doubling present coal throughput. It should be reemphasized however that such expansion is contingent upon the complex optimization of diverse activities such as coordinating rail-to-ship transfer and, most importantly, upon a return to the high demand for coal originating in the Appalachian fields.

Shipments of coal from the South Chicago facility have demonstrated a decline similar in magnitude to the Toledo facility. In 1975 this facility handled less than half the coal it shipped in 1967. Resumption of coal transshipment to 1967 levels would result in an additional four million tons of Great Lakes coal traffic. Like Toledo, this area has historically transshipped coal of a relatively high sulfur content. The future revitalization of this port is highly contingent upon the quality of coal originating from this port to the lakes.

The new coal shipping facility at Superior, Wisconsin has been in operation only one year, so it is unreasonable to equate historic capability with the capacity limitations of the facility. This coal transshipment facility handles low sulfur western coal from Montana. Reported to be the largest bulk handling facility in terms of cargo handled per unit time, the Superior facility is designed for an eventual transshipment capacity of 20 million tons per year.

This facility, in addition to expanded shipments through South Chicago and Toledo, could essentially double the coal traffic tonnage moved on the Great Lakes in 1975.

The capabilities of the system for coal movement on the lakes is presently not in excess of need. This assumption is based on a nonspecific demand for coal quality and may vary considerably according to fuel quality. An analysis of the factors affecting this demand is presented in the section on regional scenarios.

The capacity of facilities shipping oil on the Great Lakes is of lesser concern in relation to a fuel supply for electric power generation in the region. The development of extensive oil movement by pipeline, combined with a negligible future development of refinery capacity in the area, indicates at best a very conservative rate of growth in shipping of petroleum products. Indiana Harbor, the primary location of petroleum movement on the Great Lakes, reports operation well within historic capabilities and anticipates no major expansions.

(3) Demand

The pressures placed on the capabilities of ports and terminals is a function of the demand for fuels to be transported by lake vessel. The demand for coal on the Great Lakes is largely generated by utilities, coke and gas companies, and retail dealers. Coal for utility consumption accounted for 51% of the coal traffic on the Lakes in 1975. Coke and gas facilities acquired 34%, while 15% of the U.S. coal transshipped through U.S. and Canadian ports was received by retail dealers and other users. Of the Great Lakes states only Michigan, New York, Ohio and Wisconsin were reported to receive bituminous or lignite coal via the Great Lakes in 1975 [604]. Nearly 47% of the present market for U.S. coal transported on the Great Lakes is located in Canada [604].

A number of projections have been developed forecasting the future demand for Great Lakes coal traffic. These projections as analyzed in the Great Lakes Transportation System [147] predict either growth or stabilization to occur on the Great Lakes over the next 40 years.

The U.S. Army Corps of Engineers in 1961 projected coal movements on the Great Lakes to increase steadily from 93.4 million tons in 1975 to 148.5 million tons in 2015. These projections were based on a study of the major consumers of coal: electric utilities, steel plants and cement plants.

The projections by the Bureau of Mines (1970) assumed a growth rate of Great Lakes coal traffic of 3.1% per year, commensurate with the national energy needs through 1980. Increased development of nuclear power was assumed to reduce this growth rate to 2.5% per year after 1980. This projection predicted that 73 million tons of coal would be shipped on the Great Lakes in 1995.

The International Great Lakes Levels Board (IGLLB) extended the Bureau of Mines forecast beyond 1995, projecting stabilization of coal shipments at 74 million tons through the year 2020. This projection was balanced by their high and low forecasts for Great Lakes coal shipping. The high forecast predicted an increase of 73 million tons between 1970 and 1995. Beyond 1995 shipping levels would stabilize at 134 million tons per year through 2020. The low projection assumed a 1.25 percent growth rate until 1995 then leveled off at 43 million tons through 2020. In either case the projections assumed the same ratio of coal production to shipping as postulated by the Bureau of Mines.

A recent projection of coal shipments for the Great Lakes Region, published by A. T. Kearney Inc. in 1976 for the U.S. Army Corps of Engineers [243], seems the most likely of the trend projections (Table 63). The Kearney study took a conservative approach in forecasting potential western coal movement on the Great Lakes and St. Lawrence Seaway (GL/SLS). Only the movements currently planned were included in the forecast potential. Additionally the study operated under the assumptions that:

- Few, if any, existing facilities would be converted to western coal due to high conversion costs.
- Only new facilities that have announced plans for use of western coal would be included in the forecast.
- Stack gas scrubbers would be economically efficient and available by 1990.
- Current emission standards will remain unchanged throughout the forecast period.
- Variances to burn high sulfur coal will be extended until stack gas scrubbing technology becomes available.
- Canada will adopt emission standards that will not preclude usage of U.S. eastern coals.
- The development of nuclear power generation facilities will be delayed and retarded by environmental, safety and economic factors.

- Environmental concerns regarding strip mining will not restrict the growth of coal mine development in the West.

The Kearney projection of a 2% average annual increase shows coal movement tripling by the year 2040. As the Kearney report points out, U.S. movements assume the largest share of the total growth at 2.1% per year, while Canada initiates domestic movements and shows movement of 12.6 million tons by 2040. This traffic is expected as a result of Canadian western coal movement to the Lake Ontario facilities of Ontario Hydro.

TABLE 63

Potential GL/SLS Coal Movements
(Millions of Tons)

	United States Domestic	Canada Domestic	United States to Canada	Total
1972 Base	44.1	0	17.8	61.9
1980	58.3	5.0	22.7	86.0
1990	77.7	6.4	26.8	110.9
2000	94.7	8.0	30.4	133.1
2010	114.9	10.1	34.3	159.3
2020	134.0	11.0	36.5	181.5
2030	156.7	11.7	38.7	207.1
2040	184.2	12.6	41.0	237.8

Source: A. T. Kearney, Inc.

Table 64 and Figure 36, adapted from Schenker [147] and with the addition of the Kearney projection, illustrate the variations among the previously described demand projections of Great Lakes coal movement.

The demand for U.S. shipments of liquid fuels on the Great Lakes was, in a projection by Schenker [147], determined to have difficulty competing with pipeline transportation. Pipelines, as a long-term capital investment, maintain a high rate of utilization once constructed. Therefore the continued development of the pipeline network throughout the region was assumed to have a substantial negative impact on the future demand for Great Lakes shipping of liquid fuels. Rail movement, though usually more costly than waterborne movement, is important to high volume consumers such as electric utilities, because of its reliability.

TABLE 64

PROJECTIONS OF U.S. GREAT LAKES SHIPMENTS OF COAL

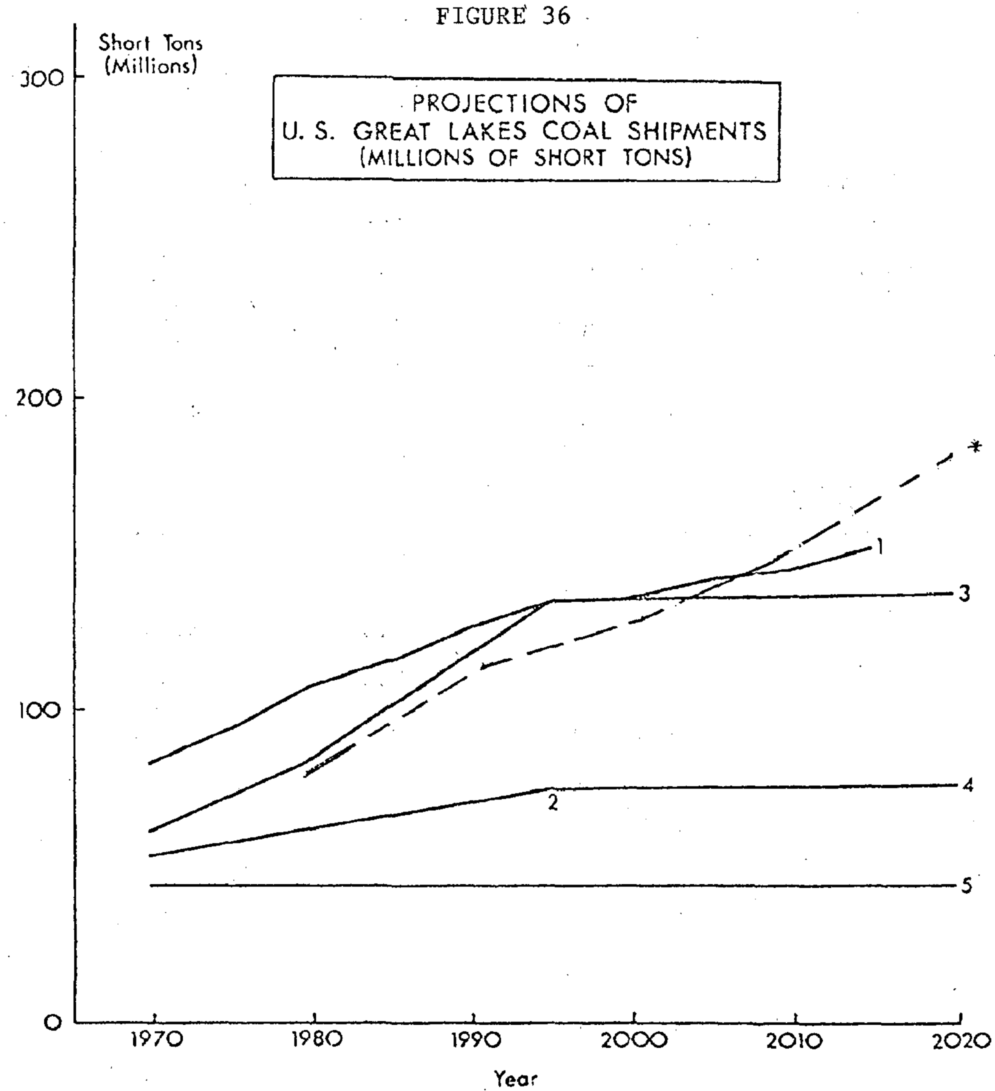
(Millions of Short Tons)

		1970	1975	1980	1985	1990	1995	2000	2005	2010	2015	2020
Corps of Engineers (1961)	(1)	83.5	93.4	106.7	114.6	124.9	130.3	135.0	139.6	143.2	148.5	--
Bureau of Mines (1970)	(2)	53.0	58.0	62.0	66.0	69.0	73.0	--	--	--	--	
IGLLB -High (1973)	(3)	61.0	--	83.0	--	--	134.0	134.0	--	--	--	134.0
-Medium	(4)	53.0	--	62.0	--	--	74.0	74.0	--	--	--	74.0
-Low	(5)	44.0	--	43.0	--	--	43.0	43.0	--	--	--	43.0
Kearney (1976)	(*)			81.0		104.5		105.1		149.2		170.5

NOTE: The Kearney projections are for domestic traffic only

SOURCE: [147]

FIGURE 36



The problems of storing large supplies of liquid fuels combined with the seasonal nature of lake traffic encourages use of pipelines and rail transportation instead of waterborne movement. Schenker [147], in considering expansion of pipeline traffic and conservation efforts, suggests the projection giving slightly more weight to the immediate past is most accurate.

TABLE 65

TREND PROJECTIONS OF GREAT LAKES
AND ST. LAWRENCE SEAWAY SHIPMENTS OF
CRUDE PETROLEUM AND SELECTED PETROLEUM PRODUCTS
1975-1985

(Millions of Short Tons)

	1975	1980	1985
Great Lakes			
Unweighted trend:	14.6	15.0	15.5
Weight of immediate past:			
Slightly Stronger:	13.8	14.1	14.3
Strong:	13.6	13.7	13.9
Very Strong:	13.7	14.0	14.3
St. Lawrence Seaway			
Unweighted trend:	4.5	5.4	6.4
Weight of immediate past:			
Slightly Stronger:	3.9	4.3	4.7
Strong:	4.5	5.3	6.2
Very Strong:	4.6	5.5	6.4

Source [147]

(4) Origins and Destinations of Fuels Handled

An important adjunct to the increased demand for fuels, particularly coal, is the effect such demand will have on the pattern of waterborne traffic around the lakes. Competition between the various modes of transport, water, rail, pipeline, etc., insures a constant flux in the patterns of movement between origins and destinations.

Historically, the bulk of coal movement on the Great Lakes has originated from the ports on Lake Erie. Located in proximity to the major Appalachian coal fields these ports developed as transit points for coal and iron ore movement in the region. Table 66 illustrates the destinations on a regional basis for coal moving through Toledo, Sandusky, Lorain, Ashtabula and Conneaut.

TABLE 66

BITUMINOUS COAL SHIPMENTS TO UNITED STATES PORTS FROM LAKE ERIE

To U.S.	To Lake Superior	To Sault	To Lake Huron	To Lake Michigan	To Lower Rivers	To Lake Erie	Total
Toledo	1,370,004	44,442	301,878	1,427,757	7,254,639	823,954	11,222,674
Sandusky	725,539	40,590	100,090	45,857	511,177	78,742	1,502,004
Lorain	---	---	161,507	---	887,688	215,759	1,264,954
Ashtabula	234,241	---	192,244	267,976	37,494	---	731,955
Conneaut	616,644	18,965	109,965	613,214	155,557	---	1,514,345
Total 1975	2,946,428	103,997	865,693	2,354,804	8,846,555	1,118,455	16,235,932
Percent 1975	8.88	.31	4.06	7.10	26.67	3.37	48.94
Total 1974	2,521,287	232,090	1,210,502	2,568,195	9,576,237	725,396	16,833,707
Percent 1974	8.46	.78	4.06	8.62	32.14	2.43	56.49

To Canada	To Lake Superior	To Sault	To Lake Huron	To Lower Rivers	To Lake Erie	Thru Welland Canal	Total
Toledo	25,710	1,992,674	41,843	19,135	32,839	1,319,745	3,431,946
Sandusky	---	---	---	---	51,005	2,785,050	2,836,055
Lorain	---	---	---	---	---	---	---
Ashtabula	78,449	---	---	943,606	943,737	1,887,061	3,852,853
Conneaut	---	---	---	1,937,872	2,781,988	2,098,794	6,818,654
Total 1975	104,159	1,992,674	41,843	2,900,613	3,809,569	8,090,650	16,939,508
Percent 1975	.31	6.01	.13	8.74	11.48	24.39	51.06
Total 1974	229,145	1,791,127	48,269	3,151,810	1,487,482	6,259,219	12,967,052
Percent 1974	.77	6.01	.16	10.58	4.99	21.00	43.51

SOURCE: Lake Carriers Association. Annual Report: Lake Carrier's Association. 1975.

The table shows that over half of the coal shipped from these ports is destined for Canada. This trend is most pronounced at the ports of Conneaut and Ashtabula, which ship 82 and 84%, respectively, of their coal to Canadian markets. The cross-lake traffic in coal to Canada primarily supplies steel mills and the power facilities of Ontario Hydro. Traffic to utilities and the steel industry accounted for 95% of the U.S. coal movement on the Great Lakes to Canada [604].

The domestic movement of coal from the Lake Erie ports is dominated by the Port of Toledo. Seventy percent of the Great Lakes coal movement to United States ports originated from this port. Of this traffic over 60% was destined for the steel mills and utilities of southeastern Michigan. The future of this short haul movement from Toledo to the Detroit area is uncertain. Unit train movements from mine directly to the consumer and downbound traffic of western coal from Lake Superior are satisfying a greater percentage of the electrical fuel demands of this region.

Movement of coal to Lake Superior from the port of Lake Erie remains a major traffic movement. Nearly 50% of the domestic shipments from Sandusky are destined for ports on Lake Superior. The electric power facilities at Marquette account for the majority of this traffic. While Sandusky supplies coal for Lake Superior ports, over 60% of all coal shipped on the Great Lakes from this port goes to Canada. Lorain, the only major coal handling port on Lake Erie not to export to Canada, shipped primarily to the electric power facilities of the Detroit Edison Company. Regulations on the sulfur content in coal and competition from rail traffic have been instrumental in the decline of Lorain as a major coal facility.

The facility at South Chicago on Lake Michigan was the point of origin for approximately four million tons of coal shipped on the Great Lakes. Coal from this port was destined primarily for the Consumers Power units of western Michigan and the facilities of the Wisconsin Electric Power Company. Coal traffic from South Chicago has declined by about one-half over the last decade, largely because of sulfur regulations.

The new transshipment facility at Superior, Wisconsin, was designed to benefit from the regulations on coal quality that have plagued many of the other transshipment facilities. Handling low sulfur coal from western states, Superior is the origin for low-sulfur coal shipped to the electric power facilities of Detroit Edison. Presently serving only Detroit Edison, extensive expansion to other markets is anticipated. The Superior facility is designed for an eventual capacity of 20 million tons throughput.

Electric utilities provide the major demand for coal shipped on the lakes. In 1975 48% of the coal shipped on the Great Lakes was destined for use by utilities. Coke and gas plants consumed 28%, while retail dealers and others consumed the remaining 24% [604]. These destinations were located almost exclusively in either Michigan or Wisconsin. These states purchased 96% of all domestic coal transported by lake for utilities, and Michigan alone was the destination for 91% of the waterborne coal used by coke and gas plants.

Petroleum shipments on the lakes originated primarily from the ports of Indiana and Chicago on Lake Michigan's southern shore. These ports accounted for more than 70% of the petroleum products shipped on the Great Lakes.

The destination points for lakewise movements of these fuels are scattered throughout the region with virtually every major port receiving and storing liquid fuels. The widespread distribution of receiving terminals throughout the region reflects the flexibility shipping offers over pipelines in smaller scale delivery of this fuel.

(5) Planned or Scheduled Facilities

Port expansion or new port construction is often the direct consequence of the development of additional energy facilities. Such port development is particularly applicable to the construction of coastal dependent coal-fired electric generating facilities, which historically have relied on waterborne fuel delivery.

U.S. Great Lakes coal traffic originates from three major districts: Lake Erie, South Chicago and Superior, Wisconsin. In 1975, the Lake Erie ports of Toledo, Ashtabula, Conneaut, Lorain and Sandusky shipped 33.2 million tons of coal, or 85% of the coal traffic on the lakes. Within the last ten years coal shipments from these ports have declined 28%, a decrease of 12.7 million tons since 1965. Consequently, most of the ports in this region operate at levels well below their previous capabilities. The only major Lake Erie coal harbor presently contemplating extensive expansion is Conneaut. Conneaut, presently storing four million tons and shipping approximately eight million tons, anticipates a substantial increase in coal traffic.

The proposed expansion will provide substantially more storage space and will include a conveyor belt system, travelling stacker, and bucket wheel reclaimer. Much of the expansion is projected for Canadian use, particularly by the Ontario Hydro utility facilities. Eighty percent of all coal shipments from

Conneaut are presently destined for Canada. The expansion may double storage capacity to 8 million and increase throughput to 13 million tons. Barring delays in permit approval and construction, expansion completion is set for the spring of 1978. The ports of Sandusky, Toledo, Ashtabula and Lorain anticipate no near term major expansions. Officials at these ports feel the facilities can accommodate the expected increases in coal traffic.

The South Chicago harbor on Lake Michigan shipped eight million tons of coal in 1967. In 1975 this facility found market for about four million tons of coal. There are no plans to expand. Much of the coal moving through this port originates from the midwestern coal fields in Illinois. The high sulfur content of this coal has accelerated the decline in volume transshipped from this port. A minor quantity of western coal has moved through the Chicago port and could contribute to future redevelopment of capacity capabilities.

The third major coal shipping region is located in Superior, Wisconsin. This single facility completed in 1976 will have an eventual capacity to transship 20 million tons. Coal shipments have risen sharply in Lake Superior. In 1973, 130,592 tons of coal were shipped from Lake Superior ports. Completion of the facility in Superior, Wisconsin in 1976 will add 2.2 million tons to the total coal shipments from Lake Superior ports. The facility was developed in response to the demand from the Detroit Edison Company for low sulfur coal. This utility contracted for 180 million tons of low sulfur western coal from the Decker mine in Montana. This contract for western coal extends over a 26-year period and was projected for use by Edison's St. Clair and Belle River power plants. However, construction plans for the Belle River plant have been delayed due to financial difficulties, and Detroit Edison is in the process of analyzing alternatives for the consumption of coal originally designated for Belle River.

A development similar to the Superior facility is being constructed at Thunder Bay, Ontario, on Lake Superior. Low sulfur coal originating from mines in Alberta, Saskatchewan and British Columbia will be delivered by Canadian National and Canadian Pacific unit trains. Scheduled to begin operation at the start of the 1977 shipping season, this facility is expected to initially ship 3 million tons of coal per year. These shipments are destined for Canadian markets in Ontario and eastern Canada and may compete with future coal shipments originating from the U.S. ports on southern Lake Erie [147].

A major expansion in demand for coal receipts from Superior, Wisconsin, may occur near Buffalo. The Niagara-Mohawk Power Corporation is planning two 850 MW coal-fired plants near Dunkirk, New York, on Lake Erie for 1985 and 1987. Low sulfur western coal is anticipated for use as the fuel source. Operation of the two Lake Erie power plants will require approximately six million tons per year.

Niagara-Mohawk was faced with two major options for transshipment of their western coal to the plants at Dunkirk. They could either have coal delivered to Buffalo and then transport it by unit train or barge approximately 50 miles to Dunkirk, or develop a separate transshipment facility at Dunkirk. Were coal delivered directly to Buffalo high costs would be incurred both in the development of a large coal facility at the port and in transportation rates by short haul unit train or barge to Dunkirk. Development of a new deepwater harbor at Dunkirk also appeared prohibitive in that the lake bottom in that area is essentially bedrock.

The utility is presently developing plans for an offshore unloading facility at a site in Lake Erie approximately eight miles west of Dunkirk Harbor. This structure would consist of a number of concrete bresting and mooring dolphins, one of which is designed with an open shaft to accept coal from the self-unloading coal vessels. The coal will drop down the shaft to a conveyor tunnel approximately 23 feet in diameter running beneath the lake bottom. The tunnel would emerge onshore for reclamation and distribution by conveyor to the plant. The tunnel will also house a water pipeline to supply makeup water for the plant. Total cost for the unloading facility and tunnel conveyor is estimated at about $60 million.

Such a facility represents a unique approach to traditional coal transshipment design. Projecting the development of future facilities of this kind at other Great Lakes sites is difficult as this facility may be the direct result of the geological characteristics that hamper economical dredging activity at Dunkirk. The Dunkirk plans represent a major addition in coal transshipment facilities for power production in the Great Lakes through 1985. Table 67 outlines the expected fuel origin, type, and method of movement for scheduled fossil-fuel power facilities greater than 300 MWe in the Great Lakes coastal counties through 1985.

TABLE 67

FUEL TYPE, ORIGIN AND TRANSPORTATION FOR FOSSIL-FUEL FACILITIES SCHEDULED THROUGH 1985

PLANT NAME	UTILITY	GENERAL LOCATION	FUEL TYPE	FUEL ORIGIN	LIKELY FUEL TRANSPORT METHOD
Edgewater	Wisconsin Power & Light	Sheboygan, WI	Coal	Western fields	Unit Train
Prairie View	Wisconsin Power & Light	Kenosha, WI	Coal	Western fields	Unit Train
Campbell 3	Consumers Power	Holland, MI	Coal	Eastern fields	Unit Train
Karn 4	Consumers Power	Bay City, MI	Oil	Sarnia, Canada and Lakehead pipeline	Train-Sarnia Pipeline - Superior,WI
Belle River	Detroit Edison	St.Clair, MI	Coal	Western fields	Lake Vessel
Greenwood	Detroit Edison	Port Huron, MI	Oil	Sarnia, Ontario	Barge to Pipeline
Dunkirk	Niagara-Mohawk	Dunkirk, NY	Coal	Western fields	Lake Vessel
Oswego #6	Niagara-Mohawk	Oswego, NY	Oil	South America	Ocean Tanker to Barge

The information in Table 67 was gathered from each utility and is presented as their current estimate for fuel supply. Certain entries are, of course, more definite than others. The Edgewater and Prairie View plants in Wisconsin each anticipate utilization of western coal. Their geographic locations allow fairly direct access from eastbound unit trains. The Edgewater site could conceivably receive coal by lake carrier through Sheboygan, but the officials at Wisconsin Power and Light presently favor direct unit train transportation. The Consumers Power Company is investigating use of low sulfur eastern coal delivered by unit trains for their Campbell #3 unit on Lake Michigan. This utility anticipates that the low sulfur eastern coal will have better heat value, be a more reliable supply, and have lower transportation costs than western coal.

Three of the eight new facilities listed in Table 67 are designed to burn oil for power production. Both the Karn and Greenwood units are to receive their oil fuel supply from Sarnia, Ontario. Each utility assumes a different approach to the transportation of this fuel. Detroit Edison's Greenwood facility plans to transship fuel oil by barge from Sarnia across the St. Clair River. Once across the river the oil would then be pumped into a pipeline that runs approximately 15 miles inland to the Greenwood plant.

The Karn unit near Bay City also plans to receive oil from Sarnia. However, they intend to receive fuel delivered by train. Additional oil from the Lakehead pipeline will supplement the fuel deliveries from Sarnia. Karn units #3 and #4 combined will consume approximately 30,000 barrels per day. Seventy-five percent of the fuel supply to these units will be delivered by train while the balance will be supplied by pipeline.

It is expected that fuel for the Oswego #6 unit will be delivered by the same barge system that presently serves the existing Oswego oil-fired units. No major expansions are planned for fuel transshipment. Presently oil from South America moves by tanker to refineries in the Caribbean. The refined product is shipped northward into the St. Lawrence Seaway for delivery to storage facilities in Montreal. Oil is transferred to barges in Montreal for delivery in Oswego.

c. Refineries

The total refinery capacity in the eight Great Lakes states is 3,513,380 barrels of crude per day (calendar day figures* are refiners' averages for the number of barrels per day a refinery yields on the average). Of this refining capacity 1,045,185 bbl/day or 30% is located in the coastal zone. All eight states have some refining capacity, with Minnesota, Pennsylvania and Illinois having no capacity located within their coastal zone. With respect to the relative numbers of barrels refined within each state the breakdown is shown in Table 68.

Current refinery construction in the Great Lakes states is presently restricted to expansion of existing facilities. These expansions amount to only 95,440 bbl/day (includes coking operations) of which only 2,400 bbl (Sun Oil Co., Toledo, Ohio) are in the coastal zone area.

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* from Oil and Gas Journal, April, 1976.

TABLE 68

BARRELS OF CRUDE OIL REFINED IN EACH GREAT LAKES STATE

	Total bbl/day Capacity (State)	Total bbl/day Capacity (Coastal Zone)	Percent In Coastal Zone
New York	111,385	111,385	100%
Pennsylvania	757,020	0	0
Indiana	561,160	486,000	87%
Illinois	1,176,800	0	0
Michigan	147,200	65,000	44%
Minnesota	216,800	0	0
Ohio	589,770	337,400	57%
Wisconsin	45,400	45,400	100%
Great Lakes Total	3,513,380	1,045,185	30%
U.S. Total	15,074,845 bbl/day		
Great Lakes total as % of U.S. Total	23%		
Great Lakes Coastal Zone as % of U.S. total	7%		

Source: Oil and Gas Journal, April, 1976

Texaco's Lockport, Illinois, plant has announced a planned expansion of input capacity of 25 x 10^3 bbl/day with an uncertain operational start date. The Cirillo Brothers of Albany, New York have announced a new refinery of 20,000 bbl/day input capacity of uncertain operational date and product output. The largest new facility to be announced in the coastal zone is New England Petroleum's Oswego, New York, refinery of an expected 200,000 bbl/day input capacity. Again, no operational date or product output ahs been announced for this proposed plant.

High costs of refinery construction combined with uncertainty about long-range government energy policy has led to the smallest increase in U.S. refinery capacity (1975 - 146,000 bbl/day) since 1965. Further, this increase was approximately 240,000 bbl/day less than had been forecast. Nationwide, the expansion of existing facilities accounted for most of the U.S. increase in refinery capacity.

Each refinery is a specially designed unit with the specifications and requirements of the facility being very dependent upon the type of crude and the products to be refined. Therefore, generalizations about refineries are often inaccurate outside the context of site, product and process specificity. Allowing for such, the following "rule-of-thumb" guidelines for refineries have been suggested.*

There are three main determinants of refinery siting: (1) proximity to major product market area, (2) relative proximity to sources of crude, and (3) availability and costs of various modes of transport. This last is a major reason for refineries' preference for coastal siting.

Between 200 and 1,000 acres are needed for 100,000 bbl/day refinery complexes, with the lower limit representing a simple fuels refinery with a 40-day storage capacity and the upper limit a complex fuels-petrochemical refinery with a 120-day storage capacity. This large difference in land requirements (with land generally being 5-10% of total refinery cost) represents the large variations in the complexity of refineries as well as the different storage capacity requirements at specific refineries. Almost all refineries have minimum storage facilities sufficient for a 30-day supply of crude oil plus additional capacity for mixing and storage of refined products (i.e., heating oil in summer or gasoline if delivery of crude is erratic). Refineries which are tanker fed (necessarily coastal dependent) require more storage area due to the non-continuous nature of the tanker delivery system. This last factor tends to be of smaller concern to Great Lakes refineries as they are predominantly pipeline supplied.

A 200,000 bbl/day refinery capacity is considered an optimal size. Such a size is needed to introduce the economies of scale necessary to offset high construction costs of new facilities so that they can be competitive with old plants. These sizes are also necessary to keep operating costs to a minimum. A few years ago, a rule-of-thumb cost for refineries ran approximately $1500/bbl/day capacity. Now a more realistic figure would be $3,500 to $4,000/bbl/day capacity, with some plants going as high as $6,500 to 7,000/bbl/day capacity.

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* Communication, National Petroleum Refiners' Association.

For the past few years, the national trend has been to build new refineries outside the continental U.S., particularly in the Caribbean, to take advantage of lower total taxes, less strict environmental controls, deepwater ports and competitive transport costs.* However, this trend is being reversed (balanced expansion) somewhat by high tarrifs on imported refined products and low domestic crude prices, along with considerations for national defense policy. The probable increase of national refining capacity coupled with refineries' desire for close proximity to transport facilities and areas of demand may indicate a renewed interest in the Great Lakes coastal zone for siting refinery complexes.

The two major obstacles to new refinery development are high construction costs and environmental considerations. Of the latter, by far the greatest concern to refineries is oxidant level requirements set by the Environmental Protection Agency. According to the refining industry, the low levels allowed by EPA virtually preclude new refinery construction in already developed areas, precisely where the refining industry wants to be. The major source of this problem is the emission of hydrocarbons (a 100,000 bbl/day refinery with 30-day capacity may emit as much as 10,000 lbs/day, even with advanced containment technologies), with most hydrocarbons released during storage and tank filling. Other pollutants associated with petroleum refining are particulates, sulfur oxides, aldehydes, ammonia, and hydrogen sulfide. Water use is being minimized (H_2O/bbl capacity) by using water recirculating cooling systems. New refinery construction is depending more on air cooling, resulting in a lessened dependency on large water resources. Further, better water treatment is being utilized, which further reduces water consumption (by increasing usable life span of water) and thus the coastal dependency of facilities.

New refineries are most dependent on environmental and economic considerations, many of which are not easily controllable by the individual states. With the problems of capital formation and air/environmental quality requirements, the development of refineries in the Great Lakes Region would seem slim. A further factor which dictates against Great Lakes Region siting of refineries is the relatively lower cost of refining mideastern and most domestic crude oil in the

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* Communication, National Petroleum Refiners' Association.

Gulf Coast states [370]. Refinery economics are such that in most instances, it is less expensive to pipe refined products to the Great Lakes Region, than it is to refine the crude locally. These three major factors would seem to dictate against any large expansion of refinery capacity.

One factor which might influence further refinery development in the Great Lakes Region would be the piping of Alaskan crude through the region. The proposed Trans-Provincial or Northern Tier pipelines could potentially bring between 700,000 to 1,000,000 bbl of oil daily into Minnesota. Such a development might necessitate the building of two or three new refineries, but would not significantly influence the coastal zone.

4. PLANNED OR SCHEDULED FACILITIES FOR ELECTRICAL GENERATION

a. Types and Location by State and Region

Future electric power generation in the eight Great Lakes states will be very dependent upon coastal zone facilities. Of the eight Great Lakes states, Illinois, Minnesota and Pennsylvania currently have no confirmed plans through 1985 for new generating capacity within their coastal zones. A single 800 MW coal-fired plant has been discussed for the Pennsylvania coastal zone around 1990, with the utility's land holdings at the projected site being sufficient for an additional unit. The western portion of Erie County, Pennsylvania, is largely undeveloped, with a large percentage of the land held by Penn Electric, United States Steel, and the Boy Scouts. Hence, the potential for facility development in Pennsylvania still exists.

Illinois also has a relatively small coastal zone, but one of the most highly developed in the Great Lakes states. The potential for future expansion is seen to be limited due to the difficulty of obtaining sufficient acreage for energy facility development [568]. The pressures on the coastal zone area for uses other than energy facility siting are such that no major facilities are currently being considered. Access to the coastal zone water resources and fuel transshipment facilities for inland generating sites will most probably comprise the major use of the Illinois coastal counties for electric generation purposes. The utilities within the State of Illinois have currently planned eight coal-fired facilities, five oil-fired and eight nuclear-powered generating units, totaling 11,370 MW by 1984. This schedule reflects Illinois' continuing development of a high nuclear generating capability.

The Minnesota utilities currently have no announced plans for generating facilities in their coastal counties. With respect to future development the Minnesota Energy Agency suggests that: "Water availability, population density and location to relative load centers would all seem to point toward increasing pressure on the coastal zone area especially if demand grows as rapidly as the utilities project."* Statewide, Minnesota currently has five coal-fired generating facilities scheduled to come on line by 1984. No oil or nuclear facilities have been announced for the state. The curtailment of Canadian oil will probably further the development of coal-fired facilities. One event which may alter Minnesota's energy future is the transporting of Alaskan crude oil through the state via the proposed Northern Tier pipeline or the Trans-Provincial pipeline. Such a circumstance might alter the future fuel mix for electric power generation or reduce the substitution of electricity for other energy sources, thus reducing projected demand for electric power.

Indiana currently has one scheduled facility in its coastal zone, the 645 MW Bailly nuclear facility. The coastal zone of Indiana is fairly industrialized, with 22 miles of the 45 mile coastal zone industrially developed and 17 miles devoted to public recreation lands [436]. Future development in this area may be restricted by air or water quality regulations. As with Illinois, Indiana may only be able to utilize the waters of the coastal zone for inland energy facility sites. The Indiana utilities have currently planned 10 coal-fired and 3 nuclear powered generating facilities, totaling 9,220 MW by 1984 (this includes the one coastal zone facility).

Wisconsin has seven coal-fired facilities scheduled, three of which will be in the coastal counties. With 140 miles of their 619 mile coastal zone currently agricultural or undeveloped, the potential for new generating facilities in the coastal zone is large [436]. The two Koshkonong nuclear 900 MW units scheduled for 1983 and 1984 have been deferred until 1986. Similarly, the Tyrone nuclear station has been deferred indefinitely. The coastal zone resources of Wisconsin, as in many states, will be in greater demand in the future due to limited availability of inland water in quantities sufficient for a modern generating station. The Pleasant Prairie plant is an example of a station that will site near existing transmission and fuel transportation systems but close enough to the coastal zone for economical utilization of lake water. For many

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* Communication from R. D. Visness, Minnesota Energy Agency.

future facility sitings the access to coastal zone water resources will be of high importance. The availability of western coal combined with the deferment of nuclear facilities will emphasize the use of coal in the near future.

The States of Michigan, New York and Ohio have the most ambitious plans for developing energy facilities in their coastal zone. This reflects their relatively longer coastal zones, the lack of adequate inland sites, proximity of the coastal zone to load centers, and the generally higher energy demand in these three states.

All planned facilities in Michigan (with the exception of the Midland plants) are scheduled for the coastal zone (as defined by the first tier of counties and a use or impact of/on coastal zone resources). Of these facilities four are coal-fired, two oil-fired and five nuclear-fired, totaling 10,550 MW by 1984.

Nuclear generating capacity comprises almost 50% of planned capacity, with the oil and coal being respectively 16% and 33% of the scheduled generating capacity. This scheduled fuel mixture represents an increased emphasis on nuclear generating capability in Ohio and New York, similar to what has been found in Illinois. Within Michigan a number of nuclear facilities have been delayed or cancelled for such reasons as lack of capital, equipment delivery delays, inflation, questions over fuel availability and safety, etc. Nuclear generating facilities have been hardest hit by delays and cancellations. The problems currently faced by the Michigan utilities apply to all types of electric generating plants as well as to utilities in the other states. The current decline in electric energy demand coupled with high reserve margins and lack of utility capital have been the main reasons for the delay in Michigan's scheduled generating capacity additions. These problems notwithstanding, the coastal counties of Michigan have the most ambitious energy facility development plan of any Great Lakes state. The justification for siting in the Michigan coastal zone, ease of fuel transportation, proximity to load centers, relative availability of coastal land, sufficient quantities of water and the design of the power grid, will continue to be the reasons for power plant siting there. Currently, the utilities plan to continue construction of coal-fired plants for the mid-term, hoping that nuclear generating capacity can be added soon to prevent future electric power shortages.

The Ohio utilities are also planning a large nuclear power generation development program. All plants scheduled for the Ohio coastal zone through 1985 are nuclear facilities. Currently, only one nuclear facility is being planned outside of the coastal zone, with the remaining scheduled capacity for the state consisting of eight coal-fired plants totaling 3,815 MW. The pressure on the Ohio coastal zone for energy facility siting is expected to continue to grow. The demand on the coastal zone will be for both siting and water resource access. The Ohio utilities face many of the same problems as the other Great Lakes states' utilities with respect to construction delays, capital shortages and siting problems. The intensive development of nuclear power in the Ohio coastal zone indicates a shift in the fuel mix of the state from almost total coal-fired base load generation toward a more balanced nuclear-coal mix.

The New York state fuel mix for electric generation deviates from the seven other Great Lakes states through its heavy reliance on oil- and gas-fired generation. The scheduled changes in capacity indicate a lessening dependence on oil and a relatively large increase in nuclear generating capacity. Statewide, seven nuclear, four coal- and three oil-fired plants have been scheduled through 1984, totaling approximately 12,000 MW [303]. Of these facilities four have been located in Great Lakes coastal counties: two nuclear facilities, one coal-fired facility and one oil-fired facility. Of New York's 292-mile Great Lakes shoreline, approximately 134 miles of this is agricultural or undeveloped [436]. Due to the problems of siting and water availability within the state, the pressure for energy facility siting in the coastal zone will increase. As indicated earlier the power flows in New York are generally east and south, with areas such as Oswego becoming major exporters of electric power. The role of nuclear generating capacity can be clearly seen as expanding. The future role of coal is projected to increase slightly statewide, while the use of oil is projected to decline in relative terms.

On a regional basis more nuclear generating facilities have been scheduled than either oil or coal facilities. However, the number of delays and cancellations announced during 1974-1975 reduce significantly the amount of nuclear capacity that will come on line during the next ten years. This gap in generating capabilities will more than likely be made up by fossil fuel-fired plants (predominantly coal), giving the utilities time to see how post-1973 growth patterns develop with respect to both demand and fuel type. During the mid-1980's the utilities' on line capacity will increasingly reflect their effort to cope with foreseeable fuel, legal and environmental restraints.

TABLE 69

CHANGES IN NUCLEAR UNIT SCHEDULES DURING 1972-1975
(All changes listed involved change in the year of commercial operation.)

During Year	No. of units changed	Plant-yr added	No. to indefinite	No. cancelled
1972	54	72		3
1973	52	67		
1974	104	201	16	9
1975	102	116	(-1)	12

Data taken for the most part from ERDA tabulations of industry information.

Nearly as many units were changed in 1975 as in 1974, but the total impact was lower in some respects.

It is noteworthy that 34 new unit orders were entered in 1974 while 9 were cancelled. In 1975, only 4 new orders were entered while 12 were cancelled.

The 1974 changes (104) affected 56% of all nuclear units on order or under construction through 1974. The 1975 changes (102) affected 59% of the units remaining on order or under construction through 1975.

Power Engineering/April, 1976.

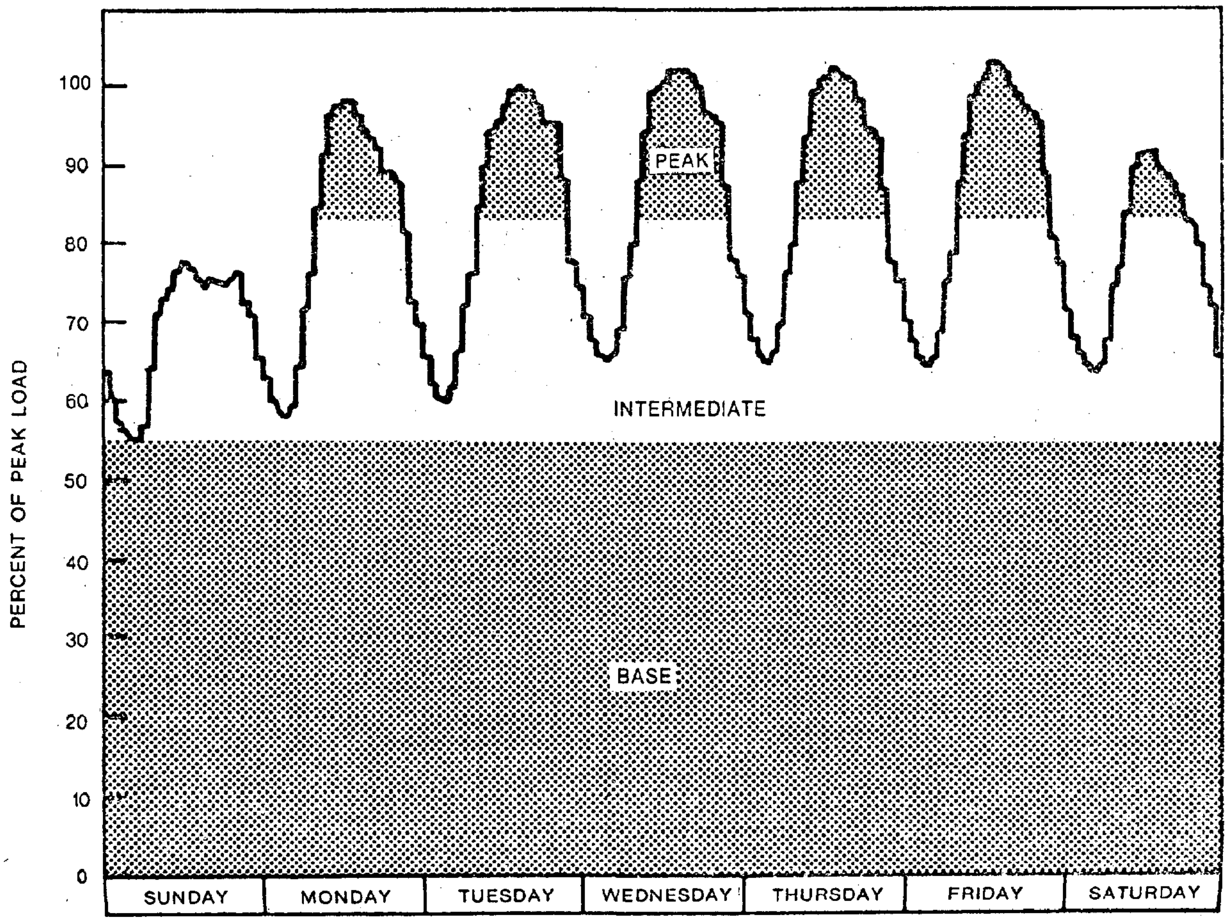
b. Estimated Capacity and Projected Demand

The ability of an electric company to meet a future electric power demand level is dependent upon many factors, most of which are not controlled by the utility. Availability of electric power in the future depends on present planning and construction based upon future estimates of demand. This current planning and construction for future needs is very sensitive to long-range forecasts, capital availability, assessments of fuel availability and a host of other factors which since 1973 have become difficult problems for the utilities.

The first problem faced by the utilities is what will the future demand for electricity be? Historically, demand has grown 7% annually, but during 1974 the growth rate was near zero. Current best estimates assume 5.5% growth rate in demand, tapering off somewhat after 1985 [344]. Some utilities, however, feel that demand may once again return to historical rates. Whatever the future demand may be there is an inherent difficulty in planning and constructing for unknown future demand levels in the context of the present uncertain consumption patterns. In addition to uncertain demand levels, current low load factors and high reserve levels further confound the future energy demand picture. Over the last few years total electricity demand has grown less than peak demand, resulting in lower load factors [364]. A shift towards increased peak demand in the utilities' load schedule has required a large increase in peak load generating capabilities and produced a large reserve capacity. This accentuation of the peaks in the load schedule necessitates the construction of capacity to meet small peak load periods (Figure 37).

Figure 37

WEEKLY LOAD CURVE



An increase of 10% in the load factor (e.g., from 60% to 66%) would result in a 10% reduction of total capacity, and about 40% less peaking capacity [344; p.440]. To bring about increased load factors and reduced peaking capacity requirements, peak load pricing has been suggested. Peak load pricing will result in redistribution of costs to various end users, but its aggregate effects on electrical energy demand and in fact its very workability are less certain [344].

The Federal Power Commission has suggested some reasons for the problems in utility planning:

> Rapid increases in energy prices, the downturn in economic activity, the sluggish growth of electricity demand following the Arab oil embargo, curtailments of natural gas service to industrial customers and embargoes on new gas hookups, and the talk of moving toward oil import independence in part through increased reliance upon nuclear and coal-fired electricity generation have created a good deal of uncertainty about the growth of future loads. Will the "pause" of 1974 be matched by a "spurt" at some later point in time? Will recent historical growth rates reemerge, but from a lower-than-anticipated base? Or will growth rates continue to be lower than in the past? Utilities are finding it necessary to adapt their methods of planning for system expansion to include the effects of considerably more uncertainty in load growth than heretofore [534].

Besides uncertain load growth factors the utilities are facing difficult problems in assessing the future availability of primary fuels for electric power generation. The utilities' low priority in the FPC's natural gas allocation program and the nation's desire to reduce the dependence on foreign oil suggest the limited future use of these two fuels for base load units [534]. However, the cost and difficulty of switching operating units using oil and gas to coal-fired units indicate that there will be a continuing demand for these fuels by the utility sector. Many utilities, having accepted the limited future of using oil and gas for base load generation, are confronted by a number of constraints which until resolved serve to increase the uncertainty of future power availability. Assuming that coal and uranium are the only fuels readily available for large scale power generation, some of the restrictions faced by the utilities may be: a lack of a firm commitment by the government to the use of coal and/or uranium, delays in developing new coal mining capability, especially of western low-sulfur coal, doubts about the adequacy of coal transport facilities, controversies over clean air regulations, uncertainties surrounding the mining and milling of uranium, unresolved issues of the nuclear fuel cycle, and questions about the availability of technology for clean coal utilization [421]. Many of these problems can only be remedied by legislative or governmental administrative action, which again serves to compound the problems surrounding future power availability. The question of future fuel mix for power generation is dependent on many factors of which neither the utilities nor government have complete control.

A last major factor in determining the availability of future electric supplies is the financing of construction. The utilities, already one of the most capital-intensive industries in the U.S., are facing increased costs from both owning and operating their generating units, while at the same time suffering from a reduced earning power. Inflation, tight money and eroding investor confidence have contributed to a general rise in the cost of capital financing [534]. Environmental standards and construction cost escalation have also boosted the cost of investing in new capacity. The Federal Power Commission has suggested some reasons for the utilities' reduced earnings:

> The delay by some utility managers in seeking adequate rate relief, compounded by the lag in some regulatory commission responses to such requests, lower than expected sales,* and sharply rising costs of fuel and other inputs have been the principal sources of earnings deficiencies. They have seriously impaired the industry's ability to carry out construction programs and may have put pressure on some utilities to reduce these programs to levels dictated by their current ability to raise capital, rather than by their judgement concerning long-term growth expectations [534].

All the above factors are shown in an attempt to understand the magnitude and complexity of the problem of providing sufficient future supplies of electric power. Other issues such as system reliability and delays in expanding capacity also bear upon the problem of assessing the adequacy of future electric power supplies. The question of the adequacy of presently planned generating capacity with respect to some future demand level for electric power is one surrounded by many problems. Given the number of delays and cancellations in new generating capacity over the past two or three years, there is a possibility of a serious inadequacy of electric power if growth rates return to their historical levels [564]. The combined planned and scheduled generating capacity of the eight Great Lakes states is 74,067 MW through 1984. If load factors and reserve margins were held at 1973 levels this capacity might be expected to accommodate an annual growth rate of 6 percent.

c. <u>Implications of Emerging Technologies</u>

Over the next 15-20 years no major changes in the technology of large-scale power production are expected to be implemented on a commercial basis. This

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* Temporary decreases in sales serve to reduce current revenues without necessarily reducing current capital requirements.

is to suggest that current technologies will continue largely unchanged for the next twenty years. Efficiencies of the generating process will continue to improve as will those of the transmission networks. The nuclear technologies are not expected to change as to type or process; but rather an improvement in the engineering and fuel cycle aspects of nuclear technology might be expected. An increasing reliance on emerging coal technologies may alter the existing patterns of coal use. These might include fluidized bed combustors, gasification or liquefaction, low Btu gasification for use in combined cycle systems, and the development of technologies cleaning up coal's adverse impacts. In short, major technological changes in electric power generation systems are not expected to play a large role in the next 15 to 20 years.

The pressure on the Great Lakes coastal zone from energy facilities will continue to increase in the future. The increase in demand for energy, the restricted thermal capacity of many inland water supplies, the proximity to load centers, and access to transport routes all suggest that demand for the coastal zone water resource (either direct siting on the coastal zone or simply access to the resource) will increase in the future. Tables 70 and 71 compile the announced generating facilities in the Great Lakes Region through 1984.

TABLE 70

PLANNED OR SCHEDULED ADDITIONS IN GENERATING

CAPACITY IN THE COASTAL ZONE, 1976

(Plants over 300 MWe)

State and Plant Name	Fuel Type	MWe	County	Date in Service	Source of Information
Illinois					
None	---	---	---	---	303
Indiana					
Bailly	Nuclear	685	Porter	Indefinite	303
Michigan					
Greenwood #1	Oil	815	St. Clair	Indefinite	303
Karn #3	Oil	605	Bay	May, 1977	303
Belle River #1	Coal	697	St. Clair	Indefinite	303
Belle River #2	Coal	697	St. Clair	Indefinite	303
Campbell #3	Coal	770	Ottawa	May, 1980	303
Enrico Fermi #2	Nuclear	1,215	Monroe	Indefinite	303
Greenwood #2	Nuclear	1,341	St. Clair	Indefinite	303
Greenwood #3	Nuclear	1,341	St. Clair	Indefinite	303
D.C. Cook #2	Nuclear	1,100	Berrien	Indefinite	303
Minnesota					
None	---	---	---	---	303
New York					
Oswego #6	Oil	850	Oswego	May, 1979	450
Lake Erie #1	Coal	850	Sheridan or Pomfret	Nov., 1985	450
Lake Erie #2	Coal	850	Sheridan or Pomfret	Nov., 1987	450
Nine Mile Pt. #2	Nuclear	1,080	Oswego	Nov., 1982	450
Sterling	Nuclear	1,150	Sterling	May, 1984	450
Ohio					
Davis Besse #1	Nuclear	906	Ottawa	April, 1977	325
Davis Besse #2	Nuclear	906	Ottawa	April, 1983	325
Davis Besse #3	Nuclear	906	Ottawa	April, 1985	325
Erie #1	Nuclear	1,200	Erie	April, 1984	324
Erie #2	Nuclear	1,200	Erie	April, 1986	324
Perry #1	Nuclear	1,205	Lake	Dec., 1981	325
Perry #2	Nuclear	1,205	Lake	June, 1983	325
Pennsylvania					
None	---	---	---	---	---
Wisconsin					
Pleasant Prairie #1	Coal	617	Kenosha	April, 1980	303
Pleasant Prairie #2	Coal	617	Kenosha	April, 1982	303
Lakeside	Coal	310	Milwaukee	April, 1982	303

TABLE 71

PLANNED AND SCHEDULED ADDITIONS IN GENERATING CAPACITY IN THE GREAT LAKES REGION

1976 - 1984

(Plants Over 300 MW)

NOTE: No. of facilities indicated in brackets, [ ].

	ILLINOIS[1]	INDIANA[2]	MICHIGAN[3]	MINNESOTA[4]	NEW YORK[5]	OHIO[6]	PENNSYLVANIA[7]	WISCONSIN[8]
State Total Coal	4,040MW [8]	5,315MW [10	2,154 [3]	3,460MW [5]	2,700MW [4]	3,815MW [8]	3,600MW [3]	3,337MW [7]
Percent of Total	27%	65%	26%	100%	22%	38%	28%	100%
State Total Oil	2,500MW [5]		1,443MW [2]	None	2,000MW [3]	None	1,191MW [2]	None
Percent of Total	16%			-	17%	-	9%	
State Total Nuclear	8,536MW [8]	2,905MW [3]	4,622MW [5]	None	7,350MW [7][a]	6,262MW [6]	8,000MW [5]	None
Percent of Total	57%	35%	56%	-	61%	%	62%	•
Coastal County Total Oil	None	None	2,154MW [3]	None	850MW [1]	None	None	1,560 MW [3]
Percent of Coal			100%		46%			47%
Percent of Oil	None	None	1,443MW [2]	None	850MW [1]	None	None	None
			100%		42%			
Coastal County Total Nuclear	None	645MW [1]	3,351MW [3]	None	2,250MW [2]	4,222MW [4]	None	None
Percent of Nuclear		22%	73%		31%	67%		

1 Reference No. 199 and 303
2 " " 303
3 " " 303 and 395
4 " " 303
5 " " 303 and 450
6 " " 303
7 " " 236 and 303
8 " " 199 and 303

(a) Announced between 1985-1990 (8) nuclear plants totaling 10,300MW plus 3,000MW of pumped storage.

NOTE: Data developed from FEA information.

Chapter V

REGIONAL SCENARIOS OF ENERGY DEVELOPMENT

A. INTRODUCTION TO SCENARIO APPROACH

The rates of growth in demand for electrical power and the fuel mix used to generate that power are the key variables in attempting to evaluate the electric energy future of the Great Lakes coastal zone. To facilitate the assessment of the future pressures put on the Great Lakes coastal zone by electricity generating facilities, four alternative fuel mix scenarios have been postulated. The basic approach is to make certain assumptions for each fuel mix future and then examine the possible impacts if they were to hold true. The scenarios will then be evaluated in the context of three electrical demand growth rates to provide an indication of the resources required for future energy facility development.

This study shall define a scenario as a set of assumptions relating to a particular fuel mix and its ability to generate electric power in required quantities. A scenario should not be confused with a forecast. Each scenario is developed on assumptions which provide a basis for analysis of the possible future. It is not based on conclusions or predictions as to what the future will be. Furthermore, scenarios do not assess the feasibility of the political, economic, and social events which must take place for any particular scenario to occur.

The number of potential fuel mixes for future electric power generation is essentially unlimited. The scenarios have been selected to be representative of the major potential fuel mix development routes. This method allows for a comparison of their associated impacts and suggests the range of future fuel mixes that can occur. The values assigned to each scenario represent a reasonable level of supply and utilization that might be associated with the different technologies of the scenarios.

The attempt has been made to evaluate those scenarios which, under varying situations and circumstances, have a potential of occurring within the 20-year time span being considered. A comparison of multiple alternatives serves to illustrate many of the variables influencing the Great Lakes Region's energy future.

A further objective of the scenario approach is to identify and evaluate possible problems and impacts of future developments, thereby aiding policy decisions for power facility siting. It should be noted that no one set of policy options is associated with a particular scenario. Although the relationship between energy production and the economy has not been thoroughly investigated in the context of this study, it is assumed to be uniform throughout the four scenarios. The basic energy demand for end use is constant for each scenario.

The four scenarios are based on variations in the fuel mix used for electrical energy production. As differences in the relative capital costs and environmental considerations among types of generating facilities have been used elsewhere in this study, the fuel mix for power generation becomes the critical issue. (Another important issue is that of development of controlled technology for the environmentally sound use of these fuels.) The availability, price, and environmental and social impact of primary fuels for electric energy generation are major questions which point to the important role fuels will play in the future. The future fuel mix is dependent upon factors such as: federal and state regulations, commercialization of new technologies, availability of foreign fuel sources, and other facts which will be discussed as they relate to fuels for electricity production.

B. DESCRIPTION AND DETERMINANTS OF SCENARIOS

1. SCENARIO I - RECENT TRENDS

The nature of the utility industry is such that plans for the next ten years have been fairly well established. Such planning is directed by the lead times necessary for developing and constructing new generating facilities. Development time for nuclear facilities is often 9-12 years and 5-7 years for large fossil fuel plants, from planning through operation. Given the planning requirements of utilities it would appear that the capacity mix used for power generation is "locked in" until 1983 or so. Thus, the recent trends scenario includes the 1976-1983 time period and the facilities scheduled to come on line as its base.

The assumptions within this scenario suggest that present fuel mix trends will stay relatively unchanged over the next 20 years, except that future capacity will continue to grow some 35%. Future fuel requirements might be predicted by extrapolating the current consumption patterns at a given electrical demand growth rate.

As mentioned previously, these scenarios have been developed to show what the relative pressures and resource demands on the Great Lakes coastal zone might be in the future. Essentially, recent trends is a continuation of presently utilized fuel mix site selection process and power generating technologies. The recent trends scenario assumes no major change in regulatory policy or in the social institututions which may affect the use or supply of electric power. This base case scenario is one with which the other scenarios will be compared and shall be used as the departure point for developing the other cases.

Recent trends is the only scenario which deals explicitly with oil- and gas-fired generation. As the percentage of power generated from oil and gas is expected to hold fairly constant until the early 1980's and then decrease, the role of these fuels in power generation will only be discussed in the context of the recent trends scenario.

Three major variations appear in currently used fuel mixes. The States of Ohio, Michigan, and Pennsylvania use the highest percentage of coal for power generation. Wisconsin, Minnesota, Indiana, and Illinois use somewhat less. New York State uses the least amount of coal of any Great Lakes Region state [192/421]. A weighted average was used to determine the present regional fuel mix (of which a breakdown appears in Table 75). The current planned and scheduled facilities were then worked into the regional generating fuel mix. The result is

TABLE 72

SCENARIOS: MAJOR ASSUMPTIONS FOR BASE LOAD GENERATION FOR THE REGIONAL SCENARIOS

	RECENT TRENDS	HIGH COAL	HIGH NUCLEAR	NEW TECHNOLOGIES
ECONOMIC				
Fuel Costs	Oil and natural gas increasing faster than coal. Overall increase through 20-year period	Less expensive fuel costs than recent trends scenario, but increasing due to environmental considerations	High fuel costs due to incomplete fuel cycle and increasing scarcity, plus delay in breeder development	Increasing for conventional fuels.
Capital Availability	Tight for next 5 years then expanding, closely related to state of economy	→	Federal Assistance	→
G.N.P. growth	overall between 3 and 4%	→	→	→
DEMOGRAPHIC				
Population	OBERS "E" assumptions	→	→	→
RESOURCES				
Coal	Local resources stated in study, national resources; 1975 BOM est.	→	→	→
Labor	Available	→	→	→
Water	Available, but at higher costs due to env. considerations	→	→	→
Oil & Natural gas	Available, but decreasing after mid-1980's. Foreign supplies also available	→	→	→

SCENARIOS: MAJOR ASSUMPTIONS (Continued)

	RECENT TRENDS	HIGH COAL	HIGH NUCLEAR	NEW TECHNOLOGIES
ENVIRONMENTAL				
Air/Water	Existing standards/ meet new schedules	→	→	→
Land	Stricter stip-mine laws	→	Increased siting control	Little change from R.T.
TECHNOLOGY				
Electric Production	Minor increases in efficiency	→	→	Major increases in the overall efficiency of energy production process
Plant factor	minor increases	→	→	→
Environmental	Improvement in pollution control technology	Acceleration of R.T. development	Same as R.T. →	→
Fuel Research	Continue present trends	→	→	Increase in research for new technologies
INSTITUTIONAL				
Anti-trust/ tax structure	No major change	→	→	→
Nuclear Power	No significant change	More anti-nuclear policy	Policies which promote nuclear development	No major change
Price regulation	Gradual de-regulation of all fuels	→	→	→
State/local Policy	No limitations to growth	→	→	→

a projected 1995 fuel mix comprised of 50% coal-fired generation, 30-35% nuclear, and 15% oil, gas, and hydroelectric.

2. SCENARIO II - HIGH COAL ELECTRIC

With the recent trends scenario extending until 1982-1983, a high coal fuel mix would not be evident before the mid-80's. A possible exception to this supposes that a change in the fuel mix of currently planned facilities, combined with an increase in demand for electrical power, would favor the growth of fossil fuel plants to meet this demand, due to their considerably shorter construction period. The variations among current fuel mixes in the eight Great Lakes states, shown on Table 75, indicate that many states currently have what might be termed "high coal" fired generation. For these states the variations between their present fuel mix and the high coal scenario may not be substantial.

There are certain conditions necessary for the development of a high coal scenario. A primary condition would be the further development of reliable technologies for the clean utilization of coal, including desulfurization and removal of particulates and NO_x. At the same time, actions such as a reduction in air quality standards (on a case-by-case basis remaining consistent with health and environmental standards), the development of more mining and transportation activity and a political commitment sufficient to sustain the increased utilization of coal for power generation would be needed for coal to play a larger role in generation of electric power. Furthermore, strenuous use of coal would be facilitated by a higher relative cost for nuclear power or the impositions of restrictions on nuclear facilities development.

It is assumed here that the coal fuel mix will be approximately 15-20% higher between 1990 and 1995 than in the recent trends scenario. The fuel mix for the high coal scenario will break down as follows: 70% coal-fired, 15% nuclear and 15% oil, gas, and hydroelectric.

An additional factor influencing the rate of coal use is the rate of conversion of oil-fired generating plants to the burning of coal. This would apply to both currently operating and planned facilities. The federal government will be the primary factor in determining the rate at which conversion will take place, assuming that some policy position will be forthcoming on oil to coal conversion of generating facilities. Currently, two plants in New York, the

Albany and Danskammer, have been ordered to convert to coal by the Federal Energy Administration.* (The order for the Albany Station is not presently effective.)

3. SCENARIO III - HIGH NUCLEAR ELECTRIC

The high nuclear scenario suggests a rapid development of nuclear generating capabilities exceeding that associated with recent trends. Nuclear generation of electrical power remains one of the few fuel mix options sufficiently developed to assume a major role as a regional power supplier. Nuclear power currently provides 10-12% of the Great Lakes Region's electrical energy demand. As is projected in the recent trends scenario, by 1995 it will comprise approximately 30-35% of the generating capacity. The nuclear scenario then further assumes that the Great Lakes Region's nuclear generating capacity will be approximately 45% of the 1995 total generating capacity.

Nuclear development on such a scale would require major actions by both the utilities and the federal government. The acceleration of the siting process in conjunction with the alleviation of capital cost and formation problems of nuclear facilities would be necessary in order to achieve a high nuclear scenario. Furthermore, problems in the entire nuclear fuel cycle, from scarcity of fuels and transportation security to radioactive waste, require serious consideration and improvement. In short, the questions being raised regarding the expansion of the nuclear power industry, combined with the long lead time for planning and construction, indicate that a firm commitment to continue building will be needed in the near future.

The high nuclear scenario will reflect the continued decrease in the use of oil and natural gas as primary fuels for base load power generation. Coal-fired units will make up the remaining required generating capacity (45%), with few large coal units scheduled past 1985.

4. SCENARIO IV - APPLIED EMERGING TECHNOLOGIES

The fourth scenario assumes a more rapid development of new technologies for power generation than is presently anticipated. During the 20-year period under consideration, the rate of new technology implementation is dependent on

* Personal communication, Brookhaven National Laboratory.

the price of conventional fuels (including nuclear), the emphasis on commercialization of new technologies, and the size of electricity demand. Problems with the use of the two primary fuels for future power generation might limit the rate at which facilities fired by coal or nuclear fuel come on line. Such a slowdown would provide additional impetus for the development and commercialization of new power producing technologies.

The environmental and social problems of coal use have been investigated, but there remain many unknown factors associated with coal utilization. The questions of siting, nuclear wastes and the availability of fuel are crucial to the further development of nuclear facilities. Thus, the degree to which the two primary fuels may be utilized in the future is an unanswered issue.

One new technology would be the use of a low Btu coal-gasification process for production of fuel in a combined cycle generating unit, resulting in higher heat rate efficiencies and prevention of the more deleterious effects of coal utilization. Such a project is currently planned by Commonwealth Edison on a 100-200-MWe scale, with future development in some degree dependent on the facilities' operating record.

A fuel mixture composed of garbage-coal or biomass (i.e., crops grown specifically for combustion on energy plantations or simply agricultural wastes) could be utilized in conventional generating facilities, thereby reducing resource pressure and the negative impacts of conventional fuel use.

Although no firm commitment has been made by private industry or government, high Btu gasification or liquefaction could potentially make an impact on electrical generation systems by 1995 (by decreasing the demand due to end use substitution). The use of fluidized bed systems for combusion of coal would reduce the negative effects of coal utilization as well as increase generation efficiencies. (This changes only the process and not the primary fuel, but as a new technology it is included in the fourth scenario.)

Further new technologies might include: wind-actuated electric power generation; small-scale "total energy" systems for commercial or industrial use, which would greatly increase overall efficiency; bioconversion processes for natural gas production and use in electrical generating facilities; solar-assisted heating units which would decrease electrical demand thereby possibly altering the fuel mix; fuel cells for thermo-electric generation; and generally, combinations of technologies which produce electric power and reduce the pressure on the primary fuels.

The future of any of these technologies is uncertain. Given that these and other technologies have potential for development and implementation in the next 20 years, their possible impact should be noted.

Under optimum conditions the generation attributable to such technologies would be 15 to 30% of the region's total by 1995. The remaining generating capability would come from standard sources with conventional coal boilers constituting approximately 40-50% and nuclear accounting for 20-35%.

C. INTRODUCTION TO DEMAND PROJECTIONS

While the fuel mix for electric power generation is fairly well set for the next several years, the demand for power is not. Of the two critical variables for future electric power production, the demand variable is the most difficult to estimate over the time horizons of this study. The demand rate for electric power, then, may be the only major surprise in the electric power equation for the Great Lakes Region.

Historically, electricity demand has been the major factor in determining the rate of electrical power supply. With the advent of higher prices and shortages of primary fuels for generation, demand for power is no longer the only variable to consider. Factors such as fuel shortages, rapid increase in prices, fluctuating demand levels, and governmental regulation have increased the difficulty and complexity of projecting future demands for electric power [549]. But the long lead time necessary for power plant planning is the very reason why forecasts must be made.

Electrical demand forecasts have been studied in order to give an idea of the possible future pressures on the Great Lakes coastal zone due to the need for siting increasing numbers of power generating facilities. A combination of different growth rates with fuel mixes may give an indication of the resource requirements necessary for various electrical power futures. These requirements may then be used to develop policies for future power plant planning.

The electrical demand growth rate is that figure which represents the percentage increase over the previous time period (defined as one year) in electrical power consumed, as determined by the additional number of kilowatt hours consumed. Before 1973 this figure had grown at an average rate of approximately 7% per year, or doubling every 10 years. Since 1973 the demand for electrical energy has fluctuated greatly. It is currently 5.4% per year, but the future level of this number is one of great contention [421].

The variations among electrical energy growth forecasts are tremendous, largely due to the absence of a standard methodology and a single set of reliable facts.*

Given the speculative nature of forecasting and its reliance on past trends, 100% accuracy should never be expected. Growth forecasts are generally derived from a model describing the process that is under study. These models vary greatly with respect to scope, specificity, assumptions, emphasis, etc. Development of a single, comprehensive model is not recommended [45]. The degree of sophisitication and variation among forecasting models is a significant factor in assessing the usefulness or accuracy of growth models. Regardless of their sophistication, econometric models always depend on statistical observation and interpretation of the past [549] and hence are only valid as long as structural changes of relationships or independent variables do not occur during the models' time frame [549].

To suggest that prediction is the purpose for which models have been developed would be misleading. Rather their purpose is to identify, organize, and clarify the parameters and variables influencing electrical power demand, hopefully giving improved information as to how the future may develop.

When analyzing electric energy forecasts there are a number of major points which should be kept in mind, including: the time span being studied, the need to understand key assumptions and how they are incorporated into the forecast, for whom and by whom the studies are prepared, the comprehensiveness of the model, and the degree of detail it covers. In addition, the capabilities of the forecasting model (particularly in adapting to policy and technology changes) and its economic aspects (i.e., inter-fuel and regional competition, determinants of supply and demand) [45] are important to understand.

Actual projection analysis is based on certain key factors which are representative of the individual variables that have been selected as effectors of future demand for energy. The factors to be considered and their weighted importance in the analysis are very important, as the potential for altering the analysis and outcome is greatly influenced by the factors selected. As in the

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* Dr. Miller B. Spangler, An Appraisal of Future Energy Developments Affecting the National and Regional Economic Outlook for Nuclear-Generated Electricity During the Next Forty Years. March 1976.

selection of the methodology and assumptions to be employed for an analysis, the key factors are selected on the basis of their judged relative importance by the group doing the analysis.

The factors used in assessing future demand for electrical energy are different for long- and short-term projection analysis. These factors also vary among projections which analyze the same time period. "The short-run projections (2-3 years) must recognize the experienced factors such as the current recession period, level of unemployment, and the leading economic indicators as the key variables" [394]. "Long-run projections, on the other hand, hinge on factors such as trends in population growth, household formations, changes in stock of appliances, long-term business and economic outlook, availability of fuel substitutes and their prices, environmental regulations, and technological change" [394]. Somewhat differently, Oakridge National Laboratory considers population growth, per capita personal income, price of electricity, price of competing energy sources and price of electric appliances as the key factors in assessing future electricity demand. The key factors used in a projections analysis are as important in shaping the final output of energy demand modes as are the assumptions and methodologies employed.

D. REVIEW OF PAST PROJECTIONS

1. OVERVIEWS OF AVAILABLE PROJECTIONS

The projected growth rates analyzed for this study vary greatly with respect to region, fuel mix, approach and results. Projections relevant to the demand for future electrical power were gathered to assess the variations described above and how they might relate to the Great Lakes coastal zone. Given that no projection has been done specifically for the Great Lakes coastal zone, the growth rate for electrical power in this region can only be inferred. Table 73 lists the projections reviewed, along with a number of major factors which should be considered during a review of the projections.

The degree of diversity between the projected growth rates can be explained by the various assumptions, methodologies and key factors used in the respective studies. As might be expected there is some degree of correlation between the party preparing the projections and their implications for future growth rates. Those groups having a direct relationship to electrical energy production (i.e., utilities, component producers, or independent firms hired by utilities) tend to develop higher rates of projected electrical energy demand

TABLE 73

OVERVIEW OF ELECTRIC POWER PROJECTIONS[1/]

FORECASTER	DONE FOR	REGION	PERIOD	FORECASTED AVERAGE COMPOUND RATE OF ANNUAL DEMAND GROWTH %	COMMENTS
Duane Chapman,		E.C.A.R.	1974-1980	2.6%	Agricultural economist, Cornell University
New York Power Pool	Utility planning purpose	New York	late 1970's-1990	4.0% declining to 3.5% by 1990	
Stanford Research Institute	Wisconsin Utilities Assoc.	Wisconsin	1975-2000	4.5%	
Jim Griffin		U.S.	1974-1981	4.8%	Economist, University of Pennsylvania
Michigan Public Service Comm.		Detroit Edison Service Area Consumer Power Service Area	1979-1982	4-5.6% 4.6-5%	Re-forecast of company's forecasts, same methodology, different assumptions
Detroit Edison	Planning use	Detroit Edison Service Area	1974-1985	5.6%	
Consumers Power	Planning use	Consumers Power Service Area	1974-1985	5.0%	
Dept. of Interior (Bureau of Mines)		U.S.	1975-2000	5.5%	Revised Edition
Edison Electric Institute		U.S.	1975-1980	6.0%	
Utilities within states	Ohio Power Siting Commission	Ohio	1974-1985	6.13%	
Cincinnati Gas & Electric Co.	Ohio Power Siting Comm.	Cincinnati G.& E. Co. Service Area	1976-1986	6.7%	Service area of 3000 sq. mi. and 1.7 million people
R.T. Cornell		U.S.	1977-1990	8.0%	Utility Securities Analyst for Institutional Investors, E.F. Hutton Co.
Westinghouse		U.S.	1975-1980	9.1%	

[1/] Adapted from Forecasting Electric Energy Demand in Michigan, by Waino H. Pihl and Lawrence M. Glazer, February, 1976.

growth than groups not so involved. This is not to suggest that either group's projections are deliberately biased. Differences are due to the different natures of the groups, the emphasis placed on different variables, and human judgement. The differences in the projections, between what might be termed vested interest groups and independents, should further emphasize the need for projections from many sources in assessing the needs for future power requirements.

The majority of the states within the Great Lakes Region have limited capability for making independent electrical energy demand forecasts. The Public Service Commissions (in some states Public Utility Commissions) within the eight states rely heavily upon the utilities for their future demand forecasts. Due to limited staff, budget, resources, etc., these commissions' forecasting capabilities are often limited to analyzing the utilities' projections.* More often the commissions' role has been to act on a request for a construction permit, deciding whether or not a new plant should be approved.

Many of the state energy agencies' electrical demand forecasting capabilities are also very limited, such that in many states only the utilities have the capability of making long-range energy forecasts. Minnesota, as an example of a state having forecasting capabilities, has two forecasting groups: one concerned with reviewing the utilities' forecasts and a second producing independent energy forecasts working with the Minnesota Energy model. Wisconsin, in conjunction with the University of Wisconsin, utilizes the Wisconsin Energy model (WISE) in assessing the future state electrical demands. Overall the eight Great Lakes states have limited forecasting capabilities. Hence there tends to be a reliance solely on utility forecasts to assess the future needs for electrical energy.

The Ohio Power Siting Commission and the New York State Board on Electric Generation Siting and the Environment are the only state agencies within the Great Lakes Basin that deal specifically with the issue of the siting of electrical generating facilities. The Ohio Power Siting Commission has the capability of making electrical demand forecasts independently of the utilities. This forecasting ability allows for verification of and comparison with the projections prepared by the utilities. The commission also reviews the utilities' projections for compilation of the state's ten-year forecast for electric power [514]. The format and content of the forecasts are specified by the commission with a primary goal of the process being the need for the utilities to justify the rationale that underlies their decisions to strive for a given resource requirement [514]. Towards this end the commission has stipulated that all assumptions and special information related to the forecasts be listed and explained. The Commission reports:

> While most of the utilities complied with the requirement (9-01(D)(3)) to list the assumptions used in the preparation of

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* Personal communication, Office of Energy Emergency Assistance, Wisconsin.

> the forecasts, some reporting utilities either failed to justify the inclusion of these assumptions or described the assumptions in such general terms as to be meaningless. Further, the impact of the assumptions on their basic forecast was not adequately addressed [514].

Other issues which the commission felt to be inadequately addressed in the utilities' forecasts included the impact of alternate rate structures on demand, the effect of changes in the relative price of electricity, and the optimal use of generation capacity. The role of the Ohio Power Siting Commission, as both reviewer of utility forecasts and forecaster, is to "review and comment and certify the need for new facilities" in Ohio [514].

2. ANALYSIS OF SELECTED PROJECTIONS

A detailed analysis of energy projection models has been performed by Argonne National Laboratory. This study gives useful insight into the workings and problems of energy modeling. The following comments were developed to better understand differences between projections, what they were designed to do, how they developed, as well as shortcomings of the energy modeling situation.

Argonne's purpose was to evaluate several existing energy models to determine their usefulness for ERDA's Regional Studies program and identify areas where future work should be undertaken due to certain weaknesses found in the models. Three basic criteria were used in evaluating the models: (1) model capability, (2) economic aspects, and (3) model comprehensiveness.

Projection models can be divided into "local impact," used for substate or state regions, which are particularly useful for end-use details, and "National synthesis," which analyzes energy availability and/or consumption on a larger scale [45]. These two basic groups differ markedly in their abilities and outputs, such that in many instances combining the two provides a more comprehensive result. For instance, if a regional policy affects the national energy picture (such as high energy facility development in the Great Lakes coastal zone), this output could then be used as input for the larger national model. Conversely, a national model could provide a regional energy supply and demand analysis consistent with national policy as input for a local model [45]. The point being that rarely will a single model be sufficient to cover all relevant relationships, suggesting that more than one projection should be utilized in a decision-making process.

The Battelle Columbus-EPA Energy Quality model, the Proejct Independence Evaluation System, and the Wisconsin Energy model are representative of sophisticated energy projection models that vary in methodology, scale, and type of output. "The Battelle-EPA Energy Quality model is a large linear program that determines a minimum national cost of the distribution of coal, natural gas, residual oil, distilate oil, and nuclear power in the contiguous United States under specified conditions of supply, price and demand."* The model's output describes the fuel policy and use schedule for each region (PAD or AQCR) and a schedule of fuel shipped from a supply to a use region [45]. Due to its spatial detail and regionalized energy consumption and costs (including transport) it is considered of value when undertaking regional energy studies [45].

"The Project Independence model (PIES) of the nation's energy system is probably the most comprehensive and all-inclusive energy model yet produced."** This national model has the capability of analyzing regional energy situations on an interregional basis with the end product being an instrument against which policy and technology development for national and regional energy strategies may be measured and evaluated. The model provides for total energy demands to be linked to economic growth. With the detail in the level of supply and demand, interfuel competition can be assessed [45]. The PIES model has been criticized for underestimating capital and environmental costs, the uncertainty in supply and price of fuels, and the lack of constraints on production [45].

With respect to the "local impact" type model the Wisconsin Energy model (WISE model) has "stressed flexibility with maximum room for innovations"*** in developing their modular format. "The main subcomponents of the system are the socioeconomic, primary energy source, end-use demand, electricity production, and environmental impact models," [45] which provide excellent evaluation capability on the state level. The model can evaluate local regulatory policies, provide for analysis of regional technology options, include engineering design parameters, and assess the social and economic impacts of energy systems [45].

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* Battelle Columbus Laboratories, <u>A Proposal to Develop Energy Price and Availability Projections</u>, p. A-2, April, 1973.

** Federal Energy Administration, <u>Project Independence Report</u>, Project Independence, p. 18, November, 1974.

*** Foell, W.K. <u>The Wisconsin Energy Model: A Tool for Regional Energy Policy Analysis</u>, Energy Systems and Policy Research Report No. 101, p.6, November, 1974.

The model further permits a description of future changes in policy and technology to examine the resulting energy scenario. The WISE model "does not predict the future, nor constrain all future trends to be like the past" [45]. With modification the WISE model could be utilized by other states and as a data base input into inter-regional (national synthesis) energy projection models.

The primary results of Argonne's analysis of these state energy projection models is as follows: (1) all models were found deficient in that they failed to consider interregional competition and did not integrate energy supply and demand forecasts with economic growth, and (2) none of the models studied were able to adequately predict and analyze regional effects of national energy actions [45]. This analysis should help to emphasize that the variations among projection models, due to differing methodologies, assumptions, and purpose, are quite large. They also indicate that relying on a single model or source in developing policy or plans for future energy demand should be avoided.

3. SELECTED GROWTH RATES FOR PROJECTIONS

For the purpose of evaluating future potential pressures on the Great Lakes coastal zone, a number of potential fuel mix scenarios have been postulated. The actual pressure on the coastal zone will be a function of the increase in the demand for electric power, the utilities' ability to construct sufficient capacity, and the type of fuel chosen for the new generating capacity. The choosing of an average or best-gues electrical demand growth rate would assume that accurate knowledge of the future energy picture is known. The use of high, medium, and low growth rates encompasses a number of possible energy futures. More importantly it gives a range to the potential impacts of new energy facilities from which it may be possible to determine the requirements for fulfilling the various scenarios. The integration of these growth rates with the four scenarios described earlier will give an indication of the resources that might be required by a certain fuel mix and electrical demand growth rate. These figures can then be used by interested parties in developing policies that relate to the fuels (need, transport, cost, etc.), siting, and regulation of future plants.

To this end, three growth rates have been chosen representing a low (3% per annum), a medium (5.5%) and a high (8%). The low growth rate might be tied to high conservation rates; the medium rate will be close to the electrical demand growth rate since the 1973 Arab oil embargo; and the high growth rate might be associated with an intensive electrification process due to substitution for other fuel types.

E. IMPLICATIONS OF SCENARIOS

The direct extrapolation of generating capacities does not take into consideration critical factors which will greatly influence the determination of quantities and types of current generating capacity. Thus, in conducting the resource impact analysis, a number of assumptions were made which have a direct bearing on the results of the analysis.

The mix of new generating facilities is assumed to be the following: 75% base load, 20% intermediate load, and 5% peak load capability. Coal and nuclear facilities will compete for base load generation capability and for half of the intermediate load. Oil, gas, and hydroelectric facilities will be used primarily in intermediate and peak facilities. (Oil will continue to be used in decreasing amounts as the base load fuel source.) Load factors for the new facilities are assumed to be 65%.

Prices of primary fuels for electric power generation were not considered in the analysis, but availability and price will play a major role in determining the types and numbers of facilities constructed. No assumptions were made as to the substitution of electricity for other energy end use purposes, but such a trend would be reflected in higher rates of demand for electricity. The analysis further assumes a standard 1000-MW unit size with the option to locate multiple units on a site. Further expansion of present utility sites and reconstruction on retired sites were assumed, thereby potentially lowering demand for total land requirements by 15-25%. Two nuclear units were assigned to each site with potential of up to 4 units per site before additional land would be required. Approximately one-half of the water required for a closed-cycle system is consumed. The assumption was made that facility retirements would not substantially affect the amount of new capacity to be installed.

There are a number of critical points which greatly affect the demand for electricity which have been ignored in this analysis. Any one of these issues could greatly alter the demand for electricity and the capacity needed over the next twenty years.

The analysis does not consider the effect of prices on the demand for electricity, a central issue in most projections. No account is taken of the potential slackening in demand as population growth levels off or as some saturation level for electricity is approached. Straight extrapolations of present generating capacity do not consider increasing efficiencies over time in the generation, transmission or end use of electricity. The present situation of high reserve capacities and low load factors, which may delay need for additional capacity (increasing load factors will substantially reduce short-term need to increase capacity), is not addressed. Also not considered is the regional or power pool level of demand analysis which allows for a potential reduction in required generating capacity due to better management and the sharing of power through well-developed transmission networks. This partial list of "critical factors not accounted for" suggests the many weaknesses of the analysis. The point should be emphasized, however, that the analysis was conducted as a demonstration of the magnitude of the resources required, should certain capacity expansion schedules be followed, and not as a forecast of capacity expansion in the Great Lakes Region.

Based on present (1975) generating capacity and electricity demand (by state), future generating capabilities and demand levels have been postulated, using the three growth rates (3%, 5.5%, 8%) at time increments of 10 and 20 years. Using a simple compounded interest formula, the current electrical power capacity and demand levels were extrapolated at the three growth rates to give an indication of future potential resource requirements needed for new energy facilities. While both capacity and demand projections were made for analysis purposes only, electric generating capacity will be used in the assessment of future resource requirements.

Working through projected required capacity figures provides a graphic display of how fast new capacity would be required at various growth rates. Given certain assumptions, such as traditional load factors and utility operating practices, a number of possible resource requirement schedules for the different growth rates can be postulated. The purpose of such an exercise is to give a rough indication of what future demands for electric power might mean in terms of land, water, and fuel resources required for the new capacity. When these resource requirements are combined with the four scenarios, some indication of the number and types of facilities may be estimated.

F. PROJECTED GENERATING CAPACITY AND RESOURCE REQUIREMENTS

On a regional level, using a standard 1000-MW generating unit, the additional projected capacity needed at a 3% growth rate through the year 1995 would be roughly 126,686 MW. Similarly, for the same time span, the amount of capacity needed at growth rates of 5.5% and 8% would be 300,677 MW and 575,642 MW respectively. These numbers were determined by taking each state's 1975 generating capacity and extrapolating at the three growth rates over a twenty year period. Assuming no present facilities decommission, a rough estimate of the number of new 1000-MW generating units (multiple units may be located on one site) needed by 1995 would be 126 at a 3% growth rate, 300 at a 5.5% rate, and 575 at 8%. Due to the nature of the assumptions previously listed these figures contain a substantial margin of error.

TABLE 74

NEW GENERATING CAPACITY REQUIREMENTS FOR 1995 (in MW)

State	(1975) Base	Projections (1995) 3%	5.5%	8%
Illinois	25,500	46,055	74,402	118,854
additional capacity		20,555	48,802	93,354
Indiana	13,315	24,048	38,850	62,060
additional capacity		10,733	25,535	49,745
Michigan	18,926	34,316	55,437	88,558
additional capacity		15,390	36,511	69,632
Minnesota	6,700	12,100	19,548	31,228
additional capacity		5,400	12,848	24,528
New York	29,000	52,377	84,614	135,167
additional capacity		23,377	55,614	106,167
Ohio	25,780	46,561	74,943	120,159
additional capacity		20,881	49,163	94,379
Pennsylvania	28,770	51,961	83,943	134,095
additional capacity		23,191	55,173	105,325
Wisconsin	8,881	16,040	25,912	41,393
additional capacity		7,159	17,031	32,512
Region Total	156,872	283,556	457,547	732,512
total additional capacity		126,686	300,677	575,642

The land, water, and fuel resources required for these facilities could be determined by using figures available for existing facilities. The result represents an average or ideal facility requirement and is subject to debate.

For coal-fired plants, fuel requirements are assumed to be 228 tons per hour, or approximately 2 million tons of coal per year. The Btu value of the coal averages 20 x 10^6 per ton. For low Btu western coal, the heat value could be 15-20% lower. Conversely for a higher Btu coal the heat content could be as much as 15-20% higher.

Land requirements for a 1000-MW coal-fired facility are 400 acres per unit. This includes the land required for the plant with on-site ash and SO_x disposal, natural draft cooling towers, and storage for a six-month coal supply. Depending on the mix of these variables, total land requirements can vary as much as 100 acres. Water requirements vary substantially between closed-cycle cooling systems and open-cycle or once-through cooling, such that two sets of numbers will be postulated to represent each system. The water requirements for a natural draft cooling tower are 700,000 gallons per minute (gpm) (assuming a 12°-13°F temperature rise across the condenser) for the open-cycle and 10,000 gpm for closed-cycle system.

Resource requirements for nuclear units vary as greatly as those of a coal-fired station. The fuel requirement for nuclear units has been deleted from this analysis due to the unique problems posed by the handling, transport, and processing of nuclear fuels. Land requirements average 1,335 acres per unit (135 for the actual facilities, and the additional 1,200 acres as exclusion zone). Nuclear facilities, unlike coal facilities, are able to economize by siting multiple units on a single site, requiring no additional land for up to 4 units.

Nuclear facilities require more water than do coal facilities, averaging an additional 15,000 gpm for a closed-cycle system, of which approximately 50% is consumptive use, and up to 1 million gpm for an open-cycle system, with some consumption (assuming a 15°F temperature rise across the condenser).

These resource requirements are used in conjunction with the four scenarios to indicate potential pressures on the Great Lakes Region in the siting of new electric generating facilities. With the major exception of New York, the Great Lakes states rely primarily on coal for base load generation, with an average of 66%. The remaining capacity is made up of hydroelectric, 5% (expected to provide a decreasing percentage of electric power as suitable sites become scarce), oil and gas-fired, 17%, for base and peak supply, and nuclear, currently 12% and expected to comprise roughly 35% by 1990. The question of oil-fired generating units is somewhat more crucial to New York State, as it presently accounts for about 40% of the state's power.

TABLE 75

1975 FUEL MIX BY TYPE FOR POWER GENERATION (Btu percentage by state)

State	Oil	Gas	Coal	Hydro	Nuclear
Illinois	8%	4%	63%	.1%	24%
Indiana	3%	2%	93%	1%	0%
Michigan	10%	6%	72%	1%	10%
Minnesota	3%	12%	63%	2%	19%
New York	39%	5%	15%	24%	17%
Ohio	4%	2%	94%	0%	0%
Penn.	14%	1%	74%	1%	9%
Wisconsin	1%	9%	57%	1%	28%
Regional Weighted Average	13%	4%	66%	5%	12%

The recent trends scenario suggests that nuclear generating capability will grow to approximately 35% of the total generation over the next 15 to 20 years.

Based on 1975 figures, determined by weighted average of the eight Great Lakes states' fuel mix distribution, this works out to approximately 70,000 MW, or 70 nuclear units, and 40,000 MW, or 40 new coal units, at the 3% rate by 1995. This would bring the nuclear capacity up to 35% of the generating capability for the region with coal comprising 50%, and oil, gas, and hydroelectric making up the remaining 15%, accounting for roughly 18 new units.*

* The method for arriving at these figures involved determining the current generating capabilities by fuel type for the states and weighing them, accounting for differences in each state's generating capacity, and coming up with an average regional fuel mix. These figures were then used to determine the approximate amount of capacity for each fuel type in the region. Then, with the additional capacity required by the three growth rates, the number of new units was determined by multiplying the expected capacity percentage for each fuel type by the total capacity in 1995 and subtracting the present capacity.

Land requirements for nuclear facilities in the recent trends scenario at a 3% growth rate are on the order of 46,725 acres for the region. This assumes that two units per site would require no additional land. Additional units per site would reduce land requirements further. The water requirements for these 70 nuclear facilities, using a closed-cycle cooling system, are 1,512 x 10^6 gallons per day (gpd), while for a once-through cooling system, 1,008 x 10^8 gpd would be needed. Similarly for the coal-fired units, land requirements total 16,000 acres and fuel consumption would equal 80 x 10^6 tons per year. Once-through cooling water equals some 403 x 10^8 gpd, and a closed-cycle system would utilize some 576 x 10^6 gpd. As is evident, even at a low growth rate the number of new 1,000-MWe units required by 1995 is substantial and indicates the need for rational long-term planning.

The amount of new capacity required at a 5.5% growth rate would be 141,000 MWe, or 141 nuclear units and 121,000 MWe, or 121 units, for coal-fired generation. Oil, gas, and hydroelectric might contribute up to an additional 35,000 MWe.

Nuclear facilities would require 93,120 acres of land, 3,046 x 10^6 gpd of water for a closed-cycle system, and 2,030 x 10^8 gpd for a once-through cooling system. The coal-fired facilities would require 48,400 acres of land, 242 million tons of coal per year, 1,220 x 10^8 gpd for a once-through cooling system, and 1,742 x 10^6 gpd for a closed-cycle cooling system.

Table 76

ADDITIONAL FACILITIES REQUIRED BETWEEN 1975-1995 FOR SCENARIO I, RECENT TRENDS

Type	Growth Rates		
	3%	5.5%	8%
Nuclear (units)	70	141	238
land requirements (acres)	46,725	94,120	158,865
water requirements (gpd):			
once-through	1,008 x 10^8	2,030 x 10^8	2,427 x 10^8
closed-cycle	1,512 x 10^6	3,046 x 10^6	5,141 x 10^6
Coal (units)	40	121	185
land requirements (acres)	16,000	48,400	74,000
fuel requirements (millions of tons/year)	80	242	370
water requirements (gpd):			
once-through	403 x 10^8	1,220 x 10^8	1,865 x 10^8
closed-cycle	576 x 10^6	1,742 x 10^6	2,664 x 10^6

At a growth rate of 8%, approximately 238,000 MW, or 238 nuclear units, would be required and 185,000 MW, or 185 units, for coal-fired generation. The nuclear units would need 158,865 acres of land, $5{,}141 \times 10^6$ gpd of water for a closed-cycle cooling system, and $3{,}427 \times 10^8$ gpd for a once-through system. The coal units would require 74,000 acres of land, 370 million tons of coal, $2{,}664 \times 10^6$ gpd of water for a closed-cycle cooling system, and $1{,}865 \times 10^8$ gpd for a once-through system.

The second scenario postulates a fuel mix for the year 1975 comprised of 70% coal, 15% nuclear, and 15% oil and gas. At the 3% growth rate the number of new facilities required by this scenario will be approximately 96 coal units (1,000 MW each), 24 nuclear units, and about 20 oil or hydroelectric units. The resource requirements for these facilities are shown in Table 77.

Table 77

ADDITIONAL FACILITIES REQUIRED BETWEEN 1975-1995 FOR SCENARIO II, HIGH COAL ELECTRIC

Type	Growth Rates 3%	5.5%	8%
Nuclear (units)	24	50	92
land requirements (acres	16,020	33,380	61,410
water requirements (gpd):			
once-through	346×10^8	720×10^8	$1{,}325 \times 10^8$
closed-cycle	518×10^6	$1{,}080 \times 10^6$	$1{,}987 \times 10^6$
Coal (units)	96	217	410
land requirements (acres)	38,400	86,800	164,000
fuel requirements (millions of tons/year)	192	434	820
water requirements (gpd):			
once-through	968×10^8	$2{,}187 \times 10^8$	$4{,}133 \times 10^8$
closed-cycle	$1{,}382 \times 10^6$	$3{,}125 \times 10^6$	$5{,}904 \times 10^6$

The third scenario assumes that nuclear generating capability will equal that of coal-fired generation. The fuel mix breakdown for this scenario is approximately: 45% nuclear, 45% coal, and 10% oil.

The fourth scenario postulates a rapid development of new technologies, hence, a somewhat reduced dependence on more conventional generation technologies. It suggests a fuel mix having the same proportions between fuel types as that of recent trends, but with a reduction of 20-25% in the number of new coal and nuclear facilities required. Given this similarity, the resource requirements for the new technologies scenario are assumed to be 70-80% of those postulated for the recent trends scenario.

Table 78

ADDITIONAL FACILITIES REQUIRED BETWEEN 1975-1995 FOR SCENARIO III, HIGH NUCLEAR

Type	Growth Rates		
	3%	5.5%	8%
Nuclear (units)	104	177	311
land requirements (acres)	60,420	118,150	207,590
water requirements (gpd):			
once-through	$1,498 \times 10^8$	$2,549 \times 10^8$	$4,478 \times 10^8$
closed-cycle	$2,246 \times 10^6$	$3,823 \times 10^6$	$6,718 \times 10^6$
Coal (units)	12	91	227
land requirements (acres)	4,800	36,400	90,800
fuel requirements (millions of tons/year)	24	182	454
water requirements (gpd):			
once-through	121×10^8	917×10^8	$2,288 \times 10^8$
closed-cycle	173×10^6	$1,310 \times 10^6$	$3,269 \times 10^8$

G. COASTAL ZONE RESOURCE IMPACT ANALYSIS

1. RELATION OF PROJECTED DEMAND TO POWER PLANTS

The implications of these figures vary greatly from county to county in the Great Lakes coastal zone. The limitations of the analysis notwithstanding, the potential impact of energy facility siting can be estimated by assessing the current importance to the states of coastal county energy facilities and then assuming that this current proportion will hold constant in the future.

For the States of Illinois, Pennsylvania, and possibly Indiana, the future of their coastal counties with respect to energy facilities will most probably be limited to demands for access to the water rather than the physical siting of facilities on or near the shoreline. This aspect of coastal zone utilization is further limited by the difficulty of siting new generating units in the already heavily developed Indiana and Illinois counties. Pennsylvania's coastal county, being somewhat less developed, has a slightly higher potential for access. It may turn out, however, that as an increasing number of facilities require water supplies no longer obtainable from inland sites, there will be increased pressure to transport coastal waters further inland.

Minnesota currently has the lowest number of energy facilities in the coastal zone. The current percentage of coastal zone generating facilities of the state total is roughly 5%. Further, there are no plans at present to construct any facilities. If land presently categorized as agricultural or undeveloped were considered potentially available for the siting of energy facilities, Minnesota would have 11 miles of coast land available for energy facilities.

By taking the total new generating capacity required by the four scenarios and determining Minnesota's portion based on the percentage of current capacity, a rough idea of the number of new Minnesota facilities required could be derived. (This procedure will be followed for the remaining states.) Minnesota's share of the postulated new facilities would range from 6 plants at a 3% growth rate to 23 facilities at an 8% rate. Maintaining 5% of its total capacity in the coastal counties, only one or two new coastal facilities would be required. These facilities would take approximately 1000 - 2000 acres of land, with the water and fuel resources presenting little additional burden to the coastal zone. Assuming a pressure to site an increasing percentage of the state's total generating capacity in the coastal zone, the number of new facilities there may rise to five or six.

Following the same procedure, the pressure on the coastal counties in Wisconsin is seen to be substantially greater than that in Minnesota. Currently 59% of Wisconsin's generating capacity is located in coastal counties. With 8,881 MWe, Wisconsin comprises 6% of the Great Lakes Region's total generating capacity. Based on these figures, the potential number of new facilities required in the Wisconsin coastal counties ranges from 8 at a 3% growth rate to 20 at 8%. The resources required for these new facilities will vary depending upon the scenario. Assuming equal development of both nuclear and coal facilities the requirements in the coastal counties might be the following: land requirements--from 5,870 acres for 8 facilities to 10,675 acres for twenty; water requirements--for a closed-cycle cooling system from 100,000 gpm to 250,000 gpm, and for an open-cycle cooling system between 6.8×10^6 gpm to 17×10^6 gpm. With one-half of the new facilities being coal-fired the fuel requirement would range from 8 million tons/year to 20 million tons/year.

Ohio's current generating capacity is approximately 25,225 MWe of which 21% is located in coastal counties. Under the regional projections, Ohio's coastal counties would need to accommodate 4 new generating units at the 3% growth rate and 19 at the 8% level. Again, assuming equal numbers of both coal and nuclear facilities the resource requirements would be within the following range: land--from 2,135 acres for 4 units to 10,140 acres for 19 units; water--for closed-cycle systems between 50,000 gpm and 237,500 gpm, and for open-cycle systems, requirements would fall between 3.4×10^6 gpm and 16.15×10^6 gpm. The fuel requirements for the coal-fired facilities vary between 4 million tons/year and 19 million tons/year.

New York's generating capacity is currently 29,000 MWe of which 27% is in coastal counties. The number of new facilities in the coastal counties would range from 7 plants at a 3% growth rate to 29 at the 8% rate. With these numbers of potential new coastal zone facilities the additional pressure on the coastal zone would be significant. The resources required for these new facilities break down as follows: land--from 3,740 acres to 15,480 acres for 29 new units; water--from 87,500 gpm for 7 units closed-cycle cooling to 362,500 gpm for 29 units. For open-cycle cooling these numbers range from 5.95×10^6 gpm to 24.65×10^6 gpm. Coal requirements would fall between 7 million tons/year for the 3% growth projection to 29 million tons/year for the high growth rate.

The State of Michigan has the highest percentage (73%) of its generating capacity (18,926 MWe) located in coastal counties. Michigan's coastal counties' share of the projected new capacity would be 11 units at a 3% growth rate and 51 units at the 8% level. The requirements on Michigan's coastal counties break down as follows: land--between 5,870 acres and 27,220 acres; water--in a closed-cycle-cooling system between 137,500 gpm and 637,500 gpm, and for the open-cycle system between $9.3^5 \times 10^6$ gpm and 43.35×10^6 gpm. The coal requirements, assuming an approximate 50% coal fuel mix for projected base load generation, would range between 11 million tons/year and 51 million tons/year.

The number of postulated new facilities in the coastal counties associated with the 3% growth rate might be assumed to accurately represent the minimum over the next twenty years. This is supported by the following: (1) "best guess" estimates for growth in energy demand hover around 5.5%, hence a 3% growth rate might reduce the errors in many of the assumptions made in the analysis, (2) the thermal loading of inland waters will increase the pressure on the Great Lakes for cooling purposes (a good example of which might be the Ohio River system), and (3) the proportion of generating capacity currently located in the coastal zone (or utilizing land and water resources) may rise in the future rather than remain constant. At this time, it should be apparent that the demand for electricity over the next twenty years will be a major factor controlling pressures on the Great Lakes coastal zone with respect to energy facility siting.

2. RELATION OF PROJECTED ELECTRICAL AND FUEL DEMANDS TO FUEL TRANSSHIPMENT AND STORAGE

The future demands for electrical energy production interact with the expansion and development of fuel transshipment and storage facilities in a complex and diverse manner. The discussion of this topic will center primarily on the effects coal movements may have on the future of these facilities.

Oil, presently contributing a smaller percentage of the region's fuel mix, is expected to have a minor impact on the future development of ports and terminals. It was felt that the facilities were adequately developed to handle liquid fuels and that competition from pipelines and rail movement would, in the future, further reduce the relative percentage of this fuel moved on the lakes. Additionally, the questionable role of oil in the future generation of base load power was taken into account.

Coal, which is expected to contribute to the major fossil fuel demands for power generation in the region, will continue to depend heavily on movement through transshipment facilities.

Assessing the adequacy of these facilities is complicated by a number of intrinsic and external variables. In previous sections of this report the capacity of ports and terminals was analyzed from a historical perspective. In examination of the prior ten-year period it was determined that the system could presently double the coal tonnage moved on the Great Lakes. This would involve additional shipments of approximately forty million tons. The assessment, however, does not specify the quality or origin of the coal transported. Under this evaluation, higher sulfur eastern and midwestern coal would contribute heavily to the total shipments through the facilities on Lakes Erie and Michigan. The relative percentage of eastern versus low sulfur western coal moved on the Great Lakes is crucial in any assessment of future impacts of coal on ports and terminals. This eastern/western mix is largely dependent on the development of low-cost technologies of sulfur removal either before or after combustion.

The competition between rail and lake vessel movement is also central to an examination of future demands on ports and terminals. In 1975, 4.4% of the coal used in the eight Great Lakes states for electric power generation was moved on the Great Lakes [604]. Fluctuations in this relative percentage will naturally affect the impact that coal shipments on the Great Lakes will have on transshipment facilities.

The previous section developed a number of scenarios based on the future fuel mix for electric power generation. An examination of the scenario projecting a high coal fuel mix is most relevant to the future coal movement on the Great Lakes. A general discussion of impacts on ports and terminals can be developed through examination of this scenario. Analysis of projected activities at particular ports on the lakes is not feasible and would be highly speculative, considering the vagaries of future competition from other modes of transport and the relative utilization of high or low sulfur coal. It is possible, however, to analyze the overall implications of such a high coal scenario on transshipment facilities.

Taking the 8% growth rate developed in the high coal scenario for electric generation as an upper bound, the fuel requirements are projected as an additional 820 million tons of coal for the eight Great Lakes states. Assuming Lake traffic contributes 4.4% to the total movement of coal for electric power generation, waterborne coal movement would increase by 36 million tons. It must be stressed that this figure is the product of extended extrapolations and as such becomes increasingly removed from the eventual realities of coal transshipment. Based on a relative fuel mix at a given growth rate, assuming an average heat value of coal and a relative percentage of Lake movement, the figure of an additional 36 million tons by 1995 for utility use on the lakes should be viewed with guarded skepticism. This tonnage figure will be used strictly as representative of a substantial increase in coal traffic on the Great Lakes and may rise to higher levels if shipping takes a larger share of the total transport market of coal to electric utilities.

The impact of this additional tonnage demand on transshipment facilities can be discussed on a regional level varying the coal origin (eastern versus western) as it relates to the geographically specific locations of transshipment. If one assumes that utilities, in an effort to comply with air quality regulations and in the absence of efficient sulfur removal techniques, purchase western low sulfur coal, then the pattern and movement of Lake traffic of coal will shift substantially. A considerable increase in western coal utilization of the magnitude previously described would place enormous stress on the facilities presently in use. This is compounded by the fact that generally western coal has a lower heating value than coal from eastern mines, necessitating even greater volume throughout. Facilities at Superior, Wisconsin and perhaps Chicago would handle much of the additional load. However, with the cost advantages in shipping over long distances one would expect that additional facilities would be required and expansion of present coal handling ports would occur. It is difficult to project the location of the additional facilities on a site-specific basis, but relative to cost reduction in delivered price one would assume a maximation of the direct waterborne portion of transportation, encouraging further developments on the western end of Lake Superior.

The high coal scenario hinges primarily on the absence of efficient low-cost sulfur technologies. With such development the pressures on transshipment facilities may return to the ports of the lower Lakes and specifically to the facilities on Lake Erie. The long-established and highly developed ports of this region would require less overall new development and expansion than would be expected for increases in western coal use. The upbound movement from these ports would facilitate the continuation of the traditionally economically beneficial iron ore/coal interchange at the Lake Erie ports.

Either extreme of strictly western versus eastern coal is unrealistic. In this discussion the pressures on the transshipment facilities are examined from a perspective of the relative emphasis of coal origins. Utilities commonly blend coal of varying sulfur contents to achieve a mix that will meet air quality standards. Future demands on the movement of coal through transshipment facilities are largely a function of what the future mix will be as related to the economies and technologies of coal-fired generation and emissions control.

Chapter VI

POLICY OPTIONS RELATED TO THE SITING OF ENERGY FACILITIES IN THE GREAT LAKES COASTAL ZONE

A. INTRODUCTION

The principal objective of this study is the development of a full range of policy options for the siting of energy facilities in the Great Lakes coastal zone. Institutional arrangements and technical-environmental-economic approaches are emphasized in the options. The institutional options cover options for: (1) siting policy, (2) organizational arrangements, (3) functional responsibilities, (4) siting procedures, (5) siting criteria and standards, (6) financial mechanisms, and (7) intergovernmental relations. The technical options include options for: (1) the exclusion of all new facility development from the coastal zone management area including access to coastal waters and related fuel transshipment; (2) exclusion of all new facility development from the coastal zone management area, but allowing coastal water access, related fuel transportation and product transmission through the coastal zone; and (3) inclusion of new facility development in the coastal zone management area except in designated sensitive areas in which additional development would be precluded.

These options are only suggestive. No recommendations are made that a state or program should adopt any of the options proposed. The situation in each state will dictate the kinds of options it might employ in planning for and managing the effects of energy facilities sited in or near the coastal zone. Some of the options would entail major reorganization of institutions or revision of siting criteria, regulations and standards. Other options suggest use of existing institutional arrangements or augmenting present siting criteria and regulation.

Selection of certain options will preclude choosing other options. However, selection of combinations of options within and among the categories mentioned above are essentially unrestricted.

This listing of options is comprehensive, but is not intended to be exhaustive. The agencies affected will probably identify additional options and develop the details of these options as they relate to their respective programs.

The energy growth rates used in this study (in Chapter V) do not affect which options might be chosen, but they do serve to suggest: how much emphasis a particular state might place on developing an energy facility siting program; how comprehensive that program might be in terms of facilities and fuels; what the areal extent of the program jurisdiction should be; which levels of government should be involved with the program; what involvement the state coastal zone management program might have in such a program; and what authorities and sanctions should be vested in the program.

B. INSTITUTIONAL OPTIONS

1. INTRODUCTION

Options discussed in this section were derived from the study of existing state programs for the siting of energy facilities and of various proposals for improving such programs. Where an option can be identified with a particular state program, the state is indicated by its two-letter postal service abbreviation in parentheses. In this manner, the interested reader is directed to the appropriate state program description or to the state itself for additional information.

The options discussed in this section range from general approaches to more specific procedures and criteria that may be employed in the regulation of energy facility siting. The seven categories are: Siting Policy, Organizational Structure and Arrangements, Functional Responsibilities, Siting Procedures, Siting Criteria and Standards, Financial Mechanisms, and Intergovernmental Relations.

2. SITING POLICY

Energy facility siting is closely related to numerous traditional functions of state government. In establishing policies to regulate energy facility siting, a state may choose to specify the relationship of the siting program to one or more of these functions, thereby imposing a philosophy of operation on the siting process. Several of these relationships and their possible impacts are described below. The lack of any such relationship would imply that utilities and other energy producers/distributers have almost complete freedom in site selection.

a. Traditional Utility Regulation

This approach represents the status quo in most states that have not recently enacted energy facility siting legislation. Traditional utility regulation has received criticism for a variety of reasons, including: failure to consider all aspects of the siting issue; lack of early public participation; the multiplicity of independent local and state agencies with responsibility over some phase of siting; and the delays that result from this process. However, these "problems" do not seem to be inherent features of traditional utility regulation. The process may be improved by means of interagency agreements or orders of the Governor, while maintaining the basic system of responsibilities.

Implications. Possible consequences of this arrangement include subordination of environmental considerations and the inability to address the broader issues of energy policy and land use. Without a legislative mandate it may not be possible to assure that the criticisms listed in the above paragraph are dealt with adequately. Utility regulatory commissions are traditionally concerned primarily with economic matters affecting service charges and return on utility investment and the safety and engineering aspects of facilities. The resolution of conflicts over economic and environmental issues, which are common in energy facility siting, may require expanding the regulatory commission to include members with appropriate backgrounds.

b. Energy Policy

The siting function may be handled in the broad context of state energy policy. The emphasis would be on regulation/allocation of fuels to assure adequate supplies of each type for essential or best purposes, and also to assure adequate supplies of electricity. The program may include methods of limiting electricity demand and conserving energy in all forms.

Implications. Projections of (electrical) energy demand indicate an escalating demand for sites. The siting function would be simplified if the demand for sites could be reduced by means of an aggressive state energy conservation program. Thus, the option of foregoing sites is contingent upon reducing demand.

Another aspect of energy policy, the interchangability of fuels to provide energy, is also closely related to siting questions. For example, the fuel type of a power plant has definite environmental implications that affect the suitability of a site, while the choice of fuel type must be made in light of state or national requirements for alternative uses and for environmental protection. Extraneous factors that affect siting decisions might include the environmental degradation accompanying the strip mining of coal, the scarcity of natural gas and its requirement for other industrial and domestic purposes, the precarious situation entailed by dependence on foreign supplies of oil, and the problems associated with the reprocessing and disposal of nuclear wastes. Combining the responsibilities for siting regulation and energy policy in one agency would facilitate these decisions. Lack of a coherent national energy policy also affects local and regional facility siting regulation by not providing adequate direction for future fuel use, and thus the types of plants that should be constructed.

c. Land Use Policies

This option would treat all major construction projects, including energy facilities, as significant impacts requiring state approval. The emphasis would be on patterns of land development and regional economic and environmental impacts. A corollary to this option would be to limit land use control jurisdiction to the coastal zone. Such an approach would recognize the unique and valuable aspects of coastal lands and the heavy development pressures they are subject to. Whatever energy facility siting process applied to the remainder of the state would necessarily be closely coordinated with the coastal zone management function.

Implications. For the state to assume land use control requires the retaking of authority that has traditionally been relegated to local units of government. This may not be a popular approach, and heavy restrictions on the size and type of facility or project or the geographic area that would be subjected to state control may be required. It may be appropriate to recognize the regional nature of many large facilities, including power plants and other energy facilities, and provide for state control of their siting. Restricting control to the coastal zone would recognize the critical importance of this region and would satisfy the requirements of Section 306(e)(1) of the Coastal Zone Management Act. Less direct state land use control in the coastal zone is also an option under the Act.

d. Pollution Control/Environmental Protection

This option would place emphasis on pollution standards and the relevant technology to assure protection of air, land and water resources. Siting control would probably reside with the state's environmental protection agency. Critical or fragile areas would be heavily protected.

Implications. Environmental protection is a primary concern in energy facility siting. Historically, utility regulation commissions have placed more emphasis on adequate provision of energy than on environmental issues associated with energy production. In many states the environmental protection agency already has major responsibilities for issuing permits and certifying the environmental compatibility of facilities. It would generally be only a small step to enable such agencies to have overall authority for site certification. However, it may be difficult to obtain unbiased decisions from an agency with an historic emphasis in one direction.

e. Scope of Facility Siting Regulation

Two basin options exist for the types of energy facilities subject to state regulation, though the intervening ground is a continuum between the two. One one hand, regulation may apply to all energy facilities: power plants, transmission lines, pipelines (gas and oil), refineries, transfer and storage facilities, and coal gasification and liquefaction facilities, and perhaps large scale solar collectors, etc. On the other hand, regulation may be limited to facilities constructed by regulated monopoly utilities (i.e., gas and electric companies). This approach might even limit itself to power plants and transmission lines, in light of their high public visibility and the need to balance the demand for electricity with the protection of the environment and economic issues.

Implications. The scope of facility siting regulation may depend on the overall responsibility or emphasis of the primary siting agency. If the state has a program to deal with energy policy, it may be feasible to regulate a broad range of facilities, whereas maintenance of the traditional system of utility regulation with a slightly broader scope to address siting issues might dictate a limiting of the regulatory process to utility-owned facilities.

f. State Power Authority

A state may elect to compete with or supersede public utilities in the matter of construction of base load power plants. A state power authority could construct and operate power plants and sell power at cost to utilities for ultimate distribution to customers. The power authority would have primary responsibility for selecting facility sites that are compatible with all aspects of environmental and economic concerns.

Implications. Recent economic developments affecting interest rates, construction costs and fuel costs have raised doubts concerning the ability of investor-owned, privately managed utilities to meet the future demand for electric power. Numerous power plant plans have been delayed or cancelled. Implementation of the state power authority concept would be a response to perceptions of the present or potential severity of this situation. The state authority would be able to borrow money at lower rates through the issuance of tax-exempt bonds and would not be required to pay stock dividends.

The critical question in establishment of a state energy authority is: Who may best serve the public in the production of electrical energy; the private sector or the public sector? The private sector may argue that they have traditionally served the public well, that the profit motive guarantees continued high quality service, and that the current regulatory process is a major source of difficulty. An evaluation of the relative merits of each side of the question is beyond the scope of this report. Interested persons might obtain the Brickley Commission Report, Governor's Advisory Commission on Electric Power Alternatives, State of Michigan, August 1976.

3. ORGANIZATIONAL STRUCTURE AND ARRANGEMENTS

Within any of the general policy mechanisms discussed in the previous section, a variety of agency structures are possible for the regulation of energy facility siting. A state may elect to forego establishment of formal siting procedures, in essence leaving siting regulation in the hands of local zoning authorities. However, compliance with the Coastal Zone Management Act requires, at the least, that states establish criteria and standards to guide local authorities in establishing zoning restrictions in the coastal zone, subject to state review and enforcement of compliance.

The organizational arrangements discussed below are intended to apply to an agency or formal program for the regulation of energy facility siting. Subsequent institutional options will not necessarily require the establishment of a siting agency.

a. Multi-stop Process

This option requires review and approval by each agency with an interest in the various aspects of energy facility siting and is the process that has evolved in many states (IL, IN, MI, PA). The public utilities commission, air and water pollution control agencies, local zoning boards and perhaps several other state and local agencies would all be involved in the siting process. Within this framework, it is possible to establish a coordination mechanism that provides for the timely siting of facilities and minimum duplication through a unified application procedure and concurrent hearings.

Implications. This option takes advantage of existing expertise within various state agencies and does not unnecessarily tie up a permanent staff for infrequent siting work. However, even with provisions for coordination, the process will lack the ability to resolve conflicts among competing interests in the siting process, since no single body has such authority. The lack of public participation at the decision-making levels may adversely affect the credibility and responsiveness of the agency.

b. Consolidation of Authority

Again using existing agencies, but shifting primary responsibility to one or two agencies (WI), this option facilitates the siting process by streamlining it and providing for consideration of conflicting interests by a single agency. (Even where two agencies share responsibility, each would consider several opposing issues.) Primary candidates for this arrangement would be the public utility commission and the environmental protection agency. Local authority would be preempted.

Implications. A shift in responsibilities of this magnitude would probably require legislative action. The public utility commission would be involved only with regard to regulated utilities, so that in a program encompassing an extensive range of energy facilities it would be more appropriate to place major responsibility for site approval in an environmental protection agency, perhaps acting through a siting council within the agency. Certification of facilities constructed by regulated utilities would still be under the purview of the public utility commission.

c. Siting Agency Composed of Heads of State Agencies

The principal siting agency would be composed of the heads (or their designees) of the state agencies whose missions relate to or are affected by the siting of energy facilities (MD, WA, OR). This could include representation of the department of natural resources (DNR), the state environmental protection agency (if separate from the DNR), the public utility commission, the department of economic development or commerce, the department of public health, the department of transportation and possibly others. It would also be possible to include a representative of the state coastal zone management program on this council. The council would meet several times during the site approval process and engage existing agency staffs for requisite research and information functions. The chairman of such a council could be the head of the state agency in which the state CZM program is situated. If organizational arrangements would preclude this, then the chairmanship could be shifted to the head of the state agency which has responsibility for the state CZM program when the proposed facility affects the coastal zone.

Implications. This approach would insure direct involvement in the siting decision process of the concerns and interests represented by the principal state agencies and draw on the varied expertise of the agency heads. It would also permit efficient transfer of information between supporting staff and siting agency members by using the existing lines of intra- and inter-agency communications, or by minor modifications thereof. The administrators are familiar with the details of their respective policies, programs, and legal authorities and are well equipped to evaluate siting proposals in terms of these factors. Adequate consideration of coastal zone policies could be achieved if the CZM program were represented directly or if the DNR representatives were to represent coastal zone interests as part of overall DNR concerns.

This option does not provide for direct public participation in siting decisions. It would be necessary to provide extensive opportunities for public access to information and for the expression of public opinion. Insurance of adequate consideration of a wide range of the problems and needs associated with energy facility siting would be dependent on the comprehensiveness of the agency programs and the structure of the overall energy facility siting program.

d. Public Members

A siting council may be composed entirely of public members or only partially so. Public members would most likely be appointed by the Governor, possibly with state senate approval. The backgrounds of members may be specified in order to insure a wide range of expertise or experience in applicable fields. It may be desirable to restrict the past and future employment of council members by those regulated (potential applicants).

Implications. Direct public involvement enhances credibility with public members either representing the broad public interest or with a balance of biases (backgrounds) specified by law. Specification of backgrounds helps assure a wide range of expertise. Employment restrictions further enhance credibility and may be applied to nonpublic council members as well.

Including public members on a council of state agency heads (MN) would enhance credibility while taking advantage of existing exertise in matters related to siting.

e. Hearings Examiners

Various proposals exist for establishing a siting council based on the legal system. The council members would have both legal and technical backgrounds and would act as hearings examiners. The various interests involved would all be represented and the case would be decided on the merits of the arguments.

Implications. The court system is currently used as a last resort in the adjudication of siting issues. Relegating siting responsibility to hearings examiners may reflect an increasing difficulty in reaching decisions under another system and a desire to obviate court action. This may be an effective means for rational decision making on siting issues, relying on the professional integrity of the small (three to five member) board of hearings examiners.

f. Independent Staff

Within the structure of an energy facility siting council such as c., d., or e. above, there may be established an independent staff to collect and analyze data on energy demand and other matters, to conduct environmental studies on proposed sites, and to provide whatever other information the council requests.

Implications. The requirement for an independent staff may be predicated on the amount of work to be done (number of facilities to be sited) which may depend on the range of facilities addressed. There are probably sufficient numbers of power plants projected for each of the Great Lakes states to warrant an independent staff. The staff would help determine the need for energy facilities and could establish itself as a source of expert information on all aspects of energy facility siting.

g. Ad Hoc Member(s)

This option entails ad hoc representation on the siting council by a citizen of the region being considered as a possible site. Appointment may be by the legislative body (municipal or county) with jurisdiction over the proposed site, and the representative may or may not be a member of such body. Service on the council would be for the duration of deliberations on that site.

Implications. This option promotes credibility by assuring that the views of the affected community are expressed and considered in the siting process. But if the application process requires consideration of alternative sites, there may be two or three (competing) representatives of the several candidate communities on the council.

4. FUNCTIONAL RESPONSIBILITIES

Several functions are associated with the regulation of energy facility siting. Of the functions listed in this section, not all would necessarily be performed in each state. Those which are performed may come under the purview of any of several organizational entities, including federal, interstate, state, intrastate, and local governments; the private (corporate) sector; and the general public. Within each of these categories, consideration is limited to the agencies that have been established with authority to undertake such responsibilities. The discussion of each function will attempt to identify those entities most likely to assume responsibility for that function and the possible consequences of such delegation of authority.

a. Long Range Planning

Utilities and other potential constructors of energy facilities engage in long range planning, but such plans are often proprietary, leading to a "plan-disclose-defend" paradigm of energy facility siting. Long range planning, including demand projections and evaluation of alternative prospective sites, is an essential part of the overall siting process. If a state finds a need to regulate energy facility siting, one of the first steps is to regulate the preparation and disclosure of long range plans so that a comprehensive view of expected future development may be obtained. The desirability of such a future may then be evaluated and siting decisions made in terms of their impacts on the future.

(1) Long Range Energy Planning and Forecasting Performed by Private Sector Without State Intervention

Under this option, determination of long range energy demands and forecasts and evaluation of potential sites would be the function of the power industry. Plan disclosure would not be required, and the corporate sector would operate under its own guidance.

Implications. This option recognizes the technical expertise and monetary and personnel resources available to the private sector to invest in long range energy planning. If a state chooses not to engage in its own independent planning and forecasting, this approach assumes that the factors considered and the assumptions employed by the private sector adequately reflect the problems and needs of the general public. Preliminary evaluation and selection of prospective sites would be based primarily on economic criteria and on compliance with existing federal and state environmental protection laws. There would be no assurance that there would be adequate consideration of the full range of problems and needs expressed by the general public. Since public disclosure of plans and forecasts would not be required under this option, public accountability of energy facility siting decisions would be very limited.

(2) Independent Long Range Planning and Forecasting Performed by the State

Independent long range planning and forecasting conducted by the state could be concerned with projections and trends of future energy use, and with future site and facility requirements.

Implications. There are some advantages associated with state independent energy site planning and forecasting. First of all, the state is able to maintain a better overview of the total energy picture in the state. Factors affecting the various sectors of energy development and consumption could be evaluated in a comprehensive, coordinated manner, and the relationships between these sectors could be determined. This would facilitate the development of a unified, integrated, statewide energy policy and would serve as a sound basis for future siting decisions. One fundamental implication of this option is the underlying assumption that sufficient legal authority exists to provide for compliance with these plans by the private sector. If this were not the case, there would be no means by which to tie future siting decisions into such plans and forecasts. The lack of such adequate authority would limit the value of independent plans and forecasts to merely identifying the differences between the long range goals and objectives of the private and public sectors.

(3) Long Range Energy Plans and Forecasts Prepared by Private Sector with State Designated Guidelines and Criteria

This option provides for regulatory oversight of private long range plans and forecast preparation. Under this approach the state would stipulate the conditions for plan and forecast preparation. This would involve promulgation of rules and regulations outlining procedural requirements, public participation in the planning process, identification of planning and forecast methodologies employed, substantive content of informational requirements, the number and types of alternatives that must be examined, and other factors. It is also possible to include within these guidelines the criteria by which to assess the probable environmental impacts of the prospective sites outlined in the long range plans and forecasts. Another approach would be to require the evaluation of these sites in terms of some set of state designated site suitability criteria.

Implications. This option implies legislated authority for government involvement in long range planning conducted by the private sector. It also involves public disclosure of energy plans and forecasts. There are several advantages associated with this particular approach. Opening the planning process up to public scrutiny greatly increases the accountability of actions by the private sector. Establishment of standards and criteria by which to prepare such plans and forecasts provides a well defined and consistent basis on which the private sector can rely. This reduces confusion, improves the efficiency of government, and limits unnecessary cost incurred by the private sector. Administration of such a program could be achieved by a public utility commission, a state energy office, the principal energy facility siting office, the lead coastal zone management agency, or some combination of these organizations.

b. Environmental Impact Assessment

An important concern in the siting of energy facilities is the impact of the facility on the surrounding environment. Options for delegating responsibility for impact assessment include: (1) require the applicant for a facility site to provide a report on environmental impacts to the state; (2) assign the responsibility to a state agency; or (3) require that the assessment be performed by an independent consultant. The independent consultant may in turn be responsible to either the applicant, a state agency, or perhaps, the local government with jurisdiction over the proposed site (NY).

Implications. The credibility of impact assessments would probably be enhanced if the responsibility were placed with a government agency. If the actual study were performed by the state, it might be easier to achieve a uniform methodology for comparing sites. If the assessment were performed by the private sector, assessment criteria could be established by the state.

c. Final Site Approval

Land use control (zoning) has largely been delegated by the states to local units of government. Retaking of a segment of this power by a state would involve major decisions. At the state level, final responsibility for site approval may rest with a siting council (NY, OH, MD) or with the Governor (OR, WA) or with the legislature. Legislative approval may be reserved for special cases such as nuclear power plants (VT). The status quo in many states would keep zoning as the province of local units of government. However, compliance with the Coastal Zone Management Act requires that the state exercise at least a modicum of control over local zoning in the coastal zone. The Act lists two options short of direct state land use control: 1) state establishment of criteria and standards for local implementation, or 2) state review of all development plans, projects, and zoning regulations for consistency with the state's coastal zone management program. The state may choose to extend control in either case to the entire state. Note that this would effectively address all projects and facilities; not just those related to energy.

Implications. Giving authority for site approval to local governments does not provide for consideration of the regional or statewide interests involved in large energy facilities. Distinguishing the control over coastal zone siting from that which applies to the remainder of the state may hinder the rational selection of a site from among coastal and inland alternatives. A state siting agency, with provisions for prior approval by the coastal zone management agency of proposed sites in the coastal zone (CA), would provide for both consideration of state/regional interests and special attention to the coastal zone.

d. Monitoring

All states are required by federal law to monitor the quality of air and water resources within their jurisdiction. A state may choose to expand this monitoring program to include a broader range of environmental factors affected by energy facilities (MD). This would involve sampling of natural parameters such as physical, chemical, and biological effects, and cultural parameters such as changes in land use patterns and social and economic conditions associated with the construction, operation, and maintenance of a facility. Responsibility for environmental monitoring could be: 1) delegated to local government, 2) assigned to a private consultant, 3) assigned to the energy corporation, or 4) placed with the state environmental protection agency or department of natural resources.

Implications. A comprehensive program for monitoring the environmental effects of energy facilities would provide valuable insight into those aspects of energy development that are typically of greatest concern. It may also indicate substantive areas in which criteria and standards for energy facility siting and for protection of air or water quality in general appear to be either overly stringent, reasonably sufficient, or inadequate.

e. Conservation

In recognition of the scarcity of energy resources on an economic or geographic basis, or of the adverse environmental impacts resulting from their use, the state may choose to implement a program of energy conservation. The scope of such a program may range from a requirement that utilities (and others) describe conservation efforts as part of their plans, to a state agency with responsibility for specifying building codes, appliance and automobile efficiencies and other measures to reduce demand and thereby reduce the number of energy facilities required.

Implications. Energy facilities in general represent huge commitments of resources, including land, and have significant adverse impacts on the environment. If an aggressive state program for energy conservation can slow the rate of growth in energy demand, the effect should be to slow the rate of construction of energy facilities, and, thus, slow the rate at which siting decisions must be made and reduce the number of sites occupied at any given time in the future. Conservation can provide the siting regulation process with the option of not siting a proposed facility. For further details related to this option, the reader should consult Chapter V, Regional Scenarios of Energy Development. The discussion there concerns a range of electrical energy growth.

The energy industry, as part of our economic system, is probably dependent on growth for its economic well-being. In the regulated utility sector, a slower growth rate may require adjustments in the rate scheme, but this could be handled by the traditional regulatory mechanism. In the private sector, the gradual slowing of the rate of energy consumption could result in the shifting of economic resources away from energy production.

5. SITING PROCEDURES

The siting process may entail a variety of procedures, most of which are independent of the responsible regulatory agency. However, the procedures listed here generally assume a strong state role in the regulation of energy facility siting. Several options and their implications are discussed for each of four procedural categories: the application process, site selection, treatment of generic issues, and funding.

a. Application Process

The regulation of siting implies that the construction of facilities will follow an application process to decide the merits of a site. The formal application may be preceded by a notice of intent to file such an application. Actions taken on the notice of intent would include a preliminary evaluation of the site and notification of potentially interested parties. Public hearings may be held on the notice of intent.

The application itself may describe the site and the facility to be constructed thereon. Public hearings would most likely be held at this stage with time limits specified for the completion of the site approval process. The state may require that the application include not only a preferred site, but one or more alternative sites as well. Coastal states may specify that at least one alternative be outside the coastal zone. A separate application process may be established for sites in the coastal zone.

Implications. Requiring a notice of intent allows time for a preliminary site evaluation before an application fee may be required. Public hearings at intervals throughout the site approval process help assure that the results are responsive to public needs and desires. The specification of time limits for the process assures the applicant that there will be no delays while allowing ample time for consideration of all aspects of the issue.

Where the constructor of an energy facility is free to select which sites to propose, the requirement for proposing alternative sites allows comparisons of the relative advantages of each site. This is especially important with regard to coastal sites where both the magnitudes of the advantages and disadvantages may be greater than for an inland site. The requirement for prior approval by a coastal zone management agency for sites in their jurisdiction insures protection of the coastal zone but denies the opportunity to compare the relative merits of coastal and inland sites. With regard to comparison of coastal and inland sites, the reader is directed to the case Study and discussion of coastal dependence that appears in Chapter IV.A.6.

b. Site Selection

Several options exist for a state to assure selection of acceptable sites for energy facilities. The normal situation would leave the decision to the constructor of the facility through the application process. Advance consideration of siting problems by the state may lead to one of the following: establishment of criteria to be used by the constructor in the selection of sites (MN); designation of regions of the state that are suitable/unsuitable for various types of energy facilities (OR); establishment of inventory of specific sites (MN); or actual purchase of land by the state for eventual lease or sale as sites (MD).

Implications. The plan-disclose-defend paradigm of site selection is no longer satisfactory when a state chooses to regulate the siting of facilities. An applicant for site approval deserves to at least be aware of the criteria that the state will use in evaluating the suitability of proposed sites. Establishment of such criteria facilitates generic treatment of siting cases (see section c. below) and serves to reduce ambiguity in the decision-making process.

The designation of suitable and unsuitable regions for various energy facilities may be used in addition to siting criteria. Such designations result from the application of certain criteria, most likely those related to air and water quality, to all regions (such as airsheds and watersheds) of the state, taking into account the expected environmental impacts of each type of facility. This would also serve to provide applicants with needed information to reduce wasted efforts of studying and proposing unsuitable sites.

Carrying the process one step further, the state could establish an inventory of suitable sites, taking over the site selection function altogether. Potential applicants could work with the state in establishing the inventory and in proposing sites to be included. This may require the prior establishment of criteria to be used in the selection of sites and the whole process might be relatively time-consuming and expensive, but once the inventory is established, siting would be a relatively simple process.

The purchase of potential sites by the state can serve to assure that suitable sites are available, even if proposed sites are rejected. A revolving fund could be established to purchase an initial inventory of sites.

c. Treatment of Generic Issues

In the siting of energy facilities there are a number of issues that recur in the siting process. Such issues include: "questions of proper demand policies, allocation of research efforts, the amount of new capacity needed, and proper safety, environmental and land use standards" [613]. Some aspects of these generic issues may be decided upon separate from (and prior to) the site approval process. Some generic issues related to site selection are discussed in the previous section b.

Implications. Treating common issues beforehand simplifies the siting process by reducing the volume of material to be considered in individual cases. It can also serve as a means for providing applicants with information that enables them to forego making proposals that are unacceptable to the state. Furthermore, separate treatment of generic issues serves to reduce ambiguity in the site approval process.

d. Funding

As a function of state government, the regulation of siting may simply be funded through the normal budgetary process. However, energy facilities offer a great potential source of funds that may be applied either directly or indirectly to the siting process. Assessments may be considered in two broad categories: application fees and annual fees. The two are not mutually exclusive.

The application fee is a one-time charge to be paid upon submission of an application for site approval. The amount may be fixed or may be a variable charge based on the size of the facility, measured either in terms of its estimated cost or its design capacity (megawatts, barrels per day, etc.). The fee may fund the general operations of the siting process or be earmarked for a specific purpose, such as environmental impact assessment.

An annual fee may be assessed against all potential applicants for an energy facility site, or at least against those with existing facilities. The fee may again be a fixed fee, or a variable one based on the output of the facility in the past year, measured either in terms of quantity of output or dollar sales. The state may choose to determine an adequate sum for funding the siting process and associated functions and assess those regulated on a proportional basis.

Implications. Making site regulation financially independent relieves the burden on the state's general budget and obviates arguments against the establishment of such a function on financial grounds. The resultant higher energy rates may slightly reduce demand.

6. SITING CRITERIA AND STANDARDS

a. State Designation of Site Suitability Criteria

The state may wish to develop a set of criteria by which to evaluate various energy facility siting proposals. These criteria could be quite general or they could be specified in detail. General criteria usually involve rather broad statements that relate to protection of the environment, provision of adequate supplies of energy, protection of the general public health, safety, and welfare, conformance with existing land use and/or energy plans, and other factors (NY,OH). Specific site suitability criteria involve a detailed analysis of the physical capabilities of the resources affected, the specific resource requirements of the types of facilities under consideration, and the probable environmental impacts of those facilities. These criteria can be translated into geographic areas within the state which represent varying degrees of suitability for energy facilities. The state could thus maintain an inventory of suitable sites by which to evaluate future siting proposals (MD, MN).

Implications. Site suitability criteria designated by the state would insure consideration of factors in the evaluation of alternative sites that are of statewide concern. If the criteria were structured to incorporate factors representing the broad spectrum of environmental protection and natural resources management policies, the site review process could be streamlined and the relationship between these various policies and the resultant trade-offs could be identified and evaluated. The success of this approach depends largely on either a unified statewide land use policy, or an integrated, comprehensive set of policies which together represent an overall statewide policy.

The use of general criteria provides for consideration of general concerns about the environment, future energy needs, and other factors. It permits considerable flexibility in the means by which the criteria are satisfied. However, past experience indicates that other state and federal laws that have taken this approach have been subject to a wide variety of interpretations in the early stages of applying such criteria, and a great deal of uncertainty often exists as to what is required to satisfy these general criteria.

Through the application of specific site suitability criteria, it is possible to incorporate specific elements of existing state land use and energy development policy into the energy facility siting process. Such elements include air and water quality standards, soil erosion and sedimentation control criteria, solid waste disposal standards, radiological standards, and other factors. It is also possible to incorporate other state policies and program elements such as areas determined to be of critical stae environmental concern, areas in which economic development is encouraged, natural hazard areas, and so forth.

Establishment of energy facility site suitability criteria would probably be achieved through promulgation of rules and regulations by the lead state siting agency, such as a public utility commission, a department of natural resources, a siting council, or some other agency.

b. <u>Separate Site Suitability Criteria for Different Types of Energy Facilties</u>

Separate criteria could be developed for each type of energy facility, such as petroleum refineries, nuclear power plants, coal power plants, etc. It would also be possible to establish criteria for different size facilities. Under this approach, proposed energy facilities could be grouped in generic categories and evaluated under separate site suitability criteria. Another approach would be to conduct a statewide inventory of sites that would be suitable for these generically different types. Technical analyses would be conducted for the various types of energy facilities of concern to the state and specific resource requirements could be determined. The physical capabilities of air, land, and water resources to support these generic types could also be ascertained.

<u>Implications.</u> This option could streamline the energy facility siting

process considerably. Similar siting proposals could be evaluated more efficiently, since past experience would identify those factors that are likely to warrant special consideration and those that are routinely similar. In order to implement this option a considerable amount of research and planning would be required. This may involve extensive monitoring of existing energy facilities (MD).

c. Detailed Siting Criteria for the Coastal Zone

This option would involve the application of detailed criteria to proposed energy facility sitings in the coastal zone of a particular state. This option presumes that the state had not established siting criteria for non-coastal areas. These criteria could be based on a detailed resource inventory of the state's coastal zone and could indicate suitability of various land and water uses in the coastal zone through consideration of areas of particular concern, permissible uses, priority uses, etc. In addition, coastal zone siting criteria could include factors such as environmental opportunities or constraints determined by applicable air and water standards and other factors related to physical capability.

Implications. This option could foster the achievement of policies for energy facility siting in the coastal zone in states where regulation of energy facilities is limited. Because the institutional framework for coastal zone management has been developed to a higher degree than that for non-coastal areas in several states, it may be easier to approach the energy facility siting problem by working within the existing CZM planning framework. However, separate and distinct treatment of energy facility siting in the coastal zone, as opposed to a broader statewide approach, may result in a lack of balance regarding both coastal and non-coastal needs and problems. This problem could be partially eliminated if suitability criteria for energy facility siting in the coastal zone were developed with full consideration of the remainder of state, regional, and local policies, standards, and criteria relating to land use and energy development. In order to implement this option, enforcement provisions would have to be established to insure adequate consideration of these coastal-specific criteria in the siting process. This could be achieved by placing authority within the lead CZM agency, by establishing a mandatory review and comment process, or by formal or informal interagency agreements.

d. Point of Application of Suitability Criteria

(1) Application of Suitability Criteria to Long Range Plans and Forecasts

This option involves the application of site suitability criteria to the prospective energy facility sites identified in long range plans and forecasts. Two states (MD, MN) have taken this approach in the regulation of electric generating plants. This option would involve evaluation of the land holdings of the various energy companies or of sites under consideration for acquisition. It would facilitate the development of an inventory of suitable sites within the state. Determination that a site was unsuitable could serve as grounds for elimination of that site from further consideration.

Implications. The application of suitability criteria at the long range planning stage would have many desirable implications. For example, demonstration by the energy development companies that a proposed site is deemed acceptable by a set of reasonable yet comprehensive suitability criteria would increase the likelihood that the site would receive final approval. This would greatly reduce the uncertainties associated with energy development, and may well reduce the regulatory lag time that has plagued energy facility siting in the past. This would also permit adequate lead time for local and regional interests to express their views and to adequately plan for the provision of necessary public services and to manage the resultant environmental impacts.

This option implies some state involvement in development of long range energy plans and forecasts. It also implies that the appropriate decision-making body has authority to establish policies and procedures requiring compliance by the private sector. Presumably, satisfaction of the suitability criteria would constitute acceptance of a proposed site, and failure to satisfy the criteria would imply either outright rejection of the site or acceptance only upon satisfaction of certain site development conditions.

(2) Analysis of Site Suitability at Time of Application for Approval

This option would provide for the evaluation of the suitability of a specific site at the time of application for site approval. The private sector would conduct its own preliminary assessment of alternative potential sites and would choose a preferred alternative. In states where there is no principal lead agency to administer the existing energy facility siting program, the suitability analysis at the time of application could be handled by the state coastal zone agency, by the state environmental review board, or by the principal environmental protection or natural resources management agency. Adequate consideration of regional and local problems and needs could be arrived at through a variety of organizational structures, review procedures, public involvement mechanisms, and other means.

Implications. Under this option, it would be the prerogative of the private sector to conduct preliminary site suitability analysis according to its own criteria. However, the state-designated site suitability criteria to be applied at the time of application for approval would significantly influence the preliminary site suitability criteria employed by the private sector, because pursuit of sites unlikely to satisfy the state-designated suitability criteria may be a poor investment of time and money. If the state criteria were sufficiently comprehensive and sufficiently flexible to allow for variable conditions, these criteria could serve as an effective set of guidelines by which state utilities and other energy companies could evaluate the suitability of their prospective future sites. The application of these suitability criteria implies some sort of state regulatory authority over energy facility site locations. Such authority would be necessary if this approach is to be effective.

e. Designation of Environmental Impact Assessment Criteria for Site Evaluation

A state may wish to establish criteria for the assessment of the environmental effects of siting proposals. Following the lead of the National Environmental Policy Act of 1969 (NEPA), numerous states have taken the initiative in this area and have developed their own statewide environmental impact review processes (IN, MI, MN, NY, WI). Other states (NY, OH) have incorporated assessment criteria in their power plant siting regulatory programs. Criteria can either be very general or quite specific. General impact assessment criteria are broad statements which permit a great deal of flexibility in their interpretation. Specific criteria often take the form of various categories of information required, and often list specific data that must be collected to supply this information. These criteria can also include information that is required under the various federal and state permit programs in effect in the state, such as those required under the Clean Water Act (NPDES permit) and the Clean Air Act (permits to construct and operate), and state programs for soil erosion/sedimentation control, resource recovery, critical area or resource protection, and other applicable programs. In addition, assessment criteria could be developed to reflect factors of particular concern to the coastal zone.

Implications. There are several advantages to stipulating environmental impact assessment criteria for proposed energy facilities. Carefully designed criteria can include nearly all of the information and data requirements included in the various permit systems, and can thus serve as a mechanism by which to streamline the approval process. Also, criteria that are clearly stated and well understood can serve as a solid foundation for adequate consideration of those areas of greatest concern in coastal and inland locations. This would also reduce uncertainty in the private sector about the kinds of information that would ultimately be required in the siting process. Once a particular set of impact assessment criteria has been applied to various proposed site locations, a correlation would be established between various kinds of energy facilities and the probable environmental impacts.

7. FINANCIAL MECHANISMS

It is generally agreed that financial problems are among the most severe of problems currently facing energy development. These problems have arisen from uncertainties about governmental policies and from difficulties in capital formation in the private sector. If implemented, many of the options outlined above could streamline the regulatory process and thereby reduce uncertainties and resultant financial risks. For a number of reasons, the states may wish to employ various financial mechanisms to facilitate the wise development of energy. In addition to directly encouraging or discouraging the siting of new facilities, financial techniques can be employed to promote energy conservation and thereby reduce the need for new facilities, insure an adequate mix of fuels, encourage the application of new technologies, and ameliorate the adverse effects of facility sitings. Options associated with these mechanisms can be categorized under three headings: 1) methods of generating financial resources, 2) direct public investment in energy development, and 3) incentives for energy development by the private sector.

a. Methods of Generating Financial Resources

Several options are open with regard to obtaining revenues for the administration of various aspects of energy facility programs. The following list of such methods is presented to stimulate additional thinking in this area and is not intended to be exhaustive.

(1) Appropriations from General State Revenues
(2) Issuance of Industrial Revenue Bonds
(3) Consumption Tax on Fuels and/or Energy Forms
(4) Tax on Goods that are Less Energy Efficient than other Goods of the Same Type Due to Design or Construction
(5) Tax on Energy-intensive Goods
(6) Charges for Operating Source of Pollution
(7) Federal Assistance from a Potentially Wide Variety of Sources
(8) Fees for Site Applications and Long Range Plans and Forecasts.

Implications. Numerous scenarios can be developed which incorporate one or more of these options with other institutional options outlined in this report. The implications of employing one or more of these revenue sources will depend on the details involved. No attempt will be made to elaborate on these implications.

b. Direct Public Investment

(1) Direct Siting of Facilities and Production of Energy (Electric Power) by the State

This option and its implications were discussed above under Section 2, Siting Policy. In particular see Section 2.f., State Power Authority.

(2) Joint State Provate Sector Corporations

This option would entail the joint financial underwriting of new energy facilities by both the public and private sectors. This would probably be most feasible for the electric and gas industries. Public and private sector siting considerations and investment criteria would be combined to determine siting decisions.

Implications. Under this option, state government would be required to work closely with one or more of the various sectors of the energy industry to jointly finance new facility sitings. It is not inconceivable that such an arrangement may require extensive negotiations involving two sectors of society that are often diametrically opposed. Details of other phases of the siting process, including long range planning, site selection, and site certification, would have to be clearly defined so that a high degree of visibility could be achieved in this potentially controversial arrangement.

This option has the potential for providing the best features of both public and private sector involvement in energy facility siting. The state may be more able to provide a stable source of financial resources for facility development [457]. It can also provide adequate insurance, through the democratic process, that public financial resources will be invested in projects that reasonably satisfy objectives for economic development, equitable distribution of resources, and environmental quality.

(3) State Financing of Energy Facility Development by the Private Energy Corporations

This option would involve state financial assistance to the energy corporations. Options for raising the necessary capital were presented in the previous section. The probable means of financing would be state loans or loan guarantees.

Implications. This option would require legislative authority to invest public resources in quasi-public (electric and gas utilities) or private (fuel production) energy companies. It is likely that the state would require that certain conditions or criteria be met by the private sector, although these would not be as extensive as those encountered with a more direct state involvement.

c. Incentives for Energy Development by the Private Sector

Options under this heading imply a lower degree of economic risk in ventures undertaken and probably a slower market response to the stimuli.

(1) Positive Financial Incentives for Siting

(a) Tax incentives

Tax incentives can be used in a number of ways to encourage energy facility siting. Investment tax credits could be employed to stimulate the development of associated facilities. Accelerated depreciation allowances might also be used to achieve these ends. In addition, deferred taxation may be applied to minimize immediate siting costs. The state may also wish to provide credits against state income tax for local property taxes paid by energy facilities.

Implications. Tax incentives must be justified as an appropriate solution to a well-defined problem (private market imperfections in the energy industry). They have been employed at the federal levels (oil depletion allowance) and they tend to come under close public scrutiny. Tax incentives would have to be designed to avoid undesirable redistributions of income.

Tax incentives are related to the facility rather than to the site. Since facility development, operation and maintenance costs are very large compared to site acquisition costs, incentives to limit the former may be quite effective in stimulating new energy facilities.

(b) Financial incentives for site location

This option builds on the concept of the previous option. It may be desirable to provide strong positive financial incentives to site energy facilities at predetermined locations or at sites that are otherwise deemed suitable. This could be achieved by providing the tax incentives of the previous option for predetermined sites or for sites that meet state-designated suitability criteria. Such incentives would not be available for other sites.

A variation on this option would entail state acquisition of suitable sites with the sites subsequently being sold to energy corporations at either a token price or at a somewhat reduced price. The previous option could then be tied into the arrangement.

Implications. The legality of this option would have to be determined. In order to be acceptable, the use of this option would probably have to be based on well-defined long range plans for energy development and economic growth. Steps would have to be taken to insure equitable distribution of the related costs and benefits.

(2) Negative Financial Incentives for Siting

Options under this heading would be characterized by fees, penalties, or other charges to discourage the siting of energy facilities in certain areas or to provide a source of revenue to ameliorate the adverse effects of locating a site in those areas. This option could be used to discourage siting in coastal areas that are deemed unsuitable for energy facilities. Negative financial incentives could be graduated to reflect the relative desirability of siting in various coastal or inland areas.

Implications. The employment of negative financial incentives implies a reactive approach to siting regulation. This option, along with other options that provide financial incentives or disincentives, should be based on a rational plan for energy development in the state. Since these options tend to create spillovers into other sectors of the local or regional economy, the probable implications would have to be fully assessed.

8. INTERGOVERNMENTAL RELATIONS

a. State-Federal Relations

The federal role in energy facility siting outlined in Section III.B. indicates that there are several aspects of siting that involve federal agencies. Section 307 of the Coastal Zone Management Act (CZMA) requires that federal actions be consistent with approved state CZM plans. The Act also requires that states consider the national interest in the development of CZM plans and programs. Greater coordination between the states and the federal government in energy policy and in the siting of energy facilities will promote economically efficient, publicly acceptable and environmentally sound energy development. The options described below suggest alternative mechanisms by which the Great Lakes states might interact with the federal government to achieve these objectives and implement the portions of the Act requiring consistency.

(1) Coordination and Consolidation of Siting Procedures

A variety of options exist under this general heading. These options are associated with the phases of energy facility siting regulation that are typically encountered in state siting programs. The approaches taken by a particular state would depend on the siting procedures currently employed or on those that may be selected by the state from the institutional options outlined above.

(a) Long range planning

To align the long range plans and forecasts for energy development of the federal and state governments, the states may attempt to incorporate federal agencies concerned with long range energy planning (e.g., ERDA, NRC, FEA, and the FPC) into the long range planning process employed by the state. This could be achieved by requesting extensive review and comment by these agencies on state plans, by requesting that these agencies attend public hearings and administrative meetings held by the state on long range plans and forecasts, and by seeking clarification of federal policy in various substantive areas addressed in the state energy planning process.

Implications. This option implies that the state has some involvement in long range energy planning. It may facilitate the identification of those aspects of state and federal energy facility siting policy that are likely to generate controversy and thus require special attention. Resolution of these issues early in the process will streamline siting regulation by reducing delays.

(b) Involve federal agencies in the state site certification process

This option would provide for direct involvement of the appropriate federal agencies in the site review and evaluation process. Representatives of these agencies would participate in the internal review process by acting as resident liaisons between their respective agencies and the state siting bureaucracy and CZM agency. For example, representatives of the U.S. Environmental Protection Agency could interpret applicable air and water quality standards as they relate to the specific siting proposal under consideration in the state application process. The FPC could evaluate the proposal (for an electric generation facility) in terms of the degree to which it increases the reliability of electricity production and meets well-defined energy demands. Other federal agencies could be incorporated in the process as warranted by the types of energy facilities and locations involved.

At the same time, federal agencies could take this opportunity to obtain state approval for federal actions affecting the coastal zone as required under the consistency provisions of the CZMA. Permits issued by the Corps of Engineers for structures in navigable waters or by the EPA for pollutant discharges could be discussed and a determination made with regard to joint state and federal approval.

Implications. Increased participation of the federal government in the state energy facility site certification process would have to be handled very carefully to avoid charges of federal encroachment in state siting matters. The important point with regard to this option is that the states as well as the federal government could benefit from increased communication and cooperation in the certification of energy facility sites. This option would provide for enunciation in the siting decision process of the specific aspects of federal policy, such as site evaluation or site suitability criteria, and air, land, and water pollution control standards, which must be complied with, or which reflect those interests and concerns of society that are represented by the federal government. Importantly, the Coastal Zone Management Act requires consideration of the national interest in the siting of facilities that are of greater than local significance. Also, by bringing the federal agencies into the certification process, and by encouraging public participation, the states could facilitate the resolution of policy conflicts with the federal government.

(2) Consolidation of State and Federal Environmental Impact Assessment Processes

Federal agency environmental assessments under NEPA, and state environmental assessments required under a statewide program or under the state's energy facility siting regulatory program would be consolidated under this option. This could involve combined assessment criteria, uniform time limits, coordinated review procedures, and joint public hearings. This option could be applied to environmental impact assessments of prospective sites outlined in long range plans or of sites for which application for final approval has been made.

These combined assessments could be performed by the lead state siting agency, or by a consultant, or the individiual agencies could contribute their respective inputs to be compiled, possibly by the state.

Implications. This option would eliminate much of the duplicated effort that currently exists in the regulation of energy facilities. A significant savings of public resources might result. This option may also reduce the overall time required to evaluate proposed sites. Each interested party could review the resultant impact statement with its own particular interests in mind. Impact assessment guidelines should be developed to insure that all significant impacts are addressed in the analysis.

b. Options for Interstate Relations

Many of the problems and needs related to energy facility siting can be handled either on an intrastate basis or through establishment of appropriate state-federal relations. However, several siting issues will probably not be adequately addressed by these institutional mechanisms. It is with regard to these issues that a sound case for an interstate regional approach to siting regulation can be made.

(1) Establishment of Multi-State Regional Siting Council

This option would entail the formation of an organization by two or more states to deal with siting-related problems and needs that are not confined to one state. This organization could take a variety of forms. Membership would depend on the functions and authority assigned.

Contiguous Great Lake states may wish to employ such an organization comprised of CZM program administrators to coordinate energy facility siting in the coastal zone. The influence of a regional CZM siting council would depend not only on the authority of the council itself but on that of the CZM programs within the respective states. Another approach to an interstate regional siting council would be to include as members the heads of the lead state energy facility siting regulation agencies. This would involve CZM considerations as part of the broader set of statewide siting considerations.

If the principal function of the regional siting council were to assess the impacts of proposed sitings, the council might be structured to include heads of natural resource departments and/or environmental protection agencies, or representatives from state-level environmental review boards of citizen advisory committees.

It would also be possible to establish a skeletal framework for a regional siting council and activate it on an ad hoc basis as the need arose.

Implications. There are several advantages associated with this option. An interstate organization would provide a mechanism for the resolution of energy facility siting-related conflicts between states. It would also provide a single forum for interacting with federal energy-related agencies, and would strengthen the position of the states vis a' vis the federal government. With regard to electric power generation, the private sector, through federal encouragement, has already recognized the need for such cooperation by establishing regional reliability councils to coordinate interstate electric power flows.

Implementation of this option would require some form of agreement between the states, such as parallel state legislation, memoranda of agreement or other mechanisms to bring the states together.

(2) Establish an Interstate Regional Siting Approval Process

This option would entail joint approval of certain kinds of energy facilities by the states involved. This process could be limited to those proposed sitings that would have significant, direct impacts on the environments of two or more states, or that will substantially alter the future availability of energy in two or more states. For example, the siting of, say, a large nuclear or coal-fired electric generation plant in a state's coastal zone may have significant direct impacts on coastal or other areas of one or more nearby states, and it may materially influence future growth patterns in those states as well.

Implications. This option would necessitate a formal mechanism for agreement between two or more states. This implies either approval by a formal interstate siting council or the separate approval by the agency or agencies that have regulatory authority for siting in the states involved. In addition, approval by the federal sector (depending on the location and type of facility) would also be required, as would approval by other levels of organization within a particular state.

The effectiveness of this option would be maximized if the individual siting regulation programs of the states involved were well defined and well coordinated with other environmental and land use policies and programs in those states. Public acceptance of this option would be critical to its success. This option also implies that the states participating in regional site certification are capable of and willing to adopt specific policies regarding siting-related issues to guide their actions in joint siting decisions. This option may act as a catalyst in forcing the states to delineate these policies.

(3) Institute an Interstate Regional Process for Predesignation of Suitable Sites

This option is an extension of one described earlier. It would involve the aggregation of sites deemed suitable by each state into an overall set of suitable sites in the Great Lakes Basin or some sub-region thereof. It could involve the entire area or only the coastal zone of each state.

Implications. Through this approach the states could strengthen their bargaining positions with other levels of organization in the overall siting process. Also, this option fosters an active rather than reactive approach to siting regulation by identifying suitable sites, thereby indicating areas where energy development could generally be favorably received. Identification and predesignation of suitable energy facility sites implies the application of some criteria by which to judge site suitability. The relationships between the suitable sites of adjacent states would have to be determined to avoid conflicts and to reasonably meet each state's goals and objectives for energy development, economic growth, and environmental quality.

This option implies that the appropriate organizations and legal authorities exist in various states to pursue a multi-state regional approach to energy facility siting. To be most effective, this approach requires active state participation in the preparation of long range energy resource and facility plans and demand forecasts. An ongoing, multi-state, long range energy planning process would increase the rationality of siting and would largely determine the site suitability criteria and the priorities for siting new facilities with a particular state. This option would be strengthened if the states chose to acquire certain interests in sites and to encourage development on those sites through a promotional campaign.

C. TECHNICAL OPTIONS

1. FRAMEWORK

The technical options related to energy facility siting and development with regard to the coastal zone have been arranged to provide a full range of policy choices consistent with the Coastal Zone Management Act of 1972. The three major groups of options have been categorized as they relate to jurisdictional decisions. They are:

- Exclusion of all new facility development from the coastal zone management area, including access to coastal waters and related fuel transshipment.
- Exclusion of all new facility development from the coastal zone management area, but allowing coastal water access, related fuel transportation, and product transmission through the coastal zone.
- Inclusion of new facility development in the coastal zone management area, except in designated sensitive areas in which additional development would be precluded.

The coastal zone management area is defined as that area the Great Lakes states will designate as the coastal zone subject to their management program. The definition of coastal zone used by Coastal Zone Management Act of 1972, P.L. 92-583, is as follows:

> Coastal zone means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the lands therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal states, and includes transitional and intertidal areas, salt marshes, wetlands, and beaches. The zone extends, in Great Lakes waters, to the international boundary between the United States and Canada and, in other areas, seaward to the outer limits of the United States territorial sea. The zone extends inland from the shorelines only to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters. Excluded from the coastal zone are lands the use of which is by law subject solely to the discretion of or which is held in trust by the Federal Government, its officers or agents (Sec. 304(a)). [582]
>
> "Coastal waters" means (1) in the Great Lakes area, the waters within the territorial jurisdiction of the United States consisting of the Great Lakes, their connecting waters, harbors, roadsteads, and estuary-type areas such as bays, shallows, and marshes; and (2) in other areas, those waters, adjacent to the shorelines, which contain a measurable quantity or percentage of sea water, including but not limited to sounds, bays, lagoons, bayous, ponds, and estuaries (Sec. 304(b)) [582].

Assumptions included in this discussion of technical policy options are:

- All present and anticipated environmental quality standards and controls will be a minimum requirement.
- Guidelines of the Coastal Zone Management Act as presently stated will be followed in the development of the state CZM programs.

It is intended that the following policy options provide a wide range of considerations but at the same time avoid any preference or bias toward either the conservational or developmental viewpoint regarding the future of the coastal zone.

2. DESCRIPTION OF OPTIONS

a. Exclusion of All New Facility Development from the Coastal Zone Management Area Including Access to Coastal Waters and Related Fuel Transshipment

New facility development in the coastal zone as well as all conveyance of fuel or coastal waters through the management area are excluded by this option. The aim of this option is to substantially reduce the impacts characteristic of energy facilities located in the coastal zone. Exclusion of all new facility development is visualized as aesthetically and environmentally beneficial. This option presumes a conservative attitude towards the development of coastal resources and considers energy facilities to be incompatible with conservation-oriented planning objectives in the coastal zone.

In the discussion of this option, the implications developed will focus on many of the technical, environmental, and economic impacts associated with a policy of facility exclusions.

Although the policy of exclusion may be the least viable of the three general options presented, this option is included to present a full range of options for the siting of energy facilities. Complete exclusion of new facility development from the coastal zone may not, in fact, serve the intent of the Coastal Zone Management Act to include the siting of facilities of national or regional concern.

The Coastal Zone Management Act specifies that adequate consideration be given to the siting of facilities that serve the requirements of the national interest. Such characterization of energy facility siting may preclude an arbitrary exclusion of development within or through the coastal management area. This option is therefore presented to illustrate the range of coastal implications associated with inland siting and is not designed to portray a prescriptive policy concerning energy.

Implications. The primary intent of this option concerns the preservation of the environmental, aesthetic, and recreational uniqueness of the coastal resources of the Great Lakes. The exclusion of new facility development from the coastal zone would permit sizable tracts of shoreline which would otherwise be used for energy facilities to remain in existing uses or be used for purposes of ostensibly less detrimental environmental impact. One would assume that a reasonable adjunct to this stringent policy framework would be an exclusion of similar large scale facilities, e.g., steel plants, from the coastal zone. Depending on the viewpoint, implementation of a policy excluding major industrial uses from the management area would either greatly enhance the flexibility of coastal resource planning or impose rigid, restrictive, and inflexible management of the area. Certainly, land no longer required for energy facilities or their associated access rights-of-way for coastal waters or fuels would be available for a wide range of uses. Public access to the coast could directly benefit, increasing the recreational and aesthetic value of the coastal zone. The natural characteristics of shoreline and near-shore areas not heavily used for recreation would be preserved by this option.

The development of smaller scale, less resource-intensive, commercial activities might serve to offset the economic liabilities in the management area. Small scale activities like light industry may benefit particularly in development at sites once used for energy production. Land around decommissioned fossil-fuel energy facilities could be redeveloped for other purposes. However, redevelopment of a portion of a retired nuclear facility directly adjacent to the reactor vessel would be generally infeasible due to radioactive contamination of the site.

Complete exclusion of new energy facility development in the management area would reduce the continuation of such long-term environmental impacts in the coastal zone. This option would also largely eliminate the milieu of short-term and operating impacts associated with the development of additional energy facilities in the coastal zone.

The movement of fuels would depend heavily on inland modes of transportation. The exclusion of access through the coastal zone for transportation of fuels would have a direct and significant economic impact on the future of commercial lake navigation. The land and inland waterway transportation modes, train, pipeline, truck or barge, would assume the balance of additional fuel movement. The resulting reduction of cost-efficient Great Lakes vessel transportation and the increased use of inland modes would generally raise the delivered price of fuels.

A technical spinoff of the decrease in lake transportation of fuels could be an increased utilization of coal scrubbers. The availability of low sulfur coal from the western states has been abetted by the low-cost transportation rates via dry bulk vessel on the Great Lakes. The denial of future western coal transshipment from lake vessel to new facilities would shift the movement of this coal to other carriers. The resultant transportation costs may encourage utilities to revert to eastern and Appalachian sources and install sulfur scrubbing systems. A sulfur scrubbing system would then increase the acreage required for solid waste disposal. It is estimated that the use of sulfur scrubbers necessitates a 100 to 200 percent increase in land available for solid waste disposal. The expense of this additional land acquisition may be partially offset by the generally lower costs and increased availability of larger tracts of land inland than are commonly prevalent in the coastal zone. Moreover, the competition for land use is regarded as less intense inland than on the coast.

The benefits in lower land acquisition costs are largely counterbalanced with the economies of inland water utilization. The use of inland water resources would in most cases require installation of complex cooling systems (mechanical or natural draft, spray ponds, canals, etc.), which in comparison to once-through cooling demand a higher level of maintenance and operation investment. The exclusion of access to coastal waters for cooling purposes would place enormous pressure on the inland water resources. It is questionable whether these resources could fully accommodate the increase in water demand. In some instances, this would require use of currently expensive technologies (e.g., dry cooling towers) and may result in installation of uneconomically sized units and/or the use of other types of technology for generating electric power which may not presently be fully developed.

The policy of facility and access exclusion might also, over time, shift the existing pattern of power flow. The prevalent coastal power load might gradually shift inland as facilities on the coast were decommissioned, although some older urban sites would be redeveloped with energy facilities which might even use clean fuels. Depending on site location this trend may involve extensive construction of high voltage lines to transmit electricity back to the coastal load centers. Overall, the implications would entail a general reorientation of transmission systems.

Many of the technical drawbacks that have surfaced within the facility exclusion option would probably encourage research in and development of alternative energy sources less dependent on water. Closed-cycle cooling systems would be an obvious component in inland siting. Perhaps other systems fueled by renewable sources (e.g., solar, wind) might evolve under the constraints of non-coastal siting.

The attempt throughout development of this policy option has been to stress the major implications that a program of energy facility and coastal access exclusion would involve. The orientation of such an approach is the future preservation of the unique resources of the coastal zone. While the approach in totality may be extreme and possibly would not comply with the provisions of the Coastal Zone Management Act, certain aspects of this option may be adapted within the CZM programs. The presentation of this option of total exclusion represents an effort to consider the full range of policy choices for the CZM programs.

b. Exclusion of All New Facility Development from the Coastal Zone Management Area, but Allowing Coastal Water Access, Related Fuel Transportation, and Product Transmission through the Coastal Zone

This general option excludes the major negative environmental impacts associated with energy facilities in the coastal zone, while allowing access to the most coastal-dependent features such as cooling water and fuel delivery, and providing corridors for transmission of products such as electricity and oil back into the coastal zone.

In the following discussions of each option and its implications, references will be made to various types of access corridors and rights-of-way. These would include utility corridors and rights-of-way for transmission lines, cooling water pipelines, and for fuel and product conveyance, including coal and oil transport by pipeline, conveyor, barge, or rail. It is assumed that any necessary acquisition of corridors or rights-of-use would be accomplished through a fee simple purchase or a granting of easement where feasible.

It is felt that the above general option is viable under the guidelines of the Coastal Zone Management Act because the exclusion of facilities from the coastal zone is neither complete nor arbitrary in view of the limited coastal resources under consideration. Furthermore, exclusion of these resources from facility development would allow flexibility of planning by state CZM programs for potential uses of higher priority.

(1) Limit Expansion or Conveyance of Construction of Conveyance Systems to Existing Corridors and Rights-of-Way

Implications. Where feasible, this option would limit expansion of conveyance and development of conveyance systems to those corridors presently owned and developed for such uses, such as railroads, transmission lines, and pipelines.

The primary intent and implication of this option would be to limit further commitment of coastal land resources to development of new access routes, while at the same time concentrating those environmental impacts associated with access routes (such as the above ground aesthetic intrusions and effects on adjacent property values and uses) along presently developed corridors.

Restriction of future development to existing corridors would have an effect on conveyance capacity as well. In those cases where present capacity of pipeline, rail, transmission line, or barge conveyance is not being fully utilized, expansion of conveyance could conceivably take place without construction. In those cases where existing conveyances are at full capacity, it might be possible to construct higher capacity systems on the same corridors. Finally, in those areas where existing corridors could support no further expansion in capacity, a necessary limitation on transportation and transmission capabilities would result from this option.

If this option were implemented, it is possible that inland siting of energy facilities would be limited to those areas closest to the existing conveyance corridors, depending, of course, on the relative transportation costs outside the coastal zone. Concentrated conveyance use along existing corridors could result in an overall decrease of operation and maintenance costs, especially in cases where existing capacity can be utilized without new construction. In the case of below-ground transmission lines and pipelines, concentration of such facilities may involve strict control of above-ground land uses to provide for adequate access and maintenance. This latter possibility may involve fewer aesthetic or economic effects.

(2) Avoid Areas of Particular Concern in Determination of Access Routes and Rights-of-Way

Implications. Areas of particular concern would include those areas designated by the state CZM programs according to the guidelines of the CZM regulations. Examples are areas of unique habitats, high natural productivity, substantial recreational value, significant hazard, etc. The implication of such an option would be to encourage preservation of and restrict use of such areas by siting access routes and conveyance corridors elsewhere or in such a way as to avoid them. In cases where the state would designate so many areas of particular concern that access through the coastal zone would be difficult, a limitation on conveyance capacity would result.

(3) Disperse New Access Routes and Corridors

Implications. A dispersal of access routes and conveyance corridors would presumably result in a corresponding dispersal of the environmental and economic costs and benefits associated with the specific conveyance. For instance, aesthetic impacts such as noise generated by rail traffic might be lessened due to dispersal of tracks. Likewise, economic benefits and costs derived from construction and maintenance of dispersed conveyances would be spread out over a larger area.

Increases in land requirements due to dispersal within the coastal zone would increase acquisition costs and at the same time remove land from other or previous uses. Additionally, inland facility siting would tend to be dispersed, corresponding to the water and fuel access dispersal.

(4) Concentrate Access Routes and Corridors

Implications. This option takes the opposite tack from the previous option, but the implications fall into the same categories. Also, this option differs from option (1) by permitting new access and corridors in addition to existing access and corridors. Concentration of access routes and corridors would result in a corresponding concentration of environmental/economic impacts in specified areas. This in turn would confine impacts to the specified areas, while not further affecting other areas. In addition, economic benefits and costs associated with construction of new access facilities would be concentrated. The less even distribution of new access facilities along the coastal zone would permit the use of other lands for other existing or future uses. In conjunction with this concentration of access routes, a corresponding clustering of energy facilities inland might possibly result.

Land requirements related to this option would be greater than in the case of restricting new development to existing corridors, but less than in the previous option of dispersal. Costs of land acquisition would also increase. Finally, it is possible that the implementation of this option would have the overall effect of limiting transmission and transportation capabilities in the event that cost feasibility could no longer be justified.

(5) Specify Development Areas

Implications. This option would allow the state CZM programs or other state agencies to designate those areas which could be developed for access routes and conveyance corridors, thus facilitating long-range coastal zone planning. This option would blend well with option (2), which suggests determination of areas of particular concern, thus identifying those corridors which could be developed for access or conveyance with least negative impact on the remaining coastal zone. Additionally, the review and permitting process might be completed more rapidly, as these specified areas would be more acceptable to the reviewing agency, and therefore reduce in advance possible disagreement over the selected site.

This option would shift the responsibility of corridor site selection from the utilities to the planning agencies and potentially present problems to the utilities in terms of their long-range expansion plans. Given the go-ahead to develop along specified areas, the net result might be a concentration of facilities and their associated impacts. This should be foreseen and planned for in the initial specification of development areas.

(6) Develop Buffer Control Areas

Buffer control areas here refer to zones bordering either side of an access route or conveyance corridor that would reduce or contain the visual and/or auditory impacts of facilities such as railroads, transmission lines, conveyor belts, or above-ground pipelines. This buffering effect might be accomplished by raised, landscaped mounds or simply by retention of a natural green belt during development.

Implications. The reduction of visual and auditory impacts accomplished by the buffer zones would be offset to a certain degree by the increased costs to the developer (utility or railroad) of additional land requirement and landscaping costs. This ratio of benefits and costs would be of a site-specific nature. Such a buffer zone might have a positive effect on adjacent land values and uses.

This option would effectively limit some uses of the land alongside the corridor such as industrial development or perhaps agriculture, but at the same time might provide increased public recreational areas where safety would allow.

(7) Develop Multiple-Use Corridors and Rights-of-Way

In the development of new access routes or corridors, or in the expanded use of existing ones, provisions for multiple uses of the land could be stressed or required. This would be restricted to those uses that would benefit from long continuous stretches of access such as would be expected along rail lines, transmission corridors, or pipeline paths. Such uses might include recreation, such as hiking, or bicycle routes, or multiple facility uses such as combining transmission lines with pipeline paths or rail routes.

Implications. The intent and implication of such an option would be to increase the number of uses in a previously single-use facility route or corridor. This in turn would reduce demand on other coastal lands. Total land costs would be reduced for multiple users of rights-of-way, though construction and maintenance costs might increase in the case of recreation development along rights-of-way. In the case of multiple conveyance use of rights-of-way, a combination of conveyances could possibly significantly increase the visual or noise impacts to the point of offsetting those benefits gained from multiple use. Finally, increased safety hazards resulting from increased public use of conveyance corridors would require appropriate safeguards.

(8) Establish Limit on Resource Utilization

Within this report, figures have been developed for the various resource requirements of different energy facility types. This option would specify the amount of land or water that might be used by energy facilities and thus limit the development or use of access routes or corridors through the coastal zone as determined by utility/CZM joint planning. This would probably require some form of legislation, regulations, or standards to facilitate implementation.

Implications. This option would encourage conservation of land resources in the coastal zone and promote land use that will be of higher priority as future demand increases. By limiting the amount of land available for development of access routes and corridors, inland facility development would necessarily be controlled by capacity limitations of access routes or might be displaced to other coastal zone locations.

Limitations on water resource utilization would be intended to preserve coastal water quality and quantity for future use and development, as well as for future development of the shoreline. A limit on water availability for cooling and other uses would result in reduction or displacement of water consumption and have impacts on water quality. It would likely encourage development of technologies which use less water or return higher quality water to the environment. This, in turn, could increase the cost of using water.

(9) Provide Financial Assistance to Affected Areas for Impact Assessment and Amelioration

(a) Impact assessment

Implications. The intent of this option is to direct monies collected from the utilities or facility owners, or provided by the state or federal government, to the areas affected by proposed facilities for impact assessment. This would ostensibly improve initial assessment and aid identification of potential impacts early in the facilities planning stage by aiding local planning efforts. Additionally, this option would increase public involvement in both the planning and decision-making process.

In providing for local input to impact assessment, this might also result in an overall increase in time taken to reach decisions. Also, regardless of who provides the monies, planning costs will increase. Finally, the increase in money for local planning efforts would provide for added employment in the impact assessment field, e.g., consultants or planners.

(b) Impact amelioration

Implications. Provision of monies for amelioration of impacts associated with energy facilities access routes would increase costs but also increase local benefits as a result of potential upgrading of environment in the vicinity of the facility in question. It would also obviate negative impacts of access route development.

(10) Use Technologies Requiring Least Land Area for Access Rights-of-Way

Implications. It is intended that this requirement would result in preservation of coastal land for future higher priority use and development. This option would encourage both the use of existing technologies and development of new technologies that would require less land. Development costs might increase but land costs would decrease. Examples of such technologies might be coal slurry pipelines replacing short haul rail routes, or narrower or underground transmission line requirements.

c. Inclusion of New Facility Development in the Coastal Zone Management Area, Except in Designated Sensitive Areas in Which Additional Development Would be Precluded

This set of options is designed to address the present status of energy facility siting, which places no geographical or locational restrictions on siting in the coastal zone, except in designated sensitive areas. These options are intended to maintain the present policy of siting in the coastal zone management area but suggest possible limiting or restrictive policies which would enhance or preserve coastal resources for future use and development.

All facilities previously described in this report are included for consideration, and the support materials regarding facility type descriptions and associated impacts serve as the basis for the option selections. The implications following each option are intended to look at the ramifications (intended or otherwise) of an option if implemented. Furthermore, it should be realized that these options are not presented for blanket approval and implementation. It is possible that they may be implemented individually or in combinations where feasible. It is equally possible that none of the options will be implemented as presented.

It is felt that this group of options represents a framework of potential policies that could be most easily implemented by the state CZM programs, short of doing nothing at all. Under the Coastal Zone Management Act and its amendments, the state programs will have management responsibilities for those lands and uses of land having a direct and significant impact on coastal waters. The following options suggest various forms of management of new energy facilities in the coastal zone.

(1) Limit Expansion or Reconstruction to Existing Industrial or Utility Areas

This option would prohibit commitment of coastal lands and other resources to future energy facility development by restricting new development or capacity expansions to those areas presently developed for such uses.

Implications. This option would require new electric generating units to be built on sites which have already been developed for electrical generation, thus increasing productivity per unit of land without increasing land requirements. Presently, large tracts of land are developed for generating facilities with only a small percentage of this land being utilized for the generating plant (see facility descriptions on coal and nuclear facilities), allowing for potential expansion.

Those environmental/economic costs and benefits associated with facility development would be concentrated at existing sites as a result. However, many of the negative environmental impacts associated with site preparation would be avoided and associated costs would be less also. Some environmental impacts of operation and maintenance would be concentrated and thus further degrade the quality of the existing site. Economic benefits would be restricted to specific areas of previous facility development.

In cases where existing energy facility sites could not technically support further expansion, generating or refining capacity would be displaced to other or non-coastal sites.

(2) Avoid Areas of Particular Concern, Including Sensitive Areas

Areas of particular concern would include those areas designated by the state CZM programs according to the guidelines of the CZM Regulations. Examples are areas of substantial recreational value, significant hazard, and great sensitivity, such as areas of unique habitats and high natural productivity, as well as others.

Implications. This option would preserve applicable coastal resources for future development possibilities and provide for protected environmental preserves. It would restrict facility siting in the coastal zone, intensify competition for remaining coastal areas between energy facilities and other uses, and could ultimately promote inland siting in those cases where remaining coastal lands are not sufficient or satisfactory for energy facility development.

(3) Encourage Development of Dispersed Siting

Implications: Dispersed siting of new energy facilities or a deliberate spatial distribution of new developments would tend to disperse environmental impacts and at the same time increase systems reliability.

This option also would have the effect of increasing construction and fuel transport costs as distance from load centers increased. To offset long distance transportation costs it is entirely possible that an increase in development of fuel transshipment facilities would result. Economic costs and benefits associated with facility construction and operation would be more evenly distributed but would increase or decrease depending on the site specifics.

(4) Encourage Multiple Unit/Single Site Development

This option would allow development of new areas of coastal land, but in a manner that would obtain the highest energy production per unit of land.

Implications. It is felt that implementation of this option would have the effect of reducing land requirements, therefore preserving coastal lands for future use. It would reduce development costs per unit of energy and would reduce transport and transmission costs.

As with the first option in this section, this option would tend to concentrate the environmental/economic costs and benefits in specific areas.

(5) Specify Development Areas

State CZM programs, in addition to designating areas of particular concern, would specify those areas, including energy resource areas, remaining in the coastal zone where facility development would be permitted.

Implications. Ideally, this would provide the coastal zone planning agency with some control of the degree of concentration of facilities and their impacts. In addition, it would facilitate future coastal zone land use planning.

Adoption of this option would remove some control of the site selection process from the utilities and shift the burden of planning to the state CZM or other planning agencies. Because of the intricate nature of suitable site selection for such facilities as nuclear and coal-fired power plants, an expansion or addition of necessary expertise within these agencies would be required. Hence, there would be an employment benefit, but this would be offset by the increase in costs of this added responsibility.

(6) Specify Facility Type and Size in the Coastal Zone

Based on their associated impacts, only certain types of facilities determined by the CZM agencies would be allowed to site in the coastal zone. An example of this would be to allow the coastal siting of nuclear plants with cooling towers rather than coal-fired plants with once-through cooling. The intent here would be to specify a facility which does not commit large areas of land to coal and fly ash storage and does not have significant entrainment/impingement impacts on the lakes. This is only an example and does not indicate a preference.

Implications. This option, if implemented, would provide for control of the type and scale of impacts to be permitted in the coastal zone. Because of the extensive planning required to determine what impacts will and will not be acceptable, an increase in cost of planning programs is foreseen. Likewise, development costs and associated planning problems would increase for the facility owners.

(7) No Restrictions on Facility Type and Size in the Coastal Zone

This option, while assuming that present environmental standards will be maintained, provides for no further siting restrictions or controls with regard to the coastal zone.

Implications. The intent of this option would be to promote the most rapid and inexpensive development of energy facilities per unit of production and capacity. This would allow the utilities to more readily "meet America's growing energy needs."

(8) Give Coastal Development Priorities to Energy Facilities

This option would give first priority to energy facilities in the development of coastal lands. In other words, if a tract of land might be available for an auto plant development or a refinery, under this option the refinery would be given priority by the state CZM program.

Implications. Implementation of this option would provide for lower cost energy production by facilitating utility access to fuel and water resources. This would also encourage lake transportation of fuels and promote expansion of harbor and transshipment facilities.

In addition, this option would reduce coastal land and other resources which might be used for other development. Facility impacts on the coast would increase, e.g., thermal loading from cooling water, aesthetic intrusions of transmission lines, and increase in construction employment. This option would increase coastal zone transmission capacity requirements in areas devoid of previous development.

(9) Site Close to Existing Transshipment Facilities

Implications. The intent of this option would be to decrease costs and negative environmental impacts associated with the transportation of fuels within the coastal zone. Land committed to these conveyance systems would be reduced as well. This option would limit siting alternatives, depending on the number or variety of transshipment facilities in existence. The merit of this option would depend also on the relative location of the transshipment facility to major transmission systems. In some cases, higher cost of transmission would offset fuel transportation cost savings.

Expansion of existing transshipment facilities might necessarily follow, as generating plant fuel demands increased in a concentrated area. This clustering of plants in the vicinity of transshipment facilities would concentrate those economic benefits and environmental costs as well, resulting in either a financial shot in the arm for the local community or an environmental eyesore, depending on the quality of planning.

(10) Locate in Proximity to Existing Electric Power Grid

The electric power grid is the network of extra high voltage (ehv) transmission lines used for regional distribution of electricity. The intent of this option in contrast to the preceding one would be to site close to the transmission system to reduce construction and maintenance costs of new tie-in lines.

Implications. This would reduce those environmental and economic impacts associated with the construction and maintenance of new transmission lines required to tie distant generating facilities into the power grid system. This would increase the cost of fuel transportation and water conveyance in those cases where the existing power grid was not near the coast. Siting alternatives would necessarily be limited as a result of this option, and in some cases capacity of existing systems might have to be increased to handle new generating demands.

(11) Assign Priorities for Facility Development to Those Facilities Employing By-Product Utilization

By-product utilization includes use of waste heat from generating plants for industrial processes, mixture of fly ash with asphalt, utilization of thermal discharges for mariculture, and others.

Implications. This would reduce the local negative environmental impacts associated with fuel utilization, such as air pollution, waste storage, and cooling discharges, and at the same time promote efficient use of resources. By prioritizing siting, an incentive for development of by-product utilization would be established. Operating costs would be reduced overall because of more efficient utilization of primary fuels.

Development costs would necessarily increase in order to make these by-product usages technically and economically feasible. Symbiotic siting of generating facilities and industrial users of by-products would result in concentration of environmental/economic impacts in specific areas.

(12) Develop Buffer Zones

As specified in the second set of options, buffer zones are areas designed to reduce or contain aesthetic intrusions associated with energy facilities. Examples might be green belts surrounding refineries, preservation of natural areas around power plants, or vegetated berms around coal storage areas.

Implications. Development of buffer zones would reduce visual, auditory and other impacts on the human senses which may be undesirable. Green belts have been shown to naturally filter out some types of air pollution. In some cases, increased recreational use may accompany development of buffer zone areas. However, uses such as industrial development would be restricted. Costs of developing these buffer zones would fall on the owners of the energy facility contained within and therefore raise the cost of the facility overall.

(13) Maintain or Increase Public Access to the Shoreline in the Event that a Facility's Property has Shoreline Frontage

Under this option the new facility owner would include plans for public access to shoreline areas if his property includes shoreline.

Implications. Ideally, this option would provide for increased public access to scarce shoreline areas for uses such as recreation. This would in effect shift some of the burden of public access acquisition and development from state and local agencies to utilities and facility owners. Development costs would increase for the utilities, but these might be passed along to the consumers.

There might possibly be restrictions to this option in the case where safety regulations would not allow such activities (i.e., nuclear safety exclusion zones).

(14) Establish Restrictions on Cooling Type

Implications. This option would provide stricter controls on those environmental impacts associated with condenser cooling methods. The environmental control and planning agencies, rather than the utilities, would select cooling systems and would decide which type would be most desirable in the coastal zone. This might result in a decision to ban flow-through cooling because of negative effects on aquatic life, or a ban on cooling ponds because they require large amounts of land area. Finally, the costs to utilities to implement these prescribed cooling types might be so restrictive as to encourage inland siting.

(15) Adopt Air and Water Quality Standards Compatible with Coastal Siting

This option would allow the state CZM programs to suggest stricter environmental standards for energy facility operation in the coastal zone.

Implications. The thrust of this option would be to improve air and water quality, or at least prevent further degradation of coastal environments. This option would increase costs of environmental controls, and in cases where these costs would be prohibitive, discourage coastal siting. It is entirely possible that adoption of stricter environmental standards for the coastal zone would result in a favoring of those facility types which most easily meet the new standards. However, as noted in Section III.B.1.d. of this report, the states may not be able to adopt stricter (or more lenient) environmental standards specified only for their coastal zones.

(16) Provide Financial Assistance to Local Areas for Impact Assessment and Amelioration

(a) Impact assessment

Implications. Similar to option (9)(a) in the second grouping, this would provide monies to the area affected by a proposed facility to aid local planning agencies in initial identification of potential deleterious impacts. This would increase public involvement in the planning process and decision making. This might also increase the time required for decision making. Increased employment in the planning and consulting field would result from these monies, but these planning costs would have to be met elsewhere.

(b) Impact amelioration

Implications. Monies allocated for this purpose would obviate negative impacts of energy facilities and may in the long run increase benefits to a local area due to overall increases in environmental or economic quality.

(17) Permit Shoreline Site Location of Energy Facilities

This option would permit the location of power plants and refineries next to or near the shoreline, as well as permit the use of coastal resources. Unless shorelines are presently zoned for other uses, this option is essentially the status quo.

Implications. This option would result in shoreline use for energy facilities, thereby precluding its use for other major development or conservation purposes. However, with proper planning, other uses could be accommodated in some areas of the energy facility site. The development of the land near shorelines and its use for energy facilities might possibly induce local shoreline damage. By competing with other possible uses of the shoreline, energy facilities development of the shoreline might increase its value and local land acquisition costs. The presence of an energy facility next to or near the shoreline may also affect adjacent land values and uses. By doing so, commercial-industrial development of the shoreline may be encouraged, possibly discouraging other uses of neighboring shorelines. Related to these considerations are the visual-aesthetic effects of large facilities on the shoreline.

An advantage of shoreline or near shoreline location is that docking facilities might be developed for water transportation of fuels and other materials, if water transportation is less expensive. Shoreline location would also provide ready access to water for cooling or other plant processes.

(18) Specify Shoreline Setback Distance for Energy Facilities

Under this option, a setback distance for energy facilities would be required. The setback distance could vary depending on the location and local conditions and characteristics. The setback requirement could be established by local ordinance or by legislative action. Such a requirement could affect fuel storage areas for docking facilities, but not the docking facilities themselves. This option would not be intended to affect access to coastal resources for the facilities discussed in this report.

Implications. By specifying a setback distance for energy facilities, the integrity and aesthetic qualities of the shoreline would be preserved. This option might increase multiple use of shoreline property if public access were permitted; i.e., the property could be used for access to coastal resources and for recreation. A required setback distance for energy facilities would increase capital and operation costs for a pipeline and pumping station, particularly if once-through cooling is used and/or the increase in elevation is large between the water source level and the plant. Additionally, if fuel or products are received by water transportation, transportation costs of these materials would be increased. For a discussion of these increased water provision and transportation costs, the reader is referred to Sections IV.A.5.b.(1).(a) and (b) of this report. The use of a setback distance might also affect adjacent development along the shoreline as well as development behind the setback distance. For example, the setback line might preserve shoreline for natural or recreational uses on the property affected as well as encouraging such uses on adjacent areas. This situation may influence adjacent land values also. Behind the setback line, commercial-industrial as well as residential development might cluster, depending on provision of roads and utility services.

The use of a setback distance might also encourage companies and governments to purchase property for energy facilities that would not have property frontage on the shoreline, as long as resource access was available, such as through the purchase of an easement.

With respect to the distance considered for setback, a 1000-foot setback for the plant and appurtenances might be similar to not having any setback requirement at all. This would be particularly true in the case of aesthetic and shoreline use effects. A setback distance approximately 1/2 to 1 mile might be more beneficial from the aesthetic and shoreline use standpoints, but would involve some incrementing water provision costs and possibly transportation costs. However, as in the case of the Pleasant Prairie facility in Wisconsin, an inland location may be advantageous to tying in to the existing transmission system.

(19) Permit Only Those Facilities Absolutely Requiring Shoreline Location to be Located on or Near the Shoreline

This option would necessitate some kind of legislative action at the local or state level. It would be similar to zoning areas for particular uses; in this case, zoning certain shoreline areas for particular energy facilities which absolutely require a shoreline location. Under this option, energy facilities would still have access to coastal resources.

Implications. This study has not identified any energy facilities, except docking and transshipment facilities for water transportation, which absolutely require shoreline locations. This option would permit areas along the shoreline to remain in existing use or to be used for other purposes, rather than be used for energy facilities. Considerations for shoreline location should emphasize economic as well as environmental factors. Inland locations in some areas may result in significantly greater economic costs which may not be warranted, even when compared to the environmental effects. Thus, this approach would have to be used on a case-by-case basis, and yet applied stringently enough to have a recognizable effect on shoreline uses. This option might place considerable emphasis on a state-required environmental report on energy facilities, an approach already adopted by some Great Lakes states. Other implications such as effects on shoreline and inland development, tie-in to the transmission system, and water provision and transportation costs would be similar to technical option (18) above.

D. SUMMARY

The institutional and technical policy options provide a broad range of directions that the states and their coastal zone management programs might take. The options in the various categories serve to highlight the many possibilities for: (1) developing new institutions to address the current and complex problems related to energy facilities siting; (2) utilizing existing institutions with new or expanded arrangements among them and, in some cases, additional responsibilities; (3) developing financial approaches to assist the companies and governments involved in energy facility siting; and (4) developing technical, environmental and economic approaches to locating energy facilities with respect to the coastal zone management area and the shoreline. Particular emphasis was given to integrating these options with state coastal zone management programs. Selection of some options within certain categories necessarily precludes choosing other options within or among the categories. For the most part though, the selection of combinations of options in various categories is unrestricted. Individual or collective decisions by the states and their CZM programs regarding well-defined policies for review and examination of guidelines for energy facility siting may assist the utility companies and other energy-related industries in their short and long range planning for facilities.

Chapter VII

SUMMARY AND CONCLUSIONS

This study covers several broad subjects related to energy facility siting in a manner that should be useful to the Great Lakes coastal zone management programs. Some general conclusions from this study can be made in each of the major areas of analysis.

A. INSTITUTIONAL CONSIDERATIONS

At present, four of the eight Great Lakes states (Minnesota, New York, Ohio, and Wisconsin) have instituted concerted and fairly well defined site selection processes for electric generating facilities. However, these states have not addressed to a significant degree the selection of sites for other types of energy facilities. The four remaining states have only limited involvement in the regulation of sites for all energy facilities, and have concentrated primarily on the certification of a proposed facility with respect to compliance with standards for air, water and land resource protection. In all Great Lakes states, policies to guide the siting of energy facilities in the coastal zone are in the early stages of development.

The authorities of several federal agencies, notably the Nuclear Regulatory Commission and the Environmental Protection Agency, will have a significant influence on energy facility siting. The policies, standards and guidelines of the EPA for the protection of air and water resources define a framework within which other agencies or interests of the public and private sector may operate. The greatest federal impact on future selection of sites for energy facilities will probably be through the Coastal Zone Management Act of 1972 and its 1976 Amendments. Several provisions of the Act deal with energy facility siting.

With respect to incorporating energy facility siting policies into a comprehensive program for coastal zone management, numerous institutional options are available to the states.

The Coastal Zone Management Act allows the states considerable freedom in the development of plans and in the establishment of programs for the management of their coastal zones. The mere fact that such plans and programs are being developed, that they will be reviewed and approved at the state and federal level, and that subsequent actions must be consistent with such plans, will introduce a measure of comprehensiveness and coordination to energy facility siting as well as to the entire process of resource management for the coastal zone. The requirement for a planning process for energy facilities in the Great Lakes states coastal zone management programs provides the foundation for energy facility siting programs that address and emphasize the problems and opportunities of energy facility siting in the Great Lakes coastal zone.

B. TECHNICAL CONSIDERATIONS

1. FACILITIES SITING AND COASTAL DEPENDENCE

The major types of energy facilities included in this study--fossil-fuel and nuclear power plants, coal and oil transshipment facilities, and refineries--were described and their particular site and resource requirements discussed. In addition, a discussion of their major environmental and economic impacts were presented and a framework for analyzing these "activity impacts" suggested. Finally, an analysis of some of the major cost components was given. Based on this material, a description of the coastal dependent, or nondependent, aspects of facility siting was presented. The major conclusion drawn from this analysis is that, like so many other siting factors, the degree of coastal dependence exhibited by an energy facility is a function of the facility type, the geographic area within which it is to be located, and the availability of alternative sites. In addition, certain facility types--refineries, fuel transshipment facilities, and coal conversion facilities--are not expected to have a major impact in the Great Lakes coastal zone during the period considered in the study.

It can generally be concluded that an electrical generating facility does not require a location on or near the coast. However, certain aspects of the facility, such as cooling system and water provision, mode of fuel supply, local geological and topographical conditions, meteorology, location of the existing transmission system, may make a coastal site more or less favorable than an available inland location. An evaluation of this degree of coastal dependence should be carried out for each proposed facility so that it can be compared to other, less displaceable, uses of the Great Lakes coastal zone.

The following general conclusions can be sited with respect to the coastal dependence of power plants:

- Facilities using once-through cooling must be located on or near the shoreline because of substantial inland transportation (pipeline) costs of water provision.

- Facilities using closed-cycle cooling are less dependent on locations on or near the shoreline than are facilities using once-through cooling, assuming all other factors to be approximately equal. Site conditions will determine the type of closed-cycle cooling system used. However, the further inland a facility is located, the greater are the construction (capital) costs for water provision and blowdown pipelines.

- For facilities using closed-cycle cooling, the cost of locating on the shoreline versus the cost of locating inland are essentially trade-offs between construction and operation costs for transmission lines, water supply and cooling facilities, facilities for delivery and handling of fuels, and other supplies, and disposal of waste material.

- Nuclear facilities require very large and massive components, which in most cases are delivered by water transportation. However, rail or road corridors of adequate width and load-carrying capacity can be utilized for delivery of these components. If these rail or road cooridors are not available to potential sites, the location of nuclear facilities may be more dependent on shoreline or near shoreline locations. In any event, field assembly is becoming more common, thus possibly negating some of this shoreline dependence. Otherwise, nuclear facility coastal dependence considerations would be those in the previous conclusion.

The coastal dependence of fuel transshipment and storage facilities and refineries can be summarized as follows:

- Fuel (coal and oil) transshipment and storage facilities receiving or shipping their commodities by water must locate near the shoreline, although storage areas do not have to be located on the shoreline. Storage area location is highly dependent on industrial needs, future transportation requirements, and onsite and offsite use of stored fuel.

• Refineries are not coastal dependent, but do need water for processing and cooling. Coastal dependence for water supply and wastewater disposal considerations is decreasing due to increased water recycling. Air cooling is also decreasing refinery dependence on easy access to water. Refinery location decisions are increasingly becoming market oriented, with decisions being made on a national basis, due to the existence of the national product distribution pipeline.

The degree of coastal dependence exhibited by a proposed energy facility of a type discussed in this report may vary from nonexistent or slight, to very strong or complete, depending on a range of site and facility characteristics. In light of the limited, and in some cases unique, coastal land available in the Great Lakes Basin, an evaluation of the best use of the coastal land should be included in a site selection or approval process. In this way, use of the Great Lakes coastal zone can be reserved for those uses least suited to inland locations. While this may include energy facilities in some cases, it will ensure that a more comprehensive view of coastal development is taken.

2. ENERGY CONSUMPTION AND MOVEMENT

Intensive energy consumption in the Great Lakes Region is facilitated by the availability of an abundant fuel resource, proximity to major water resources, and the unique transportation system afforded by the Great Lakes.

Extensive coal resources in the nearby Appalachian and midwestern regions supply the bulk of the fuel for generating electricity in the Great Lakes states. Oil, a very versatile fuel, has less application historically for the generation of base load power in the Great Lakes Basin. However, the broad and diverse end-use of oil make it crucial to the region's energy needs.

The waters of the lakes are also a source of hydroelectric power for the region and a heat sink for the nuclear and fossil fuel power plants that line the coast.

Transportation of fuels to these plants is facilitated by low-cost waterborne movement on the lakes. The patterns of fuel traffic through the region arise from a complex relation among costs, reliability, and legal regulations.

The arrival of low sulfur western coal on the lakes has marked a change in the prevalent upbound traffic pattern of this commodity. Long-term investments in this movement assure continuation of a new pattern. Complementing and competing with lake movement of coal is the extended use of unit train coal transport.

Unit train movement typically runs directly from the mine to consumer. Litigation by the lake carriers is presently seeking for Great Lakes ports the lower unit train rates already available for other destinations.

Coal will continue to play a dominant role in the future fuel mix of the region. The preeminence of this fuel will depend largely on resolving many of the unanswered questions that presently plague the development of nuclear energy facilities. The use of coal also depends on adjustments of air quality standards or improvements in combustion/air quality control technologies.

New generating capacity is not planned or scheduled to be in service by 1984 in the coastal counties of Illinois, Minnesota or Pennsylvania. The combined planned and scheduled additional electrical energy generating capacity for the entire Great Lakes states area through the mid-1980s is 74,067 MWe, with 19,433 MWe to be located in the Great Lakes coastal counties. (A state-by-state analysis is presented in Chapter VI, Technical Considerations--Energy Consumption and Movement in the Great Lakes Region.) Of this 19,433 MWe of additional capacity by 1984, 28 percent will be coal-fired (Michigan, New York and Wisconsin), 12% will be oil-fired (Michigan and New York), and 60% will be nuclear (Michigan, New York, Ohio, and Indiana).

3. REGIONAL SCENARIOS OF ENERGY DEVELOPMENT

Regional scenarios of energy development (principally electrical energy generation) were prepared to develop a perspective on potential resource impacts of siting new energy facilities in the Great Lakes coastal zone. The scenarios are based on different fuel mix assumptions. The four scenarios with their respective fuel mix assumptions are:

- Scenario I, Recent Trends--50% coal, 35% nuclear, 15% oil, gas and hydroelectric
- Scenario II, High Coal--70% coal, 15% nuclear, 15% oil, gas, and hydroelectric
- Scenario III, High Nuclear--45% coal, 45% nuclear, 10% oil, gas, and hydroelectric
- New Technologies--40-50% coal, 20-35% nuclear, 15-20% new technologies (solar, wind, fluidized bed, etc.)

In developing regional resource requirements for land, water, and fuel (coal), these scenarios were applied to a range of electrical energy demand growth projections (3%/year, 5.5%/year, and 8%/year), an assumed mix of generating facilities (75% base load, 20% intermediate load, and 5% peak load), and an assumed capacity load factor (65%). The resource requirements of the generalized facilities (coal-fired and nuclear power plants) were then applied to these assumptions to evolve the regional resource requirements of energy development.

For the purposes of this study, a three percent growth rate per year in electrical energy consumption was assumed to be a lower bound in projecting future power plant development, given present uncertain circumstances. Actual growth in the future may be considerably higher or somewhat lower. These situations are not disputed or argued. This 3% growth rate will then describe the minimum amount of resources required to meet future electrical energy consumption, as shown in Table 79.

TABLE 79

ADDITIONAL RESOURCE REQUIREMENTS OF THE GREAT LAKES STATES, 1975-1995 SCENARIOS AT 3%/YEAR GROWTH RATE IN ELECTRICAL ENERGY CONSUMPTION

Additional Requirements (1975-1995)	Scenarios		
	I	II	III
Nuclear (units)	70	24	104
land (acres)	46,725	16,020	69,420
water (gpd)			
once-through	$1,008 \times 10^8$	346×10^8	$1,498 \times 10^8$
closed-cycle	$1,512 \times 10^6$	518×10^6	$2,246 \times 10^6$
Coal (units)	40	96	12
land (acres)	16,000	38,400	4,800
fuel (millions of tons per year)	80	192	24
water (gpd)			
once-through	403×10^8	968×10^8	121×10^8
closed-cycle	576×10^6	$1,382 \times 10^6$	173×10^6

Requirements under Scenario IV, New Technologies, is assumed to be about 80% of those in Scenario I, Recent Trends, due to a postulated reduced dependence on more conventional generation technologies.

Assuming an 8%/year growth rate, Scenario I, Recent Trends, projects an additional 238 nuclear units and 185 coal units needed, with land requirements of 233,000 acres, water withdrawals of 5,292 x 10^8 gpd for once-through cooling or 7,805 x 10^6 gpd for closed-cycle cooling, and coal requirements of 370 million tons per year.

Table 80 shows the general projected resource requirements (assuming a 50% coal/50% nuclear fuel mix for additional capacity between 1975 and 1995, which is an approximate average of the four scenarios) that were developed for the Great Lakes coastal counties on the basis of an analysis of the scenarios and each state's energy development.

TABLE 80

ADDITIONAL RESOURCE REQUIREMENTS OF THE GREAT LAKES COASTAL COUNTIES, 1975-1995, ASSUMING A 3% GROWTH RATE IN ELECTRICAL ENERGY CONSUMPTION*

State	Additional Requirements					
	Generating Units*	Generating Capacity (MWe)	Land (Acres)	Water Withdrawals (gpm) Once-Through	Water Withdrawals (gpm) Closed Cycle	Coal (Millions of Tons per year)
Illinois	---	---	---	---	---	---
Indiana**	---	---	---	---	---	---
Michigan	11	11,000	5,870	9.35×10^6	137,500	11.0
Minnesota	1-2	1-2,000	1-2,000	$0.9\text{-}1.7 \times 10^6$	12-25,000	2-4.0
New York	7	7,000	3,740	5.95×10^6	87,500	7.0
Ohio	4	4,000	2,135	3.4×10^6	50,000	4.0
Pennsylvania	---	---	---	---	---	---
Wisconsin	8	8,000	4,270	6.8×10^6	100,000	8.0

*Coal and nuclear units, assuming a 50% coal/50% nuclear mix, as noted above.

**Does not include Bailly nuclear unit, Porter County, on site already containing two coal-fired units.

If an 8% growth rate is assumed, the figures in the table above would increase by factors ranging from 2.0 to 4.8, depending on the state. This indicates that considerable pressure might be placed on the coastal counties of Great Lakes Basin for electrical energy generation facilities.

4. OTHER CONSIDERATIONS

A host of other factors not addressed in this report will affect energy facility siting. Some of these factors involve economic and political circumstances. The economic development and stimulation provided by the siting of an energy facility may be attractive to relatively less developed areas located near load or market centers. In many cases, utilities and industries already have purchased land in outlying areas. Such development may be more acceptable in these localities, and indeed, campaigns for the facilities may be undertaken. Thus, political factors may influence the final location of these facilities. Such political-economic factors are difficult to examine in an objective analysis of energy facility siting, and are beyond the scope of this study.

State energy policies relating to consumption, rates, construction and building requirements, and other factors will affect the need for additional facilities and the types of fuels to be used. Public reaction to the location of individual facilities or types of facilities and energy use will have obvious effects on where facilities will be located as well as when they will be constructed and placed into operation.

The absence of a federal energy policy is permitting public acceptance, environmental and market factors, and state policies to influence energy use and energy facility siting at the national level. The present national energy policy is thereby made up of these subsets of policies which affect each other but are developed separately. While these factors and subsets of energy policies must be incorporated into a federal policy because of their importance, there is no consistency or coherence among them. On one hand, this absence of a federal energy policy does not lock the country into energy developments that may not be advantageous in the long run. On the other hand, the lack of a federal policy results in a piecemeal approach to energy development, inconsistency in dealing with energy consumption and facility siting problems, and confusion for utility and energy related companies as to future planning and investments.

C. POLICY OPTIONS

The institutional policy options described in Section VI.B. indicate the range of options available to the states under the Coastal Zone Management Act, as well as other applicable federal and state legislation. An attempt was made, within the constraints of reasonableness, to make the list as thorough as possible. The options are structured to encourage the reader to develop new options through permutations and combinations of those presented. Note that while special attention is given to matters related to the coastal zone, the options also address the broad issues of energy facility siting on a statewide basis. It is important to relate CZM-specific policy options to the institutional framework of the state as a whole, and to provide consideration of statewide energy facility siting regulation where such programs do not exist.

The technical options were developed within the limits of present or probable technical feasibility to provide as wide a range of choices as possible for future energy facility siting in the Great Lakes coastal zone. The technical options are not constrained by traditional and present institutional policies. This permits consideration of innovative siting options. Given the conclusions of the coastal dependence analysis, the state coastal zone management programs are encouraged to give strong consideration to the siting of energy facilities other than shoreline fuel transshipment facilities) inland from the shoreline, but with access to coastal resources. The technical options suggest how this might be accomplished.

D. IMPLICATIONS FOR FURTHER RESEARCH

During the course of this project, several topics were encountered for which there was a lack of available information or that were beyond this study's scope. Time constraints precluded any extensive investigation of these topics by the study staff so they are offered here as suggestions for additional research. All have a bearing on the siting of energy facilities in the coastal zone.

1. LAND VALUES

Attempts to compare coastal and inland sites for energy facilities were impaired by a lack of information on relative land values. Not only is there a lack of data comparing actual land costs, but the intangible land values associated with aesthetic, recreational and psychological aspects of the coastline also require additional investigation.

2. NUCLEAR FUEL CYCLE

Nuclear power plants require a variety of facilities for the enrichment of nuclear fuel and the processing and disposal of wastes. While none of these facilities are currently located in the coastal zone of the Great Lakes, some are nearby and others are proposed. The scope of the study did not permit adequate consideration of the coastal dependency of such facilities. The transportation of radioactive materials on the Great Lakes also requires additional investigation with regard to transshipment and storage facilities and the potential hazard to the lakes from radioactivity.

3. MULTIPLE-USE SITING

The use of land for one purpose may not preclude all other uses. The intensity of land use in some coastal areas suggests that it may be judicious for states to investigate the possibilities for multiple uses of lands, such as transportation corridors and the shoreline, associated with energy facilities.

4. SYMBIOTIC SITING

The waste heat from a power plant and the heat from incinerating municipal trash both offer opportunities for symbiotic siting. Waste heat may be dissipated in a beneficial, industrial application, while trash may supplement other fuels in the production of electricity or perhaps serve as the sole fuel. Practical problems with implementation of such schemes require investigation.

5. CONSERVATION

While research is underway into various methods of conserving electricity and other forms of energy, the potential for the mitigation of adverse impacts on the coastal zone could be investigated.

6. OTHER FACILITIES

Coastal zone management plans and programs will deal with a wide variety of facilities and land uses. The coastal dependency of these other facilities and uses could be investigated so that a comparison could be made with the results of this report and the relative requirements for coastal access among all land uses could be established.

7. SMALLER SCALE FACILITIES

Although electrical generating facilities were covered in detail in this report, a factor that may affect the construction of large generation facilities is the development of combined cycle generation. Research is being directed toward examining the use of combined cycle generation for facilities (less than 150 MWe) that would serve small communities or neighborhoods and large individual industrial plants. Future pricing policies for electricity use and for natural gas may encourage their application. The use of smaller scale fossil-fuel power plants (other than combined cycle) should also be evaluated and compared to possible use of combined cycle plants. The significance of the possible use of these facilities and their implications for future land, water, air, and fuel use should be examined.

8. DETAILED STATE POLICY ANALYSIS

A highly detailed analysis should be made of the policies, programs, and legal authorities within each state that significantly influence energy facility siting in both coastal and inland areas. This greater level of detail is a logical spinoff from this study and is a necessary prerequisite for each state's development of comprehensive institutional framework to implement energy facility siting policies and/or programs.

9. RELATIONSHIP BETWEEN STATE AND FEDERAL POLICIES

Further research into a number of substantive areas of energy policy in the Great Lakes Basin is needed. A detailed analysis should be made of the specific implications of the various aspects of federal energy facility siting policy for each of the eight Great Lakes states.

10. STATE AND FEDERAL POLICIES

Policy research is necessary in state and federal policies affecting energy use. Suggestions should be made for the establishment of coherent framework within which the present energy use policies can be viewed and future policies developed. Furthermore, the interaction among policy development, technology, and resource requirements needs considerable attention.

At the state level, the effect of electric and fuel rates on the need for energy facilities should be investigated. At the federal level, a comprehensive fuels use-environmental policy would provide guidance to the energy industry.

11. SHORELINE USE

A detailed study of shoreline land use should be undertaken on a state-by-state as well as regional basis. Energy facilities compete with other uses of the shoreline. A better understanding of these uses and their relationship and dependence on shoreline locations could greatly assist coastal zone management planning.

12. ENVIRONMENTAL AND ECONOMIC EFFECTS

Load centers for electricity and facilities to provide this power are clustered near the coastline of the Great Lakes. The environmental and economic effects of these facilities on the Great Lakes coastal zone in the context of resource and impact management should be investigated.

13. LOCAL PLANNING AND DECISION MAKING

Planning and decisions made at the local (municipal, county, multi-county) level can have a significant impact on the availability and use of resources. Planning for energy facilities is a case in point. Further research should be directed toward how local planning and decision-making affect resource management and what are the types of policies, institutions, and processes involved in this planning and decision-making.

14. THE GREAT LAKES BASIN AS A FUTURE EXPORTER OF ELECTRICITY

The Great Lakes provide a water resource for cooling and process water in the energy industry as well as for other industries. The potential exists for this use of Great Lakes water to expand in the future. Energy facilities do not need to locate on the shoreline to use this resource, but can be located inland and still draw on it. If large energy facilities or clusters of facilities locate in or near the coastal zone of the Great Lakes and export energy from this area while utilizing its water resources, the social, economic, political, and environmental implications of this circumstance should be examined in detail.

15. INTERNATIONAL IMPLICATIONS

Great Lakes ports engage in international shipment of fuels for energy production. In addition, electricity is transmitted back and forth (primarily on a seasonal basis in the Great Lakes Region) across the international boundary. Further study should be undertaken by the United States and Canada to determine the implications of this for plant requirements and the associated resource demands and impacts.

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Appendix C

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While a broad group of technical advisors from both the public and private sectors participated in the study by reviewing and commenting on preliminary material and the draft report, this should not be taken as their endorsement of this final report. They served only as advisors, reactors, and providers of information.

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Appendix F

SUMMARY OF AIR QUALITY EFFECTS OF SO_2, PARTICULATES, AND NO_2

Effects of Sulfur Dioxide

1. Effects on Humans

- 1500 $\mu g/m^3$ (0.52 ppm) of sulfur dioxide (24-hour average), and suspended particulate matter measured as a soiling index of 6 cohs or greater: increased mortality may occur (American data).
- 715 $\mu g/m^3$ (0.25 ppm) of sulfur dioxide and higher (24-hour mean), accompanied by smoke at a concentration of 750 $\mu g/m^3$: increased daily death rate may occur (British data).
- 500 $\mu g/m^3$ (0.19 ppm) of sulfur dioxide (24-hour mean), with low particulate levels: increased mortality rates may occur (Dutch data).
- 300 $\mu g/m^3$ to 500 $\mu g/m^3$ (0.11 ppm to 0.19 ppm) of sulfur dioxide (24-hour mean), with low particulate levels: increased hospital admissions of older persons for respiratory disease may occur; absenteeism from work, particularly with older persons, may also occur (Dutch data).
- 715 $\mu g/m^3$ (0.25 ppm) of sulfur dioxide (24-hour mean), accompanied by particulate matter: a sharp rise in illness rates for patients over age 54 with severe bronchitis may occur (American data).
- 600 $\mu g/m^3$ (about 0.21 ppm) of sulfur dioxide (24-hour mean), with smoke concentrations of about 300 $\mu g/m^3$: patients with chronic lung disease may experience accentuation of symptoms (British data).
- 105 $\mu g/m^3$ to 265 $\mu g/m^3$ (0.037 ppm to 0.092 ppm) of sulfur dioxide (annual mean), accompanied by smoke concentrations of about 185 $\mu g/m^3$: increased frequency of respiratory symptoms and lung disease may occur (Italian data).
- 120 $\mu g/m^3$ (0.046 ppm) of sulfur dioxide (annual mean), accompanied by smoke concentrations of about 100 $\mu g/m^3$: increased frequency and severity of respiratory diseases in school children may occur (British data).

Material in this appendix is adapted from Environmental Protection Study, prepared by ICF, Incorporated, for the Michigan Public Service Commission. May, 1975.

- 115 $\mu g/m^3$ (0.040 ppm) of sulfur dioxide (annual mean), accompanied by smoke concentrations of about 160 $\mu g/m^3$: increase in mortality from bronchitis and from lung cancer may occur (British data).

2. Effects on Visibility

- 285 $\mu g/m^3$ (0.10 ppm) of sulfur dioxide, with comparable concentration of particulate matter and relative humidity of 50 percent: visibility may be reduced to about five miles (American data).

3. Effects on Materials

- 345 $\mu g/m^3$ (0.12 ppm), accompanied by high particulate levels: the corrosion rate for steel panels may be increased by 50 percent (American data).

4. Effects on Vegetation

- 85 $\mu g/m^3$ (0.03 ppm) of sulfur dioxide (annual mean): chronic plant injury and excessive leaf drop may occur (Canadian data).
- 860 $\mu g/m^3$ (0.3 ppm) of sulfur dioxide for 8 hours: some species of trees and shrubs show injury (American data).
- 145 $\mu g/m^3$ to 715 $\mu g/m^3$ (0.05 ppm to 0.25 ppm): sulfur dioxide may react synergistically with either ozone or nitrogen dioxide in short-term exposures (e.g., 4 hours) to produce moderate to severe injury to sensitive plants (American data).

Effects of Particulates

1. Effects on Humans

- 750 $\mu g/m^3$ and higher for particulates on a 24-hour average, accompanied by sulfur dioxide concentrations of 715 $\mu g/m^3$ and higher: excess deaths and a considerable increase in illness may occur (British data).
- A decrease from 140 $\mu g/m^3$ to 60 $\mu g/m^3$ (annual mean) in particulate concentrations may be accompanied by a decrease in mean sputum volume in industrial workers (British data).
- If concentrations above 300 $\mu g/m^3$ for particulates persist on a 24-hour average and are accompanied by sulfur dioxide concentrations exceeding 630 $\mu g/m^3$ over the same average period, chronic bronchitis patients will likely suffer acute worsening of symptoms (British data).
- Over 200 $\mu g/m^3$ for particulates on a 24-hour average, accompanied by concentrations of sulfur dioxide exceeding 250 $\mu g/m^3$ over the same average period: increased absence of industrial workers due to illness may occur (British data).
- 100 $\mu g/m^3$ to 130 $\mu g/m^3$ and above for particulates (annual mean) with sulfur dioxide concentrations (annual mean) greater than 120 $\mu g/m^3$: children residing in such areas are likely to experience increased incidence of certain respiratory diseases.

- Above 100 $\mu g/m^3$ for particulates (annual geometric mean) with sulfation levels above 30 mg/cm^2-mo.: increased death rates for persons over 50 years of age are likely (American data).
- 80 $\mu g/m^3$ to 100 $\mu g/m^3$ for particulates (annual geometric mean) with sulfation levels of about 30 mg/cm^2-mo.: increased death rates for persons over 50 years of age may occur (American data).

2. Effects on Direct Sunlight

- 100 $\mu g/m^3$ to 150 $\mu g/m^3$ for particulates, where large smoke turbidity factors persist: in middle and high latitudes direct sunlight is reduced up to one-third in summer and two-thirds in winter (American data).

3. Effects on Visibility

- 150 $\mu g/m^3$ for particulates, where the predominant particle size ranges from 0.2 to 1.0 and relative humidity is less than 70 percent: visibility is reduced to as low as 5 miles (American data).

4. Effects on Materials

- 60 $\mu g/m^3$ (annual geometric mean), to 180 $\mu g/m^3$ for particulates (annual geometric mean), in the presence of sulfur dioxide and moisture: corrosion of steel and zinc panels occurs at an accelerated rate (American data).

5. Effects on Public Concern

- 70 $\mu g/m^3$ for particulates (annual geometric mean), in the presence of other pollutants: public awareness and/or concern for air pollution may become evident and increase proportionately up to and above concentrations of 200 $\mu g/m^3$ for particulates (American data).

Effects of Nitrous Oxide

1. Effects on Humans

- 225 $\mu g/m^3$ (0.12 ppm) for nitrogen dioxide: an odor becomes detectable.
- 9,400 $\mu g/m^3$ (5 ppm) for nitrogen dioxide for 10 minutes: has produced transient increase in airway resistance.
- 162,200 $\mu g/m^3$ (90 ppm) for nitrogen dioxide for 30 minutes: has produced pulmonary edema 18 hours later.
- 118 to 156 $\mu g/m^3$ (0.063 to 0.083 ppm) for nitrogen dioxide (24-hour standard) with a mean suspended nitrate level of 2.6 $\mu g/m^3$ or greater: increased acute bronchitis among infants and school children.
- 117 to 205 $\mu g/m^3$ (0.062 to 0.109 ppm) for nitrogen dioxide (24-hour mean) with a mean suspended nitrate level of 3.8 $\mu g/m^3$ or greater: increased acute respiratory disease in family group.

2. Effects on Materials

- <u>470 $\mu g/m^3$</u> (0.25 ppm) for nitrogen dioxide for 8 months caused leaf abscission and decreased yield among navel oranges.
- <u>940 $\mu g/m^3$</u> (0.5 ppm) for nitrogen dioxide for 35 days resulted in leaf abscission and chlorosis on citrus fruit trees.
- <u>1,900 $\mu g/m^3$</u> (1 ppm) for nitrogen dioxide for one day can cause overt leaf injury to sensitive plants.

Appendix G

ELECTRIC GENERATING FACILITIES

COUNTY LOCATION	COMPANY	PLANT NAME	MWe	FUEL	WATER SOURCE	AVG CFS INTAKE	PLANT HEAT RATE	# OF UNITS	STATE
Ashtabula	Clev. Elect. Illum. Co.	Ashtabula	640	Coal/Oil	Lake Erie	658	BTU/KWH 11,428	9	Ohio
Lorain	Clev. Elect. Illum. Co	Avon Lake	1,275	Coal/Oil	Lake Erie	947	10,338	9	Ohio
Lake	Clev. Elect. Illum. Co.	East Lake	1,275	Coal/Oil	Lake Erie	1,270	9,512	5	Ohio
Cuyahoga	Clev. Elect. Illum. Co.	Lake Shore	514	Coal/Oil	Lake Erie	456	11,552	5	Ohio
Lake	Commonwealth Edison Co.	State Line	972	Coal/Gas	Lake Michigan	1,259	10,573	4	Indiana
Cook	Commonwealth Edison Co.	Fisk	547	Coal/Gas	Chicago Canal	401	11,302	3	Illinois
Cook	Commonwealth Edison Co.	Calumet	107	Gas	Calumet River	67	13,224	1	Illinois
Cook	Commonwealth Edison Co.	Crawford	702	Coal/Gas	Chicago Canal	593	10,292	3	Illinois
Cook	Commonwealth Edison Co.	Ridgeland	690	Oil/Gas	Chicago Canal	742	11,177	4	Illinois
Lake	Commonwealth Edison Co.	Waukegan	933	Coal/Oil	Lake Michigan	962	10,195	7	Illinois
Lake	Commonwealth Edison Co.	Zion	1,098	Nuclear	Lake Michigan	1,618	13,269	1	Illinois
Muskegon	Consumers Power Co.	Cobb	510	Coal/Oil	Lake Muskegon	619	10,590	5	Michigan
Charlevoix	Consumers Power Co.	Big Rock Point	75	Nuclear	Lake Michigan	114	11,421	1	Michigan
Bay	Consumers Power Co.	Karn	550	Coal/Oil	Saginaw River	454	9,136	2	Michigan
Ottawa	Consumers Power Co.	Campbell	650	Coal/Oil	Pigeon Lake	504	9,097	2	Michigan
Van Buren	Consumers Power Co.	Palisades	720	Nuclear	Lake Michigan	900	10,981	1	Michigan
Wayne	Detroit Pub. Lightng.Comm.	Misteroky	174	Coal	Detroit River	243	BTU/KWH 10,909	6	Michigan
Ashland	Lk.Superior Dist.Pwr.Co.	Bay Front	82	Coal/ Oil/Gas	Lake Superior	46	13,213	6	Wisconsin
Manitowoc	Manitowoc Public Util.	Manitowoc	69	Coal	Lake Michigan	51	14,999	5	Wisconsin
Marquette	Marquette Brd. of Lt & Power	Sheras	37	Coal/Gas	Lake Superior	30	14,243	2	Michigan
St. Louis	Minn. Power & Light.	Aurora	110	Coal/Oil	Lake Colby	210	13,030	2	Minnesota
St. Louis	Minn. Power & Light.	Hibbard	124	Coal/ Oil/Gas	St.Louis River	364	14,576	4	Minnesota
Oswego	Niagara-Mohawk Pwr.Co.	Oswego	376	Oil	Lake Ontario	500	11,545	4	New York
Erie	Niag.-Mohawk Power Co.	Huntley	828	Coal	Niagara River	1,160	10,380	6	New York
Chautauqua	Niag.-Mohawk Power Co.	Dunkirk	628	Coal/Oil	Lake Erie	890	10,059	4	New York
Oswego	Niag.-Mohawk Power Co.	9 Mile Point Nuc	500	Nuclear	Lake Ontario	518	10,709	1	New York
Porter	No.Ind.Public Serv. Co.	Bailly	615	Coal/Gas	Lake Michigan	470	10,008	2	Indiana
Bay	Consumers Power Co.	Weadock	614	Coal/Gas/ Oil	Saginaw River	545	10,614	8	Michigan
Monroe	Consumers Power Co.	Whiting	325	Coal/Oil	Lake Erie	362	9,913	3	Michigan
Wayne	Detroit Edis	Conners Creek	510	Coal/ Oil/Gas	Detroit River	796	13,050	8	Michigan

COUNTY LOCATION	COMPANY	PLANT NAME	MWe	FUEL	WATER SOURCE	AVG CFS INTAKE	PLANT HEAT RATE	# OF UNITS	STATE
Wayne	Detroit Edis	Delray	375	Oil/Gas	Detroit River	375	14,440	6	Michigan
Monroe	Detroit Edis	Fermi	158	Oil	Lake Erie	82	14,626	1	Michigan
Huron	Detroit Edis	Harbor Beach	121	Coal/Oil	Lake Huron	154	BTU/KWH 10,600	1	Michigan
St. Clair	Detroit Edis	Marysville	200	Coal/Gas	St.Clair River	461	12,300	7	Michigan
Wayne	Detroit Edis	Pennsalt	37	Coal/Oil	Detroit River	18	54,657	7	Michigan
Wayne	Detroit Edis	River Rouge	933	Coal/ Oil/Gas	Detroit River	1,041	9,450	3	Michigan
St. Clair	Detroit Edis	St. Clair	1,905	Coal/ Oil/Gas	St.Clair River	2,290	9,220	7	Michigan
Wayne	Detroit Edis	Trenton Channel	876	Coal/ Oil/Gas	Detroit River	1,400	10,450	5	Michigan
Wayne	Detroit Edis	Wyandotte	54	Coal/ Oil/Gas	Detroit River	152	11,800	8	Michigan
Monroe	Detroit Edis	Monroe	2,462	Coal/Oil	Raisin River	1,796	9,600	3	Michigan
Lake	No. Indiana Public Serv.	Mitchell	529	Coal/Gas	Lake Michigan	690	10,124	4	Indiana
Laporte	No. Indiana Public Serv.	Michigan City	215	Coal/Gas	Lake Michigan	223	12,349	3	Indiana
Charlevoix	No. Mich. Elec.Coop.Inc.	Advance	37	Coal	Lake Charlevoix	856	12,636	3	Michigan
Lorain	Ohio Edison Co.	Edgewater	193	Coal	Lake Erie	181	11,747	3	Ohio
Erie	Pennsylvania Elec. Co.	Front Street	119	Coal	Lake Erie	220	14,295	5	Penn.
Monroe	Rochester Gas & Elec. Corp.	Rochester #3	196	Coal/ Oil/Gas	Genessee River	147	18,849	9	New York
Monroe	Rochester Gas & Elec.Corp.	Rochester #7	253	Coal/Oil	Lake Ontario	231	10,534	4	New York
Wayne	Rochester Gas & Elec.Corp.	Rochester#13	490	Nuclear	Lake Ontario	842	10,803	1	New York
Lucas	Toledo Edison Co.	Acme	321	Coal/ Oil/Gas	Maumee River	309	BTU/KWH 12,994	5	Ohio
Lucas	Toledo Edison Co.	Bay Shore	638	Coal/Oil	Maumee River	1,100	9,238	4	Ohio
Marquette	Upper Penin. Gen. Co.	Presque Isle	175	Coal/Oil	Lake Superior	184	11,283	4	Michigan
Milwaukee	Wisconsin Elec.& Pwr Co	Commerce	35	Oil/Gas	Milwaukee River	72	16,021	1	Wisconsin
Milwaukee	Wis. Elect. & Power Co.	Lakeside	310	Oil/Gas	Lake Michigan	41	17,159	8	Wisconsin
Milwaukee	Wis. Elect. & Power Co.	North Oak Creek	500	Coal/Oil	Lake Michigan	686	10,301	4	Wisconsin
Ozaukee	Wis. Elect. & Power Co.	Port Washington	400	Coal	Lake Michigan	623	11,585	5	Wisconsin
Milwaukee	Wis. Elect. & Power Co.	South Oak Creek	1,192	Coal/Oil	Lake Michigan	1,457	9,685	4	Wisconsin
Milwaukee	Wis. Elect. & Power Co.	VAlley	272	Coal/Gas	N. Menominee Canal	182	14,145	2	Wisconsin
Manitowoc	Wis. Elect. & Power Co.	Point Beach	1,047	Nuclear	Lake Michigan	1,287	10,934	2	Wisconsin
Sheboygan	Wis. Elect. & Power Co.	Edgewater	437	Coal/Oil	Lake Michigan	295	10,085	4	Wisconsin
Brown	Wis. Elect. & Power Co.	Pulliam	393	Coal/Oil/ Gas	Fox River	500	11,351	8	Wisconsin
Berrien	Ind. & Mich. Electric Co.	Cook, D.C.	1,089	Nuclear	Lake Michigan	1,537	10,771	1	Michigan

ACRONYMS

AQCR - air quality control region

ACRS - Advisory Committee on Reactor Safety

ASLB - Atomic Safety and Licensing Board

BWR - boiling water reactor

cfs - cubic feet per second

DER - Department of Environmental Resources

DES - Draft Environmental Statement

DNR - Department of Natural Resources

EHV - extra high voltage

EPA - Environmental Protection Agency

EQC - Environmental Quality Council

ESECA - Energy Supply and Environmental Coordination Act

ERDA - Energy Research and Development Administration

FEA - Federal Energy Administration

FES - final environmental statement

FPC - Federal Power Commission

gpd - gallons per day

gpm - gallons per minute

kWh - kilowatt (1,000 watts) hour

LMFBR - liquid metal fast breeder reactor

LNG - liquefied natural gas

MW = megawatt (1,000,000 watts)

NO_x - nitrous oxides

NPDES - National Pollutant Discharge Elimination System

NRC - Nuclear Regulatory Commission

PCRV - prestressed concrete reactor vessel

PSC - Public Service Commission or Power Siting Commission

PUC - Public Utility Commission

SIP - state implementation plan

SNG - synthetic natural gas

SO_x - sulphur oxides

GLOSSARY

Base load unit - an electric generating facility which is normally operated to carry base load and which, consequently, operates essentially at a constant load.

Base loading - the operation of a unit at or near its rated output to supply the base load of a system.

Benthic organisms - organisms attached, resting, or living on or in the bottom sediments.

Blowdown - release or cleaning out of water with high solids content, the solids having accumulated each time water evaporates.

BWR - boiling water reactor - a nuclear reactor in which water, used as both coolant and moderator, is allowed to boil in the core.

Btu - (British thermal unit) - the amount of energy necessary to raise the temperature of one pound of water by one degree Farenheit, from 39.2 to 40.2 degrees.

Capacity - maximum rating of a generating unit most often in Kw or Mw.

Capacity factor - the ration of the average load on a machine, or equipment, for the period of time considered, to the capacity rating of the maching or equipment.

Cooling Systems -

Once through systems - where cooling water is taken from a suitable source, passed through the condenser, and returned to the source body of water. Same as direct cooling.

Closed cycle systems - (evaporative cooling) where cooling water is contained in a closed system and its heat dissipated to the air through heat exchangers. Includes dry and wet cooling towers, spray ponds, canals, mechanical draft, etc.

Core meltdown - failure in control mechanism or cooling system of nuclear reactor which results in nuclear pile going super-critical with meltdown and rupture of the reactor vessel potentially occurring.

Efficiency - (heat rate) - measure of how effectively a thermal generating station is operating, generally expressed in Btu per net kilowatt hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt hour generation.

Energy - the capacity for doing work, often measured in kilowatt hours.

Energy facility - broad term which includes development, production, conversion, storage, processing, transfer or transportation of any energy resource. These would include refineries, fuel transshipment and storage facilities and electric generating units.

EHV lines - transmission lines which have a rated capacity above and including 230 kilovolts.

Generating facility - broad term encompassing all types of electric generating facilities.

Intermediate load plant - a generating unit that is normally operated to provide power for loads between base load and peak load levels.

kW - MW - GW - (kilowatt, megawatt, gigawatt) instantaneous measure of electric power equal to 1,000 watts, 1 million watts, and 1 billion watts, respectively.

kWh - Kilowatt hour - the basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric current steadily for one hour.

Load center - a point at which the load of a given area is assumed to be concentrated.

Load factor - the ratio of the average load in kilowatts, supplied during a designated period, to the peak or maximum load in kilowatts occurring in that period.

LWR - light water reactor - a nuclear reactor which uses water (H_2O) to transfer heat from the fissioning of uranium to a steam turbine.

Load schedule - same as load curve - a curve of demand versus time of occurrence in chronological sequence the magnitude of the load for each unit of time of the period covered.

Makeup water - that quantity of water added to a closed cycle cooling system needed to replace water lost through evaporation or blowdown.

Nektonic - swimming organisms able to navigate at will.

Particulates - microscopic pieces of solids which emanate from a range of sources and are the most widespread of all substances usually considered air pollutants.

Peak demand - same as peak load - the maximum load in a stated period of time.

Peaking facility - same as peaking generation - same as peaking unit - a unit which is normally operated only to provide power during high demand periods.

Plant factor - same as capacity factor.

Planktonic - floating organisms whose movements are more or less dependent on currents.

Power - the time rate at which work is done or energy emitted or transferred, measured instantaneously in kilowatts.

Power plant - same as generating facility

Power pool - regional grouping of utilities to promote reliability, production and transmission of electricity.

PWR - Pressurized water reactor - a nuclear reactor in which heat is transferred from the core to a heat exchanger by water kept under high pressure to achieve high temperature without boiling in the primary system. Steam is generated in the secondary system.

Reliability councils - coordinate in varying degrees the planning, construction, and operation of transmission and generating facilities of groups of utilities. They effect an adequate supply of low-cost power.

Reserve margin - same as reserve capability-the difference between net system capability and system maximum load requirements.

Slurry pipeline - mixture of coal and water transported in pipelines.

Unit train - a train dedicated to transporting one commodity from source to user.

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