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20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

The technical report describes what energy resources are now available in the proposed M-X deployment regions, how much energy would be needed, when it would be needed, and how its usage would affect the continued availability of energy resources. It describes the potential impacts of the energy and power distribution systems.
The report proceeds from analysis of potential regional energy impacts of analysis of site-specific impacts for each M-X deployment alternative. Each analysis identifies the cause-and-effect relationships for its region or

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alternative. After presenting the analyses, the report proceeds to describe ways in which to mitigate the identified impacts. This report briefly describes alternative energy techologies and their potentials for augmenting the energy resources currently utilized in the M-X deployment areas, and also energy conservation measures that may be employed with an estimate of possible energy savings.

M-X ETR-24

ENVIRONMENTAL CHARACTERISTICS OF ALTERNATIVE DESIGNATED DEPLOYMENT AREAS: POWER AND ENERGY

Prepared for

United States Air Force
Ballistic Missile Office
Norton Air Force Base
California

By

Henningson, Durham and Richardson
Santa Barbara, California

22 December 1980

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INTRODUCTION

This energy report is one of a set of technical reports documenting information further explaining the significance of the impacts identified in the Environmental Impact Statement for the M-X project. Deployment of the M-X system would be a large-scale defense project in Nevada, New Mexico, Texas and Utah; and involving thousands of temporary construction workers and permanent military and civilian employees. The project would include construction of approximately 8,000 miles of new roads and all would be open to the public. The M-X system's two permanent operating bases would constitute large new employers. Among other effects, the inmigrant workers and USAF employees would cause large increases in traffic and energy consumption.

The following discussion describes what energy resources are now available in the proposed M-X deployment regions, how much energy would be needed, when it would be needed, and how its usage would affect the continued availability of energy resources. It describes the potential impacts of the energy and power distribution systems.

The report proceeds from analysis of potential regional energy impacts to analysis of site-specific impacts for each M-X deployment alternative. Each analysis identifies the cause-and-effect relationships for its region or alternative. After presenting the analyses, the report proceeds to describe ways in which to mitigate the identified impacts. This report briefly describes alternative energy technologies and their potentials for augmenting the energy resources currently utilized in the M-X deployment areas, and also energy conservation measures that may be employed with an estimate of possible energy savings.

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SUMMARY

The M-X program will require electric power and fuels of various forms supplied on both a relatively short term (2-5 years) for construction needs, and a longer term (about 30 years) for operational requirements. At a time of diminishing energy supplies and increasing competition for energy, including gasoline, the potential effects of the project on energy resources must be considered. The majority of the information in this report represents the best available data as of September 1980.

Energy Resources Available

Fuel supplies are more readily available in the Texas/New Mexico region than in the Nevada/Utah region because of the greater population and petroleum and natural gas related industries. Underground pipelines carrying natural gas, crude oil and refined products are more extensively found in Texas/New Mexico. Natural Gas is the preferred heating fuel in that area, while in Nevada/Utah, Number 2 fuel oil, bottled gase and electricity are prevalent. Projected consumption quantities and existing and proposed pipeline plots are presented. Fuel allocation programs administrered by the Department of Energy through regional offices permit redistribution if a dramatic increase of population causes a corresponding increase in demand.

Electric power is generally available on a regional basis including many power plants and not only the local utility. The Nevada/Utah deployment area would be served by the Western Systems Coordinating Council (Regions 27, 28 and 30). The Texas/New Mexico deployment area is served by the Southwest Power Pool (SWPP). Both areas have sufficient projected available excess power, providing proposed projects are not delayed. The system in Texas/New Mexico is more extensive than in Nevada/Utah.

Energy Requirements

Estimated energy requirements include M-X technical facilities, housing on and off-base for both military and civilians brought to the region, transportation, and equipment operation. A summary of energy requirements by alternative is presented in Section 2.

Between the peak construction year and the operations phase, the annual gasoline consumption for the Proposed Action is expected to fall from about ten to less than three percent of the projected Nevada/Utah consumption without M-X. For Alternative 7, located in Texas/New Mexico, the annual gasoline consumption would fall from about two to 0.3 percent of that two-state region. Similarly, diesel fuel requirements for the Proposed Action would fall from 42 percent to 17 percent of the two-state consumption; for Alternative 7 from four to two percent. Natural gas is not considered to be used extensively in Nevada/Utah. For Alternative 7, natural gas consumption would be less than 0.05 percent for both construction and operations.

The electric power requirements are estimated to increase from about 80 MW and 260 MW between the peak construction year and the operations phase. Approximately 150 MW are associated with the Designated Deployment Area facilities. 260 MW is about one percent of the projected 1989 available reserves of the Nevada/Utah electric region, and varies from about seven to three percent of the Texas/New Mexico electric region available reserves, depending on season.

Impacts

Fuel: the primary impact of M-X deployment on the fuel situation is the increased competition for available supplies. However, it is expected that allocation readjustments will be made to accommodate the increased demand. The new storage, distribution facilities and pipelines have not yet been sited, but are not considered to be extensive. Impacts from these facilities would probably be minor if properly designed and located. Air pollution is also not expected to be significant.

There are two favorable impacts that may occur as a result of M-X deployment. The first is that many persons, civilian and military, would be relocating from harsher climates where energy requirements are higher. As a result of construction complying with the latest state and federal energy conservation standards, and employing solar features, energy consumption for homes and work areas would be less. On a national basis, therefore, energy consumption for homes and work areas may be reduced. The second is the development and utilization of renewable energy resources which may be used for both technical and support facilities. A major program is underway to develop alternative energy systems which can provide reliable operating power for the M-X system. The program is a joint Department of Defense and Department of Energy effort. The systems under study include photovoltaics, wind, solar energy, thermal troughs, solar thermal dishes, solar thermal central receivers, geothermal, and biomass technologies such as alcohol and methane production. These systems may be employed either separately or integrated with conventional sources. The Nevada/Utah region in particular has excellent potential for geothermal development because of the number of geothermal resources. Both regions have excellent solar potential because of the high number of clear, bright days. Developable wind energy resources are likely to be found in the mountains, ridges, and passes of the Nevada/Utah Basin and Range Province, and in the windy open areas of the Texas/New Mexico High Plains Region.

Electric Power

No new power plants will be required in either region, other than previously proposed facilities such as the Intermountain Power Project, the White Pine Power Project, and the Harry Allen plant. Upgrading existing facilities and construction of new transmission and distribution facilities would be required to a greater degree in the Nevada/Utah region. These facilities may produce aesthetic and right-of-way impacts in pristine areas. The extensive cable plowing or trenching required for installation of the underground cables for power distribution to the clusters may have a temporary disruptive effect.

Information concerning transmission and distribution facility locations has not been developed, preventing a more detailed impacts analysis. In many cases however, the impact would most likely be minor, because the lines would often be located along existing roads. Alternative energy systems may produce a significant positive impact by reducing the electric load in the DDA and the need for power lines. Energy conservation measures will further reduce the impact of M-X deployment.

1.0 ENERGY SUPPLIES

1.1 FUEL SUPPLY

The primary fuels required for the M-X system and support communities would be natural gas, propane, diesel fuel, gasoline, and No. 2 fuel oil. Baseline data for recent and projected consumption of fuels are presented for the United States, Nevada/Utah region and Texas/New Mexico region in Tables 1.1-1, 1.1-2 and 1.1-3 respectively.

The location, ownership, and size of existing and proposed crude oil, petroleum product and natural gas pipelines were determined from detailed plan and profile drawings obtained from the various energy companies in the M-X region. This information was plotted on United States Geological Survey (USGS) maps at a scale of 1:24,000 and 1:62,500 and inputted into the computer.

The resulting computer plots of existing and proposed underground pipelines in the Nevada/Utah M-X region are shown on Figure 1.1-1. Similar plots for the Texas/New Mexico M-X region are shown on Figure 1.1-2. These plots are being updated as new information is received.

Regulatory procedures are in effect for obtaining petroleum product supplies that would be needed to support the population growth associated with M-X program development in Nevada, Utah, Texas and New Mexico. The attention focuses on procedures for obtaining an allocation for a new retail sales outlet, and to obtain an increase in the current allocation for an existing retail outlet experiencing increased demands because of population growth.

A firm proposing a new retail motor gasoline outlet must apply to the regional ERA office for an assignment of a base period volume and supplier under 10 CFR 211. If a "willing" supplier cannot be identified, the ERA will designate a supplier. The application is processed according to "Guidelines for Evaluation of Applications for Assignment of Supplier" and "Base Period Use to New Retail Motor Gasoline Outlets" (Federal Energy Guidelines (Guidelines) 14.712 and the general criteria of 10 CFR 205.35 and 10 CPR 211).

The Fuels Regulation Office in the DOE regional office in Lakeland, Colorado reports that applications for new retail outlets in Utah are already being received in which justification rests in part upon anticipated population growth from program M-X activities.

The time currently required to process an application for an assignment and issue of an Assignment Order is about 90 days.

1.2 ELECTRIC POWER

The electric power industry in the United States is divided into nine regional electric reliability council areas as shown in Figure 1.2-1. The regional areas are divided into subregions for the contiguous United States. Figure 1.2-2 shows that the Nevada/Utah study area is serviced by Regions 25, 27, 28 and 30 of the Western Systems Coordinating Council (WSCC), and that the Texas/New Mexico study area is serviced by Region 22 of the Southwest Power Pool (SWPP).

Table 1.1-1. Fuel consumption projections-- United States.

FUEL	U. S.		
	1978	1985	1990
Total Petroleum (10^3 BBLS)[1]	6,879,020	5,606,400	5,675,190
Natural Gas (Dry) (10^6 ft^3)	19,627,480	18,646,100	19,431,200
Total Fuel Oils (10^3 BBLS)	1,252,560	1,009,560	1,078,450
Diesel Fuel (10^3 BBLS)	291,000	234,550	250,550
Heating Fuel (10^3 BBLS)	533,000	429,600	458,910
Gasoline (10^3 BBLS)	2,705,310	2,267,050	2,156,130
Jet Fuel (10^3 BBLS)	385,660	385,660	420,750

3307

1 Barrel = 42 Gallons

Actual consumptions for 1978. Assumed same proportions of total fuel oils for 1985 and 1990 projections. (DOE/EIA - 0113 (78) - Energy Data Reports).

Source: DOE-State Energy Data Report.

Table 1.1-2. Fuel consumption projections--
Nevada/Utah.

FUEL	NEVADA			UTAH		
	1978	1985	1990	1978	1985	1990
Total Petroleum (thousands of barrels)[1]	29,320	23,890	24,190	40,210	32,770	33,170
Natural Gas (Dry) (millions of cubic ft)	64,510	61,280	63,860	118,510	112,590	117,330
Total Fuel Oil (thousands of barrels)	3,830	3,080	3,290	9,020	7,270	7,770
Diesel Fuel (thousands of barrels)	1,500	1,210	1,290	2,130	1,720	1,830
Heating Fuel (thousands of barrels)	480	380	410	1,380	1,110	1,190
Gasoline (thousands of barrels)	11,700	9,800	9,320	17,480	14,650	13,930
Jet Fuel (thousands of barrels)	6,650	6,650	7,260	1,900	1,900	2,070

3309

1 Barrel = 42 Gallons

Actual consumptions for 1978. Same proportions assumed of total fuel oils for 1985 and 1990 projections.

(DOE/EIA - 0113 (78) - Energy Data Report.

Table 1.1-3. Fuel consumption projections--Texas/New Mexico.

FUEL	TEXAS			NEW MEXICO		
	1978	1985	1990	1978	1985	1990
Total Petroleum (10^3 BBLS)	448,520	398,150	403,030	42,910	34,970	35,400
Natural Gas (Dry) (10^6 ft^3)	4,211,430	4,000,860	4,169,320	213,700	203.010	211,560
Total Fuel Oil (Dist.) (10^3 BBLS)	8,170	65,420	69,900	9,630	7,760	8,290
Diesel Fuel (Dist.) (10^3 BBLS)	25,230	20,330	21,730	3,570	2,880	3,070
Heating Fuel (Dist.) (10^3 BBLS)	10,080	8,120	8,680	520	420	450
Gasoline (10^3 BBLS)	201,990	169,270	160,990	18,920	18,920	15,080
Jet Fuel (10^3 BBLS)	28,540	28,540	31,130	2,790	2,790	3,050

3309

1 Barrel = 42 Gallons

SEE FIGURE 3.2.3.6-1
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Figure 1.1-1. Existing and proposed pipelines in Nevada/ Utah region.

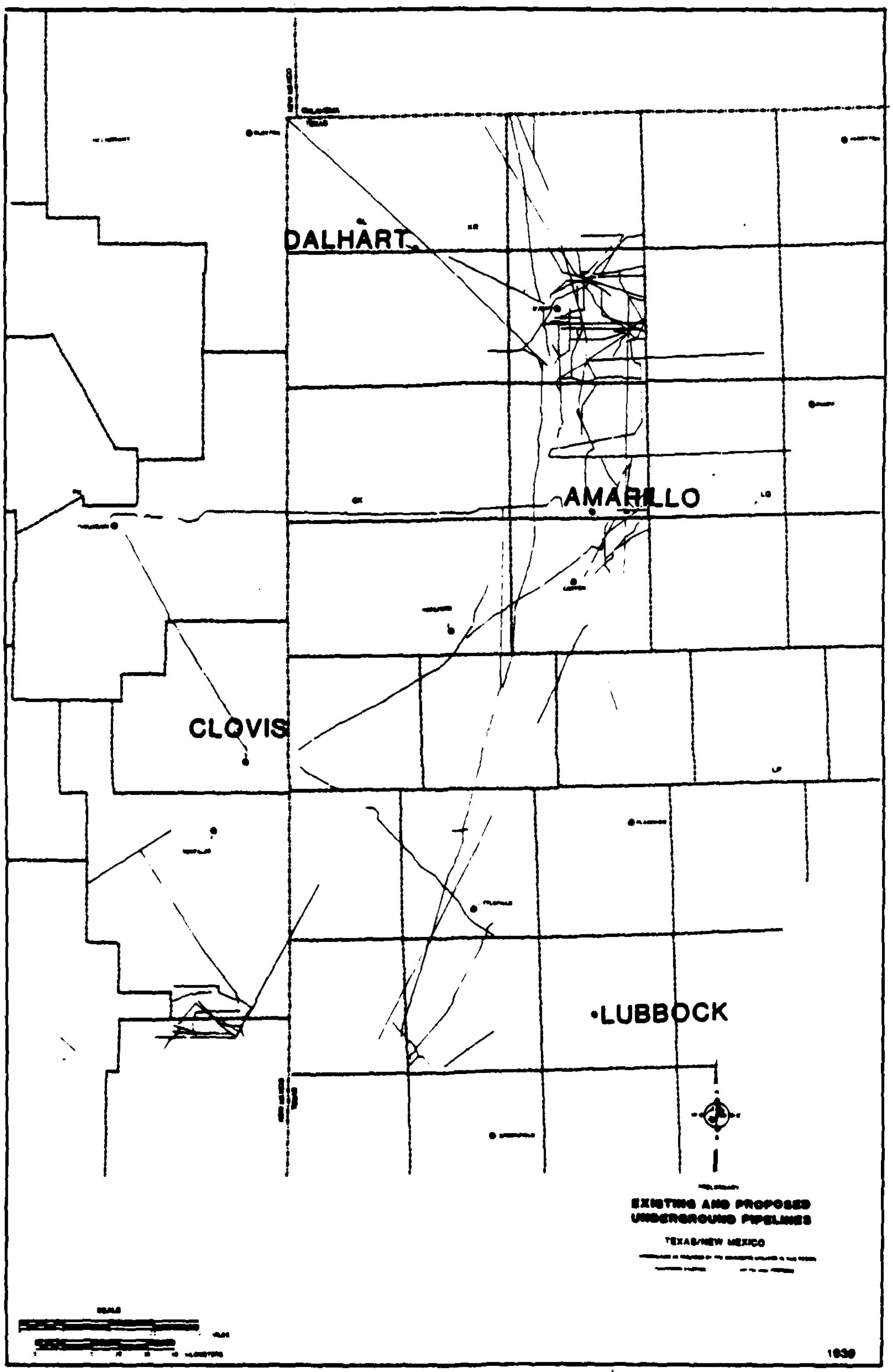

Figure 1.1-2. **Existing** and proposed pipelines in Texas/
New Mexico.

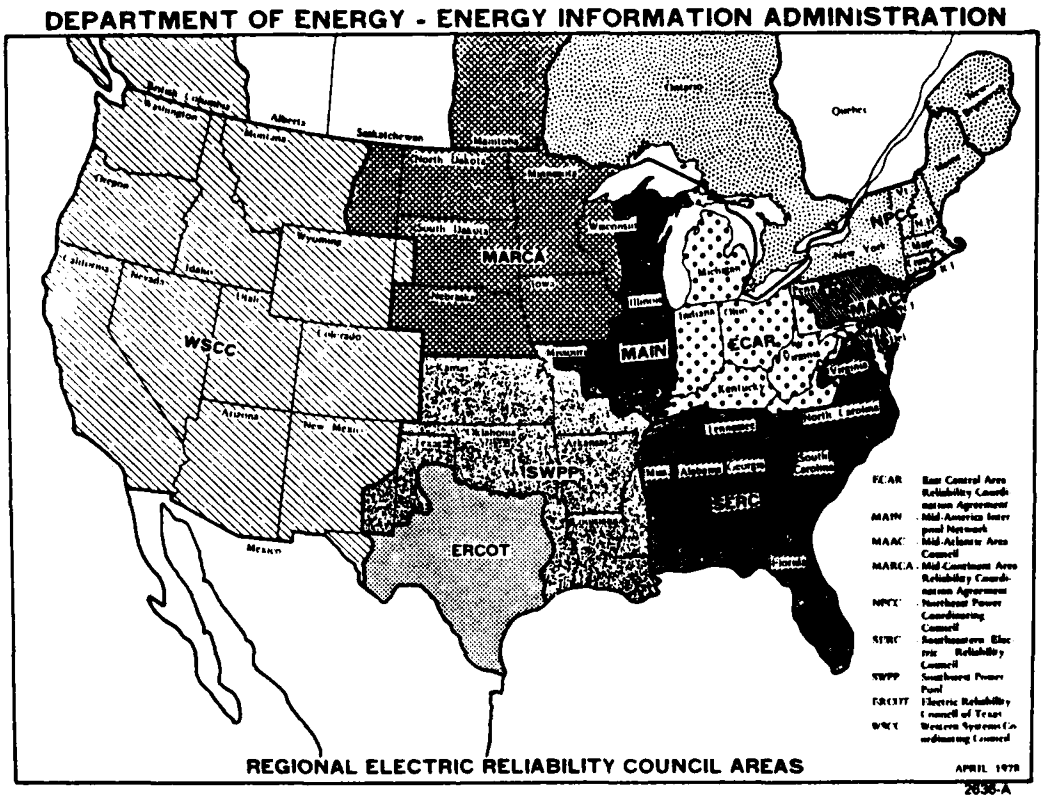

Figure 1.2-1. Regional electric reliability council areas.

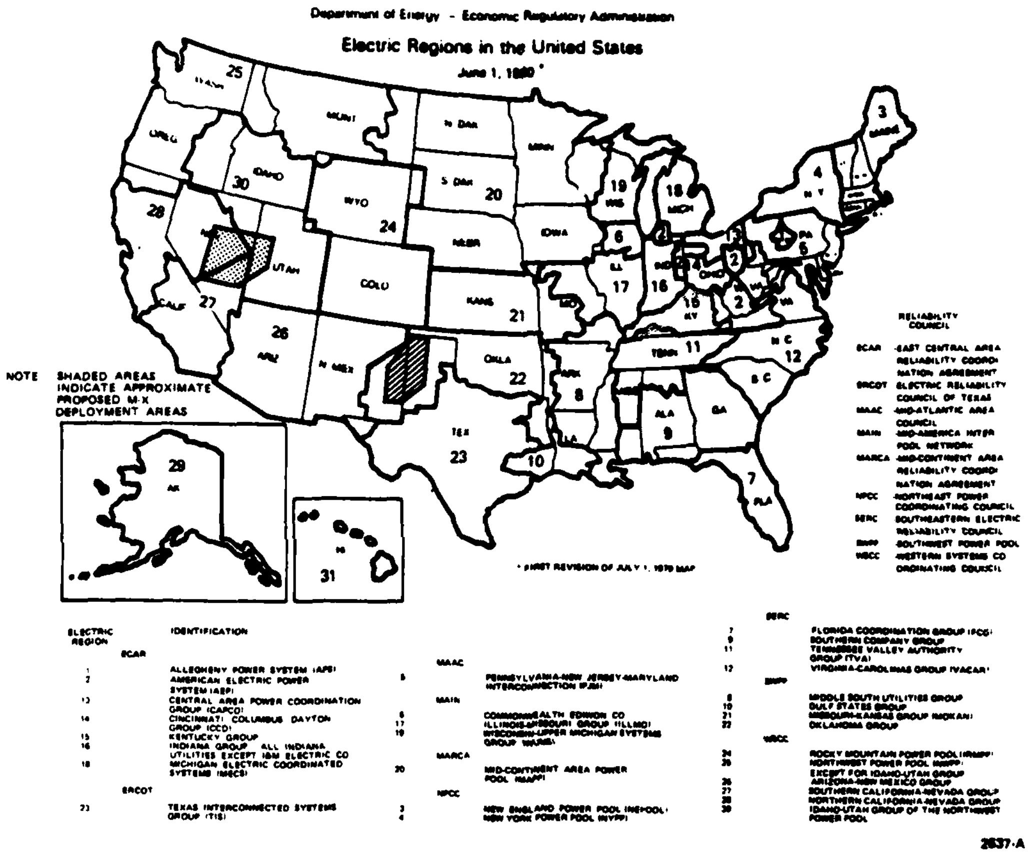

Figure 1.2-2. Electric regions in the United States.

Projected electrical peak demands, operable resources and adjusted margins for summer and winter conditions respectively for the regions affected by the proposed deployment areas but without the M-X system, are shown in Figures 1.2-3 and 1.2-4 for Nevada/Utah and in Figures 1.2-5 and 1.2-6 for Texas/New Mexico. The difference between the operable resources and peak demand is designated the "adjusted margin" and represents actual available reserve capacity for each electrical system.

Computer plots of existing and proposed transmission lines are presented for the Nevada/Utah region, and the Texas/New Mexico region in Figures 1.2-7 and 1.2-8 respectively. Line-plan sheets obtained from the power companies serving the region were used in conjunction with U.S. Geological Survey maps to prepare these maps. These plots are being updated as information is received.

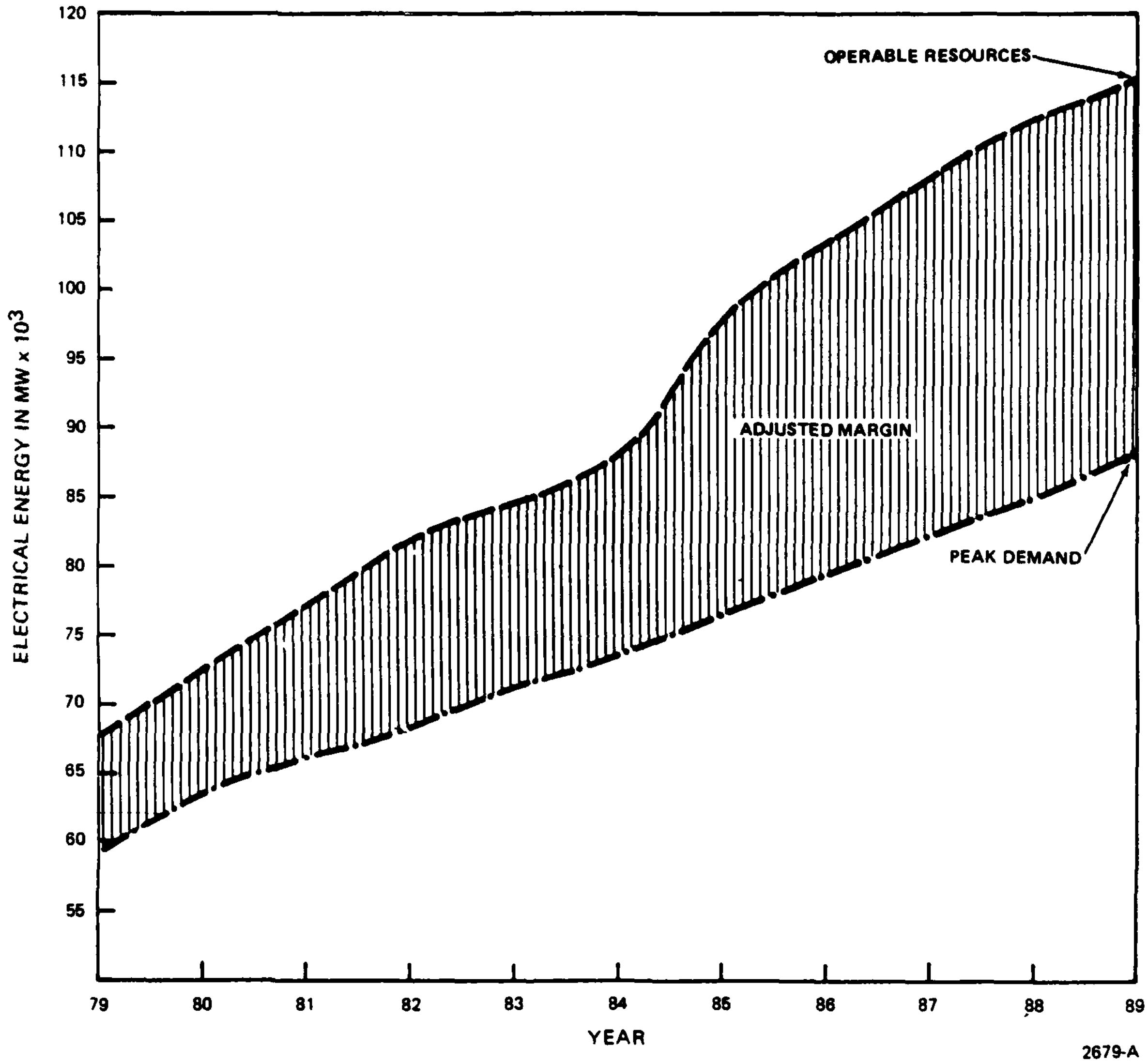

Figure 1.2-3. Western Systems Coordinating Council (WSCC), Regions 25, 27, 28, and 30. Projected peak demands and resources, summer conditions, Nevada/Utah.

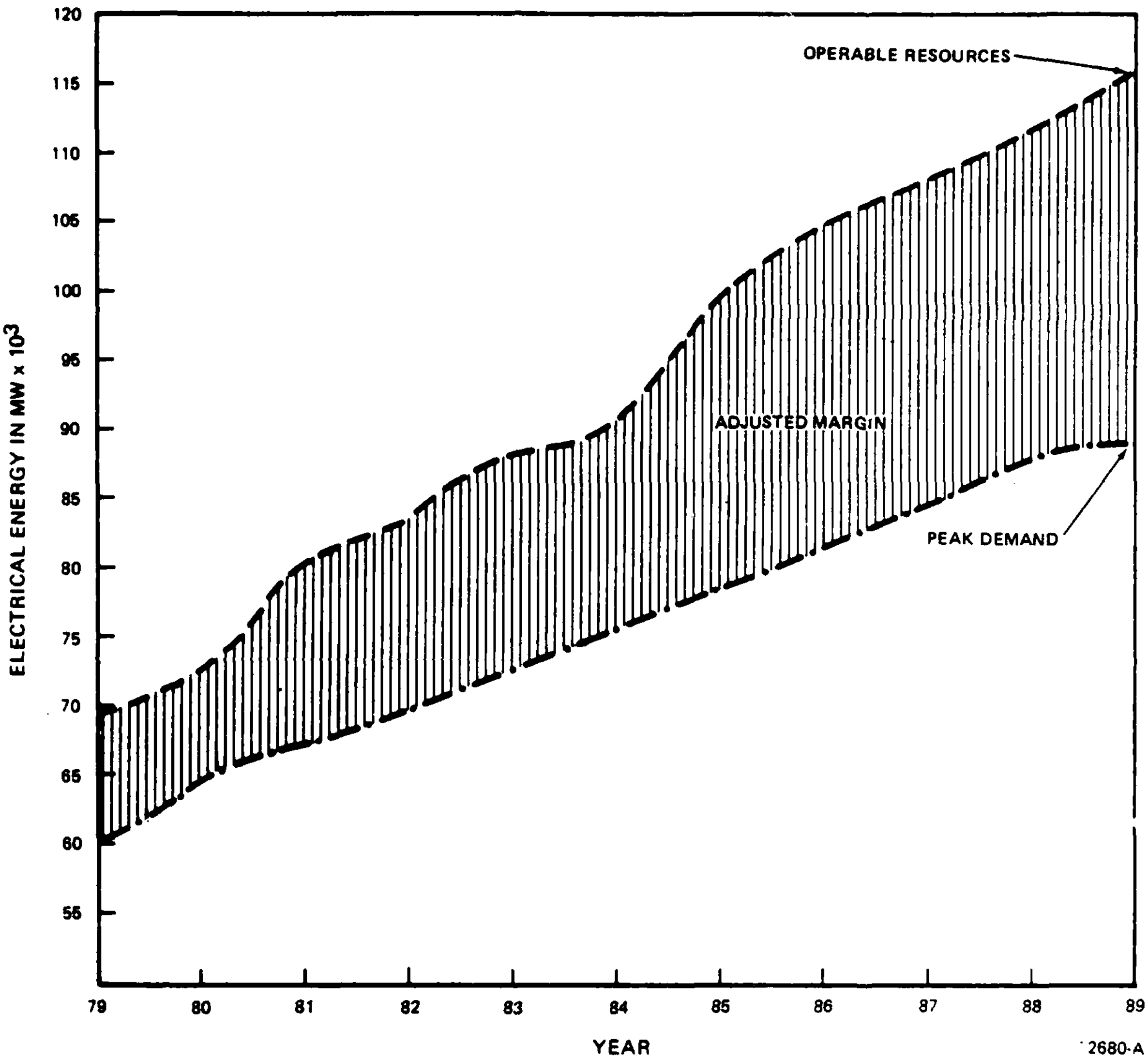

Figure 1.2-4. Western Systems Coordinating Council, Regions 25, 27, 28, and 30. Projected peak demands and resources, winter conditions, Nevada/Utah.

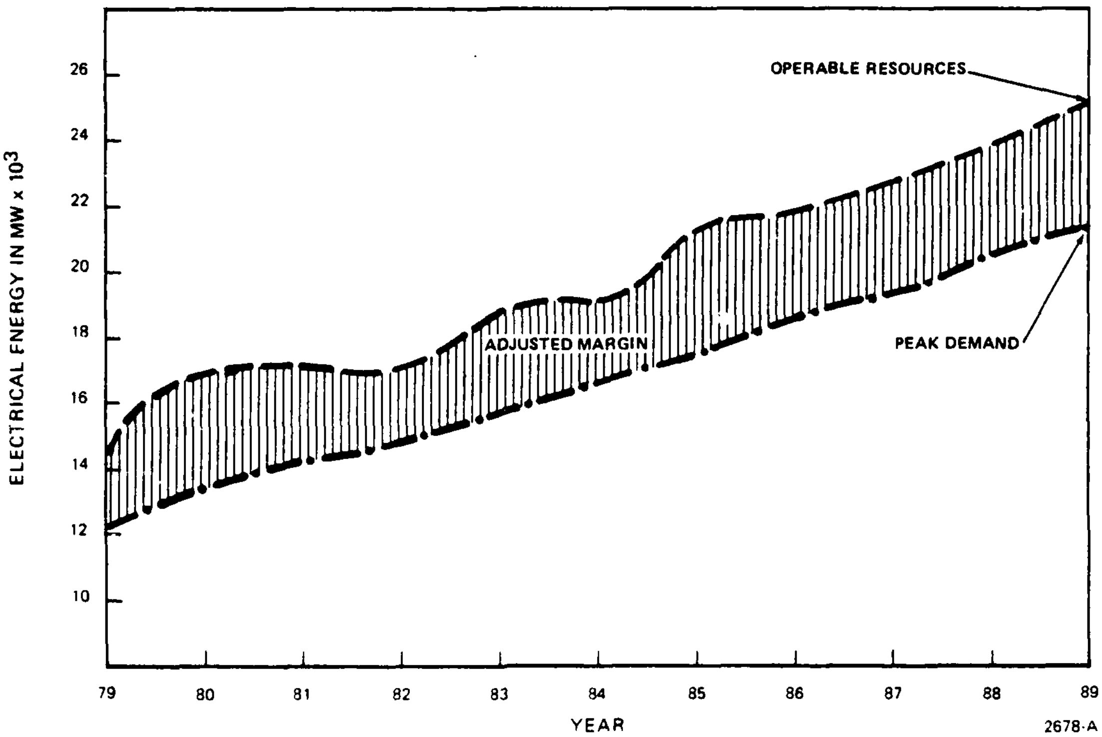

Figure 1.2-5. Southwest Power Pool (SWPP), Region 22, projected peak demands and resources, summer conditions, Texas/New Mexico.

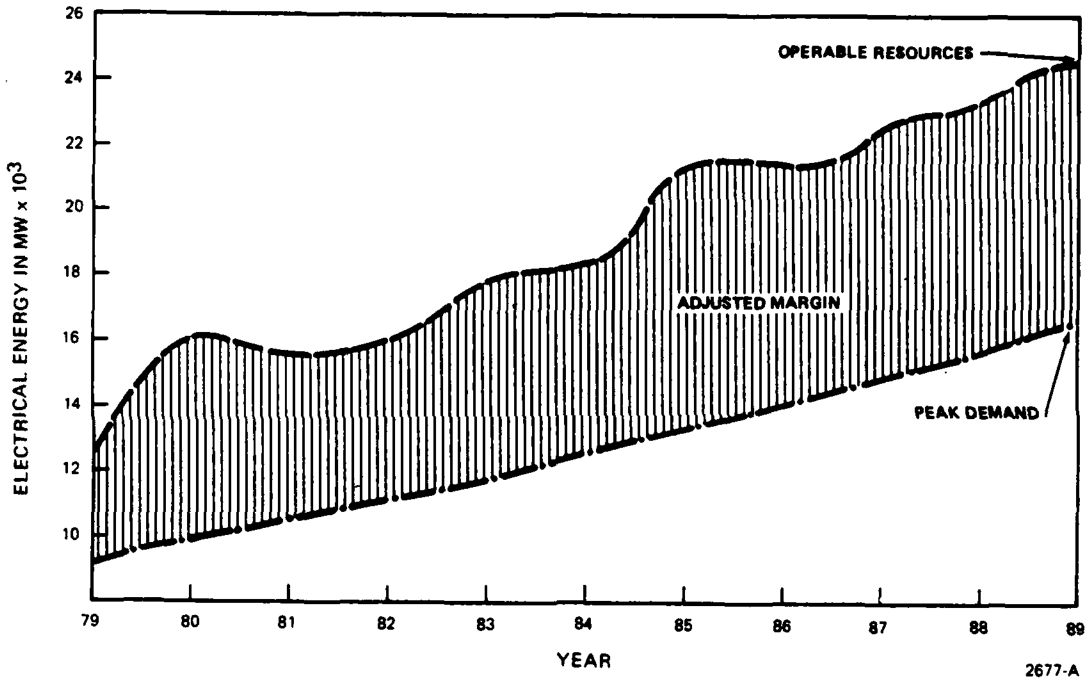

Figure 1.2-6. Southwest Power Pool (SWPP), Region 22, projected peak demands and resources, winter conditions, Texas/New Mexico.

SEE FIGURE 3.2.3.6-4
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Figure 1.2-7. Existing and proposed transmission lines in Nevada/Utah.

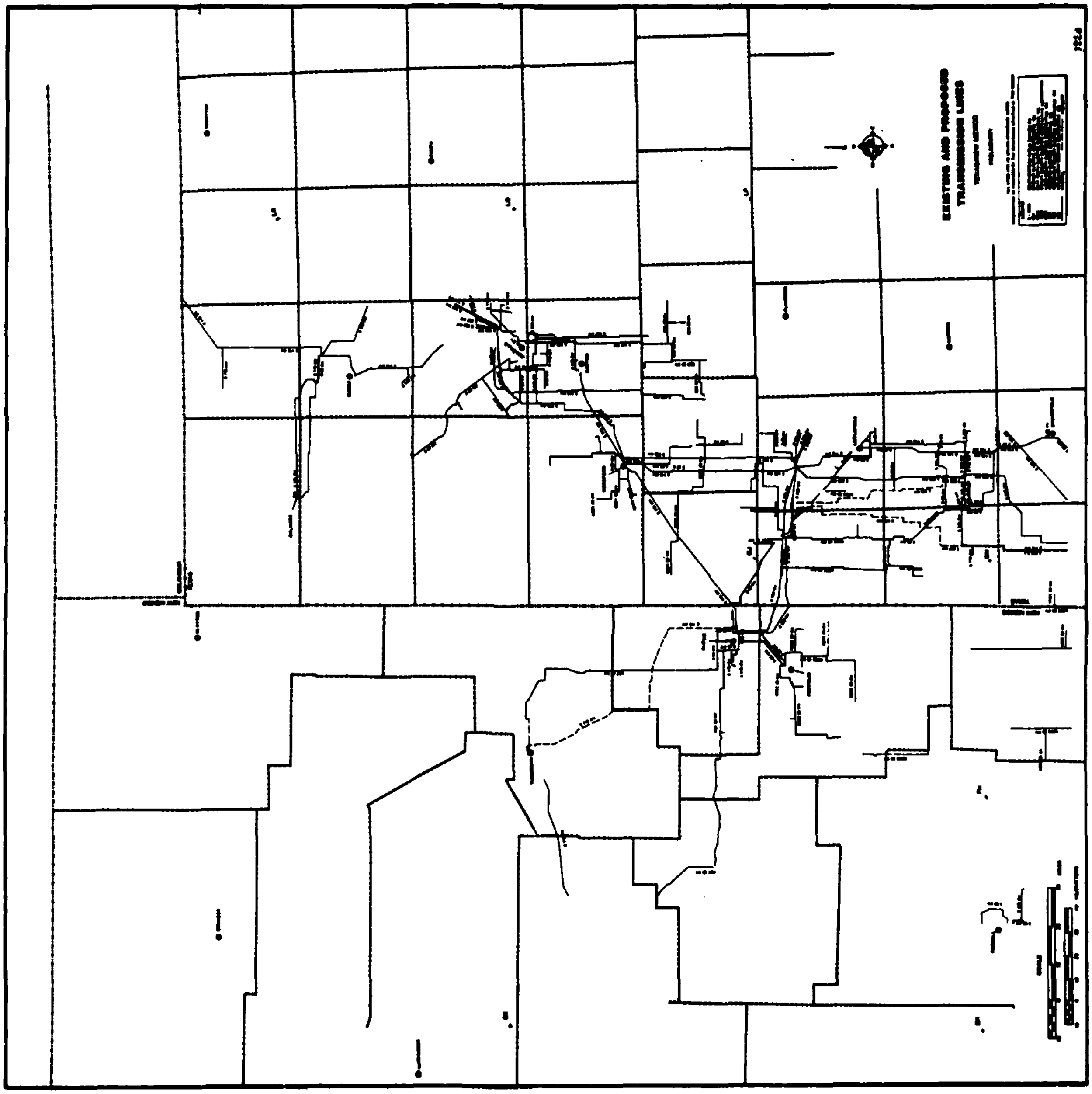

Figure 1.2-8. Existing and proposed transmission lines in Texas/New Mexico.

2.0 DESCRIPTION OF THE M-X PROJECT ENERGY REQUIREMENTS

2.1 M-X SYSTEM ENERGY BREAKDOWN

The deployment of the M-X system will require additional regional expenditures of energy, electrical and fuels, for both direct and indirect purposes. During construction, energy will be required for activities such as construction camp facilities, personnel commuting and recreation, construction equipment operation and community development for indirect workers who are brought to the area. During the operations phase, there will be an energy requirement for the maintenance and security of the system in the DDA and for the heating, ventilation and airconditioning (HVAC) of the base facilities and off-base support housing, personnel commuting and recreation for the operating bases and surrounding communites. An M-X system energy breakdown diagram is presented in Figure 2.1-1.

2.2 SUMMARY OF ENERGY REQUIREMENTS BY ALTERNATIVE

Table 2.2-1 presents a summary of the annual energy requirements for the Proposed Action and alternatives for the peak construction year (1986) and for the operation phase (1992). Table 2.2-2 gives a summary of the total construction energy requirements by alternative. These figures include the Designated Deployment Area, operating bases and support community usages.

For the construction phase, the electrical demand is about a quarter of the operations phase demand, approximately 75 MW. Gasoline consumption varies from about 80 million gallons per year for Alternative 4, to about 100 million gallons per year for the Proposed Action, to about 150 million gallons per year for Alternative 7. Fuel oil consumption is approximately 20 million gallons per year for the Nevada/Utah alternatives.

For the operations phase, the electrical demand and usage is essentially the same for all alternatives; approximately 260 MW demand and 1200 MWH per year. Gasoline consumption, based on the traffic modeling, varies from about 21 million gallons per year for Alternative 7 to 28 million gallons per year for the Proposed Action. Fuel oil consumption varies from a negligible amount for Alternative 7 because of availability of natural gas, to a range of 10 to 15 million gallons for the Nevada/Utah full basing alternatives, with 10 million gallons per year for the Proposed Action. Diesel fuel consumption is shown to be about 22 million gallons per year for all alternatives. Information is not available at this time for further refinement.

2.3 ESTIMATING METHODOLOGY FOR FUEL AND ENERGY REQUIREMENTS

Introduction (2.3.1)

The energy requirements for deployment of the M-X system are defined in terms of maximum demand and annual energy consumption. Mechanical and electrical loads for the M-X facilities are tabulated separately for the various regions under consideration for deployment of the system. These are shown later.

Electrical data include normal lighting, convenience outlets, motors as required for the working environment, and equipment necessary for specific tasks.

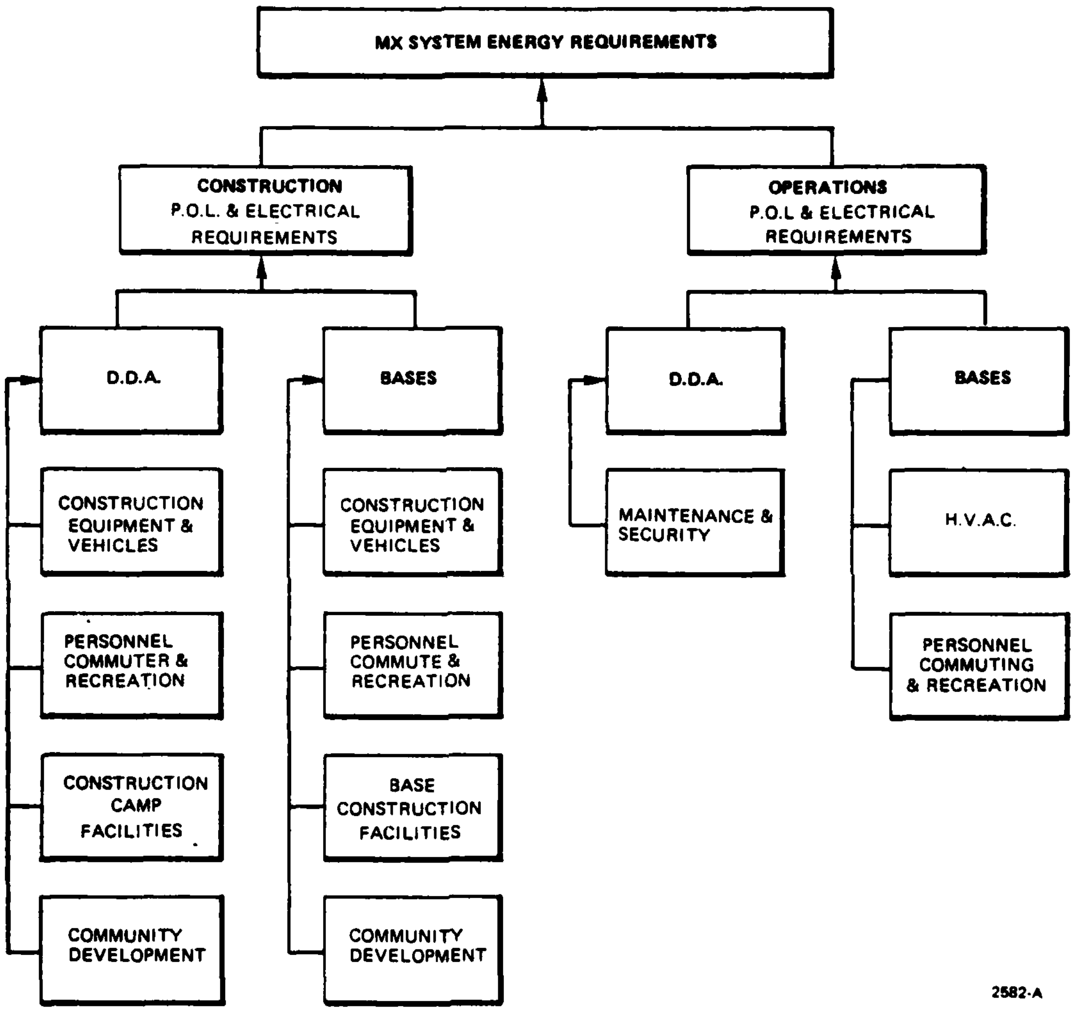

Figure 2.1-1. M-X system energy breakdown diagram.

Table 2.2-1. Summary of annual energy requirements for the Proposed Actions and alternatives for the peak construction year (1986) and for the operation phase (1992).

ALTERNATIVE	CONSTRUCTION (1986)						OPERATIONS (1992)					
	P.O.L.			NATURAL GAS	ELECTRICAL		P.O.L.			NATURAL GAS	ELECTRICAL	
	GASOLINE 10^6 GAL	DIESEL 10^6 GAL	FUEL OIL 10^6 GAL	10^6 CF	DEMAND MW	TOTAL USE 10^3 MWH	GASOLINE 10^6 GAL	DIESEL 10^6 GAL	FUEL OIL 10^6 GAL	MW	DEMAND MW	TOTAL USE 10^3 MWH
P/A	104	52	19		75	235	28	22	10		258	1,225
1	101	52	18		73	230	27	22	10		258	1,226
2	105	52	19		76	236	26	22	10		256	1,221
3	80	52	20		75	228	21	22	15		262	1,212
4	78	52	17		63	189	25	22	12		259	1,225
5	88	52	22		85	249	22	22	15		262	1,211
6	85	52	19		71	213	26	22	12		259	1,223
7	151	41	—	2,124	88	261	21	22	—	1,570	269	1,236
8	111	44	9	982	80	240	24	22	4	710	261	1,241

Notes: 4100

Annual electrical usage shown excludes estimated electricity generated by standby diesel generators.

Annual diesel fuel quantities shown includes estimated diesel fuel required by the standby diesel generators and JP-4 fuel.

10^6 = million; 10^3 = thousand.

P.O.L. = petroleum oil and lubricants.

Table 2.2-2. Summary of total energy requirements by alternative.

ALTERNATIVE	CONSTRUCTION TOTALS					
	P.O.L.			NATURAL GAS	ELECTRICAL	
	GASOLINE 10^6 GA	DIESEL 10^6 GA	FUEL OIL 10^6 GA	10^6 CF	DEMAND MW	TOTAL USE 10^3 MWH
P/A	322	163	60			729
1	303	158	54			691
2	315	158	59			713
3	292	190	74			821
4	285	190	61			705
5	295	175	74			820
6	280	172	62			701
7	580	156	—	8,200		1,005
8	427	168	31	3,780		924

4101

Energy data were developed for space heating, domestic water heating and air conditioning loads for the respective facilities, all expressed in Btu. Applying appropriate efficiencies, heating values of the fuels and conversion factors, heating loads in Btu were converted to quantities of fuels and cooling loads to electric energy. It was assumed that No.2 fuel oil would be used in Nevada/Utah and natural gas in Texas/New Mexico. A detailed engineering analysis is necessary to determine the most energy-efficient system or systems based on the life cycle cost of operation, given definite information on building location, construction, and occupancy.

The energy requirements for the M-X system are based on the specific requirements for various components of the system and on applicable state energy codes and/or ASHRAE Standard 90-75. Energy used in buildings is based on climatic conditions at the site (temperature, humidity, wind, sun), building construction, occupancy, and the type of working environments and equipment required. Every building in the M-X system will require electrical service from a public utility system.

Maximum electrical demand for the Texas/New Mexico region corresponds with peak air conditioning use during summer working hours with maximum heat gain from solar radiation. Maximum electrical demand for the Nevada/Utah region occurs during the winter months to meet lighting and heating requirements.

Seven sites are under consideration for base locations. It is assumed that population increases will occur in the county or counties in which the bases are located. Climatic conditions of the counties under consideration were used to determine the building envelope heat loss and heat gain. Domestic hot water usage is based on ASHRAE standards for design temperature and flow.

Estimating Methods for Determining Heating, Ventilation and Air Conditioning (HVAC) (2.3.2)

All the building types and sizes were taken from the TRW "Preliminary Estimated Resource Analysis for the SAC Operation Base (SAC-OB)" dated January 21, 1980. This information and the HVAC calculation methods are given in Appendix F, "Estimating Methods for Determining HVAC Requirements."

Estimating Methods for Determining Electrical Requirements (2.3.3)

Electrical operational requirements for the M-X system were derived from the "Power Systems Study Interim Report", dated April 17, 1980 by Boeing. Electrical requirements for all M-X support facilities were calculated based on appropriate conventional watts per square foot, estimated occupancy and hours of usage.

Estimating Methods for Determining Off-Base Personnel Fuel and Electric Power Requirements (2.3.4)

Additional fuel and electric power will be required in nearby communities by the increase in civilian population to support the M-X system. As explained above, energy requirements for base housing, units were calculated based on conventional estimating practices. Assuming that an average of 2.5 persons occupy each housing unit and that off-base housing would be of similar construciton, per capita energy

requirements were developed for each region as shown in Tables 2.3.4-1 and 2.3.4-2. Total off-base energy requirements were then calculated by multiplying each per capita energy value by projected off-base population increases for each alternative.

2.4 DESIGNATED DEPLOYMENT AREA (DDA): ENERGY REQUIREMENTS

DDA Construction: Energy Requirements (2.4.1)

During the construction phase, most of the energy requirements will be in the form of petroleum, oil and lubricants (P.O.L.) to operate the construction equipment, concrete patch plants, generators and vehicles required for this phase.

The induced growth in the construction site area will create support communities. These communities will require between about 45 and 65 MW of electric demand, depending on the alternative.

There will be up to 20 construction camps located throughout the deployment area. The camps will be approximately 30 miles apart and will employ 1,500-2,500 construction workers. Each camp will be in operation for approximately three years, of which one week will be at peak staffing level.

Each construction camp will be a self-contained community with all associated support systems in close proximity. All electrical requirements at the construction camps were assumed to be generated by diesel generators.

The construction camps will be dismantled after the missile is ready for deployment.

The construction energy requirements for the DDA are site-specific and are discussed in Section 3.0.

DDA Operations: Energy Requirements (2.4.2)

After the construction is completed the operations phase of the DDA will reduce the consumption of fossil fuels and increase the demand for electricity.

Fossil fuels will be used for emergency power, support vehicles, helicopters, and the transporter. "Annual fuel requirements for the DDA include about three million gallons for standby diesel generators, one half million gallons diesel fuel for the barrier vehicles and cranes, and about 2.2 million gallons JP-4 for the transporters."

The electrical energy requirements for the DDA operations summarized in Table 2.4.2-1 are typical for each full basing and split basing alternative.

2.5 OPERATING BASES (OB): ENERGY REQUIREMENTS

OB Construction: Energy Requirements (2.5.1)

As with the DDA, the operating base construction phase will require a construction camp. Along with the base construction, a marshaling yard will be in operation. This construction camp will also be self-contained with all life support being provided on site. All electrical demands were assumed to be met by diesel generators.

Table 2.3.4-1. Energy demand for off-base civilian housing based on population increases due to M-X deployment.

LOCATION	PEAK DEMAND PER INDIVIDUAL			
	ELECTRIC[4] kw	HEATING Btu/hr	COOLING Btu/hr	HOT WATER Btu/hr
Nevada				
White Pine County				
Ely	.6	15,100	8,550	1,180
Clark County				
Coyote/Kane Springs	.6	9,000	9,450	1,180
Utah				
Iron County				
Beryl	.6	13,700	8,750	1,180
Beaver County				
Melford	.6	13,700	8,900	1,180
Midland County				
Delta	.6	14,700	8,950	1,180
Texas[2]				
Dalhart	.65	13,500	8,950	1,180
New Mexico[3]				
Clovis	.65	13,100	8,850	1,180

3187-1

[1]The energy requirements are based on "per individual-per hour". An average occupancy of 2.5 persons per home is assumed.

[2]Typical for all counties in Texas.

[3]Typical for all counties in New Mexico.

[4]Does not include cooling.

Table 2.3.4-2. Annual energy usage for offbase civilian housing based on population increases due to M-X deployment.

	ANNUAL USAGE PER INDIVIDUAL			
	ELECTRIC* kwh	HEATING X 10^6 Btu	COOLING X 10^6 Btu	HOT WATER X 10^6 Btu
Nevada				
White Pine County				
Ely	4,080	38.2	4.7	10.3
Clark County				
Coyote/Kane Springs	4,080	12.7	24	10.3
Utah				
Iron County				
Beryl	4,080	30	10	10.3
Beaver County				
Melford	4,080	31.4	9.2	10.3
Midland County				
Delta	4,080	31	9.6	10.3
Texas [2]				
Dalhart	3,840	19.5	10.8	10.3
New Mexico [3]				
Clovis	3,750	18.6	10.9	10.3

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[1]The energy requirements are based on "per individual-per year". An average occupancy of 2.5 persons per home is assumed.

[2]Typical for all counties in Texas.

[3]Typical for all counties in New Mexico.

*Does not include cooling.

Table 2.4.2-1. Electric power requirements for DDA.

FACILITY	NUMBER OF FACILITIES	PEAK DEMAND		ANNUAL USE	
		LOAD PER FACILITY (kw)	TOTAL LOAD (kw)	USE PER FACILITY (kwh)	TOTAL USE (kwh)
PSS	4,600	21	96,600	183,960	846,216,000
RSS	200	11	2,200	96,360	19,272,000
CMF	200	260	52,000	359,320	71,864,000
ASC	4	840	3,360	1,226,400	4,905,600
DDA Total	5,004	1,132	154,160	1,866,040	942,257,600
Total Operating Requirements = 154,160 kw x 0.78 = 120,245 kw[1].					

3232-1

[1]Peak demand times 0.78 use factor equals total DDA demand requirements.

The induced growth in the construction site areas will create support communities. These communities will require approximately 26 MW of electric demand, depending on the alternative.

The energy requirements for the construction phase of the operating bases are site-specific and are discussed for each alternative in Section 3.0.

Some of the fuel requirements for heating will be provided by bottled gas trucked in from major distribution centers.

OB Operations: Energy Requirements (2.5.2)

The operating bases, when constructed, will utilize electricity from the local utility companies for motors, lighting, communications, etc. The heating source has been assumed to be fuel oil for the Nevada/Utah region, and natural gas for the Texas/New Mexico region. Cooling has been assumed to be electric.

Diesel generators will be installed at the operating bases and each of the distribution centers to provide standby power in the event of a power outage.

The operations energy requirements for the OB are site-specific and are discussed for each alternative in Section 3.0. Operating bse annual fuel consumptions include the following quantities:

Vehicle	Fuel	Million gallons/year
Special Transporter Vehicle	JP4	0.3
Helicopter	JP4	3.6
ALCC (Radar planes)	JP4	8.9
General/Special Vehicles	Diesel	2.0
General/Special Vehicles	Gasoline	5.5

The electrical energy requirements of the OB operations, summarized in Table 2.5.2-1, are typical for each full basing alternative, excluding the energy requirements for the associated population increase. These requirements are specific for each alternative and are covered in Section 3.0.

Summary Tables for Energy Requirements for Operating Bases and Support Communities (2.5.3)

Tables 2.5.3-1 and 2.5.3-2 present hourly peak demand and annual use of the operating bases and the support community for each alternative. These energy requirements do not include present or future populations in the area who do not directly or indirectly support the M-X system.

Table 2.5.2-1. Electric power requirements for each full basing alternative-operating bases.

FACILITY	NUMBER OF FACILITIES	PEAK DEMAND (kw)	ANNUAL USAGE (kwh)
First OB	1	42,690	103,684,300
DAA	1	2,430	7,028,600
Second OB	1	19,490	74,427,200
OBTS	1	775	1,435,400
OB Total	4	65,385	186,575,500

2689-2

*Total full basing operating demand requirement = 65,385 kw x 0.78 = 51,000 kw.

*Split basing alternative will include additional DAA.

*Total split basing operating demand requirement = 67,815 kw x 0.78 = 52,900 kw.

*Total annual energy requirement for split basing is 193,604,100 (kwh).

*Peak demand times 0.78 use factor equals total demand requirement for the operating bases.

Table 2.5.3-1. Energy requirements for operating bases and support communities by alternative - hourly peak demands.

BASES AND AFFECTED COMMUNITIES	HOURLY PEAK DEMAND: HEATING MILLION BTU/HR	DOMESTIC HOT WATER MILLION BTU/HR	TOTAL HEATING & HOT WATER MILLION BTU/HR	COOLING MILLION BTU/HR	COOLING POWER (MW)	OTHER ELECTRICITY (MW)	TOTAL ELECTRIC (MW)
Coyote, NV	183	60	243	127	13	46	59
Communities	48	6	54	33	4	2	6
Milford, UT	181	40	221	80	8	20	28
Communities	118	10	128	54	7	4	11
Proposed Action	530	116	646	294	32	72	104
Coyote, NV	183	60	243	127	13	46	59
Communities	51	6	59	34	4	2	6
Beryl, UT	181	40	221	79	8	20	28
Communities	117	10	127	52	7	4	11
Alt. 1	532	116	650	292	32	72	104
Coyote, NV	183	60	243	127	13	46	59
Communities	45	6	51	32	4	2	6
Delta, UT	191	40	231	81	8	20	28
Communities	108	9	117	46	6	3	9
Alt. 2	527	115	642	286	31	71	102
Beryl, UT	277	60	337	119	12	46	58
Communities	156	13	169	71	9	5	14
Ely, NV	200	40	240	78	8	20	28
Communities	107	8	115	42	5	3	8
Alt. 3	740	121	861	310	34	74	108
Beryl, UT	277	60	337	119	12	46	58
Communities	157	14	171	71	9	5	14
Coyote, NV	120	40	160	84	8	20	28
Communities	43	5	48	27	3	2	5
Alt. 4	597	119	716	301	32	73	105
Milford, UT	277	60	337	121	12	46	58
Communities	159	14	173	72	9	5	14
Ely, NV	200	40	240	78	8	20	28
Communities	103	8	111	41	5	3	18
Alt. 5	739	122	861	312	34	74	108
Milford, UT	277	60	337	121	12	46	58
Communities	160	14	174	73	9	5	14
Coyote, NV	120	40	160	84	8	20	28
Communities	38	5	43	26	3	2	5
Alt. 6	595	119	714	304	32	73	105
Clovis, NM	266	60	326	120	12	46	58
Communities	131	12	143	62	8	5	13
Dalhart, TX	179	40	219	81	8	20	28
Communities	171	15	186	80	10	6	16
Alt. 7	747	127	874	350	38	77	115
Coyote, NV	150	60	210	105	10	46	56
Communities	45	46	51	32	4	2	6
Clovis, NM	220	40	260	100	10	22	32
Communities	131	12	143	62	8	5	13
Alt. 8	546	118	664	299	32	75	107

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Table 2.5.3-2. Energy requirements for operating bases and support communities by alternative - annual use.

BASES AND AFFECTED COMMUNITIES	ANNUAL USE						
	HEATING BILLION BTU/HR	DOMESTIC HOT WATER BILLION BTU/HR	TOTAL HEATING & HOT WATER BILLION BTU/HR	COOLING BILLION BTU/HR	COOLING POWER THOUSAND MWH	OTHER ELECTRICITY (THOUSAND MWH)	TOTAL ELECTRIC (THOUSAND MWH)
Coyote, NV	260	150	410	320	32	112	144
Communities	76	51	127	79	10	14	24
Milford, UT	417	107	524	83	8	75	83
Communities	267	89	356	57	7	25	32
Proposed Action	1,020	397	1,417	539	57	226	283
Coyote, NV	260	150	410	320	32	112	144
Communities	84	54	138	79	10	15	25
Beryl, UT	400	107	507	90	9	75	84
Communities	260	88	348	59	7	24	31
Alt. 1	1,004	399	1,403	548	58	287	284
Coyote, NV	260	150	410	320	32	112	144
Communities	67	50	117	78	10	14	24
Delta, UT	410	107	517	87	9	75	84
Communities	227	76	303	44	6	21	27
Alt. 2	964	383	1,347	534	57	283	279
Beryl, UT	610	150	760	136	13	112	125
Communities	346	117	463	79	10	33	43
Ely, NV	510	107	617	43	4	75	79
Communities	270	73	343	23	3	20	23
Alt. 3	1,736	447	2,183	281	30	240	270
Beryl, UT	610	150	760	136	13	112	125
Communities	348	118	466	79	10	33	43
Coyote, NV	170	107	277	212	21	75	96
Communities	73	43	116	60	7	12	19
Alt. 4	1,201	418	1,614	487	57	232	283
Milford, UT	637	150	787	125	12	112	124
Communities	360	119	479	77	10	33	43
Ely, NV	510	107	617	43	4	75	79
Communities	260	71	331	22	3	20	23
Alt. 5	1,767	447	2,214	267	29	240	269
Milford, UT	637	150	787	125	12	112	124
Communities	360	120	480	77	10	33	43
Coyote, NV	170	107	277	212	21	75	96
Communities	60	40	100	60	7	11	18
Alt. 6	1,227	417	1,644	474	50	231	281
Clovis, NM	377	150	527	148	15	112	127
Communities	186	103	289	76	10	26	36
Dalhart, TX	260	107	367	98	10	75	85
Communities	246	131	377	96	12	34	46
Alt. 7	1,069	491	1,560	418	47	247	294
Coyote, NV	214	150	364	266	27	112	139
Communities	67	50	117	77	10	14	24
Clovis, NM	310	107	417	123	12	88	100
Communities	186	103	289	77	10	26	36
Alt. 8	777	410	1,187	543	59	240	299

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2.6 ELECTRICAL POWER TRANSMISSION AND DISTRIBUTION

Under the current plan, all electric power for the M-X system will be purchased from area utilities. However, alternative energy sources are currently being developed that could minimize the impacts on nonrenewable resources and reduce the system's dependence on other area energy sources.

The M-X system concept (Boeing report dated 4/17/80) is shown in simplified form in Figure 2.6-1. Power will be taken from the utility transmission grid through substations which transform the voltage from, typically, 500 KV, 345 KV, or 230 KV, down to an appropriate transmission voltage in the 138 KV class. The power will then be transmitted over 138 KV transmission lines to area substations where voltage will be transformed to a nominal 25 KV distribution voltage.

Power from the area substations will be transmitted via 25 KV overhead distribution lines to distribution centers dispersed throughout the DDA. Underground cables will be used to transmit power from the distribution lines to M-X distribution centers to protective structures and other DAA facilities. Standby diesel generators will be available at the distribution centers to supply power in the event of an outage.

The actual system of transmission lines, substations and distribution lines to serve M-X will be developed by area utilities in accordance with USAF reliability criteria and long-range utility planning considerations. Specific transmission system details, such as transmission line and substation locations, cannot be determined until a specific site and basing configuration is established. However, it is possible to indicate the general type and approximate quantity of transmission facilities required based on a conceptual design for a representative Nevada/Utah basing configuration (Boeing/EDA, 12/31/79).

A representative transmission system conceptual design developed for the Nevada/Utah region is shown in Figure 2.6-2. This figure shows a possible system of utility bulk-power substations, 138 KV transmission lines, M-X area substations, and base substations. It is not intended to show proposed transmission line or substation locations, but it does provide a useful quantitative picture.

The M-X electrical load will be dispersed over the wide geographical extent of the DDA. From a transmission system design standpoint, the primary problem will be one of maintaining voltage support over distance, not bulk-power transfer. For this reason, a proliferation of large bulk-power transmission lines is not anticipated. For example, a computer transmission network load-flow optimization study for the representative Nevada/Utah design shows that the relatively light and widely distributed M-X load can be supplied by 138 KV transmission lines in the same voltage range - primarily 115 KV lines - prevalent throughout Texas and New Mexico. It should be noted that most new or proposed bulk-power transmission lines in this county are rated 345 or 500 V, and that a 115 or 138 KV line is relatively small.

Transmission Lines (2.6.1)

The design of the transmission lines will be determined by utility standards, wind and ice loading conditions, right-of-way considerations, terrain, and other

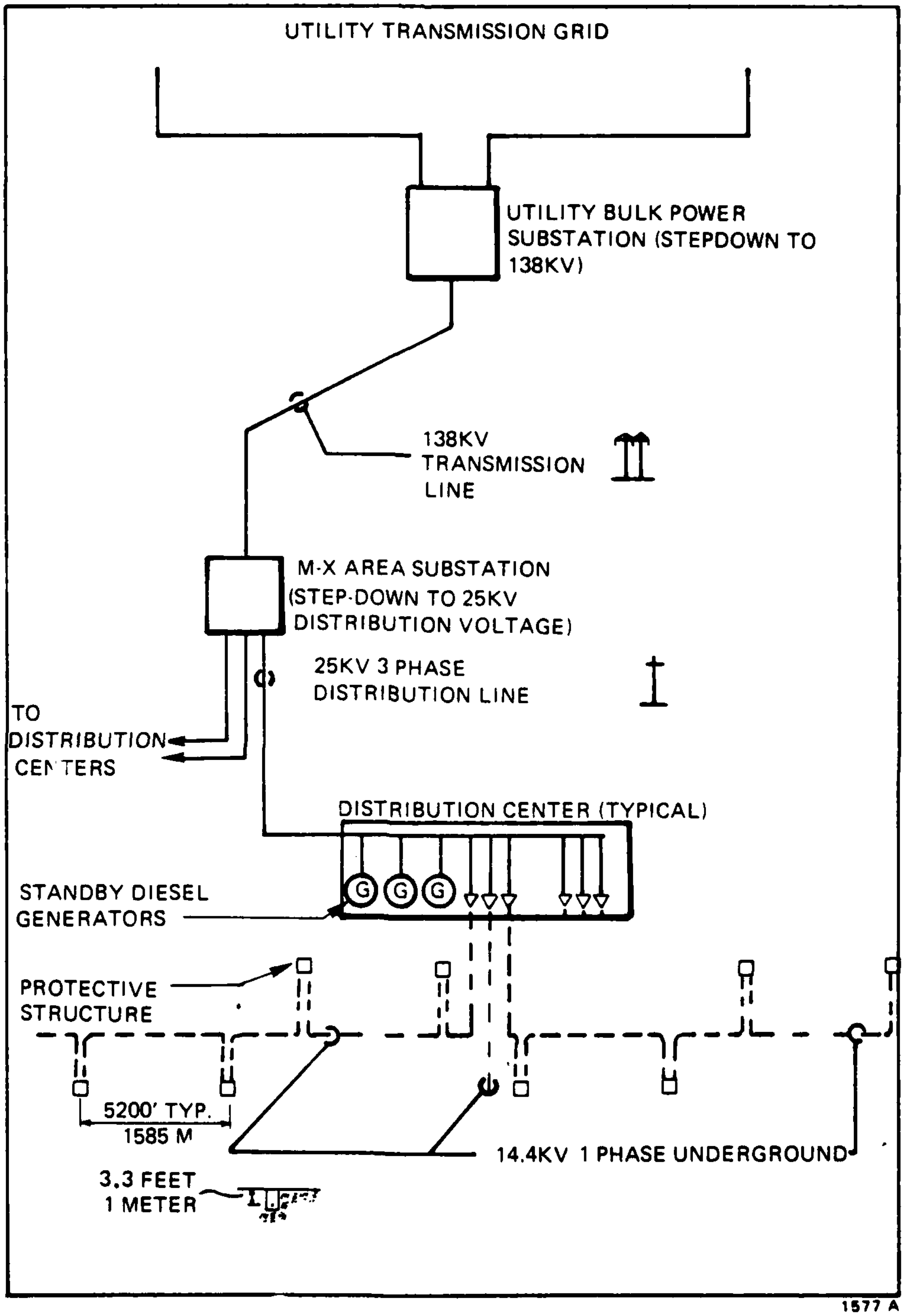

Figure 2.6-1. M-X power system concept.

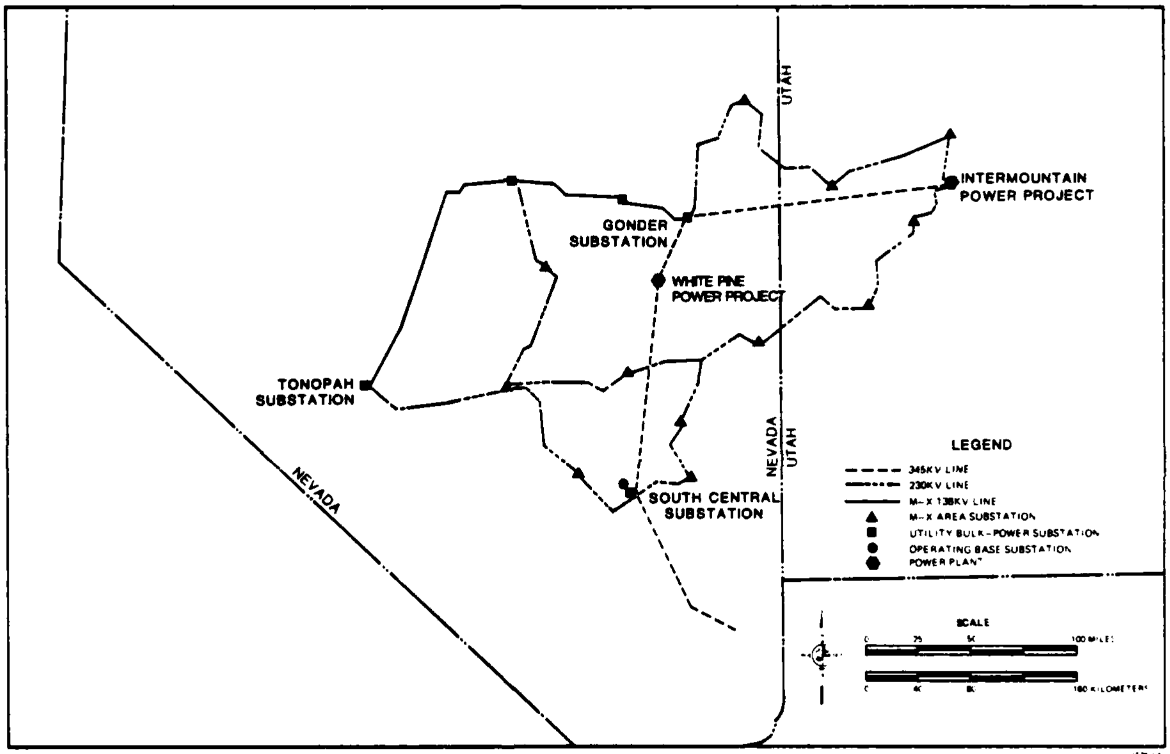

Figure 2.6-2. Conceptual Nevada/Utah transmission system configuration.

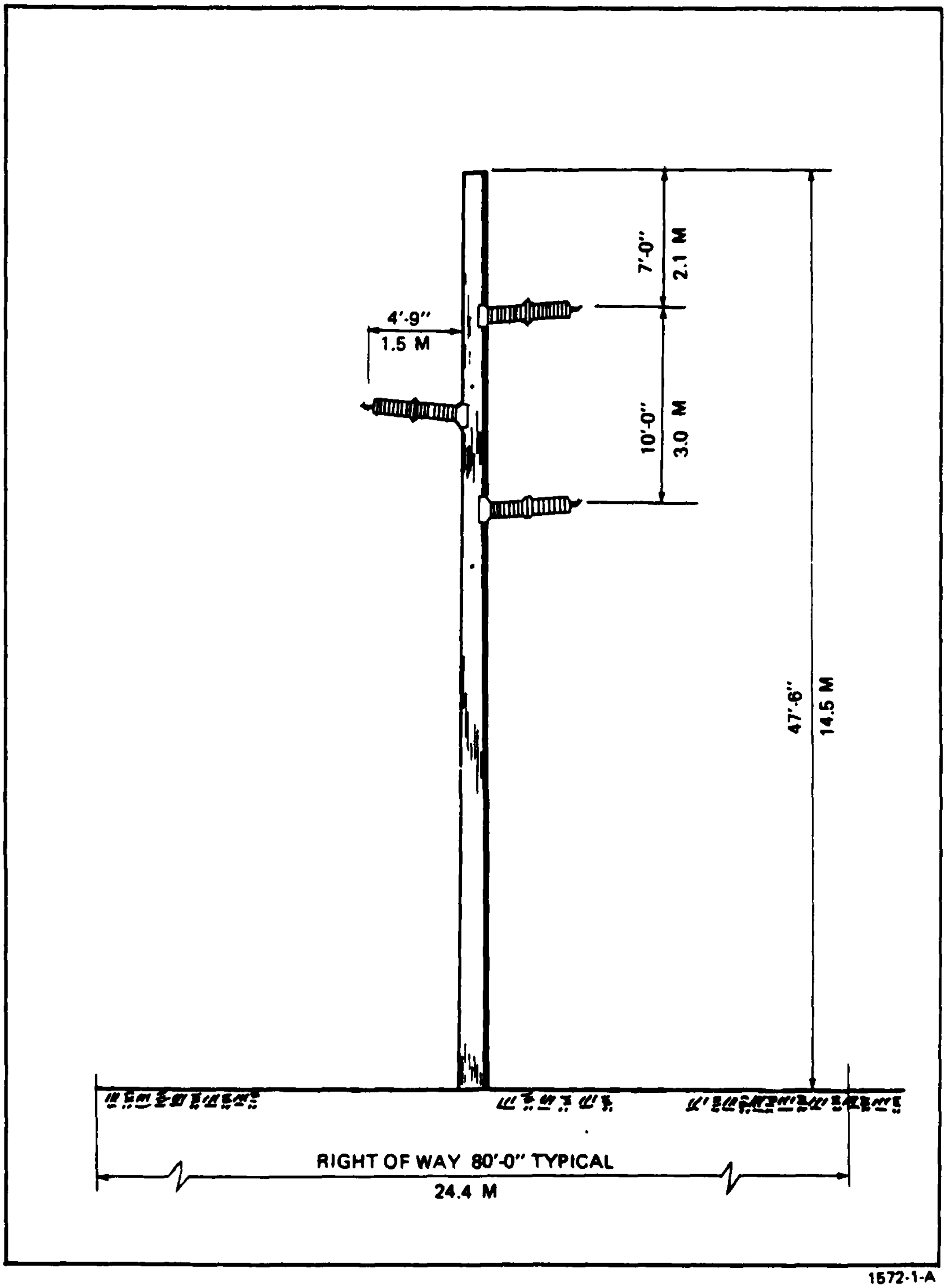

Figure 2.6.1-1. 138 KV transmission line post structure.

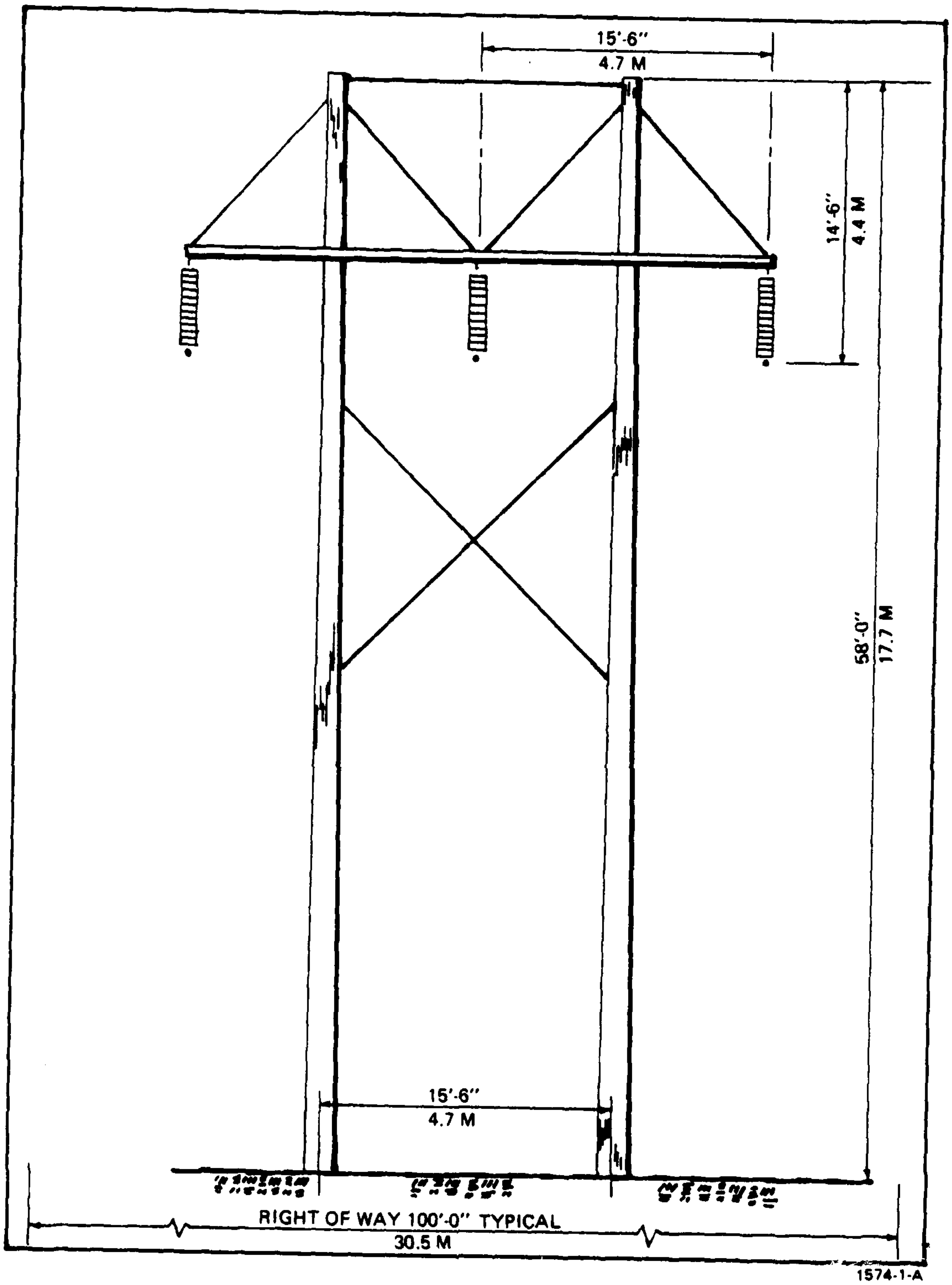

Figure 2.6.1-2. 138 KV transmission line H-frame structure.

factors. Typical structure types for a 138 KV line include the compact "line post" design and the "H-frame" design are illustrated in Figures 2.6.1-1 and 2.6.1-2. The actual type and number of structures and miles of lines required for the system are dependent on specific site conditions. However, the approximate system requirements are indicated by the representative Nevada/Utah design, which requires 554 miles of 138 KV transmission lines.

Substations (2.6.2)

The actual number of substations required will depend on actual basing configuration and the density of existing distribution substations in the DDA. It is anticipated that there will be at least one substation for each base. The representative Nevada/Utah design shown in Figure 2.6-2 has five utility bulk-power substations, twelve area substations, and one base substation. Utilities would provide power up to the distribution centers.

Figures 2.6.2-1 through 2.6.2-3 show typical dimensions for utility bulk-power substations, operating base substations, and area substations, respectively. Fenced areas for the three types of substations are 5.4 acres (2.2 hectares), 1.6 acres (0.65 hectare) and 0.8 acre (0.3 hectare) respectively.

Overhead Distribution Lines (2.6.3)

A typical 25 KV distribution structure for overhead lines is shown in Figure 2.6.3-1. Commonly found in residential areas and on rural distribution systems, this type of structure is normally constructed on or immediately adjacent to the road right-of-way. The 25 KV distribution voltate is more precisely termed 24.9 Y/14.4 KV. This designation means that the distribution lines carry 14.4 KV single-phase power and 24.9 KV three-phase power.

The large number of distribution centers required for the system (approximately 120), a substantial mileage of overhead distribution lines will be needed. The representative Nevada/Utah conceptual design required 1,700 miles of 25 KV distribution lines. The requirement for new lines will vary depending on the actual site. Some rural areas have extensive distribution systems which could be utilized to serve M-X in addition to other loads; this would minimize the need for new line construction.

Distribution Centers (2.6.4)

The main equipment required for a distribution center is shown in Figure 2.6.4-1. The representative Nevada/Utah conceptual design requires about 20 distribution centers. However, the actual number and location of distribution centers will depend on the basing configuration.

Underground Power Cables (2.6.5)

Within the clusters, power would be transmitted through underground cables. These cables supply 14.4 KV single-phase power to protective structures and remote

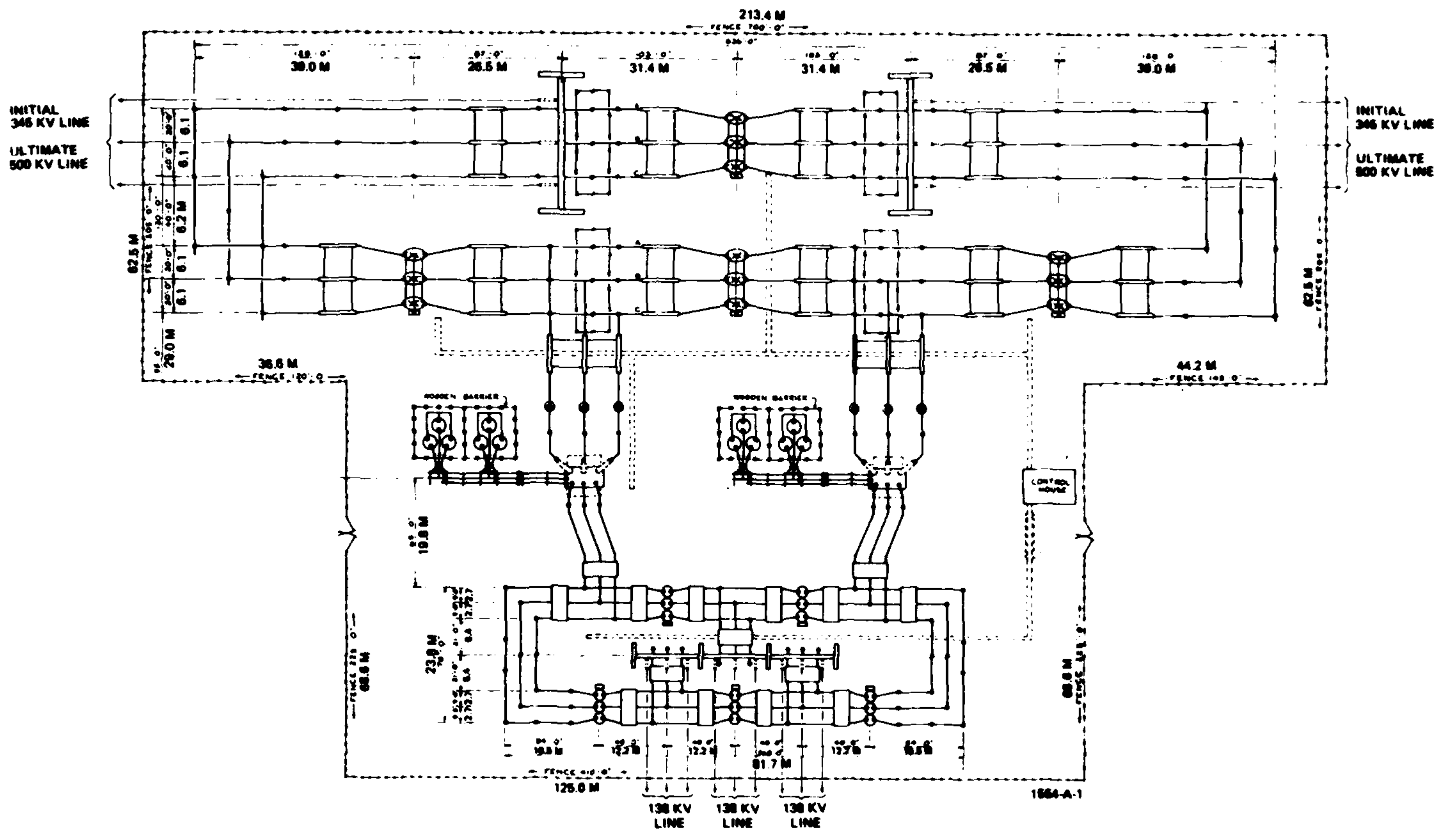

Figure 2.6.2-1. 'ypical utility bulk-power substation.

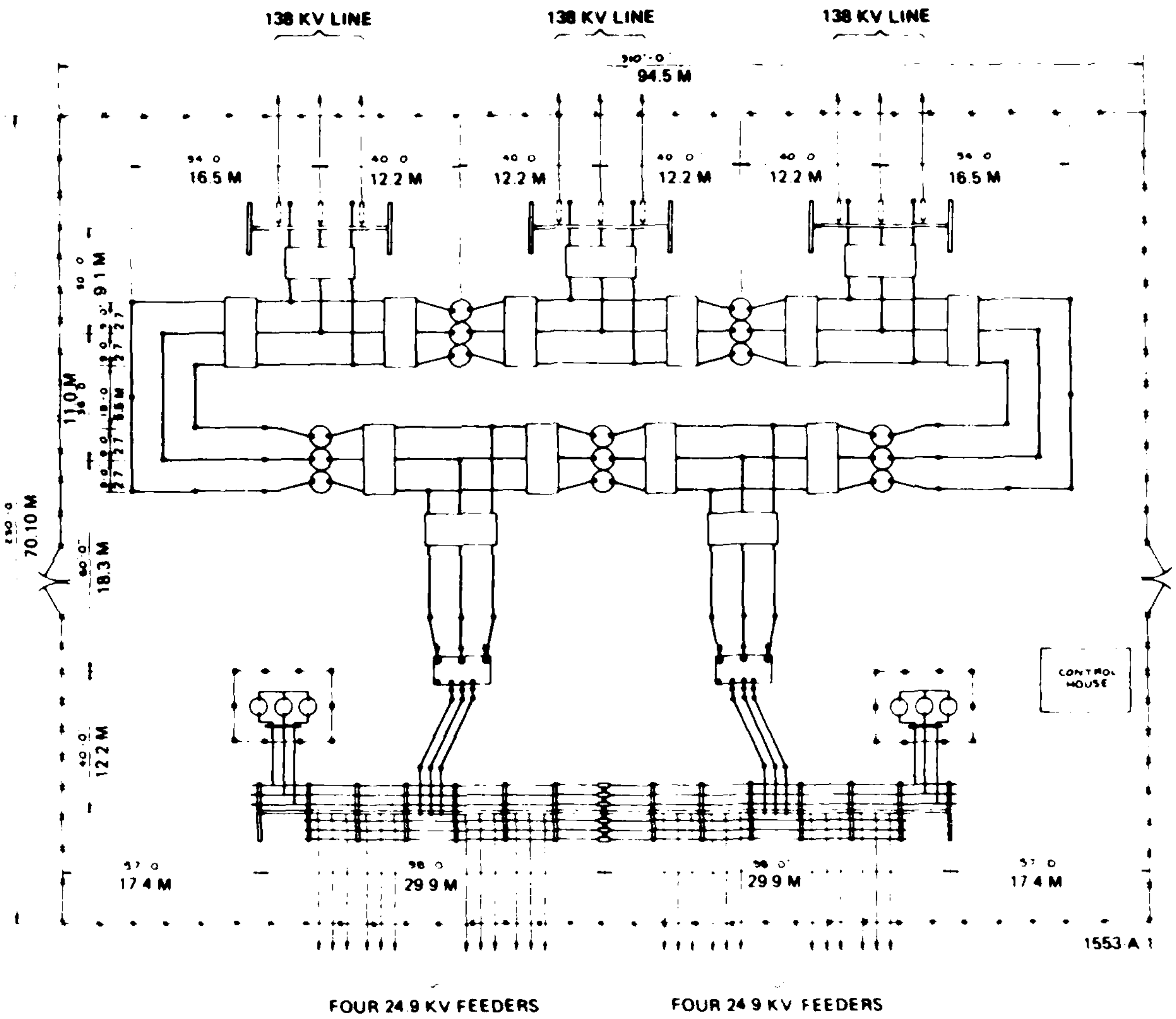

Figure 2.6.2-2. Typical operating base substation.

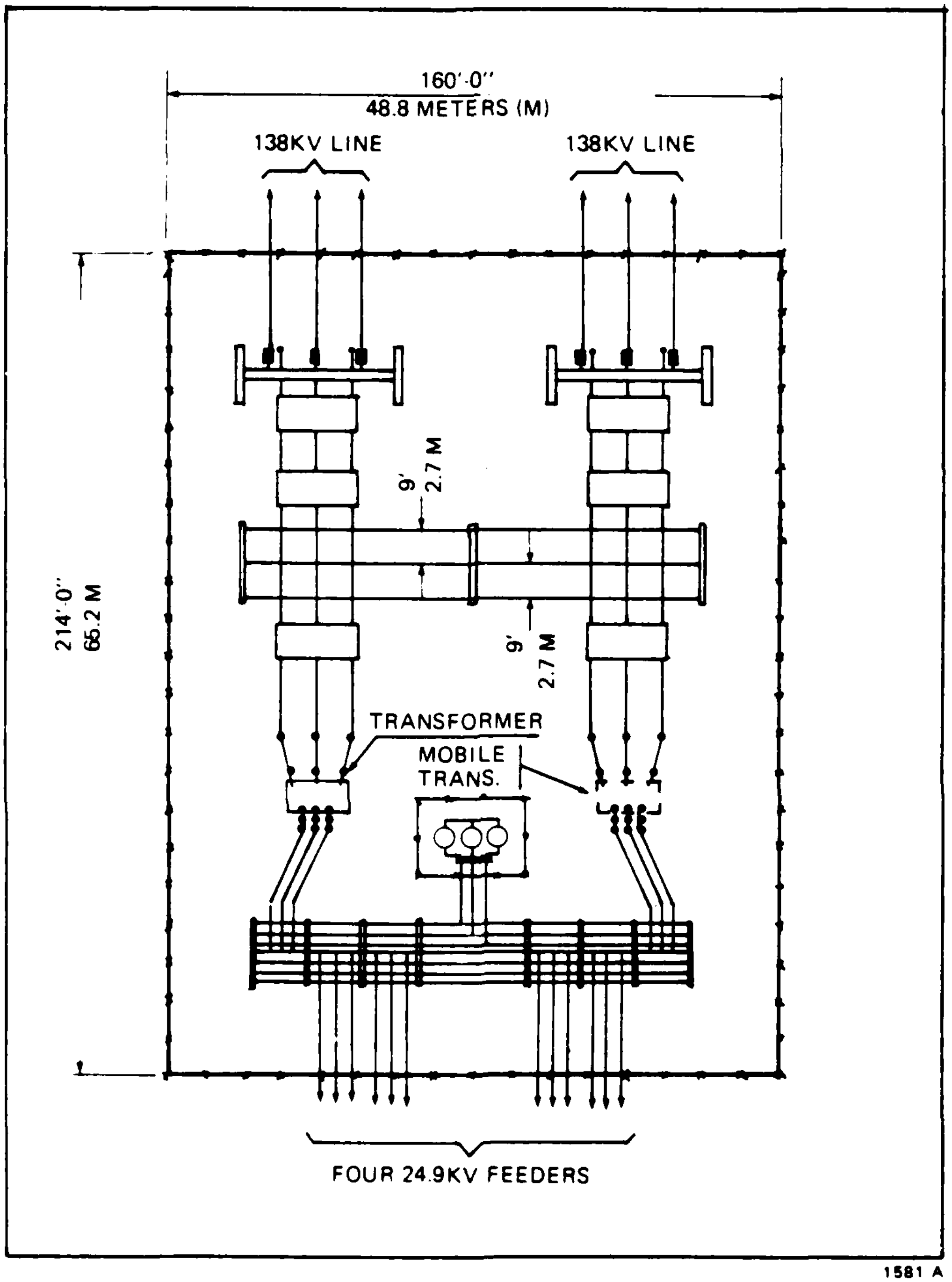

Figure 2.6.2-3. Typical M-X area substation.

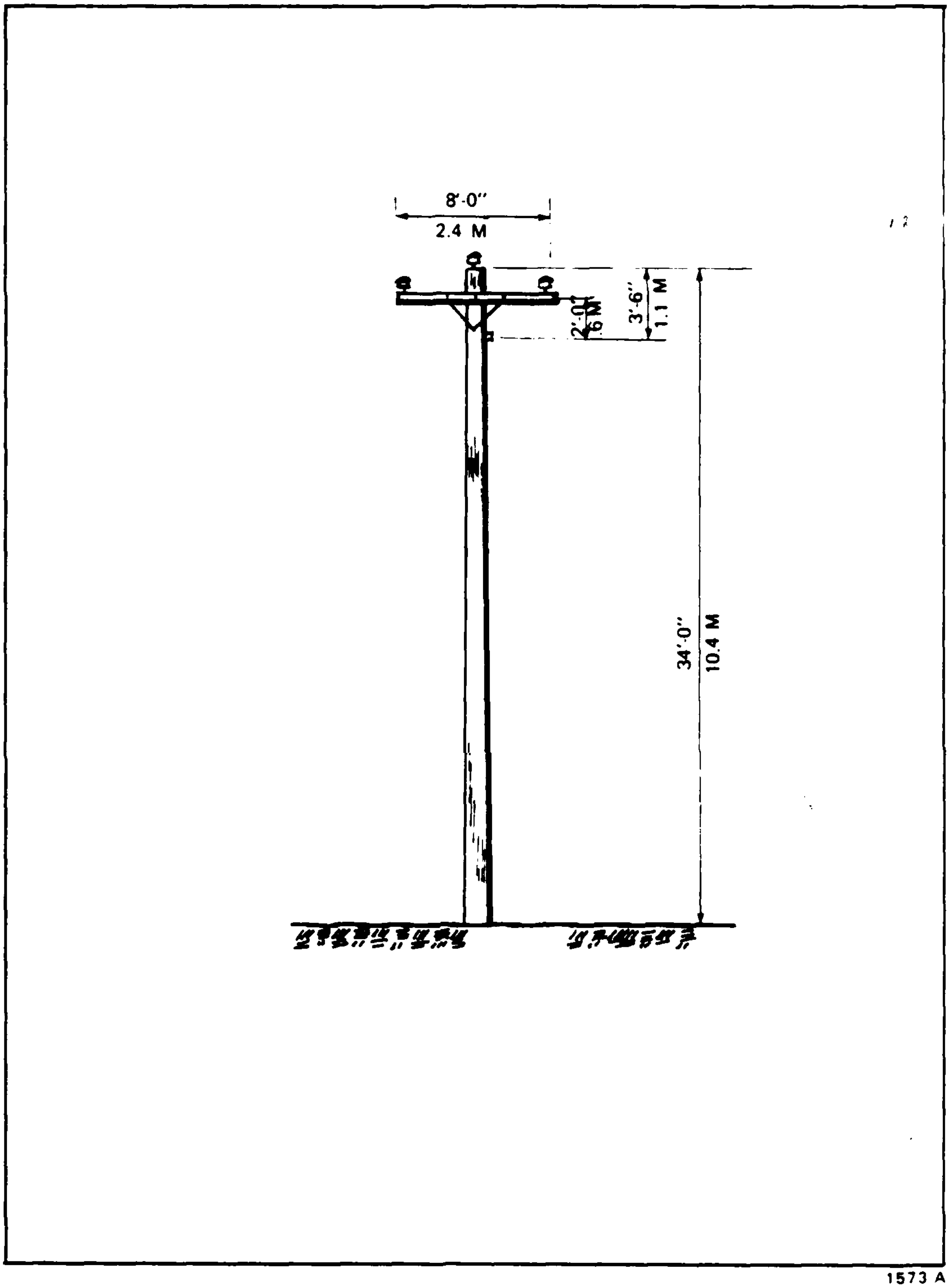

Figure 2.6.3-1. Typical 25 KV overhead distribution line structure.

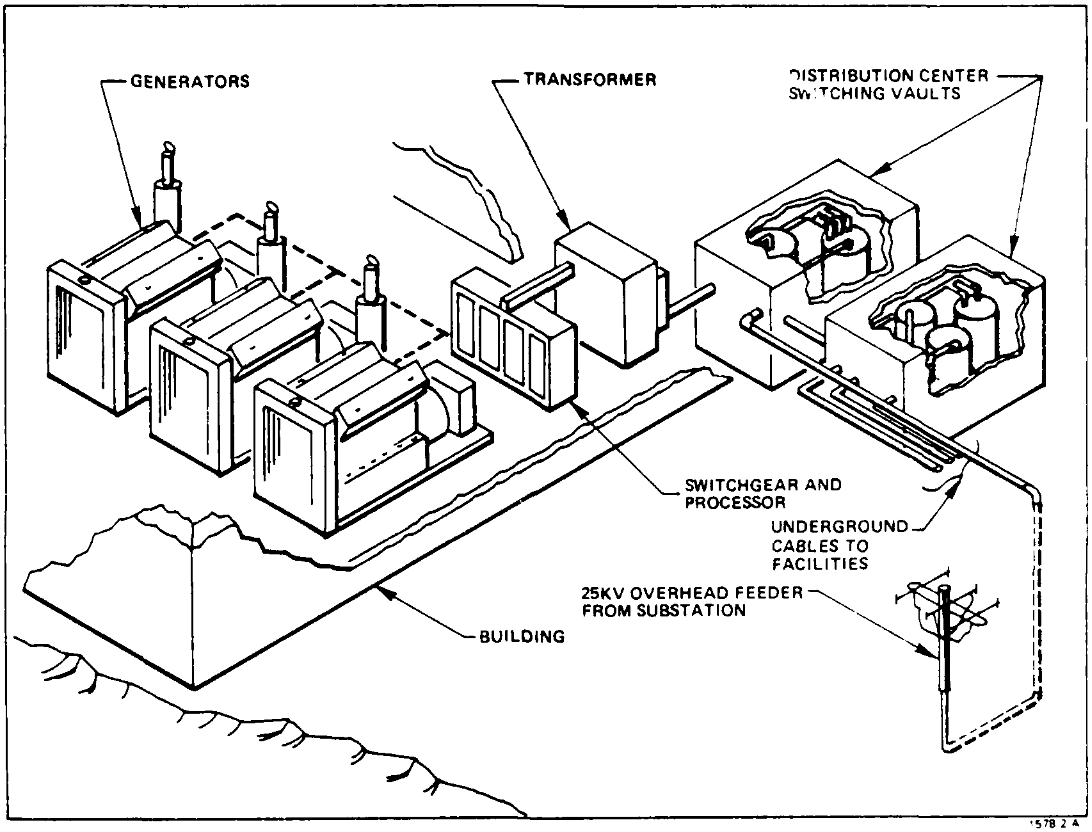

Figure 2.6.4-1. Distribution center equipment.

surveillance sites and supply 24.9 KV three-phase power to cluster maintenance facilities and deployment area support centers.

Three possible methods of power cable installation are: duct bank installation, cable plowing, and trenching and backfilling.

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3.0 ALTERNATIVES

This section discusses site-specific fuel and electric energy requirements for each of the nine proposed alternatives for the M-X system.

Fuel and electric energy would be required for both the construction and operation of the M-X designated deployment areas and operating bases plus the increased population entering the region to support the system. Diesel fuel and gasoline will be required for vehicles during both construction and operation, for construction equipment and electric generation during construction and for standby diesel generators in the operating base power house and the DDA. It is assumed No. 2 fuel oil in Nevada/Utah and natural gas in Texas/New Mexico will be used to meet space heating and hot water heating needs in these regions. Electrically driven air conditioning units are assumed in all cases.

The primary considerations in comparing alternate sites with respect to electrical energy are: (1) the planning, engineering, construction, and maintenance resources of the affected utility; (2) bulk-power availability; and (3) the adequacy of existing transmission and distribution facilities serving the proposed base and deployment areas. New facilities can be constructed if needed, but cost and lead time considerations are signficant.

Estimated overall fuel and electrical energy requirements for each alternative are given in Table 2.2-1 showing the maximum annual requirements for construction (1986 data) and operation (1992 data). Total energy requirements of the construction period for each alternative are given in Table 2.2-2.

3.1 PROPOSED ACTION - COYOTE SPRING VALLEY; MILFORD

The Proposed Action (P/A) is located in the Nevada/Utah region with a First Base at Coyote Spring Valley, Nevada and a Second Base at Milford, Utah. Energy requirements for construction and operation are presented in Table 3.1-1.

Fuel Supply (3.1.1)

The Proposed Action and the existing and proposed pipelines (not 100 percent complete) are presented in Figure 3.1.1-1.

Designated Deployment Area (DDA)

As previously mentioned, there are relatively few pipelines in the Nevada/Utah deployment area. Fuel storage and distribution facilities would probably be constructed to support the project.

First Base; Coyote Spring Valley

Coyote Spring is located approximately 55 miles north-northeast of Las Vegas in a sparsely populated area with no natural gas service. The closest natural gas service is about 8 to 10 miles north of Las Vegas. Natural gas service could be extended to the Coyote Spring area by Southwest Gas Corporation of Las Vegas, but presently there are no plans for such expansion.

Table 3.1-1. Annual energy requirements—Proposed Action.
(Page 1 of 2)

USE CATEGORY	NEVADA						UTAH					
	POL			NAT. GAS	ELECTRICITY		POL			NAT. GAS	ELECTRICITY	
	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH
Construction												
DDA												
Equip & Vehicles	2	32					1	13				
Commute & Rec	24						29					
Support-Camps	*	2					*	1				
Support-Commun			8		26	73			6		23	70
Bases												
Equip & Vehicles	1	1					1	1				
Commute & Rec	32						14					
Support-Camps		1						1				
Support-Commun			2		13	52			3		13	40
Total Construction	59	36	10		39	125	45	16	9		36	110
USE CATEGORY	10^6 GA/YR	10^6 GA/YR	10^6 GA/YR	10^6 CF/YR	MW	10^6 MWH/YR	10^6 GA/YR	10^6 GA/YR	10^6 GA/YR	10^6 CF/YR	MW	10^6 MWH/YR
Operations												
DDA	*	4			108	660		2			46	282
Bases												
Technical Op	4	11			46	112	2	5			20	75
Support-Onbase			3		13	32			4		8	8
Support-Offbase			1		6	24			2		11	32
Comm & Rec-Milt	5						4					
Comm & Rec-Civ	8						5					
Total Operations	17	15	4		173	828	11	7	6		87	397

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Table 3.1-1. Annual energy requirements—Proposed Action. (Page 2 of 2)

USE CATEGORY	TOTAL					
	POL			NAT. GAS	ELECTRICITY	
	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH
Construction						
DDA						
Equip & Vehicles	3	45				
Commute & Rec	53					
Support-Camps		3				
Support-Commun			14		49	143
Bases						
Equip & Vehicles	2	2				
Commute & Rec	46					
Support-Camps		2				
Support-Commun			5		26	92
Total Construction	104	52	19		75	235
USE CATEGORY	10^6 GA/YR	10^6 GA/YR	10^6 GA/YR	10^6 CF/YR	MW	10^3 MWH/YR
Operations						
DDA		6			154	942
Bases						
Technical Op	6	16	1		66	187
Support-Onbase			7		21	40
Support-Offbase			3		17	56
Comm & Rec-Milt	9					
Comm & Rec-Civ	13					
Total Operations	28	22	10		258	1225

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SEE FIGURE 4.3.2.10-3,
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Figure 3.1.1-1. Proposed Action layout with existing and proposed underground pipelines.

The closest petroleum product pipeline in the area is the CAL-NEV pipeline which terminates at Las Vegas. The bottled gas, fuel oil, gasoline and diesel fuel distributors that truck these fuels throughout the region do not have the capacity to handle the increased fuel demand associated with the influx of people for the M-X project. Natural gas and/or petroleum product pipelines would have to be extended into the Coyote Spring area for the M-X project, or the present fuel hauling capabilities would have to be expanded.

Second Base; Milford, Utah

Milford is located in an area without natural gas service. Service could be extended into the area by Mountain Fuel Supply (MFS) in Salt Lake City, but there are no plans for such expansion.

Pacific Gas Transmission (PGT), a subsidiary of Pacific Gas and Electric in San Francisco, has proposed to build a wye-shaped 30-inch high-pressure gas transmission line from Kremmerer, Wyoming and Bonanza, Utah, joining east of Provo, Utah near Strawberry Reservoir, and continuing along Interstate 15 through Cedar City, Utah and Las Vegas, Nevada areas to southern California. This line will have sufficient capacity to transport natural gas for M-X if the USAF can make commitments soon enough for MFS and PGT to reach the appropriate agreements.

Home energy requirements in Milford are presently supplied by bottled gas, fuel oil and electricity. The fuels are trucked from bulk fuel handling terminals in Las Vegas and Salt Lake City to regional distribution centers in St. George and Cedar City. If natural gas service is extended into the area, the fuel trucking companies could help supply the increased gasoline and diesel fuel loads. However, a considerable portion of the increased fuel demands would have to be transported by expanding the present truck fleet, by adding new suppliers, or by using military tanker trucks.

Electric Power (3.1.2)

The Proposed Action and the existing and proposed transmission lines without M-X (not complete) are presented in Figure 3.1.2-1.

Designated Deployment Area (DDA)

As shown on the plot, the Nevada/Utah region has very limited transmission facilities. The only bulk-power line in the area, Sierra Pacific's 230 KV line, is currently operating near capacity and is not available for M-X requirements. The major transmission lines associated with the proposed IPP and White Pine generating plants are scheduled to be in service in 1986. Transmission facilities to supply M-X prior to 1986 will be severely limited unless construction schedules can be moved up.

Most of the medium-voltage transmission lines or subtransmission lines required to supply M-X area substations would have to be newly constructed due to the scarcity of such lines in the Nevada/Utah region. Because of the low density of rural distribution lines in the area, a substantial mileage of new distribution lines in the 25 KV or 12.5 KV range would also have to be newly constructed to supply M-X distribution centers.

SEE FIGURE 4.3.2.10-1,
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Figure 3.1.2-1. Proposed Action layout with existing and proposed transmission lines.

Electrical energy for the Nevada/Utah DDA would be obtained by scheduling power with area utilities. The power would be supplied from currently planned generating projects such as the H. Allen plant at Dry Lake, Nevada, the White Pine plant in White Pine County, Nevada, the IPP plant near Lyndall, Utah, and the Moon Lake project in northeastern Utah. Deployment of M-X in the Nevada/Utah region may require an acceleration in construction for one or more of these generating projects, but no new generating plants constructed specifically for the M-X project are anticipated.

First Base, Coyote Spring Valley

There are no electrical load or power system facilities in Coyote Spring. This area is on the southern boundary of the Lincoln County Power District (LCPD), which has a system peak demand of approximately 16 MW. There are no suitable transmission lines in the immediate area. A 69 KV transmission line from the Moapa generating plant passes through the area, but the line is operating at capacity and cannot be utilized to supply a base at Coyote Spring.

The estimated electrical load increase in the Coyote Spring area due to the M-X base is 65 MW. Because the LCPD has a peak demand of 16 MW, and because there are no suitable transmission lines in the area, transmission facilities would have to be newly constructed to serve M-X. Because Coyote Spring is on the boundary between the service areas of LCPD and the Nevada Power Company, these two utilities have met to discuss how the M-X load might be served. Based on these meetings, it is anticipated that there would be close cooperation between LCPD and the Nevada Power Company in the planning, engineering, and construction of required transmission facilities.

It is anticipated that power for a base at Coyote Spring could be supplied from the H. Allen plant at Dry Lake, Nevada. The H. Allen plant is scheduled for 1986 completion. Utah Power and Light representatives state that M-X bulk-power requirements are significant, and they stress the importance of an early and definite commitment by the Air Force to permit scheduling of power in accordance with required lead times.

Second Base, Milford

Electric power is supplied to the Milford area by Utah Power and Light Company via two 46 KV lines with a present load of about 5 MW. The bulk-power requirements for the operating base and associated area population increase are estimated to be about 39 MW. Typical plant construction time is three years from ground breaking to on line and normal planning lead time is 4 to 5 years from identification of the requirements to completion of major facilities. A concerted effort must be made to schedule the construction of the operating base and the Intermountain Power Project (IPP) to assure that electric power is available when required.

3.2 ALTERNATIVE 1 - COYOTE SPRING VALLEY; BERYL

Alternative 1 is located in the Nevada/Utah region with a First Base at Coyote Spring Valley, Nevada and a Second Base at Beryl, Utah. Energy requirements for construction and operation are presented in Table 3.2-1. The fuel supply situation is similar to the Proposed Action.

Table 3.2-1. Annual energy requirements - Alternative 1.

USE CATEGORY	NEVADA						UTAH						TOTAL					
	P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY	
	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH
Construction																		
DDA																		
Equipment & Vehicles	2	32					1	13					3	45				
Commute & Recreation	24						26						50					
Support—Camps		2						1						3				
Support—Communities			8		26	73			5		20	61			13		46	134
Bases																		
Equipment & Vehicles	1	1					1	1					2	2				
Commute & Recreation	32						14						46					
Support—Camps		1						1						2				
Support—Communities			2		13	52			3		14	44			5		27	96
Total	59	36	10		39	125	42	16	8		34	105	101	52	18		73	230
Operations																		
DDA		4			108	660		2			46	282		6			154	942
Bases																		
Technical Operations	4	11			46	112	2	5			20	75		16			66	137
Support—Onbase			3		13	32			4		8	9			7		21	41
Support—Offbase			1		6	25			2		11	31			3		17	56
Commute & Recreation-Military	5						3						8					
Commute & Recreation-Civilian	8						5						13					
Total	17	15	4		173	829	10	7	6		87	397	27	22	10		258	1,226

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Electrical power is supplied to the Beryl area by Dixie-Escalante Rural Electric Association, Inc., which has a peak system demand of approximately 20 MW. The utility purchases its power from the Western Area Power Administration and the Department of Energy. Beryl is presently served by a 12.5 KV rural distribution line. New transmission facilities would be required to handle a substantial load increase.

The estimated electrical load increase in the Beryl area due to the M-X base and the anticipated population increase is 39 MW. Since the present Dixie-Escalante system peak demand is approximately 20 MW, this increase in electrical load will have a substantial impact. One or more transmission lines into Beryl would have to be constructed to serve the M-X system, and new substations and distrubtion facilities would also be required.

Dixie-Escalante is a member of the Intermountain Consumers Power Association and is a participant in the Moon Lake, Hunter, and Intermountain Power Project (IPP) generating plant projects. A potential conflict exists between the IPP transmission line routing and the conceptual operating base location. Representatives of Dixie-Escalante indicate that the bulk-power requirements of the M-X base can be met if a sufficiently early and definite commitment is made by the Air Force to permit scheduling of power.

3.3 ALTERNATIVE 2 - COYOTE SPRING VALLEY; DELTA

Alternative 2 is located in the Nevada/Utah region with a First Base at Coyote Spring Valley, Nevada and a Second Base at Delta, Utah. Energy requirements for construction and operation are presented in Table 3.3-1. The fuel and electric power situations are similar to the Proposed Action.

Delta is located in an area without natural gas service. Service could be extended into the area by the Mountain Fuel Supply of Salt Lake City, but there are no plans for such an expansion. Delta is approximately 26 miles west of the pipeline route proposed by Pacific Gas Transmission as described in the Proposed Action for Milford. Home energy requirements are supplied by bottled gas, fuel oil and electricity as described for the Proposed Action.

Electric power is supplied to the Delta area by Utah Power and Light Company via two 46 KV subtransmission lines. The present electrical load at Delta is 6 MW. The estimated increase in electrical load due to the population increase associated with a base is 37 MW. Because this is a substantial increase over the present loan, new transmission and distribution facilities will be required. As a major investor-owned utility with a load of approximately 2,400 MW (total of firm and interruptible loads), Utah Power and Light has the planning, engineering, and construction resources to construct the required new facilities.

3.4 ALTERNATIVE 3 - BERYL; ELY

Alternative 3 is located in the Nevada/Utah region with a First Base at Beryl, Utah and a Second Base at Ely, Nevada. Energy requirements for construction and operation are presented in Table 3.4-1. Because of the more severe climates, the heating and cooling requirements for Alternative 3 are higher than for the Proposed Action. The energy supply situation for Beryl has been discussed in Alternative 1.

Table 3.3-1. Annual energy requirements - Alternative 2.

USE CATEGORY	NEVADA						UTAH						TOTAL					
	P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY	
	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH
Construction																		
DDA																		
Equipment & Vehicles	2	32					1	13					3	45				
Commute & Recreation	24						30						54					
Support—Camps		2						1						3				
Support—Communities			8		26	73			6		24	73			14		50	146
Bases																		
Equipment & Vehicles	1	1					1	1					2	2				
Commute & Recreation	32						14						46					
Support—Camps		1						1						2				
Support—Communities			2		13	51			3		13	39			5		26	90
Total	59	36	10		39	124	46	16	9		37	112	105	52	19		76	236
Operations																		
DDA		4			108	660		2			46	282		6			154	942
Bases																		
Technical Operations	4	11			46	112	2	5			20	75	6	16			66	187
Support—Onbase			3		13	32			4		8	9			7		21	41
Support—Offbase			1		6	24			2		9	27			3		15	51
Commute & Recreation-Military	5						3						8					
Commute & Recreation-Civilian	8						4						12					
Total	17	15	4		173	828	9	7	6		83	393	26	22	10		256	1,221

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Table 3.4-1. Annual energy requirements - Alternative 3.

USE CATEGORY	NEVADA						UTAH						TOTAL					
	P.O.L.			NAT.	ELECTRICITY		P.O.L.			NAT.	ELECTRICITY		P.O.L.			NAT.	ELECTRICITY	
	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	GAS 10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	GAS 10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	GAS 10^6 CF	DEMAND MW	USE 10^3 MWH
Construction																		
<u>DDA</u>																		
Equipment & Vehicles	2	32					1	13					3	45				
Commute & Recreation	27						28						55					
Support—Camps		2						1						3				
Support—Communities			9		31	86			5		19	68			14		50	154
<u>Bases</u>																		
Equipment & Vehicles	1	1					1	1					2	2				
Commute & Recreation	5						15						20					
Support—Camps		1						1						2				
Support—Communities			2		8	23			4		17	51			6		25	74
Total	35	36	11		39	109	45	16	9		36	119	80	52	20		75	228
Operations																		
<u>DDA</u>		4			108	660		2			46	282		6			154	942
<u>Bases</u>																		
Technical Operations	2	5			20	75	4	11			46	112	6	16			66	187
Support—Onbase			4		8	4			6		12	13			10		20	17
Support—Offbase			2		8	23			3		14	43			5		22	66
Commute & Recreation-Military	1						4						5					
Commute & Recreation-Civilian	3						7						10					
Total	6	9	6		146	762	15	13	9		118	450	21	22	15		262	1,212

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The Second Base at Ely is in an area without natural gas service. Service could be extended into the area by Southwest Gas Corporation (SGC) in Las Vegas. The closest point on the SGC distribution system is approximately 125 miles north-northwest of Ely in the Elko area. There is a possibility that the Rocky Mountain Pipeline (natural gas) may pass near Ely.

Home energy requirements in Ely are supplied by bottled gas, fuel oil, and electricity. Bottled gas, fuel oil, gasoline and diesel fuel are trucked from bulk fuel handling terminals in Salt Lake City and Las Vegas to local distribution centers. The bottled gas (propane) is marketed locally by three companies - H&R Propane, CAL-Gas, and Turner Gas - and fuel oil, gasoline, and diesel fuel are distributed by local representatives of four major U.S. oil companies - Amoco, Chevron USA, Phillips 66, and Texaco. Increases in fuel demands would have to be met by expanding the present truck fleets, by adding new suppliers, by using military tanker trucks, or by extending natural gas and/or petroleum product pipelines into the area.

Electrical energy is supplied to the Ely area by Mount Wheeler Power, Inc. (MWP), a rural electric cooperative. Mount Wheeler Power has no generating facilities and relies on purchases power transmitted from other utilities via transmission lines. Because the transmission line capacity in the Ely area is presently limited, the availability of transmission lines to meet the M-X time and capacity requirements is a matter requiring attention.

The estimated electrical load increase in the Ely area due to an M-X base and the associated area population increase, is about 36 MW. Since the present Mount Wheeler Power system peak is approximately 25 MW, this increase in electrical load would have a substantial impact.

The only principal bulk-power transmission line in the Ely area, Sierra Pacific's 230 KV line, cannot be utilized to serve the increased load due to M-X. New transmission lines are currently being planned for the area in connection with the IPP generating plant in Utah and White Pine generating plant in White Pine County, Nevada. However, because current schedules indicate that these transmission lines will not be available prior to 1986, there is concern about financing new transmission facilities to meet M-X requirements prior to 1986. Assistance from the federal government may be requested by MWP in this regard, both in constructing new transmission facilities and in scheduling bulk-power to meet M-X requirements.

3.5 ALTERNATIVE 4 - BERYL; COYOTE SPRING VALLEY

Alternative 4 is located in the Nevada;Utah region with a First Base at Beryl, Utah and a Second Base at Coyote Spring Valley, Nevada. Energy requirements for construction and operation are present in Table 3.5-1. The energy requirements are somewhat increased over that of the Proposed Action and Alternative 1 in which the operating bases are reversed, with the First Base at Coyote Spring. This is because of the larger population and greater number of facilities associated with the First Base, and because Beryl is colder during the winter than Coyote Spring Valley. The energy supply situations have been described in the Proposed Action for Coyote Spring Valley and in Alternative 1 for Beryl.

Table 3.5-1. Annual energy requirements - Alternative 4.

USE CATEGORY	NEVADA						UTAH						TOTAL					
	P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY	
	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH
Construction																		
DDA																		
Equipment & Vehicles	2	32					1	13					3	45				
Commute & Recreation	24						28						52					
Support—Camps		2						1						3				
Support—Communities			8		26	73			5		22	67			13		48	140
Bases																		
Equipment & Vehicles	1	1					1	1					2	2				
Commute & Recreation	6						15						21					
Support—Camps		1						1						2				
Support—Communities						1			4		15	48			4		15	49
Total	33	36	8		26	74	45	16	9		37	115	78	52	17		63	189
Operations																		
DDA		4			108	660		2		46	282	660		6			154	942
Bases																		
Technical Operations	2	5			20	75	4	11		46	112	75	6	16			66	187
Support—Onbase			2		8	21			6	12	13	21			8		20	34
Support - Offbase			1		5	19			3	14	43	19			4		19	62
Commute & Recreation-Military	2						4						6					
Commute & Recreation-Civilian	6						7						13					
Total	10	9	3		141	775	15	13	9	118	450	775	25	22	12		259	1,225

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3.6 ALTERNATIVE 5 - MILFORD; ELY

Alternative 5 is located in the Nevada/Utah region with a First Base at Milford, Utah and a Second Base at Ely, Nevada. Energy requirements for construction and operation are presented in Table 3.6-1. The energy supply situations have been described in the Proposed Action for Milford and in Alternative 3 for Ely.

3.7 ALTERNATIVE 6 - MILFORD; COYOTE SPRING VALLEY

Alternative 6 is located in the Nevada/Utah region with a First Base at Milford, Utah and a Second Base at Coyote Spring Valley, Nevada. Energy requirements for construction and operation are presented in Table 3.7-1. The energy supply situation is the same as described for the Proposed Action, since the operating bases are located at the same locations.

3.8 ALTERNATIVE 7 - CLOVIS; DALHART

Alternative 7 is located in the Texas/New Mexico region with a First Base at Clovis, New Mexico and a Second Base at Dalhart, Texas. Energy requirements for construction and operation are presented in Table 3.8-1.

Fuel Supply (3.8.1)

Designated Deployment Area (DDA)

As previously discussed, there are numerous pipelines carrying crude oil, refined products and natural gas within the Texas/New Mexico area. A limited number of fuel storage and distribution facilities may be needed for the support of the project.

First Base: Clovis

The Clovis base is located in an area served by the Gas Company of New Mexico, a subsidiary of Southern Union Gas Company, Dallas. Gas supplies throughout the area appear to be excellent, and the increased natural gas demand could be met without major problems if adequate lead time is allowed to construct any required facilities. Petroleum product and crude oil pipelines traverse the Clovis area. Fuel supplies are excellent and no major problems should be encountered.

Second Base: Dalhart

The Dalhart area is served by Pioneer Natural Gas Company of Amarillo and by Peoples Natural Gas. Because Dalhart is located in a major gas producing area, natural gas supplies are excellent and the increased demands could be handled without major problems if adequate lead time is allowed to construct any required facilitites. Because a large petroleum refining center is located approximately 75 miles southeast of Dalhart at Amarillo, petroleum product supplies should be adequate to supply the increased fuel demand.

Table 3.6-1. Annual energy requirements - Alternative 5.

USE CATEGORY	NEVADA						UTAH						TOTAL					
	P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY	
	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH
Construction																		
DDA																		
Equipment & Vehicles	2	32					1	13					3	45				
Commute & Recreation	27						35						62					
Support—Camps		2						1						3				
Support—Communities			9		31	86			7		29	90			16		60	176
Bases																		
Equipment & Vehicles	1	1					1	1					2	2				
Commute & Recreation	5						16						21					
Support—Camps		1						1						2				
Support—Communities			2		8	22			4		17	51			6		25	73
Total	35	36	11		39	108	53	16	11		46	141	88	52	22		85	249
Operations																		
DDA		4			108	660		2			46	282		6			154	942
Bases																		
Technical Operations	2	5			20	75	4	11			46	112	6	16			66	187
Support—Onbase			4		8	4			6		12	12			10		20	16
Support—Offbase			2		8	23			3		14	43			5		22	66
Commute & Recreation-Military	1						5						6					
Commute & Recreation-Civilian	3						7						10					
Total	6	9	6		144	762	16	13	9		118	449	22	22	15		262	1,211

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Table 3.7-1. Annual energy requirements - Alternative 6.

USE CATEGORY	NEVADA						UTAH						TOTAL					
	P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY	
	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH
Construction																		
DDA																		
Equipment & Vehicles	2	32					1	13					3	45				
Commute & Recreation	24						34						58					
Support—Camps		2						1						3				
Support—Communities			8		26	73			7		28	87			15		54	160
Bases																		
Equipment & Vehicles	1	1					1	1					2	2				
Commute & Recreation	6						16						22					
Support—Camps		1						1						2				
Support—Communities									4		17	53			4		17	53
Total	33	36	8		26	73	52	16	11		45	140	85	52	19		71	213
Operations																		
DDA		4			108	660		2			46	282		6			154	942
Bases																		
Technical Operations	2	5			20	75	4	11			46	112	6	16			66	187
Support—Onbase			2		8	21			6		12	12			8		20	33
Support—Offbase			1		5	18			3		14	43			4		19	61
Commute & Recreation-Military	2						5						7					
Commute & Recreation-Civilian	6						7						13					
Total	10	9	3		141	774	16	13	9		118	449	26	22	12		259	1,223

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Table 3.8-1. Annual energy requirements - Alternative 7.

USE CATEGORY	TEXAS						NEW MEXICO						TOTAL					
	P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY	
	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH
Construction																		
DDA																		
Equipment & Vehicles	1	18					1	16					2	34				
Commute & Recreation	78						44						122					
Support—Camps		2						1						3				
Support—Communities				1,070	44	130				470	20	59				1,540	64	189
Bases																		
Equipment & Vehicles	1	1					1	1					2	2				
Commute & Recreation	7						18						25					
Support—Camps		1						1						2				
Support—Communities				181	8	22				403	16	50				584	24	72
Total	87	22		1,251	52	152	64	19		873	36	109	151	41		2,124	88	261
Operations																		
DDA		2			77	471		4			77	471		6			154	942
Bases																		
Technical Operations	2	5			20	75	4	11			46	112	6	16			66	187
Support—Onbase				370	8	10				530	12	15				900	20	25
Support—Offbase				380	16	46				290	13	36				670	29	82
Commute & Recreation-Military	3						2						5					
Commute & Recreation-Civilian	7						3						10					
Total	12	7		750	118	602	9	15		820	151	634	21	22		1,570	269	1,236

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Electric Power (3.8.2)

Designated Deployment Area (DDA)

A substantial transmission and distribution system exists in Region 22 of the Southwest Power Pool. These facilities could be utilized to serve M-X, minimizing the need for new line construction. However, some new and upgraded lines would still be required. The actual amount of construction cannot be determined until a detailed layout for the M-X is developed and the Southwest Power Pool planning studies are completed.

First Base: Clovis

Electrical energy is supplied to Clovis by Southwestern Public Service Company (SWPS) via two 115 KV transmission lines. The present 10 MW electrical load at Cannon AFB is supplied by SWPS via a 69 KV transmission line from Clovis. The estimated electrical load increase in the Clovis area due to an M-X base and the corresponding population increase is 71 MW. This additional load might be supplied by upgrading the existing line or constructing new transmission facilities.

The increased electrical load due to a base and the associated population increase at Clovis or Dalhart would not represent a major impact to SWPS. Planning, engineering, and construction of required transmission and distribution facilities would be handled by the SWPS main office. SWPS is a major utility with a system peak demand of approximately 2,600 MW; the utility is active in substantial cooperative research projects with the DOE and the EPA.

Second Base: Dalhart

Electrical energy is supplied to Dalhart by Southwestern Public Service Company via a 115 KV transmission line and a 69 KV transmission line. The present peak electrical demand of Dalhart is approximately 30 MW. The estimated electrical load increase in the Dalhart area due to a base and the associated population increase is 44 MW. Because this is a significant increase in load, some new transmission and distribution facilities will be required.

The increased electrical load due to a base and the associated population increase at Clovis or Dalhart would not represent a major impact to SWPS. Planning, engineering, and construction of required transmission and distribution facilities would be handled by the SWPS main office. SWPS is a major utility with a system peak demand of approximately 2,600 MW; the utility is active in substantial cooperative research projects with the DOE and the EPA.

3.9 ALTERNATIVE 8 - COYOTE SPRING VALLEY; CLOVIS

Alternative 8 is a split basing mode with part of the system located in Nevada/Utah with a First Base in Coyote Spring Valley, Nevada and part of the system located in Texas/New Mexico with a Second Base in Clovis, New Mexico. Energy requirements for construction and operation are presented in Table 3.9-1. The energy supply situations have been discussed for Coyote Spring Valley in the Proposed Action and for Clovis in Alternative 7. With split basing, the impact on fuel and electric power supply and demands are reduced from the full basing deployment mode.

Table 3.9-1. Annual energy requirements - Alternative 8. (Page 1 of 2)

USE CATEGORY	NEVADA						UTAH						TOTAL					
	P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY	
	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH
Construction																		
DDA																		
Equipment & Vehicles	1	14					1	10										
Commute & Recreation	4						3											
Support—Camps	12	1																
Support—Communities			2		8	22			4		18	55						
Bases																		
Equipment & Vehicles	1	1																
Commute & Recreation	32																	
Support—Camps		1																
Support—Communities			1		4	16			2		8	25						
Total	50	17	3		12	38	4	10	6		26	80						
Operations																		
DDA		2			54	330		2			23	141						
Bases																		
Technical Operations	3	8			46	112												
Support—Onbase			3		10	27												
Support—Offbase			1		6	24												
Commute & Recreation-Military	5																	
Commute & Recreation-Civilian	8																	
Total	16	10	4		116	493		2			23	141						

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Table 3.9-1. Annual energy requirements - Alternative 8. (Page 2 of 2).

USE CATEGORY	TEXAS						NEW MEXICO						TOTAL					
	P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY		P.O.L.			NAT. GAS	ELECTRICITY	
	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^5 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH	GAS 10^6 GA	DIESEL 10^6 GA	F.O. 10^6 GA	10^6 CF	DEMAND MW	USE 10^3 MWH
Construction																		
DDA																		
Equipment & Vehicles	1	10						3					3	37				
Commute & Recreation	7						2						16					
Support—Camps	11	2					27						50	3				
Support—Communities				147	6	18				510	22	63			6	657	54	158
Bases																		
Equipment & Vehicles							1	1					2	2				
Commute & Recreation							8						40					
Support—Camps								1						2				
Support—Communities				61	3	8				264	11	33			3	325	26	82
Total	19	12		208	9	26	38	5		774	33	96	111	44	9	982	80	240
Operations																		
DDA		1			28	170		1			49	301		6			154	942
Bases																		
Technical Operations							3	1			22	88	6	16			68	200
Support—Onbase										420	10	12			3	420	20	39
Support—Offbase				10	1	2				280	12	34			1	290	19	60
Commute & Recreation-Military							2						7					
Commute & Recreation-Civilian							3						11					
Total		1		10	29	172	8	9		700	93	435	24	22	4	710	261	1,241

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4.0 EFFECTS ON ENERGY SYSTEMS

4.1 ENERGY SUPPLY - NEVADA/UTAH

Fuel Supply (4.1.1)

The effect of M-X development could cause the natural gas companies in the Nevada region to extend service into the proposed deployment areas. The extended gas lines will require right-of-ways which will have a 100-ft wide corridor. Proper pre-planning and commitment from the Air Force and gas companies will be required to assure adequate and timely fuel supplies.

Other fuels (i.e., gas and diesel) will have to be reevaluated for increased allocations due to M-X construction and operations. During the construction phase, bottled gas, diesel, gasoline and fuel oil requirements will increase. Truck fleets will have to increase and distribution centers will be required to support M-X construction.

Electric Power (4.1.2)

Regionally, the induced effect of M-X on the total energy scene is relatively minor. The proposed White Pine Power Project and IPP project will facilitate growth in the region. Site-specific impacts are related to transmission line construction and the upgrading of local utilities to meet operating base requirements. All of the proposed transmission lines are routed in close proximity to the alternative operating base locations. Additional transmission lines and substations will have to be constructed to serve the operating bases from these proposed lines, but impacts will be small.

The local utilities that would be affected by M-X development do not at this time have the capacities in their existing transmission line system to serve M-X needs. Proper pre-planning to upgrade the systems is needed to bring the load carrying capacities in transmission lines on line in time to facilitate M-X development. The utilities have asked for a lead time of up to 4 to 5 years, to assure that their systems will be capable of serving the M-X development.

4.2 ENERGY SUPPLY - TEXAS/NEW MEXICO

Fuel Supply (4.2.1)

The Texas/New Mexico siting region is located in the proximity of energy producing resources. Natural gas is available for all of the proposed operating sites and can be used to facilitate all heating requirements. The largest impact on the region will not be in energy supply from this resource, but its possible effect in the siting of the clusters as there is a large company network of pipelines between Hereford, Texas and Clayton, New Mexico. The magnitude of the existing pipeline system and its impact on siting the M-X system is still undetermined.

Electric Power (4.2.2)

The Texas/New Mexico region interfaces with an abundant network of power transmission lines. Some of the lines will have to be upgraded to support the increased load to site-specific areas.

The impact of M-X on the transmission/distribution system can be minimized with proper pre-planning.

4.3 EFFECT ON ENERGY SYSTEMS NEAR OPERATING BASES

Beryl, Utah Area (4.3.1)

The effect of construction and operation of the M-X system for Alternatives 3 and 4 (First Base), and Alternative 1 (Second Base) at Beryl, Utah, will require improvements in energy capabilities for the area.

Fuel

Natural gas supplies will not be available in the Beryl area during the first years of M-X development, as the Pacific Gas Transmission (PGT) gas line will not be completed until 1986.

During the interim, bottled fuel and fuel oil will have to be trucked in from Las Vegas and Salt Lake City.

Diesel fuel and gasoline will have to be re-evaluated for allocations in the Beryl area to satisfy increased demands in consumption due to construction and operations.

Electric power

The estimated electrical load increase in the Beryl area due to operation of the M-X operating base and anticipated population increase is about 72 MW for a First Base and 39 MW for a Second Base. The present Dixie-Escalante system peak demand is 20 MW.

Dixie-Escalante has indicated that it can handle and manage the construction of required transmission lines and distribution facilities with a firm commitment from the air force before embarking on such a venture. Dixie-Escalante would require two to four years lead time.

The critical period for supply of electrical energy occurs prior to 1986. IPP is not scheduled for completion until 1986.

Clovis, New Mexico Area (4.3.2)

The effect of construction and operation of M-X system for Alternatives 7 and 8 (First Base) at Clovis, New Mexico, will be minimal. Very few additional facilities will be required to handle the increased energy demands.

Fuel

The primary energy-related problem with be interferences between proposed M-X facilities, oil-producing fields, and pipelines systems. It is anticipated this problem may eliminate a sizeable portion of the Texas/New Mexico region from consideration as potential sites for clusters.

Electric power

It is estimated that the increase in electrical load due to the operation of an M-X operating base and associated population increase would be about 71 MW. This additional load could be supplied by upgrading the existing line or construction of new transmission facilities.

The increased electrical load due to the operating base and associated population increase in the area would not represent a major impact to Southwestern Public Service Company (SWPC). Planning, engineering, and construction of required transmission facilities would be handled by the SWPS main office. The bulk-power requirements can be readily supplied by SWPS.

Coyote Spring Valley, Nevada Area (4.3.3)

The effect of construction and operation of the M-X system for the Proposed Action and Alternatives 1, 2 and 8 (First Base) and Alternatives 4 and 6 (Second Base) at Coyote Spring Valley, Nevada will require improvements in energy transportation capabilities. In addition, development of required energy generating facilities must be in concert with M-X system development.

Fuel

To meet the demand for fossil fuels due to M-X development, natural gas lines could be extended into the area by Southwest Gas Corporation. There are presently no plans for such an extension of lines into the area.

Diesel and gasoline will have to be reallocated to meet the direct and induced consumption increases due to M-X construction and operations.

Electric Power

The electrical load increase in the Coyote Spring Valley area due to operation of the M-X operating base and associated area population increase would be approximately 65 MW for a First Base and 33 MW for a Second Base. Lincoln County Power District, which serves the area, has a present peak service capacity of 16 MW. The increase in electrical load will have significant impact.

Discussions with Lincoln County Power District and Nevada Power Company to determine the most expeditious way of serving the M-X system are in progress. Both companies will cooperate in the planning, engineering, and construction of transmission facilities. Utah Power and Light will require four to five years lead time to construct appropriate transmission lines.

To assure that power will be available when the operating base requires it, the Air Force and the federal government will assist in the planning and construction process.

Dalhart, Texas Area (4.3.4)

The effect of construction and operation of the M-X system with Dalhart, Texas as a Second Base in Alternative 7, will be minimal. Very few additional facilities will be required to handle the increased energy demand.

Fuel

The primary energy-related problem will be the interferences between proposed M-X facilities, energy-producing fields, and pipeline systems.

Electric Power

It is estimated that the increase in electrical load due to an operating base and associated population increase would be approximately 44 MW. Since this is an increase in load, some new transmission and distribution facilities will be required.

The increased electrical load due to the operating base would not represent a major impact to SWPS. Planning, engineering, and construction of required transmission facilities would be handled by the SWPS main office. The bulk-power requirements can be readily supplied by the SWPS.

Delta, Utah Area (4.3.5)

The effect of construction and operation of the M-X system for Alternative 2, with the second operation base at Delta, Utah will require substantial improvements in energy transportation capabilities. Development of required energy handling systems must be in concert with M-X system construction.

Fuel

Induced service due to M-X development and the development of the IPP Power Plant could decrease the lead time for construction of the PGT natural gas line.

Diesel and gasoline allocations for the Delta area will have to be re-evaluated to meet the direct and induced consumption increases from the M-X and IPP development.

Electric power

The estimated electrical load increase in the Delta area due to operation of the M-X operating base and associated population increases would be approximately 37 MW. The present electrical load at Delta, Utah is 6 MW.

Delta is served by Utah Power and Light, which presently has a 2,700 MW load capacity and is a major partner in the development of the IPP project. UPL has the planning, engineering and construction capabilities to construct the required new facilities; however, time is the issue. IPP is not scheduled to be on line prior to 1986.

Ely, Nevada Area: (4.3.6)

The effects of construction and operation of the M-X system for Alternatives 3 and 5, with the second operating base at Ely, Nevada, will require improvements in energy transportation capabilities. In addition, development of required energy generating facilities must be in concert with M-X system construction.

Fuel

To meet the demand for fossil fuels due to M-X development, natural gas lines could be extended into the area by the Southwestern Gas Corporation. There are presently no plans for such an extension into the area.

Diesel and gasoline will be reallocated to meet direct and induced consumption due to M-X construction and operations.

Electric power

The estimated electrical load increase in the Ely area due to operation of the M-X operating base and the associated area population increase would be about 36 MW. The present Mount Wheeler Power (MWP) system peak is approximately 25 MW. This increase in electrical load would have a substantial impact.

The severest impact on power supplies would occur prior to 1986. The IPP and Moon Lake generating plants are scheduled to be on-line in 1986 and the White Pine plant is scheduled for 1989. Plans indicate that a 230 KV line from IPP would pass through the area and be located in MWP service area, but could not provide power before 1986.

As a rural cooperative, MWP can get a loan from the rural electrification administration. However, the rate payers in the MWP service area have to repay construction loans. The federal government could provide financial assistance for the construction of new 230 KV lines to minimize impact on MWP users and to accelerate construction of new lines to bridge the gap between power needs in 1984 and 1986.

Milford, Utah Area (4.3.7)

The effect of construction and operation of the M-X system for Alternatives 5 and 6 (First Base) and for the Proposed Action (Second Base) at Milford, Utah will require improvements in energy capabilities for the area.

Fuel

The fuel scenario described for the Beryl, Utah area is also applicable to the Milford, Utah area.

Electric power

The estimated electrical demand for the Milford area is about 72 MW for a First Base and 39 MW for a Second Base. Presently, Milford has a load of approximately 5 MW and is supplied by two 46 KV lines.

Construction of new transmission and distribution facilities as required to serve the operating base will be constructed by Utah Power and Light.

The bulk-power requirements for the operating base and associated area population increase are significant and need to be scheduled early. Typical plant construction time is 3 years from ground breaking to on-line, and normal planning

lead time is 4 to 5 years from identification of requirements to completion of major facilities. The Air Force will make an early commitment to take into account required lead times.

The supply conditions are similar to Beryl, Utah. A concerted effort must be made by the Air Force and Utah Power and Light to schedule the construction of the operating base with the IPP project, to assure that electric power is available when required.

5.0 MITIGATIONS

5.1 MITIGATION MEASURES - ENERGY SUPPLY AND DEMAND

Alternative Energy Systems - Energy Supply (5.1.1)

The purpose of this section is to present an overview of which alternative energy technologies would be most appropriate for implementation to supply specific electric load centers in the M-X system and to replace conventional energy sources. For further information on alternative energy system, see Appendix G. The following combinations of load sizes have been selected for an example presentation.

1. Various combinations of operating bases and facilities requiring generating capacity increments of 20 MW, 46 MW and up to 115 MW.

2. Single cluster or group of clusters with loads from 0.75 MW up to 4.0 MW.

3. Single shelters at 14.5 KW continuous power and 21.0 KW peak power.

Operating Base (5.1.1.1)

Incremental power requirements of 20 MW, 46 MW and up to 115 MW for operating bases and support communities could be satisfied by a combination of alternative energy sources. A base loaded system may be required, using possibly either geothermal and/or direct combustion biomass electric generating plants. These systems could achieve capacity factors of approximately 75 percent. Various capacity combinations could be incorporated to satisfy availability and incremental power requirements; however, the optimum size of both geothermal and biomass plants is approximately 50 MW.

Energy conservation measures mentioned in Section 5.1.2 could be applied to reduce the demand. If still additional power is needed, both solar and wind energy systems could be incorporated into the base grid.

Clusters (5.1.1.2)

Continuous power outputs of 0.75 MW up to 40 MW could not be derived from a single alternative energy source. Geothermal and/or biomass systems would be too large, while wind and solar could only achieve capacity factors of 40 to 50 percent. Alcohol fuels in gas turbines would be too expensive for continuous use. A combination of courses would be required.

Dispersed parabolic thermal or photovoltaic systems could be located adjacent to the various load centers and provide power during daylight hours. Storage could add a few hours per day to the capacity. During evening hours and extended cloudy weather, the load centers would have to be connected to the geothermal or biomass base system or regional utility grid.

Wind turbines could be sited in mountainous areas adjacent to the load centers and probably supply 40 to 50 percent of the power (without storage) or 60 percent

(with storage) on an annual basis. During calm wind conditions, the load centers would have to be connected to the base system or backup utility grid.

Single Shelter (5.1.1.3)

The relatively small 14.5 to 21 KW power output required for a single shelter would best be supplied by a photovoltaic solar system during daylight operation. During the night and during extended cloudy weather, the shelter electrical system would have to be connected to the geothermal or biomass base load system.

Wind would not be a good choice to supply such a small load center, especially in Nevada/Utah, since the turbine would have to be located in the mountains and transmission line losses would probably be prohibitive. On the High Plains, average wind speeds are somewhat more favorable than in the valleys of the Great Basin. Further development of low wind speed turbines may make them practical for use adjacent to shelters in Texas/New Mexico.

Alternative Energy Systems - Energy Conservation (5.1.2)

In the planning and design phases, alternative energy systems such as passive solar should be considered to reduce the heating and cooling demands of the buildings. This alternative system uses similar building material such as concrete and glass, so there are no additional costs involved. The only factors are the correct building orientation, the amount of southern glass exposure, and creative design for using the sun's energy for heating the buildings. These measures could be adopted both for buildings on the bases and new housing in the communities.

This type of design could save up to 70 percent of the heating loads, and 10-20 percent of the cooling loads, depending on the climatic conditions. Group housing on the base should be considered in order to reduce heat gains and losses in the building envelope.

Active solar systems could be used to supply about 50-60 percent of the domestic hot water load for new residential housing. These systems could be installed on individual homes. This could add approximately an additional $800 to the cost of each home after federal tax incentives.

Energy Conservation (5.1.3)

During the planning and design period, priority should be placed on more energy conserving mechanical and lighting systems. Also the application of increased insulation should be enforced. This could reduce the heat gains and losses through the building of up to 50 percent for the heating season, and up to 20 percent during the cooling season, depending on the climatic conditions and amount of insulation.

Greater energy savings could be achieved by centralization of the heating and the cooling systems for all the buildings and residences on the bases.

Electric power consumption for lighting could be reduced by 30-35 percent through reduction of interior and facade lighting and also by use of more efficient lights such as lower wattage incandescent or fluorescent lights. This application

could also reduce the cooling loads of the buildings. Other electric savings could be achieved by installation of high efficiency motors, appliances and load management devices. All these measures combined could save up to 15 percent of the total electric consumption of the bases and the new homes in the surrounding communities.

At this time, there is not sufficient detailed information on the electrical consumption in the DDA, and therefore it is not included in this section.

Installation of high efficiency hot water heaters, insulation of hot water tanks and pipes, and reducing the hot water set temperature to 120°F could reduce the energy consumption for domestic hot water by 10 percent.

Table 5.1.3-1 shows the comparison between energy consumption with the above-mentioned building construction and energy conservation methods for the bases and the communites for each alternative. Passive and active solar energy reductions were not included in these calculations. R-values for insulation were based on the minimum proposed federal rules and regulations for affected states (see Appendix H).

5.2 MITIGATION MEASURES - ENERGY FACILITIES

Mitigations for Pipelines and Fuel Facilities (5.2.1)

Energy transmission and production facilities installed or modified to serve the M-X system can be designed to mitigate potential impacts. In many cases, the selection of specific sites and rights-of-way can contribute the greatest effect toward the mitigation of impacts.

New natural gas or petroleum pipelines needed to supply fuel to M-X support facilities can be constructed either above ground or underground. A comparison of these techniques will be conducted and the technique having the least impact will be utilized. The design and selection of colors and materials for architectural screens, above-ground pipelines, and related facilities can be coordinated with landscaping to provide a pleasing appearance harmonious with its surroundings. The design configuration can minimize right-of-way requirements, thereby allowing a reduction in the clearing and removal of vegetation. The use of joint rights-of-way for roads, fuel, pipelines and electrical transmission lines should be explored wherever possible.

The possibility of plowing in fiber optic cable to minimize surface disturbances might also be investigated.

Mitigations for Electric Power Facilities (5.2.2)

Energy transmission and production facilities that will be installed and/or modified as the M-X system is implemented can be designed to mitigate potential impacts. In many cases, the selection of specific sites and rights-of-way can contribute most toward the mitigation of impacts. Utilities may select transmission line structures designed for minimum right-of-way requirements, and substations may be of the low-profile type construction to maintain low structure height and to avoid the cluttered appearance of highbay lattice type design.

Table 5.1.3-1. Annual energy consumption for operating bases and support community by alternative, with and without conservation measures, during operations phase.

ALTERNATIVES	NO CONSERVATION (1992)				WITH CONSERVATION (1992)			
	FUEL OIL 10^6 GA	NATURAL GAS 10^6 CF	DEMAND MW	ANNUAL USE 10^3 MW	FUEL OIL 10^6 GA	NATURAL GAS 10^6 CF	DEMAND MW	ANNUAL USE 10^3 MW
Proposed Action	10		104	283	7		82	233
1	10		104	284	7		82	234
2	10		102	279	7		81	228
3	15		108	270	10		86	219
4	12		105	283	8		83	225
5	15		108	269	10		85	228
6	12		105	281	7		83	234
7		1,570	115	294		1,021	90	244
8	4	710	107	299	3	531	84	241

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Note: Passive and active solar energy reductions are not included in this table. Energy consumption of DDA is not included.

In addition, the design and selection of colors and materials for substation fencing and transmission towers can be coordinated with landscaping to provide a pleasing appearance blended with the surroundings. Consideration can also be given to the aesthetic appearance of free-standing towers and structural supports for communications and control equipment. The configuration of conductors can be designed to minimize right-of-way requirements, allowing a possible reduction in the clearing and trimming of vegetative cover. Similar mitigative measures are possible for petroleum and natural gas facilities. Good right-of-way selection and aesthetic considerations in design should be emphasized. Joint right-of-way use should be explored wherever possible.

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APPENDIX A

Baseline POL Demand Estimates for Nevada, Utah, Texas, and New Mexico

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BASELINE POL DEMAND ESTIMATES FOR NEVADA, UTAH, TEXAS, AND NEW MEXICO

Based on data from the Energy Information Administration, Department of Energy, the following estimates of current and projected consumption of total petroleum, fuel oil, gasoline, jet fuel, and natural gas are presented to 1985 and 1990.

It should be emphasized that projections of petroleum products consumption are subject to wide margins of error and derive from current assumptions on U.S. energy policy, domestic production and overseas imports.

1978 has been presented as the baseline year for individual State consumption statistics, based on available data presented in: DOE/Energy Information Administration, State Energy Data Report, Statistical Tables and Technical Documentation 1960 through 1978 (April 1980).

Projections to 1985 and 1990 derive from data for the United States as a whole. It is assumed that individual states petroleum products consumption will move in consonance with overall U.S. consumption patterns.

Of course, allocation mechanisms will cause variation in these consumption patterns among states. These variations should correlate with varying population growth rates.

HDR's own projections of population without M-X project for the potential M-X impact systems indicate a whole disparity in growth (see Table 1).

Table 2 presents 1978 baseline consumption estimates of specific petroleum products and natural gas.

Projections of domestic demand for selected petroleum products and natural gas to 1985 and 1990 are available for the United States as a whole.

They are presented in Table 3 and represent a mid-range set of estimates.

Total U.S. petroleum consumption is anticipated as declining by over 17 percent over the 12 year period 1978 to 1990, while natural gas consumption remains almost constant.

If we apply the projected total U.S. consumption rates of change for selected petroleum products and natural gas to the 1978 baseline state consumption data for Nevada, Utah, Texas, and New Mexico, a first approximation consumption forecast is derived for 1985 and 1990 (see Table 4).

The forecast ignores differences in population growth among states and the potential impact of M-X on aeolian petroleum products and natural gas consumption.

First approximation adjustments to these state consumption projections should be made on the basis of relative population growth rates.

Table 1. Index of projected population without the M-X project, for the M-X impact region 1980-1990. (1980 = 100.0)

STATE AND REGION	1980	1985	1990
Nevada (6 counties)	100.0	128.1	158.1
Utah (7 counties)	100.0	121.4	134.1
New Mexico (7 counties)	100.0	112.6	124.7
Texas (10 counties)	100.0	107.5	113.3

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Table 2. 1978 baseline consumption estimates of specific petroleum products and natural gas.

PRODUCT	U.S.	NEVADA	UTAH	TEXAS	NEW MEXICO
Total Petroleum (000 bbls)	6,879,017	29,317	40,209	488,524	42,905
Motor Gasoline (000 bbls)	2,705,309	11,698	17,478	201,991	18,922
Distillate Fuel Oil (000 bbls)	1,252,556	3,822	9,023	81,171	9,633
Aviation Gas (000 bbls)	14,155	202	147	1,249	117
Jet Fuel (000 bbls)	385,658	6,652	1,898	28,537	2,793
Natural Gas (dry) (mill. ft^3	19,627,478	64,506	118,513	4,211,432	213,698

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Source: DOE/EIA, State Energy Data Report: 1960 through 1978 (April 1980) pp. 13, 247, 271, 367, 375.

Table 3. Projections of U.S. consumption of selected petroleum products and natural gas to 1985 and 1990.

PRODUCT UNITS	1978	1985	1990
Total Petroleum (mill bbls/day)	18.9	15.4	15.6
Index (1978=100.0)	100.0	81.5	82.5
Motor Gasoline (mill bbls/day)	7.4	6.2	5.9
Index (1978=100.0)	100.0	83.8	79.7
Distillate Fuel Oil (mill bbls/day)	3.6	2.9	3.1
Index (1978=100.0)	100.0	80.6	86.1
Jet Fuel (mill bbls/day)	1.1	1.1	1.2
Index (1978=100.0)	100.0	100.0	109.1
Other (mill bbls/day)	3.8	3.9	4.2
Index (1978=100.0)	100.0	102.6	110.5
Natural Gas (quad btu/yr.)	20.0	19.0	19.8
Index (1978=100.0)	100.0	95.0	99.0

3010

Source: DOE, Energy Information Administration Annual Report to Congress, 1979, Vol. 3 Projections. pp 115, 126

Table 4. Petroleum products and natural gas consumption forecast for Nevada, Utah, Texas, and New Mexico (1985 and 1990).

PRODUCT UNITS	1985	1990
Total Petroleum (000 bbls)		
Nevada	23,893	24,187
Utah	32,770	33,172
Texas	398,147	403,332
New Mexico	34,968	35,397
Motor Gasoline (000 bbls)		
Nevada	9,603	9,323
Utah	14,647	13,930
Texas	169,268	160,987
New Mexico	15,857	15,081
Distillate Fuel Oil (000 bbls)		
Nevada	3,081	3,291
Utah	7,273	7,769
Texas	65,424	69,888
New Mexico	7,764	9,294
Jet Fuel (000 bbls)		
Nevada	6,652	7,257
Utah	1,898	2,071
Texas	28,537	31,134
New Mexico	2,793	3,047
Natural Gas (dry) (mill ft^3)		
Nevada	61,281	63,861
Utah	112,587	117,328
Texas	4,000,860	4,169,318
New Mexico	203,013	211,561

3011

Source: Tables 2, and 3.

Table 1 indicates that even in the absence of M-X deployment there is a growing divergence in population growth among the four states in areas of potential M-X impact.

For example, over the ten year period 1980-1990 the average annual population growth rate varies from 2.00 percent (Texas ten county area) to 4.68 percent (Nevada, six county area).

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DOE/EIA-0113(78) Order No. 762

Energy Data Reports

Department of Energy
Energy Information Administration
Washington, D.C. 20461

For information call Mary E. Zitomer
Telephone: 202 252-5130

Fuel Oil Sales, Annual

SALES OF FUEL OIL AND KEROSINE IN 1978

Domestic sales of distillate fuel oils, residual fuel oils, and kerosine increased 0.4 percent from 2,416 million barrels in 1977 to 2,424 million barrels in 1978, according to the Energy Information Administration, United States Department of Energy. Sales for on-highway diesel and vessel bunkering uses continued the upward trends of recent years, while sales for heating use were lower for the second straight year. Sales of fuel oils for electric-utility use, after sharply increasing in 1977, showed a decrease in 1978.

Distillate Fuel Oils:

Sales of distillate fuel oils in 1978 showed a gain for the third straight year, exceeding previous levels. Total sales of distillate fuel oil reached 1,257 million barrels in 1978, showing an increase of 2.2 percent from the 1,230 million barrels in 1977. Sales for heating use in 1978 continued downward from the 1976 peak, decreasing at about the same rate as in 1977. The 533 million barrels sold for heating use this year were 1.1 percent lower than the 539 million barrels sold in 1977. Of the total distillate fuel oil sales in 1978, 42.4 percent was for heating use, compared with 43.8 percent in 1977, and 47.3 percent in 1976.

Sales of diesel oil for on-highway use in 1978 of 291 million barrels showed a 10.0 percent increase from the 264 million barrels sold in 1977. Sales for on-highway use reached record levels in 1978, and accounted for a larger portion of distillate fuel oil sales than in any previous year. Of the total distillate fuel oil sold during the year, 23.2 percent was sold for on-highway use, compared with 21.5 percent in 1977.

After increasing sharply during 1976 and 1977, sales of distillate fuel oil for industrial use decreased 1.8 percent in 1978. Sales for oil-company use were lower as well, falling 2.7 percent from the 1977 level. Sales for vessel bunkering and off-highway diesel uses continued upward, increasing 12.2 percent and 5.1 percent respectively.

Residual Fuel Oils:

The 1.6 percent decrease in residual fuel oil sales in 1978 to 1,103 million barrels from 1,121 million barrels in 1977 was reflected primarily in the sales to electric-utility companies. Sales for electric-utility use fell 6.4 percent, from 569 million barrels in 1977 to 533 million barrels in 1978. The electric-utility portion of residual fuel oil sales was lower as well, accounting for 48.3 percent in 1978, compared with 50.8 percent in 1977.

In contrast, sales for vessel bunkering use were at record levels in 1978, continuing the upward trend from 1974. Sales for vessel bunkering in 1978 of 157 million barrels showed an increase of 22.2 percent from the 129 million barrels sold in 1977. The portion of residual fuel oil sales accounted for by vessel bunkering use was 14.3 percent in 1978, whereas in 1977 and 1976 this category accounted for only 11.5 percent.

Sales for heating, industrial, and oil-company uses showed small decreases of 2.2 percent, 1.5 percent, and 4.8 percent respectively.

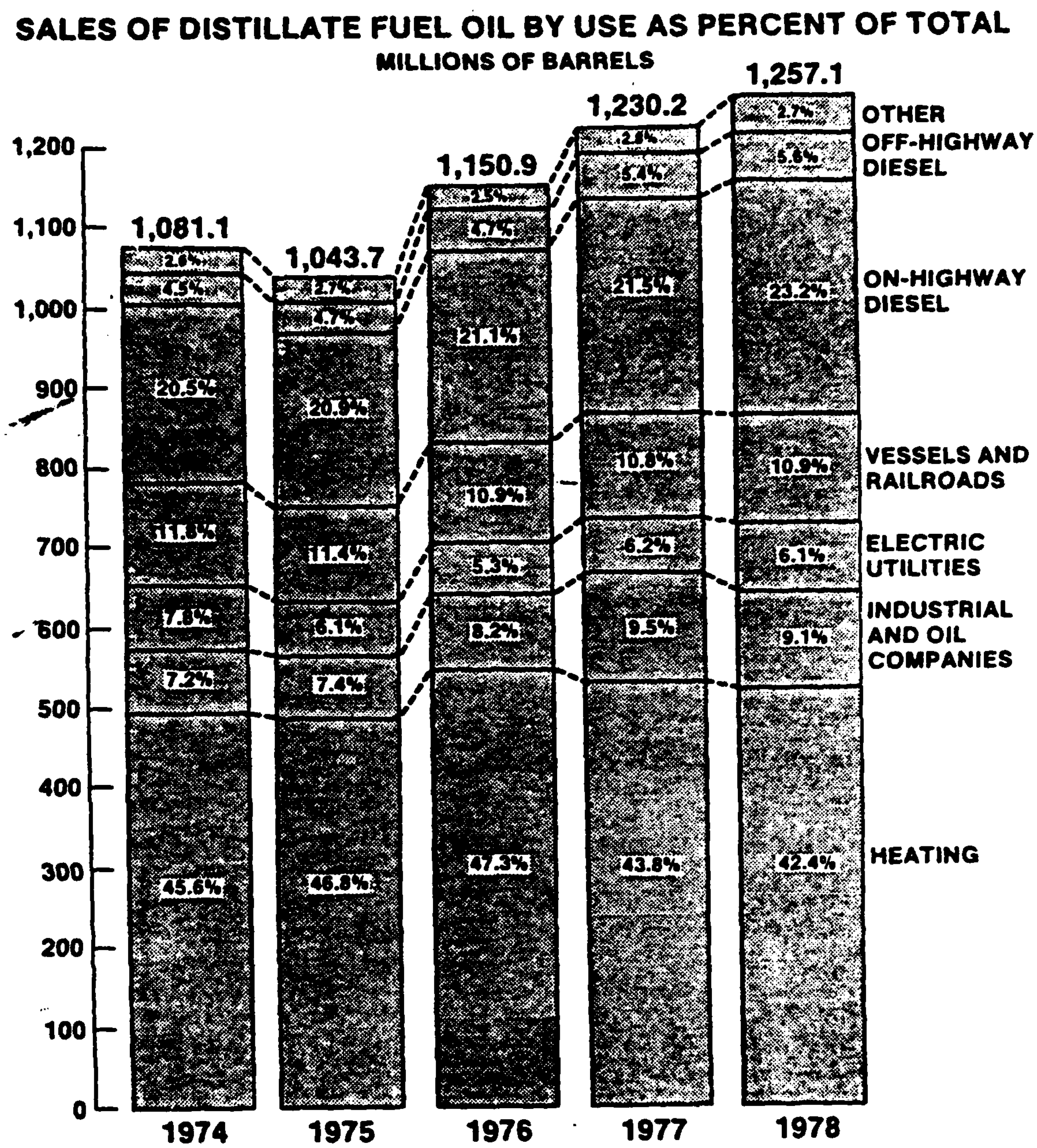
Kerosine:

Sales of kerosine decreased 0.6 percent from 64.4 million barrels in 1977 to 64.0 million barrels in 1978. Kerosine sold for heating purposes was 44 million barrels, 4.6 percent lower than in 1977. Of the total kerosine sales in 1978, 68.8 percent was sold for heating use, compared with 71.7 percent in 1977.

Prepared October 30, 1979 in the Office of Energy Data and Interpretation.

Released for Printing: November 6, 1979

FIGURE 1



For additional information see Table 2.

Table 6.—Sales of Distillate-type Heating Oils in the United States, by P.A.D. District and State: 1978 and 1977

(Thousands of barrels)

P.A.D. District and State	Heating Oils						
	1978					1977[1]	
	No. 1						
	Automatic burners	Other heating	No. 2	No. 4	Total	No. 2	Total
District I:							
New England, total	1,346	906	91,220	5,470	98,942	94,193	102,193
Connecticut	173	36	16,816	1,628	18,653	16,723	18,619
Maine	308	361	9,753	291	10,713	10,649	11,778
Massachusetts	375	213	47,535	3,084	51,207	49,591	53,312
New Hampshire	193	118	6,962	151	7,424	6,948	7,387
Rhode Island	99	101	6,382	240	6,822	6,555	7,096
Vermont	198	77	3,772	76	4,123	3,727	4,006
Delaware	142	44	2,321	95	2,602	2,345	2,694
District of Columbia	89	37	1,739	191	2,056	1,760	2,051
Florida	281	252	3,192	6	3,731	3,250	4,008
Georgia	187	67	1,801	3	2,058	2,690	3,080
Maryland	57	180	11,074	163	11,474	11,636	12,107
New Jersey	43	219	38,303	2,693	41,258	39,043	43,400
New York	797	456	82,098	6,503	89,854	83,693	92,695
North Carolina	519	293	7,833	37	8,682	8,508	9,650
Pennsylvania	753	284	38,003	1,419	40,459	39,730	42,665
South Carolina	234	243	2,611	23	3,111	2,934	3,486
Virginia	448	577	8,643	188	9,856	9,632	11,010
West Virginia	41	47	1,260	2	1,350	1,461	1,582
Total 1978	4,937	3,605	290,098	16,793	315,433	XXX	XXX
Total 1977	5,758	4,154	[1] 300,875	19,834	XXX	300,875	330,621
District II:							
Illinois	2,289	387	24,414	65	27,155	22,579	25,353
Indiana	1,523	888	15,910	39	18,360	15,977	18,117
Iowa	587	260	4,663	-	5,510	4,109	4,891
Kansas	137	19	2,132	-	2,288	1,884	2,006
Kentucky	262	184	3,841	12	4,299	4,099	4,677
Michigan	3,862	1,281	21,985	85	27,213	20,919	26,284
Minnesota	1,618	805	14,265	434	17,122	14,565	17,290
Missouri	782	399	5,895	4	7,080	4,988	5,915
Nebraska	143	152	2,792	-	3,087	2,397	2,656
North Dakota	159	184	823	6	1,172	803	1,094
Ohio	1,648	664	17,322	23	19,657	17,199	19,388
Oklahoma	232	152	2,680	-	3,064	2,074	2,401
South Dakota	238	32	823	-	1,093	733	974
Tennessee	269	63	2,557	-	2,889	2,463	2,751
Wisconsin	2,289	870	17,056	571	20,786	16,871	20,276
Total 1978	16,038	6,340	137,158	1,239	160,775	XXX	XXX
Total 1977	15,259	5,894	[1] 131,660	1,260	XXX	131,660	154,073
District III:							
Alabama	186	25	2,596	-	2,807	2,790	2,996
Arkansas	117	78	1,166	-	1,361	1,361	1,538
Louisiana	233	51	2,858	-	3,142	3,001	3,274
Mississippi	275	118	2,921	343	3,657	2,923	3,597
New Mexico	219	97	522	-	838	447	856
Texas	1,997	340	10,081	735	13,153	8,644	11,430
Total 1978	3,027	709	20,144	1,078	24,958	XXX	XXX
Total 1977	2,991	673	[1] 19,166	861	XXX	19,166	23,691
District IV:							
Colorado	420	512	806	-	1,738	863	1,768
Idaho	516	764	2,383	-	3,663	1,969	3,197
Montana	135	517	1,445	-	2,097	1,301	1,892
Utah	338	77	1,384	111	1,910	1,425	1,956
Wyoming	214	301	851	-	1,366	694	991
Total 1978	1,623	2,171	6,869	111	10,774	XXX	XXX
Total 1977	1,580	1,864	6,252	108	XXX	6,252	9,804
District V:							
Alaska	944	369	2,795	360	4,468	2,578	3,751
Arizona	25	150	977	85	1,237	583	844
California	453	114	2,482	602	3,651	2,406	3,280
Hawaii	1	-	87	-	88	75	75
Nevada	99	15	476	82	672	404	538
Oregon	782	108	3,165	14	4,069	3,476	4,788
Washington	1,617	287	4,952	88	6,944	5,426	7,380
Total 1978	3,921	1,043	14,934	1,231	21,129	XXX	XXX
Total 1977	3,781	1,093	14,948	834	XXX	14,948	20,656
United States total, 1978	29,546	13,868	469,203	20,452	533,069	XXX	XXX
United States total, 1977	29,365	13,678	[1] 472,901	22,897	XXX	472,901	538,845

[1] Revised

Source: Bureau of Mines Form 6-1337-A and 6-1337-AS.

Table 14.—Sales of Distillate-Type and Residual-Type Oils for Miscellaneous Uses in the United States, by P.A.D. District and State: 1978 and 1977

(Thousands of barrels)

P.A.D. District and State	Distillate-type Oils						Residual-type oils	
	1978					1977 total[1]	1978 total	1977 total
	Diesel-type			Other uses	Total			
	On highway	Off highway	Total					
District I:								
New England, total	8,953	905	9,858	320	10,178	9,841	53	64
Connecticut	2,281	523	2,804	69	2,873	3,003	23	10
Maine	1,315	97	1,412	61	1,473	1,423	-	5
Massachusetts	3,668	143	3,811	41	3,852	3,409	27	46
New Hampshire	573	23	596	8	604	549	-	-
Rhode Island	507	59	566	55	621	530	3	3
Vermont	609	60	669	86	755	927	-	-
Delaware	522	88	610	22	632	725	101	135
District of Columbia	415	19	434	27	461	532	2	2
Florida	8,876	2,287	11,163	241	11,404	10,261	218	120
Georgia	9,493	1,069	10,562	375	10,937	10,084	10	24
Maryland	3,074	698	3,772	237	4,009	3,862	10	139
New Jersey	6,649	421	7,070	172	7,242	7,159	97	87
New York	7,943	1,929	9,872	474	10,346	9,732	262	385
North Carolina	8,388	1,159	9,547	337	9,884	10,233	11	17
Pennsylvania	14,979	3,531	18,510	202	18,712	18,116	271	299
South Carolina	4,204	439	4,643	152	4,795	5,169	34	12
Virginia	5,937	884	6,821	241	7,062	6,861	36	107
West Virginia	1,886	886	2,772	266	3,038	2,968	-	-
Total 1978	81,319	14,315	95,634	3,066	98,700	XXX	1,105	XXX
Total 1977	75,669	[1]16,096	[1]91,765	3,778	XXX	95,543	XXX	1,391
District II:								
Illinois	14,831	922	15,753	513	16,266	14,846	170	262
Indiana	9,146	689	9,835	284	10,119	11,147	7	89
Iowa	6,146	1,176	7,322	228	7,550	7,387	4	56
Kansas	3,781	2,628	6,409	130	6,539	5,983	35	1
Kentucky	5,158	2,553	7,711	330	8,041	7,113	-	-
Michigan	8,718	1,684	10,402	305	10,707	9,913	89	122
Minnesota	5,987	1,063	7,050	212	7,262	6,266	28	18
Missouri	8,150	1,236	9,386	482	9,868	8,781	54	17
Nebraska	3,188	1,095	4,283	275	4,558	3,996	11	31
North Dakota	1,319	136	1,455	132	1,587	1,612	6	6
Ohio	15,109	2,541	17,650	358	18,008	16,365	78	136
Oklahoma	5,937	2,311	8,248	343	8,591	7,618	-	-
South Dakota	1,426	534	1,960	104	2,064	1,593	10	10
Tennessee	9,036	1,816	10,852	261	11,113	10,083	-	-
Wisconsin	6,849	758	7,607	302	7,909	7,138	14	5
Total 1978	104,781	21,142	125,923	4,259	130,182	XXX	506	XXX
Total 1977	96,964	[1]18,427	[1]115,391	4,450	XXX	119,841	XXX	753
District III:								
Alabama	6,285	2,805	9,090	149	9,239	8,185	253	352
Arkansas	4,988	1,843	6,831	487	7,318	6,569	68	41
Louisiana	5,957	5,698	11,655	1,048	12,703	11,335	321	294
Mississippi	4,126	2,471	6,597	187	6,784	5,988	8	32
New Mexico	3,574	1,228	4,802	94	4,896	4,407	38	112
Texas	25,229	6,206	31,435	1,692	33,127	29,085	635	851
Total 1978	50,159	20,251	70,410	3,657	74,067	XXX	1,323	XXX
Total 1977	43,492	[1]18,630	[1]62,122	3,447	XXX	65,569	XXX	1,687
District IV:								
Colorado	3,169	968	4,137	428	4,565	4,482	458	117
Idaho	1,638	986	2,624	157	2,781	2,834	11	16
Montana	2,380	417	2,797	240	3,037	3,403	80	76
Utah	2,132	829	2,961	47	3,008	2,975	99	98
Wyoming	2,244	1,538	3,782	277	4,059	3,741	194	128
Total 1978	11,563	4,738	16,301	1,149	17,450	XXX	842	XXX
Total 1977	10,550	[1]5,443	[1]15,993	1,442	XXX	17,435	XXX	435
District V:								
Alaska	749	1,229	1,978	170	2,148	2,433	3	7
Arizona	4,614	1,185	5,799	511	6,310	5,380	32	144
California	25,578	4,203	29,781	641	30,422	25,761	214	54
Hawaii	360	495	855	89	944	716	27	171
Nevada	1,500	392	1,892	93	1,985	1,615	15	36
Oregon	5,364	720	6,084	129	6,213	5,453	21	18
Washington	4,956	1,186	6,142	295	6,437	5,512	39	38
Total 1978	43,121	9,410	52,531	1,928	54,459	XXX	351	XXX
Total 1977	37,737	7,856	45,593	1,277	XXX	46,870	XXX	463
United States total, 1978	290,943	69,856	360,799	14,059	374,858	XXX	4,127	XXX
United States total, 1977	264,412	[1]66,452	[1]330,864	14,394	XXX	345,258	XXX	4,729

[1] Revised. See Table 14a for detail.

Source: Bureau of Mines Form 6-1337-A and 6-1337-AS

APPENDIX B

Correspondences with Power Companies

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July 31, 1980

Mr. Leon Bowler
Dixie-Escalante Rural Electric
Association, Inc.
Beryl, Utah 84714

Dear Mr. Bowler:

Thank you for our recent telephone conversations concerning the impact of a possible M-X operating base on the Dixie-Escalante system. Based on these conversations, we understand the following:

1. An operating base in your service area would be served by Dixie-Escalante. That is, Dixie-Escalante would not intend to defer this to some other utility and Dixie-Escalante can handle or manage the construction of transmission and distribution facilities required.

2. Presently Beryl is served over a 12.5 KV rural distribution line and the Dixie-Escalante peak system load is approximately 20 MW.

3. Possibly power for the OB would be obtained by tapping one of the proposed bulk-power lines associated with the White Pine or Intermountain Power projects. Substations and lines into Beryl would be constructed as required.

4. In order to schedule bulk-power, an early and definite commitment by the Air Force is important. Dixie-Escalante is a member of the Intermountain Consumers Power Association and is a participant in the Moon Lake, Hunter, and IPP generating plant projects.

5. Since the Dixie-Escalante system is relatively small, the operating base and associated population increase would have a major impact on the Dixie-Escalante system.

If there is any additional information that you would like included in the record of our telephone conversations, please advise.

Very truly yours,

HENNINGSON, DURHAM & RICHARDSON, INC.

William H. Ohm

William H. Ohm
Electrical Engineer

WHO:wmm

July 31, 1980

Mr. Bill Coffman
Mt. Wheeler Power, Inc.
East Ely, Nevada 89315

Dear Mr. Coffman:

Thank you for our recent telephone conversations concerning the impact of a possible M-X operating base on the Mt. Wheeler Power (MWP) system. Based on these conversations, we understand the following:

1. An operating base near Ely would be in the service area of MWP.

2. Present MWP system peak load is approximately 25 MW.

3. MWP is a Rural Electric Cooperative which has no generation facilities and purchases power from other utilities. Power to MWP is transmitted over the nearby 230 KV transmission line owned by Sierra Pacific Power Company and the amount of power that can be delivered to MWP is limited by the capacity of the line and the power requirements of Sierra Pacific.

4. The severest impact on power supplies would occur prior to 1986. This is because the IPP and Moon Lake generating plants are scheduled to be on-line in 1986 and the White Pine plant is scheduled for 1989. Current plans indicate that a 230 KV line from IPP would pass through MWP service area and the White Pine plant will be located in MWP service area. Therefore, some of the major facilities which could be used to supply an M-X operating base will not be available prior to 1986. However, with whatever additional power supplies the Government may be able to make available, and with assistance in providing for earlier construction of the proposed 230 KV line from IPP to MWP at Ely, the power supply problem prior to 1986 can be overcome.

5. As a Rural Electric Cooperative all of the MWP service area facilities are constructed with loan funds from the Rural Electrification Administration under the U. S. Department of Agriculture from funds provided by the Office of Management and Budget. The rate payers in the MWP service area repay these loans. The Federal Government may be asked to provide financial assistance for construction of facilities for individual loads that result from the presence of an operating base; thereby minimizing the impact on MWP rate payers.

July 31, 1980

Mr. Bill Coffman
Page two.....

If there is any additional information that you would like included in the record of our telephone conversations, please advise.

Yours very truly,

HENNINGSON, DURHAM & RICHARDSON, INC.

William H. Ohm

William H. Ohm
Electrical Engineer

WHO:v

July 31, 1980

Mr. Bill Lynch
Lincoln County Power District
Pioche, Nevada 89043

Dear Mr. Lynch:

Thank you for our recent telephone conversation concerning the impact on the Lincoln County system of a possible M-X operating base near Coyote Springs (Kane Springs), Nevada. Based on this conversation, we understand the following:

1. There is no existing load and there are no existing substation or distribution facilities at Coyote Springs. A 69 KV line from the Moapa steam plant passes through the Coyote Springs area but it is operating at capacity and would not be suitable to supply M-X facilities at Coyote. Accordingly, all distribution, substation, and transmission line facilities required would be new.

2. The Lincoln County system peak demand is approximately 16 MW.

3. Since the area under consideration around Coyote Springs is on the boundary between the service areas of Lincoln County Power District (LCPD) and Nevada Power Company, there have been meetings between LCPD and Nevada Power to discuss how the load might be served. Based on these meetings, it is anticipated that there would be close cooperation between LCPD and Nevada Power Company in the planning, engineering and construction of required transmission facilities. It is also anticipated that the required bulk power can be supplied from the Allen plant at Dry Lake, Nevada.

If there is any additional information that you would like included in the record of our telephone conversation, please advise.

Yours very truly,

HENNINGSON, DURHAM & RICHARDSON, INC.

William H. Ohm
Electrical Engineer

WHO:wmm

July 31, 1980

Mr. J. C. Taylor
Utah Power and Light Company
1406 West No. Temple Street
Box 899
Salt Lake City, Utah 84110

Dear Mr. Taylor:

Thank you for our recent telephone conversation considering the impact on the UP & L system of the electrical load associated with a possible M-X operating base near Delta or Milford, Utah. Based on this telephone conversation,we understand the following:

1. Delta and Milford are in the service area of Utah Power and Light Company.

2. At present, Delta has a load of approximately 6 MW and is supplied by two 46 KV lines. Milford has a load of approximately 5 MW and is also supplied by two 46 KV lines.

3. Construction of new transmission and distribution facilities, if required, to serve the operating base will not be a problem for UP & L.

4. The bulk-power requirements for the operating base and associated area population increase are significant and need to be scheduled. Typical plant construction time is 3 years from ground breaking to on-line, and normal planning lead time is 4 to 5 years from identification of requirements to completion of major facilities. Accordingly, it is most important that the Air Force makes an early commitment to take into account required lead times.

If there is any additional information that you would like included in the record of our telephone conversations, please advise.

Yours very truly,

HENNINGSON, DURHAM & RICHARDSON, INC.

William H. Ohm
Electrical Engineer

WHO:wmm

August 1, 1980

Mr. Gary Gibson
Southwestern Public Service Company
P.O. Box 1261
Amarillo, Texas 79170

Dear Mr. Gibson:

The following summarizes recent telephone conversations with Mr. Dorough, local manager at Clovis, New Mexico, and Mr. McCabe, local manager at Dalhart, Texas, concerning the M-X E.I.S. topic of what will be the impact of a possible operating base on the local utility system:

1. Cannon AFB, near Clovis, and Dalhart are served by Southwestern Public Service Company.

2. In evaluating the impact of an operating base on the local utility system, it is appropriate to view the new OB load and new loads associated with area population increases as loads added to the overall SWPS system rather than as new loads impacting a small local utility.

3. Presently the peak demand of Dalhart is approximately 30 MW and Dalhart is served by a 115 KV line and a 69 KV line. Increased load due to an OB would be supplied by upgrading existing lines or constructing new lines and construction of new substation facilities as required. Planning, engineering, and construction of facilities would be handled by the SWPS main office staff.

4. The present load at Cannon AFB is approximately 10 MW and is supplied by a 69 KV line from Clovis. Increased load at Cannon might be supplied by upgrading the existing line and substation, or construction of new facilities as required. Planning, engineering, and construction of facilities would be handled by the SWPS main office staff.

5. The operating base load and increased load due to area population increase, whether at Clovis or Dalhart, would not represent a major impact to SWPS in that SWPS can supply the bulk power requirements and handle the transmission and distribution additions to the system as a matter of course.

If there is any additional information that you would like included in the record of these telephone conversations, please advise.

Sincerely yours,

HENNINGSON, DURHAM & RICHARDSON

William H. Ohm
Electrical Engineer

WHO/mh

July 31, 1980

Mr. Gary Gibson
Southwestern Public Service Company
Box 1261
Amarillo, Texas 79170

Dear Mr. Gibson:

The following summarizes the meeting held at the offices of Southwestern Public Service Company on May 22, 1980 to discuss electric service for possible M-X facilities in the SWPS service area.

Attendees:

Bill Esler	Southwestern Public Service Company
W. T. Seitz	Southwestern Public Service Company
Gary Bibson	Southwestern Public Service Company
Major Tom Hughes	United States Air Force
Ken Fishbeck	TRW/NAFB
Charles W. Heaton	TRW/NAFB
Kunihiro Kishaba	Corps of Engineers
Akira Murakami	AFRCE
Bob Dague	HDR, INC.
Bill Ohm	HDR, INC.

Salient points of the meeting are as follows:

1. The meeting was held to describe general M-X electrical energy requirements and inquire about the possibility of SWPS supplying electrical service.

2. SWPS anticipates no difficulty in constructing required transmission and distribution facilities and supplying the required power.

3. SWPS can construct facilities which meet USAF reliability criteria.

If there is any additional information that you would like included in the record of the meeting, please advise.

Yours very truly,

HENNINGSON, DURHAM & RICHARDSON, INC.

William H. Ohm

William H. Ohm
Electrical Engineer

WHO:wmm

APPENDIX C

Electric Power Supply and Demand for the Contiguous United States 1980-1989

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DIST. Category 97C

Electric Power Supply and Demand for the Contiguous United States 1980-1989

June 1980

U.S. Department of Energy
Economic Regulatory Administration
Division of Power Supply and Reliability
Washington, D.C. 20585

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I. SUMMARY

I.1 Highlights

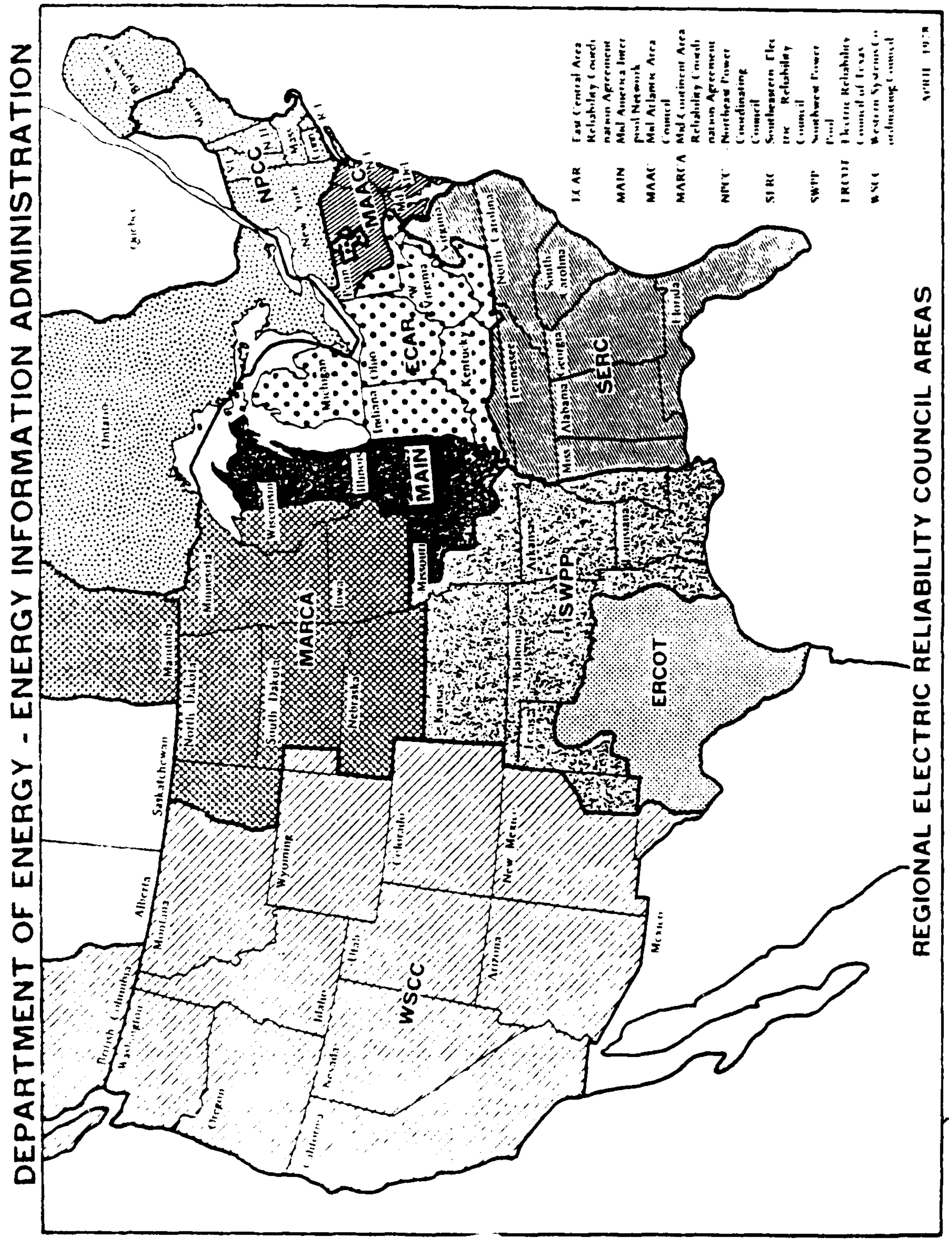
- Power supply reliability in most regions of the contiguous U.S. is expected to be adequate for the period 1980-1985, but problems exist in some areas.

- Requirements for electric energy and peak demand can reasonably be expected to increase at a rate in the range of 2.1% to 2.9% per year through the end of 1983.

- Failure to have in operation (as now scheduled) those nuclear units slated for completion by the end of 1985 could result in the use of some 700 million additional barrels of oil.

- The timely licensing and construction of nuclear power plants, consistent with all applicable safety and environmental considerations, could play a key role in the improvement of power supply adequacy and reliability in several regions.

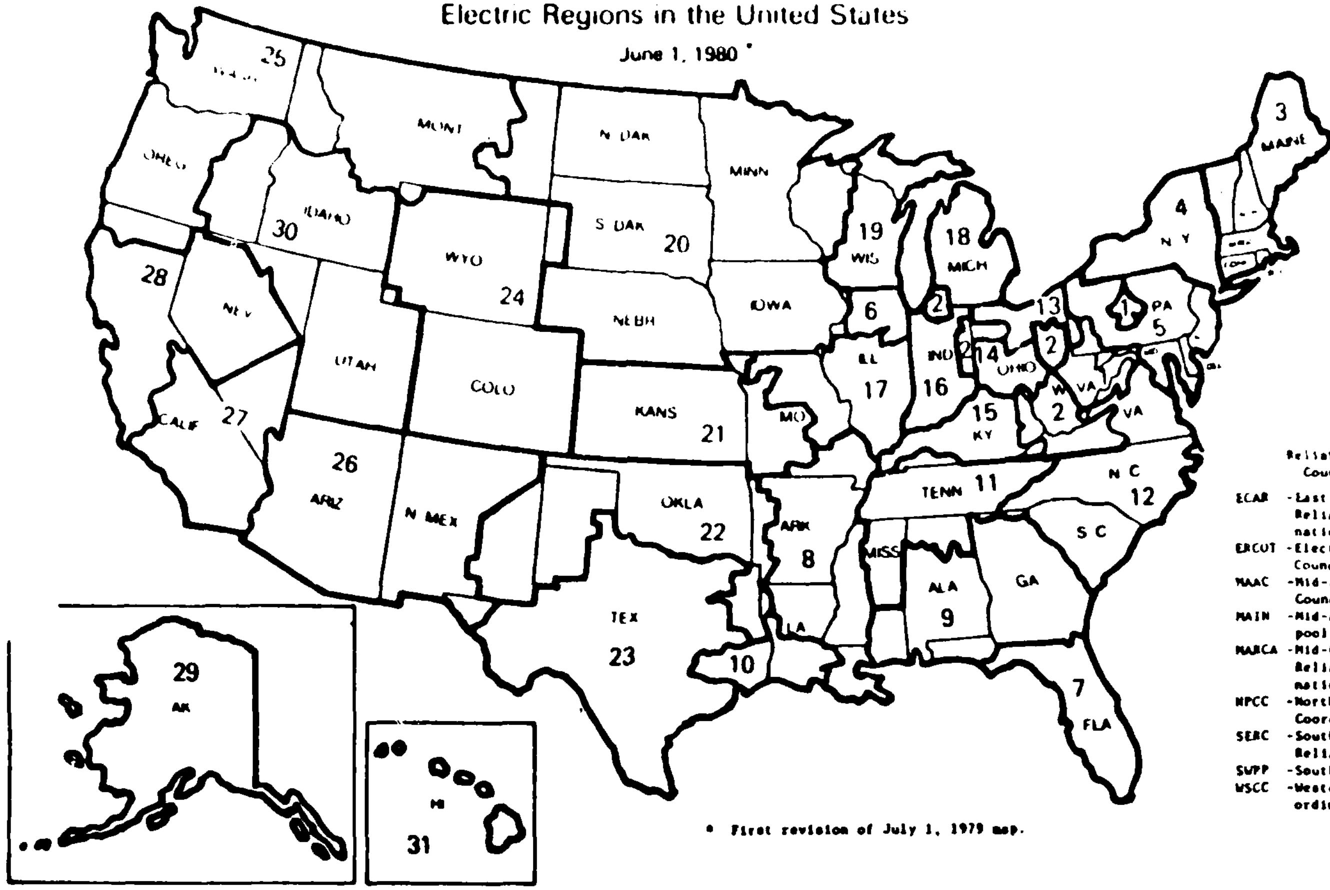
- Acceleration of coal unit construction could save some 70 million barrels of oil by the end of 1989.


DEPARTMENT OF ENERGY - ENERGY INFORMATION ADMINISTRATION
NPCC
MAAC
ECAR
MAIN
SERC
MARCA
SWPP
ERCOT
WSCC
REGIONAL ELECTRIC RELIABILITY COUNCIL AREAS

Department of Energy Economic Regulatory Administration

Electric Regions in the United States

June 1, 1980 *



Reliability Council

ECAR	-East Central Area Reliability Coordination Agreement
ERCOT	-Electric Reliability Council of Texas
MAAC	-Mid-Atlantic Area Council
MAIN	-Mid-America Interpool Network
MARCA	-Mid-Continent Area Reliability Coordination Agreement
NPCC	-Northeast Power Coordinating Council
SERC	-Southeastern Electric Reliability Council
SWPP	-Southwest Power Pool
WSCC	-Western Systems Coordinating Council

* First revision of July 1, 1979 map.

Electric Region	Council	Identification
	ECAR	
1		Allegheny Power System (APS)
2		American Electric Power System (AEP)
13		Central Area Power Coordination Group (CAPCO)
14		Cincinnati, Columbus, Dayton Group (CCD)
15		Kentucky Group
16		Indiana Group - All Indiana Utilities except I&M Electric Co.
18		Michigan Electric Coordinated Systems (MECS)
	ERCOT	
23		Texas Interconnected Systems Group (TIS)
	MAAC	
5		Pennsylvania-New Jersey-Maryland Interconnection (PJM)
	MAIN	
6		Commonwealth Edison Co.
17		Illinois-Missouri Group (ILLMO)
19		Wisconsin-Upper Michigan Systems Group (WUMS)
	MARCA	
20		Mid-Continent Area Power Pool (MAPP)
	NPCC	
3		New England Power Pool (NEPOOL)
4		New York Power Pool (NYPP)
	SERC	
7		Florida Coordination Group (FCG)
9		Southern Company Group
11		Tennessee Valley Authority Group (TVA)
12		Virginia-Carolinas Group (VACAR)
	SWPP	
8		Middle South Utilities Group
10		Gulf States Group
21		Missouri-Kansas Group (MOKAN)
22		Oklahoma Group
	WSCC	
24		Rocky Mountain Power Pool (RMPP)
25		Northwest Power Pool (NWPP) Except for Idaho-Utah Group
26		Arizona-New Mexico Group
27		Southern California-Nevada Group
28		Northern California-Nevada Group
30		Idaho-Utah Group of the Northwest Power Pool

Southwest Power Pool

Introduction

The Southwest Power Pool (SPP) area includes all of the states of Arkansas, Kansas, Louisiana and Oklahoma and part of the states of Mississippi, Missouri, New Mexico, and Texas, and serves a population of around 21,000,000. The SPP area is divided into four regions: Region 8 (Middle South Utilities Group), Region 10 (Gulf States Group), Region 21 (Missouri-Kansas Group), and Region 22 (Oklahoma Group).

Region 8 (Middle South Utilities Group) encompasses most of Arkansas, approximately one-half of both Mississippi and Louisiana, and a small portion of southeast Missouri. Approximately 95 percent of the electric load served in Region 8 is supplied by the Middle South Utilities Company, Inc. Middle South is a holding company consisting of Arkansas Power & Light Company, Louisiana Power & Light Company, Mississippi Power & Light Company, New Orleans Public Service Company and Arkansas-Missouri Power Company.

Region 10 (Gulf States Group) includes the southern portion of Louisiana, excluding the New Orleans area, and the east central portion of Texas that is within the SPP. Regions 8 and 10 are combined into a single group by SPP and systems operating within the two Regions coordinate their planning through the SPP planning Subcommittee.

Region 21 (Missouri-Kansas Group) covers almost the entire state of Kansas and the remaining part of Missouri that is in the SPP. The majority of the electric systems operating in Region 21 are members of the MOKAN Power Pool.

Region 22 (Oklahoma Group) covers the largest area of the four electric regions in SPP ranging from western Louisiana to eastern New Mexico. It includes all of Oklahoma and portions of Arkansas, Kansas, Louisiana, Texas, and New Mexico.

All Electric Regions within SPP experience their annual peak demand in the summer, usually during prolonged hot-dry periods called heat storms. The growth of peak demand for the entire

SPP has been declining since the early 1970's, and as a result, the systems have been revising and reducing their projected rate of growth annually. Table 8.1 shows projected rates of growth for summer and winter peak demands and annual energy as reported by SPP in its 1970, 1975 and 1980 reliability reports. The growth rates are for ten year periods.

Table 8.1

Compound Annual Growth Rate
Southwest Power Pool

Report Year	Peak Demand Summer (%)	Peak Demand Winter (%)	Annual Energy
1970	10.7	10.1	13.4
1975	8.2	8.5	8.3
1980	5.1	5.3	5.3

Although each Electric Region in SPP has coal-fired generating units either in service or under construction, and one, Region 8, has two nuclear units in operation, the area is heavily dependent upon natural gas and oil for electric generation. During the year 1978 SPP obtained 59.2 percent of its electric generation from natural gas, 18.7 percent from fuel oil, 16.8 percent from coal, 2.7 percent from nuclear and 2.6 percent from hydroelectric plants. SPP burned 61,618,000 barrels of oil in 1978, 86.8 percent of which was residual oil. During the period 1980 through 1989 systems in SPP are projectin g 27,215 megawatts of new coal-fired capacity, 6,311 megawatts combustion turbine and internal combustion capacity and 380 megawatts of capacity which is undecided. Tables 8.2 and 8.3 provide lists of projected coal-fired capacity and nuclear-fueled capacity, respectively.

The SPP has a backbone transmission system at the 500-kV level in Regions 8 and 10 and 345-kV in Regions 21 and 22. The 500-kV system was developed primarily to effect a 1,500 MW diversity interchange with the Tennessee Valley-Authority which commenced in June 1967. The interchange was reduced to 1,100 MW in 1979 and will be further decreased to 700 MW in 1981 and 200 MW in 1984.

The Central and South West Operating Company (Public Service Company of Oklahoma and Southwestern Electric Power Company in SPP and Central Power & Light Company and West Texas Utilities Company in ERCOT) made application to the F.E.R.C. on February 9, 1979, for an interconnection between SPP and ERCOT. The interconnecting lines proposed by Central & South West were shown on the map furnished by SPP in its 1980 ERA-411; however, they were not included in the list of proposed bulk lines in Item 5-B of ERA-411.

In the remainder of this report a four-part examination, consisting of historical perspective, current perspective, near-term future perspective, and long-term future perspective, is made for each electrical region in SPP. The historical section covers actual load and supply conditions in 1977 through 1979 for systems reporting on the monthly EIA Form 12E-2. The current near-term and long-term sections report the projected load and supply conditions for members of SPP gas, therefore, the coferage is not exactly synonymous. Table 8.4 provides a list of Form 12E-2 respondents and members of SPP and indicates the difference in coverage. In addition, the final section of each electric region text discusses peak demand and annual energy projections and the resulting annual load factors for the period 1980 through 1989.

Oklahoma Group (Region 22)

Historical Perspective

The Oklahoma Group includes all of Oklahoma and portions of Arkansas, Louisiana, New Mexico, and Texas. The Region has been a predominantly natural gas burning area, but it does use some coal and a little oil. As has occurred in most areas of the country, the growth rates for demand and energy have been declining. The historical growth rates are listed in Table 8D.1.

Table 8D.1

Compound Annual Growth Rates
Oklahoma Group

Period	Peak Demand (%)	Annual Energy (%)
1950-1960	12.0	11.6
1960-1970	8.7	8.6
1970-1976	6.5	7.2

In addition, the historical growth rates from 1977 to 1979 have shown an even more drastic decrease (see Table 8D.3). The 1979 peak demand and annual energy were less than 1978 figures with growth rates of -3.88 percent and -0.53 percent, respectively.

Tables 8D.4.1 and 8D.4.2 show the 1977-79 actual reserves for three summer and three winter months. The Oklahoma Group has had total reserves that ranged from 19.8 percent to 32.6 percent during the summer, and actual reserves that ranged from 16.9 percent to 22.9 percent.

Table 8D.2 shows the capacity mix by fuel type and the generation by fuel type for 1979.

Table 8D.2

Capacity Mix and Generation by Fuel Type for 1979
Oklahoma Group

Fuel Type	Capacity (GWh	(% of Total)	Annual Generation (GWh)	(% of Total)
Coal	3,458	19.2	13,554.9	18.6
Oil	293	1.6	166.2	0.2
Natural Gas	11,767	65.5	52,953.7	72.7
Nuclear	-0-	0.0	-0-	0.0
Hydro	2,438	13.5	6,075.5	8.4
Other *	42	0.2	85.5	0.1
Total	17,998	100.0	72,835.8	100.0

* Includes a co-generation unit and an expander turbine using hot inert gas from a chemical process.

During the 1980-89 period, the Oklahoma Region is projecting 9,259 MW of additional coal-fired capacity, 900 MW of nuclear capacity (Black Fox No. 1) and 214 MW of hydro capacity. This will result in the following capacity mix, by the winter of 1989-90, as a percent of the total: Coal - 48.2 percent, oil - 1.1 percent, natural gas - 36.7 percent, nuclear - 3.5 percent, hydro - 10.3 percent, and other - 0.2 percent.

The Oklahoma Region has, for the 1977-79 summer and winter periods, been a net seller of power. This is due in part to the Department of Energy's Southwestern Power Administration which sells power to the MOKAN systems (Region 21) and Middle South Systems (Region 8). For the entire Region 22, net energy sales were 5,939.8 GWh for 1977, 9,735.0 GWh for 1978, and 13,039.7 GWh in 1979, which constitutes 9.6 percent, 14.1 percent, and 18.1 percent of their system's net generation, respectively.

Current Perspective

The Oklahoma Group is projecting 866 MW of coal-fired capacity in service by the 1980 summer peak and an additional 965 MW by the winter peak. There are no anticipated delays of these units.

Total, available, and actual reserves appear adequate for the summer and winter periods as shown on Table 8D.5. Total reserves will be 25.1 percent and 71.7 percent for the summer and winter, respectively. There is no scheduled maintenance or inoperable capability projected for the 1980 summer and 126 MW of scheduled maintenance for the winter. This results in available resrves of 25.1 percent for the summer and 70.4 percent for the winter. Estimated forced outages based on historical forced outage trends would result in actual reserves of 20.4 percent and 62.2 percent for the summer and winter, respectively.

Table 8D.9 provides projected generation mix by fuel type during the summers of 1980, 1985, and 1989. During the 1980 summer peaking period, the Oklahoma Group plans to have 4,324 MW of coal-fired capability, 10,790 MW fired by natural gas, 295 MW by oil, 2,542 MW of hydro capability and 42 MW of other (includes a co-generation unit and an expander turbine using hot inert gas).

Future Perspective

The Oklahoma Group is projecting a peak demand growth rate of 5.5 percent for the 1981-1984 period. This is slightly higher than the 5.2 percent growth rate for the 1985-1989 period. As stated previously in the Historical Perspective, most of the capacity additions in the 1980-1989 period will be coal-fired. During the 1981-1984 period, 2,417 MW of coal-fired capacity and 58 MW of hydro capacity is projected. Due to the limited number of viable hydroelectric sites remaining, hydro will not play much of a role in future capacity expansion plans.

Total reserves for the summer peak (which are based upon planned generating resources and any power purchases and sales) are projected to range from 18.4 percent to 28.9 percent (see Table 8D.6). This is above the SPP criteria of

15 percent. Available reserves (which show the effect of scheduled maintenance and any inoperable capability) will range freom 17.2 percent to 28.9 percent. Again, this is well above the criteria.

Actual reserves (which reduce available reserves by estimated forced outages) range from 13.7 percent to 24.2 percent. This is considerably above the SPP actual reserve criteria of 6 percent. The forced outages were estimated using 1977-1979 historical outage rates obtained from Form 12E-2 data. This average summer rate was approximately 4.7 percent for Region 22.

In addition, possible nuclear and coal unit delays were examined to see what effect they might have on operating reserves. There were no nuclear delays expected but it was estimated using status codes in ERA-411 and other available information that GRDA No. 1 (490 MW), Welsh No. 3 (528 MW), Hugo No. 1 (376 MW), and Tolk No. 1 (508 MW) may be delayed as much as one year each. This would result in 490 MW and 1,412 MW of additional capability unavailable for the 1981 and 1982 summer peaks, respectively. The resultant actual reserve margins for these two years would be 20.7 percent and 13.9 percent which would appear quite adequate.

The Region is interconnected via EHV transmission lines to the Middle South Group (500 kV) and to the Missouri-Kansas Group with two 345-kV lines.

A 345-kV tie with the Gulf States Group to relieve overloads is projected to 1981 and a 345-kV tie is proposed for 1983 with MOKAN in order to deliver Associated Electric Cooperative's share of the Black Fox No. 1 nuclear unit. In addition, two internal 345-kV lines and a 230-kV interconnection with MOKAN are projected for 1984 to increase interchange capability.

The Oklahoma Group should have adequate reserves to cover possible outages and possible unit delays during the 1981-1984 period.

Region 22 is projecting 5,011 MW of coal-fired capacity in the 1985-1989 period along with a 900 MW share of Black Fox No. 1 nuclear unit and 52 MW of hydro capacity.

Table 8D.7 shows that summer actual reserves will range from 17.9 percent to 21.4 percent. Reserves which do not include any estimated scheduled maintenance or forced outages, but do include projected nuclear delays range from 15.8 percent to 21.4 percent for the summer peak period. The Black Fox No. 1 unit is estimated to be delayed from its 1987 date beyond the 1989 period by NRC.

In addition to those transmission lines previously mentioned, the Oklahoma Group is projecting two 345-kV internal lines for 1986 to increase interchange capability.

The Oklahoma Group should have adequate reserves throughout the 1980-1989 period to cover all but abnormal circumstances.

During the 10-year period (1980-1989), the Oklahoma Group is projecting that its summer peak demand, winter peak demand and annual energy requirements will grow at an average rate of 5.4 percent, 5.7 percent, and 5.5 percent, respectively.

Table 8D.8 presents the numerical estimates and shows annual projected growths for each of the three items. Table 8D.8 also shows the calculated annual load factor. The Oklahoma Group is projecting that its annual load factor will remain fairly constant at a 54 percent level throughout the period.

In order for annual energy requirements to be served by the Region, an adequate supply of natural gas must be maintained. During the 1989 summer peak period, it is projected that 38.6 percent of the Region's generating capability will be fueled by natural gas (see Table 8D.9).

Table 8D.3

HISTORICAL LOAD GROWTH

Oklahoma Group (Region 22)

	Demand				Annual Energy Requirements		Annual Load Factor
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWh)	Growth (%)	(%)
1977	12,010	-	9,403	-	56,246	-	53.5
1978	12,576	4.71	9,156	-2.63	59,429	5.66	53.9
1979	12,088	-3.88	8,981	-1.95	59,115	-0.53	55.8

Table 8D.4.1

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Oklahoma Group (Region 22)

	SUMMER								
	1977			1978			1979		
	Jun	Jul	Aug	Jun	Jul	Aug	Jun	Jul	Aug
1. Planned Capability	14655	14650	14681	15825	16140	16131	16530	16527	16526
2. Peak Demand	10698	12010	11625	11716	12576	12561	11460	11941	12088
3. Planned Reserves (1-2)	3957	2640	3056	4109	3564	3570	5070	4586	4438
4. Planned Reserves (%) (3/2)x100	37.0	22.0	26.3	35.1	28.3	28.4	44.2	38.4	36.7
5. Net Transactions (Imports-Exports)	-722	-260	-558	-1037	-1070	-907	-1455	-694	-537
6. Total Capability (1+5)	13933	14390	14123	14788	15070	15224	15075	15833	15989
7. Total Reserves (6-2)	3235	2380	2498	3072	2494	2663	3615	3892	3901
8. Total Reserves (%) (7/2)x100	30.2	19.8	21.5	26.2	19.8	21.2	31.5	32.6	32.3
9. Scheduled Maintenance	216	18	0	477	18	137	762	423	35
10. Capability after Maintenance (6-9)	13717	14372	14123	14311	15052	15087	14313	15410	15954
11. Reserves after Maintenance (10-2)	3019	2362	2498	2595	2476	2526	2853	3469	3866
12. Reserves after Maintenance (%) (11/2)x100	28.2	19.7	21.5	22.1	19.7	20.1	24.9	29.1	32.0
13. Inoperable Capability	198	148	156	33	152	271	82	225	187
14. Available Capability (10-13)	13519	14224	13967	14278	14900	14816	14231	15185	15767
15. Available Reserves (14-2)	2821	2214	2342	2562	2324	2255	2771	3244	3679
16. Available Reserves (%) (15/2)x100	26.4	18.4	20.1	21.9	18.5	18.0	24.2	27.2	30.4
17. Forced Outages	538	94	281	583	170	128	152	694	1159
18. Actual Capability after Forced Outages (14-17)	12981	14130	13686	13695	14730	14688	14079	14491	14608
19. Actual Reserves (18-2)	2283	2120	2061	1979	2154	2127	2619	2550	2520
20. Actual Reserves (%) (19/2)x100	21.3	17.7	17.7	16.9	17.1	16.9	22.9	21.4	20.8

Table 8D.4.2

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Oklahoma Group (Region 22)

	W I N T E R								
	1977/78			1978/79			1979/80		
	Dec	Jan	Feb	Dec	Jan	Feb	Dec	Jan	Feb
1. Planned Capability	15509	15474	15468	16655	16609	16599	17054	17473	17501
2. Peak Demand	8466	8705	9403	8844	9156	8932	8973	8981	8836
3. Planned Reserves (1-2)	7043	6769	6065	7811	7453	7667	8081	8492	8665
4. Planned Reserves (%) (3/2)x100	83.2	77.8	64.5	88.3	81.4	85.8	90.1	94.6	98.1
5. Net Transactions (Imports-Exports)	-1632	-2048	-1730	-2281	-1651	1642	-1795	-2349	-2704
6. Total Capability (1+5)	13877	13426	13738	14374	14958	14957	15259	15124	14797
7. Total Reserves (6-2)	5411	4721	4335	5530	5802	6025	6286	6143	5961
8. Total Reserves (%) (7/2)x100	63.9	54.2	46.1	62.5	63.4	67.5	70.1	68.4	67.5
9. Scheduled Maintenance	1676	1157	1874	1412	2086	1150	1738	1776	1013
10. Capability after Maintenance (6-9)	12201	12269	11864	12962	12872	13807	13521	13348	13784
11. Reserves after Maintenance (10-2)	3735	3564	2461	4118	3716	4875	4548	4367	4948
12. Reserves after Maintenance (%) (11/2)x100	44.1	40.9	26.2	46.6	40.6	54.6	50.7	48.6	56.0
13. Inoperable Capability	138	57	31	58	98	215	141	46	199
14. Available Capability (10-13)	12063	12212	11833	12904	12774	13592	13380	13302	13585
15. Available Reserves (14-2)	3597	3507	2430	4060	3618	4660	4407	4321	4749
16. Available Reserves (%) (15/2)x100	42.5	40.3	25.8	45.9	39.5	52.2	49.1	48.1	53.7
17. Forced Outages	864	474	440	163	632	1397	908	584	198
18. Actual Capability after Forced Outages (14-17)	11199	11738	11393	12741	12142	12195	12472	12718	13387
19. Actual Reserves (18-2)	2733	3033	1990	3897	2986	3263	3499	3737	4551
20. Actual Reserves (%) (19/2)x100	32.3	34.8	21.2	44.1	32.6	36.5	39.0	41.6	51.5

Table 8D.5

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
Oklahoma Group (Region 22)

	1980 Summer	1980/81 Winter
1. Planned Capability 1/	17993	18819
2. Peak Demand	13391	9776
3. Planned Reserves (1-2)	4602	9043
4. Planned Reserves (%) (3/2)x100	34.4	92.5
5. Net Transactions (Imports-Exports)	-1240	-2038
6. Total Capability (1+5)	16753	16781
7. Total Reserves (6-2)	3362	7005
8. Total Reserves (%) (7/2)x100	25.1	71.7
9. Scheduled Maintenance	0	126
10. Capability after Maintenance (6-9)	16753	16655
11. Reserves after Maintenance (10-2)	3362	6879
12. Reserves after Maintenance (%) (11/2)x100	25.1	70.4
13. Inoperable Capability	0	0
14. Available Capability (10-13)	16753	16655
15. Available Reserves (14-2)	3362	6879
16. Available Reserves (%) (15/2)x100	25.1	70.4
17. Forced Outages 2/	629	802
18. Actual Capability after Forced Outages (14-17)	16124	15853
19. Actual Reserves (18-2)	2733	6077
20. Actual Reserves (%) (19/2)x100	20.4	62.2

1/ No Nuclear Unit delays.

2/ Estimated by ERA staff based on historical forced outage amounts.

Table 8D.6

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Oklahoma Group (Region 22)

	1981 Summer	1981 Winter	1982 Summer	1982 Winter	1983 Summer	1983 Winter	1984 Summer	1984 Winter
1. Planned Capability	19510	19370	20975	20792	20881	20763	20783	21085
2. Peak Demand	14110	10277	14908	10942	15757	11634	16607	12317
3. Planned Reserves (1-2)	5400	9093	6067	9850	5124	9129	4176	8768
4. Planned Reserves (%) (3/2)x100	38.3	88.5	40.7	90.0	32.5	78.5	25.1	71.2
5. Net Transactions (Imports-Exports)	-1324	-2337	-1876	-2208	-1460	-1559	-1119	-1295
6. Total Capability (1+5)	18186	17033	19099	18584	19421	19204	19664	19790
7. Total Reserves (6-2)	4076	6756	4191	7642	3664	7570	3057	7473
8. Total Reserves (%) (7/2)x100	28.9	65.7	28.1	69.8	23.3	65.1	18.4	60.7
9. Scheduled Maintenance	0	337	0	561	0	661	0	775
10. Capability after Maintenance (6-9)	18186	16696	19099	18023	19421	18543	19664	19015
11. Reserves after Maintenance (10-2)	4076	6419	4191	7081	3664	6909	3057	6698
12. Reserves after Maintenance (%) (11/2)x100	28.9	62.5	28.1	64.7	23.3	59.4	18.4	54.4
13. Inoperable Capability	0	0	193	193	193	193	193	193
14. Available Capability (10-13)	18186	16696	18906	17830	19228	18350	19471	18822
15. Available Reserves (14-2)	4076	6419	3998	6888	3471	6716	2864	6505
16. Available Reserves (%) (15/2)x100	28.9	62.5	26.8	63.0	22.0	57.7	17.2	52.8
17. Forced Outages	663	843	508	704	548	761	588	817
18. Actual Capability after Forced Outages (14-17)	17523	15853	18398	17126	18680	17589	18883	18005
19. Actual Reserves (18-2)	3413	5576	3490	6184	2923	5955	2276	5688
20. Actual Reserves (%) (19/2)x100	24.2	54.3	23.4	56.5	18.6	51.2	13.7	46.2
Nuclear Unit Delays as Projected by Nuclear Regulation Commission								
21. Nuclear Delays	0	0	0	0	0	0	0	0
22. Actual Capability (18-21)	17523	15853	18398	17126	18680	17589	18883	18005
23. Actual Reserves with Nuclear Delays (22-2)	3413	5576	3490	6184	2923	5955	2276	5688
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	24.2	54.3	23.4	56.5	18.6	51.2	13.7	46.2
Coal Unit Delays Assumed Possible by ERA								
25. Possible Coal Delays	490	490	1412	1412	0	0	0	0
26. Actual Capability w/Nuclear & Coal Delays (22-25)	17033	15363	16986	15714	18680	17589	18883	18005
27. Actual Reserves w/Nuclear & Coal Delays (26-2)	2923	5086	2078	4772	2923	5955	2276	5688
28. Actual Reserves w/Nuclear & Coal Delays (%) (27/2)x100	20.7	49.5	13.9	43.6	18.6	51.2	13.7	46.2

1/ Estimated by ERA staff based on historical forced outage amounts.

Table 8D.7

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Oklahoma Group (Region 22)

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	22526	22487	23336	22965	24947	24908	25879	25541	26940	26720
2. Peak Demand	17517	13042	18464	13812	19421	14563	20406	15349	21431	16163
3. Planned Reserves (1-2)	5009	9445	4872	9153	5526	10345	5473	10192	5509	10557
4. Planned Reserves (%) (3/2)x100	28.6	72.4	26.4	66.3	28.5	71.0	26.8	66.4	25.7	65.3
5. Net Transactions (Imports-Exports)	-1068	-1244	-1369	-1645	-1333	-1609	-1236	-1512	-1132	-1408
6. Total Capability (1+5)	21458	21243	21967	21320	23614	23299	24643	24029	25808	25312
7. Total Reserves (6-2)	3941	8201	3503	7508	4193	8736	4237	8680	4377	9149
8. Total Reserves (%) (7/2)x100	22.5	62.9	19.0	54.4	21.6	60.0	20.8	56.6	20.4	56.6
9. Scheduled Maintenance 1/	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	21458	21243	21967	21310	23614	23299	24643	24029	25808	25312
11. Reserves after Maintenance (10-2)	3941	8201	3503	7508	4193	8736	4237	8680	4377	9149
12. Reserves after Maintenance (%) (11/2)x100	22.5	62.9	19.0	54.4	21.6	60.0	20.8	56.6	20.4	56.5
13. Inoperable Capability	193	193	193	193	157	157	119	119	83	83
14. Available Capability (10-13)	21265	21050	21774	21127	23457	23142	24524	23910	25725	25229
15. Available Reserves (14-2)	3748	8008	3310	7315	4036	8579	4118	8561	4294	9066
16. Available Reserves (%) (15/2)x100	21.4	61.4	17.9	53.0	20.8	58.9	20.2	55.8	20.0	56.1
17. Forced Outages 1/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	21265	21050	21774	21127	23457	23142	24524	23910	25725	25229
19. Actual Reserves (18-2)	3748	8008	3310	7315	4036	8579	4118	8561	4294	9066
20. Actual Reserves (%) (19/2)x100	21.4	61.4	17.9	53.0	20.8	58.9	20.2	55.8	20.0	56.1
Nuclear Unit Delays as Projected by Nuclear Regulation Commission										
21. Nuclear Delays	0	0	0	0	900	900	900	900	900	900
22. Actual Capability with Nuclear Delays (18-21)	21265	21050	21774	21127	22557	22242	23624	23010	24825	24329
23. Actual Reserves with Nuclear Delays (22-2)	3748	8008	3310	7315	3136	7679	3218	761	3394	8166
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	21.4	61.4	17.9	53.0	16.1	52.7	15.8	49.9	15.8	50.5

1/ Information on Scheduled Maintenance and Forced Outages not available for the 1985/89 period.

NOTE: No Coal Unit Delays Anticipated by ERA.

Table 8D.8

FUTURE LOAD GROWTH
Oklahoma Group (Region 22)

	Demand				Energy Requirements		Annual Load Factor (%)
	Summer (MW)	Growth (%)	Winter (MW)	Growth (%)	Amount (GWh)	Growth (%)	
1980	13,391	-	9,776	-	63,100	-	53.6
1981	14,110	5.4	10,277	5.1	66,800	5.9	54.0
1982	14,908	5.7	10,942	6.5	70,500	5.5	54.0
1983	15,757	5.7	11,634	6.3	74,300	5.4	53.8
1984	16,607	5.4	12,317	5.9	78,400	5.5	53.7
1985	17,517	5.5	13,042	5.9	82,800	5.6	54.0
1986	18,464	5.4	13,812	5.9	87,300	5.4	54.0
1987	19,421	5.2	14,563	5.4	92,000	5.4	54.1
1988	20,406	5.1	15,349	5.4	96,800	5.2	54.0
1989	21,431	5.0	16,163	5.3	101,900	5.3	54.3
1980-89		5.4		5.7		5.5	

Table 8D.9

GENERATION MIX BY FUEL TYPE
Oklahoma Group (Region 22)

Type Fuel	Summer 1980 Capability (MW)	Summer 1980 % of Total (%)	Summer 1985 Capability (MW)	Summer 1985 % of Total (%)	Summer 1989 Capability (MW)	Summer 1989 % of Total (%)
Nuclear	0	-	0	-	900	3.3
Coal	4,324	24.0	8,854	39.3	12,717	47.2
Gas	10,790	60.0	10,739	47.6	10,394	38.6
Oil	295	1.6	239	1.1	235	0.9
Hydro	2,542	14.2	2,652	11.8	2,652	9.8
Other	42	0.2	42	0.2	42	0.2
Total	17,993	100.0	22,526	100.0	26,940	100.0

Western Systems Coordinating Council (WSCC)

Introduction

Western Systems Coordinating Council (WSCC) was organized in 1967 to promote bulk power system reliability through coordinated planning and operation. Present membership includes 47 Member Systems and 14 Affiliate Members. These utility systems provide substantially all of the electric service in the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming, as well as portions of Nebraska, South Dakota, West Texas, and the Provinces of Alberta and British Columbia, Canada 1/. The region extends over approximately 1.8 million square miles and represents a service area equivalent to more than onehalf of the continguous land area of the United States.

The WSCC consists of five subregions or areas. These subregions are the Northwest Power Pool Area, consisting of the states of Washington, Oregon, Idaho, and Utah, and parts of Montana, Wyoming, Nevada and California; the Rocky Mountain Power Area, consisting of the states of Colorado and part of Wyoming, South Dakota, and Nebraska; the Arizona-New Mexico Power Area, consisting of the states of Arizona and parts of New Mexico and Texas; the Southern California-Nevada Power Area consisting of the southern portion of the states of California and Nevada; and the Northern California-Nevada Power Area, consisting of the northern portions of the states of California and Nevada. Electric Regions identified in this report are consistent with the WSCC Areas and may differ slightly from the ERA Electric Regions currently defined. Identification of reporting utilities within the respective Regions is attached.

1/ This report excludes Canadian portions of WSCC.

Table 9.1
Electric Regions Within WSCC

WSCC Area	Electric Region
Northwest Power Pool	25 and 30
Rocky Mountain Power Pool	24
Arizona-New Mexico Group	26
Southern California-Nevada Group	27
Northern California-Nevada Group	28

To the east WSCC abuts the mid-Continent Area Power Pool, the Southwest Power Pool and Electric Reliability Council of Texas; WSCC abuts Mexico to the South and Canada to the North.

Table 9.2

Utility Systems Within WSCC Electric Regions

Electric Regions 25 and 30

Northwest Power Pool Area (NWPP)

Bonners Ferry
Bonneville Power Administration
B.C. Hydro & Power Authority
Bountiful, City of
Calgary Poer Ltd.
Centralia, City of
Chelan County PUD
Cowlitz County PUD
Douglas County PUD
Eugene Water & Electric Board
Grant County PUD
Grays Harbor PUD
Idaho Powr Company
Montana Power Company
Pacific Power & Light Company
Pend Oreille County PUD
Portland General Electric Company
Puget Sound Power & Light Company
Seattle City Light
Snohomish PUD
St. George, City
Tacoma City Light
U.S.V.P. - Pacific Northwest Region -
  BPA (So. Idaho System)
USUC Loads Wheeled by Utah Power & Light Co.
U.S. Corps of Engineers (North Pacific Div.)
Utah Powr & Light Company
Washington Water Power Company
West Kootnay Power & Light Company

Table 9.2 (Cont'd)

Utility Systems Within WSCC Electric Regions

Electric Region 24

Rocky Mountain Power Area (RMPA)

Basin Electric Power Cooperative (Wyoming
and Black Hills Power and Light Company
Colorado Springs, City of
Colorado-Ute Electric Association
Lamar, City
Platte River Power Authority
Public Service Co. of Colorado
So. Colorado Power Division, Central
Telephone & Utilities Corp.
Tri-State Generation & Transmission
Association, Inc.
U.S.W.P - Lower Missouri Region
U.S.W.P. - Upper Colorado Region
Western Area Power Administration
Denver Area
Western ARea Power Administration
Salt Lake Area

Electric Region 26

Arizona-New Mexico Power Area (AZ-NM)

Arizona Electric Power Cooperative
Arizona Power Authority
Arizona Public Service Company
Citizens Utilities Company
El Paso Electric Company
Imperial Irrigation District
Los Alamos Systems
Navajo Tribal Utility Authority
Plains Electric G & T Cooperative
Public Service Co. of New Mexico
Salt River Project
San Carlos Irrigation project
Southern California Edison Company
(Blythe District)
Tucson Electric Power Company
U.S.W.P. - Lower Colorado Region (Including
USUC Loads in LC Region)
U.S.W.P. Rio Grande Project (SW Region)
Western Area Power Administration
Boulder City Area

Table 9.2 (Cont'd)

Utility Systems Within WSCC Electric Regions

Electric Region 27

Southern California-Nevada Power Area (S.CA-NV)

Anaheim, City of
Burbank, City of
California Dept. of Water Resources
California-Pacific Utilities Company
Glendale, City of
Intermountain Consumer Power Association
Lincoln County Power District
Los Angeles Dept. of Water & Power, City of
Metropolitan Water District/So. California
Nevada Power Company
Pasadena, City of
Riverside, City of
San Diego Gas & Electric Company
Southern California Edison Company
State of Nevada
U.S.W.P. at Boulder City

Electric Region 28

Northern California-Nevada Power Area (N.CA-NV)

California Dept. of Water Resources
Pacific Gas & Electric Company
Sacramento Municipal Utility District
San Francisco, City and County of
Sierra Pacific Power Company
Turlock and Modesto Irrigation Districts
U.S.W.P. - Mid Pacific Region
Western ARea Power Administration - Mid Pacific Region

Electric Regions 25 and 30 - Northwest Power Pool Area

Historical Perspective

The Northwest Power Pool Area (NWPP) includes 25 reporting systems which voluntarily operate on a coordinated basis. The pool area is comprised of the states of Washington, Oregon, Idaho, Utah, most of Montana and parts of Wyoming, Nevada and a small part of Northern California. Originally, the pool was divided into an East Group and West Group; however, increased interconnections between the two groups resulted in designation of the area as one entity. The Pacific Northwest Utilities Conference Committee (PNUCC), which is an outgrowth of the Northwest Power Pool, maintains the designation of West Group area. The PNUCC coordinates regional power planning and provides regional suport for the Federal Marketing Agency for electric power by the U.S. Corps of Engineers and U.S. Water and Power Resources services (formerly U.S. Bureau of Reclamation).

The Northwest Power Pool Area has a pronounced winter peak that is heavily influenced by a significant saturation of electric heating loads. During the 1960's the area experienced an average annual growth rate of 6.9 percent. For the 1970-75 period the growth rates was about 3.8% which represents a substantial reduction from the 1960 decade. This reduction is generally attributed to a downturn of the economy, the 1973 oil embargo, and the 1973 drought, and resultant effects of customer conservation.

The conservation theme plus other load reduction efforts carried into the latter half of the 1970's resulted in a continuing lower growth rate. Since the area is heavily dependent on hydroelectric generation, power supply is very much affected by annual precipitation. In 1977, a serious drought occurred and in fact affected the entire WSCC area. Consequently, Northwest utilities curtailed secondary energy deliveries and issued appeals for voluntary customer curtailments of 10 percent. Additionally, procedures were adopted for mandatory curtailments in a four-state area. Because of hydroelectric generation deficiencies, the area imported significiant amounts of energy to meet its load requirements. The drought ended in 1978 with a return to near normal water conditions. By fall of 1978, however, precipitation was again below normal in the Northwest resulting in lower than normal hydroreservoir storage entering the 1978-79 winter peak period. The effects of these water conditions are reflected in the growth rates for the 1977-79 period.

The below normal precipitation continued into 1979. On July 31, 1979, the date that Coordinated System reservoirs are programmed to refill, reservoir storage was only 90.7 percent of normally full contents, equivalent to 4.4 billion kilowatt hours of energy deficiency. During August the reservoirs deficiency increased to 5.4 billion kilowatt hours below normal.

Precipitation continued below normal during the remainder of 1979 creating a serious power supply situation for the 1979-80 water peak period.

No surplus hydro-generation was available from the Federal Columbia River Power System during the last half of 1979.

Actual load requirement data for the years 1977 through 1979 including annual growth rates and load factors are shown in the following table.

Table 9B.1

Historical Load Growth
Northwest Power Pool Area

		1977	1978	1979
Annual Electric Energy -	Gwh	153,023	165,288	173,193
Growth Rate	%	-1.5	8.0	4.8
Winter Peak Demand	MW	25,584	31,495	32,021 1/
Growth Rate	%	-4.0	23.1	1.7
Load Factor	%	68.2	59.9	61.7

1/ Estimated for January 1980.

In 1979 hydroelectric generation supplied 70.3 percent of the total generation. Capability of oil and gas-fired steam-electric generating plants as of December 31, 1979 totaled only 316 MW or 0.8 percent of the total capacity. These plants are old and are used only for emergency peaking purposes. The sole combined cycle plant in the area is the 534 MW Beaver Plant installed in 1977 by Portland General Electric Company. The plant normally burns distillate oil but is capable of burning No. 4 oil. Facilities are now being installed at the Beaver Plant to accomodate use of natural gas. The lone coalfired generating plant in the West Group area is the two-unit 1300 MW Centralia Plant located in Centralia, Washington.

Presently, there is one nuclear generating plant operating in the Northwest: Trojan (1130 MW), operating by Portland General Electric Company (PGE). The Hanford, WA. Nuclear Power Reactor facility is not considered dependable capability for planning purposes.

The remainder of the Regions supply emanates primarily from East Group area coal-fired plants. Within the Regions, a total of 11.7 billion MCF of natural gas was burned in 1979 - equivalent to 1.9 million barrels of oil. Oil consumption was 1.64 million barrels.

Table 9B.7 shows operation by type of plant and fuel consumption for 1979.

Because of heavy dependency on hydroelectric generation a unique feature of the Northwest is that, during adverse water conditions, capability may be sufficient but energy supply can be simultaneously deficient. This was evident during the 1977 drought when the area imported large amounts of energy to met load requirements but maintained sufficient capability margins.

Generally, high capacity reserve margins occur during the summer peak season. Excess summer capacity and associated energy serves secondary markets and interruptible loads. Historically, summer and winter capacity reserve margins have been more than adequate in the Northwest Power Pool Area.

Forced shutdown of the 1130 MW Trojan Nuclear Plant during the latter half of 1978, due to regulatory action, necessitated imports of oil fired energy from California and Canada. These imports resulted in a larger oil burn within the WSCC region than would have otherwise been required. Trojan was again shut down in October 1979 for maintenance and NRC required modifications. The loss of the Trojan plant coupled with below normal water conditions in the Northwest resulted in a very tight power supply situation for PGE entering the 1979-80 winter peaking season. The problem was alleviated somewhat when Trojan returned to service on December 31 and precipitation increased.

Table 9B.8 shows summer and winter peak loads, resources, and reserve margins for the years 1977 through 1979.

The Northwest Power Pool Area is a highly interconnected area. As of January 1, 1979, there were 38,900 circuit miles of transmission which represents 47% of the total transmission miles in the entire WSCC region. Bonneville Power Administration provides the electric power transmission network for marketing power for the Federal Columbia River Power System to major load centers of the Northwest. The BPA transmission system also serves as the backbone grid for all the Northwest utilities and covers a service area of some 300,000 square miles.

The lack of adequate east-west transmission across the Northwest Power Pool Area due principally to construction delays has frequently limited transfers of Montana and Wyoming area coal-fired generation to Pacific Coast load centers and has contributed to increased vulnerability of the interconnected system to major disturbances. A case in point was the major disturbance of November 27, 1979 when the Grand Coulee Power Plant lost 720 MW of generation. This loss of generation coupled with the scheduled outage of the 500 kV Pacific Northwest - Southwest Intertie resulted in conditions severe enough to cause islanding of the entire WSCC interconnected system. Construction has been chronically delayed on several major lines: notably the Colstrip, MT - Hot Springs, WY, double circuit 500 kV line; the Midpoint, ID - Malin, OR, 500 kV line; and the Kinport, ID - Midpoint, ID 345 kV line.

Northwest Power Pool Area is strongly interconnected to the Northern and Southern California Areas by three major transmission lines. Two of the lines are 500 kV (AC) with a total transfer capability of 2500 MW. The third is an 800 kV (DC) line with a capacity of 1440 MW. These interties are used to transmit surplus NWPP secondary energy to the south and southwest and for diversity exchange between the areas.

Current Perspective

For the 1980-81 winter peak season, requirements are estimated to increase by 9.9% for energy and 5.8% for peak load over that experienced during the 1979-80 winter season in the Northwest Power Pool area.

Since November 1979, adjusted monthly energy for loads have shown small amounts of growth over the previous year's corresponding monthly loads. December 1979 energy for load was 2 percent above the energy for load of December 1978 - 3.3 percent below forecast. Energy for loads for January, February and March 1980 increased by about 1 percent over the loads of corresponding

months of 1979. The annual growth rate had been consistently above five percent for several years preceding this period. This low growth in recent months is partly due to the curtailment of BPA's direct service industrial load. Other likely factors are a general economic slowdown and conservation effects.

Heavy precipitation was recorded in most of the Region during December 1979 and near normal water conditions continued through the first quarter of 1980. Reservoir storage at the end of March 1980 was very close to the level required for refill this summer. The outlook is for the area's reservoirs to be substantially full

by mid-August. However, performance of thermal generating plants, electric energy demands and upcoming fisheries operations in May will have major effects on the actual refill program. In any case, studies indicate there will be very little surplus hydro-generated energy available for non-firm loads, displacement of thermal generation, or export from the Northwest before next fall.

Capability additions scheduled in service for 1980 include 1,075 MW of hydroelectric, 930 MW of coal-fired and 178 MW of gas/oil fired generation. Utah Power & Light Company's Hunter No. 2 400 MW, and Portland General Electric Company's Boardman, 530 MW, both coalfired units, are scheduled for service in June and November, respectively. In November, Puget Sound Power & Light Company is planning to install two combustion turbine units totalling 178 MW which will burn either natural gas or distillate oil.

The Trojan nuclear plant was shut down April 11 for refueling and maintenance. Trojan is expected to return to service by summer 1980.

The following table shows the schedule in-service dates for major generating units during 1980.

Table 9B.2

Major Capability Additions in 1980
Northwest Power Pool Area

	Type	Capability MW	In-Service Date
Grand Coulee No. 24	Hydro	700	May 80
Hunter No. 2	Coal	400	Jun 80
Boardman	Coal	530	Nov 80

The Boardman plant in-service date is the probable energy date which is determined by the PNUCC from a standardized schedule reflecting anticipated average planning and construction times. The estimated commercial operation date is July 1980.

Estimated operation by type of plant and fuel use under median hydro conditions (energy) is shown in Table 9B.9.

For reserve study purposes the U.S. portion of the Northwest Power Pool Area is assumed to be an infinite bus. Present transfer capability between the East Group and West Group is limited to an extent which may limit transfer of energy to the West Group area.

Anticipated available and planned reserve margins for the 1980 winter peaking season appear sufficient based on WSCC's "Power Supply Design Criteria," criterion 1 and the Pacific Northwest Coordination Agreement Method (LOLP - one day in 20 years), but not the PNUCC West Group Criterion 1(b) (13 percent of firm peak load). Reserve margins shown in Table 9B.10 are much lower than those listed prior to last year. This reduction is due to BPA changing the representation of the Federal hydro capability from a one hour peak to a ten hour sustained peaking capability. Grand Coulee hydro capability has been reduced by 1543 MW through the summer of 1983 due to a tailwater problem. Also, it should be noted that in Table 9B.10, dependable capability includes hydro resources based on adverse water conditions. It is difficult to obtain median or average water condition ratings for hydro plants; however, it is known that, based on magnitudes of scale, dependable hydro capability based on median conditions is less than five percent above those rated on adverse conditions.

Future Perspective

The Northwest Power Pool Area loads are projected to increase in the five-year period from 1980-85 at an average annual rate of 4.4 percent for winter peak demand and 4.5 percent for annual energy use. This energy growth rate is somewhat higher than the 3.7 percent experienced during the 1977-79 period when below normal water conditions occurred twice in three years.

For the years 1985 through 1989 peak demand average annual growth rate is forecast at 2.8 percent while energy use is estimated to increase at a 3.5 percent average annual rate.

Although growth rates are declining, total growth nevertheless is forecasted to be substantial. Energy use is estimated to increase from 173,193 GWh in 1979 to 272,025 GWh in 1989. Peak demand is forecast to increase from 32,021 MW to 46,378 MW during that same period.

Additions to generating capacity for the Regions total 7,056 MW for the period 1981 through 1985. Table 9B.3 lists the significant units by type and delays of in-service dates.

Table 9B.3

Scheduled Capability Additions
Northwest Power Pool Area

Generating Unit	Type	MW Capability	In-Service Date Original	In-Service Date Current	Total Delay (Months)
WNP 2	Nuclear	1100	3/78	1/83 1/	58
Hunter 3	Coal	400		6/83	
Colstrip 3	Coal	700	7/78	1/84	66
WNP 1	Nuclear	1250	9/80	6/85 1/	57
Junter 4	Coal	400		6/85	
Colstrip 4	Coal	700	7/79	9/85	64
WNP 3	Nuclear	1240		6/86 1/	

1/ Revised from 1980 ERA-411 by Washington Public Power Supply System

Significant additions include 2200 MW of coal-fired and 3,590 MW of nuclear units. Current in-service dates are "Probable PNUCC Energy Dates" using the Milestone procedure based on critical path analysis methods. The milestone procedure reflects the possible plant delays in excess of those considered in scheduled commercial operation dates.

As shown in the Table 9B.3, significant delays have occurred since conception for four major plants. Even since the report of April 1, 1979, one year ago, there have been several delays. Units affected and the months of delay since last year's report are listed in Table 9B.4.

Table 9B.4

Unit Delays from 3/79 - 3/80
Northwest Power Pool Area

Generating Unit	In-Service Date April 1, 1979	In-Service Date Current	Delay (Mo.)
Colstrip 3	3/83	1/84	6
Colstrip 4	3/85	9/85	6
Boardman	7/80	11/80	4
WNP 1	12/83	6/85 1/	18
WNP 2	9/81	1/83 1/	16

1/ Revised from 1980 ERA-411 by Washington Public Power Supply System.

For the period 1986 through 1990 a total of 8,908 MW is planned for addition to the Regions' capability. Significant unit additions for this period are listed by type in Table 9B.5.

Table 9B.5

Major Capability Additions 1986 - 1990
Northwest Power Pool Area

Generating Unit	Type	Net Capability MW	Schedule in Service Date
WNP 4	Nuclear	1250	6/86 1/
WNP 5	Nuclear	1240	6/87 1/
Intermountain 1	Coal	750	7/86
Intermountain 2	Coal	750	7/87
Wellington 1	Coal	500	6/88
Intermountain 3	Coal	750	7/88
Intermountain 4	Coal	750	7/89
Skagit 1	Nuclear	1285	7/90

1/ Revised from 1980 ERA-411 by Washington Public Power Supply System.

Intermountain coal plant is a joint project: forty-two percent of the project's output will be shared by Utah utilities and the remainder will be transmitted to southern California utilities.

There are also 453 MW of combustion turbine generation planned for installation during the 1981-89 period. Of this amount, 178 MW is specified to use distillate oil as the primary fuel.

Tables 9 B.13 and 9 B.14 show the estimated operation by type of plant and fuel use for the years 1985 and 1989. Under median hydro conditions estimated oil/gas-fired generation will supply 0.9 percent of the total generation in 1985 and 0.6 percent in 1989.

The PNUCC "West Group Forecast" reports that nearly every unit of planned resources for the West Group area is behind schedule by three years since the 1977 forecast. A noteworthy change in its latest forecast is the planned deferrals of two unlicensed nuclear plants: Skagit and Pebble Springs. Only Skagit unit No. 1, now scheduled for July 1990, is shown in the current PNUCC forecast.

Presently, Colstrip Unit Nos. 3 and 4 are on schedule but in-service dates of WNP 1 and 2 are being reviewed. Delays in unit installations have produced only small peak deficiencies to date; however, peak demand reserve margins are projected to decrease and energy deficits are projected to increase significantly with each additional unit delay.

The estimated reserve margins for the Northwest Power Pool Area are indicated in Table 9B.12.1 and 9B.12.2. During the period July 1981 through June 1983 the Pool does not meet WSCC criteria 1 for desired reserve margins. It should be noted that BPA, for planning purposes, includes approximately 1000 MW of interruptible loads in its firm load. If these interruptible loads were to be used for reserve, there could be sufficient reserve margin for the entire ten-year period. Also, for this forecast, hydro resource capabilities are estimated on an adverse water year basis.

Reserve requirements vary considerably depending on the criteria used. WSCC reliability criteria is defined on Table 9 B.11. The Pacific Northwest Coordination Agreement reserve criteria provides for capability reserves based on a loss of load probability of one day in 20 years. The most stringent requirements are those of the

West Group which basically requires a reserve margin of twelve percent of firm peak load the first year, increasing one percent per year to twenty percent, and remaining at twenty percent thereafter. The West Group reliability criteria indicates deficiencies in reserve margin for the entire period through June 1984.

Since the Pool Area is basically a hydro oriented system energy resources are important in assessing the forecasted load-supply situation.

Studies conducted in conjunction with the West Group Forecast indicate there is a probability that the resources in the western portion of the Pool will be insufficient to meet total energy load under adverse water conditions during the ten year forecast period.

In addition, for purposes of this report, a delay of 6 months was assumed for the major coal plants, shown in Table 9B.3.

Table 9B.6 shows the affects on reserve margins of nuclear plants' delays and an assumed 6 months delay in specified coal plant units.

Table 9B.6

Estimated Available Reserve Margins (%)
Northwest Power Pool Area
Winter Peak Period

	1980	1981	1982	1983	1984	1985
			- Percent -			
Present Schedule	7.7	6.2	5.0	8.8	9.7	15.3
Delayed Schedule	7.7	6.2	5.0	8.8	6.6	10.7

There are three critical bulk power transmission facilities that will not be in service when desired. A discussion of each line and its effects on the bulk power system follows.

The Kinport, ID - Midpoint, ID 345 kV line is to be constructed, owned and operated by Idaho Power Company (IPC) to permit transfer of Wyoming resources through IPC's service area. This line was scheduled for service concurrent with the start-up of Jim Bridger Unit 4 in December 1979, but has now been delayed to October 1981 due to delays in obtaining necessary construction permits.

Pacific Power and Light Company's (PP&L) Midpoint, ID - Malin - Medford, OR 500 kv line will serve as an interconnection between IPC and PP&L. The line represents a critical link in the transmission system that is being constructed in cooperation with IPC to permit transfer of PP&L's Wyoming resources to the West Group area. In addition, the proposed line is purportedly required to reinforce the bulk power supply to PP&L's Southern Oregon load area.

It is estimated that the 445 mile Malin-Midpoint section of the line will be delayed approximately three years from the originally scheduled in-service date of October 1978. Final Federal permits were received in October and construction of the line was started in December 1979. The completion date is now scheduled for September 1981. As a result of this delay West Group area deficiencies will be increased by up to 900 MW of capability and 400 MW of average energy.

The Montana Power Company's Bozeman-Dillion 161 kV line and associated facilities were scheduled for November 1978. The line has been postponed pending resolution of a law suit relating to environmental concerns. This delay adversely affects the reliability of service in the Dillion, MT area.

Table 9B.7
1979 Operation by Type of Plant
Northwest Power Pool Area

Plant Type	Fuel Type	Capability (as of 12/31/79) MW	Capability (as of 12/31/79) % of Total	Annual Energy Gwh	Annual Energy % of Total	Fossil Fuel Consumption (x 1000)	
Hydro	Water	30753	75.0	125503	70.3	-	
Hydro Pumped Storage	Water	100	0.2	0	-	-	
Steam	Coal	7498	18.3	41860	23.4	24874	Tons
Steam	Oil	316	0.8	303	0.2	642	Barrels
Steam	Gas			581	0.3	6968	MCF
Steam	Nuclear	1080	2.6	8634	4.8		
Combustion Turbine	Oil	637	1.6	20	-	46	Barrels
Combustion Turbine	Gas			385	0.2	4713	MCF
Combined Cycle	Oil	534	1.3	577	0.3	952	Barrels
Combined Cycle	Gas			0			
Geothermal	GST	-					
Internal Combustion	Oil	33	0.1	0			
Fuel Cell	---	---					
Other		70	0.2	705	0.4		
Total		41021	100.0	178568	100.0		

Total Fuel Consumption	
Coal (tons x 1000)	24874
Gas (MCF x 1000)	11681
Gas (equivalent bbls x 1000)	1904
Oil: distillate (bbls x 1000)	998
residual	642
crude	0
Total Oil	1646

Table 9B.8

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Northwest Power Pool Area

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability 1/	34694	34280	37859	39784	39169	37641
2. Peak Demand	20501	25584	22283	31495	23014	32021
3. Planned Reserves (1-2)	14193	8696	15576	8289	16155	5620
4. Planned Reserves (%) (3/2)x100	69.2	34.0	69.9	26.3	70.2	17.6
5. Net Transactions (Imports-Exports)	-3135	-1655	-3281	-1747	-3075	-1730
6. Total Capability (1+5)	31559	32625	34578	38037	36094	35911
7. Total Reserves (6-2)	11058	7041	12295	6542	13080	3890
8. Total Reserves (%) (7/2)x100	53.9	27.5	55.2	20.8	56.8	12.1
9. Scheduled Maintenance	7051	2602	5136	4689	7398	776
10. Capability after Maintenance (6-9)	24508	30023	29442	33348	28696	35135
11. Reserves after Maintenance (10-2)	4007	4439	7159	1853	5682	3114
12. Reserves after Maintenance (%) (11/2)x100	19.5	17.4	32.1	5.9	24.7	9.7
13. Inoperable Capability	0	100	0	130	30	167
14. Available Capability (10-13)	24508	29923	29442	33218	28666	34968
15. Available Reserves (14-2)	4007	4339	7159	1723	5652	2947
16. Available Reserves (%) (15/2)x100	19.5	17.0	32.1	5.5	24.6	9.2
17. Forced Outages 2/	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	24508	29923	29442	33218	28666	34968
19. Actual Reserves (18-2)	4007	4339	7159	1723	5652	2947
20. Actual Reserves (%) (19/2)x100	19.5	17.0	32.1	5.5	24.6	9.2

1/ Excludes Canadian Systems.
2/ Information not reported separately.

Table 9B.9
Estimated 1980 Operation by Type of Plant
Northwest Power Pool Area

Plant Type	Fuel Type	Capability (as of 2/31/80) MW	Capability (as of 2/31/80) % of Total	Annual Energy 1/ Gwh	Annual Energy 1/ % of Total	Fossil Fuel Consumption (x 1000)
Hydro	Water	27373	72.7	140589	73.4	-
Hydro Pumped Storage	Water	100	0.3	-		-
Steam	Coal	7498	19.9	40031	20.9	23104 Tons
Steam	Oil	316	0.8	-		
Steam	Gas			244	0.1	3235 MCF
Steam	Nuclear	1080	2.9	10555	5.5	-
Combustion Turbine	Oil	637	1.7			
Combustion Turbine	Gas			112	0.1	1562 MCF
Combined Cycle	Oil	534	1.4	0		
Combined Cycle	Gas			0		
Geothermal	GST	-				
Internal Combustion	Oil	33	0.1	0		
Fuel Cell	-	-				
Other		70	0.2			
Total		37641	100.0	191531	100.0	

Total Fuel Consumption	
Coal (tons x 1000)	23104
Gas (MCF x 1000)	4797
Gas (equivalent bbls x 1000)	785
Oil: distillate (bbls x 1000)	-
residual	-
crude	-
Total Oil	0

1/ Median Hydro Conditions.

Table 9B.10

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent) - 1980/81
Northwest Power Pool Area

	Summer 1980			Winter 1980/81		
	Dec	Jan	Feb	Dec	Jan	Feb
1. Planned Capability 1/	36611	38241	38238	39351	39059	38534
2. Peak Demand 2/	26010	25898	25550	32801	33888	32147
3. Planned Reserves (1-2)	12601	12343	12688	6550	5171	6387
4. Planned Reserves (%) (3/2)x100	48.4	47.7	49.7	20.0	15.3	19.9
5. Net Transactions (Imports-Exports)	-2956	-2939	-2954	-1585	-1605	-1622
6. Total Capability (1+5)	35655	35302	35284	37766	37454	36912
7. Total Reserves (6-2)	9645	9404	9734	4965	3566	4765
8. Total Reserves (%) (7/2)x100	37.1	36.3	38.1	15.1	10.5	14.8
9. Scheduled Maintenance	2633	3058	3192	988	781	894
10. Capability after Maintenance (6-9)	33022	32244	32092	36778	36673	36018
11. Reserves after Maintenance (10-2)	7012	6346	6542	3977	2785	3871
12. Reserves after Maintenance (%) (11/2)x100	27.0	24.5	25.6	12.1	8.2	12.0
13. Inoperable Capability	167	167	167	167	167	167
14. Available Capability (10-13)	32855	32077	31925	36611	36506	35851
15. Available Reserves (14-2)	6845	6179	6375	3810	2618	3704
16. Available Reserves (%) (15/2)x100	26.3	23.9	25.0	11.6	7.7	11.5
17. Forced Outages 3/	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	32855	32077	31925	36611	36506	35851
19. Actual Reserves (18-2)	6845	6179	6375	3810	2618	3704
20. Actual Reserves (%) (19/2)x100	26.3	23.9	25.0	11.6	7.7	11.5

1/ No delays anticipated in new generating units since submittal of 1980 ERA-411.
2/ Includes 461 MW of interruptible capability.
3/ Information not available.

Table 9B.11

WSCC Power Supply Design Criteria
Recommended Minimum Performance Table
Northwest Power Pool Area

It is recommended that areas or systems defined for analysis should meet or exceed at least one of the following WSCC criteria for installed and planned generating capacity:

Criteria	Minimum Design Performance
1. Monthly Reserve Capability After Deducting Scheduled Maintenance (MW)	Greater of R, or the largest Risk plus 5% of Load Responsibility
2. Monthly Reseve Capability After Deducting Scheduled Maintenance	2 largest Risks
3. Annual reliability criterion based on probability of loss of load, either	
a. Frequency of loss of load or,	1 day in 10 years
b. probability of meeting all loads in a year	0.90

Definitions

$$R = \left(\frac{.05\,H + .15\,T}{H + T}\right) \times L$$

H = Monthly hydro capability after deducting scheduled maintenance.

T = Monthly thermal capability after deducting scheduled maintenance.

L - Load Responsibility: System or area monthly firm peak load demand plus those firm sales minus those firm purchases for which reserve capacity must be provided by the supplier.

Reserve Capability after Deducting Scheduled Maintenance = H + T - L

Risk: Capability reduction caused by outage of a generator or transmission line.

Performance Table Adopted by Executive Committee - September 19, 1974.

Table 9B.12.1

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Northwest Power Pool Area

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	39464	39750	41171	41151	41679	44277	44175	46344
2. Peak Demand 1/	27269	35449	28303	37181	29760	38843	30875	40404
3. Planned Reserves (1-2)	12195	4301	12868	3970	11919	5434	13300	5940
4. Planned Reserves (%) (3/2)x100	44.7	12.1	45.5	10.7	40.1	14.0	43.1	14.7
5. Net Transactions (Imports-Exports)	-3135	-1136	-2389	-1139	-2242	-1058	-2371	-1046
6. Total Capability (1+5)	36329	38614	38782	40012	39437	43219	41804	45298
7. Total Reserves (6-2)	9060	3165	10479	2831	9677	4376	10929	4894
8. Total Reserves (%) (7/2)x100	33.2	8.9	37.0	7.6	32.5	11.3	35.4	12.1
9. Scheduled Maintenance	3951	788	3819	793	3986	803	4698	804
10. Capability after Maintenance (6-9)	32378	37826	34963	39219	35451	42416	37106	44494
11. Reserves after Maintenance (10-2)	5109	2377	6660	2038	5691	3573	6231	4090
12. Reserves after Maintenance (%) (11/2)x100	18.7	6.7	23.5	5.5	19.1	9.2	20.2	10.1
13. Inoperable Capability	167	167	167	167	167	167	167	167
14. Available Capability (10-13)	32211	37659	34796	39052	35284	42249	36939	44327
15. Available Reserves (14-2)	4942	2210	6493	1871	5524	3406	6064	3923
16. Available Reserves (%) (15/2)x100	18.1	6.2	22.9	5.0	18.6	8.8	19.6	9.7
17. Forced Outages 2/	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	32211	37659	34796	39052	35284	42249	36939	44327
19. Actual Reserves (18-2)	4942	2210	6493	1871	5524	3406	6064	3923
20. Actual Reserves (%) (19/2)x100	18.1	6.2	22.9	5.0	18.6	8.8	19.6	9.7
Nuclear Unit Delays as Projected by Utilities								
21. Nuclear Delays 3/	0	0	1100	0	0	0	0	1250
22. Actual Capability (18-21)	32211	37659	33696	39052	35284	42249	36939	43077
23. Actual Reserves with Nuclear Delays (22-2)	4942	2210	5393	1871	5524	3406	6064	2673
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	18.1	6.2	19.1	5.0	18.6	8.8	19.6	6.6

1/ Includes 461 MW of interruptible load.
2/ Information not available.
3/ Washington Public Power Supply System update of 1980 ERA-411.

Table 9B.12.2

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Northwest Power Pool Area

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	46447	49465	49166	50788	50540	51030	51345	51697	51431	53548
2. Peak Demand 1/	32079	41893	33165	43403	34219	44975	35343	46534	36486	46765
3. Planned Reserves (1-2)	14368	7572	16001	7385	16321	6055	16002	5163	14945	6783
4. Planned Reserves (%) (3/2)x100	44.8	18.1	48.2	17.0	47.7	13.5	45.3	11.1	41.0	14.5
5. Net Transactions (Imports-Exports)	-2237	-988	-2178	-35	-646	900	247	1324	671	1654
6. Total Capability (1+5)	44210	48477	46988	50753	49894	51930	51592	53021	52101	55202
7. Total Reserves (6-2)	12131	6584	13823	7350	15675	6955	16249	6487	15616	8437
8. Total Reserves (%) (7/2)x100	37.8	15.7	41.7	16.9	45.8	15.5	46	13.9	42.8	18.0
9. Scheduled Maintenance 2/	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	44210	48477	46988	50753	49894	51930	51592	53021	52102	55202
11. Reserves after Maintenance (10-2)	1213	6584	13823	7350	15675	6955	16249	6487	15616	8437
12. Reserves after Maintenance (%) (11/2)x100	37.8	15.7	41.7	16.9	45.8	15.5	46.0	13.9	42.8	18.0
13. Inoperable Capability	167	167	167	167	167	167	167	167	167	167
14. Available Capability (10-13)	44043	48310	46821	50586	49727	51763	51425	52854	51935	55035
15. Available Reserves (14-2)	11964	6417	13656	7183	15508	6788	16082	6320	15449	8270
16. Available Reserves (%) (15/2)x100	37.3	15.3	41.2	16.5	45.3	15.1	45.5	13.6	42.3	17.7
17. Forced Outages 2/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	44043	48310	46821	50586	49727	1763	51425	52854	51935	55035
19. Actual Reserves (18-2)	11964	6417	13656	7183	15508	6788	16082	6320	15449	8270
20. Actual Reserves (%) (19/2)x100	37.3	15.3	41.2	16.5	45.3	15.1	45.5	13.6	42.3	17.7
Nuclear Unit Delays as Projected by Utilities										
21. Nuclear Delays 3/	0	1240	0	0	0	0	0	0	0	0
22. Actual Capability (18-21)	44043	47070	46821	50586	49727	51763	51425	52854	51935	55035
23. Actual Reserves with Nuclear Delays (22-2)	11964	5177	13656	7183	15508	6788	16082	6320	15449	8270
24. Actual Reserves with Nuclear Delays (%) (23/2)x100	37.3	12.4	41.2	16.5	45.3	15.1	45.5	13.6	42.3	17.7

1/ Includes 461 MW (Summer 1985) and 387 MW all other periods of interruptible load.
2/ Information on scheduled maintenance and forced outages not available.
3/ Washington Public Power Supply System update of 1980 ERA-411.

Table 9B.13
Estimated 1985 Operation by Type of Plant
Northwest Power Pool Area

Plant Type	Fuel Type	Capability (as of 1/1/85) MW	Capability (as of 1/1/85) % of Total	Annual Energy 1/ Gwh	Annual Energy 1/ % of Total	Fossil Fuel Consumption (x 1000)	
Hydro	Water	30366	65.4	141465	60.4	-	
Hydro Pumped Storage	Water	300	0.6	0	-		
Steam	Coal	10380	22.4	69236	29.5	35002	Tons
Steam	Oil	316	0.7	-			
Steam	Gas			245	0.1	3235	MCF
Steam	Nuclear	3400	7.3	21409	9.1		
Combustion Turbine	Oil	993	2.1				
Combustion Turbine	Gas			245	0.1	3035	MCF
Combined Cycle	Oil	534	1.2	1707	0.7	2875	Barrels
Combined Cycle	Gas						
Geothermal	GST						
Internal Combustion	Oil	33	0.1				
Fuel Cell							
Other		112	0.2				
Total		46434	100.0	234307	100.0		

Total Fuel Consumption	
Coal (tons x 1000)	39637
Gas (MCF x 1000)	6260
Gas (equivalent bbls x 1000)	1025
Oil: distillate (bbls x 1000)	2875
residual	
crude	
Total Oil	2875

1/ Energy estimated for median hydro conditions.

Table 9B.14
Estimated 1989 Operation by Type of Plant
Northwest Power Pool Area

Plant Type	Fuel Type	Capability (as of 1/1/89) MW	Capability % of Total	Annual Energy 1/ Gwh	Annual Energy 1/ % of Total	Fossil Fuel Consumption (x 1000)	
Hydro	Water	30709	58.1	142876	52.4		
Hydro Pumped Storage	Water	300	0.6	0			
Steam	Coal	12352	23.4	82053	30.1	45586	Tons
Steam	Oil	316	0.6	0			
Steam	Gas			245	0.1	3238	MCF
Steam	Nuclear	7160	13.5	46367	17.0		
Combustion Turbine	Oil	1343	2.5	0	-	46	Barrels
Combustion Turbine	Gas			245	0.1	3035	MCF
Combined Cycle	Oil	534	1.0	1127	0.4	1898	Barrels
Combined Cycle	Gas						
Geothermal	GST	-					
Internal Combustion	Oil	33	0.1				
Fuel Cell	-	-					
Other		112	0.2				
Total		52859	100.0	272913	100.0		

Total Fuel Consumption	
Coal (tons x 1000)	45586
Gas (MCF x 1000)	6237
Gas (equivalent bbls x 1000)	1027
Oil: distillate (bbls x 1000)	1898
residual	
crude	
Total Oil	1898

1/ Energy estimated for median hydro conditions.

Southern California-Nevada Power Area - Region 27

Historical Perspective

The Southern California-Nevada Power Area (S.CA-NV) consists mainly of the service areas of Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), Los Angeles Department of Water and Power (LADWP), and Nevada Power Company (NPC). These utilities operate independently but are joint participants in several generating plants.

The S.CA-NV experiences a pronounced summer peak. During the period 1960 through 1973 the region experienced an average annual growth in energy for load of 7.6 percent. However, for the period 1973 through 1979, this growth rate was reduced to less than two percent despite continued economic and population growth. SDG&E experienced the fastest energy for load growth rate with a 3.6 percent annual average increase from 1973 through 1978; conversely, LADWP has had a slightly negative load growth rate during the corresponding period.

Table 9D.1 presents electric load data for the years 1977-1979. Growth rate data appear high for 1978 because of the effects of conversion spurred by the 1976-1977 drought in California. The energy load decrease for 1979 is a probable reporting error as each utility in the Region experienced an actual load increase.

Table 9D.1
Historical Load Growth
Southern California-Nevada Power Area

	1977	1978	1979
Energy Load (GWh)	96666	102317	102014
Growth rate from previous year (%)	1.0	5.8	-0.3
Peak Demand (MW)	18815	20150	20507
Growth rate from previous year (%)	1.6	7.1	1.8
Load Factor (%)	58.6	58.0	56.8

The California utilities have historically relied heavily upon oil/gas fired additions to meet load growth requirements. Coal supplies are practically non-existent within the state and past economics and environmental concerns precluded major importation of coal for generating purposes.

As of December 1979 fully 67.8 percent of the Electric Region 27 installed generating capability was oil and/or gas fired. Gas and oil accounted for 63.7 percent of the total electric energy generation in 1978. For 1978, fuel oil consumption amounted to 70.8 million barrels and natural gas consumption was 18.4 billion cubic feet, which is equivalent to 31.4 million barrels of oil. Fuel consumption and generation data is not available for this Region for 1979.

This pronounced dependence on oil and gas as a fuel for generating purposes makes the California portion of this Region the largest consumer of oil and gas within the WSCC. The Nevada portion of the Region contains substantial amounts of coal-fired generation. Southern California utilities jointly own coal-fired generating capacity located in Southern Nevada and elsewhere. Their share of these units is included in Table 9D.10.

Oil and gas consumption is substantially reduced when better than adverse water conditions are experienced in the Pacific Northwest. During these periods surplus PNW hydroelectric energy is transferred to southern California consequently displacing incremental generation (usually oil) in the area. During the past several years Pacific Northwest secondary transfers to S.CA-NV averaged roughly 5,000 GWh, equivalent to 8 million barrels of oil per year.

Reliability criteria vary from utility to utility within the Southern California-Nevada area. However, the various criteria applied by each utility result in an area installed planning reserve margin requirement of approximately 20 percent at the time of the annual peak.

Table 9D.2
Reserve Margins (%)
Southern California-Nevada Power Area

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
Total	33.3	68.5	29.9	60.2	22.2	67.9
Reserves after Maintenance	24.1	54.9	18.4	43.6	22.2	67.9
Actual	19.6	37.8	6.1	35.0	3.1	31.7

Reserve margins have been low at the time of the past two summer peak periods due to excessive forced outage caused by the continuous

operation of system capacity in order to assist utilities to the north during energy shortages. Additionally, in 1979 the area experienced an early heat storm while scheduled maintenance of some major units was still in progress. SCE has been pursuing an aggressive maintenance program which is expected to reduce system forced outages by one third.

As of December 1979 the majority of the region's high voltage transmission was rated at 230 kV and totaled more than 4600 circuit miles. Strong 500 kV interties exist between Los Angeles, southern Nevada, Arizona, and New Mexico to the east, and to the north through northern California to the Pacific Northwest. The 800 kV-DC Pacific Northwest/Southwest intertie connects southern California with the Pacific Northwest. There are no intermediary taps along the DC intertie.

The combined northern AC and DC intertie is designated as the Pacific Intertie and in addition to firm transfers and significant seasonal diversity exchange the interties are used to transfer the aforementioned surplus hydro energy from the Pacific Northwest.

The total transfer capability between Electric Region 27 and northern utilities is approximately 3300 MW. Eastern transfer capability is 2300 MW from east to west and 900 MW from west to east.

While the existing transmission system is more than adequate to support intra-area and inter-area transfers, a problem area does exist in the region: the single 230 kV interconnection between SCE and SDG&E which carries participants' output of the San Onofre Nuclear Unit #1 and other transfers to SDG&E. This line is susceptible to outage brush fires and no appropriate back-up transmission exists.

Table 9D.3
1979 Capability by Type of Plant
Southern California-Nevada Power Area

Plant Type	Fuel Type	Capability (as of 12/31/79) MW	Capability (as of 12/31/79) % of Total
Hydro	Water	2692	10.5
Hydro Pumped Storage	Water	1247	4.9
Steam	Coal	3871	15.1
Steam	Oil/Gas	14698	57.5
Steam	Nuclear	436	1.7
Combustion Turbine	Oil/Gas	1501	5.9
Combustion Cycle	Oil/Gas	1113	4.3
Internal Combustion	Oil	30	0.1
Total		25588	100.0

Table 9D.4

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Southern California - Nevada Power Area

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	22197	22314	24771	25131	24156	24509
2. Peak Demand	18815	15125	20150	16355	20507	15432
3. Planned Reserves (1-2)	3382	7189	4621	8776	3649	9077
4. Planned Reserves (%) (3/2)x100	18.0	47.5	22.9	53.7	17.8	58.8
5. Net Transactions (Imports-Exports)	2877	3167	1404	1065	912	1406
6. Total Capability (1+5)	25074	25481	26175	26196	25068	25915
7. Total Reserves (6-2)	6259	10356	6025	9841	4561	10483
8. Total Reserves (%) (7/2)x100	33.3	68.5	29.9	60.2	22.2	67.9
9. Scheduled Maintenance	1730	2050	2318	2711	0	0
10. Capability after Maintenance (6-9)	23344	23431	23857	23485	25068	25915
11. Reserves after Maintenance (10-2)	4529	8306	3707	7130	4561	10483
12. Reserves after Maintenance (%) (11/2)x100	24.1	54.9	18.4	43.6	22.2	67.9
13. Inoperable Capability	840	2582	2482	1404	3921 2/	5595 2/
14. Available Capability (10-13)	22504	20849	21375	22081	21147	20320
15. Available Reserves (14-2)	3689	5724	1225	5726	640	4888
16. Available Reserves (%) (15/2)x100	19.6	37.8	6.1	35.0	3.1	31.7
17. Forced Outages 1/	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	22504	20849	21375	22081	21147	20320
19. Actual Reserves (18-2)	3689	5724	1225	5726	640	4888
20. Actual Reserves (%) (19/2)x100	19.6	37.8	6.1	35.0	3.1	31.7

1/ Information not reported separately.

2/ Includes scheduled outages.

Table 9D.5

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
Southern California - Nevada Power Area

	1980 Summer	1980/81 Winter
1. Planned Capability 1/	22096	22303
2. Peak Demand	20805	17111
3. Planned Reserves (1-2)	1291	5192
4. Planned Reserves (%) (3/2)x100	6.2	30.3
5. Net Transactions (Imports-Exports)	4008	3745
6. Total Capability (1+5)	26104	26048
7. Total Reserves (6-2)	5299	8937
8. Total Reserves (%) (7/2)x100	25.5	52.2
9. Scheduled Maintenance	934	3100
10. Capability after Maintenance (6-9)	25170	22948
11. Reserves after Maintenance (10-2)	4365	5837
12. Reserves after Maintenance (%) (11/2)x100	21.0	34.1
13. Inoperable Capability	459	459
14. Available Capability (10-13)	24711	22489
15. Available Reserves (14-2)	3906	5378
16. Available Reserves (%) (15/2)x100	18.8	31.4
17. Forced Outages 2/	1632	1575
18. Actual Capability after Forced Outages (14-17)	23079	20914
19. Actual Reserves (18-2)	2274	3803
20. Actual Reserves (%) (19/2)x100	10.9	22.2

1/ No delays anticipated in new generating units since submission of 1980 ERA-411.

2/ 3-Year historical average forced outage (1976-78).

Present Perspective

Reserves above forecasted 1980 peak demands are expected to be adequate for the Southern California-Nevada Power Area. Expected 1980 reserves are in excess of minimum criteria partially as a result of peak demand growth reductions due primarily to expected increased energy conservation. Annual peak demand growth from 1979 to 1980 is projected to be 1.5 percent and energy load growth to be 3.4 percent.

The only scheduled resource additions in the area during 1980 are 57 MW of hydroelectric capacity in southern California and a 70 MW gas turbine unit planned by the Nevada Power Company.

The San Onofore Nuclear Unit No. 1 (436 MW) is scheduled for refueling from April 11 to June 1, 1980. Turbine blading problems have been experienced in units of similar age and type. Discovery of turbine trouble could extend the shutdown or cause derating of the unit.

The major southern California utilities participate in the statewide emergency reserve sharing and demand reduction program (see discussion for Electric Region 28) and under this plan they may be called upon to assist the northern California utilities during possible capacity shortages there.

No surplus energy is expected from the Pacific Northwest, and Northwest economy receipts are anticipated to be significantly below average during 1980 due to below normal runoff predictions and already overdrafted reservoir conditions in the Northwest. This situation is estimated to result in an increased 1980 oil consumption in southern California of approximately 9 million barrels. Power plant fuel supplies are generally abundant throughout California.

Table 9D.6
1980 Installed Capability by Type of Plant
Southern California-Nevada Power Area (Region 27)

		Capability	
Plant Type	Fuel Type	MW	% of Total
Hydro	Water	2739	10.6
Hydro Pumped Storage	Water	1247	4.9
Steam	Coal	3871	15.1
Steam	Oil/Gas	14698	57.2
Steam	Nuclear	436	1.7
Combustion Turbine	Oil/Gas	1571	6.1
Combined Cycle	Oil/Gas	1113	4.3
Internal Combustion	Oil	30	0.1
Total		25705	100.0

Future Perspective

The utilities in the Southern California-Nevada Power Area (S.CA-NV) project load growth for the Region to average 3.0 percent in peak demand from 1980 to 1985 and 3.2 percent from 1985 through 1989. Associated annual energy load growth projections are 3.0 percent through 1985 and 3.3 percent from 1985 through 1989. These projections are significantly higher than actual growth rates experienced during the past several years.

In contrast to the utilities' forecast, the California Energy Commission (CEC) in its 1979 Biennial Report forecasts only a 2 percent growth in energy load through the 1980's for the major Southern California utilities which serve 90 percent of the Region's load. The CEC forecast is used in determining the need for additional generating resources during the State's powerplant site certification process.

Within the S.CA-NV, generating resource additions planned through 1985 include 2200 MW of nuclear capability (San Onofre 2 & 3), 500 MW of coal-fired cabability in southern Nevada and 530 MW of combustion turbines.

Beyond 1985 significant amounts of coal-fired additions are planned. Continued expansion of combustion turbine capability is also scheduled. Other planned resources include hydro, geothermal, and wind. No nuclear units are planned within the area after the scheduled San Onofre unit additions. However, area utilities are joint participants in scheduled nuclear capacity outside of the S.CA-NV. These utilities' will share a total of 819 MW by 1990.

Table 9D.10 lists significant capability additions scheduled through 1989 for the Region. Table 9D.12 illustrates the utilities' projected generating capability listed by types for the years 1985 and 1989.

In conjunction with the CEC's recently adopted load forecast, the Commission has proposed a preferred resource mix which is significantly different from that foreseen by the California utilities. This CEC outlook capitalizes on alternative and renewable resources including increased development of geothermal, cogeneration, wind, and conservation with a proposed limit on coal-fired generation of 5800 MW. In contrast, present statewide utilities' plans include a total of nearly 12,000 MW of coal-fired generation by 1990.

Delays in construction of nuclear or coal-fired resources would most likely result in additional fuel oil consumption. Additional oil consumption is estimated to be nearly one million barrels per year per 100 MW of slippage. Assuming a one-year delay from the utilities' present scheduled in-service dates for nuclear, and six-months' delay for all coal-fired additions, fuel oil consumption would increase by about 2.1 million barrels in 1981, 10.4 million barrels in 1982, and 9.5 million barrels in 1983. During the five-year period through 1985, the resulting annual average increased oil burn is estimated to be 4.5 million barrels per year for S.CA-NV.

A recent development which will result in reduced area oil burn is Southern California Edison's agreement with Arizona Public Service Company (APS) to purchase power from APS's 350 MW coal-fired Cholla Unit No. 4 for a five-year period starting in June 1984. Under the terms of the agreement, SCE will receive 35 percent of the unit's capability the first year, 100 percent for the next three years and 41 percent for the final year. The purchase will reduce equivalent oil consumption by an estimated 12.5 million barrels during the five-year period.

Under the utilities' present resource schedule and peak load forecast, the actual reserve margins at the time of the system peak for the S.CA-NV area are projected to range from 10.9 percent in 1980 and 1981 to 23.5 percent in 1989.

Table 9D.7
Reserve Margins (%)
Southern California-Nevada Power Area

	1981	1982	1983	1984	1985
Total	26.2	26.6	28.5	25.6	22.2
Reserves after Maintenance	21.0	21.9	22.0	21.3	27.2
Actual	18.8	19.8	19.7	21.0	21.4

Table 9D.8 shows the estimated installed reserve margins reflecting the effect of the delayed case for nuclear and coal-fired units. Reserves remain within desired margin requirements.

Table 9D.8
Estimated Actual Reserve Margins (%)
Southern California-Nevada Power Area

	1981	1982	1983	1984	1985
Delayed schedule	18.8	14.8	13.7	21.0	20.8

Use of the lower CEC load forecast to determine reserves results in installed margins of up to 30 percent (1983) using the utilities presently scheduled capability additions. It may be assumed that scheduled additions will necessarily be delayed if the CEC's rigorous "need" determination continues as in past licensing hearings.

For S.CA-NV, only the effective dates for rerating two oil-fired units have been rescheduled since the April 1, 1979, WSCC report.

Table 9D.9
Schedule Capability Delay
Southern California-Nevada Power Area

Unit Name & No.	Capability (MW)	Previous Date	New Date	Delay (months)
Cool Water 4	+61	6/79	9/79	3
Long Beach 11	+56	7/79	1/81	17

Proposed bulk power line additions for the area through 1989 consist of 13 miles of 138 kV line, 342 miles of 230 kV line, 300 miles of 345 kV line, 1508 miles of 500 kV line, and 986 miles of 1000 kV (± 500 kV) DC line. The DC line is scheduled to deliver Utah coal-fired capacity to southern California in the late 1980's. Also, the 540 mile existing 800 kV DC line from the Pacific Northwest to Sylmar is scheduled to be upgraded to 1000 kV in 1984.

The addition of two 230 kV lines by San Diego Gas and Electric Company is planned to overcome the existing deficiency associated with the San Onofre line as well as deliver added generator output in the early 80's. Additional 230 kV and 500 kV lines are proposed by the company to provide substantial ties with Mexico and eastern utilities by 1985.

Table 9D.10
Significant Planned Additions to Generating Capacity
Souther- California-Nevada Power Area

Unit	Type	Capability MW	Scheduled In-Service Date
San Onofre 2	Nuclear	1100	10/81
San Onofre 3	Nuclear	1100	1/83
Reid Gardner 4	Coal	250	6/83
Warner Valley 1	Coal	63 1/	6/85
Warner Valley 2	Coal	63 1/	6/86
Harry Allen 1	Coal	230 2/	6/86
Intermountain 1	Coal	434 3/	7/86
Harry Allen 2	Coal	230 2/	6/87
Intermountain 2	Coal	434 3/	7/87
Harry Allen 3	Coal	230 2/	6/88
Intermountain 3	Coal	434 3/	7/88
California	Coal	500	9/88
Harry Allen 4	Coal	230 2/	6/89
Intermountain 4	Coal	434 3/	7/89
California 2	Coal	500	9/89

1/ 25% of 250 MW unit.
2/ 46% of 500 MW unit.
3/ 57.9% of 750 MW unit.

Table 9D.12
1985 and 1989 - Installed Capability by Type of Plant
Southern California-Nevada Power Area

Plant Type	Fuel Type	1985 Capability MW	1985 Percent of Total	1989 Capability MW	1989 Percent of Total
Hydro	Water	2875	9.8	3195	9.3
Pumped Storage	Water	1247	4.3	1247	3.6
Steam	Coal	4141	14.2	7582	22.1
Steam	Oil/Gas	14688	50.3	14567	42.3
Steam	Nuclear	3182	10.9	3455	10.0
Combustions Turbine	Oil/Gas	1854	6.3	2949	8.6
Combined Cycle	Oil/Gas	1144	3.9	1144	3.3
Geothermal		9	0.0	88	0.3
Internal Combustion	Oil	30	0.1	30	0.1
Cogeneration	___	47	0.2	60	0.2
Wind	___	3	0.0	84	0.2
Total		29220	100.0	34401	100.0

Table 9D.11.1

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Southern California - Nevada Power Area

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability 1/	22525	23616	23587	23798	24726	25005	24814	25054
2. Peak Demand	21238	17542	21975	18055	22633	18604	23369	19227
3. Planned Reserves (1-2)	1287	6074	1612	5743	2093	6401	1445	5827
4. Planned Reserves (%) (3/2)x100	6.1	34.6	7.3	31.8	9.2	34.4	6.2	30.3
5. Net Transactions (Imports-Exports)	4275	3834	4212	3995	4284	3981	4529	4063
6. Total Capability (1+5)	26800	27450	27799	27793	29010	28986	29343	29117
7. Total Reserves (6-2)	5562	9908	5824	9738	6377	10382	5974	9890
8. Total Reserves (%) (7/2)x100	26.2	56.5	26.5	53.9	28.2	55.8	25.6	51.4
9. Scheduled Maintenance	1111	2518	1003	1679	1754	2491	827	1912
10. Capability after Maintenance (6-9)	25689	24932	26796	26114	27256	26495	28516	27205
11. Reserves after Maintenance (10-2)	4451	7390	4821	8059	4623	7891	5147	7978
12. Reserves after Maintenance (%) (11/2)x100	21.0	42.1	21.9	44.6	20.4	42.4	22.0	41.5
13. Inoperable Capability	459	459	459	459	175	175	245	245
14. Available Capability (10-13)	25230	24473	26337	25655	27081	26320	28271	26960
15. Available Reserves (14-2)	3992	6931	4362	7600	4448	7716	4902	7733
16. Available Reserves (%) (15/2)x100	18.8	39.5	19.8	42.1	19.7	41.5	21.0	40.2
17. Forced Outages 2/	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	25230	24473	26337	25655	27081	26320	28271	26960
19. Actual Reserves (18-2)	3992	6931	4362	7600	4448	7716	4902	7733
20. Actual Reserves (%) (19/2)x100	18.8	39.5	19.8	42.1	19.7	41.5	21.0	40.2

1/ No delays anticipated in new generating units since submission of 1980 ERA-411.
2/ Information on forced outages not available.

Table 9D.11.

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Southern California - Nevada Power Area

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	25298	25759	27614	28070	29339	29800	31567	31675	33779	33840
2. Peak Demand	24172	19835	24962	20520	25814	21149	26664	21775	27461	22411
3. Planned Reserves (1-2)	1126	5924	2652	7550	3525	8651	4903	9900	6318	11429
4. Planned Reserves (%) (3/2)x100	4.7	29.9	10.6	36.8	13.7	40.9	18.4	45.5	23.0	51.0
5. Net Transactions (Imports-Exports)	4229	3945	3206	2909	2156	1855	1226	933	405	109
6. Total Capability (1+5)	29527	29704	30820	30979	31495	31655	32793	32608	34184	33949
7. Total Reserves (6-2)	5355	9869	5858	10459	5681	10506	6129	10833	6723	11538
8. Total Reserves (%) (7/2)x100	22.2	49.8	23.5	51.0	22.0	49.7	23.0	49.7	24.5	51.5
9. Scheduled Maintenance 1/	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	29527	29704	30820	30979	31495	31655	32793	32608	34184	33949
11. Reserves after Maintenance (10-2)	5355	9869	5858	10459	5681	10506	6129	10833	6723	11538
12. Reserves after Maintenance (%) (11/2)x100	22.2	49.8	23.5	51.0	22.0	49.7	23.0	49.7	24.5	51.5
13. Inoperable Capability	175	175	269	269	269	269	269	269	269	269
14. Available Capability (10-13)	29352	29529	30551	30710	31226	31386	32524	32339	33915	33680
15. Available Reserves (14-2)	5180	9694	5589	10190	5412	10237	5860	10564	6454	11269
16. Available Reserves (%) (15/2)x100	21.4	48.9	22.4	49.7	21.0	48.4	22.0	48.5	23.5	50.3
17. Forced Outages 1/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	29352	29529	30551	30710	31226	31386	32524	32339	33915	33680
19. Actual Reserves (18-2)	5180	9694	5589	10190	5412	10237	5860	10564	6454	11269
20. Actual Reserves (%) (19/2)x100	21.4	48.9	22.4	49.7	21.0	48.4	22.0	48.5	23.5	50.3

1/ Information not available.

Northern California-Nevada Power Area (Region 28)

Historical Perspective

The major service area within the Northern California-Nevada Power area (N.CA-NV) of the WSCC is the combined Pacific Gas and Electric Company (PG&E)/Sacramento Municipal Utility District (SMUD) area in northern California. The two utilities operate together (central dispatch) and serve approximately 90 percent of the total area electric load. In northern Nevada the major utility is the Sierra Pacific Power Company (SPP).

The N.CA-NV energy load growth averaged 6.6 percent annually from 1960 through 1973 and approximately 3 percent from 1973 through 1979. The area experiences a summer peak dominated by air conditioning and irrigation pumping loads. However, Sierra Pacific Power Company is a winter peaking utility.

During the winter of 1976-77 California experienced its worst drought record, consequently, hydroelectric powerplant output was dramatically reduced. The impact of the drought resulted in significant voluntary conservation and negative load growth from 1976 to 1977. The high peak demand growth figures for 1978 are artificially high because of this. 1979 showed a return to a more normal growth rate.

Table 9E.1
Historical Load Growth
Northern California-Nevada Power Area

	1977	1978	1979
Energy Load (GWh)	76044	79220	82690
Growth from previous year (%)	-1.3	4.2	4.4
Peak Demand (MW)	14461	15772	16016
Growth from previous year (%)	-1.1	9.1	1.5
Load Factor (%)	60.0	57.3	58.9

In 1978, an above average water year, hydro generation amounted to 28407 GWh or 41.2 percent of the area's total generation. At the end of 1979, the region's hydroelectric resources accounted for 36.8 percent of total area dependable capability. Other generating capability includes oil/gas-fired, geothermal, and nuclear, representing 53.1, 4.2, and 5.9 percent of the 1979 total capability, respectively.

Ninety-five percent of the area's oil and gas-fired generation is owned and operated by PG&E (SPP owns the remainder). The amount of natural gas burned in PG&E's steam units, which are capable of burning both oil and gas, varies depending on the fuel availability. Natural gas use has been averaging about 50 percent on a total Btu basis over the past several years. For 1978 the area's total oil burn for powerplant generating purposes was 31.2 million barrels and natural gas usage was 12.6 billion cubic feet, equivalent to 20.4 million barrels of oil. 1979 generation and fuel consumption data is not available for this area.

Geothermal development has continued at the Geysers location with 161 MW of capacity added in 1979 for a total of 663 MW of base load capability.

As of December 31, 1979, nuclear capacity in the area totalled 966 MW consisting of SMUD's Rancho Seco plant (875 MW summer and 903 MW winter capability) and PG&E's Humbolt Bay Unit #3 (63 MW) which has been out of service for the past 3 years. PG&E's Diablo Canyon Nuclear Units No. 1 and No. 2 (2190 MW) are essentially complete but remain off-line pending NRC licensing. To date, commercial operation of these units has been delayed nearly four years due to various licensing requirements. The licensing delay has been mainly the result of seismological safety design requirements as well as Three Mile Island related concerns. During the interim, additional oil consumption (the incremental fuel) is estimated at 20 million barrels per year.

Because of the delayed installation of the Diablo Canyon units coupled with the effect of higher than normal outages at thermal power plants, actual reserve margins for the PG&E/SMUD service area have been relatively low. N.CA-NV reserves have ranged from 10.3% to 12.9% for the past three summer and winter peak periods.

Table 9E.2
Reserve Margins (%)
Northern California-Nevada Power Area

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
Total	21.5	49.6	15.4	35.9	20.2	37.3
Reserves after Maintenance	18.9	29.6	14.6	20.9	20.2	37.3
Actual	10.5	11.4	10.3	11.7	10.7	12.9

PG&E estimates northern California reserve requirements based on a loss of load probability of one day in ten years. The resultant installed reserve margin requirement is approximately 15 percent above the annual peak. Sierra Pacific requires a 17 percent reserve margin.

PG&E/SMUD service area available reserves have been down to 7 percent on several occasions over the past 3 years and PG&E officials have indicated concern over the high probability of load loss.

The bulk transmission network within N.CA-NV consists of 6668 miles of 115 kV lines, 6978 miles of 230 kV lines, and 1419 miles of 500 kV lines. The 500 kV system is part of the Pacific Intertie and is capable of inter-area transfers of approximately 2500 MW with the West Group of the Northwest Power Pool and 2000 MW with the N.CA-NV. The transfer capabilities are based on stability studies and are a function of load period and specific system conditions. In addition to contractual exchange, intertie capacity is used to transmit Northwest secondary hydro energy to California, to purchase economy energy, to exchange power and reserve support, and to accommodate major loop circulating flow.

The only existing interconnection between northern California and northern Nevada consists of two 115 kV lines which are limited to 160 MW west to east and 35 MW east to west. As such, SPP operates separately from nothern California with the exception of a 108 MW firm contract with PG&E. The only other existing major line into the SPP service area is a 230 kV interconnection with the East Group of the Northwest Power Pool in Utah.

Another interconnection with the East Group which was originally scheduled for operation in 1977 was delayed to mid-1980 completion. This 400 MW 345 kV line presently under construction will link northern Nevada and southern Idaho. The major effects of the line delay reportedly have been increased oil consumption by SPP and reduced system reliability.

Table 9E.3

HISTORICAL CAPABILITY (MW) AND RESERVES (MW and Percent)
Northern California - Nevada Power Area

	1977		1978		1979	
	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	15539	16086	16278	16432	16926	16517
2. Peak Demand	14461	11974	15772	12591	16016	12566
3. Planned Reserves (1-2)	1078	4112	506	3841	910	3951
4. Planned Reserves (%) (3/2)x100	7.5	34.3	3.2	30.5	5.7	31.4
5. Net Transactions (Imports-Exports)	2036	1822	1925	681	2327	730
6. Total Capability (1+5)	17575	17908	18203	17113	19253	17247
7. Total Reserves (6-2)	3114	5934	2431	4522	3237	4681
8. Total Reserves (%) (7/2)x100	21.5	49.6	15.4	35.9	20.2	37.3
9. Scheduled Maintenance	375	2394	132	1892	0	0
10. Capability after Maintenance (6-9)	17200	15514	18071	15221	19253	17247
11. Reserves after Maintenance (10-2)	2739	3540	2299	2630	3237	4681
12. Reserves after Maintenance (%) (11/2)x100	18.9	29.6	14.6	20.9	20.2	37.3
13. Inoperable Capability	1215	2177	671	1151	1523 2/	3062 2/
14. Available Capability (10-13)	15985	13337	17400	14070	17730	14185
15. Available Reserves (14-2)	1524	1363	1628	1479	1714	1619
16. Available Reserves (%) (15/2)x100	10.5	11.4	10.3	11.7	10.7	12.9
17. Forced Outages 1/	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	15985	13337	17400	14070	17730	14185
19. Actual Reserves (18-2)	1524	1363	1628	1479	1714	1619
20. Actual Reserves (%) (19/2)x100	10.5	11.4	10.3	11.7	10.7	12.9

1/ Information not reported separately.

2/ Includes scheduled outages.

Table 9E.4
1979 Capability by Type of Plant
Northern California-Nevada Power Area

Plant Type	Fuel Type	MW	% of Total
Hydro		5553	34.9
Hydro Pumped Storage		295	1.9
Steam	Oil/Gas	7775	48.9
Steam	Nuclear	938	5.9
Combustion Turbine	Oil/Gas	440	2.8
Geothermal		663	4.2
Internal Combustion	Oil	50	0.3
Cogeneration	Oil/Gas	179	1.1
Total		15893	100.0

Current Perspective

Northern California utilities continue to operate under a high risk situation mainly because of the delay of bringing the Diablo Canyon nuclear units into service. Available reserve margins for N.CA-NV are expected to be only 9.14 percent this summer. This does not include the effects of forced outage. The 1980 margins reflect the expected above average hydro conditions and include more than 800 MW of short-term capacity for which PG&E has made arrangements.

Summer and winter peaks are forecast to grow 5.5 and 8.6 percent respectively over the same period of the preceding year. The only significant resource additions scheduled for 1980 consist of 245 MW of geothermal capability at the Geysers.

The estimated summer peak reserve margins for the area are higher than indicated in earlier studies because of late seasonal precipitation. Summer margins for the combined PG&E/SMUD service area were revised by the utilities based upon February 29, 1980, hydrological data as well as updated information on system thermal capacity and available purchases. Revised load forecasts were prepared based on the assumption that utility customers will observe approximately the same level of conservation as in 1979 (which presumes active utility appeals). These data indicate that northern California reserve margins will approximate 10 percent this summer, which is estimated to be the minimum acceptable margin necessary to cover expected forced outages.

The utilities' calculated reserve margins include the assumption that SMUD's Rancho Seco nuclear unit will be back on-line in early April following refueling and NRC required modification. Latest information indicates that Rancho Seco is presently on line.

Because of delays in bringing new resources on line and recent adverse hydrological conditions, California thermal-electric plants have operated at relatively high capacity factors leading to unusually high forced outage rates. After consideration of the historic five year-average forced outage, the northern California utilities' projected 1980 reserve margins are reduced to as little as 1.8 percent with Rancho Seco in service. Should PG&E experience higher than average forced outage rates, as was the case last year, utility officials state that either additional unidentified short-term capacity purchases will be required or rotating service outages will become necessary.

While some additional purchases from the Pacific Northwest have been included in the utilities' resource calculations, unused firm intertie capability remains available. However, the Northwest has experienced below normal precipitation this year and further purchases if available would probably be limited to capability with energy payback required within 24 hours of receipt.

The statewide critical period reserve sharing and load reduction plan remains in effect this year. Under this plan the State's five major electric utilities will share reserves if the operating reserve margin of any utility drops below 7 percent. Peak demand diversity between northern and southern California averages approximately 1000 MW. Load reduction measures will be implemented in three stages beginning when statewide reserves drop to 5 percent and calling for rotating circuit interruptions when reserves drop to 1.5 percent.

Transmission systems within the Northern California-Nevada Power Area are expected to be adequate to accommodate planned peak and energy transfers with one possible exception. Completion of the Mid-point-Valmy-Tracy 345 kV line between the Idaho and northern Nevada areas may result in relatively large magnitudes of circulating loop flow on the northern Nevada northern California interconnection. Under certain conditions the northern Nevada-northern California interconnection may have to be opened to prevent overloading of the 115 kV system in the northern California area.

Table 9E.5

CURRENT CAPABILITY (MW) AND RESERVES (MW and Percent)
Northern California - Nevada Power Area

	1980 Summer	1980/81 Winter
1. Planned Capability 1/	17782	16709
2. Peak Demand	16896	13647
3. Planned Reserves (1-2)	886	3062
4. Planned Reserves (%) (3/2)x100	5.2	22.4
5. Net Transactions (Imports-Exports)	1265	395
6. Total Capability (1+5)	19047	17104
7. Total Reserves (6-2)	2151	3457
8. Total Reserves (%) (7/2)x100	12.7	25.3
9. Scheduled Maintenance	12	705
10. Capability after Maintenance (6-9)	19035	16399
11. Reserves after Maintenance (10-2)	2139	2752
12. Reserves after Maintenance (%) (11/2)x100	12.7	20.2
13. Inoperable Capability	550	368
14. Available Capability (10-13)	18485	16031
15. Available Reserves (14-2)	1589	2384
16. Available Reserves (%) (15/2)x100	9.4	17.5
17. Forced Outages 2/	1206	1160
18. Actual Capability after Forced Outages (14-17)	17279	14871
19. Actual Reserves (18-2)	383	1224
20. Actual Reserves (%) (19/2)x100	2.3	9.0

1/ No delays anticipated innew generating units since submission of 1980 ERA-411.

2/ 3-Year historical average forced outage (1976-78).

Table 9E.6
1980 Installed Capability by Type of Plant
Northern California-Nevada Power Area

Plant Type	Fuel Type	Capacity	
		MW	Percent
Hydro	Water	5560	34.5
Pumped Storage	Water	295	1.8
Steam	Oil/Gas	7775	48.2
Steam	Nuclear	938	5.8
Combustion Turbine	Oil/Gas	440	2.7
Geothermal	GST	908	5.6
Internal Combustion	Oil	50	0.3
Cogeneration		179	1.1
Total		16145	100.0

Future Perspective

Electric loads in northern California and northern Nevada have been projected by the area's utilities to increase at the rates of 3.3 percent per peak demand and 3.8 percent for energy for load over the five-year period from 1980 through 1985. For the following fouryear period through 1989, the forecasted increase is 4.2 percent peak growth and 4.6 percent energy growth.

The recently adopted California Energy Commission (CEC) forecast for the northern California region is lower than that projected by the Region's utilities. The CEC forecast will be used by the Commission to determine the need for new generating facilities during the State's certification process. This forecast indicates a growth rate for the PG&E/SMUD service area of 2 percent in peak demand and energy through the decade of the 1980's.

PG&E has very recently (April 1980) announced the results of a new load forecast which has not yet been incorporated into the resource plan. The revised forecast is much closer to that projected by the Energy Commission, averaging 2.7 percent growth per year between 1980 and 2000.

The addition of the Diablo Canyon nuclear units is now scheduled for 1981. Any further delay could seriously jeopardize system reliability and cause additional fuel oil burn of nearly two million barrels per month. Other near-term scheduled capability additions through 1985 include 959 MW of geothermal, 552 MW of conventional hydro, 1120 MW of pumped storage hydro, 313 MW of coal-fired (including joint ownership in facilities outside of the Region), 378 MW of gas-fired combined cycle, and 691 MW of

cogeneration. If the Diablo Canyon nuclear units were delayed an additional year, and all coal and geothermal additions were delayed six months, the effect on fuel oil consumption would total about 25 million barrels over the five-year period through 1985, and coal and geothermal delays would account for approximately one million additional barrels of oil consumption annually.

Beyond 1985 the area's predominant scheduled additions include the continued development of geothermal potential and significant amounts of coal-fired capability. Major capacity additions (over 100 MW) are listed in Table 9E.10. In addition, PG&E's coal-fired plants planned for northern California in the late 1980's have tentatively been slipped one to two years due to reduced load growth. This slippage will result in a total of about 30 million barrels of additional fuel oil consumption per year of delay.

Table 9E.7 shows the major planned additions during the next five years which have been delayed from the schedule of one year ago.

Table 9E.7
Unit Delays from 3/79 - 3/80
Northern California-Nevada Power Area

Under Construction Unit & No.	Type	Capability (MW)	Scheduled In-Service Date: Present	Scheduled In-Service Date: Previous	Delay (months)
Geysers 13	Geothermal	135	4/80	10/79	6
Geysers 14	Geothermal	110	8/80	4/80	4
Diablo Canyon 1	Nuclear	1084	2/81	7/79	19
Diablo Canyon 2	Nuclear	1106	8/81	3/80	17
Helms P.S. 1	Hydro	374	12/81	6/81	6
Helms P.S. 2	Hydro	373	4/82	6/81	10
Helms P.S. 3	Hydro	373	5/82	6/81	11
Geysers 17	Geothermal	110	7/82	6/82	13
Under Licensing Unit & No.					
Potrero 7	Combined Cycle	378	6/83	6/81	24
Kerckhoff 2	Hydro	151	10/83	12/82	10
Geysers 16	Geothermal	110	11/83	9/82	10

The PG&E/SMUD service area reserve margins are short of meeting even the minimum Reliability Council criterion for 1980 and 1981. Following the full commercial operation of Diablo Canyon, present schedules indicate adequate reserve margins for the Region.

Table 9E.8
Projected Reserve Margins (%)
Northern California-Nevada Power Area

	1981	1982	1983	1984	1985
Total	10.1	22.1	20.4	18.1	17.1
Reserves after Maintenance	10.1	21.7	20.4	18.1	17.1
Actual	10.1	21.7	20.4	18.1	17.1

Further delays in bringing new generating units on-line could worsen the reserve shortage as indicated below. The delayed schedule is based on the aforementioned one year nuclear and six months coal and geothermal slippage.

Table 9E.9
Actual Reserve Margin (%)
Northern California-Nevada Power Area

	1981	1982	1983	1984	1985
Delayed Schedule	(2.6)	21.1	20.4	18.1	17.1

Scheduled transmission additions from 1980 through 1985 include 531 miles of 230 kV, 564 miles of 345 kV, 52 miles of 500 kV line. Additionally PG&E plans 357 miles of 500 kV line in the second half of the decade to deliver proposed northern California coal-fired generator output and to increase Pacific intertie capability.

The 52 mile Gates to Gregg 500 kV line has been rescheduled to May 1983, a 3 year delay resulting from State regulatory denial of certification. This delay will limit pump-back operation at the Helms pumped storage project and also restrict interconnection capability with the Southern California-Nevada Region.

Table 9E.10

Significant Planned Additions to Generating Capacity Northern California-Nevada Power Area

Unit Name & Number	Type	Capability (MW)	Scheduled In-service Date
Geysers 13	Geothermal	135	4/80
Geysers 14	Geothermal	110	7/80
Diablo Canyon 1	Nuclear	1084	2/81
New Melones	Hydro	300	2/81
Diablo Canyon 2	Nuclear	1106	8/81
Valmy 1	Coal	125 1/	10/81
Helms	Pumped Storage	374	12/81
Helms	Pumped Storage	373	4/82
Helms	Pumped Storage	373	5/82
Potrero 7	Combined Cycle	273*	6/82
Geysers 17	Geothermal	110	7/82
Geysers 18	Geothermal	110	10/82
Kerckhoff 2	Hydro	113	10/83
Geysers 16	Geothermal	110	11/83
Valmy	Coal	125 1/	10/84
Industrial Cogen.	Cogeneration	140	6/85
Oil Field Cogen.	Cogeneration	280	7/85
Geysers 20	Geothermal	110	9/85
Harry Allen	Coal	230 2/	6/86
Geysers 21	Geothermal	110	7/86 3/
Montezuma 1	Coal	800	7/86
Harry Allen 2	Coal	230 2/	6/87
Montezuma 2	Coal	800	7/87
Harry Allen 3	Coal	230 2/	6/88
Fossil 3	Coal	800	6/88 3/
Geothermal	Geothermal	110	6/88
Geothermal	Geothermal	110	6/88
Harry Allen 4	Coal	230 3/	6/89
Fossil 4	Coal	800	6/89 3/

1/ 50% of 250 MW unit.
2/ 46% of 500 MW unit.
3/ These units have recently been delayed one to two years
* To be converted to combined cycle operation at 378 MW as of 6/83.

Table 9E.11.1

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1981-84
Northern California - Nevada Power Area

	1981		1982		1983		1984	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability 1/	17875	19281	21023	20547	21230	21531	21760	21626
2. Peak Demand	17407	14206	17844	14610	18264	15138	19026	15876
3. Planned Reserves (1-2)	468	5075	3179	5937	2966	6393	2734	5750
4. Planned Reserves (%) (3/2)x100	2.7	35.7	17.8	40.6	16.2	42.2	14.4	36.2
5. Net Transactions (Imports-Exports)	1291	295	762	-148	762	-189	711	-321
6. Total Capability (1+5)	19166	19576	21785	20399	21992	21342	22471	21305
7. Total Reserves (6-2)	1759	5370	3941	5789	3728	6204	3445	5429
8. Total Reserves (%) (7/2)x100	10.1	37.8	22.1	39.6	20.4	41.0	18.1	34.2
9. Scheduled Maintenance	0	1413	64	1631	0	1812	0	1227
10. Capability after Maintenance (6-9)	19166	18163	21721	18768	21992	19530	22471	20078
11. Reserves after Maintenance (10-2)	1759	3957	3877	4158	3728	4392	3445	4202
12. Reserves after Maintenance (%) (11/2)x100	10.1	27.9	21.7	28.5	20.4	29.0	18.1	26.5
13. Inoperable Capability	5	7	5	7	5	8	5	8
14. Available Capability (10-13)	19161	18156	21716	18761	21987	19522	22466	20070
15. Available Reserves (14-2)	1754	3950	3872	4151	3723	4384	3440	4194
16. Available Reserves (%) (15/2)x100	10.1	27.8	21.7	28.4	20.4	29.0	18.1	26.4
17. Forced Outages 2/	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	19161	18156	21716	18761	21987	19522	22466	20070
19. Actual Reserves (18-2)	1754	3950	3872	4151	3723	4384	3440	4194
20. Actual Reserves (%) (19/2)x100	10.1	27.8	21.7	28.4	20.4	29.0	18.1	26.4

1/ No delays anticipated in new generating units since submission of 1980 ERA-411.
2/ Information on forced outages not available.

Table 9E.11.2

FUTURE CAPABILITY (MW) AND RESERVES (MW and Percent) - 1985-89
Northern California - Nevada Power Area

	1985		1986		1987		1988		1989	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1. Planned Capability	22616	22773	23852	23889	25531	24795	26493	25785	27351	26374
2. Peak Demand	19902	16644	20720	17455	21611	18250	22505	19139	23442	19794
3. Planned Reserves (1-2)	2714	6129	3132	6434	3920	6545	3988	6646	3909	6580
4. Planned Reserves (%) (3/2)x100	13.6	36.8	15.1	36.9	18.1	35.9	17.7	34.7	16.7	33.2
5. Net Transactions (Imports-Exports)	698	-246	943	3	540	238	777	475	1007	655
6. Total Capability (1+5)	23314	22527	24795	23892	26071	25033	27270	26260	28358	27029
7. Total Reserves (6-2)	3412	5883	4075	6437	4460	6783	4765	7121	4916	7235
8. Total Reserves (%) (7/2)x100	17.1	35.3	19.7	36.9	20.6	37.2	21.2	37.2	21.0	36.6
9. Scheduled Maintenance 1/	0	0	0	0	0	0	0	0	0	0
10. Capability after Maintenance (6-9)	23314	22527	24795	23892	26071	25033	27270	26260	28358	27029
11. Reserves after Maintenance (10-2)	3412	5883	4075	6437	4460	6783	4765	7121	4916	7235
12. Reserves after Maintenance (%) (11/2)x100	17.1	35.3	19.7	36.9	20.6	37.2	21.2	37.2	21.0	36.6
13. Inoperable Capability	5	8	5	8	5	8	5	8	5	7
14. Available Capability (10-13)	23309	22519	24790	23884	26066	25025	27265	26252	28353	27022
15. Available Reserves (14-2)	3407	5875	4070	6429	4455	6775	4760	7113	4911	7228
16. Available Reserves (%) (15/2)x100	17.1	35.3	19.6	36.8	20.6	37.1	21.2	37.2	20.9	36.5
17. Forced Outages 1/	0	0	0	0	0	0	0	0	0	0
18. Actual Capability after Forced Outages (14-17)	23309	22519	24790	23884	26066	25025	27265	26252	28353	27022
19. Actual Reserves (18-2)	3407	5875	4070	6429	4455	6775	4760	7113	4911	7228
20. Actual Reserves (%) (19/2)x100	17.1	35.3	19.6	36.8	20.6	37.1	21.2	37.2	20.9	36.5
Coal Unit Delays Assumed Possible by ERA										
21. Possible Coal Delays 2/	0	0	800	800	800	800	800	800	800	800
22. Actual Capability w/Nuclear & Coal Delays (18-21)	23309	22519	23990	23084	25266	24225	26465	25452	27553	26222
23. Actual Reserves w/Nuclear & Coal Delays (22-2)	3407	5875	3270	5629	3655	5975	3960	6313	4111	6428
24. Actual Reserves w/Nuclear & Coal Delays (%) (23/2)x100	17.1	35.3	15.8	32.2	16.9	32.7	17.6	33.0	17.5	32.5

1/ Information not available.
2/ These units have recently been delayed 1 to 2 years from the dates shown.

XI.9.81

Table 9E.12
1985 and 1989 Installed Capacity by Type of Plant
Northern California-Nevada Power Area

Plant Type	Fuel Type	1985 Capability MW	1985 Percent of Total	1989 Capability MW	1989 Percent of Total
Hydro	Water	5818	26.7	6023	23.8
Pumped Storage	Water	1430	6.6	1430	5.7
Steam	Coal	313	1.4	3145	12.4
Steam	Oil/Gas	7669	35.2	7319	28.9
Steam	Nuclear	3128	14.4	3128	12.4
Combustion Turbine	Oil/Gas	440	2.0	530	2.1
Combined Cycle	Oil/Gas	378	1.7	378	1.5
Internal Combustion	Oil	50	0.2	50	0.2
Geothermal	GST	1622	7.4	2112	8.3
Cogeneration		870	4.0	1120	4.4
Other		80	0.4	80	0.3
Total		21798	100.0	25315	100.0

APPENDIX D

Estimating Methods for Determining HVAC Requirements

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ESTIMATING METHODS FOR DETERMINING HVAC REQUIREMENTS

All the building types and sizes were taken from the TRW "Preliminary Estimated Resource Analysis for the SAC Operation Base (SAC-OB)," dated January 21 ,1980.

The concrete administrative and operational buildings were assumed by TRW to be 100 ft x 300 ft each with two or three stories for a total of 50 buildings as shown on pages 7 thru 15 of the TRW report.

The concrete administrative and operational buildings were assumed to be 80 ft x 100 ft each with one, two, or four stories for a total of 64 buildings as shown on pages 16 thru 22 of the TRW report.

The 16 ft-high metal airfield maintenance buildings were assumed to be 60 ft x 322 ft each (page 24-TRW) for a total of nine buildings.

The 20 ft-high metal airfield maintenance buildings were assumed to be 60 ft x 520 ft each (page 25-TRW) for a total of four buildings.

The aircraft hangar was assumed to be 150 ft wide x 200 ft long with 70 ft clear in center with semi-cylindrical roof (page 26-TRW).

Family housing assumed were two bedroom, one bath, 40 ft x 30 ft = 1,200 sq. ft. units. Total housing units on the operating base = 6,000 (pages 27 thru 29-TRW).

Heat loss calculations for the M-X system in Utah and Nevada are based on ASHRAE 90-75 with construction for the above building types, and degree day figures from State codes or ASHRAE.

Heat loss calculations for the M-X system in Texas and New Mexico were also based on ASHRAE 90-75 with construction for the above building types and degree day data from 1973 ASHRAE Handbook, Chapter 43. The yearly heat losses were figured using the following formula with Ely, Nevada as an example.

Equation #1

$$H = \frac{(h \times 24 \times D)}{\Delta t} = \frac{h \times 24 \times 7,814}{74^\circ} = 2,534 \text{ h (for Ely only)}$$

where:
- H = Btu annual heat loss
- h = design heat loss in Btu's per hour (calculated)
- 24 = 24 hours per day
- D = number of degree days per year
- t = temperature difference in degrees F, assuming 72° F design temperature

This is a simplified version of the formula on Page 8, Chapter 43 of the 1965 Systems Handbook (ASHRAE) from which was deleted the efficiency, heating

value of fuel, and correction factors. It must be remembered that all answers are in Btu (or 10^6 Btu) and are heating loads for the respective buildings and not fuel units used. For fuel units use 70 percent efficiency and electricity 100 percent efficiency.

Cooling loads were based on the above building types, weather data in ASHRAE 1977 fundamentals handbook, Utah Energy Code, and Page 1-54, Handbook of Air Conditioning and Heating. Delta, Utah is used here as an example.

The following formula was used:

Equation #2

$$T = \frac{t \times D \times 24}{\Delta t} = \frac{t \times 764 \times 24}{18^\circ} \approx 1{,}000\ t \text{ (for Delta only)}$$

(60° Base)

and

$$T = \frac{t \times D \times 24}{\Delta t} = \frac{t \times 764 \times 24}{12^\circ} \approx 1{,}400\ t \text{ (for Delta only)}$$

(66° Base)

where:
- T = total yearly ton-hours
- t = tons at design conditions (calculated0
- D = cooling degree days
- 24 = 24 hours per day
- t = temperature difference in degrees F, assuming 78° F design temperature

APPENDIX E

Alternative Energy Systems for M-X

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1.0 ALTERNATIVE ENERGY SYSTEMS

1.1 CONTEXT

This section briefly describes alternative energy resources and their potential to augment conventional energy resources. It sumarizes ETR-265. "M-X Systems Environmental Program, Analysis of Alternative Energy Systems" (HDR Sciences, March 1980). It is intended as a technical report to support revisions to the "Deployment Area Selection and Land Withdrawal/Acquisition DEIS", (HDR Sciences, 15 October 1980).

Related documents and sources of information include the following:

1. U.S. Department of Energy, Office of Procurement Operations. "M-X Renewable Energy Systems (M-X/RES) Information Package," September 1980.

2. Fugro National, Inc., "Alternative Energy Sources for the M-X System Nevada/Utah," 25 February 1980.

1.2 TECHNOLOGIES CONSIDERED

This report considers altrnative energy systems which could be technically feasible for utilization in the M-X program. These include: solar thermal, solar electric, wind, energy storage, geothermal, wood, alcohol fuels, and solid waste.

These technologies are alternatives to conventional systems, such as fossil fuel, nuclear, and hydroelectric; and they have a near-term potential for commercialization, as distinct from magnetohydrodynamics and nuclear fusion. In addition, they do not include synthetic fuel development for oil shale which is fossil-based and non-renewable.

1.3 ANTICIPATED ENERGY REQUIREMENTS

Energy requirements include electrical power, thermal energy, and mobile fuels during both construction and operation of the M-X System and are presented in the body of this report.

Since alternative energy systems will be developed, tested, and built to support long-term operations of the system, they may be available only during the latter stages of construction. Construction power will be provided primarily from commercial utilities and temporary generators. If gasohol or dieselhol were available at competitive costs, up to 10 percent of the gasoline and diesel fuel requirements could be supplied by ethanol, an alternative energy source.

During operation, baseline electical power loads are estimated to be as follows (M-X/RES Information Package):

FACILITY	NUMBER	DEMAND POWER LOAD	
		EACH	TOTAL
Shelter	4,600	14.5 KW	66.7 MW
Remote Surveillance Site (RSS)	183	9.3 KW	1.7 MW
Area Support Center (ASC)	2	400 KW	0.8 MW
Cluster Maintenance Facility (CMF)	200	11.5 KW	2.3 MW
Operating Base (OB) with Designated Assembly Area (DAA)	2	18.55 MW	37.1 MW
Total			108.6 MW

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The anticipated connected electrical load for M-X technical facilities will be approximately 180 megawatts-electrical (MWe). The maximum direct and induced load for the system will be approximately 300 MWe.

The M-X/RES Program proposes that alternative energy systems be developed at three levels of demand, depending on application as follows:

APPLICATION	AVERAGE	PEAK
Single Shelter	14.5 kWe	21.06 kWe
10 Clusters: 230 shelters 10 CHF's, 10 RSS's	3,536 kWe	3,970 kWE
Operating Base #1: DAA, OBTS, ASC	26.3 MWe 645.5×10^9 Btu/yr	35.78 MWe 401.4 Btu/hr

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These quantities may vary among alternatives and as preliminary designs are developed; however, they provide order-of-magnitude information for purposes of this report.

1.4 REDUNDANCY AND REPLACEMENT

Alternative energy systems would mitigate M-X energy impacts by replacing conventional generating capacity and fossil fuels which would otherwise be needed. They could also be used to improve reliability by providing one more degree of redundancy to the system as shown below:

<u>Sources of M-X Electrical Energy</u>

Base and Intermediate Loads

1. Multiple connections to the commercial utility grid.
2. Alternative energy systems.

Peaking and Emergency Loads

1. Standby generators in the power distribution centers.
2. Survival batteries in the M-X launcher MOSE equipment compartment.
3. Alternative energy storage systems.

1.5 AVAILABILITY vs. CAPACITY FACTORS

Availability is defined as the ratio of the time power of acceptable quality is available to the time it is required, which in the case of M-X, is continuous. According to the M-X/RES Information Package ~~(Attachment 11, 4.3)~~, the power availability requirement at the interface of each technical facility, i.e., each shelter and each RSS, is 0.9999. The requirement at the interface of each nontechnical facility, i.e., OBs, DAAs, ASCs, OBTSs, and CMFs, is 0.999. Thus, unavailable time is limited to no more than ~~0.876~~ 8.76 hours per year for shelters and remote surveillance sites, and ~~8.76~~ 87.6 hours per year for the nontechnical facilities.

Each energy technology can be categorized by means of its capacity factor (ratio of its annual energy actually produced compared to its nameplate capacity if operated for 8,760 hours - number of hours in a year). Technologies are described as:

	HOURS PER YEAR	CAPACITY FACTOR
Base	More than 5,000	More than 0.60
Intermediate	3,500 to 5,000	0.40 to 0.60
Peaking	Less than 1,500	Less than 0.20

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This categorization is a good indication of the applicability of each technology, as summarized in Table 1.5-1.

None of the alternative energy systems have a capacity factor which would permit 0.999 or 0.9999 availability without multiple units and considerable storage or backup conventional systems.

1.6 DISCUSSION CRITERIA

In the remaining sections of this appendix the following aspects of each alternative energy technology are briefly discussed:

1. Technical overview
2. Demonstration and commercialization status
3. Siting considerations
4. System description
5. Environmental concerns

The final section discusses which technologies would be applicable to which electric load centers in the M-X system.

Additional discussion and sketches of the alternative energy concepts may be found in ETR-265, "Analysis of Alternative Energy Systems," (HDR Sciences, March 1980).

Table 1.5-1. Applicable technologies.

TECHNOLOGY AND CAPACITY FACTOR	PROBABLE SUPPLY FUNCTION
Solar	
Central Collector (0.35 to 0.50[1])	Intermediate
Parabolic Dish and Trough (0.35 to 0.50[1])	Intermediate
Photovoltaic (0.35 to 0.50[1])	Intermediate
Wind	
Horizontal Axis Turbine (0.35 to 0.60[1])	Intermediate
Vertical Axis Turbine (0.35 to 0.60[1])	Intermediate
Geothermal (0.75)	Base
Biomass	
Wood Pelletization (0.75)	Base
Methanol from Wood (0.20)	Peaking
Ethanol from Agricultural Crops (0.20)	Peaking
Ethanol for Mobile Fuels	Mobile
Solid Waste	Base
Energy Storage	
Underground Pumped Storage	Peaking
Compressed Air in Caverns	Peaking
Batteries	Intermediate-Peaking
Thermal Storage	Intermediate
Fuel Cell	Intermediate-Peaking

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[1]Indicates: with storage

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2.0 SOLAR ENERGY SYSTEMS

The sun is the source of many forms of energy, including hydroelectic power, biomass, wind energy, waves, thermal currents, and thermal density gradients. Fossil fuels contain stored solar energy. In the context of this report, however, there are two basic concepts for solar energy systems: thermal and photovoltaic.

2.1 TECHNICAL OVERVIEW

Solar thermal systems include: flat plate collectors, parabolic trough and dish, and heliostats for the central power tower concept. Their collection capabilities and primary applications are as follows:

Table

COLLECTOR	TEMPERATURE RANGE	PRIMARY APPLICATION
Flat Plate	Low to Medium 50° C to 150° C	Heating and air conditioning
Parabolic Trough or Dish	Medium to High 200° C to 800° C	Process heat and electricity
Heliostats and Central Receiver	High 200° C to 1,100° C	Process heat and electricity

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Photovoltaic cells convert sunlight directly into electricity through the use of semiconductor materials.

2.2 DEMONSTRATION FACILITIES

The following are amoung numerous solar demonstration facilities being planned, constructed, or operating throughout the United States:

LOCATION	TYPE	RATING	STATUS
Sandia Laboratories Albuquerque, NM	Central Receiver	5 MWt	Completed in 1978; undergoing testing and evaluation.
Barstow, CA	Central Receiver	10 MWe	To be completed by late 1981; experimental
DOE Studies	Central Receiver	50-100 MWe	Mid-1980s; hybrid concepts.
Sandia Laboratories Albuquerque, NM	Parabolic Trough and Dish	32 kWe 200 kWt	Testing and in-house use.
1,500-man Barracks Ft. Hood, TX	Parabolic Trough	200 kWe	1981 startup
Knitwear Factory Shenandoah, GA	Parabolic Dish	400 kWe	1981 startup
Mississippi County Community College, Blythesville, AK	Photo-voltaic	250 kWe peak	1980 startup

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2.3 SITING CONSIDERATIONS

The southwestern United States, in which the alternative M-X deployment regions are located, is one of the best geographic areas in the country for high incident solar radiation and annual coverage total hours of sunshine. In this region, solar radiation generally increases as follows:

1. From east to west due to prevailing winds and the influence of mountains on weather patterns and cloud cover.

2. From north to south due to decreasing latitude.

3. With increasing elevation because atmospheric losses are less at higher altitudes.

Possible sites for solar power plants should contain sufficient level land with no shadowing from surrounding topographical features. Generally, shadows should not be present when the sun is 10° or higher above the horizon at any time of the year. Baseline monitoring of sky cover and solar radiation would be required prior to final site selection and design of solar power systems.

2.4 SYSTEM DESCRIPTION

Flat Plate Collectors (2.4.1)

The flat plate collector is the most common type of solar energy collector, and it is commercially available in various configurations from many manufacturers. The classic flat plate collector consists of a black metal absorber enclosed in an

insulated box with a glass or plastic cover. Various materials and coatings, piping configurations,etc., enchance the collector's efficiency. Collected heat is transferred to a "working" fluid, such as air or water, and piped to its end-use, or to storage to await its end-use.

Flat plate collectors are generally fixed into position and are very sensitive to climate. They are used primarily for low temperature applications, and it is envisioned that they could be utilized for heating and cooling of M-X buildings and factory areas.

Parabolic Trough and Dish (2.4.2)

A dispersed collector system uses individual parabolic trough or parabolic dish collectors. The parabolic trough or line concentrator, resembles a long half-of-a-cylinder shape (or trough) which pivots on a single horizontal axis to track the sun from east to west. An absorber pipe runs parallel to the collector's horizontal axis and coincident with the parabolic focal point. A working fluid is circulated to collect and transport the solar heat away from the collectors.

A dish collector resembles a radar-tracking bowl in appearance. Its concave parabolic surface reflects and concentrates the solar insolation to a single focal point. At the focal point, a single receiver/absorber is mounted to convey the working fluid for heat transfer. Due to the single focusing point of the dish collector, it must always be oriented directly toward the sun. This requires a dual-axis tracking system. Since it is continually tracking the sun, its efficiency is approximately the same throughout the solar day.

A distancy advantage of a dispersed solar collector system (dish or trough) is that their modularity could be very conducive for supplying electricity or process heat to individual shelters, clusters, or other facilities scattered throughout the M-X region. These smaller units could provide better adaptability to available land sites, shorter transmission lines, and probably shorter construction periods.

Central Receiver Solar Plant (2.4.3)

Heliostats are dual-axis mirrors which "track" the sun; reflect, concentrate, and focus solar radiation toward a receiver/absorber "point" on a large tower-mounted receiver ("power tower"). A circulating working fluid can be piped through the receiver/absorber to absorb the concentrated solar energy and transfer it away as thermal energy for process heat or electric generation. A heliostat array for the M-X program would probably be used primarily as a central receiver electric power plant. The optimal capacity size based on technical and economic considerations would probably be on the order of 50 to 300 MWe.

Photovoltaic Solar Cell (2.4.4)

The basic components of a photovoltaic solar plant are: the cell array, electrical interconnect, power conditioner, and energy storage.

The manufacure of a photovoltaic cell involves the diffusion of controlled amounts of impurities, such as boron on silicon, within crystals of silicon to create an electrical semiconductor junction. This junction generates an electric field

within the cell. When solar light energy, or photons, are absorbed by the cell, free electrons migrate to the top of the cell, while positive charges migrate to the bottom. This migration creates an electrical current which is collected by a grid of contacts on the top and bottom of the cell. Interconnecting an array of cells could create large electrical outputs suitable for a power plant. Photovoltaic cell arrays can be either of a flat plate of concentrator configuration.

2.5 ENVIRONMENTAL CONCERNS

The most important concern is siting where solar insolation is optimal and where transmission losses can be minimized. The M-X region represents on the best overall situations for solar power in the United States.

Water requirements for cooling would be minimal if dry-air cooled systems are used. It is expected that some water would be used to clean the reflectors, collectors, and photovoltaic arrays to maintain their efficiencies. Evaporating solvents and wind-blown cleaning agents are expected to be of little concern.

Land area requirements are approximately linear at the ratio of approximately 10 acres per MWe. Land should be level with no adjacent structures or natural features to cause shading.

Solar systems should avoid nearby mining or industrial activities whose airbourne emissions may cover or corrode collector surfaces.

Solar systems should be designed to withstand the following environmental phenomena:

1. Low levels of earthquake activity in the deployment region.
2. Damage from wind loads and from debris carried by wind. Heliostats can be turned face down when wind speeds exceed certain limits.
3. Flooding, hail, and excessive snow loads.

A unique environmental concern of solar collectors, espcially heliostats, is "stray" solar reflections. These high energy reflections could be injurious to humans, animals, vegetation, and materials. Proper security measures and adequate control devices should safeguard against this concern. Most maintenance on heliostats and collectors must be done at night to avoid human exposure to the intense solar reflections. Flat plate photovoltaic systems would not have this problem.

The largest cost components of solar power plants are associated with the heliostats, collectors, and photovoltaic cell arrays. Since the manufacturing steps for heliostats and parabolic reflectors are relatively easy and conducive to mass production techniques, increased demand could dramatically reduce their cost. Increased research and development in the photovoltaic and allied semiconductor industries could greatly reduce the cost of photovoltaic cells as well.

3.0 WIND ENERGY SYSTEMS

3.1 TECHNICAL OVERVIEW

Wind energy has been used for centuries for pumping water, grinding grain, propelling ships, etc. In recent years, however, technology has been applied to develop large wind turbines capable of generating electricity in the megawatt ranges. Wind energy could supply several percent of the total U. S. supply by the turn of the century.

There are basically two configurations of wind turbines: horizontal axis and vertical axis. Horizontal axis turbines are reminiscent in appearance to windmills, while vertical axis turbines have two or three fixed-pitch curved blades which have both ends attached to a rotating vertical shaft.

The most important point in wind power is adequate and sustained wind velocity. Power input is a function of wind velocity cubed. To increase the average wind speed blowing past a turbine from 10 mph to 15 mph results in a power output increase of 238 percent.

Average wind speeds of 15 to 18 mph and greater, which are desirable for turbines, are more likely to be found in the mountains, ridges, and passes of the Basin and Range Province in the M-X region. Wind speeds on the valley floors usually average less than 10 mph.

3.2 DEMONSTRATION FACILITIES

The following horizontal axis turbines are part of a wind energy demonstration program by the U.S. Department of Energy and NASA:

TYPE	ROTOR DIAMETER (ft)	CAPACITY (KWe)	WIND STRENGH (mph)	LOCATION	YEAR OF STARTUP
MOD-O	125	100	18	Plum Brook, OH	1976
MOD-OA	125	200	18	Clayton, NM	1978
MOD-OA	125	200	18	Culebra, PR	1978
MOD-OA	125	200	18	Block Island, RI	1979
MOD-OA	125	200	18	Oahu, HA	1980
MOD-1	200	2,000	26	Boone, NC	1979
MOD-2	300	2,500	20	*	1980
Advanced	200	*	Low	*	1982
Advanced	125	*	Low	*	1983

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*To be determined.

The Schachle turbine has a three-blade rotor that turns at a variable speed depending on wind velocity rather than the two-blade constant speed of the DOE/NASA concept. By "riding-the-wind" the machine can maintain an optimum blade top speed to wind speed ratio and maximize its efficiency through a wide range of wind velocities. Demonstration facilities for the Schachle turbine include:

LOCATION	RATING	SIZE	STATUS
Moses Lake, WA	—	72' diameter	Operating since 1972
San Gorgonio Pass, CA So. California Edison	3 Mwe	165' diameter	Startup mid-1980 for testing in system
Vertical Axis Turbine Projects Include the Following:			
Magdalen Islands, Gulf of St. Lawrence	200 kWe		Operating since 1977
Sandia Laboratories Albuquerque, NM	50-60 kWe		Operating
Eugene, OR	500 kWe		Planned
San Gorgonio Pass, CA So. California Edison	500 kWe		Planned

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3.3 SITING CONSIDERATIONS

In the M-X study region nearLy all wind speed data is obtained at weather stations which are located at local airports in wide valleys where average wind speeds are not sufficient to justify wind energy systems. Yelland Field at Ely, Nevada, has one of the highest average wind speeds (10.5 mph) for airports in the region. Average wind speeds of 15 to 18 mph and greater, which are desirable for siting wind energy conversion systems, are more likely to be found in the mountains, ridges, and passes. At the Ely Tracking Site on Kimberley Mountain the average wind speed is reported to be 20 to 25 mph.

There are many mountains in the study region, however, other siting problems such as access, isolation, rime ice, excessive winds, etc., would militate against siting wind generators in such exposed locations. Preferable sites include mountain passes, ridges, and other changes of topography which cause increases in wind speed due to the Bernoulli effect (converginG of streamlines), especially those which are perpendicular to the direction of the prevailing wind. In the siting region, elevations below 7,000 to 8,000 feet may be required to avoid rime ice accumulations which could cuase structural damage to wind turbines blades and electrical transmission lines.

Preliminary siting of wind turbines can be achieved by surveying ecological indicators such as wind-induced deformities of trees or other foliage.

Other considerations requiring siting or design precautions include:

1. Wind turbulence due to weather or terrain.
2. Wind shear due to large changes in wind speed or direction over the diameter of the rotor.
3. Extreme winds.
4. Thunderstorms and lightning.
5. Icing.
6. Heavy snow loads.
7. Moisture infiltration
8. Freeze-thaw cycles.
9. Blowing dust.

3.4 SYSTEM DECRIPTION

Horizontal Axis Turbine (3.4.1)

The main components of a horizontal axis wind turbine include: rotors, transmission system, generator and electrical subsystem, controls, and tower. The rotor is the largest production cost element of a wind turbine and practically the only component not available "off-the-shelf".

Key design criteria requirements for a rotor are:

1. Maximum aerodynamic efficiency.

2. Structural integrity to withstand high winds, icing, bird strikes, temperature extremes, and lightning.

3. Long operating life.

4. Conducive to mass production technologies.

Technology associated with wind turbine rotors is somewhat similar to that already developed for propeller rotors and helicopter blades. Propeller-type rotors offer a stiffer structure in the flapwise and torsional direction. Smaller blade deflections reduce clearances required between the rotor and the tower support. For a maximum weight-strength combination, a probable blade assembly would be a fiberglass filament-wound exterior with an aluminum interior shell or honeycomb.

The transmission system must transfer the low-revolution, speed high torque of the rotor (typically 20 to 40 mph) to a high-speed, low-torque (about 1,800 rpm) generator shaft. A fixed-ratio gear system tied to a fixed 1,800 rpm generator (to synchronize with the utility grid) means that the rotors must be variable pitch to maintain constant rotor speed in a variable wind speed pattern. To mimimize transmission length and complexity, the generator is normally placed atop the tower at the hub of the rotor. The Schachle turbine's generator is placed on the ground, however, and a hydraulic transmission, rather than mechanical, links it with the rotor.

The control system helps to maximize power output from variable wind speed and direction.

Vertical Axis Turbine (3.4.2)

A vertical axis (Darrieus) turbine has the following advantages over a horizontal turbine:

1. Accepts wind from all directions requiring no direction control.

2. The self-regulating turbine requires no pitch control. Speed is compatible with utility grid at 60 H with no power conditioning required.

3. All working parts (generator, transmission, controls, etc.) are at ground level. No tower is required and there are no weight or bulk limitations.

The primary disadvantages of a vertical axis turbine are that it is not self-starting, even in high winds, and its theoretical upper power coefficient is only about 0.35 compared to about 0.47 for a horizontal turbine.

3.5 ENVIONMENTAL CONCERNS

Wind energy has few environmental concerns. The primary ones are:

1. Visual: The maximum tower plus rotor heights can be approximately 300 feet (90 meters). Since they will likely be placed on hilltops and ridges, they will be visible for long distances.

2. Ecological: Rotating blades could cause threats to birds, insects, etc. At 35 rpm, the tips of a 200-foot diameter rotor would be moving at 250 mph.

3. Electromagnetic waves: Wind turbines with metal rotors cuase interference with local radio, TV, and communications.

4. Noise and vibration: At Boone, North Carolina, the turbine rotor operates downwind of the tower. When the lower end of the blade swings through the slight turbulence in the lee of the tower, it causes low frequency noise and vibration.

4.0 ENERGY STORAGE

4.1 TECHNICAL OVERVIEW

When contemplating the use of solar and wind energy systems, the need for energy storage becomes more critical due to the diurnal and seasonal variations of solar insolation and the capricious nature of the wind. Several concepts for large scale energy storage are at various stages of availability. Concepts which seem to have potential for implementation in the M-X program include the following.

1. Pumped hydro
2. Compressed air storage
3. Batteries
4. Thermal storage
5. Fuel cells

4.2 PUMPED HYDRO

Pumped hydro is currently the only well established energy storage technology that is available on an electric utility grid scale. Currently in the United States there is approximately 10,000 MW of installed pumped storage capacity in addition to about 59,000 MW of hydroelectric capacity. Pumped storage facilities include those at Taum Sauk, Arkansas; Ludington, Michigan; and Niagra Falls, New York. Additional projects have been proposed for northern California.

The concept of pumped storage is simple. Inexpensive base-loaded power is used to store energy during off-peak hours by pumping water from a lower reservoir to an upper reservoir. During peak hours, the water flows from the upper reservoir through a hydroelectic turbine down to the lower reservoir.

The use of conventional pumped hydro in the M-X region does not seem likely due to the scarcity of water and large evaporative losses which would occur from surface reservoirs. However, underground pumped hydro storage is being investigated by several utilities. Underground excavations or natural caverns could be considerably smaller than surface reservoirs because the elevation difference could be several thousand feet compared to a typical surface pumped-storage system which is generally less than 1,000 feet. Energy-storage capacity is directly proportional to the elevation differential.

The primary environmental concerns of underground pumped storage would be the negative impacts of construction activity and disposal of excavated material. A minor problem may be the disruption of underground aquifers.

Although an underground pumped hydro system is technically possible for implementation in the M-X program, it is highly unlikely that one would ever be built due primarily to the minimum required capacity. It appears that economic viability would require a minimum generation capacity of 200 MW, which is larger than the 180 MW connected load for M-X technical facilities and considerably larger than any peak loads for which this tyupe of energy storage is intended.

4.3 COMPRESSED AIR STORAGE

Considering M-X needs and the geologic characteristics of the region, an underground compressed air storage system seems more appropriate than pumped hydro. In this type of system, air is compressed during off-peak hours and stored in large underground reservoirs which could be natural caverns, salt domes, abandoned mine shafts, depleted gas and oil fields, or other types of man-made caverns. During peak hours the air is released through a turbine-generator.

This method has several advantages over pumped hydro: a wider choice of geological formations, higher energy density for compressed air than stored water, and a smaller minimum size for economic attractiveness.

The world's only compressed air storage facility is located near Bremen, West Germany. During off-peak hours, air is compressed to 1,000 psi and stored in two caverns leached out of a salt dome. During peak demand, the air is released, heated by natural gas, and expanded through high and low pressure turbines which can generate 290 MW for about 2 hours. Companies investigating compressed air storage in the U.S. include the Potomac Electric Company in Maryland, the Electric Power Reserach Institute in Kansas, and Public Service of Indiana.

To supply a peaking capability for the M-X system of 20 to 40 MW for 6 hours would require a storage volume of 2 to 4 million cubic feet at 600 to 800 psi. Possible geotechnically suitable sites in the M-X region for underground storage of compressed air include the following:

1. Natural solution caves in carbonate rocks
2. Abondoned mine shafts and tunnels
3. Salt domes in the Las Vegas area
4. Natural gas and oil-bearing strata
5. Confined aquifers
6. Caverns created by underground nuclear explosions

Containment of high pressures may be difficult in certain formations because of fractures and interconnected solution cavities. Underground nuclear explosions, such as at the Nevada Test Site, do not produce large net volumes of open space, and extensive redioactive cleanup would be required.

4.4 BATTERIES

Batteries are advantageous for energy storage since their input and output is entirely electrical and their response to changes in electric load is quick and efficient. They are particularly attractive to wind turbine and photovoltaic solar systems, to modular construction, and to dispersed use in the distribution system.

Lead-acid battery modules should be suitable in the capacity range of 20 to 50 MW, which would match M-X program requirements. Other types of batteries using various metals and chemicals for electrodes and electrolytes have promise for higher energy density storage capabilities and lower costs than lead-acid batteries. Some of the combinations include: nickel-iron and nickel-zinc, zinc-chlorine, sodium-sulfur, and others. First commerical availability of these batteries is in the early to mid-1980s. Redox energy storage systems are also being considered.

The primary environmental concern is human exposure to the chemicals and gases produced during the charging and discharging cycles.

4.5 THERMAL STORAGE

A thermal storage system has the greatest application with a thermal solar central receiver or a parabolic dish or trough collector system. Thermal storage systems involve the use of well insulated chambers filled with heat-retaining materials, such as: rock, oil, eutectic (low melting point) salts, water, cast iron, and other materials. High temperature and pressure steam or other working fluids from the solar collectors or power towers are directed to the storage chamber during the solar day. When the sun is down or clouded over, thermal heat can be recovered from the storage chamber and fed directly to the electric generating equipment.

The primary environmental concerns of thermal storage relate to potential leaks of heated working fluids which leach salts into surrounding aquifers and accidental discharge of toxic materials, which may be part of the working fluid.

4.6 FUEL CELL

A fuel cell has the capability of acting as an energy storage-conversion system and being used as a peaking (load-following) device in the M-X system. A fuel cell system includes a fuel processor, a power section, and a power conditioner. The fuel processor converts a utility fuel such as naptha, natural gas, methanol, or ethanol to a hydrogen-rich gas by steam reforming. The power section, consisting of a phosphoric acid electrolyte sandwiched between two electrodes, combines the hydrogen-rich gas and oxygen to produce water and electric power. Waste heat can be used for the fuel processor and/or other uses. The power conditioner converts d.c. electrical output to a.c. which is compatible with a standard utility grid.

A fuel cell has a higher conversion efficiency than conventional thermal generators, and its efficiency is not size dependent. Modular units can be quickly added to a fuel cell plant as demand increases.

A 4.5 MW demonstration fuel cell plant, sponsored by DOE, EPRI and Con.Ed. of New York, is being built in Manhattan. Delays have been experienced due to pressure testing and other measures to meet stringent local fire code requirements for flammable materials.

A fuel cell plant has few environmental concerns. It is quiet and has few emissions other than carbon dioxide, air, and water. Sulfur and other emissions could result from the fuel processor if petroleum or coal-derived fuels are used.

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5.0 GEOTHERMAL ENERGY SYSTEMS

5.1 TECHNICAL OVERVIEW

Recovery and utilization of heat trapped within the earth's crust is the primary object of geothermal energy development. Depending on the quantity and quality of geothermal resources tapped by drilling, geothermally heated fluids may be used for electrical generation or in a variety of direct applications, such as space heating/cooling or industrial process use.

Depending on their geologic origin and associated characteristics, geothermal resources are classified into four basic categories:

1. Convective hydrothermal
2. Geopressurized hydrothermal
3. Hot dry rock
4. Magna-molten rock.

Convective hydrothermal resources are the only geothermal sources used commercially at the present time. These resources are characterized by relatively shallow (less than 10,000 feet) underground reservoirs of hot water and/or steam contained in porous and fractured sediments overlain by impermeable surface layers. Temperatures range from 195°F to more than 480°F. Convective hydrothermal resources are categorized as vapor dominated if they release steam or liquid dominated if they produce hot water. The only known vapor dominated systems in the United States occur at the Geysers, at Lassen Volcanic National Park in northern California, and at Yellowstone National Park in Wyoming. Within the M-X region, it is anticipated that liquid dominated convective hydrothermal resources would be most prevalent.

Geopressurized hydrothermal resources consist of thermal heat, pressurized gases, and dissolved methane trapped in deep sedimentary rock formations under high pressure. Thermal and kinetic energy contained in geopressurized reservoirs would be recovered in addition to valuable methane gas. These resources are known to exist primarily in the Gulf of Mexico and Gulf Coast states. No commercial wells are yielding geopressurized energy, but major research efforts are underway.

Geologic formations containing high heat gradients but insufficient fluids for hydrothermal activity are known as hot dry rock resources. Exploitation requires drilling two wells, fracturing the rock, and circulating a heat transfer fluid to extract geothermal heat. Technology for large scale fracturing of rock and heat extraction on a commercial basis has not been demonstrated.

Long range research goals are to extract energy from very high temperature molten rock where it lies close to the earth's surface. Major problems include the fact that drilling equipment cannot withstand such extreme temperatures (7000-8,000°F), and the theoretical difficulty that magma will solidify around any type of heat extractor.

5.2 OPERATING AND DEMONSTRATION FACILITIES

LOCATION	TYPE	CAPACITY	COMMENTS
Geysers, CA, Pacific Gas & Elec.	Vapor Dominated	700 MWe	Only commercial plant in U.S.
Larderello, Italy	Vapor Dominated	406 MWe	—
Matsukawa, Japan	Vapor Dominated	20 MWe	—
Cerro Prieto, Mexico	Liquid Dominated Direct Flash	150 MWe	400 MWe by 1985
Wairakei, New Zealand	Liquid Dominated	160 MWe	—
Niland, CA	Liquid Dominated Binary Cycle	10 MWe	Geothermal loop experimental facility
East Mesa, Holtville, CA, Magma Power Co.	Liquid Dominated Binary Cycle	11 MWe	Pilot scale (isobutane and propane)
Brawley and Heber, CA	Liquid Dominated Direct Flash	—	Planned
Valles Caldera, NM	Liquid Dominated Binary Cycle	50 MWe	Planned for 1983
Fenton Hill, NM Los Alamos Scientific Laboratory	Hot Dry Rock	—	Developing fracturing and circulation technology

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5.3 GEOTHERMAL RESOURCES IN THE M-X REGION

The Basin and Range Province is characterized by high regional heat flows induced by tectonic activity. The insulating effect of thick sedimentary layers in many valley areas increases the already high thermal gradient. Extensive fault systems provide conduits for deep water circulation. In addition, young volcanic activity in several areas has created local hot spots.

Numerous liquid dominated hydrothermal systems have been identified across northern Nevada. Additional systems occur at Roosevelt Hot Springs and Sulphurdale near Milford, in southwestern Utah, at Valles Caldera in northern New Mexico, and in the Lightning Dock area of southwestern New Mexico. Numerous well drilling, remote sensing, and other activities are underway to further identify and assess geothermal reservoirs. Gravity anomaly maps are being used to determine areas of New Mexico and west Texas that may be conducive to geothermal energy development, but no reservoirs are currently known in the region.

5.4 SYSTEM DESCRIPTION

Geothermal resources with temperatures less than about 300^{o}F are considered marginal prospects for electrical generation based on current technology. Lower temperature reserves are best suited for direct application in space heating/cooling or industrial process use.

There are two basic energy conversion concepts suitable for electrical energy production from liquid dominated, hydrothermal resources: direct flash and binary fluid plants.

In a direct flash system, heated geothermal liquid is extracted from wells, introduced into a single or multiple flash chamber(s) and "flashed" to steam. Flashed steam is expanded through a turbine generator to produce electricity.

In a binary cycle system, geothermal liquid or flashed steam is run through a heat exchanger to release its heat and vaporize a secondary organic fluid such as isobutane, isopentane, or propane. The secondary fluid vapor is expanded through a turbine generator to produce electricity. The secondary fluid vapor is exhausted from the turbine, condensed, and pumped back to the heat exchanger for recirculation. The geothermal liquid is pumped back into the ground to recharge the hydrothermal reservoir.

Geothermally heated fluids can also be used in a hybrid concept with fossil fuels to heat boiler feedwater and/or combustion air so that fossil fuels are burned more efficiently in a power plant.

Design requirements for a geothermal plant are unique in certain aspects. The combination of high dissolved solids content plus high temperatures can create a very harsh environment which causes erosion, corrosion, and sediment buildup in piping and equipment. Binary plants must be well protected against leaks of highly flammable organic liquids or vapors at high temperatures and pressures.

5.5 ENVIRONMENTAL AND INSTITUTIONAL CONCERNS

Environmental concerns with geothermal energy development include the following:

1. Air: primary air emissions are non-condensable gases associated with geothermal fluids such as hydrogen sulfide, carbon dioxide, methane, and ammonia.

2. Water: geothermal brine spills could be a source of thermal and water pollution. Electrical generating plants require water for cooling, unless less efficient dry-air systems are used.

3. Land subsidence: removal of geothermal fluids without reinjection can result in sinking of the land surface. Reinjection is recommended.

Institutional constraints with geothermal development include the following:

1. Lack of clear environmental guidelines which tends to delay approvals required from regulatory agencies.

2. Uncertainty as to the legal classification of geothermal resources as minerals or water, and applicable usage rights. Water rights have traditionally been associated with potable sources. At issue is whether landowners, who routinely possess title to surface water, also have the rights to geothermal resources on their property.

3. Existing and proposed leases for geothermal resource areas.

4. Patents and trade secrets involved in new technologies.

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6.0 BIOMASS

6.1 TECHNICAL OVERVIEW

Within the M-X region, biomass does not occur in significant quantitities that are renewable on a long term basis, except for solid waste in scattered communities and agricultural crops in the High Plains Region. However, sufficient biomass materials may exist in states surrounding the region.

The most likely biomass sources include:

1. Ethanol derived by fermentation of agricultural crops
2. Solid waste energy recovery
3. Wood wastes densified into pellets
4. Methanol derived by thermochemical decomposition of wood wastes

6.2 ETHANOL

Ethanol is produced by the fermentation of agricultural foodstock. It can be used to generate electricity in fuel cells or conventional gas turbines. It can also be used as a mobile fuel in internal combustion engines (gasohol, dieselhol, or straight ethanol).

Sufficient foodstock exists in numerous counties in California, Idaho, Arizona and the Great Plains region to supply millions of gallons per year of ethanol from wheat, corn, grain, sorghum, barley, rye and potatoes.

The primary byproducts from an ethanol plant are protein rich syrups and distillers dried grain which have a high market value as feed supplements. Carbon dioxide is another byproduct which can be used to produce dry ice or fire extinguisher charges, or to decrease spoilage in feedstock storage.

6.3 SOLID WASTE

Solid waste is a byproduct of human consumption and its quantity is directly related to population and density.

Considerable solid waste resources exist in urban areas within the M-X region. Since landfill costs are generally low, additional economic incentives would probably be necessary to stimulate community participation in a solid waste energy recovery program.

Primary solid waste energy conversion systems include: mass burning, processed waste (refuse derived fuel), and modular combustion units.

The M-X operating base and support community could be designed to incorporate an energy conversion system. Because of the relatively small waste generation potential (200 to 250 tons/day), a small modular incineration system would be appropriate to produce steam for heating, cooling, and to process heat within the base or the community.

6.4 WOOD

The primary sources of wood waste would be forest residue and mill wastes located in northern California, southwestern Oregon, and eastern Texas. If available, these sources would be sufficient to supply 50 MWe or more to the M-X system.

Wood cut in the forest has a high moisture content and low energy density. Chipping, drying and pelletizing wood reduces moisture content and increases energy density, so that it becomes transportable for greater distances. Wood pellets can be combusted in conventional boilers having ash handling capabilities.

Environment impacts and concerns with wood energy development are as follows:

1. Harvesting: Removal of trees from a forested area may cause soil erosion, nutrient depletion, aesthetic degradation, reduced water quality, and deterioration of wildlife habitat. However, "weeding out" non-commercial species and damaged, diseased , or overmature trees is good forest management. It can increase the growth rate of a forest and diversify wildlife habitat.

2. Dust: Fugitive dust from logging roads and from handling and storage of pellets can be a concern.

3. Transportation: A 50 MWe power plant would require apprxoximately 10,000 pellet trucks per year (38 per working day) entering and exiting the site.

4. Air: Particulate matter from combustion would be the primary concern. Wood has an inherently low sulfur content and thus minimum sulfur dioxide emissions. Likewise its nitrogen oxide emissions are lower than conventional fossil fuels.

5. Water: Power plant cooling water would be required, the same as a conventional plant, unless dry-air cooling towers were incorporated.

6.5 METHANOL

Methanol production is currently derived primarily from the thermochemical conversion of natural gas or refinery light-gas streams. However, any carbonaceous material, such as coal, lignite, wood, and other materials can likewise be converted. The basic steps involve gasification, purification, shift reaction, and methanol synthesis. All processes except gasification are commercially established, but numerous groups are developing the gasification technology.

The primary biomass feedstock for methanol in the M-X region is wood. As with ethanol and wood pelletization, the intention is to produce methanol in the vicinity of the resource and transport it to an energy converstion facility closer to the energy demand.

The primary environmental concerns of energy from alcohol fuels are related to harvesting and transporting large quantities of wood for methanol or large quantities of agricultural crops for ethanol. Alcohol fuels have a positive advantage over fossil fuels since they are completely devoid of sulfur, heavy metals,

and particulate matter. They burn at lower temperatures than natural gas or oil, and thus produce lower quantities of nitrogen oxides. Ethanol can be used to extend petroleum products (gasohol and dieselhol) and it can be burned alone with appropriate engine modifications.

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APPENDIX F

Conservation and Renewable Resource Measures

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STATE	HUD/MPS REGION	CATEGORY OF RESIDENTIAL BUILDING	CONSERVATION MEASURES: Ceiling Insulation (R-Value)*	Wall Insulation	Floor Insulation (R-Value)*	Storm or Thermal Windows	Storm or Thermal Doors	RENEWABLE RESOURCE MEASURES: Solar Domestic Hot Water Systems	Active Solar Space Heating Systems	Combined Active Solar Space Heating & Solar Domestic Hot Water Systems	Wind Energy Devices
Texas (Continued)	2	Electricity	22	X		X		X		1,2	X
		Gas	19	X				X			X
		Oil	19	X				X			X
		Electric Heat Pump	19	X							X
	3	Electricity	30	X	11	X		X		1,2	X
		Gas	22	X							X
		Oil	22	X				X			X
		Electric Heat Pump	22	X							X
	4	Electricity	30	X	19	X		X		1,2	X
		Gas	30	X	11	X					X
		Oil	30	X	11	X		X			X
		Electric Heat Pump	30	X	11	X					X
	5	Electricity	30	X	19	X	X	X		1,2	X
		Gas	30	X	11	X		X			X
		Oil	30	X	11	X		X			X
		Electric Heat Pump	30	X	11	X					X
Utah	5	Electricity	30	X	19	X	X	X1,2		1,2,3	
		Gas	30	X	11	X					
		Oil	30	X	11	X		X1,2		1,2,3	
		Electric Heat Pump	30	X	11	X					
	6	Electricity	30	X	19	X	X	X1,2		1,2	
		Gas	30	X	11	X					
		Oil	30	X	11	X		X1,2		1,2	
		Electric Heat Pump	30	X	19	X	X				
	7	Electricity	38	X	19	X	X	X1,2		1,2	
		Gas	30	X	11	X					
		Oil	30	X	11	X		X1,2		1,2	
		Electric Heat Pump	38	X	19	X	X				
	8	Electricity	38	X	19	X	X	X1		1	
		Gas	38	X	19	X	X				
		Oil	38	X	19	X	X	X1		1	
		Electric Heat Pump	38	X	19	X	X				
Vermont	7	Electricity	38	X	19	X	X				X
		Gas	30	X	11	X					
		Oil	30	X	11	X					
		Electric Heat Pump	38	X	19	X	X				X
	8	Electricity	38	X	19	X	X				
		Gas	38	X	19	X	X				
		Oil	38	X	19	X	X				
		Electric Heat Pump	38	X	19	X	X				

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NOTE: 1 = Single-family
2 = Attached buildings
3 = Mobile Homes

*These R-Values are minimums. The State may propose, in a State Plan, either (1) to substitute a higher level, subject to the Assistant Secretary's approval, as the program measure, or (2) to offer other levels (higher or lower) as States measures in addition to the program measures.

STATE	HUD/MPS REGION	CATEGORY OF RESIDENTIAL BUILDING	CONSERVATION MEASURES: Ceiling Insulation (R-Value)*	CONSERVATION MEASURES: Wall Insulation	CONSERVATION MEASURES: Floor Insulation (R-Value)*	CONSERVATION MEASURES: Storm or Thermal Window	CONSERVATION MEASURES: Storm or Thermal Doors	RENEWABLE RESOURCE MEASURES: Solar Domestic Hot Water Systems	RENEWABLE RESOURCE MEASURES: Active Solar Space Heating Systems	RENEWABLE RESOURCE MEASURES: Combined Active Solar Space Heating & Solar Domestic Hot Water Systems	RENEWABLE RESOURCE MEASURES: Wind Energy Devices
Rhode Island	6	Electricity	30	X	19	X	X	X			X
		Gas	30	X	11	X					X
		Oil	30	X	11	X					X
		Electric Heat Pump	30	X	19	X	X				X
South Carolina	2	Electricity	22	X		X		X			X
		Gas	19	X							
		Oil	19	X				X			
		Electric Heat Pump	19	X							
	3	Electricity	30	X	11	X		X			X
		Gas	22	X							
		Oil	22	X				X			
		Electric Heat Pump	22	X							X
	4	Electricity	30	X	19	X		X			
		Gas	30	X	11	X					
		Oil	30	X	11	X		X			
		Electric Heat Pump	30	X	11	X					
South Dakota	7	Electricity	38	X	19	X	X	X			X
		Gas	30	X	11	X					
		Oil	30	X	11	X		X			
		Electric Heat Pump	38	X	19	X	X				X
	8	Electricity	38	X	19	X	X	X			X
		Gas	38	X	19	X	X				
		Oil	38	X	19	X	X	X			
		Electric Heat Pump	38	X	19	X	X				X
Tennessee	3	Electricity	30	X	11	X		X			
		Gas	22	X							
		Oil	22	X				X			
		Electric Heat Pump	22	X							
	4	Electricity	30	X	19	X					
		Gas	30	X	11	X					
		Oil	30	X	11	X		X			
		Electric Heat Pump	30	X	11	X					
	5	Electricity	30	X	19	X	X				
		Gas	30	X	11	X	X				
		Oil	30	X	11	X		X			
		Electric Heat Pump	30	X	11	X					
Texas	1	Electricity	19	X				X			X
		Gas	19	X							
		Oil	19	X				X			
		Electric Heat Pump	19	X							X

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STATE	HUD/MPS REGION	CATEGORY OF RESIDENTIAL BUILDING	CONSERVATION MEASURES: Ceiling Insulation (R-Value)*	Wall Insulation	Floor Insulation (R-Value)*	Storm or Thermal Windows	Storm or Thermal Doors	RENEWABLE RESOURCE MEASURES: Solar Domestic Hot Water Systems	Active Solar Space Heating Systems	Combined Active Solar Space Heating & Solar Domestic Hot Water Systems	Wind Energy Devices
New Jersey	5	Electricity	30	X	19	X	X	X			X
		Gas	30	X	11	X					X
		Oil	30	X	11	X		X			X
		Electric Heat Pump	30	X	11	X					X
	6	Electricity	30	X	19	X	X	X			X
		Gas	30	X	11	X					X
		Oil	30	X	11	X					X
		Electric Heat Pump	30	X	19	X	X				X
New Mexico	3	Electricity	30	X	11	X		X1		1,2,3	X
		Gas	22	X				X			X
		Oil	22	X				X		1	X
		Electric Heat Pump	22	X							X
	4	Electricity	30	X	19	X		X1		1,2,3	X
		Gas	30	X	11	X		X			X
		Oil	30	X	11	X		X1		1	X
		Electric Heat Pump	30	X	11	X					X
	5	Electricity	30	X	19	X	X	X1		1,2,3	X
		Gas	30	X	11	X		X			X
		Oil	30	X	11	X		X		1	X
		Electric Heat Pump	30	X	11	X					X
	6	Electricity	30	X	19	X	X	X1		1,2,3	X
		Gas	30	X	11	X		X			X
		Oil	30	X	11	X		X1		1,2	X
		Electric Heat Pump	30	X	19	X	X				X
	7	Electricity	38	X	19	X	X	X1		1,2,3	X
		Gas	30	X	11	X		X			X
		Oil	30	X	11	X		X1		1,2	X
		Electric Heat Pump	38	X	19	X	X				X
	8	Electricity	38	X	19	X	X	X1		1,2,3	X
		Gas	38	X	19	X	X	X			X
		Oil	38	X	19	X	X	X1		1,2	X
		Electric Heat Pump	38	X	19	X	X				X
New York	6	Electricity	30	X	19	X	X	X			X
		Gas	30	X	11	X					X
		Oil	30	X	11	X					X
		Electric Heat Pump	30	X	19	X	X				X
	7	Electricity	38	X	19	X	X	X			X
		Gas	30	X	11	X					
		Oil	30	X	11	X					
		Electric Heat Pump	38	X	19	X	X				X

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STATE	HUD/MPS REGION	CATEGORY OF RESIDENTIAL BUILDING	CONSERVATION MEASURES: Ceiling Insulation (R-Value)*	Wall Insulation	Floor Insulation (R-Value)*	Storm or Thermal Windows	Storm or Thermal Doors	RENEWABLE RESOURCE MEASURES: Solar Domestic Hot Water Systems	Active Solar Space Heating Systems	Combined Active Solar Space Heating & Solar Domestic Hot Water Systems	Wind Energy Devices
Nebraska (Continued)	8	Electricity	38	X	19	X	X	X	[illegible]	[illegible]	X
		Gas	38	X	19	X	X				
		Oil	38	X	19	X	X	X			
		Electric Heat Pump	38	X	19	X	X				X
Nevada	2	Electricity	22	X		X		X1,2		1,2,3	X
		Gas	19	X				X			
		Oil	19	X				X1		1,2	
		Electric Heat Pump	19	X							X
	3	Electricity	30	X	11	X		X1,2		1,2,3	X
		Gas	22	X				X			
		Oil	22	X				X1		1,2	
		Electric Heat Pump	22	X							X
	4	Electricity	30	X	19	X		X1,2		1,2,3	X
		Gas	30	X	11	X		X			
		Oil	30	X	11	X		X1		1,2,3	
		Electric Heat Pump	30	X	11	X					X
	5	Electricity	30	X	19	X		X1,2		1,2,3	X
		Gas	30	X	11	X		X			
		Oil	30	X	11	X		X1		1,2,3	
		Electric Heat Pump	30	X	11	X					X
	6	Electricity	30	X	19	X	X	X1		1,2	X
		Gas	30	X	11	X		X			
		Oil	30	X	11	X		X1		1	
		Electric Heat Pump	30	X	19	X	X				X
	7	Electricity	38	X	19	X	X	X1		1,2	X
		Gas	30	X	11	X		X			
		Oil	30	X	11	X		X1		1	
		Electric Heat Pump	38	X	19	X	X				
	8	Electricity	38	X	19	X	X	X1		1,2	
		Gas	38	X	19	X	X				
		Oil	38	X	19	X	X	X1		1	
		Electric Heat Pump	38	X	19	X	X				
New Hampshire	7	Electricity	38	X	19	X	X				X
		Gas	30	X	11	X					
		Oil	30	X	11	X					
		Electric Heat Pump	38	X	19	X					X
	8	Electricity	38	X	19	X	X				X
		Gas	38	X	19	X	X				
		Oil	38	X	19	X	X				X
		Electric Heat Pump	38	X	19	X	X				

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