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WIPP Conceptual Design Report

Addendum D: A Report to Holmes & Narver, Inc., Anaheim, California, on Alternative Energy Sources for Waste Isolation Pilot Plant, Carlsbad, New Mexico. Prepared by Envirodyne Energy Services, Anaheim, California (A647).

Prepared by Sandia Laboratories, Albuquerque, New Mexico 87115 and Livermore, California 94550 for the United States Energy Research and Development Administration under Contract AT(29-1)-789

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A REPORT TO

HOLMES & NARVER, INC.

ANAHEIM, CALIFORNIA

ON

ALTERNATIVE ENERGY SOURCES

FOR

WASTE ISOLATION PILOT PLANT

CARLSBAD, NEW MEXICO

PREPARED BY

951 0902

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March 17, 1977

77100
A647

Holmes & Narver, Inc.
400 East Orangethorpe Avenue
Anaheim, California 92801

Attention: Mr. Kent R. Brown
Project Manager

Subject: Report on Alternative Energy Sources for Waste
Isolation Pilot Plant

Gentlemen:

As covered by your Consultant Agreement #1977-AN-002Y, we submit 20 copies of the above report for your consideration. When you have had an opportunity to study the report, we will be happy to discuss any phase on which you desire additional information.

We wish to express our appreciation to Holmes & Narver, Inc., personnel for their active cooperation with us in preparing the report. We particularly want to thank Messrs. Kent R. Brown, Morris Klatskin and Richard Marine.

Respectfully submitted,

ENVIRODYNE ENERGY SERVICES
A Division of Envirodyne Engineers, Inc.

Gordon W. Neal, P.E.
Vice President

GWN:sk

Enclosures

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1. SUMMARY AND RECOMMENDATIONS

1.1 Summary

This report presents the results of a technical and economic analysis of alternative methods of meeting the energy needs of a proposed Waste Isolation Pilot Plant (WIPP) to be located in southeastern New Mexico. The WIPP is a facility for underground storage of radioactive wastes in a deep salt bed.

The report analyzes a total of sixteen possible methods for meeting WIPP energy requirements, consisting of purchased electricity and on-site generation in various combinations from full purchased to full on-site. These methods are summarized as follows:

1. Full purchased electricity (Mode P-1).
2. Steam turbines (Modes S-1 through S-7)
 - a. Three modes of full on-site generation.
 - b. Three modes for on-site generation of vital loads only, with remaining electricity purchased.
 - c. One mode for on-site generation of by-product power (governed by amount of turbine reject heat required to meet WIPP requirements), with remaining electricity purchased.

3. Gas turbines (Modes G-1 through G-3)
 - a. One each of full on-site, vital generation only, and by-product power.
4. Combined cycle: Gas turbines in combination with steam turbines (Modes C-1 and C-2)
 - a. One each of full on-site and by-product power.
5. Reciprocating (diesel) engines (Modes E-1 through E-3)
 - a. One each of full on-site, vital and by-product.

Fuels selected for on-site generation are coal for the steam turbine modes and, because of technical limitations, fuel oil for the remaining modes.

The local electric utility, Southwestern Public Service Company, currently has one 350 MW coal-fired station in operation and has two additional 350 MW stations in prospect. For this reason, the additional utility system loads that would be imposed by the WIPP would more than likely be met with coal.

In terms of estimated primary fuel energy input, only the diesel engine modes would be lower than full purchased electricity. Diesels would, however, require oil fuel for operation.

Economic analyses were performed on a 25-year life cycle using present value with an 8 percent discount (interest) rate

as the comparison basis. Projected inflation rates were applied to estimated costs as detailed in following sections of the report.

The economic analyses indicated that none of the on-site generation modes were more cost-effective than full purchased electricity. While future conditions differing from the assumptions used in the economic analyses could alter degrees of comparison, only major deviations would be likely to change the relationship of purchased electricity vis-a-vis on-site generation.

The primary reason for the unfavorable showing of on-site generation is the inability of the WIPP to absorb sufficient prime mover reject heat. The estimated heat/power ratio of the WIPP is approximately 0.6 MBtu/kWh, while the most favorably situated prime movers, diesel engines, have recoverable heat values ranging from 2 to 4 MBtu/kWh. To make on-site generation feasible would require a WIPP heat/power ratio from 4 to 20 times greater than projected. With a more favorable heat/power ratio, on-site generation would show highly attractive energy and cost savings over purchased electricity.

A summary of the estimated energy consumption and economics of the alternatives considered is as follows:

	<u>Energy Usage Million Btu/yr</u>	<u>Present Value (1980) \$1000</u>
1. Purchased electricity (Mode P-1):	802,450	45,620
Percent of base:	Base	Base
2. On-site generation		
a. Mode with lowest fuel energy input: Mode E-1, Diesel Engines, Full on- site generation:	653,277	59,970
Percent of base:	81	131
b. Most cost-effective on-site generation mode: Mode S-1, steam turbines (800 psig, 750F). Full on-site generation:	1,046,825	46,720
Percent of base:	130	102

1.2 Recommendations

Recommendations resulting from the technical and economic analyses outlined herein are summarized as follows:

1. Purchase all electric energy requirements for the WIPP from Southwestern Public Service Company.
2. Use electric energy to meet all of the energy needs of the WIPP. Use electric-driven chillers for space cooling, and through reverse cycle operation, for space heating.

3. Install equipment for correcting the overall power factor to 100 percent.
4. Purchase electricity at the voltage required by the WIPP, i.e., with utility ownership of transformers serving the site.

Beyond the greater cost-effectiveness indicated by purchased electricity is the fact that operation could terminate before completion of the full 25-year life cycle. The heavy initial investment needed for on-site generation can be justified only when the project being served is assured of long-term operation. Early abandonment of the WIPP could create a heavy cost burden in terms of idled on-site generation equipment.

A further recommendation relates to the type of prime mover to be used for standby service for the vital loads. Reciprocating (diesel or dual-fuel) engines are recommended in preference to gas turbines (the only other feasible type) for the following reasons:

1. While gas turbine and reciprocating engines have similar overall reliability records, failure to start is a more prevalent malfunction with gas turbines. This can be an important factor in standby service.
2. The substantially lower heat rate of reciprocating engines creates smaller fuel storage requirements for a given running time.

3. While a gas turbine itself occupies less space for a given capacity, the need for larger intake and exhaust ducts results in overall space requirements comparable with engines.
4. Dual-fuel (liquid and gaseous fuels) configurations are available with both types of units, a factor which can be important if a secondary standby fuel, such as liquified petroleum gas, is deemed necessary. Gas turbines do, however, require considerably higher gas pressures and a consequent need for relatively large auxiliary compressors.
5. Initial investment costs for the two types of units are comparable.

Steam turbines, which were also considered for on-site generation in this analysis, are not suitable for standby service because of the inability to come on the line rapidly from a cold start and because of high initial installation costs.

2. BACKGROUND AND PURPOSE OF REPORT

A Waste Isolation Pilot Plant (WIPP) is proposed for a location approximately 25 miles east of Carlsbad, New Mexico. The WIPP is a facility for storing radioactive wastes in a benign, isolated environment. The proposed storage method consists of placing the wastes in a specially developed mine in a deep salt bed. As currently projected, construction and operation of the WIPP would start in 1981.

Mining operations and above ground facilities will require considerable quantities of energy, particularly electricity. The purpose of this report is to present the results of a comprehensive analysis covering alternative energy supply methods for the WIPP.

Basic activities carried out within the scope of the analysis were as follows:

1. Gather data relating to energy requirements and possible energy sources
2. Develop alternative methods of meeting energy needs
3. Analyze the methods so developed, both from a technical and an economic standpoint
4. Present conclusions and recommendations resulting from the technical and economic analyses.

3. DEVELOPMENT OF DATA

Material used in this report was developed from the following sources:

1. A meeting held on February 2, 1977, among personnel of Sandia Laboratories, Fenix and Scisson, Holmes & Narver, Inc., and Envirodyne Energy Services
2. A meeting held on February 17, 1977, among personnel of Sandia Laboratories, Holmes & Narver, Inc., and Southwestern Public Service Company
3. A meeting held on March 3, 1977, among personnel of Sandia Laboratories, Holmes & Narver, Inc., and Envirodyne Energy Services
4. Several telephone conversations and personal visits conducted among personnel of Holmes & Narver, Inc., Southwestern Public Service Company, equipment suppliers and Envirodyne Energy Services
5. Data and directives delivered to Envirodyne Energy Services by Holmes & Narver, Inc., including:

- a. WIPP equipment lists
 - b. WIPP system drawings
 - c. Estimates of thermal loads for equipment that could be heat operated
 - d. ERDA data and directives
6. Publications and other data taken from Envirodyne Energy Services files or acquired during the course of the work.

An itemized list of reference sources is included in the Appendix contained in this report.

Methods of developing the information to arrive at the conclusions and recommendations are covered in the pertinent areas of the report.

4. ENERGY REQUIREMENTS AND SOURCES

4.1 Energy Requirements

Since mining operations constitute a large proportion of facility activities, the bulk of the WIPP energy needs must be met by electricity. Space heating and cooling comprise the only loads that can be practically met with thermal energy.

Energy requirements were estimated by analyzing, in conjunction with Holmes & Narver personnel, equipment lists, drawings, heat gain and heat loss calculations, projected operational modes and other pertinent data. Appropriate modifying ratios, such as diversity and demand factors, were applied to the raw data. Three independent evaluations were conducted for arriving at electrical demand. Annual space heating and cooling requirements were apportioned throughout the year by means of heating and cooling degree days as listed by the National Weather Service for Carlsbad.

Energy usage under the full purchased electricity mode (P-1) is predicated upon all-electric operation. Electric driven chillers would be used to furnish space cooling, and through reverse cycle operation, space heating. This would eliminate a need for space heating boilers. Furthermore, it provides optimum energy efficiency under the full purchased electricity mode.

Energy usage with any degree of on-site power generation is predicated upon supplying all space heating and cooling with thermal energy: direct heat transfer for heating and absorption refrigeration for cooling. This is necessary to permit

maximum utilization of reject heat from any prime movers used to generate on-site power.

Table 4-1 lists estimated annual energy use on a month-by-month basis under both full purchased electricity and on-site generation modes for operation with mining (1983-1995). It is noteworthy that the use of heat operated space heating and cooling results in a reduction of only 2452 MWh/yr (68,155 - 65,703), a difference of less than 4 percent.

Table 4-2 shows estimated annual electric and thermal energy use for each year over the anticipated 25 year life cycle of the facility.

It should be noted that estimated electric energy for on-site generation covers only the net requirements of the WIPP itself: it does not include auxiliary energy required for the on-site plant. Plant auxiliary requirements are covered in a later section.

Electrical load factors (ratio of maximum demand to average demand) derived from Table 4-2 are as follows:

<u>Years</u>	<u>Phase</u>	<u>Shifts/day (5 day week)</u>	<u>Load Factor, %</u>
1981	Construction	3	79
1982	Startup	3	79
1983-1995	Operation with Mining	1	54
1996-2005	Operation Without Mining	1	80

The foregoing values correspond closely with those experienced by other mining operations in the Southwestern Public Service Company (SWPS) service territory. SWPS personnel indicate that load factors for single-shift mining operations are in the range of 50 to 60 percent, while those of continuous refinery operations go as high as 85 percent. The high load factor shown for the single-shift 1996-2005 period results from the pronounced reduction in weekday demand created by cessation of mining operations: demand during the remaining hours remains essentially the same as that of the preceding 1983-1995 period.

4.2 Energy Sources

a. Purchased Electricity: Electric energy is available from the locally franchised public utility, Southwestern Public Service Company (SWPS), under Tariff 4106.3, Large General Service. Present indications are that the WIPP would be served by a 115 kv transmission line brought in by SWPS from a line currently under construction that extends due south from Potash Junction. Connection point for the WIPP service line would be approximately ten miles due west of the WIPP site. Should a separate standby source be required, a second line would be brought in from another 115 kv line connecting Hobbs and Carlshad. SWPS records indicate that the Potash Junction substation has experienced no interruptions in the past ten years.

Until recently, natural gas was the primary fuel used by SWPS for electric generation. A 350 MW coal-fired central station has recently gone into operation and two additional 350 MW coal-fired units are scheduled for 1979 and 1981.

Completion of these units would result in total coal-fired capacity of 1050 MW, approximately one-third of total system capability.

Because of the existing and proposed SWPS coal-fired units, there is little likelihood that use of purchased electricity by the WIPP would create increased consumption of the nation's natural gas resources.

b. Fuel: Fuel used for on-site generation is determined largely by the characteristics of the prime movers. Under present technology, prime movers considered for application to this facility are practically restricted to the following fuels:

1. Steam turbines: No restrictions
2. Gas turbines: Liquid or gaseous fuels
3. Reciprocating engines: Liquid or gaseous fuels

In line with the nation's need to conserve premium fuels as contained in ERDA directives, the following fuels have been selected for prime mover evaluation:

1. Steam turbines: Coal
2. Gas turbines and reciprocating engines:
Fuel oil

Coal is available from several locations throughout the Western United States. Fuel oil is commercially available virtually anywhere in the nation.

Table 4-1

ESTIMATED ANNUAL ENERGY USE: OPERATION WITH MINING 1983-1995

MONTH	OPERATING MODE							
	Purchased Electricity				On-Site Generation			
	Electric Energy, MWh				Electric Energy MWh	Steam, 1000 lb		
	Basic	Heating	Cooling	Total		Heating	Cooling	Total
Jan	5637	322	0	5959	5637	4180	0	4180
Feb	5074	229	0	5303	5074	2981	0	2981
Mar	5594	170	3	5767	5594	2210	61	2271
Apr	5381	49	31	5461	5381	634	551	1185
May	5548	0	117	5665	5548	0	2101	2101
Jun	5374	0	247	5621	5374	0	4446	4446
Jul	5555	0	287	5842	5555	0	5160	5160
Aug	5554	0	267	5821	5554	0	4813	4813
Sep	5371	0	145	5516	5371	0	2610	2610
Oct	5562	55	35	5652	5562	720	632	1352
Nov	5422	194	0	5616	5422	2519	0	2519
Dec	5631	301	0	5932	5631	3906	0	3906
Total	65703	1320	1132	68155	65703	17150	20374	37524

Table 4-2

ESTIMATED ENERGY USE OVER 25-YEAR LIFE CYCLE

YEAR	PHASE	PURCHASED ELECTRICITY		ON-SITE GENERATION			
		Demand kW	Energy MWh/yr	Electricity		Steam	
				Demand kW	Energy MWh/yr	Demand lb/hr	1000 lb/yr
1981	Construction	10,500	72,664	10,500	72,664	0	0
1982	Start-Up	12,000	83,271	12,000	83,271	0	0
1983	Operation with Mining	14,300	68,155	13,800	65,703	13,900	37,524
1984	↓	↓	↓	↓	↓	↓	↓
1985		↓	↓	↓	↓	↓	↓
1986		↓	↓	↓	↓	↓	↓
1987		↓	↓	↓	↓	↓	↓
1988		↓	↓	↓	↓	↓	↓
1989		↓	↓	↓	↓	↓	↓
1990		↓	↓	↓	↓	↓	↓
1991		↓	↓	↓	↓	↓	↓
1992		↓	↓	↓	↓	↓	↓
1993		↓	↓	↓	↓	↓	↓
1994		↓	↓	↓	↓	↓	↓
1995		↓	↓	↓	↓	↓	↓
1996	Operation without Mining	8,000	55,591	7,500	53,139	13,900	37,524
1997	↓	↓	↓	↓	↓	↓	↓
1998		↓	↓	↓	↓	↓	↓
1999		↓	↓	↓	↓	↓	↓
2000		↓	↓	↓	↓	↓	↓
2001		↓	↓	↓	↓	↓	↓
2002		↓	↓	↓	↓	↓	↓
2003		↓	↓	↓	↓	↓	↓
2004		↓	↓	↓	↓	↓	↓
2005		↓	↓	↓	↓	↓	↓

5. ALTERNATIVE ENERGY SUPPLY SYSTEMS

5.1 Modes of Operation

Alternative energy supply systems have been categorized on the basis of two criteria: (1) degree of on-site generation and (2) type of prime mover. Detailed information on the systems evaluated is listed in Table 5-1.

Degree of on-site generation was evaluated on the following bases, in order of increasing generation:

1. None
2. By-product power
3. Vital power only
4. Full on-site generation

As noted in Chapter 4, with no on-site generation all energy requirements (except emergency standby) would be purchased from Southwestern Public Service Company (SWPS), including space heating and cooling. Under the three degrees of on-site generation (by-product, vital and full), space heating and cooling equipment would be heat operated in order to utilize prime mover reject heat.

Under by-product power generation, prime mover power output is governed by the heat requirements of the facility. This method of operation minimizes energy input for the portion of the electrical requirements generated on-site, inasmuch as heat and power are always in optimum balance. The amount of electricity that can be generated under this method is severely limited as can be seen from Table 5-2. This mode would require parallel operation with utility power.

Under vital generation, only the electrical requirements of equipment that can be supplied from the emergency system is generated on-site, and the remaining requirements are purchased. Since vital loads can be electrically isolated from the remaining loads, this mode does not require parallel operation with utility power. As noted in Table 5-2, approximately 44 percent of electrical requirements would be generated on-site.

An attractive feature of the vital generation option is that utility power can be conveniently used for standby. Nonvital demand is higher than vital demand. An outage of vital power could therefore be picked up by utility power with no increase in overall utility demand by switching utility power from the nonvital bus to the vital bus. This would, of course, create an outage of nonvital power.

Under full on-site generation the entire energy requirements are met by on-site equipment and the facility is operated as an isolated entity with no electric utility connection. Standby equipment is provided on-site to assure continuity of service.

Alternate prime mover and heat recovery arrangements evaluated are as follows:

1. Steam turbines: Noncondensing and automatic-extraction condensing.
2. Gas turbines with exhaust heat recovery boilers.
3. Combined cycle (gas turbines/steam turbines): Extraction or exhaust steam from steam turbines.

4. Reciprocating (diesel) engines with jacket water and exhaust heat recovery boilers.

Details of the alternative energy supply systems are covered in Table 5-1 and in Figures 5-3, 5-4, 5-5, 5-6 and 5-7. Systems are summarized as follows:

1. Mode P-1: Full purchased electricity
2. Steam Turbine Installations

<u>Mode</u>	<u>Degree of On-Site Generation</u>	<u>Throttle Conditions psig/F</u>	<u>Unit Size kW</u>
S-1	Full	800/750	5000
S-2	Full	1250/900	5000
S-3	Full	1250/900	7500
S-4	Vital	1250/900	2500
S-5	Vital	1250/900	3750
S-6	Vital	1250/900	5000
S-7	By-Product	1250/900	875

3. Gas Turbine Installations

<u>Mode</u>	<u>Degree of On-Site Generation</u>	<u>Unit Size kW</u>
G-1	Full	1952
G-2	Vital	1952
G-3	By-Product	574

4. Combined Cycle Installations

<u>Mode</u>	<u>Degree of On-Site Generation</u>	<u>Unit Size, kW</u>	
		<u>Gas Turbine</u>	<u>Steam Turbine</u>
C-1	Full	1952	1000
C-2	By-Product	574	100

Note:

All gas turbine unit sizes are corrected for 3500 ft. elevation, 100F ambient air and flow restrictions at inlet and exhaust.

5. Reciprocating (Diesel) Engine Installations

<u>Mode</u>	<u>Degree of On-Site Generation</u>	<u>Unit Size kW</u>
E-1	Full	2412
E-2	Vital	2412
E-3	By-Product	2412

Gross electric generation for the on-site generation modes was determined by adding the following percentages to net plant output for plant auxiliaries:

1. Steam turbines: 5.5 percent
2. Gas turbines: 1.0 percent
3. Combined cycle: 2.0 percent
4. Reciprocating engines: 3.0 percent

The foregoing percentages were developed from data on existing installations. Steam turbine, gas turbine and combined cycle data were taken from Envirodyne Energy Services files. Reciprocating engine data were developed from ASME Diesel and Gas Engine Power Costs.

Steam conditions for space heating and cooling under all on-site generation modes have been taken at 15 psig. Use of steam at higher pressures exacts a penalty in steam turbine heat rate and in recoverable heat quantities for other prime movers. Lower pressures would create capacity penalties for absorption chillers.

An important criterion for on-site generation energy savings is the ability of the energy using system to absorb prime mover waste heat. This is expressed mathematically as the heat/power ratio of the system. The projected heat/power ratios of the WIPP are:

1983-1995: 0.5/ MBtu /kWh
1996-2005: 0.71 MBtu /kWh

Optimum energy savings occur when the energy using system heat/power ratio closely matches, both in timing and quantities, that of the prime movers. Typical heat/power ratios for prime movers evaluated herein are:

	<u>MBtu /kWh</u>
1. Diesel engines:	2 to 4
2. Combined cycle:	5 to 10
3. Gas turbines with unfired recovery boiler:	8 to 16
4. Autoextraction condensing steam turbines:	8 to 18
5. Noncondensing steam turbines:	15 and higher

A comparison of the WIPP heat/power ratios with those of the prime movers shows that even the most favorable prime mover (diesel) would develop considerable excess reject heat, although the combination of favorable gross heat rate and heat recovery makes energy input of the diesel modes the lowest of any alternatives considered.

5.2 Purchased Electricity

Energy input for Mode P-1 and the purchased portion of the vital and by-product modes was determined from Federal Power Commission statistics pertaining to Southwestern Public Service Company operations, i.e., Steam-Electric Plant Construction Cost and Annual Production Expenses, and Statistics of Privately Owned Electric Utilities in the United States. Values derived are as follows:

Composite SWPS station heat rate: 10,852 Btu/kWh

System losses as percent of energy delivered:
8.5 percent

User heat rate: $10,852 \times 1.085 = 11,774$ Btu/kWh

The user heat rate thus derived has been applied to purchased electricity to determine primary energy input.

5.3 Steam Turbines

Steam turbines possess a great deal of flexibility in selection of operating conditions and unit sizes. Two sets of throttle conditions, 800 psig/750F (S-1) and 1250 psig/900F (S-2 through S-7), were evaluated. The latter conditions

are considered to be the maximum practical limit for on-site plants, although utility central stations go considerably higher.

Steam turbine heat rates were determined on the basis of the theoretical steam rates and the engine (internal) and generator efficiencies listed by manufacturers for the unit sizes and operating conditions in question. All modes, except S-7, were developed on the basis of three stages of regenerative feed water heating.

Gross and net (with credit for heat recovery) heat rates derived for the various modes of operation are as follows:

<u>Mode</u>	<u>Heat rate, Btu/kWh</u>	
	<u>Gross</u>	<u>Net</u>
S-1	15,900	15,200
S-2	14,800	14,100
S-3	13,900	13,200
S-4	16,000	14,500
S-5	15,200	13,700
S-6	15,200	13,700
S-7	26,300	4,300

Net heat rates shown above are for illustrative purposes only. They were determined by subtracting the recovered heat, in Btu/kWh, from the gross heat rate. Net heat rate would be of primary interest only if heat powered space heating and cooling equipment were to be used in the absence of on-site generation.

Of particular interest is the paradoxically pronounced spread between gross and net heat rates for Modes S-7 (By-product power). The low net rate illustrates the value of matching power output to heat requirements. Unfortunately,

the low heat needs of the WIPP create an extremely small by-product power capability. This in turn reduces the size and consequent efficiency of the generating equipment, thereby creating a substantial rise in the gross heat rate.

Steam turbine modes are illustrated in Figures 5-3 and 5-4.

5.4 Gas Turbines

Simple cycle gas turbines (Modes G-1, G-2, G-3) are characterized by high gross heat rates, although they do possess valuable heat recovery characteristics for certain applications. The low heat requirements of the WIPP mitigates against their use for this facility. As shown in Table 5-2, gas turbines have the highest energy input of the alternatives evaluated under each degree of on-site generation.

Gas turbines are highly sensitive to entering and leaving air conditions. High elevations and air temperatures create pronounced reductions in turbine capability. The 3500 ft elevation, 100F site design temperature and restrictions on the inlet and exhaust (silencing and heat recovery) cause a 25 to 30 percent reduction in turbine capability from standard ISO conditions (sea level, 59F, no restrictions on inlet or exhaust).

Gas turbine unit sizes shown in Tables 5-1 and 5-2 are based on commercially available equipment. Gas turbine modes are illustrated in Figure 5-5.

5.5 Combined Cycle

The combined cycle (C-1, C-2) mode, as illustrated in Figure 5-6, consists of a gas turbine equipped with a heat recovery boiler, which in turn supplies steam to a steam turbine. Power is therefore developed from both the gas turbine and the steam turbine. Since fuel is fed only to the gas turbine, overall heat rate is reduced substantially below that of a gas turbine alone.

As is also true with steam turbine installations, combined cycles can have a wide variety of operating conditions. In evaluating combined cycle modes for the WIPP, seven different combinations were considered: only those with the lowest overall energy input are listed in Tables 5-1 and 5-2.

Two variations in conditions were evaluated: (1) raising steam turbine throttle conditions, and (2) refiring the heat recovery boiler.

With an unfired heat recovery boiler, the reduced steam rate resulting from higher throttle conditions is offset by reduced boiler steaming capability. Refiring the boiler does create more steam, but the boiler fuel energy is used only for the steam turbine and therefore loses the benefit of first producing work in the gas turbine. Neither variation resulted in an improved heat rate.

5.6 Reciprocating Engines

Diesel reciprocating engines have low heat rates which results in a low amount of rejected heat. This makes them

attractive candidates for the WIPP with its low heat requirements. In certain applications, the low level of available heat recovery (15 psig, 250F) from the jacket water limits their usefulness. For this facility, however, this limitation is not of concern since heat can be effectively used at that level.

As noted in Table 5-2, reciprocating engines have the lowest primary energy input of any alternate considered. The major drawback is the need to use fuel oil for operation.

Capacity ratings are predicated on turbocharged units, which do not require derating for site conditions.

Diesel modes are illustrated in Figure 5-7.

5.7 System Summary

Energy consumption characteristics of the alternative energy supply systems are summarized as follows:

1. It is unlikely that use of purchased electricity will increase natural gas consumption.
2. Of the on-site generation alternatives, the only ones capable of coal-firing (steam turbines) would result in fuel input greater than purchased electricity.
3. The only alternatives that would consume less energy than purchased electricity (diesels) require the use of fuel oil.

4. The low heat/power ratio of the WIPP does not lend itself to substantial energy savings through an on-site power generation/heat recovery system.

Table 5-1
ALTERNATIVE ENERGY SUPPLY SYSTEMS
OPERATIONAL MODES

	MODE															
	Purch.	Steam Turbines							Gas Turbines			Comb. Cycle		Diesel Engines		
	P-1	S-1	S-2	S-3	S-4	S-5	S-6	S-7	G-1	G-2	G-3	C-1	C-2	E-1	E-2	E-3
On-Site Generation(A)	-	F	F	F	V	V	V	B	F	V	B	F	B	F	V	B
Fuel	←	Coal							←	Oil						
No. of Units	-	4	4	3	4	3	3	1	8	4	2	6	2	8	4	4
Unit Size (MW)	-	5.0	5.0	7.5	2.5	3.75	5.0	0.9	2.0	2.0	0.6	3.0	0.7	2.4	2.4	2.4
Installed Capacity (MW)	-	20.0	20.0	22.5	10.0	11.3	15.0	0.9	16.0	8.0	1.2	18.0	1.4	19.3	9.6	9.6
Firm Capacity (MW)	-	15.0	15.0	15.0	7.5	7.5	10.0	0	14.0	6.0	0.6	15.0	0.7	16.9	7.2	7.2
Standby Capacity (MW)	-	5.0	5.0	7.5	2.5	3.75	5.0	0	2.0	2.0	0	3.0	0	4.8	2.4	2.4
Emergency Capacity (MW) (B)	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	0	0	9.6	0	9.6	0	0	0
Steam Turbine Type (C)	-	C/A							NC	-	-	C/A	NC	-	-	-
Throttle Pressure (psig)	-	800	1250							-	-	-	125	125	-	-
Throttle Temperature (F)	-	750	900							-	-	-	575	575	-	-
Process Stm. Press.(psig)	-	15							15							
Cond. Exhaust (In.Hg.)	-	2							-	-	-	2	-	-	-	-
									(D)							

NOTES:

- F: Full On-Site Generation; V: Vital On-Site Generation; B: By-Product Power Generation.
- A separate hardened emergency plant is not required under modes where zero (0) capacity is indicated since all or portions of the normal on-site power plant can be hardened to meet this criteria.
- C/A: Condensing Single Auto-Extraction; NC: Noncondensing.
- Gas turbine capacities based on site design conditions: 3500 ft elev., 100F ambient air.

Table 5-2

ALTERNATIVE ENERGY SUPPLY SYSTEMS ENERGY USE
1983-1995

MODE	ON-SITE GENERATION						ENERGY OUTPUT			ENERGY INPUT	
	Fuel (A)	Degree Generated (B)	Net MWh/yr	% of Total	Unit Size kW	Heat Rate Btu/kWh (C)	Elec. (D) MWh/yr		Steam Mlb/yr	Million Btu/yr	% of Base
							Net	Gross			
P-1	Full Purchased Electricity			0	--	11,774	68,155	--	--	802,450	Base
Steam Turbines:											
S-1	C	F	65,703	100	5000	15,930	65,703	69,317	37,524	1,046,825	130
S-2	C	F	65,703	100	5000	14,830	65,703	69,317	37,524	974,118	121
S-3	C	F	65,703	100	7500	13,910	65,703	69,317	37,524	913,661	114
S-4	C	V	28,900	44	2500	15,980	65,703	67,293	37,524	895,052	112
S-5	C	V	28,900	44	3750	15,200	65,703	67,293	37,524	872,551	109
S-6	C	V	28,900	44	5000	15,150	65,703	67,293	37,524	871,240	109
S-7	C	B	2,157	3.3	875	26,270	65,703	65,822	37,524	805,000	100
Gas Turbines:											
G-1	O	F	65,703	100	1952	16,920	65,703	66,360	37,524	1,111,819	139
G-2	O	V	28,900	44	1952	16,920	65,703	65,992	37,524	922,375	115
G-3	O	B	4,424	6.7	574	19,410	65,703	65,747	37,524	807,354	101
Combined Cycles:											
C-1	O	F	65,703	100	2950(E)	12,350	65,703	67,017	37,524	811,672	101
C-2	O	B	5,834	8.9	674(E)	16,780	65,703	65,820	37,524	802,820	100
Diesel Engines:											
E-1	O	F	65,703	100	2412	9,940	65,703	67,674	37,524	653,277	81
E-2	O	V	28,900	44	2412	9,940	65,703	66,570	37,524	720,705	90
E-3	O	B	12,500	19	2412	9,950	65,703	66,088	37,524	750,826	94

NOTES:

(A) C: Coal; O: Oil

(B) F: Full; V: Vital; B: By-Product

(C) Heat rate for Mode P-1 is utility heat rate for kWh delivered to user. On-site generation heat rate is based on kWh delivered to WIPP. All heat rates are gross (without heat recovery credit).

(D) Net MWh/yr is energy delivered to WIPP. Gross MWh/yr is net plus on-site generation auxiliaries.

(E) Breakdown of unit sizes, kW: C-1: 1950 gas turbine/1000 steam turbine

C-2: 574 gas turbine/100 steam turbine

Figure 5-3

5-14 CONDENSING-AUTOMATIC EXTRACTION STEAM TURBINE FLOW DIAGRAM
 MODES S-1, S-2, S-3, S-4, S-5, S-6

Figure 5-4

Figure 5-5

5-16 SIMPLE CYCLE GAS TURBINE HEAT RECOVERY FLOW DIAGRAM

MODES G-1, G-2, G-3

Figure 5-6
 FLOW DIAGRAM FOR COMBINED CYCLE
 MODES C-1, C-2

Figure 5-7

6. ECONOMIC ANALYSIS

6.1 Methods

Economic comparisons among the alternative energy supply systems are based on net present value life cycle costs. Pertinent factors used in the analysis are:

1. Discount (interest) rate for determining present value: 8 percent
2. Projected life cycle: 25 years
3. Starting point for present value determinations (project year zero): 1980
4. Projected annual cost inflation rates, in percent
 - a. Purchased electricity: 6.0
 - b. Coal: 5.0
 - c. Fuel oil: 8.0
 - d. Miscellaneous operating costs: 3.5

Discount rate and life cycle data were furnished by Holmes & Narver, Inc. Project year zero for present value (1980) was established on the basis that the first year of WIPP activity would be 1981. Inflation rates for coal and fuel oil were taken from ERDA projections furnished by Holmes & Narver, Inc.

Inflation rate for purchased electricity is based on Southwestern Public Service Company projections. The value of

6 percent corresponds closely with a 5.7 percent rate projected by ERDA for the mountain states as a whole.

Inflation rate for miscellaneous operating costs was derived by analyzing the Department of Labor Consumer Price Index and using the average rate that has occurred during the past 25 years.

Present value was determined by dividing cash costs during each year of project life by the factor 1.08^n , in which n is the project year number.

6.2 Costs

a. Purchased Electricity: Cost of purchased electricity has been estimated from Southwestern Public Service Company Tariff 4106.3, Large General Service. A copy of this rate schedule is included in the Appendix. Information from SWPS indicates a projected purchased fuel adjustment of 1.772 ¢/kWh in August 1978. This adjustment has been used to arrive at 1978 projected costs, which in turn are escalated by the previously noted inflation factor.

Purchased electric energy costs are based on an 86 percent power factor and utility-owned transformers.

For information purposes, the projected unit costs, adjusted to a 1980 basis, are as follows:

<u>Period</u>	<u>¢/kWh</u>
1981	3.02
1982	3.02
1983-1995	3.21
1996-2005	3.02

b. Construction Costs: Estimated construction costs for the alternative energy supply systems are listed in Table 6-1. As noted on the table, costs for use in economic comparisons have been escalated to 1980 at an inflation rate of 6 percent per year. The inflation rate was derived from an analysis of the Handy-Whitman Index of Public Utility Costs and the Engineering New Record cost indexes.

Estimated construction costs were developed from a number of sources, including:

1. Cost records from Envirodyne Energy Services files
2. Budget price estimates from equipment suppliers
3. Published cost estimating data

Wherever possible, costs have been developed from more than one source.

Note that vital and by-product generation modes show no charge for the electric utility connection. Because of the lowered utility revenues under these modes, it is likely that SWPS would require an adjustment, either by charging for part of the connection cost or through a longer minimum contract period.

c. Fuel Costs: These costs were developed from Federal Power Commission published data, information from SWPS on coal costs, information provided by Holmes & Narver, Inc., and previously developed data by Envirodyne Energy Services. Fuel costs adjusted to a 1980 basis are:

Coal: 89.5¢/million Btu

Oil: 40¢/gallon

In connection with coal cost, the value is based on a current (1977) cost of 77.3¢/million Btu, corresponding with a price of \$19 per ton and a high heat value of 24,580,000 Btu/short ton as designated by ERDA. This compares with a current cost of 70.6¢/million Btu currently experienced by SWPS for larger scale purchases, reflecting a reasonable correlation.

d. Miscellaneous Operating Costs: Miscellaneous operating costs include operating labor, maintenance, lubricating oil and other items attendant to plant operation. Factors used to determine miscellaneous operating costs are as follows:

1. Average annual labor cost: \$18,500 per person
2. Operating staff levels

<u>Mode</u>	<u>Full On-Site</u>	<u>Vital and By-Product</u>
Steam turbine	20	15
Gas turbine	10	10
Combined Cycle	15	11
Diesel	14	10

3. Maintenance, mills/rated kWh

- a. Steam turbines: 1.7
- b. Gas turbines: 1.5
- c. Diesel engines: 2.7

Rated kWh = prime mover rating times
operating hours

4. Lube oil (diesel only)

- a. Consumption: 5000 rated kWh/gal
- b. Price: \$1.50/gal

Maintenance costs were developed from published data (ASME, Gas Turbine Publications, Inc., etc.), records from previous installations and maintenance contracts offered by equipment suppliers.

Miscellaneous operating costs for full purchased electricity include costs of insuring that the standby generating equipment will operate when called upon. This includes periodic operation of units, inspections and other costs.

6.3 System Economic Comparisons

Table 6-2 tabulates the results of the present value life cycle analyses of each alternative considered. As will be noted, the life cycle costs of all on-site generation modes exceed those of full purchased electricity (Mode P-1). Excess costs range from 2 percent for Mode S-1 to 98 percent for Mode G-1.

6.4 Cost Sensitivity Factors

Energy cost comparisons are affected in varying degrees by changes in conditions. The following sections illustrate factors that could materially change system economics.

a. Fuel Cost Inflation: Fuel constitutes a major portion of energy supply system cost. Furthermore, fuel costs occur throughout the life of the facility: as contrasted with items such as construction costs, which in most cases occur only once at the beginning. These factors make life cycle costs sensitive to projected fuel cost inflation rates. Although discounting recurring annual costs to present value tends to reduce the effect of costs occurring late in project life, assumed inflation rates can have a material effect as illustrated by the following example. The example portrays the effect on the diesel engine modes resulting from a reduction in assumed fuel oil inflation rate from the 8 percent value used in Table 6-2 to 6 percent.

<u>Mode</u>	<u>Total Present Value, \$1000</u>		<u>Percent Reduction</u>	<u>Percent of Base</u>	
	<u>8%</u>	<u>6%</u>		<u>8%</u>	<u>6%</u>
E 1	59,970	49,330	18	131	108
E-2	49,780	44,560	10	109	98
E-3	49,940	48,400	3	109	106

The change not only creates varying degrees of life cycle cost reduction, it also alters the relative rank of the three modes.

The diesel modes were selected for comparison because coal costs are likely to have the same effect on both purchased power and the coal-fired on-site modes.

b. Recoverable Heat: As noted previously, the ability of an energy using facility to absorb prime mover reject heat has a marked influence on the feasibility of on-site generation. This can be illustrated by showing the effect of a heat demand sufficient to absorb all of the reject heat created under steam turbine Mode S-1 (coal-fired, full on-site generation, 800 psig/750F, 5000 kW units). This would require a rise in facility heat usage from the projected rate of approximately 0.6 MBtu/kWh to 10.8. Results, based on items chargeable to electric generation, are as follows:

		<u>Heat Usage</u>	
		<u>As</u>	<u>All</u>
		<u>Projected</u>	<u>Produced</u>
1.	Present value, Mode S-1, \$1000:	46,550	35,750
	Percent reduction:	--	23
	Percent of Mode P-1 (base):	102	78
2.	Fuel chargeable to power, million Btu/yr:	1,035,418	309,187
	Percent reduction:	--	70
	Percent of Mode P-1 (base):	129	39

It should be emphasized that the above costs and energy usage apply only to the electric generation portion of the energy requirements under the assumed conditions. They illustrate the effects of combining power and steam generation in a facility having substantially higher thermal energy requirements than those projected for the WIPP.

6.5 Purchased Electricity Options

Since purchased electricity, Mode P-1, shows the most cost-effective arrangement, two options were evaluated in connection therewith: (1) power factor correction, and (2) primary service (customer transformer ownership).

a. Power Factor Correction: The pertinent SWPS electric rate schedule, Tarrif 4106.3, is arranged to impose additional charges for low power factors (lower than 88 percent) and credits for high values (above 93 percent). Costs shown in Table 6-2 are predicated upon use of power factor correction for the miners, resulting in an overall power factor of 86 percent. Two additional cases were considered: overall correction to 96 percent and to 100 percent. Each case was evaluated with and without cost inflation during the 25-year life cycle.

Figure 6-3 illustrates accumulated costs without considering inflationary trends. Note that savings exceed costs after 5 years for correction to 96 percent and after 4-1/2 years for correction to 100 percent.

A present value analysis was also made of the two cases, using the previously noted 8 percent per year discount rate and 6 percent per year cost inflation rate. Results are as follows, adjusted to a 1980 basis:

	<u>Present Value, \$</u>	
	<u>96%</u>	<u>100%</u>
	<u>P.F.</u>	<u>P.F.</u>
Life cycle savings	116,330	319,000
Installation cost	<u>26,200</u>	<u>50,900</u>
Net savings	90,130	268,100

Power factor correction therefore shows a clear economic advantage both with and without cost inflation.

b. Primary Service: The utility rate schedule provides for a 3 percent discount if the customer accepts electric service at primary voltage (115 kv). Under this condition

transformer ownership and maintenance costs are assumed by the customer. Furthermore, metering is done on the primary side, so transformer losses (approximately 1 percent of energy use) are also assumed by the customer.

Figure 6-4 illustrates estimated cumulative savings and ownership costs without inflation. Note that costs exceed savings throughout the entire life cycle.

A present value (1980) analysis, based on the previously noted inflationary trends (6 percent), shows the following:

	<u>Present Value, \$</u>
Life cycle savings	241,180
Installation cost	<u>196,520</u>
Net savings	44,660

While inclusion of inflationary trends does result in an estimated net savings in present value, the relatively small (20 percent of installation cost) amount indicates a marginal situation. A reduction of slightly more than one percent in the assumed inflation rate creates a break-even condition. Beyond this is the fact that the utility is in a more favorable position for maintaining and replacing the transformer, should the need arise.

For the foregoing reasons, primary service is not considered to be economically attractive.

Table 6-1

ALTERNATIVE ENERGY SUPPLY SYSTEMS
ESTIMATED CONSTRUCTION COSTS
in \$1000

Page 1

PURCHASED POWER	P-1
Utility Connection	No Charge
Emergency Generator Plant	<u>3,000</u>
Total Cost-1976	3,000
1980	3,750

COMBINED CYCLE	C-1	C-2
Utility Connection	---	No Charge
Emergency Generator Plant	---	3,000
Gas Turbine Plant	4,800	650
Heat Recovery Boiler Plant	1,100	240
Turbo-Generator Plant	3,200	335
Oil Handling and Storage	530	75
Emission Control	<u>160</u>	<u>50</u>
Total Plant Cost 1977	9,790	4,350
1980	11,660	5,200

Table 6-1

ALTERNATIVE ENERGY SUPPLY SYSTEMS
ESTIMATED CONSTRUCTION COSTS
in \$1000

Page 2

STEAM TURBINES	S-1	S-2	S-3	S-4	S-5	S-6	S-7
Utility Connection	---	---	---	No Charge	No Charge	No Charge	No Charge
Emergency Generator Plant	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Turbo-Generator Plant	7,500	8,000	8,550	5,500	5,200	6,000	630
Boiler Plant	5,280	7,500	7,000	4,900	4,725	5,625	910
Coal Handling and Ash Removal	1,500	1,500	1,500	1,100	1,100	1,100	800
Emission Control Equipment	<u>850</u>	<u>800</u>	<u>800</u>	<u>660</u>	<u>660</u>	<u>660</u>	<u>200</u>
Total Plant Cost							
1976	18,130	20,800	20,850	15,160	14,685	16,385	5,540
1980	22,850	26,220	26,290	19,100	18,500	20,610	6,950

Table 6-1

ALTERNATIVE ENERGY SUPPLY SYSTEMS
ESTIMATED CONSTRUCTION COSTS
in \$1000

Page 3

GAS TURBINES	G-1	G-2	G-3
Utility Connection	---	No Charge	No Charge
Emergency Generator Plant	---	---	3,000
Gas Turbine Plant	6,400	3,200	650
Heat Recovery Boiler Plant	1,400	700	240
Oil Handling and Storage	700	350	75
Emission Control Equipment	<u>200</u>	<u>100</u>	<u>50</u>
Total Plant Cost 1977	8,700	4,350	4,015
1980	10,400	5,200	4,800

DIESEL ENGINES	E-1	E-2	E-3
Utility Connection	---	No Charge	No Charge
Emergency Generator Plant	---	---	---
Engine Generator Plant	5,700	2,850	2,850
Heat Recovery Boiler Plant	900	450	450
Oil Handling and Storage	500	250	250
Emissions Control	<u>100</u>	<u>50</u>	<u>50</u>
Total Plant Cost 1977	7,200	3,600	3,600
1980	8,580	4,290	4,290

Table 6-2

ALTERNATIVE ENERGY SUPPLY SYSTEMS
ECONOMIC COMPARISONS

MODE	DESCRIPTION			PRESENT VALUE (1980) \$1000											
	Fuel (A)	Degree Generated (B)	Unit Size kW	Construction	Electric Energy	Fuel	Misc. Operation	Total	% of Base						
P-1	Full Purchased Electricity			3,750	40,170	---	1,700	45,620	Base						
Steam Turbines:															
S-1	C	F	5000							22,850	---	15,890	7,980	46,720	102
S-2	C	F	5000							26,220	---	14,790	7,980	48,990	107
S-3	C	F	7500							26,290	---	13,870	7,980	48,140	106
S-4	C	V	2500							19,100	20,330	6,240	5,480	51,150	112
S-5	C	V	3750							18,500	20,330	5,930	5,480	50,240	110
S-6	C	V	5000							20,610	20,330	5,920	5,480	52,340	115
S-7	C	B	875							6,950	39,650	700	4,880	52,180	114
Gas Turbines:															
G-1	O	F	1952							10,400	---	75,220	4,550	90,170	198
G-2	O	V	1952							5,200	20,330	35,250	3,680	64,460	141
G-3	O	B	574							4,800	39,470	6,060	3,250	53,580	117
Combined Cycles:															
C-1	O	F	$\frac{1950}{1000}$							11,660	---	54,920	6,160	72,740	159
C-2	O	B	$\frac{574}{100}$							5,200	38,650	6,490	3,590	53,930	118
Diesel Engines:															
E-1	O	F	2412	8,580	---	44,200	7,190	59,970	131						
E-2	O	V	2412	4,290	20,330	20,730	4,430	49,780	109						
E-3	O	B	2412	4,290	33,910	8,260	3,480	49,940	109						

Notes: (A) C: Coal O: Oil
(B) F: Full V: Vital B: By-Product

Figure 6-3

POWER FACTOR CORRECTION
WITHOUT INFLATION

Figure 6-4

PRIMARY ELECTRICAL SERVICE
WITHOUT INFLATION

7. CONCLUSIONS

Overall conclusions reached in the course of this report are:

1. Although natural gas has been primarily used in the past for local utility power, use of utility power by the WIPP is unlikely to increase consumption of natural gas. The most recent and all projected utility plant additions are coal-fired.
2. None of the coal-fired on-site plant (steam turbines) evaluated herein would have a fuel energy input lower than that of utility power.
3. The only on-site generation option showing lower fuel energy input than utility power uses diesel engines: an operation requiring oil fuel.
4. The thermal energy requirements of the WIPP are too low for effective use of an on-site generation/heat recovery plant.
5. None of the on-site generation options evaluated herein are more cost-effective than purchased electricity.

6. With utility supplied electric energy, power factor correction is justified but primary service (customer-owned transformers) is not.
7. Nominal deviations from projections used herein could create changes in relative positions, but it is unlikely that the basic conclusions would be altered.

8. APPENDIX

8.1 References

8.2 Southwestern Public Service Company Tariff 4106.3
and Service Territory Map

8.3 ERDA Directives

- a. Action Memorandum: Energy Management in
ERDA Facilities
- b. ERDA Standard Btu Conversion Factor for
Energy Conservation Reporting
- c. Life Cycle Costing: Energy Real Growth
Rates

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23. National Oceanic and Atmospheric Administration Environmental Data Service, Climatology of the United States, Monthly Normals of Temperature, Precipitation and Heating and Cooling Degree Days, New Mexico.

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29. Cost Indexes, Engineering News Record.
30. National Technical Information Service, Publication Number PB-228 893, Economic Evaluation of Total Energy, July 1973.
31. Waste Isolation Pilot Plant Preliminary Analysis of Electrical Power Supply Alternative, Holmes & Narver, Inc., December 16, 1976.
32. ERDA Action Memorandum, Energy Management in ERDA Facilities.
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17.07

Southwestern
PUBLIC SERVICE
Company

P. O. Box 1688
CARLSBAD, NEW MEXICO 88220

February 4, 1977

Mr. Bill Neal
Envirodyne Energy Services
2130 S. Dupont Dr.
Anaheim, Calif. 92806

Dear Sir:

Enclosed is a copy of our Large General Service Tariff 4106.3 and a copy of our company territory map showing plants and transmission lines as requested by you in our telephone conversation of this date.

Please contact us if we can be of further service.

Yours truly,

W. K. Rotan
District Manager

WKR: bd

Enclosures

cc: Bill Slade
Bill Helton

See TERRITORY Below
Community, Town or City

CANCELLING.....Revised

N.M.P.S.C. SHEET NO. 502

FOR COMMISSION USE ONLY

APPROVED

AUG 22 1974

NEW MEXICO PUBLIC SERVICE COMMISSION

By Order # 384LARGE GENERAL SERVICE

Tariff 4106.3

(X)

Page 1 of 2

APPLICABLE: To all commercial and industrial electric service supplied at one point of delivery, and measured through one kilowatt-hour meter, where facilities of adequate capacity and suitable voltage are adjacent to the premises to be served. Water heating and space heating service will be furnished in conjunction with the Company's standard General Service Heating Rider.

Not applicable to temporary, breakdown, standby, supplementary, resale or shared service, or to service for which a specific rate schedule is provided.

TERRITORY:	Artesia	Dexter	Loving	Portales
	Carlsbad	Hagerman	Malaga	Roswell
	Clovis	Lake Arthur	Otis	Texico

RATE: Demand Charge: \$396.00 for the first 200 kw, or less, of demand per month.
\$1.34 per kw for all additional kw of demand per month.

Energy Charge: .86¢ per kwh for the first 230 kwh used per month per kw of demand, or the first 120,000 kwh used per month, whichever is greater.
.59¢ per kwh for the next 230 kwh used per month per kw of demand.
.49¢ per kwh for all additional kwh used per month.

DETERMINATION OF DEMAND: The kw determined from Company's demand meter for the 30-minute period of customer's greatest kw use during the month, but not less than 60% of the highest demand established in the preceding eleven months.

(To be inserted by utility)

Issued by

(To be inserted by N.M.P.S.C.)

S-2

ADVICE NO. 97

Paul M. Springer
Name

DATE FILED AUG 21 1974

BILLING

NO. 504

EXECUTIVE VICE PRESIDENT EFFECTIVE

FOR COMMISSION USE ONLY

APPROVED

AUG 22 1974

NEW MEXICO PUBLIC SERVICE COMMISSION

By Order #384

LARGE GENERAL SERVICE

Tariff 4106.3 (X)

Page 2 of 2

POWER FACTOR ADJUSTMENT: Bills computed under the above rate will be increased \$0.25 for each kvar by which the reactive demand exceeds, numerically, 0.53 times the measured kw demand, and will be reduced \$0.25 for each kvar by which the reactive demand is less than, numerically, 0.40 times the measured kw demand.

PRIMARY SERVICE DISCOUNT: A discount of 3% will be allowed when (X) service is supplied at a line voltage of 12 kv, or greater, and no transformation is made by the Company at the customer's location.

FUEL COST ADJUSTMENT: The charge per kwh of the above rate shall (X) be increased or decreased by the amount that the Company's average cost of fuel and purchased power per kwh delivered exceeds or is less than \$.002165 per kwh, as specified by General Order of the New Mexico Public Service Commission.

TAX ADJUSTMENT: Billings under this schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

TYPE OF SERVICE: A-C; 60 hertz; at one available standard voltage. (X)

CONTRACT PERIOD: A period of not less than one year.

MINIMUM CHARGE: The demand charge.

(To be inserted by utility)

Issued by

(To be inserted by N.M.P.S.C.)

ADVICE NO. 97

Paul M. Jennings
Name

DATE FILED AUG 21 1974

ORDER NO. PDV

Executive Vice President

SEP 1 1974

S-3

INDEX TO PRINCIPAL ELECTRIC POWER PLANTS

PLANT	CAPABILITY
1 PLANT "X"	487,500 KW.
2 NICHOLS STATION	481,000 KW.
3 DENVER CITY	86,000 KW.
4 AMARILLO	80,000 KW.
5 CUNNINGHAM STATION	290,000 KW.
6 MOORE COUNTY	74,100 KW.
7 RIVERVIEW	32,000 KW.
8 CARLSBAD	50,100 KW.
9 ILLU	47,000 KW.
10 ROSWELL	27,800 KW.
11 C. B. JONES STATION	512,000 KW.
STEAM PLANT CAPABILITY	2,162,500 KW.
RIVERVIEW, COMBINED CYCLE (GAS TURBINE CAPABILITY)	25,000 KW.
ROSWELL GAS TURBINE	10,000 KW.
PLANT "CZ" EXPANDER TURBINE	12,000 KW.
PLANT "66" GAS TURBINE	30,400 KW.
GUYMON GAS TURBINE	15,200 KW.
* TOTAL PLANT CAPABILITY	2,255,100 KW.
MADDOX STATION (N.M.E.S.CO.)	123,000 KW.
TOTAL SYSTEM CAPABILITY	2,378,100 KW.

STEAM PLANT ADDITIONS:
UNDER CONSTRUCTION

HARRINGTON STATION, UNIT NO.1
(COAL FIRED BOILER) 356,700 KW. JUNE, 1976

* DEMONSTRATED GROSS CAPABILITY

THIS LINE
NOW IN SERVICE

- LEGEND
- ELECTRIC TRANSMISSION LINES
- 230,000 VOLTS
 - 115,000 VOLTS
 - 66,000 VOLTS
 - LINES UNDER CONSTRUCTION
(VOLTAGE INDICATED BY LINE WIDTH)
 - OTHER LINES
 - TRANSMISSION LINE INTERCONNECTION

TERRITORY SERVED BY

The
ELECTRIC
Company

AUGUST 31, 1974

0 10 20 30 40
SCALE OF MILES

UNITED STATES
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
WASHINGTON, D.C. 20545

ACTION MEMORANDUM

TO: Administrator

FROM: Acting Assistant Administrator for Administration

SUBJECT: ENERGY MANAGEMENT IN ERDA FACILITIES

Issue

ERDA policy regarding use of natural gas, and selection of fuel for major fuel burning installations (MFBI) such as central plants.

Background

It is the present stated policy of some Federal agencies, notably the Department of Defense, to reduce the use of and reliance on natural gas and petroleum. It is the purpose of this paper to present the need for an authorization of a similar policy with respect to ERDA facilities.

The need for such policy is further indicated by legislation, notably the Energy Supply and Environmental Coordination Act of 1974, P.L. 93-319, as amended by P.L. 94-163, which empowers the Federal Energy Administrator, under certain circumstances, to require that a major fuel burning installation in the early planning process be designed and constructed to use coal as its primary energy source. Pursuant to this legislation, FEA on December 29, 1976 issued to all agencies a requirement to report on the status of their MFBI's to enable FEA to determine which may be candidates for such orders. The Act further empowers the Federal Energy Administrator, under certain circumstances, to prohibit existing major fuel burning installations from burning natural gas or petroleum products as their primary energy sources where coal burning capability and equipment exist. *

ERDA's consumption of natural gas in FY 1976 was 7,500,000 thousand cubic feet or 7,850 billions Btu, at a cost of about \$3.4 million. This represented about 9.4% of ERDA's FY 1976 energy usage, exclusive of the uranium enrichment process.

Discussion

Forecasts of the American Gas Association and the Federal Power Commission show natural gas reserves are becoming depleted. Since natural gas is a superior fuel its use in new major fuel burning installations should be avoided and conversion of existing plants using natural gas should be effected wherever environmentally feasible and where the impact on operating cost is reasonable.

The Program Proposal for Energy Management in ERDA Facilities, July 1976, recommended that most ERDA sites relying on natural gas should be studied to establish feasibility of conversion, and that the overall cost of such studies was estimated to be approximately \$5.5 million. Major plant conversion (or replacement) projects, some costing up to \$50 million, would be expected to be funded on an individual basis. Overall cost of feasible conversions throughout ERDA is not known at this time, but probably would approach \$500 million. A comparable policy pertaining to new plants should be established.

Because of ERDA's high public visibility as the Nation's technical energy agency and as the second largest Federal overall user of energy (third in use of natural gas), ERDA should take the lead in reducing reliance on natural gas.

Proposed Policy

For new plants and replacements for non-convertible existing plants establish ERDA policy requiring:

1. MFBI of 100 Mega Btuh capacity or larger to be designed to burn coal, including coal derivatives, and/or refuse derived fuel (RDF) wherever feasible. Determination of feasibility shall include such considerations as availability of coal, availability and dependability of RDF source, and capability to meet air pollution and other environmental standards.
2. MFBI of greater than 50 Mega Btuh but less than 100 Mega Btuh capacity shall be capable of burning either coal, including coal derivatives, RDF, or oil, with immediate selection of fuel to be determined by cost. Determination of primary fuel would include consideration of local availability and air pollution requirements as well as purchase cost. Use of oil as the primary fuel would require HQ approval. *

Pro 1: Will conserve natural gas.

2: Will establish ERDA's role in reducing national reliance on natural gas.

3: Will decrease vulnerability of ERDA facility operations to natural gas curtailment.

Con 1: First costs of new and replacement plants will be higher in many cases.

2: Operating costs may be higher in many cases, in the short term.

3: Could lead to investment in secondary fuel capability (in 50-100 Mega Btuh plants) that might never be used.

Recommendation

That ERDA policy with respect to major fuel burning installations, as proposed above, be established and implemented.

Approve _____

Disapprove _____

Date _____

ERDA STANDARD BTU CONVERSION FACTOR
FOR ENERGY CONSERVATION REPORTING (1)

<u>Form of Energy</u>	<u>Btu Content</u>	<u>Btu x 10⁹ per Reporting Unit</u>
Electricity (2)	11,600 Btu/KWH	0.0116 per MWH (Megawatt hour)
Fuel Oil	138,700 Btu/Gal.	0.1387 per 1000 Gallon
Natural Gas	1,031 Btu/C.F.	0.001031 per 1000 C.F.
LPG (3)	95,500 Btu/Gal.	0.0955 per 1000 Gal.
Coal	24,580,000 Btu/Short ton	0.2458 per short ton
Other (Examples) - Steam (4)	1,390 Btu/Lb.	0.00139 per 1000 Lbs.
- Chilled Water (5)	24,000 Btu/Ton-hour	0.024 per 1000 ton-hours
- Methanol	63,500 Btu/Gal.	0.0635 per 1000 Gal.
Automotive Gasoline	125,000 Btu/Gal.	0.125 per 1000 Gal.
Diesel	138,700 Btu/Gal.	0.1387 per 1000 Gal.
Aviation Gasoline	125,000 Btu/Gal.	0.125 per 1000 Gal.
Jet Fuel	130,000 Btu/Gal.	0.130 per 1000 Gal.

- (1) The use of different conversion factors is permitted only where such factors are identified and justified, and is subject to FCM approval.
- (2) Electricity - Assumes 10,536 Btu per KWH generated at station and 9% line loss.
- (3) Includes Propane and Butane.
- (4) Assumes 1000 Btu per pound of steam generated at boiler plant, 80% boiler efficiency at 11% line loss.
- (5) Assumes 12,000 Btu per ton-hour, and overall efficiency and 11% line loss.

TABLE 2
LIFE CYCLE COSTING
ENERGY REAL GROWTH RATES

*25 years
Money 8%*

COAL 5% Annually
FUEL OIL 8% Annually
GAS (Natural or LPG) 10% Annually

ELECTRICITY:

REGION		REGION	
NEW ENGLAND	6.9% Annually	EAST NORTH CENTRAL	5.6% Annually
CONNECTICUT		ILLINOIS	
MAINE		INDIANA	
MASSACHUSETTS		MICHIGAN	
NEW HAMPSHIRE		OHIO	
RHODE ISLAND		WISCONSIN	
VERMONT			
MIDDLE ATLANTIC	5.9% Annually	WEST NORTH CENTRAL	5.6% Annually
NEW JERSEY		IOWA	
NEW YORK		KANSAS	
PENNSYLVANIA		MINNESOTA	
		NEBRASKA	
SOUTH ATLANTIC	5.8% Annually	NORTH DAKOTA	
DISTRICT OF COLUMBIA		SOUTH DAKOTA	
FLORIDA			
GEORGIA		WEST SOUTH CENTRAL	7.5% Annually
MARYLAND		ARKANSAS	
NORTH CAROLINA		LOUISIANA	
SOUTH CAROLINA		OKLAHOMA	
VIRGINIA		TEXAS	
WEST VIRGINIA			
EAST SOUTH CENTRAL	5.6% Annually	MOUNTAIN	5.7% Annually
ALABAMA		ARIZONA	
KENTUCKY		COLORADO	
MISSISSIPPI		IDAHO	
TENNESSEE		MONTANA	
		NEVADA	
PACIFIC	7.3% Annually	NEW MEXICO	
CALIFORNIA		UTAH	
OREGON		WYOMING	
WASHINGTON			

NOTE: An annual compounded 5% growth rate is equivalent to the following factors - 1st year - 1.05, 5th year-1.276, 10th year-1.629, 15th year-2.079, 20th year-2.653 and 25th year-3.386.

D. USE OF APPROPRIATE SERVICE LIFE.

The LCC study estimated economical useful life, shall not exceed 25 years. We selected 25 years as the maximum useful life or payout period because of the speculative validity of benefits or savings in excess of 25 years.