INDEN 5350 - CREATIVE COMPONENT

A METHODOLOGY TO DETERMINE COGENERATION LOADS AND OPERATING COSTS FOR AN OFFICE BUILDINGS COMPLEX

BY

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PREFACE

Cogeneration is today, practiced mostly in large scale, industrial plants. The major reason for this is the ability to utilize the waste heat off the prime movers for industrial process needs. But, cogeneration can be used effectively in a large commercial complex also, where there are no thermal process needs, but where the heat generated can be used for heating and air conditioning via absorption chilling. The purpose of this report is to develop a methodology to calculate the total electrical and thermal loads that would have to be generated by a central cogeneration plant for a building complex. Methods have also been developed to calculate the operating costs for a central cogeneration plant, under two different technologies and three different loading options. The two technologies that have been considered are Gas Turbines and Gas Engines, each with heat recovery steam generators and electrical generators. The loading options that have been considered are Electrically Isolated, Electrically Baseloaded and Thermally Baseloaded options. A complete case study has been included in the appendix.

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TABLE OF CONTENTS

LIST OF TABLES AND FIGURES

CHAPTER 1

INTRODUCTION

Cogeneration is defined as the coincident generation of necessary heat and power - electrical and/or mechanical - or the recovery of low-level heat for power production. (4) Two-thirds of the energy consumed by conventional electric power plants is normally lost to the environment. (2) Cogeneration systems recapture much of the otherwise wasted thermal energy and use this energy for a variety of purposes.

Natural gas-fired cogeneration systems are an attractive option from both an environmental and an energy efficiency standpoint. (2) Gas-fired cogeneration systems such as gas turbines or gas engines offer a clean and efficient means of power production.

What do utilies think about cogenerators? Limaye (3) attempted to answer this question. According to him, many utilies, looking ahead, see their best prospects in (a) completing plants now almost completed, and (b) to some extent discouraging increases in load growth. As part of this basic approach, all utilities would find it advantageous to flatten their system load curve, and to reduce or eliminate use of expensive peaking generation requiring use of high cost fuels in relatively inefficient power plants. Cogeneration could contribute significantly in this approach. It appears that the changing economic and institutional environment will lead electric utilities in the 1980s and 1990s towards a gradual redefinition of their traditional role. Thus, utilities may actively encourage cogeneration and may even participate in such projects.

The methodology used to estimate total electrical and thermal loads and operating costs for an office-buildings complex was developed as part of a study for the Oklahoma State Office of Public Affairs (OPA). The study is concerned with studying cogeneration potential for an eight-buildings complex. A more detailed explanation of the problem and the complete study can be found in Appendix A.

To size the cogeneration plant for the complex, the total electrical and thermal loads that would have to be generated had to be determined. The total monthly electrical KWH, KW and monthly thermal loads are shown in Table 1.1. A detailed explanation of how they were determined is included in the section entitled `Methodology Used to Develop the Total Loads for the Complex'. The first step towards determining the total loads for the cogeneration complex was to determine each building's individual loads. This was done by using `Peak Day Analysis Plots' supplied by the local utility, knowledge of existing equipment, and the natural gas bills. A breakdown of the total monthly electrical load in each building was made. The breakdown included lighting and office equipment loads, a baseload that always exists and chiller loads. A major assumption made at this stage was that all buildings will be cooled via absorption chilling. Therefore, for those buildings that do not have absorption chilling, the total monthly electrical consumption by chillers was converted into equivalent MMBTUs that would need to be generated. The thermal loads were broken down into monthly baseloads, monthly cooling loads and monthly heating loads, if any. A detailed explanation of the breakdown follows in the section entitled `Methodology Used to Develop Individual Building Loads and Use of Peakday Analysis Plots'.

Once the total loads for the cogeneration complex were determined, prime movers were sized under the different loading options. Next, a methodology was developed to calculate operating costs under different scenarios. The complete case study for OPA is included in Appendix A. This case study includes an economic analysis of the various alternatives and the present worth criterion has been used to determine the best alternative.

TABLE 1.1
TOTAL LOADS - ELECTRICAL AND THERMAL

MONTH	DAYS IN MONTH	KWH/MO	CHP_ELEC PEAK KW	AVG_KW	LOAD-FAC	MMBTU	THERMAL MMBTU/HR
1	31	2692461	4765	3619	0.76	17074	34.4
2	29	2520804	4870	3622	0.74	12022	25.9
3	31	2788671	4860	3748	0.77	11768	23.7
4	30	2712386	4965	3767	0.76	12674	26.4
5	31	3013931	5215	4051	0.78	12657	25.5
6	30	3130500	5610	4348	0.78	13238	27.6
7	31	3555456	6050	4779	0.79	17282	34.8
8	31	3378026	5875	4540	0.77	16204	32.7
9	30	3038571	5460	4220	0.77	15837	33.0
10	31	2846641	5090	3826	0.75	9714	19.6
11	30	2755500	5210	3827	0.73	11354	23.7
12	31	2715290	4920	3650	0.74	11727	23.6

CHAPTER 2

LOADING OPTIONS FOR COGENERATION

Hay (2) points out that design alternatives are limited only by the creativity of the design engineers. However, for purposes of exploring the feasibility of a potential cogeneration system, only a limited number of alternatives have been considered in this report. These concepts are described briefly below.

Isolated Operation, Electric Load Following

The facility is independent of the electric utility grid, and the cogenerator is required both to produce all power required on-site and to provide all reserves required for scheduled and unscheduled maintenance. According to Hay (2), this type of system generally provides the least attractive economic return and the construction of this type of facility is extremely rare.

Baseloaded, Electrically Sized

An electrically baseloaded system is sized to satisfy that end user electric demand which is always available. The energy end user purchases supplemental power from the utility grid, and, in general, no power is sold to the grid. Supplemental heat is provided by on-site boilers or burners.

Baseloaded, Thermally Sized

A thermally baseloaded system is sized to provide most of the site's required thermal energy using recovered heat from the engine prime mover. The engines are operated to follow the thermal demand with supplemental boilers fired as required. This option frequently results in the production of more power than is required on-site and this power may be sold to the electric utility.

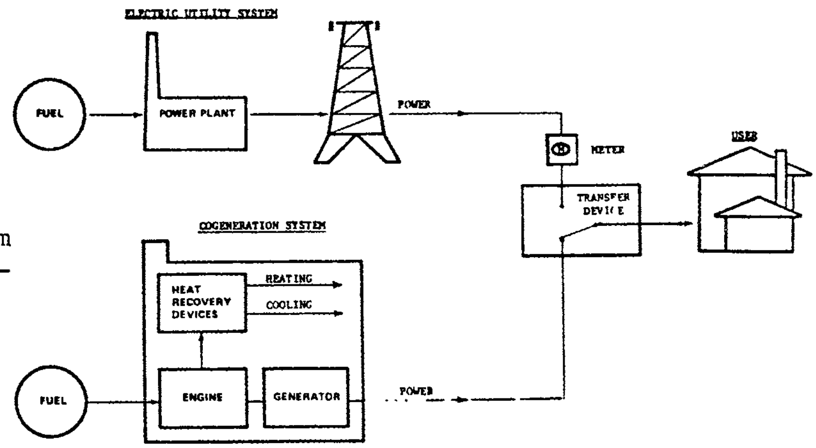
Each of these concepts is illustrated in Figure 2.1.

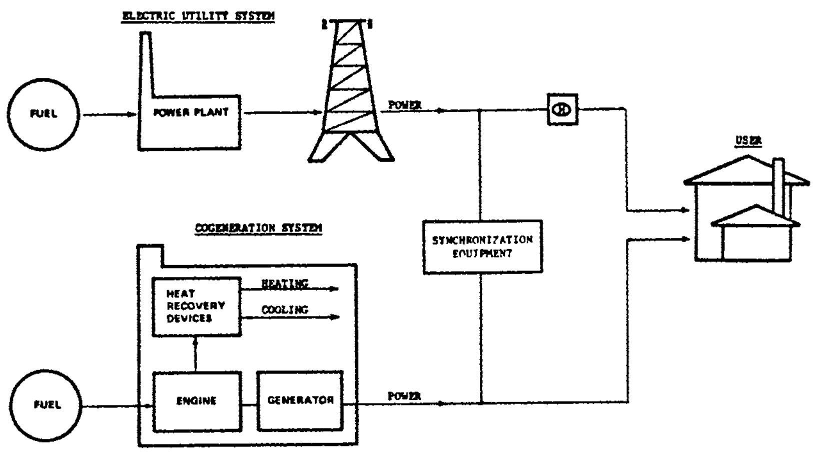
FIGURE 2.1

COGENERATION OPTIONS

ISOLATED COGENERATOR

User receives all power from Cogeneration System or Electric Utility System.



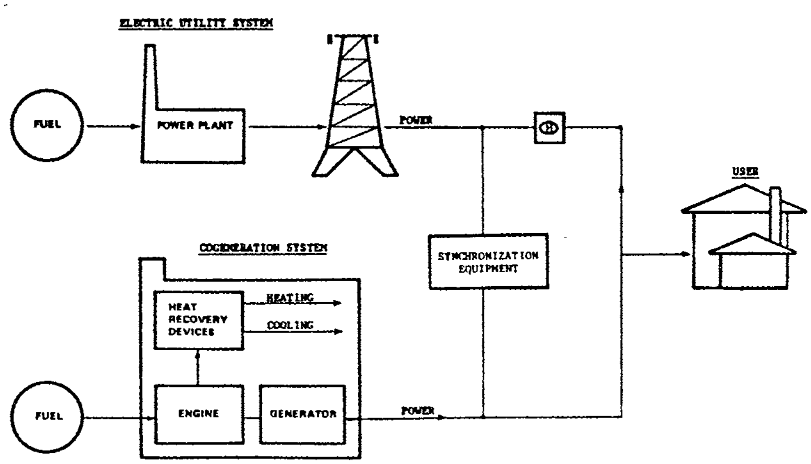


ELECTRICALLY BASE-LOADED COGENERATION

User receives power from Cogeneration System and purchases power from the Electric Utility System

THERMALLY BASELOADED COGENERATION

User receives power from Cogeneration System and cogenerator sells power to the Electric Utility.



URCE: A.G.A. MANUAL – COGENERATION FEASIBILITY ANALYSIS

CHAPTER 3

METHODOLOGY USED TO DEVELOP INDIVIDUAL BUILDING LOADS - BUILDING LOADS SPREADSHEET

The first step to developing the total loads for the cogeneration complex was to determine each building's individual loads. Knowledge of the buildings already existed and information on the total monthly electrical demand and consumption was also available. But, a detailed breakdown of each building's electrical and thermal loads was necessary.

Peak Day Analysis Plots were obtained from the local utility for this purpose. These plots can be found in Appendix B. A typical Peak Day Analysis Plot shows the load variation in 15 minute intervals for the peak day in a particular month. It also shows the load variation for the day before the peak day and the day after the peak day. Twelve Peak Day Analysis Plots were obtained for each building, one for each month in 1988.

To explain the methodology, a typical building's (Jim Thorpe) Peak Day Analysis Plots have been used. The Building Loads Spreadsheet is shown in Tables 3.1 and 3.11. Table 3.1 shows the electrical loads, while Table 3.11 shows the thermal loads. The main idea here was to breakdown the electrical and thermal loads, as talked about earlier. An explanation of each of the individual columns follows. All references to KW and hours per day of operation have been obtained from the Peak Day Analysis Plots and some knowledge of the way in which the building operates.

Column A - Average hours per day that lights are on in the building.

Column B - Average KW towards lighting and Office Equipment for the month. This is obtained by noting the increase in KW from 07 hours to 08 hours on the Peak Day Analysis Plots (Figure 3.1).

Column C - The total KWH/day for Lighting and Office Equipment is obtained by multiplying Column A with Column B.

Column D - The total hours per day that the baseload exists. The average KW is so selected that this load always exists in the month.

Column E - The average KW towards baseload for the month. The baseload is made up of fans and pumps and lights that are always on. This is obtained from the Peak Day Analysis Plots as shown in Figure 3.1.

Column F - The total KWH per day attributed to the baseload is obtained by multiplying Column D with Column E.

Columns

G,H,I,J - The total KWH attributed to chillers has been broken down into two components - an average hrs/day (Column G) at an average load (Column H) and an other average hrs/day (Column I) at another average load (Column J). This has to be done in order to convert chilling KWH into equivalent MMBTUs assuming that absorption chilling will be incorporated in all buildings.

Column K - The total KWH per day attributed to chillers is obtained by multiplying (Column G with Column H) and (Column I with Column J) and adding the two together.

Column L - The electrical KWH/month to be generated by the CHP plant is obtained by multiplying (Column F by 7days/week) and (Column C by 5 days/week) and adding the two. This figure is then multiplied by the number of weeks in the month.

Column M - The total estimated KWH/month is obtained by multiplying (Column F by 7) and (Column C by 5) and (Column K by 5) and adding the three together. This figure is then multiplied by the number of weeks in the month.

Column N - The total KWH/month metered is obtained from the information supplied by OG&E. This figure is used to compare with Column M.

Column O - The baseload for each building is just the domestic hot water demand.

Column P - The heating requirements have been generated from the gas bills.

Column Q - The cooling requirements for the buildings which do not have any absorption chilling have been calculated as follows:

$$\frac{(\text{Monthly chiller KWH})(3412\ \text{BTU/KWH})(2.5)}{(1.375)(0.8)(1000000\ \text{BTU/MMBTU})},$$

where

2.5 = Average COP of centrifugal chiller

1.375 = COP of 2 stage absorption chiller

0.8 = Efficiency of heat recovery generator

Monthly Chiller KWH = Column K times the number of days in the month.

For buildings that are equipped with absorption chillers, the cooling load has been derived from the bill plots.

Column R - The total thermal load is obtained by adding together columns O, P & Q.

FIGURE 3.1 – DERIVING LIGHTING AND BASELOADS

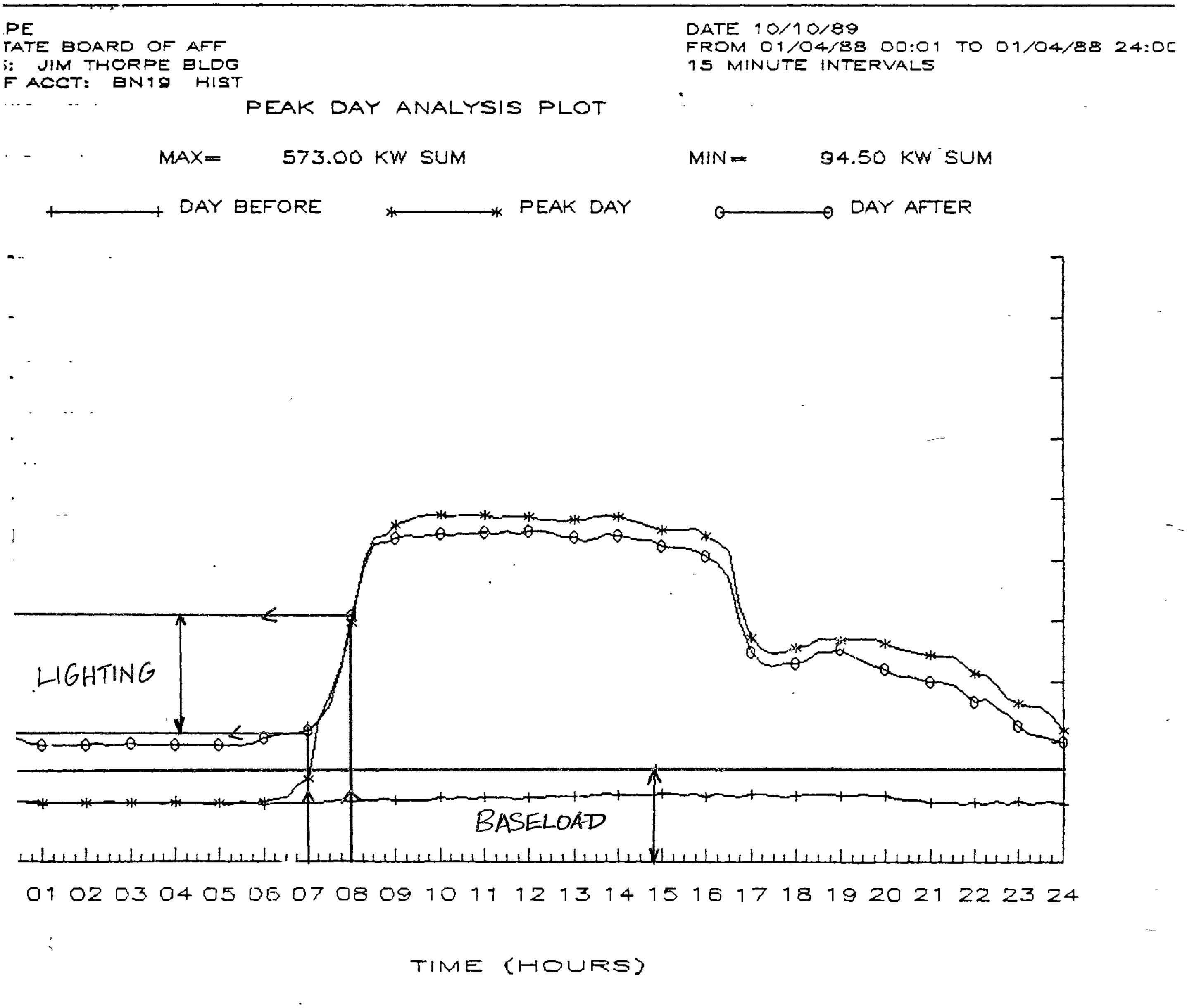


TABLE 3.1

BLDG.: J. THORPE YEAR: 1988

		A	B	C	D	E	F	G	H	I	J	K	L
					ELECTRICAL LOADS								
MONTH	DAYS IN	LIGHTS/OE			BASELOAD			CHILLER					CHP-ELEC
	MONTH	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY-1	AVG.kW-1	HR/DAY-2	AVG.kW-2	kWH'/DAY	KWH/MO.
1	31	11	200	2200	24	150	3600	3	175	9	175	2100	160314
2	29	11	200	2200	24	100	2400	3	200	10	250	3100	115171
3	31	11	200	2200	24	175	4200	3	150	8	175	1850	178914
4	30	11	200	2200	24	200	4800	3	150	8	200	2050	191143
5	31	12	200	2400	24	200	4800	3	250	9	325	3675	201943
6	30	12	200	2400	24	225	5400	3	275	9	325	3750	213429
7	31	11	200	2200	24	225	5400	5	300	9	350	4650	216114
8	31	11	200	2200	24	250	6000	5	250	8	325	3850	234714
9	30	11	200	2200	24	225	5400	7	225	9	325	4500	209143
10	31	11	200	2200	24	225	5400	5	200	8	175	2400	216114
11	30	11	200	2200	24	200	4800	3	150	9	175	2025	191143
12	31	11	200	2200	24	200	4800	3	125	8	125	1375	197514

M	N
TOTAL KWH/MONTH	
ESTIMATED.	METERED
206814	209200
179386	204800
219879	218000
235071	218800
283318	282000
293786	298000
319079	325600
319964	316400
305571	312800
269257	253200
234536	240000
227961	190400

TABLE 3.11
BLDG: J. THORPE

O P Q R

THERMAL LOADS (MMBTU)

BASELOAD	HEATING	COOLING	TOTAL
134	1555	432.7	2121.7
134	668	597.5	1399.5
134	466	381.2	981.2
134	911	408.8	1453.8
134	43	757.2	934.2
134	0	747.8	881.8
134	0	958.1	1092.1
134	0	793.3	927.3
134	0	897.3	1031.3
134	91	494.5	719.5
134	1123	403.8	1660.8
134	1619	283.3	2036.3

CHAPTER 4

METHODOLOGY USED TO DEVELOP THE TOTAL LOADS FOR THE COMPLEX - TOTAL LOADS SPREADSHEET

As stated earlier, developing the total loads was the key to the whole problem. The total electrical and thermal loads that need to be generated will then determine the size of the prime movers. The Total Loads Spreadsheet is shown in Table 4.1. From this spreadsheet, the prime movers can be sized for each of the three loading options that have been discussed. All Building Loads Spreadsheets that have been used to generate the Total Loads Spreadsheet can be found in Appendix A. An explanation for each of the columns of the Total Loads Spreadsheet follows.

<u>Column A</u> - The total KWH/month that needs to be generated is obtained by adding together Column L from the Building Loads Spreadsheet (for the buildings that presently do not have absorption chilling) and Column M from the Building Loads Spreadsheet (for those buildings that presently have absorption chilling).

<u>Column B</u> - The peak KW that needs to be satisfied in each month is obtained by adding together Columns B & E from the Building Loads Spreadsheet, for all the buildings.

<u>Column C</u> - The average KW for the month is obtained by dividing Column B by the total hours in the month.

Column D - The load factor for each month is obtained by dividing Column C by Column B.

Column E - The total thermal load for each month is the sum of the individual thermal loads for each building. (Column R from the building loads spreadsheet)

Column F - The thermal requirement in MMBTU/hr for each month is obtained by dividing the monthly thermal load (Column E) by the number of hours in the month.

TABLE 4.1
TOTAL LOADS - ELECTRICAL AND THERMAL

		A	B	C	D	E	F
MONTH	DAYS IN MONTH	KWH/MO	CHP_ELEC PEAK KW	AVG_KW	LOAD-FAC	MMBTU	THERMAL MMBTU/HR
1	31	2692461	4765	3619	0.76	17074	34.4
2	29	2520804	4870	3622	0.74	12022	25.9
3	31	2788671	4860	3748	0.77	11768	23.7
4	30	2712386	4965	3767	0.76	12674	26.4
5	31	3013931	5215	4051	0.78	12657	25.5
6	30	3130500	5610	4348	0.78	13238	27.6
7	31	3555456	6050	4779	0.79	17282	34.8
8	31	3378026	5875	4540	0.77	16204	32.7
9	30	3038571	5460	4220	0.77	15837	33.0
10	31	2846641	5090	3826	0.75	9714	19.6
11	30	2755500	5210	3827	0.73	11354	23.7
12	31	2715290	4920	3650	0.74	11727	23.6

CHAPTER 5

METHODOLOGY BEHIND DEVELOPING OPERATING COSTS FOR EACH ALTERNATIVE

Having developed the Total Loads Spreadsheet, the next step was to size the prime mover. Two different prime movers were considered for this purpose - Gas Engine and Gas Turbine. Each of these was sized under the three loading options. Thus, there were six different alternatives to consider. Appendix A carries a detailed explanation on prime mover sizing. Once the prime movers were sized, operating costs had to be calculated for each alternative. The objective of the spreadsheets to follow is to develop fuel (natural gas) costs for the cogeneration system and to determine the quantity and cost of excess electricity and natural gas that would need to be purchased from the local utility. These costs have been developed on a month-by-month basis.

1. ELECTRICALLY BASELOADED ANALYSIS - GAS TURBINE

Table 5.1 shows the spreadsheet used to evaluate the operating costs for this alternative. The total yearly operating costs for this alternative are $1,404,307, when gas is available at $2.5/MCF. It should be noted that with the equipment selected, a certain amount of gas needs to be bought from the utility (Columns M & N). This gas needs to be bought at $3.6/MCF. However, with supplementary firing at the cogeneration plant, this problem can be overcome. If supplementary firing is not done, a small steam generator can be bought, or a boiler or boilers can be fired in some buildings. Sensitivity analysis has been carried out in Tables 5.11 and 5.12. The details for each column follow.

Columns

A,B,C - KWH/mo, Peak KW, Avg. KW that needs to be generated- Copied from Total Loads spreadsheet.

Column D - This is the peak KW that can be generated by the selected equipment.

Column E - This is the total KWH that can be generated by the selected equipment.

Column F - Fuel consumption by the system - This is obtained from multiplying Column E with 0.013 MMBTU/KWH - Manufacturer's Data.

Column G - System Fuel Costs - Column F multiplied by $2.5/MCF.

Column H - System Maintenance Costs - Column E multiplied by $0.0035/KWH -Manufacturer's Data.

Column I - KWH that would need to be bought from OG&E are obtained by subtracting Column E from Column A.

Column J - KW that would need to be bought from OG&E are obtained by subtracting Column D from Column B.

Column J1 - Column J is multiplied by the appropriate demand charge and Column I by the energy charge. These are electricity charges being paid currently by the State.

Column K - System Thermal Requirements - Copied from Total Loads Spreadsheet.

Column L - MMBTU/hr capable of being produced by the selected equipment multiplied by the number of hours per month.

MMBTU/hr - Calculated from Manufacturer's Data.

= (lb/hr of steam at 150 psig)(appropriate BTU/lb)(1/0.8) ,

where

0.8 = heat recovery generator efficiency.

Column M - The MMBTUs that need to be bought from ONG are obtained by subtracting Column L from Column K.

Column N - Column M is multiplied by $3.6/MCF, the average rate at which the State buys gas from ONG.

Column O - The total monthly fuel cost for the system is the sum of Columns N, J1, H and G.

TABLE 5.1 - ELECTRICALLY BASELOADED ANALYSIS- GAS TURBINE

CHP GAS PRICE - $2.5/MCF

		A	B	C	D	E	F	G	H	I	J	J1
MONTH	DAYS IN		CHP_ELEC			SYSTEM PERFORMANCE					OG&E SUPPLY	
	MONTH	KWH/MO	PEAK KW	AVG_KW	PEAK KW	KWH	FUEL MCF	FUEL COST $	MAINT. $	KWH	KW	COST
1	31	2692461	4765	3619	3743	2784792	36202	90506	9747	0	1022	3403
2	29	2520804	4870	3622	3743	2605128	33867	84667	9118	0	1127	3753
3	31	2788671	4860	3748	3743	2784792	36202	90506	9747	3879	1117	3856
4	30	2712386	4965	3767	3743	2694960	35034	87586	9432	17426	1222	4684
5	31	3013931	5215	4051	3743	2784792	36202	90506	9747	229139	1472	12986
6	30	3130500	5610	4348	3743	2694960	35034	87586	9432	435540	1867	21583
7	31	3555456	6050	4779	3743	2784792	36202	90506	9747	770664	2307	48298
8	31	3378026	5875	4540	3743	2784792	36202	90506	9747	593234	2132	40437
9	30	3038571	5460	4220	3743	2694960	35034	87586	9432	343611	1717	27833
10	31	2846641	5090	3826	3743	2784792	36202	90506	9747	61849	1347	14507
11	30	2755500	5210	3827	3743	2694960	35034	87586	9432	60540	1467	7021
12	31	2715290	4920	3650	3743	2784792	36202	90506	9747	0	1177	3919

K	L	M	N	O
		ONG SUPPLY		TOTAL
MMBTU REQD.	SYSTEM MMBTU	MMBTU	COST $	$
17074	14746	2328	8382	112038
12022	13795	0	0	97538
11768	14746	0	0	104109
12674	14270	0	0	101703
12657	14746	0	0	113238
13238	14270	0	0	118602
17282	14746	2536	9130	157681
16204	14746	1458	5249	145938
15837	14270	1566	5638	130490
9714	14746	0	0	114760
11354	14270	0	0	104040
11727	14746	0	0	104172
				1404307

TABLE 5.11 - ELECTRICALLY BASELOADED ANALYSIS- GAS TURBINE
CHP GAS PRICE - $2.0/MCF

MONTH	DAYS IN MONTH	KWH/MO	CHP_ELEC PEAK KW	AVG_KW	SYSTEM PERFORMANCE PEAK KW	KWH	FUEL MCF	FUEL COST $	MAINT. $	OG&E SUPPLY KWH	KW	COST
1	31	2692461	4765	3619	3743	2784792	36202	72405	9747	0	1022	3403
2	29	2520804	4870	3622	3743	2605128	33867	67733	9118	0	1127	3753
3	31	2788671	4860	3748	3743	2784792	36202	72405	9747	3879	1117	3856
4	30	2712386	4965	3767	3743	2694960	35034	70069	9432	17426	1222	4684
5	31	3013931	5215	4051	3743	2784792	36202	72405	9747	229139	1472	12986
6	30	3130500	5610	4348	3743	2694960	35034	70069	9432	435540	1867	21583
7	31	3555456	6050	4779	3743	2784792	36202	72405	9747	770664	2307	48298
8	31	3378026	5875	4540	3743	2784792	36202	72405	9747	593234	2132	40437
9	30	3038571	5460	4220	3743	2694960	35034	70069	9432	343611	1717	27833
10	31	2846641	5090	3826	3743	2784792	36202	72405	9747	61849	1347	14507
11	30	2755500	5210	3827	3743	2694960	35034	70069	9432	60540	1467	7021
12	31	2715290	4920	3650	3743	2784792	36202	72405	9747	0	1177	3919

SYSTEM MMBTU	ONG SUPPLY MMBTU	COST $	TOTAL $
14746	2328	4657	90211
13795	0	0	80604
14746	0	0	86008
14270	0	0	84185
14746	0	0	95137
14270	0	0	101084
14746	2536	5072	135522
14746	1458	2916	125504
14270	1566	3132	110467
14746	0	0	96658
14270	0	0	86522
14746	0	0	86071
			1177975

TABLE 5.12 - ELECTRICALLY BASELOADED ANALYSIS- GAS TURBINE
CHP GAS PRICE - $3.0/MCF

MONTH	DAYS IN MONTH	KWH/MO	CHP_ELEC PEAK KW	AVG_KW	SYSTEM PERFORMANCE PEAK KW	KWH	FUEL MCF	FUEL COST $	MAINT. $	OG&E SUPPLY KWH	KW	COST
1	31	2692461	4765	3619	3743	2784792	36202	108607	9747	0	1022	3403
2	29	2520804	4870	3622	3743	2605128	33867	101600	9118	0	1127	3753
3	31	2788671	4860	3748	3743	2784792	36202	108607	9747	3879	1117	3856
4	30	2712386	4965	3767	3743	2694960	35034	105103	9432	17426	1222	4684
5	31	3013931	5215	4051	3743	2784792	36202	108607	9747	229139	1472	12986
6	30	3130500	5610	4348	3743	2694960	35034	105103	9432	435540	1867	21583
7	31	3555456	6050	4779	3743	2784792	36202	108607	9747	770664	2307	48298
8	31	3378026	5875	4540	3743	2784792	36202	108607	9747	593234	2132	40437
9	30	3038571	5460	4220	3743	2694960	35034	105103	9432	343611	1717	27833
10	31	2846641	5090	3826	3743	2784792	36202	108607	9747	61849	1347	14507
11	30	2755500	5210	3827	3743	2694960	35034	105103	9432	60540	1467	7021
12	31	2715290	4920	3650	3743	2784792	36202	108607	9747	0	1177	3919

MMBTU REQD.	SYSTEM MMBTU	ONG SUPPLY MMBTU	COST $	TOTAL $
17074	14746	2328	6985	128742
12022	13795	0	0	114471
11768	14746	0	0	122210
12674	14270	0	0	119220
12657	14746	0	0	131339
13238	14270	0	0	136119
17282	14746	2536	7608	174260
16204	14746	1458	4374	163165
15837	14270	1566	4699	147068
9714	14746	0	0	132861
11354	14270	0	0	121557
11727	14746	0	0	122273
				1613284

2. ELECTRICALLY ISOLATED ANALYSIS - GAS TURBINE

Table 5.2 shows the operating costs for this alternative. The total yearly operating costs for this alternative are $1,265,337, when gas is available at $2.5/MCF. It can be noted that the equipment selected can satisfy peak electrical as well as thermal demands (a check was performed to determine if monthly thermal requirements will be satisfied) and therefore, the cogenerator is totally isolated from the utility. The cogeneration equipment can be run either in an electrical load following mode or in a thermal load following mode. When in an electrical load following mode, there might be situations when supplementary firing may need to be done to satisfy the thermal requirements. Unless the hourly requirements of steam are known, it is difficult to estimate the extent of supplementary firing that needs to be done, if any. Sensitivity analysis is carried out in tables 5.21 and 5.22. The details for each column follow.

Columns

A,B - KWH/mo and Peak KW that need to be satisfied - These have been copied from the Total Loads Spreadsheet.

Column C - This is the peak KW that can be generated by the selected equipment.

Column D - This is the maximum KWH that can be generated in a given month by the selected equipment.

Column E - System Fuel Requirements - (Column A) multiplied by (0.013 MMBTU/KWH) -From Manufacturer's Data.

Column F - System Fuel Costs - Column E times $2.5/MCF.

Column G - System Maintenance Costs - Column B times $0.0035/KWH -From Manufacturer's Data.

Column H - Total System Operating Costs - Column G + Column F.

TABLE 5.2 - ELECTRICALLY ISOLATED ANALYSIS - GAS TURBINE
CHP GAS PRICE - $2.5/MCF

		A	B	C	D	E	F	G	H
MONTH	DAYS IN		CHP_ELEC	SYSTEM PERFORMANCE					TOTAL
	MONTH	KWH/MO	PEAK KW	PEAK KW	MAX. KWH	FUEL MCF	FUEL COST $	MAINT. $	$
1	31	2692461	4765	7238	5385072	35002	87505	9424	96929
2	29	2520804	4870	7238	5037648	32770	81926	8823	90749
3	31	2788671	4860	7238	5385072	36253	90632	9760	100392
4	30	2712386	4965	7238	5211360	35261	88153	9493	97646
5	31	3013931	5215	7238	5385072	39181	97953	10549	108502
6	30	3130500	5610	7238	5211360	40697	101741	10957	112698
7	31	3555456	6050	7238	5385072	46221	115552	12444	127996
8	31	3378026	5875	7238	5385072	43914	109786	11823	121609
9	30	3038571	5460	7238	5211360	39501	98754	10635	109389
10	31	2846641	5090	7238	5385072	37006	92516	9963	102479
11	30	2755500	5210	7238	5211360	35822	89554	9644	99198
12	31	2715290	4920	7238	5385072	35299	88247	9504	97750
									1265337

TABLE 5.21 - ELECTRICALLY ISOLATED ANALYSIS - GAS TURBINE
CHP GAS PRICE - $2.0/MCF

MONTH	DAYS IN MONTH	KWH/MO	CHP_ELEC PEAK KW	SYSTEM PERFORMANCE PEAK KW	MAX. KWH	FUEL MCF	FUEL COST $	MAINT. $	TOTAL $
1	31	2692461	4765	7238	5385072	35002	70004	9424	79428
2	29	2520804	4870	7238	5037648	32770	65541	8823	74364
3	31	2788671	4860	7238	5385072	36253	72505	9760	82266
4	30	2712386	4965	7238	5211360	35261	70522	9493	80015
5	31	3013931	5215	7238	5385072	39181	78362	10549	88911
6	30	3130500	5610	7238	5211360	40697	81393	10957	92350
7	31	3555456	6050	7238	5385072	46221	92442	12444	104886
8	31	3378026	5875	7238	5385072	43914	87829	11823	99652
9	30	3038571	5460	7238	5211360	39501	79003	10635	89638
10	31	2846641	5090	7238	5385072	37006	74013	9963	83976
11	30	2755500	5210	7238	5211360	35822	71643	9644	81287
12	31	2715290	4920	7238	5385072	35299	70598	9504	80101
									1036873

TABLE 5.22 - ELECTRICALLY ISOLATED ANALYSIS - GAS TURBINE
CHP GAS PRICE - $3.0/MCF

MONTH	DAYS IN MONTH	CHP_ELEC KWH/MO	PEAK KW	SYSTEM PERFORMANCE PEAK KW	MAX. KWH	FUEL MCF	FUEL COST $	MAINT. $	TOTAL $
1	31	2692461	4765	7238	5385072	35002	105006	9424	114430
2	29	2520804	4870	7238	5037648	32770	98311	8823	107134
3	31	2788671	4860	7238	5385072	36253	108758	9760	118519
4	30	2712386	4965	7238	5211360	35261	105783	9493	115276
5	31	3013931	5215	7238	5385072	39181	117543	10549	128092
6	30	3130500	5610	7238	5211360	40697	122090	10957	133046
7	31	3555456	6050	7238	5385072	46221	138663	12444	151107
8	31	3378026	5875	7238	5385072	43914	131743	11823	143566
9	30	3038571	5460	7238	5211360	39501	118504	10635	129139
10	31	2846641	5090	7238	5385072	37006	111019	9963	120982
11	30	2755500	5210	7238	5211360	35822	107465	9644	117109
12	31	2715290	4920	7238	5385072	35299	105896	9504	115400
									1493800

3. ELECTRICALLY BASELOADED ANALYSIS - GAS ENGINE

The spreadsheet to calculate the operating costs is shown in Table 5.3. The total yearly operating costs for this alternative are $1,460,261 when gas is available at $2.5/MCF. It can be noted that a fair amount of natural gas has to be purchased as compared to the electrically baseloaded case with a gas turbine. The reason for this is the comparitively low heat recovery rates off gas engines. Sensitivity analysis has been carried out in Tables 5.31 and 5.32. The details for each column follow.

Columns

A,B,C - KWH/mo, Peak KW and Avg. KW - Copied from Total Loads Spreadsheet

Column D - This is the peak KW that can be generated by the selected equipment.

Column E - This is the total KWH that can be generated by the selected equipment.

Column F - System Fuel requirements - Column E multiplied by 0.01 MMBTU/KWH -From Manufacturer's Data.

Column G - System Fuel Costs - Column F multiplied by $2.5/MCF.

Column H - System Maintenance Costs - Column E multiplied by $0.005/KWH -From Manufacturer's Data.

Column I - KWH that would need to be bought from OG&E is obtained from (Column A - Column E).

Column J - KW that would need to be bought from OG&E is obtained from (Column B - Column D).

Column J1 - (Column J multiplied by the appropriate demand charge) + (Column I times $0.03528/KWH).

Column K - MMBTU requirements - Copied from Total Loads Spreadsheet.

Column L - MMBTUs capable of being generated by system -

= (0.7 * Jacket Heat + 0.8 * Exhaust Heat)(Column D)

(No. of hrs/mo)/0.8/1000000 BTU/MMBTU

Jacket Heat - 2480 BTU/KWH - Manufacturer's Data

Exhaust Heat - 1622 BTU/KWH - Manufacturer's Data

Heat Recovery Generator Efficiency - 0.8 - Manufacturer's Data

Column M - Gas that needs to be purchased from ONG is obtained by subtracting Column L from Column K.

Column N - Cost of purchased gas - Column M times $3.6/MCF.

Column O - Total System Operating Costs - Column N + Column J1 + Column H + Column G.

TABLE 5.3 - ELECTRICALLY BASELOADED ANALYSIS- GAS ENGINE

CHP GAS PRICE - $2.5/MCF

		A	B	C	D	E	F	G	H	I	J	J1
MONTH	DAYS IN MONTH	KWH/MO	CHP_ELEC PEAK KW	AVG_KW	SYSTEM PERFORMANCE PEAK KW	KWH	FUEL MCF	FUEL COST $	MAINT. $	OG&E SUPPLY KWH	KW	COST
1	31	2692461	4765	3619	3750	2790000	27900	69750	13950	0	1015	3380
2	29	2520804	4870	3622	3750	2610000	26100	65250	13050	0	1120	3730
3	31	2788671	4860	3748	3750	2790000	27900	69750	13950	0	1110	3696
4	30	2712386	4965	3767	3750	2700000	27000	67500	13500	12386	1215	4483
5	31	3013931	5215	4051	3750	2790000	27900	69750	13950	223931	1465	12779
6	30	3130500	5610	4348	3750	2700000	27000	67500	13500	430500	1860	21382
7	31	3555456	6050	4779	3750	2790000	27900	69750	13950	765456	2300	48050
8	31	3378026	5875	4540	3750	2790000	27900	69750	13950	588026	2125	40189
9	30	3038571	5460	4220	3750	2700000	27000	67500	13500	338571	1710	27591
10	31	2846641	5090	3826	3750	2790000	27900	69750	13950	56641	1340	14259
11	30	2755500	5210	3827	3750	2700000	27000	67500	13500	55500	1460	6820
12	31	2715290	4920	3650	3750	2790000	27900	69750	13950	0	1170	3896

K	L	M	N	O
MMBTU REQD.	SYSTEM MMBTU	ONG SUPPLY MMBTU	COST $	TOTAL $
17074	7053	10021	36077	123157
12022	6598	5424	19525	101555
11768	7053	4715	16975	104371
12674	6826	5848	21054	106537
12657	7053	5604	20176	116654
13238	6826	6412	23084	125466
17282	7053	10229	36825	168575
16204	7053	9151	32943	156833
15837	6826	9011	32440	141031
9714	7053	2661	9580	107539
11354	6826	4528	16301	104121
11727	7053	4674	16826	104422
				1460261

TABLE 5.31 - ELECTRICALLY BASELOADED ANALYSIS- GAS ENGINE
CHP GAS PRICE - $2.0/MCF

MONTH	DAYS IN	CHP_ELEC			SYSTEM PERFORMANCE					OG&E SUPPLY		
	MONTH	KWH/MO	PEAK KW	AVG_KW	PEAK KW	KWH	FUEL MCF	FUEL COST $	MAINT. $	KWH	KW	COST
1	31	2692461	4765	3619	3750	2790000	27900	55800	13950	0	1015	3380
2	29	2520804	4870	3622	3750	2610000	26100	52200	13050	0	1120	3730
3	31	2788671	4860	3748	3750	2790000	27900	55800	13950	0	1110	3696
4	30	2712386	4965	3767	3750	2700000	27000	54000	13500	12386	1215	4483
5	31	3013931	5215	4051	3750	2790000	27900	55800	13950	223931	1465	12779
6	30	3130500	5610	4348	3750	2700000	27000	54000	13500	430500	1860	21382
7	31	3555456	6050	4779	3750	2790000	27900	55800	13950	765456	2300	48050
8	31	3378026	5875	4540	3750	2790000	27900	55800	13950	588026	2125	40189
9	30	3038571	5460	4220	3750	2700000	27000	54000	13500	338571	1710	27591
10	31	2846641	5090	3826	3750	2790000	27900	55800	13950	56641	1340	14259
11	30	2755500	5210	3827	3750	2700000	27000	54000	13500	55500	1460	6820
12	31	2715290	4920	3650	3750	2790000	27900	55800	13950	0	1170	3896

	ONG SUPPLY			TOTAL
MMBTU REQD.	SYSTEM MMBTU	MMBTU	COST $	$
17074	7053	10021	36077	109207
12022	6598	5424	19525	88505
11768	7053	4715	16975	90421
12674	6826	5848	21054	93037
12657	7053	5604	20176	102704
13238	6826	6412	23084	111966
17282	7053	10229	36825	154625
16204	7053	9151	32943	142883
15837	6826	9011	32440	127531
9714	7053	2661	9580	93589
11354	6826	4528	16301	90621
11727	7053	4674	16826	90472
				1295561

TABLE 5.32 - ELECTRICALLY BASELOADED ANALYSIS- GAS ENGINE
CHP GAS PRICE - $3.0/MCF

MONTH	DAYS IN	CHP_ELEC			SYSTEM PERFORMANCE					OG&E SUPPLY					ONG SUPPLY		TOTAL
	MONTH	KWH/MO	PEAK KW	AVG_KW	PEAK KW	KWH	FUEL MCF	FUEL COST $	MAINT. $	KWH	KW	COST	MMBTU REQD.	SYSTEM MMBTU	MMBTU	COST $	$
1	31	2692461	4765	3619	3750	2790000	27900	83700	13950	0	1015	3380	17074	7053	10021	36077	137107
2	29	2520804	4870	3622	3750	2610000	26100	78300	13050	0	1120	3730	12022	6598	5424	19525	114605
3	31	2788671	4860	3748	3750	2790000	27900	83700	13950	0	1110	3696	11768	7053	4715	16975	118321
4	30	2712386	4965	3767	3750	2700000	27000	81000	13500	12386	1215	4483	12674	6826	5848	21054	120037
5	31	3013931	5215	4051	3750	2790000	27900	83700	13950	223931	1465	12779	12657	7053	5604	20176	130604
6	30	3130500	5610	4348	3750	2700000	27000	81000	13500	430500	1860	21382	13238	6826	6412	23084	138966
7	31	3555456	6050	4779	3750	2790000	27900	83700	13950	765456	2300	48050	17282	7053	10229	36825	182525
8	31	3378026	5875	4540	3750	2790000	27900	83700	13950	588026	2125	40189	16204	7053	9151	32943	170783
9	30	3038571	5460	4220	3750	2700000	27000	81000	13500	338571	1710	27591	15837	6826	9011	32440	154531
10	31	2846641	5090	3826	3750	2790000	27900	83700	13950	56641	1340	14259	9714	7053	2661	9580	121489
11	30	2755500	5210	3827	3750	2700000	27000	81000	13500	55500	1460	6820	11354	6826	4528	16301	117621
12	31	2715290	4920	3650	3750	2790000	27900	83700	13950	0	1170	3896	11727	7053	4674	16826	118372
																	1624961

4. ELECTRICALLY ISOLATED ANALYSIS - GAS ENGINE

The spreadsheet to calculate the operating costs under this alternative is shown in Table 5.4. The total yearly operating costs for this alternative are $1,216,973 when gas is available at $2.5/MCF. Even under this alternative, not all the thermal requirements are met and gas has to be purchased to make up for the deficiency. Sensitivity analysis has been carried out in Tables 5.41 and 5.42. The details for each column follow.

Columns

A,B,C - KWH/mo, Peak KW and Avg. KW - Copied from Total Loads Spreadsheet.

Column D - This is the peak KW that can be generated by the selected equipment.

Column E - This is the total KWH that can be generated by the equipment.

Column F - System Fuel Requirements - Column A multiplied by 0.01 MMBTU/KWH -From Manufacturer's Data.

Column G - System Fuel Costs - Column F multiplied by $2.5/MCF.

Column H - System Maintenance Costs - Column A multiplied by $0.005/KWH.

Column I - MMBTU requirements - Copied from Total Loads Spreadsheet.

Column J - MMBTUs capable of being produced

= (0.7 * Jacket Heat + 0.8 * Exhaust Heat)

(KW generated)(No. of hrs/mo)/0.8/1000000 BTU/MMBTU.

Column K - Gas that needs to be purchased - (Column I - Column J) needs to be bought from ONG.

Column L - Cost of purchased gas - Column K * $3.6/MCF.

Column M - Total System Cost - Column L + Column H + Column G.

TABLE 5.4 - ELECTRICALLY ISOLATED ANALYSIS- GAS ENGINE

CHP GAS PRICE - $2.5/MCF

		A	B	C	D	E	F	G	H	I	J	K	L	(
MONTH	DAYS IN		CHP_ELEC			SYSTEM PERFORMANCE						ONG SUPPLY		TO
	MONTH	KWH/MO	PEAK KW	AVG_KW	PEAK KW	KWH	FUEL MCF	FUEL COST $	MAINT. $	MMBTU REQD.	SYSTEM MMBTU	MMBTU	COST $	
1	31	2692461	4765	3619	7500	5580000	26925	67312	13462	17074	8962	8112	29204	10
2	29	2520804	4870	3622	7500	5220000	25208	63020	12604	12022	8569	3453	12431	8
3	31	2788671	4860	3748	7500	5580000	27887	69717	13943	11768	9141	2627	9459	9
4	30	2712386	4965	3767	7500	5400000	27124	67810	13562	12674	9037	3637	13093	9
5	31	3013931	5215	4051	7500	5580000	30139	75348	15070	12657	9809	2849	10256	10
6	30	3130500	5610	4348	7500	5400000	31305	78263	15653	13238	10211	3027	10896	10
7	31	3555456	6050	4779	7500	5580000	35555	88886	17777	17282	11379	5903	21251	12
8	31	3378026	5875	4540	7500	5580000	33780	84451	16890	16204	11050	5154	18555	11
9	30	3038571	5460	4220	7500	5400000	30386	75964	15193	15837	9938	5899	21235	11
10	31	2846641	5090	3826	7500	5580000	28466	71166	14233	9714	9573	141	507	8
11	30	2755500	5210	3827	7500	5400000	27555	68888	13778	11354	9483	1871	6735	8
12	31	2715290	4920	3650	7500	5580000	27153	67882	13576	11727	9254	2473	8904	9

TABLE 5.41 - ELECTRICALLY ISOLATED ANALYSIS- GAS ENGINE
CHP GAS PRICE - $2.0/MCF

MONTH	DAYS IN MONTH	KWH/MO	CHP_ELEC PEAK KW	AVG_KW	SYSTEM PERFORMANCE PEAK KW	KWH	FUEL MCF	FUEL COST $	MAINT. $	MMBTU REQD.	SYSTEM MMBTU	ONG SUPPLY MMBTU	COST $	TO
1	31	2692461	4765	3619	7500	5580000	26925	53849	13462	17074	8962	8112	29204	9
2	29	2520804	4870	3622	7500	5220000	25208	50416	12604	12022	8569	3453	12431	7
3	31	2788671	4860	3748	7500	5580000	27887	55773	13943	11768	9141	2627	9459	7
4	30	2712386	4965	3767	7500	5400000	27124	54248	13562	12674	9037	3637	13093	8
5	31	3013931	5215	4051	7500	5580000	30139	60279	15070	12657	9809	2849	10256	8
6	30	3130500	5610	4348	7500	5400000	31305	62610	15653	13238	10211	3027	10896	8
7	31	3555456	6050	4779	7500	5580000	35555	71109	17777	17282	11379	5903	21251	11
8	31	3378026	5875	4540	7500	5580000	33780	67561	16890	16204	11050	5154	18555	10
9	30	3038571	5460	4220	7500	5400000	30386	60771	15193	15837	9938	5899	21235	9
10	31	2846641	5090	3826	7500	5580000	28466	56933	14233	9714	9573	141	507	7
11	30	2755500	5210	3827	7500	5400000	27555	55110	13778	11354	9483	1871	6735	7
12	31	2715290	4920	3650	7500	5580000	27153	54306	13576	11727	9254	2473	8904	7

104

TABLE 5.42 - ELECTRICALLY ISOLATED ANALYSIS- GAS ENGINE
CHP GAS PRICE - $3.0/MCF

MONTH	DAYS IN		CHP_ELEC		SYSTEM PERFORMANCE							ONG SUPPLY		TO
	MONTH	KWH/MO	PEAK KW	AVG_KW	PEAK KW	KWH	FUEL MCF	FUEL COST $	MAINT. $	MMBTU REQD.	SYSTEM MMBTU	MMBTU	COST $	
1	31	2692461	4765	3619	7500	5580000	26925	80774	13462	17074	8962	8112	29204	12
2	29	2520804	4870	3622	7500	5220000	25208	75624	12604	12022	8569	3453	12431	10
3	31	2788671	4860	3748	7500	5580000	27887	83660	13943	11768	9141	2627	9459	10
4	30	2712386	4965	3767	7500	5400000	27124	81372	13562	12674	9037	3637	13093	10
5	31	3013931	5215	4051	7500	5580000	30139	90418	15070	12657	9809	2849	10256	11
6	30	3130500	5610	4348	7500	5400000	31305	93915	15653	13238	10211	3027	10896	12
7	31	3555456	6050	4779	7500	5580000	35555	106664	17777	17282	11379	5903	21251	14
8	31	3378026	5875	4540	7500	5580000	33780	101341	16890	16204	11050	5154	18555	13
9	30	3038571	5460	4220	7500	5400000	30386	91157	15193	15837	9938	5899	21235	12
10	31	2846641	5090	3826	7500	5580000	28466	85399	14233	9714	9573	141	507	10
11	30	2755500	5210	3827	7500	5400000	27555	82665	13778	11354	9483	1871	6735	10
12	31	2715290	4920	3650	7500	5580000	27153	81459	13576	11727	9254	2473	8904	10
														139

CONCLUSION

A methodology was developed to calculate the total electrical and thermal loads for an office buildings complex. This was a major step in evaluating the various alternatives in terms of their feasibility and economic worth. Converting the chiller electrical load to equivalent MMBTUs to incorporate absorption chilling has ensured an almost complete use for recovered heat, especially in the Gas Turbine cases. In the cases where Gas Engines are the prime movers, a significant amount of natural gas has to be purchased from the utility. Developing the operating costs for the various alternatives was also a big step towards determining the savings that can be expected after implementation of the cogeneration system. Operating costs are also extremely sensitive to gas prices. To ensure maximum savings, it would be necessary to obtain natural gas for the cogeneration plant at low prices.

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Turner Wayne C., Editor "Energy Management Handbook" - 1982.

APPENDIX A

CASE STUDY - A CENTRAL COGENERATION PLANT FOR THE OKLAHOMA STATE CAPITOL COMPLEX

STAGES OF THE CHP PROJECT FOR THE STATE CAPITOL COMPLEX

The following different stages of the project were observed.

0. Self Help Gas Opportunity.
1. Determining what buildings to come under the CHP Plant.
2. Policy Decisions and up-front assumptions.
3. Using Peak Day Analysis Plots to determine each building's monthly electrical loads.
4. Using the gas bills and plots to determine each building's monthly thermal requirements.
5. Developing each Building's Loads.
6. Developing the Total Loads for the complex.
7. Sizing the prime mover and selecting equipment for each of the following operating conditions:
    a. Electrically Baseloaded
    b. Electrically Isolated
    c. Thermally Baseloaded
8. Developing spreadsheets to calculate operating costs for each operating condition under Gas Turbine and Gas Engine Technologies.
9. Developing Transmission Costs.
10. Performing the Economic Analysis.
11. Determining the best alternative.

POLICY DECISIONS AND UP-FRONT ASSUMPTIONS

Certain decisions and assumptions were made at the start of the project. These are enumerated below:

1. No power sales to the utility.
2. Absorption Chilling in all buildings.
3. Only two technologies will be considered, Gas Turbine and Gas Engine. Each of these technologies will be evaluated under the following operating conditions:
    a. Electrically Isolated from the Utility.
    b. Baseloaded, Electrically Sized.
    c. Baseloaded, Thermally Sized.
4. Steam and chilled water will be generated in the Central Plant and sent to the various buildings. Existing absorption chillers and boilers will be used as back-up.
5. All energy conservation recommendations for the buildings in question have yet to be implemented. Also, for the Capitol building, it is assumed that the HVAC system is as-is.
6. Oklahoma Land Commission gas will be used for the Central Power Plant.
7. Assumptions for the economic analysis are stated later.

INTRODUCTION

The Oklahoma State Capitol Complex in Oklahoma City is a large consumer of electricity and natural gas. The Energy Division of the Office of Public Affairs requested a study to evaluate cogeneration. The fact that the State Office Buildings at the Capitol Complex require heat and power year around, makes cogeneration a possible technical option for the Office of Public Affairs. Five buildings in the North part of the Complex and three buildings in the Southwest part of the Complex were considered to come under the central cogeneration complex. The decision to include these buildings was based on ease of distribution of power and other utilities. The five buildings in the North part of the Complex are:

1. Conners Building (Tax)
2. Hodge Building (Education)
3. Will Rogers Building
4. Sequoyah Building
5. State Capitol Building

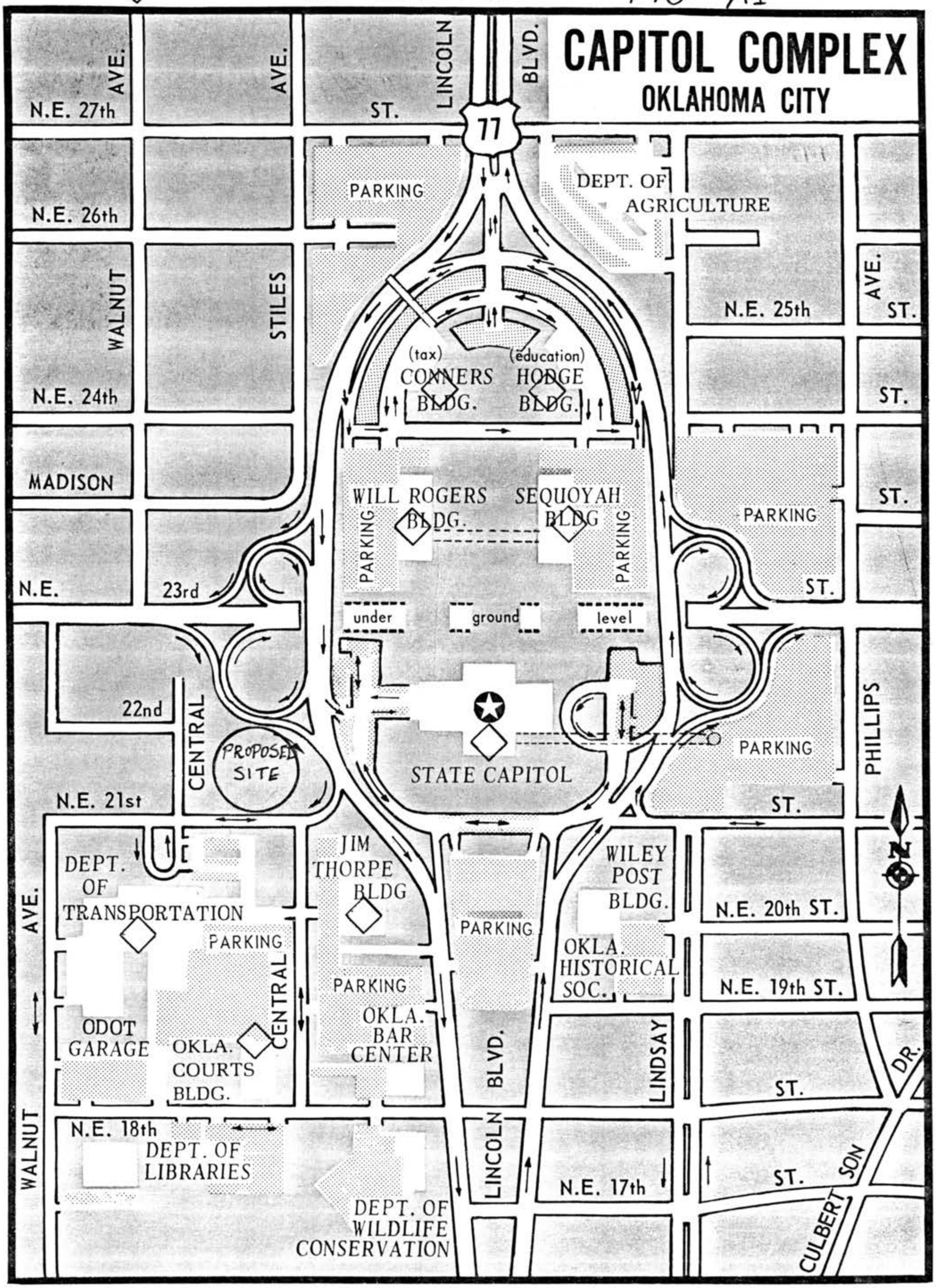
The three buildings in the Southwest part of the Complex are:

1. Department of Transportation
2. Jim Thorpe Building
3. Oklahoma Courts Building

The site proposed for the central complex is where the central boiler plant now exists, close to NE 21st Street and

◇ - PROPOSED BUILDINGS

FIG. A1



Lincoln Blvd.

The natural gas supply options were then examined. It was concluded that several options were available to obtain "self help" natural gas from the Oklahoma Land Commission (OLC) or Oklahoma Natural Gas (ONG) at a price significantly lower than the present average price of $3.6/MCF. Under the alternative of buying gas from ONG or OLC with the installation of only one supply point and one meter, the cost of gas will be $1.75/MCF plus carriage if gas is purchased from OLC, or $2.05/MCF if ONG provides for the fuel.

With natural gas being available so cheap, it is logical to think of cogeneration, where electricity and heat will result from supplying natural gas to prime movers. For the efficiency of a central plant to be maximum, however, the heat resulting from the production of electric power will have to be utilized year around. This will not be a problem in the winter months, but in the summer months, with the existing configuration of chilling equipment in the different buildings, the heat will be under utilized. In order to better utilize the heat in the summer months, it has been assumed that absorption chillers will be used in the central cogeneration plant and that chilled water will then be distributed to the various buildings. Those buildings which are already equipped with absorption chillers, (Conners, Hodge, Department of Transportation) will also receive chilled water from the central plant. The absorption chillers in these buildings will be maintained for back-up purposes.

Obviously, the number of technologies that can be used for the central cogeneration complex are numerous. But, for simplicity of analysis, only 2 technologies will be considered. These are:

1. Gas Turbine with Heat Recovery Steam Generator and Absorption Chillers.
2. Gas Engine with Steam Generator and Absorption Chillers.

Furthermore, each of these technologies will be studied in the light of 3 loading options:

1. Isolated Operation, Electric Load Following.
2. Baseloaded, Electrically Sized.
3. Baseloaded, Thermally Sized.

It has also been assumed that no power sales will be made to the utility and that no detailed engineering for the cogeneration plant will be carried out.

BUILDING LOADS SPREADSHEETS - A DETAILED BREAKDOWN OF EACH BUILDING'S ELECTRICAL AND THERMAL LOADS

TABLE A1.1

LDG: SEQUOYAH YEAR:1988

		ELECTRICAL LOADS												
ONTH	DAYS IN	LIGHTS/OE			BASELOAD			CHILLER					CHP-ELEC	
	MONTH	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY-1	AVG.kW-1	HR/DAY-2	AVG.kW-2	kWH'/DAY	KWH/MO.	
1	31	13	200	2600	24	200	4800	3	200	11	300	3900	206371	
2	29	13	200	2600	24	230	5520	2	300	10	300	3600	213937	
3	31	13	200	2600	24	190	4560	11	350	7	120	4690	198931	
4	30	13	200	2600	24	200	4800	2	200	10	500	5400	199714	
5	31	13	200	2600	24	280	6720	13	320	5	320	5760	265891	
6	30	13	150	1950	24	450	10800	10	250	0	0	2500	365786	
7	31	13	200	2600	24	480	11520	12	250	0	0	3000	414691	
8	31	13	200	2600	24	480	11520	10	250	2	200	2900	414691	
9	30	13	200	2600	24	275	6600	8	275	12	375	6700	253714	
10	31	13	200	2600	24	300	7200	2	175	11	200	2550	280771	
11	30	13	200	2600	24	250	6000	3	200	10	450	5100	235714	
12	31	13	200	2600	24	225	5400	5	100	10	300	3500	224971	

TOTAL KWH/MONTH	
ESTIMATED.	METERED
292729	296400
288509	286400
302781	300800
315429	313200
393434	392400
419357	407600
481120	483600
478906	466000
397286	409200
337236	316000
345000	331600
302471	293200

TABLE A1.2
BLDG: SEQUOYAH
THERMAL LOADS (MMBTU)

BASELOAD	HEATING	COOLING	TOTAL
92	951	803.6	1846.6
92	712	693.9	1497.9
92	510	966.4	1568.4
92	353	1076.8	1521.8
92	0	1186.8	1278.8
92	0	498.5	590.5
92	0	618.1	710.1
92	0	597.5	689.5
92	0	1336.0	1428.0
92	431	525.4	1048.4
92	608	1017.0	1717.0
92	939	721.2	1752.2

TABLE A2.1

BLDG.: W. ROGERS YEAR: 1988

		ELECTRICAL LOADS													
ONTH	DAYS IN	LIGHTS/OE			BASELOAD			CHILLER					CHP-ELEC	TOTAL KWH/MONTH	
	MONTH	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY-1	AVG.kW-1	HR/DAY-2	AVG.kW-2	kWH'/DAY	KWH/MO.	ESTIMATED.	METERED
1	31	10	180	1800	24	470	11280	3	150	9	175	2025	389537	434376	403600
2	29	12	180	2160	24	500	12000	3	240	0	0	720	392743	407657	415600
3	31	12	180	2160	24	480	11520	3	180	9	150	1890	404949	446799	438800
4	30	12	180	2160	24	480	11520	3	180	9	300	3240	391886	461314	450400
5	31	12	180	2160	24	500	12000	3	375	9	445	5130	419829	533421	536400
6	30	12	180	2160	24	500	12000	3	250	11	520	6470	406286	544929	567200
7	31	12	180	2160	24	750	18000	2	180	9	275	2835	605829	668604	649600
8	31	12	180	2160	24	725	17400	2	180	9	300	3060	587229	654986	616400
9	30	12	180	2160	24	650	15600	9	320	2	180	3240	514286	583714	571600
10	31	12	180	2160	24	480	11520	10	400	2	200	4400	404949	502377	450000
11	30	12	180	2160	24	500	12000	9	400	2	180	3960	406286	491143	496000
12	31	12	180	2160	24	460	11040	2	180	9	200	2160	390069	437897	426800

TABLE A2.2
BLDG: W. ROGERS
THERMAL LOADS (MMBTU)

IASELOAD	HEATING	COOLING	TOTAL
88	662	417.2	1167.2
88	716	138.8	942.8
88	514	389.4	991.4
88	357	646.1	1091.1
88	121	1057.0	1266.0
88	0	1290.1	1378.1
88	0	584.1	672.1
88	0	630.5	718.5
88	0	646.1	734.1
88	0	906.6	994.6
88	276	789.6	1153.6
88	636	445.1	1169.1

TABLE A3.1
BLDG.: J. THORPE YEAR: 1988

		ELECTRICAL LOADS											
'ONTH	DAYS IN	LIGHTS/OE			BASELOAD			CHILLER					CHP-ELEC
	MONTH	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY-1	AVG.kW-1	HR/DAY-2	AVG.kW-2	kWH'/DAY	KWH/MO.
1	31	11	200	2200	24	150	3600	3	175	9	175	2100	160314
2	29	11	200	2200	24	100	2400	3	200	10	250	3100	115171
3	31	11	200	2200	24	175	4200	3	150	8	175	1850	178914
4	30	11	200	2200	24	200	4800	3	150	8	200	2050	191143
5	31	12	200	2400	24	200	4800	3	250	9	325	3675	201943
6	30	12	200	2400	24	225	5400	3	275	9	325	3750	213429
7	31	11	200	2200	24	225	5400	5	300	9	350	4650	216114
8	31	11	200	2200	24	250	6000	5	250	8	325	3850	234714
9	30	11	200	2200	24	225	5400	7	225	9	325	4500	209143
10	31	11	200	2200	24	225	5400	5	200	8	175	2400	216114
11	30	11	200	2200	24	200	4800	3	150	9	175	2025	191143
12	31	11	200	2200	24	200	4800	3	125	8	125	1375	197514

TOTAL KWH/MONTH	
ESTIMATED.	METERED
206814	209200
179386	204800
219879	218000
235071	218800
283318	282000
293786	298000
319079	325600
319964	316400
305571	312800
269257	253200
234536	240000
227961	190400

TABLE A3.2
BLDG: J. THORPE

THERMAL LOADS (MMBTU)

ASELOAD	HEATING	COOLING	TOTAL
134	1555	432.7	2121.7
134	668	597.5	1399.5
134	466	381.2	981.2
134	911	408.8	1453.8
134	43	757.2	934.2
134	0	747.8	881.8
134	0	958.1	1092.1
134	0	793.3	927.3
134	0	897.3	1031.3
134	91	494.5	719.5
134	1123	403.8	1660.8
134	1619	283.3	2036.3

TABLE A4.1

BLDG.: D.O.T. YEAR: 1988

'his building is equipped with absorption chilling and therefore the
:hiller load talked about here refers to the additional fans and
umps that come on during the peak hours of the day.
;ometimes this load can also refer to additional equipment being on.

		ELECTRICAL LOADS												
MONTH	DAYS IN	LIGHTS/OE			BASELOAD			CHILLER					TOTAL KWH/MONTH	
	MONTH	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY-1	AVG.kW-1	HR/DAY-2	AVG.kW-2	kWH'/DAY	ESTIMATED.	METERED
1	31	11	380	4180	24	530	12720	3	275	0	0	825	505145	505800
2	29	11	500	5500	24	510	12240	3	250	0	0	750	484424	484800
3	31	11	450	4950	24	510	12240	3	250	8	100	1550	523369	528900
4	30	11	425	4675	24	600	14400	3	150	0	0	450	541821	522000
5	31	11	450	4950	24	550	13200	3	125	3	400	1575	553682	549600
6	30	9	600	5400	24	600	14400	3	250	0	0	750	563786	567900
7	31	9	550	4950	24	710	17040	3	150	0	0	450	647811	632700
8	31	10	625	6250	24	625	15000	3	250	0	0	750	620000	581100
9	30	11	550	6050	24	625	15000	0	0	0	0	0	579643	582000
10	31	11	500	5500	24	500	12000	0	0	0	0	0	493786	490200
11	30	10	675	6750	24	525	12600	3	275	0	0	825	540321	544500
12	31	10	550	5500	24	550	13200	6	300	0	0	1800	570843	488700

TABLE A4.2
BLDG: D.O.T.
THERMAL LOADS (MMBTU)

'ASELOAD	HEATING	COOLING	TOTAL
173.0	1684.8	421.2	2279
173.0	1272.0	318.0	1763
173.0	723.0	723.0	1619
173.0	0.0	2379.0	2552
173.0	0.0	2928.0	3101
173.0	0.0	3517.0	3690
173.0	0.0	5229.0	5402
173.0	0.0	4787.0	4960
173.0	0.0	4346.0	4519
173.0	849.5	849.5	1872
173.0	1460.8	365.2	1999
173.0	1753.6	438.4	2365

TABLE A5.1

BLDG.: CONNERS YEAR: 1988

'his building is equipped with absorption chilling and therefore the :hiller load talked about here refers to the additional fans and iumps that come on during the peak hours of the day. iometimes this load can also refer to additional equipment being on.

		ELECTRICAL LOADS										
1ONTH	DAYS IN	LIGHTS/OE			BASELOAD			CHILLER				
	MONTH	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY-1	AVG.kW-1	HR/DAY-2	AVG.kW-2	kWH'/DAY
1	31	10	130	1300	24	600	14400	9	170	0	0	1530
2	29	10	150	1500	24	600	14400	8	150	0	0	1200
3	31	10	130	1300	24	600	14400	8	200	3	100	1900
4	30	10	150	1500	24	625	15000	3	125	3	150	825
5	31	10	175	1750	24	650	15600	8	175	0	0	1400
6	30	10	150	1500	24	625	15000	8	200	2	150	1900
7	31	10	200	2000	24	625	15000	9	225	7	150	3075
8	31	10	180	1800	24	675	16200	8	100	0	0	800
9	30	10	175	1750	24	650	15600	8	250	2	150	2300
10	31	10	200	2000	24	575	13800	8	150	0	0	1200
11	30	10	200	2000	24	625	15000	10	200	0	0	2000
12	31	10	150	1500	24	575	13800	8	150			1200

TOTAL KWH/MONTH	
ESTIMATED.	METERED
509064	479100
473529	468300
517257	511200
499821	497700
553350	532200
522857	516000
577375	579300
559771	551400
554786	553500
498657	485700
535714	545700
487586	480000

TABLE A5.2
BLDG: CONNERS
THERMAL LOADS (MMBTU)

ASELOAD	HEATING	COOLING	TOTAL
79.0	906.8	226.7	1212.5
79.0	596.4	149.1	824.5
79.0	371.0	371.0	821
79.0	0.0	1464.0	1543
79.0	0.0	2059.5	2138.5
79.0	0.0	2039.5	2118.5
79.0	0.0	3127.0	3206
79.0	0.0	3021.0	3100
79.0	0.0	2721.0	2800
79.0	561.5	561.5	1202
79.0	753.2	188.3	1020.5
79.0	748.0	187.0	1014

TABLE A6.1

BLDG.: CAPITOL YEAR: 1988

MONTH	DAYS IN MONTH	LIGHTS/OE HR/DAY	LIGHTS/OE AVG. kW	LIGHTS/OE kWH'/DAY	BASELOAD HR/DAY	BASELOAD AVG. kW	BASELOAD kWH'/DAY	CHILLER HR/DAY-1	CHILLER AVG.kW-1	CHILLER HR/DAY-2	CHILLER AVG.kW-2	CHILLER kWH'/DAY	CHP-ELEC KWH/MO.
1	31	10	280	2800	24	550	13200	6	400	3	450	3750	471200
2	29	10	280	2800	24	525	12600	8	450	3	500	5100	423400
3	31	10	250	2500	24	600	14400	8	425	0	0	3400	501757
4	30	10	280	2800	24	525	12600	8	600	3	550	6450	438000
5	31	10	280	2800	24	700	16800	8	500	3	600	5800	582800
6	30	10	280	2800	24	875	21000	8	600	3	825	7275	690000
7	31	10	280	2800	24	875	21000	8	700	3	750	7850	713000
8	31	10	280	2800	24	750	18000	8	700	3	750	7850	620000
9	30	10	280	2800	24	650	15600	8	600	3	750	7050	528000
10	31	10	280	2800	24	650	15600	8	500	3	650	5950	545600
11	30	10	280	2800	24	525	12600	8	470	3	500	5260	438000
12	31	10	280	2800	24	500	12000	8	400	3	400	4400	434000

TOTAL KWH/MONTH ESTIMATED.	METERED
554236	544000
529043	528800
577043	558400
576214	557600
711229	664000
845893	709600
886821	804800
793821	719200
679071	674400
677350	520800
550714	556800
531429	492000

TABLE A6.2
BLDG: CAPITOL
THERMAL LOADS (MMBTU)

ASELOAD	HEATING	COOLING	TOTAL
122.7	1562.8	772.7	2458.2
122.7	679.2	983.1	1785.0
122.7	477.2	700.6	1300.5
122.7	921.8	1286.1	2330.6
122.7	51.3	1195.1	1369.1
122.7	10.4	1450.7	1583.8
119.1	0	1617.5	1736.6
110.3	0	1617.5	1727.8
122.7	5.4	1405.8	1533.9
122.7	99.8	1226.0	1448.5
122.7	468.9	1048.9	1640.5
122.7	780.6	906.6	1809.9

TABLE A7.1

BLDG.: HODGES YEAR: 1988

		ELECTRICAL LOADS										
ONTH	DAYS IN	LIGHTS/OE			BASELOAD			CHILLER				
	MONTH	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY-1	AVG.kW-1	HR/DAY-2	AVG.kW-2	kWH'/DAY
1	31	10	300	3000	24	250	6000	2	100	0	0	200
2	29	10	300	3000	24	250	6000	0	0	0	0	0
3	31	10	300	3000	24	270	6480	0	0	2	150	300
4	30	10	300	3000	24	250	6000	0	0	2	100	200
5	31	10	275	2750	24	250	6000	0	0	0	0	0
6	30	10	275	2750	24	250	6000	0	0	0	0	0
7	31	10	275	2750	24	250	6000	0	0	0	0	0
8	31	10	250	2500	24	230	5520	0	0	0	0	0
9	30	10	250	2500	24	250	6000	0	0	0	0	0
10	31	9	250	2250	24	225	5400	0	0	0	0	0
11	30	10	325	3250	24	200	4800	0	0	3	175	525
12	31	10	325	3250	24	200	4800	0	0	0	0	0

TOTAL KWH/MONTH	
ESTIMATED.	METERED
256857	266700
236143	236100
273951	276300
248571	255000
246893	247200
238929	239100
246893	274800
226477	228300
233571	234300
217221	215700
224893	252000
220764	226200

TABLE A7.2
BLDG: HODGES
THERMAL LOADS (MMBTU)

ASELOAD	HEATING	COOLING	TOTAL
79.0	906.8	226.7	1212.5
79.0	596.4	149.1	824.5
79.0	371.0	371.0	821
79.0	0.0	1464.0	1543
79.0	0.0	2059.5	2138.5
79.0	0.0	2039.5	2118.5
79.0	0.0	3127.0	3206
79.0	0.0	3021.0	3100
79.0	0.0	2721.0	2800
79.0	561.5	561.5	1202
79.0	753.2	188.3	1020.5
79.0	748.0	187.0	1014

TABLE A8.1

BLDG.: COURTS YEAR: 1988

ONTHDAYS IN		ELECTRICAL LOADS LIGHTS/OE			BASELOAD			CHILLER					CHP-ELEC
	MONTH	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY	AVG. kW	kWH'/DAY	HR/DAY-1	AVG.kW-1	HR/DAY-2	AVG.kW-2	kWH'/DAY	KWH/MO.
1	31	10	120	1200	24	225	5400	0	0	0	0	0	193971
2	29	10	120	1200	24	225	5400	0	0	0	0	0	181457
3	31	10	100	1000	24	225	5400	8	80	0	0	640	189543
4	30	10	100	1000	24	250	6000	8	50	0	0	400	201429
5	31	10	100	1000	24	225	5400	9	150	0	0	1350	189543
6	30	10	100	1000	24	150	3600	10	375	0	0	3750	129429
7	31	10	100	1000	24	150	3600	12	350	0	0	4200	133743
8	31	10	100	1000	24	125	3000	13	350	0	0	4550	115143
9	30	10	100	1000	24	200	4800	12	300	0	0	3600	165429
10	31	10	100	1000	24	225	5400	10	250	0	0	2500	189543
11	30	10	100	1000	24	225	5400	10	225	2	100	2450	183429
12	31	10	100	1000	24	225	5400	0	0	0	0	0	189543

TOTAL KWH/MONTH	
ESTIMATED.	METERED
193971	197400
181457	181800
203714	201300
210000	209400
219436	216600
209786	213600
226743	227700
215893	211200
242571	245400
244900	244200
235929	234000
189543	190500

TABLE A8.2
BLDG: COURTS
THERMAL LOADS (MMBTU)

BASELOAD	HEATING	COOLING	TOTAL
197.9	4578.8	0.0	4776.7
197.9	2786.7	0.0	2984.6
197.9	3336.1	131.9	3665.9
197.9	361	79.8	638.7
153.1	0	278.2	431.3
128.9	0	747.8	876.7
197.9	193.9	865.4	1257.2
43.4	0	937.5	980.9
197.9	74.6	717.8	990.3
197.9	514.1	515.1	1227.1
197.9	455.5	488.5	1141.9
197.9	368.6	0.0	566.5

PRIME MOVER SIZING

GAS TURBINE

All references to Gas Turbine equipment are obtained from trade literature provided by Solar Turbines Inc., makers of Caterpillar Gas Turbines. All units selected are completely packaged units, with heat recovery generator.

Electrically Baseloaded Alternative:

Load to be satisfied -	3619 KW (Column C of Total Loads Spreadsheet - Table 4.1)
Equipment selected -	One Centaur Type H Turbine
Peak Electrical Output -	3743 KW

Electrically Isolated Alternative:

Load to be satisfied -	6050 KW * Safety Factor (1.2) = 7260 KW (6050 KW is the peak load that needs to be satisfied - Column B of Total Loads Spreadsheet - Table 4.1)
Equipment selected -	Two Centaur Type H Turbines
Peak Electrical Output -	7486 KW

Thermally Baseloaded Alternative:

This alternative turns out to be the same as the Electrically Baseloaded Alternative as most of the thermal requirements are satisfied by the same equipment selected in the Baseloaded case.

Therefore, this alternative will not be considered any more.

PRIME MOVER SIZING

GAS ENGINE

All references to gas engine equipment are obtained from Energy Services Group, Cooper Industries.

Electrically Baseloaded Alternative

Load to be satisfied -	3619 KW (Column C of Total Loads Spreadsheet - Table 4.1)
Equipment selected -	Two Superior 16SGTB Engines
Peak Electrical Output -	3750 KW

Electrically Isolated Alternative:

Load to be satisfied -	6050 KW * Safety Factor (1.2) = 7260 KW (6050 KW is the peak load that needs to be satisfied - Column B of Total Loads Spreadsheet - Table 4.1)
Equipment selected -	Four Superior 16SGTB Engines
Peak Electrical Output -	7500 KW

Thermally Baseloaded Alternative:

This is not a very good option because of the low heat recovery rates from gas engines. It can be noticed that even in the Electrically Isolated case, some gas has to be purchased. Therefore, it will be very uneconimical to size the equipment such that all or most of the thermal requirements are met. This argument was confirmed by the vendor. This alternative will not be considered any more.

TRANSMISSION COSTS

For any cogeneration plant, pipes are needed for the supply of steam, chilled water supply and return, and condensate return. Also, an electrical distribution network is needed to supply electricity to the various buildings. For the State Office Buildings, the cogeneration plant will supply steam, chilled water and power to the proposed buildings. For all these buildings trenches need to be dug for the pipes and electrical cables. The cost of pipes and electrical cables are shown in Table A9.

Figure A2 shows the layout for piping and electrical cables. The distances between the cogeneration plant and the respective buildings have been measured from a map of the State Buildings complex. Existing trenches between Sequoyah and Will Rogers, and between Hodge and Connors will be used.

For each building, the cost of electrical cables and the various pipes, steam supply, condensate return, chilled water supply and return have been calculated.

<u>Calculation of Trench cost</u> :

The digging and refilling cost of a trench has been taken as $5/ft. This was derived from information provided by Mr. William King.

Calculation of chilled water supply and return pipe sizes and cost :

Total cooling tonnage requirement per building has been obtained from the PSA reports. This information has also helped in determining the size of the absorption chillers that will be needed at the central plant (approximately 3000 tons). It has been assumed that chilled water will be supplied at velocity of 8 to 10 ft/sec and on average, a 20 F temperature drop will be obtained. The flow rate is thus calculated and for a given flow rate and given velocity, the pipe size is determined. Steel pipes (sch. 40) are used for both supply and return. The costs of pipes are taken from MEANS MECHANICAL COST DATA BOOK (5).

Calculation of Steam supply pipe sizes and cost :

The peak steam requirements from the cogeneration plant are known to be 30,000 lb/hr (Table 4.1) and steam requirements for each individual building have been approximated using the present boiler size as a guideline. The steam is assumed to be supplied at a maximum pressure of 30 psig and allowing for a pressure drop of less than 5 psig, pipes size have been calculated using the ARMSTRONG Catalog. Steel pipes (sch. 40) are used for steam supply and prices for the pipes have been taken from MEANS MECHANICAL COST DATA BOOK (5).

Calculation of condensate return pipe sizes and cost :

Knowing the steam supply rate to all buildings and assuming that 90 % of the steam is returned as condensate, condensate pipe sizes and costs have been calculated.

<u>Calculation of pump sizes and cost</u> :

Head losses for the given pipe diameter and water velocity have been calculated using "Heating, Ventilating and Air Conditioning, Analysis and Design - Mcquiston and Parker. Once the total head losses are known, the MEANS MECHANICAL COST DATA BOOK (5) has been used to determine the pump sizes and calculate costs. Prices for variable frequency drives on the pumps have also been included.

<u>Determination of Electrical Cable sizes and cost</u> :

The electrical cables have been conservatively sized assuming a peak generation of 8 MW. It has been assumed that in the baseloaded cases, there will be a tie-in with the utility at the central plant. Each building's peak requirements have been determined from a knowledge of the building. Figure A2 shows the distances required for the electrical cables for all the buildings included in the central cogeneration plant. The cost of the cables has been taken from MEANS ELECTRICAL COST DATA BOOK (4). The total cost for electric cables has thus been determined to be **$341,576**.

TABLE A9

CHP PIPING LAYOUT AND COST

source	dest.	ONE-WAY distance (ft)	Req Pipe Capacity Tons	Flow gpm	CHW LINE supp/ret diam, in*	HEAD LOSS FT WATER	PUMP STATION	CHW LINE supp/ret ($)	TRENCH COST ($)
CHP PLANT	DOT	1430	741	890	8	20.59	1	97240	7150
DOT	COURT	1300	222	267	4	59.28	1	41600	6500
CHP PLANT	THORPE	1820	222	267	4	82.99	1	58240	9100
CHP PLANT	CAPITOL	2210	2039	2447	12	26.52	2	251940	11050
CAPITOL	W.R	1690	1594	1913	10	36.91	2,3	158860	8450
W.R	SEQ.	1170	472	566	6	14.04	2,3	79560	5850
W.R	CONNORS	1170	667	801	8	14.04	2,3	81900	
CONNORS	HODGE	1170	297	356	6	14.04	2,3	79560	
TOTAL			3000					848900	48100

*Based on 8-10 ft/sec velocity

CHILLED WATER
VARIABLE VOLUME PUMP STATIONS

STATION #	Flow gpm	HEAD LOSS FT WATER	PUMP UNITS	PUMP HP	INSTALLED UNIT COST ($)	VFD UNIT COST ($)
1	1157	83	2	10	$2,275	2900
2	2447	37	2	20	$3,025	3135
3	1913	37	2	15	$2,575	3500
			6	45	$15,750	$19,070
					TOTAL:	$34,820

STEAM AND COND. RETURN PIPING LAYOUT AND COST

source	dest.	ONE-WAY distance (ft)	STEAM FLOW lb/hr	STEAM LINE diam, in*	COND.RET Flow gpm	COND.RET LINE diam, in*	STEAM LINE ($)	COND.RET LINE ($)
CHP PLANT	DOT	1430	10350	6	21	2	37180	11440
DOT	COURT	1300	2750	3	6	1	16900	7800
CHP PLANT	THORPE	1820	1500	3	3	1	23660	10920
CHP PLANT	CAPITOL	2210	19800	8	40	2	77350	17680
CAPITOL	W.R	1690	16700	8	33	2	59150	13520
W.R	SEQ.	1170	3100	3	6	1.5	15210	8190
W.R	CONNORS	1170	9000	6	18	2	30420	9360
CONNORS	HODGE	1170	4500	3	9	1.5	15210	8190
TOTAL			31650				275080	87100

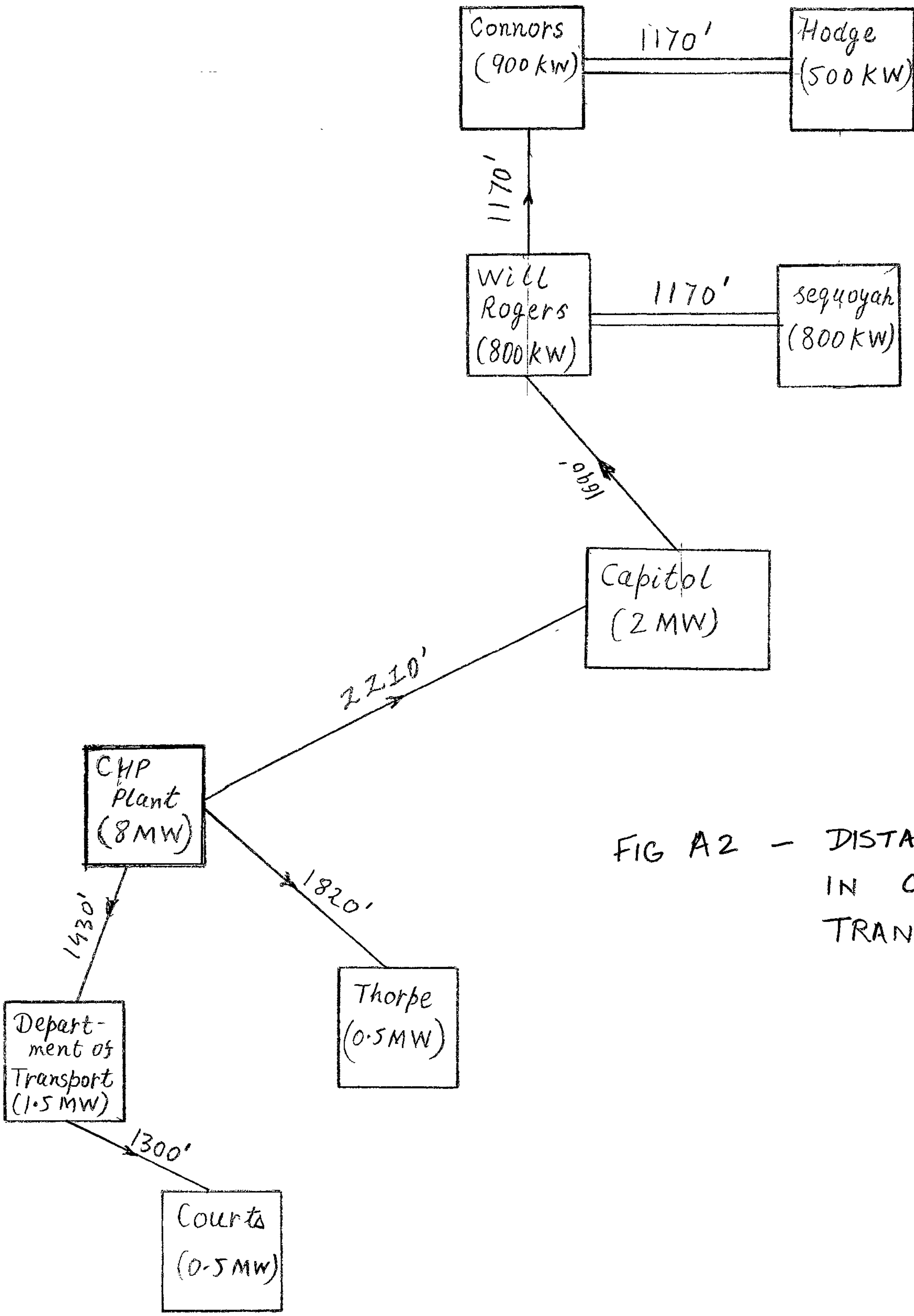


FIG A2 – DISTANCES USED IN CALCULATING TRANSMISSION COS

ECONOMIC ANALYSIS OF ALL ALTERNATIVES

Some basic assumptions have been made with regard to the economic analysis. These are enumerated below:

1. Economic life of all projects is 15 years.
2. Inflationary effects have been ignored.
3. The cost of additional personnel for the central power plant will be offset by the reduced cost to maintain cogeneration equipment. Hence, no maintenance savings will be claimed.
4. Salvage values of existing equipment will not be taken into account. This is a conservative assumption.

ECONOMIC ANALYSIS FOR ELECTRICALLY BASELOADED CASE - GAS TURBINE

Installed Cost -	\$700/KW (Manufacturer)
Annual CHP Operating Cost -	\$1,404,307 (Table 5.1)
Present Annual Operating Costs -	\$2,398,801 (from Bills)

Annual Savings in Operating Costs

= (Present Operating Costs - CHP Plant Operating Costs)

= (\$2,398,801 - \$1,404,307)

= \$994,494/yr

Summary of Total Installed Costs

* Packaged unit with Turbine, Generator
  & Heat Recovery Generator
  = (\$700/KW)(3743 KW)
  = \$2,620,100

* Absorption Chillers

4 x 700 Ton Hitachi Model 19G Chillers or 4 x 750 Ton Trane Model ABSC-07C Chillers with a pressure reducing valve.

Installed Cost - \$600/ton - From Gas Energy Inc.
166 Montague Street
Brooklyn, NY 11201

Total Cost of Absorption Chillers

= (2800 Tons)(\$600/Ton)

= \$1,680,000

* Transmission Costs

Chilled Water Lines -	$848,900
Steam & Condensate Lines -	$362,100
Trenches -	$48,100
Pumps and VFDs -	$34,820
Electric Underground Cables -	$341,576
Total Transmission Costs -	$1,635,576

* Total System Installed Costs

  = $2,620,100 + $1,680,000 + $1,635,576

  = $5,935,676

Present Worth at 7% MARR & 15 years life

= -$5,935,676 + ($994,494)(P/A, 7, 15)

= -$5,935,676 + ($994,494)(9.1079)

= $3,122,076

Present Worth at 10% MARR & 15 years life

= -$5,935,676 + ($994,494)(P/A, 10, 15)

= -$5,935,676 + ($994,494)(7.6061)

= $1,628,545

Present Worth at 15% MARR & 15 years life

= -$5,935,676 + ($994,494)(P/A, 15, 15)

= -$5,935,676 + ($994,494)(5.8474)

= -$120,472

ECONOMIC ANALYSIS FOR ELECTRICALLY ISOLATED CASE - GAS TURBINE

Installed Cost -	$700/KW (Manufacturer)
Annual CHP Operating Cost -	$1,265,337 (Table 5.2)
Present Annual Operating Costs -	$2,398,801 (from Bills)

Annual Savings in Operating Costs

= (Present Operating Costs - CHP Plant Operating Costs)

= ($2,398,801 - $1,265,337)

= $1,133,464/yr

Summary of Total Installed Costs

* Packaged unit with Turbine, Generator

  & Heat Recovery Generator

  = ($700/KW)(7238 KW)

  = $5,066,600

* Absorption Chillers

  4 x 700 Ton Hitachi Model 19G Chillers or 4 x 750 Ton Trane Model ABSC-07C Chillers with Pressure Reducing Valve.

  Installed Cost - $600/ton - From Gas Energy Inc.

  166 Montague Street

  Brooklyn, NY 11201

  Total Cost of Absorption Chillers

  = (2800 Tons)($600/Ton)

  = $1,680,000

* Transmission Costs

Chilled Water Lines -	\$848,900
Steam & Condensate Lines -	\$362,100
Trenches -	\$48,100
Pumps and VFDs -	\$34,820
Electric Underground Cables -	\$341,576
Total Transmission Costs -	\$1,635,576

* Total System Installed Costs

= \$5,066,600 + \$1,680,000 + \$1,635,576

= \$8,382,176

Present Worth at 7% MARR & 15 years life

= -\$8,382,176 + (\$1,133,464)(P/A, 7, 15)

= -\$8,382,176 + (\$1,133,464)(9.1079)

= \$1,941,300

Present Worth at 10% MARR & 15 years life

= -\$8,382,176 + (\$1,133,464)(P/A, 10, 15)

= -\$8,382,176 + (\$1,133,464)(7.6061)

= \$239,065

Present Worth at 15% MARR & 15 years life

= -\$8,382,176 + (\$1,133,464)(P/A, 15, 15)

= -\$8,382,176 + (\$1,133,464)(5.8474)

= -\$1,754,359

ECONOMIC ANALYSIS FOR ELECTRICALLY BASELOADED CASE - GAS ENGINE

Installed Cost of each 16 SGTB - $1,350,000/unit

Superior Gas Engine (Packaged Unit)

Annual CHP Operating Cost - $1,460,261 (Table 5.3)

Present Annual Operating Costs - $2,398,801 (from Bills)

Annual Savings in Operating Costs

= (Present Operating Costs - CHP Plant Operating Costs)

= ($2,398,801 - $1,460,261)

= $938,540/yr

Summary of Total Installed Costs

* 2 Packaged units with Engine, Generator

  & Heat Recovery Generator

  = (2 units)($1,350,000/unit)

  = $2,700,000

* Absorption Chillers

  4 x 750 Ton Trane Model ABSC-07C Chillers

  Installed Cost - $600/ton - From Gas Energy Inc.

  166 Montague Street

  Brooklyn, NY 11201

  Total Cost of Absorption Chillers

  = (3000 Tons)($600/Ton)

  = $1,800,000

* Transmission Costs

Chilled Water Lines -	$848,900
Steam & Condensate Lines -	$362,100
Trenches -	$48,100
Pumps and VFDs -	$34,820
Electric Underground Cables -	$341,576
Total Transmission Costs -	$1,635,576

* Total System Installed Costs

= $2,700,000 + $1,800,000 + $1,635,576

= $6,135,576

Present Worth at 7% MARR & 15 years life

= -$6,135,576 + ($938,540)(P/A, 7, 15)

= -$6,135,576 + ($938,540)(9.1079)

= $2,412,553

Present Worth at 10% MARR & 15 years life

= -$6,135,576 + ($938,540)(P/A, 10, 15)

= -$6,135,576 + ($938,540)(7.6061)

= $1,003,053

Present Worth at 15% MARR & 15 years life

= -$6,135,576 + ($938,540)(P/A, 15, 15)

= -$6,135,576 + ($938,540)(5.8474)

= -$647,557

ECONOMIC ANALYSIS FOR ELECTRICALLY ISOLATED CASE - GAS ENGINE

Installed Cost of each 16 SGTB -	$1,350,000/unit
Superior Gas Engine (Packaged Unit)	
Annual CHP Operating Cost -	$1,216,973 (Table 5.4)
Present Annual Operating Costs -	$2,398,801 (from Bills)

Annual Savings in Operating Costs

= (Present Operating Costs - CHP Plant Operating Costs)

= ($2,398,801 - $1,216,973)

= $1,181,828/yr

Summary of Total Installed Costs

* 4 Packaged units with Engine, Generator
  & Heat Recovery Generator
  = (4 units)($1,350,000/unit)
  = $5,400,000

* Absorption Chillers
  4 x 750 Ton Trane Model ABSC-07C Chillers
  Installed Cost - $600/ton - From Gas Energy Inc.
  166 Montague Street
  Brooklyn, NY 11201
  Total Cost of Absorption Chillers
  = (3000 Tons)($600/Ton)
  = $1,800,000

* Transmission Costs

Chilled Water Lines -	$848,900
Steam & Condensate Lines -	$362,100
Trenches -	$48,100
Pumps and VFDs -	$34,820
Electric Underground Cables -	$341,576
Total Transmission Costs -	$1,635,576

* Total System Installed Costs

  = $5,400,000 + $1,800,000 + $1,635,576

  = $8,835,576

Present Worth at 7% MARR & 15 years life

= -$8,835,576 + ($1,181,828)(P/A, 7, 15)

= -$8,835,576 + ($1,181,828)(9.1079)

= $1,928,395

Present Worth at 10% MARR & 15 years life

= -$8,835,576 + ($1,181,828)(P/A, 10, 15)

= -$8,835,576 + ($1,181,828)(7.6061)

= $153,526

Present Worth at 15% MARR & 15 years life

= -$8,835,576 + ($1,181,828)(P/A, 15, 15)

= -$8,835,576 + ($1,181,828)(5.8474)

= -$1,924,995

SUMMARY OF RESULTS

The following summary table below results:

OPTION	PRESENT WORTHS 7%	10%	15%
Elect. Base Load Gas Turbine	$3,122,076	$1,628,545	-$120,472
Elect. Isolation Gas Turbine	$1,941,300	$239,065	-$1,754,359
Elect. Base Load Gas Engine	$2,412,553	$1,003,053	-$647,557
Elect. Isolation Gas Engine	$1,928,395	$153,526	-$1,924,995

CONCLUSION

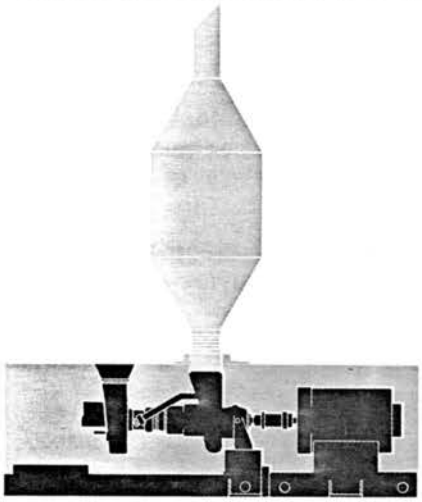
The Electrically Baseloaded operating mode with a Gas Turbine as its prime mover has the highest present worth ($3,122,076). Therefore, using the present worth criterion, this alternative is better than the present system and should be selected.

SOLAR TURBINES INCORPORATED
2625 BUTTERFIELD ROAD
SUITE 315W
OAK BROOK, IL 60521
312-572-0303

CONTACT: ROBERT F. KOVARIK

GAS TURBINE DI

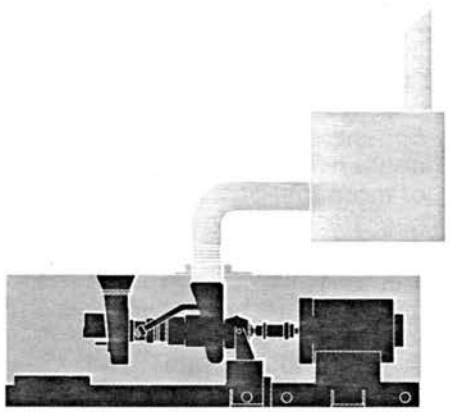
SITE EXAMPLES



Steam Producing*

	Saturn Turbine	Centaur T-4500 Turbine	Centaur Type H Turbine	Mars Turbine	Jupiter Turbine
Stack Temperature °F	319	317	294	311	345
Steam Output lb/hr	6297	18,336	23,113	41,877	61,065
Exhaust Temperature °F	837	848	969	878	693
Fuel Input million Btu/hr	12.9	40.1	46.9	95.9	170.0
Electrical Output kW	800	3028	3743	8589	15,739
Air Mass Flow thousand lb/hr	49.3	140.1	138.0	299.0	716.3
Net Fuel Rate Btu/kW-hr	6010	5462	4595	4900	5816

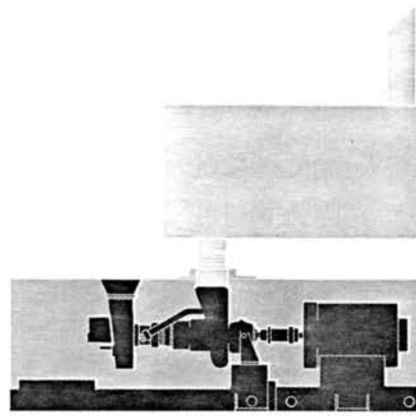
Turbine exhaust producing 150 psig steam.



Supplemental Firing*

	Saturn Turbine	Centaur T-4500 Turbine	Centaur Type H Turbine	Mars Turbine	Jupiter Turbine
Stack Temperature °F	250	250	250	250	250
Steam Output lb/hr	18,566	52,796	51,991	112,667	269,874
Additional Fuel to Burner million Btu/hr	12.2	34.3	29.2	70.8	205.9
Exhaust Temperature °F	837	848	969	878	693
Turbine Fuel Input million Btu/hr	12.9	40.1	46.9	95.9	170.0
Electrical Output kW	800	3028	3743	8589	15,739
Air Mass Flow thousand lb/hr	49.3	140.1	138.0	299.0	716.3
Net Fuel Rate Btu/kW-hr	1553	2165	2482	2552	1850

This example assumes exhaust with supplemental firing to 1700°F in 150 psig boiler.



Hot Air Source*

	Saturn Turbine	Centaur T-4500 Turbine	Centaur Type H Turbine	Mars Turbine	Jupiter Turbine
Heat Credit million Btu/hr	9.74	28.15	32.0	62.34	115.57
Exhaust Temperature °F	837	848	969	878	693
Fuel Input million Btu/hr	12.9	40.1	46.9	95.9	170.0
Electrical Output kW	800	3028	3743	8589	15,739
Air Mass Flow thousand lb/hr	49.3	140.1	138.0	299.0	716.3
Net Fuel Rate Btu/kW-hr	3950	3946	3981	3907	3458

Cogeneration system with turbine exhaust used directly as hot air source.

CAPITOL COST – $70(
MAINTENANCE COST – $0.(

GAS TURBINE DATA

PERFORMANCE

ISO Performance

The ability to use gas turbine exhaust for heat recovery, supplemental firing, and in a wide range of heat-to-electric power ratio applications makes the gas turbine the leading prime mover for cogeneration systems. Available exhaust energy and net electrical output of Solar's gas turbine generator sets at ISO conditions are given below.

	Saturn Turbine	Centaur T-4500 Turbine	Centaur Type H Turbine	Mars Turbine	Jupiter Turbine
Exhaust Temperature °F	813	840	961	870	685
Fuel Input million Btu/hr	12.64	40.52	47.33	97.06	173.18
Electrical Output kW	800	3130	3880	8840	16,400
Exhaust Flow thousand lb/hr	49.7	141.4	140.8	302.2	726.8

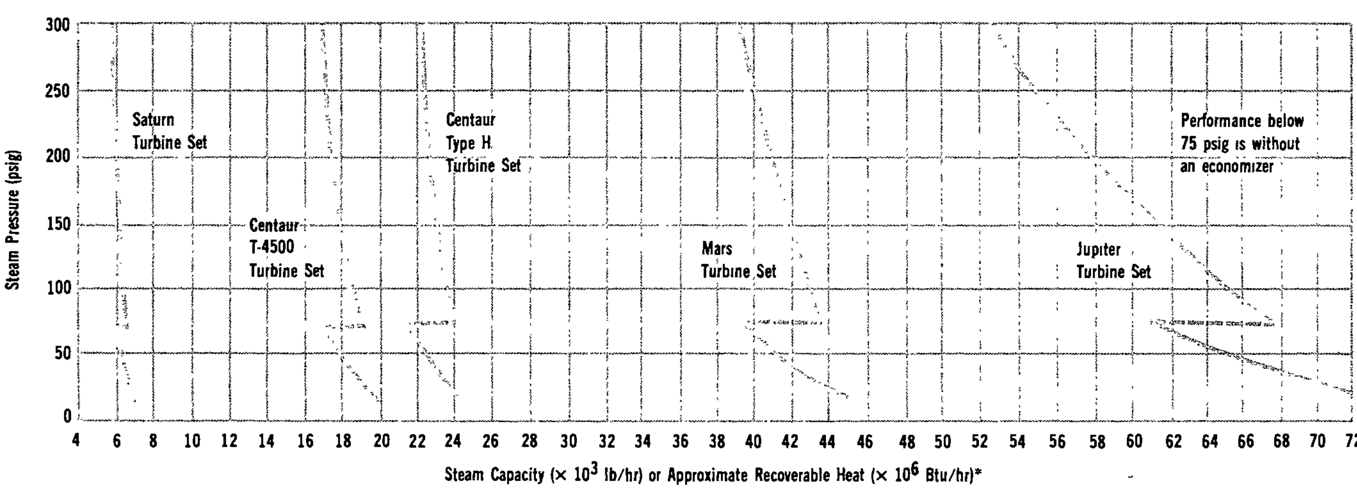
Specific Site Examples

The values shown in the examples on the facing page are based on the following tables:

ASSUMPTIONS:	
Ambient conditions	Sea level and 60°F
Fuel	Liquid or gas
Load	100 percent
Inlet pressure loss	3 inches water
Exhaust pressure loss	7 inches water

STEAM DATA:	
Condensate return	200°F
Steam conditions	Dry and saturated
Pinch temperature	30°F
Alternate boiler efficiency	80 percent

Heat Recoverable from Solar Gas Turbines



*Assuming latent heat of vaporization equals 1000 Btu/lb.

GAS ENGINE SPECIFICATIONS

All information supplied by :

Energy Services Group

Cooper Industries

4405 S. 74 E. Ave.

Box 470383

Tulsa, OK 74147

918-622-4670

Contact: Randy Bissey

SUPERIOR GAS ENGINE

Model -	16SGTB
Gen. Set Rating -	1875 KW
Engine Speed -	900 RPM
Fuel Rate -	10,025 BTU/KWH
Characteristics -	Clean-burn, straight gas engine

Heat Rejection:

Jacket Water -	77,500 BTU/min (2,480 BTU/KWH)
Water Temp -	180 F
Water Flow -	775 gpm
For 15 psig steam:	
Recoverable Exhaust -	3,041,000 BTU/hr (1,622 BTU/KWH)
Exhaust Flow -	458 lb/min

Exhaust Temp - 785 F

Exhaust gases are taken down to 350 F.

COSTS

Completely packaged unit

Engine & Generator (on skid) plus Heat Recovery Generator plus plate heat exchanger for jacket water:

Cost:	$1,100,000/unit
Installation:	$250,000
Maintenance:	$0.005/KWH

APPENDIX B - PEAK DAY ANALYSIS PLOTS

19

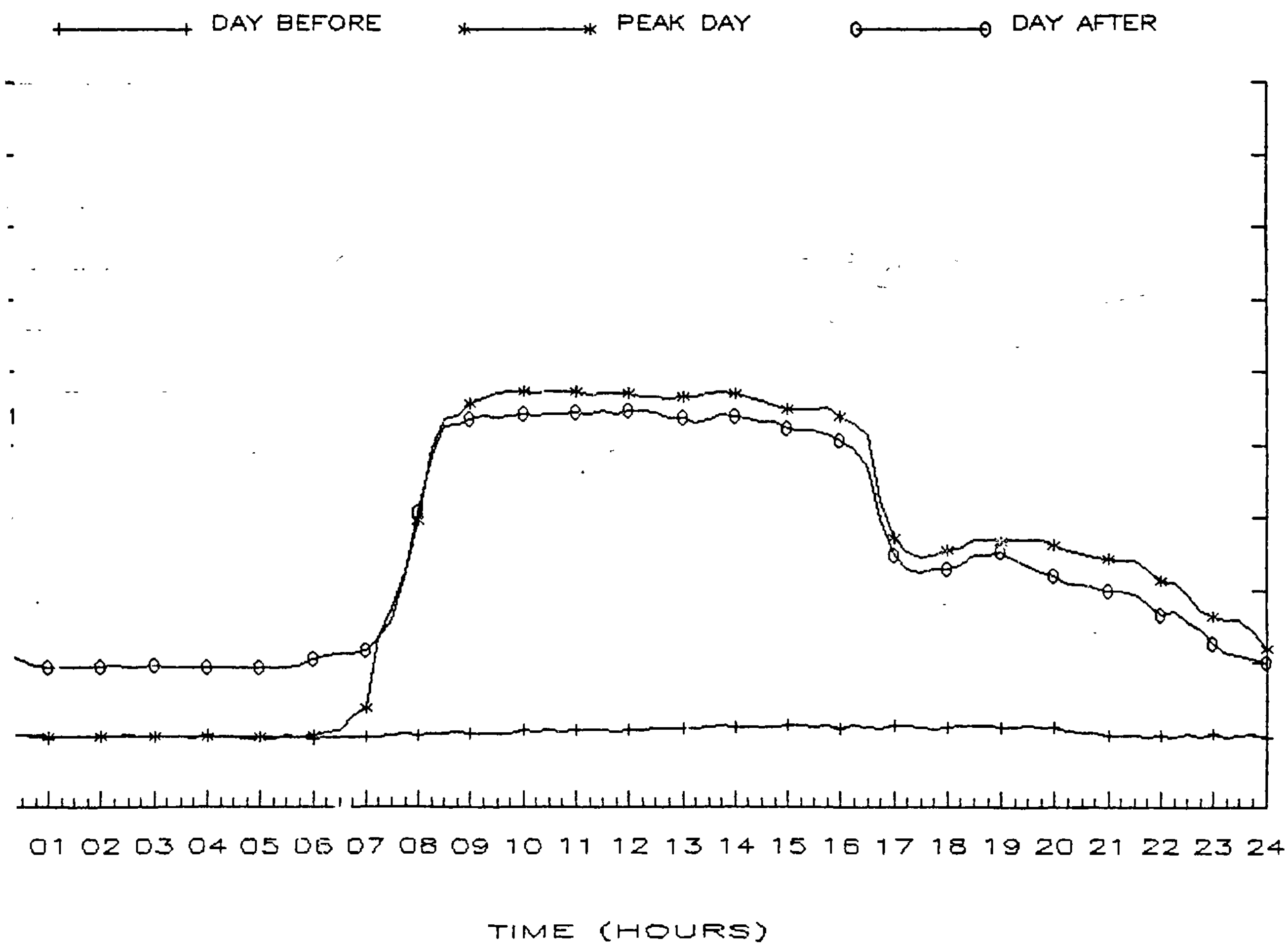
:PE
TATE BOARD OF AFF
S: JIM THORPE BLDG
F ACCT: BN19 HIST

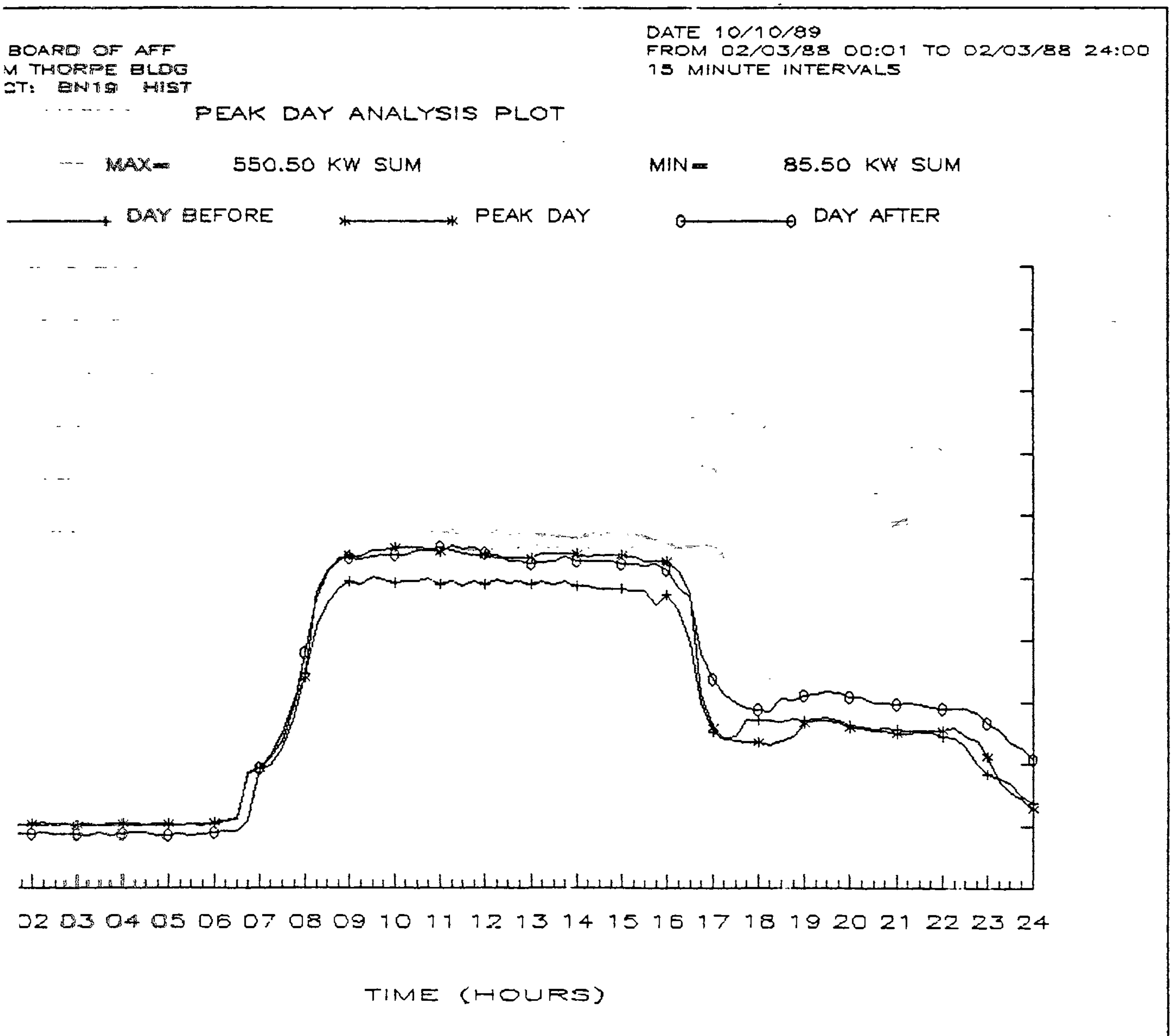
DATE 10/10/89
FROM 01/04/88 00:01 TO 01/04/88 24:0C
15 MINUTE INTERVALS

PEAK DAY ANALYSIS PLOT

MAX= 573.00 KW SUM

MIN= 94.50 KW SUM




BOARD OF AFF
M THORPE BLDG
CT: BN19 HIST
DATE 10/10/89
FROM 02/03/88 00:01 TO 02/03/88 24:00
15 MINUTE INTERVALS
PEAK DAY ANALYSIS PLOT
MAX= 550.50 KW SUM
MIN= 85.50 KW SUM
DAY BEFORE
PEAK DAY
DAY AFTER
02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
TIME (HOURS)

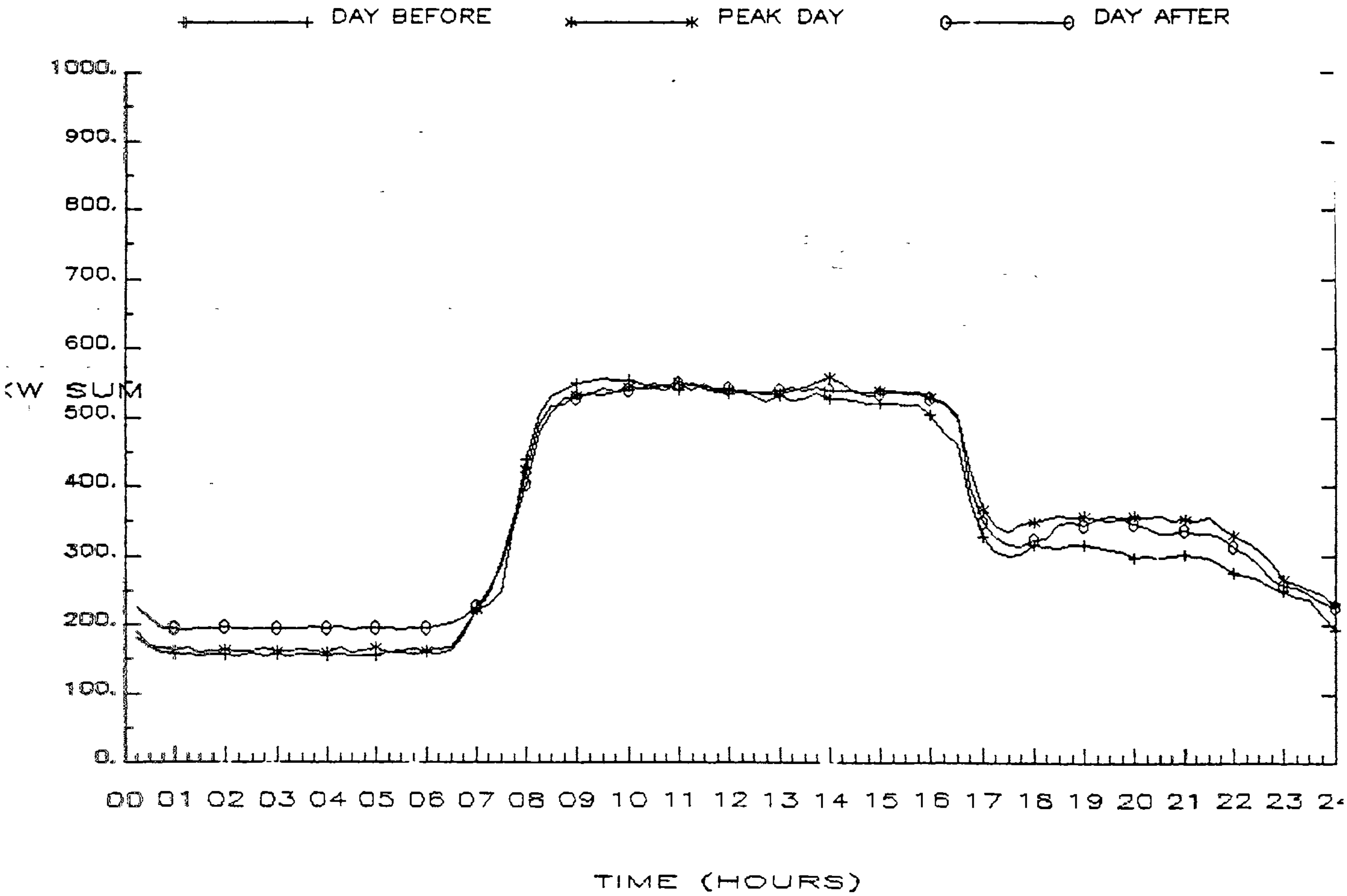
ID: THORPE
NAME: STATE BOARD OF AFF
ADDRESS: JIM THORPE BLDG
CLASS OF ACCT: BN19 HIST

DATE 10/10/89
FROM 03/16/88 00:01 TO 03/18
15 MINUTE INTERVALS

PEAK DAY ANALYSIS PLOT

MAX= 558.00 KW SUM

MIN= 154.50 KW SUM

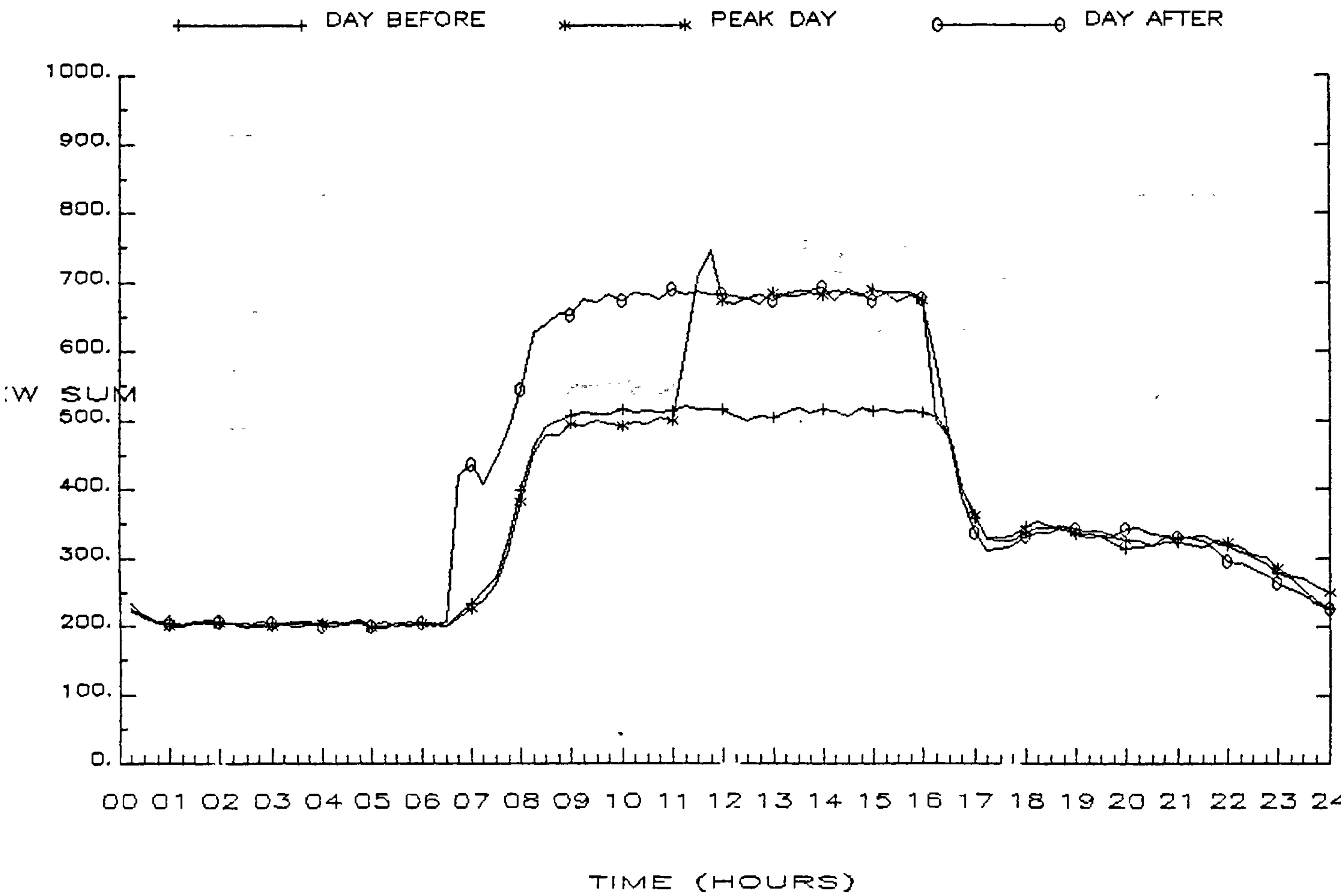


ID: THORPE
NAME: STATE BOARD OF AFF
ADDRESS: JIM THORPE BLDG
CLASS OF ACCT: BN19 HIST

DATE 10/10/89
FROM 04/14/88 00:01 TO 04/14
15 MINUTE INTERVALS

PEAK DAY ANALYSIS PLOT

MAX= 747.00 KW SUM MIN= 198.00 KW SUM



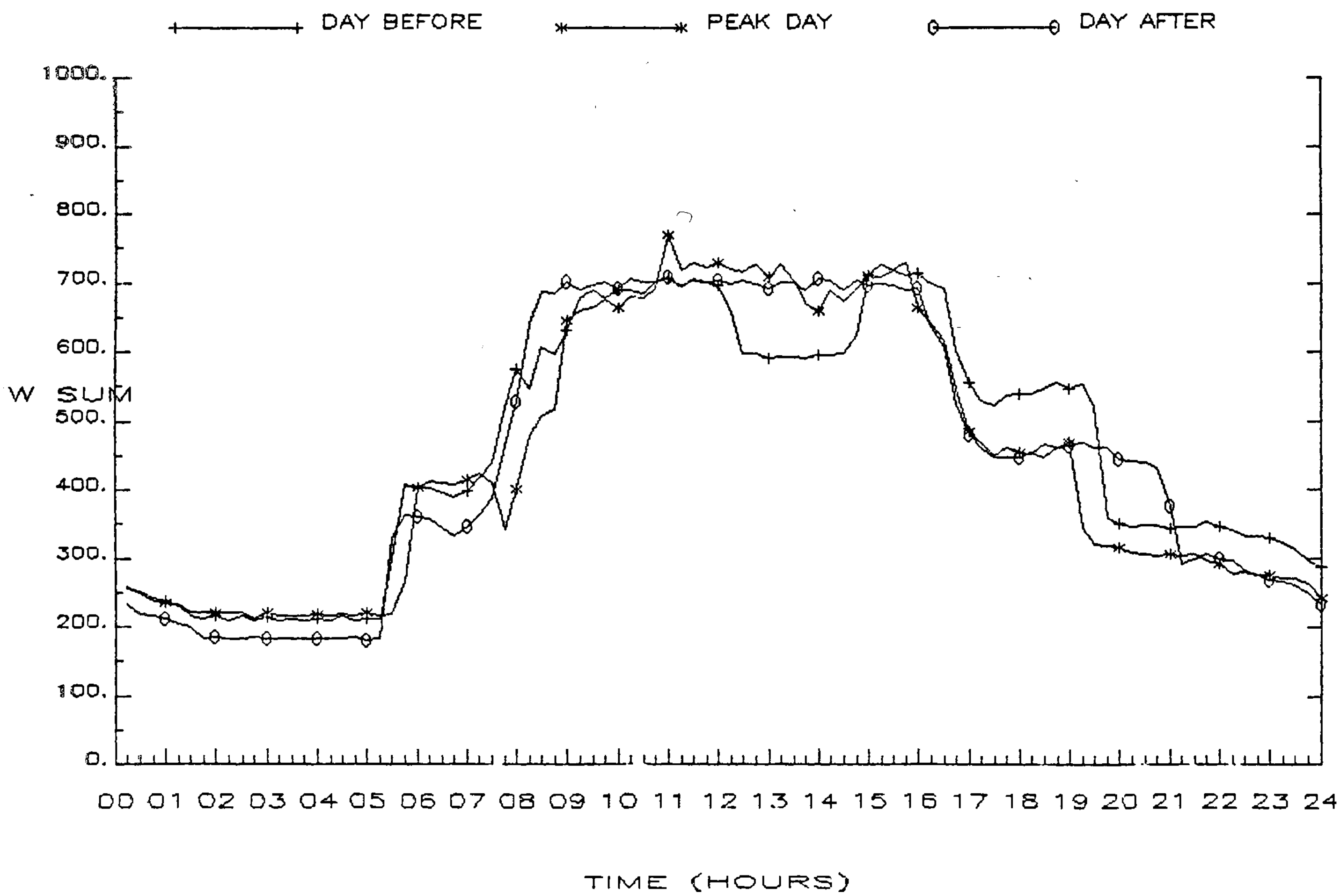
ID: THORPE
NAME: STATE BOARD OF AFF
ADDRESS: JIM THORPE BLDG
CLASS OF ACCT: BN19 HIST

DATE 10/10/89
FROM 05/11/88 00:01 TO 05/11,
15 MINUTE INTERVALS

PEAK DAY ANALYSIS PLOT

MAX= 769.50 KW SUM

MIN= 181.50 KW SUM

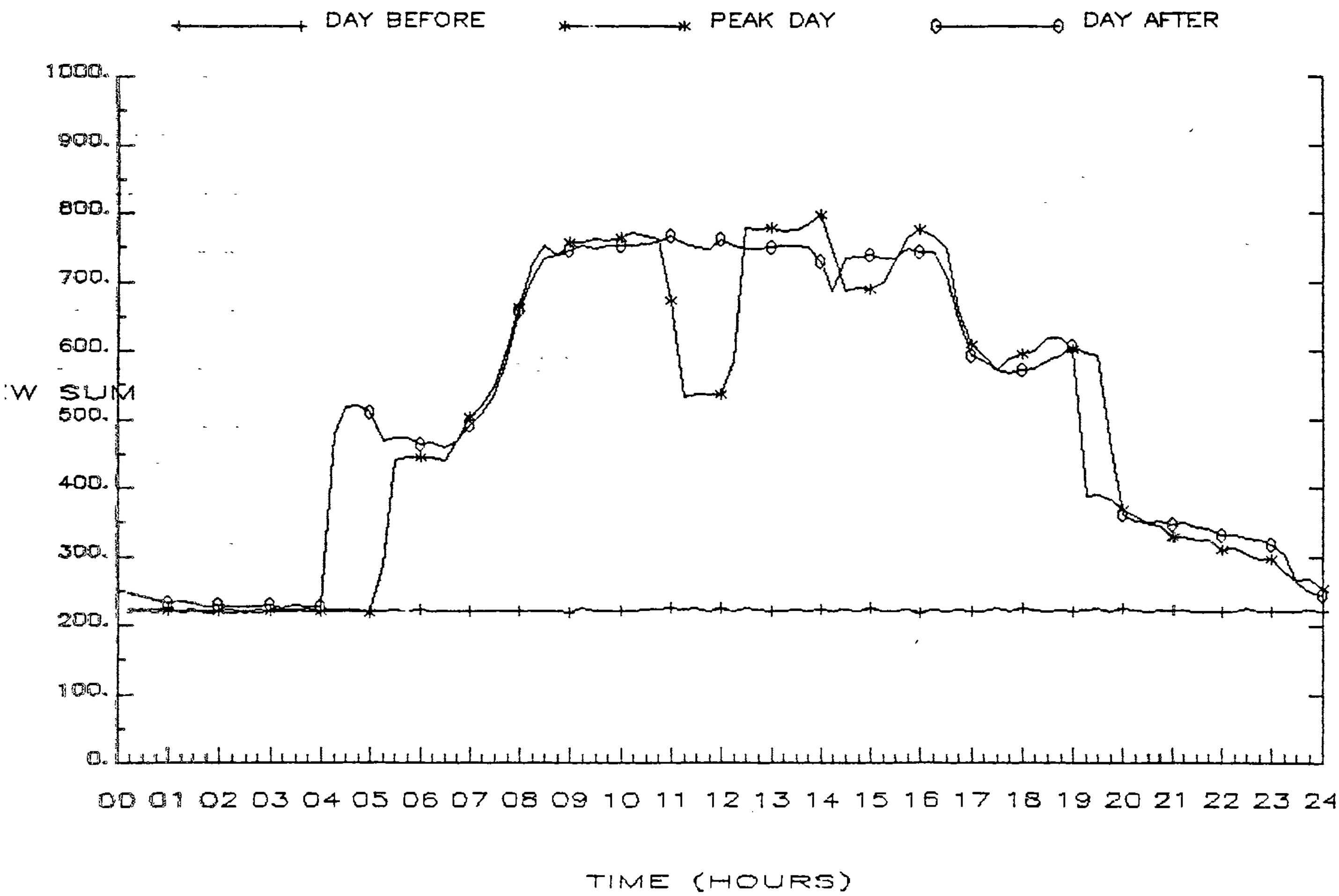


ID: THORPE
NAME: STATE BOARD OF AFF
ADDRESS: JIM THORPE BLDG
CLASS OF ACCT: BN19 HIST

DATE 10/10/89
FROM 06/20/88 00:01 TO 06/20,
15 MINUTE INTERVALS

PEAK DAY ANALYSIS PLOT

MAX= 796.50 KW SUM MIN= 219.00 KW SUM

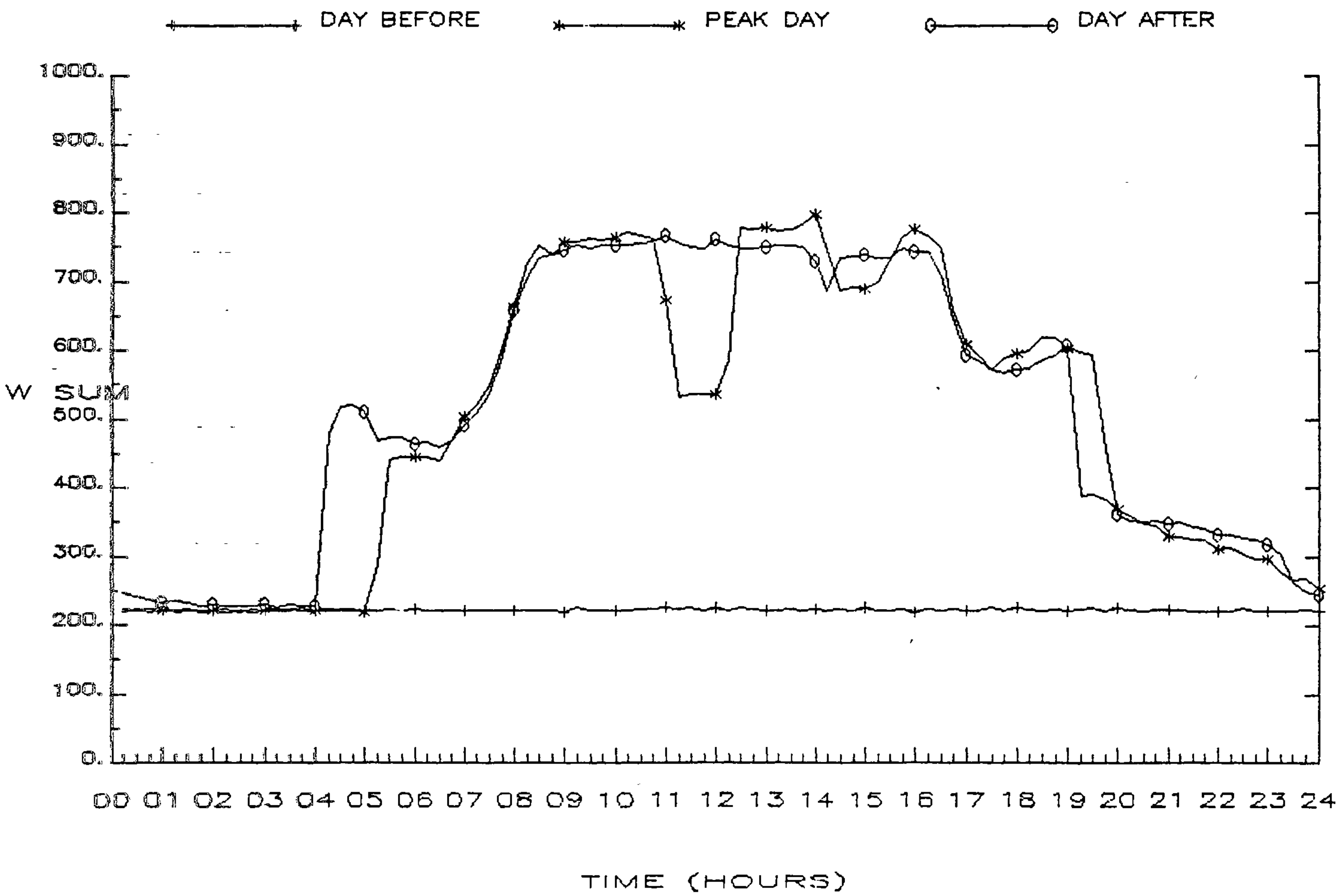


ID: THORPE
NAME: STATE BOARD OF AFF
ADDRESS: JIM THORPE BLDG
CLASS OF ACCT: BN19 HIST

DATE 10/10/89
FROM 06/20/88 00:01 TO 06/20/
15 MINUTE INTERVALS

PEAK DAY ANALYSIS PLOT

MAX= 796.50 KW SUM MIN= 219.00 KW SUM



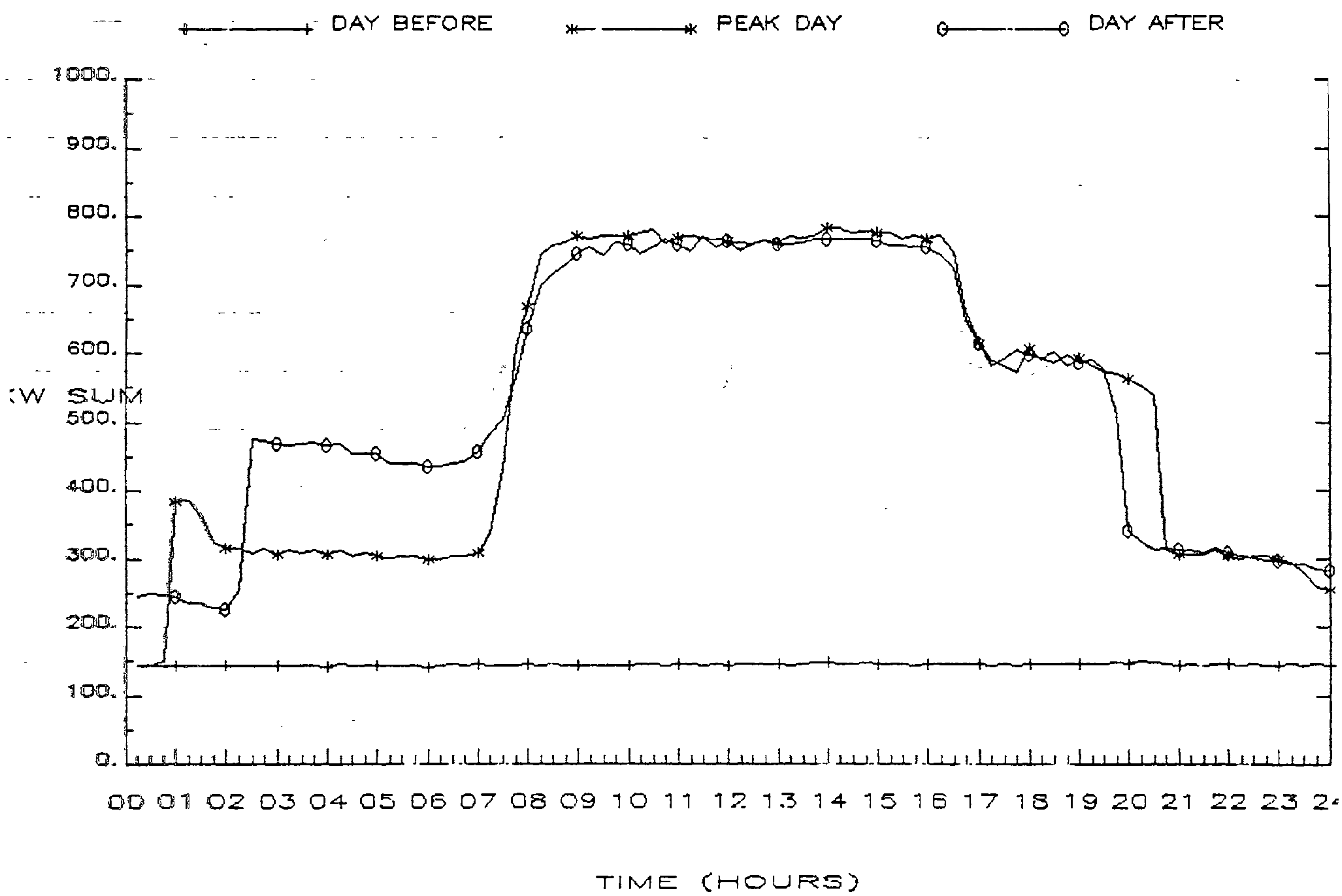
ID: THORPE
NAME: STATE BOARD OF AFF
ADDRESS: JIM THORPE BLDG
CLASS OF ACCT: BN19 HIST

DATE 10/10/89
FROM 08/22/88 00:01 TO 08/22
15 MINUTE INTERVALS

PEAK DAY ANALYSIS PLOT

MAX= 784.50 KW SUM

MIN= 141.00 KW SUM

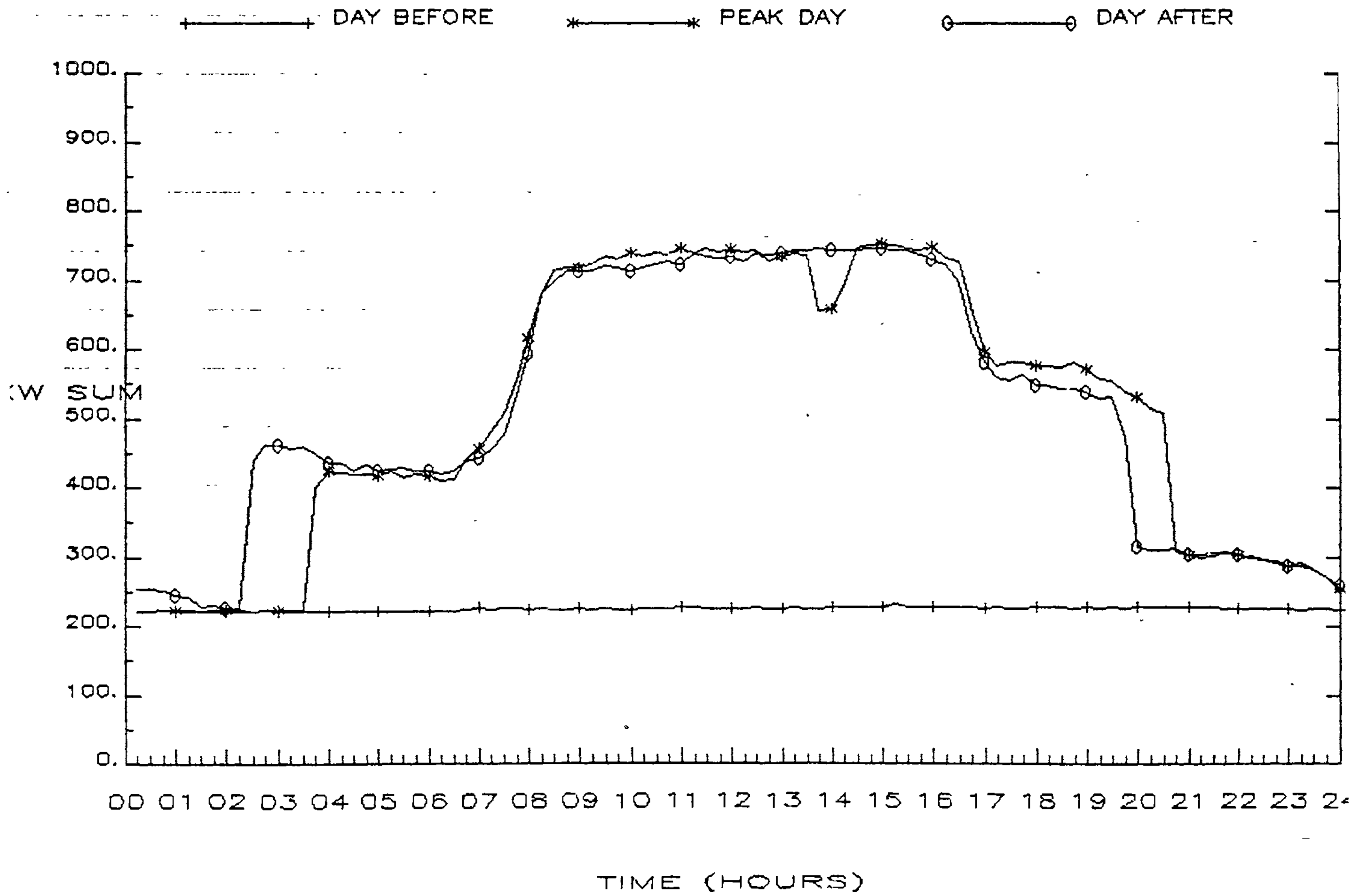


ID: THORPE
NAME: STATE BOARD OF AFF
ADDRESS: JIM THORPE BLDG
CLASS OF ACCT: BN19 HIST

DATE 10/10/89
FROM 09/12/88 00:01 TO 09/12
15 MINUTE INTERVALS

PEAK DAY ANALYSIS PLOT

MAX= 753.00 KW SUM MIN= 220.50 KW SUM



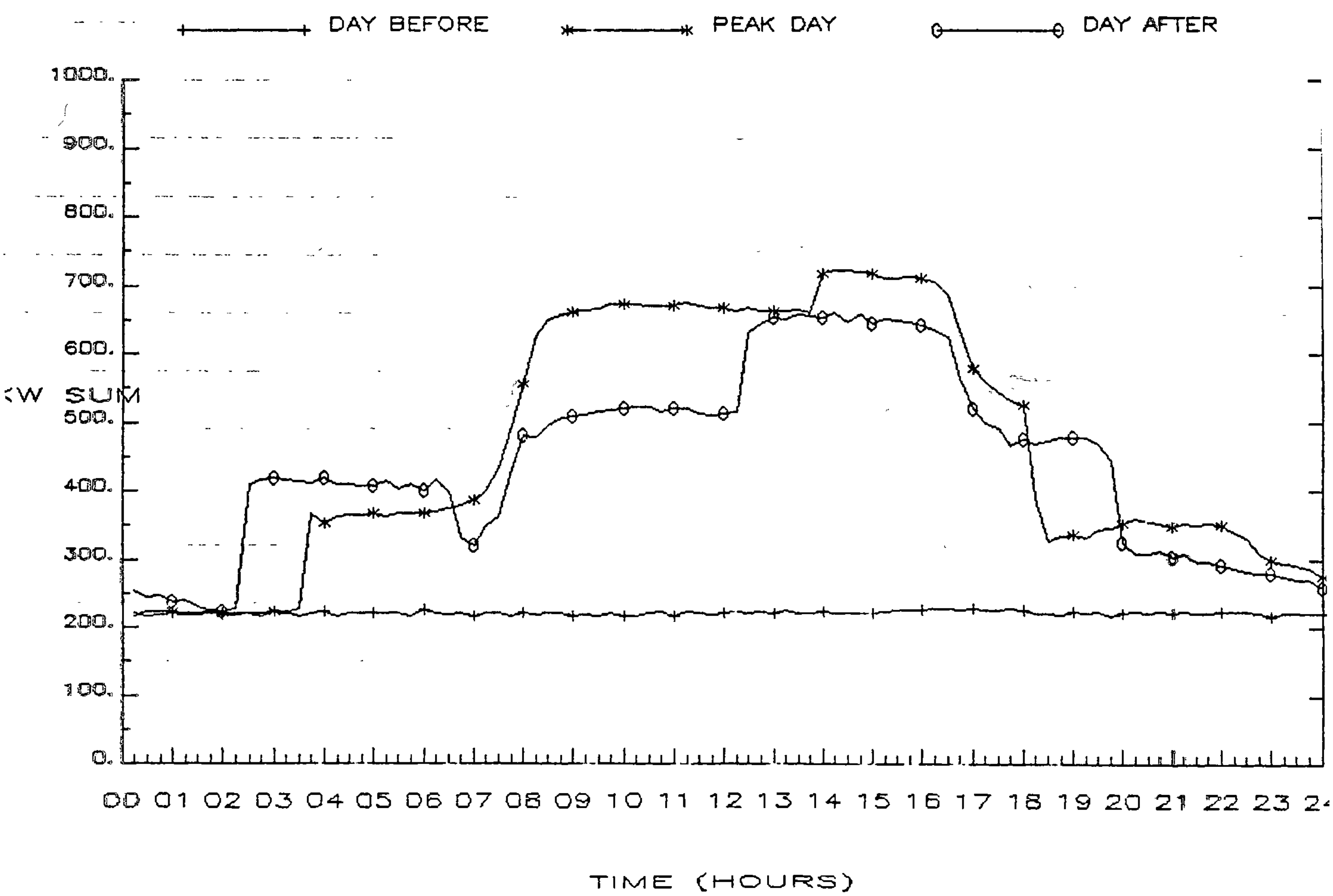
ID: THORPE
NAME: STATE BOARD OF AFF
ADDRESS: JIM THORPE BLDG
CLASS OF ACCT: BN19 HIST

DATE 10/10/89
FROM 10/17/88 00:01 TO 10/17
15 MINUTE INTERVALS

PEAK DAY ANALYSIS PLOT

MAX= 721.50 KW SUM

MIN= 216.00 KW SUM



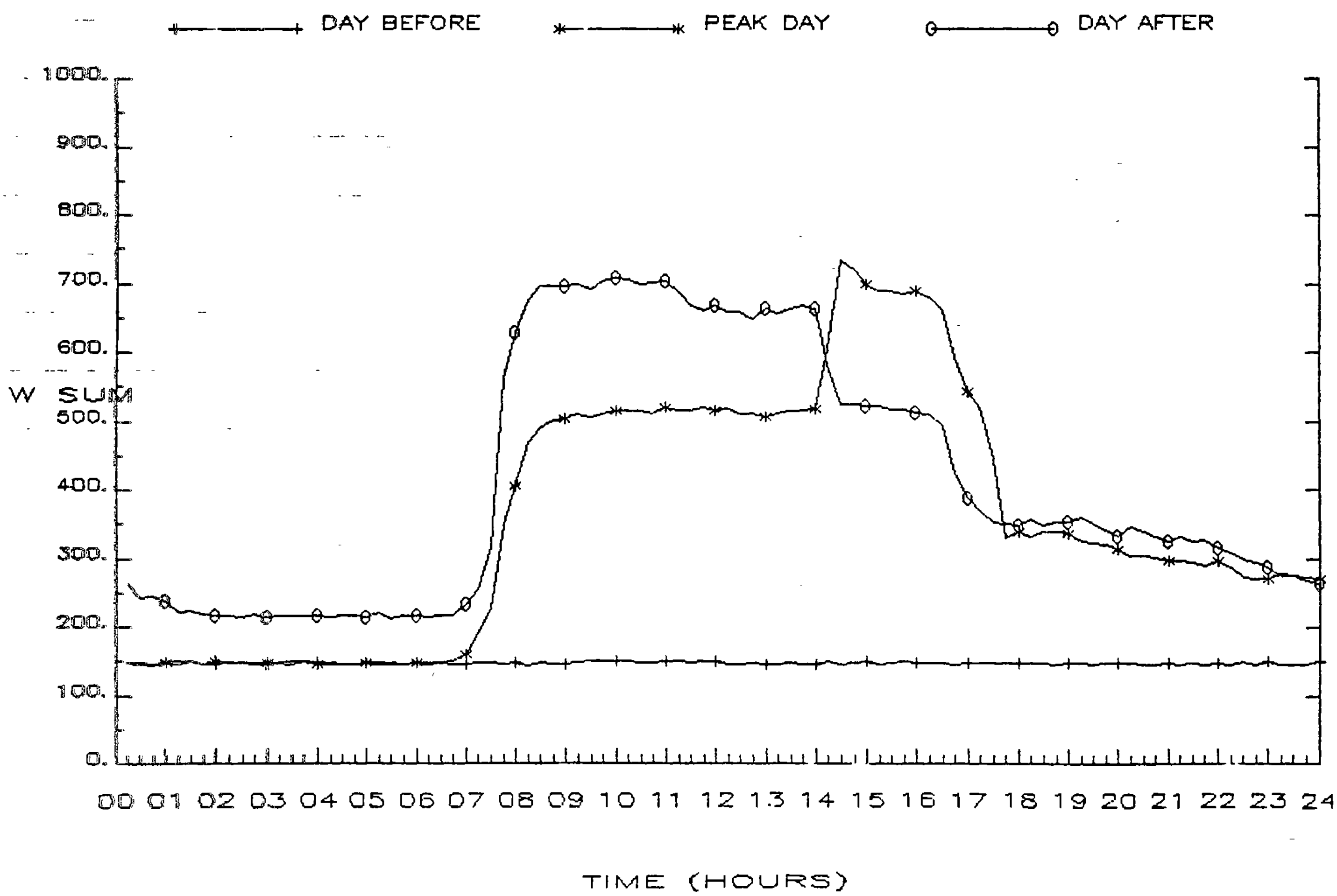
ID: THORPE
NAME: STATE BOARD OF AFF
ADDRESS: JIM THORPE BLDG
CLASS OF ACCT: BN19 HIST

DATE 10/10/89
FROM 11/14/88 00:01 TO 11/14/
15 MINUTE INTERVALS

PEAK DAY ANALYSIS PLOT

MAX= 735.00 KW SUM

MIN= 144.00 KW SUM



ID: THORPE
NAME: STATE BOARD OF AFF
ADDRESS: JIM THORPE BLDG
CLASS OF ACCT: BN19 HIST

DATE 10/10/89
FROM 12/01/88 00:01 TO 12/01
15 MINUTE INTERVALS

PEAK DAY ANALYSIS PLOT

MAX= 774.00 KW SUM

MIN= 190.50 KW SUM