11944

THE ECONOMIC FEASIBILITY OF UTILIZING GEOTHERMAL HEAT FOR AN AGRICULTURAL CHEMICAL PLANT

Peter B. Sherwood

WESTEC Services, Inc.
San Diego, California

ABSTRACT

The engineering and economic feasibility of utilizing geothermal heat from the Heber KGRA for industrial processing purposes at the Valley Nitrogen Producers, Inc. El Centro, California agricultural chemical plant was investigated. The analysis proceeds through the preliminary economics to determine the restraints imposed by geothermal modification size on internal rates of return, and through the energy utilization evaluation to determine the best method for substituting geothermal energy for existing fossil fuel energy. Finally, several geothermal utilization schemes were analyzed for detailed cost-benefit evaluation. An economically viable plan for implementing geothermal energy in the VNP Plant was identified and the final conclusions and recommendations were made based on these detailed cost-benefit analyses. Costs associated with geothermal energy production and implementation were formulated utilizing a modified Battelle Pacific Northwest Laboratories' "GEOCOST" program.

BACKGROUND

Valley Nitrogen Producers is a grower-owned agricultural cooperative corporation, whose primary purpose is to provide fertilizer products at the lowest possible cost to agricultural producers. With growers constantly facing increased costs of farming operations, most of which are energy related, low cost fertilizers become essential to economically viable food production in the United States.

The El Centro plant, operating at full production since 1969, is an energy intensive operation consuming over 25 million SCF of natural gas per day for ammonia feedstock, reformer fuel, and steam generation and over 180,000 KWH per day of electrical power. The plant's location in the Heber KGRA makes VNP an appropriate candidate for detailed engineering and economic evaluation of possible applications of geothermal heat to plant energy needs.

A detailed engineering survey of the VNP plant was conducted which concluded that the substitution of geothermal energy for fossil fuel energy can best be accomplished by a reduction in fired steam production, which consumes 40 percent of the plant fossil fuel. The survey revealed that there are three major steam systems; 1,500 psi, 450 psi, and 50 psi produced by a combination of fossil fuel and waste heat, and interconnected by a complex system of twenty extraction, full condensing and back pressure turbines. A simplified plant steam cycle appears in Figure 1.

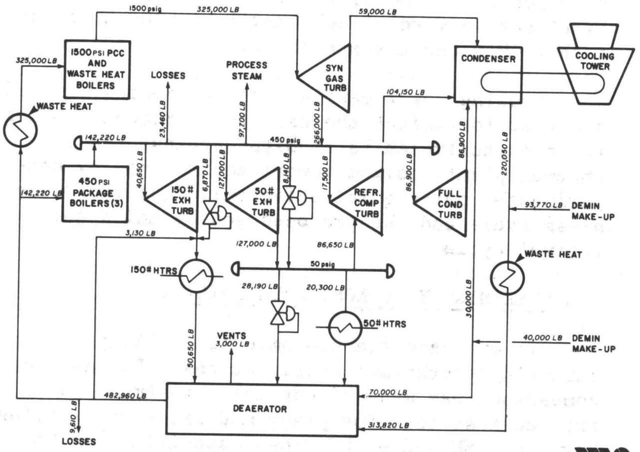

FIGURE I. SIMPLIFIED PLANT STEAM CYCLE

WESTEC Services, Inc.

All plant turbine drivers can be replaced by geothermal energy, either with low pressure saturated steam turbines, binary vapor expanders or electric motors. All high pressure process steam requirements (1,500 psi and 450 psi) can be met with existing waste heat recovery from both exothermic chemical reactions and the burning of natural gas in other process functions. Low pressure process steam requirements (50 psi) can be met with steam flashed from geothermal brine. Techniques for the production of electricity from liquid dominated geothermal resources are well documented. Therefore, the engineering feasibility exists to provide the electrical demand and replace the fossil fuel used for steam production in the VNP plant with geothermal energy.

1. PRELIMINARY ECONOMIC EVALUATION

1.1 INTRODUCTION

A preliminary economic evaluation was performed to determine the overall economic feasibility of substituting geothermal energy for fossil fuel energy at the VNP Plant. The evaluation was completed by comparing the energy cost savings incurred by geothermal energy substitution with the capital costs required for mechanical modifications to the plant. The energy cost savings were calculated by factoring the predicted geothermal brine costs and fossil fuel costs by the net efficiencies for the existing steam cycle and a proposed geothermal cycle.

1.2 GEOTHERMAL CAPITAL COST MODELS

The computer model used for the economic and thermodynamic analysis of the VNP Geothermal Plant was a modified version of the "GEOCOST" program developed by Battelle Pacific Northwest Laboratories to analyze geothermal electric production costs.

The "GEOCOST" capital cost estimates were modified to eliminate unnecessary equipment costs which are more typical of power plants. The capital cost estimates for turbines and associated piping were modified to eliminate the cost of a generator and to reflect the fact that the VNP Plant has many relatively small turbine applications rather than one large turbine.

Cooling tower capital cost estimates were also modified to reflect the fact that present cooling tower capacity can be credited against the geothermal plant cooling tower requirements by comparing the net thermal efficiencies of the present steam cycle and the proposed geothermal plant thermal cycle.

1.3 PRELIMINARY ECONOMIC FEASIBILITY

To evaluate the economic feasibility of substituting geothermal energy at the VNP Plant, a comparison was made of capital investment costs and fuel cost savings for plant modifications ranging between 5 MW and 30 MW gross capacities for both binary and flash steam geothermal plants. Yearly energy cost savings were calculated for the period 1980 through 1989 by comparing the energy costs and net thermal efficiencies of the existing plant and an alternative geothermal plant of the same capacity using the following equation:

$$S = \frac{C}{eg}\left(a\,\frac{eg}{ef} - b\right)$$

where:

- S = Yearly cost savings, \$/YR
- C = Yearly geothermal plant net power output, BTU/YR
- ef = Fossil plant net thermal efficiency
- eg = Geothermal plant net thermal efficiency
- a = Cost of fossil fuel, $\$/10^6$ BTU
- b = Cost of geothermal fuel, $\$/10^6$ BTU

and C can be calculated by:

$$C = (\text{Net Power, KW})\left(3412.2\ \frac{\text{BTU}}{\text{KWH}}\right)\left(8760\ \frac{\text{HR}}{\text{YR}}\right)(\text{Capacity Factor})$$

Yearly energy cost savings were calculated using projected constant dollar fuel costs. VNP requires a minimum internal rate of return of 10 percent in ten years for major capital expenditures, therefore the present worth for each year's energy cost savings were calculated in December 1977 dollars at 10 percent interest and compared to the plant capital cost estimates also in December 1977 dollars. Incremental benefit-cost ratios were calculated along with internal rates of return. The results are shown in Tables 1 and 2.

Table 1

FINANCIAL SUMMARY - BINARY CYCLE PLANTS (CONSTANT \$ 1977)

Plant Size (MW)	Number of Turbines Replaced	Capital Investment for Geothermal Conversion (\$ Millions)	Present Worth of Energy Cost Savings Over First 10 Years @ 10% (\$ Millions)	Incremental Benefit-Cost Ratio	Internal Rate of Return Over First 10 Years %
5	1	6.2	5.9	0.95	9.1
10	2	10.5	12.0	1.42	12.7
15	3	14.1	18.1	1.69	15.4
20	3	18.5	24.1	1.36	15.7
25	4	21.6	30.3	2.00	17.3
30	12	27.6	36.2	0.98	15.8

Table 2

FINANCIAL SUMMARY - STEAM CYCLE PLANTS (CONSTANT \$ 1977)

Plant Size (MW)	Number of Turbines Replaced	Capital Investment for Geothermal Conversion (\$ Millions)	Present Worth of Energy Cost Savings Over First 10 Years @ 10% (\$ Millions)	Incremental Benefit-Cost Ratio	Internal Rate of Return Over First 10 Years %
5	1	9.4	6.8	0.72	5.9
10	2	13.6	14.1	1.73	10.7
15	3	18.7	21.2	1.39	12.6
20	3	22.7	28.5	1.82	14.8
25	4	25.4	35.8	2.71	17.6
30	12	33.6	42.8	0.85	15.2

This preliminary analysis assumes that the substitution of geothermal energy will offset an equivalent amount of fuel energy and that each increment of fossil fuel reduction will have the same thermal efficiency as the overall plant thermal efficiency. With the large amount of waste heat input to the VNP Plant steam cycle and the differences in equipment efficiencies in various parts of the plant, neither of these assumptions may prove to be totally correct. However, this analysis serves the purpose of indicating restraints imposed by geothermal modification size on internal rates of return.

1.4 SUMMARY

All geothermal steam and binary cycle plant sizes considered show internal rates of return exceeding 10 percent with the exception of the 5 MW binary cycle and 5 MW steam cycle plants. The capital investments for the steam cycle plants are greater than the capital investments for the same size binary cycle plants, due primarily to higher turbine costs and higher transmission costs for two-phase brine.

Incremental benefit-cost ratios for each plant size also appear in Tables 1 and 2. These ratios indicate whether each 5 MW increase in plant size is a cost-effective investment satisfying the 10 percent rate of return requirement. Tables 1 and 2 show that the 30 MW binary cycle and steam cycle plants would be questionable investments, because the incremental benefit-cost ratio is less than 1. This is due primarily to the high capital cost of multiple turbine applications. All other incremental benefit-cost ratios, except the 5 MW binary cycle and steam cycle plants, with their low internal rates of return, are greater than 1 indicating that they are all acceptable capital investments.

1.5 CONCLUSIONS OF THE PRELIMINARY ECONOMIC EVALUATION

The preliminary economic evaluation shows that the substitution of geothermal energy for fossil fuel energy at the VNP Plant can be economically feasible for either binary or flash steam cycle plants, if the plant size is at least 10 MW and the capital costs for large plant modifications can be held down by limiting the number of geothermal turbine substitutions. This result is largely based on the fuel pricing assumptions made for both fossil fuel and geothermal energy, which provide for an increasing constant dollar price differential over the study period. The future announcement of the price structure of geothermal fluid contracts on the Heber Reservoir will confirm or refute this assumption.

2. ENERGY UTILIZATION EVALUATION

2.1 INTRODUCTION

An energy utilization evaluation was performed to determine the most cost-effective method for substituting geothermal energy for fossil fuel energy at the VNP Plant. The evaluation was completed by assigning a total unit charge rate in $/Hp-hr to each existing equipment driver in the plant steam cycle, which reflects the levelized operating cost for the period 1980 through 1989, and to each alternative equipment driver in a new power cycle, which reflects both plant modification capital costs and operating costs for the same period. Capital costs for providing the geothermal cycle equipment drivers and the new electric motors were based on budget quotations received from leading equipment manufacturers.

2.2 ENERGY CHARGES FOR EXISTING TURBINES

The cost of operating existing steam turbines was calculated to compare continued operation of these turbines against other alternatives available in the future. Energy charges for steam usage were calculated on a cost per horsepower-hour basis and were based on the levelized fuel oil cost for the period 1980 through 1989. The cost of steam was based on the energy required to heat the steam from saturated liquid at the condensing pressure to turbine inlet conditions, taking boiler efficiency into account. In addition to conventional backpressure and full condensing turbines, four special cases of extraction, induction, and high backpressure turbines were calculated, namely the Synthesis Gas Compressor, Refrigeration Compressor, Process Air Compressor, and Hydraulic Supply Pump Turbines.

2.3 TOTAL CHARGES FOR GEOTHERMAL TURBINES

The total cost of operating new geothermal turbines was calculated to compare with continued operation of existing fossil fuel steam turbines. The total charges were calculated as the sum of the geothermal plant demand charge, the geothermal turbine capital cost charge, and the geothermal turbine energy charge all computed on a cost per horsepower-hour basis for the period 1980 through 1989.

2.4 TOTAL CHARGES FOR ELECTRIC MOTORS

The total cost of operating existing and new electric motors was calculated to compare with operation of turbine powered equipment drivers, both geothermal and fossil fuel powered. Existing electric motor operating costs were based on energy charges for each source of electrical power from both off-site and on-site generation. New electric motor total operating costs were based on the sum of the capital cost charges for new electric motors and the electric energy charges from each power source considered. All charges were computed on a cost per horsepower-hour basis for the period 1980 through 1989.

2.5 SUMMARY

Levelized costs for operating each of twenty turbine driven pumps and compressors with fossil, geothermal, and off-site electrical energy are summarized in Table 3. Costs are in $/Hp-hr units, which minimizes the effect of capital cost estimates and reflects more heavily the cost of energy for equipment operation. Several trends appear from this technique, however, care must be taken in drawing conclusions from this method of analysis:

> Existing backpressure steam turbines are much more economical than the full condensing steam turbines. This is not to say that running existing backpressure turbines should be chosen over all other alternatives.
>
> Operating a combination of existing and new electric motors on off-site electrical power would be a cost effective alternative. This assumes that the local utility can supply the additional electrical demand and that the present declining block rate structure will remain unchanged.
>
> The binary cycle process appears to be favored over the flash cycle process as an alternative to more conventional energy sources.

Table 3 weighs the cost of each alternative on an equal basis, regardless of equipment size. However, to arrive at the best alternative plant arrangement, it was necessary to weigh the cost of each alternative taking equipment size into consideration. Therefore, the costs from Table 3 were multiplied by the rated horsepower for each equipment driver to give costs in units of $/hr. These costs allowed the comparison of various alternatives by adding the $/hr cost for each piece of equipment and determining a relative total plant operating cost.

From this analysis it was determined that the major portion of potential cost savings will come

Table 3

LEVELIZED COSTS FOR PERIOD 1980-1989 $/Hp-hr TURBINES	RATED Hp	EXISTING TURBINES (FOSSIL)	EXISTING MOTORS OFFSITE POWER	EXISTING MOTORS ONSITE POWER (FOSSIL)	EXISTING MOTORS ONSITE POWER (BINARY)	EXISTING MOTORS ONSITE POWER (FLASH)	BINARY TURBINE	FLASH TURBINE	NEW MOTORS OFFSITE POWER	NEW MOTORS ONSITE POWER (FOSSIL)	NEW MOTORS ONSITE POWER (BINARY)	NEW MOTORS ONSITE POWER (FLASH)
1. SYN. GAS COMPRESSOR	14,000	.0296	NA	NA	NA	NA	.0345	.0509	.0388	.0754	.0601	.0670
2. REFRIG COMPRESSOR	7,325	.1398	NA	NA	NA	NA	.0466	.0529	.0390	.0756	.0603	.0672
3. AIR COMPRESSOR	5,625	.0946	NA	NA	NA	NA	.0468	.0529	.0380	.0746	.0593	.0662
4. H.P. BFW PUMP	1,320	.0223	.0362	.0728	.0575	.0644	.0463	.0604	NA	NA	NA	NA
5. COOLING WATER PUMP	980	.1429	.0362	.0728	.0575	.0644	.0527	.0541	.0396	.0762	.0609	.0678
6. NATURAL GAS COMPRESSOR	960	.0217	NA	NA	NA	NA	.0511	.0649	.0396	.0762	.0609	.0678
7. T.E.A. SOL'N PUMP	960	.0222	.0362	.0728	.0575	.0644	.0508	.0624	NA	NA	NA	NA
8. HYDRAULIC SUPPLY PUMP	840	.0208	NA	NA	NA	NA	.0512	.0610	.0400	.0766	.0613	.0682
9. I.D. FAN	275	.0267	NA	NA	NA	NA	.0637	.0525	.0398	.0764	.0611	.0680
10. H.P. BOILER CIRC. PUMP	248	.0267	.0362	.0728	.0575	.0644	.0632	.0564	NA	NA	NA	NA
11. ERIE 2 BFW PUMP	250	.0292	.0362	.0728	.0575	.0644	.0583	.0586	NA	NA	NA	NA
12. AUX CARBAMATE PUMP	250	.0412	NA	NA	NA	NA	.0583	.0680	.0403	.0769	.0616	.0685
13. TURBO-GENERATOR	186	.0474	NA	NA	NA	NA	.0727	.0718	NA	NA	NA	NA
14. L.P. BFW PUMP	95	.0359	.0362	.0728	.0575	.0644	.0811	.0675	NA	NA	NA	NA
15. DEMIN. WATER PUMP	80	.3252	.0362	.0728	.0575	.0644	.0897	.0702	.0418	.0784	.0631	.0700
16. SYN SEAL OIL PUMP	80	.3745	.0362	.0728	.0575	.0644	.0827	.0702	NA	NA	NA	NA
17. SYN LUBE OIL PUMP	80	.3745	.0362	.0728	.0575	.0644	.0810	.0702	NA	NA	NA	NA
18. FM LUBE OIL PUMP	40	.3252	.0362	.0728	.0575	.0644	.1204	.0946	NA	NA	NA	NA
19. REFRIG LUBE OIL PUMP	30	.7686	.0362	.0728	.0575	.0644	.1465	.1118	NA	NA	NA	NA
20. FM SEAL OIL PUMP	22.5	.3252	.0362	.0728	.0575	.0644	.1881	.1212	NA	NA	NA	NA

from changes to the three largest turbines in the plant, which represent about 80 percent of the total fossil fuel turbine costs. It can be assumed, for the present, that large blocks of "inexpensive" off-site electrical power will not be made available to the VNP Plant, in the near term, for operating large electrical motors. Therefore, the optimum solution to reducing fossil fuel energy costs in the VNP Plant steam cycle appears to be:

Minimize operating costs for the three largest turbines;

Maintain maximum waste heat utilization; and

Maintain a balanced steam cycle using a combination of backpressure turbines and electric motors.

2.6 CONCLUSIONS OF THE ENERGY UTILIZATION EVALUATION

The energy utilization evaluation shows that a viable solution for reducing fossil fuel costs in the VNP Plant will come by integrating a geothermal binary cycle into the existing plant steam cycle. The Refrigeration Compressor and Process Air Compressor would be run by new binary cycle turbines. The maximum available off-site electrical power level would be maintained in the plant with the remaining plant equipment run on electrical power generated from a geothermal binary cycle turbine-generator set. The inclusion of in-house electrical generating capacity would also increase plant reliability.

A conclusion regarding the economics of substituting a binary expander for the Synthesis Gas Compressor Turbine cannot be drawn based on this analysis because of the affect of the large amount of waste heat used for high pressure steam generation. Only a detailed economic evaluation of several proposed design schemes can determine the optimal solution along with the actual internal rate of return for geothermal substitution in the VNP Plant.

3. DETAILED ECONOMIC EVALUATION

3.1 INTRODUCTION

An economic evaluation was performed to compare geothermal utilization schemes, which were identified in the energy utilization analysis, as a conclusion to this feasibility study. The evaluation was accomplished by comparing the energy cost savings incurred by geothermal energy substitution with the capital costs required for plant modifications. The energy cost savings were calculated by comparing the predicted geothermal brine costs with the fossil fuel cost savings based on detailed plant thermal cycle heat balances. Yearly fuel costs for both fossil fuel and geothermal energy were calculated based on the constant dollar fuel cost projections for the ten year period under consideration. For comparison, both geothermal flash steam turbines and binary expanders were evaluated for detailed economics.

Due to the inconclusive results of the Energy Utilization Evaluation regarding substitution of the Synthesis Gas Turbine with geothermal energy, the Detailed Economic Evaluation was conducted in two phases. This two-phase concept allows for verification of the incremental cost effectiveness of replacing this highly efficient machine.

The Phase I Modification would replace the existing Refrigeration Compressor and Process Air Compressor Turbines with geothermal energy while the remaining small turbines would be replaced by existing back-up or new electric motors. The electrical power would come from a combination of on-site geothermal and off-site fossil power generation. The Phase I Modification would result in the elimination of the fossil fuel requirement for the three fired package boilers.

The Phase II Modification would replace the existing Refrigeration Compressor, Process Air Compressor, and Synthesis Gas Compressor Turbines with geothermal energy. Three replacement schemes were explored both from an energy and an economic standpoint. The first scheme would utilize a binary two-stage ammonia turbo-expander in conjunction with Phase I flashed steam turbines. The second scheme would utilize a low-pressure steam turbine in conjunction with Phase I flashed steam turbines. The third scheme would employ an isobutane turbo-expander in conjunction with a Phase I binary system.

The Phase II Modification would result in the elimination of the fossil fuel requirement for all fired steam production in the VNP Plant, resulting in a 40 percent reduction in plant fossil fuel consumption. The remaining plant fossil fuel consumption would constitute the natural gas used as ammonia feedstock and fuel for the primary gas reform which do not lend themselves to presently economical or practical alternatives.

Total capital costs were calculated for each proposed scheme and incremental benefit-cost ratios were calculated between Phase I and Phase II modifications. Final conclusions and recommendations were drawn based on this detailed economic evaluation.

3.2 SUMMARY

Data from each of the cases considered in the detailed economic evaluation is summarized in Table 4. The compression work listed refers to the amount of geothermal turbine work done to replace the three largest steam turbines in the plant. All Phase I schemes require substituting geothermal powered turbines for the Refrigeration Compressor and Air Compressor Turbines. All Phase II schemes require substituting geothermal powered turbines for the Refrigeration Compressor, Air Compressor, and Syn Gas Compressor Turbines.

The total plant power demand listed includes power to supply new and existing process plant motors, geothermal plant auxiliary power requirements, and the present 8,000 KW plant electrical demand. Various combinations of off-site and on-site power generation were considered. Off-site power refers to electrical demand supplied by the local utility, namely the Imperial Irrigation District, while on-site power refers to geothermal power generation.

Incremental cooling water requirements were included to indicate the amount of additional cooling tower capacity required for each case. Incremental canal water make-up requirements were also indicated, where numbers in parentheses indicate reductions in total canal water requirements. Components of canal make-up water required to maintain brine reinjection inventory may be reduced if plant waste water can be successfully substituted.

Incremental benefit-cost ratios were calculated for each Phase II case to check the acceptability of the incremental investment over a comparable Phase I case.

3.3 CONCLUSIONS OF THE DETAILED ECONOMIC ANALYSIS

From Table 4 it can be concluded that, if off-site power is made available to the VNP Plant under the present rate structure, the geothermal flash steam and binary power cycles can return a rate greater than the 10 percent minimum required by VNP, with the binary cycle return rate consistently higher for a comparable case. If, however, off-site power is not made available to the VNP Plant or is not available under the present rate structure, only the geothermal binary power cycle can return a rate greater than the 10 percent minimum required by VNP while providing on-site geothermal power generation. Until present electrical rates change, no geothermal power cycle considered can economically replace the present 8 MW off-site electrical demand.

Also from Table 4 it can be seen that only the geothermal binary power cycle gives an acceptable incremental benefit-cost ratio for a Phase II modification. This indicates that only the geothermal binary cycle is economically acceptable for a Phase II modification, which results in eliminating all fossil fuel requirements for steam production in the VNP Plant.

Table 4

DETAILED ECONOMIC EVALUATION SUMMARY	PHASE I: Scheme 1, Without Onsite Power Generation	PHASE I: Scheme 1, With Onsite Power Generation	PHASE I: Scheme 2, Without Onsite Power Generation	PHASE I: Scheme 2, With Onsite Power Generation	PHASE II: Scheme 1, Without Onsite Power Generation	PHASE II: Scheme 2, Without Onsite Power Generation	PHASE II: Scheme 3, Without Onsite Power Generation	PHASE II: Scheme 3, With Onsite Power Generation	PHASE II: Scheme 3, With Total Onsite Power Generation
POWER CYCLE	FLASH	FLASH	BINARY	BINARY	HYBRID	FLASH	BINARY	BINARY	BINARY
RESERVOIR TEMP, °F	360	360	360	360	360	360	360	360	360
BRINE FLOW, 10^3 lb/hr	1,978	3,887	1,041	2,338	3,237	3,701	1,354	3,084	4,155
COMPRESSION WORK, Hp	11,772	11,772	11,772	11,772	24,532	24,532	24,532	24,532	24,532
TOTAL PLANT POWER DEMAND, KW*	16,400	17,500	17,700	20,200	19,600	18,100	20,900	24,200	26,200
OFFSITE POWER DEMAND, KW	16,400	8,000	17,700	8,000	19,600	18,100	20,900	8,000	-0-
ONSITE GENERATOR OUTPUT, KW	-0-	9,500	-0-	12,200	-0-	-0-	-0-	16,200	26,200
INCREMENTAL C.W. REQ'D, GPM	4,000	19,000	3,900	31,500	7,000	14,000	14,500	51,200	73,800
INCREMENTAL CANAL WATER, GPM	(110)	300	(50)	650	(120)	175	200	1,060	1,580
PLANT MODIFICATION COST, $\$10^3$, (1977)	13,773	24,593	10,837	21,419	21,927	22,122	15,153	26,715	34,424
INTERNAL R of R @ 10 YRS, %	24.3	5.9	32.1	10.2	18.4	17.1	34.6	14.5	7.3
INCREMENTAL BENEFIT-COST RATIO	NA	NA	NA	NA	0.86	0.68	2.91	2.18	0.64

*Includes Present 8,000 KW Demand