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ENGINEERING AND ECONOMIC
FEASIBILITY OF UTILIZING
GEOTHERMAL HEAT FROM THE HEBER
RESERVOIR FOR INDUSTRIAL PROCESSING
PURPOSES AT VALLEY NITROGEN
PRODUCERS INC., EL CENTRO
AGRICULTURAL CHEMICAL PLANT

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SECOND QUARTERLY REPORT

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MASTER

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TABLE OF CONTENTS

<u>Section</u>	<u>Title</u>	<u>Page</u>
Section 1	INTRODUCTION	1
1.1	Background	1
1.2	Scope of the Second Quarterly Report	2
Section 2	OVERALL ECONOMIC EVALUATION	3
2.1	Introduction	3
2.2	Geothermal Fluid Pricing	3
2.3	Escalated Energy Costs	10
2.4	Geothermal Capital Cost Models	14
2.5	Overall Economic Evaluation	29
2.6	Preliminary Conclusions	35
Section 3	ENERGY UTILIZATION EVALUATION	40
3.1	Introduction	40
3.2	Energy Charges for Existing Turbines	41
3.3	Total Charges for Geothermal Turbines	49
3.4	Total Charges for Electric Motors	59
3.5	Summary	67
3.6	Conclusion	72
Appendix A	DERIVATION OF COOLING TOWER INCREMENTAL COST FACTOR	A-1 THRU A-2
Appendix B	STEAM CYCLE THERMAL EFFICIENCY	B-1 THRU B-5
Appendix C	LEVELIZED UNIT FUEL COSTS	C-1 THRU C-2
Appendix D	FIXED CHARGE RATE CALCULATION	D-1
Appendix E	CALCULATION OF BRINE FLASHING PRESSURES	E-1 THRU E-2

LIST OF FIGURES

<u>Figure</u>	<u>Title</u>	<u>Page</u>
Section 2		
2-1	Single-Phase Brine Cost	8
2-2	Two-Phase Brine Cost	9
2-3	Constant Dollar Fuel Costs	11
2-4	Nominal Fuel Costs	12
2-5	Two-Stage Flash Steam Plant	16
2-6	Sub-Critical Binary Fluid Cycle Plant	17
2-7	Flash Plant Steam Turbines (0-1500 Hp)	22
2-8	Flash Plant Steam Turbines (0-15,000 Hp)	23
2-9	Binary Plant Turbo-Expanders (0-1500 Hp)	25
2-10	Binary Plant Turbo-Expanders (0-15,000 Hp)	26
Appendix B		
B-1	Simplified Plant Steam Cycle	B-2

LIST OF TABLES

<u>Table</u>	<u>Title</u>	<u>Page</u>
Section 2		
2-1	Reservoir Data	5
2-2	Flash Steam Turbine Costs	21
2-3	Binary Expander Costs	24
2-4	Turbine Piping Cost Factors	27
2-5	Annual Energy Cost Savings for Geothermal Binary Cycle Plants	31
2-6	Annual Energy Cost Savings for Geothermal Steam Cycle Plants	31
2-7	Financing and Repayment of Bank Loan for 25 MW Binary Cycle Plant	33
2-8	Financing and Repayment of Bank Loan for 25 MW Steam Cycle Plant	34
2-9	Present Worth and Internal Rate of Return for 25 MW Binary Cycle Plant	36
2-10	Present Worth and Internal Rate of Return for 25 MW Steam Cycle Plant	37
2-11	Financial Summary-Binary Cycle Plants	38
2-12	Financial Summary-Steam Cycle Plants	38
Section 3		
3-1	Waste Heat Attributable to Fossil Fuel	46
3-2	Existing Steam Turbine Energy Charges	48
3-3	Binary Plant Demand Charges	51
3-4	Flash Steam Plant Demand Charges	52

LIST OF TABLES (Cont.)

<u>Table</u>	<u>Title</u>	<u>Page</u>
3-5	Ratio of Brine Flow to Isobutane Flow	53
3-6	Geothermal Binary Expanders- Levelized Charges for Period 1980 to 1989	57
3-7	Geothermal Flashed Steam Turbines- Levelized Charges for Period 1980 to 1989	58
3-8	New Electric Motor Demand Charges	61
3-9	New Electric Motor Demand Charges	62
3-10	On-Site Turbine-Generator Quotation	64
3-11	Levelized Operating Costs for Period 1980-1989, \$/Hp-hr	68
3-12	Levelized Operating Costs for Period 1980-1989, \$/hr	71
3-13	Equipment Driver Cost Options	73
Appendix B		
B-1	Steam Cycle Heat Loss Analysis	B-3
Appendix C		
C-1	Levelized Unit Fuel Costs	C-2

Section 1

INTRODUCTION

1.1 BACKGROUND

The Valley Nitrogen Producers El Centro plant is part of a grower-owned system of major fertilizer production and distribution facilities organized to provide fertilizer products at low 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. Its location in the Heber Known Geothermal Resource Area (KGRA) makes it an appropriate candidate for detailed engineering and economic evaluation of possible applications of geothermal heat to plant energy needs.

The First Quarterly Report documented the completion of the plant and resource phase of the study. A model of the plant in terms of its present energy utilization was developed and alternative approaches to possible geothermal heat applications were identified for further study. Basic reservoir characteristics to be used for engineering calculations and preliminary design schemes were also established.

1.2 SCOPE OF THE SECOND QUARTERLY REPORT

This report provides the initial economic evaluation of the alternatives to natural gas consumption identified in the First Quarterly Report. Using estimates of well costs, well flow, well life, temperature, enthalpy, and rates of return on invested capital, the cost of brine production has been estimated in terms of a demand charge and an energy charge. Capital costs of geothermal flash steam and binary systems from 5 to 30 Gross MW capacities have been estimated utilizing a modified Batelle Pacific Northwest Laboratories "GEOCOST" computer program. Fossil fuel costs, geothermal brine costs, and rate of inflation have been projected through 1997. Using these data, the thermal cycle efficiencies, and the capital cost data, the projected annual cost savings and the internal rate of return, as a function of the amount of fossil fuel displaced by geothermal energy, have been calculated and preliminary conclusions have been drawn based on this overall economic evaluation.

In addition to an overall economic evaluation, an individual energy utilization evaluation was undertaken. Using estimates of capital costs, energy costs, and energy conversion efficiencies, a total unit charge rate in \$/Hp-hr was assigned to each existing equipment driver and each proposed energy alternative to determine the best method for substituting geothermal energy for existing fossil fuel energy in the VNP Plant Steam Cycle. An optimal cost-effective plan for individual energy utilization in the VNP Plant Steam Cycle was developed from this evaluation and preliminary conclusions drawn.

Section 2

OVERALL ECONOMIC EVALUATION

2.1 INTRODUCTION

An economic evaluation has been completed 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 plant modifications. 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. Capital cost estimates were based on a modified "GEOCOST" computer program developed by Battelle Northwest Laboratories.

2.2 GEOTHERMAL FLUID PRICING

One purpose of this study is to determine the potential cost savings that will be incurred by replacing fossil fuel energy with geothermal energy in the VNP plant. Therefore, an accurate prediction of brine pricing over the study period is essential.

The following scenario for brine pricing on the Heber Reservoir has been assumed: Brine pricing will consist of a demand charge and a usage charge. The demand charge will be assessed for the hook-up to the wellhead regardless of the brine usage. The usage charge will reflect actual brine flows. The demand charge will escalate with a cost index reflecting costs

for exploration and reservoir development, while the usage charge will escalate with the cost of other industrial fuels. Prices will be structured to recover the cost of exploration and resource development, while providing a reasonable rate of return. The reservoir manager will be selling only the rights to the thermal energy and will maintain the rights to the brine; therefore brine inventory must be maintained. The unit of sale will be BTU/HR and brine will be priced on a cost per million BTU basis. The BTU's will be measured between the actual brine inflow and a reference temperature. The reference temperature will be 160°F for single-phase brine and 200°F for two-phase brine. The brine temperature at the reinjection wellhead will have to be maintained above 160°F.

Initial brine prices were assumed to be \$0.75/10⁶ BTU for two-phase brine and \$0.90/10⁶ BTU for single-phase brine at the wellhead, including both demand and usage charges. Initial brine prices are based on a belief that brine will be priced such that the bus-bar fuel costs, in mils/KWH for both binary and flash cycle geothermal plants, will be equal.

To test this assumption, a computer model for exploration and reservoir development on the Heber Reservoir was made utilizing the "GEOCOST" program developed by Battelle Pacific Northwest Laboratories. The computer model was used to determine geothermal fluid prices based on drilling and exploration data and to determine the most probable split between demand and usage charges. The Reservoir Data used in the model is shown in Table 2-1.

Table 2-1
RESERVOIR DATA

Average well life = 10 years
Well flow rate = 440,000 lb/hr
Fraction of spare wells = 0.2
Fraction of dry wells = 0.2
Ratio of production wells to injection wells = 2
Reservoir well spacing = 20 acres
Cost of drilling one production well = \$300,000 (DEC '75)
Cost of drilling one dry well = \$300,000 (DEC '75)
Cost of drilling one injection well = \$300,000 (DEC '75)
First year of operation = 1980
Property tax rate = 0.0232
Property insurance rate = 0.0019
Plant operating life = 20 years
Royalty payments = 10%
Geothermal brine temperature at the wellhead = 340°F.
Intangible drilling costs = 0.512
Distance from plant to production field = 2.5 miles
Distance from plant to reinjection field = 1 mile
Plant availability = 75%
Federal Income Tax rate = 0.48
State Income Tax rate = 0.09

Two reservoir financing options were used to bracket a reasonable development cost:

- (A) 81% Stockholders' Equity
19% Long-Term Debt
8% Bond Interest
15% Return on Equity
- (B) 100% Stockholders' Equity
20% Return on Equity

Option (A) is based on the consolidated balance sheet in the 1976 Annual Report of a major lease holder on the Heber Reservoir. Option (B) is a classic treatment for capital investment analyses. The cost of brine computed reflects both the field development costs and the field operating costs incurred by the lease holder.

The costs for the transmission and disposal systems were assumed to be shared by the lease holder and VNP. All costs associated with the piping systems between the reservoir and the plant were assigned to VNP. The costs for connecting wells within the field were assigned to the lease holder. The binary cycle plant will require a downhole pump for each well to pressurize the brine and prevent it from flashing. A cost of \$100,000 per pump was assumed based on data obtained from pump manufacturers. The downhole pumping costs were assigned to the lease holder.

The flash steam plant was assumed to use two-phase brine which is allowed to flash in the well casing and is transmitted to the VNP Plant under its own pressure. The single-phase brine requires a booster pump to transmit the brine from the wellhead to the VNP Plant without flashing. Transmission pumping costs for the single-phase brine were assigned to the lease holder.

The difference in enthalpies between the wellhead temperature (340°F) and the reference temperatures are 165 BTU/lb for two-phase brine (200°F reference) and 205 BTU/lb for single-phase brine (160°F reference). Using these enthalpies and the "GEOCOST" Program Reservoir Model, the cost of brine as a function of brine flow was calculated for the two reservoir financing options. The results of the computer analysis are shown in Figures 2-1 and 2-2.

Figure 2-1 shows the cost of single-phase brine for flows up to seven million pounds per hour. The assumed price of \$0.90/10⁶ BTU falls between the curves for the two reservoir financing options, which suggests that it is a reasonable price. The lower curve (81% equity, 19% bonds) levels out at \$0.76/10⁶ BTU in December 1977 dollars. Assuming the cost is based on a fully developed reservoir, where the cost of brine has leveled, we shall assume that the demand charge is \$0.76/10⁶ BTU, which will give a reasonable return on equity regardless of brine usage. The difference between this demand charge and the assumed price is \$0.14/10⁶ BTU, which we shall call the usage charge. Thus the demand charge is 84 percent of the total brine cost, which appears to be reasonable.

Figure 2-2 shows the cost of two-phase brine for flows up to seven million pounds per hour. The lower curve (81% equity, 19% bonds) levels out at \$0.80/10⁶ BTU which is close to the assumed price of \$0.75/10⁶ BTU. Using the same criteria applied to determining the demand and usage charges for the single-phase

SINGLE-PHASE BRINE

FIGURE 2-1

TWO-PHASE BRINE

FIGURE 2-2

brine, and assuming for the moment that the lease holder's price will be formulated on an equal bus-bar cost basis to encourage the development of flash steam geothermal plants on the Heber Reservoir, we have assigned a demand charge equal to 84 percent of the total assumed brine cost of $\$0.75/10^6$ BTU. Thus the demand charge for two-phase brine is fixed at $\$0.63/10^6$ BTU and the usage charge is fixed at $\$0.12/10^6$ BTU.

2.3 ESCALATED ENERGY COSTS

In any study of alternative energy cost effectiveness it is essential to establish a conservative model of conventional energy cost escalations during the study period. Each of the conventional energy sources available to the VNP Plant was evaluated for constant dollar cost escalations over the study period and appear in Figure 2-3. Following this, a rate of inflation was assumed for the study period and nominal fuel costs were calculated, which appear in Figure 2-4. The following assumptions were made in determining the constant dollar and nominal fuel costs:

1. Purchased electricity from the off-site utility will increase 20 percent overall between 1977 and 1985. This 20 percent increase over an eight-year period is equivalent to a 2.3 percent escalation rate per year. Between 1985 and 1990, off-site electricity real costs will be constant. After 1990, the cost of off-site electricity becomes confused

CONSTANT DOLLAR FUEL COSTS (DEC '77)
(DOLLARS PER MMBTU)

FIGURE 2-3

FIGURE 2-4

by the number of scenarios involving the development of conventional and alternative energy sources.

However, since the economic evaluation will be based on a ten-year period from 1980 to 1989, there is no requirement to predict off-site electrical costs beyond the year 1990.

(The assumptions for the cost of purchased electricity do not reflect changes in the present declining block rate structure now being considered by the CERDC and the CPUC, which would greatly increase electrical costs to the VNP Plant, or the ability of the local utility (Imperial Irrigation District) to supply additional electrical demand requirements to the plant.)

2. Fuel oil costs will increase at a rate of five percent per year reflecting the demand for a diminishing resource.
3. Natural gas prices will approach the price of fuel oil between 1977 and 1980 at rates of 18.5 percent in 1978 and 23.5 percent in 1979 and 1980. After 1980, natural gas costs will escalate at five percent per year, following fuel oil prices. Since the natural gas for steam production in the VNP Plant could be heavily curtailed by the California Public Utilities Commission during the study period, it will not be considered further in this economic analysis.

4. Single-phase and two-phase brine costs will be divided into demand and usage charges as described in Section 2.2. The demand charges will remain constant on a constant dollar basis and will only reflect the inflation rate chosen for the nominal fuel cost comparison. The usage charges will reflect the increase in fuel oil costs and will escalate at the rate of five percent per year on a constant dollar basis.
5. Nominal fuel costs were calculated by inflating the constant dollar fuel costs at an annual inflation rate of 6.5 percent during the study period. A rate of 6.5 percent appears to be both realistic and conservative based on government budget announcements, congressional appropriation history, recent wage settlements in basic industries, and projected labor productivity rates.

2.4 GEOHERMAL CAPITAL COST MODELS

2.4.1 Introduction

In determining the economic feasibility of replacing fossil fuel, as a source of energy in the VNP Plant with geothermal energy, it is necessary to make a capital cost and thermodynamic model of the geothermal energy plant. The model will be useful in several areas of the study, such as estimating the capital cost of modifying the plant, estimating the demand

charge for comparing individual equipment replacement options, and calculating the internal rate of return to VNP as a function of the geothermal plant size.

2.4.2 Computer Model

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 computer model was used to estimate the costs of a 5, 10, 15, 20, 25, and 30 gross megawatt plant for both the binary and flash steam power cycles.

The steam cycle is a two-stage flash process driving low pressure saturated steam turbines as shown in Figure 2-5. The geothermal fluid, which is allowed to flash in the well casing, contains 2.5 percent steam at the wellhead and is transmitted to the VNP Plant under its own pressure as two-phase flow.

The binary cycle assumes isobutane as the working fluid, driving high pressure vapor expanders in a sub-critical rankine power cycle as shown in Figure 2-6. The geothermal fluid, which is pressurized in the well casing using a downhole pump, is transmitted to the VNP Plant by a booster pump as single-phase flow.

The "GEOCOST" capital cost estimates were modified to eliminate unnecessary equipment costs and to reflect cost increases resulting from multiple turbine applications rather than

FIGURE 2-5

TWO-STAGE FLASH STEAM PLANT

SUB-CRITICAL BINARY FLUID CYCLE PLANT

FIGURE 2-6

one centrally located turbine. The modifications to the capital cost estimates are discussed in more detail in the following section.

The following categories of equipment and other costs were included in the flash steam plant capital cost estimates:

- Piping, insulation, and tanks
- Turbines
- Flashers
- Miscellaneous process support equipment
- Instrumentation and controllers
- Electrical support equipment
- Condensers
- Installation testing
- Buildings, foundations and support equipment
- Gas ejectors (steam-driven)
- Cooling Water Pump
- Flash Water Reinjection Pump
- Cooling Tower Reinjection Pump
- Cooling Tower System
- Engineering and design
- Administration and indirect costs
- Geothermal fluid transmission system
- Geothermal fluid disposal system
- Other operating costs

The "GEOCOST" cost estimates (in December 1975 dollars) were escalated by 11.8 percent (based on CPI records and projections)

to obtain December 1977 dollars. The total capital cost for each flash steam plant size is shown in Table 2-12.

The following categories of equipment and other costs were included in the binary plant capital cost estimates:

- Piping, insulation, and tanks
- Turbines
- Vapor generator (boiler)
- Miscellaneous process support equipment
- Instrumentation and controllers
- Electrical support equipment
- Condensers
- Installation testing
- Buildings, foundations, and support equipment
- Binary fluid pumps
- Cooling tower system
- Engineering and design
- Administration and indirect costs
- Geothermal fluid transmission system
- Geothermal fluid disposal system
- Other operating costs

The "GEOCOST" cost estimates (in December 1975 dollars) were escalated by 11.8 percent (based on CPI records and projections) to obtain December 1977 dollars. The total capital costs for each binary cycle plant size is shown in Table 2-11.

2.4.3 Modifications to the Capital Cost Estimates

The "GEOCOST" capital cost estimates were modified to eliminate unnecessary equipment costs which are more typical of power plants, such as an overhead crane for a turbine-generator set and a switchyard for large-scale power transmission. The "GEOCOST" program calculates the cost of one turbine-generator set for each plant size, therefore 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 cooling tower requirements, calculated in the thermodynamic model of the geothermal plant, by comparing the net thermal efficiencies of the present steam cycle and the proposed plant thermal cycle.

2.4.3.1 Turbine Costs

Budget quotations for low pressure saturated steam turbines, for flash plant equipment drives, were requested and received from three turbine manufacturers: Turbodyne, Elliott, and Terry. The steam turbine capital costs were converted from April 1977 dollars to December 1975 dollars* and compared to the cost of a totally installed turbo-generator set using the

*The present "GEOCOST" program performs all economic calculations in terms of December 1975 dollars.

"GEOCOST" capital cost equation. From the comparison of vendor information and the "GEOCOST" equation, shown in Figures 2-7 and 2-8, a conservative estimate of total installed costs for steam turbines was made as a function of turbine size. The cumulative installed turbine costs for each plant size are tabulated along with the "GEOCOST" estimate of the cost of a single turbo-generator set of the same size.

Table 2-2
FLASH STEAM TURBINE COSTS

<u>Plant Size</u>	<u>GEOCOST*</u>	<u>Assumed Cumulative Turbine Costs</u>	<u>No. of Turbines</u>
(MW)	(DEC 75 \$'s)	(DEC 75 \$'s)	
5	1,641,000	1,570,000	1
10	2,616,000	2,725,000	2
15	3,444,000	4,295,000	3
20	4,190,000	5,925,000	3
25	4,880,000	7,495,000	4
30	5,528,000	10,530,000	12

*Based on one turbine-generator set

From Table 2-2 it can be seen that the costs assumed for turbines is greater than what "GEOCOST" would have predicted for a comparable size power plant, thereby accounting for the added cost of multiple turbines in a process plant application.

The binary plant turbine costs were handled in a likewise manner. Budget quotations for radial inflow binary vapor expanders, for the binary plant equipment drives, were requested

FLASH PLANT STEAM TURBINES (0-1500 HP)

FIGURE 2-7

○ STEAM TURBINE COSTS (DEC'75 \$'S)

FLASH PLANT STEAM TURBINES (0-15,000 HP)

FIGURE 2-8

○ STEAM TURBINE COSTS (DEC '75 \$'S)

and received from three vapor expander manufacturers: Rotoflow, Mafi-Trench, and Lotema. The vapor expander capital costs were converted from April 1977 dollars to December 1975 dollars* and compared to the cost of a totally installed turbo-generator set using the "GEOCOST" capital cost equation. From the comparison of vendor information and the "GEOCOST" equation, shown in Figures 2-9 and 2-10, a conservative estimate of total installed costs for binary expanders was made as a function of expander size. The cumulative installed expander costs for each plant size are tabulated along with the "GEOCOST" estimate of the cost of a single turbo-generator set of the same size.

Table 2-3

BINARY EXPANDER COSTS

<u>Plant Size</u>	<u>GEOCOST**</u>	<u>Assumed Cumulative Expander Costs</u>	<u>No. of Expanders</u>
(MW)	(DEC 75 \$'s)	(DEC 75 \$'s)	
5	864,000	660,000	1
10	1,491,000	1,330,000	2
15	2,355,000	1,990,000	3
20	2,689,000	3,040,000	3
25	3,553,000	3,700,000	4
30	8,562,000	5,405,000	12

**Based on one expander-generator set.

From Table 2-3 and Figures 2-9 and 2-10 it can be seen that the "GEOCOST" capital cost estimates for vapor expanders are high

*The present "GEOCOST" program performs all economic calculations in terms of December 1975 dollars.

BINARY PLANT TURBO - EXPANDERS (0-1500 Hp)

FIGURE 2-9

BINARY PLANT
TURBO-EXPANDERS
(0-15,000 Hp)

FIGURE 2-10

compared to the vendor budget quotations, even at the highest plant size, where we compare the cost of twelve vapor expanders to one expander-generator set.

2.4.3.2 Piping Costs

The "GEOCOST" program calculates the total piping capital costs for a geothermal power plant based on one turbine-generator set. With multiple turbine applications, inherent in a chemical processing plant, it was necessary to estimate the impact on total plant piping costs of adding additional turbine drivers. For the purposes of this study, it was assumed that each additional flash steam turbine increases plant piping costs by 5 percent and each additional vapor expander increases plant piping costs by 3 percent. Therefore, for the cost estimating cases run, the "GEOCOST" program piping costs were multiplied by the following factors to account for additional turbine piping costs.

Table 2-4

TURBINE PIPING COST FACTORS

<u>Plant Size</u>	<u>No. of Turbines</u>	<u>Flash Plant Cost Factor</u>	<u>Binary Plant Cost Factor</u>
(MW)			
5	1	1	1
10	2	1.05	1.03
15	3	1.10	1.06
20	3	1.10	1.06
25	4	1.15	1.09
30	12	1.55	1.33

2.4.3.3

Cooling Tower Costs

The "GEOCOST" program estimates the total installed cost of providing cooling towers to provide the heat rejection load calculated in the thermodynamic plant model. However, since the existing VNP Plant has cooling tower capacity, it will only be necessary to provide an incremental increase in capacity to reflect the difference in net thermal cycle efficiencies between the two plant cycles. In other words, if the present steam cycle and the proposed geothermal cycle operated at the same net thermal efficiency the total cooling tower requirement would remain constant. However, since the geothermal cycle operates at a lower temperature, and therefore a lower thermal efficiency, the geothermal cycle will reject more heat per horsepower output than the existing steam cycle. Therefore, an incremental cooling tower capacity will be required to handle the increased heat rejection load.

In Appendix A an equation is derived for calculating the fraction of the total cooling tower capacity, given by the "GEOCOST" thermodynamic model, required to meet the incremental heat load increase. It is assumed that the capital cost estimate for cooling towers is proportional to the cooling tower capacity. Therefore, we will factor the cooling tower capital cost estimate, by the fraction of the total cooling tower capacity required, to determine the incremental cooling tower cost.

Assuming a net thermal cycle efficiency for a geothermal plant of 12 percent and using the VNP Plant steam cycle

net thermal efficiency of 17 percent calculated in Appendix B, the incremental cooling tower cost fraction is:

$$\text{Cooling Tower Cost Fraction} = 1 - \left[\frac{(1-0.17)(0.12)}{(1-0.12)(0.17)} \right] = 0.33$$

Therefore, 33 percent of the "GEOCOST" capital cost estimates for cooling towers are used for each plant size.

2.5 OVERALL ECONOMIC EVALUATION

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. Capital cost estimates for plant modifications were made, as described in Section 2.4, using a modified "GEOCOST" program developed by Battelle Pacific Northwest Laboratories. 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:

$$S = \frac{C}{e_g} \left[a \frac{e_g}{e_f} - b \right]$$

where:

- S = Yearly cost savings, \$/YR
- C = Yearly geothermal plant net power output, BTU/YR
- e_f = Fossil plant net thermal efficiency
- e_g = Geothermal plant net thermal efficiency
- a = Cost of fossil fuel, \$/10⁶ BTU
- b = Cost of geothermal fuel, \$/10⁶ BTU

and C can be calculated by:

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

Yearly energy cost savings were calculated using the nominal yearly fuel costs in Figure 2-4. The net thermal cycle efficiency of 17.4 percent for the existing fossil fuel plant, calculated in Appendix B, was used for this calculation along with geothermal plant net thermal cycle efficiencies of 6.7 percent for the binary cycle and 10 percent for the flash plant cycle, as calculated by the "GEOCOST" geothermal plant thermodynamic model. The yearly energy cost savings are shown for the period 1980 through 1989 in Tables 2-5 and 2-6 for binary and flash steam cycle geothermal plants as a function of gross installed geothermal capacity. The net geothermal capacities can be calculated using the auxiliary power requirements for each geothermal cycle with the following equation:

$$\text{Net Capacity} = \text{Gross Capacity} (1 - \% \text{ Aux. Power})$$

The auxiliary power requirement for each geothermal flash steam cycle is 12 percent, while the geothermal binary cycle requires 20 percent auxiliary power.

Payout periods for financing and repayment of bank loans were calculated for each geothermal plant size. Examples of 25 MW binary and flash steam geothermal plants appear in Tables 2-7 and 2-8. Capital costs for the plant modifications were assumed to be incurred uniformly over a three-year construction period beginning in 1977. Thus the beginning outstanding debt

Table 2-5

Annual Energy Cost Savings for Geothermal
Binary Cycle Plants, \$ Millions

Year	Installed Geothermal Capacity					
	5 MW	10 MW	15 MW	20 MW	25 MW	30 MW
1980	0.43	0.86	1.29	1.72	2.14	2.57
1981	0.53	1.05	1.57	2.09	2.61	3.13
1982	0.66	1.32	1.97	2.63	3.28	3.94
1983	0.81	1.62	2.42	3.22	4.01	4.82
1984	0.99	1.97	2.94	3.91	4.88	5.86
1985	1.18	2.35	3.51	4.66	5.82	6.99
1986	1.41	2.80	4.19	5.58	6.96	8.35
1987	1.64	3.26	4.88	6.49	8.10	9.72
1988	1.94	3.86	5.76	7.67	9.57	11.49
1989	2.25	4.48	6.69	8.90	11.11	13.33

Table 2-6

Annual Energy Cost Savings for Geothermal
Steam Cycle Plants, \$ Millions

Year	Installed Geothermal Capacity					
	5 MW	10 MW	15 MW	20 MW	25 MW	30 MW
1980	1.15	2.28	3.39	4.52	5.62	6.77
1981	1.31	2.60	3.87	5.16	6.42	7.73
1982	1.50	2.98	4.44	5.92	7.36	8.87
1983	1.73	3.42	5.09	6.79	8.45	10.18
1984	1.97	3.90	5.80	7.74	9.63	11.60
1985	2.24	4.44	6.60	8.80	10.95	13.19
1986	2.56	5.07	7.54	10.06	12.50	15.07
1987	2.89	5.74	8.54	11.38	14.16	17.06
1988	3.29	6.52	9.70	12.94	16.09	19.39
1989	3.73	7.40	11.01	14.69	18.26	22.00

in 1977 is one-third of the initial capital investment. A loan interest rate of 8 percent was assumed along with a property insurance rate of 0.19 percent and a property tax rate of 2.32 percent. The insurance and taxes are based on 20-year straight-line depreciation of the initial capital investment. For the three years prior to plant operation, the insurance and taxes are equal to:

$$CI \times 0.0251 \times \left[(3 - (1979 - \text{YEAR})) / 3 \right]$$

where CI is the initial capital investment. For the years of plant operation, the insurance and taxes are equal to:

$$CI \times 0.0251 \times \left[(2000 - \text{YEAR}) / 20 \right]$$

The energy cost savings are taken directly from Tables 2-5 and 2-6. The ending outstanding debt for each year is equal to the beginning outstanding debt for the year, plus the interest, plus the insurance and taxes, minus the energy cost savings. The loan is completely repaid during the year when the energy cost savings become greater than the sum of the debt plus interest plus insurance and taxes.

Present worth and internal rate of return calculations were done for each geothermal plant size. Examples of 25 MW binary and flash steam geothermal plants appear in Tables 2-7 and 2-8. The net savings shown is the difference between the energy cost savings and the taxes and insurance. To compute the internal rate of return, the present worth of the net savings must be compared with the present worth of the initial investment.

Table 2-7

FINANCING AND REPAYMENT OF BANK LOAN FOR 25 MW BINARY CYCLE PLANT

<u>Year</u>	<u>Beginning Outstanding Debt</u>	<u>Interest @ 8%</u>	<u>Insurance & Taxes @ 2.51%</u>	<u>Energy Cost Savings</u>	<u>Ending Outstanding Debt</u>
1977	7,213,000	577,000	181,000	-----	7,971,000
1978	15,184,000	1,215,000	362,000	-----	16,761,000
1979	23,975,000	1,918,000	543,000	-----	26,436,000
1980	26,436,000	2,115,000	543,000	2,140,000	26,954,000
1981	26,954,000	2,156,000	516,000	2,610,000	27,016,000
1982	27,016,000	2,161,000	489,000	3,280,000	26,386,000
1983	26,386,000	2,111,000	462,000	4,010,000	24,949,000
1984	24,949,000	1,996,000	435,000	4,880,000	22,500,000
1985	22,500,000	1,800,000	407,000	4,820,000	18,887,000
1986	18,887,000	1,511,000	380,000	6,960,000	13,818,000
1987	13,818,000	1,105,000	353,000	8,100,000	7,176,000
1988	7,176,000	574,000	326,000	9,570,000	Loan Repaid
1989					

Table 2-8

FINANCING AND REPAYMENT OF BANK LOAN FOR 25 MW STEAM CYCLE PLANT

<u>Year</u>	<u>Beginning Outstanding Debt</u>	<u>Interest @ 8%</u>	<u>Insurance & Taxes @ 2.51%</u>	<u>Energy Cost Savings</u>	<u>Ending Outstanding Debt</u>
1977	8,473,000	678,000	213,000	-----	9,364,000
1978	17,837,000	1,427,000	425,000	-----	19,689,000
1979	28,163,000	2,253,000	638,000	-----	31,054,000
1980	31,054,000	2,484,000	638,000	5,620,000	28,556,000
1981	28,556,000	2,284,000	606,000	6,420,000	25,026,000
1982	25,026,000	2,002,000	574,000	7,360,000	20,242,000
1983	20,242,000	1,619,000	542,000	8,450,000	13,953,000
1984	13,953,000	1,116,000	510,000	9,630,000	5,949,000
1985	5,949,000	476,000	479,000	10,950,000	Loan Repaid
1986					
1987					
1988					
1989					

Since VNP requires at least a 10 percent rate of return over the first 10 years of operation, for major capital investments, the net present worth of the cash flows are first calculated at a fixed 10 percent rate of return. A positive net present worth indicates that the actual rate of return is higher than 10 percent. The actual internal rate of return is calculated by trial and error, until the net positive present worth approaches zero at the interest rate chosen. The actual internal rate of return for the 25 MW binary plant, shown in Table 2-9, is calculated to be 15 percent over the first 10 years of operation; while the actual internal rate of return for the 25 MW flash plant, shown in Table 2-10, is calculated to be 28.5 percent over the first 10 years of operation.

2.6 PRELIMINARY CONCLUSIONS

Financial summaries for each binary and steam cycle plant size appear in Tables 2-11 and 2-12. All geothermal plants, both steam and binary cycle, show internal rates of return exceeding 10 percent with the exception of the 5 MW binary plant. Although the capital investments for the steam plants are greater than the capital investments for the same size binary plants, the steam plants have much higher internal rates of return over the first 10 years of operation. This is due to the much greater energy cost savings achieved in the steam plants as a result of the higher plant thermal cycle efficiencies.

Incremental benefit-cost ratios for each plant size also appear in Tables 2-11 and 2-12. These ratios indicate whether

Table 2-9

PRESENT WORTH AND INTERNAL RATE OF RETURN FOR 25 MW BINARY CYCLE PLANT

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Energy Cost Savings</u>	<u>Net Savings</u>	<u>Present Worth Factor @ 10%</u>	<u>Present Worth @ 10%</u>	<u>Present Worth Factor @ 15%</u>	<u>Present Worth @ 15%</u>
1980	543,000	2,140,000	1,597,000	0.909	1,452,000	0.870	1,389,000
1981	516,000	2,610,000	2,094,000	0.826	1,730,000	0.756	1,583,000
1982	489,000	3,280,000	2,791,000	0.751	2,096,000	0.658	1,836,000
1983	462,000	4,010,000	3,548,000	0.683	2,423,000	0.572	2,029,000
1984	435,000	4,880,000	4,445,000	0.621	2,760,000	0.497	2,209,000
1985	407,000	5,820,000	5,413,000	0.564	3,053,000	0.432	2,338,000
1986	380,000	6,960,000	6,580,000	0.513	3,376,000	0.376	2,474,000
1987	353,000	8,100,000	7,747,000	0.467	3,618,000	0.327	2,533,000
1988	326,000	9,570,000	9,244,000	0.424	3,919,000	0.284	2,625,000
1989		11,110,000	11,110,000	0.386	4,288,000	0.247	2,744,000
TOTAL:					28,715,000		21,760,000
Initial Investment:					(21,640,000)		(21,640,000)
Net Present Worth:					7,075,000		120,000
Internal Rate of Return:							15%

Table 2-10

PRESENT WORTH AND INTERNAL RATE OF RETURN FOR 25 MW STEAM CYCLE PLANT

<u>Year</u>	<u>Taxes & Insurance</u>	<u>Energy Cost Savings</u>	<u>Net Savings</u>	<u>Present Worth Factor @ 10%</u>	<u>Present Worth @ 10%</u>	<u>Present Worth Factor @ 28.5%</u>	<u>Present Worth @ 28.5%</u>
1980	638,000	5,620,000	4,982,000	0.909	4,529,000	0.778	3,876,000
1981	606,000	6,420,000	5,814,000	0.826	4,802,000	0.606	3,523,000
1982	574,000	7,360,000	6,786,000	0.751	5,096,000	0.471	3,196,000
1983	542,000	8,450,000	7,908,000	0.683	5,401,000	0.367	2,902,000
1984	510,000	9,630,000	9,120,000	0.621	5,664,000	0.285	2,599,000
1985	479,000	10,950,000	10,471,000	0.564	5,906,000	0.222	2,325,000
1986	-----	12,500,000	12,500,000	0.513	6,413,000	0.173	2,163,000
1987	-----	14,160,000	14,160,000	0.467	6,613,000	0.135	1,912,000
1988	-----	16,090,000	16,090,000	0.424	6,822,000	0.105	1,689,000
1989	-----	18,260,000	18,260,000	0.386	7,048,000	0.082	1,497,000
TOTAL:					58,294,000		25,682,000
Initial Investment:					(25,420,000)		(25,420,000)
Net Present Worth:					32,874,000		262,000
Internal Rate of Return:							28.5%

Table 2-11

FINANCIAL SUMMARY - BINARY CYCLE PLANTS

Plant Size (MW)	Year Bank Loan Repayed With Energy Cost Savings	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	1991	6.2	5.6	0.90	8.0
10	1990	10.5	11.3	1.33	11.0
15	1989	14.1	17.1	1.61	13.5
20	1989	18.5	22.8	1.30	14.0
25	1988	21.6	28.7	1.90	15.0
30	1989	27.6	34.1	0.90	14.0

Table 2-12

FINANCIAL SUMMARY - STEAM CYCLE PLANTS

Plant Size (MW)	Year Bank Loan Repayed With Energy Cost Savings	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	1989	9.4	11.2	1.19	13.5
10	1987	13.6	23.1	2.83	21.0
15	1986	18.7	34.6	2.25	23.0
20	1986	22.7	46.4	2.95	25.5
25	1985	25.4	58.3	4.41	28.5
30	1986	33.6	69.6	1.38	26.0

each 5 MW increase in plant size is a cost-effective investment, satisfying the 10 percent rate of return requirement. Table 2-11 shows that the 30 MW binary plant would be a questionable investment, because the incremental benefit-cost ratio is less than 1. Therefore, although the 30 MW binary plant would have an internal rate of return of 14 percent over the first 10 years of operation, the incremental increase in energy cost savings, over the 25 MW plant size, would not justify the incremental increase in capital investment. Thus, the internal rate of return for this incremental investment will be less than 10 percent over the first 10 years of operation, which would not satisfy the minimum VNP requirement for major capital investments. All other incremental benefit-cost ratios, except the 5 MW binary plant with its low internal rate of return, are greater than 1 indicating that they are all acceptable capital investments.

Section 3

ENERGY UTILIZATION EVALUATION

3.1 INTRODUCTION

An energy utilization evaluation has been completed 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 power cycle are based on the "GEOCOST" computer program, while capital costs for providing the geothermal cycle equipment drivers and the new electric motors are based on budget quotations received from leading equipment manufacturers. The escalated costs of energy for the period 1980 through 1989 were simplified by calculating a levelized energy cost in present worth 1980 dollars to facilitate the calculation of energy charges for each equipment driver option. The calculation of levelized energy costs is shown in Appendix C.

3.2 ENERGY CHARGES FOR EXISTING TURBINES

3.2.1 Introduction

The cost of operating existing steam turbines has been calculated to compare continued operation of these turbines against other alternatives available in the future. Energy charges for steam usage have been calculated on a cost per horsepower-hour basis and have been based on the levelized fuel oil cost, calculated in Appendix C, of \$5.90/MMBTU for the period 1980 through 1989. An additional charge of \$0.50/1000 lb of steam has been added to the steam cost to account for demineralizing condensate. The cost of steam has been 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. Energy charges for each turbine have been based on the amount of usable energy remaining at the turbine exhaust compared to the total energy used to produce the steam. For example, 50 psi backpressure turbines have been charged for the actual amount of energy used in the steam expansion between the inlet conditions and the exhaust conditions, while full condensing turbines have been charged the total steam cost. In addition to conventional backpressure and full condensing turbines, four special cases of extraction, induction, and high backpressure turbines have been calculated, namely the Synthesis Gas Compressor, Refrigeration Compressor, Process Air Compressor, and Hydraulic Supply Pump Turbines. The results of these calculations are shown in Table 3-2.

3.2.2 Steam Cost

The heat added in steam production, assuming a boiler efficiency of 76 percent, equals:

$$Q_{ADDED} = \frac{(1298.6 - 93.34)}{0.76} \text{ BTU/HR} = \frac{1205.26}{0.76} = 1585.9 \text{ BTU/LB}$$

The cost of steam, using a levelized fuel cost of \$5.90/MMBTU and assuming \$0.50/1000 lb for demineralizing costs is:

$$\begin{aligned} \text{Steam Cost} &= \left[1585.9 \frac{\text{BTU}}{\text{LB}} \times \frac{1000}{1000} \times \frac{\$5.90}{10^6 \text{ BTU}} \right] + \left[\frac{\$0.50}{1000 \text{ lb}} \right] \\ &= \frac{\$9.34}{1000 \text{ lb}} + \frac{\$0.50}{1000 \text{ lb}} = \frac{\$9.85}{1000 \text{ lb}} \end{aligned}$$

3.2.3 Full Condensing Turbines

Since full condensing turbines are charged the total steam cost, it follows that the energy charge in dollars per horse-power-hour is a function of the steam cost and the actual turbine steam rate, namely:

$$(\text{Energy Charge})_{FC} = \frac{\$9.85}{1000 \text{ lb}} \left[\text{S.R.} \frac{\text{lb}}{\text{Hp-hr}} \right] = \frac{\$}{\text{Hp-hr}}$$

The steam rates and energy charges for full condensing turbines are shown in Table 3-2.

3.2.4 Backpressure Turbines

Backpressure turbines in the VNP Plant are designed to exhaust at 70 psia and 360°F. Therefore, assuming a constant exhaust enthalpy for all backpressure turbines of 1211.4 BTU/LB, and with a turbine inlet enthalpy of 1298.6 BTU/LB, the fraction of the total steam cost chargeable to each backpressure turbine is:

$$\frac{1298.6 - 1211.4}{1298.6 - 93.34} = 0.0724 \text{ of the full condensing cost.}$$

The energy charge for backpressure turbines then becomes:

$$\begin{aligned} (\text{Energy Charge})_{BP} &= \frac{\$9.85}{1000 \text{ lb}} \left[\text{S.R.} \frac{\text{lb}}{\text{Hp-hr}} \right] [0.0724] \\ &= \frac{\$0.713}{1000 \text{ lb}} \left[\text{S.R.} \frac{\text{lb}}{\text{Hp-hr}} \right] = \frac{\$}{\text{Hp-hr}} \end{aligned}$$

The steam rates and energy charges for backpressure turbines are shown in Table 3-2.

The cost chargeable to the steam exhausting from the backpressure turbines can now be calculated as:

$$\begin{array}{l} \text{Backpressure Exhaust} \\ \text{Steam Cost} \end{array} = \frac{\$9.85}{1000 \text{ lb}} - \frac{\$0.71}{1000 \text{ lb}} = \frac{\$9.14}{1000 \text{ lb}}$$

The backpressure turbine exhaust system supplies a low pressure steam system within the VNP Plant referred to as the 50 psi Steam System.

3.2.5 Hydraulic Supply Pump Turbine

The Hydraulic Supply Pump Turbine is a special case of a backpressure turbine with the turbine exhausting at 175 psia rather than 70 psia. Therefore, assuming a turbine exhaust enthalpy of 1251.6 BTU/LB, based on Figure 2-6 of the First Quarterly Report, and with a turbine inlet enthalpy of 1298.6 BTU/LB, the fraction of the total steam cost chargeable to the Hydraulic Supply Pump Turbine is:

$$\frac{1298.6 - 1251.6}{1298.6 - 93.34} = 0.039 \text{ of the full condensing cost.}$$

With a steam rate of 54.2 lb/Hp-hr, the energy charge for the Hydraulic Supply Pump Turbine then becomes:

$$\begin{aligned}
 (\text{Energy Charge})_{\text{HSPT}} &= \frac{\$9.85}{1000 \text{ lb}} \left[\text{S.R.} \frac{\text{lb}}{\text{Hp-hr}} \right] [0.039] \\
 &= \frac{\$9.85}{1000 \text{ lb}} \left[54.2 \frac{\text{lb}}{\text{Hp-hr}} \right] [0.039] = \frac{\$0.02083}{\text{Hp-hr}}
 \end{aligned}$$

3.2.6 Process Air Compressor Turbine

The Process Air Compressor Turbine is a special case of a full condensing turbine with a 3000 lb/hr extraction flow at 150 psig. Since the extraction flow is small and at a pressure close to the turbine inlet condition, the turbine steam rate is calculated using the steam flow going to full condensing and the design horsepower rating. The energy charge is calculated as a full condensing turbine, namely:

$$\begin{aligned}
 \text{Steam Rate} &= \frac{49,000 \text{ lb/hr}}{5112 \text{ Hp}} = 9.6 \frac{\text{lb}}{\text{Hp-hr}} \\
 (\text{Energy Charge})_{\text{PACT}} &= \frac{\$9.85}{1000 \text{ lb}} \left[\text{S.R.} \frac{\text{lb}}{\text{Hp-hr}} \right] \\
 &= \frac{\$9.85}{1000 \text{ lb}} \left[9.6 \frac{\text{lb}}{\text{Hp-hr}} \right] = \frac{\$0.09460}{\text{Hp-hr}}
 \end{aligned}$$

3.2.7 Refrigeration Compressor Turbine

The Refrigeration Compressor Turbine is a special case of a full condensing turbine with induction flow from the 50 psi Steam System. Both the 450 psi throttle steam and the 50 psi induction steam go to full condensing, therefore, each stream is charged the full cost for steam at its energy level. The steam flows used in this calculation are from the turbine vendor

data sheet and are not the same as those appearing on the steam flow diagrams. The charge for 450 psi steam is:

$$\frac{\$9.85}{1000 \text{ lb}} \times 20,300 \frac{\text{lb}}{\text{hr}} = \frac{\$200.00}{\text{hr}}$$

The charge for 50 psi steam (from Section 3.2.4) is:

$$\frac{\$9.14}{1000 \text{ lb}} \times 80,000 \frac{\text{lb}}{\text{hr}} = \frac{\$731.20}{\text{hr}}$$

At a design horsepower rating of 6660 Hp, the total charge rate becomes:

$$(\text{Energy Charge})_{\text{RCT}} = \frac{\$200.00 + \$731.20}{\text{hr} (6660 \text{ Hp})} = \frac{\$0.13984}{\text{Hp-hr}}$$

Using the energy charge and the cost of 450 psi steam, an equivalent steam rate for this turbine then becomes:

$$\text{Equivalent S.R.} = \frac{\$0.13984}{\text{Hp-hr}} \left[\frac{1000 \text{ lb}}{\$9.85} \right] = 14.2 \frac{\text{lb}}{\text{Hp-hr}}$$

3.2.8 Synthesis Gas Compressor Turbine

The Synthesis Gas Compressor Turbine is a special case of a full condensing turbine with extraction flow to the 450 psi Steam System. The extraction steam flow is charged as a backpressure turbine, while the condensing steam flow is charged as a full condensing turbine.

The 1500 psi inlet steam to the Syn Gas Turbine comes from the high pressure steam system, and is generated from a combination of fossil fuel and waste heat. The waste heat is actually a combination of fossil fuel heat from the Primary Reformer and the heat from exothermic reactions in the process.

In order to properly charge the energy used in the Syn Gas Turbine, it is necessary to calculate the cost of 1500 psi steam based on the amount of fossil fuel heat used both in the direct fired boiler and as waste heat.

The following Table 3-1 shows the assumptions made for the proportions of waste heat attributable to fossil fuel and exothermic heats of reaction for each source of waste heat recovery.

Table 3-1

	<u>Fossil Fuel</u>	<u>Chemical Reaction</u>
BFW & Condensate Heater (E-409)	100%	0%
BFW Heater (E-709)	0%	100%
BFW Heater (E-106)	100%	0%
Feedwater Economizer (D-104)	100%	0%
Reform Gas W.H. Boiler (E-105)	33%	66%
Converted Gas W.H. Boiler (E-103)	0%	100%

Therefore, using the waste heat loads shown in Table B-1 of Appendix B the following amounts of waste heat will be included with the fossil fuel in calculating 1500 psi steam costs:

BFW & Cond. Heater (E-409)	1	x	(0.385 x 10 ⁸ BTU/HR)	=	0.385 x 10 ⁸ BTU/HR
BFW Heater (E-106)	1	x	(0.063 x 10 ⁸ BTU/HR)	=	0.063 x 10 ⁸ BTU/HR
FW Econ. (D-104)	1	x	(0.433 x 10 ⁸ BTU/HR)	=	0.433 x 10 ⁸ BTU/HR
R.G.W.H.B. (E-105)	0.33x		(0.908 x 10 ⁸ BTU/HR)	=	0.300 x 10 ⁸ BTU/HR
TOTAL				=	1.181 x 10 ⁸ BTU/HR

Therefore, the fraction of fossil fuel contributing to waste heat, based on the assumption in Table 3-1 is:

$$\text{Fraction of Fossil Fuel} = \frac{1.181 \times 10^8}{2.444 \times 10^8} = 0.48 \text{ or } 48\%$$

The fossil fuel heat attributable to the generation of 1500 psi steam from saturated liquid at the condensing pressure to the Synthesis Gas Turbine inlet condition is now calculated along with the steam cost, taking boiler efficiency into account.

Fossil Fuel Waste Heat	=	1.18×10^8	BTU/HR
PCC Boiler	=	0.63×10^8	BTU/HR
PCC Superheater	=	0.45×10^8	BTU/HR
PCC Superheater	=	0.25×10^8	BTU/HR
TOTAL	=	2.51×10^8	BTU/HR

Assuming a boiler efficiency of 76 percent, based on vendor data sheets, the cost of 1500 psi steam becomes:

$$1500 \text{ psi Steam Cost} = \left[\frac{2.51 \times 10^8 \text{ BTU/HR}}{0.76} \right] \left[\frac{\$5.90}{10^6 \text{ BTU}} \right] \left[\frac{\text{hr}}{325,000 \text{ lb}} \right] \left[\frac{1000}{1000} \right]$$

$$= \frac{\$6.00}{1000 \text{ lb}}$$

The extraction steam flow is charged as a backpressure turbine, while the condensing steam flow is charged as a full condensing turbine. Therefore, the charge for the extraction steam flow is:

$$\frac{\$6.00}{1000 \text{ lb}} \left[266,000 \frac{\text{lb}}{\text{hr}} \right] \left[\frac{1316.4 - 1298.6}{1316.4 - 93.34} \right] \frac{\text{BTU/lb}}{\text{BTU/lb}} = \frac{\$23.23}{\text{hr}}$$

The charge for the full condensing steam flow is:

$$\frac{\$6.00}{1000 \text{ lb}} \left[59,000 \frac{\text{lb}}{\text{hr}} \right] = \frac{\$354.00}{\text{hr}}$$

At a design horsepower of 12,760 Hp, the total charge rate becomes:

$$(\text{Energy Charge})_{\text{SGCT}} = \frac{\$23.23 + \$354.00}{\text{hr} (12,760 \text{ Hp})} = \frac{\$0.0296}{\text{Hp-hr}}$$

Using the energy charge and the cost of 1500 psi steam, an equivalent steam rate for this turbine then becomes:

$$\text{Equivalent S.R.} = \frac{\$0.0296}{\text{Hp-hr}} \left[\frac{1000 \text{ lb}}{\$6.00} \right] = 4.93 \frac{\text{lb}}{\text{Hp-hr}}$$

3.2.9 Conclusion

As a check of the calculation of energy charges attributed to each steam turbine in the VNP Plant, the overall

Table 3-2

<u>Turbine</u>	<u>Type</u>	<u>Design Hp</u>	<u>Steam Rate</u> <u>lb/Hp-hr</u>	<u>Energy Charge</u>	
				<u>\$/Hp-hr</u>	<u>\$/hr</u>
1. Syn Gas Comp	*	12,760	4.9	0.0296	377.70
2. Refrig Comp	*	6,660	14.2	0.1398	931.07
3. Air Comp	*	5,112	9.6	0.0946	483.60
4. H.P. BFW PP	BP	1,000	31.3	0.0223	22.30
5. Cooling Water PP	FC	1,880	14.5	0.1429	268.65
6. Nat'l Gas Comp	BP	870	30.5	0.0217	18.88
7. TEA Soln PP	BP	860	31.1	0.0222	19.09
8. Hydr. Supply PP	**	765	54.2	0.0208	15.91
9. I.D. Fan	BP	275	37.4	0.0267	7.34
10.H.P. Blr. Circ. PP	BP	230	37.5	0.0267	6.14
11.Erie II BFW PP	BP	200	41.0	0.0292	5.84
12.Aux. Carbamate PP	BP	200	57.8	0.0412	8.24
13.Turbo-Generator	BP	150	66.5	0.0474	7.11
14.L.P. BFW PP	BP	91	50.3	0.0359	3.27
15.Demin. Water PP	FC	80	33.0	0.3252	26.02
16.Syn Seal Oil PP	FC	62	38.0	0.3745	23.22
17.Syn Lube Oil PP	FC	55	38.0	0.3745	20.60
18.FM Lube Oil PP	FC	29	33.0	0.3252	9.43
19.Refrig L.O. PP	FC	22.5	78.0	0.7686	17.29
20.FM Seal Oil PP	FC	<u>22.5</u>	33.0	0.3252	<u>7.32</u>
TOTAL:		31,324 Hp			2,279.02

FC = Full Condensing

BP = Backpressure

* = Special Case - Full Condensing

** = Special Case - Backpressure

unit cost rate was calculated and compared to the gross unit cost rate using the gross unit efficiency calculated in Appendix B.

$$\text{Overall Unit Cost Rate} = \frac{\sum \left[\frac{\$}{\text{Hp-hr}} \right] \text{Hp}}{\sum \text{Hp}} = \frac{\$2279.02/\text{hr}}{31,324 \text{ Hp}} = \frac{\$0.073}{\text{Hp-hr}}$$

Now, using the gross unit efficiency of 20 percent, the gross unit cost rate becomes:

$$\text{Gross Unit Cost Rate} = \frac{\$5.90}{106 \text{ BTU}} \left[\frac{2544.4 \text{ BTU}}{\text{Hp-hr}} \right] \left[\frac{1}{0.20} \right] = \frac{\$0.075}{\text{Hp-hr}}$$

Therefore, there appears to be good agreement between the approach taken to access energy charges to each steam turbine and the overall plant charge rate based on the calculation of gross rankine cycle thermal efficiency.

3.3 TOTAL CHARGES FOR GEOTHERMAL TURBINES

3.3.1 Introduction

The total cost of operating new geothermal turbines has been 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.

3.3.2 Geothermal Plant Demand Charges

For any comparison of equipment driver options utilizing geothermal energy in place of fossil fuel, it is

necessary to calculate the demand charge for building the geothermal plant to supply geothermal energy in a usable form to drive plant equipment. Therefore, geothermal plant demand charges were calculated for both binary and flash steam plants based on the capital cost estimates discussed in Section 2.4. The demand and energy charge for each equipment driver will be added later, therefore the geothermal plant demand charges are calculated for all plant equipment except the turbines. Results of the calculations are shown in Tables 3-3 and 3-4. Because the demand charge varies with the plant size, it is assumed, for these calculations, that the total plant modification is in the range of 20 to 30 MW. Therefore the binary plant demand charge is assumed to be \$670/Hp, while the flash steam plant demand charge is assumed to be \$625/Hp.

Using the fixed charge rate of 17.4 percent, calculated in Appendix D, to convert capital investment costs into annual charge rates, and a plant capacity factor of 75 percent, a unit charge rate for geothermal demand charges is calculated in \$/Hp-hr. Therefore, the unit demand charge rates become:

$$\begin{aligned} \text{Binary Plant Unit Demand Charge Rate} &= \frac{\$670}{\text{Hp}} \times \frac{0.174}{\text{yr}} \times \frac{\text{yr}}{8760 \text{ hr}} \times \frac{1}{0.75} = \frac{\$0.0177}{\text{Hp-hr}} \\ \text{Flash Plant Unit Demand Charge Rate} &= \frac{\$625}{\text{Hp}} \times \frac{0.174}{\text{yr}} \times \frac{\text{yr}}{8760 \text{ hr}} \times \frac{1}{0.75} = \frac{\$0.0165}{\text{Hp-hr}} \end{aligned}$$

Table 3-3

BINARY PLANT DEMAND CHARGES

Gross Capacity MW	Total Capital Cost \$ Millions	Installed Turbine Cost \$ Millions	Net Plant Capacity KW	Demand Charge \$/KW	Demand Charge \$/Hp
5	6.20	.74	4,000	1,365	1,018
10	10.53	1.49	8,100	1,116	833
15	14.06	2.22	12,100	979	730
20	18.46	3.40	16,200	930	694
25	21.64	4.14	20,200	866	646
30	27.55	6.04	24,300	885	660

Assuming the geothermal plant will be in the 20 to 30 Gross MW range, use a demand charge of \$670/Hp

Table 3-4

FLASH STEAM PLANT DEMAND CHARGE

<u>Gross Capacity MW</u>	<u>Total Capital Cost \$ Millions</u>	<u>Installed Turbine Cost \$ Millions</u>	<u>Net Plant Capacity KW</u>	<u>Demand Charge \$/KW</u>	<u>Demand Charge \$/Hp</u>
5	9.39	1.76	4,400	1,734	1,294
10	13.61	3.05	8,800	1,200	895
15	18.69	4.80	13,200	1,052	785
20	22.73	6.62	17,600	915	683
25	25.42	8.38	22,000	775	578
30	33.60	11.77	26,400	827	617

Assuming the geothermal plant will be in the 20 to 30 Gross MW range, use a demand charge of \$625/Hp.

3.3.3 Energy Charges for Geothermal Turbines

3.3.3.1 Binary Plant Vapor Expanders

Energy charges for operating new radial inflow isobutane vapor expanders were calculated based on converting the isobutane flow rates quoted by the expander vendors to equivalent brine flow rates and charging the expander for the full cost of that equivalent single-phase brine flow. To calculate an equivalent brine flow rate, a comparison of total isobutane flow rates was made based on the "GEOCOST" program geothermal plant thermodynamic model. The results of this comparison are listed in the following Table 3-5.

Table 3-5

RATIO OF BRINE FLOW TO ISOBUTANE FLOW			
Plant Size MW	Brine Flow Rate lb/hr	Isobutane Flow Rate lb/hr	Ratio of Brine Flow To Isobutane Flow
5	1,007,496	673,892	1.495
10	2,002,296	1,343,564	1.490
15	2,991,867	2,011,849	1.487
20	3,980,426	2,680,078	1.485
25	4,967,549	3,347,314	1.484
30	5,963,953	4,018,453	1.484

For our calculations we will assume a value for the ratio of brine flow to isobutane flow of 1.486. Therefore, with this ratio, the rated horsepower, the isobutane flow rate quoted by

the vendor, and the levelized single-phase brine cost of \$1.50/10⁶ BTU from Table C-1 of Appendix C, the vapor expander energy charge was calculated in \$/Hp-hr by the following equation:

$$\frac{\$}{\text{Hp-hr}} = \left[\frac{\text{Isobutane Flow, lb/hr}}{\text{Rated Hp}} \right] \times \left[1.486 \frac{\text{lb brine}}{\text{lb isobutane}} \right] \times \left[\frac{\$1.50}{10^6 \text{ BTU}} \right] \times \left[183.3 \frac{\text{BTU}}{\text{lb}} \right]$$

3.3.3.2 Flash Plant Steam Turbines

The three brine flashing pressures for the flash steam cycle plant were determined by calculations appearing in Appendix E. Therefore, the energy charges for operating new saturated flash steam turbines were calculated based on steam costs found by proportioning the cost of two-phase brine between the three flash stages as a function of the total BTU's extracted from each stage. Assuming 1000 pounds of brine entering the first flash stage of the three stage cascading flash system, the three flash stages will generate the following amounts of steam: 48 pounds of 65 psia steam, 44 pounds of 33 psia steam, and 37 pounds of 16 psia steam. The brine rejected from the final stage will therefore be at the saturation temperature corresponding to 16 psia, namely 216°F.

Energy charges were based on the levelized cost for two-phase brine of \$1.25/10⁶ BTU from Table C-1 of Appendix C for the period 1980 through 1989. Therefore, levelized steam costs are calculated for each flash steam pressure and are \$1.37 per 1000 pounds of 65 psia steam, \$1.35 per 1000 pounds of 33 psia steam, and \$1.33 per 1000 pounds of 16 psia steam.

The energy charge in \$/Hp-hr for each full condensing saturated steam turbine is calculated in an identical

manner to the calculation of energy charges for the existing full condensing steam turbines operating on fossil fuel, by multiplying the actual turbine steam rate by the cost per 1000 pounds of the throttle steam at its inlet pressure. Therefore,

$$\frac{\$}{\text{Hp-hr}} = \left[\frac{\$, 1000}{1 \text{ lb}} \right] \times \left[\text{S.R.}, \frac{1 \text{ lb}}{\text{Hp-hr}} \right]$$

Induction steam turbine energy charges were calculated using the steam flows to each turbine inlet to determine total \$/hr steam costs and dividing by the rated Hp to give \$/Hp-hr energy charges.

3.3.4 Conclusions

3.3.4.1 Binary Plant Vapor Expanders

The total charges for binary vapor expanders in \$/Hp-hr were calculated as the sum of the geothermal plant demand charge, binary vapor expander installed capital cost charge, and the brine energy charge all in \$/Hp-hr. The geothermal plant demand charge is calculated in Section 3.3.2. The brine energy charge equation is given in Section 3.3.3.1. The binary vapor expander installed capital cost was calculated based on budget quotations submitted by three vapor expander manufacturers: Rotoflow, Mafi-Trench, and Lotema. Capital cost charges for vapor expanders were calculated using the fixed charge rate of 17.4 percent (calculated in Appendix D), factors for inflation and installation costs, and a capacity factor of 75 percent. Total charges in \$/Hp-hr were calculated for each vapor expander

proposed and the lowest total charge was selected for each expander application. A summary of the calculations of the lowest total charges for each vapor expander is shown in Table 3-6. Item 21 in Table 3-6 is for an 8 MW turbo-generator set to provide the present plant electrical demand and will be used later in this study to determine on-site power generation costs from a geothermal binary plant.

3.3.4.2 Flash Plant Steam Turbines

The total charges for flash plant steam turbines in \$/Hp-hr were calculated as the sum of the geothermal plant demand charge, flash steam turbine installed capital cost charge, and the brine energy charge, all in \$/Hp-hr. The geothermal plant demand charge is calculated in Section 3.3.2. The brine energy charge equation is given in Section 3.3.3.2. The flash steam turbine installed capital cost was calculated based on budget quotations submitted by three steam turbine manufacturers: Elliott, Turbodyne, and Terry. Capital cost charges for steam turbines were calculated using the fixed charge rate of 17.4 percent (calculated in Appendix D), factors for inflation and installation costs, and a capacity factor of 75 percent. Total charges in \$/Hp-hr were calculated for each steam turbine proposed and the lowest total charge was selected for each turbine application. A summary of the calculations of the lowest total charges for each steam turbine is shown in Table 3-7. Item 21 in Table 3-7 is for an 8 MW turbo-generator set to provide the present plant electrical demand and will be used later in this study to determine on-site power generation costs from a geothermal flash steam plant.

TABLE 3-6

GEOTHERMAL BINARY EXPANDERS
LEVELIZED CHARGES FOR PERIOD 1980 TO 1989
\$/Hp-hr

<u>Replace Existing Turbines</u>	NORMAL HP	RATED HP	DESIGN RPM	ISOBUTANE FLOW (lb/hr)	TURBINE COST \$(1977)	TURBINE INSTALLED COST \$(1977)	CAPITAL COST \$/HP-HR (1980)	DEMAND CHARGE \$/HP-HR (1980)	EXPANSION EFFICIENCY %	ENERGY CHARGE \$/HP-HR (1980)	TOTAL CHARGES \$/HP-HR (1980)
1. SYN GAS COMPRESSOR	12,760	14,000	12,300	703,000	200,000	230,000	.0005	.0177	83	.0206	.0388
2. REFRIG COMPRESSOR	6,600	7,325	8,550	682,700	350,000	402,500	.0018	.0177	84	.0382	.0576
3. AIR COMPRESSOR	5,112	5,625	3,625	525,157	300,000	345,000	.0020	.0177	84	.0383	.0579
4. H.P. BFW PUMP	1,000	1,320	3,570	112,000	130,000	149,500	.0036	.0177	83	.0348	.0561
5. COOLING WATER PUMP	940	980	5,280	104,730	120,000	138,000	.0045	.0177	81	.0438	.0660
6. NATURAL GAS COMPRESSOR	870	960	8,585	97,400	110,000	126,500	.0042	.0177	81	.0416	.0635
7. T.E.A. SOL'N PUMP	860	960	3,570	96,354	110,000	126,500	.0042	.0177	81	.0411	.0630
8. HYDRAULIC SUPPLY PUMP	765	840	4,500	83,790	110,000	126,500	.0048	.0177	81	.0409	.0634
9. I.D. FAN	275	275	4,496	34,610	80,000	92,000	.0107	.0177	76	.0516	.0800
10. H.P. BOILER CIRC. PUMP	230	248	4,500	29,600	80,000	92,000	.0119	.0177	76	.0489	.0785
11. ERIE 2 BFW PUMP	200	250	3,550	26,500	70,000	80,500	.0103	.0177	75	.0434	.0714
12. AUX. CARBAMATE PUMP	200	250	2,000	26,500	70,000	80,500	.0103	.0177	75	.0434	.0714
13. TURBO-GENERATOR	150	186	1,870	19,000	130,000	149,500	.0257	.0177	75	.0419	.0853
14. L.P. BFW PUMP	91	95	3,550	14,545	55,000	63,250	.0213	.0177	68	.0627	.1017
15. DEMIN. WATER PUMP	80	80	3,550	13,725	55,000	63,250	.0253	.0177	68	.0703	.1133
16. SYN SEAL OIL PUMP	62	80	3,550	11,480	55,000	63,250	.0253	.0177	68	.0588	.1018
17. SYN LUBE OIL PUMP	55	80	3,550	10,925	55,000	63,250	.0253	.0177	66	.0560	.0989
18. FM LUBE OIL PUMP	29	40	3,550	7,715	55,000	63,250	.0506	.0177	55	.0790	.1473
19. REFRIG LUBE OIL PUMP	22.5	30	3,550	6,885	55,000	63,250	.0675	.0177	53	.0940	.1792
20. FM SEAL OIL PUMP	22.5	22.5	3,550	6,885	55,000	63,250	.0899	.0177	53	.1254	.2330
<u>Add Additional Turbine</u>											
21. TURBO-GENERATOR	10,725	12,000	3,600	1,224,539	500,000*	575,000	.0015	.0177	84	.0418	.0610

*INCLUDES GENERATOR

TABLE 3-7

GEOHERMAL FLASHED STEAM TURBINES LEVELIZED CHARGES FOR PERIOD 1980 TO 1989 \$/Hp-hr												
<u>Replace Existing Turbines</u>	NORMAL HP	RATED HP	DESIGN RPM	THROTTLE PRESS. PSIA	INDUCTION PRESS. PSIA	TURBINE COST \$(1977)	TURBINE INSTALLED COST \$(1977)	CAPITAL COST \$/HP-HR (1980)	DEMAND CHARGE \$/HP-HR (1980)	STEAM RATE lb/HP-HR	ENERGY CHARGE \$/HP-HR (1980)	TOTAL CHARGES \$/HP-HR (1980)
1. SYN GAS COMPRESSOR	12,760	14,000	12,300	33	16	950,000	1,016,500	.023	.0165	21.4	.0287	.0475
2. REFRIG COMPRESSOR	6,600	7,325	8,550	33	16	800,000	856,000	.0037	.0165	21.84	.0293	.0495
3. AIR COMPRESSOR	5,112	5,625	3,625	33	16	750,000	802,500	.0046	.0165	21.15	.0284	.0495
4. H.P. BFW PUMP	1,000	1,320	3,570	33	-	165,000	176,550	.004	.0165	27.0	.0365	.0570
5. COOLING WATER PUMP	940	980	5,280	33	-	200,000	214,000	.0068	.0165	20.3	.0274	.0507
6. NATURAL GAS COMPRESSOR	870	960	8,585	33	-	315,000	337,050	.0112	.0165	25.0	.03375	.0615
7. T.E.A. SOL'N PUMP	860	960	3,570	33	-	165,000	176,550	.006	.0165	27.0	.0365	.0590
8. HYDRAULIC SUPPLY PUMP	765	840	4,500	33	-	260,000	278,200	.0106	.0165	22.6	.0305	.0576
9. I.D. FAN	275	275	4,496	33	-	40,000	42,800	.0016	.0165	23.0	.031	.0491
10. H.P. BOILER CIRC. PUMP	230	248	4,500	33	-	40,000	42,800	.0055	.0165	23.0	.031	.0530
11. ERIE 2 BFW PUMP	200	250	3,550	33	-	40,000	42,800	.0055	.0165	24.6	.0332	.0552
12. AUX. CARBAMATE PUMP	200	250	2,000	33	-	45,000	48,150	.0062	.0165	31.0	.04185	.0646
13. TURBO-GENERATOR	150	186	1,800	33	-	55,000	58,850	.010	.0165	31.0	.04185	.0684
14. L.P. BFW PUMP	91	95	3,550	33	-	40,000	42,800	.0144	.0165	24.6	.0332	.0641
15. DEMIN. WATER PUMP	80	80	3,550	33	-	40,000	42,800	.0171	.0165	24.6	.0332	.0668
16. SYN SEAL OIL PUMP	62	80	3,550	33	-	40,000	42,800	.0171	.0165	24.6	.0332	.0668
17. SYN LUBE OIL PUMP	55	80	3,550	33	-	40,000	42,800	.0171	.0165	24.6	.0332	.0668
18. FM LUBE OIL PUMP	29	40	3,550	33	-	40,000	42,800	.0342	.0165	30.0	.0405	.0912
19. REFRIG LUBE OIL PUMP	22.5	30	3,550	33	-	40,000	42,800	.0514	.0165	30.0	.0405	.1084
20. FM SEAL OIL PUMP	22.5	22.5	3,550	33	-	40,000	42,800	.0608	.0165	30.0	.0405	.1178
<u>Add Additional Turbine</u>												
21. TURBO-GENERATOR	10,725	--	3,600	33	16	1,250,000	1,337,500*	.004	.0165	22.3	.030	.0505

*INCLUDES GENERATOR

3.4 TOTAL CHARGES FOR ELECTRIC MOTORS

3.4.1 Introduction

The total cost of operating existing and new electric motors has been 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.

3.4.2 Capital Cost Charges for New Electric Motors

New electric motors were considered as alternative drivers for plant equipment, with electrical power supplied from both on-site and off-site sources, where on-site electrical power includes both fossil and geothermal sources of energy. Therefore, it was necessary to determine the cost of installing new electric motors for plant equipment drivers. Installed capital costs were estimated based on all work being performed by an outside electrical contractor, with associated labor costs, indirect costs, and profit included.

Prices for electric motors, motor controls, and required gearing for capacities in excess of 250 Hp were based on budget prices received from a major motor manufacturer. Vendor

quotations included prices for NEMA type 1 motor starters and circuit breakers. Feeder material and installation costs were based on 500 lineal feet conductor pull-through for each motor. Space heater, instrumentation, and emergency shut-down wiring and installation was not included. Differentiation of conductor and conduit size was considered, however their effect on the total installation cost was determined to be of little significance. The total capital costs for materials and installation are summarized for each motor size in Table 3-8.

Prices for synchronous electric motors and motor controls for capacities between 20 Hp and 250 Hp were taken directly from industrial cost estimating standards. Electric motors, motor starters, and circuit breakers were assumed to be explosion proof. Feeder material and installation costs were based on 500 lineal feet conductor pull-through for each motor. Space heater, instrumentation, and emergency shut-down wiring and installation was not included. Differentiation of conductor and conduit size was considered, however their effect on the total installation cost was determined to be of little significance. The total capital costs for materials and installation are summarized for each motor size in Table 3-9.

The demand charge for each electric motor was calculated from the total capital cost by means of the fixed charge rate, rated horsepower, capacity factor, and escalation rate. Motor demand charges for each motor size also appear in Tables 3-8 and 3-9.

TABLE 3-8

NEW ELECTRIC MOTOR DEMAND CHARGES \$/Hp-hr	NORMAL H.P.	RATED H.P.	SPEED RPM	MATERIAL COSTS \$(1977)	CONTRACT LABOR COSTS \$(1977)	CONTRACT INDIRECT COSTS \$(1977)	CONTRACT PROFIT \$(1977)	CAPITAL COST \$(1977)	DEMAND CHARGE \$/Hp-hr (1980)
1. SYN GAS COMPRESSOR	12,760	14,000	12,300	795,635	156,908	81,782	103,324	1,137,757	.0026
2. REFRIG COMPRESSOR	6,660	8,000	8,550	489,622	96,558	50,328	63,651	700,159	.0028
3. AIR COMPRESSOR	5,112	5,500	3,625	324,593	64,013	33,365	42,197	464,168	.0027
4. H.P. BFW PUMP	1,000	1,500	3,570	154,053	27,619	14,395	19,606	215,673	.0046
5. COOLING WATER PUMP	940	1,000	5,280	114,915	17,855	9,306	14,208	156,284	.0050
6. NATURAL GAS COMPRESSOR	870	1,000	8,585	104,950	16,934	8,826	13,071	143,781	.0046
7. T.E.A. SOL'N PUMP	860	1,000	3,570	111,795	18,039	9,402	13,924	153,160	.0049
8. HYDRAULIC SUPPLY PUMP	765	900	4,500	108,830	17,560	9,152	13,554	149,096	.0053
9. I.D. FAN	275	300	4,496	46,196	7,177	3,740	5,711	62,824	.0067
10. H.P. BOILER CIRC. PUMP	230	250	4,500	44,817	6,963	3,629	5,541	60,950	.0078

NOTES: 1. ALL MOTORS ARE WEATHER PROTECTED, TYPE 2, 1800 RPM: 4,000 VOLT/3 PH/60 HERTZ: SERVICE FACTOR 1.0
 2. MOTOR PRICES INCLUDE COST OF INSTALLED GEARING.
 3. STARTER AND SWITCHGEAR BREAKER ENCLOSERS ARE NEMA 1.
 4. ASSUME \$6.88 PER MANHOUR FOR CONTRACTORS INDIRECT COSTS.
 5. ASSUME 10% PROFIT FOR CONTRACTOR.
 6. ASSUME LABOR COST AT \$13.20 PER MANHOUR.

TABLE 3-9

NEW ELECTRIC MOTOR DEMAND CHARGES \$/Hp-hr	NORMAL H.P.	RATED H.P.	SPEED RPM	MATERIAL COSTS \$(1977)	CONTRACT LABOR COSTS \$(1977)	CONTRACT INDIRECT COSTS \$(1977)	CONTRACT PROFIT \$(1977)	CAPITAL COST \$(1977)	DEMAND CHARGE \$/Hp-hr (1980)
11. ERIE 2 BFW PUMP	200	250	3,550	21,552	5,955	3,104	3,061	33,672	.0043
12. AUX. CARBAMATE PUMP	200	250	2,000	20,052	5,955	3,104	2,911	32,022	.0041
13. TURBO-GENERATOR	150	186	1,800	-----	-----	-----	-----	-----	-----
14. L.P. BFW PUMP	91	95	3,550	10,087	3,883	2,024	1,599	17,593	.0056
15. DEMIN. WATER PUMP	80	80	3,550	8,095	2,923	1,524	1,254	13,796	.0059
16. SYN SEAL OIL PUMP	62	80	3,550	8,095	2,923	1,524	1,254	13,796	.0059
17. SYN LUBE OIL PUMP	55	80	3,550	8,095	2,923	1,524	1,254	13,796	.0059
18. FM LUBE OIL PUMP	29	40	3,550	3,967	1,938	1,010	691	7,606	.0061
19. REFRIG LUBE OIL PUMP	22.5	30	3,550	3,564	1,911	996	647	7,118	.0076
20. FM SEAL OIL PUMP	22.5	22.5	3,550	2,580	1,536	800	492	5,408	.0069

NOTES: 1. ALL MOTORS ARE EXPLOSION PROOF, CLASS 1, GROUP D, 480 V/3PH/60 HERTZ.
 2. STARTERS AND CIRCUIT BREAKERS ARE EXPLOSION PROOF.
 3. ASSUME \$6.88 PER MANHOUR FOR CONTRACTORS INDIRECT COSTS.
 4. ASSUME 10% PROFIT FOR CONTRACTOR.
 5. ASSUME LABOR COST AT \$13.20 PER MANHOUR.

3.4.3 Energy Charges for Electric Motors

3.4.3.1 Introduction

Total charges were calculated for operating existing VNP Plant electrical motors and proposed new electrical motors on off-site and on-site electrical power from both fossil and geothermal sources of energy. Off-site power was charged at the levelized cost for the period 1980 through 1989, calculated in Appendix C. On-site fossil fuel electrical power costs include the cost of providing a turbine-generator set that operates off of the existing VNP Plant steam system. On-site geothermal electrical power costs include the cost of providing a complete geothermal power plant. A conversion efficiency for electrical power from bus-bar kilowatt-hours to shaft horsepower-hours of 74 percent was assumed, which is equivalent to 1 KW/Hp.

3.4.3.2 Off-site Electrical Power

The levelized off-site electrical power cost for the period 1980 through 1989, calculated in Appendix C, is \$10.53/10⁶ BTU. Using the ideal conversion ratio between BTU's and Hp-hr's and the assumed electrical conversion efficiency of 74 percent, the energy charge rate for electric motors operating on off-site electrical power becomes:

$$(\text{Energy Charge})_{\text{OFFSITE}} = \frac{\$10.53}{10^6 \text{ BTU}} \times \frac{2544.4 \text{ BTU}}{\text{Hp-hr}} \times \frac{1}{0.74} = \frac{\$.0362}{\text{Hp-hr}}$$

This figure constitutes the total charge for operating existing motors on off-site electrical power. The

total charge for operating new electric motors on off-site electrical power is calculated by adding the total energy charge to the capital cost charge for new electric motors calculated in Section 3.4.2 and listed in Tables 3-8 and 3-9.

3.4.3.3 On-site Fossil Fuel Power

The total charge for generating on-site fossil fuel electrical power at the VNP plant was based on using 450 psig extraction steam from the Synthesis Gas Turbine Drive and providing a 25 MW turbine-generator set. A budget quotation was received from a leading turbine manufacturer, satisfying the above conditions:

Table 3-10

25 MW Turbine-Generator Set
 Inlet Conditions: 465 psia, 595° F
 Exhaust Conditions: 4" HgA
 Speed: 3600 r.p.m.
 Actual Steam Rate: 8.65 lb/Hp-hr
 Turbine Cost: \$1,030,000
 Generator Cost: \$1,000,000

Assuming the total installed cost for a 25 MW Turbine-generator is twice the equipment cost, the capital charge rate is calculated using the fixed charge rate, escalation rate, and plant capacity factor:

$$25,000 \text{ KW} \times \frac{\text{Hp}}{0.746 \text{ KW}} = 33,512 \text{ Hp}$$

$$\begin{aligned} \left[\begin{array}{l} \text{Capital} \\ \text{Charge} \\ \text{Rate} \end{array} \right] &= (\$4,060,000)(1.208)(0.174) \left[\frac{1}{33,512 \text{ Hp}} \right] \left[\frac{\text{YR}}{8760 \text{ hr}} \right] \left[\frac{1}{0.75} \right] \\ &= \$0.0039/\text{Hp-hr} \end{aligned}$$

The energy charge for operating the full condensing turbine was calculated by multiplying the actual turbine steam rate with the cost charge for 450 psi extraction steam. From previous calculations in Section 3.2.8, the cost for 1500 psi steam to the Syn Gas Turbine is \$1950/hr. The energy charge for the Syn Gas Turbine is \$377.23/hr. Therefore, the cost for the 266,000 lb/hr extraction steam from the Syn Gas Turbine is:

$$\begin{aligned} \text{Extraction Steam Cost} &= \frac{\$1950}{\text{hr}} - \frac{\$377.23}{\text{hr}} = \frac{\$1572.77}{\text{hr}} \\ &= \frac{\$1572.77}{\text{hr}} \times \frac{\text{hr}}{266,000 \text{ lb}} \times \frac{1000}{1000} = \frac{\$5.90}{1000 \text{ lb}} \end{aligned}$$

Therefore, the energy charge for the 25 MW Turbine-Generator is:

$$\left[\text{Energy Charge} \right]_{25 \text{ MW T.G.}} = \frac{\$5.90}{1000 \text{ lb}} \left[\frac{8.65 \text{ lb}}{\text{Hp-hr}} \right] = \frac{\$0.0510}{\text{Hp-hr}}$$

Assuming a 74 percent conversion efficiency from the bus-bar electrical power to the electric motor shaft horsepower, the total charge for on-site fossil fuel power generation is the sum of the Capital Charge Rate and the converted Energy Charge Rate:

$$\left[\text{Total Energy Charge} \right]_{\text{ON-SITE FOSSIL}} = \frac{\$.0039}{\text{Hp-hr}} + \frac{\$.051}{(0.74) \text{ Hp-hr}} = \frac{\$.0728}{\text{Hp-hr}}$$

This figure constitutes the total charge for operating existing motors on off-site electrical power. The total charge for operating new electric motors with on-site fossil fuel electrical power is calculated by adding the total energy charge to the capital cost charge for new electric motors calculated in Section 3.4.2 and listed in Tables 3-8 and 3-9.

3.4.3.4

On-site Geothermal Binary Cycle Power

The total charge for generating on-site power utilizing a geothermal binary cycle was calculated using the Turbine Capital Cost Charge, Geothermal Plant Demand Charge, and the Turbine Energy Charge listed in Table 3-6 as Item 21, "Additional Turbo-Generator". Energy charges were converted assuming a 74 percent conversion efficiency from the bus-bar electrical power to the electric motor shaft horsepower. Therefore, the total charge for on-site geothermal binary cycle electrical power is:

$$\begin{aligned} \left[\begin{array}{l} \text{Total Energy} \\ \text{Charge} \end{array} \right]_{\text{ONSITE BINARY}} &= \left[.0015 + .0177 + \frac{.0418}{0.74} \right] \frac{\$}{\text{Hp-hr}} \\ &= \frac{\$.0757}{\text{Hp-hr}} \end{aligned}$$

The total charge for operating new electric motors with on-site geothermal binary cycle electrical power is calculated by adding the total energy charge to the capital cost charge for new electric motors calculated in Section 3.4.2 and listed in Tables 3-8 and 3-9.

3.4.3.5

On-site Geothermal Flash Cycle Power

The total charge for generating on-site power utilizing a geothermal flash steam cycle was calculated using the Turbine Capital Cost Charge, Geothermal Plant Demand Charge, and the Turbine Energy Charge listed in Table 3-7 as Item 21, "Additional Turbo-Generator". Energy charges were converted assuming a 74 percent conversion efficiency from the bus-bar

electrical power to the electric motor shaft horsepower. Therefore, the total charge for on-site geothermal flash steam cycle electrical power is:

$$\begin{aligned} \left[\begin{array}{c} \text{Total Energy} \\ \text{Charge} \end{array} \right]_{\text{ONSITE FLASH}} &= \left[.0040 + .0165 + \frac{.0300}{0.74} \right] \frac{\$}{\text{Hp-hr}} \\ &= \frac{\$.0610}{\text{Hp-hr}} \end{aligned}$$

The total charge for operating new electric motors with on-site geothermal flash steam cycle electrical power is calculated by adding the total energy charge to the capital cost charge for new electric motors calculated in Section 3.4.2 and listed in Table 3-8 and 3-9.

3.5 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 3-11. 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. These are relative costs for comparison and are not meant to represent total plant operating costs. Columns 1 through 5 deal with operating existing steam turbines on fossil fuel and operating existing back-up electric motors on both off-site power, and on-site fossil and geothermal energy. The "not applicable" symbol (NA) is used in columns 2 through 5 where there is no existing back-up electric motor. Columns 6 and 7 deal with operating new binary vapor expanders and flash

TABLE 3-11

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 ¹	NA	NA	NA	NA	.0388 ²	.0475	.0388 ³	.0754	.0783	.0636
2. REFRIG COMPRESSOR	7,325	.1398	NA	NA	NA	NA	.0576 ³	.0495 ²	.0390 ¹	.0756	.0785	.0638
3. AIR COMPRESSOR	5,625	.0946	NA	NA	NA	NA	.0579 ³	.0495 ²	.0380 ¹	.0746	.0775	.0628
4. H.P. BFW PUMP	1,320	.0223 ¹	.0362 ²	.0728	.0757	.0610	.0561 ³	.0570	NA	NA	NA	NA
5. COOLING WATER PUMP	980	.1429	.0362 ¹	.0728	.0757	.0610	.0660	.0570 ³	.0396 ²	.0762	.0791	.0644
6. NATURAL GAS COMPRESSOR	960	.0217 ¹	NA	NA	NA	NA	.0635	.0615 ³	.0396 ²	.0762	.0791	.0644
7. T.E.A. SOL'N PUMP	960	.0222 ¹	.0362 ²	.0728	.0757	.0610	.0630	.0590 ³	NA	NA	NA	NA
8. HYDRAULIC SUPPLY PUMP	840	.0208 ¹	NA	NA	NA	NA	.0634	.0576 ³	.0400 ²	.0766	.0795	.0648
9. I.D. FAN	275	.0267 ¹	NA	NA	NA	NA	.0800	.0491 ³	.0398 ²	.0764	.0793	.0646
10. H.P. BOILER CIRC. PUMP	248	.0267 ¹	.0362 ²	.0728	.0757	.0610	.0785	.0530 ³	NA	NA	NA	NA
11. ERIE 2 BFW PUMP	250	.0292 ¹	.0362 ²	.0728	.0757	.0610	.0714	.0552 ³	NA	NA	NA	NA
12. AUX. CARBAMATE PUMP	250	.0412 ²	NA	NA	NA	NA	.0714	.0646 ³	.0403 ¹	.0769	.0798	.0651
13. TURBO-GENERATOR	186	.0474 ¹	NA	NA	NA	NA	.0853 ³	.0684 ²	NA	NA	NA	NA
14. L.P. BFW PUMP	95	.0359 ¹	.0362 ²	.0728	.0757	.0610 ³	.1017	.0641	NA	NA	NA	NA
15. DEMIN. WATER PUMP	80	.3252	.0362 ¹	.0728	.0757	.0610 ³	.1133	.0668	.0418 ²	.0784	.0813	.0666
16. SYN SEAL OIL PUMP	80	.3745	.0362 ¹	.0728	.0757	.0610 ²	.1018	.0668 ³	NA	NA	NA	NA
17. SYN LUBE OIL PUMP	80	.3745	.0362 ¹	.0728	.0757	.0610 ²	.0989	.0668 ³	NA	NA	NA	NA
18. FM LUBE OIL PUMP	40	.3252	.0362 ¹	.0728 ³	.0757	.0610 ²	.1473	.0912	NA	NA	NA	NA
19. REFRIG LUBE OIL PUMP	30	.7686	.0362 ¹	.0728 ³	.0757	.0610 ²	.1792	.1084	NA	NA	NA	NA
20. FM SEAL OIL PUMP	22.5	.3252	.0362 ¹	.0728 ³	.0757	.0610 ²	.2330	.1178	NA	NA	NA	NA

steam turbines using geothermal energy in both cases. Columns 8 through 11 deal with operating new electric motors on both off-site power, and on-site fossil and geothermal energy. The "not applicable" symbol (NA) is used in columns 8 through 11 where back-up electric motors already exist, except for the Cooling Water Pump and Demin Water Pump which have half-capacity back-up electric motors and would require additional motor capacity.

The three lowest cost alternatives for each equipment driver are ranked in Table 3-11 from lowest to highest. Several trends appear from this ranking process, however, care must be taken in drawing conclusions from this method of analysis:

1. 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, but merely if a choice arose between keeping a full condensing or a backpressure turbine, the back-pressure turbine should be maintained.
2. Operating a combination of existing and new electric motors on off-site electrical power would be a very cost effective alternative. This assumes that the local utility can supply the additional electrical demand without increases in cost from providing more generating capacity and larger feeder lines to the plant.

3. A combination of flash steam turbines and flash steam electrical power will be the best geothermal alternative to more conventional energy sources.

Table 3-11 weighs the cost of each alternative on an equal basis, regardless of equipment size, however, to arrive at the best alternative plant arrangement, it will be necessary to weigh the cost of each alternative taking equipment size into consideration, because the potential energy cost savings are much greater from the larger equipment than from the smaller equipment. Therefore, in Table 3-12 the costs from Table 3-11 have been multiplied by the rated horsepower for each equipment driver to give costs in units of \$/hr. These are relative costs and are not meant to represent total plant operating costs, however these costs will allow the comparison of various alternatives by adding the \$/hr cost for each piece of equipment and determining a relative total plant operating cost. From Table 3-12 it can be seen that the major portion of potential cost savings will come from changes to the three largest turbines in the plant, which represent about 80 percent of the total fossil fuel turbine costs. Therefore, the optimum solution to reducing fossil fuel energy costs in the VNP plant steam cycle appears to be:

1. Minimize operating costs for the three largest machines;
2. Maintain maximum waste heat utilization; and
3. Maintain a balanced steam cycle using a combination of backpressure turbines and electric motors.

TABLE 3-12

LEVELIZED COSTS FOR PERIOD 1980-1989 \$/HR		EXISTING TURBINES (FOSSIL)	EXISTING MOTORS OFFSITE POWER	EXISTING MOTORS ONSITE POWER (FOSSIL)	EXISTING MOTORS ONSITE POWER (BINARY)	EXISTING MOTORS ONSITE POWER (FLASH)	BINARY TURBINES	FLASH TURBINES	NEW MOTORS OFFSITE POWER	NEW MOTORS ONSITE POWER (FOSSIL)	NEW MOTORS ONSITE POWER (BINARY)	NEW MOTORS ONSITE POWER (FLASH)
TURBINES		RATED Hp										
1. SYN GAS COMPRESSOR	14,000	414.4 ¹	NA	NA	NA	NA	543.2 ²	665	543.2 ³	1055.6	1096.2	890.4
2. REFRIG COMPRESSOR	7,325	1024.0	NA	NA	NA	NA	421.9 ³	362.6 ²	285.7 ¹	553.8	575.0	467.3
3. AIR COMPRESSOR	5,625	532.1	NA	NA	NA	NA	325.7 ³	278.4 ²	213.8 ¹	419.6	435.9	353.3
4. H.P. BFW PUMP	1,320	29.4 ¹	47.8 ²	96.1	99.9	80.5	74.1 ³	75.2	NA	NA	NA	NA
5. COOLING WATER PUMP	980	140.0	35.5 ¹	71.3	74.2	59.8	64.7	55.9 ³	38.8 ²	74.7	77.5	63.1
6. NATURAL GAS COMPRESSOR	960	20.8 ¹	NA	NA	NA	NA	61.0	59.0 ³	38.0 ²	73.2	75.9	61.8
7. T.E.A. SOL'N PUMP	960	21.3 ¹	34.8 ²	69.9	72.7	58.6	60.5	56.6 ³	NA	NA	NA	NA
8. HYDRAULIC SUPPLY PUMP	840	17.5 ¹	NA	NA	NA	NA	53.3	48.4 ³	33.6 ²	64.3	66.8	54.4
9. I.D. FAN	275	7.3 ¹	NA	NA	NA	NA	22.0	13.5 ³	10.9 ²	21.0	21.8	17.8
10. H.P. BOILER CIRC. PUMP	248	6.6 ¹	9.0 ²	18.1	18.8	15.1	19.5	13.1 ³	NA	NA	NA	NA
11. ERIE 2 BFW PUMP	250	7.3 ¹	9.1 ²	18.2	18.9	15.3	17.9	13.8 ³	NA	NA	NA	NA
12. AUX. CARBAMATE PUMP	250	10.3 ²	NA	NA	NA	NA	17.9	16.2 ³	10.1 ¹	19.2	20.0	16.3
13. TURBO-GENERATOR	186	8.8 ¹	NA	NA	NA	NA	15.9 ³	12.7 ²	NA	NA	NA	NA
14. L.P. BFW PUMP	95	3.4 ¹	3.4 ²	6.9	7.2	5.8 ³	9.7	6.1	NA	NA	NA	NA
15. DEMIN. WATER PUMP	80	26.0	2.9 ¹	5.8	6.1	4.9 ³	9.1	5.3	3.3 ²	6.3	6.5	5.3
16. SYN SEAL OIL PUMP	80	30.0	2.9 ¹	5.8	6.1	4.9 ²	8.1	5.3 ³	NA	NA	NA	NA
17. SYN LUBE OIL PUMP	80	30.0	2.9 ¹	5.8	6.1	4.9 ²	7.9	5.3 ³	NA	NA	NA	NA
18. FM LUBE OIL PUMP	40	13.0	1.4 ¹	2.9 ³	3.0	2.4 ²	5.9	3.6	NA	NA	NA	NA
19. REFRIG LUBE OIL PUMP	30	23.1	1.1 ¹	2.2 ³	2.3	1.8 ²	5.4	3.3	NA	NA	NA	NA
20. FM SEAL OIL PUMP	22.5	7.3	0.8 ¹	1.6 ³	1.7	1.4 ²	5.2	2.7	NA	NA	NA	NA

This solution can be verified by a comparison of alternatives utilizing the \$/hr costs from Table 3-12. The alternative cost comparisons are listed in Table 3-13, where the "% Reduction" shows the operating cost savings over running the existing turbines on fuel oil.

3.6 CONCLUSION

From Table 3-13, it appears that an optimal solution for reducing fossil fuel costs in the VNP plant will come by integrating a geothermal flash steam cycle into the existing plant steam cycle. The Syn Gas Turbine would be maintained and every attempt would be made to run the turbine on steam generated from waste heat exclusively. The extraction steam from the Syn Gas Turbine would be used primarily for process steam requirements with any remaining steam going to backpressure turbines and intermediate pressure steam requirements. The Refrigeration Compressor and Process Air Compressor would be run by new flash steam 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 flash cycle turbine-generator set. The inclusion of in-house electrical generating capacity will also increase plant reliability. With Options 3 and 4 in Table 3-13 giving rates of return of 15 percent and 28.5 percent, respectively (from Tables 2-11 and 2-12), it is safe to assume that the optimal solution, listed as Option 7 in Table 3-13, will give an even higher rate of return.

Table 3-13

<u>Equipment Driver Cost Options</u>	<u>\$/hr</u>	<u>% Reduction</u>
1. Run existing turbines on fuel oil	2372.6	0
2. Best case using existing equipment	2150.7	9.4
3. Run binary plant exclusively	1748.9	26.3
4. Run flash plant exclusively	1702.0	28.3
5. Keep Syn Gas TD, replace Refrig and Air Compressor TD's with flash turbines and generate flash power	1473.8	37.9
6. Keep Syn Gas TD and all BP TD's, replace Refrig and Air Compressor TD's with electric motors and generate flash power	1447.7	39.0
7. Keep Syn Gas TD and BP TD's, replace Refrig and Air Compressor TD's with flash turbines and generate flash power	1268.2	46.5

Appendix A

DERIVATION OF COOLING TOWER INCREMENTAL COST FACTOR

The incremental cooling tower cost is defined as:

$$\frac{\text{Increase in C.T. Load}}{\text{Geothermal C.T. Load}} \left[\text{Geothermal C.T. Cost} \right]$$

which is:

$$(1) \quad \frac{(Q_R)_g - (Q_R)_f}{(Q_R)_g} \left[\$ \text{ C.T.} \right]_g$$

where: Q_R = Heat rejection load in C.T.
 g = Geothermal plant cycle
 f = Fossil plant cycle

It is most convenient to calculate the heat rejection load (Q_R) in each plant cycle in terms of the amount of work output from the cycle (W) and the cycle thermal efficiency (EFF) for comparison of two plant cycles. By definition:

$$(2) \quad EFF = \frac{W}{Q_A} \quad \text{where } Q_A = \text{Heat added to the cycle}$$

and

$$(3) \quad Q_A = W + Q_R$$

Therefore, we can eliminate Q_A from these two independent equations and find Q_R as a function of W and EFF as follows:

From equation (2):

$$Q_A = \frac{W}{EFF}$$

and substituting into equation (3):

$$\frac{W}{EFF} = W + Q_R$$

$$Q_R = \frac{W}{EFF} - W$$

$$Q_R = W \left[\frac{1}{EFF} - 1 \right] = W \frac{(1-EFF)}{EFF}$$

Simplifying equation (1):

$$1 - \left[\frac{(Q_R)_f}{(Q_R)_g} \right] \left[\$ \text{ C.T.} \right]_g$$

Therefore, we can find the ratio of heat rejected in the fossil fuel plant to the heat rejected in the geothermal cycle plant as follows:

$$(Q_R)_f = W_f \frac{(1-EFF_f)}{EFF_f}$$

$$(Q_R)_g = W_g \frac{(1-EFF_g)}{EFF_g}$$

Therefore:

$$(4) \quad \frac{(Q_R)_f}{(Q_R)_g} = \frac{W_f (1-EFF_f) EFF_g}{W_g (1-EFF_g) EFF_f}$$

However, since the amount of work done by the geothermal cycle is exactly the amount of work previously done by the fossil fuel cycle,

$$W_f = W_g$$

and

$$\frac{W_f}{W_g} = 1$$

Equation (4) simplifies to:

$$\frac{(Q_R)_f}{(Q_R)_g} = \frac{(1-EFF_f) EFF_g}{(1-EFF_g) EFF_f}$$

and therefore, equation (1) becomes:

$$\text{Incremental C.T. Cost} = \left[1 - \frac{(1-EFF_f) EFF_g}{(1-EFF_g) EFF_f} \right] \left[\$ \text{ C.T.} \right]_g$$

Appendix B

STEAM CYCLE THERMAL EFFICIENCY

Calculation of the VNP Plant steam cycle thermal efficiency is required to determine the amount of fossil fuel required to produce a given amount of shaft work. This calculation is important because it allows us to compare the cost of operating the existing thermal cycle with the cost of operating an alternative thermal cycle, namely a geothermal energy cycle.

A simplified form of the VNP Plant steam cycle is shown in Figure B-1. This figure is a compilation of Figures 2-2 through 2-9 of the First Quarterly Report. It can be seen from Figure B-1 that there is a large amount of heat and mass flow entering and leaving the cycle. Since the Rankine Cycle Efficiency is only defined for the closed portion of the cycle, it is necessary to account for the amount of heat that is lost from the cycle and the amount of heat that is providing shaft work. Heat losses from the cycle are in two forms: 1. Mass flow heat losses, such as process steam and header steam losses; and 2. process heat losses, such as 150 psi and 50 psi process heaters. Therefore, the Rankine Cycle Efficiency is defined as:

$$\text{efficiency} = \frac{WK_{OUT}}{(QADDED)_{NET}}$$

Where:

WK_{OUT} = Turbine Shaft Work

$(QADDED)_{NET}$ = Waste Heat + Fossil Fuel - Mass Flow - Process
Heat Losses Heat Losses

Table B-1 summarizes the information necessary to calculate $(QADDED)_{NET}$ by tabulating the waste heat added, fossil

SIMPLIFIED PLANT STEAM CYCLE

TABLE B-1

Waste Heat Added

BFW & Condensate Heater (E-409)	=	0.385×10^8	BTU/HR
BFW Heater (E-709)	=	0.579×10^8	BTU/HR
BFW Heater (E-106)	=	0.063×10^8	BTU/HR
Feedwater Economizer (D-104)	=	0.433×10^8	BTU/HR
Reform Gas W.H. Boiler (E-105)	=	0.908×10^8	BTU/HR
Converted Gas W.H. Boiler (E-103)	=	0.076×10^8	BTU/HR
TOTAL	=	2.444×10^8	BTU/HR

Fossil Fuel Heat Added

Package Boilers	142,220 lb/hr	(1070.6 BTU/lb)	=	1.52×10^8	BTU/HR
PCC Boiler	109,200 lb/hr	(578.7 BTU/lb)	=	0.63×10^8	BTU/HR
PCC Superheater	302,000 lb/hr	(148.7 BTU/lb)	=	0.45×10^8	BTU/HR
PCC Superheater	23,000 lb/hr	(1088.4 BTU/lb)	=	0.25×10^8	BTU/HR
TOTAL			=	2.85×10^8	BTU/HR

Mass Flow Heat Losses

(mh) OUT

Process Steam	97,700 lb/hr	(1298.6 BTU/lb)	=	1.269×10^8	BTU/HR
Steam Header	23,460 lb/hr	(1298.6 BTU/lb)	=	0.305×10^8	BTU/HR
Deaerator	3,000 lb/hr	(1167 BTU/lb)	=	0.035×10^8	BTU/HR
Feedwater	9,610 lb/hr	(228 BTU/lb)	=	0.022×10^8	BTU/HR
TOTAL =	133,770 lb/hr			1.631×10^8	BTU/HR

(mh) IN

Demin Make-up	93,770 lb/hr	(44.8 BTU/lb)	=	0.042×10^8	BTU/HR
Demin Make-up	40,000 lb/hr	(44.8 BTU/lb)	=	0.018×10^8	BTU/HR
TOTAL =	133,770 lb/hr			0.060×10^8	BTU/HR

$$\text{Mass Flow Heat Losses} = (\dot{m}h)_{\text{OUT}} - (\dot{m}h)_{\text{IN}} = 1.571 \times 10^8 \text{ BTU/HR}$$

Process Heat Losses

(mΔh) LOST

Urea Plant	32,100 lb/hr	(857 BTU/lb)	=	0.275×10^8	BTU/HR
Urea Plant	15,560 lb/hr	(901 BTU/lb)	=	0.140×10^8	BTU/HR
Urea Plant	4,700 lb/hr	(917 BTU/lb)	=	0.043×10^8	BTU/HR
MEA Purifier	3,000 lb/hr	(966 BTU/lb)	=	0.029×10^8	BTU/HR
Client Offsites	11,160 lb/hr	(958 BTU/lb)	=	0.107×10^8	BTU/HR
Client Offsites	4,440 lb/hr	(1031 BTU/lb)	=	0.046×10^8	BTU/HR
TOTAL =	70,960 lb/hr			0.640×10^8	BTU/HR

fuel heat added, mass flow heat losses, and process heat losses. The only modification to the numbers in Table B-1 is the inclusion of the boiler efficiency with the fossil fuel heat added to determine the actual amount of fossil fuel burned for steam production. Assuming a boiler efficiency of 76%, based on boiler vendor data, the calculation of $(Q_{ADDED})_{NET}$ becomes:

$$\begin{aligned}(Q_{ADDED})_{NET} &= (2.44 + \frac{2.85}{0.76} - 1.57 - 0.64) \times 10^8 \text{ BTU/HR} \\ &= 4.00 \times 10^8 \text{ BTU/HR}\end{aligned}$$

The calculation of W_{KOUT} is made by adding the design horsepower ratings of the steam driven turbines and converting the total horsepower to BTU's per hour.

$$W_{KOUT} = 31,324 \text{ Hp} (2544.4 \text{ BTU/Hp-hr}) = 0.800 \times 10^8 \text{ BTU/HR}$$

Therefore, the Gross Rankine Cycle Efficiency becomes:

$$\text{eff} = \frac{W_{KOUT}}{(Q_{ADDED})_{NET}} = \frac{0.800 \times 10^8 \text{ BTU/HR}}{4.00 \times 10^8 \text{ BTU/HR}} = 0.20 \text{ or } 20\%$$

Many of the turbines included in the calculation of the Gross Rankine Cycle Efficiency are used in the plant steam cycle itself for circulating feedwater, cooling water, and demineralized water. This horsepower requirement along with the electrical power used to operate and control the plant steam cycle constitute the plant auxiliary power requirement. Both the existing thermal cycle and any alternative thermal cycle have auxiliary power requirements which must be satisfied to operate the cycle. Therefore in analyzing alternative cycles we compare them on the basis of their thermal cycle efficiencies, which

accounts for the amount of plant auxiliary power required to run each cycle. The auxiliary power is always stated as a percentage of the gross power output, therefore we define the net power output as:

$$\text{Net Power Output} = \text{Gross Power Output} (1 - \% \text{ Auxiliary Power})$$

This equation can also be written in terms of the thermal cycle efficiencies, namely:

$$\text{Net Cycle Eff} = \text{Gross Cycle Eff} (1 - \% \text{ Auxiliary Power})$$

For the purposes of our calculations we assume an auxiliary power requirement for the VNP Plant steam cycle of 13 percent. Therefore, the net thermal cycle efficiency becomes:

$$\text{Net Cycle Efficiency} = 0.20 (1 - 0.13) = 0.174 \text{ or } 17.4\%$$

Appendix C
LEVELIZED UNIT FUEL COSTS

A levelized unit fuel cost is an equivalent unit fuel cost which is used to compute the present worth total plant fuel expenses as would be produced by the sum of the present worth of the annual fuel expenses throughout the entire study period. The levelized unit fuel costs were calculated for the study period in order to eliminate the added complexity of dealing with yearly escalation, thereby simplifying the analysis to one cost for each fuel during the study period. The calculation of levelized unit fuel costs was done on a present worth basis for the year 1980 and covers the study period of 1980 through 1989. Nominal fuel costs, as shown in Figure 2-4, were used and an interest rate of 8 percent was assumed for the calculation. Levelized unit fuel costs are calculated by dividing the sum of the present worth fuel costs by the sum of the present worth factors for the study period. The calculation is summarized in Table C-1.

Table C-1

LEVELIZED UNIT FUEL COSTS
Period 1980-1989

End of Year	PWF 8%	Purchased Electricity		Fuel Oil		Natural Gas		One-Phase Brine		Two-Phase Brine	
		\$/10 ⁶ BTU	PW	\$/10 ⁶ BTU	PW	\$/10 ⁶ BTU	PW	\$/10 ⁶ BTU	PW	\$/10 ⁶ BTU	PW
1977		5.86		2.66		1.52		0.900		0.75	
1978		6.38		2.97		1.90		0.966		0.81	
1979		6.94		3.31		2.47		1.04		0.86	
1980	0.926	7.55	6.99	3.69	3.41	3.21	2.97	1.20	1.031	0.93	0.858
1981	0.857	8.21	7.04	4.11	3.52	3.59	3.08	1.28	1.025	0.99	0.853
1982	0.794	8.94	7.10	4.58	3.64	4.01	3.18	1.38	1.019	1.07	0.850
1983	0.735	9.72	7.15	5.11	3.76	4.49	3.30	1.48	1.014	1.15	0.845
1984	0.681	10.58	7.20	5.70	3.88	5.02	3.42	1.60	1.011	1.24	0.842
1985	0.630	11.51	7.25	6.35	4.00	5.61	3.53	1.72	1.005	1.33	0.838
1986	0.584	12.25	7.15	7.09	4.14	6.27	3.66	1.85	1.003	1.43	0.835
1987	0.540	13.04	7.04	7.90	4.27	7.01	3.79	1.99	0.997	1.54	0.831
1988	0.500	13.89	6.95	8.81	4.41	7.84	3.92	2.14	0.994	1.66	0.828
1989	0.463	14.80	6.85	9.82	4.55	8.76	4.06	2.31	0.992	1.78	0.826
TOTAL:	6.710		70.72		39.58		34.91		10.091		8.41
LEVELIZED UNIT FUEL COST:		10.53		5.90		5.20		1.50		1.25	

Appendix D

FIXED CHARGE RATE CALCULATION

The fixed charge rate for capital investments by VNP is calculated in the same manner as a government owned utility, since both organizations secure capital by means of long term loans and both organizations pay no income taxes. Therefore, the fixed charge rate is calculated by the following equation:

$$FCR = CRF + p$$

where: FCR = Fixed Charge Rate
 CRF = Capital Recovery Factor
 p = Property taxes and insurance

$$CRF = \frac{i (1 + i)^N}{(1 + i)^N - 1}$$

where: i = Loan Interest Rate
 N = Loan Repayment Period

For the VNP economic analysis, the following assumptions are made:

i = 8%
 N = 10 years
 p = 2.32% (Property tax) + 0.19% (Property Insurance)
 p = 2.51%

$$FCR = \frac{0.08 (1 + 0.08)^{10}}{(1 + 0.08)^{10} - 1} + 0.0251$$

$$FCR = 0.149 + 0.0251 = \underline{0.174}$$

Appendix E

CALCULATION OF BRINE FLASHING PRESSURES

Three brine flashing stages are envisioned for a geothermal flash steam plant at VNP. The first stage will flash brine at 65 psia to satisfy the present 50 psi steam requirements. The second and third flash stages are chosen to optimize the energy extracted from the brine as a driving force for the single and double entry saturated steam turbines. To optimize the turbine inlet pressures, equations from work done by Milora and Tester (Ref.) were used. With the first flash stage pressure set at 65 psia and a temperature, T , of 298°F (758°R), and a sink temperature, T_0 , of 126°F (586°R) corresponding to a turbine backpressure of 4"HgA, T_1^{OPT} and T_2^{OPT} become:

$$T_1^{OPT} = (T_0 T^2)^{1/3} = [586(758)^2]^{1/3} = 696^\circ R = 236^\circ F \text{ (23.3 psia)}$$

$$T_2^{OPT} = (T_0 T_1^{OPT})^{1/2} = [586(696)]^{1/2} = 638^\circ R = 178^\circ F \text{ (7.4 psia)}$$

This optimized flash system results in a sub-atmospheric steam pressure (7.4 psia) at the third flash stage. This condition is generally undesirable for the following reasons:

1. Increased specific volume of the steam with resulting larger piping, valves and fittings.
2. More complicated plant start-up.
3. Possible in-leakage of oxygen, causing corrosion in piping and equipment, and resulting in more condensate polishing required.

To avoid sub-atmospheric pressures, the third flash stage is maintained slightly above atmospheric pressure at 16 psia. On this basis, the second stage flash pressure is computed to give an optimum between 65 psia and 16 psia. Therefore, T_1^{OPT} is computed as:

$$T_1^{OPT} = (T \times T_2^{OPT})^{1/2} \quad \text{where: } T = 758^\circ R \text{ (65 psia)}$$

$$T_2^{OPT} = 216^\circ F = 676^\circ R \text{ (16 psia)}$$

$$T_1^{OPT} = [758(676)]^{1/2} = 716^\circ R = 256^\circ F \text{ (33 psia)}$$

The brine flash conditions are therefore:

First Stage	65 psia
Second Stage	33 psia
Third Stage	16 psia