STAFF REPORT

Evaluation Of A Superheater Enhanced Geothermal Steam Power Plant In The Geysers Area

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CALIFORNIA ENERGY COMMISSION

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FINAL REPORT

CALIFORNIA ENERGY COMMISSION

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ABSTRACT

This study was conducted to determine the attainable generation increase and to evaluate the economic merits of superheating the steam that could be used in future geothermal steam power plants in the Geyser-Calistoga Known Geothermal Resource Area (KGRA).

It was determined that using a direct gas-fired superheater offers no economic advantages over the existing geothermal power plants.

If the geothermal steam is heated to 900°F by using the exhaust energy from a gas turbine of currently available performance, the net reference plant output would increase from 65 MW to 159 MW (net). Such hybrid plants are cost effective under certain conditions identified in this document.

The power output from the residual Geyser area steam resource, now equivalent to 1,437 MW, would be more than doubled by employing in the future gas turbine enhancement. The fossil fuel consumed in these plants would be used more efficiently than in any other fossil-fueled power plant in California.

Due to an increase in evaporative losses in the cooling towers, the viability of the superheating concept is contingent on development of some of the water resources in the Geysers-Calistoga area to provide the necessary makeup water.

EXECUTIVE SUMMARY

Improving the performance of geothermal power plants by fossil fuel augmentation has been analyzed periodically and the results reported in the literature (see references 2, 3, 4, 6, 7, 8, 9, 10, 12 and 13). In these previous studies, many techniques common to steam power plant engineering have been evaluated for their theoretical applicability to geothermal steam plants. Typically, these hybrid energy schemes have involved a hypothetical hot brine plant that employs coal firing to superheat the flashed steam. In spite of clear gains in cycle performance, no one has built a hybrid fossil/geothermal plant of any type.

The objective of this study is to compare the performance and the cost of electricity produced in an existing state-of-the-art geothermal plant that uses the 348°F steam as produced in the Geysers-Calistoga KGRA with a modified plant, using the same flow of geothermal steam, but designed to superheat the steam with fossil energy to 900°F. By superheating the steam the power output from the remaining uncommitted geothermal resource could be increased more than twofold.

The scope of this study covers direct-fired superheating and also recovery of heat from a gas turbine exhaust to superheat the geothermal steam. Only "clean"-burning pipeline fuel was considered, as it is the most practical form of fossil energy deemed deliverable to the Geysers area. Only new power plants that could be constructed in the future were considered.

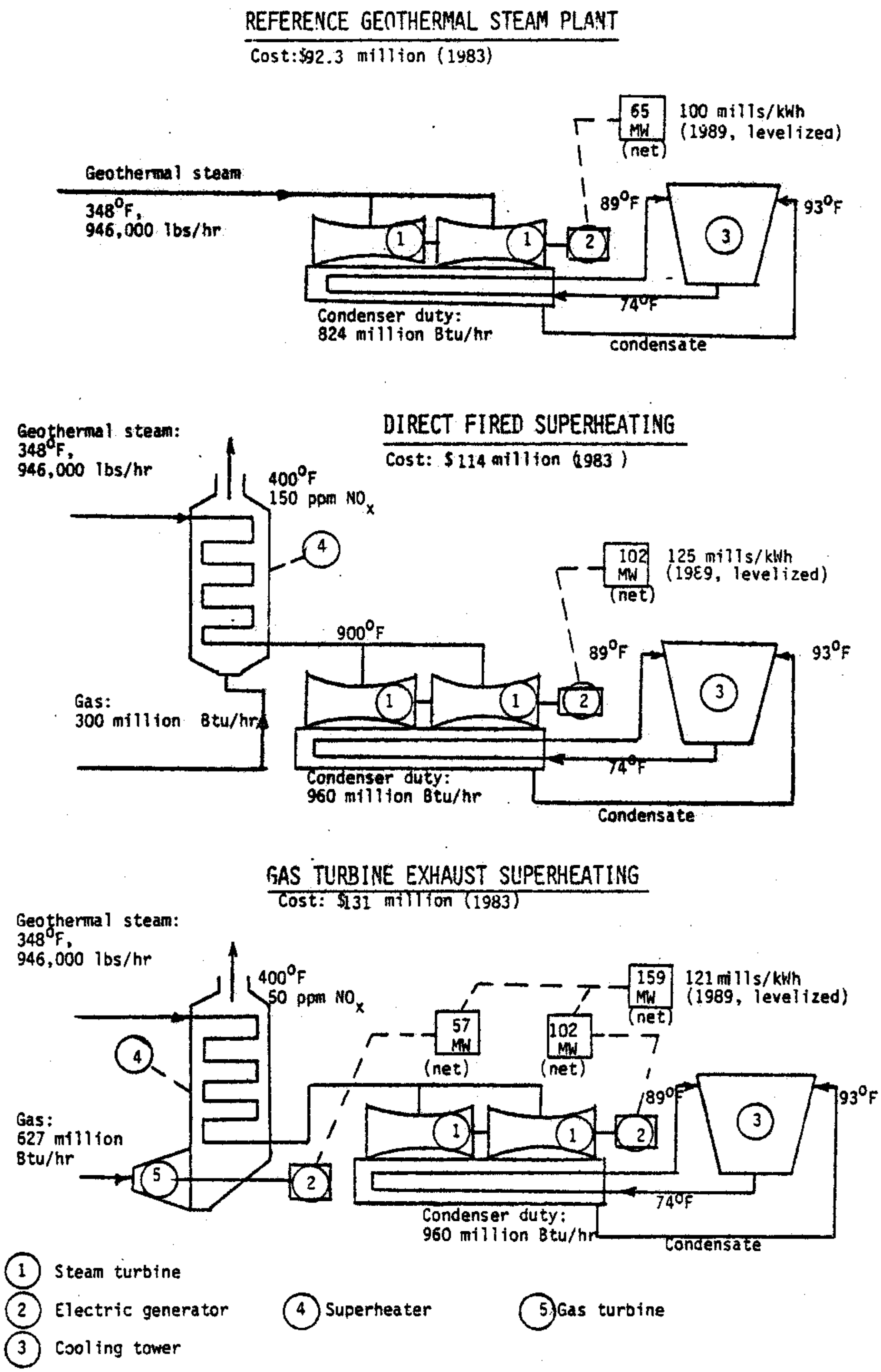
The determination of attainable generation enhancement and analyses of economic merits were limited to comparison with a 65 megawatt (MW) net, low

back pressure, four-flow geothermal steam turbine (Sacramento Municipal Utility District model).

A schematic description of these concepts is presented in Figure S-1.

FIGURE S-1

SCHEMATIC SUMMARY OF SUPERHEATING OPTIONS



CONCLUSIONS

The results of this study produce the following findings and conclusions:

1. As in previous studies of hybrid energy schemes (see references), superheating the geothermal steam was found to increase steam turbine output. In this study, using a 65 MW plant in the Geyser area as a reference, it was determined that by employing a superheater to raise the 348°F steam temperature to 900°F and maintaining the same throttle steam flow, the net plant output increases from 65 to 102 MW.

2. By utilizing the thermal energy in the exhaust of a 57 MW gas turbine-generator unit to superheat the reference plant flow of geothermal steam, the total plant output increases to 159 MW. Of the fossil fuel consumed, 51.2 percent of the fossil energy is converted to net plant electricity. By way of comparison, a combined cycle plant using the same gas turbine is only 45.2 percent efficient.

3. Exclusive of costs for development of water resources to secure evaporation makeup water, the capital cost of the direct-fired and the gas turbine enhanced geothermal plants, per installed kilowatt (kW), will be about 79 and 58 percent, respectively, of the unenhanced reference plant's capital cost. The cost of a gas pipeline has been included in the gas price.

4. The reference unenhanced geothermal plant requires 15.12 pounds of geothermal steam per kilowatt-hour (kWh) of generation. The direct-fired enhanced geothermal plant will require 9.64 pounds of geothermal steam <u>and</u> 2,940 Btu of fossil fuel per kWh of generation. The gas turbine

enhanced plant requires 6.18 pounds of geothermal steam and 3,940 Btu of fossil fuel per kWh of generation.

5. The Geysers area power generation potential from the residual resource could be increased from an estimated 1,437 MW to 3,514 MW from the use of 22 gas turbines-superheaters in the remaining planned plants and uncommitted steam resources using currently available gas turbines.

6. The 2,077 MW of additional Geysers area generation will effect a net reduction in fossil fuel use of 8.0 million barrels of oil equivalent annually, using currently available gas turbines.

7. A direct-fired superheater offers no economic advantages.

8. The integrated gas turbine-superheater enhanced geothermal power plant can be compared in cost and performance to a reference unenhanced geothermal plant together with a combined cycle plant each operating separately. Only a utility which will continue to use gas and geothermal steam to generate electricity, and, therefore, has the option to integrate a gas turbine with a geothermal power plant rather than operate two such facilities separately may have a slight economic advantage (and so would the rate payer) in doing so. In 1988, depending on the rate of inflation and the real escalation rates of gas prices, a turbine exhaust superheater-enhanced geothermal power plant will cost about \$30 million less; it will produce 11 MW more, and will operate at 1 to 2 ¢/kWh (levelized) less than the sum of both geothermal and combined cycle plants operating separately with the respective use of gas and geothermal steam being the same. Such an advantage could be totally or in part

eliminated if the costs of development of the necessary make-up water availability were included.

For a utility which is not likely to use gas for power generation in the future or for a small power producer who sells energy at avoided costs, superheating the geothermal steam offers no advantage. Even without the additional cost of acquiring cost of make-up water, the generation cost using turbine exhaust for superheating the geothermal stea would be at best 0.4 ¢/kWh less, but perhaps as much as 2.0 ¢/kWh more (15 to 25 percent more, depending on the rate of inflation and gas prices) than the cost of electricity produced by the reference geothermal plant without superheating.

9. A significant environmental impact resulting from operation of enhanced geothermal plants would be the emission of nitrogen oxides (NO_x). However, the cumulative NO_x emissions from all 22 plants would not violate state or federal air quality standards in any Geysers area community.

10. The enhanced geothermal power plant poses several disadvantages identified below.

    a. A 16 percent increase in heat dissipation capacity will result in evaporation of all available condensate.

    b. This represents a minimum annual deficiency (for 22 plants) of 10,000 acre-feet needed for water injections into the gas turbine for NOx control, cooling tower lowdown and reinjection into the steam field.

c. To satisfy this need, construction of reservoirs would be required because all of the watershed in the Geysers-Calistoga KGRA (Big Sulfur, Dry, Putah and Kelsey creeks) have only a minimal or zero flow during the summer months.

d. Additional (not included in these analyses) capital and operational (pumping) costs would be incurred.

e. There would be environmental impacts associated with construction of these reservoirs.

f. Planned or forced outages of either gas turbine or geothermal steam turbine will cause a shutdown of the entire plant.

g. Environmental impacts associated with the construction of the gas pipeline.

On balance, the CEC staff concludes that there are no clear cut advantages that would justify superheating the geothermal steam at the Geysers at this time.

UNCERTAINTIES

In addition to the advantages and disadvantages identified above, there are a few uncertainties pertaining to the concept of superheating the geothermal steam. These are as follows:

1. Gas availability

   The long-term availability of the gas needed for the project (22 plants) could only be assured through a long-term contract(s) with the supplier(s). It is not certain that the supplier(s) would be willing to make a long-term committment and that the terms of the contracts would assure an economic advantage of superheating over the plant's life.

2. Susceptibility to Corrosion

   The superheater tubes can be protected (have been in the past) against corrosive effects of H_2S at 900°F through vapor deposition of aluminum (alonizing process). However, the success of alonizing the turbine blades without dimensional distortion has not been fully demonstrated.

3. Availability of the Water Resources

   Although the median of Annual Mean Discharge of the Geysers area watersheds is about 300,000 acre-feet of which 10,000 to 40,000 acre-feet would be required to support the superheating concept and to maintain the steam resources, it is not certain that there would be no opposition to dam or reservoir construction to prevent the timely development of these resources or to preclude such development altogether. (To date, no significant opposition to construction of a dam on the Big Sulfur Creek has come forth.)

RECOMMENDATIONS

1. Should economic conditions develop to justify the superheating of the geothermal steam, the industry should be prepared to take advantage of the situation and deploy superheater-enhanced geothermal power plants. To this end, it is recommended that the California Energy Commission, the power producers, the Electric Power Research Insitute (EPRI) and the steam suppliers sponsor a research and a subscale experiment designed to:

   a. Determine if in spite of small (0.006-0.1 percent) H_2S content in the geothermal steam, a treatment of exposed surfaced at 900°F is required to prevent an increase in corrosion.

   b. Develop a process for corrosion prevention of the turbine blades, if required.

2. Considering that the hot water dominated geothermal resources in California are much more extensive than the dry steam resources, the California Energy Commission's staff should evaluate the merits of superheating the geothermal fluid from the hot water dominated resources.

I. INTRODUCTION

The utilities' resource plans show that the development of the Geysers-Calistoga Known Geothermal Resource Area (KGRA) for generation of the geothermal power will continue.

While there are other opportunities for improvement of natural gas use efficiency including repowering of the existing oil or gas-fired units, this study is devoted expressly to the question of whether the use of natural gas for superheating the steam in the planned, new geothermal power plants is justifiable.

It is not proposed that in order to implement the superheating concept in the geothermal power plants the use of gas be increased over and above its current use for production of power in the generation system. What this study suggests is a substitution of oil or gas use in currently operated (or future) less efficient or troublesome facilities. Facilities with 1380 MW total capacity operating in excess of 10,000 Btu/kWh heat rate consume all the fuel that would be required for superheating the steam needed for 22 reference 65 MW geothermal plants and thereby increase the annual power production at the Geysers-Calistoga KGRA by 2077 MW, raising the total to 3514 MW.

This study presents an economic and technical evaluation of two concepts for generation enhancement of geothermal power plants at the Geysers-Calistoga Known Geothermal Resource Area (Geysers KGRA) by comparing them to a 65 megawatt (MW) (net) Sacramento Municipal Utility District (SMUD) model geothermal power plant.

The study was prompted by two primary considerations:

(1) The low energy content in the geothermal steam in the Geysers-Calistoga KGRA requires a relatively large amount of steam to produce a unit of electricity. If the energy level (temperature) of the geothermal steam were raised, the electricity output could be significantly increased. A direct gas-fired superheater would satisfy this objective.

(2) The heat recovery from a gas turbine exhaust to generate steam from water in a typical combined cycle increases the power generation efficiency by about 35 percent. At the Geysers where steam is already available, approximately 930 British thermal units (Btu) per each pound of steam used could be saved by avoiding the need to provide the latent heat of vaporization. Thus, applying the "combined-cycle" concept to the geothermal steam at the Geysers should prove even more effective.

This study provides analyses of the degree of generation enhancement which may be attainable and the cost of electricity production from either concepts.

II. SCOPE

The scope of the study is limited to the comparison of the merits of two geothermal plant generation enhancement concepts (direct-fired super heater and recovery of heat from a gas turbine exhaust) to a 65 MW (net) reference geothermal power plant. The 65 MW plant was chosen as a reference because the cost of this unit was available, whereas the cost data needed for a similar comparative study related to a 110 MW geothermal power plant is currently not available. The consideration of fuel to be used as a source of heat was limited to natural clean-burning pipeline gas. The logistics associated with delivery of fuels such as coal, petroleum, coke, or biomass and environmental considerations, air quality in particular, placed these fuels in a second choice category and, therefore, were not evaluated.

The analysis of the cost of electricity production was made on the geothermal steam purchase basis of $/1000 lb because the generation enhancement would have no effect on the steam price. If the steam is purchased on the basis of ¢/kilowatt-hour (kWh) generated, the generation enhancement would introduce a variable (the effect of) which is not known at this time. Therefore, the effect of steam purchase on the ¢/kWh basis was excluded from the analysis.

III. SUPERHEATING GEOTHERMAL STEAM AT THE GEYSERS

A. Background

The boiler drums in fossil-fueled power plants generate steam at the temperature and pressure of the boiling water, at the so-called saturation condition. The earliest steam turbines expanded the saturated steam directly from the boiler. As the saturated steam expanded to lower pressures through successive turbine stages, a significant fraction of the steam condensed to water, creating blade wear, lowering efficiency and limiting the work obtained from a pound of entering steam.

As steam power plant technology evolved, it was determined that if the temperature of saturated steam were raised before expanding the steam through the turbine, condensation was avoided, efficiency improved and the work obtained was greatly increased. This process is referred to as steam superheating and is used in every modern fossil fueled steam power plant.

Typically, modern boilers operate at 2400 pound per square inch (psi) and superheat the 662°F saturated steam to 1,000°F or higher. Material stress limits usually set the maximum attainable temperature.

The geothermal steam found in the Geysers area typically produces turbine throttle pressure of 115 psi and temperature of 348°F. The geothermal steam is 10 degrees above the saturation temperature (boiling point at that pressure), i.e., the steam is "dry" and naturally superheated 10°F.

The Geysers area geothermal steam is relatively pure and typically contains only 0.4 percent non condensible gases, 82 percent of which is carbon dioxide, 5 percent is hydrogen sulfide, 4 percent is ammonia, and the remaining 9 percent is made up of light hydrocarbons. These gases are all thermally stable at elevated temperatures, i.e., <1,000°F. For practical purposes, the Geysers area steam should behave thermodynamically as does the pure steam produced in fossil fueled boilers.

B. Thermodynamic Effect of Superheating Geothermal Steam

The analysis, as shown in Appendix A, determines how much additional electrical generation can be obtained from a typical advanced design Geysers area plant by superheating the geothermal steam to 900°F. In addition, a determination is made of how much fossil fuel must be supplied to affect the superheating and how much of the additional energy contained in the exhaust must be continuously removed from the plant (see Appendix A).

1. Reference Geothermal Steam Plant*

The most efficient Geysers area geothermal steam power plant yet proposed achieved commercial operation status in December 1983. This plant, the SMUDGEO #1 unit, will be used as a reference in a cost and performance comparison with a plant utilizing superheated geothermal steam. The reference plant, using geothermal steam, and the enhanced geothermal

*See Appendix D, page 3.

plant, using superheated geothermal steam, would each have the steam related characteristics listed in Table 1.

TABLE 1

Steam-related Characteristics
of Reference and Enhanced Plants

	Reference Plant	vs.	Enhanced Plant
Throttle Steam Flow[a]	946,200 lbs/hr		946,200 lbs/hr
Steam Pressure[b]	115 psia		110 psia
Steam Temperature[b]	348°F		900°F
Steam Turbine Efficiency	83.4%		90%
Steam Turbine Back Pressure	1 1/2" Hg		1 1/2" Hg
Steam Turbine Type[c]	4F-TC-25" LSB[d]		4F-TC-25" LSB[d]
Steam Condensation	16%		2%
Steam Condenser Duty	824 Million (MM)Btu/hr		960 MMBtu/hr

a. Excludes 36,800 lbs/hr of ejector motive steam.
b. Turbine inlet.
c. Not the same first stages blades.
d. LSB - last stage blade.

2. Net Power Generation Increase by Superheating

The detailed thermodynamic analysis, shown in the Appendix A, establishes that heating the geothermal steam to 900°F will increase the energy content of the geothermal steam by 23.81 percent. The net plant power generation of the reference plant is increased 56.97 percent (see Appendix A, page A-5). Thus, the output of the reference plant geothermal steam turbine will increase from 65 MW (net) to 102 MW (net).

3. Fossil Energy Conversion Efficiency

The thermodynamic analysis shows that 46.80 percent of the fossil energy added to the reference geothermal steam plant is converted to net plant electricity (Appendix A, page A-5). The heat rejection requirement, i.e., plant cooling, is increased 15.93 percent (Appendix A, page A-7).

This indicates that while in the reference plant 84 percent of the condensate is evaporated through the cooling towers, an enhanced plant would sustain 100 percent of evaporative losses. As a result, there would be no water available for cooling tower blowdown or reinjection into the steam field. A make-up water would have to be provided. There are water resources in the Geysers-Calistoga KGRA (Ref. 1). A construction of a dam on the Big Sulfur Creek is currently under study by Union Oil to create a reservoir from which water could be drawn to increase the injection rates into Union's steam field. Other water resources such as Dry, Putah and Kelsey creeks could be developed as needed.

C. Engineering Options for Superheating

This analysis, as shown in Appendix B, compares the costs and benefits of different methods of superheating the geothermal steam.

1. Direct-fired Superheater

The geothermal steam can be heated from 348°F to 900°F by employing conventional tubular heat exchange equipment. A conventional air preheater would reduce stack losses to about 10 percent of the fossil fuel input. The geothermal steam would lose approximately 5 psi in pressure in passing through the superheater.

The geothermal steam superheater has several unique advantages. Unlike a heat recovery steam generator, the superheater has no thermal pinch point, i.e., a limiting temperature approach between the flowing hot gas and the boiling fluid. The geothermal steam increases steadily in temperature from 348°F to 900°F while flowing counter-current to the hot combustion gases which are cooling from 1000°F to about 400°F. The superheater requires no steam drum, deaerator, or makeup water system, and has essentially no controls and no moving parts. The hot gas side of the superheater tubes would be exposed to environment encountered in any gas-fired steam boiler. The inside of the tube walls would be in contact with geothermal steam flowing at 348°F at the inlet and exiting at 900°F. Whether or not the hydrogen sulfide content which may range from a low of 0.006 percent to a high of 0.1 percent would cause an increase in the corrosion rates is debatable (no data). However, in order to protect the superheater tubes from erosion, corrosion and scale formation on the tubes' outer surfaces, the tubes should be aluminized by vapor diffusion process. This process has been developed and perfected with wide applications over the last 20 years, the latest of which was the Texaco gasifier of the Cool Water Project. Industry users (Standard Oil of Indiana) believe that "at temperatures in the 1,800°F range, aluminizing will protect metals up to 100,000 hours." At 1,000°F, the tube life should be even longer. Tube failure due to metal fatigue would be the more likely cause of plant outage. On this basis, the staff believes that there would be no significant reduction of the plant reliability.

The $600,000 (ALON quotation) cost of aluminizing is included in the cost of the superheaters subject to this study.

Figure 1 shows a comparison of performance and cost of the reference geothermal plant with the direct fired superheater plant.

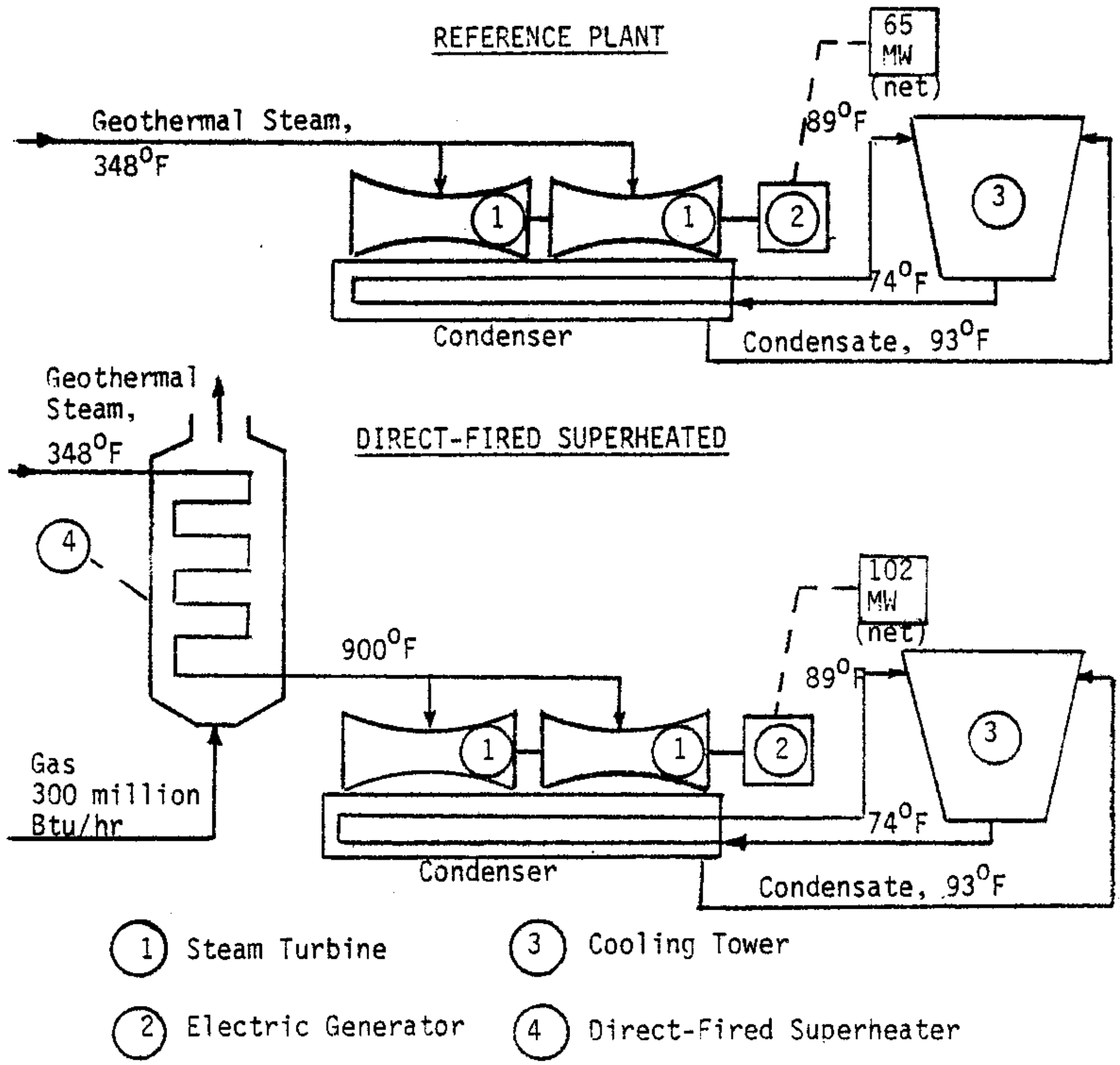
2. Gas Turbine Exhaust for Superheating

A gas turbine (GT) converts fossil energy to work at a temperature of about 2,000°F and exhausts the combustion gas at about 1,000°F. Thus, the gas turbine exhaust can, by counter current flow, transfer its higher (temperature) energy to the geothermal steam and thereby raise its temperature from 348°F to 900°F.

The thermal efficiency of gas turbines is undergoing rapid improvement. The 10-year old gas turbines now in the United States electric utility service are about 31 percent efficient (GT-31). Gas turbines of 36 percent efficiency have been in United States pipeline service for 8 years. One of the most efficient (38 percent) gas turbines for power generation service was expected to be in commercial cogeneration operation

FIGURE 1

Comparison of Reference Geothermal Plant to Direct-Fired Superheated Plant



	Reference Plant	Direct-Fired Superheater Plant
Steam Throttle Flow, M lbs/hr	946.2	946.2
Steam Temperature, °F	348	900
Steam Pressure, psia	115	110
Steam Turbine, Unenhanced, MW	65	65
Steam Turbine Enhancement, MW	-	37
Net Plant Output, MW	65	102
Fuel Use, MM Btu/hr	-	300
Fuel Use Efficiency, %	-	42.1
Condenser Duty, MM Btu/hr	824	960
Capital Investment, MM $ (1983)	92.3	114
Capital Investment/kW, $ (1983)	1420	1120

in June 1983 at Andersen, California. Some 4,000 of these same machines are now in nonutility service worldwide. Contracts have recently been signed by the gas turbine manufacturers with nonutility customers guaranteeing 1985 delivery of gas turbines which are 10 percent more efficient than the best (32 percent) now available which indicates that the 42 percent efficiency turbine for utility service can be expected to be available in the near future. Both the existing gas turbine (GT-31) and this advanced gas turbine (GT-42) are analyzed.

It can be seen from the detailed analysis in Appendix B that depending on gas turbine efficiency, 0.65 to 0.40 kilowatt (kW) enhancement can be obtained from the exhaust of the gas turbine per kW of gas turbine output. Using (conceptually) the 31 percent efficient gas turbine (GT-31) to provide the exhaust superheating, a comparison of performance and investment is shown in Figure 2. The gas turbine-superheater equipment arrangement is shown in Figure 3.

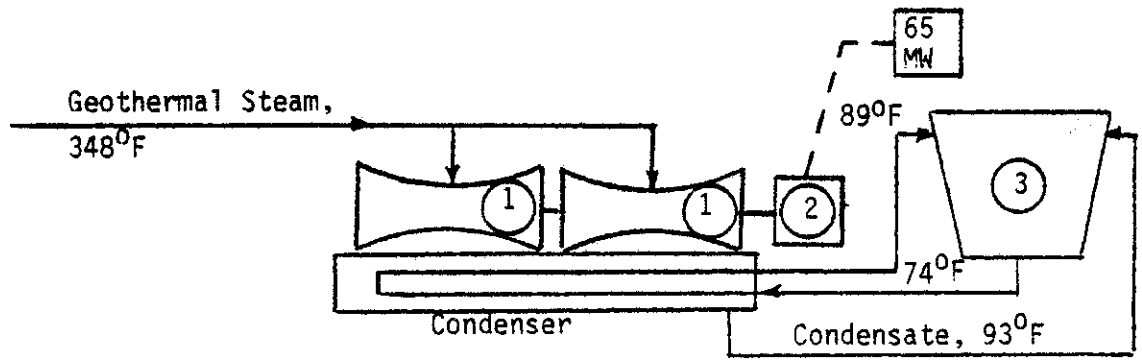
3. Waste Heat Recovery

Using the gas turbine exhaust to superheat the geothermal steam which enters the superheater at a steam temperature of 348°F means that, to have efficient heat transfer, the gas turbine exhaust gas leaving the superheater is 50°F to 100°F higher than 348°F. A bottoming cycle, i.e., recovering and converting the 400°F to 450°F superheater exhaust energy could generate 0.07 kW per kW of gas turbine output, or 4 MW of additional power (Appendix B, page B-13).

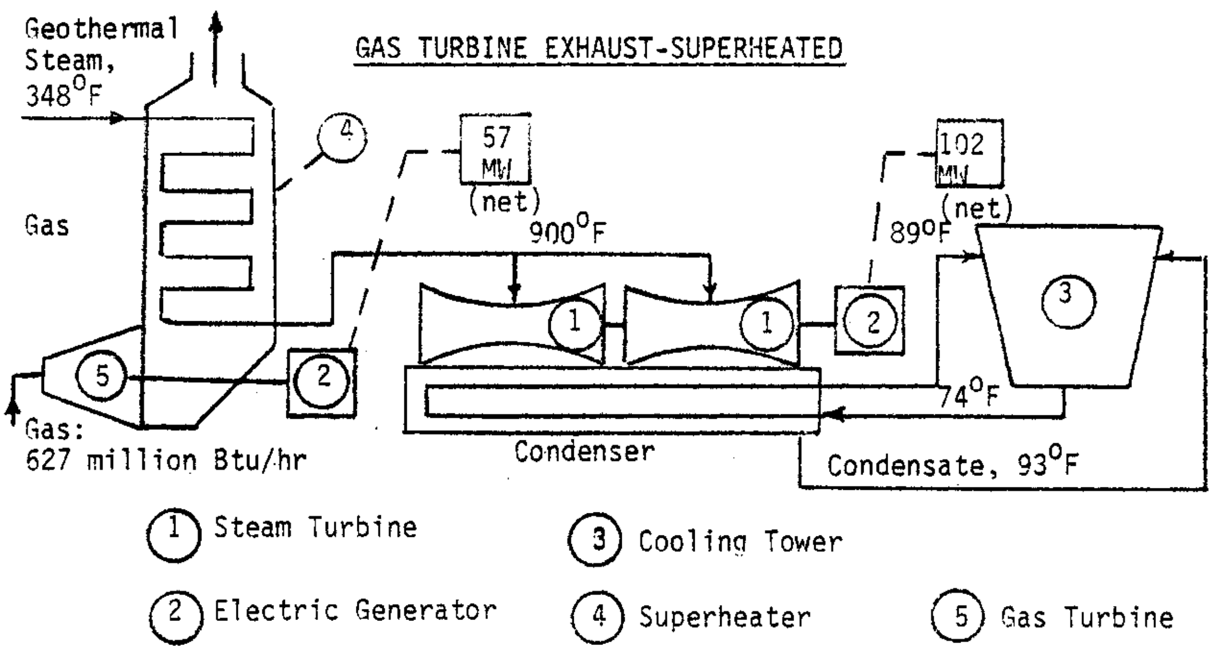
FIGURE 2

Comparison of Reference Geothermal Plant to
Turbine Exhaust-Superheated Plant

REFERENCE PLANT



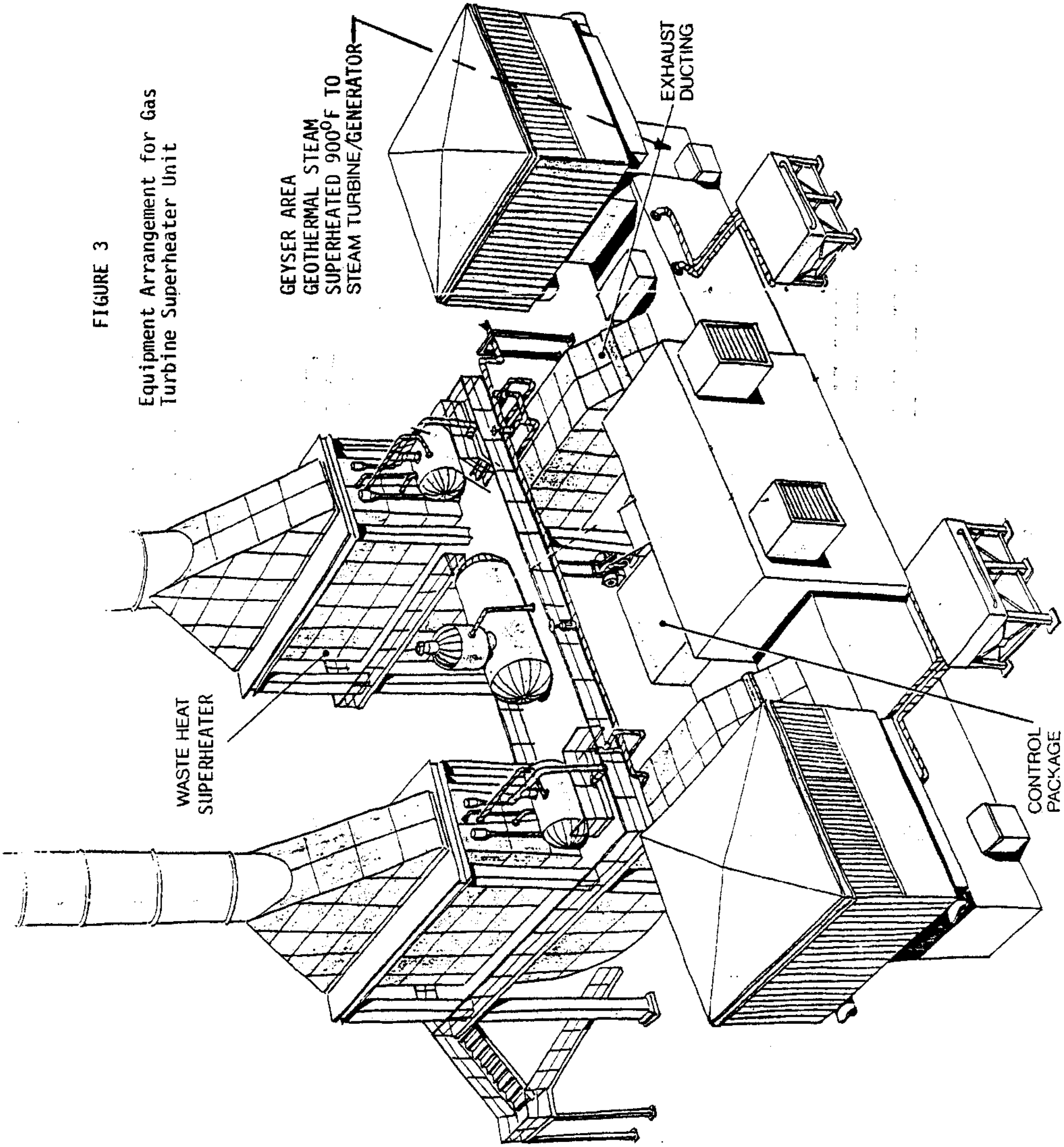
GAS TURBINE EXHAUST-SUPERHEATED



	Reference Plant	Gas Turbine Exhaust Enhanced Plant
Steam Throttle Flow, Mlbs/hr	946.2	946.2
Steam Temperature, °F	348	900
Steam Pressure, psia	115	110
Steam Turbine Unenhanced, MW	65	-
Steam Turbine Enhanced, MW	-	102
Gas Turbine Output	-	57
Net Plant Output, MW	65	159
Fuel Use, MM Btu/hr	-	627
Fuel Use Efficiency, %	-	51.2
Condenser Duty, MM Btu/hr	824	960
Capital Investment, MM $ (1983)	92.3	131
Capital Investment/kW, $ (1983)	1420	824

FIGURE 3

Equipment Arrangement for Gas Turbine Superheater Unit



Shown is the gas turbine-waste heat superheater package. The gas turbine exhaust heat will superheat about one million pounds per hour of Geyser area geothermal steam from 348°F to 900°F. The currently available gas turbines will generate 57 MW. Advanced gas turbines (> 1988) will generate 93 MW, fueled with either low-, medium-, or high-Btu fossil fuel.

Source: Rolls-Royce, Inc.

The capital investment would be about $1,000/kw (Appendix C, page C-3).

Alternatively, the exhaust heat could be recovered in a low pressure waste heat boiler and generate the require air ejector motive steam, (Appendix B, page B-10) if the necessary water resources were developed.

The exhaust heat could also be used in a waste heat boiler to generate induction steam, i.e., low-pressure steam inducted into the low-pressure turbine stages to produce additional generation.

The above schemes require increased heat rejection and a significant negative water balance of about 10 percent (Appendix B, page B-13), and are perhaps not viable. Because of water unavailability, the bottoming cycle is not included.

D. Combined-Cycle Comparison

This section provides a comparison of the relative power generation effectiveness between a fossil-fueled gas turbine used to superheat the geothermal steam with the use of the same gas turbine in a conventional combined cycle power plant.

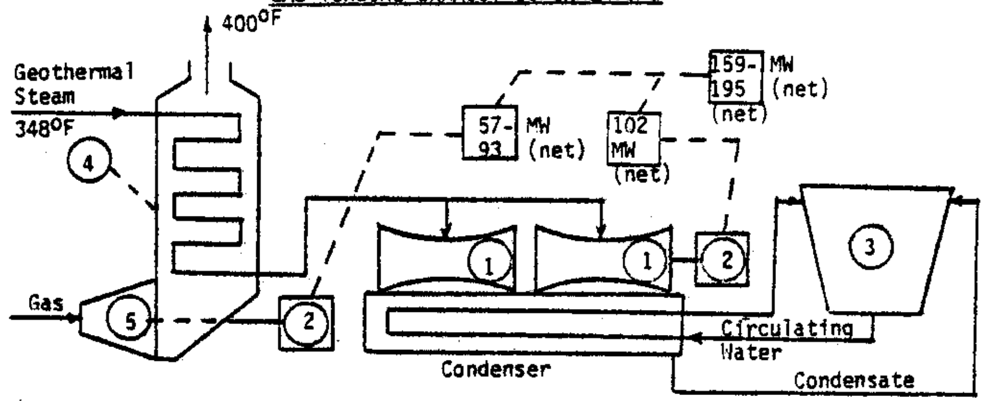
1. Conventional Combined Cycle Power Plant

The 57 MW, 31 percent efficient gas turbine (GT-31) used to superheat the reference geothermal steam flow could exhaust into a multipressure waste heat boiler and generate 26 MW in a steam turbine. The investment and performance comparison is shown in Figure 4.

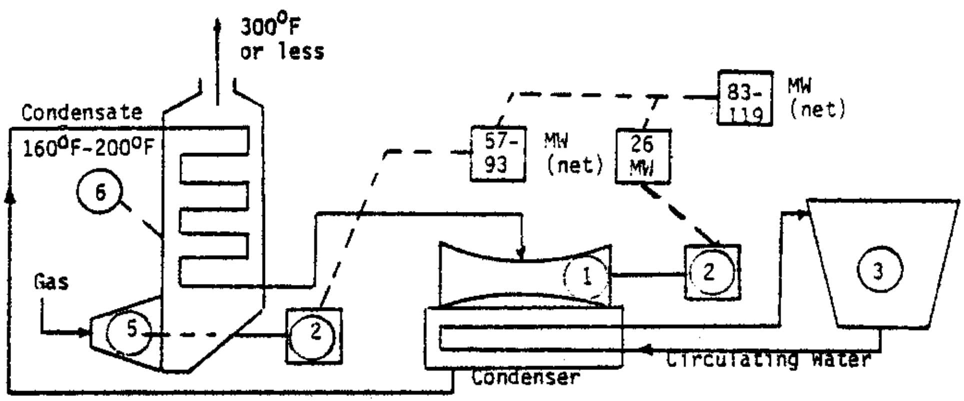
FIGURE 4

Comparison of Superheater-Enhanced Geothermal
to Combined-Cycle Power Plants

GAS TURBINE EXHAUST SUPERHEATING



COMBINED-CYCLE POWER PLANT



(1) Steam Turbine

(2) Electric Generator

(3) Cooling Tower

(4) Superheater

(5) Gas Turbine

(6) Heat Recovery Steam Generator

	Enhanced GT-31 Exhaust	Combined-Cycle GT-31	Enhanced GT-42 Exhaust	Combined-Cycle GT-42
Steam Throttle Flow, M lbs/hr	946	190	946	190
Steam Temperature, °F	900	910	900	910
Steam Pressure, psia	110	865	110	865
Steam Turbine, Unenhanced, MW	65	26	65	26
Steam Turbine, Enhanced, MW	102	-	102	-
Gas Turbine Output, MW	57	57	93	93
Net Plant Output, MW	159	83	195	119
Fuel Use, MM Btu/hr	627	627	756	756
Fuel Use Efficiency, %	51.2	45.2	58.7	53.7
Condenser Duty MM Btu/hr	960	208	960	208
Plant Cost, MM $(1983)	131	60.6	162	91.8
Installed Cost, $/kW (1983)	824	730	831	771

2. Advanced Power Plant

An advanced, 42 percent efficient (GT-42) combined-cycle gas turbine (1985 delivery projected) used to superheat the reference geothermal steam flow would generate the same 26 MW (as the GT-31 exhaust) from the same multipressure boiler and same steam turbine. However, the GT-42 would generate 93 MW from its operation. A performance and investment comparison is shown in Figure 4.

E. Differential Cost Estimate

This study was aided by the availability of utility capital and operating cost data from the most recent Geysers area geothermal steam power plants applications for certification (AFC).

A well-documented series of studies have been produced (see References) which show a significant thermodynamic advantage for incorporating fossil fuel in a geothermal steam plant. However, to date, no such plant has been built and the CEC staff has not come across any cost estimates of such units. The availability of well defined cost and performance of a Geysers area geothermal plant together with the rapid evolution in gas turbine technology has created an opportunity to evaluate and compare for the first time this form of power generation with other options.

A comparison of the required capital investments and generation costs of superheating enhancement and other generation options can be made on the basis of the first year on-line operation. Making an assumption that such plants would be constructed and "on-line" in 1983 allows the staff to use the latest capital and fuels cost data in making the comparative analyses without speculating as to what the future may hold in terms of inflation, escalation of prices and discount rates (cost of money). Admittedly, at the earliest, the superheating concepts could be incorporated into the geothermal power plants is in the year 1989, and some assumptions related to various economic parameters have to be made.

Because of the confidence in the current cost data and the need to identify the magnitude of advantage or financial risk to the utilities and the rate payer, both the 1983 first year and 1989 levelized cost comparisons are presented in this section.

One of the factors which highly influences the advantage/disadvantage of superheating the geothermal steam is the relationship between the price of steam and the price of natural gas. The higher the steam price (or the lower the gas price), the higher is the potential for reduction of power generation cost by superheating the geothermal steam. In 1983, PGandE paid for the steam about 32 mills/kWh produced, an equivalent to $1.77 per 1,000 lbs of steam compared with $1.37/1000 lb and $1.09/1000 lb paid by SMUD and the Northern California Power Agency (NCPA), respectively. Therefore, it would appear that PGandE stands to benefit more from superheating the geothermal steam than the other two utilities. However, because PGandE pays for the steam on the basis of mills/kWh produced, it is not certain if and how its contract with the steam supplier could be modified in order to avoid the potential savings to be offset by paying for the increase in energy output which is attributable to the use of gas rather than steam.

Without appropriate steam purchase contract modifications, had PGandE had in 1983 a 65 MW reference plant, it would pay for the superheated steam $22 million more than it would without superheating, and the cost of electricity would be 73 mills/kWh compared with 65.5 mills/kWh generation cost without superheating, or 54 mills/kWh with superheating if no "premium" would need to be paid for the increase in energy output.

Because of the uncertainty whether or not the PGandE contract could be modified and the clear disadvantage if it could not, the CEC staff used in its analyses $1.37/1000 lbs, the price paid by SMUD -a median within the $1.09 to $1.77 range-not subject to perturbation by an increase in energy output.

1. Elements of Capital Cost

   In developing cost comparisons for various options presented in Tables 2 and 3, the following cost elements (developed in Appendix C) were used:

   Capital Costs (1983 prices; utility and equipment suppliers data)

   - Unenhanced plant: 65,000 kW at $1,420/kWh

   - Direct-fired superheater enhanced: 102,000 kW at $1,120/kW

- GT-31 gas turbine exhaust enhanced: 159,000 kW at $824/kW

- GT-31 combined cycle: 83,000 kW at $730/kW

- GT-42 gas turbine exhaust enhanced: 195,000 kW at $831/kW

- GT-42 combined cycle: 119,000 kW at $771/kW

2. Energy cost (1983 prices; utility data and staff estimates)

   - Geothermal steam: $1.37/1000 lbs

   - Natural gas: $5.35/million Btu

3. Operation and Maintenance (O&M) Cost (1983 costs, Reference EPRI-AP-2321)

   - Geothermal plant fixed costs--$10/kW installed/yr

   - Geothermal plant variable costs--2.2 mills/kWh

   - Gas turbine plant fixed costs--$4/kW installed/yr

   - Gas turbine plant variable costs--0.2 mills/kWh

   For 1989 levelized O&M cost 4 percent of the plants' capital cost were used which is consistent with the values found in the Application for Certification (AFC) for Geysers Unit 20.

4. Cost of Electricity Production

   Table 2 provides a summary of capital, operation and total first year generation costs for six different plants if all such plants were on line in 1983. Three of these plants are

TABLE 2

Comparison of First Year (1983 Prices) Costs for Unenhanced Geothermal, Enhanced Geothermal and Combined-Cycle Power Plants

	Unenhanced Geothermal Plant	Enhanced Direct-Fired	Enhanced GT-31 Exhaust	Combined Cycle GT-31	Enhanced GT-42 Exhaust	Combined Cycle GT-42
Net Output, MW	65	102	159	83	195	119
Geothermal Steam Flow, 1000 lbs/hr[a]	983	983	983	0	983	0
Fossil Fuel Flow, millions Btu/hr	0	300	627	627	756	756
Annual Generation, millions kWh at 83% Capacity Factor	473	742	1,160	603	1,420	865
Total Capital Costs (1988) millions $	92.3	114	131	60.6	162	91.8
Annual Levelized Costs, millions $/yr (in 1983)						
Capital at 16% Fixed Charge Rates	14.77	18.24	20.96	9.70	25.92	14.69
Steam at $1.37/1000 lbs	9.79	9.79	9.79	0	9.79	0
Fuel at $5.35 per million Btu[b]	0	11.67	24.39	24.39	29.41	29.41
O&M, Variable and Fixed	1.70	1.70	2.00	0.80	2.20	1.00
TOTAL ANNUAL COSTS	26.26	41.40	57.15	34.89	67.32	45.10
Generation Costs, mills/kWh[c]	55.5	55.8	49.3	57.9	47.45	52.1
Differential Costs, mills/kWh	BASE	+0.3	-6.2	+2.4	-7.1	-3.4

a. Includes 36,800 lbs/hr of ejector motive steam.

b. Includes the cost of pipeline of 3.3 ¢/million Btu (see Appendix B, page B-13). The charge will vary between 3.3 ¢/million Btu and 13.5 ¢/million Btu for 22 plants and a single plant, respectively.

c. Does not include transmission line intertie of $40/kW or 1 mill/kWh for each geothermal case considered. The current cost of construction of a 230 kilovolt line is about $1 million per mile.

single energy type plants, and three are hybrid energy plants. All of these plants have been previously described and are shown in Figures 1, 2 and 4.

Table 2 shows that at the known 1983 prices generation enhancement achieved by using the exhaust gas from a combustion turbine to superheat the geothermal steam would result in a lower cost of electricity compared with the cost of electricity produced by either the reference 65 MW geothermal plant or a combined cycle. What the plants' capital costs, interest rates, gas and steam prices may be by 1989, the earliest year when an enhanced geothermal plant could be in service, is much less certain. Rather than speculate and assume a single set of values of these factors, the staff performed comparative analyses over a range of economic conditions which may develop in the future. The entire range of values of the economic parameters used in these analyses is presented in Table 3. Reflecting the current CEC forecast of relevant economic trends identified in this table, a comparison of 1989 generation costs levelized over 30-year plants' life is presented in Table 4. A full representation of generation costs over the entire range of economic parameters would require twenty-four additional tables. For convenience, a summary of the results of the analyses which span the entire range are presented graphically in Figure 5. This figure shows that unless the escalation rates of the gas prices will not be higher than the escalation rates of the geothermal steam prices, generation enhancement

TABLE 3

Economic Parameters for 1989 Levelized Cost
of Electricity Production Estimates

1.	General Inflation, Annual Rate (percent)	4.5	6.5*	7.5	8.5	9.5
2.	Discount Rate (percent)	10.2	13.0*	14.5	16.0	17.4
3.	Fixed Charge Rate (percent)	12.7	15.5*	17.0	18.5	19.9
4.	Plant Cost and Steam Annual Escalation Rates (percent)	4.5	6.5	7.5	8.5	9.5
5.	Steam Price Levelization Factor (L.F.)	1.508	1.705	1.790	1.868	1.946
6.	Gas Price					
	a. Real Escalation Rates (percent)	0	0	0	0	0
	b. L.F.	1.508	1.705	1.790	1.868	1.946
7.	Gas Price					
	a. Real Escalation Rates	0.5	0.5	0.5	0.5	0.5
	b. L.F.	1.588	1.791	1.879	1.955	2.034
8.	Gas Price					
	a. Real Escalation Rates (%)	1.5	1.5	1.5	1.5	1.5
	b. L.F.	1.768	1.982	2.070	2.150	2.213
9.	Gas Price					
	a. Real Escalation Rates (%)	2.5	2.5*	2.5	2.5	2.5
	b. L.F.	1.979	2.204	2.294	2.375	2.457
10.	Gas Price					
	a. Real Escalation Rates (%)	3.5	3.5	3.5	3.5	3.5
	b. L.F.	2.226	2.463	2.554	2.635	2.719

*These values represent the current CEC forecast.

TABLE 4

Comparison of 1989 Levelized Costs for Unenhanced Geothermal, Enhanced Geothermal and Combined-Cycle Plants

	Unenhanced Geothermal Plant	Enhanced Direct-Fired	Enhanced GT-31 Exhaust	Combined Cycle GT-31	Enhanced GT-42 Exhaust	Combined Cycle GT-42
Net Output, MW	65	102	159	83	195	119
Geothermal Steam Flow, 1000 lbs/hr[a]	983	953	983	0	98	0
Fossil Fuel Flow, millions Btu/hr	0	300	627	627	75	756
Annual Generation, millions kWh at 83% Capacity Factor	473	742	1,156	603	1,420	865
Total Capital Costs (1988) millions $	126.5	156.2	179.5	83.0	221.9	125.8
Annual Levelized Costs, millions $/yr						
Capital at 15.5% Fixed Charge Rate 19.61	19.61	24.21	27.82	12.87	3.40	19.59
Steam at $3.2/1000 lb	22.87	22.87	22.87	0	22.87	0
Gas at $18.2 per million Btu[b]	0	39.57	82.70	82.70	99.71	99.71
O&M Variable and Fixed	5.06	6.25	7.18	3.32	8.88	5.03
TOTAL ANNUAL COSTS	47.54	92.90	140.57	98.89	165.86	124.23
Generation Costs, mills/kWh	100.5	125.1	121.6	164.0	116.8	143.6
Differential Costs, mills/kWh	BASE	+24.6	+21.1	+63.5	+16.3	+43.1

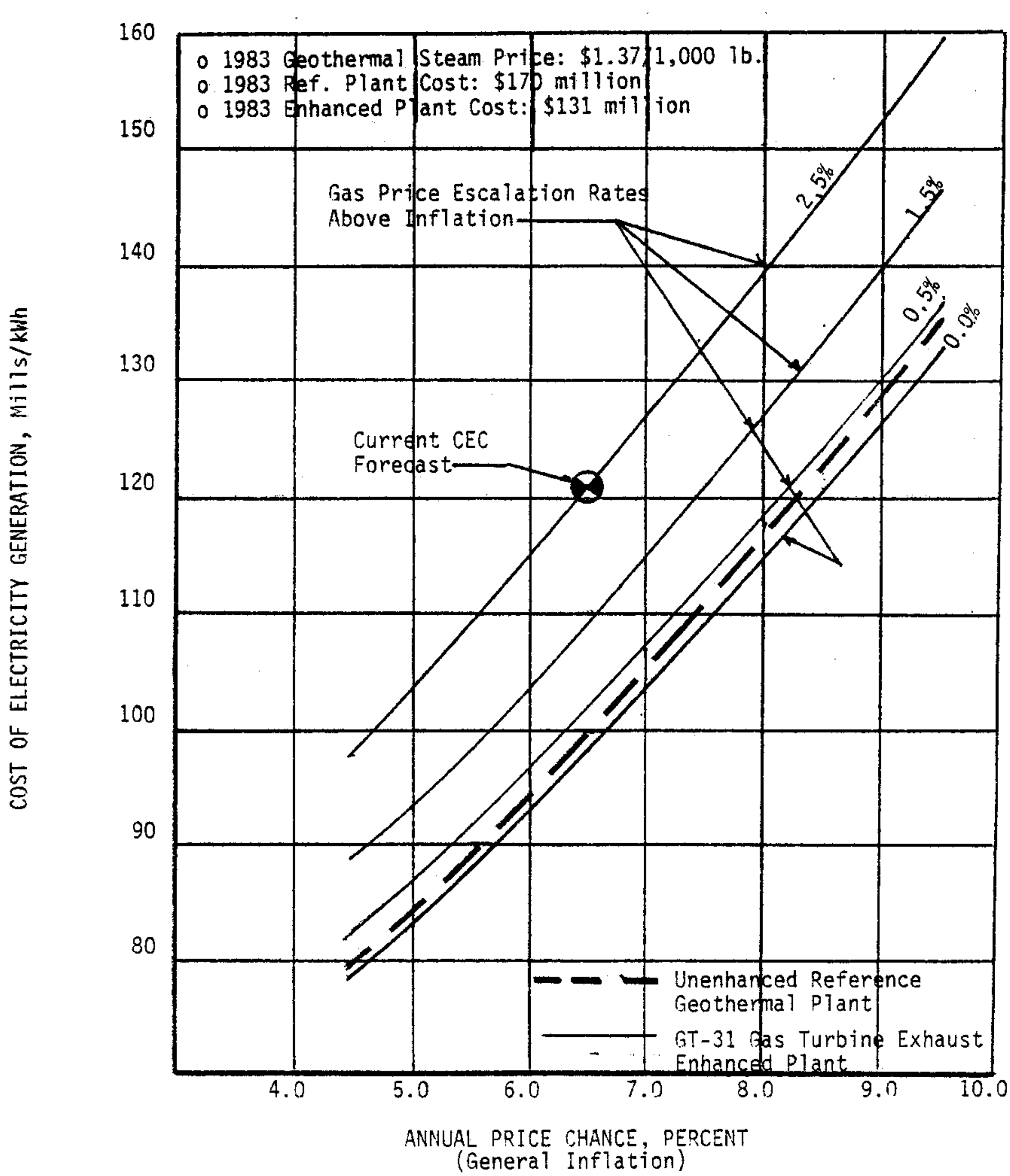
a. Includes 36,800 lbs/hr of ejector motive steam.

b. Includes 1988 cost of pipeline of 8.2 ¢/million Btu.

c. Cost of 230 kilovolt transmission line is not included.

FIGURE 5

30-Year Levelized Cost of Electricity
Production at 1-1-1989 Commercial
Operating Date at Various Rates
of Inflation and Gas Price Escalation Rates



which can be achieved through superheating the geothermal steam offers no economic advantage over an unenhanced geothermal plant. A similar conclusion based on staff analyses applies to a system in which a more efficient GT-42 gas turbine provides the heat for superheating the geothermal steam.

5. Enhanced Geothermal Vs Unenhanced and Combined-Cycle Plants Operated Separately

The merits of a geothermal-enhanced unit were also evaluated against the combined capital and generation costs of separately operated unenhanced geothermal power plants, such as the 65 MW reference plant and a GT-31 combined cycle, each using the same respective amounts of geothermal steam and gas as those required for the operation of a superheater-enhanced plant. Using the CEC forecast of economic trend parameters identified in Table 3 and the information based on these values presented in Table 4, the annual and present worth of the net differences in cost between these two generating modes is shown in Table 5.

A complete comparison of 1989 levelized cost of these two power generation models (superheater-enhanced geothermal plant and an unenhanced geothermal plant/combined-cycle plant, operating separately) covering the entire range of economic conditions is summarized in Figure 6. Examination of this figure shows that integrating the use of gas and geothermal steam into a superheater-enhanced geothermal plant results in lower generating

TABLE 5

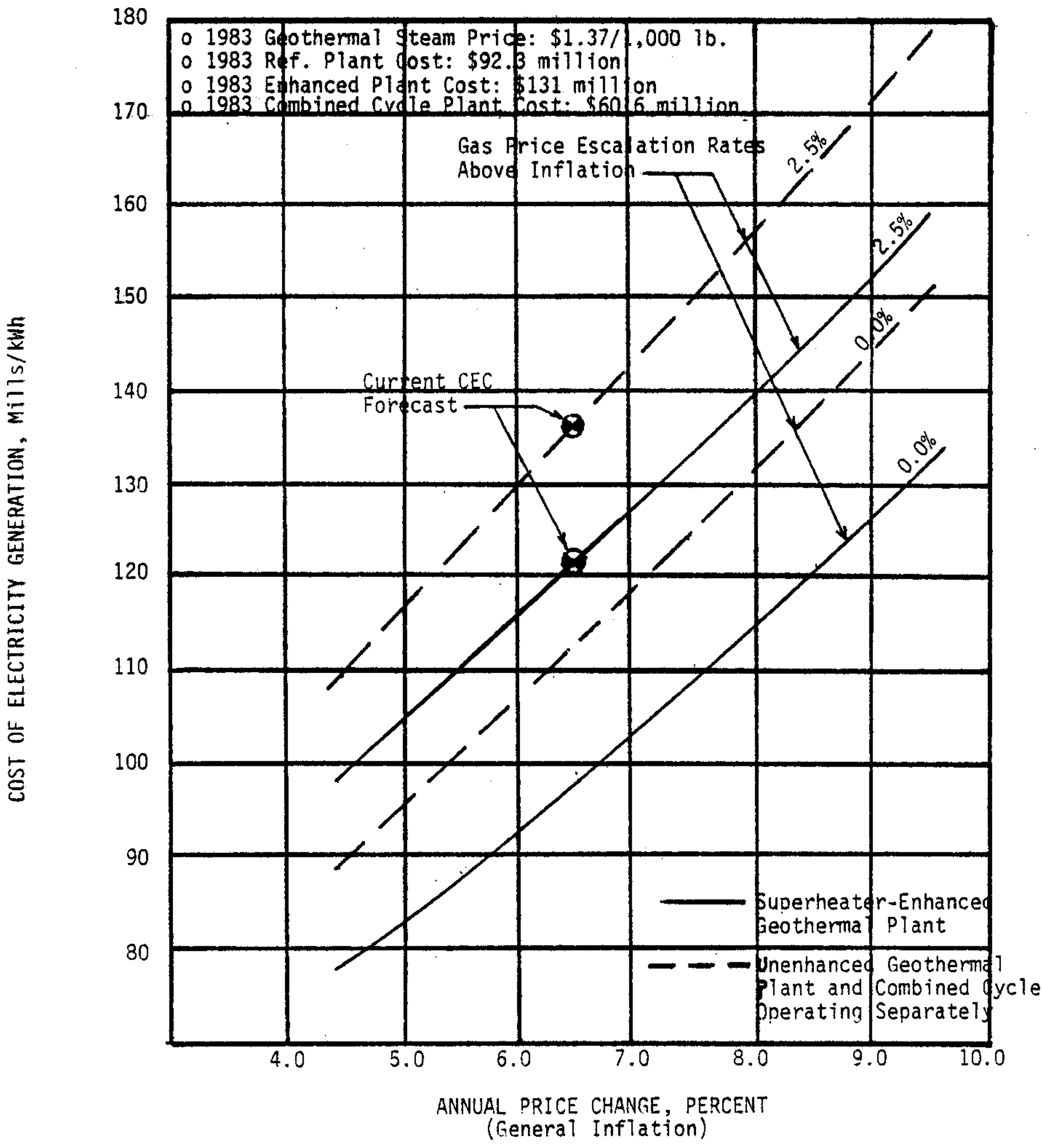
Comparison of Annual Generating Cost of a Superheater-Enhanced Geothermal Plant to Separately Operated Unenhanced Geothermal and Combined-Cycle Plants

	Annual Cost, $ millions	Net Plant Output, Millions kWh/yr and (MW)	Generation Cost, Mills/kWh	Gas Use Millions Btu/hr	Geothermal Steam Use, Thousands lbs/hr
		kWh/yr (MW)			
Reference Geothermal Plant	47.54	473(65)	100.5	0	983
Combined Cycle Plant	98.89	603(83)	164.0	627	0
Two Separate Plants Total	146.43	1,076(148)	136.1	627	983
GT-Enhanced Geothermal Plant	140.5	1,156(159)	121.6	627	983
Differentials	<5.86>	80(11)	14.5	0	0
Annual Worth of 11 MW	1.16				
Total Annual Saving	7.02				
Present Worth*	52.62				

*Present Worth Factor (PWF) = $(1.13^{30} - 1)/.13(1.13)^{30}$ = 7.4956
The Present Worth = PWF x 7.02 million.

FIGURE 6

1989 30-Year Levelized Cost of Electricity Production for a Superheater-Enhanced Geothermal Plant and Unenhanced Geothermal Plant/Combined Cycle Operating Separately



cost than those which would result from a separate use of the Geysers' steam and natural gas in an unenhanced geothermal plant and combined-cycle, respectively. This, however, is true only if (a) the opportunity to combine such separate operations into a superheater-enhanced geothermal plant exists within the utility generation system, and (b) the payments for steam would not increase in proportion to the increase in energy output by the superheater-enhanced geothermal plant.

F. Sensitivity Analyses

As previously stated, the cost information developed thus far was derived from the known 1983 plant's capital costs, gas and geothermal steam prices levelized over a range of discount rates, general inflation and gas price escalation rates.

The very recent (April 1984) industry projections of plant costs indicate that the reference plant which was built in 1983 for $92.3 million may cost $170 million by the end of 1988. If one was to allow a 5 percent general price increase (inflation) in 1984, the rate of inflation over the subsequent 4 years (1985-1988) would have to be 15 percent, which is beyond the range considered by the CEC staff. Likewise, the market forces may have caused the price of geothermal steam to escalate to $1.77 per 1,000 lb. (1983 $). The impact of these extremely high escalation rates on the relationship of the cost of electricity generation by superheater-enhanced and unenhanced power plants (such as the reference plant) is examined in this section. The sensitivity of the cost of electricity generation of each influencing parameter (plant costs and geothermal steam cost), and the combined effects are presented graphically in Figures 7 through 12.

Figure 7 provides a comparison of the cost of electricity for superheater-enhanced and unenhanced plants that would result if the plant cost would increase by 1989 about 84 percent above the 1983 costs. Comparing these values to those displayed in Figure 6 shows that (1) the overall cost of electricity would increase about 10 percent, and (2) the gas prices can escalate about 1 percent above general inflation before the advantage of superheating the geothermal steam by gas turbine exhaust would be lost. At general annual inflation not exceeding 10 percent (Figure 6), no increase in gas prices above general inflation can be tolerated if the advantage of superheating is to be realized.

Figure 8 shows that high plant cost does not alter the conclusion that a separate operation of a combined-cycle plant and an unenhanced geothermal plant (each using the respective quantities of gas and geothermal steam that would be required to operate a superheated-enhanced plant) is more costly than operating a gas turbine exhaust superheater-enhanced geothermal plant.

Figure 9 shows the effect of high geothermal steam prices. A comparison to Figure 6 shows about a 15 percent increase in generation costs and a 1-1.5 percent increase in the tolerance of gas price escalation rates before the advantage of superheating the geothermal steam would be lost.

FIGURE 7

1989, 30-Year Levelized Cost of Electricity Production
for Superheater-Enhanced and Unenhanced
Geothermal Power Plants

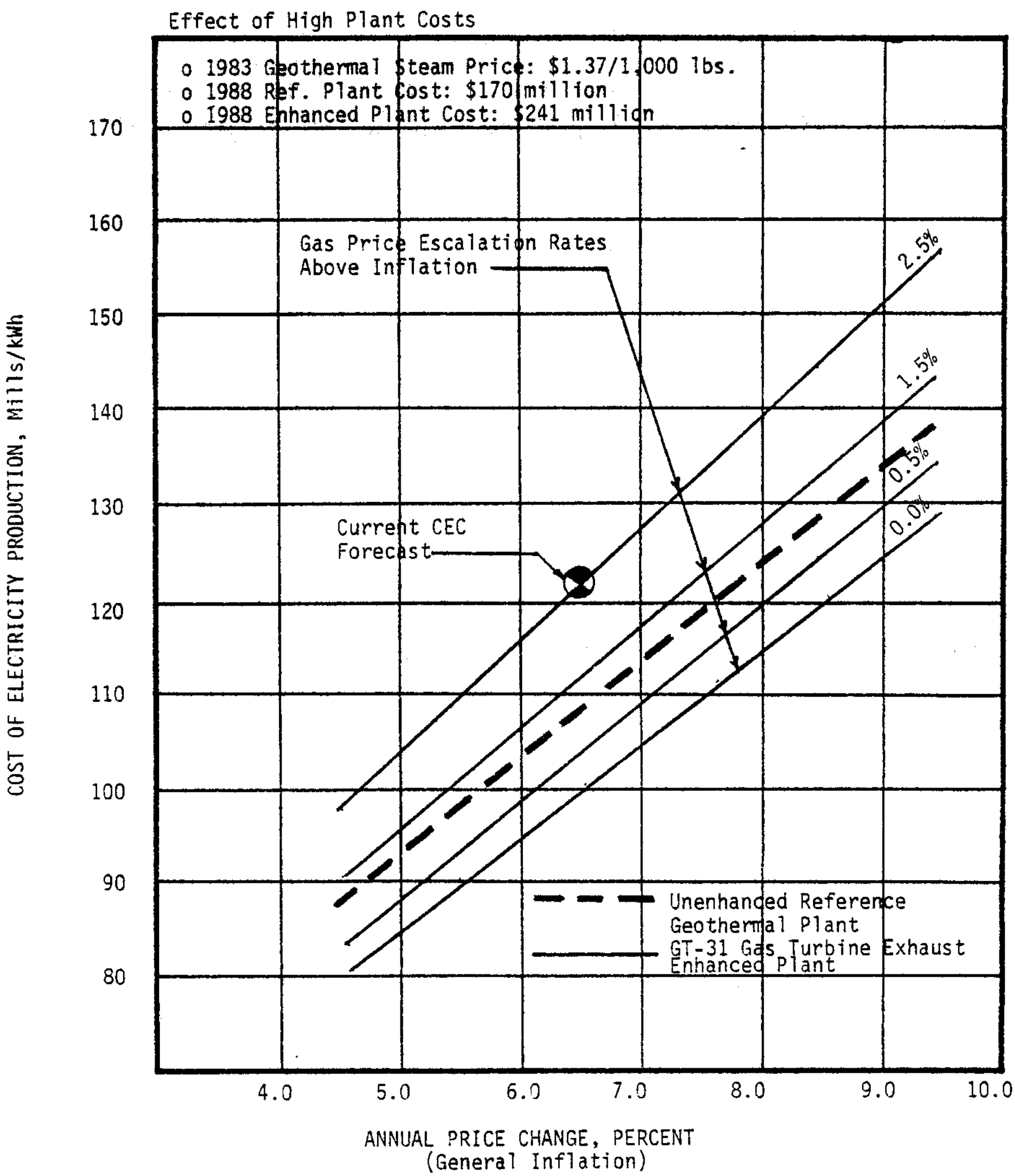
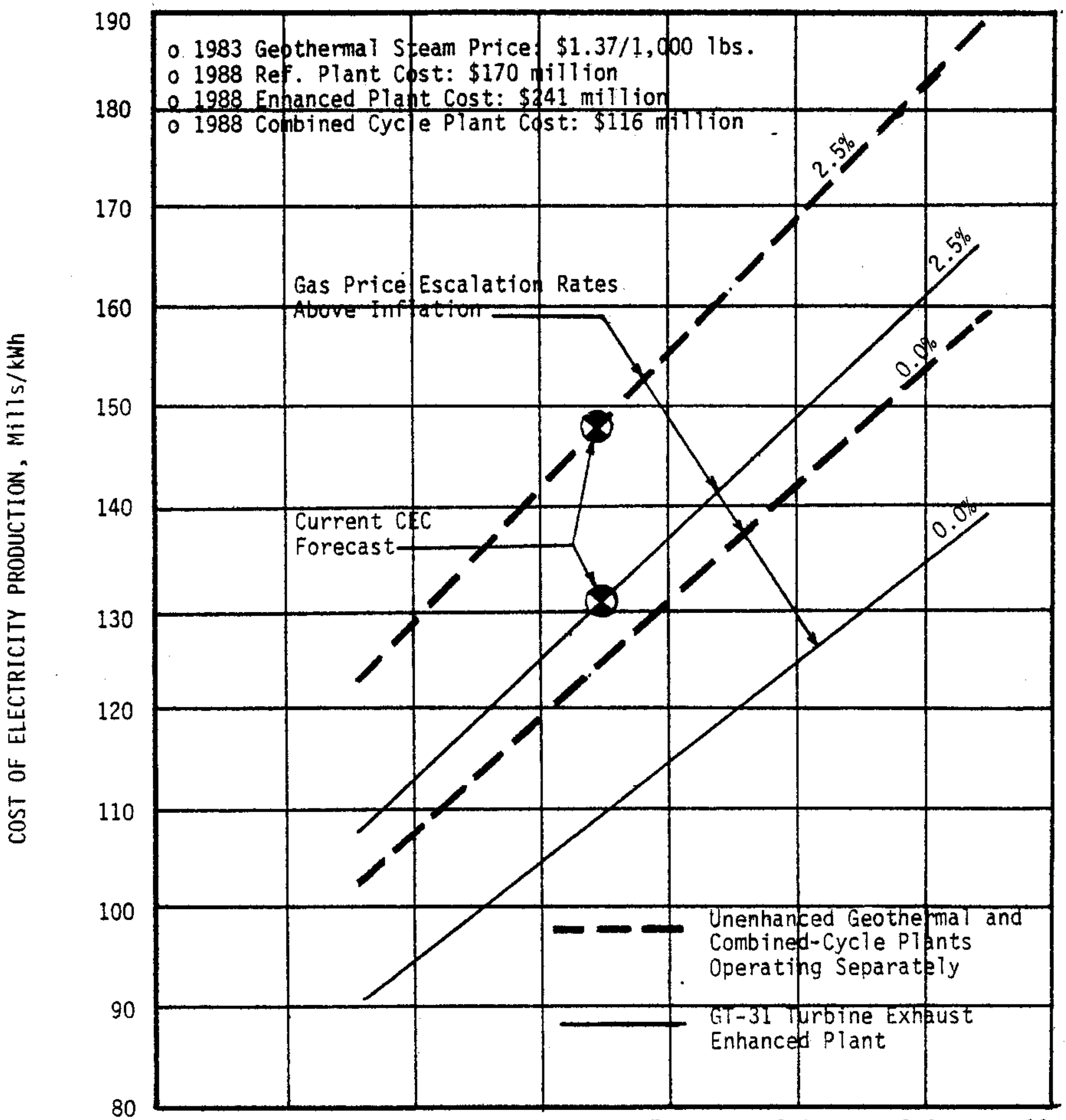


FIGURE 8

1989, 30-Year Levelized Cost of Electricity Production for Superheater-Enhanced Geothermal Power Plant and Unenhanced Geothermal Power Plant with Combined-Cycle Operating Separately

Effect of High Plant Costs



ANNAUL PRICE CHANGE, PERCENT
(General Inflation)

FIGURE 9

1989, 30-Year Levelized Cost of Electricity Production
for Superheater-Enhanced and Unenhanced
Geothermal Power Plants

Effect of High Steam Cost

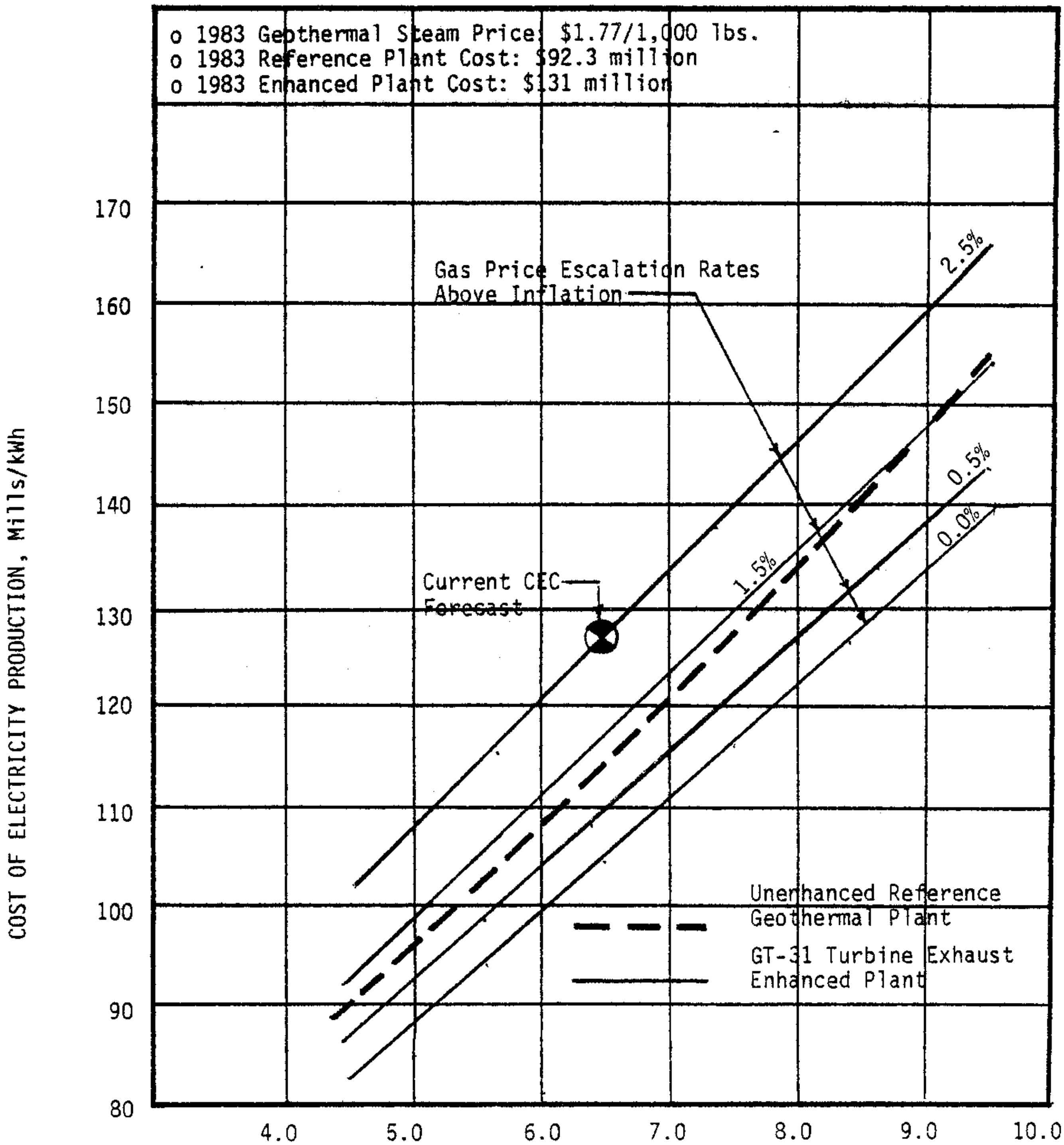


Figure 10 confirms the advantage of superheating the geothermal steam over separate operations of a combined-cycle and an unenhanced geothermal plant.

Figure 11 shows the combined effects of high plant and geothermal steam costs. Under these conditions, the gas prices could escalate about 2 percent over the general annual price increase rates before the superheater-enhanced geothermal system would become noncompetitive.

Figure 12 indicates that the combined effect of high plant costs and high cost of geothermal steam still results in cheaper operation of a superheater-enhanced plant compared with a separate operation of a combined-cycle and an unenhanced geothermal plant.

G. Generation Potential of Geysers Area Resource

The geothermal power plant development history in the Geysers-Calistoga KGRA and CEC projections (Ref. 18) through June 1991 are presented in Table 6.

1. Unenhanced Generation

As of March 1986, approximately 1828 MW of net plant output is projected to be on line in the Geysers area. The current on-line capacity is 1,237 net MW. The additional 591 MWs have been given CEC certification.

A recent CEC assessment (ref. 22) of the remaining Geyser area generation potential shows that, by the year 2002, approximately 3000 MW could be on-line. This assumes that the

FIGURE 10

1989, 30-Year Levelized Cost of Electricity Production
for Superheater-Enhanced Geothermal Power
Plant and Unenhanced Geothermal Plant with
Combined-Cycle Operating Separately

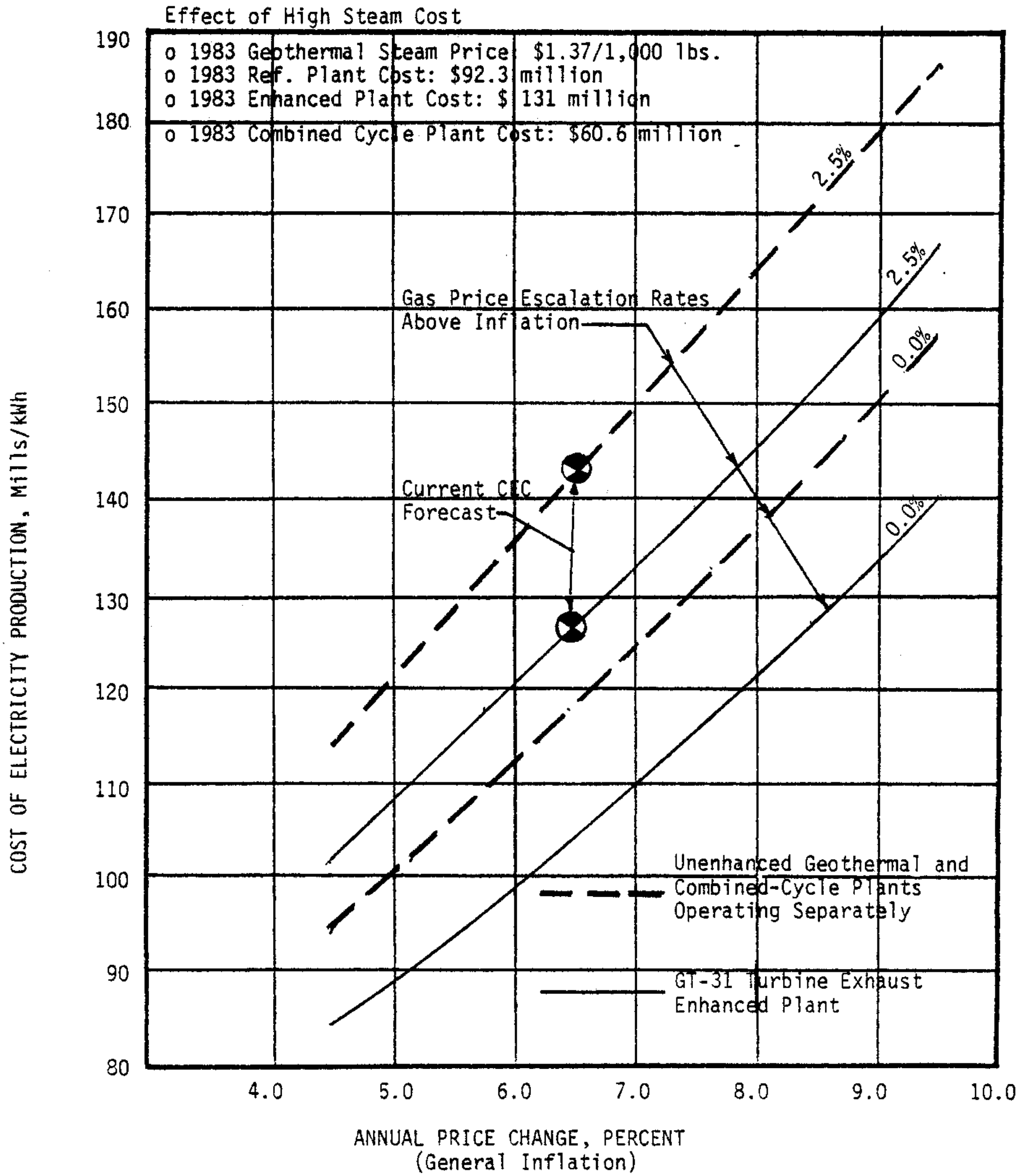


FIGURE 11

1989, 30-Year Levelized Cost of Electricity Production
for Superheater-Enhanced and Unenhanced
Geothermal Power Plants

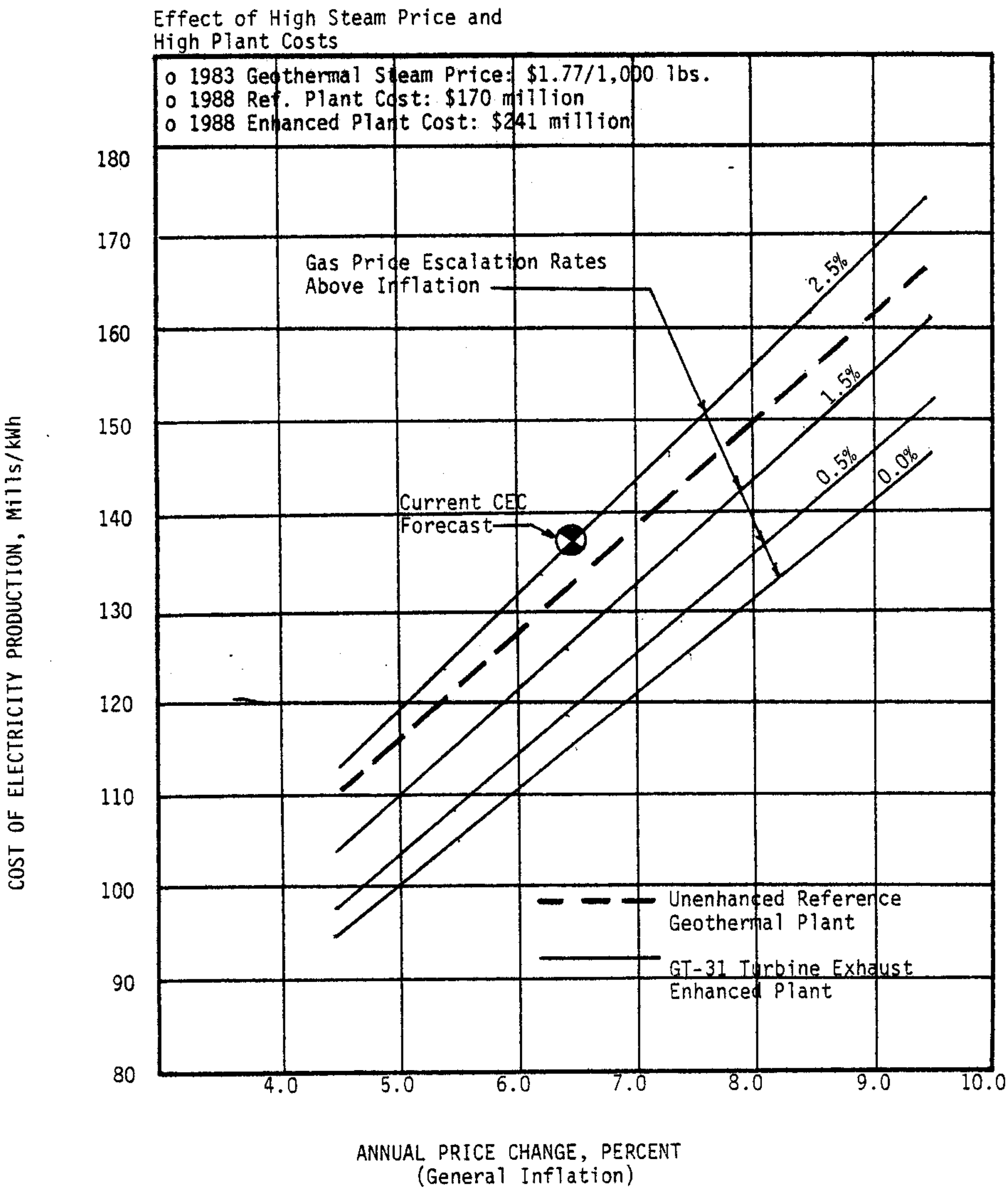


FIGURE 12

1989, 30-Year Levelized Cost of Electricity Production for Superheater-Enhanced Geothermal Power Plant and Unenhanced Geothermal Power Plant with Combined-Cycle Operating Separately

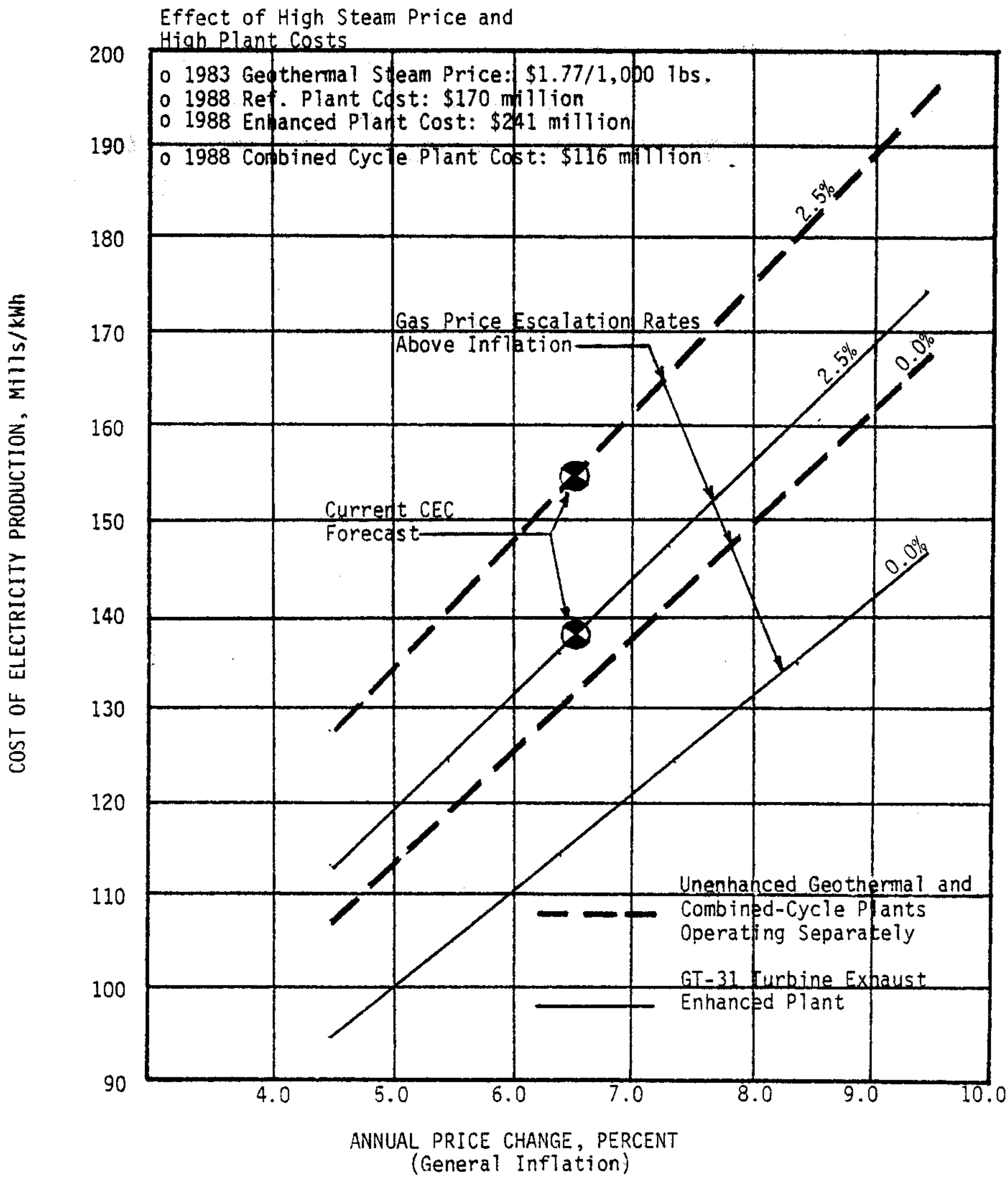


TABLE 6

Power Plant Development in the Geysers KGRA
1960 - 1991

Project	CEC Certification	Estimated On Line Date	County of Location	Gross Capacity (MW)	Net Capacity (MW)	Cumulative Net Output (MW)
PGandE 1	--	1960	Sonoma	12	11	11
PGandE 2	--	1963	Sonoma	14	13	24
PGandE 3	--	1967	Sonoma	28	27	51
PGandE 4	--	1968	Sonoma	28	27	78
PGandE 5	--	1971	Sonoma	55	53	131
PGandE 6	--	1971	Sonoma	55	53	184
PGandE 7	--	1972	Sonoma	55	53	237
PGandE 8	--	1972	Sonoma	55	53	290
PGandE 9	--	1973	Sonoma	55	53	343
PGandE 10	--	1973	Sonoma	55	53	396
PGandE 11	--	1975	Sonoma	110	106	502
PGandE 12	--	1979	Sonoma	110	106	608
PGandE 15	--	1979	Sonoma	62	59	667
PGandE 13	--	1980	Lake	138	133	802
PGandE 14	--	1980	Sonoma	114	109	911
NCPA 2	4/80	12/82	Sonoma	110	106	1,017
PGandE 17	9/79	12/82	Sonoma	120	110	1,127
PGandE 18	5/80	5/83	Sonoma	120	110	1,237
SMUDGEO #1[a]	3/81	12/83	Sonoma	72	65	1,302
DWR Bottle Rock	11/80	6/84	Lake	55	52	1,354
Occidental #1	1/81	6/84	Lake	97	80	1,434
Magma Wild Well	--	1984	Sonoma	5	5	1,439
PGandE 16	9/81	6/85	Lake	120	113	1,552
NCPA 3	12/82	8/85	Sonoma	110	106	1,658
MSR #1	--	1985	Sonoma	5	5	1,663
DWR So. Geysers	11/81	2/86	Sonoma	55	52	1,715
PGandE 20	1/83	3/86	Sonoma	120	113	1,828
NCPA 1	-- Shelved	Indefinitely --	Lake	--	--	--
PGandE 19		6/88	Lake	55 (72)	53 (65)	1,881 (1,893)
PGandE 22		6/88	Sonoma	110 (144)	106 (130)	1,987 (2,023)
PGandE 21	See notes "b" and "d"	12/88	Sonoma	110 (144)	106 (130)	2,093 (2,153)
PGandE 23		6/89	Sonoma	110 (144)	106 (130)	2,199 (2,283)
CCPA #1		1989	--	110 (144)	106 (130)	2,305 (2,413)
MID/Shell		1990	Sonoma	25 (33)	23 (28)	2,328 (2,441)
CCPA #2		1990	--	55 (72)	53 (65)	2,381 (2,505)
PGandE 24		6/91	Sonoma	110 (144)	106 (130)	2,487 (2,635)
:		:				:
Remaining Uncommitted Resource		1/02				513 (629)
					total[c]	3,000 (3,255)

Note: Data in table are current as of January 1, 1983. The power plant projects listed in this table include projects already in operation, under construction, in regulatory review, or identified in current utility resource plans.

a. Reference plant for superheater enhanced generation study.

b. Candidate plants for potential superheater enhancement.

c. Based on the efficiency of typical (other than SMUD Geo. 1) geothermal power plants, the CEC staff estimates that the total recoverable geothermal resource represents 3000 MW (net). The numbers in parenthesis indicate gross, net and cumulative generation potential that would result from efficiency improvement patterned after the reference SMUD plant.

d. Plant capacity subject to revision.

remaining residual resource of 1,172 MW (3000 MW - 1828 MW) would be developed without generation efficiency improvement reflected in the 65 MW reference plant and without enhancement through superheating of the geothermal steam. With efficiency improvement (but without superheater enhancement) applied to all future plants the remaining geothermal resource would increase to 1,437 MW (net), for a total of 3,265 MW.

In the event the geothermal resource in the Geysers-Calistoga KGRA prove to be larger than currently estimated, the environmental impacts, particularly air quality would need to be reassessed.

2. Superheater-Enhanced Generation

The earliest geothermal power plants that could incorporate the superheating concept are presently scheduled for June 1988 operation (see Table 6). By increasing their efficiency patterned after the 65 MW reference plant (still using the same amount of steam) and by using currently available gas turbine exhaust for superheating, each plant, or multiples of such units could produce 159 MW from this same amount of steam. All geothermal plants after June 1988 could utilize superheated geothermal steam. The potential for enhancing the remaining 1,437 MW (3,265 MW - 1,828 MW) resource is shown in Table 7.

TABLE 7

Geysers Area Residual Resource Utilization

	Residual Resource (Megawatts)[a]	Enhanced GT-31, Megawatts	Enhanced GT-42, Megawatts
Identified	808	1,976	2,425
Uncommitted	629	1,538	1,877
Total	1,437	3,514	4,312
Increase	BASE	2,077	2,875

a. With efficiency improvement.

The residual resource of 1.437 MW allows for construction of 22 65 MW reference plants, which through generation enhancement (GT-31) to 159 MW (each) could increase the total output at the Geysers by an additional 2,077 MW. The fuel requirements for this generation increase (and for enhanced GT-42) are shown in Table 8.

TABLE 8

Fossil Fuel Requirement for GT Enhancement

	Enhanced GT-31	Enhanced GT-42
Fossil Fuel Use, million (MM)Btu/hr/plant	627	756
Equivalent Fuel Oil, Barrels/hr/plant	111	133
Total Fuel, 22 plants, MMBbl/year	17.8	21.3
Total Annual Generation MW-yrs	2,077 x 0.83	2,875 x 0.83
Fuel Use Rate, bbl/MW-yr	10,325	8,926

This data indicates that the superheater-enhanced geothermal plants use considerably less fuel than conventional oil-based power generation systems (see Table 9).

3. Fossil Fuel Displacement

It is CEC policy to bring about a long-term reduction in the use of petroleum-derived fuel for power generation.

The 3,265 MW Geysers area geothermal power (Table 6) displaces the equivalent oil and gas use by 100 percent. The enhancement, as described in this study provides an additional opportunity for oil displacement.

Data on past and projected fuel oil-based generation in California is listed in Table 9. (Ref. 16, page 71)

TABLE 9

Oil-based Generation in California

	1978	1985	1992	2002
Fuel Oil-based Generation, MW-yrs	6,164	7,306	2,968	2,968
Fuel Oil Use, MMBbl/yr	90.5	109.5	44.9	44.9
Fuel Use Rate, bbl/MW-yr	14,682	14,988	15,128	15,128

The additional power derived from the Geyser area through fossil fuel enhancement could produce the following oil equivalent reduction listed in Table 10 by the additional statewide generation displacement:

TABLE 10

Potential for Oil Displacement

	GT-31	GT-42
Generation Displaced, MW-yrs	2,077 x 0.83	2,875 x 0.83
Oil Displaced @ 14,682 bbl/MW-yr	25.8	35.8
Oil for GT Enhancement, MMBbl/yr	17.8	21.3
Net Oil Reduction, MMBbl/yr	8.0	14.5
30 Year Oil Savings, Million barrels	240	435

In summary, the above shows that by using gas equivalent to 17.8 million barrels of oil per year to superheat the geothermal steam, 25.8 million barrels of oil would be displaced each year that otherwise would be required to generate 2,077 MW-year (1983 value of $256 million per year savings). In the future, should favorable economic conditions develop, the natural gas equivalent to 17.8 million barrels of oil per year could also be saved by gasification of coal, petroleum coke or biomass to produce low-, medium- or high-Btu gas which can be used in the gas turbines.

IV. ENVIRONMENTAL, REGULATORY, AND OTHER CONSIDERATIONS

A. Environmental Aspects

1. NO_x - The New Pollutant

The burning of fossil fuel in the Geyser area will introduce a single air pollutant, nitrogen oxides (NO_x), that is regulated by both state and federal laws.

The NO_x level in the gas turbine exhaust can be maintained at about 50 parts per million by water injection, according to the gas turbine manufacturer.

The annual water requirement for this purpose would be 63 acre-feet. Due to evaporative loss of the entire condensate, this requirement could be met only if additional water resources, as discussed in previous action, were developed.

Approximately 106 lbs/hr of NO_x would be emitted from each of the potential 22 gas turbine exhaust enhanced geothermal plants. The annual NO_x emitted would total 8,478 tons. However, as detailed in Appendix B, page B-8, the NO_x concentration in the Geysers area communities will not exceed state or federal air quality standards.

Nevertheless, it is expected that Prevention of Significant Deterioration (PDS) review by the Environmental Protection Agency (EPA) and District New Source Review would be required.

The Geysers area has been the subject of exhaustive, 5 year long, atmospheric dispersion studies. The mathematical model resulting from these studies has been developed for hydrogen sulfide (H_2S) dispersion, incorporating measured data. The atmospheric dispersion model is both site and receptor specific, and the results are widely accepted as valid by the government and industry. The enhanced plants will utilize the same geothermal steam flow, and therefore there is no increase H_2S emission.

Using this dispersion model, it was preliminarily determined that under the most adverse meteorology, the NO_x concentration in the local communities from all 22 plants would not exceed 1 hour ambient state standards of 470 micrograms (ug) of NO_2 per M^3 (see Appendix B, page B-10).

2. Air Pollution Displacement

(See Appendix B, page B-14)

The 22 (potential) enhanced geothermal plants in the Geyser area would displace oil- and gas-fueled generation and the associated air pollution, i.e., NO_x, oxides of sulfur (SO_x), and particulates. Taken from the analysis in Appendix B-14.... these quantities are:

- NO_x displacement is 13,742 tons/year,
- SO_x displacement is 17,064 tons/year, and
- Particulates displacement is 1,737 tons/year.

The reduction in pollutants would occur in areas of high population that now may exceed air pollution limits, i.e., nonattainment areas.

3. Land, Water, and Socioeconomic Impacts

a. Land

The addition of a steam superheater sized to heat 946,200 lbs per hour of geothermal steam from 348°F to 900°F and a 57 MW gas turbine-generator will occupy approximately 1/2 of an acre. The gas pipeline construction would have an as yet undetermined impact.

The referenced geothermal steam plant now requires about 5.5 fenced acres.

b. Water

The unenhanced reference geothermal plant evaporates 845,500 lbs per hour and reinjects 136,875 lbs per hour. The enhanced plant will require 15.93 percent more evaporation (see Appendix A, page A-6 and D, page D-3, low back pressure heat balance). The enhanced plant will use essentially all water normally reinjected. Water for reinjection and cooling tower basin blow down if required, will have to come from other sources, as previously discussed.

c. Socioeconomics

No significant adverse socioeconomic impacts are expected to result from the construction and operation of the enhanced geothermal power plants.

A significant economic benefit to the communities of the enhanced geothermal plant could be the introduction of natural gas to the Geysers area. Space heating is now accomplished with trucked-in propane at two to three times the cost of natural gas, had it been available.

Introduction of natural gas into the Geysers area would also reduce the amount of particulates, which are already noticeable as result of extensive wood burning.

B. Regulatory Consideration

1. Federal Energy Regulatory Commission (FERC)

FERC has jurisdiction over major fuel-burning installations (100 million Btu/hr). The Power and Industrial Fuel Use Act of 1978 (PIFUA) prohibits the use of natural gas i new power generation facilities; however, steam superheaters are specifically excluded from this restriction.

Additionally, facilities that utilize a mixture of 50 percent or greater alternate fuel (geothermal steam is called an alternate fuel) are exempt from PIFUA. The GT-31 enhanced plant uses 627 million Btu per hour of fossil fuel and about 1,180 million Btu per hour of geothermal steam.

Thus, more than 65 percent of the enhanced geothermal plant's energy use is derived from an alternate fuel, and the plant is therefore eligible for a mixture exemption to PIFUA.

2. California Public Utilities Commission (CPUC)

Neither the CPUC nor the FERC have price jurisdiction over natural gas that is purchased, transported and consumed by the same company. (Ref. 17)

By forming a consortium, all power producers in the Geysers could take advantage of the above provision.

Proposed changes in existing law will allow large volume consumers to negotiate purchase contracts with natural gas or synthetic natural gas producers anywhere in the United States (or liquefied natural gas offshore) paying only a transportation charge (Ref. 21, a provision of natural gas decontrol legislation now pending). The purpose of this provision (the "carriage" provision) is to create downward pressure on natural gas prices, which if approved would in turn lower enhanced geothermal plant generation cost.

C. Other Considerations

1. Transmission System

The electricity costs presented are at the busbar with transmission excluded. The transmission system, as proposed for the unenhanced plants in the Geysers area, is clearly inadequate in capacity for enhanced plants. The additional cost is estimated at $40 per kilowatt to connect with existing or future transmission lines, (based on preliminary staff analysis). This cost is not included in Tables 2 and 4 and Figures 5 through 12.

The cost of transmission line construction was estimated from a PG&E January 1983 "Geysers 230 kV Collector Line Study" to be about $1 million per mile.

2. Natural Gas Pipeline

The 22 gas turbine enhanced geothermal power plants will require about 0.4 billion cubic feet (BCF) of natural gas per day. A 14 inch diameter high pressure pipeline would transport the natural gas 42 airline miles due west from the existing main 36-inch diameter north-south trunk line intersecting in the north central Yolo County. The location of existing pipeline in relationship to the Geysers-Calistoga KGRA is shown on Figure 13 (see Appendix B, page B-16).

Allowing 50 actual pipeline miles and some 25 miles of smaller diameter distribution pipeline to the individual geothermal plants, the construction cost is estimated to be $18.5 million, or approximately $1 million per plant (Appendix B, item 9).

3. Geothermal Steam Contracting

This study is based on a steam contract expressed in dollars per thousand pounds of geothermal steam. However, other steam purchase contracts are expressed in cents per kilowatt-hour of generation. This latter contract would have to be modified for enhanced plants, because the generation increase would result from fossil fuel use only.

APPENDIX A

THERMODYNAMIC ANALYSIS

I. INTRODUCTION

The most sensitive parameter in estimating the thermodynamic effect of superheating geothermal steam is the assumption of turbine efficiency. The 83.4 percent turbine efficiency of the reference plant, achieved with near saturated steam conditions and with 16 percent condensation, is expected to increase when the steam is superheated.

The state-of-the-art in power recovery from low-pressure steam is documented in a recent study sponsored by the Electric Power Research Institute (EPRI), EPRI-AP-2321, (Ref. 23). The work was performed by a manufacturer of gas and steam turbines. Low- (LP), intermediate- (IP), and high-pressure (HP) steam turbines were utilized. The HP and IP steam was reheated to 950°F. The 93 psia LP turbine was superheated to 600°F. Both the LP and IP steam turbines were rated at 91 percent efficiency. The 1,500 psia HP turbine was rated at only 83 percent efficiency.

Based on the above reference study, the geothermal steam turbine operating on 900°F superheated 110 psia steam will be assumed, for this study, to have a 90 percent efficiency. A more conservative assumption of 85 percent turbine efficiency (similar to that achieved by the reference plant) would not alter the conclusions regarding the viability of superheater-enhanced geothermal power plants.

II. THERMODYNAMIC EFFECT OF SUPERHEATING GEOTHERMAL STEAM

Assuming a throttle steam temperature of 900°F, a pressure of 110 psia, 1.5 inches of mercury back pressure, and a steam turbine of 90 percent efficiency with neglible "leaving losses," the thermodynamic effect of superheating the geothermal steam can be readily determined from the 1967 American Society of Mechanical Engineers (ASME) steam tables as follows:

A. The Ideal Exhaust Enthalpy Determination

Throttle conditions are: 110 psia, 900°F, the enthalpy, h and entropy, s, are:

h = 1,480.1 Btu/lb $\qquad$ s = 1.8732 Btu/lb/°F

Exhaust conditions are: 1.5 inches Hg and 92°F; the vapor (v) and liquid (l) properties are:

h_v = 1,101.6 Btu/lb; h_l = 60.014 Btu/lb; s_v = 2.0033 Btu/lb/°F;

s_l = 0.1152 Btu/lb/°F

For an ideal isentropic expansion:

$$s_{throttle} = s_{exhaust} \quad \text{(100 percent efficient)}$$

The ideal % moisture content (y) is given by equating the total entropy to the sum of vapor and liquid entropy:

$$1.8732 = (y)0.1152 + (1 - y)2.0033$$

$$y = (2.0033 - 1.8732)/(2.0033 - 0.1152) \times 100 = 6.89\%$$

Similarly, the ideal exhaust enthalpy is given by equating the total enthalpy to the sum of the vapor and liquid enthalpies:

$$h_{total} = 1{,}101.6 \text{ Btu/lb} - 0.0689(1{,}101.6 \text{ Btu/lb} - 60.014 \text{ Btu/lb})$$

$$= 1{,}029.83 \text{ Btu/lb}$$

The actual exhaust enthalpy is given by a turbine enthalpy balance:

$$h_{exhaust} = 1{,}480.1 \text{ Btu/lb} - 0.9(1{,}480 \text{ Btu/lb} - 1{,}029.83 \text{ Btu/lb})$$
$$= 1{,}074.86 \text{ Btu/lb}$$

The actual % moisture is given by equating total enthalpy to vapor and liquid enthalpy:

$$1{,}074.86 = (y)60.014 + (1 - y)(1{,}101.6)$$
$$y = (1{,}101.6 - 1074.86)/(1{,}101.6 - 60.014) \times 100 = 2.57\%$$

This value is near the steam turbine manufacturer recommended optimum of about 2.0 percent, which insures no superheat is wasted in the condenser.

B. Discussion of Turbine Efficiency Assumption

The targeted value of exactly 2.0 percent moisture in the turbine exhaust flow was exceeded by 0.57 percent. This means the 90 percent efficient steam turbine will support (theoretically) a slightly higher than 900°F throttle temperature. Fixing the moisture at 2.0 percent and back calculating gives an initial superheat temperature of 932°F. Similarly, if the superheater pressure drop had been 4 rather than 5 psi, the 111 psia throttle steam will give a superheat temperature of 903°F.

The most sensitive parameter is the turbine efficiency. If the turbine efficiency is assumed 91 percent, as in the recent EPRI design study (Ref. 23), the superheat temperature at exactly 2.0 percent moisture, and the 5 psi superheater pressure drop is 989°F.

Clearly, determining the optimum turbine efficiency, corresponding exhaust moisture, and maximum useful superheat temperature, are all part of the same design problem.

C. Generation Increase:

The generation increase (G.I.) per pound of steam achieved over the reference geothermal plant at 348°F by superheating the turbine throttle steam to 900°F with the turbine exhaust steam maintained at 92°F is given by turbine enthalpy balances (See Appendix D-2 and D-3, for a generation comparison of a high turbine back pressure and low turbine back pressure plant) as follows:

$$G.I. = (H_2 - h_2)N_2 \times e - A_2 - (H_1 - h_1)N_1 \times e - A_1$$

$$G.I. = (1,480.1 - 1,029.83).9 \times 0.98 - 30.2 - (1,195.5 - 878.05).834 \times 0.98 - 25.7$$

Where:

G.I. is the generation increase per pound of steam: Btu_e/lb

H_1 is the geothermal steam enthalpy:	1,195.5 Btu/lb
H_2 is the superheated steam enthalpy:	1,480.1 Btu/lb
h_1 is the isentropic exhaust enthalpy without superheat:	878.05 Btu/lb
h_2 is the isentropic exhaust enthalpy with superheat:	1,029.83 Btu/lb
N_1 is the turbine efficiency without superheat:	0.834
N_2 is the turbine efficiency with superheat:	0.900
A_1 is the plant auxilliaries without superheater:	25.7 Btu/lb
A_2 is the plant auxilliaries with superheater:	30.2 Btu/lb
e the generator efficiency:	0.98

The equation reduces to enhanced minus unenhanced generation:

= 366.94 Btu_e/lb - 233.76 Btu_e/lb

= 133.18 Btu_e/lb (increase in net generation per pound of steam)

Thus, the effect of superheating the geothermal steam is to enhance the net turbine output by:

(366.94/233.76 - 1)100 or 56.97%

The turbine steam rate is now 3,412 Btu/kWh/366.94 Btu/lb or 9.30 lbs/kWh (with auxilliary steam, 9.64 lbs/kWh)

By way of numerical example, the reference 65 MW net geothermal plant throttle steam flow of 0.9462 million pounds per hour would now yield an enhanced power as follows:

(366.94 Btu/lb x 946,200 lb/hr) / 3,412 Btu/kWh

= 101,758 net kilowatts from the geothermal steam turbine.

D. Energy Requirements

Superheating the geothermal steam from 348°F to 900°F will require an addition of energy. That portion of the energy added that is not converted to electricity must be rejected in the condenser.

1. Energy Addition Requirement

The additional energy required to superheat the steam is given by the enthalpy difference:

1,480.1 Btu/lb - 1,195.5 Btu/lb = 284.6 Btu/lb

Therefore, the incremental energy conversion efficiency is given by generation increase/energy added:

(133.18/284.6) 100% or 46.80% (% increase in steam enthalpy is 284.6/1195.5 x 100 = 23.81%)

2. Discussion of Energy Addition Requirements

In order to increase the geothermal steam temperature from 348°F to 900°F, 284.6 Btu of energy must be added to each pound of steam, regardless of the methods or source of energy.

For the reference geothermal throttle steam flow of 946,200 pounds per hour, the energy requirement is 269.3 million Btu/hr. In a conventional steam superheater, the steam flows through tubes, and hot combustion gases heat the tubes. The superheater efficiency as a maximum would be about 90 percent. The fuel requirement, in this case, would then be 269.3/0.9 = 299.2 million Btu/hr of fuel.

3. Energy Rejection Requirement

The energy rejected (Q reject) in the condenser is given by the enthalpy difference between the throttle steam and the saturated condensate less the generation. In geothermal plants without the superheater, referring to page A-4,

$$Q \text{ reject} = H_1 - N_1(H_1 - h_1) - \text{condensate enthalpy}$$

$$Q \text{ reject} = 1{,}195.5 \text{ Btu/lb} - 0.834(1{,}195.5 \text{ Btu/lb} - 878.05 \text{ Btu/lb}) - 60.014 \text{ Btu/lb}$$

$$= 870.73 \text{ Btu/lb must be rejected in the condenser}$$

In the superheater enhanced geothermal plant, referring to page A-4:

Q reject H_2 - $N_2(H_2 - H_2)$ - Condensate enthalpy

Q reject = 1,480.1 Btu/lb - 0.9(1,480.1 Btu/lb - 1,029.8 Btu/lb) 60.014 Btu/lb

= 1,014.82 Btu/lb must be rejected in the condensate.

Thus, the heat rejection rate is increased by the addition of a superheater by:

1,014.82/870.73 x 100 or 16.55%

To maintain the same turbine back pressure and full superheat utilization, condenser surface, circulating water flow and cooling tower capacity will have to increase 15.93 percent. (The ejector steam flow reduces the overall increase to 15.93 percent.)

The incremental capital cost increase is known in the industry to vary with 0.4 to 0.8 power of the duty increase.

Thus, the capital cost increase for the entire heat dissipation system could range from 6.3 percent to 13 percent. The staff used 10 percent capital cost increase in this analysis. Using either of the extremes of the above range would not alter the conclusions of this report.

A superheater enhanced geothermal plant offers a new incentive to maximize the heat rejection system investment, i.e., lower the turbine back pressure from the typical 3 to 4 inch of Hg.

A plant employing 900°F, 110 psia throttle steam would leave superheat, i.e., waste fuel in the typical turbine exhaust. By way of example, if the back pressure were 3 inch of Hg (115°F) and above, maintaining 2 percent exhaust moisture would necessitate lowering the throttle temperature to 785°F, whereas lowering the turbine back pressure would simultaneously allow raising the throttle enthalpy equivalent to 900°F and reduce the exhaust enthalpy equivalent to 92°F.

APPENDIX B

ENGINEERING OPTIONS AND ANALYSIS

I. BACKGROUND

There is one basic conventional method of superheating steam and that is to flow the steam through a suitable steel tube and then heat the tube. The design question is how best to supply heat to the tube. In the power industry, steam generation is achieved by heating the tubes by direct combustion of coal, oil or gas. In more modern plants such as combined-cycle, the heat is provided by the hot gas leaving the combustion turbine. In both cases, direct-fired and turbine exhaust heated tube surfaces are exposed to corrosive effects of carbon dioxide (CO_2) and oxides of sulfur. It cannot be ruled out that at The Geysers the hydrogen sulfide (H_2S) which is present in the geothermal steam, when superheated to 900°F would not accelerate the corrosion of the tubes' internal surfaces. One very successful process which has been developed and perfected over the last twenty years is called "alonizing." This process is an aluminum vapor diffusion into the tube steel at 1900-2000°F. The steel so treated resists chemical attack of CO_2 and sulfur compounds including such extremely corrosive agents as sulfuric acid. Depending on the type and concentration of the corrosive agents, alonizing will protect the equipment for 10,000 - 100,000 hours of operation. The latest project where alonized tubes will be used is the Southern California Edison Company Cool Water Coal Gasification Plant. Given that the tubes' outer surfaces will not be exposed to more severe corrosion environmnt than that usually encountered in direct-fired or turbine exhaust heated heat exchangers and the H_2S concentration in the geothermal steam flowing through the tubes is low (0.006-0.1 percent), the alonizing process should provide protection against any significant loss of plants' reliability.

II. ENGINEERING OPTIONS

A. Direct-Fired Superheater

There are several options for supplying heat to the superheater tubes. The most common power plant practice is to employ direct firing with fuel and air at near stoichiometric ratios (to maximize radiant heat transfer and minimize stack losses) and then pass the hot combustion gases across the superheater tube. The steel alloy tubes are heated by radiation from the highest boiler flame temperature and by convection from the flowing gases.

Another method of supplying the necessary heat to the tubes is by convection from the hot gas (typically 1,000°F) exhausting from a combustion turbine. (See Section B, on Gas Turbine Exhaust Superheating)

Regardless of the heating mode, the geothermal steam superheater has two unique requirements. The in-tube (steam side) pressure drop should be at a minimum, and heat from the 400°F plus combustion gas exiting the superheater should be recovered to increase the fuel use efficiency.

The geothermal steam superheater has several unique advantages. Unlike a heat recovery steam generator, the superheater has no thermal pinch point, i.e., a limiting temperature approach between the flowing hot gas and the boiling fluid. The geothermal steam increases steadily in temperature from 348°F to 900°F while flowing countercurrent to the hot combustion gases which are cooling from, say, 1,000°F to 400°F. The superheater requires no steam drum, deaerator, or make-up water system and has essentially no controls and no moving parts. It is to be noted that a 300°F (or less) heat recovery boiler exit gas temperature, commonly encountered in conventional combined-cycle plants, cannot be achieved in superheating the geothermal steam. The 348°F steam inlet temperature dictates that the combustion gas exit temperature could not be much less than 400°F.

B. Gas Turbine Exhaust Superheating

The geothermal steam can also be superheated from 348°F to 900°F by exchanging the heat in the exhaust of a high performance simple cycle gas turbine.

The most efficient simple cycle gas turbine available today produces 35 MW with a demonstrated efficiency of about 38 percent (9,000 Btu/kWh heat rate). However, the exhaust temperature is about 783°F which precludes heating steam much above 700°F, and is not considered in this study, but further analysis may prove it to be competitive.

A second efficient simple cycle gas turbine produces a maximum of about 24 MW at an efficiency of about 37 percent (9,200 Btu/kWh heat rate) with an exhaust temperature of 975°F and exhaust flow of 154.2

pounds/second. The geothermal steam can be heated to 900°F. The 75°F initial temperature difference is near the economic optimum, i.e., the generation gain versus the increase exchanger surface area nearly at an equal cost trade-off point. However, this gas turbine, as will be shown, does not match superheating requirements.

The superheater optimum (yielding minimum electricity cost) terminal temperature difference, i.e., outlet gas temperature minus the inlet steam temperature, cannot be determined precisely without a detailed post superheater waste heat recovery scheme.

Conceptually, the superheater will reduce the gas turbine exhaust temperature from 975°F to about 400°F. Thus, the terminal temperature difference will be given by 400-348 or 52°F. The arithmetic average and log mean (LM) superheater temperature difference with this assumption is:

$$(975 - 900 + 400 - 348)/2 = 63.5°F \text{ (arithmatic average) or}$$

$$(975 - 900 - 400 + 348)/\ln (975 - 900)/(400 - 348) = 62.8°F$$
(log mean average)

This temperature difference (TD) is attainable in conventional equipment. The optimum TD would await detailed engineering.

III. GAS TURBINE PERFORMANCE ESTIMATE

The energy in the fuel consumed in the gas turbine reappears as work or heat in five measurable places. They are (1) net electricity leaving the generator terminals (3,412 Btu/kWh), (2) heat removed from the generator windings by the hydrogen cooling system (2.5 percent), (3) heat generated in bearing friction and removed from the lubricating oil, (4) radiation losses from the hot turbine casing, and (5) heat above 59°F in the exhaust gas leaving the power turbine.

The combustion energy released by the fuel is measured, by convention, at 15°C (59°F). The water vapor produced can be condensed giving a higher heating value, or not condensed, giving the lower heating value. The gas turbine has no chance to utilize the heat of condensation. Thermal performance is, therefore, measured against the fuel's lower heating value (LHV).

Assuming a generator efficiency of 97.5 percent and allowing 1 percent for bearing and radiation losses, the thermal energy in the gas turbine exhaust that goes to superheat the geothermal steam from 348°F to 900°F is given by following formula (based on 1 kilowatt of gas turbine output):

ETS = (A - B - C)D, where:

ETS = energy to superheating, Btu/hr.

A = gas turbine heat input, 9,200 Btu/hr (Efficient, 24 MW gas turbine).

B = gas turbine shaft work, 3,412/0.975 Btu/hr.

C = bearing and radiation heat loss, 92 Btu/hr.

D = ratio superheat to total remaining exhaust heat,
(975°F - 400°F)/(975°F - 59°F).

Therefore,

ETS = (9,200 - 3,412/0.975 - 92) (975 - 400)/(975 - 59)

= 3,521 Btu/hr per gas turbine kilowatt available to superheating.

From the previous thermodynamic analysis, the net steam turbine (ST) generation increase per energy added in the superheater is:

133.18 $Btu_e/lb/284.6\ Btu_t/lb$, or 0.4680

Therefore, the gas turbine (GT) exhaust will generate steam turbine (ST) electricity as follows:

0.4680 x 3521/3412

= 0.4830 kWh of ST/kWh of GT

The incremental fuel conversion efficiency is given by:

9,200 Btu/kWh/(1 + 0.4830) = 6,204 Btu/kWh

or 3,412/6,204 x 100% = 55%

The 24 MW gas turbine will superheat the following geothermal steam flow:

3,521 Btu/kWh/284.6 Btu/lb x 24,000 KW

= 296,922 lbs/hr

Therefore, multiple 24 MW gas turbine units would be needed to superheat the reference plant's required 0.95 million lbs/hr.

IV. GAS TURBINE SELECTION

A. General Considerations

Gas turbine technology is evolving rapidly. Performance efficiency is increasing several percent per year due to intense worldwide competition.

In order to make the clearest comparison, and therefore draw appropriate conclusions between unenhanced and gas turbine enhanced geothermal plants:

- A single gas turbine was selected to exactly match the unenhanced plant geothermal steam flow,
- A combined cycle was compared using the same gas turbine, and
- Both an existing gas turbine (31 percent efficient, GT-31) and an advanced gas turbine (42 percent efficient, GT-42) are compared.

B. Gas Turbine Exhaust Generation Potential

1. Use of GT-31

An energy balance around the gas turbine shows the following:

The energy input is 1 unit of energy, 0.31/0.98 energy units go to the generator, and 0.01 energy units go to bearing and radiation loss. The remaining energy is contained in the exhaust. A temperature drop of 600°F (1,000°F-400°F) achieved in the exhaust gas which goes to increase geothermal steam temperature from 348 to 900°F, and 941°F (1000°F - 59°F) temperature difference represents the total heat available in the exhaust. Of the heat added to the geothermal steam, 0.4680 is converted to net plant electricity. (See page A-6).

Therefore, a 31 percent efficient gas turbine will generate a steam turbine enhancement calculated as follows:

$= (1 - 0.31/0.98 - .01)(1,000 - 400)/(1,000 - 59)(0.468)$

$= 0.201$ of enhancement per 0.31 of GT or 0.201/0.31

$= 0.65 \dfrac{kWST}{kWGT}$ enhancement, or 0.65 x 37 MW = 57 MW gas turbine would satisfy the requirement

Fuel Use: 57,000 kW x 3,412 Btu/kWh/0.31 = 627 MMBtu/hr

2. Use of GT-42

Similarly, analyses of a GT-42 turbine follows:

STE = $(1 - 0.42/0.98 - 0.01)(1,000 - 400)/(1,000 - 59)(0.468)$

$= 0.1675$ of enhancement per 0.42 of GT or 0.1675/0.42

$= 0.40 \dfrac{kWST}{kWGT}$ enhancement

$$\text{Power} = \frac{37}{0.40} = 93 \text{ MW}$$

Fuel Use = (93,000 kW x 3,412 Btu/kWh)/0.42

= 756 MMBtu/hr

As a check on the steam superheating capacity of the gas turbine exhaust, the following formula gives the geothermal steam flow:

For GT-31, GSF = (A-B-C)D/E

GSF = geothermal steam flow in lbs/hr superheated to 900°F

A = the gas turbine heat input, 627 MMBtu/hr.

B = the gas turbine shaft work, 57 x 3,412/0.98 MMBtu/hr.

C = the bearing and radiation loss, 0.01 x 627 MMBtu/hr.

D = superheat/total exhaust/ (1,000 - 400)/(1,000 - 59).

E = heat added to 1 lb of geothermal steam, 284.6 Btu/lb.

Therefore,

$$GSF = (627 - 57 \times 3{,}412/0.98 - 0.01 \times 627)(1{,}000 - 400)/(1{,}000 - 59)/284.6$$

$$= 0.95 \text{ MMlbs/hr (meets required flow)}$$

For GT - 42 Similarly:

$$GSF = (756 - 93 \times 3{,}412/0.98 - 0.01 \times 756)(1{,}000 - 400)/(1{,}000 - 59)/284.6 = 0.95 \text{ MMlbs/hr (meets required flow)}$$

V. GAS TURBINE EMISSION CONTROL

Since the gas turbine employs a sulfur-free gaseous fuel, the only air pollutants are nitrogen oxides (NO_x).

The NO_x emissions are controlled by water injection. The gas turbine will emit 50 ppm NOx or 106 lbs/hr. The atmospheric dispersion model developed for H_2S transport in the Geyser area will predict NO_x concentration at specific communities. The NO_x pollutant concentrations are corrected for two mitigating effects not used in H_2S calculation.

- o Temperature of plume--The H_2S is emitted from cooling tower exhaust at about 100°F. The NO_x is emitted from the gas turbine exhaust at 400°F. The additional plume rise from the hot, more buoyant exhaust will further dilute NO_2 concentration to 0.72 of H_2S concentration (CEC air quality staff estimate).

  This may not be true if the plant was located at an elevation several hundred feet below the location of the cooling tower.

o NO_2 concentration--The NO_x is composed of NO and NO_2. State standards are for NO_2 only. The concentration of NO_2 at the receptor will be 0.50 of the total NO_x emitted (CEC air quality staff estimate).

Table B-1 shows hypothetical NO_x emissions from plant sites adjacent and down wind from Anderson Springs if such plants used gas turbine exhaust for superheating the geothermal steam.

TABLE B-1

Maximum[a] NOx Concentrations in a Geysers Area Community

Plant Site	Impact Factor (ug/m^3 per lb/hr)	Exhaust Temp. Correction Factor	NO_x to NO_2 Conversion Factor	Impact (ug/m^3) for Emission Rate Shown at Anderson Springs[b] (1-hr average) 106 lb/hr
Oxy 1	0.346	0.72	0.50	13.2
SMUDGEO 1	0.35	0.72	0.50	13.3
Unit 20	0.35	0.72	0.50	13.3
NCPA 3	0.311	0.72	0.50	11.9
Unit 16	1.0	0.72	0.50	38.2
				89.9

a. Estimated by CEC staff.

b. Impacts equal the product of the impact factor, correction factors and emission rates.

The calculation of combined impacts of enhanced geothermal facilities at the sites are well below the most stringent ambient NO_2 standards in California, 470 ug/m^3. It is neither suggested, or likely that all 22 gas turbine enhanced plants would be sited at the

5 locations near Anderson Springs. But even if they were, the combined emissions would result in NO_x concentrations of 396 ug/m^3 (22/5 x 89.9 = 396) which is below the allowable concentration limit.

VI. WASTE HEAT RECOVERY

In both geothermal steam superheating methods--direct- firing and gas turbine exhaust--the temperature leaving the superheater will be in excess of 348°F by 50 to 100 degrees. These potential stack temperatures (398°F to 448°F) suggest consideration of additional heat recovery schemes.

By way of comparison, the most recently proposed combined-cycle plant will have a stack temperature of only 225°F, i.e. it has been reduced by heat recovery. In addition, the Heber geothermal demonstration plant technology can be applied to recover the enhanced plant's waste heat. The Heber plant will utilize a heat source at 360°F and generate 45 net megawatts with a 305°F throttle temperature and 110°F exhaust temperature. The overall efficiency is 12.28 percent.

About 62 percent of the Heber project generation cost is attributable to the heat supply, in this case hot brine. Given a source of heat around 400°F, an organic cycle, such as used on the Heber project, appears to be the most economic waste heat conversion scheme.

The direct-fired superheater will undoubtedly exchange the stack gas heat with the incoming combustion air. A rotary air preheater, or equivalent, would probably be employed as this is essentially common power plant practice.

The gas turbine method of superheating could not employ an air preheater, as the 400°F gas is lower in temperature than the compressed air to the combustor. The options for waste heat recovery in this case are a low-pressure boiler or an organic cycle.

A low-pressure boiler would generate ejector steam or steam turbine induction steam. Approximately 1 pound of geothermal ejector steam is required for every 26 pounds of wellhead flow at 115 psia. The low-pressure (20 psia) steam generating potential, assuming a 400°F superheater exhaust temperature and a 50 degree approach, is as follows:

SG = A x B x C x D/E

SG, steam generated; lbs/hr

A, exhaust flow; 154.2 lbs/sec

B, 3,600 sec/hr

C, temperature drop; (400 - 240 - 50)°F

D, specific heat; 0.25 Btu/°F/lb)

E, latent heat; 952.1 Btu/lb

SG = 154.2 x (3,600) x (400 - 240 - 50) x 0.25/952.1

SG = 30,610/lbs/hour

Three to four units would be needed for a total of about 100,000 lbs/hr

The ratio of superheated steam to low pressure steam is 296,922/30,610 (see B-5)

= 9.70/1, therefore, the waste heat boiler could possibly meet the ejector steam demand, i.e., 26/1. It is not obvious at this point that the low (20 psia) system offers an advantage over the 115 psia with 37,000 lbs/hr flow currently used in the reference plant.

VII. ORGANIC CYCLE WASTE HEAT RECOVERY

The Heber geothermal demonstration plant will be the first large-scale organic cycle generation facility in the United States. The engineering and design for this plant is well established. The organic cycle could be employed for waste heat recovery in the enhanced geothermal plant concept.

The Heber design (12.28 percent efficient) if adjusted for a higher temperature heat source (350°F versus 305°F), a lower temperature heat sink (90°F versus 110°F) and lower pumping power gives a net to gross power ratio of 45.7/45. (Ref. 12). The organic cycle efficiency estimate is numerically given by:

$$Eff = A \times B/C \times D$$

Where Eff is organic cycle efficiency utilizing the 400°F superheater exhaust

A = organic cycle efficiency at Heber site, 12.28%

B = the source and sink temperature difference, 350 - 90°F

C = the Heber source and sink temperature difference, 305 -110°F

D = the net power ratio, Geyser/Heber, 45.7/45

$$Eff = 12.28\% \times (350-90)/(305-110) \times 45.7/45$$

$$= 16.63\% \text{ (net)}$$

The energy available in the exhaust flow is: (heat balance)

$Q = A \times B \times C \times D$; MMBtu/hr.

A = exhaust flow, 154.2 lbs/hr.

B = 3,600 sec/hr.

C = gas temperature drop, (400 - 150)°F.

D = specific heat, 0.25 Btu/°F/lb

Q = 154.2 lbs/sec x 3,600 x (400 - 150) x 0.25 Btu/lb/°F

= 34.7 million Btu/hr

Therefore, the organic cycle power recovery is: Q x Eff./3,412

34.7 MMBtu/hr x .1663 x 1/3,412

= 1.691 MW (net) or 1.691/24 = 0.07 KW Organic Turbine/KW Gas Turbine

The heat rejection would be:

Q - output x 3,412

34.7 MMBtu/hr - 1.691 MW x 3,412

= 29 million Btu/hr, or about 29,000 lbs. of water evaporated/hr for each of the 24 MW gas turbines used.

The water requirement is 29,000 lbs/hr, which is $\frac{29,000}{296,922}$ or 10 percent of throttle flow (see B-5), and produces a negative water balance. For this reason until makeup water becomes available from other resources such as Big Sulfur Creek reservoir (Ref. 1) this concept cannot be implemented.

VIII. NATURAL GAS PIPELINE

The 22 gas turbine enhanced geothermal power plants will require @ 1 MBtu/ft^3 the following quantity of natural gas:

$22 \times 627{,}000\ ft^3/hr \times 24\ hrs/day = 331\ million\ ft^3/day.$

Using an initial pipeline pressure of 1,000 psia and an in-pipe velocity of 50 ft/sec the pipe diameter is given by the square root of:

$4/\pi \times F/V \times 144\ in^2/ft^2$

Where F/V is actual volumetric flow (gas specific volume corrected for pressure) in-pipe velocity;

$$\frac{14.7\ psia}{1{,}000\ psia} \times 331 \times 10^6\ \frac{std\ ft^3}{day} \times \frac{1\ day}{86{,}400\ sec} \times \frac{1}{50\ ft/sec}$$

$$(4/\pi \times 331 \times 10^6 \times 14.7/1{,}000 \times 1/86{,}400 \times 1/50 \times 144)^{0.5} = 14\ inch$$

Figure 13 shows the escalation of existing gas pipelines in relationship to the Geysers-Calistoga KGRA. Only the 36 inch trunkline 42 miles east of the geothermal streamfield is large enough to provide the necessary gas. The other, 12 inch line although only 12 miles west could not meet the superheating requirements and satisfy the present committments at the same time.

Installed Cost: Using \$4.38 (staff estimate)per diameter inch and 50 miles in length, plus 25 miles of 4 inch diameter distribution pipes the cost is given by:

\$4.38/in/ft (50 miles X 14" + 25 miles X 4") 5,280 ft/mile

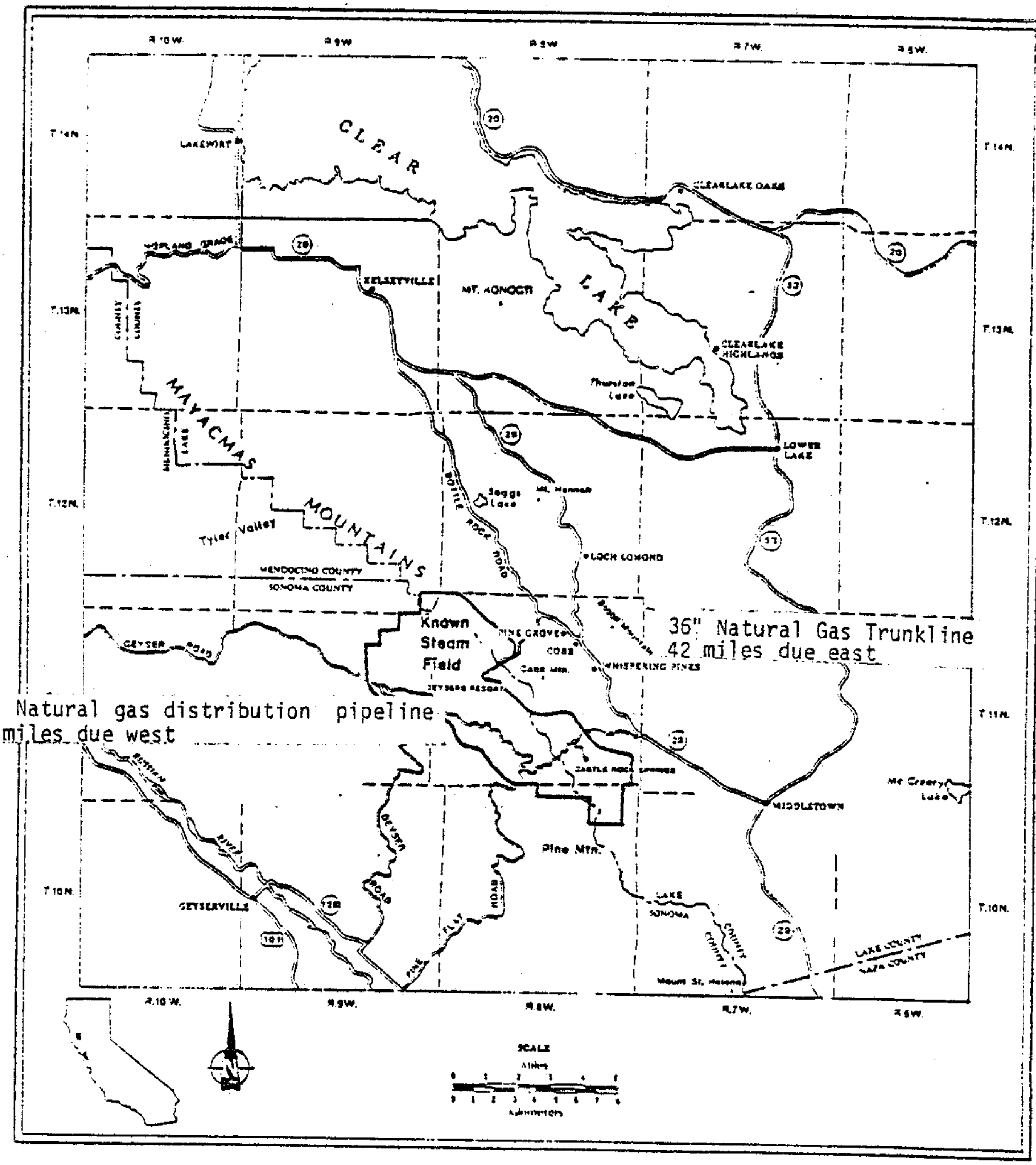
= \$18.5 million or \$840,000 per plant with 18 percent fixed charge rate (annual cost per dollar invested).

The cost per MMBtu is given by:

$$\frac{0.18 \times \$840{,}000}{.83 \times 365d/yr \times 627MMBtu/hr \times 24\ hr/d} = \frac{\$0.033}{MMBtu}$$

Figure 13

Location of Existing Gas Pipelines in Relationship to Geysers-Calistoga KGRA



- Location of the Geysers steam field. Modified from Stockton, et al (1981).

(Abstracted from Reference 22)

IX. AIR POLLUTION DISPLACEMENT

If 22 Geysers area geothermal 65 MW plants were built and enhanced by gas turbine exhaust superheating (G-31) they would produce 2,077 MW of additional generation. The equivalent fossil fueled generation (@ 50/50 oil and gas) now produce the following specific air pollution (from CEC staff estimation):

NO_x = 1.82 lbs/MWh

SO_x = 2.26 lbs/MWh

Particulates = 0.23 lbs/MWh

Thus, the air pollution displaced is:

NO_x - Geyser area annually emmission is:

22 plants x 106 lb/hr[a] x 8,760 hrs/yr x 0.83 x 1 ton/2,000 lbs = 8,478 tons/yr.

NO_x displaced @ 1.82 lb/MWh fossil generation:

2,077 MW x 8,760 x 0.83 x 1.82/2,000 lbs/ton = 13,742 tons/year

SO_x displacement @ 2.26 lbs/MWh fossil generation:

13,742 x 2.26 lbs SO_x/1.82 lbs NO_x = 17,064 tons/year vs 10,303 tons/year that would be generated in the Geysers area[b]

Particulate displacement @ 0.23 lbs/MWh fossil generation:

13,742 x 0.23/1.82 = 1,737 tons/year vs 1,046 tons/year that would be produced in the Geysers area.[b]

(a) The gas turbine heat input, 627 MMBtu/hr.
(b) If 50/50 oil and gas fossil and fuel were used in the geysers area.

APPENDIX C

CAPITAL AND FUEL COST LEVELIZATION

I. INTRODUCTION

This appendix develops the capital cost for the comparable power plants and shows the method of bringing all of the future fuel costs to a comparable basis.

The changes in electricity cost components, capital, fuel and O&M will determine the net change in the cost of electricity.

The capital cost breakdown of an unenhanced geothermal plant is based on a June 1982 paper entitled "The Economics of Geothermal Power" presented at the American Society of Cost Engineers' annual meeting (see Ref. 20).

II. CAPITAL COST ESTIMATE

A. Reference Unenhanced Plant

The reference unenhanced geothermal plant of 65 MW net is assumed to have a 1983 total capital investment of $1,420/kw, excluding transmission, of which the direct cost is $770/kw. The capital investment is: (total/direct = 1420/770) . . . 1,420 x 65,000 = $92,300,000. (The same cost reported by SMUD, Ref. 17).

B. Direct-Fired Superheating Option

The following additional direct capital costs will be required to superheat the geothermal steam by direct firing.

- Superheater (from heat transfer equipment vendor, based on the inlet and the desired outlet state point)

  @ \$2.5 million for 11,590 kW = \$216/kW

- Turbine-Generator (from manufacturers and A&E)

  @ \$31/kW + \$30/kW = \$62/kW (staff estimate for turbine modification).

- Heat Rejection System (duty ratio to 0.6 power and A&E circ. water cost)

  @ \$170/kW x $(1.1655)^{0.6}$ = 186 or \$16/kW increase.

- Transformer/Switchyard (from manufacturer)

  @ \$30/kW = \$30/kW

The total direct cost = \$324/kW, which is the sum of the above 4 items. Therefore, the total capital investment . . . (total/direct = 1420/770)

@ \$324 x 1,420/770 = \$598/kW

The total capital investment required for enhancing geothermal plants by direct firing from 65 MW to 102 MW is:

(102,000 - 65,000) \$598/kW = \$22,100,000 (increment)

The average cost is:

- Reference Plant: \$ 92,300,000
- Increment: \$ 22,100,000

TOTAL \$114,400,000, OR \$114,400,00/102,000 KW = \$1,120/KW

C. Gas Turbine

The capital cost for the gas turbine-generator is taken from a recent competitive bidding (Ref. 6). The direct capital cost including erection is \$130/kW for the 75 - 100 MW units, i.e., GT-31 class. The advanced (GT-42 class) 24 MW gas turbine-generator costs \$6 million, or \$250/kW. The total capital investment including \$30/kW for switchyard and transformer is (total/direct = 1420/770):

- o (250 + 30)1,420/770 = \$516/kW (GT-42)
- o (130 + 30)1,420/770 = \$295/kW (GT-31)

D. Other

The Potrero 7 Application for Certification (AFC) reported a total capital investment in 1983 of \$730/kW, and is used for comparison. The organic cycle will cost, based on the Heber project, \$1,000/kW. However, a bottoming cycle is not employed in this study.

III. CALCULATION OF LEVELIZED FUEL COST

The "average", or 30-year levelized energy cost, is obtained from the first year cost. The levelization factor is the ratio of present value with price escalation to the present value without price escalation.

The energy value in each future year, t, is discounted by the discount factor, i, by the term $(1+i)^{-t}$, in the tenth year. For example, discounted at 13.5 percent per year, each dollar spent has a present value of $(1+.135)^{-10}$, or 28.18¢. The sum of each of the discounted 30 years, or the present value of each annual dollar spent is $\sum_{1}^{30} (1+i)^{-t}$. This calculation assumes a constant annual nonescalating energy cost. This sum is \$7.241528798 per dollar per year of energy cost, i.e., the present value of \$1 spent each year for 30 years discounted annually at 13.5 and is called Present Worth Factor (PWF).

The annual discount term $(1+i)^{-t}$ can also be expressed as e^{-it} where $i=\ln(1+i_{\text{annual}})$. The 30 year sum is then given by $\frac{1-e^{-30\ln(1+i)}}{i}$.

The present value (pv) of the future energy cost with annual escalation (c) is given by:

$$\int_0^{30} e^{-(i-c)t}\,dt = \frac{1-e^{-30\ln\frac{1+i}{1+c}}}{i-c}$$

Numerically, if C = 6 percent escalation per year, and the discount rate i = 13.5 percent per year, the present value is \$11.61843314 per first year dollar per year.

The levelization factor (lf) is given by the ratio of pv to pwf or $\frac{11.61843314}{7.241528798}$ or 1.604417170

Combining equations gives

$$LF = \frac{1-e^{-n\ln\frac{1+i}{1+c}}}{1-e^{-n\ln(1+i)}} \times \frac{i}{i-c}$$

An equivalent and more conventional expression for the levelization also given by:

$$LF = \frac{\sum_{1}^{N} (1+c)^{n-1} \times (1+i)^{-n}}{\sum_{1}^{N} (1+i)^{-n}} = \frac{1-\left(\frac{1+c}{1+i}\right)^{N}}{1-(1+i)^{-N}} \times \frac{i}{i-c}$$

Computed values of LF, for various values of i and c are given in Table 3, page 22.

APPENDIX D

GEYSER'S STEAM PLANT HEAT BALANCES

Figure D-1 depicts a typical Geysers area geothermal steam plant. It uses about one million pounds per hour of geothermal steam and produces 53 net megawatts. This plant reinjects 20 percent (0.2 MMlbs/hr.) of the steam flow. The plant rejects 861 million Btu/hr, or 16,240 Btu/kWh.

Figure D-2 depicts the Geyser area reference geothermal plant. This plant uses about 1 million pounds per hour of geothermal steam but produces 65 net megawatts. This plant reinjects 14 percent (0.14 MMlbs/hr) of the steam flow. This plant rejects 845 million Btu/hr or 13,000 Btu/kWh.

This latter plant is taken as the reference plant in this study with which superheating is employed and compared. The heat rejection would increase to 985 million Btu/hr, or 9,660 Btu/kWh. The evaporation requirement would increase by 134,692 pounds/hour, leaving only 2,183 pounds/hour (0.22 percent) for reinjection (based on 65°F Wet Bulb Termperature (WBT), not annually average, but excludes cooling tower blow down requirements). This deficiency indicates that makeup water supply would have to be developed.

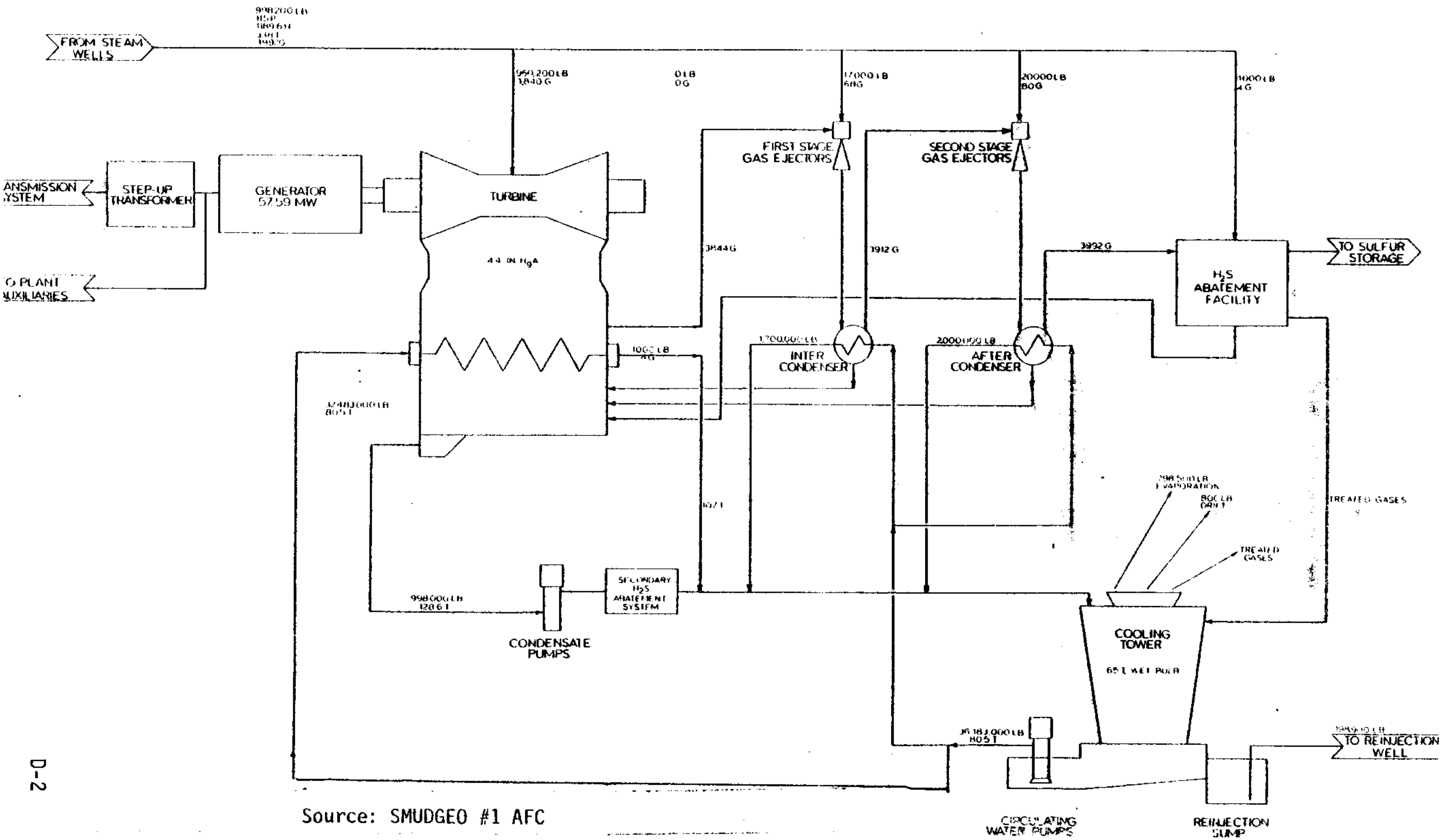
The throttle steam temperature would be increased to 900°F. The plant net generation would increase to 102 MW (see Appendix A, page A-5).

The cooling water flow, condenser surface and number of cooling towers would increase 15.93 percent (see Appendix A, page A-7)

The principal design change from a typical to the reference plant (Figures D-1 and D-2) is in the steam turbine. Figure D-1 symbolizes a 2 flow steam turbine with 23" last stage blade length, whereas Figure D-2 includes a 4 flow

FIGURE 14

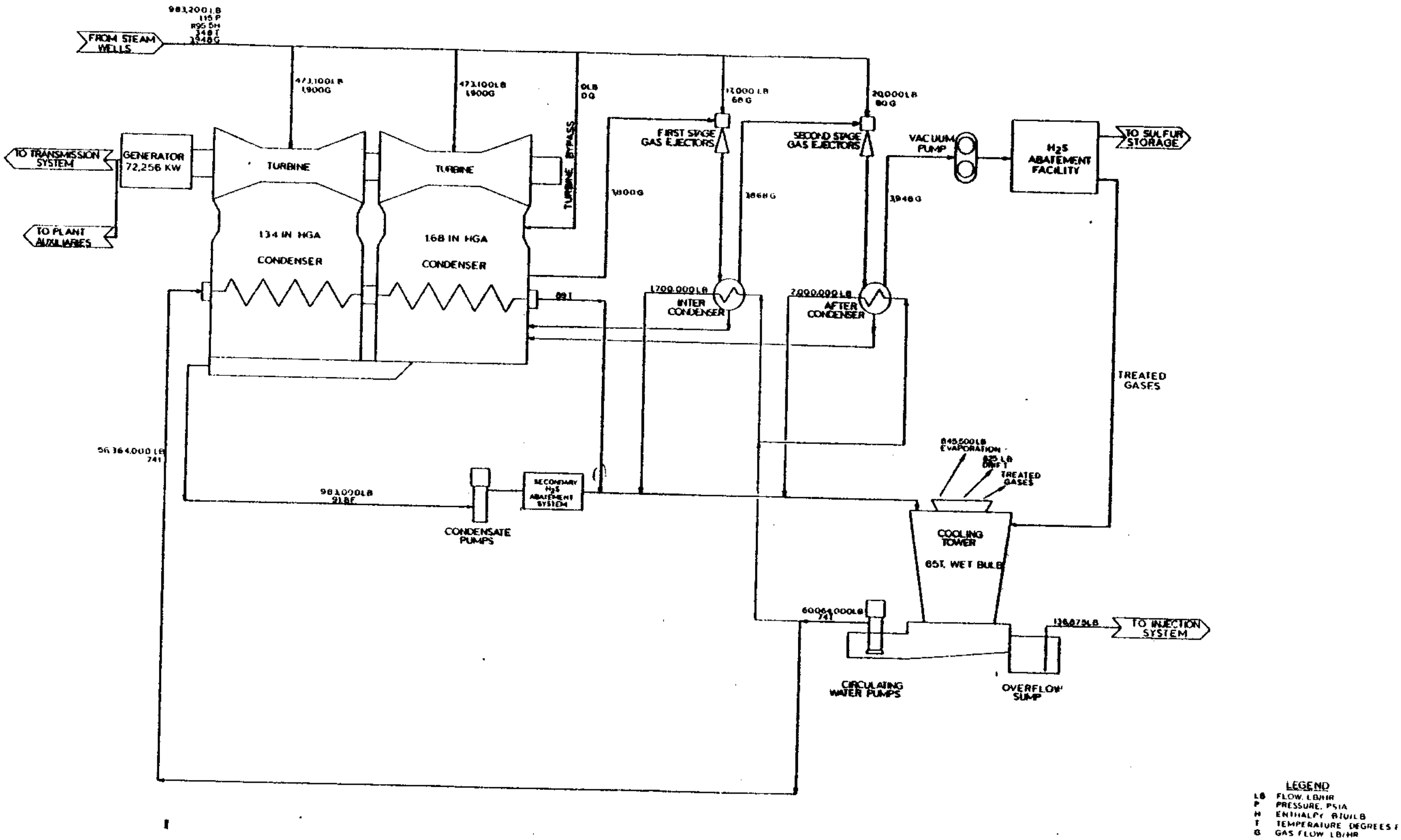
A Heat Balance of a Typical Geysers Area Geothermal Steam Plant



Source: SMUDGEO #1 AFC

FIGURE 15

A Heat Balance of a Reference Design Geyser Area Geothermal Power Plant



Source: SMDUGEO #1 AFC

steam turbine with 25" last stage blades. The steam losses leaving the turbine are greatly reduced with this design change. The turbine back pressure goes from 4.4 "of Hg to about 1.5" Hg. The gross generation increases from 57.59 MW to 72.256 MW (net 65 MW).

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