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EXPERIMENTAL GEOTHERMAL
RESEARCH FACILITIES STUDY
(Phase 0)

31 December 1974

Volume 2

Final Report No. 26405-6001-RU-00

Prepared for

THE NATIONAL SCIENCE FOUNDATION

Grant No. GI-44149

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6329000

TRW
SYSTEMS GROUP OF TRW INC.

1975

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INTRODUCTION

This report presents results of a study sponsored by the National Science Foundation as a part of their research program on utilization of geothermal resources. The study comprises Phase O of a project in "Experimental Geothermal Research Facilities", performed by TRW Systems Group under Grant No. GI-44149 of the National Science Foundation's overall program of Research Applied to National Needs (RANN).

This study focuses on identification of a representative liquid-dominated geothermal reservoir of moderate temperature and salinity, preliminary design of an appropriate energy conversion system, identification of critical technology and planning for the implementation of experimental facilities.

Volume I includes summarized results and reports on all of the major study efforts. Volume I also contains recommendations and conclusions derived from the study, including implementation plans for the next two phases of the program.

This volume, Volume II, presents detailed results of studies and analyses arranged in nine appendices including the final report by Rogers Engineering Company, a subcontractor to TRW on this study.

The specific appendices are:

- Appendix A: Geothermal Resources of the Western United States
- Appendix B: Site Selection Process and the East Mesa Geothermal Field
- Appendix C: East Mesa Geothermal Field Reservoir Characteristics
- Appendix D: Advisor's Views and Comments
- Appendix E: Thermodynamic Analyses
- Appendix F: Materials and Corrosion Factors

- Appendix G: Preliminary Reliability/Maintainability
Analyses
- Appendix H: Environmental Impact Analysis Guidelines
- Appendix I: Report to the National Science Foundation/
TRW Systems Group by Rogers Engineering
Company, Inc., San Francisco, California

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APPENDIX A

GEOTHERMAL RESOURCES OF THE WESTERN UNITED STATES

A1 RESOURCE EVALUATION

A1.1 Geologic Overview of Western U.S. Geothermal Province

The early years of geothermal energy development will be marked by the search for areas with anomalously high temperatures in ground water or rocks close to the earth's surface. With 1970's state-of-the-art technology, economic development for electric power generation will probably be limited to geothermal sources with maximum depths of 8,000 to 12,000 feet. The lower limit of temperature for economic electric power generation within the 1975-1980 period probably will be within the range of 300-400°F, possibly 325±25°F. Other geologic factors exerting significant control over the economics of a geothermal energy source are: a) water chemistry, b) reservoir characteristics, principally permeability and porosity of host rocks, c) reservoir areal extent and thickness, d) water and thermal recharge characteristics, e) potential for subsidence, and f) rock-formation characteristics affecting cost of drilling and well completion.

Some of the areas in the conterminous United States with anomalous temperature gradients are shown in Figure A-1. This map has been compiled from individual sheets of the AAPG Geothermal Survey of North America, where oil-well bottom-hole temperature were converted to temperature-gradient values, and so contains information only from areas in which such wells have been drilled. The mean temperature gradient for oil wells in the United States is 1.6°F/100 feet (29°C/km). Figure A-1 shows areas with gradients both higher and lower than this mean.

Figure A-2 shows the results of heat-flow measurements in the United States compiled from data in the open literature (Lee and Clark, 1966; Roy et al, 1968; Sass et al, 1971; Combs and Simmons, 1973; Reiter, 1973). Heat flow is the product of temperature gradient and thermal conductivity, and is generally a more reliable quantity than temperature gradient alone for comparison from place to place and for extrapolation downward from well-bottom depths. This is because heat flow is an actual energy flux that is constrained, more or less, to be constant with depth. Temperature gradient, on the other hand, is free re

to adjust itself to the local value of thermal conductivity, which may vary by a factor of three or more among common sedimentary rocks. The low temperature gradients in Texas, for example, result from normal heat flow in highly conductive evaporites and compact carbonates.

The most notable feature of the heat-flow map is the division of the United States into two clearly distinct heat-flow provinces. East of the Rockies, observed values of heat flow are narrowly distributed about a sharp peak near 1.2 heat flow unit (HFU)¹, with no values higher than 2.3 HFU. The western United States, in contrast, shows a broader distribution about a mean somewhere near 1.8 HFU, with a long tail toward higher values. This division is typical of a world-wide division of land areas into two thermal types. One type, like the eastern United States, has seen no tectonic activity since Mesozoic time, and has generally low and uniform heat flow. The other type, like the western United States, has undergone tectonic and volcanic activity in Cenozoic or Recent time, and shows higher and more scattered values of heat flow. All the producing geothermal fields of the world, and almost all the likely prospects, have been found in the second type of province; e. g., the circum-Pacific and Alpine belts; rift zones in Africa, the Middle East, and Russia; and islands associated with oceanic rifting.

In the U.S., several lines of geophysical evidence converge to indicate that the western province has a thinner crust than the eastern province, and is underlain by a hotter mantle. Magnetic deep soundings and observations of seismic travel-time anomalies also confirm the heat-flow measurements in showing that the Colorado Plateau is an island of "eastern" conditions in the western province.

Data from maps A-1 and A-2 are complementary in the areas they cover best. In particular, gradient measurements in Oregon fill a hole in the heat-flow data, while heat-flow data in Nevada and New Mexico fill some blank places on the gradient map.

¹ One heat flow unit (HFU) = 1×10^{-6} cal/cm²sec

Figure A-1

Figure A-2

Heat flow contours have been drawn on Figure A-2 wherever the density of data seemed to justify contouring. These contours are based mainly on the heat-flow data, with just a little assistance from geology and conjecture. No effort was made to stretch contours to pick up isolated data points. The 1.6 HFU contour outlines the regions of low heat flow on the Colorado Plateau and the Sierra Nevada batholith, and another area between these two in central Nevada. A single compact region of heat flow greater than 2.4 HFU is outlined in north central Nevada. Numerous other high values are certainly significant, but seemed too scattered and interspersed with lower values to allow meaningful contouring. Yellowstone National Park is marked on the map as an area where very high heat flow occurs.

One of the surface phenomena historically associated with anomalously high heat flow is the occurrence of hot springs. In the contiguous states of the U.S., hot-spring occurrences are concentrated in four mountainous areas as indicated on Figure A-3:

- a. The Appalachian Mountains, specifically, Georgia, West Virginia, and Virginia
- b. The eastern Ouachitas of S. W. Arkansas
- c. The southern end of the Black Hill Uplift of S. W. South Dakota
- d. The entire block of 11 mountainous western states essentially west of the 104° meridian, comprising New Mexico, Colorado, Wyoming, Montana, Idaho, Nevada, Utah, Arizona, California, Oregon and Washington.

However, none of the known hot springs east of the Rocky Mountain Front Range have temperatures high enough to indicate presence of a geothermal source that could be economically developed with existing technologies. In addition, most of these hot springs are thought to be the results of deep ground water circulation associated with normal geothermal gradients. All hot springs with high water temperatures lie

within the western 11 states; high temperature, as used here, is 170°F or greater. Locations of all hot springs in the western U.S. with temperatures $\geq 170^{\circ}\text{F}$ are shown in Figure A-4. These hot springs are shown in two categories, each with a temperature range of approximately 21°F; i. e., 170-190°F and 191°F to boiling. Hot-spring data in Figures A-3 and A-4 are from Waring (1965). Comparison of the temperature gradient and heat flow maps (Figures A-1 and A-2) with the hot-spring map (Figure A-3) indicates that the area with the greatest concentration of surface geothermal manifestations -- outside of Yellowstone Park -- comprises northern Nevada, northeastern California, southeastern Oregon, and southwestern Idaho.

Other active or geologically recent tectonic phenomena being used as potential indicators of geothermal deposits include:

- a. Concentrations of earthquake epicenters
- b. Traces of major fault zones
- c. Areas underlain by Tertiary volcanic rocks, especially areas containing rocks of Pleistocene or Holocene age
- d. Areas marked by alignments of recent volcanoes or of volcanic cinder cones

If all of the above geologic indicators are considered together, then the entire block of 11 western states can be viewed as a major geothermal province comprising a complex of closely related but differently controlled individual sub- or mini-geothermal provinces. Some of the more prominent of these sub-provinces include:

- a. The great belt of northwesterly trending intensely faulted rocks paralleling the San Andreas fault zone, and stretching from the Mexican border to Eureka in northern California. This belt contains at its southern end the Imperial Valley with its complex of geothermal areas including the Mesa, Heber, Niland, Brawley, Border, and Dunes anomalies. At its northern end is the Geysers geothermal field.

Figure A-3

Figure A-4

- b. A 1350-mile long arcuate belt stretching from southern Arizona to southwestern New Mexico, then trending north along the Rio Grande rift zone, extending north through Colorado paralleling the Rocky Mountain Front Range to southeastern Wyoming, then swinging northwest through Yellowstone Park and into southwestern Montana.
- c. A relatively narrow, northerly trending, sinuous belt that follows the line of major Tertiary- and Quaternary-age volcanoes in northern California, Oregon and Washington.
- d. That portion of the Great Basin and Range complex that includes northern Nevada, southern Idaho, southwestern Oregon and northeastern California. Geothermal activity here seems to be distributed throughout this great roughly circular area. However, concentrations of individual surface geothermal and tectonic features such as hot springs, earthquake epicenters and faults tend to bound the north-trending, horst and graben, block structures of the Basin and Range.

In addition to the four geothermal sub-provinces described above, several other zones of anomalous geothermal activity can be identified by alignments and masses of hot springs depicted in Figure A-3. Some of the most obvious of these zones include:

- a. The northerly trending line of hot springs and volcanic cinder cones in Owens Valley that lies just east of the Sierra Nevada fault front. Included here are the important geothermal features of the collapsed caldera of Long Valley, with its Casa Diablo Hot Springs; the Mono Craters; and the Coso Hot Springs.
- b. The northerly trending arcuate belt of hot springs that lies along the western flank of the Wasatch Range in north central Utah and the northwestern margin of the Colorado Plateau in central Utah.
- c. The easterly trending, semicircular belt of hot springs and recent volcanic deposits that follows the Snake River Graben in southwestern Idaho, continues along the Snake River Downwarp in southeastern Idaho, and ends at Yellowstone Park.
- d. The complex of hot springs distributed throughout the roughly circular body of granitic rocks of the Idaho batholith, that lies just north of the Snake River Graben and Downwarp.

Areas in the western U.S. deficient in apparent surface geothermal phenomena and which probably are poor exploration targets, include:

- a. The Colorado Plateau area of northern Arizona and southern Utah.

- b. The belt of rocks lying south of the Canadian border in eastern Washington, northern Idaho and northern Montana which is underlain by Columbia River basalts and Pre-cambrian rocks of the Belt series. However, within this broad belt, local areas of high geothermal gradients are found in association with bodies of surface or near surface intrusive igneous rocks.
- c. The northerly trending zone along the Pacific Coast stretching from northern California to the Canadian border, that lies west of the Cascades.
- d. The northwesterly trending zone in central California that includes the great California Valley and the mountain massif of the Sierra Nevadas.

Wildcat drilling for geothermal energy in the United States has been underway for approximately 20 years. The Magma Power Company was the early leader in exploration and drilled many shallow test holes in the western United States, to depths ranging from a few hundred feet to nearly 2000 feet. Siting of the holes was based mainly on the presence of surface thermal manifestations. This resulted in almost all of the holes producing steam, but only one commercial field has so far been developed as a result of this drilling program, that field being the Geysers in California.

Within the last few years, a program of drilling deeper holes has been initiated by many companies engaged in geothermal exploration. In addition to being deeper than the Magma tests, these wells also have been sited on the basis of geophysical as well as geological data. Specific areas in the western U.S. where geothermal development and/or exploration has been concentrated, are summarized in Tables A-I and A-II and shown on Figure A-5.

As can be seen on Figure A-5, exploration to date has been concentrated in five of the geothermal sub-provinces or zones described above -- 1) the northern and southern ends of the San Andreas fault zone; 2) the arcuate belt stretching from southern Arizona to southwestern Montana; 3) portions of the Basin and Range within Nevada, California and Idaho; and the mountain-front fault valleys, 4) east of the Sierra Nevadas in California; and 5) west of the Wasatch Range in Utah.

Table A-1. Geothermal Areas in the Western U. S. with Shallow Wells and/or Surface Geophysical Exploration (Dec, 1974).

Areas With Shallow Wells	Areas With Surface Geophysical Data, Most Have Shallow Wells
<ul style="list-style-type: none"> a. Darrough, Nevada b. Mount Lassen (Terminal Geyser), California c. Arrowhead Springs, California d. Monte Neva, Nevada e. Cedarville, California f. Wendel, California g. Amedee, California h. Crump (Adel), Oregon i. Lakeview, Oregon j. Fales Hot Spring, California k. Bridgeport, California l. Tecopa, California m. Randsburg, California n. Genoa, Nevada o. Smith Valley, Nevada p. Fernley (Hazen), Nevada q. Crescent Valley, Nevada r. Klamath Falls, Oregon s. Bruns, Oregon t. Desert Hot Springs, California u. Animas Valley, New Mexico v. Boise, Idaho 	<ul style="list-style-type: none"> A. Raft River Valley, Idaho B. Steamboat Springs, Nevada C. Ward (Fly) Ranch, Nevada D. Coso Hot Springs, California E. Cuddeback Lake, California F. Casa Diablo (Mammoth, Long Valley), California G. Buffalo Valley, Nevada

Table A-II. Geothermal Areas in the Western U.S. With Deep Wells or Proven Fields (December, 1974).

Areas With Deep Wells, Most Have Surface Geo- physical Surveys	Unique Geothermal Fields
<ol style="list-style-type: none"> 1. East Mesa, California 2. Heber, California 3. Baca Ranch Lease, Valles Caldera, New Mexico 4. Hot Dry Rock Test Area, Valles Caldera, New Mexico 5. Marysville, Montana 6. Mountain Home, Idaho 7. Brigham City, Utah 8. Brady's Hot Springs, Nevada 9. Beowawe, Nevada 10. Pyramid Lake, Nevada 11. Desert Valley, Nevada 12. Fallon, Nevada 13. Mono Lake, California 14. Clear Lake, Modoc County, California 15. High Valley Ranch - Tyler Creek, California 16. Lake City (Surprise Valley), California 17. Honey Lake, California 18. Chandler, Arizona 19. Casa Grande, Arizona 20. Sand Dunes National Monument, Colorado 21. Calistoga, California 22. Wilbur Springs, California 23. Wabuska, Nevada 24. Stillwater, Nevada 25. Kelley's Hot Spring, California 26. Fort Bragg, California 27. Le Grande, Oregon 	<ol style="list-style-type: none"> I. Geyser Dry Steam Field, California II. Niland High Salinity Field, California

Figure A-5

A2 SUMMARY OF GEOTHERMAL SITES IN THE U.S. WITH DEEP WELLS

A2.1 East Mesa, Imperial County, California

The East Mesa area has been under study by the U.S. Bureau of Reclamation (USBR) for a period of about **six years**. The USBR has been intensely interested in East Mesa as a potential source of two major products - desalinized water and electrical power. Discovery of this geothermal anomaly was based on a regional shallow-well thermal-gradient study of southern Imperial Valley. Other surface geophysical techniques used included gravity, electrical resistivity, microearthquake activity, and seismic noise surveys. Much of the **geophysical work** has been done for the USBR by the University of California at Riverside (UCR). Extensive detailed data on subsurface conditions has been provided by five deep wells, four of which bottom at approximately 6,000 feet and one at 8,000 feet. The East Mesa area is described further in Appendix B.

A2.2 Heber, Imperial County, California

The Heber area is one of the two (Baca Ranch, discussed next, is the other) geothermal fields of the hot water-type deposits within the United States generally considered to have been sufficiently proven to justify installation of at least a demonstration-type electric generating plant. As used here, a proven geothermal field **requires**: a) **completion** of extensive surface geophysical surveys, b) existence of several deep wells - at least three wells with depths greater than 3,000 feet, and c) full-scale production and reinjection tests of at least several months duration.

Development work at Heber is being performed by a team consisting of Chevron Oil Company, Magma Power, and San Diego Gas and Electric. Discovery of this field was based on high thermal gradients located during the drilling of shallow wells several years ago by scientists at UCR. Subsequent to discovery, a number of geophysical surveys of various types were conducted to confirm location of the anomaly.

Of the deep wells drilled, three have been incorporated into an extensive production-reinjection test program for determining reservoir characteristics. These are the "Hertz" 1 (Sec. 32, T16S, R14E) production,

the 5030-foot deep "Nowland Partnership" 1 (SE1/4, Sec 33, T16S, R14E, SBB&M) production well, and the "Hertz" 2 reinjection well. Reportedly, wells range in depth from 3,000 to 6,000 feet, and penetrate rocks with salinity of 35,000 to 40,000 ppm. Temperatures range between 450° and 550°F.

A2.3 Baca Ranch Lease, Valles Caldera, New Mexico

The Valles Caldera, located approximately 60 miles north of Albuquerque, New Mexico, was formed by the collapse of a Pleistocene volcano during eruption of massive sheets of pyroclastics. Surface geothermal phenomena in the area include the Jemez and Sulphur Hot Springs.

Geothermal waters were initially discovered in 1960 by a 3680-foot wildcat well drilled by Weslakes Petroleum Company. The temperature measured at 3650 feet was 275°F. Three wells were drilled in 1963-64 by Dunigan Tool and Supply Company and Associates. These wells -- Steam Wells Nos. 1, 2, and 3 -- were drilled to depths of 2,650, 5,600, and approximately 2,600 feet, respectively. Steam Well No. 1, tested between 1,300 - 1,500 feet at 85,000 pounds of steam per hour with temperatures up to 500°F. However, bottom-hole temperature was 310°-320°F. Steam Well No. 2 exhibited temperatures in excess of 400°F (Summers, 1965).

Current activity involves the Union Oil Company of California acting as operator for a team including Dunigan Enterprises and Baca Land and Cattle Company. Of the twelve wells drilled in a six square-mile area adjacent to the discovery well, the last seven have been drilled by Union. Dry steam is produced from some wells and steam mixed with water from others. Salinity is low. Temperatures in the Union wells are reportedly in the range of 450° to 600°F, with production being from depths ranging from 5,000 to 8,000 feet. Water in the reservoir is under hydrostatic pressure. Well location has been based on geological studies, possibly aided by resistivity and seismic-noise surveys. Reservoir engineering work by Union has included full-scale production and reinjection tests over a time span exceeding one year. Prior to reinjection, the water is held in settling ponds. Water has been produced at 500-600 gallons per minute without causing any response in adjacent wells in the field. The recently completed and

most successful well - the "Baca" 11, near the north 1/4 corner of projected Sec. 12, T19N, R3W, - was drilled to a depth of 6,829 feet and has produced separated steam with a power capacity of 6.5 MWe.

A2.4 Dry Hot Rock Test, Valles Caldera, New Mexico

In addition to the Union Oil activity within the Valles Caldera, two wells have been drilled a few miles west of the caldera as a part of the Atomic Energy Commission (AEC) program for developing geothermal energy from dry hot rocks.

In this experiment, a deep hole is drilled into anomalously hot dry rock. Rock adjacent to the hole is then fractured - by liquid explosives, hydrofracturing, or other techniques - forming a linear crack of considerable extent. A second hole is then drilled into this crack. A self-circulating closed-loop cycle is then to be established where cold water flows down the deep hole and into the crack where it is heated, then rises up the shallow well to the surface where heat is extracted and the cooled water is returned to the deep well.

The site selected by the AEC was planned to intercept Precambrian basement rocks. One hole, GT-1 (SE 1/4, Sec. 1, R2E, T19N), was drilled to a depth of 2,575 feet, the bottom 500 feet of which are in highly fractured Precambrian rocks. However, fractures in the Precambrian are closed, and the resulting low permeabilities will permit a full-scale dry hot rock experiment including rock fracturing by hydrofracturing or other techniques. At hole bottom, temperature in GT-1 is 212°F and water pressure is 2,500 psi.

Drilling at the second hole, GT-2, approximately 1-1/2 miles from GT-1, was temporarily halted by fishing operations during early December 1974. Temperatures measured at 6,500 and 8,500 feet were 284°F and 365°F, respectively. Temperature projected for the present hole bottom at 9,550 feet is between 385°F and 390°F. Plans are to drill the hole to a final depth of approximately 10,000 feet by the end of December. The hole has intercepted three major rock types - an upper zone in the Paliza Canyon formation, comprised of a wet tuff that caved badly; a cavernous limestone in the Sandia formation in which drilling fluid was lost; and Precambrian basement. In the Precambrian, a highly

fractured zone with high water flow was intercepted at 3,250 feet; however, below 3,650 feet the rocks have comprised a very tight system, and can be considered to be dry hot rock.

When the GT-2 hole bottom was at 6,700 feet, a hydrofracturing test was performed. Between 40,000 and 50,000 gallons of water were pumped into the hole, below a rigid metal packer. This resulted in creation of a single vertical fracture with a strike of N45°W, paralleling the dominant natural fracture system in the area. On reaching final hole depth, it is planned that a major fracture will be created at hole bottom by pumping approximately 1,000,000 gallons of water into GT-2. It is expected that a single vertical fracture will be created with a length of approximately 1 km. A second, shallower, hole will then be drilled approximately 100 to 200 feet from GT-2 to intercept this fracture. These two holes will comprise the subsurface installation for the dry hot rock experiment.

A2.5 Marysville, Montana

This geothermal research program, funded as a dry hot rock experiment by NSF, has involved Battelle Northwest as prime contractor, Southern Methodist University (SMU) as geotechnical advisor, and Rogers Engineering as drilling supervisor. The drilling site was located primarily on the basis of the discovery, by Dr. D. Blackwell of SMU, of high thermal gradients in shallow boreholes, with gradients of up to 38°F/100 feet. The shallow-hole survey outlined a 2-square-mile, heat-flow anomaly of 10-15 heat flow units (1 HFU = 10^{-6} cal/cm²sec). This geothermal anomaly, just west of the Marysville stock, is on the southeast side of Empire Creek (NE 1/4, Sec. 32, T12N, R6W), approximately 20 miles northwest of Helena and 3-1/2 miles west of the old gold-mining town of Marysville. The geothermal anomaly is associated with a dome in Precambrian argillites of the Belt Series. Other geophysical techniques used have included: a) **gravity surveys**, with discovery of a 4-10 milligal anomaly coincident with the structural dome and geothermal anomaly, b) magnetic surveys, with discovery of a 1500-gamma anomaly associated with the Marysville stock, but no anomaly over the geothermal area, and c) microearthquake and seismic noise surveys, with the observation of no anomalous seismic activity.

During drilling, basement was reached at 975 feet in the form of a quartz-feldspar porphyry. At 1500 feet, a series of **open fractures** was intercepted that flowed up to 1,000 gallons of hot water per minute. After plugging, the hole was continued to a depth of 6,770 feet where an extensive fracture system flowing hot water was found. At 6,790-foot maximum depth, the hole caved back to about 6,720 feet. Temperature, measured at 190°F at 1,500 feet, had increased only to a maximum 205°F at 6,720-6,790 feet. Because of this low temperature gradient, drilling was stopped and the project essentially terminated.

A2.6 Mountain Home, Idaho

The Gulf Oil Company has reported the discovery of a geothermal prospect while drilling a wildcat well about 13-1/2 miles southeast of Mountain Home. The hole, 9,678 feet deep, is entirely in a volcanic sequence of basalt flows, tuffs, and welded tuffs. The site, reportedly located by remote sensing techniques, is on a fault zone and in an area with gravitational evidence of a shallow intrusive. Bottom-hole temperature has stabilized at 382°F. Water salinity is very low; in fact, the water can be used directly for drinking purposes. Hot water from fractures at hole bottom initially flowed at an estimated 1,000 **gallon/minute** rate but decreased to a 150 **gallon/minute rate within a week**, and ceased flowing within two weeks. Consideration is being given to explosively fracturing the bottom-hole rock as a well-stimulation experiment.

A2.7 Brigham City, Utah

In early 1974, Geothermal Kinetics in conjunction with Utah Power and Light drilled the "Steam Venture - Davis" 1, as a geothermal test of a thick sequence of Paleozoic carbonate rocks just west of the Wasatch Range front. The well is adjacent to Interstate 15, six miles north of Brigham City (2,370 feet S and 4,950 feet W of the NE corner, Sec. 16, T10N, R2W, SLB&M). The well was sited with the intention of intercepting one of the faults within the Wasatch Front fault zone. The site was selected on the basis of surface geological studies combined with resistivity, seismic noise and seismic reflection surveys. The well bottomed at about 11,000 feet, and is still under test. At present, it

is not certain that temperatures are high enough for anything but space-heating applications.

Natural surface geothermal phenomena in the area include a series of warm springs along the western base of the Wasatch Front. Most prominent of these is Crystal Hot Springs, 1-1/2 miles NE of the test well; the spring flows at a rate of three cubic feet per second, at a temperature of 135°F.

A2.8 Brady's Hot Springs, Nevada

The Union Oil Company has drilled a geothermal test recently to about 7,000 feet near Brady's Hot Spring. The temperature is a "little on the low side", according to Union, which probably means about 400°F in their terms. Also, production tests show a poor performance for the well, which was drilled with mud, but the production rate is improving slowly with time. Earlier exploration at Brady's Hot Springs included the drilling of nine wells by Magma Power Company and two wells by Earth Energy, Inc., between 1959 and 1965. Maximum depth reached was 5,060 feet and maximum temperature was 418°F. The dominantly hot-water deposits contain approximately 5% steam. Surface phenomena include boiling springs and steam seeps.

A2.9 Beowawe, Nevada

The Chevron Oil Company has been drilling a geothermal test at Beowawe during the summer of 1974. The hole bottomed below 9,000 feet after many drilling problems. The only information available is that drilling the hole cost nearly a million dollars. The site is near 11 wells drilled by Magma Power Company between 1959 and 1965; maximum depth was 2,052 feet. Geothermal fluids encountered by Magma were hot water with 5-10 percent steam flashover; maximum temperature was 414°F. Surface phenomena at Beowawe include steam seeps, fumaroles, geysers, and hot springs with temperatures up to 205°F.

A2.10 Pyramid Lake, Nevada

In 1964, Western Geothermal, Inc., drilled three wells on the north end of Pyramid Lake near hot springs with a surface temperature at 208°F. Temperatures up to approximately 240°F are reported, with

maximum well depth being 5,888 feet. No further testing of this prospect has taken place because of land use problems; the site lies on an Indian Reservation.

A2.11 Sierra Valley, California

The Phillips Petroleum Company is said to have scheduled an 8,000 foot test in Sierra Valley, based on electrical resistivity and seismic noise surveys. The hole was abandoned at 2,000 feet when granite was encountered.

A2.12 Fallon, Nevada

Phillips has also drilled a shallow test on electrical resistivity and seismic noise anomalies near Fallon, but abandoned the hole without testing.

A2.13 Mono Lake Area, California

About three years ago, the Getty Oil Company drilled a geothermal test to about 7,000 feet on the north shore of Mono Lake, California. The location was based on a seismic noise survey; bottom-hole temperature was reported to be low.

A2.14 Clear Lake Area, Modoc County, California

The Getty Oil Company drilled a deep test at Mount Konocti on the south shore of Clear Lake, California, about 1972. The hole bottomed below 9,000 feet. "Interesting" temperatures were found, but no permeability was encountered. The hole was subsequently sold to Pacific Energy Corporation, who considered deepening it, but ultimately abandoned it. Earlier work at Clear Lake included the drilling of four geothermal wells between 1961 and 1964 by Magma Power Company and Earth Energy, Inc. (now a part of Union Oil Company). Maximum depth reached was approximately 5,000 feet and maximum temperature measured was 367°F. Fluids were hot water with approximately five percent steam flashover. One well, bottoming at 1,400 feet, produced over 50,000 pounds of steam and 1,500,000 pounds of hot water per hour at a pressure of approximately 100 psig. Fluid constituents include problem amounts of boron and carbon dioxide.

A2.15 High Valley Ranch - Tyler Creek, California

The Sun Oil Company drilled a geothermal test about 1972, ten miles northwest of the Geysers field. The hole, located on the basis of electrical-resistivity and seismic-noise surveys, reached about 7,000 feet with bottom-hole temperatures of about 300°F. However, the section was impermeable, and the hole was abandoned.

A2.16 Lake City (Surprise Valley), California

The Gulf Oil Company drilled a geothermal test in the vicinity of Lake City in 1973, based on resistivity and seismic noise surveys. The test was reportedly unsuccessful. Drilling of four wells, with a maximum depth of 2,150 feet, and a temperature of 320°F, by Magma Power Company in 1959 and 1962, was based on the presence of surface geothermal phenomena including hot springs and a mud volcano that erupted in 1951. Nearby drilling has included unsuccessful geothermal tests at hot springs ten miles to the southwest and a wildcat oil test in the valley to the west; temperatures approaching 300°F were measured in this 9,564 foot hole.

A2.17 Honey Lake, California

Gulf Oil Company drilled two geothermal tests on the north edge of Honey Lake during 1973. The locations were selected on the basis of electrical-resistivity and seismic-noise surveys. It is reported that a temperature reversal was found as impermeable shale beds were penetrated.

A2.18 Chandler Area, Arizona

This area was explored and drilled by Geothermal Kinetics, Inc., following geophysical surveys, primarily seismic noise and electrical resistivity. Two wells were drilled to about 10,000 feet, passing through highly altered volcanics below 6,000 feet. Bottom-hole temperatures ranging from 270°F to 370°F have been observed in these two wells, but when the wells are permitted to flow, the temperature of produced water drops to 180°F to 200°F. This indicates that the hotter rocks near the bottom of the holes probably are relatively impermeable. A well-stimulation experiment is being considered where the upper

cooler sections would be sealed off, and the lower hot rocks would be fractured by hydro or liquid-explosive techniques.

A2.19 Casa Grande, Arizona

Geothermal Kinetics, Inc., has recently completed (Nov. or Dec., 1974) a test a few miles north of Casa Grande, at a depth of about 7,000 feet. The well is currently being tested and no information is available. Location was based on electrical-resistivity surveys, seismic-noise surveys, microseismicity data, and temperatures observed in shallow water wells.

A2.20 Sand Dunes National Monument, Colorado

During early 1974, Mapco drilled a 10,000-foot geothermal test in San Luis Valley, a few miles west of Sand Dunes National Monument. Reportedly, the hole was sited by photogeological studies, and the bottom-hole temperature was very low.

A2.21 Calistoga, California

In 1960-61, the Calistoga Power Company drilled three wells at Calistoga, California, with at least one well exceeding a depth of 2,000 feet. Maximum temperature encountered was 278°F. The wells were drilled in a zone two miles long that contains numerous shallow wells used for heating greenhouses, homes, and hotels in the Calistoga area. As the thermal waters are circulated directly without benefit of heat exchangers, severe corrosion and deposition problems have been encountered. One of the shallow wells periodically geysers, with eruptions reaching a height of 40 feet. Maximum recorded temperature of hot springs in the area is 173°F.

A2.22 Wilbur Springs, California

Wells drilled by Magma Power Company in 1965 and Cordero Mining Company with Worldwide Geothermal Exploration Company in 1968 reached a maximum depth of 3,717 feet and encountered a maximum temperature of 285°F. The wells flowed large amounts of hot water with a minor steam content; total dissolved solid content was 30,000 ppm.

A2.23 Wabuska, Nevada

Three wells drilled in 1959 by Magma Power Company which reached a maximum depth of 2,223 feet, had a maximum temperature of 222°F. The wells were drilled adjacent to hot springs with temperatures up to 162°F.

A2.24 Stillwater, Nevada

In 1964, O'Neill Geothermal, Inc., and the Charles Oliphant Company drilled a well in Carson Sink near Stillwater, Nevada, to a depth greater than 3,200 feet. The well flowed large amounts of hot water; maximum temperature was approximately 240°F. There are surface phenomena; however, a nearby shallow well (270 feet deep) flows water at 190°F.

A2.25 Kelley's Hot Spring, California

Geothermal Resources International drilled a 3,206 foot well in 1969 near Kelley's Hot Spring, California. Though surface water in the hot spring was 204°F, maximum temperature encountered in the well was only 230°F.

A2.26 Fort Bragg, California

Two wells were drilled at Fort Bragg in 1965 by Northern Plains Petroleum Company based on photogeologic and geochemical prospecting data. Maximum depth reached was 3,977 feet and maximum temperature was 148°F.

A2.27 Le Grande, Oregon

A geothermal test **approximately eight miles southeast of the town** of Le Grande is being drilled to a target depth of 6,000 feet. Currently, drilling has been suspended at 3,000 feet. Temperatures at this depth are moderately warm but the actual reservoir is thought to be deeper.

Some of the data given above for the years prior to 1970, and especially prior to 1965, are from Koenig (1970).

APPENDIX A REFERENCES

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APPENDIX B

SITE SELECTION PROCESS AND THE EAST MESA GEOTHERMAL FIELD

B1 EXPERIMENTAL FACILITY SITE SELECTION PROCESS

Candidate sites for the experimental facility could be categorized in progressive order of desirability, as follows:

- a. Regional areas of geothermal potential based on favorable geologic relationships.
- b. Specific areas with known anomalously high geothermal gradients or hot-springs.
- c. Favorable areas with extensive surface geophysical exploration and shallow test wells.
- d. Favorable areas with extensive surface geophysical exploration and deep geothermal wells; i. e., wells with depths of 2,000 feet or greater.
- e. Proven or indicated geothermal fields.

In the interests of a relatively short implementation schedule for the experimental facility, candidate sites were limited to categories d and e above - that is, to those areas with extensive surface geophysics, with existing deep wells, or areas with a proven or indicated geothermal reservoir.

B1.1 Basic Criteria

The basic set of criteria then established for controlling site selection included the following:

- a. Candidate sites would be limited to areas with existing deep geothermal wells.
- b. The site selected would be representative of a major hot-water type deposit.
- c. The site selected would be limited to deposits having low to moderate salinity. Apparently unique areas, such as Niland, California, with its 20 to 30 percent salinity, would be avoided.
- d. The site selected must be capable of rapid utilization, based on technical, economical and political factors.

B1.2 Overall Characteristics

Considering the above basic criteria, a list of over all characteristics were then established for an ideal site; these comprised the following:

- a. Favorable geologic setting.
- b. History of extensive resource assessments, including
 - 1. Surface geophysical surveys
 - 2. Deep geothermal well drilling
 - 3. Geophysical well logging
 - 4. Well flow-rate, well-head and drill-stem, and production-reinjection testing
- c. Favorable reservoir characteristics, including
 - 1. Desirable porosities and permeabilities
 - 2. Thick sequence of permeable fluid-bearing strata within the reservoir
 - 3. Large areal extent of the reservoir, permitting future major development
 - 4. Inter- and intra-strata communication, permitting efficient full-field development.
- d. Geothermal data readily available.
- e. No restrictions on release of all technical data.
- f. Adequate land space readily available for the experimental facility.
- g. Minimal environmental problems.
- h. Minimal objections from local populace and political groups.

B1-3 East Mesa Evaluation

In an evaluation of candidate sites in the Western United States where deep geothermal wells exist, the East Mesa area in the Imperial Valley

of California appeared to best match the above criteria. Pertinent characteristics of the East Mesa area include:

- a. An extensive history of surface geophysical exploration, deep well drilling with geophysical logging, and well monitoring and testing.
- b. Low to moderate salinities, ranging from 2,000 to 3,000 ppm in the upper portions and 10,000 to 25,000 ppm in the deeper portions of the reservoir.
- c. Desirable temperature characteristics ranging from approximately 315°F in the upper portions to 390°F in the deeper portions of the reservoir.
- d. Located on federal lands and under federal control
- e. Absence of any known environmental problems
- f. No known major political or institutional problems

Because of the extent of geophysical exploration, the number of deep wells, and the knowledge of the reservoir characteristics, East Mesa can be considered one of the three proven or indicated geothermal fields of the hot-water type with moderate salinities in the United States today. The other two fields, Heber, California, and the Valles Caldera, New Mexico, are being developed commercially by Chevron and Union Oil Company, respectively. The East Mesa field, however, being on land that is under the ownership and control of the federal government, appears to be an excellent candidate for the experimental facility site.

Soon after the initiation of the study, TRW was directed to consider East Mesa to be the site of the experimental facility and to cease collecting data on alternate sites as a major task.

B2 EAST MESA GEOTHERMAL FIELD

The East Mesa geothermal field is centered in Section 6, T16S, R17E, approximately seven miles southeast of the town of Holtville in Imperial County, California, Figure B-1. The field is within the East Mesa Known Geothermal Resource Area (KGRA) on the Mesa anomaly; the Border anomaly lies to the southeast, within the same KGRA.

The East Mesa field currently comprises five deep (6,000 to 8,000 feet) wells drilled for the USBR by the Big Chief Drilling Company. These wells were drilled specifically as geothermal tests and are designated, in order of completion, as Mesa 6-1 (1972), 6-2 (1973), 5-1, 8-1, and 31-1 (1974). Four of these wells were planned as geothermal producers while the fifth, the Mesa 5-1, is an injection well.

Geophysical work in the area was initiated in 1968 by the USBR in cooperation with the University of California at Riverside (UCR). Resistivity and microseismic surveys were completed in 1973 and telluric and additional microseismic work is now underway.

B2-1 Geologic Setting

The East Mesa geothermal field lies on the east flank of the Salton Trough, a crustal break of global significance. The trough is the continental extension of an oceanic spreading center known as the East Pacific Rise. As the trough spread, it was filled with sediments transported largely by streams that comprised the ancestral Colorado River drainage system. These sediments underlie the Imperial Valley and the East Mesa area. The Salton Trough contains the producing geothermal field at Cerro Prieto in Mexico, the high-temperature high-salinity field at Niland, California, and the developing field at Heber, California.

There are no bedrock outcrops in Imperial Valley. Crustal rocks are exposed in the Chocolate Mountains and the Cargo Muchacho Mountains with its Ogilby Hills outlier. These outcrops are approximately 25 miles to the northeast and east, respectively. These crustal rocks are Tertiary volcanics, discordant on a basement complex of granitic gneiss and schist.

The surface at East Mesa is barren and featureless alluvium and dune sand. There are no hot springs or other surface evidence of geothermal activity.

The subsurface at East Mesa is a deltaic sequence of sands, silts and clays becoming compacted to sandstone, siltstone and claystone with depth. Seismic refraction data obtained by UCR indicate the depth to basement under East Mesa to be at least 11,000 feet. A wildcat well located approximately 3.5 miles northeast of the geothermal field was drilled to a depth of 10,624 feet without completely penetrating the deltaic section.

Figure B-1. East Mesa Geothermal Field

B2.2 Geophysics

A large amount of geophysical information has been obtained in the East Mesa area including thermal, gravity, electrical and seismic data. Each of these suites of data is discussed below.

B2.2.1 Thermal Data

Thermal data have been of prime importance in delineating the East Mesa geothermal field. Thermal data have been obtained from approximately 50 test holes drilled in the general area, 40 of which are located in the immediate East Mesa area. The test holes range in depth from 100 to 1406 feet with the maximum being at DH-127, located on the northern one-half of Section 17, T16S, R17E.

The steady-state temperature profile of each test hole was measured by thermistors. Figure B-2 depicts isothermal contours at a depth of 600 feet along with the specific test holes that are sufficiently deep to provide data at that depth. A thermal closure of approximately 20°F is indicated with the maximum lying over the geothermal field. Thermal contour maps have also been drawn for shallower depths and the closure broadens with decreasing depth. The approximate 20°F closure remains unchanged at the shallower depths as does the location of the maximum.

Heat flow is a more meaningful parameter than temperature gradient in geothermal investigations. Heat flow is defined as the product of the temperature gradient across a geologic section and the thermal conductivity of that section. Heat flow in the East Mesa has been determined by the "best clay" techniques described by USBR (1973) with results depicted in Figure B-3. The East Mesa area shows a heat-flow closure of approximately 4 HFU and covering an area of approximately 18 square miles. The geothermal field is located on the heat flow maximum.

The figure also depicts postulated faulting in the area; this faulting is discussed more fully in B3.2 below. The closure within the KGRA to the southeast is known as the Border anomaly.

B2.2.2 Gravity and Magnetic Data

A gravity survey of the East Mesa area has been made with the resulting Bouguer anomaly map shown in Figure B-4. A Bouguer density of 2.00 was assumed in the construction of this map (Rex et al, 1971). A positive anomaly of approximately five milligals is indicated. A residual map was computed from this Bouguer map and is presented in Figure B-5. Here again, a positive anomaly of approximately five milligals is seen. Both the Bouguer and residual maxima generally coincide with the geothermal field.

The positive nature of the gravity anomaly indicates a mass excess. Much of this excess has been computed to be within the sedimentary section (Rex et al, 1971); the cause has been attributed to geothermal activity in the form of silica deposition, baking of clay sediments and low grade metamorphism (USBR, 1971).

No magnetic data are available in the East Mesa area but an informal examination of magnetic data obtained by commercial interests indicates that there is no magnetic anomaly (Dr. J. Combs, Pers. Comm., 1974).

B2.2.3 Seismic Data

Seismic noise measurements in the East Mesa area have been made (USBR, 1971), with the results summarized in Figure B-6. A maximum indicating a high noise level, is seen coinciding with and trending south from the geothermal field. A later seismic noise survey conducted by the USGS failed to find indications of high noise (Iyer, 1974). These differences in results might be explained by different integration times used in data analysis. USBR data were analyzed using seismic signatures over 10-second time periods in order to remove cultural noise. Reportedly, USGS data were analyzed using 90-second integration periods.

A seismic monitoring network has been established in the area, and the epicenters of microearthquakes have been determined. These are plotted in Figure B-7 and the resulting zone of microearthquake activity coincides with the geothermal field and extends to the northwest. Additional data has been collected and is now being analyzed and interpreted by Dr. J. Combs at the University of Texas, Dallas, Texas. USBR plans to obtain more microearthquake activity data as utilization of the field increases.

Figure B-2.

Figure B-3.

Figure B-4.

Figure B-5.

Figure B-6.

B-17

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Figure B-7.

Seismic refraction data in the area indicates the depth to basement to be at least 11,000 feet. There exists some commercially acquired reflection seismograph data covering all of the East Mesa area. These data are in a 5-point stack format, making direct interpretation tedious and difficult. Placing this data on magnetic tape would allow computer processing. The resulting interpretation would yield much structural and stratigraphic information if integrated with the data available from the USBR wells.

B2.2.4 Electrical Data

Both electrical-resistivity sounding and profiling data have been obtained in the general area. The sounding data were acquired on a more regional basis and are described by Rex et al (1971 and 1972). East-west profiles have been surveyed over the East Mesa KGRA and a broad longitudinal resistivity closure of approximately 5 ohm-meters is generally coincident with the geothermal field.

Telluric data is now being collected. Preliminary results indicate that an anomaly exists and the location may move progressively to the northwest with increasing depth (Dr. J. Combs, Pers. Comm., 1974).

B2.2.5 Summary

Surface geophysical exploration techniques appear to have been used very successfully in the discovery and delineation of the East Mesa Geothermal Field. This is demonstrated by Figure B-8 where the various suites of geophysical data are depicted simultaneously. Each technique indicates the existence of a geothermal anomaly located in Section 6, T16S, R17E; this has been further demonstrated by the drilling of the five USBR geothermal wells. (NOTE: The seismic noise maxima on Figure B-8 reflect more recent data than those shown on Figure B-6.)

B3 RESERVOIR GEOLOGY

Reservoir geological data in the East Mesa area have been obtained primarily from the geophysical logs of the five USBR wells and from wildcat petroleum wells in the vicinity. Cores and cuttings are also available; however, the sandstones are relatively unconsolidated and sandstone recovery has been minimal.

B3.1 Stratigraphy

The sedimentary section of East Mesa is comprised entirely of a sand, silt and clay sequence. The deeper section is primarily sandstone with the sandstones ranging from very fine to very coarse. More clay exists in the shallower section and this may form the "cap rock" of the geothermal accumulation.

No stratigraphic marker beds have been identified on the geophysical logs and, to date, no well-to-well correlations have been discovered although the search for such correlations is continuing.

Cuttings from the Mesa 6-1 well have been examined in detail (Fournier, 1973), and again no stratigraphic marker beds have been identified, either lithological or paleontological. Color change is the only systematic lithologic characteristic and this is attributed to post-depositional factors.

B3.2 Structure

Determining the geologic structure of the area is particularly difficult because of the lack of well-to-well correlations. Dipmeter data are available in some of the wells and these should be incorporated into the structural investigation.

Major faulting in the East Mesa area has been postulated on the basis of regional studies; infrared photography, deep seismic investigations and microseismic data (USBR, 1973). The Combs-Hadley fault has been particularly well defined by the analysis of microearthquake first motions; a right lateral slip is indicated (Dr. J. Combs, Pers. Comm., 1974). Figures B-3, -6, -7 and -8 depict the location and orientation of these postulated faults.

B3.3 Hydrology

The water-table depth at East Mesa is less than 20 feet, as evidenced by water wells in the geothermal field and by observation wells drilled in the area by the Imperial Irrigation District (IID). The shallow temperature is approximately 90 F and the salinity is approximately 1,200 ppm by weight of dissolved solids (K. Mathias, Pers. Comm., 1974).

Figure B-8.

Temperature profiles of the East Mesa wells are tabulated in Table B-I and are graphically depicted in Figure B-9. These show a common characteristic: the profile steepens below approximately 2,500 feet. This change in profile probably denotes a change in heat transfer mechanism - conductive transfer occurring above 2,500 feet and convective transfer below. Temperatures in the potential reservoir zone of 4000-6000 feet in the wells lying on the heat flow maximum (Mesa 6-1, 6-2 and 8-1) are high, averaging 350°F while temperatures in the same depth zone in the Mesa 5-1 and 31-1, off the heat flow maximum are lower, averaging 290°F.

Water in the East Mesa area is of fairly good quality, an order of magnitude better than that reported in the Niland area to the northwest and substantially better than that in the Heber area to the southwest. Water characteristics will be described in more detail in Section B4.

Geophysical logs obtained from the geothermal field wells include dual induction-laterolog, compensated sonic, neutron formation density and gamma/gamma formation density logs. Similar suites of logs have also been obtained from several outlying wildcat oil wells. These logs used in combination allow the determination of various reservoir characteristics including sandstone-shale lithology, porosity, permeability, water saturation and water quality. Interpretation of such logs are described in Schlumberger (1972); the "Saraband" technique of determining reservoir characteristics from the logs by use of computer is described in Schlumberger (Ref. B).

Foot-by-foot Saraband-derived data on the porosity, permeability and water quality have been combined to provide averaged values for these properties over approximate ten-foot intervals in the Mesa 6-1 and 5-1 wells. The experimental facility site lies approximately between these two wells. Data from the Mesa 6-1 is presented in Figure B-10 and data from Mesa 5-1 is contained in Figure B-11.

The intervals of apparent zero porosity on the porosity profiles are in actuality clay intervals. The amount of clay in the section is considerably greater above 2,500 feet than below; this additional clay may differentiate the conductive heat transfer zone from the convective zone.

Table B-I. Temperature Profile of East Mesa Geothermal Wells

<u>DEPTH</u> (Feet)	<u>TEMPERATURE (°F)</u>				
	Well	6-1	6-2	8-1	5-1 31-1
500		155	155	130	155 145
1000		200	200	185	190 170
1500		245	245	225	230 200
2000		285	285	265	265 225
2500		315	315	300	280 245
3000		325	335	335	280 260
3500		330	340	345	280 270
4000		340	350	345	285 280
4500		345	355	350	290 290
5000		350	360	350	295 300
5500		355	365	355	305 310
6000		360	375	360	315 315
6500		365			
7000		370			
7500		380			
8000		390

Figure B-9. USBR East Mesa Test Well Temperature Profiles

The predominance of sandstone below 2,500 feet and the associated elevated temperatures (Figures B-10 and B-11 contain a temperature profile) limit the potential geothermal reservoir to below this depth. From 2,500 to 4,500 feet, the bulk porosity in both wells averages slightly less than 20 percent. Below 4,500 feet, the bulk porosity in both wells is slightly more than 20 percent. In the Mesa 6-1, clay content increases and porosity decreases below 7,000 feet.

The permeability data are empirically derived from the porosity and therefore may be subject to question at any one specific locality such as East Mesa. The average Saraband permeabilities below 2,500 feet of 50-100 millidarcies are in general agreement with permeabilities provided by other sources (Rex, et al, 1972). However, permeabilities derived from drill-stem test data are considerably less than indicated by the Saraband data. Because of the minimal sandstone recovery in cores, no actual measurements of porosity or permeability are available.

The permeability decreases below 7,000 feet in the 6-1 well and becomes less than one millidarcy below 7,600 feet. Production below this depth has been attributed to fracture rather than intergranular permeability.

The general porosity and permeability profiles of these wells indicate a stratigraphic sequence of relatively unconsolidated sediments at shallow depth becoming compacted sediments at deeper depths. This is further evidenced by drill-stem test data wherein sand recovery in the tests decreased with increasing depth.

B4 CHEMICAL COMPOSITION OF RESERVOIR FLUID

The subsurface section in the East Mesa field is 100 percent water saturated. The water quality (here defined as the total dissolved solids by weight) on the Mesa 5-1 well is 8,000-10,000 parts per million (ppm) above 3,000 feet with quality improving steadily with depth to 1,000-2,000 ppm at total depth, Figure B-11. The quality of the Mesa 6-1 well below 2,500 feet is 4,000-5,000 ppm decreasing to approximately 3,000 ppm below 5,000 feet. Of particular interest is the abrupt increase in dissolved solids to 10,000 ppm at 6,100 feet, Figure B-10. This depth is marked by two (12 ft.) clay beds.

The possibility arises that two geothermal reservoirs exist at East Mesa - a fresher water body with quality of approximately 3,000 ppm lying above a more saline water body with quality ranging from 10,000

GEO THERMAL SYSTEM STUDY		TRW ENVIRONMENTAL, POWER AND FACILITIES DEPARTMENT SYSTEM INTEGRATION LABORATORY
SARABAND - DERIVED DATA USBR MESA 6-1		
DATE: 12/15/74	DRWN: J. J. [Signature]	DWG. NO. 6621.15-04
CHKD: [Signature]	APPV: R. C. [Signature]	REV.

Figure B-10. Saraband-Derived Data
USBR Mesa 6-1
B-29
(Reverse of this page left blank)

GEOHERMAL SYSTEM STUDY		TRW ENVIRONMENTAL POWER AND FACILITIES DEPARTMENT SYSTEM INTEGRATION LABORATORY
SARABAND-DERIVED DATA USBR MESA 5-1		
DATE 12/11/74	DWG NO.	6621.15-015
DRAWN A. B. [Signature]		
CHECKED [Signature]		
APPROVED [Signature]	REV.	

Figure B-11. Saraband-Derived Data
USBR Mesa 5-1

to 25,000 ppm. Other wells in the area, however, are not sufficiently deep to penetrate this postulated deeper reservoir.

Water quality sections have been constructed utilizing data from the USBR field wells and wildcat oil wells in the vicinity. Figure B-12 depicts the location of these sections. Figure B-13 contains the approximate north-south section, X-X and Figure B-14 contains the approximate west-east section, Y-Y. In these sections, water quality is computed from the self-potential and resistivity geophysical logs by a computer program developed by E. Burnett of the USBR, Yuma, Arizona. The raw data were also furnished by Mr. Burnett. Conventionally, such sections are drawn with the separation between wells proportional to the ground separation. However, in this case, no well-to-well correlations have been identified and the sections are constructed with a constant separation for ease of viewing. These sections indicate that water above 6,000 feet becomes fresher (salinity decreases) as distance from the area of maximum heat flow increases. The large separation between the self-potential and resistivity curves in the Mesa 6-1 and 6-2 wells indicates that the water is more highly mineralized, i. e., contains more ions other than Na^+ and Cl^- .

Water quality measurements have been made on fluids recovered by drill-stem testing and these are summarized in Table B-II. These measurements are also plotted on the water quality sections and, in general, agree closely with the computed salinities.

In summary, the geothermal reservoir at East Mesa is considered to be between the depths of 4,200 and 6,200 feet. This interval represents the best trade-off between water temperature, water quality and formation stability. Further, this interval offers a host rock section sufficiently thick to provide the water flow (nominally 1,000 gallons/minute per well as discussed in Appendix E) required by the power generating system.

B5 SUBSIDENCE

The possibility of subsidence has been and continues to be a very important consideration in the utilization of the ground-water resources of the Imperial Valley. Subsidence monitoring activities in the area

WATER QUALITY SECTION LOCATIONS

EAST MESA AREA
IMPERIAL COUNTY, CALIFORNIA

FIGURE B-12

Figure B-13

EAST MESA AREA
IMPERIAL COUNTY, CALIFORNIA

RESERVOIR FLUID CHEMICAL CONTENT
EAST MESA GEOTHERMAL FIELD
IMPERIAL COUNTY, CALIFORNIA
OBTAINED FROM DRILL STEM TEST DATA

WELL	DATE	DEPTH	TOTAL DISSOLVED SOLIDS (ppm)	Na		K		Ca		Mg		CO ₃		HCO ₃		Cl		SO ₄		SiO ₂		
				PPM	%	PPM	%	PPM	%	PPM	%	PPM	%	PPM	%	PPM	%	PPM	%	PPM	%	
MESA 6-1	7-17-72 8-15-72	5557-5607 7292-8030	1850 12620	511 3689	27.6 29.2	44 391	2.4 3.1	38 237	2.0 1.9	1 4	— —	0 0	-- --	379 812	20.5 6.4	428 5457	23.1 43.2	370 269	20.0 2.1	185 290	10.0 2.3	50.7% Na & Cl 72.4% Na & Cl
MESA 5-1	4-25-74 4-30-74	4269-4689 5600?	2450 2035	830 620	33.9 30.5	52 109	2.1 5.4	52 59	2.1 2.9	3 4	— —	0 0	-- --	767 595	31.3 29.2	809 433	33.0 21.3	203 270	8.3 13.3	123 142	5.0 7.0	66.9% Na & Cl 51.8% Na & Cl
MESA 8-1	5-22-74	5813-5418	1543	449	29.1	40	2.6	41	2.7	4	—	0	--	375	24.3	380	24.6	249	16.1	151	9.8	53.7% Na & Cl
MESA 31-1	6-18-74	5400?	2065	690	33.4	31	1.5	36	1.7	5	—	0	--	1031	49.9	406	19.7	215	10.4	135	6.5	53.1% Na & Cl

Table B-II

are governed by the Proposed Subsidence Regulations for Geothermal Development, issued by the Division of Oil and Gas, State of California.

A first- and second-order level network has been established in the Imperial Valley by several federal and local government agencies as indicated in Figure B-15. This network was recently resurveyed to detect elevation changes that may have occurred since the initial surveys. The report on this survey is in process.

Subsidence monitoring activities at the East Mesa geothermal field include two tiltmeters and extensometers installed in two of the deeper drill holes previously used to make thermal determinations, DH-125 and DH-127. The locations of the tiltmeters and extensometers are noted on Figure B-16.

Figure B-15. Level Network
Imperial Valley, California

SCALE OF MILES

LEGEND

- ▲ EXTENSOMETER WELL
- TILTMETER SITE

SUBSIDENCE MONITORING INSTRUMENTATION

EAST MESA AREA
IMPERIAL COUNTY, CALIFORNIA

FIGURE B-16

APPENDIX C

EAST MESA GEOTHERMAL FIELD RESERVOIR CHARACTERISTICS

The East Mesa Field can be developed into a prolific liquid-dominated type geothermal producer if the reservoir is exploited by proper engineering planning and standards. Theoretical calculations show that the life of the field can be extended beyond 100 years if the produced water is reinjected into the reservoir at the produced rate.

C1 FLOW POTENTIALS AND RESERVES

Two characteristics of the East Mesa Field that are important in evaluating its potential as a source of geothermal energy are: (1) the water flow rates that can be maintained and 2) the recoverable hot water available. In addition to producing hot water at adequate rates, the water must be reinjected at similar rates. As will be noted later, reinjection is also closely related to the total recoverable heat reserves from the field. Information available for estimating these reservoir characteristics included:

- a. Geological data
- b. Geophysical well logs
- c. Pressure tests
- d. Production data

The conclusions reached from interpretation of the available data are summarized in C1.1 and C1.2 below.

C1.1 Flow Rate

Based upon the limited formation tests available and the all but negligible production history of the field to date, a productivity of approximately 0.7 gallons/minute/foot with a pressure drawdown of 1700 psi over a producing interval of 1,500 feet is indicated. This results in an average flow of 1.5×10^6 gallons/well/day.

C1.2 Reservoir Reserves

C1.2.1 Reserve Evaluations

Two methods of producing the reservoir were considered in estimating the reserves:

- a. Approximately two-thirds of the heat energy in the reservoir is contained in the rock itself; this energy can be recovered most effectively by reinjecting the reservoir fluid. By conservative estimates, the heat content of the reservoir is adequate to supply, with reinjection, in excess of 400×10^9 gallons of water at a temperature not significantly below the current reservoir temperature. This estimate assumes a reasonable volumetric sweep efficiency for the reinjected water but does not include any natural recharge or heat conducted into the reservoir from the heat source.
- b. If the reservoir pressure is depleted below the vapor pressure of water, considerable heat can be extracted from the reservoir as steam, but only at low production rates.

There is a third possibility, that of producing the reservoir with no reinjection and with no recharge. In this manner, at the required productivity, the five existing wells would deplete the reservoir to a pressure of 400 psia (above the vapor pressure of brine at 350°F) in less than two years. This means of production is obviously impractical and would not be implemented but, since the rate of recharge is as yet unknown, it does emphasize the need for reinjection, environmental considerations aside.

C1.2.2 Recommendations

To evaluate the East Mesa reservoir more fully the following testing and studies are recommended:

- a. Additional testing should be conducted to establish reservoir extent and continuity. These tests should include pressure buildup and flowing pressure measurements as the wells are produced, pulse tests, and interference tests between adjacent wells. For the purpose of water cycling, the injectivity characteristics of the formation should be determined. Additional temperature surveys are desirable. Information from these tests can be used to select the optimum location of injection wells, determine more refined values of porosity and permeability, and derive improved estimates of reservoir pressure.

- b. Since the longevity of the reservoir is dependent upon reinjection of the produced water, mathematical model studies of volumetric sweep efficiencies for a mobility ratio of unity should be made to determine the efficiency of cycling operations as a function of well location and spacing.

C2 FLOW-RATE DETERMINATIONS FROM WELL MEASUREMENTS

Because of the limited production history and reservoir test data available to date, estimation of reservoir deliverability is difficult. Thus, the drill-stem and production test data available were used to the maximum to establish estimates of reservoir productivity. These estimates were supported with calculations using simple mathematical models for radial flow systems.

Of the nine drill-stem tests (DST) made in the five field wells, seven provided reservoir productivity determinations and two of these were sufficiently complete to allow determination of reservoir pressure and permeability. The packer did not seat in two of the tests. Sand flowed into the tool in all tests above 4,500 feet.

DST No. 3 in Mesa 5-1 examined the formation in the depth interval of 5,601 to 5,637 feet. From this test a productivity of 0.57 gallons/minute/foot has been calculated for a pressure drawdown of 1,500 psi. The static reservoir pressure, obtained from the analysis of pressure transient data, is estimated at 2,400 psig. The permeability of the formation has been determined to be 0.56 millidarcy. The damage factor, sometimes referred to as skin effect, is -0.875, indicating the presence of higher permeabilities around the wellbore. This is usually caused by formation of micro fractures in unconsolidated sediments during the drilling operation.

DST No. 1 in Mesa 8-1 examined the depth interval of 5,334 to 5,418 feet. The productivity has been calculated to be 0.90 gallons/minute/foot for a pressure drawdown of 1,155 psi. The static reservoir pressure is 2,371 psig and the formation permeability has been computed to be approximately three millidarcies. The damage factor is +0.65, indicating a slight permeability reduction around the wellbore. This may be a result of mud-filtrate invasion during drilling operations.

From DST No. 3, Mesa 6-1, the productivity has been calculated from fluid recovery data. For a pressure drawdown of 838 psi, the productivity is 0.439 gallons/minute/foot. DST No. 1 in Mesa 6-2 also provided productivity information, this being 0.52 gallons/minute/foot for a pressure drawdown of 1,232 psi.

The average productivity obtained from DST data is 0.7 gallons/minute/foot for a pressure drawdown of 1,500 psi.

Some direct flow test data is available in that perforation of 197 feet of additional section in the Mesa 6-1 resulted in a production increase of approximately 825 kg/min. This corresponds to a formation productivity of 1.10 gallons/minute/foot (K. Mathias, Pers. Comm., 1974).

C3 THEORETICAL PREDICTIONS OF FLOW RATE

Darcy's Law for radial flow is the simplest mathematical model available for predicting the theoretical productivity of wells draining incompressible fluids from a reservoir under steady-state conditions. The model can be modified to represent the more realistic case of pseudo-steady-state conditions.

The steady-state model assuming continuous flow across the outer reservoir boundary is:

$$q = \frac{0.0895 \text{ } kh \text{ } \Delta p}{\mu \log (r_e / r_w)} \quad (1)$$

Where

q = flow rate in gallons/minute

k = reservoir permeability in darcies

h = vertical extent of reservoir volume
under consideration, in feet

μ = fluid viscosity in centipoises

r_e, r_w = inner and outer radii of reservoir
volume under consideration in feet

Δp = pressure gradient from r_w to r_e .

The specific numerical values used here are:

$$k = 2 \text{ millidarcies}$$

$$h = \text{unity}$$

$$\mu = 18 \text{ centipoises}$$

$$r_w = \text{drill hole radius and } \log(r_e/r_w) = 3$$

$$p = 1700 \text{ psi}$$

Evaluating equation (1) results in a theoretical flow rate of 0.56 gallons/minute/foot of section.

Equation (1) may be modified for the pseudo steady-state condition where there is no flow across the outer boundary and the reservoir is being depleted. Here, the theoretical flow rate is 0.67 gallons/minute/foot.

The sources of the numerical values used in these calculations are of interest:

The permeability of two millidarcies was derived from DST data by conventional methods. Permeabilities of 100 millidarcies or more are computed by the Saraband process; these may be suspect because it has not yet been established that the petrophysical correlations used to derive the permeabilities apply to water-saturated reservoirs. If the Saraband data are correct, the reservoir productivity would be appreciably higher than calculated above.

A sand count was made in the Mesa 6-1. Because of the erratic nature of the self-potential log, the gamma-ray and the formation compensated density logs were used to make the count. The effective production zone, between depths of 2,400 and 7,200 feet, is 2,269 feet.

Assuming no pumping, the minimum bottom hole pressure will occur at a surface pressure of one atmosphere absolute. Accordingly, the bottom-hole pressure was calculated from Figure 8, USBR (1973).

The flowing pressure gradient in the liquid section is 0.416 psi/ft, and above the flash point a value of 0.09 psi/ft is evidenced from the same figure.

$$\text{Now, } p = (d_t - d_f)0.416 + P_{vp} \quad (2)$$

Where

d_f = flashpoint depth = 4,000 feet

d_t = depth of formation pressure
measurement = 5,400 feet

P_{vp} = reservoir fluid vapor pressure = 135 psi

Evaluating equation (2), $p=700$ psi and the pressure gradient is the difference between this pressure and the formation pressure of 2,400 psi or 1,700 psi.

The theoretical calculations agree reasonably well with results from the drill-stem and flow tests. Accordingly, a conservative estimate of potential flow rate would be 0.7 gallons/minute/foot over a producing interval of 1,500 feet; because of uncertainties in the permeability figures, a flow rate of 1.0 gallons/minute/foot appears to be entirely possible. The 0.7 figure indicates a flow of 1,050 gallons/minute from a 1,500-foot producing section; this rate should be sustainable if a pressure drawdown of 1,700 psi can be maintained.

The productivities derived from drill-stem tests assume steep pressure gradients in the immediate vicinity of the drill hole and these productivities could be expected to decline with continued production. However, the productivities derived theoretically are based on pressure gradients existing through the assumed drainage volume. These latter productivities should be sustainable with recharge or reinjection to maintain reservoir pressure. Obviously, to maintain flow rates by reinjection, communication must exist between injection and producing wells.

C4 ESTIMATION OF RESERVES

To estimate the reserves of a geothermal reservoir, the reservoir size and recharge characteristics must be determined. To date, in East Mesa, no significant test data have been obtained that would establish the extent of recharge into the drainage area of the existing wells. Therefore, for a preliminary estimate of reserves, a drainage area encompassing the thermal gradient contours of 8°F/100 feet was used without considering water influx from outside these contours. Approximately ten square miles are therefore involved. With an average reservoir thickness of 1,500 feet and an average bulk porosity of 20%, reservoir fluid in place totals 6.25×10^{11} gallons.

In the absence of any recharge or reinjection, the volume of recoverable hot water is determined only by liquid expansion of the water with a corresponding decrease in pressure. The relationship is:

$$R = \phi V_B C_w \Delta p \quad (3)$$

Where

R = recoverable water in gallons

ϕ = bulk porosity

V_b = reservoir bulk volume

C_w = reservoir fluid compressibility

Δp = pressure decline

For a reservoir area of ten square miles and an average thickness of 1,500 feet, $V_b = 3.14 \times 10^{12}$ gallons, $\phi = 0.20$ and $C_w = 4 \times 10^{-6}$ psi⁻¹. Evaluating equation (3) for a pressure decline of 2,000 psi, results in recoverable reserves of 5×10^9 gallons.

If production reduces the reservoir pressure to below the vapor pressure of the fluid at the reservoir temperature, considerable additional heat can be recovered from the reservoir rock as heat of vaporization. This heat would be recovered at a low rate, however, because of the low reservoir pressure (equal to the vapor pressure of the fluid at 350° -- about 135 psia). This pressure would be the maximum

possible drawdown at the well and the fluid would be produced in the vapor phase. Calculations of producing in this manner have not been made.

The most practical method of recovering heat from the East Mesa Field involves reinjecting the produced water. A conservative estimate of the hot water that could be produced by this method of operation would be in excess of 400×10^9 gallons. In this estimate, conduction of heat into the reservoir from the heat source is neglected and no natural recharge is considered. If reservoir pressure is maintained by reinjection, recharge effects might be insignificant.

Heat is contained in the reservoir rock as well as in the water stored in the pore voids. The hot water equivalent of the heat stored in the rock can be calculated as follows:

$$\Phi = \left(\frac{1 - \phi}{\phi} \right) \frac{C_r \rho_r}{\rho_w}$$

Where

Φ = pore volume of hot water equivalent
to rock-contained heat

ϕ = bulk porosity

C_r = heat capacity of rock

ρ_r = rock specific gravity

ρ_w = water specific gravity

Evaluating this equation with $\phi = 0.20$, $C_r = 0.20$ BTU/°F/lb, $\rho_r = 2.5$ and $\rho_w = \text{unity}$, $\Phi = 2.0$.

Accordingly, the total heat content of the reservoir in terms of equivalent pore volumes of hot water is two pore volumes of rock plus the water in the pores. This is tantamount to a total of three pore volumes of hot water. A very conservative estimate of the fraction of this that could be recovered by convective heat transport in the reinjected water would be 25% of the total or 0.75 pore volumes of hot water. According to convective heat transport theory all of this water would be recovered at the initial reservoir temperature. It should be noted, however, that

additional work will be required to determine the reservoir volumes swept by the reinjected water.

The above model gives an equivalent reserve of $(0.75) (625 \times 10^9)$ or 468×10^9 gallons. At an annual production rate of 3.0×10^9 gallons/year from the five existing wells the reserves will last well over 100 years. These conservative calculations indicate that the geothermal reserves with reinjection are more than adequate to meet the needs of the experimental facility.

APPENDIX D

VIEWS AND COMMENTS BY ADVISORS

The commercial power industry must invest significant amount of new capital to install geothermal hot water power generating facilities in the near future to meet the national goals. Accordingly, TRW solicited the participation of the power industry and an environmentally oriented organization in meeting the objectives of the study.

The following individuals representing the indicated organizations acted as advisors to TRW in this study:

Dr. Hamilton Hess, Sierra Club
Mr. Tom Hinrichs, San Diego Gas and Electric Company
Mr. Lyn Rasband, Southern California Edison Company
Mr. Everett Ross, City of Riverside, California
Mr. James Woodburn, City of Burbank, California

This appendix presents the advisor's comments as received.

Summary

In summary, the utility companies consider the following areas to be the major retardants to industrial development of geothermal power, in order of priority:

- Methods or systems for determining the expected longevity and recoverable energy from geothermal reservoirs.
- Definition of a true geothermal resource. A reliable estimate of availability of geothermal energy based on true production ability.
- Development of reliable/economical production equipment; e. g., heat exchangers (most important), down-hole pumps, high quality steam separators.
- Trade-off analyses and techniques for evaluation for long-range economics.

During the early phases of the study specific meetings were held with the advisors with the results presented in the following sections:

D1. Views and Comments of Advisors: T. Hinrichs, San Diego Gas and Electric Company, L. Rasband, Southern California Edison Company

D2. Comments by Everett Ross, City of Riverside

D3. Comments by James Woodburn, City of Burbank

Upon completing the initial draft report, the advisors were asked to comment on this document and these comments are contained in the following sections:

D4. Comments by Dr. Hamilton Hess, Sierra Club

D5. Comments by Lyn Rasband, Southern California Edison Company

D6. Comments by Everett Ross, City of Riverside

D7. Comments by Tom Hinrichs and Jim Nugent, San Diego Gas and Electric Company

D1. Views and Comments of Advisors

The government program should be directed at overall acceleration of geothermal industrial growth. There are two modes available for accelerating industry: 1) delineation of available and convertible resources (defined capacity), 2) acceleration of engineering technology. The most important is discovery and delineation of reliable resources.

Paraphrased Transcript: Mr. Tom Hinrichs, San Diego
Gas and Electric Company

The primary risks to industry, retarding the accelerated entry of resource developers and utility companies are the inability to predict total reservoir energy, estimate recoverable energy, and the determination of reservoir longevity at significant production levels. The value of a particular geothermal field is tightly bound to its location in relation to load center areas. For example, a 10 MWe reservoir with a longevity of 30 years in the Mammoth area would be very economical. However, a reservoir in the Imperial Valley would have to show a production capacity of about 50 MWe with growth potential to 200-400 MWe and a longevity of 30 years.

The reliability and maintainability of equipment is another factor of concern. Not only how long will equipment last, but how often and to what extent would operational maintenance be necessary. For example, how often would a heat exchanger need cleaning and what is the probable down time. Questions concerning maintenance are important to utility company management. The heat exchanger is of most concern. Testing of tubes and bundles to determine deposit build-up is essential. Full scale testing is unnecessary as long as we can determine heat exchanger characteristics as a function of time for particular types of scaling deposits.

A full sized 10 MWe isobutane system would not be necessary for this type testing.

When looking at the use and development of geothermally produced electrical energy, do not neglect the load center. The relationship between quantities of energy available, developed production capacity and overall facility needs are directly tied to the size and location of load centers.

I think the overall government R&D program could be of great assistance to industry in two ways: First, take the risks out of determining reservoir capacity. If it can be demonstrated that a reservoir has a large capacity and will produce for an extended time, development will be greatly accelerated. Second is technological R&D. I personally think heat exchangers and downhole large volume pumps are a most important factor.

Paraphrased Transcript: Mr. Lyn Rasband, Southern California Edison Company

Subsidence is a very important issue and must be faced. I think the ultimate limit to geothermal power growth will be the availability of cooling water. Therefore, as ground water is used the subsidence factor is increased.

Southern California Edison would like to see a full scale test of a 10 MWe system (East Mesa type), including controls and total dynamic system. (The turbine may be unnecessary, an expansion valve might be adequate.) This demonstration is badly needed. Testing a total 10 MWe system and scaling 50 MWe would probably be the better approach. A good test to provide a good economic model would be of significant interest.

I agree with Tom Hinrichs, the biggest problem today is the ability to forecast reservoir capacity to guarantee a significant production level for a significant period of time. Of course "significant"

depends on the location and size of the using load center.

Southern California Edison is not married to an isobutane system or any other binary system. If we are given good quality steam, we know how to handle that. By good quality I mean something that is acceptable to the turbine manufacturer.

It appears to me that some of TRW's results would be of value in the Long Valley development. The data to be of value, must be made available in a proper time frame. It may be too late now.

I think East Mesa, a medium temperature, low salinity reservoir, will be representative of a large majority of future geothermal fields. If your (TRW) project is carried to the actual demonstration phase, some badly needed hard line reliability data could be obtained.

An issue that has us all worried is the reinjection problem. Long term runs with checks on back pressure buildup and subsurface reinjection characteristics are needed. There just is not sufficient data.

The foremost problem is reservoir assessment. Without increased capabilities in this area, interest in developing geothermal capabilities will rapidly wane. I don't mean a model for a single reservoir, but assessment standards that can be applied to all potential geothermal reservoirs. Timing on this issue along with heat exchanger development is critical. Something had better happen pretty soon.

D2. Comments: Mr. Everett Ross, City of Riverside

Riverside's Municipal Electric Department, established in 1895, originally operated its own generators, but since early 1900 has purchased all its power requirements. Since 1951, Southern California Edison Company has been our only power supplier. By means of a recently negotiated agreement with Edison, Riverside is now allowed to develop its own power resources, participate with Edison and other utilities in the sharing of reserves and utilize Edison's transmission grid in power delivery to Riverside.

We have been offered an opportunity to participate with Edison in the nuclear addition at San Onofre now under construction.

In addition, Riverside is currently involved in studies to determine the feasibility of another nuclear plant scheduled for construction in the San Joaquin Valley and a possible coal fired installation located in south-central Utah.

Riverside is also interested in participating in geothermal power developments that are economically attractive as compared to other power sources. Further, Riverside now has the financial capability to fund its share of an economically feasible project by the issuance of revenue bonds.

A municipal utility benefits from lower fixed charges (approximating a total of 9%) as compared to an investor owned utility; thus higher plant capital costs with corresponding relatively lower fuel can be justified and may well influence final plant design criteria. In addition to lower fixed charges a municipally owned utility is not subject to ad valorem taxes on plant investment initially constructed and owned by the City.

Because of Riverside's relatively small size and limited resources, it has in the past not been thought prudent to finance exploratory developments in geothermal nor have funds been available for test drilling to prove the potential of possible hot water or steam fields. However, with certain stipulations, Riverside is definitely desirous of obtaining alternate sources of power which offer savings as compared with continued purchases from the Southern California Edison Company who is presently the sole supplier of power to Riverside.

Based on Riverside's current Load-Resource plan the estimated future base load (1.25 minimum MWD) that could be utilized starting in 1978 is approximately 100 MW. This figure is estimated to increase 5% compounded annually during the following ten year period.

In order to ensure public acceptance and political backing of Riverside's commitment and participation to any major degree in a new geothermal development, most of the following conditions should appear favorable:

- A. Riverside should conclude a contract in advance of participation to provide for power utilization by one of the three following alternatives:
 - (1) Established transmission route from geothermal site to Riverside
 - (a) Utilizing Edison's existing lines (charges per Settlement Agreement).
 - (b) A new line to be constructed in combination with others from L. A. metropolitan area (i. e. Burbank and Los Angeles).
 - (2) A power exchange contract with either Imperial Irrigation District, Edison, or Metropolitan Water District.
 - (3) Outright sale of energy with on-site delivery by Riverside to IID, Edison, MWD or any other agency with a proviso for future recapture by Riverside.
- B. Review of data and test results establishing reservoir capacity following test period to ensure an energy supply for a long enough time to amortize production well costs and generation facilities. Some method during first test phase of measuring reservoir "draw down" or future life.
- C. Review of up to date economic analysis including losses, etc. of "electrical collection" of output of five MWD modules vs. "steam collection" with a larger generation unit (i. e. 50 MW). Environmental acceptance of steam collection method - if selected - i. e. slant drilling, etc.
- D. Objective analysis of estimated power costs as delivered in Riverside including investment, operating, fixed charges, transmission costs and losses must provide 90% assurance that the geothermal total power costs will be equal to or less than alternate power costs from proposed plants Riverside is presently participating in, i. e. (a) large coal fired, (b) nuclear; using best available projections of future fuel costs.
- E. From preliminary tests an annual plant capacity factor of no less than 80% should be conclusively established as alternate power sources must be arranged for Riverside during geothermal plant downtime periods.

We hope the foregoing information will be of some assistance in your study to determine what requirements a potential participant would likely set forth.

D3. Comments: Mr. Jim Woodburn, City of Burbank

We are in general agreement with the intent of the overall program to provide for rapid economic development of geothermal resources. We feel that the generation of electric power in practical quantities should be a firm objective for 1977. While such a schedule is reasonable within the bounds of today's knowledge, a longer term research and development program is needed for continuing expansion of economical generating facilities. It is with these dual purposes in mind that we offer the following comments on the NSF/TRW program.

1. Reservoir Assessment

Good practical engineering methods are needed to permit the accurate prediction of well performance in terms of temperature, pressure, flow rate and lifetime. At present, it is necessary to essentially complete a well and invest nearly \$500,000 before the developer has more than a very low certainty of what will be found. Even after a well is producing, the uncertainty is only slightly improved for a well a few feet away from the first.

Specific approaches would include:

- a. geologic modeling to make better use of surface features, very shallow holes and other data obtainable at low cost for forecasting.
- b. emphasis on obtaining the maximum of data from low cost 1,000 foot test holes.
- c. specific programs to unify the various detailed survey techniques of gravimetric, seismic, conductivity, magnetometer, etc., with correlations with test holes and wells.
- d. development of permeability logging methods which can reach out over areas of several square miles from a few widely spaced test holes or wells.

2. Proof of Concept Experiments

The Phase I program should emphasize research and development in those areas where the engineering uncertainty is potentially the most costly. Cost, in this context, includes schedule, environmental, and resource costs as well as economic costs. Listed below are some of the areas in which the engineering uncertainty is great along with a subjective estimate of the cost impact of that uncertainty on a successful national geothermal energy development program.

- a. Two phase flow (moderate)
- b. Well wall heat loss (moderate)
- c. Scaling tendency (serious)
- d. Stepped well bore (slight)
- e. Handling liquid with suspended solids (moderate)
- f. Stress corrosion from H_2S , etc. (serious)
- g. Extraction of non-condensibles at low cost (moderate)
- h. Extraction of non-condensibles ahead of the turbine (serious)
- i. Drilling muds and tools for operation at $600^{\circ}F$. (serious)
- j. Down-hole pumping (serious)
- k. Waste disposal (serious)
- l. Well abandonment techniques (moderate)
- m. Well shutdown hardware (serious)
- n. Reliability data on efficient expanders and turbines (very serious)
- o. Heat exchangers (serious)
- p. Binary system hardware (serious)
- q. Binary fluid characterization (moderate)
- r. Subsidence prediction (moderate)
- s. Separators (slight)

3. Other Problem Areas

In addition to the engineering questions, there are several problems of a wider scope which need attention. Some of these are:

- a. Availability of well pipe
- b. Availability of drillers
- c. Wheeling arrangements
- d. Economic modeling

4. Future Activities

Near term programs should be established to demonstrate in 1975, that at least promising hardware is being developed to generate power from hot water wells such as expanders, dual flash turbines, equipment for removal and disposal of non-condensibles, and a down-hole pump or heat exchanger. By 1976 we should be planning to demonstrate power generation at the level of 10 megawatts or so using alternate prime mover designs such as direct expander, turbine, binary cycle and single flash technologies.

In addition to the hardware programs, the Reservoir Assessment activities outlined above should receive serious attention.

5. Subsystem Performance

Under the TRW category of "Process Heat Rejection Options", the possible use of the irrigation canals should be added. The hydraulic type of downhole pump being studied by Sperry should be added to the pump options.

The category of Reservoir Engineering should place greater emphasis on the evaluation to slant drilling or reduce above ground piping, thus reducing environmental impacts. Areas which could be explored fully are heat loss in well casings, drilling cost, operating benefits, and environmental benefits.

The "Field Collection" should, in addition to steam and water collection, consider two phase collection and electrical collection (by using a number of smaller plants).

6. System Evaluation/Selection

In addition to the Figure of Merit (\$/KWe) evaluation of environmental impacts and savings of fossil fuel reserves for higher uses should be included. The Selected Concept, based on energy cost must also consider reliability, availability, wheeling and abandonment costs.

7. Concepts

The proposed concepts are limited to use some form of conventional steam turbine. It is strongly urged that additional systems considered include the following:

- a. Helical screw expander (Sprankle)
- b. The bladeless turbine (Possell)
- c. The Keller Roto Oscillating Vane (KROV)
- d. The Impulse Turbine (Austin)

8. Conditions for Industry Participation

We believe that for strong industry support, a geothermal power generating program must incorporate at least the features:

- a. Fast implementation
- b. Sound estimates of costs
- c. Sound operating availability estimates
- d. Wheeling contracts
- e. Environmental gains
- f. By product assessments

We feel that the proposed program represents a good approach, but there is evidence of considerable duplication and overlapping of other programs and not enough emphasis on ways and means of accelerating funding and completion of operating plants.

D4. Comments on Rough Draft of Phase O Study for Geothermal
Superheated Water through Concept Facility
From Dr. Hamilton Hess

I will clarify my own position at the outset. This project has not been submitted to the Sierra Club National office or Southern California office for appraisal or for approval. I have cleared my own service as a consultant in relation to this project with the Sierra Club office, but no official Sierra Club approval or endorsement of this project is thereby being implied.

In general, the Sierra Club favors well managed research and development in relation to geothermal as an energy source. The comments which I will be making on this project in relation to this phase, and presumably to other phases, are not to be taken as committing the Sierra Club to any particular position on the project. They will be my own comments which I will be making conscientiously in relation to what I believe to be fact and to what I believe to be consistent with general Sierra Club policy guidelines.

I would see this project as fulfilling a definite need in the exploration of the concept of the utilization of geothermal energy. I believe that the project site selected is the least environmentally sensitive of the sites that were considered and is therefore the preferable from the environmental standpoint. Certain points of environmental sensitivity which are discussed in the Environmental Impact Statement for the East Mesa Geothermal Resources Area issued by the Department of Interior should be kept in mind in the implementation of this project. One is the presence of a rare desert lily which occurs in the area and also the presence of certain rare reptiles. There is also the possibility of undesirable impacts from the standpoint of noise, dust and noncondensable gases in relation to Holtville and other nearby communities. Throughout the implementation of this project, I would urge a high priority being consciously set and carried out within it for

the development of technologies for the elimination of adverse environmental impacts. In the long run, the success of geothermal power as an alternate energy source will be significantly dependent upon its environmental acceptability. Specific aspects of impact mitigation which should be attended to are, in my opinion, the development of sealed systems with the reinjection of noncondensable gases, the development of more effective directional drilling techniques for the reduction of surface activities and pipeline occupation of land surface, low profile construction and the elimination of steam plumes for the reduction of visual impact, and muffling, insulation and baffling of noise sources for the reduction of sound levels. I would urge that the objectives of the project include the possibility of the application of information gained and technology developed to other geothermal reservoirs and other possible geothermal development situations. If this is done I feel that the project will be much more beneficial than if it is directed simply to production techniques developed for a specific location. For any given phase of the project a technical approach which has a broader applicability should be preferred to one which has applicability restricted to the present project. For instance, the development of feasible and effective environmentally acceptable means of dry cooling would be preferable to using the East Highline Canal as a heat sink, for the reason that not all potential geothermal resource sites have a conveniently located and usable heat sink of this nature.

The report is quite unclear on how the environmental impact report which will be drafted for this project will be used. I believe that it should be clarified to whom this report will be submitted, who will be the lead agency, who will circulate the report for review and who will be its reviewers. Also, as an addition to the matter for impact analysis listed on pages 4-11 to 4-14, the social impact on Holtville and other neighboring communities should be assessed.

I am sending under separate cover a copy of guidelines for the assessment of environmental impact geothermal operations which the Sierra Club geothermal task force has drawn up. We don't claim this list to be definitive, but I would suggest that it should be studied in connection with impact analysis as undertaken.

I have a few comments to make on the parameters of impact analysis listed on the pages mentioned, and my comments will be not only in reference to impact analysis itself, but in certain cases to a questioning or a suggesting of procedures to be followed in the implementation of this project.

Page 4-11 Surface Water Contamination from Mud

Reference is made to lined mud ponds as a mitigating measure. I would suggest the possibility of the using of portable containers for the containerization of drilling muds rather than the excavation of mud ponds. Mud pond excavation is an impact on the terrain which is undesirable and avoidable. Containerization of drilling muds has been successfully accomplished in certain situations of well drilling in The Geysers area. On completion, the muds are disposed of at approved industrial site under the supervision and with authorization of the Regional Water Quality Control Board.

Page 4-13 Possible Impact from Reinjection Upon Groundwaters by Seepage into Aquifers

While I would agree that the probability is low, there should be some systematic system of monitoring set up whereby groundwater wells surrounding the operational area are periodically monitored at reasonable intervals for possible contamination by reinjection of geothermal fluids.

Page 4-14 Activity Effluent Surface Disposal

This raises a question in my mind. I am not aware from discussion otherwise in the report that surface disposal is seriously contemplated.

I would certainly urge that it not be contemplated, and that the only surface disposal of effluents that should be envisioned in taking place is the emergency containments of fluids which for some reason or another cannot be disposed of immediately by reinjection. Emergency holding ponds for contingencies of this sort should be carefully designed in consultation with the Regional Water Quality Control Board and I believe, that, in any case, a waste discharge permit would be required within the federal regulations for geothermal operations in consideration of the laws of the state of California regarding surface discharges.

Page 4-14 Impact on the Local Communities

Socio-economic effects should certainly include the effects on the communities from the standpoint of their desirability as places of habitation because of nearby geothermal industrialization. The possibilities of the devaluation of residential properties should also be studied in connection with the economic effects.

I find no data on noncondensable gases given for the geothermal brines encountered in the area. I would like to see early consideration of how noncondensable gases will be handled in the various system possibilities discussed in the flash system, in a binary cycle system and in a combination system. In my opinion, the absolute elimination of the emission of noncondensables from geothermal production systems should be one of the high priorities for research and development. If we are going to look toward high-volume electrical production from geothermal, I think we have to face the fact that the emission of noncondensable gases may become a distinctively limiting factor. Not only the odor problem arising from hydrogen sulfide, but the toxicity of hydrogen sulfide and other noncondensable gases will have a detrimental effect on vegetation and life systems in the regions of production and perhaps farther afield. CO₂ emissions may also become a serious problem, given the current concern with the upsetting of the CO₂ balance in the atmosphere. Also,

radon gas has been discovered in geothermal waters in several reservoirs, and this too may become a serious problem. It would seem to me that the development of sealed systems, whereby all noncondensable gases are reinjected, is a necessity, and that for this reason the binary cycle should be the preferred system of production. This presumes, of course, that in the binary cycle system the noncondensable gases can be disposed of in this way. The binary cycle would also seem to be preferable to other systems from the standpoint of the reinjection of all fluids, the prevention of subsidence in such areas as the Imperial Valley, and the extension of reservoir longevity.

Because this project would be taking place on federal lands withdrawn for Bureau of Reclamation use and available to TRW under an NSF funded project, it is rather unclear as to what agencies will have direct jurisdiction over the project with regard to setting up standards for environmental protection and for inspection and monitoring. Particularly, I wonder what agency will set casing standards. Will it be the USGS, or will it be the State of California Division of Oil and Gas? Also, who will inspect casing and equipment for safety, who will monitor for subsidence, seismic activity, ground-water contamination, noise, and maintenance of air quality according to the State of California standards. These matters can be taken care of under existing law, but I think that it is necessary at this point for TRW to get the answers to these questions and to contact the appropriate agencies so that applicable standards can be known and inspection and monitoring programs can be set up. With regard to monitoring for subsidence, leveling stations, if not already present for the Bureau of Reclamation activities, should be set up and tied into the existing network in the Imperial Valley which has been jointly established by USGS, the California Division of Oil and Gas and the County of Imperial.

I have previously outlined the reasons why I believe the closed sealed binary cycle system to be preferable. Another reason would be that it eliminates the discharge of steam into the atmosphere. Large volumes of steam emissions might very well in the long run cause a problem of increased humidity in the dry desert environment. In enclosed air basins, among which the Imperial Valley can scarcely be numbered, the possibilities of climatic modification from large volumes of steam emissions is a serious consideration in connection with geothermal operations.

Southern California Edison Company

P. O. BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770

December 6, 1974

Mr. Robert H. Douglass, Manager
Ocean and Energy Systems
TRW Systems Group
One Space Park
Redondo Beach, California 90278

Dear Bob:

We have reviewed the preliminary report draft of the Phase 0 study for a Geothermal Proof of Concept Facility.

The following comments are submitted for your consideration in completing the final report for NSF:

1. We agree with your selection of critical technology developments needed to advance geothermal utilization. We further feel that resource evaluation techniques, heat exchanger scaling minimization, and development of better down hole pumps are most critical at this time.
2. On Pages 4-15, the plant cooling alternative of using irrigation canals as thermal sinks is unacceptable due to large flow fluctuations experienced in the Imperial Valley area. The concept might be adequate for small (10 MW) plants but cannot provide the cooling necessary for a large installation.
3. Table 5-4 is not a fair comparison between base load generation alternatives. We believe coal and nuclear power costs should be calculated at higher capacity factors--above 80% for nuclear and approximately 80% for coal. Geothermal's capacity factor is likely to be less than 80%.

Mr. Robert H. Douglass

- 2 -

December 6, 1974

We appreciate the opportunity to provide these comments on your draft report. If you have any questions, please feel free to call me.

Very truly yours,

J. Lynn Rasband
Supervising Research Engineer

JLR:cb

D6.
COMMENTS BY EVERETT ROSS - RIVERSIDE REGARDING
GEOTHERMAL I REPORT

Discussion

1. East Mesa is a good selection. The main concern is the extent of the field being sufficient to warrant construction of transmission lines to the Southern California population centers. This would probably require 500 MW or more of capacity.
2. Page 322 (this is minor) should add line on proximity to load center. Criteria is listed, but add this data.
3. Cooling - one question on 4-65 makes reference to use of ground water. How is that to be used? It is not clear how you use this. Add what other alternatives are available.

4-66 reference is made to using canal water on demonstration facility. Does not address problem of cooling a plant in excess of 10 MW.

Is 110° realistic for air cooled heat exchanges. Ambient temperature in the Imperial Valley is 115° when you most need the power. What basically is effect of ambient temperature on plant operation?
4. You should also incorporate a section of economics utilizing municipal financing. Cost analysis is entirely done on private financing. There should be an alternate based on municipal financing using interest rate of 7% and figuring no ad-valourm taxes on the improvements.
5. Page 5-1: the plant factors of 85% are used. This is also incorporated on 5-6 used for geothermal based on experience of other plants using conventional steam turbines. This may be high for proof of concept plants

(binary) using more saline brines (gets into whole group of concepts).
Also suspect that 60% of factors for coal plants is too low - should
be more on the order of 80%.

6. Potential for reservoir cooling off somewhat over the life of the plant.
Can't remember what or how much was talked about in the report. Point
being, we have had a few hot wells which have cooled off over the years.
This should be addressed a little more -- potential for cooling off.

MAJOR COMMENTS - well-done report; few typos.

SAN DIEGO GAS & ELECTRIC COMPANY

P. O. BOX 1831 SAN DIEGO, CALIFORNIA 92112

FILE NO

D7.

December 27, 1974

Mr. Robert H. Douglass
Manager, Ocean and Energy Systems
TRW
One Space Park
Redondo Beach, CA 90278

Dear Mr. Douglass:

On November 5, 1974 you transmitted a rough draft of TRW's phase zero study for the NSF covering a geothermal facility to Mr. T. C. Hinrichs. Mr. Hinrichs has joined the Magma Power Company as their Vice President of Operations and I am his replacement at San Diego Gas & Electric Company.

Since Mr. Hinrichs is most familiar with the contents of the draft and San Diego Gas & Electric Company and Magma have a joint venture in the Imperial Valley, we have asked him to review the draft and make comments. The following comments are his. They are also based on information obtained from Mr. A. M. Cooper of the Chevron Oil Company. Mr. Cooper is the project engineer for the drilling and testing operations at the Heber geothermal facilities jointly owned by SDG&E's subsidiary, New Albion Resources Company, Magma Energy, Inc. and Chevron Oil Company. SDG&E endorses the following comments.

"The report is very complete and comprehensive and the only area we challenge is the costs of the wells. On table 4.6-2 on page 4-104 the cost of each production well and injection well, respectively, is derived to be \$646,000 and \$672,000. This cost seemed excessively high as compared to actual experience at the Heber location. Details of the estimate were obtained by phone from Messrs. Hilbers and Pearson of TRW. Major Cost Items of the wells were indicated as follows:

Casing	\$ 140,000
Perforating	97,500
Drill Rig	126,000
Third Party Services (Mud, coring, logging, cementing, disposable items)	<u>180,000</u>

INVESTOR OWNED BY MORE THAN 25,000 STOCKHOLDERS

Robert H. Douglass
TRW

-2-

December 27, 1974

Total Major Items \$ 543,500

Details of the TRW well program were obtained from TRW personnel and these in turn were discussed with A. M. Cooper of Chevron Oil. The following suggestions are the result:

Casing Program

- TRW proposes 9 5/8" production casing. 8 5/8" will be sufficient and possibly 7 5/8" will be adequate. The injection well casing may be even smaller because of pressure boosts from surface pumps.
- Present estimates of casing cost is \$750 per ton. This appears higher than figure used by TRW.
- TRW proposes using 1500' of surface casing. This seems excessive since the Division of Oil and Gas requires 10% of T.D. to be depth of surface casing.
- TRW proposes to open 1500' of sand with perforations of 6 shots per foot (9000 perforations) at a cost of \$97,500. We question the need to open this amount of sand. If the productivity is only 50% of that at Heber 500' of open sand is all that will be required. Also 2 shots per foot should be sufficient, lessening the perforating cost by \$40 per foot.

Drill Rig

- TRW has used 45 days of rig time per well. 30 days will be more than adequate for an exploration well. This allows for trouble. 20 days would be ample for development wells as would be the case for a 50 Mw installation.
- TRW has used \$117/hr for drill rig cost and we feel \$130/hr would be more appropriate.

Third Party Services

- TRW has estimated third party services, including drilling, mud, coring, logging, cementing and disposable equipment at a total cost of \$180,000.

Robert H. Douglass
TRW

-3-

December 27, 1974

- Following are actual costs for these items for a 6000 foot well recently (4th quarter 1974) completed at Heber.

Mud bill	\$15,000
Coring (2 cores)	6,000
Logging (full suite of 15,000 logs)	
Cementing	20,000
Bits, Reamers, and Stabalizers	<u>10,000</u>
Total	\$ 66,000

Taking these above items into account it would appear that a well cost in the range of \$300,000 to \$350,000 would be more appropriate."

Very truly yours,

James M. Nugent
Manager - Fuel Planning

JMN:mlh

cc: CMLaffoon

Mr. A. M. Cooper
Chevron Oil Company
Minerals Staff
220 Bush Street
San Francisco, CA 94104

Mr. T. C. Hinrichs
Magma Power Company
P.O. Box 2082
Escondido, CA 92025

APPENDIX E. THERMODYNAMIC ANALYSES

E1 INTRODUCTION

E1.1 Cycle Definitions

Three thermodynamic processes were considered for the conversion of the energy in geothermal well water to electricity. These were:

- a. A flash process, wherein the high temperature, high pressure well water is throttled adiabatically producing a mixture of steam and water at a lower pressure and temperature. The steam is used directly in a turbine and the remaining water may or may not be flashed again.
- b. A binary process, wherein the well water is used, without change of phase, to heat and vaporize a secondary working fluid in a Rankine cycle.
- c. A combination of the flash and binary processes, called a hybrid, wherein the water remaining after flashing is used to heat the working fluid in the binary portion of the process.

E1.2 Basis of Comparisons

The objective of the study is to identify and describe the system which produces the greatest benefit for the least cost, including amortization of capital expenses. At the present time, the only benefit considered is the production of electrical power. The algorithms of capital and operating costs enabling direct cost comparisons to be made of different cycles, secondary fluids, or system pressures and temperatures have not been developed. The comparisons are made on the basis of minimizing the well flow rate, since the costs associated with providing the well flow are a major portion of overall costs.

To facilitate comparisons on this basis, a system efficiency has been defined as the net plant electrical output over the available energy in the well water measured between well-head and the design condensing temperatures.

E1.3 Operating Conditions and Parasitic Loads

A realistic comparison between different cycles and fluids requires that certain operating conditions and plant parasitic loads be defined. It is not required that these be exact, since small changes in, say, condensing temperature or cooling tower fan power, while perhaps having a significant impact on efficiency, are unlikely to change the relationship between the cycles or fluids. Provided these figures are realistic, the choice of a cycle and fluid for further optimization should be valid.

All analyses were performed initially on the following bases:

- Condensing temperature: 102°F .
- Reinjection: 90 psi with 40 percent pump efficiency
- Down-hole pump load: 2.3 Btu/lb pumped (0.45 HP/gpm).
- Wet cooling tower. Pump loss: 0.018 Btu/Btu condensed.
- Turbine efficiency: 0.85.
- Generator efficiency: 0.98.
- Separator efficiency: 0.95.
- Maximum secondary fluid turbine inlet temperature: 20°F below well fluid temperature.
- Regenerator efficiency: 0.80 (binary cycles, when used).
- Condenser coolant temperature rise: 15°F .
- Miscellaneous losses: 2 percent of net output.

The candidate binary systems were reanalyzed on the basis of 110°F condensing temperature and a dry cooling tower parasitic load of 0.025 btu/btu condensed when it was decided to abandon the wet cooling tower due to possible ground subsidence.

All cycles were analyzed with a well fluid temperature range of 300 to 400°F . Binary cycle performance was extended down to 200°F for purposes of calculating hybrid cycle performance since water temperatures after flashing could be that low.

E2 FLASH CYCLE ANALYSES

E2.1 Cycle Description

Typical single and double flash steam cycles are shown in Figures E-1 and E-2.

The single flash cycle operates in the following manner: Well water at a pressure above saturation is introduced into a separator. In the separator, an adiabatic throttling to a lower pressure takes place. If this pressure is below the saturation pressure at the temperature of the water, the temperature will fall to the saturation temperature corresponding to the lower pressure and part of the water will be converted to steam to maintain the same total energy.

The steam so produced is delivered to the turbine. The amount of steam delivered is that theoretically obtained times the separator efficiency. An arbitrary 2°F temperature drop between the steam separator and the turbine is used with a corresponding pressure drop to maintain saturation. The turbine exhaust is delivered to a barometric condenser which maintains a one psia turbine back pressure.

The water leaving the separator is either used as a supply for a subsequent flash cycle or processes as necessary for reinjection. Cycles with more than two flashes have not been investigated.

An important parasitic load which has not been included is the power required to remove noncondensable gases from the steam. The process of flashing reduces the pressure on the water and some of the dissolved gases will escape. If they are allowed to accumulate, the condenser pressure will gradually increase, reducing cycle output.

A possible variation of the flash cycle is to superheat the steam after separation to a temperature between flash and incoming water temperature. This was first investigated on an ideal cycle basis (no losses or parasitics). The improvement in performance was negligible and the calculations for a real cycle were not performed.

Figure E-1. Single Flashed Steam Cycle

Figure E-2. Double-Flashed Steam Cycle

E2.2 Analytical Approach

A computer program was developed to predict the performance of a power plant using geothermal hot water flashed to steam at a high pressure and the resulting water flashed again at a lower pressure. The program determined numerically the optimum flash pressures. All system parasitic loads with the exception of noncondensable gas elimination are included. Single flash system operation can be obtained by setting the first flash temperature equal to the supply water temperature.*

The steam saturation line equation given in the Steam Tables (Keenan and Keyes) was used to relate saturation line temperatures and pressures. Corresponding enthalpies and entropies were obtained by a numerical curve fit of steam table values in the form of polynomials.

The program includes the following inefficiencies or departures from an ideal system:

η_s = Separator efficiency. Ratio of pounds steam produced to ideal.

η_t = Turbine efficiency. Ratio of turbine work to that obtained from isentropic expansion.

η_g = Generator efficiency.

η_r = Reinjection pump efficiency.

D = Temperature drop (at saturation) between separator and turbine.

Provision has been made for the following parasitic losses:

Down-hole pumping power (per pound of well flow) (B_d)

Condenser pumping power (per Btu condensed) (B_c)

Reinjection pumping power (based on 90 psia injection pressure)

Other parasitic losses (percent of net output power) (B_o).

*This program written in FORTRAN and running on TRW's timeshare computer system (CDC 6500/Cyber 74) is available on request.

The following equations describe the system. (See Table E-I for nomenclature):

Amount of steam produced:

$$x_1 = \eta_s \left[h_f(T) - h_f(F_1) \right] / \left[h_g(F_1) - h_f(F_1) \right]$$

$$x_2 = \eta_s \left[h_f(F_1) - h_f(F_2) \right] / \left[h_g(F_2) - h_f(F_2) \right]$$

Conditions into turbine:

$$h_{ti} = h_g(F-D), \quad s_{ti} = s_g(F-D)$$

Isentropic expansion conditions:

$$y_{tox} = \left[s_{ti} - s_f(c) \right] / \left[s_g(c) - s_f(c) \right]$$

$$h_{tox} = h_f(c) + y_{tox} \cdot h_{fg}(c)$$

Actual outlet conditions:

$$h_{to} = h_{tox} + (1 - \eta_t) \cdot (h_{ti} - h_{tox})$$

$$y_{to} = \left[h_{to} - h_f(c) \right] / h_{fg}(c)$$

$$q_{t1} = x_1 \cdot (h_{ti1} - h_{to1})$$

$$q_{b2} = x_2 \cdot (1 - x_1) \cdot (h_{ti2} - h_{to2})$$

The parasitic losses are:

$$q_{c1} = B_c \cdot x_1 \cdot \left[h_{to1} - h_f(c) \right]$$

$$q_{c2} = B_c \cdot x_2 \cdot (1 - x_1) \cdot \left[h_{to2} - h_f(c) \right]$$

Table E-I

NOMENCLATURE

B = Parasitic coefficient
c = Condenser temperature, F
D = Separator-turbine temperature drop, F
F = Flash temperature, F
h = Enthalpy, Btu/lb.
J = Appropriate conversion factor
p = Pressure, psia
q = Work or energy, Btu/pound
R = Plant rating, Btu/hr (3412750 · megawatts)
s = Entropy, Btu/F-pound
T = Well temperature, F
W = Wellflow, pounds/hr.
x = Pounds steam/pounds water into separator
y = Quality, pounds steam/pound mixture
n = Efficiency

Subscripts

c = Condenser
d = Downhole pump
f = Saturated liquid
g = saturated vapor
G = Generator
i = inlet
o = outlet
r = reinjection pump
s = Separator
sat = Saturation
t = turbine
x = ideal
1 = First flash
2 = Second flash

$$q_{r1} = (1-x_1) \cdot [p_r - p_{sat}(F_1)] / \eta_r \cdot J$$

$$q_{r2} = (1-x_1) \cdot (1-x_2) \cdot [p_r - p_{sat}(F_2)] / \eta_r \cdot J$$

Required well flow:

$$W = \frac{R}{[\eta_G(q_{t1} + q_{t2}) - q_{c1} - q_{c2} - q_{r1} - q_{r2} - B_d] \cdot (1-B_o)}$$

E2.3 Results

The results of the analyses for a real system, including parasitic loads, are shown in Table E-II. As might be expected, the double flash is more efficient than the single flash, and the well flow rate decreases and efficiency increases with increasing well temperature. The relative insensitivity of the flow rate to minor variations in flash temperatures is shown in Figure E-3.

E3. BINARY CYCLES

E3.1 Working Fluid Selection

The original selection of working fluids consisted of Refrigerant -11, butane, and isobutane.

One of the first tasks to be accomplished was to obtain the thermodynamic properties of these fluids in a form suitable for repetitive high speed calculations on a digital computer for cycle optimization. The initial attempts were based on using the J. O. Herschfelder correlations as published by the API (Reference E-1). This effort was abandoned due to insufficient accuracy of the correlations.

A better method was found by using the correlations published by K. E. Starling (Reference E-2). These gave excellent results over a wide range of temperatures and pressures. In addition, once the computer coding is accomplished, the necessary coefficients are available for a wide range of low molecular weight hydrocarbons (and a few other substances) so that the list of candidate fluids could be expanded.

Table E-II. Steam Cycle: 10 MWe Output Condensing Temperature = 102°F

		(2) OPTIMUM REAL SINGLE FLASH					OPTIMUM REAL DOUBLE FLASH				
SOURCE WATER TEMP ⁽¹⁾ °F		300	325	350	375	400	300	325	350	375	400
WELL WATER FLOW RATE	10 ⁶ #/HR	4.407	3.175	2.415	1.907	1.546	3.302	2.405	1.845	1.466	1.196
WORKING FLUID FLOW RATE	10 ⁶ #/HR	0.414	0.340	0.297	0.265	0.240	0.396	0.329	0.286	0.254	0.288
WORKING FLUID INLET TEMP	°F	205	218	229	241	253	237/175	254/183	270/190	288/199	306/208
WORKING FLUID OUTLET TEMP	°F	102	102	102	102	102	102	102	102	102	102
TURBINE INLET PRESS	psia	12.8	16.5	20.4	25.4	31.4	23.6/6.7	32.0/8.0	41.9/9.3	55.8/11.3	73.3/13.6
TURBINE OUTLET PRESS	psia	1	1	1	1	1	1	1	1	1	1
DOWNHOLE PUMP POWER	MW	2.970	2.140	1.627	1.285	1.042	2.225	1.621	1.243	0.988	0.806
COOLANT PUMP & FAN POWER	MW	2.066	1.684	1.458	1.279	1.146	1.964	1.621	1.405	1.228	1.096
REINJECTION PUMP POWER	MW	0.684	0.465	0.325	0.235	0.174	0.996	.699	0.460	0.314	0.203
TOTAL PARASITIC LOADS	MW	5.920	4.489	3.610	2.999	2.562	5.385	4.111	3.313	2.730	2.305
TURBINE OUTPUT POWER	MW	16.245	14.783	13.904	13.273	12.824	15.702	14.405	13.582	12.992	12.562
GENERATOR OUTPUT POWER	MW	15.922	14.489	13.610	12.999	12.562	15.385	14.111	13.312	12.730	12.305
CONDENSER FLOW RATE	gpm	52,090	42,300	36,650	32,450	29,120	49,740	41,000	35,280	30,980	27,660
PLANT EFFICIENCY	%	3.87	4.76	5.61	6.43	7.23	5.17	6.28	7.35	8.36	9.35

(1) Source water temperature at the well head.

(2) Real cycle considers parasitic losses and equipment efficiency.

Figure E-3. Well Flow Required Versus Flash Temperatures
Real Double-Flash System

Any effort on using the fluorinated hydrocarbons was temporarily abandoned for four reasons:

1. Their chemical stability at elevated temperatures;
2. The absence of coefficients for use in the Starling relationship;
3. The reported inaccuracy in the Martin-Howe relationship (Reference E-3) for hydrocarbons;
4. The time required to code the Martin-Howe relationship.

E3.2 Cycle Description

The cycle considered for use with a binary working fluid is a Rankine cycle, (Figure E-4). Upon leaving the condenser, the working fluid is pressurized isentropically from P_1 to P_2 while the temperature increases slightly from T_1 to T_2 . (For computational purposes, these pressures are assumed to remain constant between pump and turbine inlet and outlets. To account for system pressure losses, P_1 is set 4 percent above the corresponding saturation pressure at condensing temperature, and pumping power is calculated on a basis of this lower pressure and a pressure 4 percent above P_2 .) The fluid then passes through a regenerator (T_2 1/2), if present; and economizer (T_3); a boiler (T_4); and a superheater (T_5). Expansion is through the turbine (T_6) and partial desuperheating through the low-pressure side of a regenerator (T_6 1/2) is followed by final desuperheating (T_7) and condensing (T_1).

Several minor variations exist:

- In the event that $T_2 \geq T_6$, the regenerator is eliminated.
- If partial boiling takes place in the regenerator, the economizer is eliminated.
- Certain combinations of fluid, pressures, and temperatures are optimum if there is no superheating.

Figure E-4. Iso-Butane Pressure-Enthalpy Diagram

E3.3 Analytical Approach

The object of the analysis was to investigate the various working fluids over the range of well flow temperatures varying turbine inlet pressure and temperature to obtain numerically the highest system efficiency.

The nature of the analytical task is twofold: given the chosen temperature and pressure, determine the enthalpy, entropy, and density at state points throughout the cycle (these are independent of all flow rates); and calculate the required flow rate and cycle performance and efficiency.

The former is a straightforward application of the Starling equation-of-state to the chosen conditions. The latter task of determining system flow rates is complicated by the highly nonlinear relationship between the enthalpy and temperature of the working fluid while it is being heated from the pump outlet to turbine inlet.

The task is one of finding the minimum ratio (W) of the working fluid flow (WC) to water flow (WH) which maintains a positive temperature difference between the water and working fluid at all points in all heat exchangers, as shown in Figure E-5.

The flow ratio of the working fluid to the brine is inversely proportional to the amount of heat transferred from the brine to the working fluid:

$$W = \frac{WC}{WH} = \frac{Q(TO) - Q(TX)}{h(TS) - h(TX)}$$

TX has that value within the domain $\{T2 \ 1/2 \leq TX < T5\}$ which produces the smallest flow rate ratio. The following equations refer to the various loads on the system (nomenclature same as previous).

ENTHALPY vs TEMPERATURE IN IDEAL

HIGH PRESSURE HEAT EXCHANGERS.

ISOBUTANE AT 480 psia

ISOBUTANE: 1.924×10^6 #/hr, 3.387×10^8 BTU/HR TRANSFERRED
 WATER: 1.445×10^6 #/hr, 3.146×10^8 BTU/HR TRANSFERRED
 REGENERATOR: 0.241×10^8 BTU/HR

Figure E-5. Enthalpy Versus Temperature in Ideal High Pressure Heat Exchanges

The condensor load is:

$$q_c = B_c \cdot [h(T_6 \text{ 1/2}) - h(t_1)]$$

the pump load:

$$q_p = [h(P_{\max}) - h(P_{\min})] / n_p;$$

the generator production:

$$q_g = \Delta h_t \cdot n_g;$$

Btu
per pound
of working
fluid

E3.4 Results

Tabulated results for a cycle with no regenerator are shown in Table E-III and for a cycle with regenerator in Table E-IV. Results are given for each fluid investigated and are those which yield maximum efficiency if system pressure is limited to 500 psia, 1000 psia, and without regard to pressure. Results for isobutane and isopentane using a 110F dry condenser are given in Table E-V.

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20°F BOILER APPROACH
 REGENERATOR: NO

Table E - IIIa

SOURCE WATER TEMP 200°F		PROPANE	BUTANE	ISOBUTANE	ISOPENTANE	PROPYLENE
WORKING FLUID						
MAX SYSTEM PRESS	psia	405*	124*	167*	54*	480*
WELLWATER FLOW	10 ⁶ #/hr	376.318	161.675	190.817	175.871	320.558
WORKING FLUID FLOW	10 ⁶ #/hr	132.186	50.557	65.380	55.254	122.067
WORKING FLUID TURBINE		SH	SA	SA	SA	SH
INLET TEMP	°F	180	159	160	159	180
OUTLET TEMP	°F	123	118	119	125	117
INLET PRESS	psia	389	119	160	52	461
OUTLET PRESS	psia	201	55	77	22	242
EXIT QUALITY	-	1.076	1.042	1.049	1.064	1.052
PARASITICS						
DOWNHOLE PUMP	MW	253.6	109.0	128.6	118.5	216.0
WORKING PUMP	MW	68.4	7.6	12.9	3.6	74.5
COOLANT PUMP	MW	99.2	40.7	49.2	44.3	85.9
OTHER	MW	0.2	0.2	0.2	0.2	0.2
TOTAL	MW	421.4	157.5	190.9	166.6	376.6
TURBINE OUTPUT	MW	440.0	171.0	205.0	180.4	394.5
GENERATOR OUTPUT	MW	431.4	167.5	200.9	176.6	386.6
CONDENSER FLOW	gpm	2,495,000	1,034,000	1,237,000	1,125,700	9,261,000
REGENERATOR REGEN. QUAL.	MW -					
EFFICIENCY	%	0.092	0.21	0.18	0.20	0.11

* (OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: NO

Table E - IIb

SOURCE WATER TEMP 225 °F							
WORKING FLUID		PROPANE	BUTANE	ISOBUTANE	ISOPENTANE	PROPYLENE	
MAX SYSTEM PRESS psia		500 675*	147*	197*	65*	500 750*	
WELLWATER FLOW 10 ⁶ #/hr		16.232 14.288	17.344	17.282	17.665	18.854 14.188	
WORKING FLUID FLOW 10 ⁶ #/hr		9.371 18.664	7.185	7.952	7.313	9.977 12.335	
WORKING FLUID TURBINE		SA SC	SA	SA	SA	SH SC	
INLET TEMP °F		181 205	172	174	172	205 205	
OUTLET TEMP °F		105 105	122	123	131	141 105	
INLET PRESS psia		480 648	141	189	62	480 720	
OUTLET PRESS psia		201 201	55	77	22	242 242	
EXIT QUALITY	-	0.953 0.603	1.054	1.062	1.081	1.154 0.736	
PARASITICS							
DOWNHOLE PUMP MW		10.939 9.629	11.689	11.647	11.905	12.706 9.562	
WORKING PUMP MW		7.039 21.922	1.423	2.127	0.621	6.574 15.673	
COOLANT PUMP MW		6.183 7.810	5.895	6.026	6.004	7.679 6.028	
OTHER MW		0.200 0.200	0.200	0.200	0.200	0.200 0.200	
TOTAL MW		24.361 39.561	19.207	20.000	18.730	27.159 31.463	
TURBINE OUTPUT MW		35.089 50.574	29.781	30.612	29.297	37.898 42.322	
GENERATOR OUTPUT MW		34.361 49.561	29.207	30.000	28.730	37.159 41.463	
CONDENSER FLOW gpm		156,660 197,330	148,560	152,180	151,380	193,570 152,670	
REGENERATOR REGEN. QUAL.	MW -						
EFFICIENCY %		1.70 1.93	1.59	1.60	1.56	1.47 1.95	

*(OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102 °F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: NO

Table E - IIIc

SOURCE WATER TEMP 250°F		PROPANE		BUTANE		ISOBUTANE	ISOPENTANE		PROPYLENE	
WORKING FLUID										
MAX SYSTEM PRESS	psia	500	790*	173	575*	235*	78	525*	500	815*
WELLWATER FLOW	10 ⁶ #/hr	7.496	6.235	8.038	7.348	7.791	8.183	7.067	9.726	6.414
WORKING FLUID FLOW	10 ⁶ #/hr	6.761	5.832	4.221	13.563	4.550	4.233	13.672	7.088	6.323
WORKING FLUID TURBINE		SA	SH	SA	SC	SA	SA	SC	SH	SC
INLET TEMP	°F	181	230	186	230	189	185	230	210	220
OUTLET TEMP	°F	105	105	125	104	127	137	104	147	105
INLET PRESS	psia	480	758	166	552	226	75	504	480	783
OUTLET PRESS	psia	201	201	55	55	77	22	22	242	242
EXIT QUALITY	-	0.953	0.844	1.065	0.486	1.075	1.099	0.477	1.177	0.859
PARASITICS										
DOWNHOLE PUMP	MW	5.052	4.202	5.417	4.952	5.251	5.515	4.763	6.555	4.323
WORKING PUMP	MW	5.074	8.678	1.060	14.598	1.575	0.466	13.212	4.674	9.022
COOLANT PUMP	MW	4.481	3.455	3.486	5.124	3.493	3.525	4.949	5.557	3.628
OTHER	MW	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
TOTAL	MW	14.807	16.535	10.163	24.874	10.519	9.706	23.124	16.986	14.173
TURBINE OUTPUT	MW	25.324	27.076	20.562	35.591	20.934	20.118	33.797	27.529	27.723
GENERATOR OUTPUT	MW	24.807	26.535	20.163	34.874	20.519	19.706	33.124	27.986	27.173
CONDENSER FLOW	gpm	113,030	77,690	88,200	129,240	88,130	91,340	124,850	140,410	91,380
REGENERATOR REGEN. QUAL.	MW									
EFFICIENCY	%	3.06	3.68	2.85	3.12	2.94	2.80	3.25	2.36	3.58

*(OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: NO

Table E - IIId

SOURCE WATER TEMP 275°F											
WORKING FLUID		PROPANE		BUTANE		ISOBUTANE		ISOPENTANE		PROPYLENE	
MAX SYSTEM PRESS psia		500	825*	204	575*	297*	93	525*	500	905*	
WELLWATER FLOW 10 ⁶ #/hr		5.020	3.771	4.806	3.766	4.510	4.917	3.756	6.541	3.852	
WORKING FLUID FLOW 10 ⁶ #/hr		4.916	3.516	3.087	6.599	3.232	3.082	6.990	6.180	3.444	
WORKING FLUID TURBINE		SH	SC	SA	SC	SA	SA	SC	SH	SC	
INLET TEMP °F		203	250	201	255	208	199	255	210	255	
OUTLET TEMP °F		126	109	129	104	131	143	104	147	118	
INLET PRESS psia		480	792	196	552	276	89	504	480	869	
OUTLET PRESS psia		201	201	55	55	77	22	22	242	242	
EXIT QUALITY -		1.085	1.012	1.077	0.591	1.088	1.118	0.573	1.177	1.058	
PARASITICS											
DOWNHOLE PUMP MW		3.383	2.542	3.239	2.538	3.039	3.314	2.531	4.409	2.596	
WORKING PUMP MW		3.692	5.404	0.972	7.106	1.480	0.432	6.757	4.064	5.666	
COOLANT PUMP MW		3.692	2.475	2.577	3.034	2.511	2.608	3.037	4.849	2.427	
OTHER MW		0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	
TOTAL MW		10.967	10.621	6.988	12.878	7.230	6.554	12.525	13.522	10.889	
TURBINE OUTPUT MW		21.388	21.040	17.334	23.349	17.589	16.887	22.990	23.998	21.310	
GENERATOR OUTPUT MW		20.967	20.621	16.988	22.878	17.230	16.554	22.525	23.522	20.889	
CONDENSER FLOW gpm		93,520	62,650	65,250	76,560	63,400	65,970	76,710	122,420	61,310	
REGENERATOR REGEN. QUAL.											
EFFICIENCY %		3.90	5.19	4.08	5.20	4.34	3.98	5.21	2.99	5.08	

*(OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: NO

Table E - IIIe

SOURCE WATER TEMP 300°F												
WORKING FLUID		PROPANE		BUTANE		ISOBUTANE		ISOPENTANE		PROPYLENE		
MAX SYSTEM PRESS psia		500	980*	250	575*	500	625*	110	525*	500	1000	1055*
WELLWATER FLOW 10 ⁶ #/hr		3.816	2.610	3.209	2.386	2.774	2.315	3.316	2.436	4.934	2.661	2.653
WORKING FLUID FLOW 10 ⁶ #/hr		4.245	2.647	2.408	3.916	2.225	3.036	2.470	4.384	5.439	2.664	2.760
WORKING FLUID TURBINE		SH	SC	SA	SC	SA	SC	SA	SC	SH	SC	SC
INLET TEMP °F		216	280	219	280	264	280	213	280	220	280	280
OUTLET TEMP °F		142	127	134	104	128	105	149	104	158	137	128
INLET PRESS psia		480	942	240	552	480	600	106	504	480	960	1013
OUTLET PRESS psia		201	201	55	55	77	77	22	22	242	242	242
EXIT QUALITY	-	1.147	1.096	1.092	0.709	1.080	0.885	1.132	0.671	1.223	1.140	1.102
PARASITICS												
DOWNHOLE PUMP MW		2.572	1.759	2.163	1.608	1.869	1.560	2.235	1.642	3.325	1.794	1.788
WORKING PUMP MW		3.209	5.051	0.978	4.216	2.032	3.589	0.418	4.241	3.586	4.991	5.535
COOLANT PUMP MW		3.399	2.014	2.040	2.160	1.715	1.913	2.128	2.227	4.424	2.020	2.029
OTHER MW		0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
TOTAL MW		9.380	9.024	5.381	8.164	5.816	7.262	4.981	8.310	11.535	9.005	9.552
TURBINE OUTPUT MW		19.781	19.415	15.703	18.555	16.141	17.618	15.295	18.683	21.977	19.394	19.946
GENERATOR OUTPUT MW		19.380	19.024	15.381	18.184	15.816	17.262	14.981	18.310	21.535	19.005	19.552
CONDENSER FLOW gpm		85,740	50,930	51,590	54,510	43,310	48,400	53,790	56,330	111,900	51,100	51,160
REGENERATOR REGEN. QUAL.	MW											
EFFICIENCY %		4.47	6.54	5.32	7.16	6.16	7.37	5.15	7.01	3.46	6.42	6.44

*(OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: NO

Table E - III_f

SOURCE WATER TEMP 325°F													
WORKING FLUID		PROPANE			BUTANE		ISOBUTANE		ISOPENTANE		PROPYLENE		
MAX SYSTEM PRESS	psia	500	1000	1140*	304	650*	500	600*	133	525*	500	1000	1215*
WELLWATER FLOW	10 ⁶ #/hr	3.112	1.985	1.967	2.262	1.749	1.812	1.747	2.386	1.742	3.991	2.046	1.988
WORKING FLUID FLOW	10 ⁶ #/hr	3.867	2.173	2.194	2.045	2.549	2.105	2.317	2.046	3.032	4.955	2.287	2.296
WORKING FLUID TURBINE													
		SH	SC	SC	SA	SC	SA	SC	SA	SC	SH	SC	SC
INLET TEMP	°F	227	298	305	238	305	264	285	229	305	230	295	305
OUTLET TEMP	°F	155	154	144	138	104	128	105	157	104	169	158	141
INLET PRESS	psia	480	960	1096	292	624	480	576	128	504	480	960	1167
OUTLET PRESS	psia	201	201	201	55	55	77	77	22	22	242	242	242
EXIT QUALITY	-	1.202	1.198	1.158	1.104	0.849	1.080	0.997	1.160	0.772	1.267	1.223	1.155
PARASITICS													
DOWNHOLE PUMP	MW	2.097	1.338	1.325	1.525	1.179	1.221	1.177	1.608	1.174	2.690	1.379	1.340
WORKING PUMP	MW	2.900	4.246	5.010	1.047	3.126	1.928	2.616	0.440	2.930	3.263	4.287	5.488
COOLANT PUMP	MW	3.228	1.803	1.766	1.717	1.676	1.625	1.648	1.796	1.776	4.187	1.864	1.765
OTHER	MW	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
TOTAL	MW	8.425	7.587	8.301	4.489	6.181	4.974	5.641	4.044	6.080	10.340	7.730	8.793
TURBINE OUTPUT	MW	18.803	17.946	18.673	14.783	16.515	15.274	15.959	14.330	16.405	20.747	18.087	19.181
GENERATOR OUTPUT	MW	18.425	17.587	18.301	14.489	16.181	14.974	15.641	14.044	16.080	20.340	17.730	18.793
CONDENSER FLOW	gpm	81,520	45,680	44,580	43,350	42,330	40,980	41,630	45,260	44,810	105,610	47,070	44,610
REGENERATOR REGEN. QUAL.	MW												
EFFICIENCY	%	4.86	7.65	7.69	6.68	8.64	8.34	8.65	6.34	8.68	3.79	7.39	7.60

*(OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: NO

Table E - IIIg

SOURCE WATER TEMP 350°F												
WORKING FLUID												
MAX SYSTEM PRESS psia												
WELLWATER FLOW 10 ⁶ #/hr												
WORKING FLUID 10 ⁶ #/hr FLOW												
WORKING FLUID TURBINE												
INLET TEMP °F												
OUTLET TEMP °F												
INLET PRESS psia												
OUTLET PRESS psia												
EXIT QUALITY												
PARASITICS												
DOWNHOLE PUMP MW												
WORKING PUMP MW												
COOLANT PUMP MW												
OTHER MW												
TOTAL MW												
TURBINE OUTPUT MW												
GENERATOR OUTPUT MW												
CONDENSER FLOW gpm												
REGENERATOR REGEN. QUAL.												
EFFICIENCY %												
•(OPTIMUM)												

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: NO

Table E - IIIh

SOURCE WATER TEMP	375°F												
WORKING FLUID		PROPANE			BUTANE		ISOBUTANE		ISOPENTANE		PROPYLENE		
MAX SYSTEM PRESS	psia	500	1000	1500*	500	675*	500	865*	196	525*	500	1000	1550*
WELLWATER FLOW	10 ⁶ #/hr	2.317	1.382	1.290	1.163	1.121	1.252	1.151	1.373	1.054	2.931	1.430	1.290
WORKING FLUID FLOW	10 ⁶ #/hr	3.280	1.734	1.620	1.562	1.608	1.924	1.631	1.530	1.641	4.179	1.865	1.690
WORKING FLUID TURBINE		SH	SC	SC	SA	SC	SH	SC	SA	SC	SH	SC	SC
INLET TEMP	°F	255	328	355	290	325	270	335	265	355	260	325	355
OUTLET TEMP	°F	187	195	178	135	118	141	150	172	105	201	196	173
INLET PRESS	psia	480	960	1441	480	648	480	830	188	504	480	960	1489
OUTLET PRESS	psia	201	201	201	55	55	77	77	22	22	242	242	242
EXIT QUALITY	-	1.333	1.365	1.293	1.096	1.044	1.125	1.156	1.210	1.002	1.395	1.374	1.283
PARASITICS													
DOWNHOLE PUMP	MW	1.562	0.931	0.869	0.784	0.756	0.844	0.775	0.926	0.710	1.975	0.964	0.869
WORKING PUMP	MW	2.464	3.389	5.091	1.441	2.063	1.761	2.754	0.515	1.587	2.748	3.496	5.398
COOLANT PUMP	MW	3.029	1.642	1.455	1.329	1.304	1.544	1.345	1.404	1.248	3.882	1.706	1.444
OTHER	MW	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
TOTAL	MW	7.255	6.162	7.615	3.754	4.323	4.349	5.074	3.045	3.745	8.805	6.366	7.911
TURBINE OUTPUT	MW	17.608	16.486	17.977	14.035	14.616	14.643	15.381	13.308	14.024	19.195	16.698	18.278
GENERATOR OUTPUT	MW	17.255	16.162	17.615	13.754	14.323	14.349	15.074	13.045	13.745	18.805	16.366	17.911
CONDENSER FLOW	gpm	76,650	41,450	17,615	33,590	32,940	39,010	33,960	35,450	31,500	98,100	43,100	36,480
REGENERATOR REGEN. QUAL.	MW												
EFFICIENCY	%	5.29	8.87	9.50	10.54	10.93	9.79	10.65	8.93	11.63	4.18	8.57	9.50

*(OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: NO

Table E - IIIi

SOURCE WATER TEMP 400°F		PROPANE			BUTANE		ISOBUTANE			ISOPENTANE		PROPYLENE		
WORKING FLUID		500	1000	1700*	500	925*	500	1000	1150	257	575*	500	1000	1740*
MAX SYSTEM PRESS	psia	500	1000	1700*	500	925*	500	1000	1150	257	575*	500	1000	1740*
WELLWATER FLOW	10 ⁶ #/hr	2.068	1.209	1.093	0.988	0.941	1.108	0.981	0.979	1.069	0.883	2.602	1.252	1.088
WORKING FLUID FLOW	10 ⁶ #/hr	3.039	1.598	1.426	1.545	1.383	1.743	1.419	1.402	1.316	1.389	3.855	1.696	1.488
WORKING FLUID TURBINE		SH	SC	SC	SA	SC	SH	SC	SC	SA	SC	SH	SC	SC
INLET TEMP	°F	273	343	380	290	360	285	360	370	292	370	280	345	380
OUTLET TEMP	°F	207	215	196	135	140	166	174	173	184	132	223	220	190
INLET PRESS	psia	480	960	1633	480	888	480	960	1104	247	552	480	960	1670
OUTLET PRESS	psia	201	201	201	55	55	77	77	77	22	22	242	242	242
EXIT QUALITY	-	1.413	1.441	1.367	1.096	1.111	1.211	1.239	1.236	1.247	1.083	1.478	1.467	1.350
PARASITICS														
DOWNHOLE PUMP	MW	1.394	0.815	0.737	0.666	0.634	0.747	0.661	0.660	0.720	0.595	1.753	0.844	0.731
WORKING PUMP	MW	2.284	3.125	5.152	1.425	2.482	1.594	2.805	3.212	0.598	1.475	2.539	3.178	5.404
COOLANT PUMP	MW	2.981	1.598	1.355	1.315	1.194	1.505	1.256	1.236	1.246	1.141	3.797	1.656	1.335
OTHER	MW	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
TOTAL	MW	6.859	5.738	7.444	3.606	4.510	4.046	4.922	5.308	2.764	3.411	8.289	5.878	7.670
TURBINE OUTPUT	MW	17.197	16.048	17.801	13.885	14.808	14.329	15.224	15.621	13.021	13.685	18.663	16.210	18.029
GENERATOR OUTPUT	MW	16.859	16.738	17.444	13.606	14.510	14.046	14.922	15.308	12.764	13.411	18.289	15.878	17.670
CONDENSER FLOW	gpm	75,300	40,400	34,200	33,230	30,160	38,020	31,680	31,230	31,440	28,800	95,910	41,860	33,800
REGENERATOR REGEN. QUAL.	MW -													
EFFICIENCY	%	5.41	9.25	10.23	11.31	11.88	10.09	11.40	11.42	10.46	12.66	4.30	8.93	10.28

*(OPTIMUM

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET.
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: $\eta = 0.8$

Table E - IVa

SOURCE WATER TEMP	°F	200	200	200	200	200	200	200
WORKING FLUID		PROPANE	BUTANE	ISOBUTANE	ISOPENTANE	PROPYLENE	PENTANE	HEXANE
MAX SYSTEM PRESS	psia	401*	124*	167*	54*	473*	43*	15*
WELLWATER FLOW	10 ⁶ #/hr	250.820	143.461	162.663	145.421	249.581	121.497	60.593
WORKING FLUID FLOW	10 ⁶ #/hr	89.140	44.861	55.733	45.687	96.467	36.085	19.668
WORKING FLUID TURBINE		SH	SA	SA	SA	SH	SA	SA
INLET TEMP	°F	180	159	160	159	180	159	154
OUTLET TEMP	°F	124	118	119	125	119	125	123
INLET PRESS	psia	385	119	160	52	454	41	14
OUTLET PRESS	psia	201	55	77	22	242	17	5
EXIT QUALITY	-	1.081	1.042	1.049	1.064	1.060	1.059	1.055
PARASITICS								
DOWNHOLE PUMP	MW	169.0	96.7	109.6	98.0	168.2	81.9	40.8
WORKING PUMP	MW	45.6	6.7	11.0	3.0	57.0	1.8	0.4
COOLANT PUMP	MW	63.2	35.3	40.0	34.9	65.8	29.2	15.8
OTHER	MW	0.2	0.2	0.2	0.2	0.2	0.2	0.2
TOTAL	MW	278.0	138.9	160.8	136.1	291.2	113.1	57.2
TURBINE OUTPUT	MW	294.0	151.8	174.1	149.1	307.2	125.7	68.5
GENERATOR OUTPUT	MW	288.0	148.9	170.8	146.1	301.2	123.1	67.2
CONDENSER FLOW	gpm	1,599,000	889,000	1,016,100	886,200	1,658,000	737,000	400,000
REGENERATOR	MW	199.2	63.9	83.4	98.0	139.7	75.8	38.0
REGEN. QUAL.	-	-0.339	-0.212	-0.254	-0.184	-0.375	-0.177	-0.156
EFFICIENCY	%	0.14	0.24	0.21	0.24	0.14	0.29	0.57

* (OPTIMUM)

Table E - IVb

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: $\eta = 0.8$

SOURCE WATER TEMP	°F	225	225	225	225	225	225	225	225	
WORKING FLUID		PROPANE	BUTANE	ISOBUTANE	ISOPENTANE	PROPYLENE	PENTANE	HEXANE		
MAX SYSTEM PRESS	psia	500	675*	147*	197*	65*	500	760*	52*	19*
WELLWATER FLOW	10 ⁶ #/hr	16.232	14.288	16.957	16.840	17.066	17.557	13.820	16.575	14.438
WORKING FLUID FLOW	10 ⁶ #/hr	9.371	18.664	7.025	7.749	7.066	9.280	14.645	6.503	5.846
WORKING FLUID TURBINE		SA	SC	SA	SA	SA	SH	SC	SA	SA
INLET TEMP	°F	181	205	172	174	172	205	205	171	169
OUTLET TEMP	°F	105	105	122	123	131	141	105	130	130
INLET PRESS	psia	480	648	141	189	62	480	730	50	18
OUTLET PRESS	psia	201	201	55	77	22	242	242	17	5
EXIT QUALITY	-	0.953	0.603	1.054	1.062	1.081	1.154	0.677	1.075	1.076
PARASITICS										
DOWNHOLE PUMP	MW	10.939	9.629	11.428	11.349	11.502	11.833	9.314	11.171	9.730
WORKING PUMP	MW	7.039	21.922	1.391	2.062	0.600	6.122	18.951	0.437	0.160
COOLANT PUMP	MW	6.183	7.810	5.515	5.605	5.451	6.431	6.601	5.294	4.717
OTHER	MW	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
TOTAL	MW	24.361	39.561	18.534	19.216	17.753	24.586	35.066	17.102	14.807
TURBINE OUTPUT	MW	35.089	50.574	29.117	29.804	28.305	35.292	45.961	27.635	25.299
GENERATOR OUTPUT	MW	34.361	49.561	28.534	29.216	27.753	34.586	45.066	27.102	24.807
CONDENSER FLOW	gpm	156,600	197,330	139,490	141,700	137,530	162,560	166,880	133,160	119,260
REGENERATOR REGEN. QUAL.	MW	-	-	12.670	14.507	19.203	38.791	-	17.193	15.653
	-	-0.792	-	-0.276	-0.341	-0.235	-0.337	-	-0.224	-0.201
EFFICIENCY	%	1.70	1.93	1.63	1.64	1.62	1.57	2.00	1.67	1.91

* (OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: $\eta = 0.8$

Table E - IVc

SOURCE WATER TEMP	°F	250		250		250		250		250		250	
WORKING FLUID		PROPANE		BUTANE		ISOBUTANE		ISOPENTANE		PROPYLENE		PENTANE	
MAX SYSTEM PRESS	psia	500	790*	173	575*	235*	78	525*	500	755*	64*	23*	
WELLWATER FLOW	10 ⁶ #/hr	7.496	6.235	7.910	7.348	7.653	7.985	7.067	9.014	6.469	7.853	7.346	
WORKING FLUID FLOW	10 ⁶ #/hr	6.761	5.832	4.153	13.563	4.469	4.131	13.672	5.946	6.742	3.837	3.709	
WORKING FLUID TURBINE		SA	SH	SA	SC	SA	SA	SC	SH	SC	SA	SA	
INLET TEMP	°F	181	230	186	230	189	185	230	230	210	185	181	
OUTLET TEMP	°F	105	105	125	104	127	132	104	169	105	136	136	
INLET PRESS	psia	480	758	165	552	226	75	504	480	725	61	22	
OUTLET PRESS	psia	201	201	55	55	77	22	22	242	242	17	5	
EXIT QUALITY	-	0.953	0.844	1.065	0.486	1.075	1.099	0.477	1.267	0.850	1.091	1.094	
PARASITICS													
DOWNHOLE PUMP	MW	5.052	4.202	5.331	4.952	5.157	5.382	4.763	6.075	4.360	5.292	4.951	
WORKING PUMP	MW	5.074	8.678	1.043	14.598	1.547	0.445	13.212	3.909	8.644	0.345	0.110	
COOLANT PUMP	MW	4.481	3.455	3.268	5.124	3.251	3.206	4.949	4.226	3.810	3.129	3.015	
OTHER	MW	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	
TOTAL	MW	14.807	16.535	9.842	24.874	10.155	9.233	23.124	14.410	17.014	8.966	8.276	
TURBINE OUTPUT	MW	25.324	27.076	20.233	35.591	20.562	19.631	33.797	24.906	27.561	19.352	18.649	
GENERATOR OUTPUT	MW	24.807	26.535	19.842	34.874	20.155	19.233	33.124	24.410	27.014	18.966	18.276	
CONDENSER FLOW	gpm	113,030	77,690	82,680	129,240	81,980	80,700	124,850	106,410	96,430	78,830	75,950	
REGENERATOR REGEN. QUAL.	MW	-	-	9.062	-	10.068	13.711	-	44.714	-	12.379	12.292	
	-	-0.792	-	-0.348	-	-0.458	-0.290	-	-0.201	-	-0.276	-0.240	
EFFICIENCY	%	3.06	3.68	2.90	3.12	3.00	2.87	3.25	2.54	3.55	2.92	3.12	

* (OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: $\eta = 0.8$

Table E - IVd

SOURCE WATER TEMP	°F	275		275		275		275		275		275			
WORKING FLUID		PROPANE		BUTANE		ISOBUTANE		ISOPENTANE		PROPYLENE		PENTANE		HEXANE	
MAX SYSTEM PRESS	psia	500	805*	204	575*	283*	93	525*	500	870*	75	510*	29	455*	
WELLWATER FLOW	10 ⁶ #/hr	4.893	3.754	4.739	3.766	4.444	4.814	3.756	6.090	3.823	4.764	3.707	4.575	3.422	
WORKING FLUID FLOW	10 ⁶ #/hr	4.402	3.155	3.045	6.599	3.222	3.017	6.990	4.679	3.312	2.835	6.919	2.701	6.672	
WORKING FLUID TURBINE		SH	SC	SA	SC	SA	SA	SC	SH	SC	SA	SC	SA	SC	
INLET TEMP	°F	215	255	201	255	207	199	255	255	255	198	255	196	255	
OUTLET TEMP	°F	141	123	129	104	130	143	104	196	125	141	104	144	103	
INLET PRESS	psia	480	773	196	552	272	89	504	480	836	72	490	28	437	
OUTLET PRESS	psia	201	201	55	55	77	22	22	242	242	17	17	5	5	
EXIT QUALITY	-	1.147	1.076	1.077	0.591	1.087	1.118	0.573	1.374	1.088	1.108	0.544	1.116	0.524	
PARASITICS															
DOWNHOLE PUMP	MW	3.298	2.530	3.194	2.538	2.995	3.244	2.531	4.104	2.577	3.211	2.498	3.083	2.307	
WORKING PUMP	MW	3.312	4.697	0.958	7.106	1.445	0.423	6.757	3.087	5.164	0.321	6.538	0.121	5.386	
COOLANT PUMP	MW	3.183	2.266	2.402	3.034	2.344	2.342	3.037	3.390	2.297	2.317	3.009	2.198	2.778	
OTHER	MW	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	
TOTAL	MW	9.993	9.693	6.754	12.878	6.984	6.209	12.525	10.781	10.238	6.049	12.245	5.602	10.671	
TURBINE OUTPUT	MW	20.389	20.098	17.094	23.349	17.346	16.533	22.990	21.119	20.658	16.374	22.689	15.922	21.092	
GENERATOR OUTPUT	MW	19.993	19.693	16.754	22.878	16.984	16.209	22.525	20.781	20.238	16.049	22.245	15.602	20.671	
CONDENSER FLOW	gpm	80,250	57,250	60,780	76,560	59,310	59,170	76,710	85,440	58,050	58,450	75,850	55,540	70,190	
REGENERATOR REGEN. QUAL.	MW	18.238	5.049	7.859	-	8.439	11.906	-	50.053	5.725	10.777	-	11.072	-	
	-	-0.606	-	-0.434	-	-0.625	-0.351	-	-0.072	-	-0.328	-	-0.291	-	
EFFICIENCY	%	4.00	5.22	4.13	5.20	4.41	4.07	5.21	3.22	5.12	4.11	5.28	4.28	5.72	
* (OPTIMUM)															

* (OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: $\eta = 0.8$

Table E - IVe

SOURCE WATER TEMP	°F	300 PROPANE		300 BUTANE		300 ISOBUTANE		300 ISOPENTANE		300 PROPYLENE			300 PENTANE		300 HEXANE	
WORKING FLUID																
MAX SYSTEM PRESS	psia	500	945*	244	575*	432	625*	111	525*	500	1000	1010*	90	510*	36	455*
WELLWATER FLOW	10 ⁶ #/hr	3.678	2.580	3.166	2.386	2.738	2.315	3.251	2.436	4.451	2.623+	2.623-	3.237	2.419	3.140	2.296
WORKING FLUID FLOW	10 ⁶ #/hr	3.786	2.536	2.420	3.916	2.267	3.036	2.405	4.384	3.942	2.626	2.643	2.266	4.376	2.157	4.361
WORKING FLUID TURBINE		SH	SC	SA	SC	SA	SC	SA	SC	SH	SC	SC	SA	SC	SA	SC
INLET TEMP	°F	230	280	217	280	249	280	214	280	280	280	280	212	280	211	280
OUTLET TEMP	°F	159	135	133	104	134	105	150	104	223	137	136	148	104	151	103
INLET PRESS	psia	480	908	234	552	415	600	107	504	480	960	970	86	490	35	437
OUTLET PRESS	psia	201	201	55	55	77	77	22	22	242	242	242	17	17	5	5
EXIT QUALITY	-	1.218	1.123	1.090	0.709	1.099	0.885	1.138	0.671	1.478	1.140	1.133	1.126	0.635	1.127	0.608
PARASITICS																
DOWNHOLE PUMP	MW	2.479	1.739	2.134	1.608	1.845	1.560	2.191	1.642	2.999	1.768	1.768	2.182	1.630	2.116	1.547
WORKING PUMP	MW	2.845	4.628	0.955	4.216	1.741	3.589	0.419	4.241	2.595	4.919	5.019	0.322	4.132	0.120	3.519
COOLANT PUMP	MW	2.770	1.845	1.920	2.160	1.661	1.913	1.877	2.227	2.908	1.845	1.860	1.859	2.218	1.767	2.112
OTHER	MW	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
TOTAL	MW	8.294	8.412	5.209	8.184	5.447	7.262	4.687	8.310	8.702	8.732	8.847	4.563	8.180	4.203	7.378
TURBINE OUTPUT	MW	18.667	18.792	15.519	18.555	15.763	17.618	14.985	18.683	19.079	19.117	19.229	14.853	18.548	14.493	17.727
GENERATOR OUTPUT	MW	18.294	18.412	15.209	18.184	15.447	17.262	14.687	18.310	18.702	18.732	18.847	14.563	18.180	14.203	17.378
CONDENSER FLOW	gpm	69,960	46,610	48,450	54,510	41,940	48,400	47,360	56,330	73,350	46,680	46,930	46,890	56,020	44,550	53,270
REGENERATOR REGEN. QUAL.	MW	24.088	7.381	7.291	-	6.506	-	11.117	-	54.356	8.086	7.562	10.101	-	10.417	-
	-	-0.507	-	-0.551	-	-1.554	-	-0.421	-	0.053	-	-	-0.391	-	-0.343	-
EFFICIENCY	%	4.64	6.62	5.39	7.16	6.24	7.37	5.25	7.01	3.84	6.51	6.51	5.27	7.06	5.44	7.44
*(OPTIMUM)																

*(OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: $\eta = 0.8$

Table E - IVf

SOURCE WATER TEMP	°F	325			325		325		325		325			325		325	
WORKING FLUID		PROPANE			BUTANE		ISOBUTANE		ISOPENTANE		PROPYLENE			PENTANE		HEXANE	
MAX SYSTEM PRESS	psia	500	1000	1100*	304	650*	500	600*	133	525*	500	1000	1165*	107	510*	44	455*
WELLWATER FLOW	10 ⁶ #/hr	2.971	1.949	1.936	2.233	1.749	1.798	1.747	2.340	1.742	3.342	1.999	1.959	2.347	1.734	2.290	1.675
WORKING FLUID FLOW	10 ⁶ #/hr	3.384	2.100	2.112	1.982	2.549	2.088	2.317	2.007	3.032	3.438	2.131	2.203	1.910	3.045	1.820	3.110
WORKING FLUID TURBINE		SH	SC	SC	SA	SC	SA	SC	SA	SC	SH	SC	SC	SA	SC	SA	SC
INLET TEMP	°F	245	300	305	238	305	264	285	229	305	305	302	305	227	305	224	305
OUTLET TEMP	°F	176	156	149	138	104	128	105	157	104	249	167	143	154	104	158	103
INLET PRESS	psia	480	960	1056	292	624	480	576	128	504	480	960	1119	103	490	42	437
OUTLET PRESS	psia	201	201	201	55	55	77	77	22	22	242	242	242	17	17	5	5
EXIT QUALITY	-	1.288	1.210	1.179	1.104	0.849	1.080	0.997	1.160	0.772	1.582	1.260	1.182	1.146	0.728	1.157	0.693
PARASITICS																	
DOWNHOLE PUMP	MW	2.002	1.314	1.304	1.504	1.179	1.211	1.177	1.577	1.174	2.252	1.347	1.320	1.582	1.168	1.544	1.129
WORKING PUMP	MW	2.542	4.103	4.634	1.027	3.126	1.912	2.616	0.432	2.930	2.262	3.994	5.006	0.330	2.875	0.128	2.508
COOLANT PUMP	MW	2.507	1.556	1.560	1.577	1.676	1.527	1.648	1.570	1.776	2.585	1.534	1.573	1.568	1.773	1.497	1.713
OTHER	MW	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
TOTAL	MW	7.251	7.173	7.698	4.308	6.181	4.850	5.641	3.779	6.080	7.299	7.075	8.399	3.680	6.016	3.369	5.550
TURBINE OUTPUT	MW	17.604	17.515	18.064	14.604	16.515	15.148	15.959	14.065	16.405	17.655	17.422	18.169	13.967	16.343	13.637	15.872
GENERATOR OUTPUT	MW	17.251	17.173	17.698	14.308	16.181	14.850	15.641	13.779	16.080	17.299	17.075	18.399	13.680	16.016	13.369	15.550
CONDENSER FLOW	gpm	63,360	39,280	39,400	39,830	42,330	38,530	41,630	39,710	44,810	65,180	38,750	39,590	39,680	44,720	37,730	43,280
REGENERATOR REGEN. QUAL.	MW	28.757	11.468	9.460	6.883	-	4.661	-	10.746	-	57.929	14.154	9.100	9.799	-	10.047	-
	-	-0.411	-	-	-0.746	-	-2.856	-	-0.504	-	0.178	-	-	-0.458	-	-0.395	-
EFFICIENCY	%	5.09	7.76	7.81	6.77	8.64	8.41	8.65	6.46	8.68	4.52	7.56	7.71	6.44	8.72	6.60	9.02

* (OPTIMUM)

Table E - IVg

REAL BINARY CYCLE:
 CONDENSER TEMP: 102°F
 TOWER: WET
 MINIMUM 20°F BOILER APPROACH
 REGENERATOR: $\eta = 0.8$

SOURCE WATER TEMP	°F	350			350		350		350		350			350		350	
WORKING FLUID		PROPANE			BUTANE		ISOBUTANE		ISOPENTANE		PROPYLENE			PENTANE		HEXANE	
MAX SYSTEM PRESS	psia	500	1000	1265*	500	613*	500	755*	161	525*	500	1000	1325*	129	510*	53	455*
WELLWATER FLOW	10 ⁶ #/hr	2.438	1.580	1.534	1.525	1.371	1.441	1.378	1.753	1.325	2.644	1.628	1.545	1.772	1.317	1.745	1.288
WORKING FLUID FLOW	10 ⁶ #/hr	2.461	1.815	1.798	1.584	1.992	2.044	1.834	1.718	2.212	3.088	1.879	1.878	1.643	2.236	1.590	2.341
WORKING FLUID TURBINE		SH	SC	SC	SA	SC	SA	SC	SA	SC	SH	SC	SC	SA	SC	SA	SC
INLET TEMP	°F	330	317	330	290	310	264	315	246	330	330	320	330	243	330	238	330
OUTLET TEMP	°F	269	181	165	135	104	128	132	164	104	275	190	162	161	104	164	103
INLET PRESS	psia	480	960	1215	480	589	480	725	155	504	480	960	1273	124	490	51	437
OUTLET PRESS	psia	201	201	201	55	55	77	77	22	22	242	242	242	17	17	5	5
EXIT QUALITY	-	1.664	1.306	1.244	1.096	0.945	1.080	1.094	1.184	0.879	1.685	1.350	1.240	1.167	0.826	1.176	0.778
PARASITICS																	
DOWNHOLE PUMP	MW	1.643	1.065	1.033	1.027	0.924	0.971	0.928	1.181	0.893	1.782	1.097	1.041	1.194	0.887	1.176	0.868
WORKING PUMP	MW	1.851	3.551	4.651	1.461	2.298	1.871	2.672	0.462	2.139	2.038	3.521	4.987	0.358	2.110	0.138	1.890
COOLANT PUMP	MW	1.951	1.370	1.348	1.260	1.462	1.495	1.348	1.351	1.475	2.363	1.374	1.362	1.355	1.474	1.309	1.449
OTHER	MW	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
TOTAL	MW	5.645	6.186	7.232	3.948	4.884	3.537	5.148	3.194	4.707	6.383	6.192	7.590	3.107	4.671	2.823	4.407
TURBINE OUTPUT	MW	15.969	16.514	17.583	14.237	15.187	14.831	15.461	13.463	15.004	16.713	16.524	17.949	13.373	14.973	13.087	14.699
GENERATOR OUTPUT	MW	15.645	16.186	17.232	13.948	14.884	14.537	15.148	13.194	14.707	16.383	16.192	17.590	13.107	14.671	12.823	14.407
CONDENSER FLOW	gpm	49,330	34,570	34,090	31,860	36,940	37,720	34,080	34,160	37,220	59,620	34,730	34,360	34,280	37,260	33,080	36,610
REGENERATOR REGEN. QUAL.	MW	49.516	15.398	11.337	4.860	-	4.561	4.574	10.566	-	61.450	17.464	10.640	9.682	-	9.881	-
	-	0.109	-	-	-2.217	-	-2.856	-	-0.608	-	0.302	-	-	-0.543	-	-0.449	-
EFFICIENCY	%	5.56	8.57	8.83	8.89	9.88	9.40	9.83	7.73	10.22	5.12	8.32	8.77	7.65	10.29	7.76	10.52

* (OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102 °F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: $\eta = 0.8$

Table E - IVh

SOURCE WATER TEMP	°F	375			375		375		375		375			375		375	
WORKING FLUID		PROPANE			BUTANE		ISOBUTANE		ISOPENTANE		PROPYLENE			PENTANE		HEXANE	
MAX SYSTEM PRESS	psia	500	1000	1445*	500	675*	500	945*	196	525*	500	1000	1500*	159	510*	63	455*
WELLWATER FLOW	10 ⁶ #/hr	1.980	1.339	1.262	1.153	1.117	1.232	1.134	1.348	1.054	2.168	1.382	1.264	1.372	1.045	1.373	1.026
WORKING FLUID FLOW	10 ⁶ #/hr	2.252	1.627	1.561	1.549	1.603	1.805	1.551	1.501	1.641	2.826	1.707	1.633	1.428	1.684	1.421	1.829
WORKING FLUID TURBINE		SH	SC	SC	SA	SC	SH	SC	SA	SC	SH	SC	SC	SA	SC	SA	SC
INLET TEMP	°F	355	334	355	290	325	277	345	265	355	355	337	355	262	355	251	355
OUTLET TEMP	°F	295	203	182	135	118	154	156	172	105	301	210	177	169	104	171	103
INLET PRESS	psia	480	960	1388	480	648	480	908	188	504	480	960	1441	153	490	61	437
OUTLET PRESS	psia	201	201	201	55	55	77	77	22	22	242	242	242	17	17	5	5
EXIT QUALITY	-	1.775	1.396	1.312	1.096	1.044	1.168	1.174	1.210	1.002	1.788	1.430	1.301	1.192	0.935	1.197	0.865
PARASITICS																	
DOWNHOLE PUMP	MW	1.334	0.902	0.850	0.777	0.753	0.830	0.765	0.908	0.710	1.461	0.931	0.852	0.925	0.704	0.925	0.692
WORKING PUMP	MW	1.694	3.185	4.702	1.429	2.056	1.650	2.885	0.506	1.587	1.862	3.198	5.019	0.390	1.590	0.149	1.476
COOLANT PUMP	MW	1.822	1.247	1.190	1.233	1.267	1.343	1.163	1.189	1.248	2.198	1.267	1.201	1.186	1.256	1.175	1.260
OTHER	MW	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
TOTAL	MW	5.050	5.534	6.942	3.639	4.276	4.023	5.013	2.803	3.745	5.721	5.596	7.271	2.701	3.750	2.449	3.628
TURBINE OUTPUT	MW	15.357	15.849	17.289	13.917	14.567	14.308	15.318	13.060	14.024	16.043	15.917	17.627	12.960	14.032	12.705	13.906
GENERATOR OUTPUT	MW	15.050	15.534	16.942	13.639	14.276	14.023	15.013	12.803	13.745	15.721	15.596	17.271	12.701	13.750	12.450	13.628
CONDENSER FLOW	gpm	46,010	31,500	30,090	31,150	31,970	33,870	29,350	30,000	31,500	55,530	32,020	30,350	29,950	31,750	29,700	31,790
REGENERATOR REGEN. QUAL.	MW	52.996	18.313	12.853	4.754	1.902	9.058	7.616	10.533	0	64.875	19.945	11.853	9.655	-	9.888	-
	-	0.262	-	-	-2.217	-	-2.629	-	-0.742	-	0.426	-	-	-0.656	-	-0.505	-
EFFICIENCY	%	6.19	9.16	9.72	10.63	10.97	9.95	10.80	9.09	11.63	5.65	8.87	9.70	8.93	11.73	8.93	11.95

* (OPTIMUM)

REAL BINARY CYCLE:
 CONDENSER TEMP: 102 °F
 TOWER: WET
 MINIMUM 20F BOILER APPROACH
 REGENERATOR: $\eta = 0.8$

Table E - IVi

SOURCE WATER TEMP °F	400 PROPANE			400 BUTANE		400 ISOBUTANE			400 ISOPENTANE		400 PROPYLENE			400 PENTANE		400 HEXANE	
WORKING FLUID	500	1000	1635*	500	900*	500	1000	1100*	257	550*	500	1000	1680*	197	505*	75	455*
MAX SYSTEM PRESS psia	500	1000	1635*	500	900*	500	1000	1100*	257	550*	500	1000	1680*	197	505*	75	455*
WELLWATER FLOW 10 ⁶ #/hr	1.654	1.167	1.066	0.980	0.933	1.085	0.963	0.962	1.049	0.875	1.825	1.203	1.063	1.081	0.869	1.107	0.841
WORKING FLUID FLOW 10 ⁶ #/hr	2.088	1.495	1.374	1.533	1.343	1.664	1.363	1.352	1.292	1.343	2.619	1.570	1.438	1.263	1.400	1.284	1.466
WORKING FLUID TURBINE	SH	SC	SC	SA	SC	SH	SC	SC	SA	SC	SH	SC	SC	SA	SC	SA	SC
INLET TEMP °F	380	350	380	290	360	290	363	370	292	370	380	355	380	282	370	266	380
OUTLET TEMP °F	321	223	201	135	144	173	179	178	184	137	326	231	194	178	109	179	103
INLET PRESS psia	480	960	1570	480	864	480	960	1056	247	528	480	960	1613	189	490	72	437
OUTLET PRESS psia	201	201	201	55	55	77	77	77	22	22	242	242	242	17	17	5	5
EXIT QUALITY	1.886	1.477	1.385	1.096	1.125	1.237	1.257	1.254	1.247	1.098	1.892	1.513	1.367	1.218	1.015	1.222	0.954
PARASITICS																	
DOWNHOLE PUMP MW	1.115	0.786	0.719	0.661	0.629	0.731	0.649	0.648	0.707	0.590	1.230	0.811	0.717	0.728	0.586	0.746	0.567
WORKING PUMP MW	1.571	2.926	4.755	1.413	2.343	1.522	2.696	2.958	0.587	1.364	1.727	2.941	5.038	0.437	1.322	0.162	1.183
COOLANT PUMP MW	1.721	1.162	1.068	1.221	1.080	1.252	1.039	1.032	1.029	1.044	2.074	1.181	1.075	1.054	1.126	1.067	1.112
OTHER MW	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200	0.200
TOTAL MW	4.607	5.074	6.742	3.495	4.252	3.705	4.584	4.838	2.523	3.198	5.231	5.133	7.030	2.419	3.234	2.175	3.062
TURBINE OUTPUT MW	14.902	15.382	17.080	13.770	14.544	13.985	14.879	15.141	12.777	13.466	15.536	15.445	17.379	12.673	13.504	12.422	13.328
GENERATOR OUTPUT MW	14.607	15.074	16.742	13.495	14.252	13.705	14.584	14.838	12.523	13.198	15.231	15.133	17.030	12.419	13.234	12.175	13.062
CONDENSER FLOW gpm	43,470	29,380	26,950	30,810	27,290	31,650	26,240	26,050	26,010	26,370	52,370	29,880	27,180	26,620	28,450	26,960	28,100
REGENERATOR REGEN. QUAL.	56.318 0.416	20.568 -	14.156 -	4.702 -2.217	5.216 -	11.970 -2.451	10.219 -	9.942 -	10.632 -0.998	4.149 -	68.181 0.551	22.177 -	12.967 -	9.690 -0.804	0.489 -	10.036 -0.570	- -
EFFICIENCY %	6.76	9.58	10.49	11.40	11.98	10.31	11.60	11.62	10.66	12.78	6.13	9.29	10.51	10.34	12.86	10.10	13.29

* (OPTIMUM)

Table E - V

REAL BINARY CYCLE: 10MWE OUTPUT
 SOURCE WATER = 350F
 MINIMUM 20F⁶ BOILER APPROACH

TOWER: DRY
 COND T: 110F
 REGEN: 0.8 = η

WORKING FLUID		ISOBUTANE		ISOPENTANE	
MAX SYSTEM PRESS	psia	500	700 (OPT)	175	525 (OPT)
WELLWATER FLOW	10 ⁶ #/hr	1.695	1.601	2.047	1.553
WORKING FLUID FLOW	10 ⁶ #/hr	2.258	2.074	1.903	2.594
WORKING FLUID TURBINE		SH	SC	SA	SC
INLET TEMP	°F	270	310	254	330
OUTLET TEMP	°F	147	145	173	112
INLET PRESS	psia	480	672	168	504
OUTLET PRESS	psia	87	87	25	25
EXIT QUALITY		1.121	1.112	1.190	0.867
PARASITICS					
DOWNHOLE PUMP	MW	1.142	1.079	1.380	1.047
WORKING PUMP	MW	2.046	2.768	0.558	2.508
COOLANT PUMP	MW	2.269	2.087	2.057	2.340
OTHER	MW	0.200	0.200	0.200	0.200
TOTAL	MW	5.657	6.134	4.195	6.095
TURBINE OUTPUT	MW	15.976	16.470	14.486	16.423
GENERATOR OUTPUT	MW	15.657	16.135	14.195	16.095
CONDENSER FLOW WATER	10 ⁶ gpm	57.340	52.770	52.010	59.090
AIR	10 ⁶ cfm	26.0	24.0	23.6	26.8
EFFICIENCY	%	8.26	8.75	6.84	9.02
REGENERATOR	MW	7.757	6.215	11.913	0

APPENDIX F: MATERIALS AND CORROSION FACTORS

F1. CORROSION MECHANISMS

The corrosion behavior of a material is influenced by the type of corrosive medium, its concentration, temperature, pressure, phase, velocity, the presence of entrained solids or gases, the presence of electrically coupled dissimilar metals, structure geometry, and time of exposure.^{(1)*} General corrosion takes place by a uniform attack over the exposed surface and the amount of damage can be assessed by a mil-per-year (MPY) figure based upon weight loss data. However, other types of corrosion can occur which make an average MPY assessment meaningless. For instance, some alloys are prone to pitting. This may occur in small areas which act as an anode and corrode at a faster rate than the surrounding material. The depolarizer, typically O_2 , is used up locally, resulting in a high corrosion rate while the surrounding area is cathodically protected. Deep penetration may occur in a short time. A pitting factor, the ratio of deepest metal penetration to average metal penetration, is used to assess damage. Similar corrosion takes place in any crevice from which the depolarizing element is excluded. Intergranular corrosion is a localized type of attack at grain boundaries of a metal. It occurs when the grain boundaries of limited area, acting as an anode, are in contact with large areas of grains acting as a cathode. Corrosion cells are set up whenever two dissimilar metals are joined and exposed to an electrolyte. The less noble metal (anodic) corrodes while the more noble metal (cathodic) does not. The presence of oxygen in the corrosive medium increases corrosion rates in nearly all metals.

F1.1 Effects of Stress-Environment Interactions

Unexpected failures have occurred in materials which have been subjected to a stress over an extended period of time while exposed to a gaseous or liquid environment. The failure stress in the sensitizing environment can be much smaller than the measured short-time material strength, temperature, pressure, and time of loading. Depending upon the material and environment, the phenomena are identified as stress

* Number in parenthesis indicate references listed in Pages F-14 to F-19.

corrosion cracking, corrosion fatigue, hydrogen embrittlement, static fatigue, and environmental stress cracking. A brief description of these failure mechanisms is given below.

Corrosion in the presence of surface forces may also occur. Erosion-corrosion is very important in areas of high fluid velocity, especially when a directional change in the flow occurs. In this type of attack, protective films are continuously removed by impingement of the fluid and the corrosion rate is accelerated. Entrained solids in the stream accentuate the problem. A similar mode of attack is fretting-corrosion. Here small mechanical displacements (due, for instance, to a vibrational load) in a faying surface causes the protective films to be continuously wiped away exposing fresh metal to the aggressive fluid.

F1.1.1 Stress Corrosion Cracking

The fracture of normally ductile metal or alloy when simultaneously stressed and exposed to certain environments is called stress corrosion cracking (SCC). It only occurs under a tensile stress (either applied or residual) and when the environment is specifically damaging to the stressed metal or alloy. Curiously, the damaging environments may not be corrosive in the normal sense of the word, i. e. , corrosion products need not be visible and the weight loss may be negligible at failure. Table F-I summarizes some of the attacking media for common metals and alloys.⁽²⁾ SCC can be prevented by cathodic polarization (opposite to the effect on hydrogen cracking). Pure metals appear immune to SCC while trace amounts of impurities can greatly inhibit or accelerate failure. Certain extraneous ions in the damaging environment will inhibit SCC. The most generally accepted mechanism is the stress sorption cracking theory.⁽²⁾ It is postulated that weakening of already strained metal atom bonds occurs through adsorption of the environment of its constituents. The surface energy of the metal is reduced which reduces the metal strength in the region of a crack tip. A monolayer of adsorbate is sufficient to decrease the affinities of surface atoms for themselves. Only adsorbed ions which affect the metal atom to atom bond strength will initiate cracks. Cathodic

Table F-I. Environments in Which Stress-Corrosion Cracking has been Observed

Material	Environment
Plain carbon and low alloy steels	Caustic solutions; calcium, ammonium, and sodium-nitrate solutions; solutions containing H ₂ S or HCN; moist CO-CO ₂ ; carbonate and bicarbonate solutions; sea water; marine and industrial atmospheres (high-strength, low-alloy steels); anhydrous ammonia; FeCl ₃ solutions (elevated temperatures); mixed acids (H ₂ SO ₄ -HNO ₃).
Aluminum alloys	Moist air, marine and industrial atmosphere; sea water; NaCl, CaCl ₂ , and NH ₄ Cl solutions; mercury.
Stainless steels	Acid and neutral chloride solutions; sea water; molten chlorides; industrial and marine atmosphere (sensitized materials); high-purity water + O ₂ at 586K (599°F); high-temperature water + fluorides; polythionic acids.
Nickel-base alloys	Fused caustics; hot concentrated caustic solutions; hydrofluoric acid; hydrofluoro-silicic acid; steam and high-temperature water containing O ₂ or traces of Pb.
Magnesium alloys	Sodium chloride-potassium chromate solutions; fluorides; tropical, industrial, and marine atmospheres; distilled water.
Titanium alloys	Red fuming nitric acid; N ₂ O ₄ + O ₂ ; sea water; chlorinated hydrocarbons; hot dry sodium chloride and other chloride salts at temperatures above 563K; HCL; methanol; mercury.
Copper alloys	Hydrogen sulfide, ammonia, mercurous nitrate.

polarization reduces the probability of anion adsorption as does the presence of certain extraneous anions (inhibitors). Adsorption probably takes place preferentially on imperfections which penetrate the surface, such as dislocations.

F1.1.2 Corrosion Fatigue

A mechanism for corrosion fatigue has yet to be established. It is characterized by a failure in a corrosive medium when the metal or alloy is subjected to cycles of repeated or alternating stresses. Cracking is transgranular in nature. The environments causing cracking are many and may not be specific to any given metal or alloy. The mechanism appears very different than that for SCC.

F1.2 Hydrogen Embrittlement

There appear to be three types of embrittlement of metals due to hydrogen. These are: hydrogen chemical reaction weakening, internal-hydrogen embrittlement, and hydrogen-environment embrittlement.⁽³⁾

The first two are characterized by a delayed fracture under low temperature, long term loading at a load below the expected failure load. The effect is more pronounced in high strength materials.⁽⁴⁾

The process is controlled by hydrogen diffusion and is temperature and pressure dependent. The third type is characterized by severe reduction of notch strengths even under short term loading conditions. The mechanisms are currently understood to be as follows:

Hydrogen chemical reactions: The most well known example of this type of mechanism is the "steam reaction" in Cu. Hydrogen reacts with oxygen in the Cu lattice to form H_2O which in turn causes blisters and cracks under stress. A similar reaction occurs in steel in which H reacts with C in the iron lattice to form methane gas. Another type of reaction is the formation of hydrides of the metal or alloying constituents. Titanium, columbium (niobium), and tantalum are among the metals which form hydrides. In Ti alloys, the α phase is hydrided which degrades the mechanical properties of the phase which can become a source of failure under load.

F1.2.1 Internal-Hydrogen Embrittlement:

Hydrogen is in solid solution at interstitial iron lattice sites in high strength steels. The presence of an internal stress provides regions of greater hydrogen solubility and the hydrogen atoms diffuse to the regions of high triaxial stress just ahead of an internal crack tip. The stress increases in this region until a micro-crack forms which links up to the main crack. The crack grows intermittently in this manner until it reaches a critical size and failure occurs.⁽⁵⁾ There is evidence that hydrogen also migrates to the crack itself and combines to form molecular hydrogen (gas). The gas pressure builds up causing increased stresses in the crack region.

F1.2.2 Hydrogen-Environment Embrittlement:

When a material is exposed to high pressure (> 10000 psi) pure hydrogen gas while under load, severe reductions in notch strength can occur with failures occurring at very low loads even for short term loading. No reduction of strength is noted if notches are not present.

High strength steels, nickel alloys, and titanium alloys are among the metals which exhibit this behavior. However, nearly all alloys are sensitive to some extent. The mechanism appears to involve the adsorption of molecular hydrogen to the surface of microcracks similar to the mechanism proposed for SCC. Some dissociation of H_2 to H may occur allowing H diffusion into the bulk material.

F1.2.3 Static Fatigue

When glass (and some ceramics) is stressed for an extended period of time in the atmosphere, failure can occur, even if the applied stress is far below the short term tensile strength.⁽⁶⁾ For instance, 70 percent strength reductions have been noted in glass when the loading time was increased from 34 seconds to 34 hours. The effect disappears in the absence of water vapor, as in a vacuum. It has been shown that water corrodes glass by attacking the loosely bound sodium ions in the glassy network, which in turn play a catalyzing role in the attack of the silicon-oxygen bond by the hydroxyl ions. This attack is accelerated under tensile stress and the rate is governed by the rate of diffusion of the sodium ions to the centers of attack. Thus, highly stressed roots of microscopic cracks become preferential sites where corrosion is most severe. When the crack grows to a critical size, rapid fracture occurs.

F1.2.4 Environmental Stress Cracking

This is a general term used to describe cracking of thermo-plastic materials when acted upon by a stress and exposed to specific sensitizing environments.^(7, 8) Actually, it is more correct to apply the term only for polyethylene since this is the material for which the term was introduced. The failure is surface initiated, usually at a stress concentration of some type, and occurs in an apparently brittle fashion. There is evidence that the stress must be polyaxial in nature if cracking is to occur. the mechanism appears to be entirely physical and no chemical changes occur to initiate or aid crack formation. This distinguishes the mechanism from oxidative or electrochemical stress-cracking, both of which involve degradation of the polymer. In addition, no swelling is associated with environmental stress-cracking. This distinguishes the process from solvent stress-cracking for which dissolution of the polymer and absorption of the solvent occurs. The mechanism for environmental stress cracking appears to be the weakening of amorphous regions between

crystalline areas (spherulites) by adsorption of the environmental medium. These amorphous regions are loosely bound by secondary bonds and foreign atoms and molecules can easily penetrate the areas between molecular chains further weakening the bonds. The weakened bonds can sever under the action of a stress forming a crack. At this time, little or no data is available for stress cracking behavior of polymers in hot brine, especially for thermo-setting plastics.

F2. SCALING AND FOULING

Scale can form on surfaces exposed to a brine environment. Usually it is formed by an oxidation reaction involving the dissolution of a metal component in the system and a redeposition as an oxide on a surface. In-situ oxidation can also cause scale to form.⁽⁹⁾ In addition, the reaction of active ions to form insoluble compounds which precipitate and grow on exposed surfaces can occur under proper temperature, pressure, fluid composition and velocity conditions. The most common of the latter types are sulfates and carbonates of Ca, Mg, and Na. It has been shown that scale formation is related to the saturation index (S.I.) at which a water is in equilibrium with the solid product. Taking Ca, for instance, at positive values of S.I., CaCO_3 will form a thin diffusion barrier film on surfaces which will protect the surface from corrosion by retarding the diffusion of dissolved oxygen to the metal surface. For negative values of S.I. (soft water), no protective film can form. The value of S.I. is a function of total acidity and alkalinity, pH, temperature, fluid velocity, and the concentration of dissolved solids in the water. As a rule of thumb, an S.I. > 0.5 indicates excessive scale formation. At high temperatures, the S.I. tends to become more positive. There are definite limitations to the use of the S.I. in predicting scale formation. The S.I. for CaCO_3 is about 2.0 for the East Mesa brines but they contain colloidal silica which can act as preferred sites for CaCO_3 precipitation. In addition, the presence of high concentrations of NaCl (up to 6000 ppm) at elevated temperatures can alter the film, thus leading to local corrosion pitting. For the East Mesa site, it appears that some tests would be in order to assess the scaling problem.

F3. WORKING FLUID (BINARY CYCLE)

The working fluid is chosen based upon thermodynamic properties, cost, availability, stability, and corrosiveness. The main candidates are low-molecular weight-hydrocarbons (paraffins) and freons (fluorinated hydrocarbons).

Hydrocarbon fluids are readily available in large quantities and relatively inexpensive. For instance, isopentane, n-pentane, and n-hexane are \$0.40/Gal, F.O.B. Texas and isobutane is \$0.45/Gal, F.O.B. Texas. Shipping costs to California by tank car (10,000 to 20,000 gal) are approximately \$0.12 to \$0.13/Gal. They are stable at the temperatures of interest (up to 400°F) and are compatible with common metallic materials, including mild steels. They are insoluble in water or brine.

Cracking (decomposition to lower molecular weight hydrocarbons) can occur as low as 500 to 550°F if a catalyst (such as aluminum chloride) is present. Otherwise, cracking occurs at high temperatures. Heavy hydrocarbons are less stable than lower molecular weight materials. For instance, cetanes can be cracked at 750°F without a catalyst.⁽¹⁰⁾

Isomerization can occur at 400°F if a catalyst is present. However, the reaction is extremely sluggish. There are two isomers of pentane (normal pentane and isopentane), two of butane (normal butane and isobutane) and five of hexane (normal hexane, neohexane, diisopropyl, 2-methyl pentane, and 3-methyl pentane).

Freons are expensive (\$5.40/Gal, delivered) and are long lead-time materials in large quantities. For instance, freon C318 is no longer manufactured and freon 22 and freon 12 have extremely long lead times due to raw material shortages. Freons are stable at temperatures up to 400°F although the amount of decomposition is dependent upon the type of materials with which it is in contact.⁽¹¹⁾ The decomposition products include low grade teflon (solid), HCl (liquid), and phosgene (gas) (if O₂ present).

Table F3-I summarizes decomposition data for four freons in contact with various metals.

Table F3-I. Percent Decomposed When Exposed
to Following Test Metal⁽¹¹⁾

Type of Freon	2 Years at 400°F					25 Hrs. at 500°F		
	Al	Inconel	316 CRES	Fe	Cu	None	316 CRES	Inconel
115	0.005	0.021	0.040	0.025	0.010	-	-	-
C318	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.017	0.020
12	2.0	0.013	Tube Burst	0.61	0.074	0.009	0.087	0.12
114	0.03	0.047	0.27	1.0	0.54	0.002	0.047	0.43

Metals tend to decompose freons in the following order: (least reactive) Inconel < 18-8 CRES < Nickel < Mild Steel < Al < Cu < Bronze < Brass < Ag (most reactive). Aluminum alloys with more than 2 percent Mg or Zn should not be used with freons. Copper and aluminum alloys should be avoided for long term exposure unless specific tests are performed to demonstrate their compatibility.

F4. EXPERIENCE IN MATERIAL BEHAVIOR IN HOT BRINE

Economic and practical arguments dictate that mild steels be employed for the majority of the structural components in the geothermal plant. Mild steel is known to corrode in brine and normally must be protected in some manner. The formation of a tough, adherent scale could protect the steel from corrosion. The geothermal plant at Cerro Prieto, Mexico, has been running for 1-1/2 years with only minor attack of the mild steel components even though the brine concentrations approach 35,000 ppm. Mild steel has been used in desalination plants. Some corrosion has been noted, especially in pipes. ⁽¹²⁾ The corrosion rate is sensitive to temperature, velocity, and oxygen content. The rate increases rapidly above 200°F, the rate doubles between 180°F and 250°F. ⁽¹³⁾ Mild steels are highly susceptible to erosion-corrosion attack.

An Oak Ridge study reported rapid deterioration in high turbulence areas involving a directional flow change. ⁽¹⁴⁾ Velocity effects become significantly more important at temperatures above 200°F. ⁽¹⁵⁾ The one

troublesome problem at Cerro Prieto is erosion-corrosion of an elbow section leading from the well to the flash chamber. High oxygen contents aggravate corrosion and erosion-corrosion of mild steel. In a desalination study, high corrosion rates were found for O_2 concentrations > 100 ppb, while for O_2 concentrations < 5 ppb, low rates were noted and the attack was uniform in nature and not effected by velocity.⁽¹³⁾ Inleakage of air may be a problem during shutdown periods and measures must be developed to protect the structure from attack.

Alloy and high strength steels are also subject to corrosion in hot brine and, like mild steels, are adversely effected by the presence of oxygen or high fluid velocities. Low Cu bearing steels (ASTM-A 242) were found to perform better in hot sea water than mild steels while 4, 8, and 3.5 percent Cr steels were unacceptable for the same application.⁽¹³⁾ Sound castings of ductile Ni-resist alloy (Cr-Ni-Si-Mn cast iron) performed well in hot brine desalination plant pump and valve components.⁽¹⁴⁾ Conventional cast iron components showed severe corrosion attack and had to be protected with epoxy during a long term (9 year) study of an ocean fed steam plant, the temperature of the brine being about 120°F .⁽¹⁶⁾ This damage was partially due to galvanically coupled noble metals.

U-bend tests of 18Ni-180 and 18Ni-200 maraging steels indicated a high resistance to stress corrosion cracking in a 3-year test in a chloride solution.⁽¹⁷⁾ Annealed welds in the same materials also performed well. The corrosion rates were about one half that of 4340 and HY80 alloy steels.

All high strength steels are susceptible to hydrogen embrittlement and, therefore, stress, and material strength level must be carefully controlled.⁽¹¹⁾ Oxygen can suppress hydrogen embrittlement in some alloys but can accelerate stress corrosion cracking in others.

Corrosion resistant steel (CRES) is prone to pitting and crevice corrosion, especially at low fluid velocities. CRES has been found to perform satisfactorily at medium and high velocities.⁽¹⁹⁾ Desalination studies of tube materials in brine up to 260°F showed that Mo bearing CRES (316) was superior to non-Mo bearing CRES (304).⁽²⁰⁾ Pump and valve components and heat transfer tubes of 316 CRES showed far superior

service compared to 304 CRES in moving sea water and brine.⁽¹⁴⁾ Another study concluded that if air and entrained solids were not present, 304 and 316 CRES were adequate for heat exchanger components in hot sea water.⁽¹⁵⁾ 409 CRES and 430 CRES are prone to severe, highly localized corrosion attack in sea water up to 250°F.⁽¹³⁾ Similarly, cast stainless steels CF-8 (304), CF-8M (316), and CA-15 (410) performed poorly in sea water up to 225°F. If oxygen content was kept under 5 ppb, the corrosion resistance of all stainless alloys is improved and cast alloy 7N7M (20 CR-29Ni) performs well.

Copper alloys show generally good corrosion resistance in hot brine, especially if the oxygen content is low.^(20,21) However, they are prone to suffer erosion-corrosion damage at high fluid velocity. The corrosion rate increases linearly with fluid velocity in some alloys, such as aluminum bronze.⁽²²⁾ Resistance to erosion-corrosion increases at temperatures above 200°F.⁽²³⁾ In quiescent hot brines, long life is expected for most copper alloys.⁽²⁴⁾ Twelve copper alloys were tested in brine at 250°F and 8 feet per second (FPS) fluid velocity. Based upon a 0.025 inch loss of wall thickness, lives of greater than 20 years were predicted from the data. Seam welded samples were included in the test with similar life expectancies. When the fluid velocity was increased to 16 FPS some localized corrosion attack was noted. After 735-day tests in quiescent sea water, cupro-nickle alloys 715 (30% Ni) and 706 (10 percent Ni) were found immune to corrosion, alloys 230 (red brass), 443 (admiralty brass), 608, 612, 614 (aluminum bronzes) were satisfactory for 2 year service while alloys 260 (cartridge brass), 268 (yellow brass), 280 (muntz metal) and 464 (naval brass) exhibited very severe dealloying.⁽²⁵⁾ Aluminum bronzes have been shown to be prone to dealumination at high fluid velocities.⁽²²⁾ In a sea water cooling plant, serious corrosion was encountered in the condenser and admiralty brass was replaced by aluminum brass and finally by cupro-nickel alloy 715 before satisfactory service was obtained.⁽²⁶⁾ Brass trimmed cast iron valves became graphitized in the same plant. Cupro-nickel alloy 715 and aluminum brass tubes showed excellent resistance to corrosion in hot deaerated brines in a falling film evaporative desalting application.⁽²⁰⁾ The brasses are subject to stress corrosion cracking, especially if H₂S or NH₃ is present.⁽²⁷⁾ All copper alloys were removed from the

Cerro Prieto plant after repeated corrosion failures due to bacterially produced H_2SO_4 from elemental sulfur and water and by H_2S induced stress corrosion cracking. In the Oak Ridge study, cupro-nickel alloys 715 and 705 were rated excellent in corrosion resistance while aluminum brass and admiralty brass were given the lowest ratings. (14) Copper alloy 194 also performed well in hot brine. Sand erosion occurred on cupro-nickel alloy 715 in a steam plant. (25)

Aluminum alloys are highly susceptible to corrosion in hot brines. Pitting corrosion occurs in neutral solutions (similar to East Mesa brine). (28, 29) The presence of CO_2 causes aggressive, non uniform attack while the corrosion rate decreases with lower pH. (30) High temperatures increase the rate (corrosion rate doubles when temperature raised from $40^\circ C$ to $90^\circ C$). Oxygen has little effect on the corrosion behavior. Extreme care must be exercised in avoiding galvanic couples since most candidate metals (Fe, Ti, Cu, etc.) are more noble than aluminum. (31, 32) In the case of galvanic corrosion, oxygen adversely effects the corrosion rate of aluminum alloys. Cladding on aluminum alloys is severely attacked by hot brines. (13) The best aluminum alloys appear to be 5052, 3003, and 5354 while 6061 appear unacceptable. It is recommended that the use of any aluminum alloys be avoided for in-stream applications for the proposed East Mesa operation.

Titanium alloys exhibit excellent resistance to general corrosion and pitting corrosion. (20, 33) Crevice corrosion is a problem at temperatures above $250^\circ F$. (14, 24) Ti-50A has been used in desalination plants at high temperatures while a new alloy, Ti-2Ni, is expected to extend the upper temperature to $400^\circ F$ in brine. Pure titanium shows excellent resistance to stress corrosion cracking and corrosion fatigue in flowing sea water. (35, 36) High fluid velocity does not appear to adversely effect the corrosion resistance of Ti and its alloys. A new alloy (Ti-.3 Mo-.8Ni), which is very resistant to pitting and crevice corrosion, is being developed by TIMET and should be commercially available in the near future. (37) High strength titanium alloys, such as Ti-6Al-4V, are susceptible to stress corrosion cracking in the presence of Cl. (38, 39, 40) It has also been found that hydriding of Ti-2Ni and pure Ti can occur if they are

galvanically coupled to less noble metals, especially Al.⁽⁴¹⁾ Stress corrosion cracking can also occur in high strength Ti alloys exposed to chlorinated hydrocarbons.⁽³⁷⁾

Organic materials have generally been limited to temperatures below 200°F in hot brine. Very few polymeric materials appear promising for higher temperatures.⁽¹⁴⁾ Tedlar (polyvinyl fluoride) and cross-linked polyethylene films were stressed to 1200 psi and 600 psi, respectively, and exposed to 7 percent NaCl brine at 200°F. No failures occurred after 9000 hours and 7000 hours respectively.⁽⁴²⁾ However, environmental stress cracking has been experienced in the New Zealand Geothermal plant for PVC (polyvinyl chloride) tubing, polyethylene, etc.⁽¹⁸⁾ Little data which addresses the problem of environmental stress cracking of polymeric materials in hot brines, is available in the literature. Polymeric protective coatings have been used in desalination plants with varying success. Formula 129 (anti-fouling black vinyl paint per MIL-P-16189) was applied to mild steel pipes over an anti-corrosive base coat.⁽⁴³⁾ It was found that a chip in the paint lead to accelerated corrosion of the steel due to the presence of Cu in the pigment. Coal tar coatings in ground piping carrying hot sea water tore loose in large sheets after four months of operation.⁽²⁶⁾ A 20 mil thick coating of epoxy was successfully used to prevent sand erosion of cupro-nickel tubes and protect against corrosion of cast iron during a 3 year exposure to 120°F sea water.⁽¹⁶⁾ Vinyl sprays were used to insulate noble metals from less noble metals. The epoxy life is estimated as 5 years. Mild steel and brine components have been protected in 150 to 200°F brine by using 60 to 80 mil thick coatings of glass reinforced epoxy or phenolic.⁽²⁰⁾ The coatings were applied by spraying or trowel. In the same plant, EPR (ethylene-propylene rubber), which was bonded with butyl cement and steam cured, has been successfully used to 250°F. In another application, sprayed-on epoxy was effective in reducing scale formation on mild steel pipes.⁽²⁰⁾ Polymeric commercial paints were found to be satisfactory in sea water and steam to 225°F but softened at higher temperatures and became susceptible to high flow rate attack.⁽⁴⁴⁾ Amercoat 78 was found to be the best coating tested, but it is very friable and some leaching was

encountered. Electrostatic spraying of powdered polymeric materials appears very promising for applying uniform protective coatings. This method is currently being considered for the external epoxy coating on the Alaskan Pipeline pipes.

Various types of protective coatings, other than polymeric types, have been investigated. Most of these newer types are still in research or development stage. Metallide coatings were applied to sea water pump components by a molten salt electrolytic process.⁽⁴⁵⁾ Diffusion coatings of Be into Cu alloys, Ni alloys and mild steel, B into steel, electro-deposited Ni and Cr onto steel, and Mo sprayed onto steel were all tried. The best coating was Be onto Cu alloys with the resistance to erosion-corrosion comparable to Inconel 718 and better than 316 CRES. Bimetallic tubes for use in a flash distillation plant were fabricated by the implosion explosive welding 316 CRES to Cupro-nickel 706.⁽⁴⁶⁾

Inorganic coatings are commonly used as liners for pipes and as construction materials.⁽¹⁴⁾ Concrete and grout are used except where oxidation of H_2S can cause sulfate attack.⁽¹⁸⁾ The highest temperature at which cement has been successfully used as a pipe liner is $280^{\circ}F$ and further investigation is required to establish its acceptability at $400^{\circ}F$. Untreated portland cement was found to be suitable at $200^{\circ}F$.⁽⁴⁷⁾ The use of sacrificial concrete extended its range to $250^{\circ}F$. Crushed limestone is unacceptable in hot brines. Corrosion of steel reinforcement rods does not appear to be a major problem.

Scale formation is a potentially serious problem, especially in areas of low fluid velocity, low temperature, or low pressure. Little or no scale has been found at the Cerro Prieto Geothermal plant except in the separated brine exhaust silencers. In these units, the brine is exhausted to atmospheric pressure while decelerating the flow to a low velocity. The precipitates appear to be carbonates, sulfates, and silicates. The presence of silica in the feedwater caused scale on the heat transfer surfaces at the Roswell, N.M., Vapor Decompression Distillation plant. Silica is present as a soluble aqueous monomer, silica tetrahydroxide.⁽⁴⁸⁾ In another desalination plant, scale formed on mild steel pipes.⁽²⁰⁾ The scale was found to be a mixture of iron oxide, calcium sulfate, and magnesium salts. In a falling film evaporative desalting plant, heat exchanger tubes were plugged by iron oxide scale from steel headers and piping and/or mineral deposits.⁽²⁰⁾

In a basic study of scale formation and prevention methods in desalination plants the following sequence was established.⁽⁴³⁾ Bicarbonate ions break up forming carbonate ions which combine with Ca to form CaCO_3 . Further heating causes some carbonate ions to react with water forming hydroxyl ions which can combine with Mg to form magnesium hydroxide scale. The scale formation rate is greater at lower temperatures and increases with the temperature difference across the heating surface. Organic dispersive compounds weaken scale and allow some scale to shed by cracking. Alkaline scale can be prevented by the appropriate quantity of hydrogen ions through injection of HCl or H_2SO_4 or by injection of ferric chloride (ferric ions). Ferric ions combine preferentially with hydroxyl ions forming ferric hydroxide which remains in suspension in the brine. Other scale prevention methods utilized by industry include the periodic injection of tetrasodium EDTA or trisodium NTA to remove calcium sulfate,⁽⁵⁹⁾ use of activated alumina and calcium aluminate to remove silica,⁽⁴⁸⁾ desulfating feedwater by the ion exchange method,⁽⁵¹⁾ removal of boron by use of a boron selective resin,⁽⁵²⁾ injecting CO_2 to precipitate salts and preferentially removing them,⁽⁵³⁾ and the use sacrificial and removable surfaces. Several power plants and desalination plants are utilizing a mechanical, circulating scraper system to maintain clean heat exchanger tubes, such as the Amertap system.⁽⁵⁴⁾ It appears that many scaling problems due to mineral deposits may be minimized by maintaining high fluid velocities. At Cerro Prieto, well plugging by salt precipitation has been experienced, probably due to flashing of the brine down the shaft with the accompanying pressure, temperature, and velocity drop.

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APPENDIX G

PRELIMINARY RELIABILITY/MAINTAINABILITY ANALYSES

G1. INTRODUCTION

Preliminary reliability-maintainability analyses were performed during Phase 0 on geothermal energy generating systems. These directly respond to a need expressed by advisors described in Appendix D of this volume. The analyses were intended to increase understanding of reliability/maintainability characteristics in individual system components. In addition, the analyses identify, through top-level failure mode studies, critical items in each of six system options under three different concepts. These include single-flash (Concept A-1, Figure G-1), double-flash (Concept A-2, Figure G-2), binary fluid (Concept B-1, 2, 3, Figure G-3), and hybrid dual cycle (Concept C, Figure G-4) systems.

G2. SYSTEM CONCEPTS AND COMPLEXITY

Candidate system concepts are depicted in Figures G-1 through G-4. The complexity of each concept varies directly with the number of major system components. Equipment elements are tabulated for each concept-option, along with a ratio of critical to total number of elements (Table G-I). In this way two relative, but generalized, measures of reliability/maintainability are provided, i.e., complexity and critical element ratio. From these measures, a basis for concept-option preference is established.

G3. FAILURE MODE ANALYSIS

A top-level failure mode and effects analysis was performed on each identified element. This is tabulated in Table G-II. Included in the tabulation are forecasts of potential failure modes that are critical. These are related to system observable symptoms and safety effects. Each critical outcome is underlined for emphasis.

G4. RELIABILITY/MAINTAINABILITY CHARACTERISTICS

Reliability and maintainability characteristics are tabulated for nine key components along with related information-data sources in Table G-III. The main sources are: (1) manufacturer contacts and

Figure G-1. Single Flashed Steam System Diagram

Figure G-2. Double Flashed Steam System Diagram

Figure G-3. Binary Fluid System Diagram

G-5

Figure G-4. Hybrid Dual Cycle System Diagram

Table G-1. System Concept Equipment Breakdown Structure and Identified Critical Elements

Equipment Element	Alternative Concept Equipment Requirements					
	Concept A		Concept B			Concept C
	Single Flash	Double Flash	n-butane	iso-butane	iso-pentane	Hybrid-Binary (isobutane)
*Downhole Pump/Motor	1/1	1/1	1/1	1/1	1/1	1/1
*Regulator Valve	1	1	1	1	1	1
Separator	1	2	-	-	-	1
Heat Exchanger	-	-	2	2	2	2
Reaction Turbine	1	1	1	1	1	2
*Alternator	1	1	1	1	1	2
Mod. Baro. Condenser	1	1	-	-	-	1
Cooling Water Pump/Motor	1/1	1/1	1/1	1/1	1/1	1/1
Steam Ejector	1	1	-	-	-	1
Working Fluid (WF)	-	-	1	1	1	1
Surge/Storage Tank	-	-	1	1	1	1
*WF Pump/Motor	-	-	1/1	1/1	1/1	1/1
*Valve, Control	1	2	-	-	-	1
*Brine Inj. Pump/Motor	1/1	1/1	-	-	-	1/1
*Gear Box	1	1	1	1	1	2
Total No. of Elements	14	16	14	14	14	23
No. of Critical Elements ^[1]	7	9	5	5	5	10
Percent Critical to Total	50%	56%	36%	36%	36%	43%

Special Tests Recommended^[2]: (a) Heat Exchanger Continuous Mechanical Cleaning at 350° F (if adopted).

(b) System Performance Degradation vs. Heat Exchanger Design and Cleanliness.

[1] Based on critical failure modes in selected equipment elements, identified with asterisk(*)

[2] Based on lack of data for critical element and failure mode considerations

Table G-II. Geothermal Project
Failure Modes and Effects Analysis
Equipment Concepts & Options

Item/ Nomenclature 1	Function 2	Failure Mode/Mechanism 3	Failure Effect 4	Observable Symptoms 5	Controls to Reduce Failure Mode Occurrence or Effects 6	Safety Effect 7
1. Downhole Pump/ Motor	Pump fluid from brine zone to separator or heat exchanger at elevated temperature and pressure	Leak, blade defect, bearing/seal wear, impeller not adjusted, cavitation	Operation degraded, loss of efficiency	Loss of pump pressure	Inspect periodically, maintain, and adjust.	Safe
			Pump damage	Excessive leakage	Ensure proper design selection and test	Safe
		Motor circuit open or short	Loss of system	<u>System inoperative</u>	Protect from environment, Inspect upon installation. Design in circuit protection.	Safe

Table G-II. Geothermal Project (Continued)

Failure Modes and Effects Analysis
Equipment Concepts & Options

Item/ Nomenclature	Function	Failure Mode/Mechanism	Failure Effect	Observable Symptoms	Controls to Reduce Failure Mode Occurrence or Effects	Safety Effect
1	2	3	4	5	6	7
2. Separator	Separate steam or vapor from superheated water/brine	Corrosion leak or fracture	Loss of steam and degraded performance	Reduced output affects turbine performance	Inspect periodically and maintain	Hazardous
		Erosion (at entrance)	Improper operation and damage		Periodic inspection and maintenance	Safe
3. Heat Exchanger	Circulate hot brine and transfer heat to working fluid loop. Receive expanded WF and condense in loop.	Corrosion	Loss of efficiency and design back pressure.	Reduced output. Affects turbine performance	Inspect periodically and clean. Implement continuous mechanical cleaning to achieve high performance	Safe

Table G-II. Geothermal Project (Continued)

Failure Modes and Effects Analysis
Equipment Concepts & Options

Item/ Nomenclature 1	Function 2	Failure Mode/Mechanism 3	Failure Effect 4	Observable Symptoms 5	Controls to Reduce Failure Mode Occurrence or Effects 6	Safety Effect 7
3. Heat Exchanger (continued)		Leak	Reduced steam tempera- ture and pressure	Reduced output.	Same as above.	Tubes enclosed in housing
		Occlusion	Plugging of tubes	Reduced output	Same as above	Tubes enclosed in housing
4. Turbine	Provide for steam or WF vapor expansion via blades to drive shaft loads	Load, bearing wear	Degraded per- formance	Loss of rpm	Inspect and replace mechanical unit periodi- cally. Refurbish unit.	Safe

Table G-II. Geothermal Project (Continued)

Failure Modes and Effects Analysis
Equipment Concepts & Options

Item/ Nomenclature 1	Function 2	Failure Mode/Mechanism 3	Failure Effect 4	Observable Symptoms 5	Controls to Reduce Failure Mode Occurrence or Effects 6	Safety Effect 7
4. Turbine (continued)		Corrosion and pitting of parts (especially double-flash option)	Higher pressure and temperature; second flash has higher concentration of chemicals. Higher velocity carries chemicals to turbine	Pitting of turbine parts upon inspection	Requires control over steam impurities to avoid turbine problems and excess maintenance. Makes any flash system with excess impurities in steam undesirable as a result of high pressure, temperature, and flow velocities.	Safe
		Blade fatigue from vibration	Break	System performance seriously affected	Structural stress and dynamics analysis	Safe

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Table G-II. Geothermal Project (Continued)

Failure Modes and Effects Analysis
Equipment Concepts & Options

Item/ Nomenclature 1	Function 2	Failure Mode/Mechanism 3	Failure Effect 4	Observable Symptoms 5	Controls to Reduce Failure Mode Occurrence or Effects 6	Safety Effect 7
4. Turbine (continued)		Erosion in turbine, especially blades	High rate of blade wear	Blade anoma- lies and replacement rate higher than usual.	Control and reduce moisture content in working fluid as it expands	Safe
5. Alternator	Generate elec- trical power via turbine shaft drive	Short or open output	No power output	<u>V/I Drop</u>	Inspect and protect from sand and dust environment	<u>Possible fire haz- ard with short circuit</u>

G-II

Table G-II. Geothermal Project (Continued)

Failure Modes and Effects Analysis
Equipment Concepts & Options

Item/ Nomenclature 1	Function 2	Failure Mode/Mechanism 3	Failure Effect 4	Observable Symptoms 5	Controls to Reduce Failure Mode Occurrence or Effects 6	Safety Effect 7
5. Alternator (continued)	Receive expand- ed steam or vapor from turbine output and condense it. Pump cooling water through heat exchanger	Bearing wear	Reduced RPM	<u>V/I Drop and Noise</u>	Inspect peri- odically and maintain	Safe
6. Baromet- ric Condenser		Leak or fracture, corrosion	Loss of vacuum	System oper- ation degrad- ed.		
7. Cooling water pump/ motor		Leak, blade defect, bearing/seal wear	Reduced flow of cooling water	Loss of pump pres- sure; noise	Inspect peri- odically and maintain	Safe
		Cavitation	Pump damage	Excessive leakage	Ensure proper design and test.	Safe

Table G-II. Geothermal Project (Continued)

Failure Modes and Effects Analysis

Equipment Concepts & Options

Item/ Nomenclature 1	Function 2	Failure Mode/Mechanism 3	Failure Effect 4	Observable Symptoms 5	Controls to Reduce Failure Mode Occurrence or Effects 6	Safety Effect 7
7. Cooling (Continued)		Motor circuit open or short	Loss of pump	Slow conden- sation rate. Degraded tur- bine perfor- mance. Reduced output.	Protect from environment. Inspect upon installation. Design in cir- cuit protec- tion. Replace motor.	Safe
8. Vacuum Pump	Provide power to turbine by expansion	Leak; fails closed	Build-up of pressure in condenser	Loss of vacuum	Inspect peri- odically and maintain	
9. Working Fluid (WF)	Remove non- condensable gases	Leakage	Loss or degradation of power output	Same as failure effect	Check for leaks	Safe

Table G-II. Geothermal Project (Continued)

Failure Modes and Effects Analysis

Equipment Concepts & Options

Item/ Nomenclature 1	Function 2	Failure Mode/Mechanism 3	Failure Effect 4	Observable Symptoms 5	Controls to Reduce Failure Mode Occurrence or Effects 6	Safety Effect 7
9. Working fluid (WF) (continued)	Circulate WF in closed loop for operation of turbine.	Impurities from chemical interaction	System foul-up	Poor system performance	Purge and con- duct chemical analysis periodically.	Safe
11. B.I. Pump/ Motor (Applica- tion TBD)		Leak, blade defect, bearing wear	Reduced flow of WF	Loss of pump pressure, noise	Inspect peri- odically and maintain	Safe
		Cavitation	Pump damage	Excessive leaking of WF	Ensure proper design and test.	<u>Hazardous</u>
		Motor circuit open or short	Loss of Pump	System inop- erative. Excessive heating in exchanger	Protect from environment. Inspect upon installation. Provide relief valve and cir- cuit protection. Replace motor	<u>Hazardous</u>

Table G-II. Geothermal Project (Continued)

Failure Modes and Effects Analysis
Equipment Concepts & Options

Item/ Nomenclature 1	Function 2	Failure Mode/Mechanism 3	Failure Effect 4	Observable Symptoms 5	Controls to Reduce Failure Mode Occurrence or Effects 6	Safety Effect 7
12. Gear Box	Provide inter- face between turbine shaft and alternator	Misalignment due to temperature difference, Gear Fracture	Power loss, lock up, free wheeling	<u>No Power Generated</u>	Check alignment, Provide fluidic temperature stabilization	Safe

Table G-III. Reliability/Maintainability Factors and Data Sources

Item Number	Equipment Component	Operating Characteristic Data		Data Sources and Comments
		Reliability Factor	Maintainability Factor	
1.	Downhole Turbine Pump/Motor (Vertical Lineshaft)	Pump Efficiency Long Life Recirculation vs. Side Seal wear, abrasion, and erosion. Bowl Assy Loading/deflection	Impeller Adjustment (30 Minutes) Warranty for 1 year Double seal replacement Tandem Adapter for Replacement	FMC Corp-- Peerless Pump Division (Bulletin B-141)
2.	Separator	Erosion at entrance by solids in flow stream	Inspect and Replace Input Elbow	Cerro Prieto, Mexico Site Trip
3.	Heat Exchanger	Tube material cleanliness vs. transfer properties Recirculating Ball Material vs. Water Temp. (350 F) Automatic continuous cleaning system uptime >3 years	Mechanical cleaning Automatic continuous cleaning Adjustment and Periodic Inspection Initial start-up problems	Amertap Corporation Garden City, N. Y. Amertap System User-Haynes DWP Plant
4.	Turbine	Long Life (Up to 25 years; depends on thermodynamic cycle) Partswear $\approx$ 2.5 yrs.	Unit level replacement (8 hours), No more than once/year	Rotoflow Corp. WLA, Calif. Airco Cryogenics

Table G-III. Reliability/Maintainability Factors and Data Sources (Continued)

Item Number	Equipment Component	Operating Characteristic Data		Data Sources and Comments
		Reliability Factor	Maintainability Factor	
5.	Alternator	Long Life (Up to 40 years) Parts wear 4 years	Rebuild bearings, windings, seals, etc.	SC Edison Experience
6.	Cooling Water Pump/Motor (3600 rpm) (Horizontal Split-Case type)	Split-Case Construction/leaking/Impeller thrust loading/seal good to 225 F	Rotating Element Removal-Gasket Replacement/impeller wear ring replacement/bearing lubrication/Mechanical seal replacement	FMC Corp--Peerless Pump Division (Bulletin B-1400)
7.	Working Fluid Pump/Motor (3500 rpm)		Easy access to pump shaft seals and packing boxes Impeller and bowl wear ring replacement	FMC Corp--Peerless Pump Division (Bulletin B-1700)
8.	Brine Injection Pump/Motor	See Item 1	See Item 1	Refer to DH Pump/Motor

literature, (2) Southern California utility contacts, and (3) TRW Systems documentation. Specific sources for the data are listed.

G5. CONCLUSIONS

Based on an overview of complexity and potential critical items in each concept option, the following order of preference is chosen:

- a. Binary System (Concept B)
- b. Single-flashed steam system (Concept A) or hybrid dual cycle system (Concept C) (tradeoff)
- c. Double-flashed steam system (Concept A-2)

In addition to establishing option preference, a few basic measures of life characteristics and maintenance requirements began to emerge on the components considered. These are described in Table G-III. These measures reflect utility experience and manufacturer recommendations, and should be useful for future studies which pertain to assessment of reliability/maintainability characteristics inherent in preferred geothermal energy generating systems.

G6. RECOMMENDATIONS

The engineering analyses which produced this report, if continued, would provide benefits in succeeding phases of the program. Emphasis would be placed on the option chosen from the several concepts evaluated during Phase 0. The following reliability/maintainability activities are recommended:

- a. Phase 1 Concept Design
 1. Develop failure mode analyses for the concept, identify critical components and related critical failure modes. Use results to enhance design selections and tradeoffs, design configuration, and success probability. Failure mode studies also can enhance maintenance costs by eliminating undesirable reliability problems.
 2. Define initial allocations of equipment spares needed for field operations by assessing expected failure rates under planned operating conditions.
 3. Identify critical components for which additional research and development is required to attain reliability objectives.
 4. Perform preliminary safety hazard analyses in conjunction with system configuration and failure mode studies.

b. Phase 2 and Beyond - Final Design, Operations

1. Establish accurate and effective means to report failures and conduct failure analyses.
2. Determine system reliability characteristics based on operating data and results of testing.
3. Identify modifications in the final design and identify additional research and development activity required.
4. Complete the preliminary hazard analyses begun during the preceding phase of the project.

APPENDIX H

H1 ENVIRONMENTAL IMPACT ANALYSIS GUIDELINES

The purpose of this Appendix is to provide environmental guidelines for the evaluation of the various candidate geothermal energy conversion concepts, and further, to facilitate the engineering design phase. This is not an environmental impact analysis of the project but rather a review of possible environmental impacts which should be considered as the design is being completed. This will permit implementation of design options to minimize the negative environmental impact and enhance the environmental benefits of the overall project.

The analysis of the environmental impact was made upon the project activities shown in Figure H-1. These are the major activities involved in the life of the project. The size of each activity varies significantly. Thus there can be several drilling sites but only one cooling tower site. The overall environmental impact is minimized with a reduction in each activity; however, as will be seen further on, the major impacts are limited to a small number of activities which are highly dependent upon the process flow design.

The potential environmental impact for each activity is shown in Table H-I. These impacts consider the effect of ambient air, water, wildlife, vegetation, topography, and other ecological factors. Also shown in Table H-I are a qualitative evaluation of the impact in terms of magnitude, duration, and probability of occurrence. These are general ratings to identify the major versus lesser impacts. In some instances ratings were not assigned because the evaluation is subjective. Mitigating factors are listed where applicable; however, not all impacts have mitigating factors.

The major environmental factors are those wherein the magnitude of the potential effect is large; wherein the duration of the impact is long-lived, and where its probability of occurrence is high. These impacts are identified by one or two stars, and require further discussion.

Figure H-1
Geothermal Power Plant Activities for Environmental Consideration

Table H-I

DRILLINGAMBIENT AIR

POTENTIAL IMPACT	MAGNITUDE	DURATION	PROBABILITY	MITIGATING MEASURES
* Fugitive dust	Large	Short	High	Watering down during construction and operating phases
Steam releases	Large	Short	High	Steam condensers

GROUNDWATER

Injection into aquifer	Moderate	Short	Low	Adequate casing design
Escape of aquifer supply	Small	Short	Low	Adequate casing design

SURFACE WATER

Contamination from mud	Moderate	Short	Low	Portable containers
Use of water supply	Small	Short	High	

VEGETATION

Destruction in work area	Small	Short	High	Minimal vegetation existing at site
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WILDLIFE

Destroy endangered species	Small	Long	Low	No endangered species cataloged
Establish attracted species	Small	Short	High	Minimal wildlife existing at site
Habitat destruction	Small	Long	Low	Minimal wildlife existing at site

TOPOGRAPHY

Grading for site and roads	Moderate	Short	High	
Erosion from runoff	Small	Long	High	
Ponds for drill mud	Small	Short	High	Site restoration after use

AESTHETICS

Visibility of drill rig	Moderate	Short	High	
* Effluent discharge plume	Large	Short	High	Steam condensers

NOISE

Equipment noise	Moderate	Short	High	
* Effluent discharge	Large	Short	High	Mufflers on exhaust line

ARCHAEOLOGY

Site destruction	Small	Long	Low	No archaeological finds at site
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EXTRACTIONGROUNDWATER

Aquifer Contamination	Moderate	Long	Low	Adequate casing design
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GEOLOGIC STABILITY

** Subsidence	Large	Long	High	Reinjection
** Fault zone activity	Moderate	Long	Moderate	Seismic reconnaissance to avoid fault zones

Table H-I

ACTIVITY	POTENTIAL IMPACT	MAGNITUDE	DURATION	PROBABILITY	MITIGATING MEASURES
H-4	<u>BRINE TRANSMISSION</u>				
	<u>SURFACE WATER</u>				
	Contamination from rupture	Moderate	Short	Low	Adequate pipe design Diked rights-of-way
	<u>VEGETATION</u>				
	Clearing along pipeline	Small	Long	High	Minimal vegetation at site
	Destruction from rupture	Moderate	Short	Low	Diked rights-of-way
	<u>AESTHETICS</u>				
	Overland pipeline visibility	Small	Long	High	Ground level or underground lines
	<u>POWER PLANT</u>				
	<u>AMBIENT AIR</u>				
	* Fugitive dust from construction	Large	Short	High	Watering down during construction
	<u>VEGETATION</u>				
	Clearing for facility	Small	Long	High	Minimal vegetation at site
	<u>WILDLIFE</u>				
	Destruction of habitat	Minor	Long	Low	Minimal wildlife at site
	<u>TOPOGRAPHY</u>				
	Site grading	Small	Long	High	
	Road grading	Small	Long	High	
	Erosion from storm runoff	Small	Long	High	
	<u>AESTHETICS</u>				
	Visibility of buildings and equipment	Moderate	Long	High	
	<u>NOISE</u>				
	Equipment noise	Moderate	Long	High	Shielding
	<u>ARCHAEOLOGY</u>				
	Site destruction	Small	Long	Low	No archaeological finds at site

Table H-I

ACTIVITY	POTENTIAL IMPACT	MAGNITUDE	DURATION	PROBABILITY	MITIGATING MEASURES
<u>REINJECTION</u>	<u>GROUNDWATER</u>				
	Seepage into aquifer	Small	Long	Low	Proper casing design
	<u>GEOLOGIC STABILITY</u>				
	Fault zone friction decrease	Moderate	Long	Low	Avoidance of fault zones
<u>COOLING WATER</u>	<u>AMBIENT AIR</u>				
<u>FACILITIES</u>	** Thermal emission from cooling towers	Large	Long	High	
	Steam emissions from cooling towers	Large	Long	High	
	<u>GROUNDWATER</u>				
	** Subsidence through evaporation	Large	Long	High	
	<u>SURFACE WATER</u>				
	** Heating of canal water	Moderate	Long	High	
	<u>TOPOGRAPHY</u>				
	Site grading	Small	Long	High	
	<u>NOISE</u>				
	** Equipment noise	Large	Long	High	Shielding
	<u>ARCHAEOLOGY</u>				
	Site destruction	Small	Long	Low	Minimal archaeological remains at site location

Table H-I

ACTIVITY	POTENTIAL IMPACT	MAGNITUDE	DURATION	PROBABILITY	MITIGATING MEASURES
<u>EFFLUENT SURFACE</u>	<u>AMBIENT AIR</u>				
<u>DISPOSAL</u>	** Emission of non-condensibles	Large	Long	High	
	<u>GROUNDWATER</u>				
	** Seepage from surface runoff	Large	Long	High	
	<u>SURFACE WATER</u>				
	** Brine discharges	Large	Long	High	
	<u>VEGETATION</u>				
	** Destruction by brine	Large	Long	High	
	Growth by fresh water	Small	Long	Low	
	<u>WILDLIFE</u>				
	Habitat changes	Small	Long	Low	
	<u>AESTHETICS</u>				
	** Vapor plumes	Large	Long	High	
<u>ELECTRICAL</u>	<u>TOPOGRAPHY</u>				
<u>TRANSMISSION</u>	Tower clearing	Small	Long	High	
	<u>AESTHETICS</u>				
	Tower and line visibility	Unknown	Long	High	
<u>UTILITIES</u>	<u>SURFACE WATER</u>				
	Facility use	Small	Long-term	High	
	Sanitary discharges	Small	Long-term	High	
<u>LOCAL COMMUNITIES</u>	<u>SOCIO-ECONOMIC</u>				
<u>COMMUNITIES</u>	Population change	Small	Long-term	High	
	Municipal service uses	Small	Long-term	High	
	Changing tax base	Small	Long-term	High	

Several major impacts are sustained on the environment early in the program during the drilling and exploration activities. These impacts include airborne emissions of fugitive dust and steam, the noise from the effluent discharge, and the negative aesthetics of the drilling rig and equipment. The drilling and exploration activities are short-term in duration and do not extend beyond the initial phases of the program. The adverse effects of these activities can be mitigated by suitable precautions such as precipitators and silencers for the effluent steam discharge; however, because of the remoteness of the test area, mitigation measures will probably not be required.

The extraction activity has a very major (two star) potential impact on the geology of the area. The first impact is due to subsidence. This will be a serious problem if the spent brine is not reinjected. Preliminary design criteria, however, require brine injection. Associated with this impact is the additional effect of fault zone activity and minor earthquakes. Seismic reconnaissance will have to be undertaken to avoid active fault zones.

Fugitive dust from all construction activities will vary in magnitude depending upon time of year. During the hot dry summer months, wetting down of the area will be required. This is not only from an off-site dust consideration, but also to protect the health and safety of the construction personnel.

The major (two star) potential environmental impacts are associated with the cooling facilities and effluent disposal. The cooling water facilities may discharge significant levels of thermal and water effluents, depending on the selected system flow process. Wet cooling towers may not have a significant steam plume due to the dry ambient atmosphere. They will, however, require large amounts of water for the same reasons. This water could be obtained from the spent brine, but it would then cause a decrease in reinjection and increase the possibility of subsidence. An alternative

would be to use the irrigational canals as thermal sinks. There will be a limit in the allowed increase of canal water temperature.

Under certain candidate design concepts, the cooling water facilities are associated with the disposal of spent brine. Unless this brine is reinjected there will be serious environmental impacts. Emissions of non-condensibles from the spent geothermal fluids will be an air emissions problem. Significant quantities of pollutants such as H_2S and CH_4 may be present in the brine. The effect of the brine upon vegetation and natural waters could be significant. These effects, combined with the potential subsidence problem, are important factors limiting disposal of the brine other than by reinjection.

In selecting from the various design options of the geothermal project, additional environmental impact guidelines may be inferred from environmental statements prepared for geothermal studies in the proposed site area. Two final environmental impact statements have been prepared by USBR for geothermal work in the vicinity of the proposed TRW site. The first statement, FES 72-9, dated April 28, 1972, addressed the impact of the "Proposed Deep Geothermal Test Well, Geothermal Resource Investigations, Imperial Valley, California." The second statement, FES 72-21, dated July 10, 1972, addressed the "Proposed Installation and Operation of a Skid-Mounted Desalting Unit and Injection Well, Imperial Valley, California." These documents provide an analysis of the environmental setting of the site and indicate that the region is fairly insensitive with respect to most environmental criteria. While TRW will be required to draft a separate environmental impact statement to be reviewed by the lead agency (Planning Department of Imperial County), and other cognizant agencies such as the Department of Water Resources, the State Department of Agriculture, the Department of Oil and Gas, the State Lands Commission, the Public Utilities Department, the Imperial County Air Pollution Control District, the Department of Building and Safety, and others, it is anticipated that the previous USBR environmental

statements will provide a "guideline" for critical evaluation of the proposed TRW geothermal activities. Hence, TRW will probably rely substantially on the results of previous statements by the USBR in drafting an Environmental Impact Report for the TRW activities, and in demonstrating the environmental acceptability of the proposed activities.

A USBR supplemental statement, FES 73-5, for exploratory drilling of a "Proposed Deep Geothermal Test Well; has also been prepared. This supplemental statement assessed the environmental impact of 8 slim (7-5/8 inch diameter) temperature recording holes to depths of 6000 feet and 30 slim holes to depths varying between 100 to 1500 feet. Thus, environmental impact statements for a significant number of test wells have been prepared for the proposed site area. Five of these test wells remain to be drilled and USBR has no immediate plans. Because of these geothermal studies already initiated in the vicinity of the TRW proposed site, it is anticipated that TRW will obtain approval for exploratory drilling with relative ease (the drilling permit will be issued upon joint approval from the Planning Department of Imperial County and the State Department of Oil and Gas).

APPENDIX I

THE NATIONAL SCIENCE FOUNDATION/
TRW SYSTEMS GROUP

10 MW GEOTHERMAL POWER PLANT
PROOF OF CONCEPT FACILITY

PHASE "O" STUDY

Prepared by

ROGERS ENGINEERING CO., INC.
111 Pine Street
San Francisco, California 94111

Job No. S-74026
December 13, 1974

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I6.	PROCESS DESCRIPTION
I7.	DISCUSSION OF ESTIMATE

II. INTRODUCTION

Rogers Engineering Co., Inc. was selected by TRW Systems Group to provide Architect-Engineer services and materials to perform certain tasks to support the TRW Proof of Concept Facility (POCE) grant from the National Science Foundation.

This Report dated December 13, 1974, is a presentation of our work.

This Report covers the following elements for the Phase "O" preliminary design work (see Dwg. No. E-04-001, Figure I-1):

- a. Thermodynamic characteristics and cycle analysis.
- b. Facility Layout drawings for the 10 MW power plant, including the Test Facility.
- c. Facility Process Piping and Instrumentation Diagram and Flow Diagram.
- d. Facility and Plant Cost Estimate.

12. SITE LOCATION AND PLANT ORIENTATION

The test site selected is adjacent to the USBR test site using the East Mesa anomaly as a geothermal resource. The proposed geothermal plant site is approximately 18 miles east of El Centro, California. This area is called the East Mesa Test Site.

The plant was oriented in the direction of the prevailing winds so as to place the Air Cooled Condenser downwind. The cooling tower was elevated 20 feet so that the top of the cooling tower would be at a higher level than the plant proper. The differential elevation will allow the condenser air-heat plume to be dissipated with a minimum recycle of warm air.

All spark creating devices were placed upwind from the prevailing wind and 75 feet from the nearest isobutane vapor containing pipelines and equipment.

12.1 SITE IMPROVEMENT

Plant access was oriented to existing roads. The access road and plant roads, which loop around the power plant buildings are located for easy access to all equipment, and are designed to support light duty as well as heavy duty vehicles so long as the heavy duty vehicles are used sparingly. The site will be sloped at the minimum necessary grade to dissipate isobutane across the site and away from the large structures in the direction of the prevailing wind.

Sewage will be handled through a small septic tank and leaching field located behind the control building. All collection and flows will be by gravity head.

A water storage pond will provide water for fire protection, and water treatment system for potable water. The pond is approximately 5,000 sq. ft. in area and five feet deep. The plant area will be fenced, with major access through one 30-foot double swing gate. An interior parking area will be provided for operating personnel and visitors.

Plant design, construction, and operation will be in accordance with local, state, and national permits and codes as well as all insurance regulations.

12.2 GENERAL CONDITIONS

The following climatological and site conditions were taken as basis for the plant design:

Elevation: Approximately 50 feet below sea level.

Dry Bulb Temperature °F: Maximum 110 - Minimum 26 Design 90

Wet Bulb Temperature °F: Maximum 81 - Minimum 23 Design 79

Wind Design Loading: 15 lb./ft.² up to 30' in Height

20 lb./ft.² above 30' in Height

Seismic Loading: Zone 3

Precipitation:

Snow - An average yearly snowfall of 1 inch or less.

Rain - Averages less than 4 inches per year.

Plant Site:

Level, requiring minimum grading

Soil Loading - Assume 3,000 lb./ft.²

13. POWER FLUID SELECTION

Two different power fluids were considered for this project: Isopentane and Isobutane.

The power fluid provides the power by expanding through an expander turbine. As the expander turbine operates entirely in the superheat region, isopentane was rejected as the power fluid because at the turbine inlet conditions isopentane is in the liquid region and would have to expand through the liquid-gas phase area under the saturation line on the pressure enthalpy diagram.

Isobutane was selected as the power fluid and some of the features in support of isobutane are:

- a. The relatively high density of isobutane at the operating conditions permit the design and use of smaller, high efficiency turbines.
- b. At the turbine inlet conditions, isobutane will be in the superheat region. Thus, isobutane is compatible with the turbine.
- c. The turbine operates entirely in the superheat region and above atmospheric pressure, so there are no problems associated with condensate erosion of turbine blades or air leakage.
- d. Isobutane is noncorrosive. All major equipment can be made of carbon steel or low cost alloys.
- e. Isobutane is compatible with the turbine seal oil.

The isobutane power cycle is shown in Section I5.

14. PLANT OPERATING FEATURES

14.1 INTRODUCTION

The instrumentation of the power plant is shown on Process and Instrument Diagram Dwg. No. E-03-001, Rev. 0 in Figure I-2. It has been laid out to provide complete control and monitoring of the power plant from the central control room. Provision has been made locally at key points in the system for installation of precision instruments. This will permit the running of an accurate heat balance.

In addition to the instruments for a normal power plant operation, instruments and controls are provided for operation as an experimental installation. At each connection for a pressure gauge or transducer, a plugged connection is provided to allow installation of a test or calibration gauge.

Instruments and controls are provided to give unattended operation after a manual startup. Parameters that reach an out of tolerance condition will cause an automatic shutdown. Manual procedures must then be followed for a restart.

All alarms will be wired to an annunciator panel in the control room. In the event of an automatic shutdown, the annunciator will give a "first-out" indication so that the cause of the shutdown may be easily traced.

14.2 HOT BRINE SYSTEM

Energy input to the plant is derived from hot brine that is pumped from the geothermal energy field. The hot brine passes through the tubes of the brine-isobutane vaporizer-superheater and is then returned to the geothermal field for reinjection. Instrumentation is provided to indicate the flow rate, pressure and temperature of the brine at the entrance to and exit from each heat exchanger branch as well as from the plant. With this information a good preventive maintenance program can be effected for the heat exchangers.

I4.3 ISOBUTANE HOTWELL TANK

The hotwell receives the condensed isobutane from the dry cooling tower which is elevated to provide a suction head in excess of the NPSH required for the isobutane booster pumps. The hotwell has a nominal capacity of 30,000 gallons. Approximately 50% of the total isobutane stored in the hotwell will be operating inventory.

I4.4 ISOBUTANE BOOSTER PUMPS

From the hotwell the isobutane is pumped to the suction of the main feed pumps by two booster pumps driven by explosion proof electric motors. The booster pumps raise the pressure of the isobutane sufficiently to accommodate the feed pump NPSH requirements. The layout of identical booster pumps is such that it permits the installation of a third pump at a later date. The capacity of each booster pump is over one-half of the full flow required for the feed pumps.

I4.5 ISOBUTANE FEED PUMPS

The isobutane loop is fed by two identical feed pumps with provisions for the installation of a future third pump. The pumps are turbine driven and each is capable of delivering one-half of the total flow of isobutane to the main turbine at design pressure.

The isobutane feed pump turbines are driven by isobutane gas. The turbine characteristics in the working range are such that the pump maintains a constant discharge pressure independently of the varying flow rates.

The pumps and pump turbines are provided with oil lubrication seals to prevent isobutane leakage.

I4.6 ISOBUTANE FEED PUMP TURBINES

The turbines that drive the feed pumps receive vapor from the line to the main turbine. A pressure control in this line regulates the speed of the feed pumps in order to maintain a constant pump discharge pressure. The exhaust conditions are the same as for the main turbine.

14.7 ISOBUTANE STARTUP PUMP

This pump is driven by an explosion proof electric motor, and the pump is capable of supplying the isobutane flow for one feed pump turbine at its rated capacity and design pressure. The pump is provided with double mechanical seals to prevent isobutane leakage.

The station power requirements for cold startup of the power plant is supplied from the tie-line. Remote controlled valves provide isolation of the two feed pumps and the startup pump.

14.8 ISOBUTANE LIQUID/ISOBUTANE VAPOR HEAT EXCHANGERS (REGENERATORS)

This group of eight heat exchangers transfers heat from the turbine exhaust to the liquid condensate. The liquid passes through the shell side and the vapor through the tube side of the heat exchanger. From the vapor and liquid side these vessels are connected in 4 parallel, 2 series arrangement.

14.9 BRINE- WATER/ISOBUTANE LIQUID- VAPOR HEAT EXCHANGERS

This group of eight heat exchangers is connected in 4 parallel, 2 series arrangement. These units vaporize and superheat the power fluid (isobutane) to the throttle conditions at the generator-turbine. The heat is obtained from the geothermal brine water which passes through the tubes and heats the isobutane which passes through the shell side of the heat exchangers.

The paralleling feature allows any group of two heat exchangers to be isolated from the system for maintenance. The remaining heat exchangers can be operated in series by closing the appropriate valves.

14.10 TURBINE-GENERATOR

The turbine is a single stage unit. The isobutane enters the turbine through a separately mounted main stop valve, check valve and control valve. The generator output is 10 MW at 13.8 kV and 60 Hz. The turbine-generator output can be regulated manually and auto-manual from a remote station by the operator. The flow of isobutane to the turbine can be controlled directly from the turbine panels. The controls include tachometer pickup, bearing vibration pickup, alarms and signals of shut-down of the unit.

The turbine is provided with rate control equipment and sufficient feedbacks from other control systems for automatic limit of rate of load change to avoid an imbalance in the control system.

Facilities are provided to take power into the plant from the step-up transformer to supply startup power. Once the generator is on the line it provides all the required station power and the load on the generator will be brought to the desired level by means of a governor control until full output power is reached.

A 9,000 rpm, gas expander turbine is connected directly to a gear reducer which reduces the speed to 3,600 rpm. The 3,600 rpm gear reducer output shaft is connected directly to the generator. The gas expander turbine-generator combination recovers the energy on expansion of the power fluid (isobutane vapor) through the turbine.

I4.11 DRY COOLING TOWER

A dry mechanical draft cooling tower will be provided to remove the heat of vaporization from the isobutane gas and cause it to condense. A standard design, mechanical draft dry cooling tower is a highly reliable, well proven method of disposing of waste heat with minimum, thermal environmental pollution. The hot exhaust gases are in a closed loop and after passing through the regenerator, enter the cooling tower (condenser). The cooling air is circulated by means of induced draft fans. The condensate discharge from the condenser has the necessary head to permit adequate gravity flow to the hotwell.

I4.12 ISOBUTANE PURGE AND BURNOFF

Piping and isolation valves are provided to permit nitrogen purging the system by parts or sections and for connecting the pressure vent system. This includes an automatic flare burner for burning the isobutane that is expelled from the system.

Additional equipment that is required but not shown on the piping and instrumentation diagram (P & ID) includes the instrument and control air system. This system will be backed up by an emergency nitrogen system.

I4.13 PROCESS INSTRUMENTATION

All process instrumentation is pneumatic except the governor control system. Pneumatic instrumentation was selected to make the system inherently explosion proof. In the event of future adaptation of the plant to remote monitoring or control, transducers may be added to convert the pneumatic signals to electronic. Final control valve operators will be pneumatic except for the electro-hydraulic governor system. The governor requires the high speed response possible with hydraulics. All important alarm conditions are monitored by a "first-in" annunciator system for ease in troubleshooting. Plant protection is provided such that any equipment that approaches an unsafe level will automatically trip that piece of equipment and shutdown the plant, e.g., overspeed or excess vibration on any rotating equipment, high lube oil or bearing temperature, loss of level in the isobutane condensate hotwell, etc.

I4.14 TURBINE-GENERATOR BUILDING

The turbine-generator building is designed to house the generator, machine shop and maintenance area. Instrument air and hydraulic oil systems are also enclosed in this building.

I4.15 CONTROL BUILDING

The control building is designed to house the control room, switch-gear, maintenance shop and living quarters for one or two people. The control room and living quarters are air conditioned for personnel comfort.

15. POWER CYCLE EVALUATION

- GENERAL

The power cycles studied are shown as Cycles I through 5 in this Section. The comparison of the five cycles is shown on the two data sheets at the end of this Section (Table I-I). The comparison is based on a 15 MW output powerplant so the figures shown do not apply to the 10 MW power plant design.

- CONCLUSION

Power Cycle No. 4 was the power cycle selected. The heat efficiency of 14.2% was higher and the cost evaluation of \$7.26 million was lower than for the other four cycles.

Thus, Cycle 4 was the optimum cycle.

15.1 CYCLE #1

Isobutane enters the turbine at 320°F, 550 psia, expanding through the turbine, passing through the regenerator and condensing in the cooling tower at 130°F.

The evaluated total differential variable costs for Cycle #1 was \$8.3 million and the thermal efficiency was 13.95%.

15.2 CYCLE #2

In Cycle #2 the turbine inlet conditions were changed slightly to 310°F and 510 psia. The condensing temperature in the cooling tower was lowered to 120°F.

The evaluated total differential variable costs for Cycle #2 was \$7.8 million and the thermal efficiency was 13.87%.

15.3 CYCLE #3

In Cycle #3 the turbine inlet pressure was changed to 650 psia and the temperature was held at 310°F. The condensing temperature was raised to 130°F.

The evaluated total differential variable costs for Cycle #3 was \$8.1 million and the thermal efficiency was 12.67%.

Based on IC4 Cycles @ 15,000kW Gross - 51.18×10^6 Btu/Hr

Cycle No.	320°F 1	560 Psia	310°F 2	510 Psia	310°F 3	650 Psia	310°F 4	460 Psia	310°F 5	400 Psia
IC ₄ Actual Drop Δh	23.0		23.8		21.3		23.0		21.3	
IC ₄ Circ $\times 10^6$ Lb/Hr	2.225		2.150		2.403		2.225		2.403	
ECONO-DROP Δh	27		22.2		-		33		43.0	
Duty $\times 10^6$ Btu/Hr	60		47.7		-		73.4		105.0	
LMTD/L/O	8.71/40		40/40		-		34/40		19.5/40	
Area $\times 10^3$ / $\$@7 \times 10^6$	173/1.21		30/0.21		-		23/0.16		134.6/0.942	
PREHEATER				)						
Duty $\times 10^6$ Btu/Hr	252		221				160		121	
LMTD/No	47/175		48/175				44.6/175		37.4/175	
Area $\times 10^3$ Ft ²	31		26	)			21		18	
VAPORIZER										
Duty $\times 10^6$ Btu/Hr	67		49				98		137	
LMTD/No	37/111		41/111				41.8/111		46.8/111	
Area $\times 10^3$ Ft ²	16		11				21		26	
SUPERHEATER										
Duty $\times 10^6$ Btu/Hr	49		99	Duty	403.7		105.		118.	
LMTD/No	33.4/80		45/80		41.5/22		48.4/80		53.2/80	
A $\times 10^3$ Ft ²	18		28				27		28	
Brine Area $\times 10^3$	65.6		64.6		79.7		68.7		72.3	
@ $\$18/\text{Ft}^2 \times 10^6$	1.18		1.16		$\$19.2/\text{Ft}^2 = 1.53$		1.237		1.301	
AIR CONDENSER	130		120		130		130		130	
Desuper Duty $\times 10^6$ Btu/Hr	35.6		43.0		49.7		31.1		45.6	
LMTD/STAB	29.8/3		34.2/3		37.8/3		34/3		31.3/3	
Area $\times 10^3$ Ft ²	398		419		438		305		486	
Cond. Duty $\times 10^6$ Btu/Hr	280.4		262.3		302.8		280.4		302.8	
LMTD/STAB	32.5/5		24.7/5		31.3/5		30.7/5		31.3/5	
Area $\times 10^3$	1726		2124		2050		1928		1935	
Area	2,124,000		2,543,000		2,488,000		2,132,000		2,421,000	
@ $\$0.9/\text{Ft}^2 \times 10^6$	1.912 $\times 1.05$		2.403		2.239		1.919		2.179	
Faus KW @ /KW/1000 Ft ²	$\times 1.05$		2,670		2,488,000		2,132		2,421	
Heat from Brine $\times 10^6$ Btu/Hr	367.0		369.4		403.7		360.5		375.5	
Drop Δh	103.1		113.3		133.5		108.2		103.1	
Geo Brine Flow $\times 10^6$ Lb/Hr	3.56		3.26		3.02		3.33		3.64	
Heat Efficiency %	13.95		13.87		12.67		14.19		13.63	

Table I-1. Cycle Comparison

Based on IC₄ Cycles @ 15,000kW Gross - 51.18×10^6 Btu/Hr

Cycle No.	320°F 1	560 Psia	310°F 2	510 Psia	310°F 3	650 Psia	310°F 4	460 Psia	310°F 5	400 Psia
IC ₄ CIRCULATION $\times 10^6$ Lb/Hr	2.225		2.150		2.403		2.225		2.403	
gpm/psi	8660/485		8240/443		9350/588		8660/489		9350/339	
LHP	2450		2226		3207		2468		1849	
BHPC .83	2950		2680		3865		2977		2228	
KW @ 0.9	2445		2222		3204		2470		1850	
DEEP WELL PUMPS										
gpm/psi	8000/400		7326/400		6787/400		7483/400		8180/400	
LHP	1866		1710		1583		1746		1909	
BHP @ 0.84	2222		2035		1886		2079		2273	
KW @ 0.9	1845		1690		1565		1725		1886	
VARIABLE COSTS $\times 10^6$ \$										
IC ₄ Regenerator	1.21		0.29		-		0.16		0.942	
Brine Exch.	1.18		1.16		1.53		1.237		1.301	
Cooling Tower	1.912		2.403		2.239		1.919		2.179	
Geo Water Pumps	0.170		0.150		0.140		0.140		0.150	
IC ₄ Pumps	0.100		0.094		0.118		0.104		0.118	
IC ₄ Turbine	1.176		1.152		1.232		1.176		1.232	
Σ Variables	5.748		5.169		5.259		4.736		5.922	
GEO WATER @ \$1/MM Btu/Hr										
400 1 year - 7000 Hrs	2.569		2.586		2.826		2.524		2.629	
EVALUATION TOTAL	8.317		7.755		8.085		7.260		8.551	
Electricity to Station KW										
Generator & Gear Loss	600		600		600		600		600	
Misc. to Station	200		200		200		200		200	
Pumping IC ₄	2,445		2,222		3,204		2,470		1,850	
Pumping Geo. Brine	1,845		1,690		1,565		1,725		1,886	
Air Fans @ Condenser	2,124		2,670		2,488		2,132		2,421	
Station	7,214		7,382		8,057		7,127		6,957	
NET TO LINE	7,786		7,618		6,943		7,873		8,043	

Table I-1 Cycle Comparison (Cont'd)

I5.4 CYCLE #4

In Cycle #4 the turbine inlet pressure was lowered to 450 psia and the temperature was held at 310°F. The condensing temperature remained at 130°F.

The evaluated total differential variable costs for Cycle #4 was \$7.26 million and the thermal efficiency was 14.2%.

I5.5 CYCLE #5

The turbine inlet pressure for Cycle #5 was reduced to 400 psia and the temperature was held at 310°F. The condensing temperature remained at 130°F.

The evaluated total differential variable costs for Cycle #5 was \$8.55 million and the thermal efficiency was 13.63%.

16. PROCESS DESCRIPTION

Referring to the Process Flow Diagram E-02-001-1 in Figure I-3:

The heat energy contained in the geothermal hot brine is transferred by heat exchangers into the closed power fluid system.

Waste heat from the power fluid system is rejected to the atmosphere via the air cooled cooling towers.

The electric generator and liquid isobutane feed pump are driven by isobutane gas expansion power turbines.

Referring to the Power Fluid Cycle on the isobutane pressure enthalpy diagram, Cycle 4 in Section I5, the power fluid cycle shown is typical of expected geothermal hot brine and cold sink temperatures at the design conditions. The cycle reflects expected pressure drops which must be allowed in the heat exchangers.

The state points shown on the isobutane pressure enthalpy diagram, Cycle 4 in Section I5, have been used to prepare the cycle data (Table I-II) and the pump summaries (Table I-III).

Table I-II. Cycle Data

Geothermal Hot Brine

Flow lb/hr	2,810,000
GPM	6,320
Temperature °F	
In	350
Out	248
Heat to Power Fluid btu/hr	295,200,000

Isobutane Power Fluid

Flow lb/hr	
Total	1,789,000
Turbine-Generator	1,572,000
Turbine Feed Pump	217,000
Temperature °F	
Into Condensate Pump	130
Out of Condensate Pump	132
Out of Regenerator	182
Out of Brine/Isobutane Heat Exchangers	310
Into Turbine	310
Out of Turbine	214
Out of Economizer	162
Out of Hot Well	130
Pressure, psia	
Into Condensate Booster Pump	110
Into Condensate Feed Pump	130
Out of Condensate Feed Pump	500
Out of Regenerator	490
Out of Brine/Isobutane Heat Exchangers	460
Into Turbine	450
Out of Turbine	116

Table I-II. Cycle Data (Cont'd)

Isobutane Power Fluid (Cont)

Out of Regenerator	113
Out of Air Cooled Condenser	100

Isobutane Enthalpy, Per Figure 1, Btu/lb.

Into Condensate Pump	16
Out of Condensate	16
Out of Regenerator	49
Out of Brine Isobutane Heat Exchangers	214
Into Turbine	214
Out of Turbine	191
Out of Economizer	158
Out of Air Cooled Condenser	16

Equivalent kW

Turbine Power To Generation	10,600
Gear Loss	200
Generator Loss	400
Gross at Generator Terminal	10,000
Station Power Requirement	
Fan Motors	1,700
Oil Pump Motors	40
Booster Pump Motors	104
Cooling Pump Motor	8
Brine Well Pumps	1,749
Miscellaneous (Lighting, etc.)	94
Subtotal to Station	3,695
Net Generation to Line	6,305

Table I-II. Cycle Data (Cont'd)

Thermal Efficiency, %

(6, 305) (3, 413)/295, 200, 000	7.3
---------------------------------	-----

Ratios

Geothermal Water/kW

Lb/Gross at Generator Terminals	281
---------------------------------	-----

Lb/Net to Line	446
----------------	-----

Table I-III. Pump Summary

<u>Pump Number</u>	<u>Service</u>	<u>Liquid Pumped</u>	<u>Flow GPM</u>	<u>Pressure Diff. H Psi</u>	<u>Eff. %</u>	<u>Power BHP</u>	<u>Electric Power</u>	<u>Eff. %</u>
14-01	Booster Pump	Isobutane	3480	20	80	51	43	
14-02	Booster Pump	Isobutane	3480	20	80	51	43	
14-04	Feed Pump	Isobutane	3480	370	80	964	Gas Turbine	
14-05	Feed Pump	Isobutane	3480	370	80	964	Gas Turbine	
14-07	Start Up	Isobutane	420	400	80	123	100	
14-08	Cooling	Fresh Water	100	120		15	13	89
14-09	Recirculation	Lube Oil	60	250		10	9	85
14-10	Fire Pump	Fresh Water	500-1000	120		120	102	92

17. DISCUSSION OF ESTIMATE

17.1 GEOTHERMAL BRINE DISTRIBUTION SYSTEM

The estimate (Table I-IV) is based on providing the brine distribution system, essentially as shown on the Equipment Layout, Drawing No. E-04-002, Figure I-4, to the fence line.

The estimate is based on carbon steel piping and fittings, and stainless steel control valves. The supply lines will be insulated with 2 inch (2") thick calcium silicate, or equal.

17.2 GEOTHERMAL ISOBUTANE SYSTEM

a. Vessels

Bid data obtained by telephone was used to cost estimate eight (8) isobutane vapor-isobutane liquid heat exchangers, eight (8) brine-isobutane heat exchangers and one (1) 30,000 gallon hot well tank.

The regenerator heat exchangers will have fixed tube sheets, C. S. tubes and C. S. shell. The vaporizer-superheater heat exchangers will have a floating head, 304 L stainless steel tubes and C. S. shell.

b. Piping, Insulation and Valves

The valves were taken off the Piping and Instrumentation diagram (P & ID), Section 9, and cost estimated according to current job bids. The piping was estimated from drawing takeoffs, using carbon steel construction.

c. Instrumentation and Controls

The instrumentation and controls were taken off the P & ID and cost estimated according to current job bids.

17.3 SINGLE ENTRY TURBINE GENERATOR SYSTEM

a. Turbine Generator, Controls and Auxiliaries

Several vendors gave bid data over the telephone and followed up with a visit to our office for discussions. The prices we received are subject to escalation.

b. Booster and Feed Pumps with Drivers

Bids were obtained by telephone for two (2) 55 percent (55%) capacity isobutane feed pumps with turbine drives, two (2)

Table I-IV. Proposed Geothermal Power Plant Estimate

Item Description	Equipment Costs F. O. B. Factory	Field Materials	Direct Field Labor	Contractor's Overhead Freight, Taxes & Insurance	Total
A. Geothermal Brine Distribution System					
1. Piping & Insulation	-	92,000	63,000	45,000	200,000
B. Geothermal Isobutane System					
1. Brine to Isobutane Heat Exchanger	1,008,000	10,000	12,000	140,000	1,170,000
2. Isobutane to Isobutane Heat Exchanger	301,000	4,000	6,000	40,000	351,000
3. Hot Well Tank	56,000	1,000	5,000	4,000	66,000
4. Piping, Insulation & Valves	-	278,000	103,000	180,000	561,000
5. Instrumentation & Controls	104,600	12,000	52,000	6,740	175,340
C. Single Entry Turbine Generator System					
1. Turbine Generator, Controls & Auxiliaries	940,000	3,000	106,000	63,000	1,112,000
2. Booster & Feed Pumps With Drivers	225,000	49,400	94,800	70,000	439,200
3. Dry Cooling Tower	1,600,000	3,000	340,000	140,000	2,083,000
4. Support & Miscellaneous Equipment	41,000	5,000	16,000	3,000	65,000
5. Instrument Air System	8,000	5,000	10,000	6,000	29,000
D. 10 MW Generator, Station Power System & Substation					
1. MCC, Power Panel, & 4.16 kV Switch Gear	191,459	INCL.	19,500	18,394	229,353
2. Lighting, Cable & Trays	110,240	INCL.	62,910	33,570	206,720
3. Substation Equipment	187,947	INCL.	30,000	26,580	244,527
4. Control Room	117,814	INCL.	INCL.	8,246	126,060
5. Overhead Distribution Lines	40,000	INCL.	INCL.	16,660	56,660
E. General Facilities					
1. Site Preparation	-	-	-	-	-
2. Buildings & Foundations	-	41,520	INCL.	4,980	46,500
a. Substation	-	8,640	INCL.	1,040	9,680
b. Turbine Generator Building	-	87,600	INCL.	10,500	98,100
c. Cooling Tower Foundation	-	4,740	INCL.	570	5,310
d. Control Building	-	37,360	INCL.	4,480	41,840
e. Pipe, Tank & Miscellaneous Supports	-	69,400	INCL.	8,330	77,730
f. Test Area, Laboratory and Offices	-	92,000	INCL.	14,000	106,000
g. Water Pond	-	9,000	INCL.	1,400	10,400
h. Roads	-	49,107	INCL.	10,203	59,310
Installed Cost Total					7,569,670
5% Small Miscellaneous Equipment					378,440
6% Contractor's Fee					476,890
15% Engineering Fee					1,286,000
Total Capital Cost					9,711,000
12% Escalation for 2- 1/2 Years					3,201,370
Most Probable Cost					12,912,370
16% Contingency					2,065,980

Table 70-1. Proposed Geothermal Power Plant

Figure I-4.

55 percent (55%) capacity isobutane booster pumps with electric motor drives and one (1) isobutane start-up pump with electric motor drive.

c. Dry Cooling Tower

Bids were obtained by telephone for 12, 16 and 32 unit dry cooling towers. The specified heat duty can be obtained in a 20 unit assembly arranged for gravity feed to the hot well. Tubes will be carbon steel as well as the supporting steel.

d. Support and Miscellaneous Equipment

This includes the turbine-generator building overhead 20 ton crane, a fire pump and other small miscellaneous equipment. Costs for this equipment were taken from current job pricing information.

e. Instrumentation Air System

Costs were estimated using current job equipment bids. This cost also includes the plant air system, the instrument air system, an air dryer, an oilless air compressor and a backup instrument air system.

17.4 10 MW GENERATOR, STATION POWER SYSTEM AND SUBSTATION

a. The station power requirements were estimated based on the electrical Single Line Power diagram, Figure I-5.

b. References used for the electrical cost estimate were:

- Commercial-Industrial Construction Estimating and Engineering Standards (Richardson)
- Current Construction Costs (Lee Saylor, Inc.)
- General Electric Company
- Westinghouse Electric Corp.

17.5 GENERAL FACILITIES

a. Site Preparation

Cost estimated for minimum work on a level site.

b. Buildings and Foundations

1. Substation

Miscellaneous concrete pads for electrical equipment were designed and cost estimated.

2. Turbine- Generator Building

A bid was obtained by telephone for a steel frame prefabricated metal building. The building and equipment loads were used in the design and pricing of the floor and foundations.

3. Cooling Tower

The cooling tower loads were obtained from the cooling tower manufacturer for the air cooled cooling towers and the slab and foundations were designed and priced using current job pricing information.

4. Control Building

Structural and architectural designs were developed and cost estimated by standard estimating procedures.

5. Pipe, Tank and Miscellaneous Supports

Civil and structural designs were developed for the supports and foundations of the heat exchangers, requestor, piping, pumps and drivers. Standard estimating procedures were used to determine the cost of these items.

6. Test Building

Six inch (6") concrete slab with perimeter beam was cost estimated and a bid was obtained by telephone for the building. Interior partitions, equipment, fixtures and air conditioning was estimated using current job pricing.

7. Water Pond

Five foot (5') deep pond with synthetic lining was cost estimated.

8. Make-up Water

The pond will be connected to the plant brine piping system.

Figure I-5.