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Geothermal

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1.0 GEOTHERMAL FUEL CYCLES

Geothermal energy systems have been demonstrated as capable of supplying a significant amount of electrical power. The Geysers' field electric generating system in California is currently rated in excess of 500 MWe. It has been estimated that 2.2 quads of electricity will be available from geothermal sources by the year 2000 (U.S. Environmental Protection Agency, 1977).

Geothermal energy systems can also be utilized for space heating and industrial process heat. In Reykjavik, Iceland, geothermal brine and steam have been used for district heating for several years.

Geothermal reservoirs can be classified into three categories:

- hydrothermal convective systems
- hot igneous systems
- geopressurized systems

Hydrothermal convective systems have the greatest near term potential for producing electricity, particularly in the West. Hydrothermal systems are defined as "convective systems of water and steam which are entrapped in fractured rocks or sediments by impermeable surface layers" (U.S. Energy Research and Development Administration, 1977). These reservoirs are accessible by drilling through the surface layers to depths of no more than three kilometers.

Hot igneous systems, which include both hot dry rocks and magma, are significantly different from hydrothermal convective systems. In a hot dry rock system, heat is contained in impermeable rocks of low porosity without a naturally circulating fluid. Due to the absence of a fluid, heat transfer is by conduction rather than convection. These systems are usually found around the perimeters of magma

systems. Current designs for utilizing these resources incorporate the injection of a fluid to create steam for heating or producing electricity. Magma systems consist primarily of molten rock occurring near the earth's surface.

The total heat energy estimated to be contained in hot igneous systems is at least 2.5×10^{22} calories at a rock temperature of approximately 650°C (1200°F); this is approximately 30 times more than the total heat energy of hydrothermal systems (U.S. Environmental Protection Agency, 1977).

Geopressured systems are also conduction-dominated systems. They are formed by the combination of heating of water by the earth's interior heat and pressurization of the water by layers of sand and shale lying beneath impermeable rocks. The temperatures of these systems range from 15°C (60°F) to 300°C (570°F) at abnormally high pressure. As the water is saturated with methane, these reservoirs have a fuel potential as well as thermal and hydraulic energy potentials.

Two base unit hydrothermal convective systems are discussed in Section 2 below. Discussions of energy production systems employing hot igneous and geopressurized systems will be presented in Sections 3 and 4, respectively, in future revisions to this document.

1.1 References

- U.S. Energy Research and Development Administration, 1977.
Environmental Development Plan: Geothermal Energy Systems.
Washington, D.C.
- U.S. Environmental Protection Agency, 1977. Western Energy Resources
and the Environment, Geothermal Energy. (EPA-600/9-77010).
Washington, D.C.

2.0 HYDROTHERMAL CONVECTIVE SYSTEMS, VAPOR DOMINATED

Hydrothermal convective systems are classified in two categories according to steam quality and temperature. Fields in which the energy medium is predominantly steam are denoted as vapor dominated systems. These systems generally possess downhole temperatures of around 240°C (464°F) and vent steam at a pressure of 35 kg/cm² (498 lbs/in²) (U.S. Environmental Protection Agency, 1977). The steam from these systems is used to drive turbines directly in the generating plant. The discussion presented on the vapor dominated field is based on Unit 12 of the Pacific Gas and Electric (PG&E) generating system at the Geysers.

The second type of hydrothermal convective system is denoted as liquid dominated. These reservoirs range in temperature between 90°C (194°F) and 250°C (662°F) with an average of 150°C (U.S. Environmental Protection Agency, 1977). The steam from these fields contains a large amount of water and therefore must be modified before it can be used to produce electricity. Figure 2-1 presents locations of known hydrothermal reservoirs.

2.1 Characteristics of the Vapor Dominated Reservoirs (Geysers)

The Geysers' field consists of approximately 175 wells of which 75 produce steam. Each well in the system produces between 75,000 and 350,000 mass pounds per hour at a wellhead pressure of 490 force pounds per square inch. The temperature of the reservoir is approximately 240°C (465°F) with a specific enthalpy of 1,204 Btus per mass pound (DiPippo, 1978).

Since the terrain of the field is generally rugged, the density of the wells varies greatly, generally between one well per 20 acres and one well per 40 acres (DiPippo, 1978). Economic considerations are also involved in the siting density of the well field.

FIGURE 2-1
LOCATIONS OF KNOWN HYDROTHERMAL RESERVOIRS

Drilling is accomplished using a combination of mud and air procedures with mud drilling being used for the larger portions of the wells where seepage of liquid could be a serious problem. Directional drilling is used to reach the more inaccessible portions of the field. The wells are connected to a gathering system composed of carbon steel pipes. A centrifugal axial separator is located on the steam line of each well to remove solids from the steam and prevent fouling of the pipelines. Usually seven wells are connected to the same gathering system, delivering one million pounds of steam per hour which is required to supply one 55 MWe plant (DiPippo, 1978). To control steam loss from the wellhead to the turbine, the pipelines are limited to 6,560 feet in length.

Steam from the geothermal field distribution system is piped to the plant where it is used directly to power a turbine generator.

The effluent steam from the turbine is condensed. Noncondensable gases from the condensers are vented to the gas ejection system after H_2S has been removed by conventional processes like the Stretford process (the unit described here does not have a H_2S removal capability). The condensate from the condenser is channeled to the cooling tower where it is cooled and reused as cooling water. Any excess condensate from the cooling tower is reinjected to the wells. Any noncondensable gases remaining in the fluid in the cooling tower are vented to the air along with water vapor.

The steam ejection system is powered by geothermal steam from the pipeline. It separates the noncondensable gases from the condenser effluent. The noncondensable gases are vented to the atmosphere while the condensate is channeled to the cooling water system.

In this study, a constant steam rate is assumed over the plant life which is probably not true. With increasing depletion, more brine/makeup water will have to be reinjected.

2.2 Constraints

2.2.1 Legislative Constraints

Several laws currently affect operations at the Geysers' field. On the national level, the following laws are operative:

- Safe Drinking Water Act of 1974
- Clean Air Act Amendments of 1977
- Geothermal Energy Research, Development and Demonstration Act of 1974

Part C of the Safe Drinking Water Act of 1974 requires the Environmental Protection Agency (EPA) to publish regulations regarding "state programs for underground injection of spent fluids to provide protection to underground supplies of drinking water."

The Clean Air Act Amendments of 1977 give the EPA jurisdiction over the emissions of various air pollutants. In addition, California's air quality standards apply enforcing hydrogen sulfide control.

The Geothermal Energy Research, Development and Demonstration Act provides government funds for geothermal research and development projects including government loans to commercial enterprises for the development of existing geothermal energy systems.

2.2.2 Siting Constraints

The Geysers' field is the only known vapor dominated hydrothermal reservoir available for commercial development in the U.S.

The field is a Known Geothermal Resource Area (KGRA) located in the Mayacmas Mountains of Sonoma and Lake Counties, approximately 75 miles north of San Francisco, California.

2.3 Resource Consumption

2.3.1 Land Use

Pacific Gas and Electric has estimated that 700 acres of land are required by a 100 MWe unit (Cossette, 1978). Ten to twenty percent of this land is used for access roads, well locations, pipelines, and plant site while the rest is undisturbed (Anspaugh, 1978). Based on this, the total land use per 10^{12} Btus annual output is approximately 275 acres with between 28 and 56 acres being permanently disturbed.

2.3.2 Water Use

The design of the plant assumes a requirement of approximately 2×10^6 mass pounds of steam per hour (DiPippo, 1978). Since all of the steam is converted to water and then either evaporated or reinjected (after use as cooling water), the plant requires approximately 1,960 acre feet of water per 10^{12} Btus of output. Of this, approximately 84 percent or 1,640 acre feet is evaporated, and 16 percent or 320 acre feet is reinjected (Anspaugh, 1978); therefore, no surface water is needed for cooling on a continuous basis, but some water may be needed on an intermittent basis during startup or for miscellaneous support purposes.

2.3.3 Materials Requirement

No comprehensive list of the materials required for other than well fields or the generating plant is presently available. A listing of selected materials required by the plant is presented in Table 2-1.

TABLE 2-1
SELECTED MATERIALS AND PLANT USE

MATERIAL	COMPONENT
Steel: carbon steel; 13% chrome steel; stainless steel; cast, forged, or fabricated steel	pipes, turbine, condenser, cooling or condensate lines, cooling towers
Aluminum	above ground water circulation lines, cooling towers
Glass Reinforced Plastic Pipe (or Cement-Asbestos Epoxy Lined pipe)	underground piping between power house and cooling tower
Redwood	cooling tower support
Polystyrene, Polypropylene, Polyvinyl Chloride	tower fill
Tin alloys	electrical equipment
Platinum	current carrying contact surfaces

2.3.4 Manpower

The manpower requirements for constructing a 110 MWe plant have been estimated by Pacific Gas and Electric Co. at 141.7 man-years with a peak work force of 85. Based on this, the manpower requirement for 1012 Btus of annual output is 57.43 man-years with a peak work force of 34.45.

The operations and maintenance crew at the Geysers was 56 in 1978. This crew serviced the entire 502 MWe facility; therefore, the total crew per 1012 Btus of annual output is calculated to be 4.97 workers per year.

2.4 Environmental Considerations

An evaluation of the environmentally-related impacts of the utilization of geothermal energy is presented in Table 2-2. Most of these effects are unquantifiable and not all of them are relevant to increased utilization of the Geysers' field.

The two most important impacts listed in Table 2-2 are contamination of surface and subsurface water and increased seismicity. At the Geysers, these are both directly related to the withdrawal and reinjection of geothermal brines. Since 1975, there has been no seismic activity at the Geysers even though excess brine has been reinjected since 1969. The data from other areas where seismic activity has increased as a result of reinjection are inconclusive (The Futures Group, 1975). Surface and subsurface contamination by brine is unquantified. Although, as long as excess brine is reinjected into the field, there will be little brine-related contamination of surface water there is a much greater probability of contaminating subsurface water. Table 2-3 lists the chemicals that are reinjected

TABLE 2-2

EVALUATION OF IMPORTANT ENVIRONMENTAL IMPACTS

IMPACT AREA	SIGNIFICANCE	NUMBER OF PEOPLE AFFECTED	LASTING QUALITIES	TIMING	SUM OF IMPACT JUDGMENT
Biota	0	1	1	2	4
Seismicity	3	3	2	2	10
Subsidence	1	1	3	2	7
Contamination of Surface and Subsurface Waters	2	3	2	3	10
Blowouts	3	1	1	2	7
Aesthetics	1	1	2	2	6
Release of H ₂ S	1	1	0	3	5
Release of NH ₃ and Other Atmospheric Contaminants	1	1	0	2	4
Noise	1	1	1	3	6
Land Use	2	2	2	1	7

Significance

3 = potentially killing
 2 = very dangerous or
 important
 1 = some danger or
 important
 0 = trivial

Number of People Affected

3 = a great many millions
 2 = many affected
 1 = localized
 0 = none

Lasting Qualities

3 = irreversible
 2 = reversible with
 great effort
 1 = some effort to
 reverse
 0 = self-correcting

Timing

3 = immediate concern
 2 = of concern within
 5 years
 1 = of concern within
 5-10 years
 0 = of concern within
 10-20 years

Note: The release of radon gas has been identified at a few geothermal sites; however, the concentrations are negligibly small or not quantified. Further data should be acquired.

Source: The Futures Group, 1975. A Technology Assessment of Geothermal Energy Resource Development. Prepared for the National Science Foundation. Washington, D.C.

TABLE 2-3

**CHEMICALS REINJECTED TO GEYSERS'
FIELD FROM ELECTRIC POWER PLANTS**

CHEMICALS	TONS PER 10 ¹² BTUS PRODUCED ANNUALLY
Carbonates	249
Ammonia	86
SO ₂	1.16
Sulfate	76.2
Sulfur	4.86
Nitrate	0.06
Chloride	2.03
Calcium	3.08
Magnesium	0.58
Silicon	2.17
Boron	9.95
Total solids	107.66
Organic/volatile solids	119.97
Water	4.36 x 10 ⁵ (or 320 acre ft)

Source: The MITRE Corporation, 1977. Environmental Research Needs
for Geothermal Resources Development. Volume I.
MTR-7419. McLean, Virginia.

in to the Geysers' field per 10^{12} Btus output. The extent of ground water contamination at the Geysers due to this reinjection is unknown.

The next most important impacts are land subsidence, blowouts, and land use. Land subsidence has been noted at several geothermal fields around the world; however, most of the data relating to subsidence are at best tentative. At the Wairakei field in New Zealand, horizontal displacement damaged steam mains at the plant (The MITRE Corporation, 1977). Presently, the subsidence at the Geysers has been measured at one to two centimeters per year, or 2.57×10^{-3} to 5.142×10^{-3} feet per year (ibid).

Well blowouts or unanticipated venting of the wells are common to all industries that drill wells into pressurized areas. The effects of a blowout are well known.

Associated with the question of how much land is disturbed are conflicts with existing land uses. These conflicts are minimal at the Geysers since the field itself is fairly remote; however, the effects of situating a geothermal plant in, for example, the Imperial Valley of California among existing agricultural industries remain to be resolved. Contamination of surface water used for irrigation, noxious air emissions, and removal of land from agricultural use are a few of the effects of geothermal energy development activities that are incompatible with current land use patterns in the Imperial Valley.

Aesthetics and noise pollution are also important concerns in geothermal development. Table 2-4 shows the levels of noise for various operations measured at the Geysers. Several of these levels exceed the OSHA standards of 95 decibels(A). The problem of aesthetics

TABLE 2-4
NOISE LEVELS MEASURED AT THE GEYSERS

SOURCE	DURATION	DECIBELS (dBA)
Well drilling		
mud drilling	60 days/well	75-80 at 50 feet
air drilling	30 days/well	85-120 at 25 feet
well cleaning (open well)	3-6 days ¹	118 at 50 feet
well testing (open well)	14 days)	118 at 50 feet
rock muffler		89 at 50 feet
well bleeding	variable	65-86 at 5 feet
well blowouts	infrequent	118 at 50 feet
Construction operations (plant)	1-2 years	70-90 at 50 feet
Plant operations	20-30 years	
muffled steam line vent	intermittent	90 at 100 feet
jet gas ejector	continuous	84-117 at 5-10 feet
steam line separator	continuous	80 at 25 feet
steam line breaks	brief, infrequent	100 at 50 feet
cooling tower	continuous	80-90 at 5-10 feet
Turbine generator building	continuous	70 outside

Source: U.S. Environmental Protection Agency, 1977. Western Energy Resources and the Environment, Geothermal Energy (EPA-600/9-77010). Washington, D.C.

is related to conflicts in land use. Geothermal power plants are aesthetically unappealing to many people. At the Geysers, this is alleviated by the remoteness of the site.

Table 2-5 shows the emissions from the operation of power plants at the Geysers per 10^{12} Btus of output. The discharges are from two major sources, namely, the gas ejector and the cooling tower.

The most objectionable pollutants released at the Geysers are hydrogen sulfide (H_2S), boron (B), and radon₂₂₂ (^{222}RN). Approximately 72 percent of the H_2S and all of the boron is released from the cooling tower, while all of the ^{222}RN and 28 percent of the H_2S emissions come from the gas ejectors. None of these pollutants are emitted in sufficient quantity at the Geysers to present a health hazard to the workers (The MITRE Corporation, 1977); however, there is evidence of boron-related damage to plant life (U.S. Environmental Protection Agency, 1977) and the "rotten egg" smell of H_2S is detectable at the site. Great damage can be done to the habitats of many species by developments of this kind. Nonetheless, the Geysers' field is used for hunting purposes in spite of the presence of the power plants.

Overall, although the environmental impacts at the Geysers' field are large, they compare very favorably to those of more conventional energy-producing activities.

2.5 Economic Data

2.5.1 Capital Cost

As of September 1978, the total expenditure for construction of Unit 12 of the Geysers was estimated to be approximately \$11,180,000 (in 1978 dollars) per 10^{12} Btus of annual output (Cossette, 1978).

TABLE 2-5

GASEOUS EMISSIONS FROM THE GEYSERS
(Tons/10¹² Btus of Output)

	GAS EJECTOR	COOLING TOWER	TOTAL
CO ₂	10,448	706	11,154
NH ₃	---	660	660
CH ₄	660	---	660
H ₂ S	210	554	764
As	---	8×10^{-4}	8×10^{-4}
B	---	1.7	1.7
Hg*	---	5×10^{-5}	5×10^{-5}
H ₂	NA	83	83
H ₂ O	---	2.9×10^6	2.9×10^6
N ₁	---	---	410
Radon ₂₂₂	3.2×10^{-10}	---	3.2×10^{-10}

*Mercury emissions may be as high as 3.22×10^{-3} tons.

Source: The MITRE Corporation, 1977. Environmental Research Needs
 for Geothermal Resources Development. Volume I.
 MTR-7419. McLean, Virginia.

2.5.2 Operations and Maintenance Costs

Operations and maintenance costs at the Geysers were estimated to be 0.6 mills per kilowatt hour (DiPippo, 1978). This is equivalent to approximately \$175,000 (in 1976 dollars) per 10¹² Btus of output.

2.5.3 Fuel Costs

Unit 12 of the Geysers field purchases steam from the consortium that controls the field. This steam costs approximately 18 mills per kilowatt hour (Anspaugh, 1978) or \$5,272,000 (in 1978 dollars) per 10¹² Btus of output.

2.5.4 Abatement Costs

Costs of two systems, namely, the Peroxide and Ozone Systems, to treat the condensate at the Geysers to achieve a 99 percent removal of hydrogen sulfide are presented in Table 2-6. In both methods, 10 percent of the hydrogen sulfide concentration in the inlet flow is assumed to be dissolved in the condensate. It is also assumed that the power plant will be equipped with a surface condenser and the Stretford system to produce marketable sulfur from hydrogen sulfide.

Capital costs for the hydrogen sulfide abatement facilities are based on \$9 to \$11 per kilowatt of electricity for the Peroxide system and \$16 to \$35 per kilowatt for the Ozone System (DiPippo, 1978). This is equivalent to a mill rate of 0.233 to 0.258 mills per kilowatt-hour for the Peroxide System and 0.414 to 0.906 mills per kilowatt-hour for the Ozone System using a capital recovery factor of 0.17 and a capacity factor of 0.75. The costs do not include expenditures for retrofitting existing plants which could be excessive since replacement of the condenser may be required.

TABLE 2-6

ABATEMENT COSTS

COMPONENT	COSTS (in 1976 dollars)
Peroxide System	
Capital	401,000 - 490,000
Operation and maintenance (O&M)	126,000 - 454,000
Ozone System	
Capital	713,000 - 1,560,000
Operation and maintenance (O&M)	129,000 - 211,000

Calculations based upon 0.75 capacity factor and $4,458 \times 10^4 \text{ KW}_e/10^2 \text{ Btu}$.

Peroxide System

Capital: $\$9\text{-}11 \times 4.458 \times 10^4 = \$401,000 - \$490,000$

O&M: $10^{12} \text{ Btu} = 2.929 \times 10^8 \text{ KW hr} \times \frac{\$.43 - 1.55}{1000} = \$126,000 - \$454,000$

Ozone System

Capital: $\$713,000 - \$1,560,000$

O&M: $\$129,000 - \$211,000$

Source: DiPippo, Ronald, 1978. Geothermal Power Plants of the United States - A Technical Survey of Existing and Planned Installations. Brown University, Division of Engineering. Providence, Rhode Island.

Operating and maintenance costs for the abatement systems are based on 0.43 to 1.55 mills per kilowatt-hour and 0.44 to 0.72 mills per kilowatt-hour for the Peroxide and Ozone Systems, respectively.

2.6 References

Anspaugh, Dr. Lynn, 1978. Personal Communication. Lawrence Livermore Laboratory, Livermore, California.

Cossette, D.J., 1978. Personal Communication. Pacific Gas and Electric Company, San Francisco, California.

DiPippo, Ronald, 1978. Geothermal Power Plants of the United States - A Technical Survey of Existing and Planned Installations. Brown University, Division of Engineering. Providence, Rhode Island.

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U.S. Environmental Protection Agency, 1977. Western Energy Resources and the Environment, Geothermal Energy. (EPA-600/9-77010). Washington, D.C.

3.0 HYDROTHERMAL CONVECTIVE SYSTEMS, LIQUID DOMINATED

Hydrothermal energy extraction from liquid dominated reservoirs which are at relatively low temperatures must convert the brine in the field to steam. Three methods are currently under investigation:

- flash injection system
- binary system
- total flow system

In the flash injection technique, geothermal brine is converted to steam by sudden pressure reductions. Since the brine includes dissolved solids, the concentration of solids in the brine is increased by each flash cycle. The brine becomes more corrosive with increasing concentration of solids. Therefore, flash injection systems cannot be used in conjunction with fields with a high concentration of dissolved solids in the brine.

The binary system avoids the problem of increasing dissolved solids concentration by employing a heat exchanger to transfer heat from the brine to a secondary working fluid. This fluid, usually isobutane or isopentane, is used to drive a gas turbine. Generally, binary systems are of low efficiency due to heat transfer limitations.

The total flow system is similar to the steam turbine cycle except that it will operate on a mixture of liquid and vapor instead of steam alone. Many of the problems associated with the other two cycles, i.e., waste disposal and noncondensable gas emissions, are present in the total flow system as well.

Although there are no commercially operating liquid dominated generating systems in this country, several sites have been evaluated for utilization in the near future.

The Heber KGRA (Known Geothermal Resource Area) has been chosen as one site for development of a flash injected geothermal generating facility. The Heber KGRA has a downhole temperature of 180°C (360°F) with a dissolved solids concentration of 14,000 parts per million and a noncondensable gas content of 0.3 percent by weight (Bechtel, 1977).

3.1 Characteristics of Liquid Dominated Systems

A typical well field can be considered to consist of three subsystems:

- production well subsystem
- reinjection well subsystem
- distribution subsystem

The production well subsystem has two components, the well and the production island. The wells are slant drilled to about 6,000 feet at the Heber site. Each production island typically covers approximately two acres and contains up to 24 wells, sand settling tanks, cold brine dump pit, cold brine reinjection pump, an insulated brine header with valves, and associated wellhead equipment.

The reinjection wells are also drilled to approximately the same depth as the production wells. The typical flow rate of the reinjection well is assumed to be twice that of a production well. Thus, up to 12 reinjection wells would be located on each two-acre reinjection island. The islands also contain an insulated brine header. The

islands must be located within about two miles of the power plant and are usually on a common radius.

The collected brine enters the plant through the production pipe distribution subsystem where it is converted to electricity. Three major subsystems are involved:

- geothermal brine subsystem
- steam subsystem
- cooling subsystem

The geothermal brine subsystem supplies heat energy to the plant. In the steam subsystem, steam is produced by pressure reduction to 50 psia in first stage flash tanks. Additional steam is produced by second stage tanks which drop the pressure to 17 psia. Each tank includes a flashing device and a mist eliminator inside of the tank. The excess brine is mixed with cooling tower blowdown and reinjected to the field through the reinjection pipe distribution subsystem.

The steam from the flash tanks is expanded through Rankine open cycle turbines which in turn power electric generators. In the third subsystem, steam is conveyed to a condenser for cooling. Noncondensable gases are removed from the condenser by a jet ejector system. These noncondensable gases are passed through conventional hydrogen sulfide removal units. The remaining gas is vented to the atmosphere while the brine is reinjected via the distribution subsystem.

The condenser uses water from a cooling tower to cool the steam. This condensate water is sufficient to supply the needs of the plant, so no external water supply is necessary.

3.2 Operating Mode Efficiency

The plant design described here assumes that the brine temperature will remain constant over time. This is not strictly true since, in practice, the brine temperature will decrease over time. To accommodate the expected decline in geothermal brine temperature, two possible plant operating modes have been considered. The first mode maintains the power output of the plant constant over time by increasing the brine flow rate as the temperature decreases. The second approach maintains the power output of the plant over constant time while keeping the brine flow rate constant; this approach requires that the plant produce more power than its average output in the early stages of operation since actual output would decrease over time. At this time, no decision has been made as to which approach is preferred. Since the costs of the system depend on the choice of operating mode, it was decided for this study to assume constant brine temperature. Considering the averaging for this operating mode, no actual thermal conversion efficiency has been stated. (Ermak [1977] reported efficiencies of 8-14% for a 375°F-brine temperature.)

3.3 Constraints

3.3.1 Legislative Constraints

The legislative constraints on the development and operation of liquid dominated systems will be essentially the same as those for vapor dominated systems (see Section 2.2.1 above).

3.3.2 Siting Constraints

Unlike the vapor dominated system, there are numerous liquid dominated geothermal reservoirs available for commercial development in the U.S. Table 3-1 is a listing of liquid dominated sites that were included in the development scenario prepared by the Energy Research and Development Administration (ERDA) Division of Geothermal

TABLE 3-1

LIQUID DOMINATED HYDROTHERMAL SYSTEMS

LOCATION	PREFERRED PLANT SYSTEM
California	
Brawley	Binary
Coso Hot Springs	Flash
East Mesa	Binary
Geysers (liquid dominated portion)	Binary
Glass Mountain	Flash
Heber	Binary
Lassen	Flash
Mono Long Valley	Flash
Salton Sea	Binary or Flash
Surprise Valley	Binary
Hawaii	
Puna	Flash
Idaho	
Bruneau-Grandview	Binary
Raft River	Binary
Weiser-Crane Creek	Binary
Oregon	
Alvord	Binary
Mount Hood	Binary
Vale Hot Springs	Binary
Washington	
Baker Hot Springs	Binary
Arizona	
Chandler	Binary
Safford	Binary
Nevada	
Beowawe	Flash
Brady Hot Springs	Flash
Leach	Binary
Steamboat Springs	Flash

TABLE 3-1 (Concluded)

LIQUID DOMINATED HYDROTHERMAL SYSTEMS

LOCATION	PREFERRED PLANT SYSTEM
New Mexico Valles Caldera	Flash
Utah Cove Fort-Sulphurdale Roosevelt Hot Springs Thermo	Binary Flash Binary

Sources: The MITRE Corporation, 1978. Site Specific Analysis of Geothermal Development-Scenarios and Requirements. Volume II. MTR-7586. McLean, Virginia.

U.S. Energy Research and Development Administration, 1977. Environmental Development Plan: Hydrothermal Energy Systems. Washington D.C.

Energy (1977). Even though the data presented here are specific to the Heber site, plants of this type can be situated at any of these sites. Table 3-1 also shows the preferred type of plant for each site at the time of the ERDA study; these preferences may have changed as more analyses were performed.

3.3.3 Technical Constraints

The generally high dissolved solid concentrations found in geothermal brines, approximately 14,000 ppm (Bechtel, 1977), pose several problems in the development of hydrothermal reservoirs. The most severe problems are the buildup of solids scaling in the pipelines that convey the brine and the corrosion of these pipelines.

The major impact of scaling and corrosion is that many fields are restricted to binary cycle installations which cost more than flash injection systems because they employ expensive heat exchangers. The heat exchangers also result in an efficiency loss, adding to the cost of power production.

Another problem faced by hydrothermal development is the use of conventional drilling technologies. Use of these technologies can result in excessive costs that could inhibit hydrothermal development in many areas.

3.4 Resource Consumption

3.4.1 Energy Requirements

To produce 50 MW (net) of electricity the power plant requires 10.12×10^6 pounds per hour of brine at 338°F and 115 psia. The brine requirement per 10^{12} Btus of output is, therefore, approximately 2.96×10^7 tons.

3.4.2 Land Requirements

The generating plant site requires 10 acres (Ermak, 1977) or 8.9 acres per 10^{12} Btus of output. It is assumed that since the plant lifetime is 30 years this land is permanently committed.

Under the assumption of nondeclining brine temperature, the plant requires one production island of two acres and one reinjection island of two acres. Furthermore, no new islands need to be drilled over the plant lifetime. The total land use for wells is, therefore, 3.57 acres per 10^{12} Btus plant output. This land is also considered to be permanently committed.

3.5 Environmental Considerations

The environmental impacts of developing liquid dominated reservoirs such as at Heber are relatively the same as those at the Geysers. The extent of environmental damage caused by a geothermal power plant system depends entirely on the site and the type of plant.

The data presented in Table 3-2 consist of estimates of releases of air pollutants from proposed operations at the East Mesa KGRA. The data were obtained from Knox and Orphan (1977) and have been converted to tons per 10^{12} Btus of output.

At the Heber plant, all of the water pollutants are reinjected into the field; therefore, surface water contamination should be minimal (except from runoff). Table 3-3 is a list of potential pollutants associated with the reinjected brine. Surface runoff from construction and operation of the plant and well field system will also contribute to surface and subsurface water contamination, but as yet this contribution is unquantified.

TABLE 3-2

ESTIMATED EMISSIONS TO THE AIR FROM A
FLASH INJECTED SYSTEM
(East Mesa KGRA)

POLLUTANT	TONS PER 10 ¹² BTUS PRODUCED
Hydrogen sulfide (H ₂ S)	19.4
Ammonia	98.8
Methane	580
Carbon Dioxide	35,500
Arsenic	NA
Boron	NA
Mercury	0.1
Hydrogen	NA
Nitrogen, argon	NA
Water vapor	4.1 x 10 ⁶
Radon ²²²	5.69 x 10 ⁻¹¹ (7.3 curies)

Source: Knox, J.B., and R.C. Orphan, 1977. Program Report.
Atmospheric and Geophysical Sciences Division,
Physics Department, Lawrence Livermore Laboratory.
UCRL-51444-77. Livermore, California.

TABLE 3-3

POTENTIAL POLLUTANTS ASSOCIATED WITH REINJECTED BRINE

Carbonates	Calcium
Ammonium	Magnesium
SO ₂	Silicon
Sulfate	Boron
Sulfur	Total Dissolved Solids
Nitrate	Barium
Chloride	Copper
Iron	Lithium
Manganese	Lead
Strontium	Zinc
CO ₃	HCO ₃
Potassium	Arsenic

Source: The MITRE Corporation, 1977. Environmental Research
Needs for Geothermal Resources Development, Volume
I. MTR-7419. McLean, Virginia.

Since no plant of this type is in operation, the noise levels of the system are assumed to be similar to those at the Geysers. Table 3-4 gives a preliminary assessment of these levels.

3.6 Economic Data

3.6.1 Capital Costs

Table 3-5 provides a breakdown of the capital and labor costs for construction of a plant producing 10^{12} Btus of output. The estimates represent two costs for the turbine generator, a low cost of \$5,281,000 and a high cost of \$8,359,000. In addition to these costs, there is an engineering services cost of between \$2,426,000 and \$2,881,000 depending on the choice of turbine. These costs bring the total expenditure up to between \$23,318,000 and \$26,385,100. This is a cost of between \$528 and \$602 per kilowatt.

Table 3-6 lists the capital costs of drilling the well field needed to supply the 50 MWe plant. Thirteen production wells (or 11.6 per 10^{12} Btus output) and six reinjection wells (or 5.4 per 10^{12} Btus output) are required.

Based on these cost estimates, the total cost of constructing a plant at the Heber KGRA was estimated to be between \$36,876,000 and \$40,409,000 (in 1976 dollars) per 10^{12} Btus of annual output.

3.6.2 Operations and Maintenance Costs

Based on studies of operations and maintenance (O&M) costs for geothermal and fossil fuel plants, it is assumed that costs for the power plant are two percent of the capital costs (Bechtel Corporation, 1977). These costs are, therefore, approximately \$466,900 to \$537,000 (in 1976 dollars) per 10^{12} Btus of annual output.

TABLE 3-4

ESTIMATED NOISE LEVELS FOR
FLASH INJECTED SYSTEM

SOURCE	DURATION	DECIBELS (A)
Well construction	intermittent	high intensity
Well operation	intermittent	high intensity
Plant construction	2 to 4 years	medium intensity
Plant operation	30 years	low intensity

TABLE 3-5

PLANT CAPITAL COST IN THOUSANDS OF 1976 DOLLARS
(per 10¹² Btus annual output)

	MATERIALS AND EQUIPMENT	INSTALLATION	SUBCONTRACTS	TOTAL COST
Mechanical Equipment				
	5,281 to			5,986 to
Turbine Generator	8,359	705		9,064
Flash Tanks	276.5	8.9		285.4
Condensers	258.7	428.2	62.4	749.3
Cooling Tower		8.9	1141.8	1150.7
Pumps and Drives	1699.4	147.2		1846.6
Auxiliary Systems	379.1	84.6	89.1	553.0
Subtotal	7894.7 to 10972.7	1382.9	1293.4	10511.0 to 13649.0
Piping and Instrumentation				
Piping, valves and insulation	1596.8	1168.6	276.5	3041.9
Instrumentation and controls	820.7	249.8		1070.5
Subtotal	2417.5	1418.4	276.5	4112.4
Electrical				
Distribution Equipment	1204.3	187.3		1391.6
Cable and raceways	374.7	570.9		945.6
Lighting and Misc.	124.9	365.7		490.6
Subtotal	1703.8	1124.0		2827.8
Civil/Structural				
Turbine Building	455	660.1	624.4	1739.5
Site Improvements	169.5	205.2	44.6	419.3
Concrete & Earthwork	303.3	874.2	44.6	1222.1
Subtotal	927.7	1739.5	713.6	3380.9
	12943.7 to			20892.1 to
Total Construction Cost	16021.7	5664.6	2283.7	23969.7

Source: Bechtel Corporation, 1977. Advanced Design and Economic
Considerations for Commercial Geothermal Power Plants at Heber
and Niland, California. (Draft).

TABLE 3-6

COST OF CONSTRUCTING WELL FIELD
(per 10¹² Btus annual output)

WELL COMPONENT	NUMBER REQUIRED	TOTAL COSTS (in 1976 Dollars)	
Production Wells	11.6	Surface Equipment:	\$5,352,000
Production Well Islands	0.89	Wells:	<u>\$7,136,000</u>
Reinjection Wells	5.4	Installation Costs:	\$12,488,000
Reinjection Well Islands	0.89	Engineering Costs:	<u>\$1,070,000</u>
		Total Cost	\$13,558,000

Source: Bechtel Corporation, 1977. Advanced Design and Economic Considerations for Commercial Geothermal Power Plants at Heber and Niland, California. (Draft).

Table 3-7 lists the operation and maintenance costs for the well field per 10^{12} Btus of plant output. Based on these figures the total operation and maintenance cost of the system is between \$1,563,600 and \$1,638,340 (in 1976 dollars) per 10^{12} Btus of annual output.

3.7 References

Bechtel Corporation, 1977. Advanced Design and Economic Considerations for Commercial Geothermal Power Plants at Heber and Niland, California. (Draft).

Ermak, D.L., 1977. Potential Growth of Electric Power Production from Imperial Valley Geothermal Resources. (UCRL-52252). Lawrence Livermore Laboratory, Livermore, California.

Knox, J.B., and R.C. Orphan, 1977. Program Report. Atmospheric and Geophysical Sciences Division, Physics Department, Lawrence Livermore Laboratory, UCRL-51444-77. Livermore, California.

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U.S. Energy Research and Development Administration, 1977. Environmental Development Plan: Hydrothermal Energy Systems. Washington, D.C.

TABLE 3-7

WELL FIELD OPERATION AND MAINTENANCE
(per 10¹² Btus annual output)

Operating expenses		
Foreman and site managers' salaries and associated overhead	\$	62,400
Various other salaries, overhead, operating chemicals, and materials		<u>223,000</u>
Subtotal	\$	<u>285,400</u>
Maintenance expenses		
Production well maintenance	\$	579,800
Reinjection well maintenance		428,200
Surface facilities maintenance		<u>26,800</u>
Subtotal		<u>\$1,034,800</u>
Total		<u>\$1,320,200</u>

Source: Bechtel Corporation, 1977. Advanced Design and
Economic Considerations for Commercial
Geothermal Power Plants at Heber and
Niland, California. (Draft).