Assessing Geothermal Energy Potential in Upstate New York

Final Report
Tasks 1,3, and 4

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ABSTRACT

New York State's geothermal energy potential was evaluated based on a new resource assessment performed by the State University of New York at Buffalo (SUNY-Buffalo) and currently commercial technologies, many of which have become available since New York's potential was last evaluated. General background on geothermal energy and technologies was provided. A life-cycle cost analysis was performed to evaluate the economics of using geothermal energy to generate electricity in upstate New York. A conventional rankine cycle, binary power system was selected for the economic evaluation, based on SUNY-Buffalo's resource assessment. Binary power systems are the most technologically suitable for upstate New York's resources and have the added advantage of being environmentally attractive. Many of the potential environmental impacts associated with geothermal energy are not an issue in binary systems because the geothermal fluids are contained in a closed-loop and used solely to heat a working fluid that is then used to generate the electricity. Three power plant sizes were selected based on geologic data supplied by SUNY-Buffalo. The hypothetical power plants were designed as 5 MW modular units and sized at 5 MW, 10 MW and 15 MW. The life-cycle cost analysis suggested that geothermal electricity in upstate New York, using currently commercial technology, will probably cost between 14 and 18 cents per kilowatt-hour.

Keywords: Geothermal, energy, binary power, power plants, New York, electricity

ACKNOWLEDGMENTS

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INTRODUCTION

Geothermal energy is heat energy from the earth. Heat, originating from the earth's molten interior or from radioactive decay in the crust, is transported to the surface by deep circulation of ground water or intrusion of molten magma into the earth's crust. The origin and subsurface manifestation of this heat energy determines the type of geothermal resource it becomes. There are four types:

- **Hydrothermal** - heated groundwater and pore fluids
- **Hot dry rock** - hot rock with little or no water present
- **Geopressured** - overpressured hot fluids buried in permeable sedimentary rocks
- **Magma** - heat from molten or partially molten rock.

The only type of geothermal energy currently used in commercial applications is hydrothermal. Hydrothermal reservoirs are created when hot water and/or steam (30°C to 375°C) collect at depths of 200 to 3,000 meters. Fluids produced from these reservoirs are used either to generate electric power or for direct-use applications such as space heating, water heating, aquaculture, greenhouses, and industrial processing. Generally, the hotter, deeper hydrothermal resources are used for power generation, while the shallower, cooler resources are used for direct-use applications.

Geothermal electric power generation converts geothermal heat into electricity directly by using the geothermal fluids or indirectly by using the fluids to heat a secondary working fluid. A well is drilled into a geothermal reservoir, and the steam and/or hot water are piped to a power plant. At the plant, a turbine converts the geothermal heat into mechanical energy, which is then converted by a generator into electricity. For this process to be economical, a geothermal resource temperature of at least 150°C is usually required, although resource temperatures as low as 100°C can sometimes be used.

In the United States, geothermal electric development began in 1960 at The Geysers, a large geothermal steam resource located in northern California. Current installed capacity at The Geysers is 1,781 MWe from 22 operating units. Total installed capacity in 1995 was 2,725 MWe for the United States and 6,328 MWe for the world (see Table 1-1).

Table 1-1. International Geothermal Development.

NATION	EXISTING PLANTS	EXISTING CAPACITY (MW)	PLANNED CAPACITY (MW)
Argentina	1	0.6	0.0
Australia	1	0.2	0.0
China	11	23.4	0.0
Costa Rica	2	57.0	107.0
El Salvador	5	105.0	60.0
France	1	4.0	0.0
Greece	1	1.8	0.0
Guatemala	1	0.0	240.0
Iceland	6	50.6	0.0
Indonesia	6	307.3	1,957.0
Italy	25	548.7	344.0
Japan	12	297.3	230.0
Kenya	1	45.0	0.0
Mexico	28	731.6	260.9
New Zealand	4	283.0	141.0
Nicaragua	1	35.0	0.0
Philippines	25	1,076.7	1,124.0
Portugal	2	6.4	0.0
Republic of China	2	3.2	0.0
Russia	1	11.0	110.0
Thailand	1	0.3	0.0
Turkey	1	15.0	0.0
United States	77	2,725.9	112.0
Total	**215**	**6329.0**	**2321.9**

Direct-use applications often require drilling geothermal wells when the natural flow of hot springs is insufficient. In the United States, direct-use projects provide about 4,000 GWh of geothermal heat annually. Examples of direct-use applications in the United States include a large district heating system in Boise, Idaho; process heat for an onion dehydration plant in Brady Hot Springs, Nevada; and greenhouse heating in Newcastle, Utah.

The following subsections describe the four types of geothermal resources in greater detail and discuss the technologies used to generate electricity from hydrothermal resources. Evaluation of direct-use applications and non-hydrothermal technologies were not within the scope of this project.

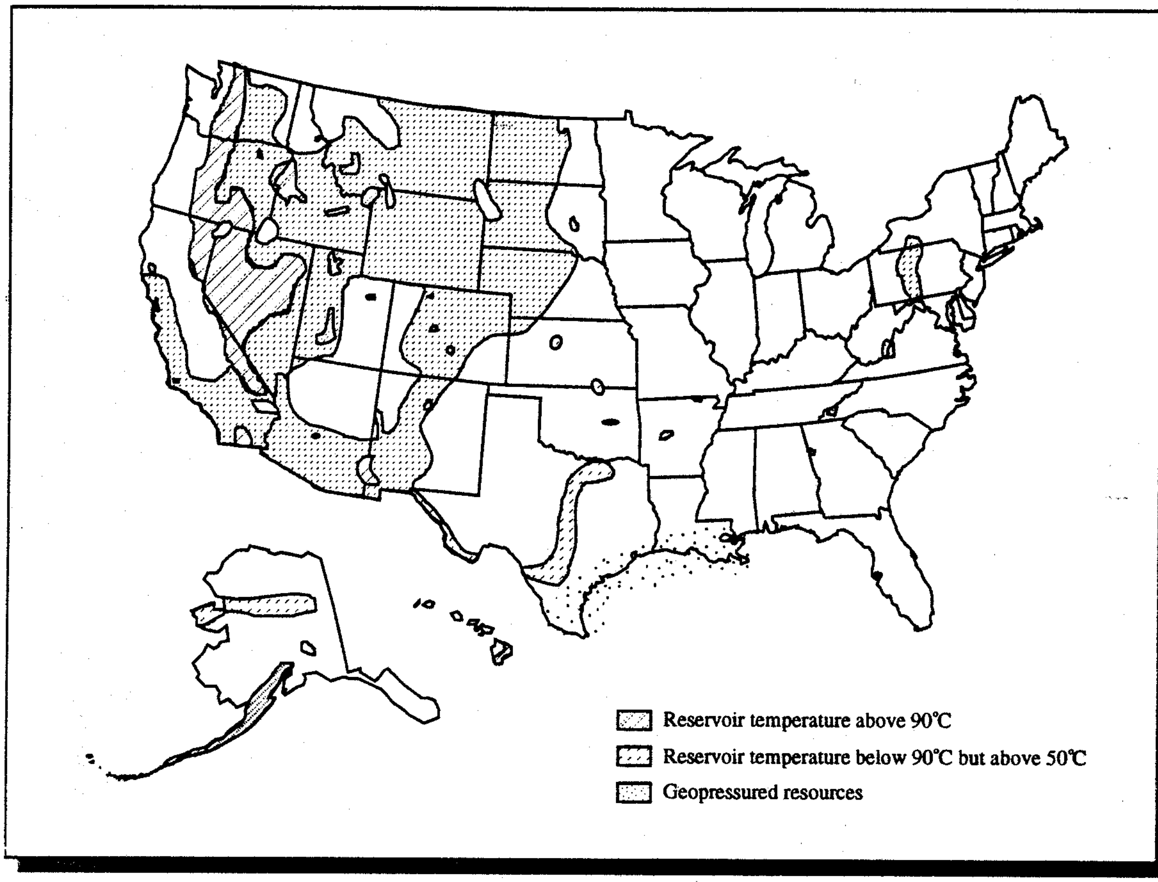
GEOTHERMAL RESOURCES

Geothermal resources are found where the earth's vertical temperature gradient is more than 70°C per kilometer. These regions may have some or all of the following characteristics: local magmatic disturbances; crustal thinning; aquifers heated to above-normal temperatures; and abnormally high proportions of radioactive rocks. High-temperature geothermal resources occur in well-defined areas, usually associated with recent seismic and/or volcanic activity. Low- to moderate-temperature resources occur at the margins of high-temperature resources, in basins with thick sediments, and where water is able to circulate along fractures to depths of several kilometers.

Indicators of possible geothermal resource areas include volcanoes, geysers, fumaroles, lava flows, mud pots, hot springs, hydrothermal alterations, and plutonic intrusions. In the United States, significant geothermal resources are located primarily in the western and Gulf Coast regions (see Figure 1-1). The total U.S. geothermal resource base is estimated to be as high as 1.5 million quads. One quad equals 10^{15} British thermal units.

There are four types of geothermal resources: hydrothermal, geopressured, hot dry rock, and magma. These resource classifications are based on geologic characteristics and on how heat is transferred to or near the earth's surface. Hydrothermal and geopressured resources are characterized by a heat source, a fluid to transport the heat from the rock to the earth's surface, and permeability in the rock sufficient to form a system to circulate the fluid. Hot dry rock and magma resources lack the second two components. The four resource types, as well as the potential for their occurrence in upstate New York, are further described in the following subsections.

Figure 1-1. U.S. Geothermal Resources.

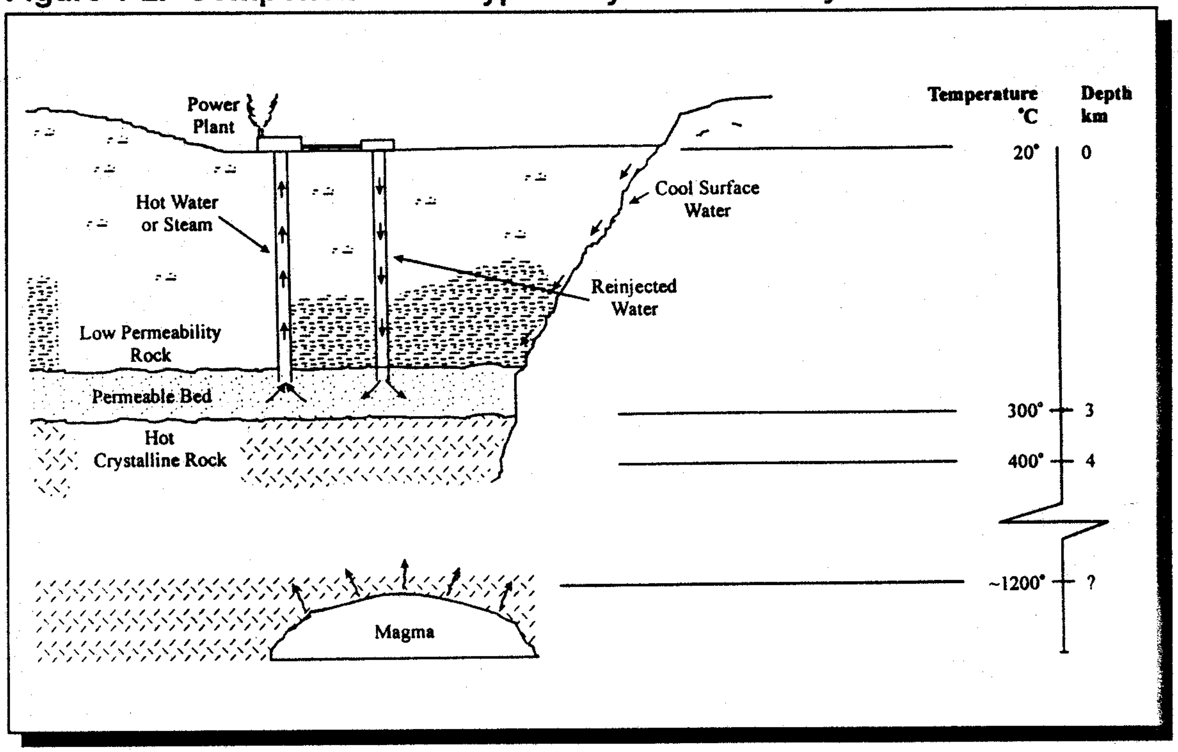


Hydrothermal

Hydrothermal resources consist of hot water and/or steam trapped in porous or fractured rocks at depths greater than 100 meters (see Figure 1-2). Hydrothermal resources are either vapor-dominated (also referred to as dry steam resources) or liquid-dominated (also referred to as hot water resources), based on the dominant phase of the geothermal fluid.

Vapor-dominated resources are the highest-quality hydrothermal resource. They consist of dry or superheated steam with little or no associated liquids and small percentages of other gases, such as carbon dioxide and hydrogen sulfide. Vapor-dominated resources are relatively rare. Worldwide, only five locations are under development: The Geysers in California, Larderello in Italy, Matsukawa in Japan, Los Azufres in Mexico, and Kamojang in Indonesia.

Figure 1-2. Components of a Typical Hydrothermal System.



Liquid-dominated resources are more common. They contain fluids with temperatures that range from less than 90°C to more than 350°C. Liquid-dominated geothermal reservoirs are created when groundwater circulating downward in open fractures becomes heated by deep, hot rocks. The water begins to rise until it is trapped by an impermeable zone, or caprock, often formed by the precipitation of minerals in the fractures and pore spaces.

Geothermal fluid, or brine as it is commonly called, has a chemical composition that is affected by the rock through which it circulates and by the fluid temperature. Geothermal brines are mainly sodium chloride solutions with varying amounts of dissolved potassium, calcium, silica, sulfates, and fluorides. As with vapor-dominated resources, noncondensible gases consist mostly of carbon dioxide and hydrogen sulfide. At least 53 liquid-dominated hydrothermal fields with fluid temperatures in the moderate to high range (over 150°C) have been identified in the United States. They include fields in California, Hawaii, Nevada, New Mexico, Oregon, Utah, and Alaska.

Upstate New York is known to have some hydrothermal resources. One such resource, discovered in Auburn, New York, has been developed for both space heating and water heating. Upstate New York's regional geology supports the presence of liquid-dominated hydrothermal resources with temperatures potentially high enough to generate electricity. However, the actual quality and quantity of the resources, and whether they are economically viable for power generation, remain undetermined.

Geopressured Resources

Geopressured resources are overpressured hot fluids deeply buried in permeable sedimentary rocks. These sedimentary rocks are covered by impermeable clay beds. As a result, the fluids in them become pressurized as overburden increases. Geopressured resources are characterized by low to moderate salinities, concentrations of dissolved methane, and temperatures in the low to moderate range (90°C to 200°C). Three sources of energy are available from geopressured resources: geothermal heat, mechanical energy from the great pressure with which these waters exit the borehole, and recoverable methane.

The best-known geopressured region is found onshore along the northern Gulf of Mexico region of the United States. Other geopressured regions in the United States include the San Joaquin-Ventura-Los Angeles Basin region and the Santa Barbara Channel-Tanner Banks area in California, the Green River Basin in Wyoming, and the Anadarko-Ardmore Basin in Texas and Oklahoma. To date, there is no geologic evidence in upstate New York that indicates the possible presence of geopressured resources.

Hot Dry Rock

Hot dry rock (HDR) resources are water-free, low-permeability rock formations heated by conduction from nearby magma bodies. HDR resources exist throughout the world, but generally the more accessible resources are located in young volcanic areas. These rocks have few pore spaces or fractures, so they contain little water and little or no interconnected permeability. Therefore, development of HDR resources requires creation of an artificial fracture system and circulation of water from the surface through the system.

Artificial reservoirs have been created experimentally by hydraulic stimulation, the pumping of high-pressured water down a well to open pre-existing fractures. To extract heat from the rock, water is circulated down an injection well. As the water migrates through the artificially fractured rock, it absorbs heat. The water is then recovered through one or more production wells and the heat is used to generate electricity. The water is then reinjected back into the first well in a closed-loop system and the process started over again. These systems have been demonstrated in research projects in the United States, Europe, and Japan. However, they are not currently used commercially because of technical and economic uncertainties.

Hot dry rock resources have not been discovered in upstate New York. The relatively low geothermal gradients typical for the region suggest that such resources, if present, would only exist at depths currently too great to warrant economic viability.

Magma

Magma resources consist of molten or partially molten igneous rock with temperatures ranging from 700°C to 1,200°C in areas at drillable depths (less than 10 km). Magma energy extraction is highly experimental. The concept involves drilling a well into the magma and circulating surface water down one pipe of a well where it is heated before returning to the surface through a second pipe in the same well. The feasibility of this concept was tested by an experimental U.S. Department of Energy well drilled into a shallow lava lake in Kilauea Iki Crater, Hawaii. However, with current technology, the development of magma resources is not economical. Major technical barriers include difficulties in locating shallow magma bodies, the high cost of deep wells, and a lack of materials that can withstand the extremely high temperatures and corrosive nature of magma. The low geothermal gradients and regional geology of upstate New York make the presence of magma resources extremely unlikely.

GEOTHERMAL TECHNOLOGIES

Technologies to develop a hydrothermal field for electric power generation fall into two broad categories. **Extraction technologies** (sometimes referred to as well field technologies) remove the geothermal heat from the earth. **Conversion technologies** (sometimes referred to as power plant technologies) generate electricity from the heat.

Most geothermal extraction technologies are adapted from the petroleum industry, and most conversion technologies are based upon conventional steam turbine technology. This section discusses technologies currently available to develop geothermal resources for electric power generation. The status of extraction technologies is reviewed, including geothermal exploration and confirmation, drilling, and reservoir engineering. The three types of geothermal power systems—dry steam, flash steam, and binary cycle— are discussed. Three new and near-commercial conversion technologies are also briefly described. Auxiliary conversion technologies related to condensing and cooling are discussed along with treatment of noncondensible gas and brine.

Extraction Technologies

Geothermal extraction technologies identify geothermal resources, establish their feasibility for development, and manage production in order to optimize the amount of geothermal energy that can be extracted from the reservoir.

Exploration and Confirmation. Exploration and confirmation identifies the geothermal resource and establishes resource size, depth, and potential production rates. An initial reconnaissance phase identifies potential geothermal prospects based on regional data. Afterward, more detailed exploration and confirmation studies determine the economic and technical feasibility of the identified prospects.

In the reconnaissance phase, the regional geology and fracture systems are studied to identify areas likely to contain geothermal reservoirs. Data for this phase come from various sources, including:

- regional geologic and geophysical maps;
- satellite imagery;
- geochemical sampling of thermal and non-thermal waters and gases;
- analysis of surface rocks and soils;
- aerial photography; and
- measurements of thermal gradients in existing wells.

The detailed exploration and confirmation studies develop an empirical geologic model that represent the prospect's expected geothermal reservoir and production characteristics. The model is based on data collected through detailed geological mapping, geophysical surveys, drilling shallow thermal gradient wells, and drilling and testing intermediate depth "slim hole" wells. It is continuously refined as more data become available.

If the geologic model indicates a promising resource, a full-sized diameter wildcat well is drilled and flow tested. Based on the success of the flow tests, additional production wells are drilled to confirm and further delineate the resource. If the additional wells are successful, the geothermal energy project proceeds into the design, financing, and construction stages.

Geothermal exploration and confirmation combines technologies adapted from the petroleum industry with innovative new technologies specifically designed for geothermal applications. Many technologies are used in an integrated program to identify and delineate the geothermal resource:

- **Surface Geological Mapping** defines the surface distribution of rock varieties, age relationships, and structural features.

- **Geochemical Surveys** chemically analyze water and gas samples from thermal and non-thermal springs and wells in the interest area.

- **Geothermometers** estimate subsurface temperature using mathematical calculations based on the concentrations of dissolved chemical species in surface waters.

- **Electrical Resistivity Surveys** measure the distribution of the electrical resistivity in the subsurface to identify the most likely locations of actively convecting geothermal cells.

- **Self-Potential (SP) Surveys** measure the electrical voltage variations on the earth's surface caused by high geothermal gradients, the movement of thermal fluids, and the existence of hydrothermally altered rocks.

- **Magnetotelluric (MT) Surveys** measure variations of natural electric and magnetic fields deep in the earth's crust caused by changes in porosity in reservoir rocks, changes in the degree of rock alteration, and elevated temperatures.

- **Seismic Surveys**
  - -- Active surveys artificially generate elastic shock waves to provide information on the composition and structure of the subsurface.
  - -- Passive surveys implant instruments just below the surface to gather subsurface data by monitoring natural microearthquake activity.

- **Magnetic Surveys** map variations in the earth's magnetic field to detect anomalies that may be due to temperature variation.

- **Gravity Surveys** measure variations in the geothermal field to identify the subsurface locations of denser and lighter rocks. Gravity highs indicate dense, igneous rocks commonly found in the vicinity of geothermal systems. Gravity lows indicate structural basins in which thermal fluids can collect.

- **Thermal Gradient Well Drilling** measures the temperature gradient in wells drilled 30 to 600 meters deep with a diameter of about 10 cm or less. Gradients in excess of 4° per 100 meters are considered significant for geothermal development.

- **Exploratory Drilling**
  - -- Slim hole wells provide geologic, temperature, and chemical data for the conceptual geologic model.
  - -- Wildcat wells provide geologic, chemical, physical, and reservoir data from a production sized well.

- **Confirmation Drilling** usually involves three to five wells. They are used to collect reservoir data needed to develop and guide development drilling.

Geothermal Drilling. Geothermal wells are drilled in conditions ranging from soft rock and high-scaling fluid environments to hard rock formations having extremely high temperatures. Well designs, materials, and drilling practices must account for the expected formation and fluid characteristics. Electric power generation systems usually require two types of wells. Production wells are used to extract the geothermal fluids that are then used in the power plant to generate electricity. Injection wells are used to return the geothermal fluids to the reservoirs after they have been used.

Rotary drilling rigs are the primary technology used to drill geothermal wells. This technology is adapted from the petroleum industry to handle the generally harsher conditions associated with geothermal drilling. The major differences between geothermal well drilling and oil or gas well drilling are:

- Temperatures of geothermal fluids may reach 400°C, compared to 200°C for typical deep oil or gas wells. The high temperatures and the temperature-elevated reactivity of corrosive chemicals in the rocks and brines cause rapid degradation of ordinary drilling equipment and drilling fluids.

- Production pressures for geothermal reservoirs are usually low, in many cases sub-hydrostatic, causing the reservoirs to become plugged if ordinary drilling muds are used.

- Geothermal formation rocks are harder and more abrasive than most oil or gas formation rocks, often causing faster degradation of drill bits and tubular materials.

- High temperatures cause elongation or expansion of the wellhead and casing, which must be considered when designing the drilling program.

- Unlike oil or gas wells, where casing is cemented only in the production intervals, geothermal wells must be cemented from top to bottom to control the effects of casing elongation or expansion due to temperature changes.

- Geothermal fluid production rates are very high with 100,000 to 500,000 kg/hr compared to 100 to 6,500 kg/hr for oil or gas. Geothermal wells, therefore, must have larger diameters at depth and be cased in ways that minimize erosion.

Although considerable progress has been made in overcoming these technical differences, geothermal drilling costs remain two to four times higher than those for a typical oil or gas well. Additional factors and operations that affect drilling and completion costs of geothermal wells include:

- running slotted production liners;

- repeated occurrences of lost circulation;

- frequent conventional fishing operations in a high-temperature environment;

- disposal or reinjection of geothermal fluids;

- well testing; and

- H_2S gas production during air or aerated drilling.

Two promising areas of R&D that may significantly reduce drilling costs are lost circulation control and directional drilling. Lost circulation results from drilling fluids invading the rock around a wellbore during drilling. Lost circulation often occurs in geothermal wells because geothermal production zones are relatively underpressured and often intersect at unpredictable intervals. Sandia National Laboratories has developed and is presently testing advanced cement packers that could significantly improve the sealing of lost circulation zones. Especially promising is the drillable straddle packer, a downhole tool for isolating and directing the flow of cement. It is designed to maximize the volume of cement delivered to a lost circulation zone and minimize dilution of the cement remaining in the wellbore.

The petroleum industry's directional drilling technologies and techniques are being investigated for application to geothermal's generally harder rocks and higher temperatures. If successful, directional drilling of geothermal wells could reduce costs through:

- enabling simpler and cheaper fluid gathering systems;
- reducing land use;
- reducing rig-moving time by drilling multiple wells from a single pad; and
- improving productivity by increasing the chances of intersecting major fractures by drilling wells perpendicular to the reservoir formation fractures.

Reservoir Engineering. Reservoir engineering consists of formation evaluation, reservoir modeling, and reservoir management. Reservoir engineers use the physical characteristics of a geothermal reservoir to guide development of the reservoir and estimate its probable capacity and longevity. These studies start during the exploration phase and continue for the productive life of the field. They form the foundation for planning the development of the reservoir.

Reservoir engineering research addresses issues such as:

- the ability of a reservoir to sustain the power plant;
- the quality and location of production and injection wells;
- well completion depth;
- production and injection rates for individual wells; and
- the use of pumps to prevent flashing in the borehole.

New sensors, improved logging tools, and analytical software are gaining widespread use in gathering data to support these activities.

Formation evaluation determines the properties and flow characteristics of the reservoir rock, identifies major fluid-bearing fractures and permeable rocks, and evaluates reservoir/well interactions. Formation evaluations may include some or all of the following:

- analyses of well logs, drill cuttings, and drill cores to derive reservoir parameters such as permeability, porosity, and fracture characteristics;
- borehole televiewer, caliper, and spinner (flowmeter) logs to confirm the presence and depth of fractures that may be major entry points for steam and hot water;
- experimental geophysical and geochemical techniques employing surface surveys and downhole instrumentation to locate and map fractures and other geologic features;
- analysis of the deep origins of reservoirs using large-scale seismic arrays that record the patterns of seismic waves passing through and beneath the reservoir;
- magnetotelluric analysis of the reservoir structure;
- monitoring and analyzing injected tracer return patterns to determine fluid flow in the reservoir;
- laboratory analyses of reservoir rocks and fluid samples to determine their constituent properties; and
- pressure-transient well tests to determine the controlling flow and storage capacity of the formation, and to delineate reservoir boundaries and heterogeneity.

A reservoir model is developed early in the production stage and is periodically refined with additional production experience and data. The model simulates the geologic structure, permeability, heat flow, fluid content, and migration of the reservoir. Recent improvements in reservoir modeling emphasize simulation of fracture-based permeability. A variety of methods are used, including the following:

- conceptual geological modeling to define the geometry and physical properties of the system;
- numerical simulation of reservoir behavior during production and injection;
- geochemical modeling to analyze changes in reservoir fluids and rocks, and to predict the movement of chemical fronts through the reservoir in response to production and recharge;

- computer analysis of well test data to determine key reservoir parameters; and
- wellbore simulation to analyze fluid flow and heat transfer inside the well.

Reservoir management begins with the initial production and continues through the entire production life of the geothermal resource. Effective management requires proper:

- well field design and operation to optimize production and injection well locations and depths;
- production and injection rates;
- production methods (flashed flow versus pumped); and
- production and injection control and data gathering systems.

Proper reservoir management ensures sufficient production for the life of the project and avoids overdevelopment, which reduces the overall field productivity.

Conversion Technologies

The three types of commercial geothermal power systems (dry steam, flash, and binary) are described. New, near-commercial innovations of flash and binary systems are also discussed. Finally, ancillary systems for handling noncondensible gases and brine and for cooling and condensing the geothermal fluids are discussed.

Geothermal conversion technologies are adapted conventional steam-powered generation technologies that account for the lower quality heat, lower pressure, corrosive nature, and environmental considerations of geothermal steam and brines. The type of conversion system is determined by the reservoir temperature, pressure, and fluid phase. Conventional steam turbine systems, adapted for lower temperatures and pressures, are used for vapor-dominated resources. Flash technology is mostly used for high-temperature, liquid-dominated resources. Binary technology is used for moderate temperature, liquid-dominated resources. In all cases, evaporative cooling is the most cost- effective cooling method, but areas that lack sufficient water may require more expensive dry cooling technologies.

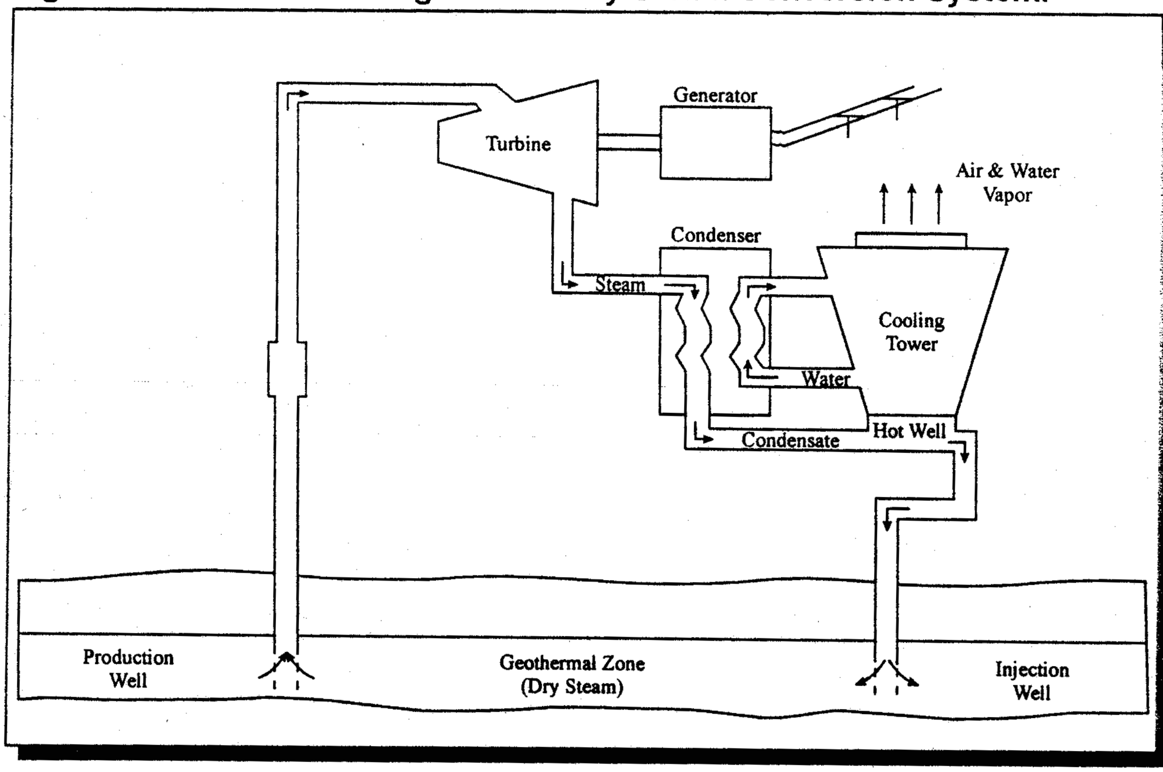
A comparison of working fluid, temperature range, typical plant capacity and cost for each conversion technology is shown in Table 1-2. Unit costs for geothermal power plants vary considerably with temperature and brine chemistry. High levels of dissolved solids and noncondensible gases, particularly hydrogen sulfide, increase both capital and operating costs. Important innovations to conversion technologies in recent years include modest increases in efficiency and reductions in cost for flash and binary cycle power plants, improved materials to withstand corrosive brines, and better methods to avoid problems with precipitation of dissolved solids.

Table 1-2. Typical Parameters for Geothermal Conversion Systems.

Conversion System ($/kW)	Working Fluid	Reservoir Temperature (°C)	Plant Size (MW)	Capital Cost ($)
Dry Steam	NA	240	20-80	1,500-2,000
Flash	NA	175-300	5-40	2,000-2,500
Binary	iso-pentane	150-200	3-30	3,000-3,500

Dry Steam Technology. Dry steam systems are the most cost effective conversion technologies due to the high enthalpy of vapor-dominated reservoirs (see Figure 1-3). Steam, extracted at the well head, is used to drive a turbine. As the steam condenses, its volume decreases, creating a pressure drop across the turbine that helps turn the turbine blades. The rotational energy is then converted to electrical energy by a generator. A

Figure 1-3. Schematic Diagram of a Dry Steam Conversion System.

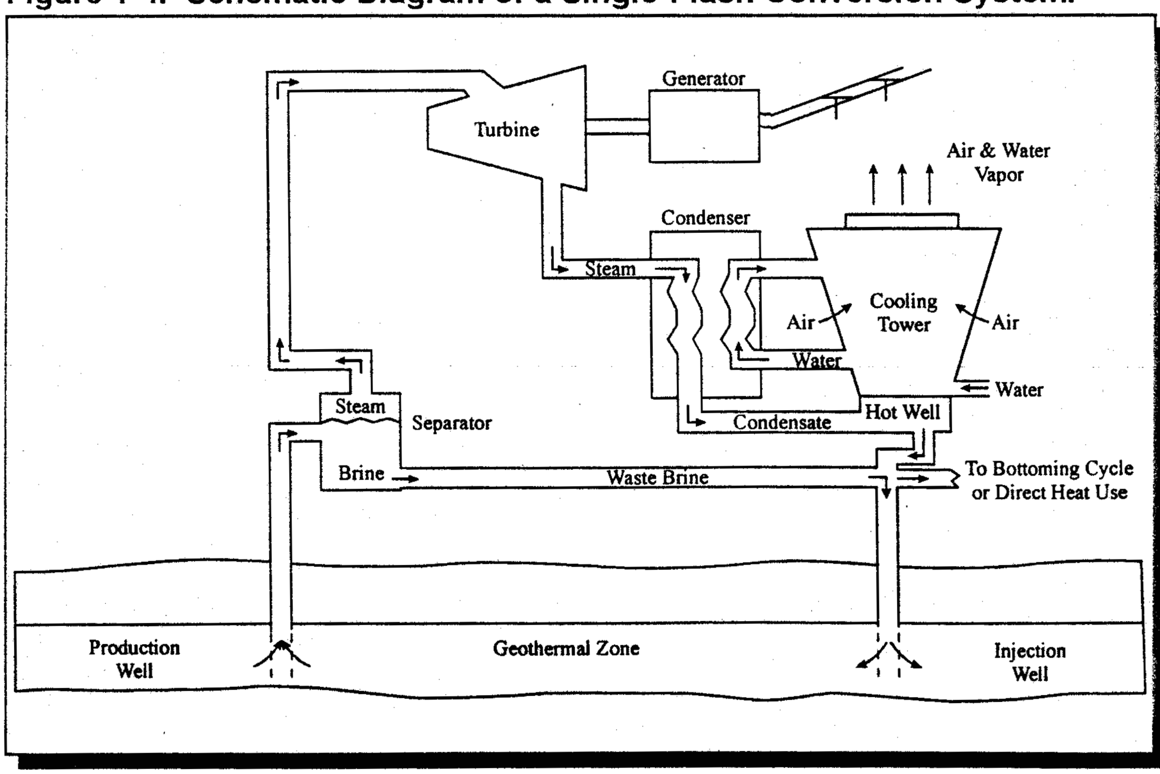


portion of the warm condensate is circulated to cooling towers. Some of the cooled brine is used by the condenser while the remainder is injected back into the reservoir. There, the brine aids in maintaining pressure in the reservoir and prolonging resource life. Hydrogen sulfide (H_2S) gas, if present, must be removed prior to the discharge of noncondensible gases into the atmosphere.

Dry steam technology is only used for vapor-dominated geothermal resources. However, these are very rare with only five fields currently under development worldwide. The only dry steam field in the United States is The Geysers, in northern California. The Geysers became the first geothermal field developed in the United States when its first plant began operation in 1960.

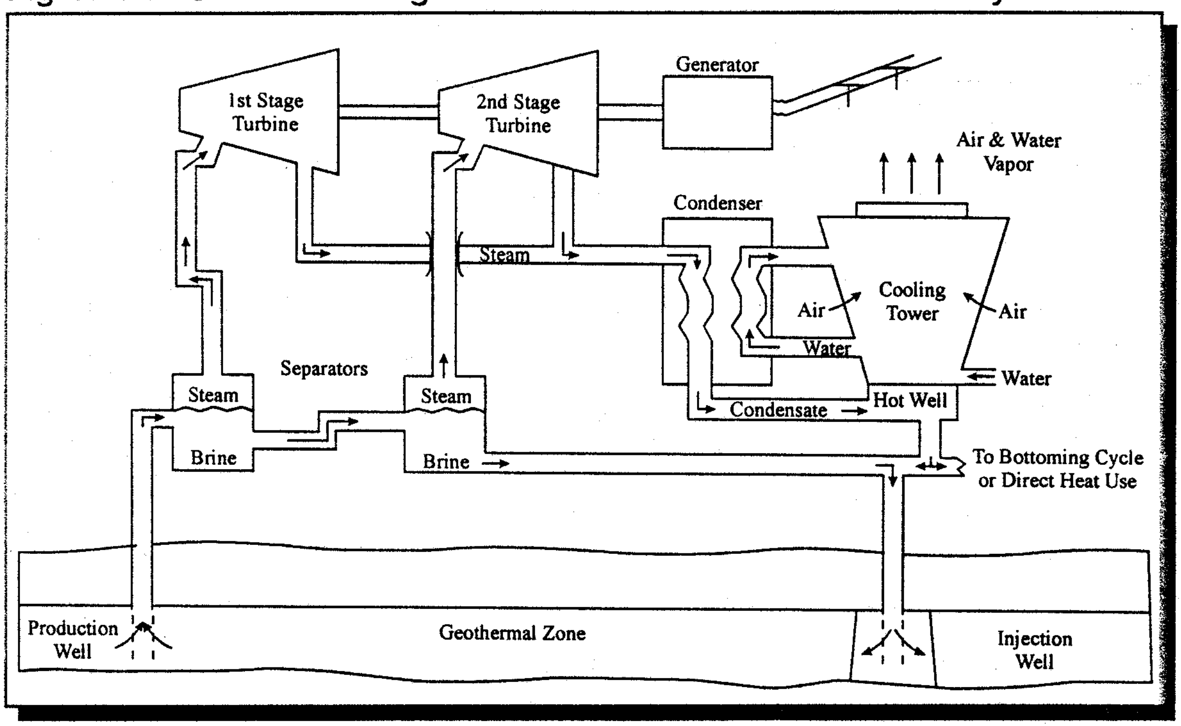
Flash Steam Technology. Flash steam technology is used when the geothermal fluid is hot enough (> 170°C) to "flash" a significant percentage of liquid into steam when the pressure of the brine is reduced. There are two types of flash systems, single flash and double flash. In a single-flash system, the geothermal brine passes through a separator or flash vessel where a reduction in pressure allows the fluid to boil or "flash" to steam. The steam is separated from the remaining hot water and routed through a turbine and condenser similar to those employed in the dry steam conversion process just described. Figure 1-4 schematically illustrates the process.

Figure 1-4. Schematic Diagram of a Single-Flash Conversion System.



Typically, about 15 to 20 percent of the fluid is vaporized, and most of the remaining hot water is injected back into the reservoir to maintain reservoir pressure and longevity. Some of the hot water may be cooled in the cooling towers to provide additional water for the condenser. If the resource temperature is high enough, a double-flash process can improve system efficiency 10 to 20 percent. The double-flash process passes the hot water from the first separator through a second, lower pressure separator where the water flashes again. The turbine is equipped with the appropriate blading and inlets for separate high-pressure and low-pressure steam supplies. Figure 1-5 presents a schematic diagram of the process. Double flash, because it is more efficient than single flash, is the dominant technology used to develop high temperature, liquid-dominated resources in the United States.

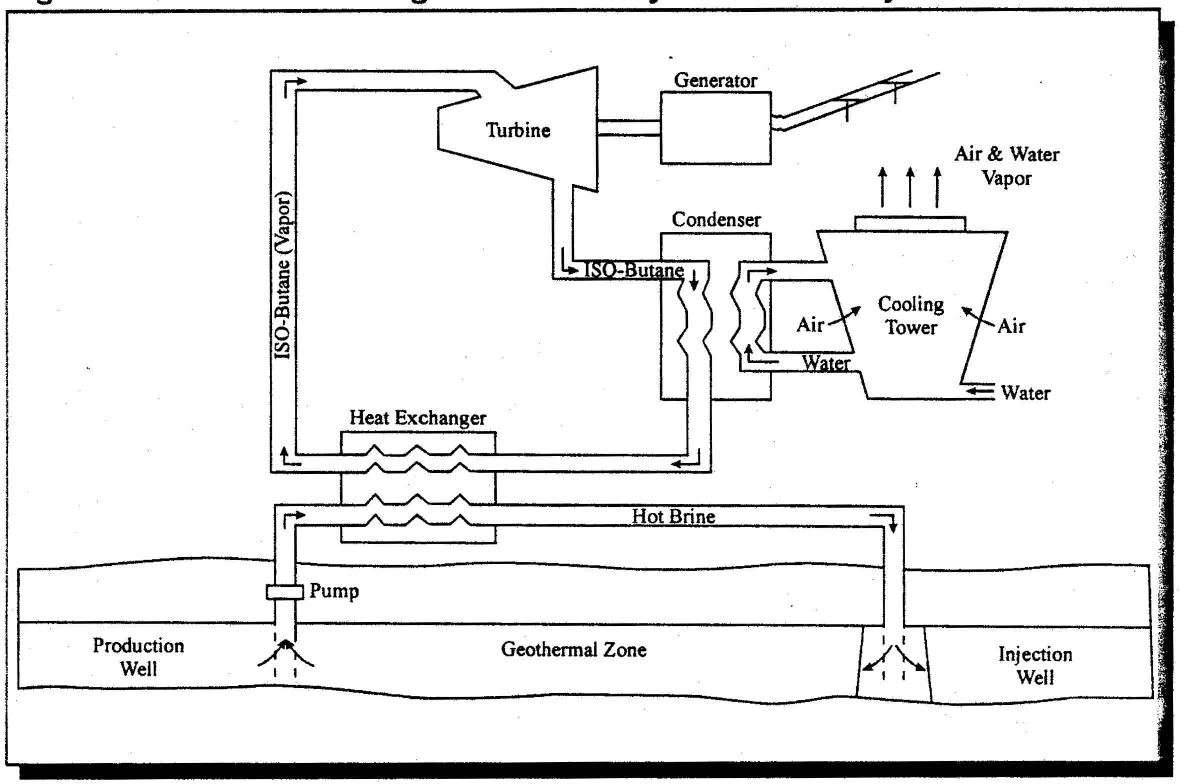
Figure 1-5. Schematic Diagram of a Double-Flash Conversion System.



Binary Cycle Technology. The binary cycle is the most efficient conversion process for moderate temperature, liquid-dominated resources ranging from 150°C to 200°C. Smaller units have been built with resource temperatures as low as 100°C, although these are generally economical only if the alternative is an expensive off-grid option such as diesel-powered generation.

Binary systems employ two separate fluids - the geothermal brine and a secondary working fluid with a low boiling temperature (usually an organic hydrocarbon such as isopentane). The geothermal brine is pumped from wells through a heat exchanger where the heat contained in the brine vaporizes a separate working fluid. From the heat exchanger, the cooled geothermal fluid is injected back into the reservoir, and the working fluid is expanded through the turbine, condensed in a water- or air-cooled condenser, and then routed back to the heat exchanger in a closed loop. A schematic of this system is presented in Figure 1-6.

Figure 1-6. Schematic Diagram of a Binary Conversion System.



The advantages of the binary system are its applicability to lower temperature resources, minimal atmospheric emissions, and reduced scale and corrosion problems since the brine remains within a closed, pressurized system. The disadvantages are fire hazards with the organic hydrocarbon working fluid and higher capital costs than the other systems.

New Innovations. Three innovations are expected to significantly improve the efficiency of current conversion technologies. They are a low temperature flash turbine, a rotary separator turbine, and the Kalina cycle, a new binary technology. The three are described below.

Low Temperature Flash Turbine. Traditionally, flash steam plants have not been considered for geothermal resources below about 170°C because lower temperatures required greater amounts of brine (higher flow rate) to produce enough steam. Current steam turbines used in flash systems cannot handle these higher flow rates.

The low temperature flash turbine is being developed to enable a flash steam plant to operate at temperatures as low as 110°C. This turbine is a split flow turbine that allows steam entering near the top of the turbine housing to flow in both directions through single- stage expanders at both ends of the turbine. Two of these turbines can be coupled together and to a single gear box-generator unit. Preliminary results indicate that a 5 MW flash system using this new turbine design and a 110°C brine can be built for about 37 percent less (excluding well field costs) than a conventional binary system of the same size.

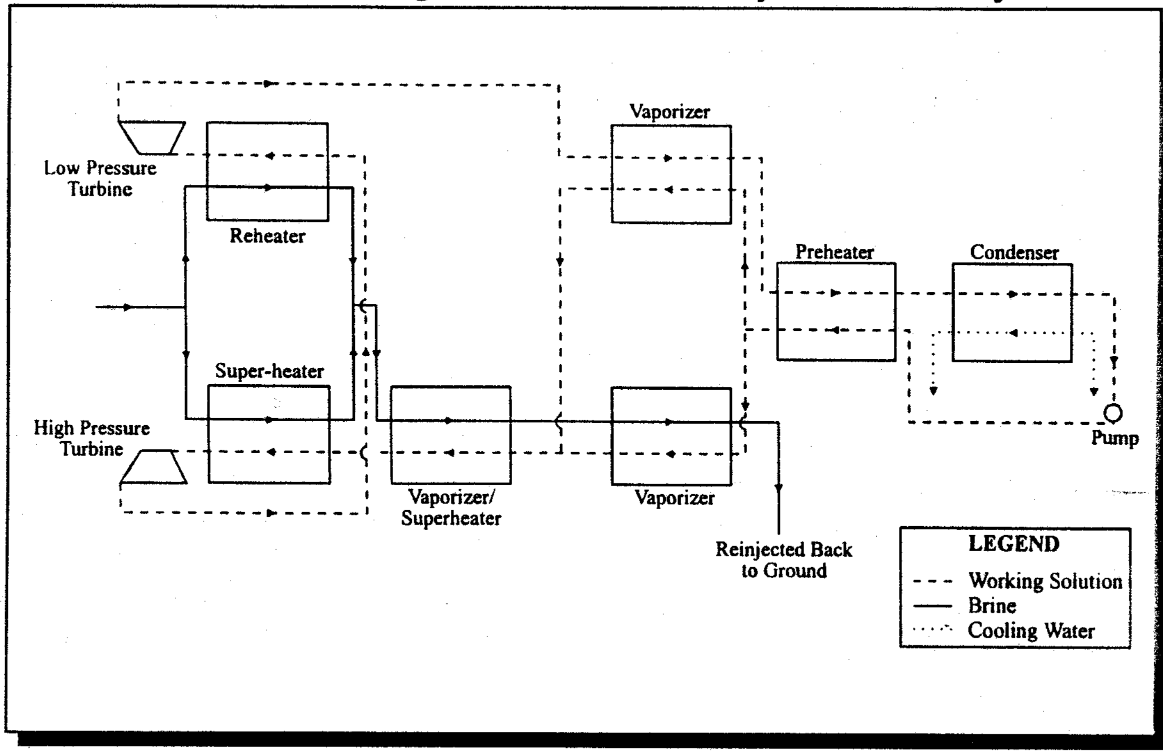
Rotary Separator Turbine. The rotary separator turbine is designed to capture a portion of the kinetic energy that is lost in the separator when the fluid pressure is reduced during the flash process. The rotary separator could be used in place of the first separator vessel in a flash system. The brine is expanded through a nozzle into a rotating drum where the liquid is impinged on a frictionless rotating wheel to generate shaft work. The steam is separated in the drum and routed to the turbine. The rotary separator turbine can potentially increase efficiency of a single-flash system by about 15 to 25 percent.

Kalina Cycle. The Kalina conversion cycle is a binary conversion process that has been proposed for use with geothermal resources. The Kalina conversion cycle uses an ammonia aqueous solution as the working fluid, instead of organic hydrocarbons. The composition of the aqueous solution is varied at different points in the system to best match the point process (boiling or condensing). The system includes two turbines (high and low pressure), recuperative heaters, superheaters, and preheaters to increase efficiency. The process is diagrammed in Figure 1-7.

Feasibility studies suggest the Kalina cycle can increase the efficiency of a binary cycle system by 20 percent. Although the Kalina cycle has not yet been demonstrated with a geothermal heat source, a small Kalina cycle demonstration plant has been operating on waste heat at Castoga Park in California. Until a geothermal Kalina plant is demonstrated in full scale, its performance and capital costs remain uncertain.

Condensing and Cooling. The thermodynamic efficiency of geothermal power plants is low when compared to conventional steam plants. Therefore, efficient cooling and condensing systems are critical for geothermal

Figure 1-7. Schematic Diagram of a Kalina Binary Conversion System.



plants. The heat from a geothermal power cycle results almost entirely from condensation of the turbine exhaust vapor. Cooling and condensing technologies for geothermal power plants are similar to those for conventional power plants.

Both wet and dry cooling tower designs are available but the wet design is preferred because of its higher efficiency and lower capital cost. Improvements in power plant cooling tower technology, such as advanced evaporative and dry cooling technologies, have gained momentum in recent years. Following are descriptions of condensing systems and wet and dry cooling techniques used in geothermal plants.

Condensers. Two types of condensers are used in geothermal systems: the direct-contact condenser and the surface condenser. A typical single-fluid direct-contact condenser sprays cooling water into the turbine exhaust steam, and condensation occurs on the water droplets. Two-fluid surface condensers, used for binary systems, employ a tube and shell construction to keep the working fluid and cooling water separate. Condensation of the turbine exhaust occurs as heat is transferred through the separating surface to the cooling water. Direct-contact condensers tend to be simpler in design than surface condensers, and have lower initial costs. In addition, there are less leakage problems than with surface condensers, and little maintenance is required.

Early geothermal plants in the United States employed barometric and low-level direct-contact condensers. More recently, plants have shifted to using shell and tube surface condensers with the steam or other working fluid typically in the shell side and the coolant flowing through the tubes. The shell and tube condenser is also preferred where H_2S abatement is required since higher H_2S partitioning (80 to 90 percent) is achievable. Surface condensers are most commonly used in larger power plants. In binary cycle systems, surface condensers are used to separate the working fluid and the condenser coolant.

Wet cooling. Wet cooling tower designs vary depending on the type of water surface (droplets vs. film), the arrangement of the water and air flows (crossflow vs. counterflow), and how the air flow is created (mechanical draft vs. natural draft). Wet cooling towers in geothermal applications are generally cross flow, mechanical draft (air forced by fans) designs. Natural draft cooling towers are seldom employed in U.S. geothermal applications because they are best suited for very large installations and they do not function well in climatic conditions typical of U.S. geothermal resource areas (high wet-bulb temperatures and low relative humidities.)

Dry Cooling. Dry cooling technologies are increasingly used because of increased water resources limitations and environmental constraints. In the case of dry cooling, the cooling tower is the condenser. In dry cooling towers, the heat to be rejected from the power cycle is transferred through the walls of an air-cooled heat exchanger to raise the dry-bulb temperature of the air stream. Mechanical-draft is used most often, although natural-draft towers that use existing air currents are sometimes constructed. In a mechanical-draft arrangement, the turbine exhaust is ducted to an extended-surface, air-cooled heat exchanger. In the indirect system, the exhaust vapor from the turbine is condensed by a coolant circulated through the condenser and to the dry cooling tower where the heat is transferred in extended-surface, air-cooled heat exchangers. Dry cooling towers are usually custom designed and fabricated by the individual engineering firm involved with the plant design and construction.

Noncondensible Gases. The existence of noncondensible gases can be problematic for flash and dry steam plants. Since these gases cannot be condensed, their presence decreases the power plant's efficiency. Removal of the noncondensible gases from the condenser, using gas ejectors or vacuum pumps, can improve efficiency 4 to 10 percent depending on their concentration.

One of the primary noncondensible gases found in geothermal fluids is hydrogen sulfide. In order to keep hydrogen sulfide emissions within regulatory limits, some plants must include hydrogen sulfide abatement systems. These abatement systems increase the capital cost of a plant by approximately 15 percent. Hydrogen sulfide is usually not a problem at binary plants because the geothermal fluid is confined to a closed system. Any hydrogen sulfide present is injected back into the ground rather than released into the atmosphere.

Brine Handling. Problems associated with handling geothermal brines include scaling (deposition of dissolved solids on equipment) and corrosion. The extent of how these problems affect the design, maintenance, and longevity of wells and surface equipment depends on the brine chemistry.

Research in materials development and brine chemistry has resulted in several techniques to avoid or mitigate these problems, including:

- scale-inhibiting chemicals to reduce carbonate scaling of flashing wells;
- acidization approaches ("pH modification") to control silica scaling in power plants;
- highly accurate computer models to estimate and predict chemistry effects in geothermal systems; and
- polymer cement coatings to reduce corrosion in heat exchangers and process piping.

Scaling. Geothermal brines may contain chemicals, such as silica or calcium carbonate, that cause scaling problems when they precipitate as temperatures decrease during flashing or heat exchange. Brines saturated with these chemicals often foul heat exchangers; precipitate in flash tanks, surface pipes, and injection wells; and plug the reservoir rock around injection sites.

Two technologies, the crystallizer-clarifier and pH-modification, are used to control silicate scaling. The crystallizer-clarifier process forces precipitates to form on seed crystals injected into the first flash tank. The precipitates are then extracted from the brine effluent stream, dried, and removed to a landfill. Precipitate removal eliminates the need to stop plant operations for scale removal and can significantly increase the longevity of injection wells.

The pH-modification process adds hydrochloric acid to the brine to reduce its pH from 5.9 to about 5.0, keeping the silica and other elements in solution. The potentially higher cost of corrosion-resistant materials needed for this process is offset by the cost savings from eliminating some of the added equipment required by the crystallizer-clarifier system. Similarly, some of the added operating costs that come with acid use are offset by eliminating the crystallizer-clarifier's solids disposal costs.

Calcium carbonate tends to precipitate whenever brines flash into steam while in production wells. When this occurs, calcite scaling rapidly chokes off the flow. Downhole pumps can be used in lower-temperature resources (less than 205°C) to keep the brine at a pressure high enough to prevent flashing. However, higher-temperature resources must periodically remove scaling in equipment and wells by reaming or acid treatment.

Another practice for reducing scaling in flashing wells is to use high-temperature, scale-inhibiting chemicals. The inhibitors are injected through small-diameter tubing lowered into the well to a depth below the flashing point. These chemicals typically reduce the cost of controlling carbonate scale by approximately 45 percent.

Corrosion. Geothermal brines frequently contain dissolved solids and gases that originate from fluid interaction with the host rock. Some of these dissolved solids, such as hydrogen chloride, hydrogen sulfide, chloride, and sulfate, are corrosive. Corrosive brines cause material failures such as stress-corrosion cracking, hydrogen embrittlement, and corrosion fatigue. Proper material selection and appropriate sizing of pipe and vessel walls are crucial to controlling corrosion and minimizing material failure.

Periodic corrosion/material performance evaluations are also conducted at power plants because the chemistry of geothermal brines can vary significantly over the life of a geothermal plant. The evaluation results assist material selection for replacing power plant components and provide information about the ability of materials to survive anticipated chemical environments.

Brine Injection. Spent, cooled brines in most geothermal fields must be injected back into the reservoir, primarily to maintain reservoir pressure and secondarily to avoid surface and groundwater pollution. The location of injection wells within the three-dimensional network of fractures that form a reservoir is critical to the successful exploitation of a field. Ideally, the brine is injected into an area of the reservoir that will allow full reheating of the injected brine before it migrates to a production well. A poorly designed injection program lowers the temperature of produced brine, resulting in reduced power generation. An understanding of the reservoir characteristics, especially the reservoir's geometry and the orientation of its fractures, is crucial to proper location of injection wells.

SECTION 2
ECONOMIC ANALYSIS

INTRODUCTION

This chapter discusses the economics of geothermal electric power generation and presents the results and methodology of a life-cycle cost analysis of electric power generation from geothermal resources in upstate New York. A preliminary study of the state's geothermal resources was conducted by the geology department of the State University of New York (SUNY) at Buffalo. The geologic study identified a target geothermal zone 19 miles east of Elmira, New York, in the Theresa geologic formation, at a depth of about 10,000 feet. Data from the geologic study is used to simulate the development of a hypothetical binary geothermal power plant based on commercial technology.

A spreadsheet model simulates the development and analyzes the costs of the hypothetical project. The spreadsheet model consists of three separate modules:

- Well field design, development, and cost module;
- Power plant design, construction, and cost module;
- Economics module to integrate the well field and power plant costs into a levelized life cycle cost of power.

The well field design, development, and unit costs are similar to those of geothermal power facilities constructed by the geothermal industry in the western United States. The power plant design and cost estimates are supplied by Barber-Nichols Engineering, a geothermal binary equipment manufacturer. The estimates are based on commercially available and proven geothermal power generation equipment suited for resource temperatures similar to the New York resource. The financial module calculates the levelized life-cycle cost of electricity using the revenue requirements methodology defined by the Electric Power Research Institute.

The following section provides a general discussion of factors affecting the cost of geothermal electric power. It is followed by a description of the methodology used to analyze geothermal electric power generation in upstate New York. Finally, the results of the analysis are presented and discussed.

GEOTHERMAL POWER ECONOMICS

For any electric power project, the type of fuel to be used largely determines the design of the plant and the economics of the project. For a geothermal electric plant, the geothermal reservoir is the fuel supply, and the characteristics of that reservoir influence the design of the facility and the economics of the project.

Five resource characteristics have the greatest influence on design and cost. They are resource depth, resource temperature, resource flow capacity, resource chemistry and resource location. Other circumstances have a lesser effect on the cost. These include things such as cost of capital, climate (cooler ambient air temperatures improve the thermodynamics of conversion), developer's experience, environmental considerations, etc.

Resource Depth

The greater the depth of the resource, the more expensive it is to drill wells to access the resource. Drilling costs increase exponentially with depth. Generally, geothermal project economics will not support drilling deeper than about 6,000 feet. Deeper resources may be economic if they contain high enthalpy geothermal fluids and have high permeability to support large flow rates.

Resource Temperature

The greater the temperature of the geothermal fluids, the more efficient the conversion to electricity, and the less geothermal fluid required to produce a given amount of electricity. Thus, fewer wells and less equipment are required.

Resource Flow Capacity

A greater flow capacity results in greater flow per well, reducing the number of wells required, and consequently reducing the cost for a given plant.

Resource Chemistry

The chemistry of geothermal fluids varies widely. Some are chemically benign, while others contain greater quantities of dissolved solids (minerals and salts) and noncondensible gases (primarily carbon dioxide and hydrogen sulfide) and require additional equipment, materials, or processes to control or avoid related problems. The problems include the formation of scale (scaling) in the reservoir and in pipes and plant equipment, corrosion, reduced efficiency due to noncondensible gases (primarily carbon dioxide and hydrogen sulfide), and toxicity and unpleasant odors related to H_2S (hydrogen sulfide). Scaling occurs when reductions in pressure and temperature of the fluid cause the precipitation of dissolved solids from the fluid. These precipitated solids build up inside pipes and other processing equipment, restricting flow and reducing efficiency. Scaling is controlled by maintaining the pressure of the geothermal fluid and by injecting acid into the fluid as it enters the production well.

At some flash and dry steam plants, the steam contains levels of noncondensible gases that require their removal. Also, where hydrogen sulfide (H_2S) emissions exceed regulatory limits, abatement is required. Both removal and abatement processes increase capital and operating costs. Capital costs for H_2S abatement systems are typically 15 to 20 percent of the total plant cost (excluding field costs). Noncondensible gases are generally not problematic at binary geothermal plants because the geothermal fluid remains in the liquid state and is confined to a closed system before it is injected back into the reservoir. If a binary plant employs wet cooling, a portion of the produced brine may be used for cooling water, and H_2S emissions may be a consideration.

Resource Location

Electricity can be transported more economically than geothermal fluids, motivating the location of geothermal power plants at the resource site. Consequently, the construction of a connecting transmission line from the site to the nearest existing power transmission line is required. The cost of the connecting line may be incurred wholly by the developer or shared between the developer and the utility. In either case, the cost may significantly affect project economics.

The costs of building transmission lines vary widely depending on the size, length, number of circuits, and the type of terrain and region of the country. Costs are highest where the terrain is mountainous or where population is dense. Line construction costs are higher in the Northeast than in other regions of the country.

In addition, a location in rugged, mountainous terrain can increase the costs for building roads and pipelines and for site preparation.

ANALYTICAL METHODOLOGY

The analytical methodology simulates a hypothetical geothermal power project and calculates the levelized life-cycle cost, or unit price, of electricity for the project. The analysis follows a logical progression beginning with a determination of the capacity of the reservoir to support electric power generation based on the reservoir parameters estimated by SUNY. An appropriate plant is then designed, and costs for its construction are based on estimates of a U.S. geothermal binary equipment manufacturer and developer (Forsha, et al., 1991). The well field is then designed based on the fluid flow requirements of the plant, reservoir parameters, and analysis of the reservoir capacity. Estimates of the cost for developing the well field are based on the experiences of geothermal developers in the western United States. Cost estimates for the plant and well field include both capital costs and operation and maintenance costs. These costs are integrated into a levelized life cycle cost using revenue requirements methodology defined by the Electric Power Research Institute (EPRI TAG, Vol. 1 and 3, 1993 and 1991). All costs are based on proven technologies that are commercially available.

The capacity of the reservoir is determined using a methodology developed by the United States Geological Survey (Brook, et al., 1978). In the methodology, the reservoir thermal energy per unit volume is calculated based on the volumetric specific heat of the rock and reservoir fluids and the difference between the reservoir fluid temperature and a reference temperature. Assuming a heat recovery rate from the reservoir and a rate of efficiency for converting the recovered heat to electrical energy, the electric capacity of the reservoir is calculated on a volumetric basis. Details of this methodology are included in Appendix A.

The life-cycle cost analysis is executed within an Excel spreadsheet consisting of three integrated modules, one each for the well field, power plant, and economics calculations. The key assumptions inherent in the model are listed below, followed by a brief description of the three modules. The modules are described in greater detail in Appendix B.

Key Assumptions

Some key assumptions are inherent in the methodology. Many of these assumptions, such as the value of the discount rate, are obvious in the spreadsheet (see Appendix C). Other assumptions are described in this section.

Accurately predicting reservoir performance requires specific geologic and reservoir data provided by drilling and flow-testing several wells in the reservoir. Some of these data are unavailable for the target reservoir area in upper New York state. Therefore, SUNY, in its geologic analysis, assumes the existence of a relatively homogenous fracture system with a permeability of 100 millidarcies, based on a general knowledge of the geology of the Theresa formation. For perspective, this results in a reservoir flow capacity (permeability times reservoir thickness) of 43,600 millidarcy-feet, compared to reservoirs developed in the western United States in which flow capacities of 100,000 to 500,000 millidarcy-feet are not unusual.

The reservoir thickness is known, but data for determining the area of the reservoir are unavailable. A practical limit of two miles is assumed for the maximum distance between the power plant and any production well. This limitation determines the area of the reservoir available to the plant and limits the size of the plant based on the productive capacity of the reservoir within this defined area.

Exploration activity is assumed to include two full-sized production wells, one successful and one unsuccessful. However, the exploration cost of $8 million includes only the cost of the unsuccessful production well. The cost of the successful exploratory production well is included in the aggregate cost of all the production wells.

Intangible well costs are assumed to be 75 percent of the total well cost, and the well completion cost is assumed to be 30 percent of the total well cost.

The design of the plant is based on conventional rankine cycle, binary technology with an iso-pentane working fluid. It assumes the availability of water for cooling purposes and incorporates a shell and tube condenser with wet cooling tower. H_2S emissions are assumed to be below regulatory limits, and thus no abatement system is included. The plant is assumed to consume approximately 25 percent of the generated power for its parasitic load.

The economic analysis assumes a constant, base load generation of power, with a capacity factor of 0.80 over the life of the project.

Power Plant Module

The Power Plant Module is based on commercially available and proven geothermal, binary power generation technology. Most of the power plant component costs in the module are estimated by Barber Nichols Engineering, a U.S. geothermal binary equipment manufacturer and plant developer. The module lists and sums the capital costs (per net kW) for the power plant components and their construction. It also includes rates for fixed and variable plant operation and maintenance costs, construction loan, profit, and contingency. Annual fixed O&M for the plant is a percentage of plant capital costs and is expressed as $/kW. The variable O&M cost, also a percentage of plant capital costs, is expressed as mills/kWh. The cost of a connecting transmission line from the plant to the nearest existing transmission system is estimated based on an assumed length. Details of the power plant module are presented in Appendix B.

Well Field Module

The Well Field Module determines the extent, timing, and costs of field development based on the experience of geothermal developers in the western United States. Total drilling costs are calculated based on the number and timing of initial production wells, injection wells, and makeup wells. Drilling costs are separated into tangible costs, which are capitalized, and intangible costs, which are expensed. Operation and maintenance costs are separated into a fixed component, expressed as $/kW/yr, and a variable component, expressed as mills/kWh. The capital costs for pumps are calculated depending on the number of wells, and the cost of the gathering system is calculated based on the number of wells and their distances from the plant. All field capital costs are summed for use in the economics module. Details of the Well Field Module are presented in Appendix B.

Economics Module

The Economics Module employs revenue requirements methodology to calculate the levelized cost of electricity for the hypothetical project. The method was developed by the Electric Power Research Institute and is widely used by the electric utility industry to assess the economic consequences of alternatives. The revenue requirement is the amount of revenue required from a project to compensate the utility for all expenditures associated with the project. In other words, the net present value of the required revenues equals the net present value of the costs. The revenues are equal to the unit price of electricity times the amount of electricity projected to be sold over the life of the project. Thus, if the costs over the life of the project are known, the unit price of electricity can be calculated.

The levelized costs are denominated in 1995 constant dollars. The revenue requirements methodology incorporates federal and state income taxes, as well as property taxes. However, the exact treatment of taxation, including depletion allowances, alternative minimum tax, etc., varies widely between companies and projects and is beyond the scope of this project. Details of the Economics Module are included in Appendix B.

RESULTS AND CONCLUSIONS

A conventional rankine cycle, binary power system is chosen as being the most suitable, commercially available technology for the moderate temperature of the resource. The design is based on iso-pentane as the working fluid, and incorporates a tube-in-shell condenser and wet cooling for the heat rejection.

Analysis of the geologic data indicates that the reservoir capacity is 4.9 MW per cubic kilometer, or one MW per 7.5 square kilometers of reservoir area. Based on the maximum limit of two miles between the power plant and any well, the power plant design is limited to 15 MW at any given facility. For this reason, the plant design is based on a 5 MW modular power plant, and the analysis includes simulations for plants of 5, 10, and 15 MW.

The model results in a levelized busbar cost ranging from 18.4 ¢/kWh for the 5 MW plant to 14.8 ¢/kWh for the 15 MW plant. The levelized costs are stated in 1995 constant dollars. A more detailed summary of the results is presented in Table 2-1. These busbar costs are considerably more than the 3 - 7 ¢/kWh range of busbar costs for geothermal power plants developed in the western United States and are far from being competitive with avoided costs of approximately 3 ¢/kWh reported by many United States utilities in 1995.

Table 2-1. Economic Model Results

Plant Size Net MW	Power Plant Costs (excludes transmission line costs)			Well Field Costs			Levelized Busbar Cost Constant 1995$ ¢/kWh
	Total Cost $k	O&M Costs		Total Cost $k	O&M Costs		
		Variable Mills/ kWh	Fixed $/kW-yr		Variable Mills/ kWh	Fixed $/kW-yr	
5	9,408	2.7	47	41,448	2.96	52	18.4
10	18,816	2.7	47	65,199	2.33	41	15.9
15	28,223	2.7	47	85,911	2.04	36	14.8

The high busbar costs are primarily the result of the combination of three factors: low reservoir temperature, low reservoir flow capacity, and great reservoir depth. Any of the three alone would not necessarily render a project uneconomic. For example, with a high-temperature, high-flow rate reservoir, fewer wells are required for a given plant. This would consequently reduce the aggregate cost and possibly justify the higher cost per well for deeper reservoirs. Due to the combination of these factors, the cost of the well field is inordinately high. The ratio of well field costs to power plant costs in the model is about 3 to 1 for the 15 MW plant. In the western United States, experience has typically resulted in values ranging from about 0.3 to 1.0 for this ratio.

In Table 2-1, note the decreasing busbar costs for increasing plant size. An economy of scale is inherent in the model design, although the model does not incorporate explicit algorithms for this purpose. It is the consequence of exploration and transmission system costs remaining constant regardless of the plant size.

Printouts of the three modules for the 5, 10, and 15 MW power plants are included in Appendix C, and a table of the model variables and formulas is found in Appendix D.

Power plant engineers are proposing new binary plant designs that may reduce plant capital costs by 25 percent to 40 percent. The designs are based on a pure ammonia or aqueous ammonia solution as the working fluid. These new designs have not been demonstrated in commercial applications and were therefore not considered for this project. Successful demonstration of these designs could lead to their eventual application to geothermal power generation in New York. However, because of the high cost of field development relative to the plant cost, as demonstrated by this model, any reduction in the cost of electricity due to the application of such designs would probably not exceed 10 percent.

SECTION 3
POTENTIAL IMPACT ASSESSMENT

INTRODUCTION

This section outlines the environmental considerations, impacts, and potential impacts of developing geothermal electricity generation in general and the more specific issues related to installing the hypothetical plant used in Section 2. The hypothetical plant is a binary cycle design, which is the best suited technology for the target reservoir identified in the geology assessment. The target reservoir was identified by the State University of New York at Buffalo (SUNY-Buffalo) as part of the resource assessment they performed for this project. A general discussion of the environmental impacts and issues is followed by a more detailed discussion of plant siting and land use requirements, water quality issues, air quality issues, and hazardous wastes.

GENERAL ENVIRONMENTAL IMPACTS

The environmental impacts of generating electricity from geothermal resources are relatively benign compared to more conventional power generation options. Geothermal power generation does not generate the federally regulated air contaminants commonly associated with power generation—sulfur dioxide, particulates, carbon monoxide, hydrocarbons, and photochemical oxidants.

The primary environmental impacts of geothermal power development are potential discharge of fluids with high levels of dissolved solids and emission of noncondensible gases. Dissolved solids, primarily sodium chloride (salt) can potentially contaminate surface or subsurface fresh water supplies. However, in most cases, groundwater contamination is not a major concern since most geothermal power systems are now designed to reinject the spent fluids back into the producing reservoir. At the Salton Sea geothermal resource in California, where high levels of dissolved solids are found in the geothermal fluid, some of the flash power plants employ a process to precipitate and remove the dissolved solids. The process creates a silica sludge which, at times, contains heavy metals in concentrations sufficient to classify it as hazardous waste.

The other concern is hydrogen sulfide (H_2S). This noncondensible gas is a nuisance at low levels because of its unpleasant odor, but more importantly, it can become toxic at high levels. Noncondensible gases must be separated from the steam, and H_2S abated if they are above regulatory limits. Whether H_2S becomes an issue in upstate New York depends entirely on the fluid chemistry of the area's resources.

The degree of environmental impacts and potential impacts depends on the size and type of geothermal power project. Geothermal power plants tend to be smaller than fossil-fueled and nuclear power plants. In the United States the largest single geothermal plant is 137 MW, and the average plant size is around 45 MW. With larger plants, land and water use requirements increase, and the potential impacts on air and water quality increase.

Binary power systems, such as the hypothetical power plant modeled in this study, are generally the most environmentally advantageous of all geothermal power systems. In binary plants the geothermal brine is confined to a closed system, eliminating or greatly reducing the potential for contamination of fresh water supplies or emission of associated gases. Also, binary plants use lower temperature fluids which usually contain less dissolved solids and noncondensible gases.

PLANT SITING AND RELATED LAND USE ISSUES

Geothermal plants are typically located at the resource in order to take maximum advantage of the fluid temperatures as they are produced from the wells. Another siting consideration is the proximity of existing power transmission lines. Geothermal resources developed close to existing transmission lines result in much lower costs since they do not require long connecting lines.

Land use issues associated with geothermal power plants include possible interference or competition with adjacent land uses, impacts on biological systems, noise, subsidence, and aesthetics. Actual land use requirements for geothermal power plants depend on the size of the plant and on the productivity of the resource. Larger plants generally require more land, not only for the plants themselves, but also for the well fields needed to supply larger volumes of fluid.

Siting

Siting of geothermal power plants is complicated by the need for the plant to be at the resource location. If the geothermal resource is located with other resources (cultural, agricultural, timber, etc.) siting is more difficult and additional requirements and permits may be imposed.

Requirements for siting any industrial facilities in New York state are outlined in the state's Master Application Procedure. This procedure is designed to facilitate identification of state permits that will be required for a specific project. While use of the form is voluntary, it provides a preliminary indication of siting requirements that may be imposed as the project proceeds.

The Project Plot Plan that is submitted to the Governor's Office of Regulatory Reform must clearly indicate the adjacent municipal or state parks, proximity to registered historic property, designated local waterfront, coastal erosion zones, wetlands and water, and other local features. Western geothermal power plants have repeatedly had to adhere to stringent mandated environmental siting requirements. Many western geothermal power plants are located on federally owned land, governed by the regulations of the Federal Bureau of Land Management and/or the United States Forest Service. These agencies require the submission of operating plans, including a detailed layout of operations and proposed measures to control or mitigate air and water pollution, noise, land subsidence, and other potential adverse effects of development.

In addition, explanation must be given of how the proposed facility fits into the aesthetics of the proposed site, and it must be verified that archaeological values do not exist. If they may exist, where land is to be disturbed, steps must be taken to survey and salvage such values before operations may begin. The geothermal industry has met these criteria in a variety of settings—historic areas, desert, mountains, and highly scenic forested areas.

Land Use

Geothermal energy's requirement for the entire cycle of operations from extraction to reinjection to be located at the resource site minimizes land use. The land requirements vary with the size of the plant and the number of supporting wells needed. For example, a 100 MW unit at The Geysers steam field in northern California is estimated to require approximately 275 acres total land use, with between 28 and 56 acres being permanently disturbed for access roads, well locations, pipelines, and plant site.

Because wells are spread out, geothermal power plants occupy a larger land area than is disturbed by their presence. The United States Forest Service estimates only 6 to 14 percent of the land at The Geysers dry steam plant and from 3 to 13 percent of several hot water plants studied is actually disturbed (United States Forest Service, 1983). In general, the total land needed for flash and binary geothermal plants is about 20 acres per megawatt (California Energy Commission, 1989).

Compatibility With Other Land Values

Early concerns regarding the potential interference of geothermal projects with the use of adjacent land have been proven unfounded. When geothermal development was first proposed in the Imperial Valley of California, there was strong opposition based on the belief that development would interfere with agriculture, the valley's major industry. An assessment of the impact of geothermal development (United States Dept. of Energy, 1980a and 1980b) indicated that the environmental effects of such development would be minimal. In its 15th year of geothermal development, irrigated crops in the Imperial Valley now extend right to the property lines of the power plants. This is also true in Larderello, Italy, where geothermal power plants and agricultural developments have coexisted for over 50 years.

The compatibility of geothermal plant operations with scenic and recreational areas is illustrated by the presence of three binary plants near Mammoth Lakes, California. Mammoth Lakes is located in one of the least populated areas in the country but is a major ski resort attracting over one million visitors annually. Tourism is the only major industry in the area and is the county's major source of income. Overcoming considerable public opposition, the project developer has succeeded in building a very unobtrusive facility by designing the plants with a low profile, painting the plant exterior to blend in with the landscape, and using dry cooling towers to eliminate the steam plume associated with most power generation facilities.

More recently, a proposed geothermal project on the flanks of Newberry Volcano in the Deschutes National Forest, Oregon, has met local opposition based on competing land values. It will be located in a scenic area that is heavily dependent on both the tourism and timber industries. In collaboration with the United States Forest Service, the developer was able to dispel local opposition through a program of community outreach that included both education and community involvement in setting the guidelines for geothermal development in their area. This successful program could serve as a guide for consensus building requirements in upstate New York.

Impacts on Biological Systems

Land disruptions, erosion and sedimentation, air and water pollution, and increased levels of noise and human activity associated with geothermal development inevitably cause some disturbance to fish, vegetation, and wildlife in the vicinity of the development. The extent and long-term consequences of impacts on biological systems depend on the chemistry of the geothermal fluids and the type of conversion technology employed. The impacts can be reduced by conscientious operation practices and appropriate pollution control technologies.

On average, 20 percent of the land leased for geothermal development is changed sufficiently in character to affect habitat. Of this 20 percent, half is devoted to permanent buildings, roads, and facilities that require the replacement of original vegetation by impervious surfaces. Also, vegetation near steam pipelines, transmission lines, facilities, and drilling pads must be kept cleared or limited. The loss of vegetation can result in reduced cover and nutritional support for wildlife, changes in soil temperature and moisture, and increased erosion. Increased erosion leads to greater suspended solids and sedimentation in streams and lakes, adversely impacting aquatic life.

Although current geothermal development practices reinject most or all produced fluids, some plants still do discharge fluids. Should water effluent from geothermal development enter streams, it could adversely impact aquatic animal life and vegetation. Various elements and compounds, particularly hydrogen sulfide, sodium chloride, chlorine, ammonia, boron, arsenic, mercury, and heavy metals such as lead and silver may be present in geothermal fluids or drilling muds. These chemicals are toxic to aquatic vegetation and fish at varying concentrations. Thermal pollution of aquatic habitat is also likely to result from the release of geothermal fluids into streams or lakes.

When gaseous emissions reach certain thresholds, they can also affect vegetation and wildlife. Hydrogen sulfide (H_2S) is of particular concern because some species such as rainbow trout are vulnerable even to relatively low concentrations of it. Also, H_2S can react with other chemicals in the atmosphere, producing sulphur oxides and sulfuric acid, and precipitate as "acid rain," which burns the leaves of trees and shrubs and contributes to the acidification of water bodies.

The impacts of noise and human activity on natural biological systems are difficult to quantify. Animals who depend on acute hearing for protection, hunting, or mating may be affected by loud, continuous noise. The effects on animals of noise inaudible to humans are not understood. The impacts of human activities on biological systems are also difficult to assess. Some species may be severely impacted while other species may experience minimal impact. Desert ecosystems are typically more fragile than woodlands or grasslands, and may be affected to a greater degree by human activity.

Subsidence

Land subsidence, or lowering of the land surface, has been of concern where large quantities of water are extracted from geothermal resources. Subsidence is not a common problem because the majority of geothermal developments inject all or most of the spent fluid back into the reservoir in order to maintain reservoir pressure and promote reservoir longevity. Monitoring of subsidence in the Imperial Valley, California, where even small amounts could hinder the irrigation of crops and adversely impact the valley's important agricultural economy, indicates no significant subsidence even with nearly 400 MW of installed capacity (United States Dept. of Energy, 1980a).

Erosion

Geothermal development requires site clearing and land disturbance, which remove protective vegetation. This may accelerate erosion of exposed soil by storm water runoff if protective measures are not adopted. Storm runoff carries the eroded soil into streams and lakes, raising levels of suspended solids and causing increased sedimentation, both of which can be harmful to aquatic life. The extent to which erosion increases due to geothermal development is dependent on the site conditions and development practices. Sites with the combination of steep slopes, poor soil structure, and high seasonal rainfall and runoff rates are the most susceptible to increased erosion. Flatter sites with better soil structure are less susceptible.

Development practices can mitigate the impacts of land disturbance and erosion. Installation of drains, matting, mulch, and replacement vegetation are effective erosion control techniques. Also, efforts can be taken to minimize the total land area disturbed.

Noise

Both well field and power plant operations are sources of noise. Drilling rigs, construction equipment, pumps, and compressors are the principal sources of noise in the well field. Most of the noise associated with the well field is temporary (drilling and construction), but if it is too close to the public, some shielding may be needed to reach acceptable levels. Occasionally, high-temperature, high-pressure wells have accidental unmuffled well venting, as occurs in a well blowout. However, blowouts are uncommon and are temporary when they do occur, usually lasting from a few hours to a few weeks.

Noise sources at the plant are the turbine, the generator, and associated pumps and motors. These run 24 hours a day most of the year. In most plant, placing most of the equipment inside a building reduces noise to acceptable levels.

WATER RESOURCES

Water resources issues affect both well field and power plant operations. Fresh water is used during drilling to cool the drill bit, control subsurface pressures, and carry the rock cuttings to the surface. Fresh water, when readily available, is preferred for the plant's cooling system. In arid regions or where water use is an issue, geothermal fluids may be condensed and used in the cooling system, or a dry cooling system may be employed. Additionally, contamination of surface or subsurface fresh water systems is always a possibility due to accidentally spilling geothermal fluids at either the well field or power plant.

Geothermal drilling often involves drilling through freshwater zones in order to reach geothermal zones below. It is important that the well design and completion practices protect the freshwater zones from contamination with the drilling fluid or produced geothermal fluid. To protect these zones and to maintain the integrity of the well, a steel casing pipe is cemented into place inside the well, and the fluids travel to and from (in the case of injection) the surface through this pipe.

The New York state regulations governing drilling are currently applied only to oil and gas wells, but their general objectives may be assumed to apply for geothermal drilling. The regulations state that "....the drilling, casing, and completion program adopted for any well shall be such as to prevent pollution....Pollution of the land and/or surface or ground freshwater resulting from exploration or drilling is prohibited" (6 NYCRR, Part 554). Drilling muds, rock cuttings, and dust, though not considered polluting fluids by New York state, still need to comply with Title 6 of New York Codes, Rules and Regulations (6 NYCRR), Part 376, Land Disposal Restrictions.

Waste disposal of spent geothermal fluids is a major environmental concern in hydrothermal well field development and use because of the possibility of contaminating freshwater sources. Disposal is typically achieved by reinjecting the fluid back into the geothermal reservoir. Occasionally, disposal is directly into surface waters, but this is rare because reinjection prolongs the life of the reservoir, and discharge of untreated fluids into surface waters would violate environmental regulations. Federal law covers waste disposal by reinjection under the Federal Underground Injection Control (UIC) Regulation, pursuant to the Safe Drinking Water Act (P.L. 95-190). In New York, waste injection and surface disposal are subject to water quality regulations under 6 NYCRR, Parts 700-705. The New York regulations classify surface and groundwater, set standards for surface and groundwater and groundwater effluent, and establish criteria governing thermal discharges.

Under the UIC regulations, geothermal injection wells are classified as Class V wells, a miscellaneous category of hard-to-classify wells. An EPA inventory of all Class V wells in the country, completed in September 1987, rated as " low" the potential of geothermal wells to contaminate underground sources of drinking water. However, the rating system used by EPA to evaluate this potential does not give as much weight to "mechanical integrity" (proper construction, operation, and maintenance) as the individual state reports on which the EPA study was based. Therefore, the EPA assessment concludes that geothermal injection wells pose a "moderate" potential for contaminating underground drinking water, although it was noted that they are generally sited, constructed, and operated in a manner to prevent this occurrence. The EPA Drinking Water staff has indicated that it will continue to rely on state regulations for drinking water protection from geothermal injection wells.

Construction and operation of the plant pose no more than a limited potential for contaminating surface or subsurface freshwater supplies. A broken pipe could discharge geothermal fluids to the surface, but most plants are equipped to quickly recognize and deal with any such occurrences.

AIR QUALITY ISSUES

The impact of geothermal power generation on air quality is an important issue. Compared with fossil fueled power generation, geothermal power generation has low levels of atmospheric emissions, as illustrated in Table 3-1. However, despite geothermal power's relatively benign nature, chemical impurities in the large volumes of hot water or steam extracted for geothermal power generation can have adverse environmental impacts. For any specific geothermal power plant, the extent of air quality impacts depends mainly on four factors—chemistry of the geothermal fluids, the size and type of plant, operation and maintenance practices, and pollution control technology.

Table 3-1. Comparison of Power Plant CO_2 and SO_x Emissions.
(source: United States Department of Energy, Geothermal Division)

Power Plant Type	CO_2 Emissions (lb/MWh)	SO_x Emissions (lb/MWh)
Geothermal	75	0.16
Coal	2,178	12
Oil	1,500	11

Atmospheric emissions of H_2S and CO_2 are the primary air quality concerns with geothermal power generation. Emissions of volatile organic compounds at binary geothermal power plants are a lesser concern. Emissions of particulate matter are insignificant.

The following sections discuss the four primary factors determining the impact of geothermal power generation on air quality. Included is general discussion as well as points specific to upstate New York and the modeled hypothetical power plant.

Geothermal Fluid Chemistry

The potential impacts of geothermal power generation on air quality depend highly on the chemistry of the geothermal fluid. Geothermal fluids often contain some level of noncondensible gases, primarily CO_2 and H_2S. Concentrations of noncondensible gas in geothermal fluids vary from 0 to about 15 percent, with about 2 to 5 percent considered fairly normal. CO_2 is not a pollutant, but it does act as a "greenhouse gas" trapping heat within the earth's atmosphere and potentially contributing to global warming. H_2S, which is subject to New

York state ambient air standards, is a highly toxic gas. If necessary, H_2S emissions at geothermal plants are kept within regulatory limits by the use of pollution control technology.

Geothermal fluids also vary greatly in concentrations of dissolved solids. These dissolved solids can cause corrosion of equipment and can also precipitate and form "scale" on the walls of pipes and other equipment parts, lowering the efficiency of the plant. Various chemicals that are added to the geothermal fluid to control corrosion and scaling can be released into the atmosphere.

Size and Type of Plant

The extent of potential air quality impacts also depends on the size of the plant and the type of conversion technology. Larger plants require more wells and greater flows of geothermal fluids, increasing the amount of associated pollutants produced. The creation of particulate matter is increased by the more extensive drilling activity required for larger plants. The ambient air standard for particulates is twofold, considering those below 10 microns in diameter and those above. The levels are more stringent for the former since the objective is to provide protection from adverse health effects whereas the objective of the latter is to alleviate the nuisance of dustfall and reduce the economic effects of air pollution (6 NYCRR, Parts 257-3, Sections 257-3.1-3.6).

The de minimis limits of particulates below which they are not regulated in nonattainment areas, designated because they do not meet one or more ambient air standards, is 25 tons per year (6 NYCRR, Part 231, Section 1.9). The geothermal target resource subject of this study is not located in a nonattainment area for particulates. Also, particulates generated by geothermal drilling are considered a "temporary" source.

Binary cycle power plants, like the one modeled in this study, are closed systems that include no design features that meet the definition of an "emission point" contained in 6 NYCRR, Part 200. In Section 1(q), an emission point is defined as "any conduit, chimney, duct, vent, flue, stack, or opening of any kind through which air contaminants are emitted into the atmosphere." In binary cycle plants, the geothermal fluids are contained in a closed system and injected back into the ground rather than being vented to the atmosphere. An exception occurs when geothermal fluids are used as cooling water in an evaporative cooling system in a binary plant. Then some release of associated compounds may occur. However, the resources typically exploited by binary development tend to be shallower and less hot, with lower concentrations of noncondensible gases and dissolved solids, than dry steam and flash type resources. Also, dry cooling is fairly common with binary systems, and no emissions are associated with dry cooling.

Some binary system designs do have a possible environmental concern in terms of "fugitive" emissions of volatile organic compounds (VOC) when they are used as the working fluids. In the binary system, heat from the geothermal fluid is transferred to this working fluid, usually a low-boiling-point VOC such as iso-pentane or iso-butane. The working fluid is vaporized, expanded through the turbine, condensed, and then reused, in a closed cycle. Leaks sometimes occur in this system, leading to fugitive emissions. These emissions are temporary though, since the leaks are usually quickly repaired or else they may seriously reduce the plant's efficiency.

A review of federal and state regulations concerning fugitive VOC emissions indicates that no regulations appear to apply to the minimal amounts that escape from geothermal binary operations. However, the iso-butane and iso-pentane, used as binary working fluids, are not officially on New York's list of acceptable VOC compounds with negligible photochemical reactivity. But, they are not subject to EPA's national emission standard for equipment leaks (fugitive emission sources) contained in 40 CFR, 61.114. The latter applies to sources operating "in volatile hazardous air pollutant service." An EPA or New York state opinion on the applicability to binary systems of the emission standards for organic hazardous air pollutants for equipment may be needed.

Finally, operators of these plants in New York will need to determine whether their VOC storage tanks are subject to the requirements of Part 229, Petroleum and Volatile Organic Liquid Storage and Transfer. The requirements vary with size of tank, true vapor pressure, and type of construction. The requirements are set forth in Section 229.1 (d) (v)-(viii); exemptions are shown in section (f) (1)-(6).

Pollution Control Technology

If H_2S concentrations are above regulatory limits, the H_2S emissions are controlled in an abatement process that removes H_2S from the steam before it enters the turbine. A separate process is used, if necessary, to remove additional H_2S from the condensate before it enters the cooling tower. The Stretford System is the most common H_2S steam scrubbing process, and a hydrogen peroxide secondary abatement system is used for the condensate.

Operation and Maintenance Practices

Operational practices include use of some chemicals that could potentially impact the environment. As stated above, hydrogen peroxide is often added to help control H_2S. At some plants, antiscalant chemicals are added to the brine to inhibit the precipitation of dissolved solids. Other chemicals are added to prevent corrosion and the growth of algae and bacteria. These chemicals may be released in the evaporative cooling systems and include chromates, chlorine, and acids.

Maintenance practices at some plants vent steam when the turbine is shut down for maintenance. However, at sites with high levels of H_2S, the systems are usually designed to route steam around the turbine and into the abatement system in the event of a turbine shutdown.

Noncondensible gases, including H_2S, can escape into the atmosphere if a well blows out. Because modern drilling rigs are designed to prevent blowouts, they are rare; however, a blowout may result in a few hours to a few weeks of unplanned emissions. After the well is completed, a mechanical well head is installed to control well production and protect against uncontrolled emissions.

HAZARDOUS WASTES

The treatment of hazardous wastes resulting from geothermal power generation falls under state jurisdiction. Again, most wastes result from dry steam or flash geothermal power systems. Since the geothermal fluids in binary power systems are contained within a closed system, hazardous waste issues rarely are a consideration. Federal regulations [40CFR 261.4(b)], exempted "Drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas, or geothermal energy" from the Federal Resource Conservation and Recovery Act (RCRA). RCRA regulates most hazardous wastes, but leaves regulation of these "low-risk" wastes to the states. EPA also exempts the following geothermal energy wastes from being regarded as hazardous under RCRA:

- drilling media and cuttings;
- fluids from geothermal reservoirs;
- piping and scale and flash tank solids;
- precipitated solids from brine effluent;
- settling pond wastes;
- cooling tower drift; and
- cooling tower blowdown.

If the geothermal resources in New York contain significant levels of H_2S, state regulators will likely promulgate more specific rules dealing with geothermal sulphur sludge if a flash rather than binary power system is installed. In California, state regulators interpreted RCRA to also exempt the waste sulphur sludge generated by geothermal plant H_2S abatement systems, even though it is not specifically exempted by RCRA.

At The Geysers geothermal site in California (a dry steam resource), vanadium and/or mercury found in the sulphur sludge cause it to be considered hazardous. Minute amounts of mercury in the geothermal fluid become concentrated in the sludge, and vanadium is a chemical added as part of the abatement process. Other hazardous substances sometimes found in the sludge, although usually at concentrations below regulatory limits, include antimony, arsenic, barium, beryllium, cadmium, chromium, cobalt, copper, lead, molybdenum, nickel, selenium, silver, thallium, and zinc.

The Salton Sea geothermal resource in California contains unusually high levels of dissolved solids in the geothermal fluid. Some flash plants operating there employ a crystallizer-clarifier process, which precipitates and removes the dissolved solids from the fluid. This process creates a silica sludge in which arsenic, copper, lead, and zinc have been detected in concentrations exceeding state regulatory limits for nonhazardous disposal. Unocal Geothermal, one of the operators in the Salton Sea, has developed two patented processes to reduce the heavy metal concentrations in the sludge and convert them into construction materials.

All of the listed substances, except molybdenum, are listed as hazardous under 6 NYCRR Part 597, and cobalt is listed as acutely hazardous. The handling, storage, and release of hazardous substances are regulated under 6 NYCRR, Parts 595 - 599. The disposal of hazardous wastes is restricted under 6 NYCRR, Part 376.

SUMMARY

Years of experience with geothermal power generation have led to operational practices and environmental control technologies that greatly minimize potential environmental impacts related to geothermal power generation. The extent of environmental impacts depends primarily on the size of the plant, the plant type (dry steam, flash, or binary), and the chemistry of the geothermal fluid. The binary plant, which is the most environmentally advantageous, was selected for the hypothetical development of the target geothermal resource in upstate New York.

Because no combustion is involved, geothermal power releases minimal air emissions. Hydrogen sulfide (H_2S) is the primary concern. Where necessary, control technologies are adopted to keep H_2S emissions within state regulatory limits.

Geothermal fluids are commonly saline, creating concern that they may contaminate surface or subsurface freshwater systems. Proper well design and waste water disposal protect against such contamination. Proper well design includes a steel casing cemented into the well through which the geothermal fluid passes, making it impossible for it to escape into freshwater aquifers. Waste disposal is usually achieved through injection of all or most of the spent geothermal fluids back into the reservoir. Injection waste disposal is regulated by the Federal Underground Injection Control regulation under the Safe Drinking Water Act (P.L. 95-190) and in New York, by water quality regulations under 6 NYCRR, Parts 700-705.

Some geothermal fluids contain potentially hazardous substances, such as heavy metals. These substances may become concentrated in the sludge wastes that are created in abating H_2S or in removing high concentrations of dissolved solids from the geothermal fluids. In New York, such wastes are subject to regulations under 6 NYCRR, Part 376 and Parts 595 - 599.

Other impacts, such as noise, land use, erosion, subsidence, sedimentation, and the effects of human activity on wildlife are relatively minor at modern geothermal power plants that are well maintained and operated.

SECTION 4
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APPENDIX A

EVALUATION OF RESERVOIR CAPACITY

This appendix describes the estimation methodology used to determine the power generation capacity of the reservoir. The methodology was originally developed by the United States Geological Survey (Brook, et al., 1978) and has been used extensively by private industry for resource evaluation. In general, the method calculates the amount of heat in the reservoir, the amount of the reservoir's heat that can be recovered, and the amount of electricity that can be generated from the heat based on an assumed conversion efficiency.

For this study, the area of the reservoir is unknown, so the heat content and electric capacity are calculated on a volumetric basis. The electric capacity per unit volume is converted to electric capacity per unit area, based on the known thickness of the reservoir. The size of the plant is then determined by limiting the maximum distance between any production well and the plant to two miles and calculating capacity of the reservoir within the defined area. This method is described in more detail below.

The amount of heat per unit volume of reservoir is calculated by the following equation:

$$q_r = C_v * V * (T - T_0)$$

where:

C_v = volumetric specific heat of the rock plus water
V = unit volume of reservoir (in this case, 1 cubic kilometer)
T = average reservoir temperature
T_0 = heat rejection temperature

The electrical energy that can be generated from a unit volume of the reservoir is calculated by:

$$E = W_a * U$$

where:

W_a = the work available by converting the heat into mechanical energy
U = utilization factor accounting for inefficiencies of the power system

Solving these equations yields the following values:

C_v = 2.94 Joules/cm^3/°C
TT = 116°C
q_r = 3.4104E17 Joules/km^3
W_a / q_r = 0.038

$$W_a = 1.29595E16 \text{ Joules/km}^3.$$
$$U = 0.4$$
$$E = 1.29595E16 \text{ Joules/km}^3 / 1.057E15 \text{ J/MW/30 year}$$
$$= 4.9 \text{ MW per km}^3.$$

Converting to an area based capacity, based on the reservoir thickness of 436 feet,

$$E = 1 \text{ MW per } 7.5 \text{ km}^2 \text{ of reservoir area}$$

The areal capacity limits the designed size of the plant (even if the area of the reservoir is infinite) because of the limited distances from the production wells to the plant. The assumed 2-mile transportation limit results in a maximum plant size of 15 MW for any given site. This two mile limit could potentially be overcome somewhat by locating a well within the 2-mile limit and slant drilling to a target beyond the limiting distance. However, the model and economic analysis did not include directional drilling because it would have increased drilling costs that were already becoming prohibitively high.

APPENDIX B

DESCRIPTION OF SPREADSHEET MODEL

This appendix describes the methodology used for the economic analysis of a hypothetical geothermal power project in upstate New York. The model consists of three separate modules. The Power Plant Module lists and sums the capital costs (per net kW) for the power plant components and their construction as well as the cost for a connecting transmission line. The Well Field Module determines the extent, timing, and costs of field development. The Economics Module integrates costs from the power plant and well field modules and calculates the levelized cost of electricity required to pay for the project. The three modules are described in more detail below. Printouts of the 3 modules for the 5, 10, and 15 MW power plants are included in Appendix C, and a table of the model variables and formulas is found in Appendix D.

POWER PLANT MODULE

The power plant module calculates the total capital cost for constructing the plant and a transmission line connecting the plant with existing transmission lines. It also calculates fixed and variable operation and maintenance costs for the plant. The module is based on a 5 MW (net) modular, binary power plant requiring a brine flow rate of 240,000 pounds per hour per net MW. The parasitic load for the plant is 1 MW (20% of the net), requiring a gross output of 6 MW. Additional runs of the model were made for 10 and 15 MW plants.

The major cost components of the plant are summed, and then a contingency cost and profit are added, resulting in the capital cost of the plant per net kW of capacity. This number is multiplied by the number of net kW to calculate the total plant capital cost. The fixed and variable operation and maintenance costs are calculated based on a percentage of the capital costs.

The connecting transmission line is assumed to be 10 miles long, and its costs are based on a 1989 report by the Federal Energy Regulatory Commission (FERC, 1989). The report provides a range of construction costs for a new single circuit, 138 kV line of $125,000 to $375,000 per mile (1985$). Additional costs for land and substations are estimated at 3 to 7% and 6 to 14%, respectively, of the total line construction costs. The power plant module used the conservative end of these reported costs. In the module, line construction costs were assumed at $375,000 (inflated to 1995$ at 4% per year). Land and substation costs were assumed to cost 7% and 10% of the line construction costs, respectively.

The model does not incorporate any explicit algorithms to reduce unit costs as plant size increases. By designing a modular power plant system and tripling the size from 5 MW to 15 MW, a developer might achieve a 10 to 15% reduction in the unit cost of some plant equipment. This would result in a somewhat smaller percentage reduction in the final cost of the constructed plant. However, in this case, the cost of the plant is small compared to the field, and the resulting percentage reduction in the busbar cost of electricity would be insignificant. For this reason, no explicit economy of scale is incorporated into the design of the model.

WELL FIELD MODULE

The well field development module determines the extent, timing, and costs of field development. Initially, the model determines the number of operating production wells required based on total fluid flow requirements of the plant, and an estimated fluid flow rate per well as determined in the geological component of this study. The total number of wells required and their costs are calculated based on the number of production wells required, a ratio of production wells to injection wells, the number of spare wells required, and a ratio of dry wells to successful wells.

Field development occurs in three phases—exploration, confirmation, and construction. Although limited capital can require spreading exploration activities over several years, a well-capitalized developer can complete all three phases of field development for a small project in 2-3 years. The well field module is based on a 1-year duration for each of the three phases.

Drilling costs are primarily a function of depth. Costs increase non-linearly with depth. Other factors also effect drilling costs. These include formation hardness, reservoir pressures, and drilling related problems, such as lost circulation. The well field module incorporates a table of costs versus depth based on the results of a geothermal drilling cost model, DRILLCOS, developed by Susan Petty Consulting and Bill Livesay and Associates for the U.S. Department of Energy. Costs for wells from 2,000 to 10,000 feet deep, in 1,000-foot increments, are included. The module uses the drilling cost corresponding to the reservoir depth in the table.

The number and timing of make-up wells (additional wells to make up for a decline in production over time) are calculated as a function of fluid requirements and a projected well flow decline rate. A separate model, written in C++, was developed for this purpose. This model's results for a set of given plant sizes are available to the well field module as a table containing the timing for drilling makeup wells during the expected life of binary plants of various sizes.

The cash flow section of the well field module allocates costs over the development period and life of the plant and adjusts them to the plant startup year using standard net present value techniques. It allocates the initial field development costs over the 3 years preceding plant startup, and allocates the cost of makeup wells over the 25-year life of the plant according to the binary table described in the preceding paragraph. The drilling costs are separated into tangible costs (25 percent) and intangible costs (75 percent). Tax laws allow industry would be insignificant. For this reason, no explicit economy of scale is incorporated into the design of the model.

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Other costs include production and injection pumps and piping, exploration, contingency, and operation and maintenance. The O&M costs are separated into variable and fixed portions. The variable O&M cost is a function of the total field capital cost and the annual power output of the plant. The fixed O&M cost is a function of the field capital cost.

ECONOMICS MODULE

The Economics Module integrates the cost information from the Well Field and Power Plant Modules and solves for the levelized busbar cost of electricity. The module employs revenue requirements methodology developed by the Electric Power Research Institute (EPRI TAG, Vol. 1 and 3, 1993 and 1991) and widely used by the electric utility industry to assess the economic consequences of alternatives. Appendix C lists the spreadsheet, and Appendix D lists the variables and formulas used in the spreadsheet.

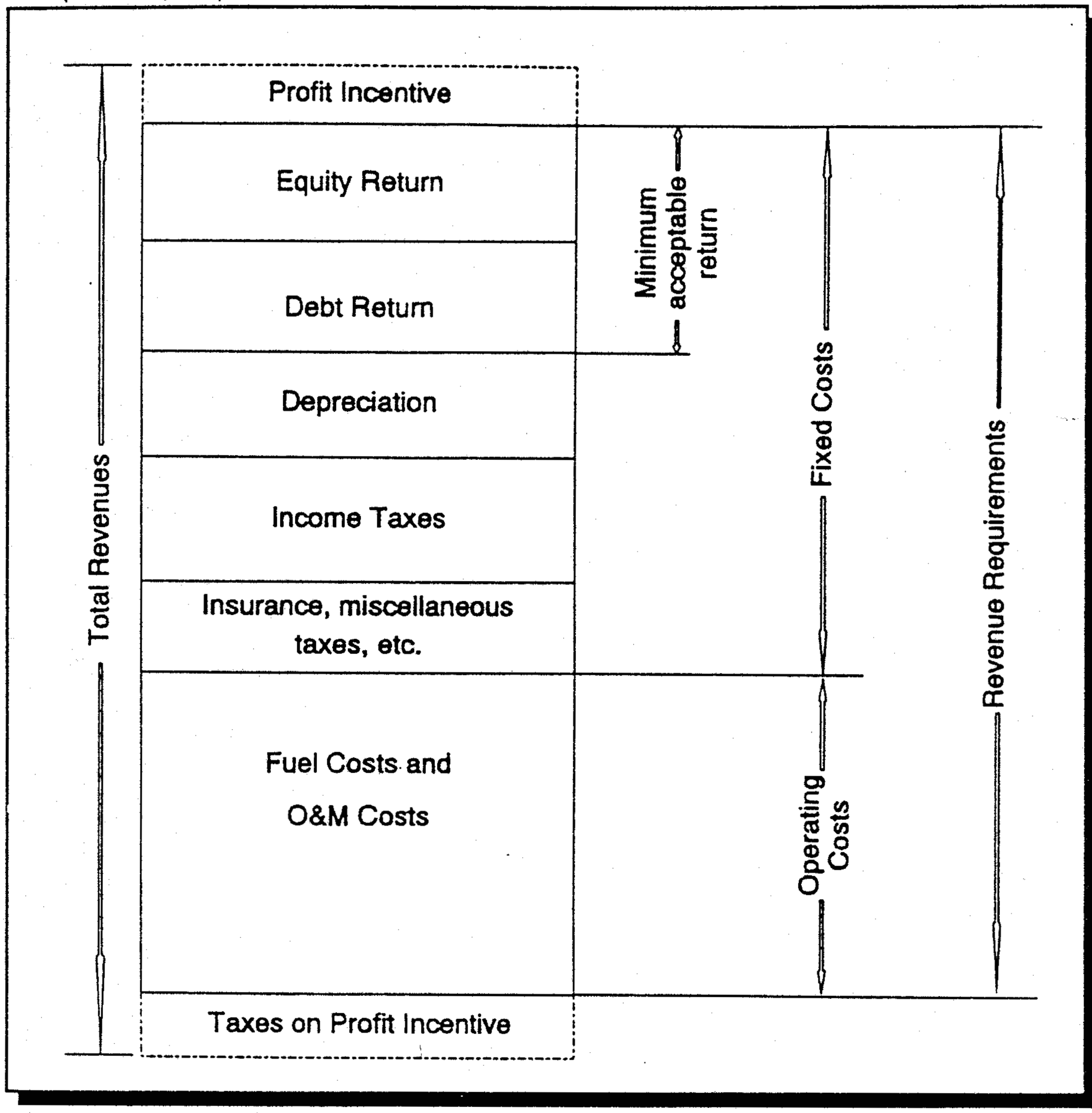
Revenue requirements are the amounts that must be covered in order to compensate the developer for all expenditures incurred as a result of undertaking the project. Total revenues must be equal to the revenue requirements, plus a small profit incentive, plus the tax on the profit incentive as illustrated in Figure B-1.

Annual revenue requirements for any project will normally vary over the life of the project. The methodology converts these varying annual revenue requirements to a levelized annual revenue requirement so that the sum of the present worths of the annual levelized values is equal to the sum of the present worths of the actual revenue requirements.

The ratio of the levelized annual fixed costs to the total investment is called the "levelized fixed charge rate." Thus, the total annual levelized revenue requirement equals the levelized annual operating costs plus the product of the levelized annual fixed charge rate and the capital investment. The levelized fixed charge rate covers the fixed costs shown in Figure B-1. It is the sum of:

- weighted cost of capital (return on debt and equity);
- dispersion allowance (statistical adjustment for variation in plant life);
- sinking fund depreciation;
- levelized annual accelerated depreciation factor;

Figure B-1. Categories for the Revenue Requirements Methodology
(EPRI TAG, 1978)



- levelized annual income tax factor;
- levelized energy investment tax credit; and
- property taxes and insurance.

The levelized busbar cost for the project is derived by setting the sum of the levelized required revenues equal to the sum of the levelized product of the busbar cost of electricity and the amount of electricity produced:

$$CRF \sum_{n=1}^{N} \{R_n / (1+r)^n)\} = CRF \sum_{n=1}^{N} \{C\ (kWh_n) / (1+r)^n\}$$

Where: R_n = Revenue requirements in year n

kWh_n	= Power generation in year n, kilowatt-hours
r	= Discount rate (weighted cost of capital)
N	= Book life, years
CRF	= Capital recovery factor at rate = r and duration = N
C	= Levelized busbar cost

Solving for the levelized busbar cost, C, yields:

$$C = \frac{\sum_{i=0}^{N} \{R_n / (1+r)^n\}}{\sum_{i=0}^{N} \{kWh_n / (1+r)^n\}}$$

APPENDIX C

PRINTOUTS OF SPREADSHEET MODEL

FOR 5, 10, AND 15 MW PLANTS

Economics Module - 5 MW Plant Size

Economics Analysis				
Fixed Charge Rate Calculation			plant size (net mW):	5
Plant Life (years)	30		Real Escalation Rate	0.02
Book Life (years)	5		Inflation Rate	0.04
Energy Tax Credit	0.1		Apparent Escalation	0.0608
Fed + State Income Tax Rate	0.38		Intermediate Variable	0.958591
Levelized Fixed Charge Rate:				
Capital Structure:				
Debt Cost	0.12			
Debt Ratio	0.46			
Pref. Stock Cost	0.1			
Pref. Stock Ratio	0.08			
Com. Stock Cost	0.14			
Com. Stock Ratio	0.46			
Weigted Cost of Capital (discount rate):		0.106624	(after tax)	
Dispersion Allowance		0.0056		
Capital Recovery Factor	0.111984			
Book Depreciation		0.00536		
Depreciation (SOYD)	0.089098			
Levelized Depreciation		-0.03418		
Levelized Income Tax		0.024904		
Levelized Energy Tax Credit		-0.01632		
Property Taxes & Insurance		0.03		

Levelized Fixed Charge Rate		0.121988		
Levelization Factor	1.863412			
Profit Incentive rate (after tax)	0.1			
Levelized Costs (mills/kwh):				
Plant Capital	17.58			
Variable Plant O&M	5.00			
Fixed Plant O&M	12.51			
Field Capital	77.62			
Intangible Drilling	10.75			
Variable Field O&M	5.51			
Fixed Field O&M	11.02			
Transmission Line	12.13			
Subtotal:	152.12			
Royalties	15.21			
Subtotal:	167.34			
Profit Incentive (after tax)	16.73			
Total:	184.07			

Power Plant Module - 5 MW Plant Size

Plant Module				
	Capital Cost		Brine Rate, klb/hr/mW	240
Plant Component	$ / net kW		Total Brine Flow, klb/hr	1440
Permits and Licenses	10		Plant Size, mW (net)	5
Site Preparation	20		Plant Size, mW (gross)	6
Heat Exchangers	135			
Condensers	305		Total Plant Cost ($k)	9,408
Cooling Tower	170			
Circulating Water Pumps	30		Profit Rate	0.1
Turbine Generator	250		Contingency Rate	0.1
Working Fluid Pumps	30			
Piping and Valves	80		Capacity Factor	0.8
Instrumentation & Controls	30			
Main Transformer	10			
Switchyard	20			
Misc. Electrical Equipment	35			
Engineering	130			
Construction	240			
Management	35		Transmission Line:	
Bonds and Insurance	55		Length (miles)	10
Subtotal:	1555		Line Const. ($k/mile)	555
Contingency	156		Line Const. Total ($k)	5551
Profit	171		Land Cost ($k)	389
Total Capital Cost	1882		Substation Cost ($k)	555
			Total ($k):	6495
O&M Rates and Costs:				
Fixed O&M, % of plant cost	2			
Variable O&M, % of plant cost	1			
Fixed Plant O&M, $/kW-yr	47			
Variable Plant O&M, mills/kwh	2.68			

Well Field Module - 5 MW Plant Size

Well Field Parameters:					
Well Depth, ft	10000		plant size (net mW):		5
Reservoir Temperature, F	266				
Reservoir Pressure, psi	4413				
Brine Production, klb/hr/well	525.6				
No. Spare Producers	1				
No. Spare Injectors	1				
No. Producers (excluding spares)	3				
Producer/Injector Ratio	4				
No. Injectors (excluding spares)	1				
Dry Hole Ratio	0.1				
Total Number of Wells Drilled	7				
Total Number of Wells Completed	6				
No. Dry Holes	1				
Fixed Field O&M (% of total cost)	0.50				
Variable Field O&M (% of total cost)	0.25				
Contingency (fraction of total cost)	0.15				
Well Field Costs:					
Production Well Cost, $k/well	3918				
Dry Well Cost, $k/well	2743				
Total Well Cost, $k	26251				
Exploration Cost, $k	8000				
Production Pump Cost, $k/well	140				
Total Prod. Pump Costs, $k/field	420				
Production Piping Costs, $/ft	50				
Total Prod. Piping Costs, $k/field	721				
Injection Pump Cost, $k/inj. well	150				
Total Inj. Pump Cost, $k/field	150				
Injection Piping Cost, $k/inj. well	500				
Total Inj. Piping Cost, $k/field	500				
Total Initial Field Cost, $k	41448				
Operation and Maintenance Costs					
Fixed Field O&M, $/ kw-yr	52				
Variable Field O&M, mills/kwh	2.96				
Intangible Drilling Costs, $/kw-yr	51				
Field Installation Cash Flow Timing:	Year (-3)	Year (-2)	Year (-1)		
	Cost, $k	Cost, $k	Cost, $k		
Exploration	8000				
Permitting	50	100	100		
Dry Holes		2743	0		
Successful Wells					
Tangible Costs		2939	2939		
Intangible Costs		8816	8816		
Gathering System & Pumps			1791		
Total Tangible:		2939	4013		
Total Intangible:	8050	11658	9632		

Well Field Module - 5 MW Plant Size
Cash Flow

Well Cost Lookup Table:	Well													
Depth, feet	Cost, $k													
2000	885													
3000	1094													
4000	1390													
5000	1758													
6000	2103													
7000	2545													
8000	2942													
9000	3482													
10000	3918													
				NPV	NPV									
Well Field Development Cash Flow				Intangible	Tangible									
year	-3	-2	-1	0	0	1	2	3	4	5	6	7	8	9
Field Installation (Tangible)	0	2939	4013		8039									
Field Installation (Intangible)	8050	11658	9632	35845										
Makeup Well (Tangible)					523	0	0	0	0	0	0	0	0	0
Makeup Well (Intangible)				1570		0	0	0	0	0	0	0	0	0
Makeup Well Contingency				235	78									
				--------------	--------------									
Totals :				37650	8641									
Binary Lookup Table for the														
Timing of Makeup Wells	year													
plant size (net mW)	1	2	3	4	5	6	7	8	9	10	11	12	13	14
5	0	0	0	0	0	0	0	0	0	1	0	0	0	0
6	0	0	1	0	0	0	0	0	0	0	0	0	0	0
8	0	0	1	0	0	0	0	0	0	0	0	1	0	0
10	0	0	1	0	0	0	0	0	0	1	0	0	0	0
12	0	0	1	0	0	0	0	0	1	0	0	0	0	0
15	0	1	0	0	1	0	0	0	0	0	1	0	0	0
18	0	0	1	0	0	0	1	0	0	0	0	1	0	0

Well Field Module - 5 MW Plant Size
Cash Flow (cont.)

year	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Field Installation (Tangible)																
Field Installation (Intangible)																
Makeup Well (Tangible)	1595	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Makeup Well (Intangible)	4785	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Makeup Well Contingency																
Totals :																
Binary Lookup Table for the																
Timing of Makeup Wells																
plant size (net mW)	15	16	17	18	19	20	21	22	23	24	25					
5	0	0	0	0	0	0	0	0	0	0	0					
6	1	0	0	0	0	0	0	0	0	0	0					
8	0	0	0	0	0	0	0	1	0	0	0					
10	0	0	0	0	1	0	0	0	0	0	0					
12	0	1	0	0	0	0	0	0	0	0	0					
15	0	1	0	0	0	0	0	1	0	0	0					
18	0	0	1	0	0	0	1	0	0	0	0					

Economics Module - 10 MW Plant Size

Economics Analysis				
Fixed Charge Rate Calculation			plant size (net mW):	10
Plant Life (years)	30		Real Escalation Rate	0.02
Book Life (years)	5		Inflation Rate	0.04
Energy Tax Credit	0.1		Apparent Escalation	0.0608
Fed + State Income Tax Rate	0.38		Intermediate Variable	0.958591
Levelized Fixed Charge Rate:				
Capital Structure:				
Debt Cost	0.12			
Debt Ratio	0.46			
Pref. Stock Cost	0.1			
Pref. Stock Ratio	0.08			
Com. Stock Cost	0.14			
Com. Stock Ratio	0.46			
Weigted Cost of Capital (discount rate):		0.106624	(after tax)	
Dispersion Allowance		0.0056		
Capital Recovery Factor	0.111984			
Book Depreciation		0.00536		
Depreciation (SOYD)	0.089098			
Levelized Depreciation		-0.03418		
Levelized Income Tax		0.024904		
Levelized Energy Tax Credit		-0.01632		
Property Taxes & Insurance		0.03		

Levelized Fixed Charge Rate		0.121988		
Levelization Factor	1.863412			
Profit Incentive rate (after tax)	0.1			
Levelized Costs (mills/kwh):				
Plant Capital	17.58			
Variable Plant O&M	5.00			
Fixed Plant O&M	12.51			
Field Capital	60.86			
Intangible Drilling	16.75			
Variable Field O&M	4.33			
Fixed Field O&M	8.67			
Transmission Line	6.07			
Subtotal:	131.76			
Royalties	13.18			
Subtotal:	144.94			
Profit Incentive (after tax)	14.49			
Total:	159.43			

Well Field Module - 10 MW Plant Size

Well Field Parameters:					
Well Depth, ft	10000		plant size (net mW):		10
Reservoir Temperature, F	266				
Reservoir Pressure, psi	4413				
Brine Production, klb/hr/well	525.6				
No. Spare Producers	1				
No. Spare Injectors	1				
No. Producers (excluding spares)	6				
Producer/Injector Ratio	4				
No. Injectors (excluding spares)	2				
Dry Hole Ratio	0.1				
Total Number of Wells Drilled	12				
Total Number of Wells Completed	10				
No. Dry Holes	2				
Fixed Field O&M (% of total cost)	0.50				
Variable Field O&M (% of total cost)	0.25				
Contingency (fraction of total cost)	0.15				
Well Field Costs:					
Production Well Cost, $k/well	3918				
Dry Well Cost, $k/well	2743				
Total Well Cost, $k	44665				
Exploration Cost, $k	8000				
Production Pump Cost, $k/well	140				
Total Prod. Pump Costs, $k/field	840				
Production Piping Costs, $/ft	50				
Total Prod. Piping Costs, $k/field	1890				
Injection Pump Cost, $k/inj. well	150				
Total Inj. Pump Cost, $k/field	300				
Injection Piping Cost, $k/inj. well	500				
Total Inj. Piping Cost, $k/field	1000				
Total Initial Field Cost, $k	65199				
Operation and Maintenance Costs					
Fixed Field O&M, $/ kw-yr	41				
Variable Field O&M, mills/kwh	2.33				
Intangible Drilling Costs, $/kw-yr	79				
Field Installation Cash Flow Timing:	Year (-3)	Year (-2)	Year (-1)		
	Cost, $k	Cost, $k	Cost, $k		
Exploration	8000				
Permitting	50	100	100		
Dry Holes		2743	2743		
Successful Wells					
Tangible Costs		4898	4898		
Intangible Costs		14693	14693		
Gathering System & Pumps			4030		
Total Tangible:		4898	7315		
Total Intangible:	8050	17535	19147		

Well Field Module - 10 MW Plant Size
Cash Flow

Well Cost Lookup Table:	Well													
Depth, feet	Cost, $k													
2000	885													
3000	1094													
4000	1390													
5000	1758													
6000	2103													
7000	2545													
8000	2942													
9000	3482													
10000	3918													
				NPV	NPV									
Well Field Development Cash Flow				Intangible	Tangible									
year	-3	-2	-1	0	0	1	2	3	4	5	6	7	8	9
Field Installation (Tangible)	0	4898	7315		14093									
Field Installation (Intangible)	8050	17535	19147	53572										
Makeup Well (Tangible)					1631	0	0	1212	0	0	0	0	0	0
Makeup Well (Intangible)				4892		0	0	3636	0	0	0	0	0	0
Makeup Well Contingency				734	245									
				--------------	--------------									
Totals :				59197	15968									
Binary Lookup Table for the														
Timing of Makeup Wells	year													
plant size (net mW)	1	2	3	4	5	6	7	8	9	10	11	12	13	14
5	0	0	0	0	0	0	0	0	0	1	0	0	0	0
6	0	0	1	0	0	0	0	0	0	0	0	0	0	0
8	0	0	1	0	0	0	0	0	0	0	0	1	0	0
10	0	0	1	0	0	0	0	0	0	1	0	0	0	0
12	0	0	1	0	0	0	0	0	1	0	0	0	0	0
15	0	1	0	0	1	0	0	0	0	0	1	0	0	0
18	0	0	1	0	0	0	1	0	0	0	0	1	0	0

Well Field Module - 10 MW Plant Size
Cash Flow (cont.)

Well Field Development Cash Flow																
year	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Field Installation (Tangible)																
Field Installation (Intangible)																
Makeup Well (Tangible)	1595	0	0	0	0	0	0	0	0	2270	0	0	0	0	0	0
Makeup Well (Intangible)	4785	0	0	0	0	0	0	0	0	6810	0	0	0	0	0	0
Makeup Well Contingency																
Totals :																
Binary Lookup Table for the																
Timing of Makeup Wells																
plant size (net mW)	15	16	17	18	19	20	21	22	23	24	25					
5	0	0	0	0	0	0	0	0	0	0	0					
6	1	0	0	0	0	0	0	0	0	0	0					
8	0	0	0	0	0	0	0	1	0	0	0					
10	0	0	0	0	1	0	0	0	0	0	0					
12	0	1	0	0	0	0	0	0	0	0	0					
15	0	1	0	0	0	0	0	1	0	0	0					
18	0	0	1	0	0	0	1	0	0	0	0					

Economics Module - 15 MW Plant Size

Economics Analysis				
Fixed Charge Rate Calculation			plant size (net mW):	15
Plant Life (years)	30		Real Escalation Rate	0.02
Book Life (years)	5		Inflation Rate	0.04
Energy Tax Credit	0.1		Apparent Escalation	0.0608
Fed + State Income Tax Rate	0.38		Intermediate Variable	0.958591
Levelized Fixed Charge Rate:				
Capital Structure:				
Debt Cost	0.12			
Debt Ratio	0.46			
Pref. Stock Cost	0.1			
Pref. Stock Ratio	0.08			
Com. Stock Cost	0.14			
Com. Stock Ratio	0.46			
Weigted Cost of Capital (discount rate):		0.106624	(after tax)	
Dispersion Allowance		0.0056		
Capital Recovery Factor	0.111984			
Book Depreciation		0.00536		
Depreciation (SOYD)	0.089098			
Levelized Depreciation		-0.03418		
Levelized Income Tax		0.024904		
Levelized Energy Tax Credit		-0.01632		
Property Taxes & Insurance		0.03		

Levelized Fixed Charge Rate		0.121988		
Levelization Factor	1.863412			
Profit Incentive rate (after tax)	0.1			
Levelized Costs (mills/kwh):				
Plant Capital	17.58			
Variable Plant O&M	5.00			
Fixed Plant O&M	12.51			
Field Capital	53.55			
Intangible Drilling	18.32			
Variable Field O&M	3.81			
Fixed Field O&M	7.61			
Transmission Line	4.04			
Subtotal:	122.42			
Royalties	12.24			
Subtotal:	134.66			
Profit Incentive (after tax)	13.47			
Total:	148.13			

Power Plant Module - 15 MW Plant Size

Plant Module				
	Capital Cost		Brine Rate, klb/hr/mW	240
Plant Component	$ / net kW		Total Brine Flow, klb/hr	4320
Permits and Licenses	10		Plant Size, mW (net)	15
Site Preparation	20		Plant Size, mW (gross)	18
Heat Exchangers	135			
Condensers	305		Total Plant Cost ($k)	28,223
Cooling Tower	170			
Circulating Water Pumps	30		Profit Rate	0.1
Turbine Generator	250		Contingency Rate	0.1
Working Fluid Pumps	30			
Piping and Valves	80		Capacity Factor	0.8
Instrumentation & Controls	30			
Main Transformer	10			
Switchyard	20			
Misc. Electrical Equipment	35			
Engineering	130			
Construction	240			
Management	35		Transmission Line:	
Bonds and Insurance	55		Length (miles)	10
Subtotal:	1555		Line Const. ($k/mile)	555
Contingency	156		Line Const. Total ($k)	5551
Profit	171		Land Cost ($k)	389
Total Capital Cost	1882		Substation Cost ($k)	555
			Total ($k):	6495
O&M Rates and Costs:				
Fixed O&M, % of plant cost	2			
Variable O&M, % of plant cost	1			
Fixed Plant O&M, $/kW-yr	47			
Variable Plant O&M, mills/kwh	2.68			

Well Field Module - 15 MW Plant Size

Well Field Parameters:					
Well Depth, ft	10000		plant size (net mW):		15
Reservoir Temperature, F	266				
Reservoir Pressure, psi	4413				
Brine Production, klb/hr/well	525.6				
No. Spare Producers	1				
No. Spare Injectors	1				
No. Producers (excluding spares)	9				
Producer/Injector Ratio	4				
No. Injectors (excluding spares)	3				
Dry Hole Ratio	0.1				
Total Number of Wells Drilled	16				
Total Number of Wells Completed	14				
No. Dry Holes	2				
Fixed Field O&M (% of total cost)	0.50				
Variable Field O&M (% of total cost)	0.25				
Contingency (fraction of total cost)	0.15				
Well Field Costs:					
Production Well Cost, $k/well	3918				
Dry Well Cost, $k/well	2743				
Total Well Cost, $k	60337				
Exploration Cost, $k	8000				
Production Pump Cost, $k/well	140				
Total Prod. Pump Costs, $k/field	1260				
Production Piping Costs, $/ft	50				
Total Prod. Piping Costs, $k/field	3158				
Injection Pump Cost, $k/inj. well	150				
Total Inj. Pump Cost, $k/field	450				
Injection Piping Cost, $k/inj. well	500				
Total Inj. Piping Cost, $k/field	1500				
Total Initial Field Cost, $k	85911				
Operation and Maintenance Costs					
Fixed Field O&M, $/ kw-yr	36				
Variable Field O&M, mills/kwh	2.04				
Intangible Drilling Costs, $/kw-yr	86				
Field Installation Cash Flow Timing:	Year (-3)	Year (-2)	Year (-1)		
	Cost, $k	Cost, $k	Cost, $k		
Exploration	8000				
Permitting	50	100	100		
Dry Holes		2743	2743		
Successful Wells					
Tangible Costs		6857	6857		
Intangible Costs		20570	20570		
Gathering System & Pumps			6368		
Total Tangible:		6857	10677		
Total Intangible:	8050	23412	25959		

Well Field Module - 15 MW Plant Size
Cash Flow

Well Cost Lookup Table:	Well													
Depth, feet	Cost, $k													
2000	885													
3000	1094													
4000	1390													
5000	1758													
6000	2103													
7000	2545													
8000	2942													
9000	3482													
10000	3918													
				NPV	NPV									
Well Field Development Cash Flow				Intangible	Tangible									
year	-3	-2	-1	0	0	1	2	3	4	5	6	7	8	9
Field Installation (Tangible)	0	6857	10677		20213									
Field Installation (Intangible)	8050	23412	25959	68307										
Makeup Well (Tangible)					2674	0	1165	0	0	1311	0	0	0	0
Makeup Well (Intangible)				8023		0	3496	0	0	3933	0	0	0	0
Makeup Well Contingency				1203	401									
				---------------	---------------									
Totals :				77534	23288									
Binary Lookup Table for the														
Timing of Makeup Wells	year													
plant size (net mW)	1	2	3	4	5	6	7	8	9	10	11	12	13	14
5	0	0	0	0	0	0	0	0	0	1	0	0	0	0
6	0	0	1	0	0	0	0	0	0	0	0	0	0	0
8	0	0	1	0	0	0	0	0	0	0	0	1	0	0
10	0	0	1	0	0	0	0	0	0	1	0	0	0	0
12	0	0	1	0	0	0	0	0	1	0	0	0	0	0
15	0	1	0	0	1	0	0	0	0	0	1	0	0	0
18	0	0	1	0	0	0	1	0	0	0	0	1	0	0

Well Field Module - 15 MW Plant Size
Cash Flow (cont.)

year	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Field Installation (Tangible)																
Field Installation (Intangible)																
Makeup Well (Tangible)	0	1659	0	0	0	0	2018	0	0	0	0	0	2553	0	0	0
Makeup Well (Intangible)	0	4976	0	0	0	0	6054	0	0	0	0	0	7660	0	0	0
Makeup Well Contingency																
Totals :																
Binary Lookup Table for the																
Timing of Makeup Wells																
plant size (net mW)	15	16	17	18	19	20	21	22	23	24	25					
5	0	0	0	0	0	0	0	0	0	0	0					
6	1	0	0	0	0	0	0	0	0	0	0					
8	0	0	0	0	0	0	0	1	0	0	0					
10	0	0	0	0	1	0	0	0	0	0	0					
12	0	1	0	0	0	0	0	0	0	0	0					
15	0	1	0	0	0	0	0	1	0	0	0					
18	0	0	1	0	0	0	1	0	0	0	0					

APPENDIX D

TABLE OF SPREADSHEET VARIABLES AND FORMULAS

Plant Module Data and Calculations					
Variable Name	Description	Units	Input Value	Calculated Value	Formula
Brine_Rate	Brine Rate	klb/hr/mW	240		
cap_plnt_kw	Total Plant Capital Cost per kW	$/kW		1881.55	= subtotal + plnt_contingency + plnt_profit
land_cost	Transmission Line Land Cost	$k		389	= 0.07 * line_cost
line_cost	Total Transmission Line Construction Cost	$k		5551	=line_length * line_unit_cost
line_length	Transmission line length	miles	10		
line_unit_cost	Line Construction Unit Cost	$k/mile	555		
plant_gross	Gross Power Production	mW		6	= CEILING((plant_net * 1.2),1)
plant_net	Net Power Production	mW	5		
plnt_cont_rate	Construction Contingency Rate	fraction	0.1		
plnt_contingency	Plant Contingency Cost	$/kW		155.5	=plnt_cont_rate * subtotal
plnt_foam	Plant Fixed O&M Annual Cost	$k/kW/yr		47	= plnt_foam_rate / 100 * tcap_plant * 1000 / plant_net / 1000 / cap_fac
plnt_foam_rate	Plant Fixed O&M Rate	%	2		
plnt_prof_rate	Contractor's Profit Rate	fraction	0.1		
plnt_profit	Contractor's Profit	$/kW		171.05	=plnt_prof_rate * (subtotal + plnt_contingency)
plnt_voam	Plant Variable O&M Cost	mills/kWhr		2.68	= plnt_voam_rate / 100 * tcap_plant * 1000 * 1000 / plant_net / 1000 / 8760 / cap_fac
plnt_voam_rate	Plant Variable O&M Rate	%	1		
substation_cost	Substation Cost	$k		555	= 0.1 * line_cost
subtotal	Sum of Capital Costs for Plant Components	$/kW		1555	=sum of listed plant components
tcap_plant	Total Plant Capital Cost	$k		9407.75	= plant_net * 1000 * cap_plnt_kw / 1000
tcap_trans	Total Transmission System Cost	$k		6495	= line_cost + land_cost + substation_cost
total_brine	Total Brine Flow	klb/hr		1440	=plant_gross * Brine_Rate

Field Module Data and Calculations:

Variable Name	Description	Units	Input Value	Calculated Value	Formula
brine_rate	Required Brine Flow Rate Per mW	klb/hr/mW	240		
cap_dry	Dry Well Cost	$k/well		2743	= 0.7 * cap_prod
cap_explore	Exploration Cost	$k	8000		
cap_inj_pipe	Inject Pipe Cost Per Well	$k/well	500		
cap_inj_pump	Injection Pump Cost	$k/pump	150		
cap_prod	Production Well Cost	$k/well		3918	= VLOOKUP(Depth, well_costs, 2, TRUE)
cap_prod_pipe	Production Pipe Cost (Installed)	$/ft	50		
cap_prod_pump	Production Pump Cost	$k/pump	140		
Depth	Production Well Depth	feet	10000		
dry_hole	Dry Hole Ratio		0.1		
fld_cont_rate	Field Contingency Cost Rate	fraction	0.15		
fld_foam	Field Fixed O&M Cost	$/kW-yr		52	= ((tcap_field * fld_foam_rate / 100) + (pv_well_repl_intgbl * (1+ fld_cont_rate)* crf)) * 1000 / (plant_net * 1000) / cap_fac
fld_foam_rate	Field Fixed O&M Rate	%	0.5		
fld_voam	Field Variable O&M Cost	mills/kWh		3	= fld_voam_rate / 100 * tcap_field * 1000 * 1000 / plant_net / 1000 / 8760 / cap_fac
fld_voam_rate	Filed Variable O&M Rate	%	0.25		
flow_per_well	Average Brine Production Per Well	klb/hr/well	525.6		
idc	Intangible Drilling Cost	$/kW-yr		51	= (pv_well_repl_intgbl * (1+ fld_cont_rate)* crf) * 1000 / (plant_net * 1000) / cap_fac
no_dry	Total Number of Dry Wells			1	= CEILING(dry_hole * total_no_wells, 1)
no_inj	Number of Injection Wells			1	= CEILING(no_prod / Prod_to_Inj,1)
no_prod	Number of Production Wells Required			3	=CEILING(total_brine / flow_per_well,1)
plant_gross	Plant Gross Power Output	mW		7	=plant_net * 1.25
plant_net	Plant Net Power Output	mW	5		
Press	Reservoir Pressure	psi	4413		
prod_to_inj	Production Well to Injection Well Ratio		4		
spare_inj	Number of Spare Injection Wells		1		
spare_prod	Number of Spare Production Wells		1		
tcap_field	Total Initial Field Installation Cost	$k		41448	(cap_explore + tcap_prod_pump + tcap_prod_pipe + tcap_inj_pipe + tcap_inj_pump + tcap_wells) * (1 + fld_cont_rate)
tcap_inj_pipe	Total Cost of Injection Well Pipe	$k		500	=no_inj * cap_inj_pipe
tcap_inj_pump	Total Cost of Injection Pumps	$k		150	= no_inj * cap_inj_pump
tcap_prod_pipe	Total Cost of Production Well Pipe	$k		721	=IF(no_prod < 5, no_prod * 4806 * cap_prod_pipe, IF(AND(no_prod >4, no_prod < 9), (4 * 4806 + (no_prod - 4) * 9286) * cap_prod_pipe, IF(AND(no_prod >8, no_prod < 13), (4 * 4806 + 4 * 9286 + (no_prod 8) * 6797) * cap_prod_pipe, 0))) / 1000
tcap_prod_pump	Total Cost of Production Pumps	$k		420	= no_prod * cap_prod_pump
tcap_wells	Total Well Cost	$k		26250.6	= total_wells_comp * cap_prod + no_dry * cap_dry
Temp	Reservoir Temperature	degrees F	266		
total_brine	Total Required Brine Flow Rate	klb/hr		1440	=plant_gross * Brine_Rate
total_no_wells	Total Number of Wells			7	= CEILING((spare_prod + spare_inj + no_prod + no_inj) / (1 - dry_hole),1)
total_wells_comp	Total Number of Wells Completed			6	= spare_prod + spare_inj + no_prod + no_inj

Economics Module Data and Calculations					
app_escal	Apparent Escalation	fraction		0.0608	= (1+escal) * (1+infl) - 1
book	Book Life	years	5		
cc	Com. Stock Cost	fraction	0.14		
cr	Com. Stock Ratio	fraction	0.46		
crf	Capital Recovery Factor			0.111983853	= (wcc * (1+wcc)^life) / ((1+wcc)^life - 1)
dc	Debt Cost	fraction	0.12		
depr	Depreciation (SOYD)	fraction		0.089097769	= (2 * crf) * (book - ((1+wcc)^book -1) / wcc / (1+wcc)^book) / (book *(book + 1) * wcc)
disp	Dispersion Allowance	fraction	0.0056		
dr	Debt Ratio	fraction	0.46		
escal	Real Escalation Rate	fraction	0.02		
etc	Energy Tax Credit	fraction	0.1		
fitr	Federal + State Income Tax Rate	fraction	0.38		
infl	Inflation	fraction	0.04		
kk	Int. variable for calculating lev. factor	fraction		0.958591175	=(1+app_escal) / (1+wcc)
lev_dep	Levelized Depreciation	fraction		-0.034178203	= (depr - 1/life) * fitr / (1 - fitr) * -1
lev_factor	Levelization Factor	fraction		1.863412006	= crf * kk * (1-kk^life) / (1-kk)
lfcr	Levelized Fixed Charge Rate	fraction		24306.4256	=wcc + disp + book depreciation + ldepr + lev_inc_tax + letc + pti
life	Plant Life	years	30		
pc	Pref. Stock Cost	fraction	0.1		
pr	Pref. Stock Ratio	fraction	0.08		
pti	Property Taxes & Insurance	fraction	0.03		
wcc	Weighted Cost of Capital	fraction		0.106624	= dc * dr + pc * pr + cc * cr - fitr * dc * dr
	Book Depreciation	fraction		0.005359853	=crf - wcc
	Levelized Income Tax	fraction		0.02490436	= (crf + disp - 1/life) * (1 - dr * dc/wcc) * (fitr / (1 - fitr))
	Levelized Energy Tax Credit	fraction		-0.016321634	= (crf * etc) / (1 + wcc) / (1 - fitr) * -1
	Plant Capital	mills/kWh		17.58	= (tcap_plant * 1000 / (plant_net * 1000)) * lfcr * 1000 / 8760 / lev_factor / cap_fac
	Variable Plant O&M	mills/kWh		5.00	= plnt_voam * lev_factor
	Fixed Plant O&M	mills/kWh		12.51	= plnt_foam * 1000 / 8760 / cap_fac * lev_factor
	Field Capital	mills/kWh		77.62	=((npv_fld_tngbl * 1000 * lfcr) + (fld_inst_intgbl * 1000 * crf)) / (plant_net * 1000) * 1000 / 8760 / lev_factor / cap_fac
	Intangible Drilling	mills/kWh		10.75	= idc * 1000 / 8760 * lev_factor
	Variable Field O&M	mills/kWh		5.51	= fld_voam * lev_factor
	Fixed Field O&M	mills/kWh		11.02	= fld_foam * 1000 / 8760 * lev_factor
	Transmission Line	mills/kWh		12.13	= (tcap_trans * 1000) / (plant_net * 1000) * lfcr * 1000 / 8760 / lev_factor / cap_fac
	Subtotal:	mills/kWh		152.12	= SUM(F86:F92)
	Royalties	mills/kWh		15.21	= 0.1 * Preceeding subtotal
	Subtotal:	mills/kWh		167.34	= Royalties + Preceeding subtotal
	Profit Incentive (after tax)	mills/kWh		16.73	=Preceeding subtotal * profit
	Total Cost of Electricity:	mills/kWh		184.07	= Preceeding Subtotal + Estimated Combined Taxes