DESIGN, CONSTRUCTION AND OPERATION OF GEYSERS UNIT 18

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INTRODUCTION

Background

The Geysers are located in the Sonoma and Lake County portion of the Mayacamas Mountains in Northern California. Pacific Gas and Electric (PG&E) owns and operates 18 of the 32 power plants at The Geysers. Total installed PG&E capacity is 1,302 MW, enough electricity for the cities of San Francisco and Oakland. Unit 1 was placed in operation in 1960, and Unit 18 started up in early 1983.

This paper covers the evolution of The Geysers, from conception to operational experience. Specific emphasis is placed on Unit 18.

Need For Project

In the early 1970s, the planning process was started for Unit 18. Load growth projections indicated new generation capacity would be necessary in the 1980s. Therefore, work on Unit 18 started in the late 1970s.

Permitting

Prior to construction of Unit 18, several regulatory agency permits were necessary. They are outlinedbelow:

PERMIT	AGENCY	AREA OF FOCUS
Certificate to Construct and Operate	California Energy Commission	Broad overview of all aspects of the ptoject.
Certificate of Convenience and Necessity	California Public Utility Commission	Need of resource
Determination of Compliance	Northern Sonoma County Air Pollution Control	Air quality
Prevention of Significant Deterioration	Environmental Protection Agency	Air quality

The entire permitting process took about 2 years to complete.

Site Selection

Prior to the site selection process, the steam suppliers had to demonstrate to PG&E and our reservoir consultant that sufficient steam existed to support a 30 year plant life. Once that was done, the site selection process started. PG&E used an elaborate selection process. The sites were evaluated in the areas of constructibility, geology, hydrology, terrestrial and aquatic habitat, air quality, and visual and noise impacts. For Unit 18, sixteen original sites were narrowed down to a single site.

Financing

PG&E finances projects similarly to most utilities. During construction, financing comes from the sale of common and preferred stock, bonds, and short term debt. Once a unit is completed it goes into the rate base. At this point, PG&E can start earning a return on the invested capital, pending approval by the CPUC.

FACILITY DESIGN

Power Cycle

The power cycle for Unit 18 is outlined in Figure 1. Each piece of equipment is discussed in more detail in the following sections.

Turbine Generator

Unit 18 uses a Toshiba turbine generator. The turbine is a twin cylinder, double flow unit with six stages of blades rated at 119 MW gross. The turbine material is a modified Cr-Mo-V. Design turbine inlet steam pressure is 100 psig at 340°F with an exhaust pressure of 3 inches Hg absolute. The generator is hydrogen cooled and rated at 137 MVA.

Condensate and Gas Removal Systems

Unit 18 has an Transamerica-DeLaval shell and tube condenser rated at 1.75×10^9 BTU/hr. The condenser has 1-inch tubes and is equipped with a GEA sponge ball-type cleaning system. Due to the high level of noncondensible gases in geothermal steam, the condenser has a gas removal section designed to handle 10,000 pounds per hour of gas. The system uses a two stage steam jet gas ejector with inter- and after-condensers to draw a vacuum on the condenser. To facilitate even gas removal throughout the condenser, the gas removal section has various sized holes. This provides an even pressure distribution throughout the condenser and, hence, even gas removal. The plant has two 100 percent capacity Peerless three stage condensate pumps rated at 4,700 gpm each. Units 13 through 20 utilize a similar condensate system.

Units 1 through 12 use a direct contact condenser. In these systems, water is drawn into the condenser by qravity. Once the steam is condensed, the cooling water-condensate mixture is pumped out through two single stage condensate pumps.

Circulating Water System

Unit 18 has an 11 cell, mechanical draft cross flow cooling tower manufactured by Marley Cooling Tower Company. Each cell has a 200 hp, 28 foot diameter fan. The tower is designed to cool 165,000 gpm of water from 105 to 80 at 65°F wet bulb temperature. The cooling water is supplied by two 50 percent capacity vertical mixed-flow pumps capable of pumping 84,000 gpm each at 97 feet of head. They are manufactured by Byron-Jackson. Total volume of the Unit 18 circulating water system is about 1.0×10^6 gallons.

All Geysers units use a similar cooling tower system. However, since Units 1 through 12 have direct contact condensers, the condensate pumps are used to pump the cooling water to the tower.

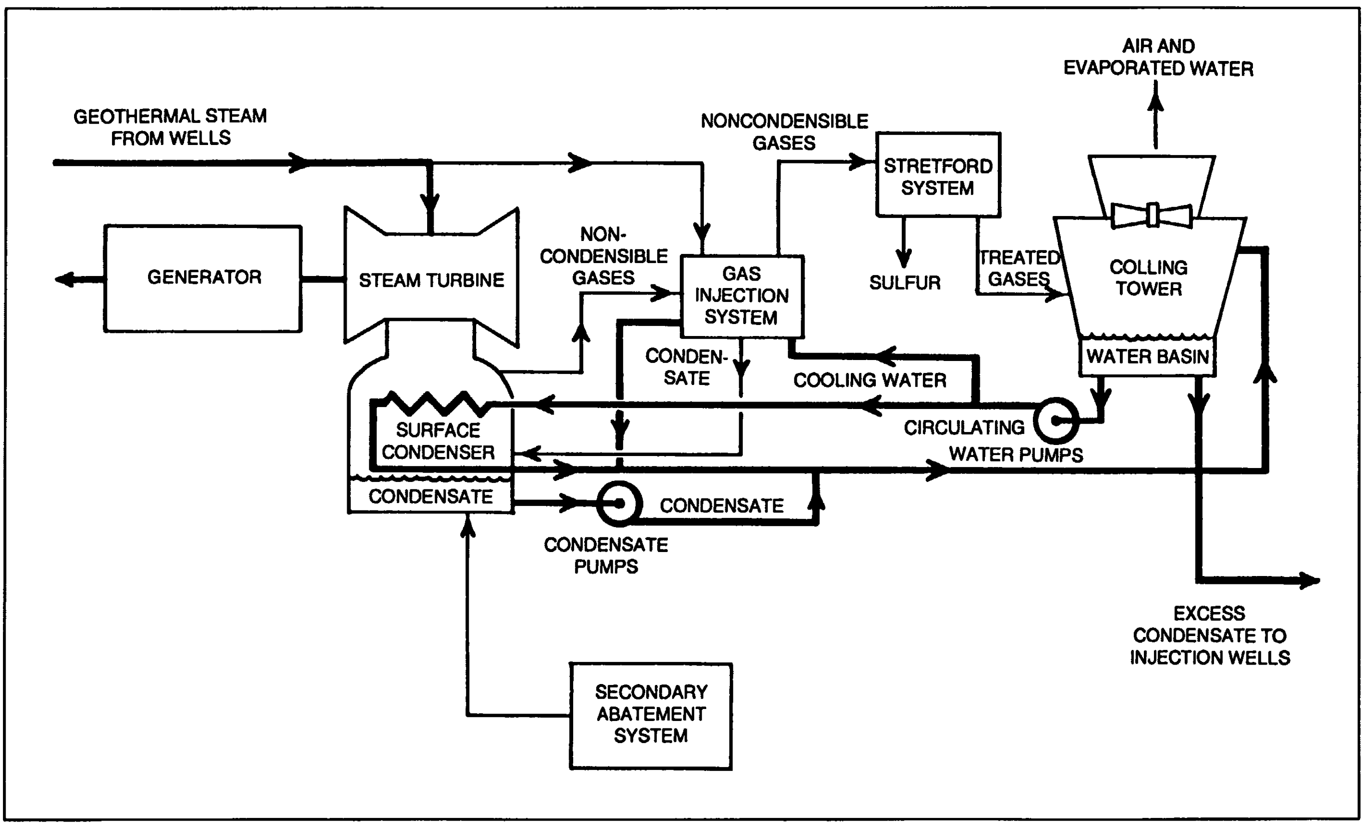


Figure 1. Unit 18 power cycle.

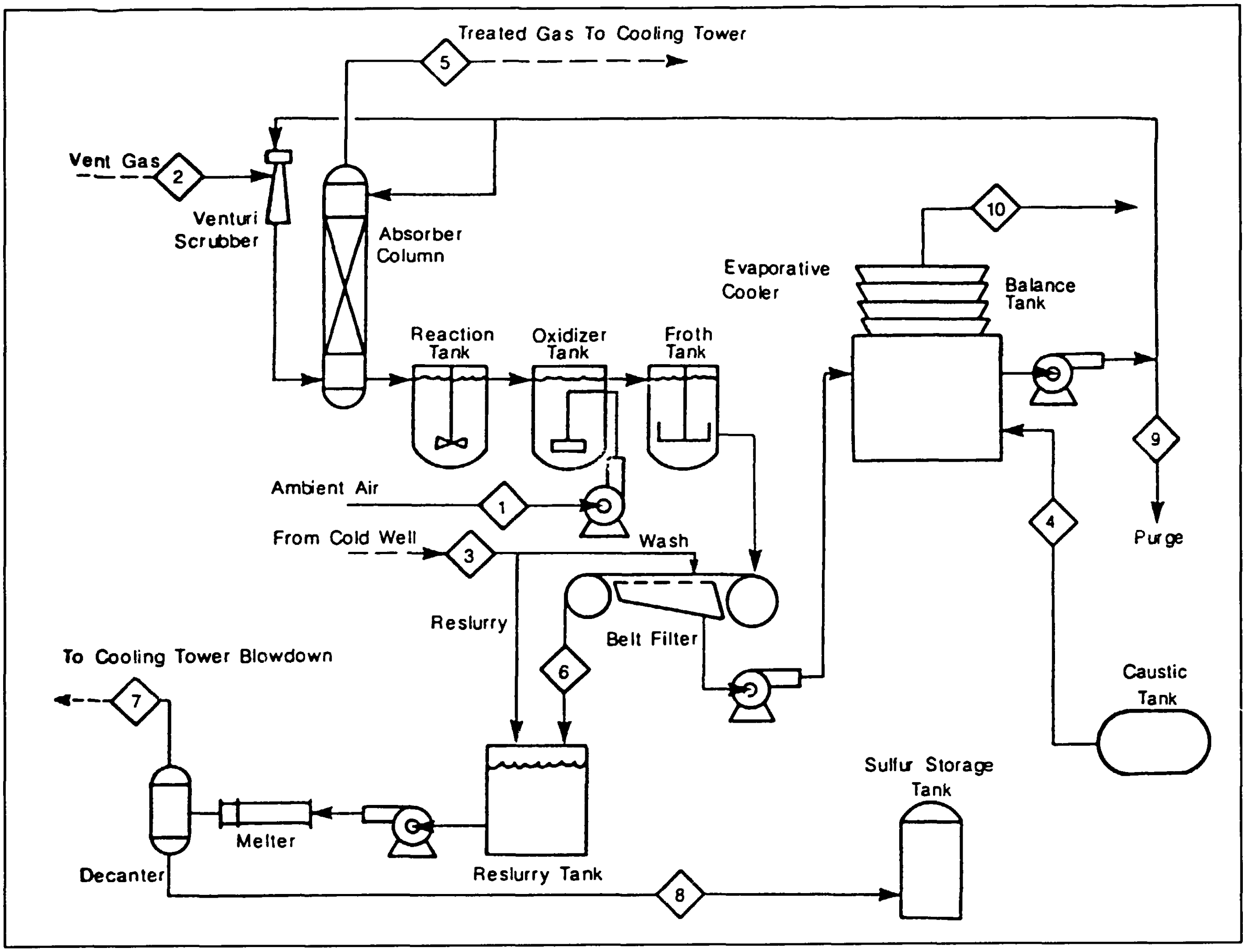


Figure 2. Flow diagram of the Stretford process.

H_2S Abatement System

Primary Abatement Systems — Unit 18 uses a Stretford system to remove H_2S from the off gas that exits the gas removal system (See Figure 2). This system is designed by Parsons for 6 long tons of sulfur per day. The system removes 99.99 percent of the H_2S in the gas phase.

The Stretford system uses a vanadium compound to convert H_2S into elemental sulfur. The sulfur is separated from the system via flotation and is purified by filtration and melting. The vanadium compound is regenerated with air and is reused in the system. Units 13 through 20 also use a Stretford system. These systems, coupled with condensate secondary abatement, typically have operating costs in the $0.25 to 1.30/MW-HR range.

The older units use a variety of H_2S abatement systems. Units 3, 4, 9 and 10 use the original iron/caustic system developed in the mid-1970s. This system uses caustic soda to transfer H_2S from the condenser off gas to the liquid phase (cooling water). An iron compound, Fe/HEDTA, is added to the cooling water to oxidize the H_2S to soluble and solid sulfur compounds. This system has very high costs, typically in the $3 to 10/MW-HR range, depending on H_2S loading.

Units 5 through 8, 11 and 12 use an incinerator system to convert the H_2S in the off gas to SO_2 (See Figure 3). The gaseous SO_2 is removed in the quench tower. This SO_2-laden water, which is acidic, is returned to the cooling water where it reduces the system pH. The lower pH tends to drive more H_2S into the gas phase, thereby reducing treatment costs. Any remaining H_2S in the cooling water is oxidized by Fe/HEDTA to soluble sulfur compounds. These systems typically have operating costs in the $1 to 3/MW-HR range.

Secondary Abatement System — As stated earlier, Unit 18 has a surface condenser. The surface condenser results in most of the H_2S remaining in the gas phase. However, a small amount does dissolve in the condensate and must

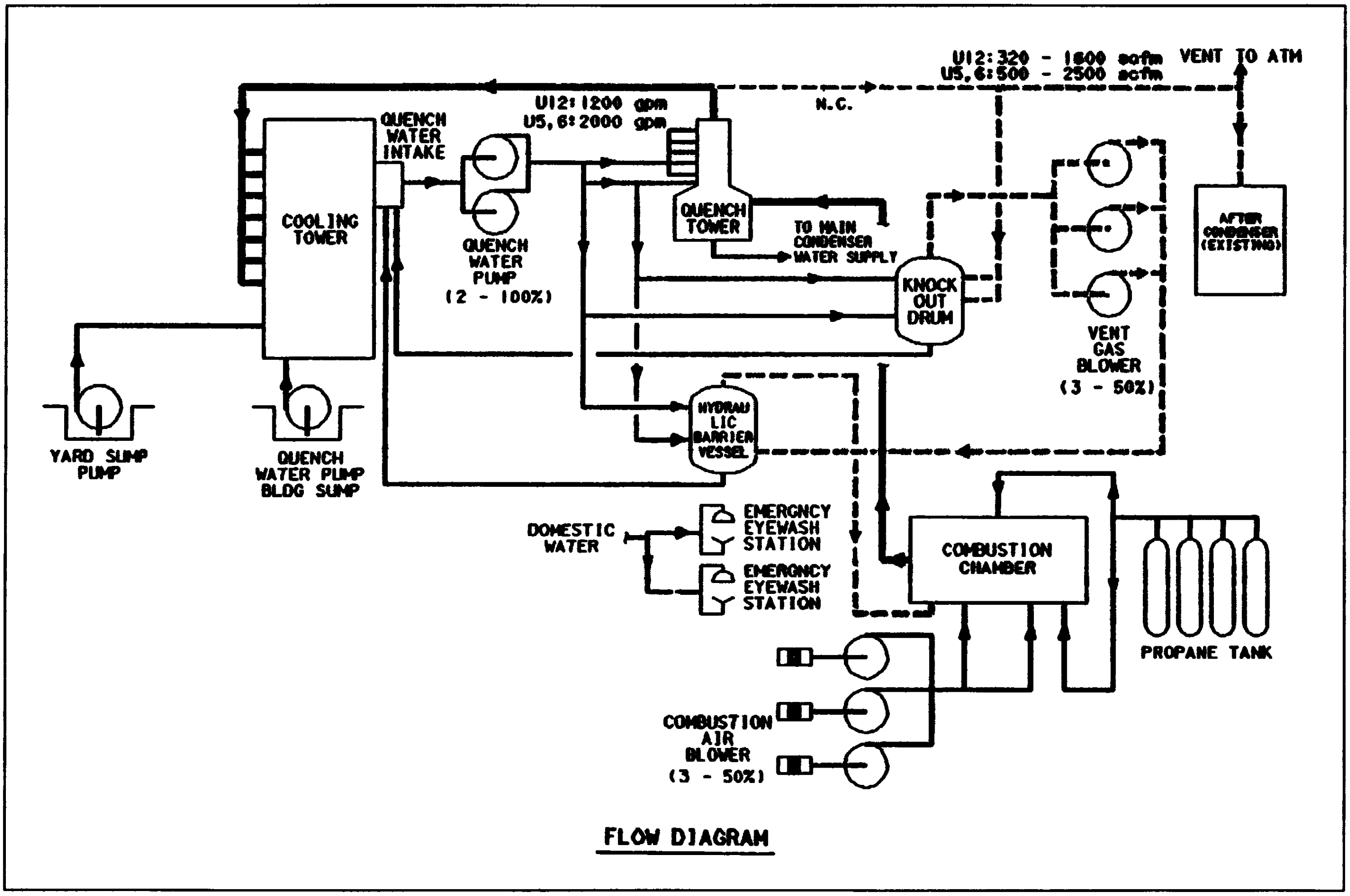


Figure 3. Vent gas treatment.

be treated by a different method. Unit 18 uses an iron compound (Fe/HEDTA) to oxidize the H_2S in the liquid phase. The iron compound is reoxidized as it flows through the cooling tower and is reused.

Electrical Systems

Electricity generated at 13.8 kV is stepped up to 230 kV through a main transformer bank rated at 138 MVA at 55°C. The plant has a SF_6 filled main line circuit breaker. Power from Unit 18 flows to PG&E's Lakeville Substation located in Petaluma, California.

Station service is fed off the generator through three auxilliary transformers. One is rated at 5,600 kVA and has a 4,160 V secondary while the other two are rated at 3,300 kVA each with a 480 V secondary. The 4,160 V system supplies power to the circulating water pumps only. The 480 V system supplies power to the remaining auxilliaries. Other Geysers units have similar electrical systems.

Computer Control Systems

Unit 18 uses a Fox 3 central control system.This system utilizes three computers — analog, digital, and datalogging systems. Following is a general description of each system:

- The analog computer controls all process loops, calculates system status to modify control of these loops, communicates with the digital computer, and maintains schematic representation of the process on the CRT.
- The digital computer provides plant start-up sequencing, automatic system startup and equipment standby starts.
- The datalogger displays all digital and analog alarms as well as providing some alarm history.

Units 16 through 20 use identical computer control systems. Units 13 through15 use an Allan-Bradley PLC and a Honeywell TDC 2000 to control plant process loops and perform startup sequencing.

Hardwired Controls

At Unit 18, hardwired manual controls are provided to permit operation during loss of the central control system. This system consists of:

- Manual/auto stations providing backup auto control of all control valves normally modulated by the Analog Fox 3.

- Control switches for on/off control of all major motors and on/off valves.
- Sufficient annuciation to allow manual operation of the power plant.

Units 16 through 20 have identical systems. Units 1 through 12 have pneumatic systems to control critical process loops. Since these units have few redundant systems there are auto start capabilities only on such equipment as air compressors, oil pumps, seal oil pumps, and auxilliary cooling water pumps.

Supervisory System (SCADA)

All Geysers units are monitored at the plant administration centers. The SCADA system provides alarm capabilities, unit status summaries, voltage adjustment and load changing capabilities. The system, which was manufactured by Landis and Gyr, also generates daily status reports. Much of the SCADA system data points are also on The Geysers Local Area Network, which allows the units to be monitored at the majority of the personal computers.

Civil and Architectural

The Unit 18 turbine building, housing the turbine generator and most of the mechanical and electrical equipment, is approximately 195 feet long, 85 feet wide, and 66 feet high. It is of steel frame construction with fluted metal siding. Several ground level entry doors and two 21 foot wide rolling overhead doors provide personnel and equipment access.

All foundations are constructed of reinforced concrete. They are designed to the requirements of the Uniform Building Code Standards, 1976 Edition, and the Building Code Requirements for Reinforced Concrete (ACI 318-77) by the American Concrete Institute. Foundations are designed using the strength method to resist all applicable loads — dead loads, live loads due to wind, seismic, and operating equipment.

Equipment was designed for a combination of normal steady state operating stresses and seismic stresses. Seismic design was based upon the supporting structure having constant simultaneous accelerations of 0.20g in a horizontal direction and 0.13g in a vertical direction. The turbine generator and condenser designs were not based solely on seismic considerations, but on factors such as operating forces and core vibration. Based on seismic experience at other installations, the Toshiba equipment will not suffer damage with a seismic acceleration of up to 0.5g. The yard at Unit 18 covers about 6 acres. All other Geysers units are of similar construction.

CONSTRUCTION

Site preparation on Unit 18 was started on June 5, 1980. The plant was constructed over a 2-year period and the total project cost was $83 million.

Due to site space limitations, all the major equipment was delivered to Healdsburg by rail and staged until it was ready for installation. The generator stator was a difficult transportation problem. At 278,000 pounds, and with a 3,000 foot elevation gain to the plant, it could not be delivered with a conventional tractor trailer. PG&E used Sheedy, Drayage to deliver the generator. They used a 120 wheel flat bed trailer. The trailer was moved by a conventional tractor in front, a loader-type tractor pushing, and a loader-type tractor pulling the conventional tractor in front. Once on site, jacks and timbers were used to place the stator up on to the turbine deck.

After completion of site grading, foundations were placed. This took about 6 months to complete. An on site concrete batch plant was provided to facilitate this work.

Erection of the structural steel and turbine building shell required about 4 months. The cooling tower was completed in about the same length of time.

Major equipment installation required approximately 6 months. Startup testing began about 24 months from the startup of construction. Following startup testing, initial turbine roll and a 48-hour fullload run, the unit was shutdown for turbine generator bearing inspection. At the end of the 2-week bearing inspection period, the unit was returned to service and released for commercial operation in February 1983.

OPERATIONAL EXPERIENCE

Unit 18 has been one of PG&E's best performing facilities. Since the beginning of operation in 1983, it has averaged 95.6 percent availability. The table below outlines the unit availability.

With 30 years of geothermal operating experience, PG&E has encountered numerous challenges. The major challenges are broken down by system and outlined below:

YEAR	83	84*	85	86	87*	88	89	90*
AVAIL.	96.9	86.4	94.9	99.5	90.2	99.5	98.4	87.3

* = Overhaul Years

Turbine Generator

Geothermal turbines operate under severe conditions. Minor design flaws that would be acceptable operating with pure steam can become a problem in the geothermal environment. The problems this system has experienced are outlined below.

Second stage blade failures have occurred in an increasing frequency on some turbines since the early 1970s. To date, about 50 second stage blade failures have occurred. Through extensive vibration modal analysis, we were able to determine that there was a blade natural frequency close to the second stage nozzle passing frequency (NPF). The problem was solved by redesigning the second stage diaphragm such that NPF is further from resonance.

Due to the corrosive nature of geothermal steam, numerous turbine rotors have experienced wheel and blade root stress corrosion-cracking (SCC). In one case, a turbine only operated for 18 months before severe SCC was observed. PG&E has taken several approaches to mitigate this problem:

1. The failed rotors have had the damaged wheels machined off and new wheels fabricated by weld repair. Once a new stage is built up, it is heat treated and machined down to original contour. This has provided us with a replacement rotor at about one-tenth the cost of a new rotor. This has been done on a Unit 18 rotor which is scheduled to go into service in September 1990.
2. Desuperheating the steam has been implemented at all units with surface condensers and three of the direct contact units. The steam is desuperheated by spraying condensate into the main steam line. This removes a majority of the silica, boron and other trace minerals that are dissolved in the steam. Although we are not sure what contaminants are promoting the SCC, desuperheating the steam seems to reduce it.

   Desuperheating the steam also reduces mineral deposits on the stationary blades, thereby allowing the turbine to operate at a lower inlet pressure.
3. Chloride has been found in trace to substantial quantities (50 to 1,000 ppb) in nearly every units steam supply. It appears to be responsible for several turbine blade failures. (Chloride concentrations in the failed section of the blades were on the order of 1/2 to 2 percent). This has been mitigated by:
   a) Desuperheating the steam at the main separator;
   b) Treating the wells with the highest concentration of chloride with sodium hydroxide at the wellhead.
4. PG&E is trying several different blade coatings, such as sulfamate Ni and Ni-Cd electroplates, ion-vapor deposited Al, Ni-Al diffusion, plasma sprayed FeCrAlY and Cr_3C_2 and electroless Ni. These have been installed on several stationary blades at Unit 11. Their effectiveness should be evaluated by early 1991.
5. As a final solution, PG&E has purchased new style rotors at Units 9, 10, 14, 16, and 20. These rotors have a much larger wheel, blade and blade root design that reduces stresses in these areas by 36 percent.

PG&E has implemented several efficiency improvements on the turbine. (Some will be done at Unit 18 during the 1990 overhaul). The major improvements have been:

a) Reduced turbine interstage belly drain size from 1-1/2 to less than 1/2-inch. This reduction still allows condensate to be drained and substantially reduces the amount of steam that passes directly into the condenser. This was a very low cost solution. It improved unit heat rate by about 1/2 percent.
b) Turbine tip seals have been installed to reduce blade to diaphragm clearances. Using an in-plant designed and installed tip seal, PG&E was able to implement this improvement for about $35,000 per rotor. Efficiency improvements are in the 1-1/2 to 3 percent range.

PG&E has experienced extensive lube and control oil system problems on Units 3, 4, 11, 13, 14, 15, 17, and 18. Investigation revealed that the carbon steel oil piping was corroding due to the H_2S in the geothermal environment. Corrosion products eventually became dislodged, contaminating the oil and plugging up the control and lube oil system. Attempts at cleaning were somewhat successful, although the piping would eventually corrode again. PG&E has installed two systems that have mitigated the oil system problems:

1. Full flow oil filters were installed on the bearing supply line. This removes nearly all the contamination in the oil.
2. A spray system was installed in the oil return line to the main reservoir. This line is large (24 inches) and is not completely full of oil except on a unit trip. This uncoated area was where a lot of corrosion was found. Continuously spraying oil on the unwetted section of pipe substantially reduces corrosion.

As stated earlier, desuperheating the steam does help maintain a cleaner steam path. However, occasionally deposits form that must be removed by water washing. In this process, desuperheated steam (at saturation) has additional water added to reduce steam quality to about 98.5 percent. The impact of the water on the first stage blades removes mineral deposits, allowing the plant to operate at a lower inlet pressure. This is done periodically on an as-needed basis.

Condenser and Gas Removal Systems

The two types of condensers (direct contact and surface) used at The Geysers have different problems. They will be discussed separately.

The direct contact condensers are fairly simple. However, the systems are prone to plugging in the water distribution trays, particularly on units without incinerators (incinerators minimize the formation of solids in the cooling water, thereby minimizing plugging). These trays must be periodically cleaned. They have also had gas removal system problems on units with high levels of noncondensible gasses. In 1986, Unit 5 was instrumented with thermocouples throughout the condenser. Testing showed that the cooling water temperature differential between the top and bottom of the condenser was about 15°F at the end of the condenser closest to the gas removal piping, but only 5°F on the end opposite the gas removal section. This indicated a large quantity of steam was passing into the gas removal section uncondensed. This led to higher condenser back pressure and a high thermal load on the intercondenser. This problem was mitigated by installing a manifold on each side of the condenser with four gas removal pipes running the length of the gas removal section.

The gas removal systems on all Geysers units from Unit 13 up were designed for 1 percent noncondensible gases. Actual gas loading at Units 16, 18, and 20, is only about 0.2 percent. On these units, PG&E has installed small capacity jets to reduce auxilliary steam usage. This resulted in steam usage reduction of about 40,000 lb/hr, or about 2.5 MW.

Shortly after the start up of Unit 15 (the first unit with a surface condenser) it became apparent that the condenser tubes were fouling and had to be manually cleaned. This necessitated a unit outage about every 6 months. In 1984, PG&E installed a condenser cleaning system on Unit 13. This system uses sponge balls that are circulated through the condenser tubes, removing any deposits. The balls are collected at the condenser outlet in a large screen and are pumped back through the system. This system was successful in eliminating condenser cleaning and has since been installed at Units 14 through 20.

H_2S Abatement Systems

The H_2S abatement systems at The Geysers have evolved from being responsible for 55 percent of PG&E's annual Geysers maintenance and operating expense in 1985 to 32 percent in 1989. This dramatic reduction was accomplished by the implementation of numerous system improvements. The major ones are outlined below:

The most dramatic cost reductions were achieved by the installation of the incinerator systems at Units 1, 2, 5-8, 11, and 12. These units previously used the iron/caustic systems (discussed in Section II-E). These systems used very large amounts of chemicals, and produced large quantities of waste, costing PG&E about $19 million per year. Installation of the incinerator systems reduced chemical costs to only $5.7 million per year. This system also produces soluble sulfur compounds thereby reducing waste generation by 90 percent plus and minimizing equipment fouling problems. The total installation cost of the incinerators was about $63 million.

The Unit 18 Stretford originally used direct melting of the sulfur-Stretford solution mixture to separate the sulfur. (See Figure 2) This method resulted in:

1. Contamination of the sulfur product.
2. High solids level in the circulating solution.
3. High chemical usage.
4. Excessive foaming.

It appeared that a chemical change took place when the Stretford solution was heated to the melting point of sulfur and subsequently returned to the system. This change was eliminated by first filtering the mixture, thereby removing the solution prior to melting. Several other methods have been used to reduce secondary abatement chemical costs.

As discussed in Section II-E, PG&E uses an iron compound to treat H_2S dissolved in the condensate. Extensive study had shown that the H_2S emissions from the cooling tower stacks were highest at the first cell of the tower and lowest at the last cell. This difference was traced to the difference in reaction time between the first and last cells (about 50 seconds). Bench testing indicated the reaction was time limited. By providing a longer reaction time, the iron concentration could be reduced. In order to provide this time, the condensate was routed back to the circulating water pump intake structure. This provided about 50 seconds additional reaction time, allowing iron usage to be reduced by 50 percent. This caused the circulating water temperature to increase by 1°F, but the impact on plant backpressure was less than 0.1-inch Hg.

PG&E has also reduced secondary abatement chemical costs by sending untreated condensate directly to the steam suppliers for injection into the reservoir. We have been able to inject about 50 percent of the condensate, which has reduced chemical costs proportionately.

On the units with direct contact condensers, the iron-H_2S reaction was found to be oxygen limited. Supplemental air compressors have been installed that provide 300 to 500 SCFM of additional air to the condensate exiting the condenser. This has cut iron costs by about 40 percent.

As stated earlier, the Stretford system uses a vanadium compound to catalyze the oxidation of H_2S to elemental sulfur. In California, wastes containing vanadium concentrations over 24 ppm are considered hazardous. This results in high waste handling costs. In an effort to reduce these costs, PG&E tested an iron based system (known as Lo-Cat) at Unit 15. Prior to changing to iron, the Stretford system required several modifications. The inside of the tanks had to be covered with a thick coating to prevent corrosion. (The iron chelate in the solution severely attacks carbon steel.) Likewise, all the carbon steel piping had to be replaced with stainless steel. Testing of the system was inconclusive. The system was able to handle about two times the H_2S loading per gallon of solution, but the chemical costs were roughly two times the cost of the Stretford system. Unit 15 has been shut down due to steam supply problems, so no long term analysis could be made.

MAINTENANCE AND OPERATIONS PRACTICES

The geothermal environment imposes special needs on the maintenance and operational practices. Some of the major ones are outlined below:

Due to the corrosive and erosive nature of geothermal steam, overhauls are conducted more frequently than on fossil facilities. Typical overhaul frequencies are every 2 to

4 years, depending on the age and condition of the power plant. Typical frequencies are outlined below:

UNIT	AGE	OVERHAUL FREQUENCY	COMMENTS
5 & 6	19	2 1/2 yrs.	
7 & 8	18	3	
9 & 10	17	4	Units have Toshiba heavy-duty rotors.
11	15	1 1/2	Existing rotor has SCC.
12	11	2	A-rotor is a first generation weld repair with high hardness in the HAZ.
13	10	3	
14	10	4	Toshiba heavy duty rotor.
15			Shutdown
16 & 20	5	4-5	Toshiba heavy duty rotor.
17 & 18	7	3	

Geothermal steam contains trace amounts of arsenic. When the OSHA arsenic rules were changed in 1981, PG&E did extensive research to determine the best methods for complying with the new regulations. Extensive air monitoring found that arsenic concentrations were well below the PEL of 10 mg/l in nearly all maintenance activities. The only practices that had arsenic concentrations greater than the PEL were needle gunning and grinding on turbine steam path components heavily laden with mineral deposits. When these types of operations are being conducted, the area is barricaded and employees doing the work wear protective coveralls and air purifying respirators. Employees must also clean their glasses, hard hats, boots, and hands following work in this area. As stated earlier, PG&E has found that desuperheating the steam substantially reduces deposits, reducing or eliminating arsenic contamination.

PG&E's geothermal facilities are spread out over a large area. Because this is a 24 hour a day operation, there is a large amount of travel time involved getting operators to and from their facilities. There is also shift turnover 3 times per day, which creates additional lost productivity. PG&E has implemented 12 hour shifts for operations personnel. This has reduced turnover and travel time by one-third, thereby reducing overtime needs from 6 to 3 percent.

STEAM FIELD DECLINE

All of PG&E's units have experienced reduced output due to steam field decline. It has ranged from about 10 percent per year in the western, lower pressure area of the field, to 20 percent in the eastern, higher pressure areas. Major declines started to occur in 1987.

Since Unit 18 is in one of the highest pressure areas at The Geysers, it has had a very high reservoir decline rate and is currently operating at only 75 percent of nameplate rating.

As stated earlier, several plant efficiency improvements have been implemented at Unit 18, they are:

1. Installing smaller gas ejectors that have a capacity closer to actual operating conditions (which are much lower than design).
2. Adding a steam desuperheating and water wash system to help maintain a clean steam path, thereby reducing turbine inlet pressure and increasing well deliverability.

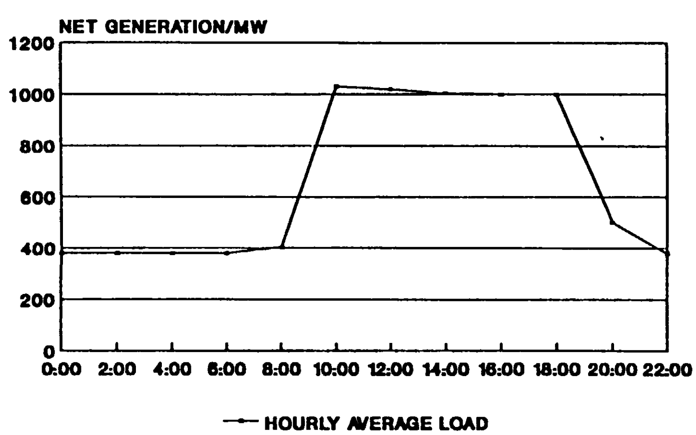
Although PG&E pays for the steam by the kW-hr, it was economical to implement these changes based solely on replacement power costs. For example, the smaller jets improve output by about 2.5 MW. Within the first year, at current replacement power costs, the project resulted in a savings that exceeded the cost of replacing the jets.

As a final method for mitigating the steam field decline, PG&E and its steam supliers have conducted a test to determine the effectiveness of moving from a base load operation to cycling. The test was conducted between May 2 and May 15, of 1990.

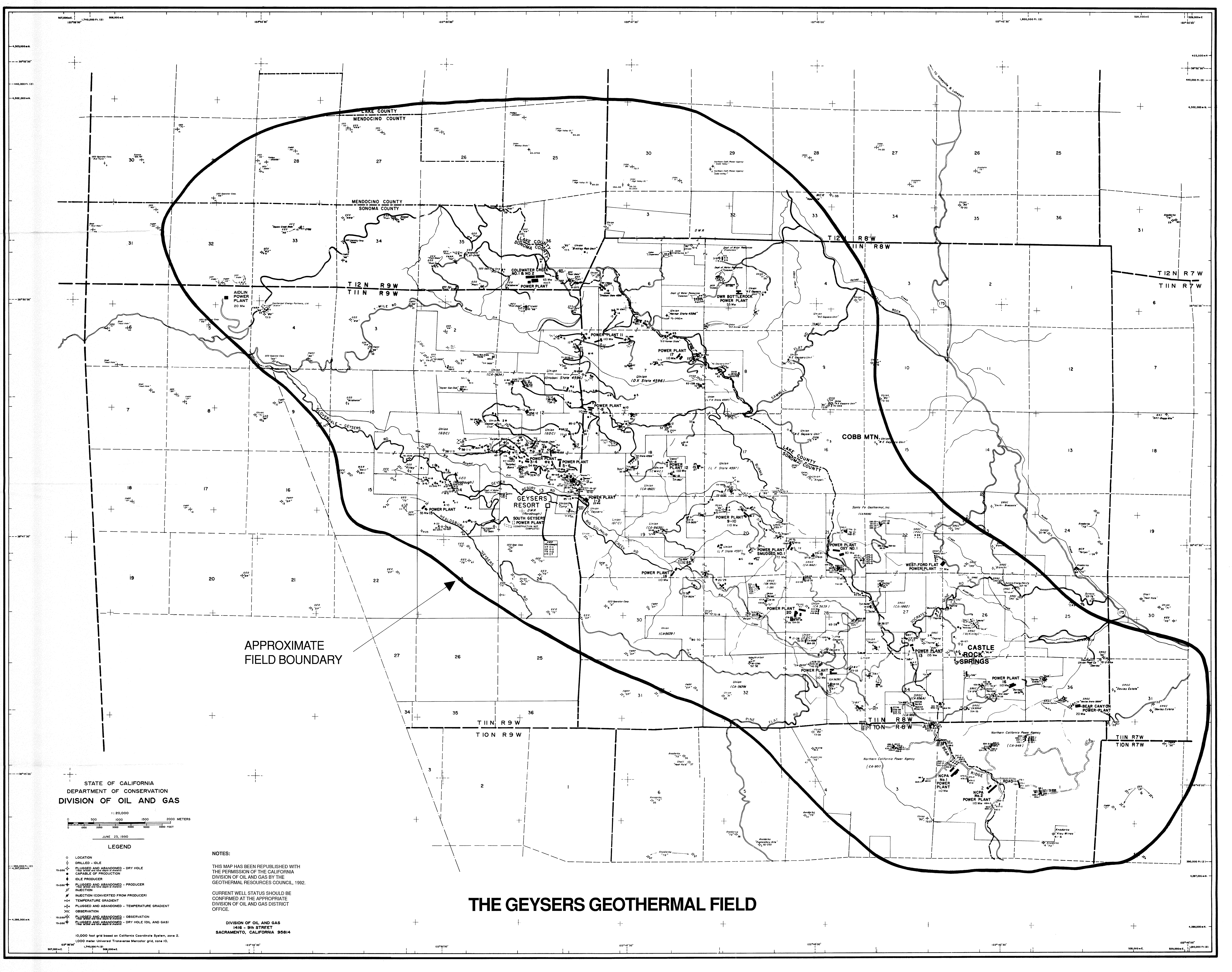
Prior to the test, the plants were base loaded at maximum field capacity, which was about 890 MW. During the test, the load was cycled down at 21:00 each night and raised to maximum field capacity by 10:00 the following morning. A typical daily cycle can be seen in Graph I.

As can be seen by this graph, maximum field capacity increased to 1,032 MW at the peak. The load declines from this maximum until load is dropped back to minimum, each night.

These test results are still being evaluated. They are currently being compared to the Unocal reservoir model to see how accurately the model predicted the reservoir's behavior. No firm conclusions on future operating modes have yet been made.



Graph 1. Typical daily load during cycling test.



THE GEYSERS GEOTHERMAL FIELD
APPROXIMATE FIELD BOUNDARY
LAKE COUNTY
MENDOCINO COUNTY
SONOMA COUNTY
T12N R9W
T11N R9W
T12N R8W
T11N R8W
T12N R7W
T11N R7W
T10N R9W
T10N R8W
T10N R7W
AIDLIN POWER PLANT 20 Mw
COLDWATER CREEK NO.1 & NO.2 POWER PLANT
DWR BOTTLEROCK POWER PLANT 55 Mw
GEYSERS RESORT
SOUTH GEYSERS POWER PLANT
COBB MTN.
WEST FORD FLAT POWER PLANT
POWER PLANT SMUDGE NO.1
POWER PLANT OXY NO.1
CASTLE ROCK SPRINGS
BEAR CANYON POWER PLANT
NCPA No.1 POWER PLANT 110 Mw
NCPA No.2 POWER PLANT 110 Mw
STATE OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS
1:20,000
0 500 1000 1500 2000 METERS
0 1000 2000 3000 4000 5000 6000 FEET
JUNE 23, 1990
LEGEND
LOCATION
DRILLED - IDLE
PLUGGED AND ABANDONED - DRY HOLE (Year drilled and total depth in meters)
CAPABLE OF PRODUCTION
IDLE PRODUCER
PLUGGED AND ABANDONED - PRODUCER (Year drilled and total depth in meters)
INJECTION
INJECTION (CONVERTED FROM PRODUCER)
TEMPERATURE GRADIENT
PLUGGED AND ABANDONED - TEMPERATURE GRADIENT
OBSERVATION
PLUGGED AND ABANDONED - OBSERVATION (Year drilled and total depth in meters)
PLUGGED AND ABANDONED - DRY HOLE (OIL AND GAS) (Year drilled and total depth in meters)
10,000 foot grid based on California Coordinate System, zone 2.
1,000 meter Universal Transverse Mercator grid, zone 10.
NOTES:
THIS MAP HAS BEEN REPUBLISHED WITH THE PERMISSION OF THE CALIFORNIA DIVISION OF OIL AND GAS BY THE GEOTHERMAL RESOURCES COUNCIL, 1992.
CURRENT WELL STATUS SHOULD BE CONFIRMED AT THE APPROPRIATE DIVISION OF OIL AND GAS DISTRICT OFFICE.
DIVISION OF OIL AND GAS
1416 - 9th STREET
SACRAMENTO, CALIFORNIA 95814