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GEOTHERMAL POWER PROJECT OF PACIFIC GAS AND ELECTRIC COMPANY AT THE GEYSERS, CALIFORNIA

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ABSTRACT

Utilization of the earth's geothermal energy resources for production of electric power has been achieved in several areas throughout the world. The only commercial development in operation in North America is at "The Geysers" north of San Francisco. A 12 MW unit commenced operation in 1960, and additional units have been added bringing the total capacity to 192 MW. Design and construction now under way will increase this to 522 MW by the end of 1974. There are plans for continuing increments of approximately 100 MW per year as steam reserves are developed. The steam supply, mechanical and electrical features, operating experience, and special problems are described.

1. INTRODUCTION

1.1 Background

It is generally believed the interior of the earth is composed of a high temperature fluid called magma. The temperature gradient between this magma and the earth's surface causes the magma's heat to flow slowly toward the surface where it is lost to the atmosphere. This cooling of the magma formed the earth's crust, which has reached an average thickness of only 20 mi (32 km). From the highly irregular features of the earth's surface, it is obvious the crust has been subjected to considerable strain. Mountain ranges have been pushed up. Earthquakes quickly shift the earth's surface over large areas, and some areas are in slow but perceptible motion relative to others. If the magma works to the surface at weak spots in the crust, the result is a volcano. In some other areas, deep faults in the crust permit surface water to come in contact with the hot solidifying magma. Additionally, the molten magma itself contains water which it releases as it solidifies. The heated water, or steam, rises to the surface and is manifested as hot springs, geysers, or fumaroles. In some of these areas, drilling operations have developed steam or hot water for the production of electric power.

The oldest and largest geothermal power installation is near Larderello, Italy, where 380 MW[1] of electric power are produced using dry steam from a vapor dominated geothermal reservoir.[2] The power development dates from 1904. On the North Island of New Zealand, 175 MW of geothermal capacity is installed at the Wairakei field,[3] and in Mexico in the State of Baja California, a 75 MW plant[4] is now under construction. Both these installations derive their energy from liquid dominated geothermal reservoirs.[2] Steam for their turbine-generators is flashed off the hot water by reducing its pressure.

In the year 1972, the Pacific Gas and Electric Company has the only geothermal power installation in the United States. It currently consists of six generating units with a total capacity of 192 MW. This plant, like Larderello, is powered by steam from a vapor dominated geothermal reservoir. The plant is in an area called "The Geysers," in the Mayacmas Mountains of northeastern Sonoma County, about 80 mi (129 km) north of San Francisco. This area was discovered in 1847 by a bear hunter who was reported to have said he had found the "Gates of Hell" when he first viewed the area's many hot springs and fumaroles (there are no true geysers at "The Geysers"). In the 1860's a stage road was established into the area and a resort featuring hot mineral baths was built. The original burned down years ago and a smaller resort is there now. The first efforts to develop this area for electric power were made in the 1920's. Several rather shallow wells were drilled which did produce steam. Two small reciprocating steam engine driven generators were installed for lighting the resort, and this was truly the first geothermal power plant in the United States.

1.2 Project Development

In 1955 the Magma Power Company of Los Angeles obtained leases on most of the property around the thermal manifestations. The next year Magma was joined by the Thermal Power Company of San Francisco and they commenced a drilling program. Six successful steam wells were drilled. PG&E was invited to test these wells and found their total output was about 300,000 lb/h at 115 psig with a small amount of superheat.

Engineering studies and cost estimates showed that small geothermal steam turbine-generator units could produce power economically if the steam could be purchased for about 2.5 mills/kWh. In 1958 PG&E signed a contract with the Magma-Thermal joint venture which provided that Magma-Thermal would drill the steam wells and install the steam gathering piping system while PG&E would install a 12 MW turbine-generator unit and buy the steam. This unit would be followed by others as the steam supply was proven by flow tests of the completed wells, and provided further that the first unit was successful.

The Geysers Unit 1 went into service in 1960. The turbine-generator used had originally been installed at Sacramento, California in 1924. Unit 2, which started up in 1963, is in the same building with Unit 1 and has a slightly higher rating of 14 MW.

In 1964 and 1965 the Earth Energy Company, a subsidiary of The Pure Oil Company, secured extensive geothermal leaseholds adjacent to the Magma-Thermal holdings. Pure Oil was later merged with the Union Oil Company of California. In 1967 Magma-Thermal and Union merged their holdings into an expanded joint venture which now controls some 15,000 acres of geothermal property in The Geysers area. Union Oil Company is the operating partner.

Units 3 and 4 are also located adjacent to each other about 1½ mi northwest of the first two units. They were put in service in 1967 and 1968 and are rated 28 MW each. Unit siting is determined mainly by the location of the steam wells. Units 5 and 6 were placed in operation in 1971 and are rated 55 MW each. They are located about

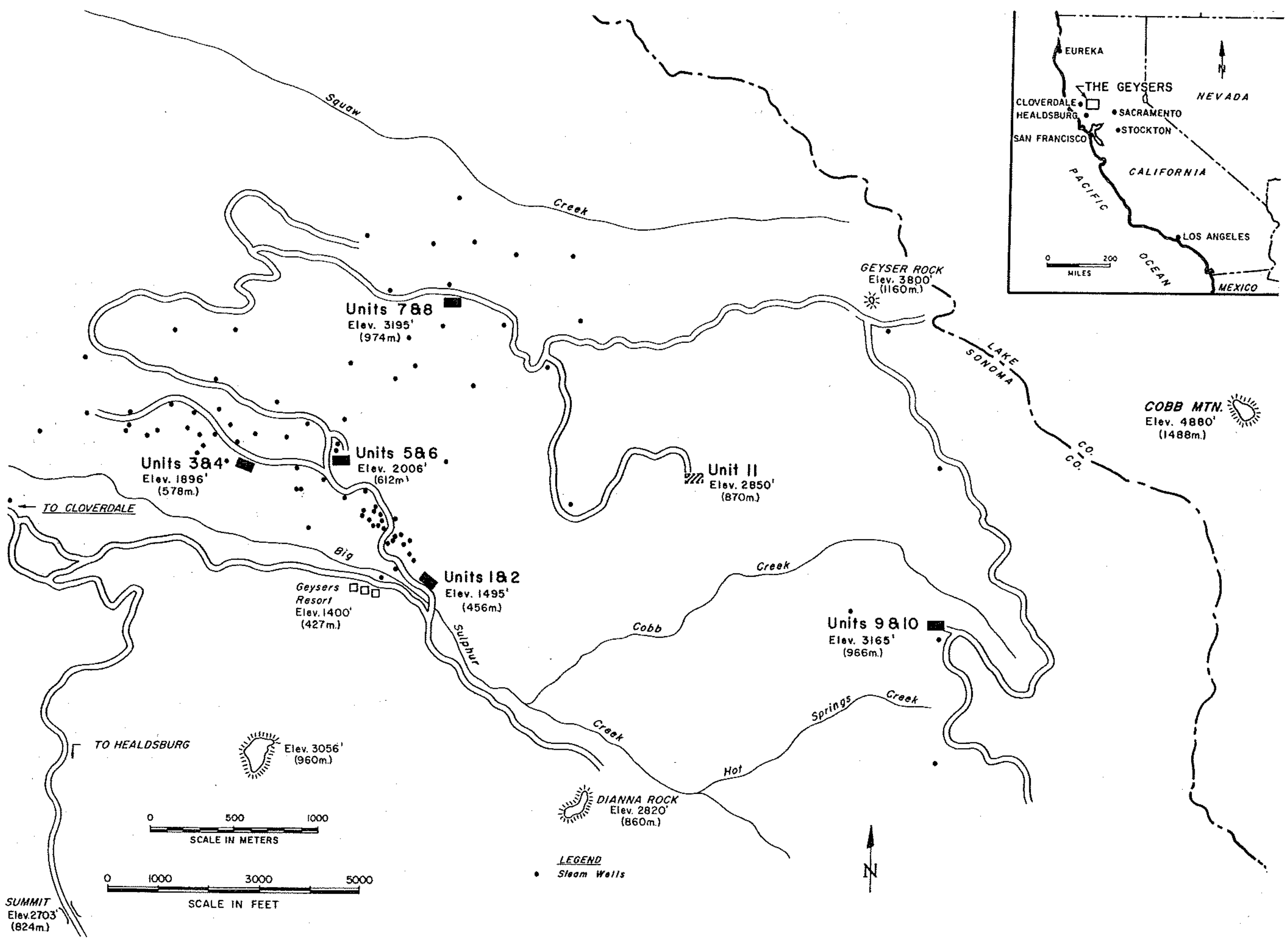

Fig. 1 Map of The Geysers area.

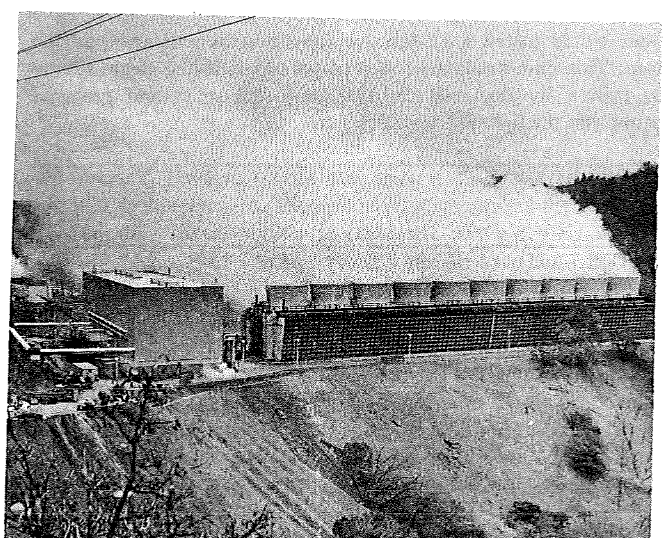

Fig. 2 Units 3 and 4 and mountainous terrain of The Geysers.

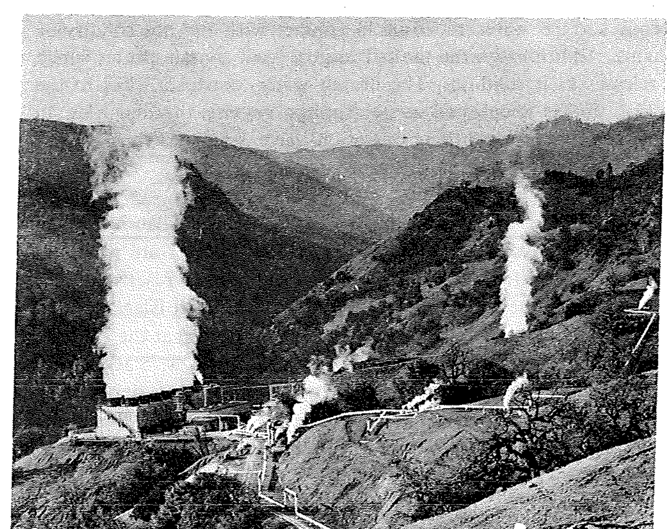

Fig. 3 Units 5 and 6 with Units 3 and 4 in the distance.

midway between Units 1 and 2 and Units 3 and 4. Units 7 and 8 and 9 and 10 are also rated 55 MW and will be put in service in 1972 and 1973. Unit 11 is a 110 MW unit which will bring the total capacity of The Geysers Power Plant up to 522 MW when it starts up in 1974. Figure 1 is a map of The Geysers area showing how the units are dispersed over a wide area. It is about a 30 minute drive from Units 1 and 2 to the site for Units 9 and 10. Figure 2 shows Units 3 and 4 and some of the steam lines. Figure 3 shows Units 5 and 6 situated on top of a ridge with Units 3 and 4 in the background.

2. STEAM SUPPLY

The early steam wells were drilled adjacent to the original natural steam vents on 200 ft to 500 ft (60-150 m) centers to depths of 400 ft to 1,000 ft (120-300 m). These produced steam flows in the range of 40,000 to 80,000 lb/h. Employing improved drilling technology, the steam suppliers have for the last six years tapped a deeper and higher pressure steam zone at depths between 2,000 ft (600 m) and 7,000 ft (2,100 m).

Wells up to 9,000 ft deep have been drilled. Many of these deep wells are far removed from the natural steam outcroppings and produce considerably higher flows. One was tested recently at 380,000 lb/h flow. A typical recent well produces 200,000 lb/h.

PG&E will install about 100 MW a year as long as the suppliers prove additional reserves for this added capacity 5 years before operation, and as long as the power is economical to PG&E. The additional reserves are proved by both step-out drilling and study of production history. The capacity of The Geysers steam field cannot be determined now, as steam has been taken from only a small portion of the suppliers' holdings. Some have estimated up to a 1,000 MW and more might ultimately be available. To the east and south of the steam suppliers' holdings, others are drilling exploratory wells so the reservoir may be even more extensive.

The steam suppliers provide the steam gathering piping system connecting the well heads with the generating units. The steam supply line to a 55 MW unit is 36 in OD, 3/8 in wall carbon steel pipe. It would typically be connected to about 7 steam wells. Centrifugal steam separators are installed in the steam pipes to remove any particulate matter and moisture. The steam contains about 1% noncondensable gases in approximately the following amounts:

Carbon Dioxide	.79
Ammonia	.07
Methane	.05
Hydrogen Sulfide	.05
Nitrogen and Argon	.03
Hydrogen	.01
	1.00%

The steam also contains powderlike dust which deposits out in protected areas of the turbines. This dust builds up on the inside of the turbine blade shrouds in the first two stages. In lower stages, the buildup appears to be washed away by water in the steam. This shroud buildup has caused blade and shroud failures. Earlier units have had heavier-duty replacement blades and shrouds installed to mitigate this problem. A turbine water-wash program is now being tried which it is believed will also improve this situation.

3. MATERIALS AND CORROSION

Prior to starting detailed design of the first unit, extensive studies were conducted to determine the suitability of various materials for the mechanical equipment and piping. It was found that the steam as it comes from the wells with a slight amount of superheat is relatively noncorrosive. Carbon steel can be used successfully for piping in this area, and the turbines do not require special corrosion resistant materials. As the steam condenses in the condenser, the noncondensable gases become more concentrated, the hydrogen sulfide partially oxidizes to very weak sulfuric acid, and the corrosiveness of the steam and condensate are greatly increased. Carbon steel, copper based alloy, zinc, and cadmium are unsuitable in this area. Austenitic stainless steels, aluminum, or epoxy-fiber glass are satisfactory. Concrete requires a coal tar epoxy coating to prevent sulfate deterioration.

Hydrogen sulfide in the air causes serious problems in the electrical equipment because it is corrosive to copper, copper alloys, and silver among other things. Few special features to prevent corrosion of electrical equipment were incorporated in the design of Unit 1. There were serious problems with electrical contacts, relay springs, wiring with exposed copper and other metal parts. Subsequently, various preventive means have been used. Tin alloy coatings have been found to resist corrosion effectively although they have not been satisfactory on current carrying contact surfaces. Aluminum seems to be particularly impervious to attack, as are stainless steel and some of the precious metals. Platinum inserts or plating appear to be a good solution to the problem with contacts, although they have not been used long enough for a complete evaluation.

Protective relays are particularly vulnerable to attack, and special relays constructed with noncorrosive materials were purchased for Units 2, 3, and 4. After Unit 4, the manufacturer discontinued the special relays. Starting with Unit 5, the relays, communication equipment, 480 V switchgear, and generator excitation cubicle were placed in a clean room environment. The clean room is actually three rooms on three levels, maintained at slightly positive pressure with clean air from activated carbon filters. Clean rooms are planned for subsequent units although not enough experience has been gained to know how successful this approach will be.

Outdoors, the air contains some corrosive gases. Additional noncondensable gases are released from the condensers by the ejectors and from the cooling towers. In the areas adjacent to the cooling towers, there are also fog and mist which cause rapid corrosion. These corrosives lead to rapid erosion of copper, steel, silver, and cadmium. Heavy galvanizing resists fairly well, and epoxy paints are quite resistant.

4. OPERATION, SUPERVISORY CONTROL AND PROTECTION

4.1 Unattended Operation

Several factors led to the determination that The Geysers units could be operated without 24-hour attendance by shift operators. Previous experience with many unattended hydro plants on the PG&E system had been satisfactory. Geothermal plants are much simpler to operate than fuel fired steam plants because there are no boilers with all the necessary auxiliaries and controls. Since The Geysers units are basically energy producers, they can be operated at blocked load settings.

All the operating and some minor maintenance is performed by roving operators. As the classification suggests, these men can perform operating duties at all the plants in the area. For operation of the first four units, the roving operators were regularly on duty only during normal daytime work hours. Starting with the operation of Units 5 and 6 in the fall of 1971, an operating headquarters was established at the Units 5 and 6 plant; and the roving operators, working out of this location, were scheduled for 24 h coverage. One or two operators work days and one is on duty afternoons and nights. A total work force of 16 operate and maintain Units 1 through 6. It is expected the staff will be increased to about 19 when Units 7 and 8 start up.

4.2 Protection and Alarms

Since two units are housed in one building, they share the same high voltage transmission line, and have a common 480 V station service bus. Any electrical faults that occur beyond either of the two generator breakers requires that both units be tripped, and in addition that the transmission line OCBs be opened. The Geysers units do not have automatic synchronizing equipment. Therefore, any tripout of the transmission line requires that the associated units be shut down. Any trip of the transmission line breakers, with the accompanying unit shutdown, leaves the two units without auxiliary power, and dc emergency oil pumps must be operated to lubricate the turbine-generator bearings until rotation has stopped. Also on loss of ac power, the hydrogen cooled machines have their emergency seal oil pumps turned on and are left on until manually turned off. The generators are purged with CO^2 if the battery voltage is reduced to a low enough level by operation of the emergency pumps. If only one of the units trips, and the transmission line OCB remains closed, ac auxiliary power will still be available to both units. For any individual unit trip operation that does occur, the main steam trip and check valves close, the generator breaker opens, and the major 480 V motor loads trip out. For trips due to turbine related troubles, the main steam trip and check valves close before the generator breaker opens. For trips due to generator electrical problems, the generator breaker is tripped simultaneously with the closing of the valves. Figure 4 is the block diagram showing the major shutdown and lockout features.

Since The Geysers units are operated unattended, it is necessary that annunciator alarms be transmitted to an attended station where appropriate action can be taken based on information received. Each 60 point unit annunciator has two output contacts. One is operated by any of the trip points, the other by any of the trouble points. These feed into a transmitter which then signals attended Fulton Substation, approximately 30 mi away, by means of a 60 kV power line carrier. This alarm does not differentiate as to which unit has tripped or alarmed. If it is a trip alarm, an operator checks each unit to determine which unit was the origin of the alarm. A trouble alarm occurring after work hours is not acknowledged until the next day.

4.3 Supervisory Control

With the installation of Units 9 and 10, planned for operation in 1973, a new supervisory control and alarm system will be installed. Units 5 and 6 will be the central location or master station for the system, and all Geysers units will be included in the system. Alarms will go to Units 5 and 6 as well as to Fulton Substation with possibly a numeric printout by means of teletype for alarm indication. Each unit's main annunciator averages approximately 60 points. The annunciators will have their point outputs arranged in 10 groups for transmission to the master station. Groupings will consist of trip or alarm points that are similar in nature. Also from Units 5 and 6, the supervisory system will have four control functions to each remote unit: one raise-lower for controlling turbine-generator power output; one raise-lower control for generator excitation; and two on-off controls for possible breaker control. Since there is only one roving

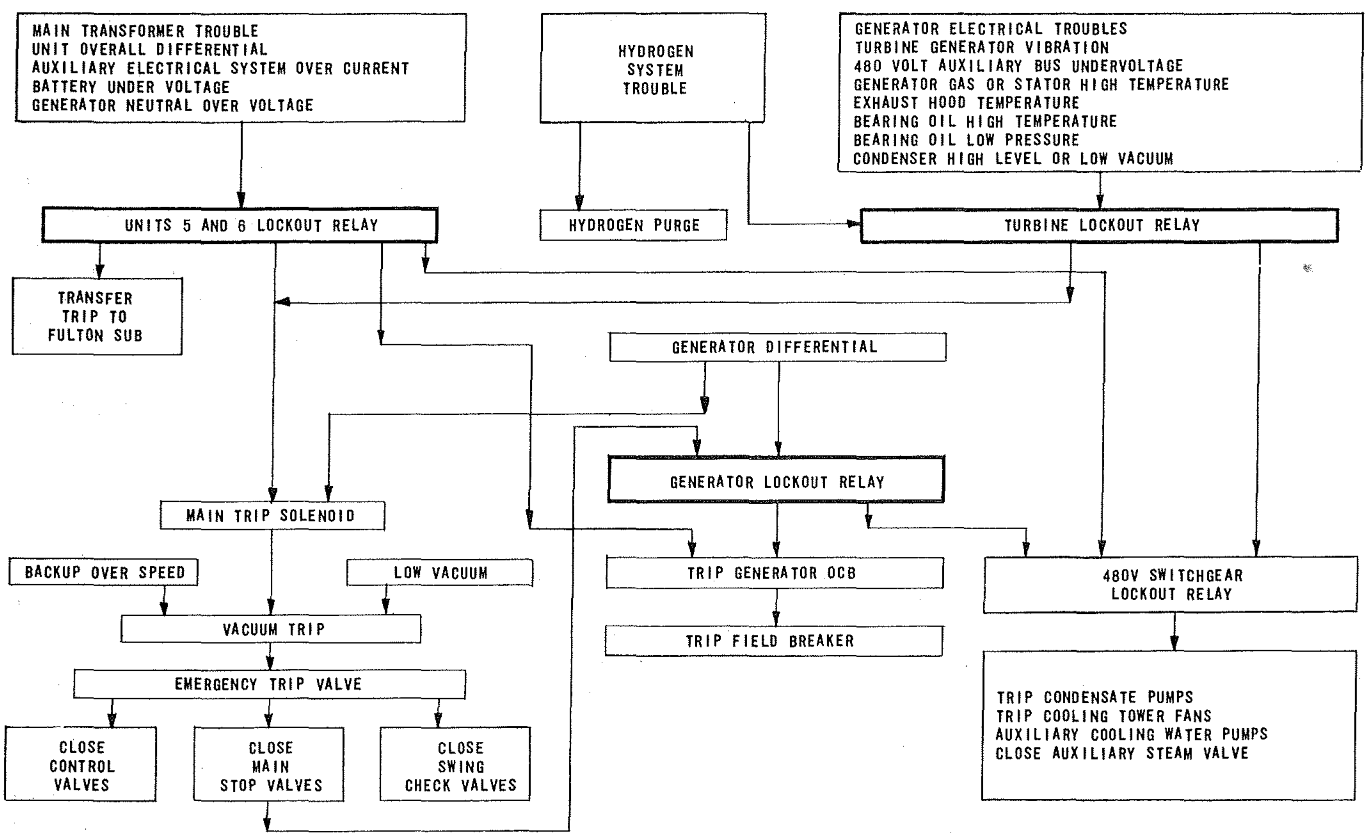

Fig. 4 Turbine-generator shutdown and lockout sequences, Unit 5.

operator to serve all The Geysers units, an interplant alarm system will be incorporated. The two 60 point annunciators at each remote location will have their point output contacts combined into urgent and nonurgent groups. Anytime an annunciator point at any unit goes into alarm, small auxiliary annunciators located at every remote location will flash either urgent or nonurgent and indicate the remote that is in trouble. When the alarm is acknowledged at any remote, all the small annunciators at all remotes will go to steady on.

5. MECHANICAL FACILITIES

5.1 Power Cycle

The power cycle for the latest 55 MW units is shown in Figure 5. Except for the flow rates and arrangement of the equipment, it is typical of cycles employed by all the units. Steam from the wells is introduced into the turbines which exhausts to direct-contact condensers located directly below the turbine. The combined condensed steam and cooling water are pumped by two condensate pumps to the cooling tower.

The turbine back pressure on all units is about 4 in (100 mm) of Hg, absolute. Cooled water from the tower basin is returned to the condenser by gravity and the vacuum head developed by the condenser. Since the cooling tower evaporation rate is less than the turbine steam flow, an excess of water is developed in the cycle. This flow is dependent upon the dry bulb temperature and relative humidity, but there is a surplus under all operating conditions. For the past several years, this excess water from the units has been returned to the steam suppliers for reinjection via several wells into the steam reservoir. Prior to this, the excess water had been allowed to flow down a watercourse into Big Sulfur Creek until it was found that this water was detrimental to fishlife. The reinjection method of disposing of the water was tried initially with some concern on the part of the steam suppliers that it might quench the producing steam wells. However, it has proven to be a success and is now part of the service the steam suppliers furnish under their steam sales contract. In fact, it is now thought reinjection could extend the productive life of the steam reservoirs as it is believed there may be more heat in the reservoir than there is vapor to extract it.

Two-stage steam jet ejectors are used to purge the noncondensable gases from the turbine condenser. The condensers for these ejectors are also the direct-contact design.

5.2 Turbines

The steam turbines are fabricated largely of the manufacturers' standard materials for low-pressure, low-temperature service. Blades and nozzles are typically of 11-13% chrome steel. Carbon steel is used for the turbine casings. Austenitic stainless steel inserts are provided in the casings opposite the rotating blades to prevent moisture erosion of the casing. The steam inlet conditions for the turbine-generator units are shown in Table I (see next page).

Lower steam pressures were used for the earlier units since their steam supply came from the shallow low-pressure steam reservoir. The later units are supplied from the deep higher pressure reservoir. All the turbines are steam sealed in a conventional manner.

In addition to the centrifixes installed in the steam suppliers' piping system to the units, the design of all units includes a wye-type steam strainer in the main steam line ahead of the turbine. The turbine emergency stop valve (or valves in the case of the larger units) is installed just downstream of the strainer. These are the turbine manufacturers' standard hydraulically operated design with internal pilot valves to supply the flow for startup of the units. Just downstream of the emergency stop valve(s), another protective valve(s) is installed as a second line of defense. These are of the trip check design in which the flapper or disc is latched open against the steam flow. They are less susceptible to seizure due to finely suspended material in the steam than the stop valve(s). They close on the same signal which activates the emergency stop valve(s). The turbine control valve(s) admits steam into the turbine to control

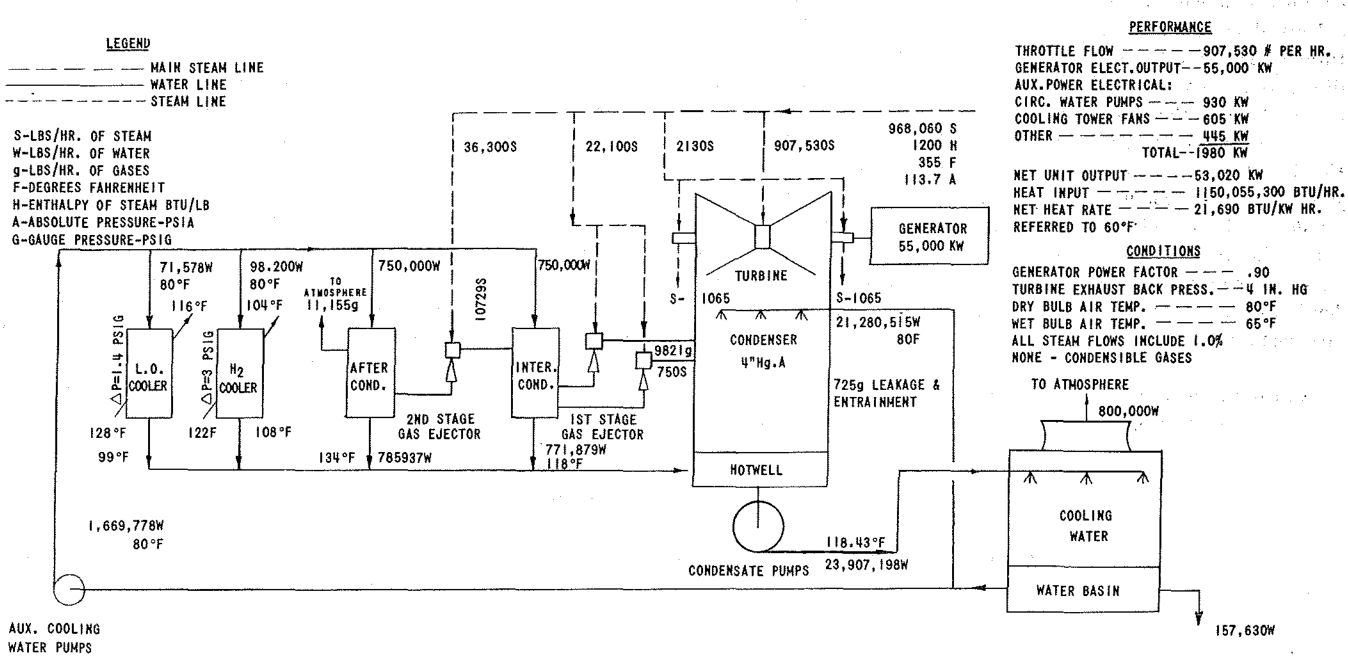

Fig. 5 Heat balance diagram, designed load, Units 5 and 6.

speed or load. These are butterfly valves because this design is less prone to malfunction due to suspended matter in the steam. Usually, two of these valves are installed to operate in sequence to give the proper control characteristics. These valves have a stainless steel disc with stellite seating surfaces.

5.3 Condensate System

The major components of the condensate system of a unit are the condenser and its gas removal equipment, the condensate pumps, and the induced-draft cooling tower. Economic evaluations have been made which relate unit output to turbine back pressure in order to optimize the investment in equipment in this system. These have shown that a 4 in (100 mm) turbine back pressure at atmospheric conditions of 60^{o} wet bulb are about optimum. As with all plants employing cooling towers, the output is slightly curtailed under high wet bulb conditions.

5.31 Turbine Condenser and Auxiliaries

The condensers are all of the direct-contact design. The first four units used the barometric type. In this type, steam from the turbine exhaust is ducted to the condenser which is located above the turbine. Steam enters the side of the condenser shell near the bottom. It is condensed by water from the cooling tower which enters the top and cascades down counter to the steam flow over a series of rings and doughnut baffles. Noncondensable gases are removed from the top of the shell. The combined condensed steam and cooling water fall down a barometric leg or tail pipe from the bottom of the condenser which is sealed in a hotwell from which it is pumped to a cooling tower. Water level is maintained near the bottom of the shell by atmospheric pressure, hence the name barometric condenser. Units 1 and 2 use one condenser shell; Units 3 and 4 use two shells per condenser. The advantage of this arrangement was its fail-safe feature such that there is no possibility of water reaching the turbine. Starting with Unit 5, the condensers are located directly beneath the turbine exhaust hood. The use of the barometric design for these larger units would have required massive exhaust ducts and structural steel supports extending high above the turbine. The costs would have been formidable. In this low level direct-contact condenser, steam from the turbine is exhausted down a central lane in the shell and is condensed in the sides of the shell by water flowing counter-flow through a series of perforated trays. Condensate and cooling water is pumped directly from the condenser hotwell to the cooling tower by the condensate pumps. The condenser shells are fabricated of clad plate of carbon steel and Type 304 stainless steel. All structural members, water trays, and piping inside the condenser shells are Type 304 stainless. Dual hotwell water level switches are provided to trip the turbine and stop water flow on high water level.

Noncondensable gases are removed from the condensers by two-stage steam jet ejectors which use steam from the main steam line ahead of the turbine stop valves. The first stage compresses the gases to about 5 psia. The second stage compresses them to about 1-2 psig for discharge up a stack extending above the roof of the power building. The ejector motive steam is condensed in barometric type direct-contact condensers. These condensers, the jets, and the interconnecting piping are of Type 304 stainless steel.

5.32 Condensate Pumps and Piping

All the units have two condensate pumps which pump water from the condensers to the cooling tower. These pumps are fabricated entirely of Type 304 stainless steel. The first four units have condensate pumps of the vertical wet-pit design installed in the barometric condenser seal well. The later units use vertical canned-type condensate pumps. The pumps for the 55 MW units are among the largest canned pumps ever built. They are rated 24,500 gal/min at 75 ft of head and require 600 hp.

The condensate piping in the power building is either aluminum or stainless steel. The buried piping between the turbine building and the cooling tower is glass reinforced plastic. Earlier units used reinforced concrete pipe for this service, but it is not proving entirely satisfactory. Cement-asbestos, epoxy lined pipe has also been used with good results.

5.4 Cooling Towers

All cooling towers are of the induced-draft design. Structural support members of the distribution headers and basins are redwood and the tower siding is transite. Earlier fill material was polystyrene and polypropylene, but polyvinyl chloride will be used in the later towers as it is fire retardant. Cooling tower basins are reinforced concrete painted with coal tar epoxy to prevent deterioration of the concrete. Cooling towers are designed to cool the condensate from 118.4F (48C) to 80F (27C) at 65F (18C) wet bulb.

6. ELECTRICAL FACILITIES

6.1 Electric Generators

All The Geysers generators are typical of units of their size used elsewhere. Units 5 and 6 can be seen in Figure 6, and the control boards are to the extreme right. The larger units are hydrogen cooled and are purged automatically under certain trouble conditions.

The connections between generators 1-4 and their step-up transformers were Company designed. Cables were used for all but Unit 3 which has tubular bus. Beginning with Units 5 and 6, the generator to bank connections are cable-bus. Design and construction has been by the supplier. Because outdoor generator oil circuit breakers are used, there is no enclosed 13.8 kV switchgear associated with the generator main connections. Outdoor potential transformers are used, and the potential taps to the bus are provided by the

Table 1—Turbine-Generator Steam Inlet Conditions

Unit No.	Rating kW	Steam Flow lb/h	Steam Pressure psig	Temperature ^{o}F
1	12,500	240,000	93.9	348
2	13,750	255,475	78.9	342
3 & 4	27,500	509,600	78.9	342
5-10	55,000	907,530	113.7	355
11	110,000	1,808,000	113.7	355

cable-bus manufacturer. Figure 7 shows the main transformer, bus, potential transformers, and oil circuit breakers at Units 5 and 6. The bus is completely fabricated at the factory. All stress cone terminations are completed, the cables are placed inside the duct, and the assembled bus is shipped in sections. Four aluminum cables of 1,500 MCM are used per phase for each generator, which gives a rating of 3,000 amperes. Cables from each generator oil circuit breaker are connected directly to the single main transformer terminals. Shielded cables with cross-linked polyethylene insulation are used.

6.2 Generator Excitation

Three different types of excitation systems are used on Units 1-4. All units after number 4 use static excitation with power potential transformers and saturable current transformers. Elimination of commutators is particularly desirable in The Geysers environment.

6.3 Switchgear

All The Geysers units have generator breakers and, therefore, the units do not require startup transformers. Units 1-4 have indoor air circuit breakers. Units 5-10 have outdoor oil circuit breakers. The decision to use OCBs was made because air breakers have a maximum interrupting capacity of 1,000 MVA while the duty on the generator breakers is 1,400 MVA, because of the common main step-up bank serving two units for Units 5-10. The oil circuit breakers have an interrupting capacity of 1,500 MVA and are rated 3,000 amperes continuous current. There have been serious maintenance problems with the air breakers, mainly contact overheating due to corrosion. One of the earlier generator breakers has had to be replaced because of this problem. This condition does not occur in the oil breakers and is a benefit obtained by using them.

Conventional high-side power circuit breakers are used at Units 1 and 2 and at Units 3 and 4. At Units 5 and 6 and later units, the usual 230 kV high-side breakers have been eliminated. For disconnecting the transformer banks, 230 kV aluminum, vertical break air switches are used. These switches have a quick-break attachment to interrupt transformer magnetizing current, platinum to platinum contact surfaces, and special treatment for corrosion resistance. Figures 8 and 9 are single-line diagrams of Units 3 and 4 and Units 5 and 6. Because rather large amounts of power will be produced, a collection switching station will be provided in the plant area. This will connect to system mainly through two 230 kV circuits. Provisions will also be made for a future outlet to the 500 kV system. The breakers at the switching station will be tripped by transfer trip from the plants in order to clear transformer and low-side bus faults. The transfer trip will operate on a cable loop interconnecting all plants and the switching station. A fully redundant system will be provided with two separate tripping channels from each plant to the switching station.

6.4 Main Transformers

Each of the first four units had its own step-up transformer. This was important for reliability since the earlier units contributed to the local power supply. When unit size increased to 55 MW, one main three-phase transformer of 132 MVA was used for each two units, with resultant savings in cost.

Transmission voltages have ranged from 60 to 230 kV. Dual voltage step-up transformers were purchased for Units 3-10. Starting with Unit 11, single-voltage 230 kV transformers can be used because the combined plant outputs will require 230 kV operation.

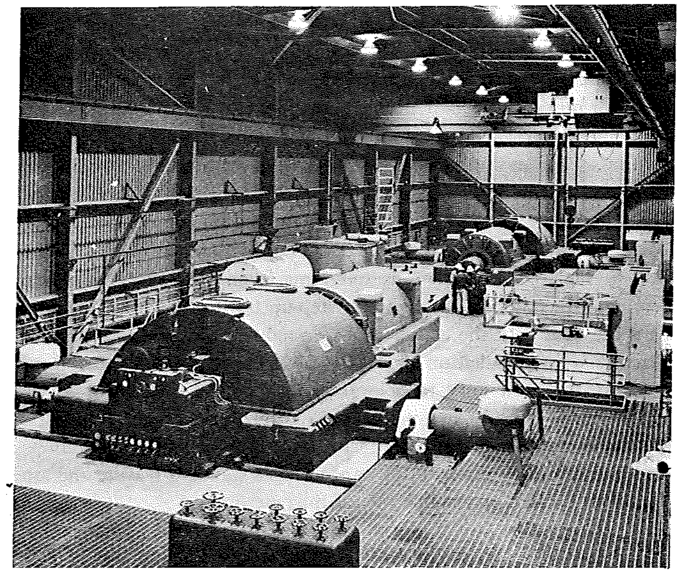

Fig. 6 Turbine-generator floor at Units 5 and 6.

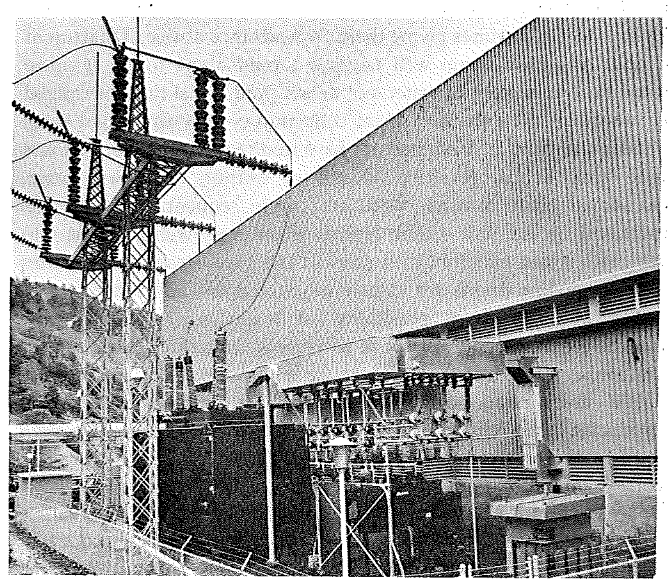

Fig. 7 Switchyard at Units 5 and 6.

6.5 Metering

Steam purchase contracts provide for payments for power delivered to transmission. Units 1 and 2 and Units 3 and 4 have transmission voltage metering sets of 60 and 115 kV, respectively. Because of the high cost of 230 kV metering equipment, Units 5 and 6 and subsequent units are metered at the low voltage side of the main transformer. Transformer losses are determined from ampere-squared-hour and volt-squared-hour meters and subtracted.

6.6 Station Power

All The Geysers units utilize a 480 V auxiliary system with no intermediate step-down voltage, rather the generator voltage is stepped down directly to 480 V. Even at Units 5-10, where there are two 600 hp condensate pump motors for each unit, it was found economical to retain the 480 V system although it is customary to switch over to 2,400 or 4,160 V at 250 hp. Starting with Unit 3, the units have 480 V switchgear buses in addition to the 480 V unit motor control center buses. The switchgear buses handle the larger motors which are for the condensate pumps and the cooling tower fans. All units have a unit motor control center that handles smaller loads directly related to the turbine-generator. There is a common station service motor control center that serves two units, being fed from one or the other unit's 480 V switchgear or unit motor control center with key interlocked breakers to prevent paralleling of the two units' 480 V buses. At Units 5 and 6, the duty on the 480 V bus is very high because there is only one main step-up transformer serving both units rather than one step-up transformer for each unit as is the case with the earlier units. To reduce costs, current limiting reactors were installed on the 480 V switchgear bus. This procedure lowered the fault duty to a level that permitted the use of lower interrupting capacity switchgear and motor control center breakers. The higher amperage breakers feeding the 600 hp condensate pumps had the necessary interrupting capacity as a standard feature and are therefore located on the line side of the reactors.

7. OPERATING EXPERIENCE

Since steam wells are operated by the Union Oil Company, closely coordinated operations are required between this company and PG&E to start, load, and secure the units. The arrangement with Union Oil Co. requires giving them 24 h advance notice of startup of a unit. A shut-in steam well requires several hours to get it up to rated flow to clear it of water and debris. Additional time is required to warm up the extensive steam collection system piping and drain condensate from it. Fast startups have resulted in fouling of turbines with well debris, resulting in loss of output, and even worse, occasional blade damage. Wells are cut in sequentially as load is increased on the unit. Union reports when every well is valved into the main steam manifold to a unit. At this time, steam temperatures and steam line drains are closely monitored for any indication of water. If there is a possibility of water in the steam, the turbine-generator unit is tripped to prevent damage. Sufficient wells are connected to a unit to provide the rated turbine throttle pressure at the unit's rated load. Since the wells are uncased in the steam producing zone, changes in the flow of steam from the formation tend to loosen small rock particles into the well bore which can be carried into the steam lines and turbine, causing erosion problems. Because of the elaborate startup procedures it is not practical to operate geothermal units as peaking units. Whenever a unit does trip, steam is released to atmosphere through pressure control valves and mufflers on the steam suppliers' piping system. If the outage is to extend over several weeks, the wells are shut in and reservoir pressure data are obtained.

Units are inspected every three years as compared to a 5 to 6 year interval used for fossil units. The turbine stop valves are tested 3 times a day just to assure there is no binding from impurities in the steam. They are also lubricated frequently.

Turbine lube oil and generator heat exchangers should be single pass or U-tube design in the cooling water side; otherwise there is apt to be plugging in the reversing water box from colloidal sulfur and rock dust in the cooling water, which is condensate from the cooling towers.

The steam jet ejectors create high noise levels which require the use of ear protectors when working near them. Methods of silencing are being investigated.

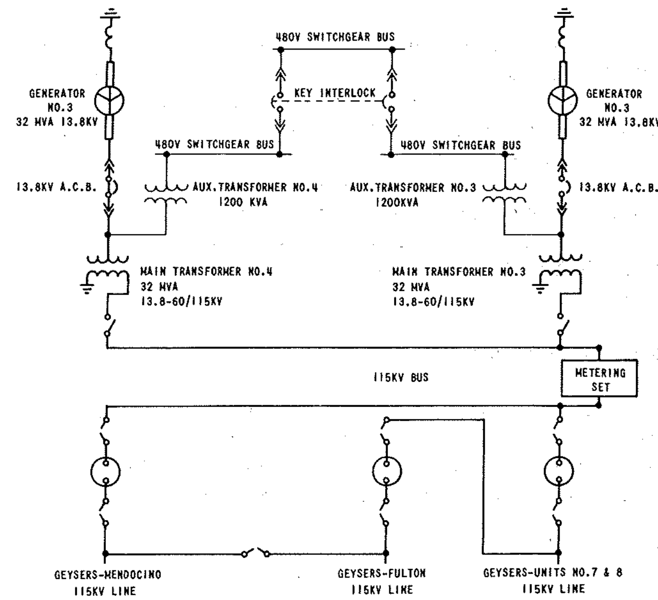

Fig. 8 Single line diagram, Units 3 and 4.

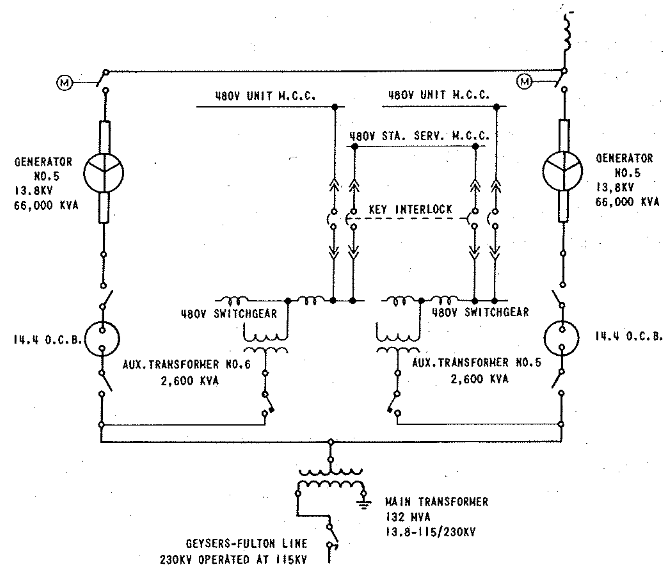

Fig. 9 Single line diagram Units 5 and 6.

8. CONCLUSIONS

Experience at The Geysers has proved that geothermal power generation is a commercial success. The cost of power generated compares favorably with power from the Company's most modern steam power plants. A total of generation of 192 MW is now operating and additions of about 110 MW per year are under construction and planned. These additions are expected to continue as long as the necessary steam supplies are developed. While the corrosives and abrasives in the steam present problems in material selection and cause added maintenance, the problems can be solved by proper design and operation.

9. REFERENCES

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Geothermal Power Project of Pacific Gas and Electric Company at The Geysers, California Update, March, 1974

Since this paper was completed in early 1972, several events of interest have occurred at The Geysers Geothermal Power Project. This addendum briefly describes these developments.

Units 7,8,9, and 10 Operational

Units 7 and 8 became operational in 1972, and Units 9 and 10 operational in 1973. These units, which are 53 mw each, increased the capacity at The Geysers Power Plant to 396 mw, making it the world's largest geothermal project.

Future Units

Unit 11, the first 106 mw single unit, is under construction and will be operational in early 1975. Unit 12, a duplicate unit, is scheduled for operation in 1976. Unit 14 is now being designed and some major equipment has already been procured. It is scheduled to be in operation in late 1976. Units 13 and 15 are in a similar stage and will be operational in early 1977.

Unit 13, rated 135 mw, is being installed under terms of a recent contract with the Signal Oil and Gas Company. It will be located on Signal's geothermal leases to the east of The Geysers area.

Unit 14 is at The Geysers and will be supplied with steam from the Union-Magma-Thermal holdings. Its capacity will be 110 mw.

Unit 15, a 55 mw unit, will use steam purchased from the Pacific Energy Corporation under a recently signed contract. It will be located south of The Geysers.

With these recent commitments, total capacity in The Geysers Project will be about 900 mw by the end of 1977. This will probably exceed the rest of the geothermal power capacity in the world at that time.

Hydrogen Sulfide Abatement Program

Pacific Gas and Electric Company is actively pursuing a research and development project to control the release of hydrogen sulfide from its units. The hydrogen sulfide in the geothermal steam is released to the atmosphere in two ways. The larger portion of it dissolves in the cooling water in the direct contact condenser and is then stripped out in the cooling tower. The remainder is removed along with other gases by the condenser off-gas removal equipment and is discharged to the atmosphere.

We plan to abate the hydrogen sulfide releases at Unit 11. To reduce releases from the cooling tower, we plan to add salts of either iron or nickel to the cooling water. These serve to catalyze the oxidation of hydrogen sulfide to elemental sulfur. The process has been demonstrated to work satisfactorily. A sulfur sludge results in the cooling water system. This presents disposal problems which are now being studied. The recovery of commercial grade sulfur, while possible, does not appear economic. The condenser off gases, which contain enough methane and hydrogen in addition to the hydrogen sulfide to be combustible, will be incinerated. The resulting sulfur dioxide will be scrubbed out in a column using cooling water. This renders the cooling water slightly acidic and neutralization may be necessary.

We are continuing our R&D program to determine if there are better methods of dealing with this problem for future units.