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A SOURCEBOOK ON THE PRODUCTION OF ELECTRICITY FROM GEOTHERMAL ENERGY

Draft of

Chapter 10

Geothermal Power Plants Around the World

by

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Abstract

This report constitutes a consolidation and a condensation of several individual topical reports dealing with the geothermal electric power stations around the world [DiPippo, 1978a-e].

An introduction is given to various types of energy conversion systems for use with geothermal resources. Power plant performance and operating factors are defined and discussed.

Existing geothermal plants in the following countries are covered: China, El Salvador, Iceland, Italy, Japan, Mexico, New Zealand, the Philippines, Turkey, the Union of Soviet Socialist Republics, and the United States. In each case, the geological setting is outlined, the geothermal fluid characteristics are given, the gathering system, energy conversion system, and fluid disposal method are described, and the environmental impact is discussed. In some cases the economics of power generation are also presented.

Plans for future usage of geothermal energy are described for the above-mentioned countries and the following additional ones: the Azores (Portugal), Chile, Costa Rica, Guatemala, Honduras, Indonesia, Kenya, Nicaragua, and Panama.

Technical data is presented in twenty-two tables; forty-one figures, including eleven photographs, are also included to illustrate the text. A comprehensive list of references is provided for the reader who wishes to make an in-depth study of any of the topics mentioned.

This report also is a draft of a chapter for the Sourcebook on the Production of Electricity from Geothermal Energy which is being produced by Brown University in cooperation with a number of other agencies, laboratories, organizations, and universities with the support of the Department of Energy, Division of Geothermal Energy, through Contract EY-76-S-02-4051.A002, C. B. McFarland, Program Manager, and J. Kestin, Principal Investigator.

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10.1 INTRODUCTION

10.1.1 Historical Overview

The first commercial use of geothermal energy as a source of electric power took place in Italy in 1904. For many decades this natural resource remained untapped except at the Larderello field in Tuscany. As with all pioneering activities in a new technology, the use of geothermal energy for electric power in Italy was beset with problems. These were relatively simple to overcome in the case of the Italian geothermal resource owing to the fact that the geothermal fluid emerges from the reservoir as a superheated vapor. As such it could be employed in more or less conventional steam turbines, albeit ones built with special materials to allow for problems of corrosion and erosion.

Most geothermal reservoirs, however, are not as easy to exploit as the dry steam field at Larderello. The majority of them produce a mixture of liquid and vapor at the wellhead. Furthermore, the fluid is often burdened with significant amounts of dissolved solids and noncondensable gases, some of which may be toxic.

Exploitation of liquid-dominated hydrothermal reservoirs did not take place on a large scale until the Wairakei plant was built in New Zealand in 1958. Since that time, several other countries have begun to use their geothermal fields for electric power generation, including the United States, Mexico, the Soviet Union, Japan, El Salvador, the People's Republic of China, the Philippines and Iceland. Furthermore, several other countries are on the verge of developing their geothermal resources. Each of these countries will be discussed in the ensuing sections of this chapter.

10.1.2 Energy Conversion Systems

There are several types of energy conversion systems currently in use for geothermal power generation throughout the world, and several new systems which are in the research and development stage. The present systems may be categorized as follows:

- Dry (or superheated) steam plants.
- Separated (or "single-flash") steam plants.
- Separated/single-flash (or "double-flash") steam plants.
- Separated/multi-flash (or "multi-flash") steam plants.
- Single-flash steam plants with pumped wells.
- Double-flash steam plants with pumped wells.
- Binary cycle plants with a secondary working fluid.

Plants of the first four types exist and are in commercial operation; plants in the last three categories are either under construction or in the testing phase (pilot plants). The total installed geothermal power capacity in the world is currently about 1,500 MW of which about 943 MW is from dry steam plants. A total of 2140 MW is now under construction or planned to be on-line by 1982, and about 1800 MW is being projected for the near-term beyond 1982. Table 10.1 lists a summary of geothermal power capacity in the world as of January 1979.

10.1.3 Power Plant Performance Factors

Throughout this chapter the performance of geothermal power plants is characterized by a geothermal resource utilization efficiency, η_u. This factor is the proper thermodynamic measure of the energy conversion process which takes place in a geothermal power plant, irrespective of the details of the particular system in use. The utilization efficiency is based on the available work (or exergy) in the geothermal fluid, either as it exists in the reservoir (or at the bottom of the well), or as it is supplied to the boundary of the plant (or at the wellhead). In most cases the latter point-of-reference is chosen since more reliable properties of the fluid are available on the surface as compared with in the reservoir.

The utilization efficiency is calculated from

$$\eta_u = w/w^o \quad , \tag{1}$$

where w is the work output of the plant (per unit mass), and w^o is the exergy of the geothermal fluid (per unit mass). The exergy is obtained from

$$w^o = h_1 - h_o - T_o\,(s_1 - s_o) \quad , \tag{2}$$

where subscript 1 is used to denote the state of the geofluid at the inlet to the plant (or at the wellhead), and subscript o denotes the ambient sink condition (i.e., saturated liquid water at a temperature T_o). In those cases where the inlet state is chosen at the bottom of the well, an additional term, -gL, must be included in eq. (2) to account for the potential energy of the fluid at a depth L below the surface. This extra term is usually quite small except for very deep wells, i.e., > 3 km (> 10,000 ft).

Another measure of plant performance that is frequently quoted is the specific geofluid consumption, or the amount of geothermal fluid that must be produced from the reservoir to generate a unit of electricity. This factor is expressed as kilograms per kilowatt hour (or lbm/kW·h).

Several factors are commonly used to describe the operations and reliability of a power plant. There are three power plant operating factors which, taken together, indicate the manner in which the plant is used to meet variations in demand. These are:

Load factor, F_L: $$F_L = \bar{L}/L^* \quad , \tag{3}$$

Capacity factor, F_C: $$F_C = \bar{L}/C \quad , \tag{4}$$

Utilization factor, F_U: $$F_U = L^*/C \quad , \tag{5}$$

where the terms used in eqs. (3)-(5) have the following meanings:

$\bar{L}$ = average load for a given period,

L^* = peak load for a given period,

C = rated capacity of the plant or unit.

The average load $\bar{L}$ is found from

$$\bar{L} = G/h \ , \tag{6}$$

where

G = total electrical generation for a given period,

and

h = number of hours in the period (usually taken as 8760 h = 1 year

It is clear that

$$F_C = F_L \times F_U \ , \tag{7}$$

and that whenever the utilization factor equals unity (i.e., pure base-load operation), then the load factor becomes identical numerically to the capacity factor.

There are three commonly used power plant reliability factors:

Availability factor, F_A: $F_A = P_S/h$, (8)

Forced outage factor, F_{FO}: $F_{FO} = P_{FO}/h$, (9)

Scheduled outage factor, F_{SO}: $F_{SO} = P_{SO}/h$, (10)

where

P_S = service period, i.e., the number of hours that the unit operated with breakers closed to the station bus;

P_{FO} = forced outage period, i.e., hours of down-time caused by equipment failure or malfunction;

P_{SO} = scheduled outage period, i.e., hours of down-time for planned maintenance.

It is clear that

$$P_S = h - P_{FO} - P_{SO} . \tag{11}$$

It will be seen from the discussions in the following sections that geothermal power plants are capable of resource utilization efficiencies as high as 55 - 60%, and are characterized generally by high capacity factors (∿ 80%), and very high availability factors (∿ 95%).

The sections which follow constitute a much-condensed summary of a thorough treatment of existing and planned geothermal power plants which will be available as a separate volume by the author.

10.2 CHINA

With the recent emphasis on education, science, and technology in the People's Republic of China, it can be expected that geothermal energy will be among those areas to be developed for practical purposes. Currently there is one geothermal electric power plant in operation in China. It is located on the slopes of the Himalayan mountains in Tibet. The plant is of the separated steam (or "single flash") type with an installed capacity of 1000 kW. Apparently the plant uses steam from a single well, obtained by means of a cyclone separator. The turbine is of the condensing type, using a barometric, direct-contact condenser. Water from a nearby river is used to supply cooling water for the condenser. Noncondensable gases are removed from the condenser by means of a water-jet ejector.

It is reasonable to assume that more details about China's geothermal energy program will become available in the near future owing to the new policy aimed at bringing China into a full partnership among the nations of the world.

10.3 EL SALVADOR

10.3.1 Overview

El Salvador is the first of the Central American countries to construct and operate a geothermal electric generating station. Exploration began in the mid-1960's at the geothermal field near Ahuachapán in western El Salvador. The first power unit, a separated-steam (or "single-flash") plant, was started up in June 1975, and was followed a year later by an identical unit. The 60 MW of geothermal capacity presently constitutes 14% of the total electric generating capacity of El Salvador, but during 1977 the Ahuachapán plant produced nearly one-third of the electricity generated in the country.

The Comisión Ejecutiva Hidroeléctrica del Río Lempa (C.E.L.) is in the process of installing the third unit at Ahuachapán, a dual-pressure ("double-flash") unit which will be rated at 35 MW. In addition, C.E.L. is actively pursuing several other promising sites for additional geothermal plants. There is the possibility that eventually geothermal energy will contribute about 450 MW of electric generating capacity. In any event it appears that by 1985 El Salvador will be able to meet its domestic needs for electricity by means of its indigenous geothermal and hydroelectric power plants, thus eliminating any dependence on imported petroleum for power generation.

10.3.2 Ahuachapán

The Ahuachapán field is located in westernmost El Salvador about 18 km (11 mi) east of the Rio Paz which forms the international boundary with Guatemala. The area consists of moderately sloping terrain on the northern side of a string of volcanic mountains. Within the 3000 ha (7400 acre) geothermal region, there are a number of areas of active surface thermal manifestations including fumaroles, hot springs, steaming ground, and boiling mud pools. The hydrothermal reservoir consists of Ahuachapán andesites, the permeability of which is created by fractures in an otherwise hard formation. Young agglomerates constitute the cap rock for the reservoir. The temperature of the geofluid in the reservoir is about 230°C (445°F). The aquifer is believed to be recharged from a volcanic lake to the south of the field.

Figure 10.1 shows the location of 27 wells that have been drilled in the vicinity of the power plant. The spacing between wells is not less than about 150 m (490 ft), with an average spacing of roughly 23 ha/well (56 acre/well); the density in the central portion of the field is greater, being nearly 11 ha/well (27 acre/well).

A typical production well has the following configuration: 17-1/2 in hole with a 13-3/8 in casing cemented to a depth of about 100 m; 12-1/4 in hole with 9-5/8 in casing to 400 m or to the top of the reservoir; 8-1/2 in open hole through the production zone. In some cases where the formation is not sufficiently hard to prevent sluff-in, a 7-5/8 in slotted liner is hung from the 9-5/8 in casing.

Reinjection wells are completed in a similar way except that they are drilled deeper, into the basement rock, and fitted with a 7-5/8 in casing down to the top of the basement to prevent the reinjected fluid from entering the aquifer. This casing is hung, not cemented, to allow for its easy removal in the event that the well should ever be used for production.

The well casings are J-55 API standard weight pipe. The cement is straight Portland; the drilling mud is of the Bentonitic type with coconut husks, coffee bean shells and mica being added to seal off loss-of-circulation zones.

Figure 10.2 shows a typical wellhead site. The two-phase geofluid emerges from the well and passes through a 14 in control valve before entering the 55 in dia. Webre-type cyclone separator which has a capacity of 350 t/h (770×10^3 lbm/h). Separated steam leaves via a 16 in bottom outlet which leads to a ball check valve. A vertical hot water collecting tank is used to direct the liquid either to the twin vertical silencers where the liquid is flashed to atmospheric conditions and thence disposed of by means of a surface channel, or to one of four reinjection wells.

Ten wells supply units No. 1 and 2. The first unit receives steam from wells AH-1, -4, -6, -7, and -24; the second unit is fed from AH-5, -20, -21, -22, and -26. The average separator pressure for the first set of wells is 635 kPa (92 lbf/in^2) and for the second set is 612 kPa (89 lbf/in^2). The total steam flow to the plant is 127 kg/s (10^6 lbm/h); the total geofluid produced from the reservoir to generate this steam flow is 726 kg/s (5.8×10^6 lbm/h) [DiPippo, 1978f].

Of the nearly 600 kg/s (4.8×10^6 lbm/h) of liquid which is separated at the wellheads, about 62% is reinjected into the basement rock. The remainder is currently being disposed of by means of surface discharge and evaporation, with the effluent from several wells being collected and conveyed through a covered concrete channel to the Pacific Ocean, 75 km (47 mi) away.

The total amount of dissolved solids in the liquid at the wells averages about 18,400 ppm, with the main constituents being: chloride (10,430 ppm), sodium, (5690 ppm), potassium (950 ppm), silica (537 ppm), calcium (443 ppm), and boron (151 ppm). Noncondensable gases amount roughly to 0.05% by weight of the total well flow, or about 0.2% of the steam flow. These gases consist mainly of carbon dioxide (86.8% by volume) and hydrogen sulfide (12.1% by volume), with small amounts of hydrogen, nitrogen, ammonia, and methane.

There are two main power units and one auxiliary power unit presently installed at Ahuachapán, and a third unit is under construction. The technical specifications for each of these units may be found in Table 10.2.

A 1.1 MW, noncondensing geothermal steam unit is used for station start-up from cold conditions. The unit is completely self-contained, requiring neither an external power source nor cooling water. Power is generated from a single Curtis stage fed with separated steam; the lubricating oil is air-cooled. All mechanical, electrical, and control elements are mounted on a single platform.

The two main power units are essentially identical. They are of the separated-steam (or "single-flash") variety. A simplified flow diagram is shown in Fig. 10.3. Each unit employs a 5-stage, double-flow turbine with impulse-reaction blading, mounted in a single housing, and develops 30 MW. Each turbine exhausts to a low-level, direct-contact condenser equipped with a slanted barometric pipe.

The geothermal energy resource utilization efficiency, η_u, may be found using the well-flow data quoted earlier, an output of 60 MW (combined for both units), and a sink temperature of 22°C (71.6°F) (the design wet-bulb temperature). It turns out that η_u = 37% for units No. 1 and 2 combined. The overall steam consumption is about 7.6 kg/kW·h (16.8 lbm/kW·h), or 43.6 kg/kW·h (96.1 lbm/kW·h) in terms of the total geofluid produced from the reservoir [DiPippo, 1978f].

The third power unit originally was planned to be a 30 MW, low-pressure (LP) unit that would have used steam flashed from separated bore liquid. As the field became more developed and confidence in the steam supply grew, it was decided instead to install a dual-pressure unit of 35 MW capacity to be supplied with medium-pressure (MP) steam from three new wells together with low-pressure (LP) steam flashed from liquid.

A highly simplified flow diagram for unit No. 3 is shown in Fig. 10.4. The broken lines represent hot water from eight wellhead separators. The liquid is flashed in two horizontal flash tanks, producing LP steam (solid lines) which is added to the turbine at the pass-in section. The MP steam (heavy lines) is scrubbed before entering the first stage of the turbine. Provision is made to flash a portion of the MP steam down to the LP section if necessary. Auxiliary steam (thin lines) is used for turbine gland seals, steam ejectors for gland steam, and noncondensable gas removal [Fuji, 1977].

The turbine will be of the dual-admission, double-flow type in a single housing, with an MP section consisting of three stages of essentially impulse blading followed by an LP section with four impulse-reaction stages. The generator will be air-cooled, rated at 40,000 kVA, 13.6 kV at 60 Hz with a 0.875 (lagging) power factor. Construction is underway and completion is expected by the end of 1979.

The geothermal resource utilization efficiency for the third unit will be about 42%, based on design specifications. Since all three units will be inter-related, the overall plant utilization efficiency, for the three units, will be approximately 43%, assuming that the thirteen wells which will supply the full plant have the same average conditions of temperature, pressure, and flow rate as the ten wells now serving units No. 1 and 2.

Two methods are used for the disposal of waste liquid from the Ahuachapán plant: reinjection and surface discharge. The temperature of the reinjected liquid is not less than 150°C, thus avoiding any problems with silica deposition that might otherwise occur at lower temperatures. Over 13 billion kilograms have been returned to the formation since reinjection was begun in 1975. The liquid is reinjected directly from the separators, at a pressure of about 550 kPa (80 lbf/in^2), thus eliminating the need for booster pumps. A portion of the liquid intended for surface disposal via the discharge channel passes first through one of two labyrinth retention tanks which provide 50-60 minutes of hold-up. This provides an effective means of converting monomer silica into polymer silica, thus stabilizing the silica in solution and essentially eliminating silica deposition in the long disposal channel. The photograph in Fig. 10.5 shows one of the open, cement retention tanks shortly after the silica deposits have been scraped from the walls of the baffles [Cuéllar, 1975; DiPippo, 1978d; Einarsson, et al, 1975].

The successful operation of the Ahuachapán plant has made it a dependable link in the electricity supply system of El Salvador. Table 10.3 gives the total generation, capacity factor, and percentage of total electricity in El Salvador contributed by the Ahuachapán plant since the first unit began operating in June 1975. The geothermal plant has been essentially free of major breakdowns. In 1977 the availability factor was 95% based on forced outages. This factor is reduced to 84% when scheduled outages for maintenance are included. A complete overhaul of each power unit is carried out once every two years and takes about one month.

10.3.3 Other Geothermal Areas in El Salvador

Berlín This field is located in eastern El Salvador, about 90 km (56 mi) from San Salvador. Exploration took place at Berlín simultaneously with Ahuachapán in 1965 when two deep wells were drilled. The terrain is considerably more rugged than that at Ahuachapán, and this fact influenced the decision to proceed with Ahuachapán for the first geothermal power plant, although the results of the early exploratory studies at Berlín were encouraging. The first deep well was drilled to a depth of about 1800 m (5900 ft) and encountered a temperature of 271°C (520°F). The geofluid at Berlín contains roughly 10,000 ppm of total dissolved solids. Exploration is continuing at Berlín which is expected to be the site of the next (i.e., the fourth) geothermal unit in El Salvador by 1984-1985. The ultimate power capacity of this area is estimated to be 100 MW.

Chinameca This field is about 20 km (12 mi) east of Berlín and 17 km (11 mi) west of the city of San Miguel. Exploration is presently underway. It is expected that a geothermal power unit will be operating there by 1985. This site may eventually support 100 MW of electrical power capacity.

Chipilapa This area is about 5 km (3 mi) east of the Ahuachapán geothermal field and was the site of the first deep well drilled in El Salvador. Chipilapa may be part of the same geothermal field as Ahuachapán and is expected to support about 50 MW in the future.

San Vicente The San Vicente geothermal field is located in east-central El Salvador, 50 km (31 mi) east of San Salvador and 40 km (25 mi) west-northwest of Berlín. Extensive exploration activity is taking place. The potential of this site is estimated at 100 MW (G. Cuéllar, personal communication).

10.4 ICELAND

10.4.1 Geological Features

Iceland is perhaps better known for its direct use of geothermal energy in space-heating applications than for geothermal electric power generation. Roughly 50 percent of the population of this island heats its homes with geothermal hot water. Essentially all of the capital city of Reykjavik is heated by means of geothermal water at about 86°C (187°F). Plans call for the expanded use of geothermal hot water to provide up to 70% of the space-heating needs of the country within the next few years [Lindal, 1977].

There are only a few locations in Iceland where electric power is generated from geothermal resources. For the most part these lie inland and to the northeast, although exploration and the beginning of exploitation are now taking place on the Reykjanes peninsula in southwestern Iceland.

Iceland is situated astride the Mid-Atlantic ridge. The Icelandic graben which sweeps from the north to the southwest through the center of the island exhibits the great tension which exists in the crustal rift zone. Figure 10.6 shows this prominent geological feature along with the major cities and the existing geothermal power plants. It has been observed that the rift zone is separating at a rate of about 2 cm/yr [Burke and Wilson, 1976]. A small geothermal plant near Grindavik is at the southwestern extremity of the west branch of the rift valley. The geothermal power plants at Námafjall and Krafla are located within the rift zone at the northern end. The geological structure of these regions is highly unstable, creating serious problems related to well completions, reservoir engineering, and geothermal power production in general.

10.4.2 Námafjall

The geothermal power plant at Námafjall is relatively small, having been built to supply electrical power for a diatomite plant at Kisilidjan. This plant processes diatomaceous earth which is used as a filter aid with geothermal steam obtained from wells at the Námafjall field.

The Námafjall geothermal region has been the site of several projects making use of the thermal anomaly in the region. Wells had been drilled to permit the extraction of sulfur from the hydrogen sulfide which constitutes a portion of the geofluid. This mining operation gave rise to the name "Námafjall" which means "the mountain of the mines" [Ragnars, et al, 1970].

The Námafjall thermal area covers about 400 - 500 ha (988 - 1235 acres), but is part of a much larger thermal region, including Krafla, which extends over 5000 ha (12,350 acres). An abundance of surface thermal manifestations are found there including boiling mud pools, steaming ground, and fumaroles. The area is highly fractured with fissures and faults trending north-northeast/south-southwest. The rocks found there are of the silicic volcanic type and range in composition from basaltic andesites to rhyolites.

The arrangement of the wells relative to the power plant and the adjacent diatomite plant is shown in Fig. 10.7. A number of shallow wells (not shown) were drilled during 1947 - 1953 for sulphur mining. The present production wells were begun in 1963, with the first of these, N1, having been completed in 1966, followed by N2 and N3 in 1968. The wells are located along two faults and are separated by about 90 m (295 ft). Since the uppermost 180 m (590 ft) of the formation are permeable, loss of circulation is often encountered during the shallow drilling phase. Repeated cementing is required to prevent the wells from collapsing. It was found necessary to install a U-pipe separator on each wellhead because of sand, mud, pebbles, and other solid material which is ejected occasionally from the wells.

Conventional cyclone separators are used to separate the vapor and liquid phases of the geofluid.

The geothermal fluid carries with it an amount of noncondensable gases equal to about 1% (by weight) of the steam flow. The composition (by volume) of the noncondensable gases is roughly as follows: hydrogen sulfide, 52%; carbon dioxide, 32%; hydrogen, 12%; other gases such as nitrogen, methane, argon, etc., 4% [Bjornsson, 1968]. The total dissolved solids in the liquid (down-hole) is about 1000 ppm, nearly 60% of which is silica. Down-hole temperatures of nearly 300°C (572°F) have been observed; normal steam delivery temperature is about 183°C (361°F). Each well produces about 25 t/h (55,000 lbm/h) of separated steam at a pressure of 1078 kPa (156 lbf/in^2).

The power plant uses a turbine of the noncondensing type with a nominal capacity of 3.0 MW. Because of the noncondensing turbine, the plant has a low resource utilization efficiency. On the assumption that 20% of the geofluid is vapor at the wellhead, and that the appropriate ambient sink temperature for the region is 11°C (51.8°F), then the utilization efficiency would be 14%, and the plant would consume 82.5 kg of geofluid/kW·h (182 lbm/kW·h). The technical specifications for the Námafjall unit may be found in Table 10.4.

10.4.3 Krafla

The geothermal power plant at Krafla is the first major power station of its type in Iceland. The plant is a state-of-the-art design incorporating a secondary flash process to generate additional steam for power generation from liquid which would otherwise be wasted.

As can be seen from Fig. 10.6, Krafla lies in the same volcanic rift zone as Námafjall. The Krafla area was most recently subjected to a series of strong seismic events. In July 1975 earthquake tremors were detected. Gradually these increased in strength, and on December 20, 1975, lava burst out in Leirhnjúkur, only 3 km (2 mi) from the site of the Krafla plant. Although the lava flow lasted only a few hours, steam continued to erupt until the end of the year. During this period, 2000 - 4000 earth tremors were recorded each day.

During the first three months of 1976, there occurred seven earthquakes of magnitude greater than 4.0 on the Richter scale, with two of these exceeding magnitude 5.0. All of these were centered within a few kilometers of the plant site. By June 1976 most of the activity had ceased, but continuous vigilance is carried out by means of seismic monitors and field observations [Sólnes, 1976].

A plan view of the power station site is given in Fig. 10.8 which shows the locations of the power house, cooling tower, cooling pond, and proposed wells. The locations of the wells are tentative and subject to change. Also shown in the figures are the sites of recent volcanic activity, Leirhnjúkur, mentioned earlier, and Víti ("Hell") a crater which was formed at the beginning of the "Fires of Mývatn" in 1724. The proximity of these centers of volcanic action to the Krafla bore field is evident.

The plant is of the separated/single-flash (or "double-flash") steam type. A highly-simplified flow diagram for the plant is shown in Fig. 10.9. Only one typical wellhead is depicted; there may be five or six wells required for each turbo-generator unit. There are two 30 MW units currently installed at Krafla although there is insufficient steam available at this time to supply even one unit fully. The technical specifications for the Krafla units are listed in Table 10.4 [MHI, 1978c].

Very little information is available on the operation of the plant. It is known that trouble has been encountered with the production wells. Although the geofluid is relatively clean (TDS ∿ 1000 ppm with about 650 ppm silica), the wells have been subject to clogging. Two plugs seem to develop: a deep plug of iron sulfide, and a shallow plug of calcium carbonate. It seems evident that the cause of the poor production from the wells is the presence of these deposits in the boreholes, rather than the collapsing of the formation from earthquake activity as was earlier thought to be the case (J. T. Kuwada, personal communication).

10.4.4 Grindavik

It has been learned that a 1 MW geothermal power unit is located at Svartsengi near Grindavik on the Reykjanes peninsula in southwestern Iceland [Gudmundsson, 1978].

The bottomhole temperature is 235°C (455°F); the temperature of the steam at the separator is 155°C (311°F). The plant presumably is of the non-condensing type and makes use of a single well. It is expected that the capacity installed at the site will be increased as field development takes place and the expansion of the plant can be justified. Table 10.4 contains what little information is known about the plant.

10.5 ITALY

10.5.1 Overview

Documentation exists which shows that the natural steam fields in Tuscany were recognized as early as the 3rd century, and that the commercial potential of these mineral-laden waters led to wars between the Tuscan republics during the Middle Ages [ENEL]. It was not until 1904, however, that the power of natural steam was first harnessed to produce electricity, the accomplishment of this feat being credited to Prince Piero Ginori Conti.

Conti's original system used a reciprocating engine which received steam separated from the geothermal fluid. The engine was of the noncondensing type, exhausted to the atmosphere, and generated about 15 kW of electric power. The output from the DC generator provided lighting for the boric acid factory at Larderello in the boraciferous region of Italy. This primitive engine was replaced by a turbo-alternator of 250 kW capacity in 1913, thus marking the beginning of the production of electricity from geothermal sources on a commercial scale [Conti, 1924].

Since that time endogenous fluid has been tapped at two other sites, Monte Amiata and Travale, and the total installed geothermal electric generating capacity in Italy has grown to 420,000 kW.

In the following sections we will summarize some of the geological features of the main geothermal regions currently under exploitation, Larderello, Monte Amiata and Travale, and discuss briefly the technical details related to the gathering and distribution of the geothermal fluid, the energy conversion systems, and the reliability of the plants.

10.5.2 Larderello (Boraciferous Region)

The Larderello region in general structural terms corresponds to a tectonic high located between the Era graben to the north and northwest and the positive feature of the crystalline basement which is evident in outcroppings to the south and southeast [ENEL]. The presence of a deep magmatic intrusion at about 6 - 8 km (4 - 5 mi) is inferred from the huge gravity deficit.

The high heat flow in the region is generated by the gross interaction between the African and Eurasian tectonic plates and several smaller plates which are in contact in the area. Heat flow, thermal gradients, and thermal conductivity measurements have also been employed as prospecting tools. The area is characterized by exceptionally high thermal gradients, being of the order of 30°C/100 m (16°F/100 ft) and in some places, as high as 100°C/100 m (55°F/100 ft). These should be compared with the accepted normal gradient of about 3°C/100 m (1.6°F/100 ft). The geothermal field at Larderello is believed to cover about 25,000 ha (62,000 acres) [Koenig, 1973], although the drilled area extends over only about 18,500 ha (45,700 acres) [Ceron, et al, 1975; Ellis and Mahon, 1977].

There are roughly 190 producing wells in the Larderello region out of a total of 511 drilled [Overton and Hanold, 1977]. The average depth of all wells is 656 m (2152 ft); wells drilled since 1969 average 1129 m (3704 ft) in depth [Ceron, et al, 1975]. A typical well produces natural steam through a 311 mm (12-1/4 in) open hole and a 400 mm (13-3/8 in) casing which is cemented within a 406 mm (16 in hole). Deeper wells typically have a 216 mm (8-1/2 in) open hole throughout the permeable zone with a 244 mm (9-5/8 in) production casing. In this case the 400 mm (13-3/8 in) casing serves as an intermediate casing for safety purposes. The casings are J-55 API heavy wall pipe to withstand the corrosive nature of the geothermal fluid and the severe temperature cycling to which the wells may be subjected. The cement used for wells at Larderello consists of a mixture of Portland 425 cement and a fine-grained silica flour, in 60-40 proportions.

Geothermal steam is transported across the sloping landscape of Larderello in a network of over 118 km (73 mi) of weldable steel pipes from the individual wells to a number of power plants of relatively small electrical generating capacity. The pipes have wall thicknesses of 6 - 8 mm (0.24 - 0.31 in), have diameters of 250, 350, 450, 650 and 810 mm (10, 14, 18, 26 and 32 in), and are insulated with asbestos fiber of thickness ranging from 30 to 120 mm (1.2 - 4.7 in) [DiMario, 1961].

The steam at Larderello contains about 5% (by weight) CO_2, and 0.5% H_2S. It is produced at temperatures ranging from 140 - 220°C (285 - 430°F) and at pressures of 200 - 700 kPa (29 - 102 lbf/in^2). Maximum flow rates vary from 50 - 100 t/h (110 - 220 × 10^3 lbm/h). Although a few wells have delivered as much as 300 t/h (660 × 10^3 lbm/h), the average flow from all wells at Larderello is about 17 t/h (37,500 lbm/h) [Ceron, et al, 1975].

There have been three types of energy conversion systems used in the Italian geothermal plants. These are referred to by the Italians as "Cycle 1", "Cycle 2", and "Cycle 3", and are depicted schematically in Figure 10.10, as (a), (b), and (c), respectively.

Cycle 1 plants are installed at locations which either have high noncondensable gas content in the geothermal steam or are not sufficiently developed to justify the construction of steam lines to join the field to the main network. Such plants are extremely simple, highly reliable, easily assembled or disassembled, and offer low costs because they may be remote controlled from a nearby power station.

Cycle 2 plants were used when it was desirable and economic to extract chemicals, such as boric acid and ammonia, from the geothermal fluid while at the same time avoiding materials corrosion problems in the turbine and taking advantage of the improved power output associated with condensing operation. However, considerable difficulty was encountered in the operation of the heat exchangers because the water tubes which formed the boiler section were subject to deposits of iron sulfide or breakage depending on whether iron or aluminum were used for the tube material. Since chemicals are no longer extracted from the fluids and the problems of corrosion of turbine blades can be avoided, this energy conversion scheme has been eliminated.

Cycle 3 plants form the mainstay of the Italian geothermal plants. The effects of impurities or corrosive substances in the steam can be reduced by scrubbers located upstream of the turbine inlet. Pure water or alkaline solutions may be injected to wash the steam; axial separators then remove the injected liquid prior to admission into the turbine. The large amount of noncondensable gases in the steam requires the use of high-capacity turbocompressors to remove the gases from the condensers.

Power is produced at the present time in Larderello by means of energy conversion systems of the "Cycle 1" and "Cycle 3" types. Prior to 1968, "Cycle 2"-type plants were also in operation. The schematic layout diagram of Fig. 10.11 shows a typical arrangement for a Cycle 3 power unit. Of particular interest are the three stages of intercooling used with the gas compressor, the first stage of which is integral with the condenser.

A typical flow diagram for a 14.8 MW (gross), 13.4 MW (net) power unit is given in Fig. 10.12. The geothermal resource utilization efficiency, based on the available work of the geofluid relative to the design wet-bulb temperature of 19.4°C (67°F), is about 52%. However, none of the actual units operating at Larderello have efficiencies as high as this; the highest actual efficiency was 47.4% for the two units located at the Sasso Pisano geothermal field [DiPippo, 1978e].

Table 10.5 gives a summary of the technical particulars for geothermal power stations in the Larderello region which are equipped with condensing steam turbines. Table 10.6 contains similar information on noncondensing units in the same region. Figure 10.13 shows the turbine hall at Castelnuovo where 26 MW of electrical generating capacity are installed.

10.5.3 Monte Amiata

The Monte Amiata geothermal region is located about 70 km (44 mi) southeast of Larderello. Although the geology of the site is similar to that of Larderello, there are a few noteworthy differences. The Monte Amiata area is marked by magmatic extrusions, a feature absent at Larderello. Unlike the case at Larderello, there are relatively few outcroppings of the main aquifer complex. The main source of recharge fluid for the reservoir is the pervious volcanic formation which is linked to the aquifer by fractures, extrusion chimneys, and volcano-tectonic faults.

The two areas of the Monte Amiata field at which power plants are located, Bagnore and Piancastagnaio, are characterized by extremely high thermal gradients of about 50°C/100 m (27°F/100 ft), nearly seventeen times the normal gradient. The gradient exceeds 10°C/100 m (5.5°F/100 ft) over a wide area of 40,000 ha (100,000 acres) [ENEL].

The wells in this region produce dry, slightly superheated steam as at Larderello, but at generally lower temperatures. The steam temperature in the Bagnore area averages about 138°C (280°F) whereas the temperature at Piancastagnaio is 183°C (361°F). At the present time, closed-in wells at Bagnore and Piancastagnaio have pressures 588 kPa (85 lbf/in^2) and 1961 kPa (284 lbf/in^2), respectively. Wellhead operating pressures at the two sites are about 309 kPa (45 lbf/in^2) and 804 kPa (117 lbf/in^2).

The amount of noncondensable gas in the geothermal steam is significantly more than for the case of Larderello. At the time the field was being developed, gas content exceeded 90% (by weight) of the natural vapors. The earliest power plants encountered "steam" that contained between 30 - 80%

(by weight) of noncondensables. This percentage has declined during exploitation and now ranges from 7 - 20%. On the average, the noncondensable gas contains 95% carbon dioxide, 0.4% hydrogen sulfide, 0.4% hydrogen, 3.5% methane, and 0.7% nitrogen (by volume) [ENEL].

The only geothermal power stations in the Monte Amiata region are of the Cycle 1 or noncondensing type. In the late 1960's there were four units in operation, two at Bagnore and one each at Piancastagnaio and Senna. The last of these was a 3.5 MW unit, very similar to the 3.5 MW unit installed at Lagoni Rossi 1 at Larderello, but has since been shut down. The technical particulars for the remaining three units are listed in Table 10.7. The geothermal utilization efficiency for the two units at Bagnore is only 16%, whereas the 15 MW unit at Piancastagnaio operates with a geothermal utilization efficiency of 24% and consumes 17.7 kg/kW·h (39 lbm/kW·h) of net electricity generated [DiPippo, 1978e].

10.5.4 Travale

The Travale geothermal field is located just on the southwest edge of the Era graben, a northwest-southeast trending feature. The geology of the site is similar to that of Larderello which lies 10 - 15 km (6 - 9 mi) to the west-northwest. In fact, the nature of the boundary between the hydrological systems of Larderello and Travale is not well known even though both regions have been the subject of a large number of surveys [Petracco and Squarci, 1975]. As of 1975, there had been a total of fourteen wells drilled at Travale, eight of these having been completed prior to 1969.

There is one power plant in operation at the Travale field. It is a noncondensing unit (Cycle 1) of 15 MW nominal capacity. The plant is essentially identical in design to the one at Piancastagnaio, M. Amiata. The unit, installed in 1973, utilizes the geofluid from well T22. The technical particulars are listed in Table 10.7. This plant is reported to have the best operating efficiency of any exhausting-to-atmosphere geothermal plant in Italy. The specific steam consumption is 13.5 kg/kW·h (29.8 lbm/kW·h) [Ceron, *et al*, 1975], and a geothermal energy net utilization efficiency of 29%.

10.6 JAPAN

10.6.1 Overview

Japan is the only country in which there are now installed geothermal plants of the dry-steam, single-flash, double-flash, and binary type. Although only 165 MW are installed at this time, there is underway an ambitious and aggressive development program aimed at putting 48,000 MW on-line by the year 2000 from all geothermal sources, including tapping volcanic magma and hot dry rocks.

The full range of geothermal activities in Japan is directed by the government's Ministry of International Trade and Industry (MITI) through the Sunshine Project. Problems relating to fundamental research and development are handled through the Geothermal Energy Research and Development Co., Ltd. (GERD), an organization which enjoys the participation of thirty institutions, mainly from industry. The Agency of Industrial Science and Technology (AIST) also oversees certain research projects, in particular, those of the Geological Survey of Japan (GSJ). Projects related more to development than research are also administered by MITI, but are channeled through the Japan Geothermal Energy Development Center (JGEC) where funding is shared between government and industry on a 90/10 ratio. Thus a concerted and effective effort is underway in Japan to develop the geothermal resources of that country involving a close partnership between government and industry.

Exploitation of geothermal energy for electric power has, nevertheless, been slow in Japan because nearly all of the outstanding geothermal prospects are located in national parks which are enthusiastically protected for their natural beauty. The construction and operation of geothermal power plants thus are subject to rigid and stringent controls.

A summary of the geothermal plants in Japan is given in Table 10.8 where information is provided for those plants which are in operation, in testing, under construction, and in planning. Each of these now will be described briefly; a more detailed treatment may be found in DiPippo [1978a].

10.6.2 Matsukawa

The geofluid at Matsukawa is dry steam which is admitted to the turbine at about 440 kPa (63.8 lbf/in^2) and 147°C (296.6°F). The steam carries about 0.5% (by weight) noncondensable gases, of which about 82% (by volume) is CO_2 and about 15% is H_2S. The turbine is a 4-stage, impulse machine, exhausting to a barometric, direct-contact condenser at a pressure of 13.5 kPa (4 in Hg). A natural draft cooling tower reduces the temperature of the condensate from 47°C to 25°C (116.6 - 77°F) for recirculation and use in the spray condenser. Figure 10.14 shows the heat balance diagram for the plant at its design output of 20 MW [Akiba, 1970].

10.6.3 Otake

The separated (or "single-flash") steam plant at Otake has been in operation since 1967. Through 1977, the plant had logged 89,345 hours of operation out of a maximum possible 92,968 hours, for a plant availability factor of 0.961. The full capacity of the plant was achieved, however, only in its first year of operation. Owing to the loss of several production wells and the failure to complete any successful replacement wells, the actual output of the Otake plant has fallen steadily. In 1967, the mean output was 6.4 MW compared with the original 10 MW capacity. The geofluid is produced from a relatively shallow reservoir of depth 300 - 500 m (986 - 1640 ft), and is of low pressure, 245 kPa (35.6 lbf/in^2), and temperature, 127°C (261°F), by the time it reaches the turbine inlet. Currently only two wells are feeding the plant, with several others serving as reinjection wells for the disposal of the waste liquid from the wellhead separators and the excess steam condensate from the cold well of the mechanically-induced-draft cooling tower. Reinjection is carried out under atmospheric pressure to guard against any chance of inducing earthquake activity. However, loss of reinjectivity has been severe, with a drop-off in flow rate of about 7% per month. Alternate disposal strategies are being considered including reinjection under pressure and chemical treatment of the waste liquid to remove harmful elements and possibly eliminate the need for reinjection [DiPippo, 1978a].

10.6.4 Onuma

The Onuma plant is nearly identical to the Otake plant in terms of its energy conversion system. The turbine and the operating pressures and temperatures are the same. From 1973 through 1977, Onuma had operated for 36,073 hours out of a possible total of 38,424 for an availability factor of 0.939. However, unlike Otake, the Onuma plant began at about one-half capacity and has steadily increased its output, achieving a mean output of 7.7 MW in 1977. Reinjection has been going on without trouble even though the fluid is returned to the reservoir at atmospheric pressure. Figure 10.15 shows a view of the plant and one of the wellhead platforms [MHI, 1978a].

10.6.5 Onikobe

The plant at Onikobe is supplied with steam from a shallow reservoir which yields a 50-50 liquid-vapor mixture (by weight) at the surface. There is a large percentage of hydrogen sulfide, H_2S, in the geothermal steam and the geofluid is highly acidic. The total noncondensable gas content of the steam is about 0.5%, with about 36% of this being H_2S. Since there are no emissions controls on the gases exhausted from the plant, a large quantity of H_2S is continuously discharged to the atmosphere. Special precautions had to be taken in the selection of materials for the plant because of the extremely corrosive nature of the geothermal fluid. Extensive corrosion fatigue tests were conducted on the materials for the turbine rotor and blades. The rotor shaft glands are especially vulnerable because of their exposure to both geothermal steam and air leakage. Because of this, titanium was selected for these elements. Over the first seventeen months of operation, the Onikobe plant had recorded an availability factor of 0.937 [Kawasaki, 1977].

10.6.6 Hatchobaru

The Hatchobaru plant is an example of an advanced design, modern geothermal power station. It has a number of unique features: (1) 2-phase, liquid-vapor transmission of the geofluid, (2) "double-flash" operation, (3) low-level jet condenser integral with the turbine foundation, and (4) a combined steam ejector/radial blower for gas extraction. Figure 10.16 shows a schematic diagram of the plant. Each well discharges the total flow into a single pipeline which is joined to other pipelines for transmission of the geofluid to the power house. There the fluid is first separated into a vapor stream (primary steam) and a liquid stream in two vertical cyclone separators, shown in Fig. 10.17. The liquid fraction is flashed in a horizontal vessel to generate secondary, low-pressure steam. The turbine is a dual-admission, double-flow unit which receives primary steam at 677 kPa (98.2 lbf/in^2) and 164°C (329°F), and secondary steam at 99 kPa (14.4 lbf/in^2) and 102°C (215.6°F), and which exhausts at 9.8 kPa (2.9 in Hg). The plant was commissioned in June 1977 and was delivering about 24 MW as of October 1978. It is expected that enough wells will be drilled by the spring of 1979 to allow the plant to reach its full 50 MW capacity [Aikawa and Soda, 1975].

10.6.7 Kakkonda

The newest Japanese geothermal plant is a 50 MW single-flash plant at Kakkonda. Nearly 400 t/h (880×10^3 lbm/h) of separated steam pass through the 4-stage, double-flow turbine. Inlet conditions are 441 kPa (64 lbf/in^2), 147°C (297°F); exhaust is at 13.5 kPa (4 in Hg). A total of eleven producing wells and fifteen reinjection wells are employed. At this plant reinjection is done at the separator pressure, i.e., at about 550 kPa. Extensive monitoring is being carried out to check for any signs of induced seismicity [DiPippo,1979].

10.6.8 Mori and Otake Pilot Binary Plants

The development of binary geothermal power cycles began in Japan in 1975 in cooperation with the Sunshine Project, promoted by the Agency of Industrial Science and Technology (AIST) of the Ministry of International Trade and Industry (MITI). Two 1 MW experimental pilot plants have been built and are being tested. The one at Mori on the northern island of Hokkaido uses refrigerant-114 as the secondary working fluid in conjunction with shell-and-tube heat exchangers and a surface condenser. The turbine is an axial-flow machine.

The Otake binary plant is a more ambitious design. It employs isobutane as the working fluid. Isobutane vapor is generated in a multistage flash heater from geothermal liquid from the separator of the Otake well No. 10. The geothermal liquid enters the heater at 130°C (266°F) with a pH of 8, and carrying about 4000 ppm of dissolved solids. A portion of the steam from the steam receiver at the nearby Otake power plant is used to provide the final heating needed to vaporize the isobutane. The turbine is a radial-inflow machine, fitted with an extraction point to allow for feedheating of the isobutane liquid as it returns from the air-cooled condenser before entering the multi-stage heater. As of October 1978, three test runs had been conducted and another was scheduled for the winter of 1978-79, during which the regenerator was to be tested for the first time. An overall view of the Otake binary test plant is shown in Fig. 10.18. A much-simplified flow diagram is shown in Fig. 10.19. Note that the regenerator is not shown in the drawing, and that the multi-flash heater actually consists of eighteen sections. A supplementary water spray is used in the air-cooled condenser during warm weather [MHI, 1977].

10.6.9 Mori

A 55 MW, single-flash plant is being built at the Mori geothermal site in the southwestern part of the island of Hokkaido. The reservoir is liquid-dominated and contains relatively high amounts of noncondensable gases. The production wells range in depth from 1.0 - 1.2 km (3280 - 3937 ft).

10.6.10 Other Promising Areas in Japan

The ultimate geothermal electric generating capacity in Japan may be as high as 100,000 MW [MITI, 1976]. A great many areas are known to be excellent sites for geothermal developments. Some of these include: Oyasu (hottest well so far in Japan), Akinomiya, Yakedake, Kirishima, Fushime, Kuzuneda, Ogachi, and Takenoyu [Mori, 1975; GERD, 1975; Iga and Baba, 1974, MITI, 1976; DiPippo, 1978a].

10.7 MEXICO

10.7.1 General Remarks

The first exploration for sources of geothermal energy in Mexico took place in 1955 west of the city of Pachuca at Pathé. This geothermal field is situated on the Neovolcanic axis which trends east-west across the country in a region of upper Tertiary and Quaternary basaltic, andesitic, rhyolitic and pyroclastic rocks [Alonso, 1975].

As of 1975, the total installed electric capacity of Mexico was 7500 MW, with 48% being supplied by hydroelectric plants, 51% from oil and gas-fired thermal power plants, and the remaining 1% by coal and geothermal. It is unlikely that expansion in hydroelectric capacity will amount to more than about 12,000 MW. Although the discovery of extensive petroleum reserves in Mexico has allowed Mexico to become an exporter of crude oil and refined petroleum products, geothermal energy will, nevertheless, play an important role in meeting the growing demand for electricity in Mexico. There are over 130 geothermal regions in the country; these appear in 24 of the 32 states. The largest concentration of geothermal sites are in the states of Michoacán (22), Jalisco (16), Baja California (15) and Guanajuato (9). Owing to their wide geographic distribution and their potential as an inexpensive source of local power, these geothermal regions will be taken seriously into account in national plans to meet the expected future demand for electricity in Mexico.

10.7.2 Pathé

Mexico's first geothermal power plant was installed at Pathé, a geothermal field located in the municipality of Tecozaulta, in the state of Hidalgo, about 80 km (50 mi) north-northeast of Mexico City. The plant began operations in 1959; it is, however, no longer operational [G. Cuéllar, personal communication]

The Pathé unit had a capacity of 3.5 MW. It employed a noncondensing turbine supplied with steam separated, most likely from one well. Very little information exists on this plant in the literature.

10.7.3 Cerro Prieto

Since 1973 the geothermal power plant at Cerro Prieto has been generating 75 MW of power on a highly reliable and economic basis. The plant recently has achieved the highest capacity factor of any power plant in Mexico. So successful has been the experience that construction is underway on an extension of the plant which will duplicate the two existing power units. The new units will bring the installed capacity to 150 MW in 1979. The full potential of the field is known to be at least 400 MW.

The Cerro Prieto geothermal field is located on a plain in the Mexicali-Imperial rift valley in the State of Baja California, roughly 35 km (22 mi) south of the city of Mexicali and the international boundary between the United States and Mexico. The resource covers an area of about 3000 ha (7400 acres). Its general location is shown in Fig. 10.20. Figure 10.21 is a highly-simplified geologic cross-section of the field [after CFE, 1971]. The reservoir is capped by a layer of plastic, impermeable clays with a thickness of 600 - 700 m (1970 - 2300 ft) over the main portion of the field. Underlying the cap clays is the main reservoir which consists of shales and sandstones possessing considerable porosity and permeability. Basement faulting contributed to the permeability of the formation. The basement rock is granitic in nature and may be seen in large outcroppings in the Sierra de los Cucapahs.

Eighteen wells are connected to the first two units of the power plant, nine for each unit. Of these about 15 or 16 are needed to generate the rated 75 MW, with the others held on stand-by reserve. Figure 10.22 shows the piping lay-out for the steam gathering system. There are four main steam gathering lines which run from the wells to the steam receivers at the power house. There are over 6 km (20,000 ft) of steam pipelines of diameters greater than 406 mm (16 in). The mean lifetime of a well at Cerro Prieto is considered to be fifteen years. There are wells that are fourteen years old, still in good condition, and producing steam [Mercado, 1976]. The fluid in the reservoir is a compressed liquid which partially flashes to vapor during its ascent through the well. Under high flow rates it is observed that annular flow exists in the well bore, i.e., liquid on the walls and vapor in the core [Reed, 1975].

The two-phase geofluid is processed conventionally in Webre-type contrifugal separators, with the separated steam passing through ball check valves before entering one of the four main steam transmission lines. The main steam is collected outside the power house in a set of receivers, and passes through a final stage of moisture separation before entering the turbines. The geothermal steam contains about 1% by weight of noncondensable gases, mainly carbon dioxide and hydrogen sulfide. The separated liquid is burdened with an amount of dissolved solids which total roughly 25,200 ppm. The main impurities are chloride, sodium and potassium, which together constitute 94% of the total.

Since all of this liquid is discharged to the environment, attention must be given to the effects of the dissolved solids on the environment. Liquid which is separated from the two-phase mixture in the wellhead separators is sent either to silencers located at each wellhead site or piped directly to an evaporation and settling pond where the pressure is let down to atmospheric. Figure 10.23 shows a view of the pond and the pressure let-down process. Eventually all waste liquid (i.e., liquid from the separators or the silencers and excess steam condensate) is discharged into the pond. It is estimated that the present pond has a capacity sufficient to support 180 MW of generation. Beyond that, another means must be found for the disposal of the waste liquid. The options include: (1) Reinjection; (2) Construction of a channel to the Laguna Salada, a dried-up lake; and (3) Construction of a channel to the Sea of Cortez [Guiza, 1975; Mercado, 1975].

Since the evaporation pond covers a saline clayey area that originally had surface thermal manifestations, it is felt that the creation of the pond did not cause any additional environmental deterioration [Mercado, 1975].

The energy conversion system is of the separated-steam (or "single-flash") type, consisting of two units, each rated at 37.5 MW capacity. The units are of the single-cylinder, double-flow variety with six stages of impulse-reaction blades in each flow. A photograph of the turbogenerator for unit No. 2 is shown in Fig. 10.24. A simplified plant schematic/heat balance diagram is given in Fig. 10.25 [Akiba, 1970; Mercado, 1976].

The condenser is of the barometric, direct-contact type and is located next to the power house. Noncondensable gases are removed from the top of the condenser shell through a gas extraction system consisting of a 2-stage steam ejector with inter- and after-condensers. There are three first-stage steam ejector nozzles operating in parallel, for redundancy. The noncondensable gases are discharged to the atmosphere through fiberglass pipes (one for each unit) which extend to a height of 40 m (131 ft) above the ground. Since the prevailing winds blow either from the northwest or the southeast, these gases should be swept away from the plant. However, on windless days, the concentration of hydrogen sulfide may reach dangerous levels in certain areas. An alarm system is connected to a series of H_2S detectors to protect personnel in and around the power house. Furthermore, an additional vent line was constructed from the power house at the base of the gas extraction stacks to the evaporation pond.

The geothermal resource utilization efficiency, η_u, of the plant is 40%, based on wellhead flow conditions, assuming 24% quality, and a sink temperature of 26.7°C (80°F) [DiPippo, 1978d].

Owing to the corrosive nature of the geothermal liquid and vapor, special attention must be paid to the selection of materials for the plant components including the wells, silencers, piping, turbines, condensers, cooling towers, and electrical equipment.

The well casings are fabricated from J-55 API standard weight pipe with buttress couplings. Extra heavy wall thickness may be required in future wells. The cement consists of API type G with silica flour, perlite and retarders as additives [Guiza, 1975]. The silencers are made of concrete with wooden stacks in a twin-silo design [Mercado, 1975].

Carbon steel is used for pipes carrying nonaerated steam. Since the corrosion rate is three times higher when the steam is in contact with air, an allowance of extra wall thickness is provided on aerated-steam pipelines. The worst case occurs in condensate lines where the corrosion rate for carbon steel is 0.66 mm/yr (0.026 in/yr). Condensate lines are therefore provided with a corrosion allowance and coated with epoxy resin [Tolivia, et al, 1975].

The turbine rotor is fabricated from a Cr-Mo-V alloy steel forging; alloy steels containing Ni are not used because of their poor corrosion resistance. The turbine blades are machined from 12 Cr alloy steel bar stock. The blades of the last row are fitted with stellite erosion shields and fastened together with lashing wire to minimize vibrations [Akiba, 1970].

The shell of the condenser is carbon steel with a coating of epoxy resin. The barometric pipe is made of naval brass. The structural members of the cooling tower are constructed from AISI-4140 steel; the packing is redwood and fiberglass [Mercado, 1976].

Since electrical equipment is susceptible to corrosive attack by hydrogen sulfide, special precautions are taken for the protection of this equipment. Most switch-boards, including the main switch-board, are installed in rooms which are provided with air-conditioning systems fitted with activated carbon filters filled with activated alumina beads impregnated with potassium permanganate [Mercado, 1974]. The electrical contacts on the high-voltage side at the substation are gold-plated, although the use of platinum may have been more appropriate.

The Cerro Prieto geothermoelectric power plant has operated very reliably since it was brought on-line in April 1973. For example, in 1976 a total of 570,000 MW·h of electricity were generated. This corresponds to a capacity factor of 87%, the highest value recorded by any Mexican power plant up to that time.

10.7.4 Future Developments of Geothermal Power in Mexico

For the foreseeable future, geothermal power developments will center on the Cerro Prieto field although there are several other promising areas that someday may be exploited.

At Cerro Prieto, units No. 3 and 4, each to be rated at 37.5 MW and essentially duplicates of units No. 1 and 2, are under construction at this time and are expected to come on-line in 1979. The next unit is expected to be a low-pressure unit rated at 30 MW which will use steam flashed from a portion of the waste liquid produced from the first four units. This unit probably will not be ready before 1982. Additional units will most likely be 55 MW units of standardized design, and be located in a different section of the Cerro Prieto field, necessitating the construction of a new power house and related peripheral equipment. The ultimate electric generating capacity of the Cerro Prieto field is not known with certainty; 400 MW seems to be a conservative estimate.

A large number of other hydrothermal areas in Mexico are listed and described by Alonso in his paper at the Second United Nation's Symposium in San Francisco in 1975. Of the 130 sites that have been discovered, only nine of these have been drilled. Using conservative estimates, the ultimate geothermal power potential of the country has been placed at 4000 MW. Some include: Ixtlán de los Hervores (State of Michoacán, eight wells drilled); Los Negritos (State of Michoacán, various surveys, one well drilled); Los Azufres (State of Michoacán, various surveys); La Primavera (State of Jalisco, various surveys, a few exploratory wells drilled); and San Marcos (State of Jalisco, various surveys, six exploratory wells drilled).

10.8 NEW ZEALAND

10.8.1 Overview

New Zealand pioneered in the use of liquid-dominated geothermal resources for the production of electricity on a commercial scale. Studies which were begun in the 1930's culminated in the construction of the Wairakei power station. Plant construction began in 1956; the first unit was commissioned on November 15, 1958, and was followed in short order by 12 additional units, the last of which was brought on-line in October 1963. Although the installed capacity at Wairakei is 192.6 MW, the present output is about 140 - 150 MW, owing to reservoir decline and planned cut-backs in draw-off to conserve the resource. It is predicted, however, that an output of 120 - 140 MW will be sustainable for an indefinite period of time [Bolton, 1977].

There are currently two other geothermal areas being used or developed for electric power generation: Kawerau and Broadlands. At Kawerau, multipurpose use is being made of geothermal energy for process heating, clean steam generation, and electricity production. At Broadlands, the New Zealand Electricity Department (NZED) is in the process of installing a 150 MW power plant in three steps of 50 MW per unit. Concerns about the environmental impact of geothermal power generation have contributed to the rather slow development of this natural resource in New Zealand.

10.8.2 Wairakei

The Wairakei geothermal field lies in an extensive thermal area on New Zealand's North Island. Wairakei is situated about 8 km (5 mi) north of the northeast corner of Lake Taupo, roughly in the middle of the thermal belt 50 km (31 mi) wide and 250 km (155 mi) long, which trends northeast-southwest across the North Island from a central group of volcanic mountains to the White Island volcano in the Bay of Plenty. Large, active andesitic volcanoes are located at each end of the zone, and the wider central portion is dominated by acid igneous activity. These include rhyolite domes, pyroclastic pumice deposits and ignimbrites.

The reservoir at Wairakei consists of a pumice breccia aquifer (Waiora formation) which varies in thickness from 60 to 150 m (200 to 500 ft), and which lies from 180 to 300 m (600 to 1000 ft) below the surface. The surface formations comprise mainly loosely consolidated breccias (Wairakei breccia) and a top layer of recently-deposited pumice cover. These surface layers extend to a depth of about 125 m (410 ft) [Bolton, 1977].

The geothermal fluid from the Wairakei field is produced as a mixture of liquid and vapor from two sets of wells, high-pressure and intermediate-pressure ones. The steam is separated from the liquid by means of a complex network of cyclone separators and flash vessels. The steam gathering system is a complicated one involving three pressure levels. The complexity arose because the original plans for the development of the area included a plant to produce heavy water for the U.K. Atomic Energy Authority. This proposal was made in 1953 and the steam pressures were selected to accommodate the requirements of the distillation plant. The proposal for the heavy-water plant was withdrawn in 1956, but only after the design of the steam system had been frozen and turbines were on order.

The present gathering system is shown schematically in Fig. 10.26 [Bolton, 1977]. Two high-pressure wells are shown. The one on the left supplies fluid to a typical flash plant which produces steam at three pressure levels: high-pressure (H.P.), intermediate-pressure (I.P.) and intermediate-low-pressure (I.L.P.). The one at the right produces only high-pressure fluid by means of a simple cyclone separator. The figure does not show the intermediate pressure wells that also produce intermediate-pressure (I.P.) steam and additional water for the flash plant.

The wellhead separators are of two types: top-outlet cyclonic (TOC) separators and bottom-outlet cyclonic (BOC) separators. The former type incorporated a U-bend upstream of the admission point to the separator which removed about 80-90% of the liquid. A baffle arrangement inside the separator trapped the remaining liquid and allowed the steam to emerge with a dryness fraction of about 99%. The latter type is much simpler and has been shown to be capable of yielding steam with a dryness fraction in excess of 99.9% [Usui and Aikawa, 1970].

A simplified flow diagram for the Wairakei plant is shown in Fig. 10.27. As can be seen, a train of turbines is fed with steam at various pressures obtained from simple separation and successive stages of throttling of geothermal liquid, each producing dry, saturated vapor at lower and lower pressures. The main steam transmission pipelines are 508, 762, 1067 and 1219 mm (20, 30, 42 and 48 in) in diameter. The largest of these carry intermediate-low pressure steam for which the specific volume is very large.

The energy conversion system consists of two 6.5 MW and two 11.2 MW back-pressure machines supplied with separated high-pressure bore steam; two 11.2 MW back-pressure machines which receive a mixture of an intermediate-pressure bore steam, intermediate-pressure flashed steam, and exhaust steam from the HP units; four 11.2 MW condensing units which run on low-pressure steam obtained from the exhaust of the IP units and let-down flashed steam from the second-stage flash vessels; and three 30 MW dual-admission condensing turbines which use the same steam which feeds the IP units and pass-in, low-pressure steam let-down from the second-stage flashers.

Of all these turbines, only the dual-admission machines may be considered as typical for a geothermal installation, the others having been installed as a consequence of the planned heavy water plant.

The choice of materials for the plant equipment is dictated by the nature of the geothermal fluid. The Wairakei fluid is relatively clean, having no more than about 5000 ppm of dissolved solids and less than 0.5% non-condensable gases (by weight) in the steam. Scrubbers are used to ensure that the total saline content of the steam which enters the turbine does not exceed 10 ppm in order to avoid problems of stress-corrosion cracking in the blades. Since there are no corrosion problems with the geothermal fluid so long as contact with oxygen is avoided, the steam transmission pipes are made of seamless, mild steel, rolled and butt-welded mild steel, and spiral-welded mild steel piping. The newer, larger pipes are insulated with 38 mm of fiberglass and covered with aluminum sheathing [NZED, 1974].

There has been a considerable reduction in field pressure during the lifetime of the project. The high-pressure wells originally produced at pressures in excess of 1400 kPa (200 lbf/in^2) [Bolton, 1977]. The dramatic decrease in field pressure may be seen in Fig. 10.28, which covers the period 1953-1975. The loss in pressure amounts to about 38% over the 23-year span, with nearly all of it having occurred since the date of the commissioning of the first machine. The pressure appears to be approaching a stable value, having lost only 6% during the last seven years.

It should be pointed out that no reinjection of the withdrawn fluid has ever taken place at Wairakei. In addition to playing a role in the pressure loss within the reservoir, this has led to significant subsidence. An area of about 6500 ha (16,000 acres) shows the effects of subsidence and horizontal land movement. The maximum total drop in elevation is in excess of 4.5 m (14.8 ft) over the 10 year period from 1964 to 1974 at a spot which is removed from the borefield but within about 500 m (1640 ft) of the steam pipelines [Stilwell, et al, 1975]. Subsidence appears to be progressing at the rate of 400 mm/yr (16 in/yr). The subsidence volume is likely related to the volume of fluid withdrawn from the field, but a precise correlation is not available.

The geothermal resource utilization efficiency, η_u, has been calculated approximately. For purposes of the calculation, the power output was taken equal to the installed capacity of the plant, i.e., 192.6 MW. The actual output at the present time is considerably below this value, being about 150 MW.

With reference to Fig. 10.27, the availability of the geofluid is composed of two contributions, one from the H.P. fluid at state a and one from the I.P. fluid at state h. Since mass flow rates are not available in the literature at states a and h, it was necessary to work backwards from the turbine main stop valve steam flows, and employ assumptions about the average dryness fraction at the H.P. and I.P. wellheads. Fair approximations for these were obtained from Hunt [1961] and Wigley [1970], after making allowances for lower wellhead pressures. Thus, the resource utilization efficiency of the Wairakei plant, under conditions of maximum output (i.e., in its original design state) is about 55%. It is likely that this value is somewhat, but not much, lower than this at the present time, owing to the general deterioration of the reservoir characteristics and the corresponding mismatch between the geofluid and the energy conversion equipment. However, the conversion of more and more wells to the multiflash arrangement shown in Fig. 10.27 will tend to maintain the level of utilization in the face of reservoir decline [DiPippo, 1978c].

A thorough study of the environmental impact of the Wairakei plant was conducted and reported by Axtmann [1974, 1975]. He examined all possible detrimental effects including the impact of chemical effluents in the liquids and gases which flow from the plant, physical effects such as thermal discharge and ground subsidence, general ecological effects, and esthetics or "visual pollution".

When discussing the effects of the Wairakei geothermal power plant on the environment, it is important, however, to keep in mind that the plant was designed and built at a time when environmental issues were regarded as far less important than they are today. The fact that an environmental impact report was not required for the construction of the plant stands as evidence. When one considers that Wairakei was the first liquid-dominated geothermal resource to be exploited for electric power, one realizes that the state of the art in geothermal technology was, in fact, in its infancy at the time it was built. Even so, the plant has operated successfully for over twenty years with a minimum of unpleasant impact on the population that lives near the plant.

The Wairakei plant has an outstanding record of reliability; forced outages have been essentially negligible. During 1973/74, the station was in service 85% of the time (availability factor) with a capacity factor of 80%. This performance is unmatched by any other power station, hydro or thermal, and is significantly superior to any thermal power plant in New Zealand. In fact, the Wairakei geothermal power station has maintained this excellent record since it was fully commissioned in 1964 [Ravenholt, 1977b].

The generating history of the Wairakei plant is given in Table 10.9. Since it has never been possible to generate sufficient geothermal steam to supply fully the installed electrical capacity of 192.6 MW, the capacity factors listed in the fourth column of the table have been adjusted accordingly. The so-called "field-limited" capacity factor is based upon the maximum load during any given year, as shown in the third column. The generation of 1207 GW·h in 1969 constituted 9.9% of the entire electricity generation in New

Zealand for that year. The latest figures available (1974) show that the plant is producing about 10% of the electricity requirements of North Island, although this percentage is expected to fall as the electrical generating capacity of the country as a whole increases [Bolton, 1977].

There are at present no plans to expand the installed capacity at Wairakei (N. C. McLeod, personal communication), although exploration is continuing at the nearby geothermal field of Te Mihi [Smith and McKenzie, 1970], and at other promising sites in the thermal belt. Additional geothermal power in New Zealand will likely come from new plants at such sites as Kawerau and Broadlands, which are discussed in the following sections.

10.8.3 Kawerau

Multiple use is being made of the geothermal resource at Kawerau, 97 km (60 mi) northeast of Wairakei. The Tasman Pulp and Paper Company, in fact, relocated their mills in the early 1950's specifically to take advantage of the geothermal energy available at Kawerau. Steam and hot water from a number of wells are used for the production of electricity, for the generation of clean steam by means of heat exchangers, and for a number of process applications including timber drying, liquor heaters, and log handling equipment.

The geothermal steam field layout including the pulp and paper mill is shown in Fig. 10.29. The most active surface manifestations of geothermal energy lie to the west of the Tarawera River (cross-hatched areas), although highly productive wells have been drilled on the east bank in close proximity to the mill [Smith, 1970].

The gathering system includes branch pipes from the individual wellheads to the main steam lines; these branch lines are 203, 305 and 406 mm (8, 12, and 16 in) in diameter. The low-pressure wells feed the plant through a 610 mm (24 in) diameter steam main which is capable of handling 145 t/h (320 klbm/h) of steam at 791 kPa (114.7 lbf/in^2). The high-pressure well (KA8) delivers through a 305 mm (12 in) supply line, at a maximum flow rate of 36 t/h (80 klbm/h) and a pressure of 1480 kPa (214.7 lbf/in^2). Noncondensable gases constitute about 2.5% (by weight) of the geothermal steam; about 91% is carbon dioxide, with the rest being mainly hydrogen sulfide.

The plant purchases 80% of its electricity from the grid and produces the other 20% in-house. A bank of turbo-alternators operate in parallel, being fed by boiler steam and geothermal steam. The latter supplies one 10 MW, noncondensing unit. Since the steam which supplies this unit is excess geothermal steam, beyond the process needs of the plant, this unit is part-loaded most of the time. Nevertheless, it is capable of operating at full load in the event of a failure of the other turbo-alternator units. At full output, the unit has a specific steam consumption of about 14.5 kg/kW·h (32 lbm/kW·h). This corresponds to a geothermal utilization efficiency for electrical production of about 24%, assuming a wellhead quality of 30% and taking the available sink temperature as 27°C (80°F) [DiPippo, 1978c].

Although the main thrust of the plan for geothermal energy utilization at Kawerau has been aimed at process heating and other industrial applications, it is likely that serious consideration will be paid to the expansion of the facility for the generation of electricity. Encouragement comes from the fact that one of the newest wells, KA21 (see Fig. 10.29), by itself, appears capable of supporting a 20 - 30 MW generator. This is 4-6 times larger than the potential of an average geothermal well. Thus, it is expected that a separate generating station, one able to supply all of the electrical needs of the mill, will be constructed at the site as soon as present investigations justify the additional investment [Ravenholt, 1977b].

10.8.4 Broadlands

The latest geothermal project in New Zealand concerns the proposed 150 MW double-flash plant at Broadlands. The plant will be built in three stages of 50 MW each. Steam will come from the liquid-dominated reservoirs at Ohaki and Broadlands. The plans for the station are currently being processed by the various regulatory agencies with jurisdiction in such matters. The first unit may not begin operating until 1984.

The Ohaki-Broadlands geothermal field has been intensively studied, and several reports on the geology of the site are available [Browne, 1970; Grindley, 1970; Grindley and Browne, 1975; Hochstein and Hunt, 1970; Macdonald, 1975]. The drilling of exploration wells began in 1965; since that time, over thirty wells have been drilled. However, only sixteen of these are considered sufficiently productive to be suitable for power production. It will take twenty producing wells to supply the required steam flow for the 150 MW power plants.

Certain details about the design of the plant's energy conversion system are undecided at the time of writing. However, preliminary technical specifications for the proposed plant are available [Bauer, et al, 1977]. On the basis of these figures, the plant would have a geothermal energy resource utilization efficiency of about 43%, relative to the thermodynamic available work of the geofluid at the wellhead, with a calculated quality of 25% at the wellhead, and a sink temperature of 27°C (80°F).

10.8.5 Other geothermal areas in New Zealand

The thermal belt across North Island from Lake Taupo to White Island in the Bay of Plenty abounds with thermal areas, some of which may prove useful for the generation of electricity, district or process heating, or other commercial or industrial applications.

Some of the areas that have been investigated include:

Ngawha . . . . . . Bottom-hole temperature = 236°C (457°F), but low reservoir permeability.

Orakeikorako . . . Few producing wells, low quality steam, infiltration of cold water.

Reporoa. . . . . . Unimpressive temperature and low reservoir permeability.

Rotokawa . . . . . Bottom-hole temperatures ≈ 306°C (583°F), high steam quality, but high noncondensables and only moderate reservoir permeability.

Tauhara. . . . . . Adjacent to Wairakei, very similar temperatures with higher pressures, some weak linkage between Wairakei and Tauhara but not enough to influence production at either site.

Te Kopia . . . . . Field aligned with fault scrap, steam output is moderate but of low quality, highest temperatures occur in upper formation, become indifferent at depth.

Te Mihi. . . . . . Extension of Wairakei field, at least one well has been connected to Wairakei system.

Waiotapu . . . . . Area of considerable thermal potential, shallow wells rapidly develop calcite deposits, deep wells are more promising.

There are other areas that hold promise, and the interested reader may consult several references for further details [Dench, 1961; Smith, 1970; Smith and McKenzie, 1970; Bolton, 1977]. Presently, however, there are no plans to install electric generating stations at any of these geothermal areas.

10.9 PHILIPPINES

10.9.1 Outlook

Geothermal energy presently accounts for 3 MW of electricity in the Philippines. According to optimistic projections this will rise to 1320 MW by 1985. By that time, geothermal energy would be supplying nearly one-quarter of the total electric generating capacity of the country.

10.9.2 Tiwi

Tiwi is the site of one of the principal geothermal fields in the Philippines. It has been one of the most popular hot springs on the island of Luzon in Albay Province. It is located at the far southeastern tip of Luzon, about 300 km (185 mi) from Manila [Muffler, 1975].

The Tiwi field has been investigated using a number of techniques including Wenner and dipole-dipole resistivity surveys, geological, heat flow and geochemical methods. The exploratory work began in 1964 through the Philippines Commission on Volcanology, supported with financial assistance from the National Science Development Board.

As a result of the surveys, an area of 2300 ha (5680 acres) was outlined as a potential reservoir at drillable depths. Fourteen wells were sunk inside the resistivity low, and confirmed the indications of the surveys. The wells produced a mixture of liquid and vapor at high flow rates, and revealed the nature of the reservoir. The Tiwi system is a liquid-dominated field in a reservoir of Quaternary andesites and subsidiary decites. It is believed that a system of microfractures lend permeability to the reservoir. A total of 20 wells have now been drilled, with 19 of these being producers; they extend to depths of between 760 - 2130 m (2500 - 7500 ft). These findings were reported by A. P. Alcaraz in 1976 and quoted by Ravenholt [1977a].

The preliminary design, equipment procurement, drafting of specifications and contract documents for the first four units at Tiwi have been completed and orders have been placed for the turbo-generators. These are identical, 55 MW single-cylinder, double-flow, 6 × 2 stage machines of the dual-admission type appropriate for use with separated-steam/hot-water flash (or "double-flash") systems. The technical specifications for the units are given in Table 10.10 [Toshiba, 1977]. It is anticipated that ten producing wells will be needed for each 55 MW unit, requiring roughly 454 t/h $(1.0 \times 10^6$ lbm/h) of geothermal steam. For an average wellhead quality of 25%, the resource utilization efficiency, η_u, would be approximately 41%. Each unit of the power plant will produce about 1247 t/h $(2.75 \times 10^6$ lbm/h) of waste liquid which will be disposed of by means of reinjection wells.

10.9.3 Los Baños (Makiling Banahaw)

Los Baños lies about 70 km (43 mi) southeast of Manila on the island of Luzon. It is part of a huge area with a geothermal potential of around 720 MW; the area extends over 153,000 ha (378,000 acres) in the Makiling - Banahaw volcanic region.

At least fourteen wells have been drilled at the Los Baños thermal area. Bottom-hole temperatures are in the range 280 - 310°C (540 - 590°F), and geofluid qualities as high as 36% at the wellhead have been reported [Ravenholt, 1977a]. Most of the wells are located about 450 m (1475 ft) above sea level near Mount Bulalo.

A small, 1.2 MW, wellhead auxiliary geothermal power unit has been operating at Los Baños since early 1977; the technical particulars of this machine may be found in Table 10.10. The main power units for Los Baños will consist of four identical units, each of 55 MW capacity, of the single-cylinder, double-flow, mixed pressure, impulse-reaction design for separated-steam/hot-water flash ("double-flash") energy conversion systems. Table 10.10 also contains the technical specifications for each of the first four units. According to these particulars, the geothermal resource utilization efficiency, η_u, will be 54% for a wellhead quality of 25% [DiPippo, 1978c].

10.9.4 Leyte (Tongonan)

A 3 MW portable geothermal unit is operating at Tongonan on the island of Leyte. The unit consists of a noncondensing turbine, a single Curtis stage, connected to a generator through a helical reduction gear. The entire unit is mounted on a platform to facilitate its transfer from one site to another. The technical specifications are given in Table 10.10.

10.9.5 Other Philippine Areas with Geothermal Potential

The potential for geothermal development in the Philippines is significant; 1320 MW by 1985, as mentioned earlier. Table 10.11 gives a breakdown of the distribution of the expected generating capacity. Resistivity surveys indicate that the potential of the fields included in the table exceeds 2200 MW.

Some idea of the scope of the effort that will be needed to achieve an installed capacity of 1320 MW in 1985 can be gotten from the fact that about 10 producing wells are needed for each 55 MW unit. Thus, 240 producing wells must be drilled. Allowing three out of every four wells drilled to be producers, a total of 320 wells must be sunk. Assuming that each well costs $1,000,000 (current costs are $750,000), this will necessitate a capital investment, for wells alone, of $320,000,000. Taking into account both the time required to prove a field and the construction lead time for a power plant, it is easy to see how difficult it will be to accomplish such an enormous project within seven years. Simply to drill the required wells within that time would mean that roughly four wells would have to be drilled each month.

Small, "wellhead" power units in the 1 - 10 MW range are expected to find application in those cases where large units are either unnecessary or impractical, particularly on the smaller islands of the Philippines such as the Visayan group of Leyte, Cebu, Bohol, Negros and Panay. The electricity produced from them is cheaper than that generated by diesel engines, and their use provides a source of revenue and local power during the early stages of development of a geothermal field. The revenue obtained thus helps to alleviate the cash flow problem faced by field developers.

The opportunity exists for the Philippines to supply a significant percentage of its electrical needs from indigenous, geothermal energy. The high cost of imported petroleum products provides a great deal of motivation to get on with the development of the geothermal resources of the country.

10.10 TURKEY

10.10.1 Introduction

The focus of geothermal energy development in Turkey is at the Kızıldere field in the Menderes River Valley, western Anatolia. A small, wellhead power-generating unit is in operation at this site, and there are plans to expand the installed capacity to about 12 MW in the near future.

Turkey is situated on an active tectonic zone and possesses great potential for geothermal energy. There are more than 600 hot springs, some with temperatures as high as 102°C (216°F), and numerous areas exhibiting hydrothermal alteration. Since 1962 the Mineral Research and Exploration Institute of Turkey (MTA) has been conducting surveys of the geothermal resources of the country by means of geological, geophysical, geochemical, and drilling studies. Fourteen promising areas have been thus far identified, the best of which is located at Kızıldere, near Sarayköy in the Denizli province [Alpan, 1975].

10.10.2 Kızıldere

The geothermal field at Kızıldere consists of two producing reservoirs, one lying between 300 and 800 m (984 - 2625 ft), and one between 400 and 1100 m (1312 - 3609 ft). The deeper reservoir is considered the main producer and has a temperature of 200°C (392°F), whereas the upper zone is at 170°C (338°F). The chemical composition of the fluids from the two zones are similar [Tezcan, 1975a]. Portions of the field may consist of isolated dry steam caps [Tezcan, 1975 b].

From 1966 to 1975 fourteen wells were drilled in the area, with twelve of these being producers. The wells ranged in depth from 370 to 1241 m (1214 - 4072 ft). Half of the producing wells terminated in the upper reservoir; half reached the deep reservoir. In general, the produced fluid may be characterized as follows [Alpan, 1975]: Maximum temperature, 207.4°C (405.3°F); Maximum wellhead pressure, 2.16 MPa (314 lbf/in^2); Maximum total flow rate (single well), 1003.5 t/h (2.2 × 10^6 lbm/h); Maximum vapor flow rate (single well), 67.6 t/h (149 × 10^3 lbm/h); Fluid dryness fraction (at wellhead), 2 - 12%, 10% average.

A 0.5 MW power unit has been installed on well KD-XIII by MTA. The composition of the geofluid produced by this well is shown in Table 10.12, along with the average composition for all twelve producing wells [Alpan, 1975]. Well KD-XIII is 760 m (2494 ft) deep, and produces from the lower reservoir which it enters at a depth of 590 m (1936 ft). The maximum temperature is 197°C (386.6°F), the production pressure is 1.08 MPa (157 lbf/in^2), and the flow rates of liquid and vapor are 522 and 20 t/h (1.15 × 10^6 and 44 × 10^3 lbm/h), respectively [Alpan, 1975]. The characteristics of the wellhead turbine are given in Table 10.13. The plant has a specific geofluid consumption rate of 79.8 kg/kW·h (176 lbm/kW·h).

A realistic appraisal of the ultimate potential of the Kızıldere field is difficult owing to serious problems of plugging of the wells. Out of a total of twelve producing wells only six have been judged to be suitable for production. However, only three of these can be relied upon at any given time because of the necessity for periodic reaming of clogged wells. With three wells in operation and 1086 t/h (2.4 × 10^6 lbm/h) of geofluid being produced, it has been estimated that 11,430 kW (gross) or 10,550 kW (net) could be generated. Under the best conditions, if six wells could be used simultaneously to produce 1640 t/h (3.6 × 10^6 lbm/h), then the system could support 32 MW (gross) or 28 MW (net). To achieve this level of output, a reliable and effective system of reinjection of waste water would need to be implemented [Alpan, 1975].

10.10.3 Other Areas Being Explored in Turkey

Exploration has reached the drilling phase in a number of areas including: Ankara (Ayaş, Çubuk, Kızılcahamam, and Mürtet), Afyon, Izmir (Agamemnun and Seferihisar-Doğanbey), Çanakkale (Tuzla-Kestanbol), and Söke (Germencik).

Preliminary investigations are being carried out at several other sites including: Bergama-Dikili, Çan-Gönen, Eskişehir, Gediz, Nevşehir-Kozaklı, Salihli-Turgutlu, Sındırğı-Hisaralın, and Tatvan-Nemrut.

It is hoped that the geothermal resources at these sites will be suitable to allow the generation of electricity, the heating of buildings and greenhouses, and the general improvement of hot springs for the tourist trade [Alpan, 1975].

10.11 UNION OF SOVIET SOCIALIST REPUBLICS

10.11.1 Overview

Although the Soviet Union has a huge potential of moderate-temperature geothermal waters which may someday be exploited for space or process heating, the only known sites at which geothermal energy is being used or contemplated for electric power production are located on the Kamchatka peninsula, well-removed from the main population centers of the country. Whereas the potential for direct heating from geothermal resources is estimated at 48,000 MW (thermal) [Tikhonov and Dvorov, 1970], the geothermal electric power capacity may only amount to several hundreds of megawatts.

Several areas in the Kurile Islands and on the Kamchatka peninsula have been identified where electric power plants could be installed [Makarenko, et al, 1970; Tikhonov and Dvorov, 1970]. These include: Pauzhetka, Uzono-Semyachik, Mutnovo-Zhirovo, Bolshoye-Bannoye, Goryachy Plyazh (Yuzhno-Kurilsk). All of these sites are in regions of recent volcanism which are characterized by dramatic surface thermal manifestations.

The locations of several major hydrothermal areas on the Kamchatka peninsula are shown in Fig. 10.30. The major population center of the area, Petropavlovsk-Kamchatskiy, is within 75 km (47 mi) of several of these geothermal prospects. By and large the resources are of low-to-moderate temperature and are situated in relatively shallow reservoirs (< 1 km). The highest bottom-hole temperatures have been found at the Pauzhetka site, e.g., about 200°C (392°F) at 400 m (1312 ft).

It is known that at least two geothermal power plants have been in operation in Russia and that several others have been mentioned as either under construction or in planning. These include the flash-steam plant at

Pauzhetka, the binary plant at Paratunka, the multiple-flash steam plant under construction at Bolshoye-Bannoye, and the steam plants proposed for Makhachkala and Yuzhno-Kurilsk. These will be discussed in the following sections.

10.11.2 Pauzhetka

Approximately 20 to 25 wells have been drilled at the Pauzhetka geothermal area. Each of these produces roughly 36 t/h (79,000 lbm/h) of steam and liquid. The geofluid is a mixture of liquid and vapor having a dryness fraction of about 9%. The wellhead pressure lies between 196 - 392 kPa (28 - 57 lbf/in^2). The fluid carries 1000 - 3400 ppm of total dissolved solids, of which about 250 ppm is silica. The noncondensable gases amount to slightly more than 0.05% (by weight) of the geofluid mixture (or 0.6% of the steam) with the bulk of the gases being CO_2 (92%), and the rest being mainly H_2S (4%) and NH_3 (3%) [Tikhonov and Dvorov, 1970].

At present, a separated-steam plant of 5 MW capacity is in operation at Pauzhetka. The plant is owned and operated by the Kamchatka Electricity Production and Distribution Administration. The plant began production in 1967. About nine wells are required to supply the station. The steam piping from the wells to the power house ranges in diameter from 210 - 370 mm (8.25 - 14.5 in) and totals 1.3 km (4300 ft) in length. The steam pipes are made of carbon steel.

The design of the plant is simple and straightforward; a flow diagram is given in Fig. 10.31. Cyclone separators with mist eliminators in the upper part yield steam of approximately 0.995 dryness fraction. The 5 MW output is obtained by means of two 2.5 MW turbines arranged in tandem. The machines were manufactured by the Thermal Turbine Machine Corporation Plant at Kuluga, and are situated in the turbine room that has a floor area of

33 m × 9 m = 297 m^2 (108 ft × 30 ft = 3200 ft^2). The condensers are of the direct-contact type, made of stainless steel, with 11 m^3 (389 ft^3) of steam volume, and are fitted with 118 nozzles through which the cooling water is sprayed.

A summary of the technical particulars for the unit may be found in Table 10.14 [Naymanov, 1970]. On the basis of the data in Table 10.14 and assuming a geofluid wellhead dryness fraction of 9%, the plant would have a resource utilization efficiency of 54% and would consume 56 kg/kW·h (123 lbm/kW·h). However, values as low as 5% have been reported for the geofluid dryness fraction [Tikhonov and Dvorov, 1970], and this would reflect a much lower utilization efficiency (about 28%). The actual value probably lies somewhere between these limits.

Power from the plant is transmitted to the town of Pauzhetka, the Ozernovsk fishing combine, and the collective farm at Krasnyy Truzhenik. The power line carries electricity at 35 kV and is 30 km (19 mi) long [ARPA, 1972].

The geothermal liquid which is separated at the wellheads is discharged into the Pauzhetka River at a temperature of 110°C (230°F) and at a rate of 110 kg/s (220 lbm/s). There were plans to make use of this hot fluid for the heating of greenhouses although it is not known whether such plans have been implemented as yet [Tikhonov and Dvorov, 1970]. The same authors also reported that the cost of electricity from the Pauzhetka geothermoelectric station is less by a factor of 10 to 15 than electricity generated by diesel power plants on the Kamchatka peninsula.

Although it has been reported that there were intentions to expand the capacity of the plant to 12.5 MW, and eventually to 20 MW, these intentions remain unfulfilled at present [ARPA, 1972]. The ultimate potential of the Pauzhetka reservoir has been estimated at between 50 and 70 MW of electrical power [Tikhonov and Dvorov, 1970].

10.11.3 Paratunka

The Paratunka geothermal power project was an ambitious attempt at providing a form of total-energy system, albeit on a rather limited scale. The power plant was a binary-fluid cycle which employed refrigerant-12 as the working fluid in conjunction with geothermal waters at temperatures as low as 81°C (178°F). The power from the plant served a small village and several Soviet state farms. Furthermore, the geothermal water, after leaving the power house and having been cooled to 45°C (113°F) in the plant's heat exchangers, was put to use to heat the soil in a series of greenhouses. Finally, the cooling water leaving the condensers of the power plant was used to water the plants in the greenhouses. It is not possible to use the waters of the Paratunka River directly for this purpose because of their low temperature of 5 - 7°C (41 - 45°F).

It is generally acknowledged that the Paratunka plant was the first binary geothermal pilot plant to generate electricity, having begun operations in 1967. The plant was built to test the design theories of geothermal binary plants. Although the plant apparently operated successfully for several years, it has been reported recently [Smith, 1978] that the power station has been closed and dismantled because of difficulties with leaks in the refrigerant-12 piping. Furthermore, the properties of refrigerant-12 are not ideally suited for geothermal applications [Naymanov, 1970]. Nevertheless, it is instructive to examine the details of the Paratunka plant.

The geothermal hot water is obtained from a number of shallow wells located about 1.5 km (0.9 mi) from the plant site. The wells range in depth from 302 - 604 m (991 - 1982 ft), and in diameter from 127 - 200 mm (5 - 7.875 in) [ARPA, 1972]. Eight wells were completed in 1964 before construction got underway on the plant; six wells were used to supply the plant with about 280 t/h (617 × 10^3 lbm/h) of hot water [Moskvicheva and Popov, 1970]. One of these wells was kept on reserve.

A simplified flow diagram of the power plant is given in Fig. 10.32; the technical specifications are listed in Table 10.15. The values given in the table are the actual values achieved during the tests reported by Moskvicheva and Popov [1970]. In certain respects, these differ from the design values. For example, the hot water inlet temperature should have been 90°C (194°F), the cooling water from the Paratunka River should have been 5°C (41°F), and the condensation temperature of the refrigerant-12 should have been 15°C (59°F), instead of the actual values of 81.5°C (178.7°F), 6 - 8°C (42.8 - 46.4°F), and 32°C (89.6°F), respectively. It should be noted, however, that the validity of the data, as reported, is doubtful since the performance data quoted in the above reference leads to a negative pinch-point temperature difference in the geofluid/refrigerant-12 heat exchanger, a result which is prohibited by the laws of thermodynamics.

Nevertheless, the efficiency of the energy conversion system was determined in terms of the amount of hot water required for a given output. Figure 10.33 shows the hot water flow rate as a function of the gross power output. It may be seen that the actual fluid consumption was roughly 65% higher than the design value at 680 kW because of the 8.5 - 9°C shortfall in geofluid temperature. In fact, even at the actual temperature, the actual fluid requirements exceeded the calculated values by about 9 percent. The specific hot water consumption at maximum load (680 kW) was about 412 kg/kW·h) (908 lbm/kW·h). This converts to a geothermal resource utilization efficiency of 23% (gross), or 15% (net) when 110 kW for the cooling water pump and 130 kW for the two refrigerant-12 circulating pumps are subtracted from the gross output. The turbo-expander reached an isentropic efficiency of 82% at full load, two percentage points below the design value.

The turbine-generator, three preheaters, the boiler/superheater, two condensers, and the associated auxiliary equipment were located in a machine hall which was 12 m wide, 24 m long and 8 m high (39 × 79 × 26 ft). A photograph of the turbine-generator is shown in Fig. 10.34.

The specific installed cost of the plant has been reported to be four times that of the other Soviet geothermal power plant which is located at Pauzhetka. The high cost of Paratunka was attributed to the small size of the unit, the costs associated with the development of the unique halocarbon turbo-expander, and with the installation of the piping system to supply the adjacent greenhouse facilities [ARPA, 1972].

10.11.4 Bolshoye-Bannoye

It was reported in 1965 [ARPA, 1972] that a sophisticated, multiple-flash geothermal power plant was under construction at Bolshoye-Bannoye. Only twenty wells had been completed and the rate of construction was slow. It is not known whether or not the plant has been completed or in operation.

It was to have a rated output of 8 MW, and use two 2.5 MW low-pressure turbines and four 750 kW very-low-pressure turbines. A flow diagram for the plant is shown in Fig. 10.35. A mixture of geothermal steam and hot water from a number of wells is fed to a series of separators at a pressure of 152 kPa (22 lbf/in^2). By the time the separated steam reaches the low-pressure turbines, the pressure has fallen to 101 kPa (14.7 lbf/in^2). An intermediate flash tank generates additional steam at one atmosphere for the low-pressure turbines from the hot water which was separated at the wellheads. The remaining hot water is first collected in a receiver and then flashed successively to produce three streams of subatmospheric steam for use in a set of four multiple-admission turbines. The liquid effluent from the final flasher must be pumped back to atmospheric pressure for disposal.

Based upon the exergy of the geofluid at the wellhead and the indicated geofluid flow rate and power output, the plant would have a gross geothermal resource utilization efficiency of 35%, or a specific geofluid consumption of 90 kg/kW·h (198 lbm/kW·h). The quality of the geofluid mixture at the wellhead would be about 7 percent. The cost of electricity from the plant was estimated to be about one-sixth the cost of electricity from conventional sources serving the city of Petropavlovsk-Kamchatskiy [ARPA, 1972].

10.11.5 Potential Soviet Geothermal Power Stations

Makhachkala A 12 MW flash-steam geothermal plant has been proposed to satisfy the electrical and heating requirements of the town of Makhachkala in the Dagestan ASSR. It is estimated that a total geofluid discharge of about 100 t/h (220×10^3 lbm/h) will be required to supply the plant. Very deep wells of the order of 4 - 4.5 km (2.5 - 2.8 mi) are needed in order to tap waters of 160°C (320°F) temperature. Water at 120°C (248°F) may be obtained from wells 2.5 - 3 km (1.6 - 1.9 mi) in depth. No other technical details on this plant have been made available.

Yuzhno-Kurilsk A geothermal power plant of about 5 - 6 MW capacity has been proposed for the Goryachy Playazh geothermal area on Kumashir Island of the Kurile Island group, about 8 km (5 mi) from the town of Yuzhno-Kurilsk. The plant will be designed to use geofluid at 130°C (266°F). Numerous surface thermal manifestations exist in the Guryachy Playazh region, with several steam vents having temperatures of 100 - 130°C (212 - 266°F).

Nizhne-Koleshevskaya Recently, a report was issued which indicated that a plant of 50 - 70 MW capacity will soon be constructed at Nizhne-Koleshevskaya [ECPE, 1977], but no additional data were included.

Avachinski Volcano The same source also reported that plans are underway to tap the Avachinski volcano on the Kamchatka peninsula at a depth of 3.5 km (11,500 ft) in the hope of establishing a resource which might supply a 5000 MW geothermal plant for 500 years.

10.12 UNITED STATES

10.12.1 Historical Background

The history of geothermal energy in the United States dates back over one hundred and thirty years. Explorer-surveyor William Bell Elliott is credited with discovering The Geysers natural steam field while bear-hunting in April 1847 between Cloverdale and Calistoga [Lengquist and Hirschfeld, 1976]. The awesome sight of clouds of water vapor shooting high into the air accompanied by the roar of escaping steam and the smell of odorous sulfur fumes led Elliott to believe he had discovered the very gates to the Inferno.

The region was exploited at first as a tourist attraction boasting the alleged therapeutic qualities of the hot fluids. When the popularity of the resort faded, an attempt was made in the early 1920s to develop its potential for electric power production. John D. Grant, a rock, gravel and cement contractor, deserves the credit for initiating the development of The Geysers [Siegfried, 1925].

Large quantities of underground steam were tapped with relatively shallow wells. Eight wells were drilled to depths of between 47 m (154 ft) and 194 m (363 ft). The steam was used to power a 250 kW generator driven by a reciprocating, noncondensing engine. Further power development at that time, however, was not carried out. Although the major technical obstacles to the use of geothermal energy seemed to have been overcome, geothermal electric power plants would have had to compete against hydroelectric plants that were appearing throughout the same areas where geothermal energy was present.

Thus the potential of The Geysers lay unexploited until B. C. McCabe, a Los Angeles lumber merchant with no engineering education and no prior experience in the power industry, decided to invest in the site in the early 1950's. He leased 1465 ha (3620 acres) from The Geysers Development Company, established a company called Magma Power Co., and drilled his first well in 1955. The well was called Magma No. 1; it was 249 m (817 ft) deep and produced 68 t/h (150,000 lbm/h) of dry steam at a wellhead pressure of 790 kPa (114 lbf/in^2).

McCabe joined forces with Dan A. McMillan, Jr. of Thermal Power Company, and together they completed six wells by 1957, ranging in depth from 161 m (527 ft) to 431 m (1414 ft). They signed a contract on October 30, 1958, with the Pacific Gas and Electric Company (PG&E) which obligated Magma-Thermal to supply steam at a flow rate of 107 t/h (235,000 lbm/h) and at a pressure of 790 kPa (114 lbf/in^2) to the strainer inlet of a 12,500 kW turbine-generator [Lengquist and Hirschfeld, 1976].

In the early days of geothermal energy discovery in the United States, several other areas besides The Geysers were explored. Most of these were areas which appeared to be promising because of surface manifestations such as steam vents, hot springs, boiling mud pots, etc. Potential sites in the Imperial Valley such as Niland and Mullet Island (Salton Sea) were studied and drilled, as early as 1927. It is interesting to note that the wells at the Salton Sea produced gas (probably carbon dioxide), steam, water, and a large amount of 'slush'. The utilization of these fluids, which contain up to 300,000 ppm of dissolved solids, remains one of the major unsolved problems in geothermal energy in the United States.

10.12.2 The Geysers - Sonoma and Lake Counties, CA

The largest geothermal electric power complex in the world is located at The Geysers in Sonoma County of northern California. The Pacific Gas and Electric Company (PG&E) produces over 500 MW at the site with over

400 MW of additional capacity under construction as of early 1979, and intends to install an additional 220 MW by 1982. The present proved capacity of The Geysers exceeds 2000 MW.

The Geysers is one of several areas of hot springs and fumaroles which occur along a section of a long fault zone in the Mayacmas Mountains in northern California. The geothermal reservoir is of the vapor-dominated type and extends over an area 21.5 km × 8.6 km (13.3 mi × 5.3 mi), bounded by the Mercuryville fault zone on the southwest and the Collayomi fault zone on the northeast [Donnelly, et al, 1976]. The drilled area covers over 5000 ha (12,350 acres) in an 11.2 km × 4.5 km (7 mi × 2.5 mi) strip lying roughly between the Big Sulphur Creek in Sonoma County and the border between Sonoma and Lake Counties.

The source of the thermal energy is believed to be a magmatic intrusion which lies at about 10 km (32,800 ft). The steam-producing areas are highly fractured regions with near-vertical orientation. The fractures occur in hard, dense graywacke (a sandstone), and steam is found in two depth ranges: a shallow zone at 300 - 600 m (984 - 1968 ft) and a deep zone at 1.5 - 3.0 km (4920 - 9840 ft) [Reed and Campbell, 1975]. It is known, furthermore, that the vapor-dominated reservoir is characterized by a pressure that is far less than the hydrostatic pressure and which extends to depths of at least 3 km (9840 ft).

Approximately 175 wells have been drilled at The Geysers, with 75 of these actively delivering steam to the first eleven units having a total installed capacity of 502 MW. Approximately 15 wells are needed to support a typical 110 MW unit. A steam well will produce 34 - 159 t/h (75,000 - 350,000 lbm/h) at a wellhead pressure of 960 kPa (140 lbf/in^2). A steam flow rate of 91 t/h (200,000 lbm/h) may be taken as typical. The closed-in pressure is about 3.4 MPa (490 lbf/in^2) and the corresponding temperature is

240°C (465°F), with a specific enthalpy of 280 kJ/kg (1204 Btu/lbm). A combination of mud and air drilling is used, with mud being used for the larger portions of the wells (dia. > 317.5 mm (> 12.5 in)). Although air drilling is faster since the cuttings are removed more quickly from beneath the drill bit, it can only be used in the smaller diameter sections where the seepage of liquid into the hole is not a serious problem.

A typical gathering system for a 55 MW unit consists of a network of carbon steel pipes, starting with 254 mm (10 in) O.D. pipes at the wellheads and ending with 914 mm (36 in) O.D. pipes of 9.5 mm (0.375 in) wall thickness at the power house. Usually seven wells must be connected to the system to supply the required 450 t/h (10^6 lbm/h) of steam. A centrifugal axial separator is situated on the steam line at each well to remove particulate matter that can cause erosion of the steam pipes and turbine blades [Matthew, 1975].

A map of The Geysers area is shown in Fig. 10.36 [Dan, et al, 1975] from which the locations of the first fifteen units may be seen. The steam pipelines are not longer than about 2 km (6560 ft) so as to control the loss of availability of the steam from the wellhead to the turbine.

The power units at The Geysers have evolved from relatively small units with barometric, external condensers and no emissions controls to units of 110 MW capacity with low-level, surface-type condensers and Stretford-type H_2S removal systems. Table 10.16 contains a list of the geothermal units at The Geysers together with some technical information on each of them. Table 10.17 contains a summary of the technical specifications for those power units in operation at The Geysers as of early 1979. A flow diagram/heat balance schematic for Units 5 - 10 is shown in Fig. 10.37, and the photograph in Fig. 10.38 shows the cooling tower and power house for Units 5 and 6.

Of the four units under construction at this time, Unit No. 13, which is expected on-line in the fall of 1979, is unique in several respects. It is the first unit to be built in Lake County rather than Sonoma County, and the first to be supplied with steam from a producer other than Union-Magma-Thermal; in this case, the supplier is Aminoil (formerly the Signal Oil and Gas Company). It will be the largest single geothermal unit in the world with a rated capacity of 135 MW. Furthermore, the unit will be fitted with a turbine manufactured in the United States, this being the first turbine from an American manufacturer to be installed at The Geysers in over a decade.

The unit was initially designed with a direct-contact condenser of the low-level jet type; however, it will be built with a surface condenser of the shell-and-tube type in order to assist the hydrogen sulfide abatement system which will also be installed on the unit. This will be the first unit to have a surface condenser at The Geysers, and the first unit of any dry steam geothermal plant in the world to be so equipped. Furthermore, this unit, and all succeeding units, will be fitted with a means of controlling the hydrogen sulfide emissions from the plant. A Stretford system will be employed on those units which are expected on-line in the near future.

The choice of materials used in the manufacture of the various components of a geothermal power plant is determined in large measure by the composition of the geothermal fluid. The steam from The Geysers field is relatively noncorrosive as it comes from the wells in a slightly superheated state. Thus, carbon steel (ASTM A106 Gr.B or equivalent) may be used in the gathering system, including main steam pipelines, valves and strainers. The turbines are made from manufacturer's standard materials for the most part, with items of cast, forged or fabricated steel. The casing is carbon steel.

The blading, however, is of 13% chrome steel. Moisture removal provisions exist in the lower pressure stages where the expansion leads to higher moisture content. Such moisture traps are of standard design and are used as well in conventional steam turbines [Finney, 1972]. The quality of the steam at the turbine exhaust hood is typically about 90%.

The corrosive nature of the geofluid becomes manifest when the steam condenses, especially in the presence of air. As with all turbines which operate under vacuum conditions, some infiltration of air into the turbine through the seals is unavoidable. Under condensation, the noncondensable gases become more concentrated, the hydrogen sulfide in the presence of air oxidizes to weak sulfuric acid, and the fluid becomes highly corrosive to such materials as carbon steel, cast iron, copper-based alloys, zinc, cadium, silver, wood and concrete.

The condenser is comprised of a shell of carbon steel plate overlaid with 1.6 mm (1/16 in) thick Type 304 (19% Cr, 9% Ni) stainless steel and internals made of solid stainless steel. The condensate lines are fabricated from Type 304 stainless steel pipe. The condensate pumps are of conventional canned, vertical design, but with all wetted parts, including impellers and bowls or volutes, made of austenitic Type 304 stainless steel. The circulating water lines above ground are made of aluminum pipe of Type 3003, 3053, or 6061. Aluminum alloys with no copper content are used.

Since copper alloys and silver are susceptible to corrosive attack by hydrogen sulfide, electrical equipment should not be made of these materials. Experience shows that tin alloy coatings are effective in resisting corrosion, but they are unsatisfactory on current-carrying contact surfaces. Aluminum, stainless steel and some precious metals are particularly effective. Platinum inserts or plating have been used on these contacts.

Approximately 20% of the mass of geothermal steam produced from the wells must be disposed of as excess liquid from the cooling tower basin. From 1960 to 1970 the problem was solved by allowing the liquid to run into the nearby Big Sulfur Creek. Beginning with Units 5 and 6, however, the excess water has been reinjected into the producing reservoir. For each 55 MW unit, 1700 m^3/day (312 gal/min) must be reinjected. In 1974, four wells were employed for the reinjection of approximately 14000 m^3/day (2570 gal/min) of excess water [Reed and Campbell, 1975]. Since the steam producing reservoir is of anomalously low pressure relative to hydrostatic conditions, it is not necessary to pump the liquid down the well; pumping is required only to move the liquid from the cooling tower sites to the reinjection wells.

The noncondensable gases are vented to the atmosphere at two places in the plant: the gas ejector and the cooling tower. The most objectionable of the gases discharged is hydrogen sulfide, H_2S, owing in part to its unpleasant smell and to the very low level of detection by the human olfactory sense. The California ambient air quality standard for H_2S is 30 parts per billion (ppb), based on an assumed odor detection threshold [Semrau, 1976]. Although no Federal standards exist for H_2S, the U.S. Environmental Protection Agency (EPA) has suggested a maximum of 200 g/MW·h of electrical production or its equivalent [Hartley, 1978].

The first ten units at The Geysers were provided with no means of control of H_2S emissions. The daily operation of these ten uncontrolled units produced 22 t/day or 2300 g/MW·h of H_2S [Weres, 1976]. All new units will be fitted with some type of H_2S abatement system. An iron hydroxide system of about 70% efficiency was tested on Unit 11. It discharges on the average 2 t/day or 800 g/MW·h into the atmosphere, including pre-plant emissions and vent emissions which occur during plant shutdown and are uncontrolled at this time [Weres, 1976]. Units 13, 14, 15, and future units will have surface condensers instead of jet condensers. Separate chemical processing plants operating on the Stretford process will remove the hydrogen sulfide on Units 13-15 [Semrau, 1976]. The product of the Stretford process is pure, marketable sulfur.

The price which PG&E must pay for steam for its Geysers units is determined from the following formula [Dutcher and Moir, 1976]:

$$C_S = [2.11\ E_F\ (\bar{C}_F/\bar{C}_F^o)\ (MHR/MHR^o) + E_N\ \bar{C}_N]/(E_F+E_N) \quad ,$$

where

C_S = cost of steam (mill/kW·h) for year n,

E_F = electricity produced from fossil fuel during year n-1,

E_N = electricity produced from nuclear fuel during year n-1,

$\bar{C}_F$ = average cost of fossil fuel for year n-1,

$\bar{C}_N$ = average cost of nuclear fuel for year n-1,

$\bar{C}_F^o$ = average cost of fossil fuel in 1968,

MHR = minimum heat rate for fossil plants during year n-1,

MHR^o = minimum heat rate for fossil plants during 1968,

2.11 = negotiable constant.

Thus, the cost of geothermal steam for any year is determined by the amount and cost of electrical production by fossil and nuclear means during the previous year. Base figures are taken for the cost of fossil fuel and fossil plant heat rate during 1968. In addition, there is a surcharge of 0.5 mill/kW·h for reinjection of the spent geofluid. The historical price of steam at The Geysers since 1969 is given below:

Year	Price (mill/kW·h)
1969	2.65
1970	2.64
1971	2.74
1972	2.90
1973	3.15
1974	3.73
1975	7.39
1976	11.35
1977	14.10
1978	16.05

The only other geothermal steam contract at The Geysers is the one signed on June 27, 1977, between Shell Oil Company and the Northern California Power Agency (NCAP). The contract calls for NCPA to pay Shell according to the amount of steam delivered. The initial price, at the time of the contract, was $0.6917/1000 lbm of steam. Beginning on July 1, 1977, the price will be adjusted semi-annually by the GNP Implicit Price Deflator Index (IPD) published by the U.S. Department of Commerce for the preceding calendar quarter [Lindsay, 1977]. The IPD is the ratio of the GNP (in current dollars) to the GNP (in constant 1972 dollars) for the current period. The geothermal steam supplied by Shell must be dry and at a pressure no lower than 799.8 kPa (116.0 lbf/in^2); when the amount of noncondensable gases exceeds 0.5% (weight), the flow rate of steam will be corrected accordingly. Uncontaminated waste liquid will be returned to Shell for disposal at a temperature not greater than 79.4°C (175°F) and at a pressure not less than 262 kPa (38 lbf/in^2).

For the operating year 1976, PG&E reported [Mahoney and Bangert, 1977] that their geothermal power plants produced electricity at the lowest cost of any other type steam plant in its system. The figures (in 1977 dollars) are as follows:

geothermal. . . . . 18 mill/kW·h

nuclear . . . . 24 mill/kW·h

coal-fired. . . . . 26 mill/kW·h

oil-fired . . . . 36 mill/kW·h.

In addition, geothermal plants were the least expensive to construct, being 26% cheaper than oil-fired plants, about half as expensive as coal-fired plants, and costing only 38% of a typical nuclear plant. All comparisons are on a dollars-per-kilowatt basis.

Table 10.18 contains a summary of the calculations of the geothermal resource utilization efficiency, η_u, for the eleven operating units together with estimates for the four units which are under construction. It may be seen that η_u ranges from 50 - 56%. Units 13 and 15 are expected to operate with steam at the lowest temperature of any unit (170°C (338°F)) and may have the lowest efficiency of all the units at The Geysers. Although they are not included in the table, Units 16 and 17 will be similar to Unit 14 in design and performance; i.e., they may be expected to operate at a 56% resource utilization efficiency.

10.12.3 Magmamax Dual Binary Plant - East Mesa, CA

The geothermal power plant being constructed at East Mesa, CA, by the Magma companies is of the binary type in which the hot geofluid is used as the heating medium for a secondary working fluid of a suitably low boiling point which is in turn used in a more or less conventional Rankine cycle. When completed early in 1979, the Magmamax[a] Dual Binary plant will be the

[a]U.S. Patent No. 3757516.

first geothermal power plant of this type in commercial operation in the United States. The plant will have a rated capacity of 11.2 MW.

The power plant incorporates pumped wells, total reinjection of spent geofluid, two parallel power cycles, one using isobutane and one using propane, an isobutane recuperator-propane preheater, and a cooling water system with combined spray cooling and phased storage ponds. If the plant lives up to its design specifications, it should operate with a specific brine consumption of about 58.5 kg/kW·h (129 lbm/kW·h) for brine at 182°C (360°F) [Hinrichs and Falk, 1978]. The reinjection temperature will be about 82°C (180°F). Roughly 11 ha (27 acres) will be dedicated to the storage ponds for the phased cooling system. The plant is located in the desert portion of the Imperial Valley where land usage is less critical. A simplified flow diagram of the patented Magmamax process is shown in Fig. 10.39, in which the cooling water lines have been omitted for the sake of clarity.

The isobutane turbine was built by the York Division of Borg-Warner Corporation to the specifications of J. Hilbert Anderson [Anderson, 1973]. The machine is of the double-flow type with each side being a 3-stage radial-inflow turbine. The unit used to be a compressor, but has been redesigned for turbine duty. The turbine is expected to operate at an isentropic efficiency of about 77%.

The propane turbine was built by Mafi-Trench and is typical of machines of the type used for low-temperature applications. It is of the radial-inflow type; the preliminary design specifications indicated an expected isentropic efficiency of about 86% [Mafi, 1978].

Preliminary design specifications for the Magmamax plant are given in Table 10.19. On the basis of the preliminary specifications, the system should be capable of a resource utilization efficiency of about 52%, assuming a sink temperature of 27°C (80°F).

10.12.4 Republic Geothermal - East Mesa, CA

Republic Geothermal, Inc. is currently developing a portion of the East Mesa geothermal field with the intention of building a 48 MW double-flash power plant which should be operating in the early 1980's. The Republic plant will be located about 5 km (3 mi) north of the Magmamax Dual Binary plant. The wells will be operated in a pumped mode using down-hole, electric-powered, submersible pumps. It is expected that each well should deliver about 85 kg/s (675,000 lbm/h) of fluid under pumped conditions.

Republic was the recipient of the first award made by the government under the Geothermal Loan Guaranty Program (GLGP). The guaranty was issued in May 1977 for $9 million to drill at least fifteen additional producing wells at the East Mesa site. Each well must be capable of producing at least 2 MW of electric power [Silverman, 1977; ERDA News, 1977].

A single-flash plant of 10 MW output is planned to be the first of its type in the United States. This pilot plant should be built by 1979 [Holt, 1977]. The main plant will be a 48 MW (net) double-flash system which is presently being designed. It is anticipated that the plant will begin operation in 1980 or 1981. An artist's impression of the proposed plant is shown in Fig. 10.40.

10.12.5 Southern California Edison - Brawley, CA

A separated steam (or "single flash") plant is being designed for the Brawley geothermal field which lies about 38 km (24 mi) northwest of East Mesa in the Imperial Valley. The plant will be operated by Southern California Edison using steam supplied by Union Oil. The unit will be rated at 10 MW and will require about 32 t/h (70,000 lbm/h) of steam. The reservoir temperature is about 260°C (500°F) and the fluid carries about 100,000 ppm of dissolved solids.

10.12.6 Planned Geothermal Plants in the Imperial Valley, CA

The Imperial Valley of southern California holds a huge reserve of geothermal energy. A recent conservative estimate of the potential of this area suggests that 8700 MW of geothermal electrical capacity may be possible assuming 20 - 30 year plant lifetimes [Younker and Kasameyer, 1978]. A number of power plants of various designs are either under construction or in the advanced stages of planning. Table 10.20 contains a list of particulars on these plants.

10.12.7 Double-Boiling Binary Plant - Raft River, ID

A 5 MW (gross) binary plant is being designed by the Idaho National Engineering Laboratory for operation at the Raft River KGRA in Idaho [Ingvarsson and Madsen, 1976]. The plant will use geothermal fluid at the relatively low temperature of 143°C (290°F), and will employ isobutane as the cycle working fluid. A simplified process flow diagram is shown in Fig. 10.41. Optimization studies show that the system should be designed with isobutane and two boilers, one at 116°C (240°F) or 2.63 kPa (382 lbf/in^2), and one at 82°C (180°F) or 1.40 MPa (203 lbf/in^2). The net output of the plant will be 3.35 MW(e). The cycle conditions and state properties for the nominal design case may be found in Ingvarsson and Madsen, [1976]. The plant will require about 141 kg/kW·h (310 lbm/kW·h), and have a resource utilization efficiency $\eta_u \approx 32\%$ [DiPippo, 1978b

Although the plant will serve primarily as a test-bed for low-temperature geothermal power plants, the electricity produced will be fed into the grid of the Raft River Electrical Cooperative. The cost of electricity is estimated to be 31.15 mill/kW·h [Ingvarsson and Madsen, 1976]. It is expected that the plant will begin operating in January 1980.

10.12.8 Hawaii Geothermal Project - Puna, HI

A separated steam (or "single flash") plant of 5 MW capacity will be installed near Cape Kumukahi in the Puna region of the Big Island of Hawaii in 1980. The geothermal area lies in the east rift zone at the easternmost tip of the island [Furumoto, 1978].

Six wells have been drilled in the area, but only one of these was successful, well HGP-A. Reservoir temperature is 358°C (676°F), and the dryness fraction of the two-phase geothermal mixture ranges from 52 - 64% [Chen, et al, 1978]. The well was drilled to a depth of 1871 m (6140 ft). The results of flow tests on this well have been highly encouraging, and it has been estimated that the Kapoho geothermal reservoir at which well HGP-A is located may be capable of supporting 50,000 MW·years [Chen and Grabbe, 1978]. Unfortunately, the greatest demand for electricity is on the island of Oahu, whereas the greatest potential for geothermal power production is on the Big Island of Hawaii. Nevertheless, a geothermal development group has been formed in 1977 to promote this resource in an attempt to reduce the State of Hawaii's dependence on imported fuel oil. The group consists of the State Department of Planning and Economic Development (DPED), the University of Hawaii's Hawaii Geothermal Project (HGP), and the County of Hawaii. In addition the Hawaiian Electric Company (Honolulu) and the Hawaii Electric Light Company (Hilo) are participating as consultants [Chen and Grabbe, 1978].

10.12.9 Double-flash Demonstration Plant - Valles Caldera, NM

The U.S. Department of Energy, through its Division of Geothermal Energy, is contributing to the support of the design and construction of a

50 MW double-flash plant to be located about 56 km (35 mi) west of Los Alamos at an area known as Baca No. 1 within the Valles Caldera of the Jemez Mountains in north-central New Mexico. The plant is scheduled to go on-line in 1982 [GEM, 1978]. The intent is to show that geothermal power plants using liquid-dominated resources can be built and operated in the United States on an economically competitive basis.

The geothermal field has been developed by the Union Oil Company which will supply steam to the Public Service Company of New Mexico. It is believed that each production well will be capable of providing 91 t/h (200,000 lbm/h) of geothermal fluid with a quality of 35% at a wellhead pressure of 965 kPa (140 lbf/in^2). Roughly fifteen wells will be needed to supply the 50 MW plant.

The U.S. Geological Survey reported that the Valles Caldera KGRA has the potential to support 1870 MW of electrical power production for 30 years [White and Williams, 1975].

10.12.10 Other Potential Geothermal Plants in the U.S.

Table 10.21 lists the proposed geothermal power plants for the United States outside California. The plants shown for Roosevelt Hot Springs, UT, Desert Peak, NV, and the hybrid coal-geothermal plant proposed by the City of Burbank, CA, are not definite, but are in advanced planning stages.

Table 10.22 shows the projected growth in installed geothermal electric generating capacity through 1983. By that time, the United States should have over 1800 MW on-line. Furthermore, geothermal energy will be contributing about 3% of the electric power needs of the states in which geothermal plants will be operating, namely, California, Hawaii, Nevada, New Mexico, and Utah.

10.13 COUNTRIES PLANNING GEOTHERMAL POWER PLANTS

10.13.1 Overall Survey

The number of countries engaged in geothermal exploration, development, or exploitation for all purposes or which have an interest in putting their geothermal resources to use is estimated to be at least sixty-five [GEM, 1977]. These include: Australia, Austria, Bahamas, Barbados, Belgium, Bhutan, Bolivia, Brazil, Canada, Chile, China, Colombia, Congo, Costa Rica, Dominican Republic, Ecuador, Egypt, El Salvador, Ethiopia, Fiji, France, Germany, Ghana, Greece, Guatemala, Guinea, Guyana, Haiti, Honduras, Hungary, Iceland, India, Indonesia, Iran, Israel, Italy, Jamaica, Japan, Kenya, Kuwait, Malaysia, Mexico, New Zealand, Nicaragua, Panama, Philippines, Portugal (Azores), Saudi Arabia, Spain (Canary Islands), Sri Lanka, Switzerland, Taiwan, Tanzania, Trinidad and Tobago, Turkey, Uganda, Union of Soviet Socialist Republics, United Arab Emirates, United Kingdom, United States, Venezuela, Yugoslavia, Zaire, and Zambia.

In the rest of this section we shall discuss those countries which are on the threshold of exploiting their geothermal resources for the generation of electricity.

10.13.2 Azores (Portugal)

The islands of the Azores lie on the Mid-Atlantic Ridge, a spreading tectonic plate boundary. Of the nine islands which comprise the group, the largest and most heavily populated is São Miguel.

In 1970 a well was drilled on the northern flank of the Agua de Pau volcano and encountered fluids in excess of 200°C (392°F) at depths greater than 550 m (1805 ft). The full depth of the well was 981 m (3219 ft) [Meucke, et al, 1974].

A 3 MW wellhead power unit is being designed for São Miguel, and could be in operation as soon as 1979 [K. Aikawa, personal communication].

10.13.3 Chile

The El Tatio geothermal field has been the subject of considerable exploration and drilling. The site is located in northern Chile, in Antofagasta province, in a region consisting of a volcanic desert plateau at an elevation of over 4000 m (13,100 ft) with Quaternary volcanic mountains rising to nearly 6000 m (19,700 ft). Owing to the extreme remoteness and near-inaccessibility of the field, exploration is proceeding slowly. Furthermore, because the region is essentially arid, any geothermal development is likely to include the production of fresh water [Koenig, 1973].

It has been estimated that about 18 MW of electricity could be generated from the existing thirteen wells [Lahsen and Trujillo, 1975]. The wells range in depth from 600 to 1820 m (1970 - 5970 ft) and have encountered geofluids at temperatures from 180 to 265°C (356 - 509°F). A small pilot plant is in operation and plans are underway to construct a 15 MW plant in the near future [Ellis and Mahon, 1977].

10.13.4 Costa Rica

The geothermal development program in Costa Rica is directed by the Instituto Costarrince de Electricidad (I.C.E.) and has concentrated on the Guanacaste province in the northwestern part of the country. The geothermal area extends for 30 km (19 mi) along the flank of a chain of active volcanoes [Furgerson and Afonso L., 1977]. An integrated program involving heat flow, temperature gradient, geochemical, electrical and hydrological investigations is being carried out in the southwestern portion of the Cordillera de Quanacaste.

Particular attention is being given to the areas of Las Hornillas de Miravalles, Las Pailas, and Borinquen, where some drilling has been conducted [Blackwell, et al, 1977]. A total of 35 exploratory wells have been sunk in the area; twenty-four have been to depths of 50 m (164 ft) or less and nine have exceeded 90 m (295 ft). Active development is underway and a 40 MW geothermal power plant is scheduled by I.C.E. to be installed by 1984-1985.

At Las Hornillas de Miravalles geochemical studies have revealed the possibility of a deep, chlorinated aquifer with reservoir base temperatures as high as 240°C (464°F) [Gardner and Corrales, 1977]. A program of deep drilling is underway with the objective of achieving a total depth of 4000 m (13,000 ft), which should allow for the completion of four wells since the aquifer is estimated to lie at a depth of between 800 - 1200 m (2625 - 3937 ft) (J. T. Kuwada, personal communication).

10.13.5 Guatemala

The national electric company of Guatemala, I.N.D.E., is aiming at a goal of 100 MW of installed geothermal capacity by the early 1980's [Meidav, et al, 1977]. Three areas, Moyuta, Amatitlán and Zunil, have been under exploration with technical assistance from Japan.

There were high hopes for the field at Moyuta which is about 25 km (16 mi) northwest of the successful project at Ahuachapán across the border in El Salvador. Shallow wells revealed temperature gradients of about 0.25°C/m (0.14°F/ft). Unfortunately, two wells produced low temperatures, and the site has been abandoned [Dominco, 1977; J. T. Kuwada, personal communication].

Attention is still being given to the other two sites; Amatitlán may someday support 50 - 100 MW, whereas Zunil appears to be a rather small area with limited prospects.

10.13.6 Honduras

In 1977 the National Electric Authority of Honduras, E.N.E.E., began a program of geothermal exploration that focused on two areas: Pavana, in the southernmost part of the country near Choluteca, and San Ignacio, which is located northwest of the capital city of Tegucigalpa [Meidav, et al, 1977]. At the present time the exploration program is temporarily in abeyance [J. T. Kuwada, personal communication]. By 1982, E.N.E.E. hopes to have 50 MW of geothermal power on-line, with an additional 50 MW by 1984-1985 [Meidav, et al, 1977].

10.13.7 Indonesia

Indonesia's location at the junction of three tectonic plates with the associated volcanism and earthquake activity together with its average annual rainfall of 2000 mm (79 in) create a potentially valuable source of geothermal (hydrothermal) power. Exploration for geothermal energy began in 1926; extensive geophysical, geological and geochemical surveys have been conducted by various teams of scientists from France, Japan, New Zealand, the United States, and the United Nations (UNESCO). A summary of these studies has recently been published [Radja, 1975].

Among the many promising thermal areas, the one at which a geothermal power plant is likely to appear first is Kawah Kamojang. Fumaroles abound at this thermal site, the oldest to be discovered and explored in the Indonesian archipelago. A 250 kW wellhead power generating unit has been purchased and will soon be operational, and a 3 MW unit has been designed and will soon be under construction at Kawah Kamojang.

Power production at Kamojang will begin with a 250 kW, noncondensing, wellhead turbo-generator under the direction of PERTAMINA, the

State Oil and Natural Gas Mining Company [GR, 1978]. The unit is self-contained and consists of a turbine, generator, controls, gearbox and exhaust silencer diffuser mounted on a platform. The package cost just over $400/kW in 1978. The power generated will be used during the development phase of the project. After the 3 MW unit is installed in the second phase, the plan is to build a 30 MW, condensing unit [Basoeki and Radja, 1978].

A large number of other thermal areas are evident throughout the Indonesian archipelago. Surface manifestations such as hot springs, boiling mud pools, solfataras, and/or fumaroles are present at the sites listed below. Some surveys have been conducted at a few of these, and the reader is referred to other sources of information for more details [Akil, 1975; Muffler, 1975; Radja, 1975].

- On the island of Java: Danau (Banten), Dieng, Ijen, Kawah Derajat, Kromong-Careme.
- On the island of Sumatra: Toba, Padang Highlands, Pasumah.
- On the island of Borneo: Kalimantan.
- On the island of Halmahera: North Halmahera.
- On the island of Sulawesi: Minahasa, Gorontalo, Central Sulawesi, South Sulawesi.
- On the islands of Nusa Tenggara: Waikokor, Wai Pesih, Magekoba.

Although there are large supplies of petroleum within Indonesia, it is often difficult to transport it to the places where power is needed. Furthermore, petroleum is a very valuable export commodity. The demand for electric power is expected to reach 5100 MW in 1990; it was less than 1000 MW in 1975. Thus, geothermal energy, with its low cost and indigenous advantages, figures to play an important role in meeting the growing demand for electrical power in Indonesia.

10.13.8 Kenya

Six wells have been drilled in the Olkaria geothermal region in the Rift Valley province of Kenya in east Africa. Although the majority of the wells encountered conditions of low permeability, the two best wells yielded roughly 30 - 40 t/h (66 - 88 × 10^3 lbm/h) of liquid-vapor mixture. The reservoir lies at 700 - 800 m (2297 - 2625 ft), and the fluid temperature is 245°C (473°F). Temperatures as high as 300°C (572°F) have been reported at a depth of 1650 m (5414 ft) [Ellis and Mahon, 1977]. A 15 MW geothermal power unit is being designed for this resource [K. Aikawa, personal communication].

10.13.9 Nicaragua

The national electric authority of Nicaragua, E.N.A.L.U.F., is predicting that 100 MW of geothermal power will be installed in Nicaragua by the early 1980's, with about 150 - 220 MW installed by 1985, 300 - 400 MW by 2000, and as much as 800 MW by the year 2020 [Meidav, et al, 1977]. The most likely candidate site for the first geothermal power plant is the Momotombo field which was investigated from 1969 to 1971, along with the San Jacinto-Tisate area. These two promising areas were explored under a program sponsored by the U.S. Agency for International Development. Work at the sites was delayed several years on account of the Managua earthquake of December 23, 1972 [Muffler, 1975], and has suffered another setback because of political problems in Nicaragua in 1978.

The geothermal field at Momotombo is located on the lower slopes of the Momotombo Volcano, on the edge of Lake Managua. A total of 25 wells have been drilled in the field. Some of these wells show drastic temperature inversions, as much as -1.5°C/m (-0.8°F/ft), indicating the presence of colder fluid at depth. Some flow rates from a few of the wells have been reported [Girelli, 1977]:

Momotombo well No. 3. . . . . 85 t/h (187 × 10^3 lbm/h)

Momotombo well No. 9. . . . . 56 t/h (123 × 10^3 lbm/h)

Momotombo well No. 12 . . . . 40 t/h (88 × 10^3 lbm/h).

Construction was scheduled to begin in 1979 on a geothermal power plant at Momotombo but the size of the unit has not been decided. The site is believed capable of supporting 100 MW, but a smaller, 30 MW unit may be installed initially until confidence in the field is thoroughly established [Girelli, 1977].

10.13.10 Panama

Panama presently has a total installed electric capacity of 237 MW with projections of 534 MW by 1984. Although hydroelectric plants constitute a significant fraction of Panama's generating capacity, it is believed that a 75 MW power plant, either conventional thermal or geothermal, will be needed by 1985.

The most promising geothermal site in Panama is at Cerro Pando. It is too early, however, to assess the quality and the potential of this area in the light of the minimal amount of exploratory work completed at this time [Ho, 1977; Meidav, et al, 1977].

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Table 10.1

Worldwide geothermal electric power capacity as of January 1979

	No. of Units in Operation	Installed Capacity, MW	Future Capacity, MW[a]
China	1	1	(NA)
El Salvador	2	60	35
Iceland	4	64	(NA)
Italy	37	420.6	(NA)
Japan	6	165	55
Mexico	2	75	105
New Zealand	14	202.6	(NA)
Philippines	2	4.2	765
Turkey	1	0.5	(NA)
U.S.S.R.	1	5	(NA)
United States	12	502	1180
Totals	82	1499.9	2140

[a] Under construction or in planning for 1982. Additional capacity may come from countries not presently using geothermal energy for electricity, such as Costa Rica, Kenya, Nicaragua, and others.

Table 10.2

Technical specifications for Ahuachapán geothermal power plant

	Unit No. 1 and 2	Unit No. 3	Auxiliary Unit
Year of start-up	1975, 1976	1980	1975
Turbine data:			
Type	Single-cylinder, double-flow, impulse, 5 × 2,	Single-cylinder, double-flow, impulse-reaction, (3, 4) × 2	Single-cylinder, one Curtis stage, non-condensing, geared
Rated capacity, MW	30, each	35	1.1
Maximum capacity, MW	35, each	40	1.3
Speed, rpm	3600	3600	7129/1800
Main steam pressure, lbf/in^2	81.1	79.5	80.2
Secondary steam pressure, lbf/in^2	(None)	21.8	(None)
Main steam temperature, °F	313.0	311.6	313.0
Secondary steam temperature, °F	(None)	232.6	(None)
Exhaust pressure, in Hg	2.46	2.46	28.4
Main steam flow rate, 10^3 lbm/h	507, each	377	46.3
Secondary steam flow rate, 10^3 lbm/h	(None)	320	(None)
Last-stage blade height, in	20.5	22.2	(NA)
Condenser data:			
Type	Low-level, direct-contact type with slanted barometric pipe		(None)
Cooling water temperature, °F	80.6	80.6	—
Outlet water temperature, °F	104.5	104.5	—
Cooling water flow rate, 10^6 lbm/h	19.1	27.0	—

(continued)

Table 10.2 (continued)

	Unit No. 1 and 2	Unit No. 3	Auxiliary Unit
Gas extractor data:			
Type	Two-stage, steam jet ejector with inter- and after-condenser		(None)
Suction pressure, in Hg	2.32	(NA)	—
Gas capacity, ft^3/min	6,886	(NA)	—
Steam consumption, 10^3 lbm/h	9.04, each	(NA)	—
Cooling tower data:			
Type	Cross-flow, mechanical induced-draft with vertical axial fans		(None)
Number of cells	5, each	5	—
Design wet-bulb temp., °F	71.6	71.6	—
Fan motor power, kW/fan	80	80	—

Table 10.3

Electricity generation at Ahuachapán

Year	Electrical Generation	Capacity Factor	% Total Generation
1975	72,331 MW·h	47%	11.8%
1976	279,800 MW·h	67%	25.4%
1977	400,051 MW·h	76%	32.3%

Table 10.4

Technical specifications for Icelandic geothermal power stations

	Námafjall	Krafla Unit 1[a]	Grindavik
Year of start-up	1969	1977	1978
Turbine data:			
Type	Single cylinder, one Curtis stage, noncondensing	Single cylinder, double-flow, dual-admission, impulse-reaction	(NA)
Rated capacity, MW	3.0	30.0	1.0
Maximum capacity, MW	3.4	35.0	1.0
Speed, rpm	3000	3000	(NA)
Main steam pressure, lbf/in^2	142.7	110.0	78.8
Main steam temperature, °F	354.5	334.4	311.0
Secondary steam pressure, lbf/in^2	—	27.5	—
Secondary steam temperature, °F	—	244.4	—
Exhaust pressure, in Hg	31.4	3.5	∿31.4
Main steam flow rate, 10^3 lbm/h	109	417	(NA)
Secondary steam flow rate, 10^3 lbm/h	—	142	(NA)
Condenser data:			
Type	(None)	low-level, direct-contact, tray type	(NA)
Cooling water temperature, °F	—	71.6	(NA)
Outlet water temperature, °F	—	115.2	(NA)
Cooling water flow rate, 10^6 lbm/h	—	12.4	(NA)

(a) Krafla Unit 2 is identical to Unit 1 and is under construction.

Table 10.5

Power system specifications for condensing units in the Boraciferous region of Italy

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Year of start-up	1938	1952-54	1969	1967	1967	1967	(NA)	1960	1960	(NA)	(NA)
Turbine data:											
Type	(1)	(1)	(2)	(1)	(1)	(1)	(2)	(3)	(1)	(2)	(1)
Installed capacity, MW	69[4]	120[5]	15	26	11	2	47[6]	6.5	27[7]	15.7[8]	12.5
Speed, rev/min	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000
Steam inlet pressure, lbf/in^2	59.7	62.6	103.8	61.1	27.0	15.6	69.7	29.9	76.8	71.1	64.0
Steam inlet temperature, °F	385	387	433	370	345	302	385	289	352	365	370
% (wt.) noncondensable gases	7.0	6.8	6.7	14.3	3.8	2.4	3.8	1.8	2.2	3.0	1.7
Exhaust pressure, in Hg	3.0	3.5	3.0	2.6	2.6	2.6	2.9	2.0	2.0	3.0	(NA)
Steam flow rate, 10^3 lbm/h	899[9]	1480[9]	238	375	127	61.7	633[9]	154	558[9]	357[9]	269
Condenser data:											
Type	All units have low-level, direct-contact, barometric condensers.										
Cooling water temperature, °F	87.8	82.9	87.8	73.4	73.4	73.4	84.2	78.8	78.8	(NA)	(NA)
Outlet water temperature, °F	105.8	106.3	105.8	98.6	98.6	98.6	104.0	95.0	95.0	(NA)	(NA)
Cooling water flow rate, 10^6 lbm/h	(NA)	(NA)	17.8	(NA)	(NA)	(NA)	(NA)	(NA)	(NA)	(NA)	(NA)
Gas extractor data:											
Type	All units have multistage centrifugal turbocompressors with interstage coolers.										
Gas capacity, 10^3 ft^3/min	$\sim$310[9]	$\sim$330[9]	196	182	(NA)	(NA)	134[9]	(NA)	134[9]	(NA)	(NA)
Power consumption, kW	$\sim$4625[9]	$\sim$5580[9]	1625	2270	(NA)	(NA)	1760[9]	(NA)	1760[9]	(NA)	(NA)
Heat rejection system data:											
Type	All units have natural-draft, water cooling towers.										
No. of towers	3	4	1	1	1	(NA)	(NA)	(NA)	(NA)	(NA)	(NA)
Design wet-bulb temp., °F	67.0	58.4	67.0	63.3	63.3	63.3	58.4	58.4	58.4	(NA)	(NA)
Water pump power, kW	(NA)	855	(NA)	750	(NA)	(NA)	560	(NA)	365[10]	(NA)	(NA)

(A) Larderello 2
(B) Larderello 3
(C) Gabbro
(D) Castelnuovo V.C.
(E) Castelnuovo V.C.
(F) Castelnuovo V.C.
(G) Serrazzano
(H) Lago 2
(I) Lago 2
(J) Sasso Pisano
(K) Monterotondo

(1) Single-cylinder, double-flow.
(2) Tandem-compound, single-flow (HP) and double-flow (LP)
(3) Single-cylinder, single-flow.
(4) 4 - 14.5 MW units; 1 - 11 MW unit.
(5) 3 - 26 MW units; 1 - 24 MW unit; 2 - 9 MW units.
(6) 1 - 15 MW unit; 2 - 12.5 MW units; 2 - 3.5 MW units.
(7) 1 - 14.5 MW unit; 1 - 12.5 MW unit.
(8) 1 - 12.5 MW unit; 1 - 3.2 MW unit.
(9) Total for all units.
(10) For the 14.5 MW unit only.

Table 10.6

Turbine specifications for noncondensing units in the Boraciferous region of Italy

	Sant'Ippolito-Vallonsordo	Lagoni Rossi 1	Lagoni Rossi 2	Sasso 1	Capriola	Molinetto
Year of start-up	1963	1961	1969	1969	1969	(NA)
Turbine type	(1)	(2)	(2)	(2)	(2)	(2)
Installed capacity, MW	0.9	3.5	3.0	7.0	3.0	3.5
Speed, rev/min	3000	3000	3000	3000	3000	3000
Steam inlet pressure, lbf/in^2	109.5	75.4	65.4	71.1	56.9	72.5
Steam inlet temperature, °F	419	313	356	369	379	370
% (wt.) noncondensable gases	3.3	3.2	3.8	2.7	4.0	3.3
Exhaust pressure, in Hg	30.4	30.4	30.4	30.4	30.4	30.4
Steam flow rate, 10^3 lbm/h	52.9	88.2	121	117	112	39.7

(1) Single-cylinder, single-flow, impulse blading.

(2) Single-cylinder, single-flow, impulse-reaction blading.

Table 10.7

Turbine specifications for geothermal units in the Monte Amiata and Travale regions of Italy

	Bagnore 1	Bagnore 2	Piancastagnaio	Travale
Year of start-up	1959	1960	1969	1973
Turbine type	(1)	(1)	(1)	(1)
Rated capacity, MW	3.5	3.5	15.0	15.0
Speed, rev/min	3000	3000	3000	3000
Steam inlet pressure, lbf/in^2	42.7	46.9	116.6	159.3
Steam inlet temperature, °F	275	286	361	414
% (wt.) noncondensable gases	8.5	7.2	21.1	10.6
Exhaust pressure, in Hg	30.4	30.4	31.3	31.3
Steam flow rate, 10^3 lbm/h	97.0	110.0	483.0	419.0

(1) Single-cylinder, single-flow, impulse-type, noncondensing.

Table 10.8

Geothermal power plant development in Japan

Plant	Type	Capacity, MW	Location		Status
			Island	Prefecture	
Matsukawa	Dry steam	20	Honshu	Iwate	Operational since 1966
Otake	Single flash	10	Kyushu	Oita	Operational since 1967
Onuma	Single flash	10	Honshu	Akita	Operational since 1973
Onikobe	Single flash	25	Honshu	Miyagi	Operational since 1975
Hatchobaru	Double Flash	50	Kyushu	Oita	Operational since 1977
Kakkonda	Single flash	50	Honshu	Iwate	Operational since 1978
Otake	Binary	1	Kyushu	Oita	Testing since 1977
Mori	Binary	1	Hokkaido	Hokkaido	Testing since 1977
Mori	Single flash	55	Hokkaido	Kokkaido	Under construction
(To be named)	Double flash	55	Kyushu	Kumamoto	In planning

Table 10.9

Annual production of electricity at the Wairakei power plant

[After Smith and McKenzie, 1970]

Year[1]	Generation GW·h (net)	Max. Load MW	Capacity factors, % Field-limited[3]	Installed[4]
1959	6.4	test runs	—	—
1960	169	50.6	37.9	27.9
1961	384	64.0	68.5	63.5
1962	491	65.6	85.5	81.3
1963	761	131	66.3	45.1
1964	1004	149	77.0	59.6
1965	1194	175	78.8	71.6
1966	1255	166	86.6	74.6
1967	1268	171	84.7	75.2
1968	1058[2]	167	72.2	78.4
1969	1207	166	83.1	71.6

(1) For the year ended March 31.

(2) Low generation caused by cut-back in geofluid flow for aquifer pressure-recovery test over 4 months during which the maximum plant capacity was 75 MW.

(3) Based on a borefield-limited effective maximum capacity, i.e., maximum load from col. 3.

(4) Based on an installed capacity of 69 MW for 1960-1962 and 192.6 MW thereafter, except for an effective installed capacity of 153.4 MW for 1968.

Table 10.10

Technical specifications for Philippine geothermal power stations

	Tiwi Units 1-4	Los Baños Wellhead Unit	Los Baños Units 1-4	Leyte Wellhead Unit
Year of start-up	1981	1977	1981	1977
Turbine data:				
Type	Single-cylinder, double-flow, dual-admission, 6 × 2	Single-cylinder, one Curtis stage, noncondensing, geared	Single-cylinder, double-flow, dual-admission, 5 × 2	Single-cylinder, one Curtis stage, noncondensing, geared
Rated capacity, MW	55	1.2	55	3.0
Speed, rpm	3600	7129/1800	3600	7554/1800
Main steam pressure, lbf/in^2	101.4	95.5	94.8	114.2
Main steam temperature, °F	329.0	324.1	324.1	338.0
Secondary steam pressure, lbf/in^2	26.8	—	24.8	—
Secondary steam temperature	244.4	—	240.1	—
Exhaust pressure, in Hg	4.0	30.4	4.0	37.6
Main steam flow rate, 10^3 lbm/h	(NA)	49.2	776.0	117.0
Secondary steam flow rate, 10^3 lbm/h	(NA)	—	276.0	—
Condenser data:				
Type	Barometric, spray jet	(None)	Barometric, spray jet	(None)
Cooling water temperature, °F	87.1	—	87.1	—
Outlet water temperature, °F	120.0	—	120.0	—
Cooling water flow rate, 10^6 lbm/h	27.8	—	29.1	—
Heat rejection system:				
Type	Cross-flow, induced-draft, cooling tower	(None)	Cross-flow, induced-draft, cooling tower	(None)

Table 10.11

Potential geothermal power generation in the Philippines

[Ravenholt, 1977a]

Geothermal Field	1978	1979	1980	1981	1982	1983	1984	1985	Est. Max. Capacity
Tiwi	110	-	55	55	-	55	55	-	560
Los Baños	55	55	-	55	55	-	55	55	720
Tongonan	-	-	55	55	-	55	55	-	(NA)
S. Negros	-	-	-	55	55	-	55	55	425
Manat-Masara	-	-	-	55	55	-	55	55	500
Total Annual	165	55	110	275	165	110	275	165	
Cumulative	165	220	330	605	770	880	1155	1320	

Notes: All values in megawatts. Wellhead units not included.

Table 10.12

Geofluid characteristics at Kızıldere field, Turkey

[after Alpan, 1975]

Substance	Concentration, ppm Well KD-XIII	Concentration, ppm Avg. 12 wells
Bicarbonate, HCO_3	2116	2247
Sodium, Na	1174	1240
Sulfate, SO_4	641	811
Silica, SiO_2	327	288
Potassium, K	131	128
Chloride, Cl	115	107
Boron, B	24.5	24.5
Fluoride, F	18.2	18.15
Ammonium, NH_4	5.8	3.95
Calcium, Ca	4.1	3.2
Magnesium, Mg	1.5	0.95
Arsenic, As	0.51	0.17
pH	8.9	8.8

Table 10.13

Characteristics of wellhead power generator

at KD-XIII, Kızıldere, Turkey

Year of start-up	1975
Turbine type: Single-cylinder, one Curtis stage, noncondensing	
Rated capacity	0.5 MW
Speed	4500 rpm
Inlet steam pressure	∿ 70.5 lbf/in^2
Inlet steam temperature	∿ 302°F
Noncondensable gas content	17% (by weight of steam)
Exhaust steam pressure	∿ 34.0 in Hg
Maximum allowable pressure	∿ 114 lbf/in^2
Turbine steam flow rate[a]	∿ 3255 lbm/h
Last stage blade height	3 in

(a) Total geofluid flow rate is ∿ 88 × 10^3 lbm/h; dryness fraction is 3.7%.

Table 10.14

Technical specifications for Pauzhetka geothermal power plant

Year of start-up	1967
Turbine data:	
Type	Tandem-compound, single-flow
Rated capacity	2 × 2.5 MW
Steam inlet pressure	28.4 lbf/in^2
Steam inlet temperature	260.6°F
Noncondensable gas content	0.6% by weight of steam
Exhaust pressure	0.87-2.32 in Hg
Steam flow rate	59.5×10^3 lbm/h
Condenser data:	
Type	Direct-contact, barometric
Gas extractor data:	
Type	Water jet ejector
Water impeller power	170 kW
Heat rejection system:	
Type	Once-through, Pauzhetka River

Table 10.15

Technical specifications for Paratunka geothermal power plant

Year of start-up	1967 (now dismantled)
Turbine data:	
Type	Radial outflow
Rated capacity	680 KW
Maximum capacity	750 KW
Secondary working fluid	Dichlorodifluoromethane, CCl_2F_2 (Ref-12)
Ref-12 inlet pressure	202.7 lbf/in^2
Ref-12 inlet temperature	149°F
Ref-12 exhaust pressure	113.8 lbf/in^2
Ref-12 exhaust temperature	∿105°F
Ref-12 mass flow rate	$\sim 640 \times 10^3$ lbm/h
Geothermal fluid data:	
Inlet pressure	42.6 lbf/in^2
Inlet temperature	178.7°F
Outlet temperature	∿113°F
Hot water flow rate	617×10^3 lbm/h
Condenser data:	
Type	Surface type, shell and tube
Cooling water inlet temperature	43-46°F
Cooling water outlet temperature	55-58°F
Cooling water flow rate	3.307×10^6 lbm/h
Heat rejection system:	
Type	Once-through, Paratunka River
Water pump power	110 KW

Table 10.16

Geothermal power plant development at
The Geysers natural steam field, California

Utility/Unit	Year of Start-up	Capacity MW	Turbine Manufacturer	Type	Condenser Type[a]	Steam Supplier
PG&E[c], No. 1	1960	11	G.E.	6x1	DCEB	U-M-T[b]
PG&E, No. 2	1963	13	Elliott	5x1	DCEB	U-M-T
PG&E, No. 3	1967	27	Elliott	7x1	DCEB	U-M-T
PG&E, No. 4	1968	27	Elliott	7x1	DCEB	U-M-T
PG&E, No. 5	1971	53	Toshiba	6x2	DCLL	U-M-T
PG&E, No. 6	1971	53	Toshiba	6x2	DCLL	U-M-T
PG&E, No. 7	1972	53	Toshiba	6x2	DCLL	U-M-T
PG&E, No. 8	1972	53	Toshiba	6x2	DCLL	U-M-T
PG&E, No. 9	1973	53	Toshiba	6x2	DCLL	U-M-T
PG&E, No. 10	1973	53	Toshiba	6x2	DCLL	U-M-T
PG&E, No. 11	1976	106	Toshiba	6x4	DCLL	U-M-T
PG&E, No. 12	1979	106	Toshiba	6x4	DCLL	U-M-T
PG&E, No. 13	1979	135	G.E.	6x4	STST	Aminoil
PG&E, No. 14	1979	110	Toshiba	6x4	STST	U-M-T
PG&E, No. 15	1979	55	G.E.	5x2	STST	Thermogenics
PG&E, No. 16	1981	110	Toshiba	6x4	STST	Aminoil
PG&E, No. 17	1981	110	Toshiba	6x4	STST	U-M-T
PG&E, No. 18	1982	110	(NA)	(NA)	STST	U-M-T
PG&E, No. 19	1982	110	(NA)	(NA)	STST	Aminoil
PG&E, No. 20	1983	110	(NA)	(NA)	STST	U-M-T
PG&E, No. 21	1983	110	(NA)	(NA)	STST	U-M-T
NCPA[d], No. 1	1981	110	(NA)	(NA)	STST	Shell Oil

(a) DCEB = Direct-contact, external, barometric type.
DCLL = Direct-contact, low-level type.
STST = Shell-and-tube, surface type.
(b) U-M-T = Union Oil - Magma Power - Thermal Power.
(c) PG&E = Pacific Gas & Electric Company.
(d) NCPA = Northern California Power Agency.

Table 10.17

Technical specifications for geothermal units in operation at The Geysers

Unit No.	1	2	3-4	5-10	11
Turbine data:					
Type[(a)]	SCSF	SCSF	SCSF	SCDF	TCFF
Rated capacity, MW	11	13	27	53	106
Speed, rpm	1800	3600	3600	3600	3600
Steam pressure, lbf/in^2	93.9	79.7	78.9	113.0[(b)]	113.3
Steam temperature, °F	348	348	341.8	355	355
Noncondensable gas, % wt.	<0.3	<0.3	<0.5	<0.5	<1.0
Exhaust pressure, in Hg	4.0	4.0	4.0	4.0	4.0
Steam flow rate, 10^3 lbm/h	240	255	510[(c)]	907.5	1808
Condenser data:					
Cooling water temperature, °F	80.6	80.6	80.6	80.0	80.0
Outlet water temperature, °F	120.8	120.0	119.8	118.4	118.4
Water flow rate, 10^6 lbm/h	5.5	∿6.0	6.41	21.3	∿62.8
Gas extractor data:					
Type	All units have steam jet ejectors.				
Gas capacity, ft^3/min	∿350	∿350	∿1000	∿1830	∿3660
Steam consumption, 10^3 lbm/h	∿10	∿10	∿23	58.4	120
Heat rejection system data:					
Type	All units have cross-flow, mechanical induced draft water cooling towers				
Number of cells	3	3	6	5	10
Design wet-bulb temperature, °F	66.5	65	66	65	65
Water pump power, kW	(NA)	(NA)	(NA)	930	1860
Fan motor power, kW	(NA)	(NA)	355	605	1210

(a) SCSF = Single-Cylinder, Single-Flow;
SCDF = Single-Cylinder, Double-Flow;
TCFF = Tandem-Compound, Four-Flow.

(b) 113.7 for Units 5 and 6.

(c) 516 for Unit 4.

Table 10.18

Resource utilization efficiency of The Geysers units[a]

Unit No.	T_1/°F	h_1/(Btu/lbm)	w°/(Btu/lbm)	w/(Btu/lbm)	η_u/%
1	348	1200.5	324.9	164.6	51
2	348	1203.2	316.2	166.9	53
3	341.8	1200.2	314.8	169.7	54
4	341.8	1200.2	314.8	167.7	53
5-6	355	1200.4	335.6	187.0	56
7-10	355	1200.6	335.3	187.0	56
11-12	355	1200.5	335.5	187.6	56
13	338	1190.3	332.8	165.3	50
14	355	1200.4	335.8	187.7	56
15	338	1190.6	332.4	164.8	50

(a) Based on a sink temperature of 80°F.

Table 10.19

Preliminary design specifications for the Magmamax Dual Binary plant, East Mesa, CA

Year of start-up	1979	
Turbine data:		
	Isobutane expander	Propane expander
Type	Tandem-compound, double-flow, radial-inflow	Single-cylinder, radial-inflow
Rated capacity	9.0 MW	2.2 MW
Speed (turbine/generator)	7000/3600 rpm	(NA)
Inlet pressure	500 lbf/in^2	474 lbf/in^2
Inlet temperature	345°F	205°F
Exhaust pressure	60 lbf/in^2	142 lbf/in^2
Exhaust temperature	230°F	102°F
Flow rate	1.031×10^6 lbm/h	274×10^3 lbm/h
Geofluid data:		
Pressure after pumps	270 lbf/in^2	
Inlet temperature	360°F	
Pressure after heat exchangers	117 lbf/in^2	
Outlet temperature	180°F	
Flow rate	1.444×10^6 lbm/h	
Condenser data:		
Type	Surface type, shell-and-tube	
Pressure	59 lbf/in^2	
Cooling water temperature	62°F	
Outlet water temperature	79.5°F	
Water flow rate	(NA)	
Heat rejection system data:		
Type	Phased cooling, storage ponds with sprays	
Number of ponds	2	
Design wet-bulb temperature	58°F	

Table 10.20

Geothermal power plants in the Imperial Valley, California

Site	Utility or Plant Owner	Field Developer	Year of Start-up	Capacity MW	Plant Type
East Mesa	Imperial Magma	Magma Power	1979	11.2	Magmamax Dual Binary
East Mesa	Republic Geothermal	Republic Geothermal	1979,80	48.0	Single and double flash
Brawley	So. Cal. Edison	Union Oil	1980	10.0	Single flash
Heber	So. Cal. Edison	Chevron	(In planning)	50	Double flash
Heber	San Diego G&E	Chevron	(In planning)	45	Binary
Westmorland	(NA)	Republic Geothermal	(In planning)	50	Double flash
Salton Sea	So. Cal. Edison	Magma/Union	(In planning)	10	Flash or Flash-binary

Table 10.21

Proposed U.S. geothermal power plants outside California

Site	Utility or Plant Owner	Field Developer	Year of Start-up	Capacity MW	Plant Type
Raft River, ID	EG&G	EG&G	1980	5	Double-boiling binary
Puna, HI	HELCO[a]	U. of Hawaii	1980	5	Single flash
Valles Caldera, NM	Public Service Co. of New Mexico	Union Oil	1982	50	Double flash
Roosevelt Hot Springs, UT	Rogers Engineering Co.	Phillips	(In planning)	52	Double flash
Desert Peak, NV	Sierra Pacific	Phillips	(In planning)	20-50	Single or double flash
(NA)	City of Burbank[b]	(NA)	(In planning)	250-750	Hybrid coal-geothermal

(a) Hawaii Electric Light Company

(b) In conjunction with a consortium of neighboring cities in the Los Angeles area.

Table 10.22

U.S. geothermal electric power development - projected through 1983

Year	Cumulative MW	New Geothermal Power Plants
1977	502.0	none
1978	502.0	none
1979	929.2	106 MW (PG&E No. 12)
		55 MW (PG&E No. 15)
		11.2 MW (Magmamax)
		135 MW (PG&E No. 13)
		110 MW (PG&E No. 14)
		10 MW (Republic Geothermal)
1980	985.55[(a)]	48 MW (Republic Geothermal)
		10 MW (So. Cal Edison-Brawley)
		3.35 MW (Raft River)
		5 MW (HGP)
1981	1315.55	110 MW (PG&E No. 16)
		110 MW (PG&E No. 17)
		110 MW (NCPA No. 1)
1982	1585.55	110 MW (PG&E No. 18)
		110 MW (PG&E No. 19)
		50 MW (Valles Caldera)
1983	1805.55	110 MW (PG&E No. 20)
		110 MW (PG&E No. 21)
		(?) 52 MW (Roosevelt H.S.)
		(?) 50 MW (So. Cal Edison-Heber)
		(?) 45 MW (SDG&E - Heber)
		(?) 50 MW (Republic Geothermal)
	(?) 2012.55	(?) 10 MW (So. Cal Edison-Niland)

(a) 48 MW of Republic Geothermal includes 10 MW plant of 1979.

Figure captions

Fig. 10.1 Arrangement of wells at Ahuachapán. ◐ Wells for unit No. 1; ◑ Wells for unit No. 2; ⊙ Reinjection wells; ○ Nonproductive wells; ⊗ Collapsed well; ⊕ Stand-by wells.

Fig. 10.2 Wellhead equipment for well AH-20. [Photo by R. DiPippo]

Fig. 10.3 Flow diagram for units No. 1 and 2 at Ahuachapán.

Fig. 10.4 Flow diagram for unit No. 3, under construction, at Ahuachapan.

Fig. 10.5 Baffled retention tank for waste liquid; well AH-1 in background; at Ahuachapán. [Photo by R. DiPippo]

Fig. 10.6 Map of Iceland showing rift zones, major cities, and sites of geothermal power plants.

Fig. 10.7 Arrangement of wells at Námafjall to serve diatomite processing plant and 3.0 MW, noncondensing power unit [after Ragnars, et al, 1970].

Fig. 10.8 Arrangement of Krafla geothermal power plant and steam wells [after Sólnes, 1976].

Fig. 10.9 Simplified flow diagram for Krafla geothermal power station.

Fig. 10.10 Energy conversion schemes at Larderello. (a) Direct-intake, noncondensing, "Cycle 1" plant: a = steam well, b = turbine, c = generator, d = exhaust to atmosphere. (b) Pure-steam, condensing, "Cycle 2" plant": a = steam well, b = heat exchanger, c = turbine, d = generator, e = degassing plant, f = condenser, g = liquid discharge, h = to and from cooling tower. (c) Direct-intake, condensing, "Cycle 3" plant: a = steam well, b = water injection (scrubber), c = axial separator, d = turbine, e = generator, f = condenser, g = gas compressor, h = to and from cooling tower.

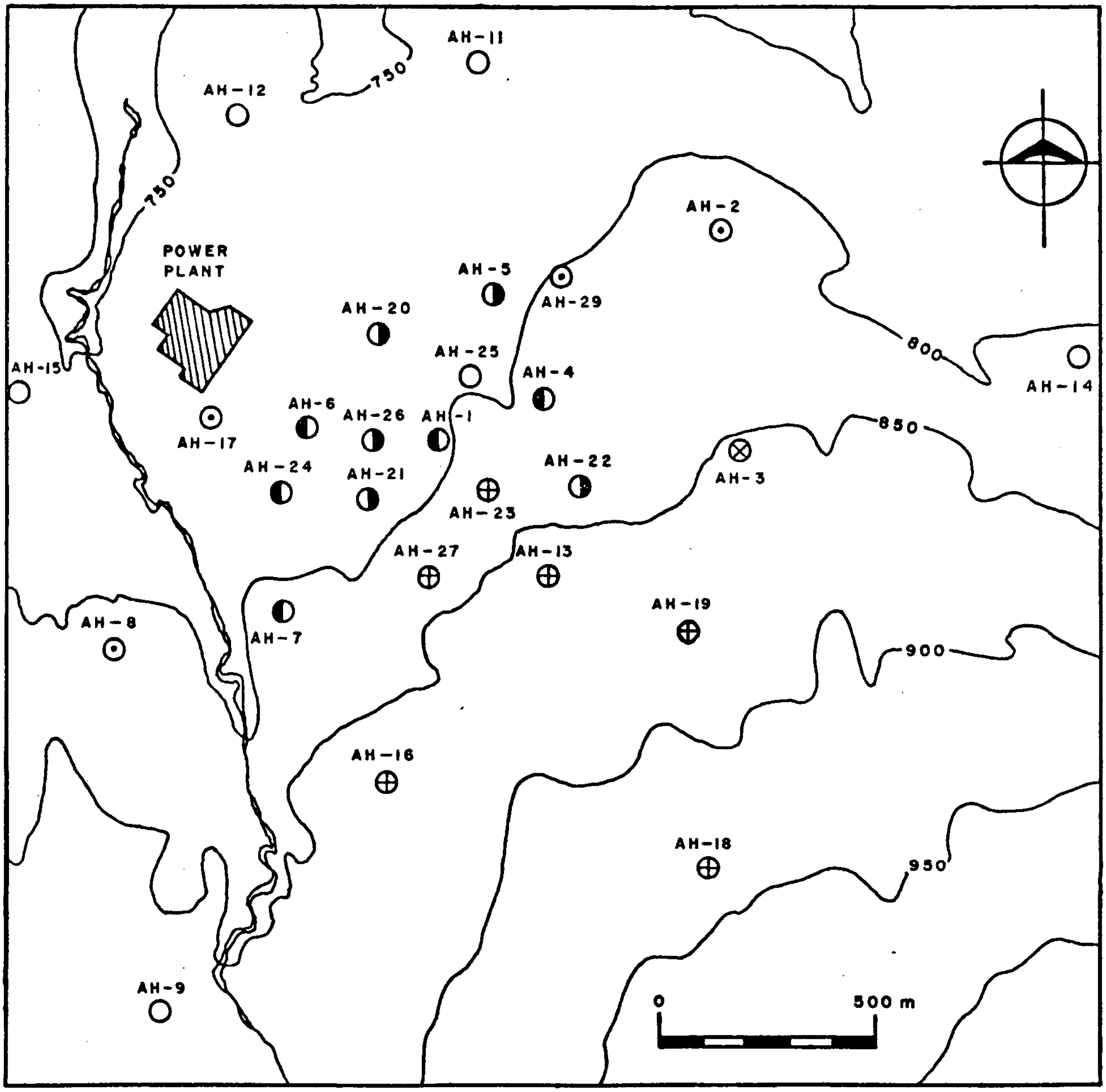

AH-11
AH-12
750
750
POWER
PLANT
AH-2
AH-5
AH-29
AH-20
AH-25
AH-4
800
AH-14
AH-15
AH-6
AH-26
AH-1
AH-17
850
AH-3
AH-24
AH-21
AH-22
AH-23
AH-27
AH-13
AH-19
AH-8
AH-7
900
AH-16
AH-18
950
AH-9
0
500 m

FIGURE 10.1

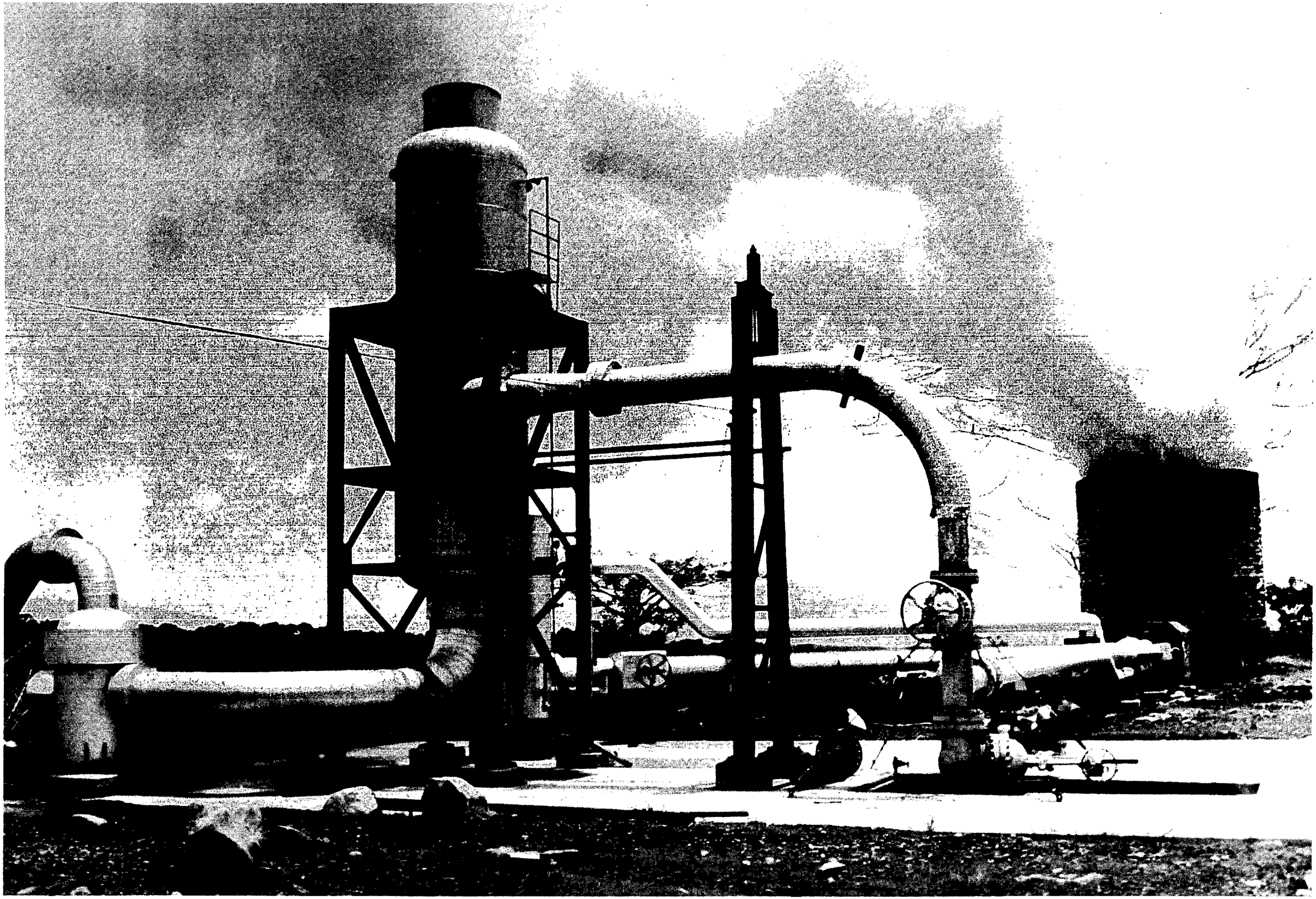


FIGURE 10.2

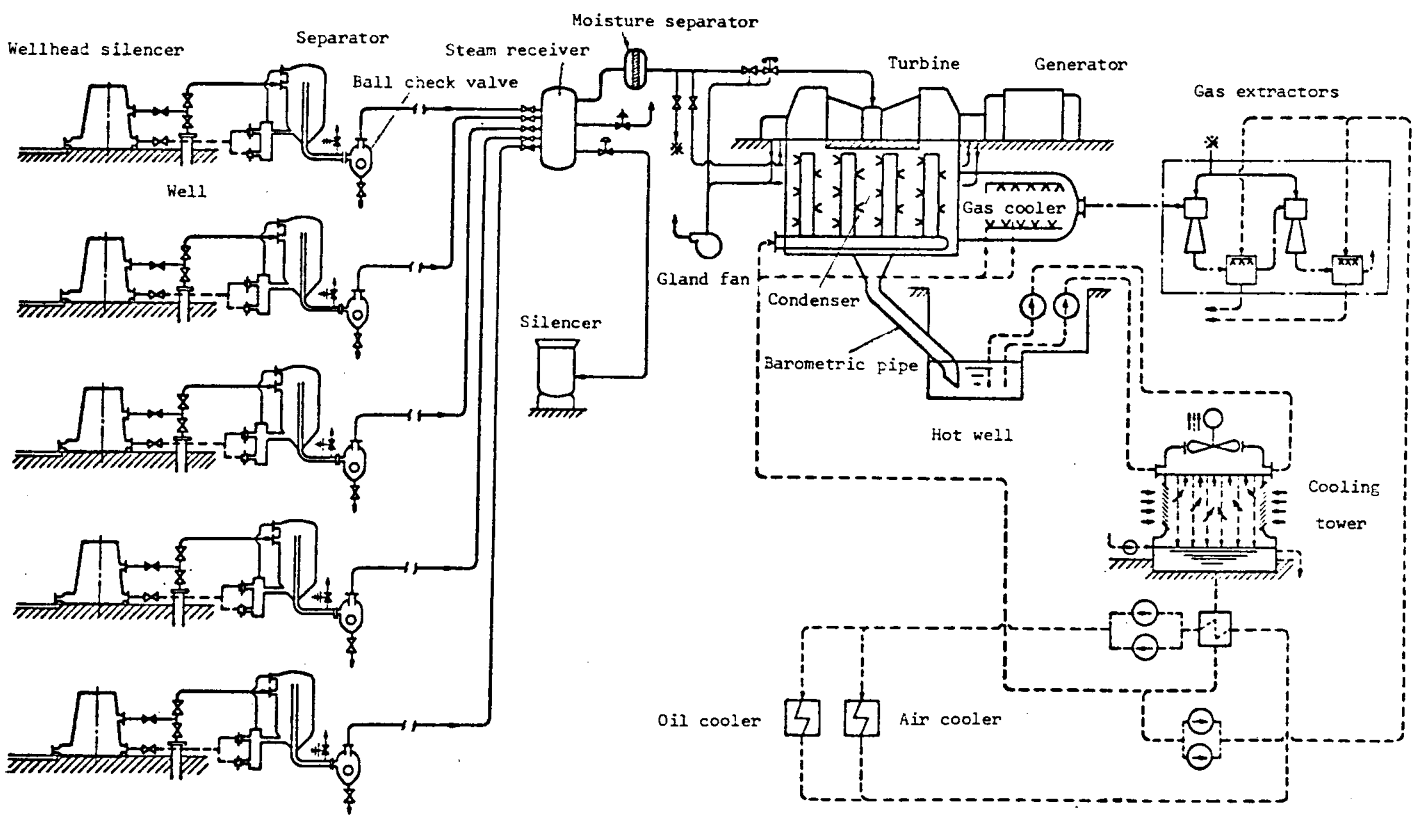

Wellhead silencer
Separator
Steam receiver
Moisture separator
Ball check valve
Turbine
Generator
Gas extractors
Well
Gas cooler
Gland fan
Condenser
Silencer
Barometric pipe
Hot well
Cooling
tower
Oil cooler
Air cooler

FIGURE 10.3

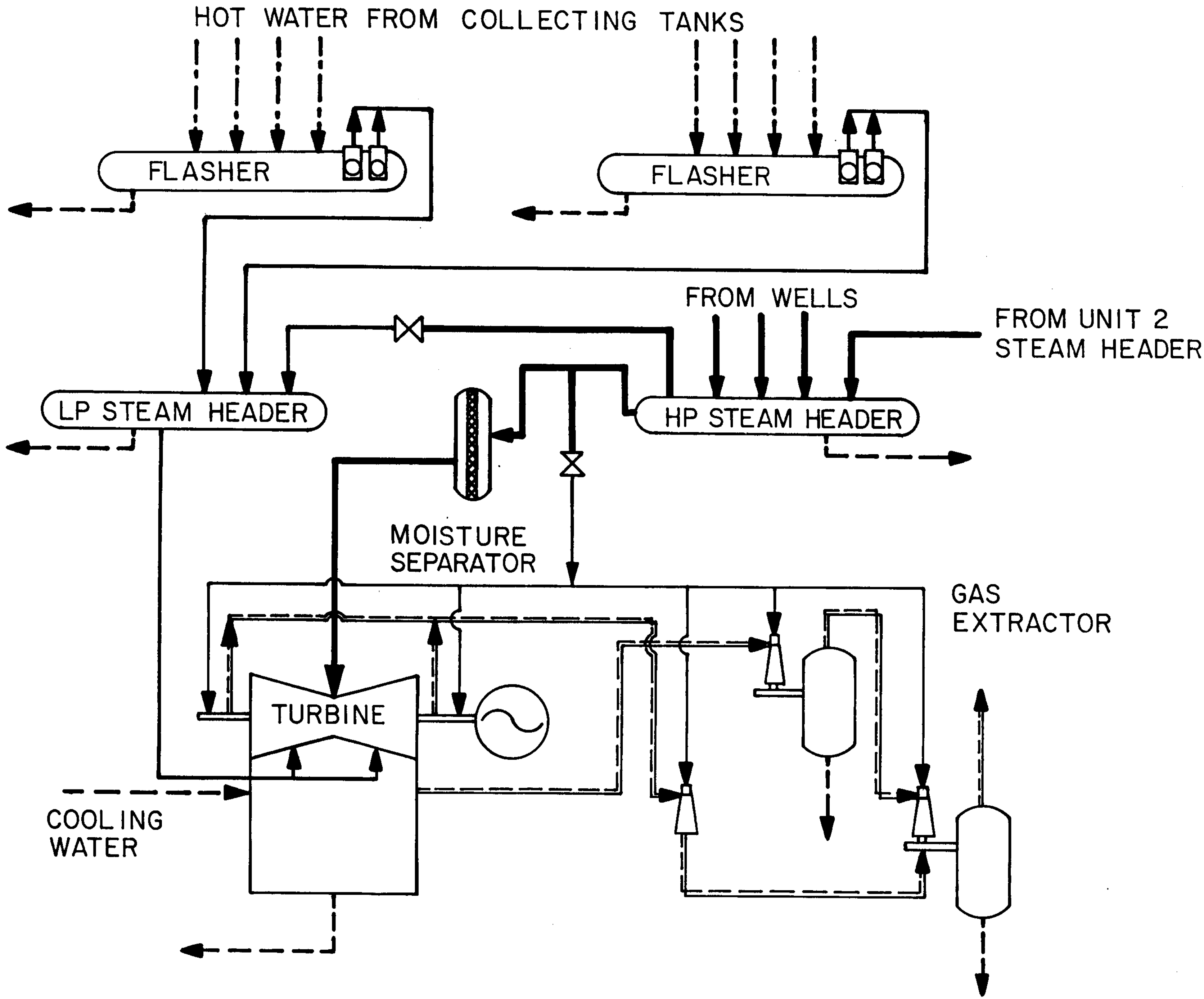

HOT WATER FROM COLLECTING TANKS
FLASHER
FLASHER
FROM WELLS
FROM UNIT 2
STEAM HEADER
LP STEAM HEADER
HP STEAM HEADER
MOISTURE
SEPARATOR
GAS
EXTRACTOR
TURBINE
COOLING
WATER

FIGURE 10.4

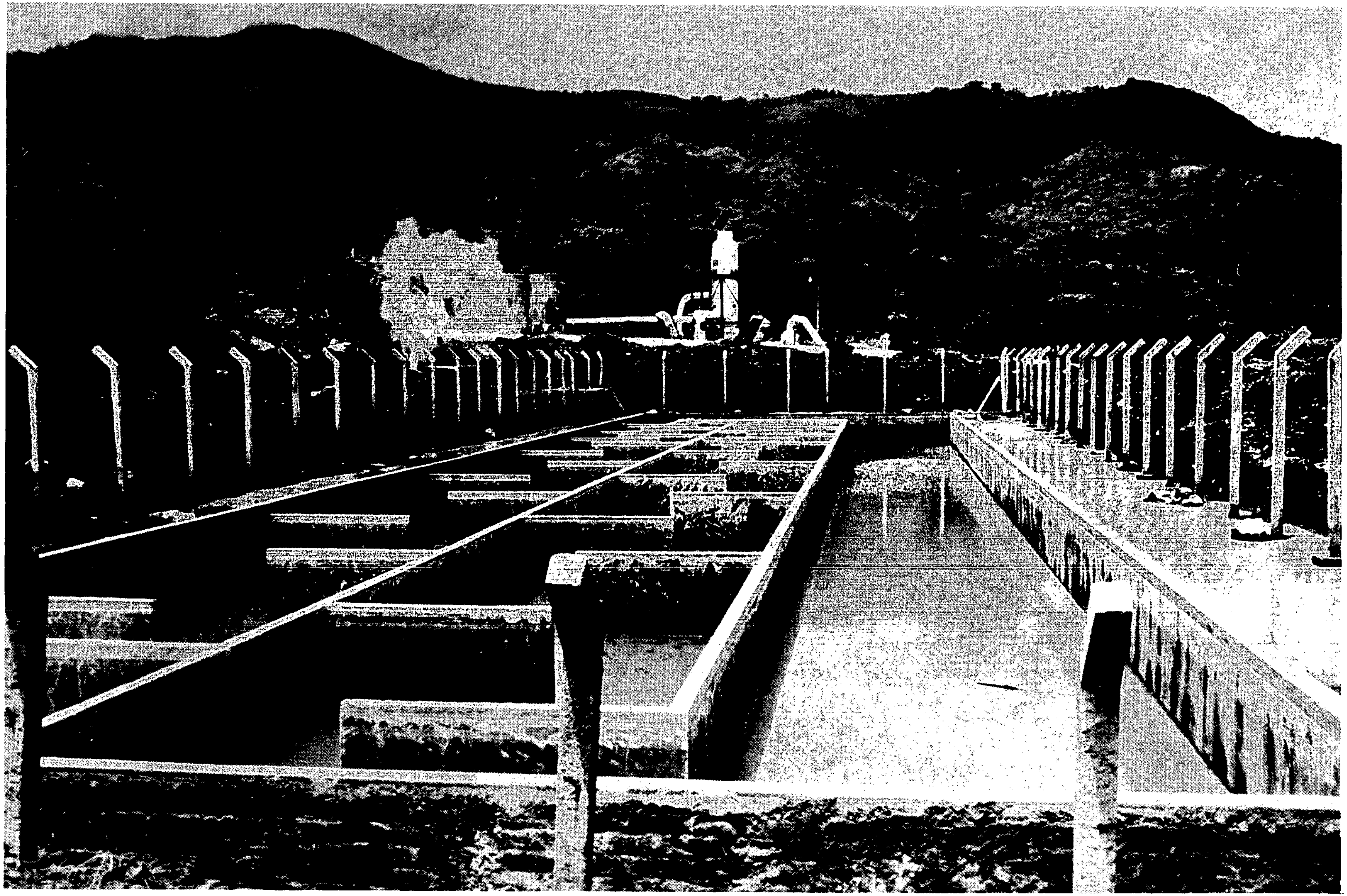


FIGURE 10.5

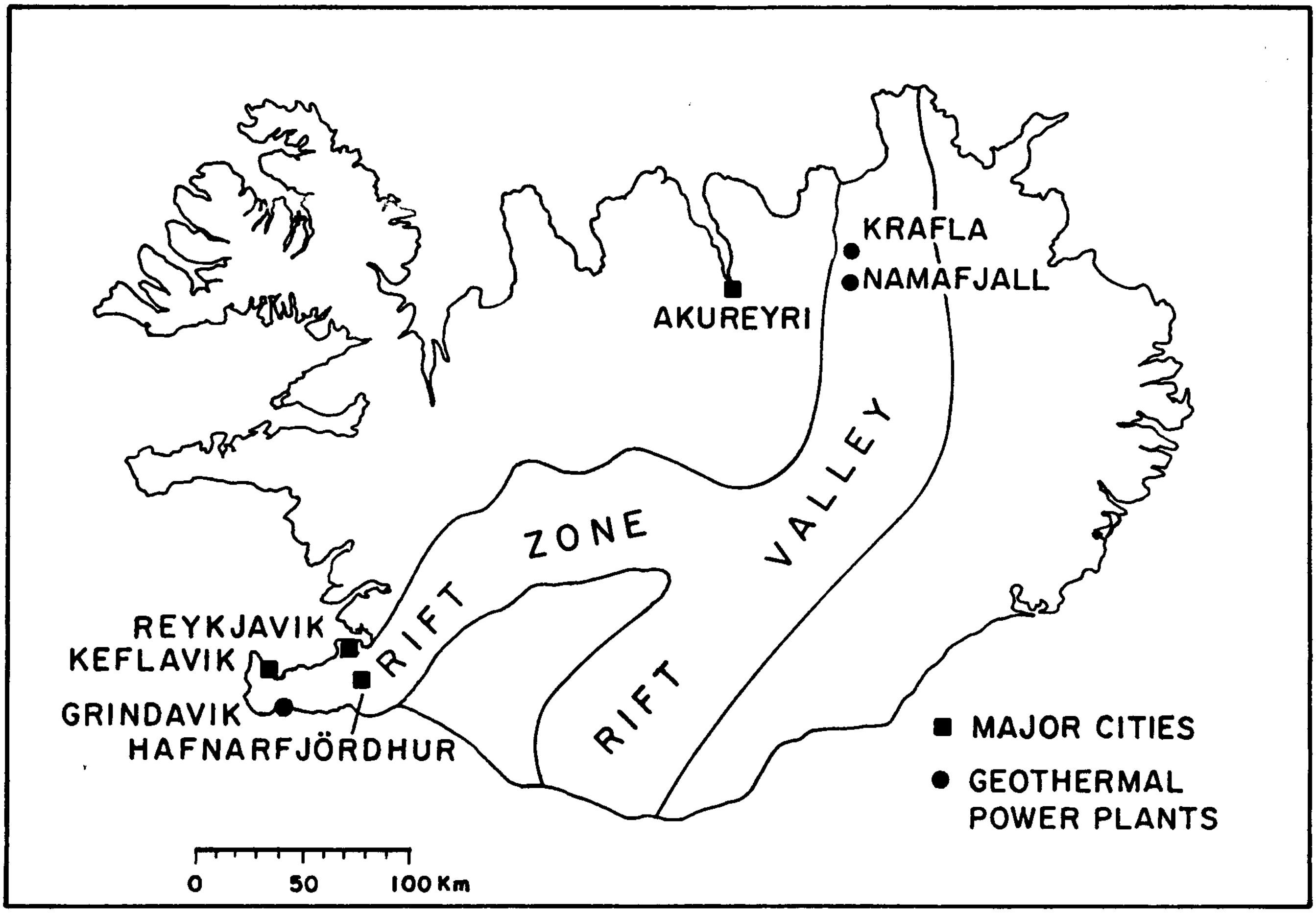

KRAFLA
NAMAFJALL
AKUREYRI
ZONE
VALLEY
RIFT
REYKJAVIK
KEFLAVIK
GRINDAVIK
HAFNARFJÖRDHUR
RIFT
MAJOR CITIES
GEOTHERMAL POWER PLANTS
0
50
100 Km

FIGURE 10.6

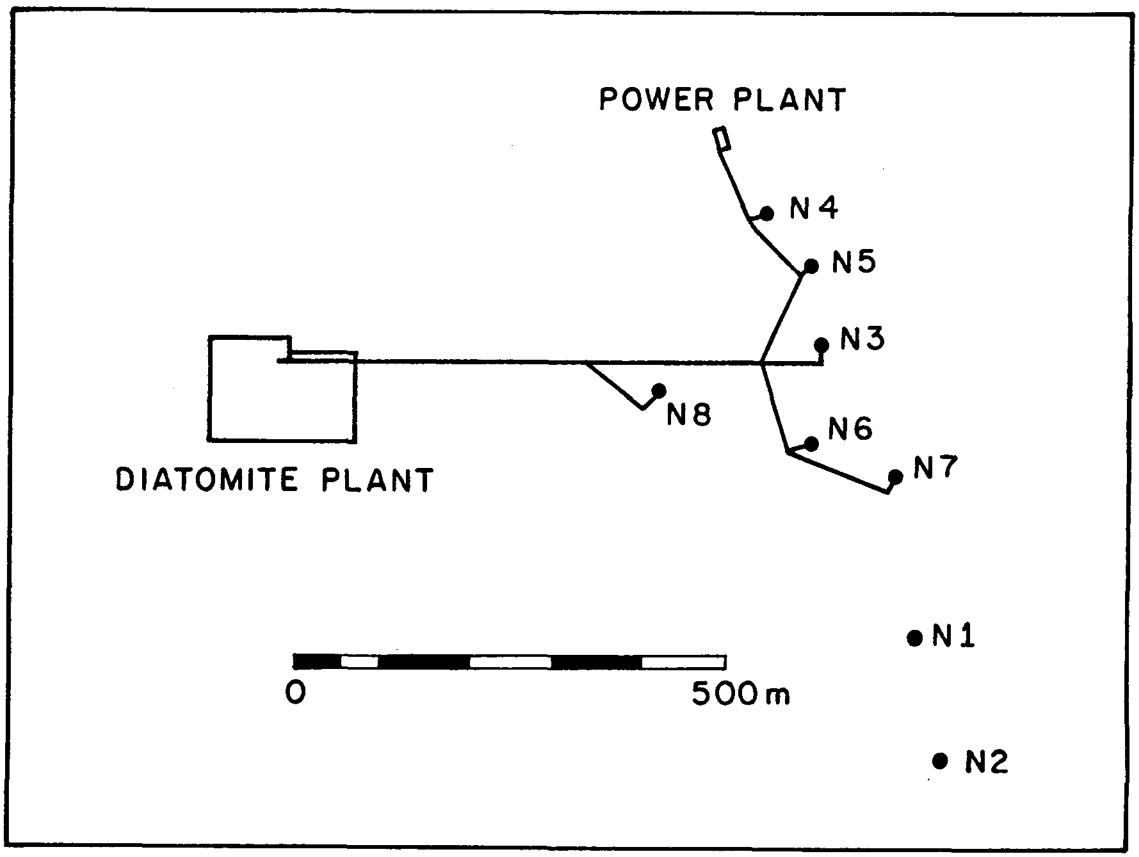


FIGURE 10.7

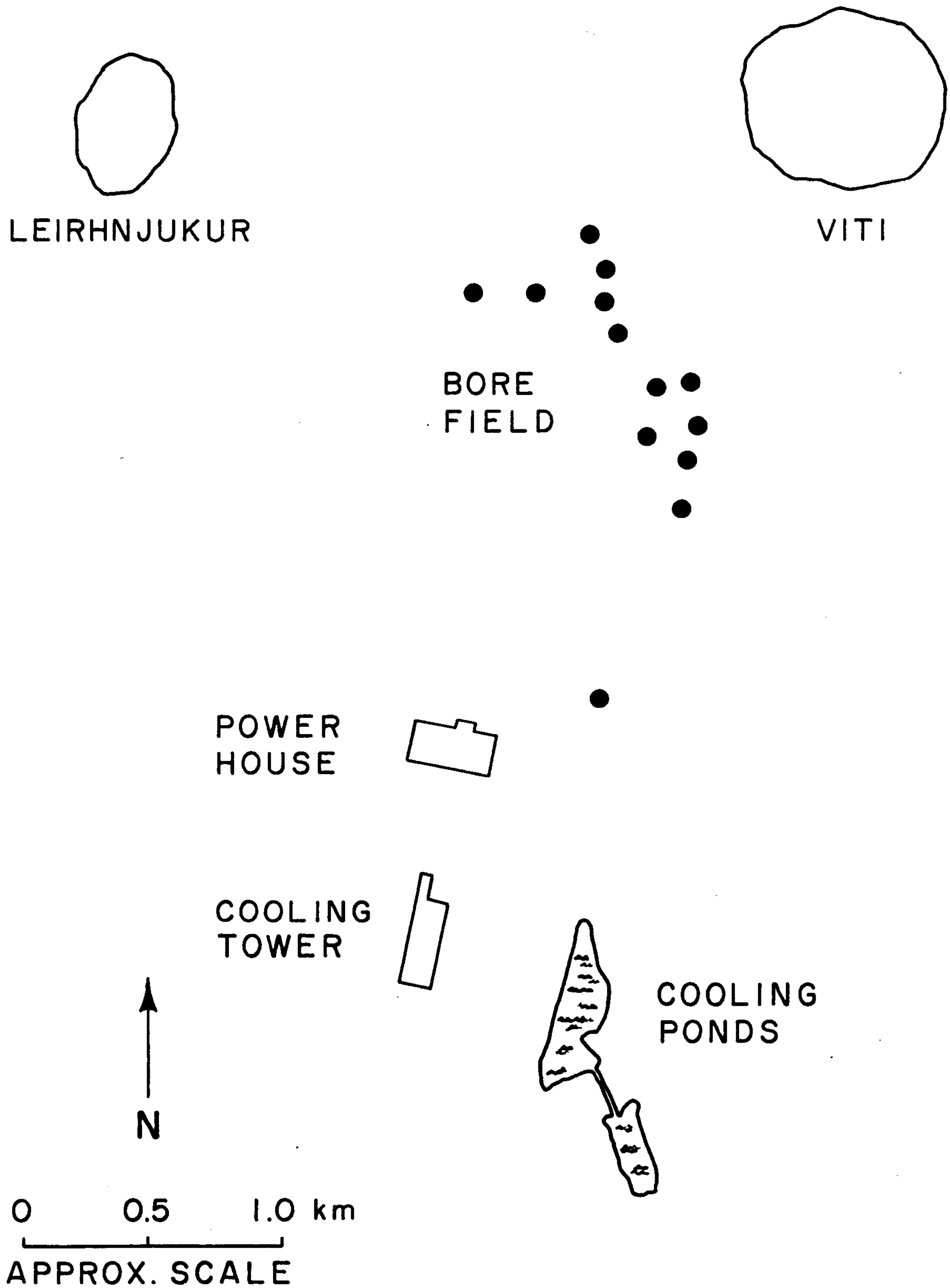

LEIRHNJUKUR
VITI
BORE
FIELD
POWER
HOUSE
COOLING
TOWER
COOLING
PONDS
N
0
0.5
1.0 km
APPROX. SCALE

FIGURE 10.8

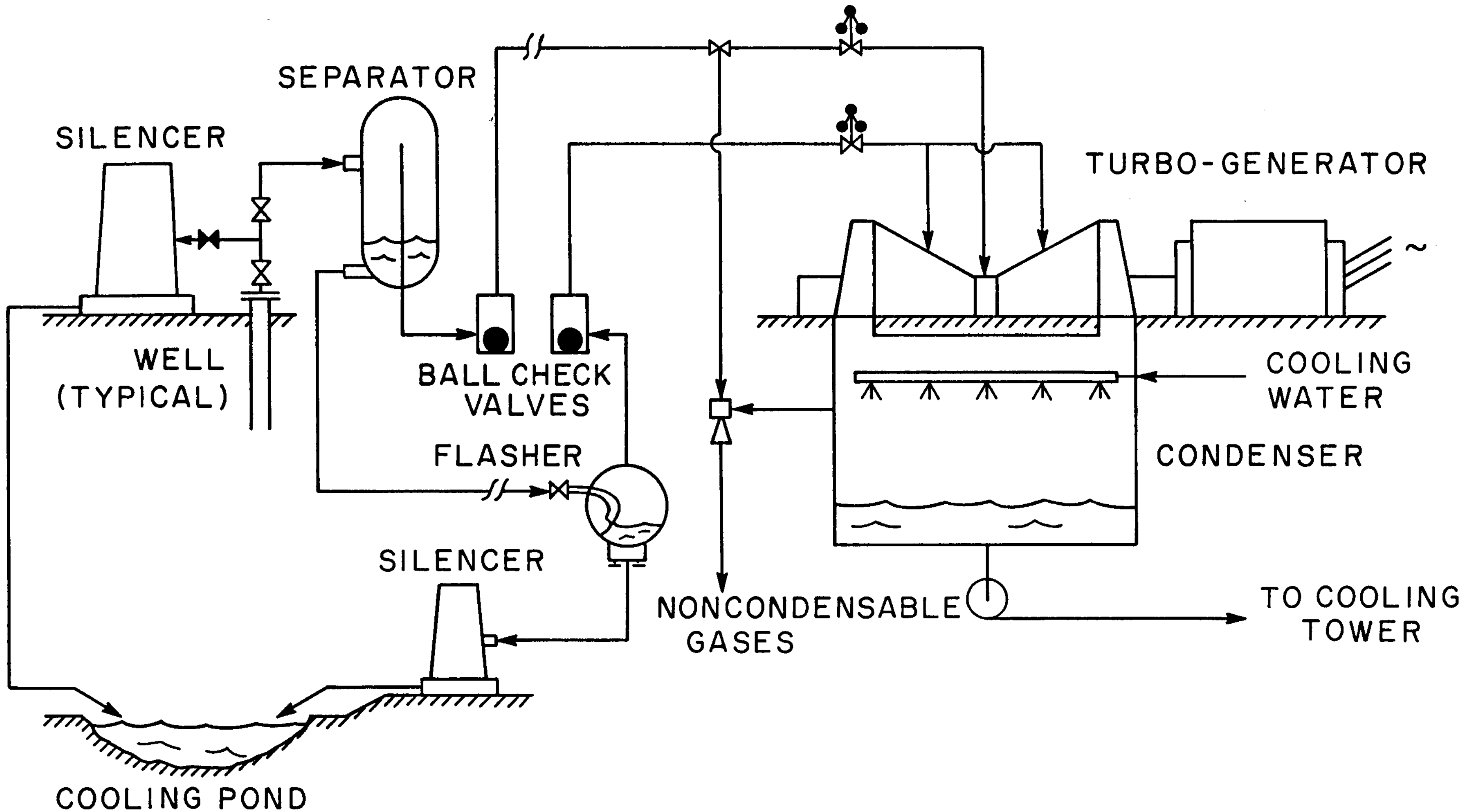
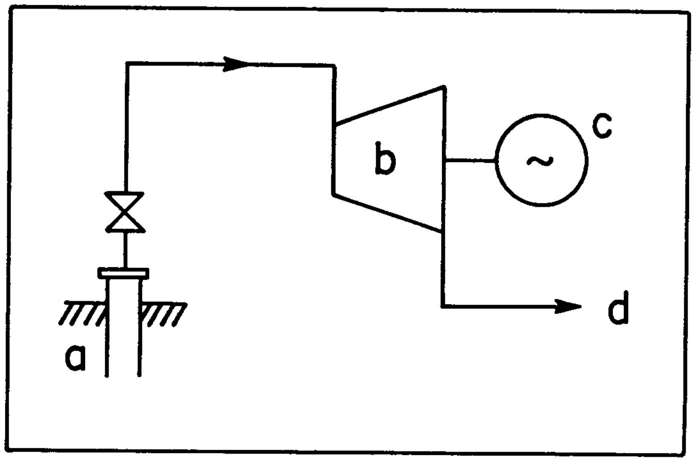
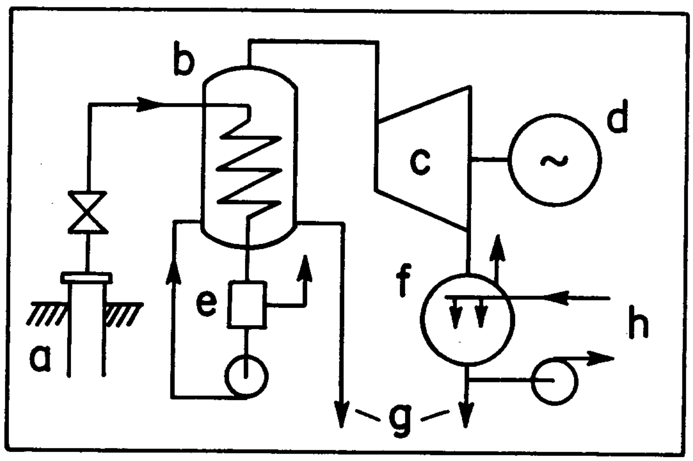

SEPARATOR
SILENCER
TURBO-GENERATOR
~
WELL
(TYPICAL)
BALL CHECK
VALVES
COOLING
WATER
FLASHER
CONDENSER
SILENCER
NONCONDENSABLE
GASES
TO COOLING
TOWER
COOLING POND

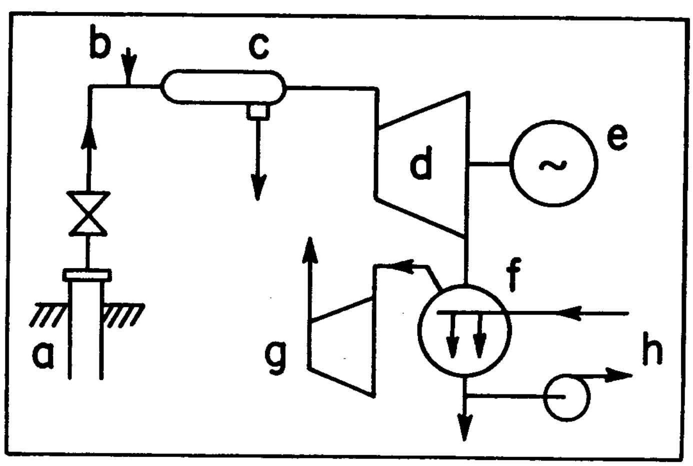
FIGURE 10.9



(a)



(b)



(c)

FIGURE 10.10

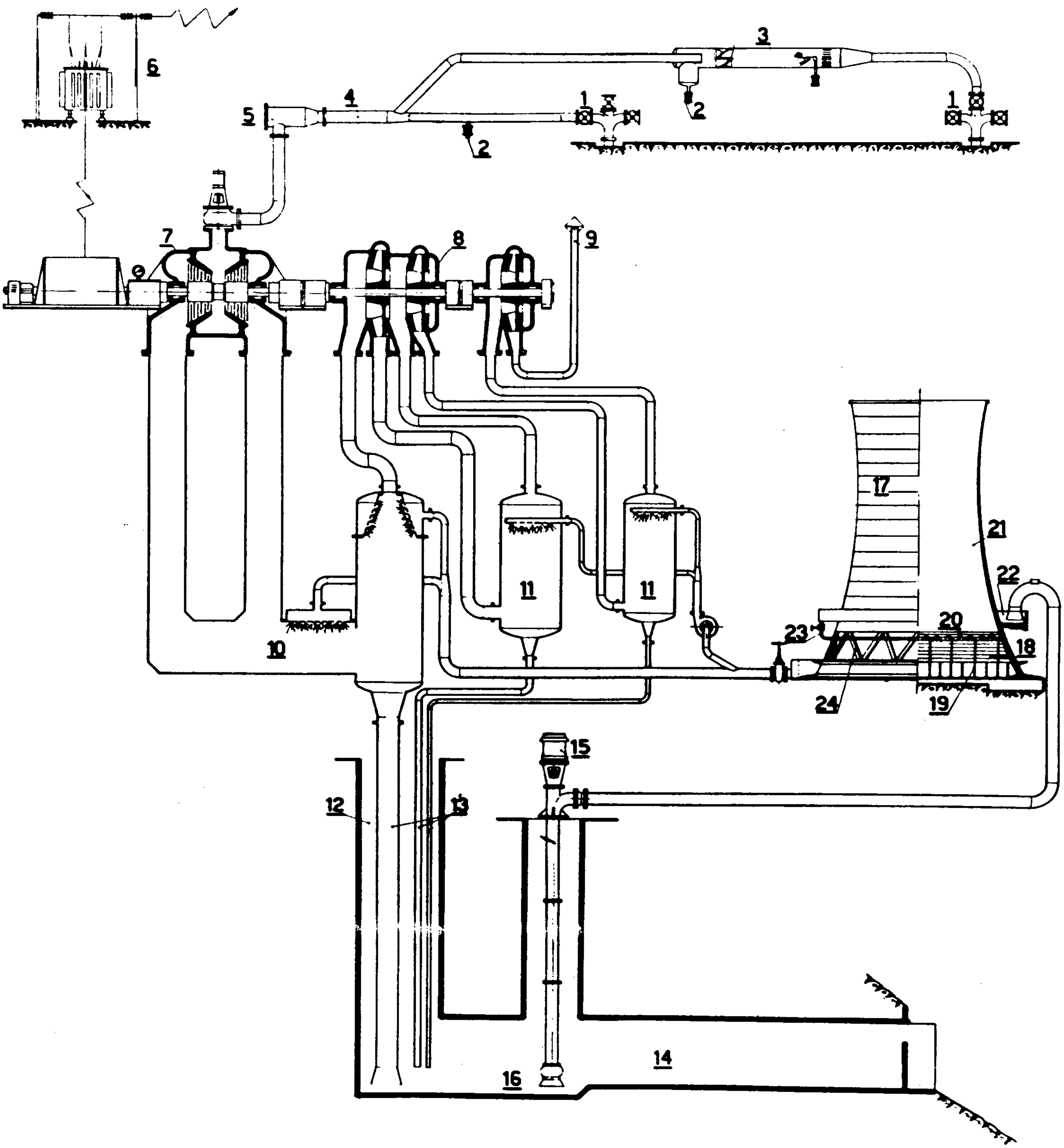


FIGURE 10.11

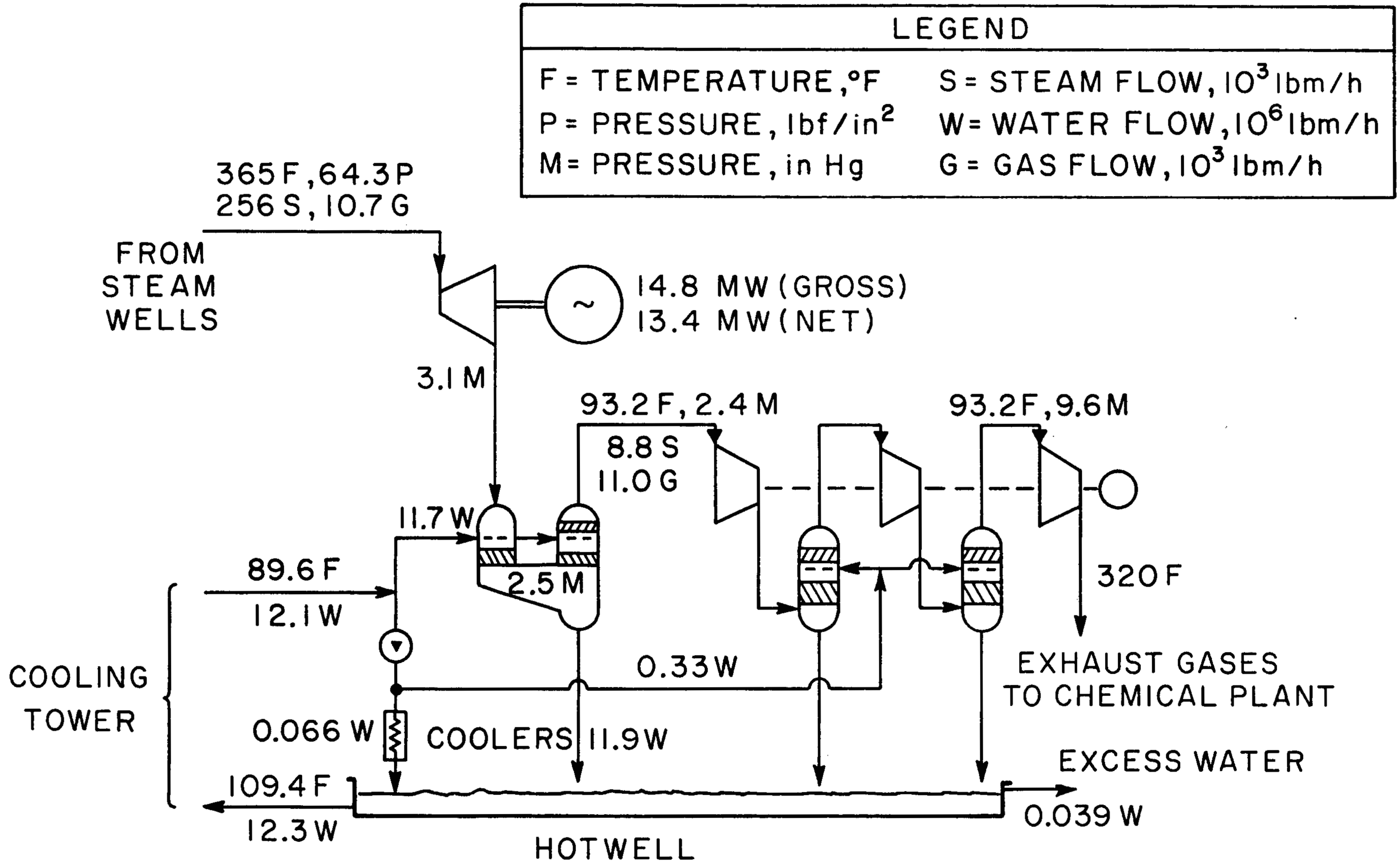

LEGEND
F = TEMPERATURE, °F
S = STEAM FLOW, 10^3 lbm/h
P = PRESSURE, lbf/in^2
W = WATER FLOW, 10^6 lbm/h
M = PRESSURE, in Hg
G = GAS FLOW, 10^3 lbm/h
365 F, 64.3 P
256 S, 10.7 G
FROM STEAM WELLS
14.8 MW (GROSS)
13.4 MW (NET)
3.1 M
93.2 F, 2.4 M
8.8 S
11.0 G
93.2 F, 9.6 M
11.7 W
2.5 M
89.6 F
12.1 W
320 F
COOLING TOWER
0.33 W
EXHAUST GASES TO CHEMICAL PLANT
0.066 W
COOLERS
11.9 W
EXCESS WATER
109.4 F
12.3 W
0.039 W
HOTWELL

FIGURE 10.12

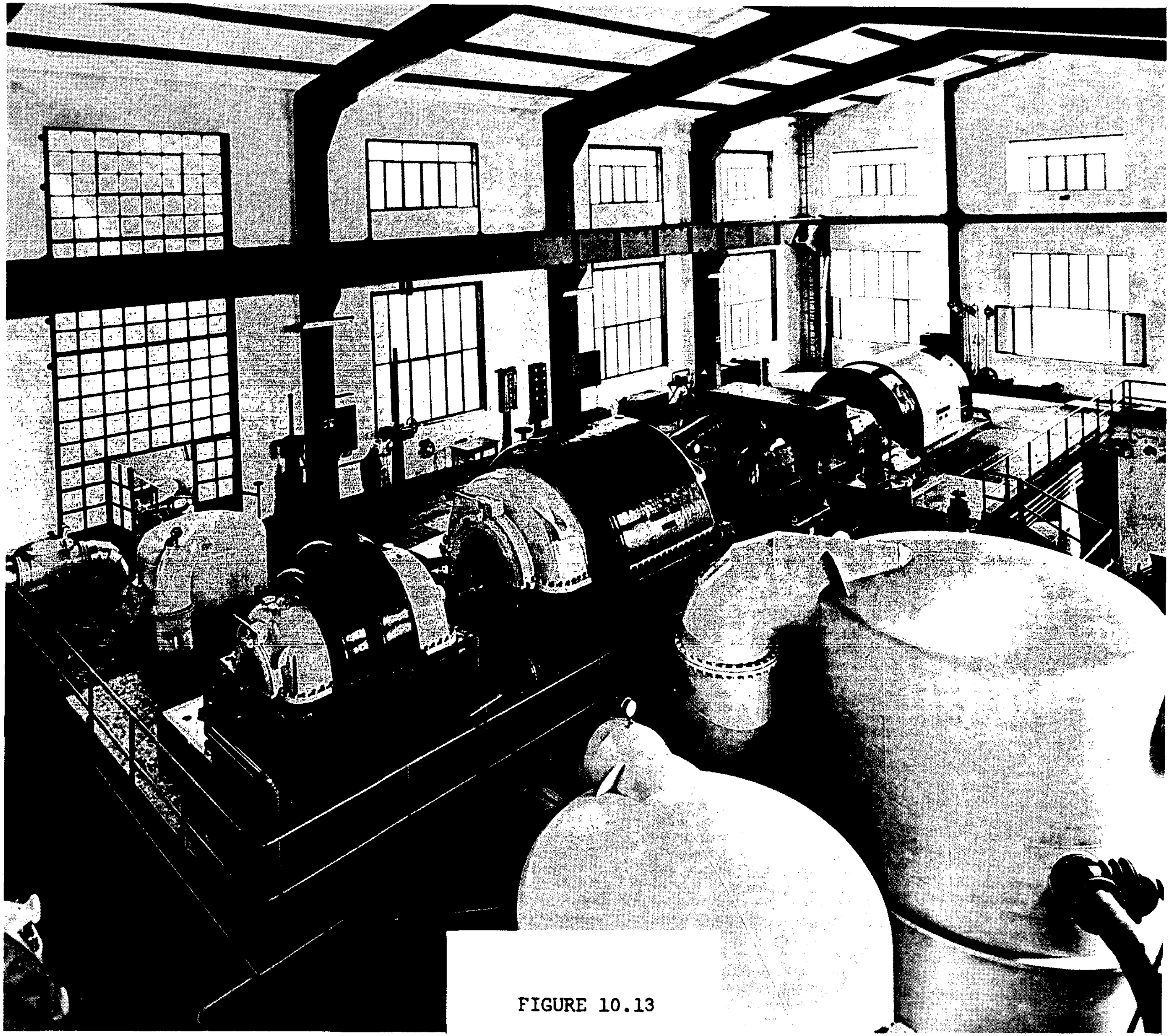
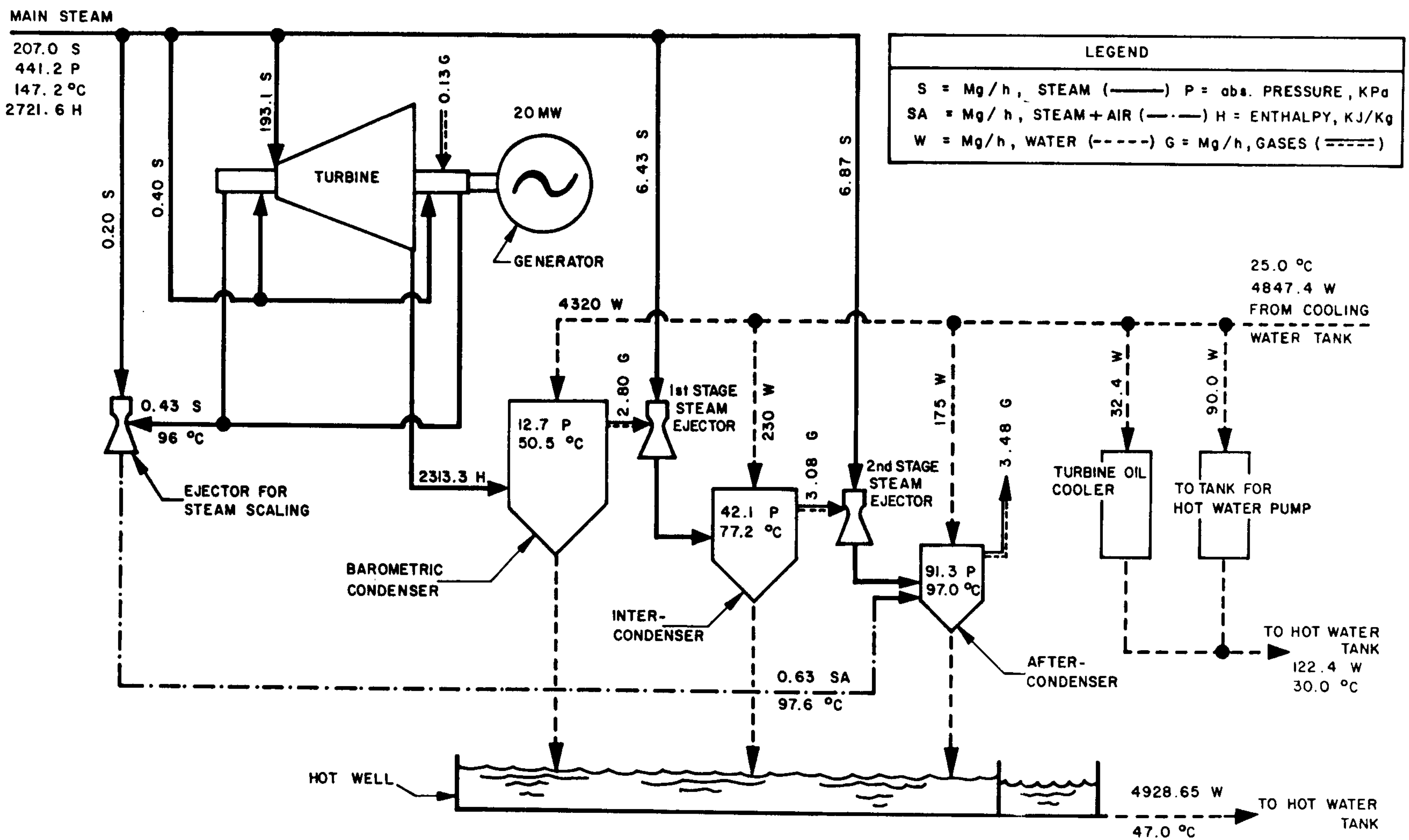


FIGURE 10.13



MAIN STEAM
207.0 S
441.2 P
147.2 °C
2721.6 H
0.20 S
0.40 S
193.1 S
0.13 G
TURBINE
20 MW
GENERATOR
6.43 S
6.87 S
LEGEND
S = Mg/h, STEAM P = abs. PRESSURE, KPa
SA = Mg/h, STEAM + AIR H = ENTHALPY, KJ/Kg
W = Mg/h, WATER G = Mg/h, GASES
4320 W
25.0 °C
4847.4 W
FROM COOLING
WATER TANK
0.43 S
96 °C
2.80 G
1st STAGE
STEAM
EJECTOR
230 W
175 W
3.48 G
32.4 W
90.0 W
12.7 P
50.5 °C
2313.3 H
3.08 G
2nd STAGE
STEAM
EJECTOR
42.1 P
77.2 °C
91.3 P
97.0 °C
TURBINE OIL
COOLER
TO TANK FOR
HOT WATER PUMP
EJECTOR FOR
STEAM SCALING
BAROMETRIC
CONDENSER
INTER-
CONDENSER
AFTER-
CONDENSER
TO HOT WATER
TANK
122.4 W
30.0 °C
0.63 SA
97.6 °C
HOT WELL
4928.65 W
47.0 °C
TO HOT WATER
TANK

FIGURE 10.14

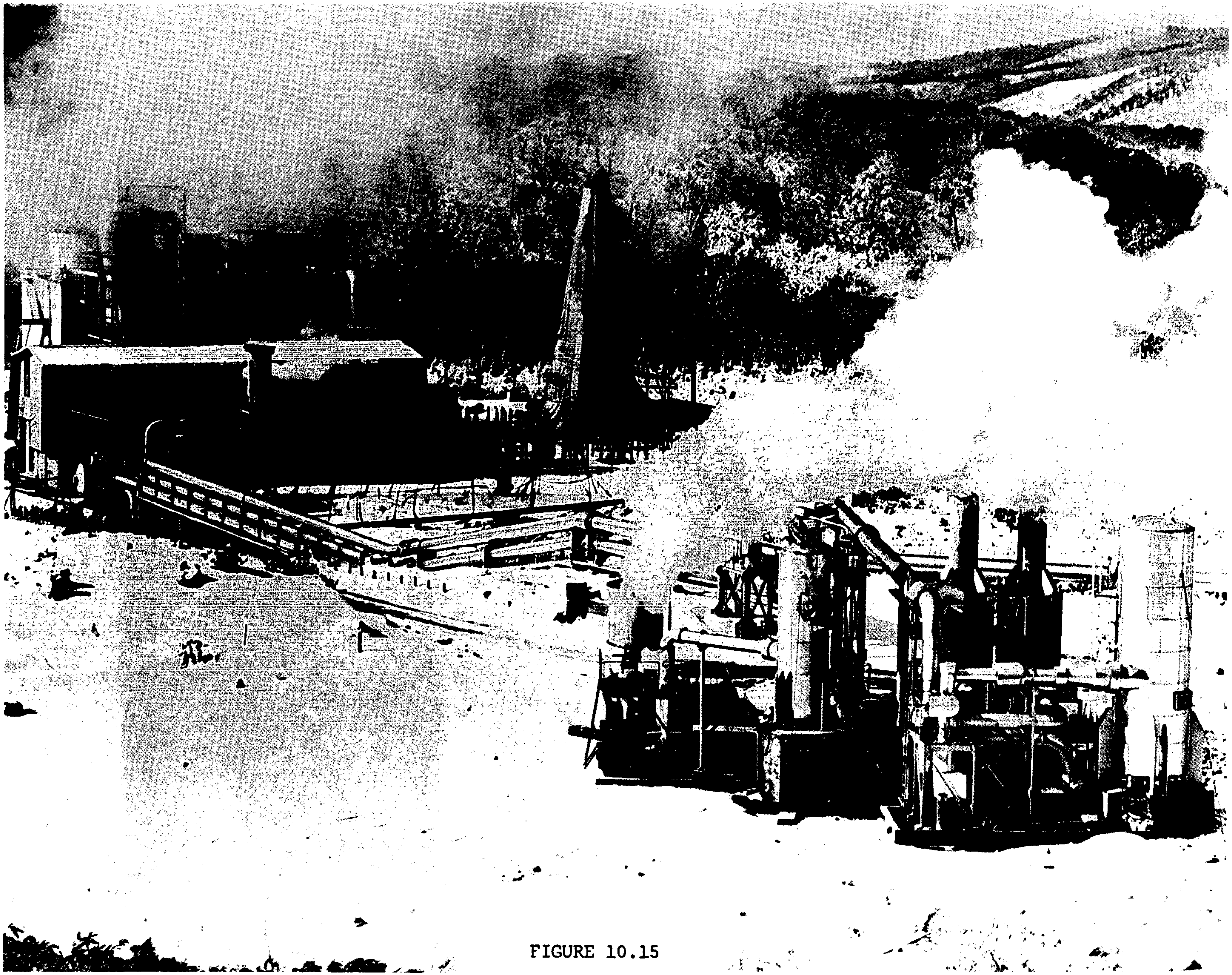


FIGURE 10.15

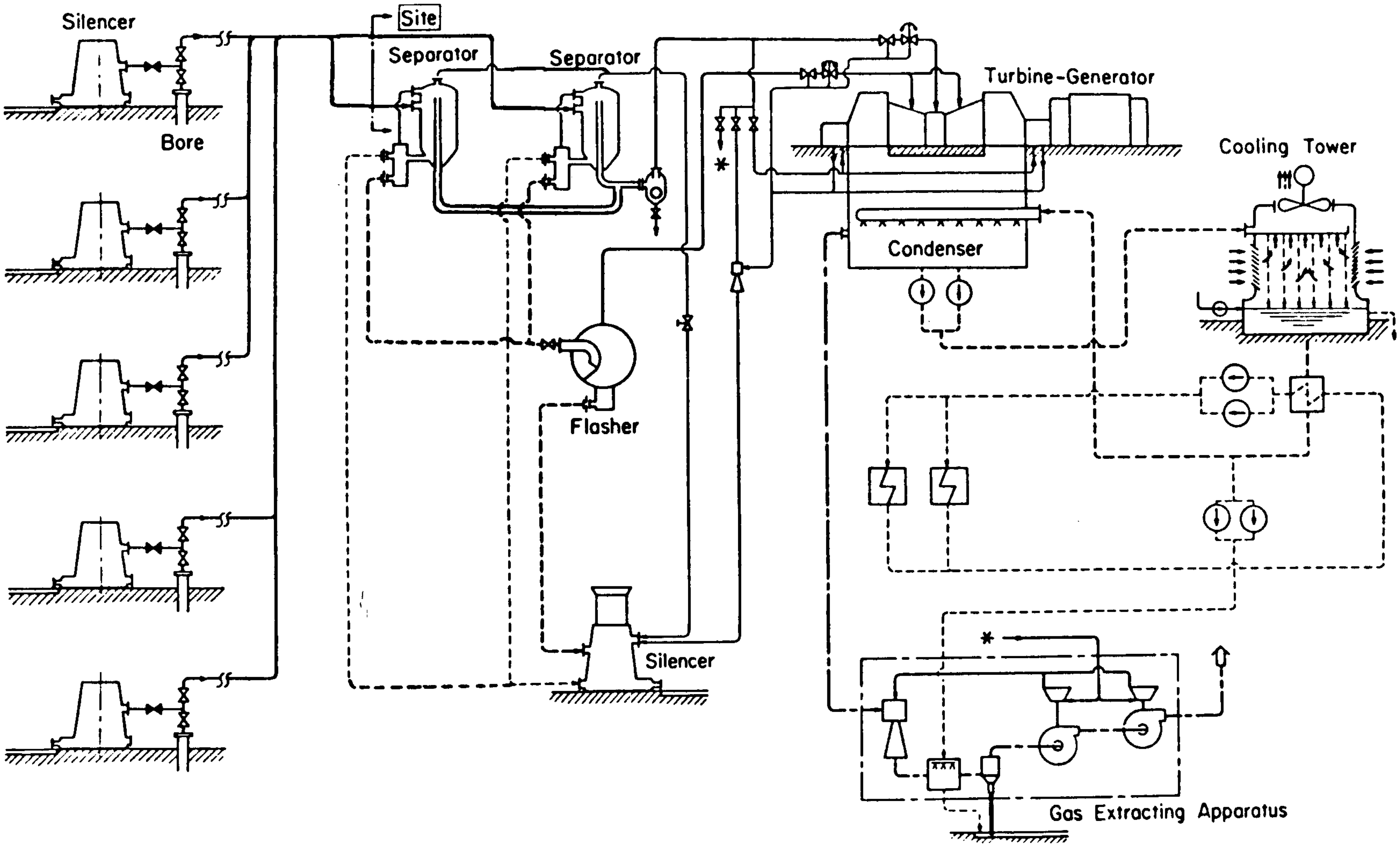

Silencer
Bore
Site
Separator
Separator
Turbine-Generator
Cooling Tower
Condenser
Flasher
Silencer
Gas Extracting Apparatus

FIGURE 10.16

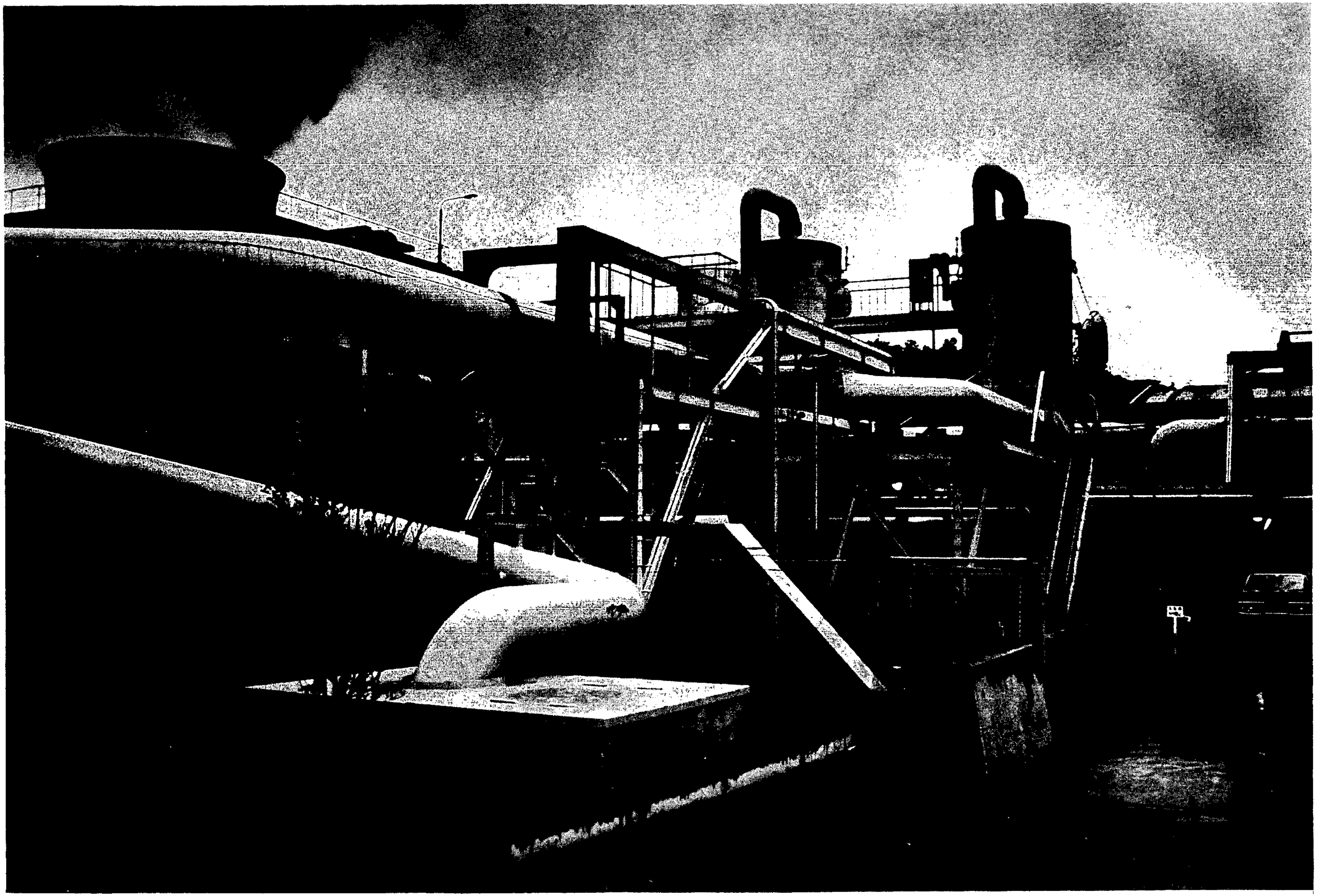


FIGURE 10.17

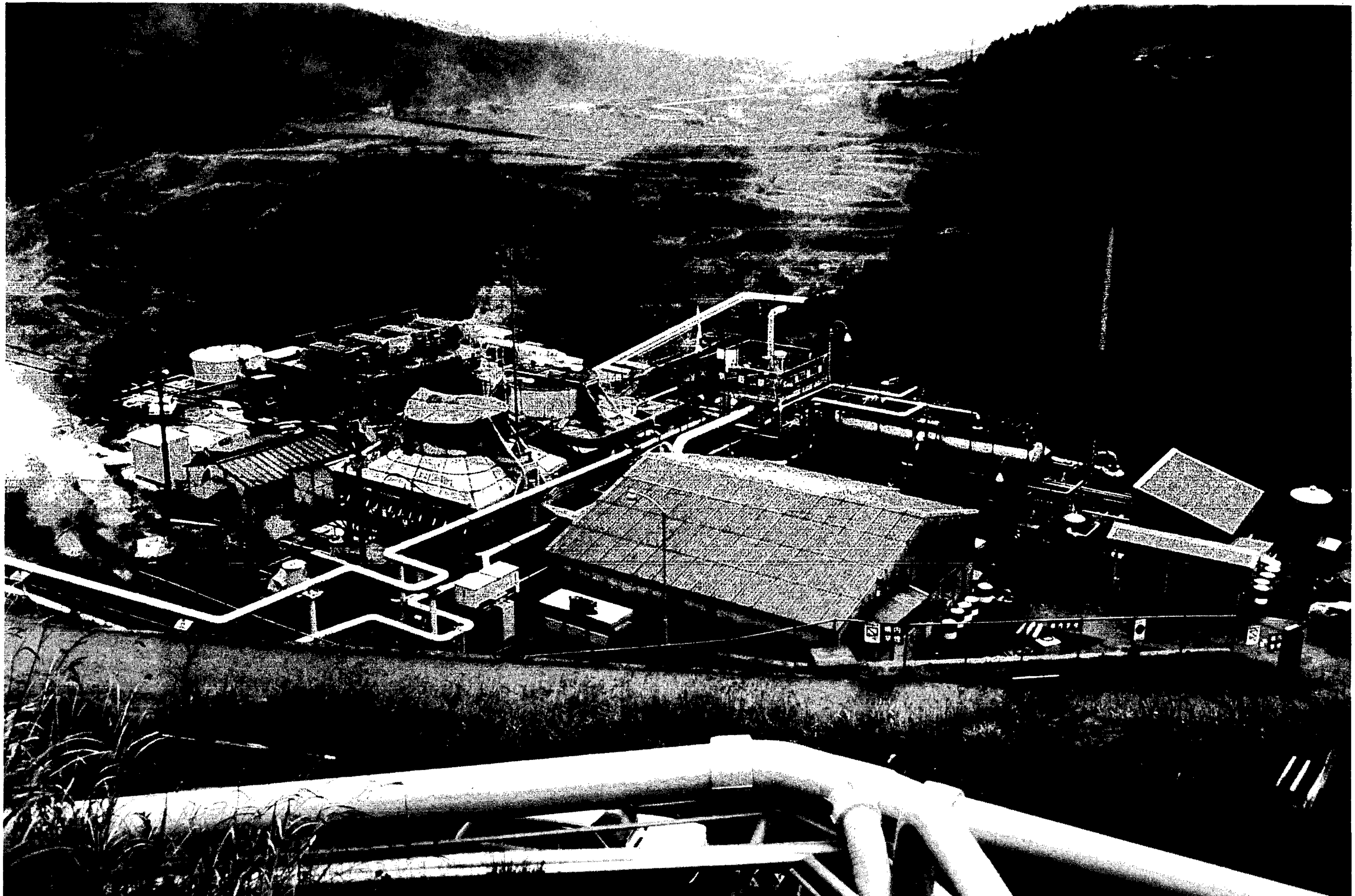


FIGURE 10.18

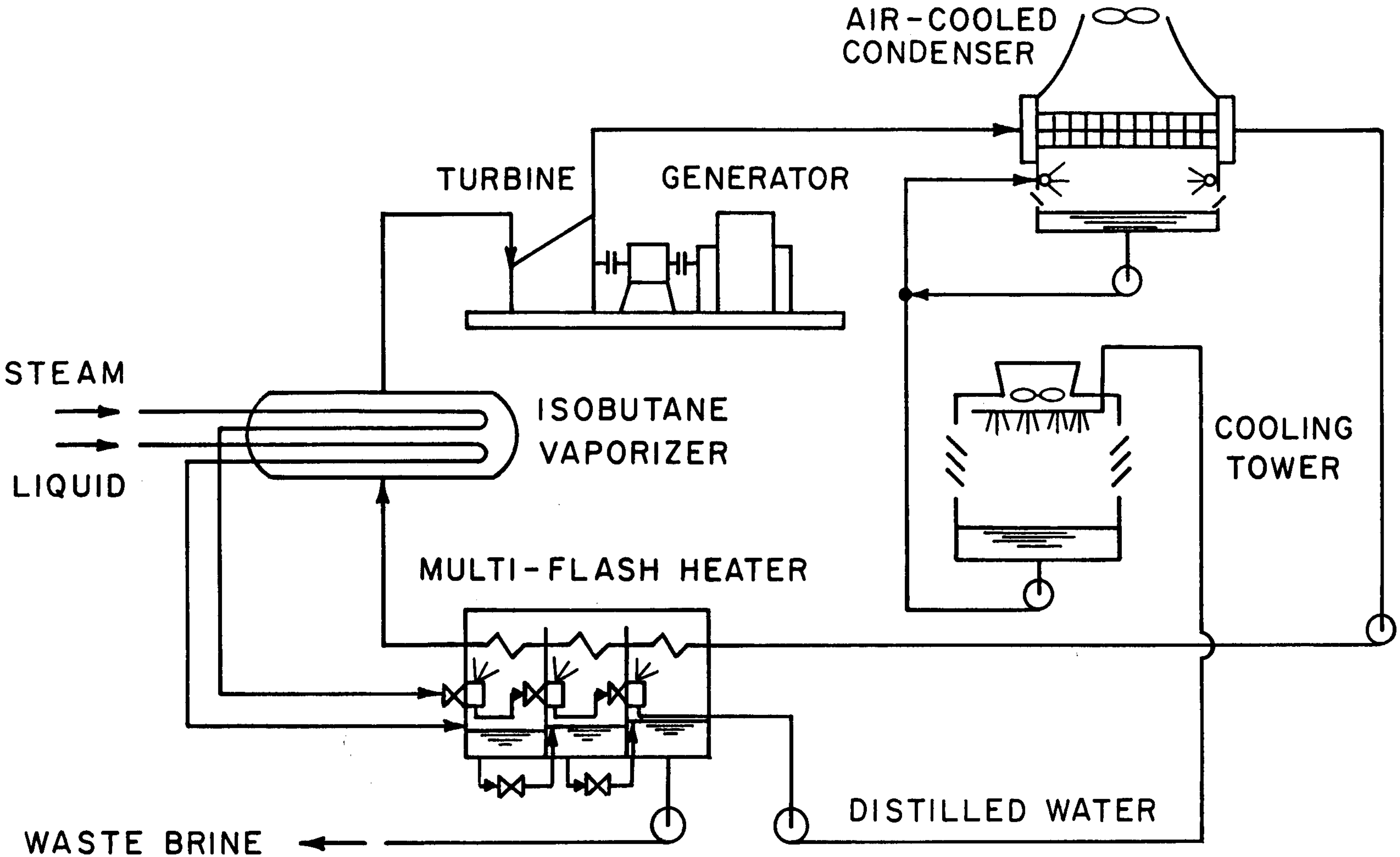

AIR-COOLED
CONDENSER
TURBINE
GENERATOR
STEAM
LIQUID
ISOBUTANE
VAPORIZER
COOLING
TOWER
MULTI-FLASH HEATER
DISTILLED WATER
WASTE BRINE

FIGURE 10.19

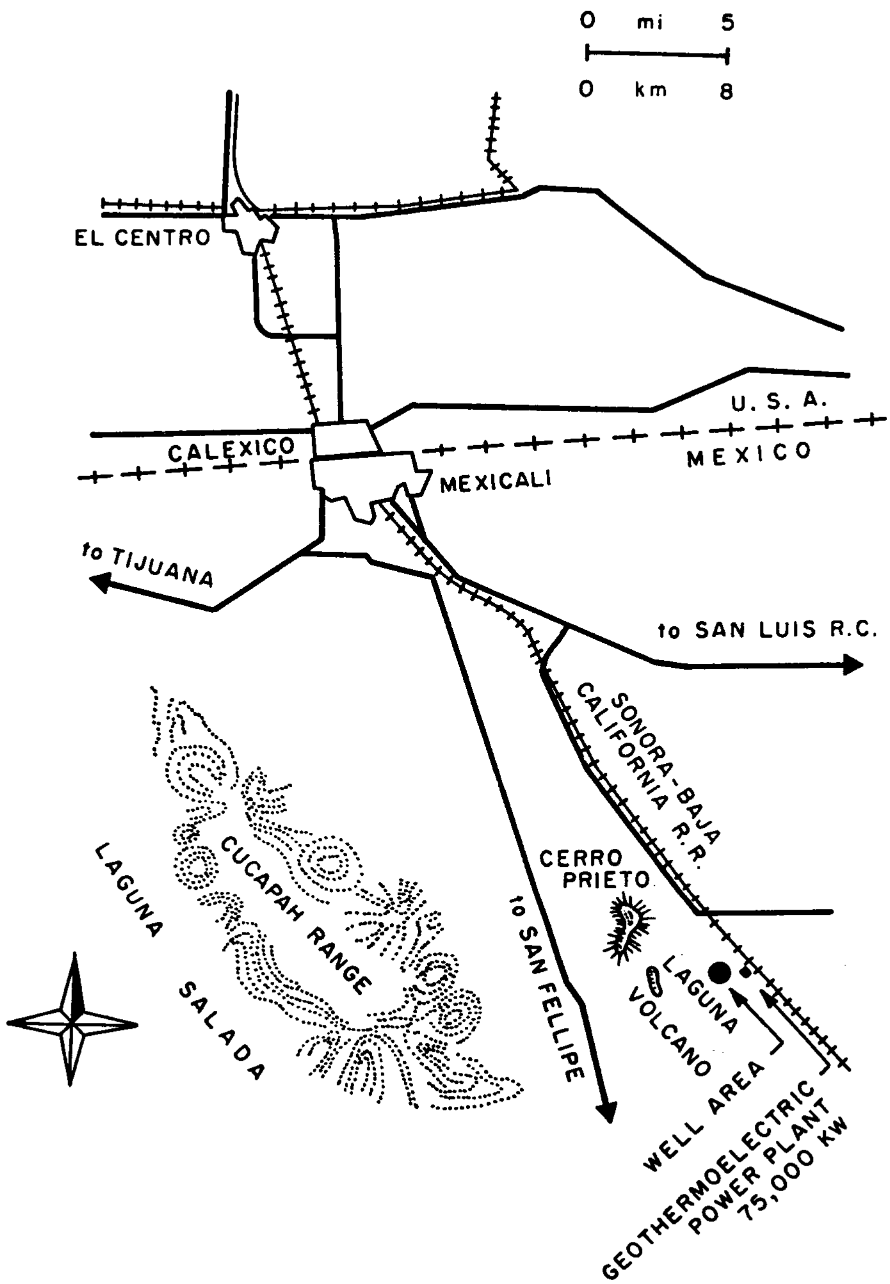

0 mi 5
0 km 8
EL CENTRO
U.S.A.
CALEXICO
MEXICO
MEXICALI
to TIJUANA
to SAN LUIS R.C.
SONORA-BAJA CALIFORNIA R.R.
CUCAPAH RANGE
LAGUNA SALADA
CERRO PRIETO
to SAN FELLIPE
LAGUNA VOLCANO
WELL AREA
GEOTHERMOELECTRIC POWER PLANT 75,000 KW

FIGURE 10.20

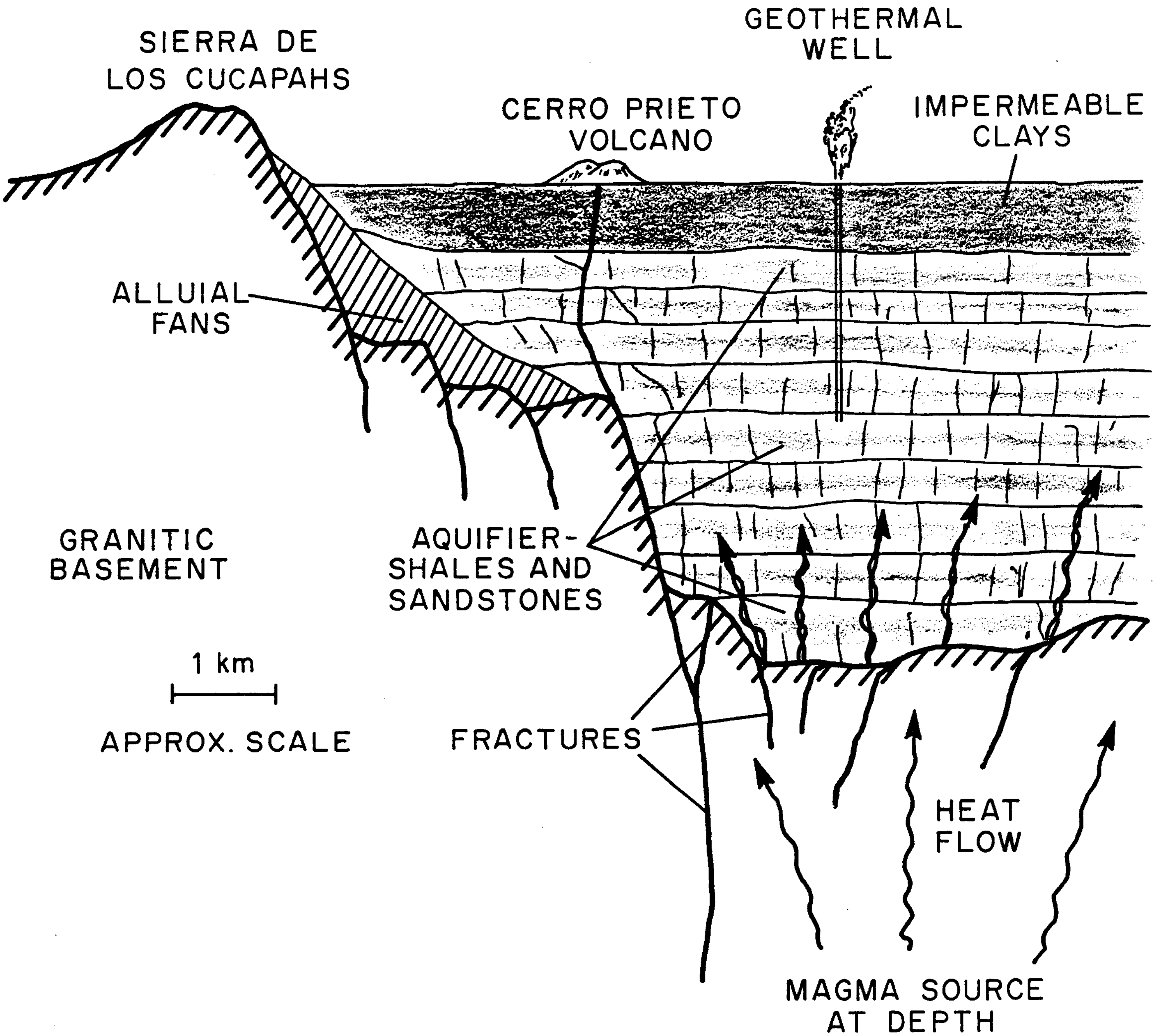

SIERRA DE
LOS CUCAPAHS
CERRO PRIETO
VOLCANO
GEOTHERMAL
WELL
IMPERMEABLE
CLAYS
ALLUIAL
FANS
GRANITIC
BASEMENT
AQUIFIER-
SHALES AND
SANDSTONES
1 km
APPROX. SCALE
FRACTURES
HEAT
FLOW
MAGMA SOURCE
AT DEPTH

FIGURE 10.21

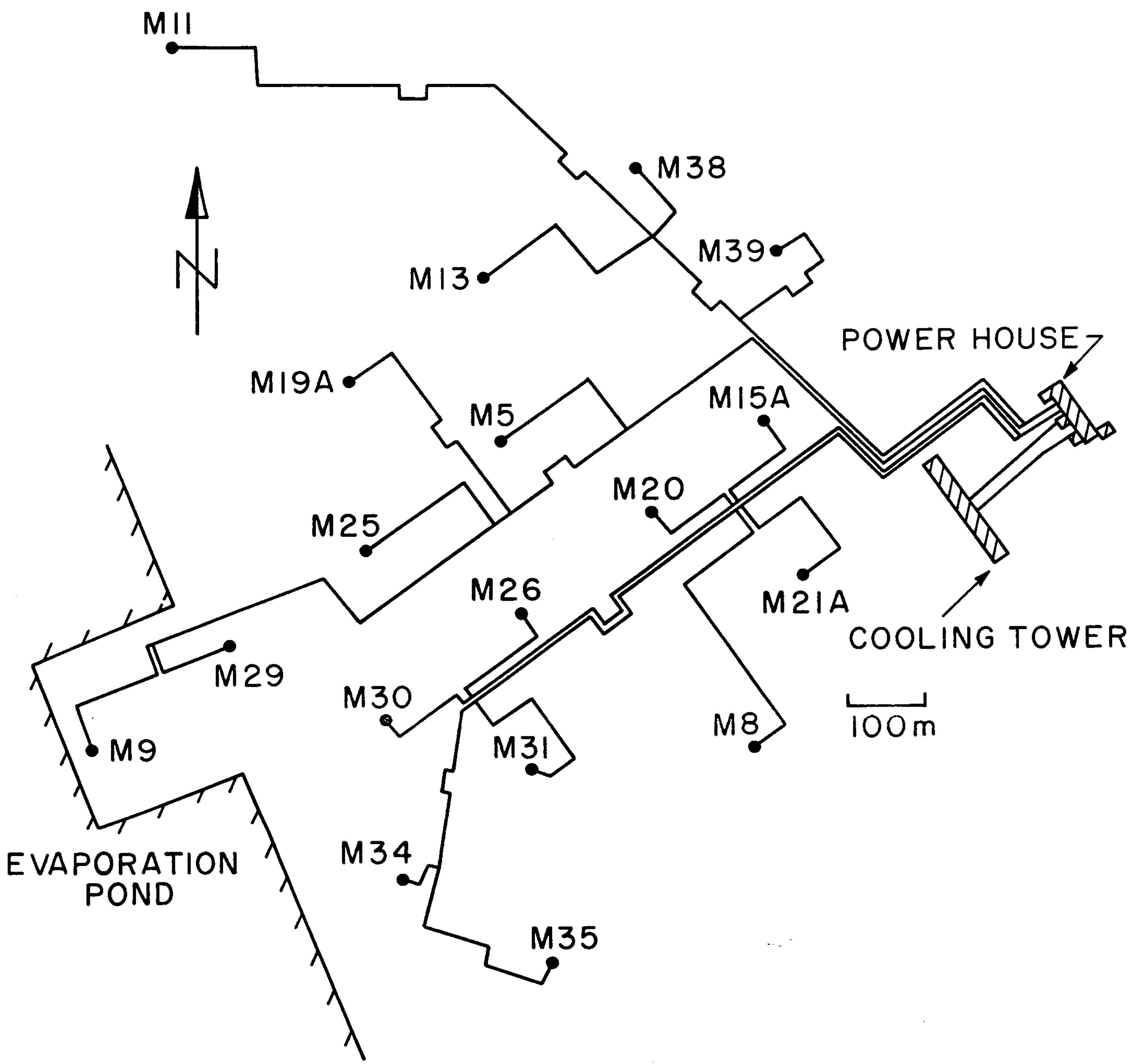

M11
M38
M13
M39
N
POWER HOUSE
M19A
M5
M15A
M20
M25
M21A
M26
COOLING TOWER
M29
M30
M9
M31
M8
100m
M34
EVAPORATION
POND
M35

FIGURE 10.22

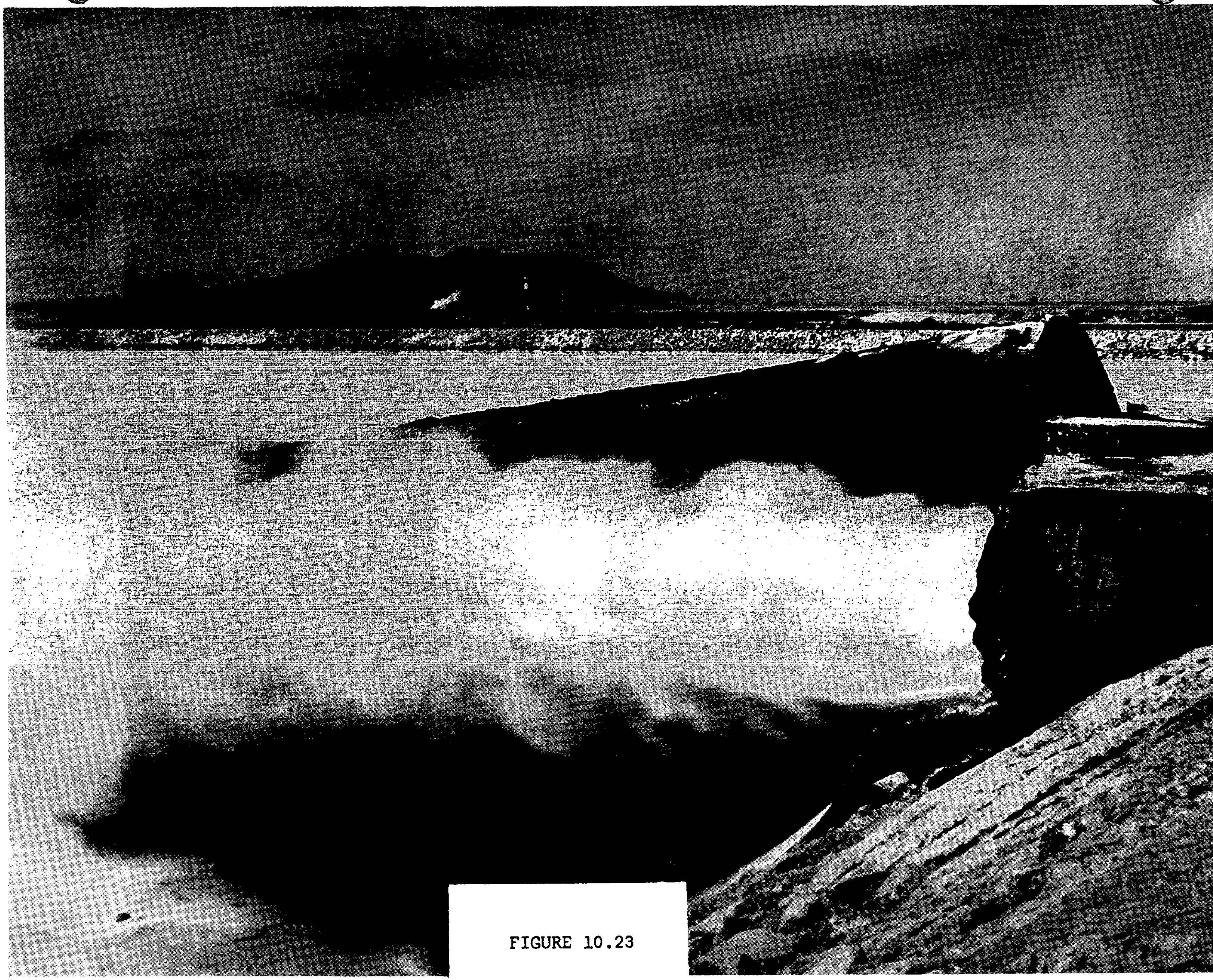


FIGURE 10.23

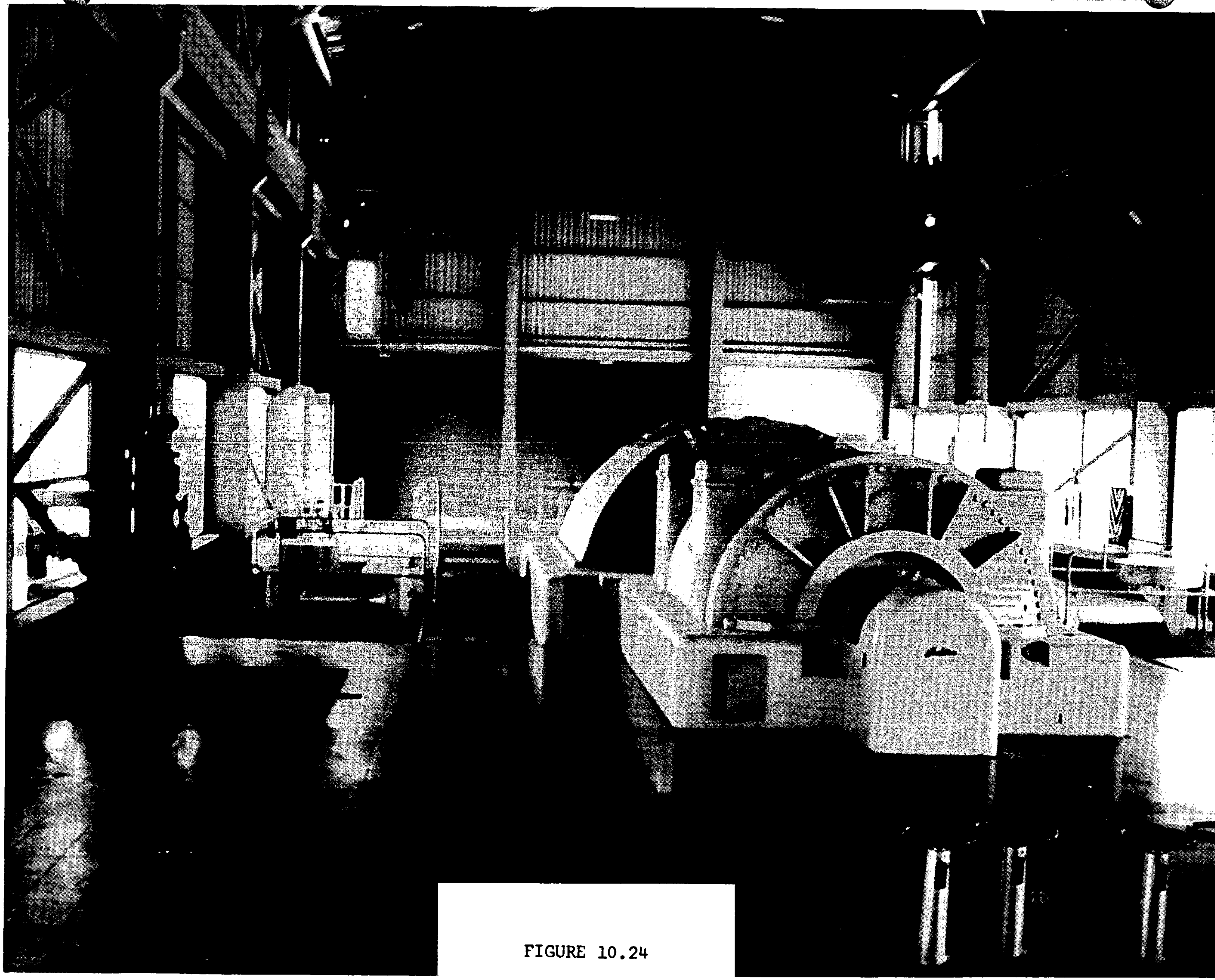


FIGURE 10.24

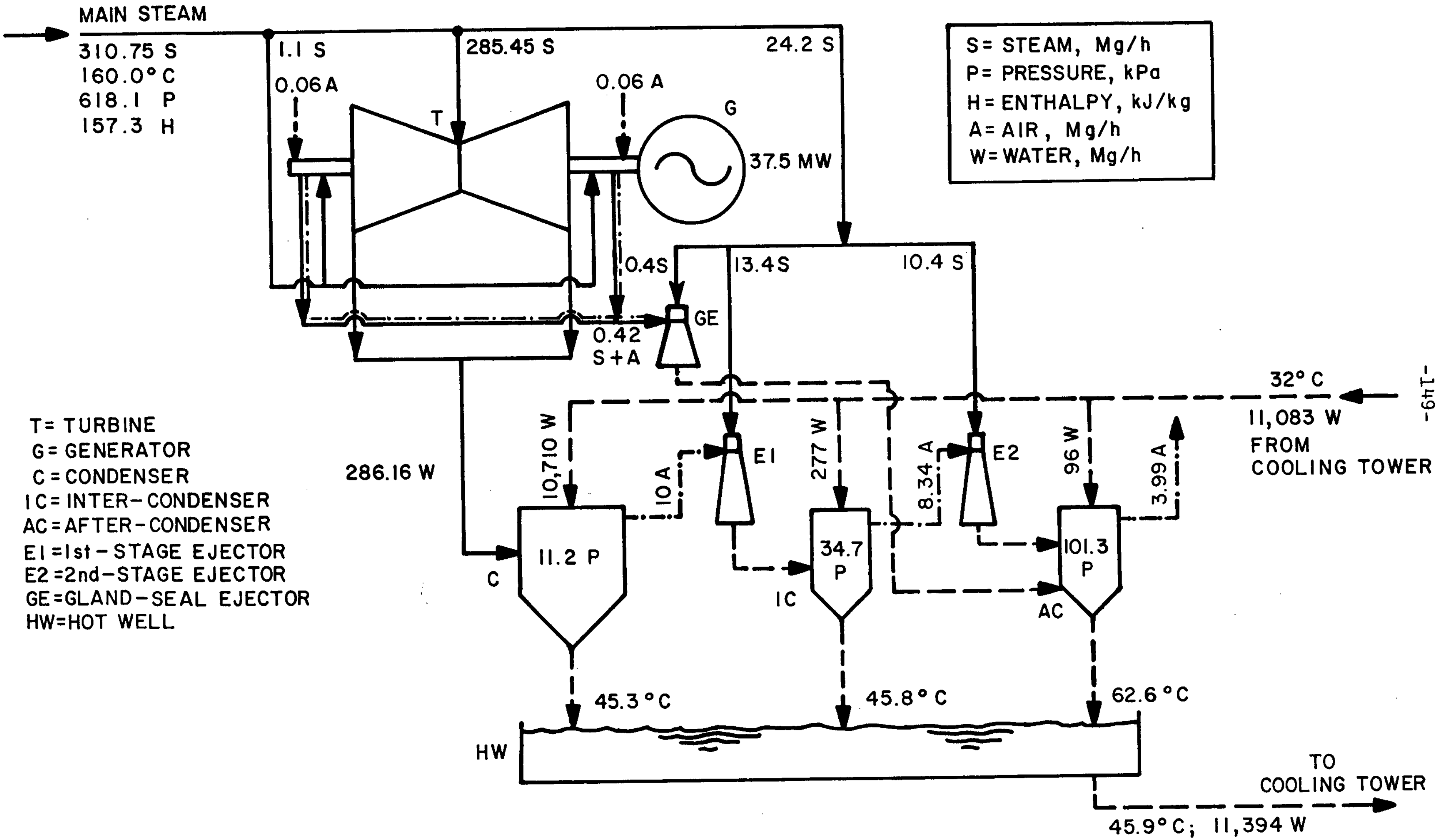

MAIN STEAM
310.75 S
160.0° C
618.1 P
157.3 H
1.1 S
285.45 S
24.2 S
0.06 A
0.06 A
T
G
37.5 MW
S= STEAM, Mg/h
P= PRESSURE, kPa
H= ENTHALPY, kJ/kg
A= AIR, Mg/h
W= WATER, Mg/h
0.4S
13.4S
10.4 S
GE
0.42
S+A
32° C
11,083 W
FROM
COOLING TOWER
T= TURBINE
G= GENERATOR
C= CONDENSER
IC= INTER-CONDENSER
AC= AFTER-CONDENSER
E1 =1st-STAGE EJECTOR
E2 =2nd-STAGE EJECTOR
GE=GLAND-SEAL EJECTOR
HW=HOT WELL
286.16 W
10,710 W
10 A
E1
277 W
8.34 A
E2
96 W
3.99 A
11.2 P
34.7
P
101.3
P
C
IC
AC
45.3 °C
45.8° C
62.6 °C
HW
TO
COOLING TOWER
45.9° C; 11,394 W

FIGURE 10.25

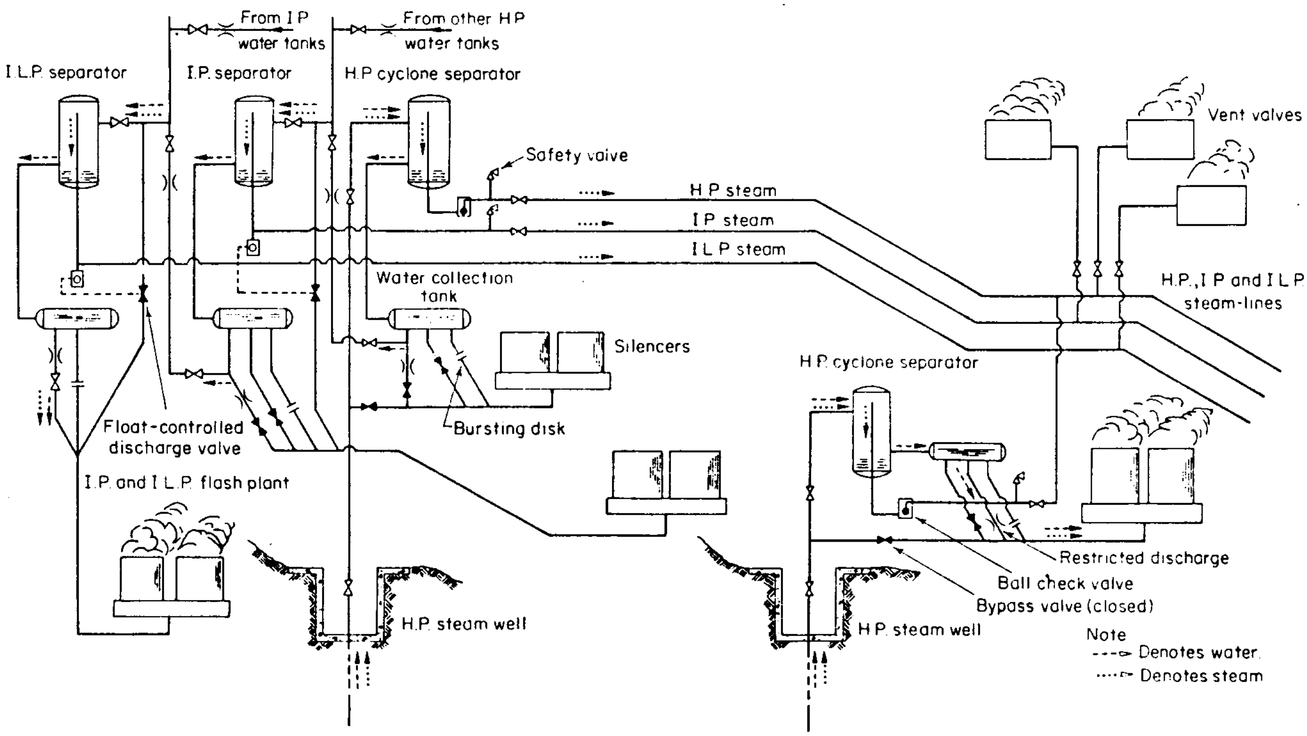

From I P
water tanks
From other H P
water tanks
I L.P. separator
I.P. separator
H.P cyclone separator
Safety valve
H P steam
I P steam
I L P steam
Vent valves
H.P., I P and I L P
steam-lines
Water collection
tank
Silencers
H P cyclone separator
Float-controlled
discharge valve
Bursting disk
I.P. and I L.P. flash plant
H.P. steam well
H P. steam well
Restricted discharge
Ball check valve
Bypass valve (closed)
Note
Denotes water
Denotes steam

FIGURE 10.26

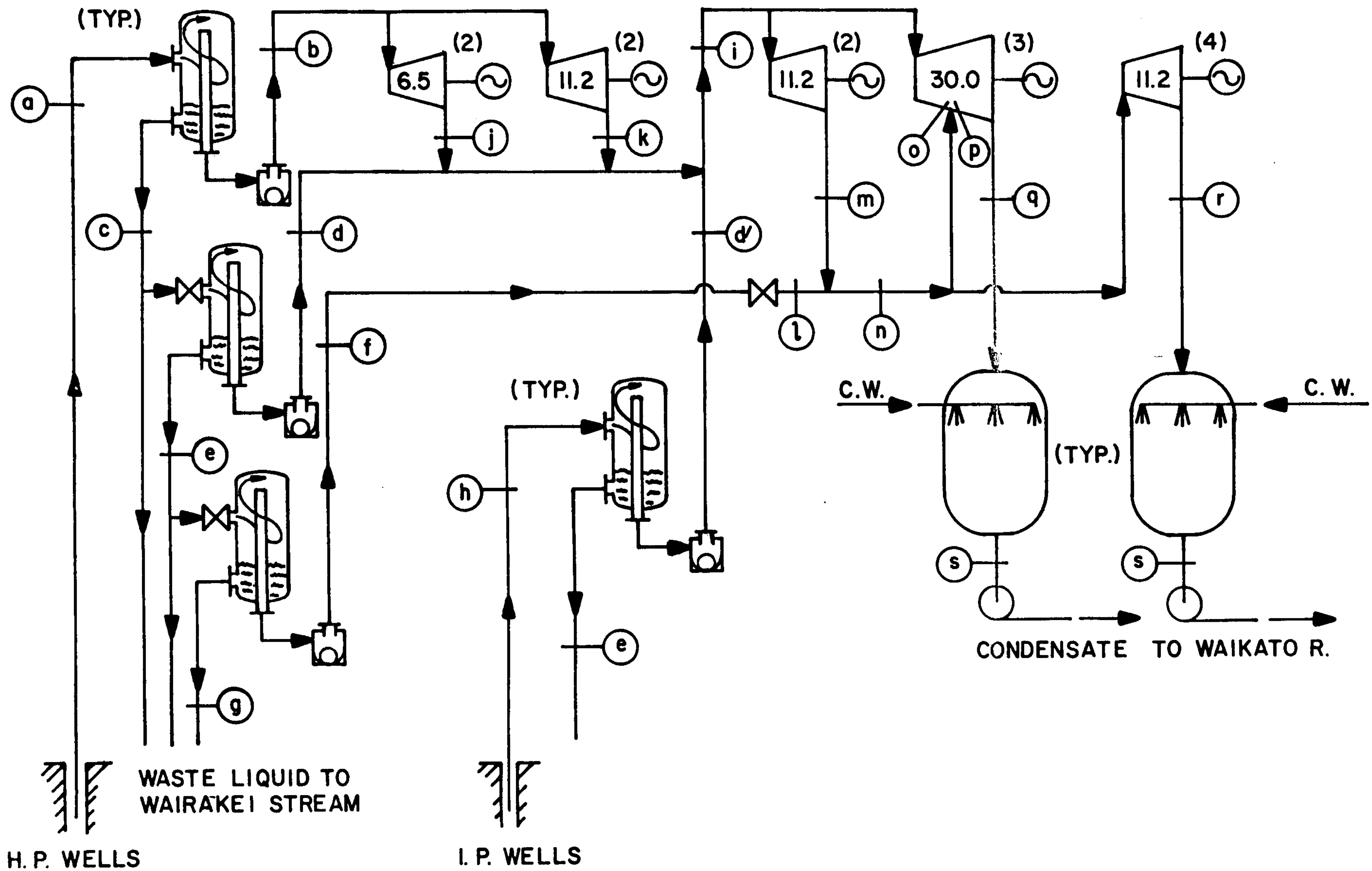

(TYP.)
a
b
c
d
e
f
g
h
i
j
k
l
m
n
o
p
q
r
s
s
d'
e
(2)
6.5
(2)
11.2
(2)
11.2
(3)
30.0
(4)
11.2
(TYP.)
C.W.
C. W.
(TYP.)
CONDENSATE TO WAIKATO R.
WASTE LIQUID TO
WAIRAKEI STREAM
H. P. WELLS
I. P. WELLS

FIGURE 10.27

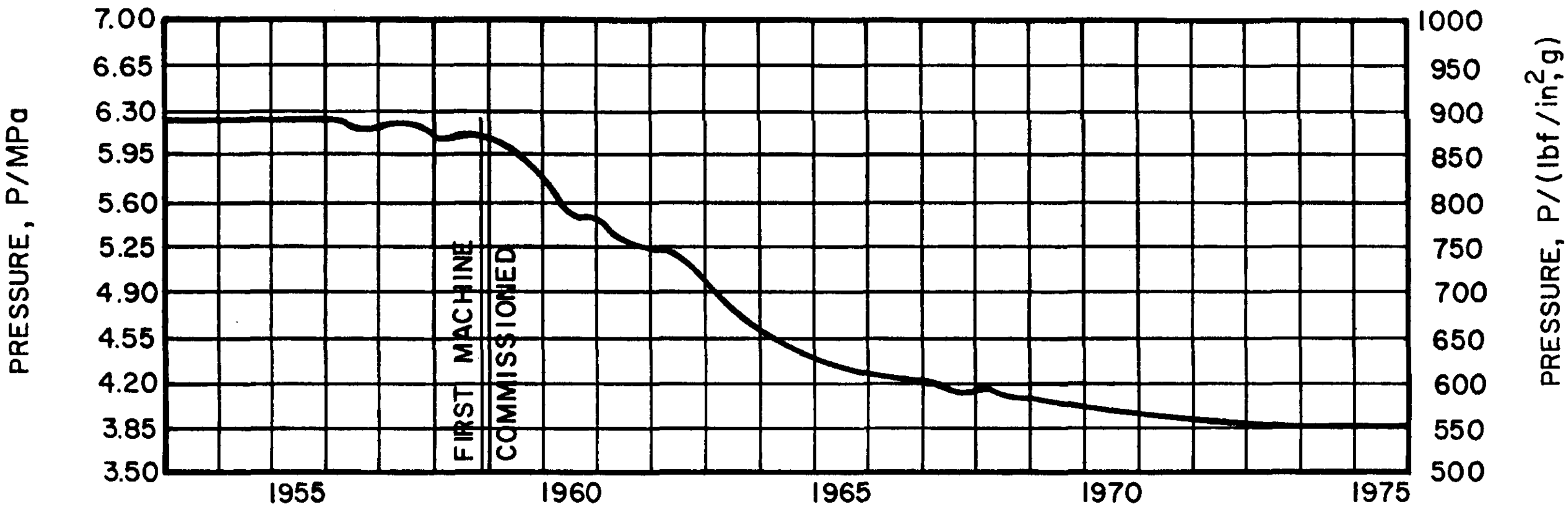

PRESSURE, P/MPa
7.00
6.65
6.30
5.95
5.60
5.25
4.90
4.55
4.20
3.85
3.50
1955
1960
1965
1970
1975
FIRST MACHINE
COMMISSIONED
1000
950
900
850
800
750
700
650
600
550
500
PRESSURE, P/(lbf/in², g)

FIGURE 10.28

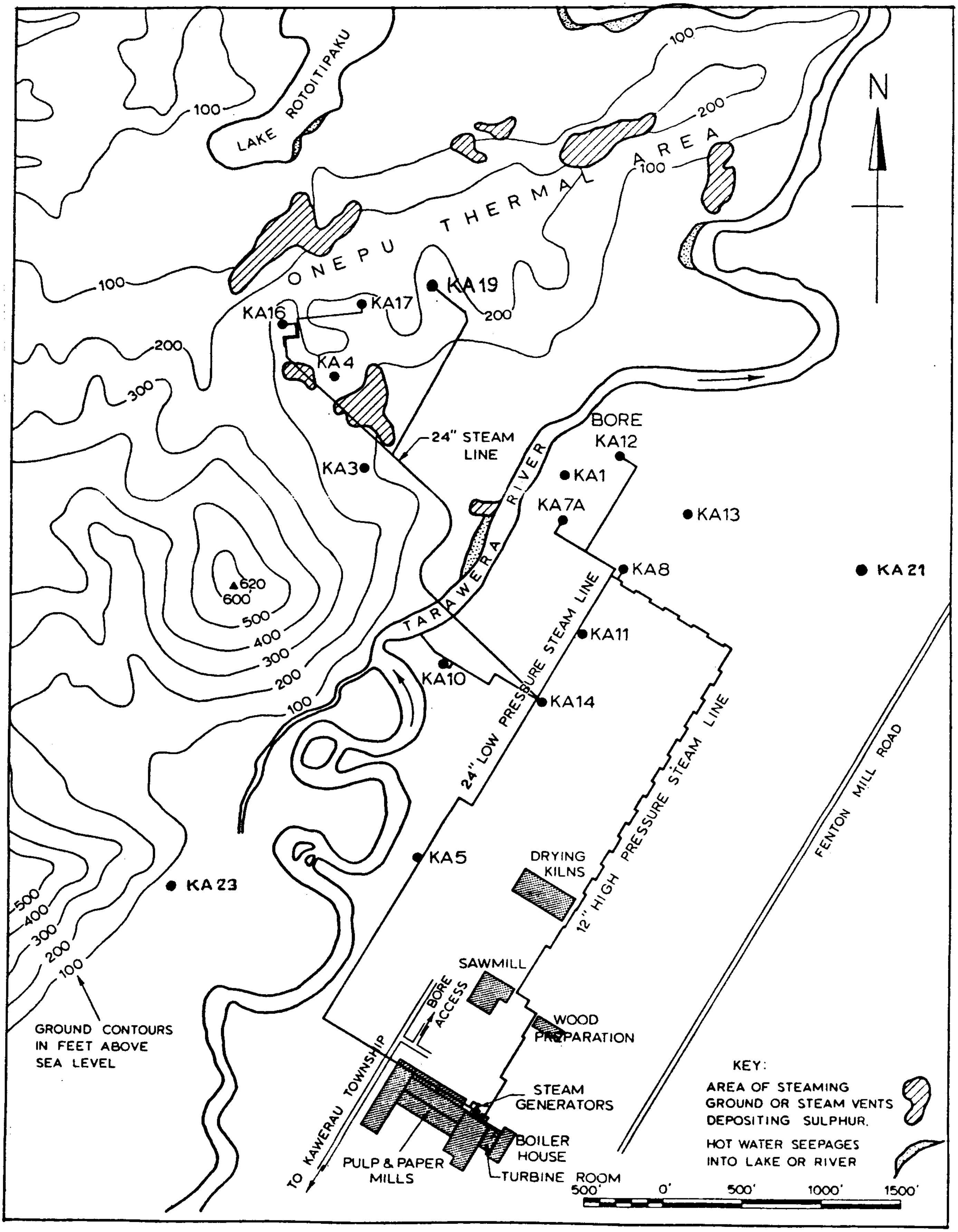

LAKE ROTOITIPAKU
ONEPU THERMAL AREA
N
100
200
300
400
500
600
620
KA16
KA17
KA19
KA4
KA3
24" STEAM LINE
BORE KA12
KA1
KA7A
KA13
KA8
KA21
KA11
KA10
KA14
TARAWERA RIVER
24" LOW PRESSURE STEAM LINE
12" HIGH PRESSURE STEAM LINE
FENTON MILL ROAD
KA5
KA23
DRYING KILNS
SAWMILL
BORE ACCESS
WOOD PREPARATION
STEAM GENERATORS
BOILER HOUSE
TURBINE ROOM
PULP & PAPER MILLS
TO KAWERAU TOWNSHIP
GROUND CONTOURS IN FEET ABOVE SEA LEVEL
KEY:
AREA OF STEAMING GROUND OR STEAM VENTS DEPOSITING SULPHUR.
HOT WATER SEEPAGES INTO LAKE OR RIVER
500'
0'
500'
1000'
1500'

FIGURE 10.29

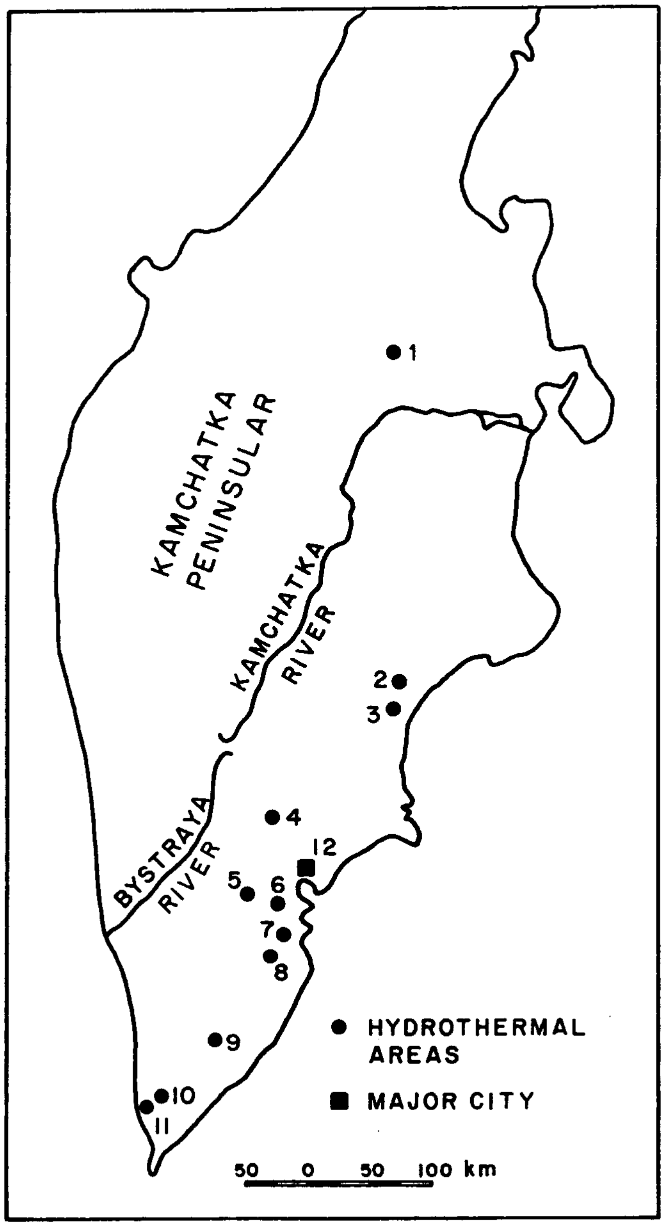

KAMCHATKA PENINSULAR
KAMCHATKA RIVER
BYSTRAYA RIVER
1
2
3
4
5
6
7
8
9
10
11
12
HYDROTHERMAL AREAS
MAJOR CITY
50 0 50 100 km

FIGURE 10.30

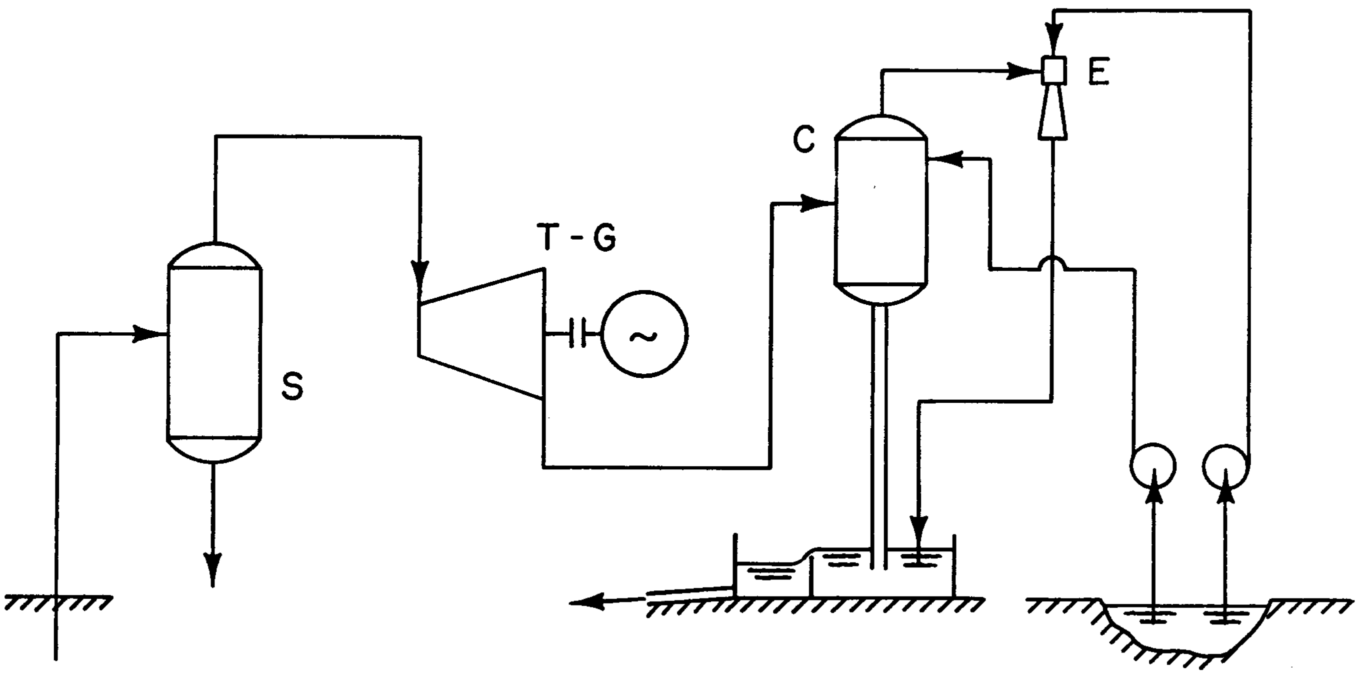


FIGURE 10.31

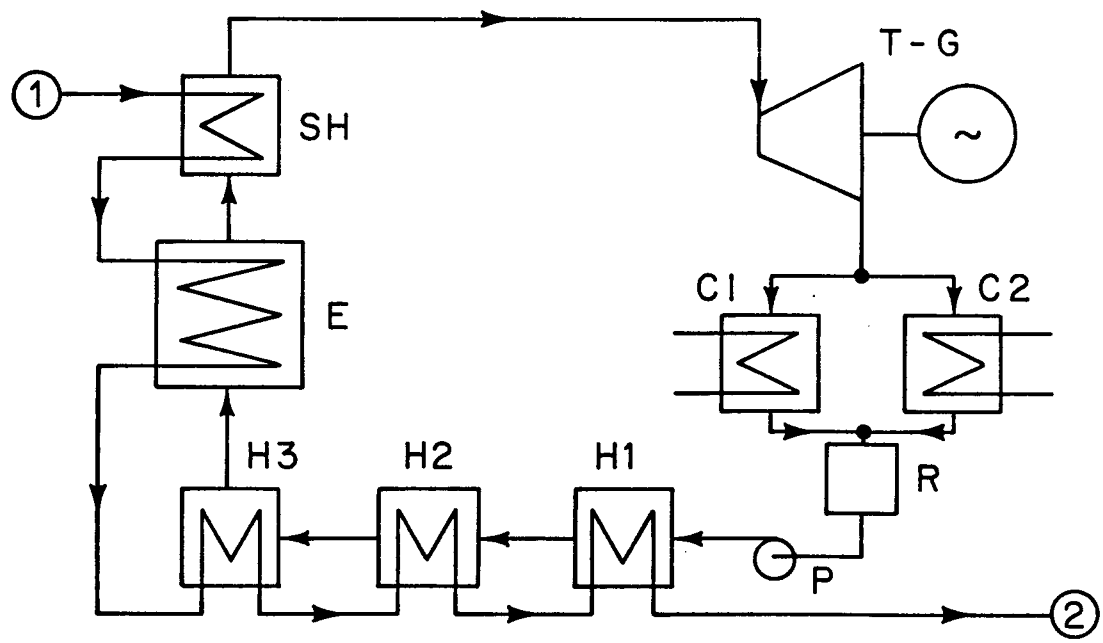


FIGURE 10.32

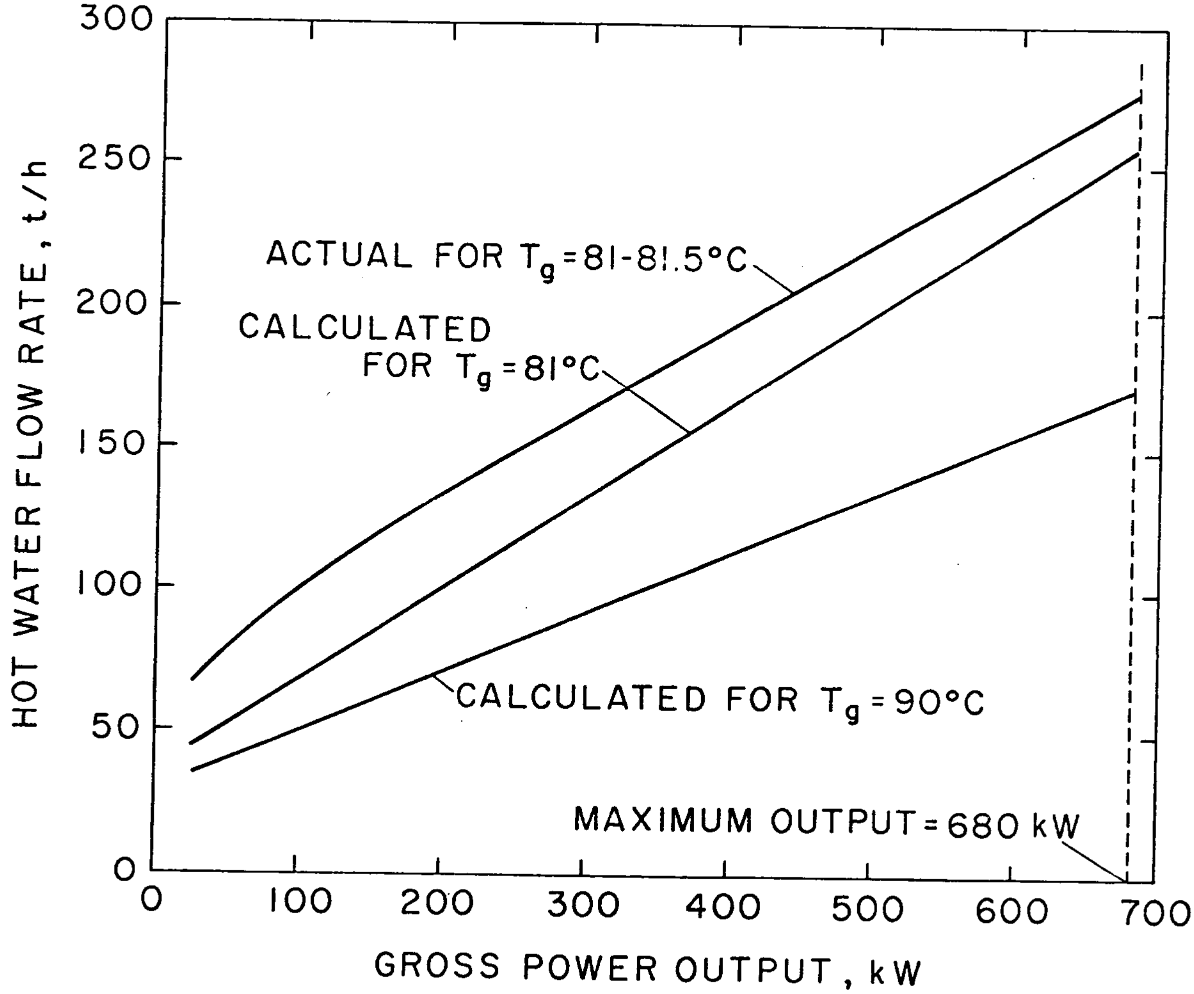

300
250
200
150
100
50
0
0
100
200
300
400
500
600
700
HOT WATER FLOW RATE, t/h
GROSS POWER OUTPUT, kW
ACTUAL FOR Tg = 81-81.5°C
CALCULATED FOR Tg = 81°C
CALCULATED FOR Tg = 90°C
MAXIMUM OUTPUT = 680 kW

FIGURE 10.33

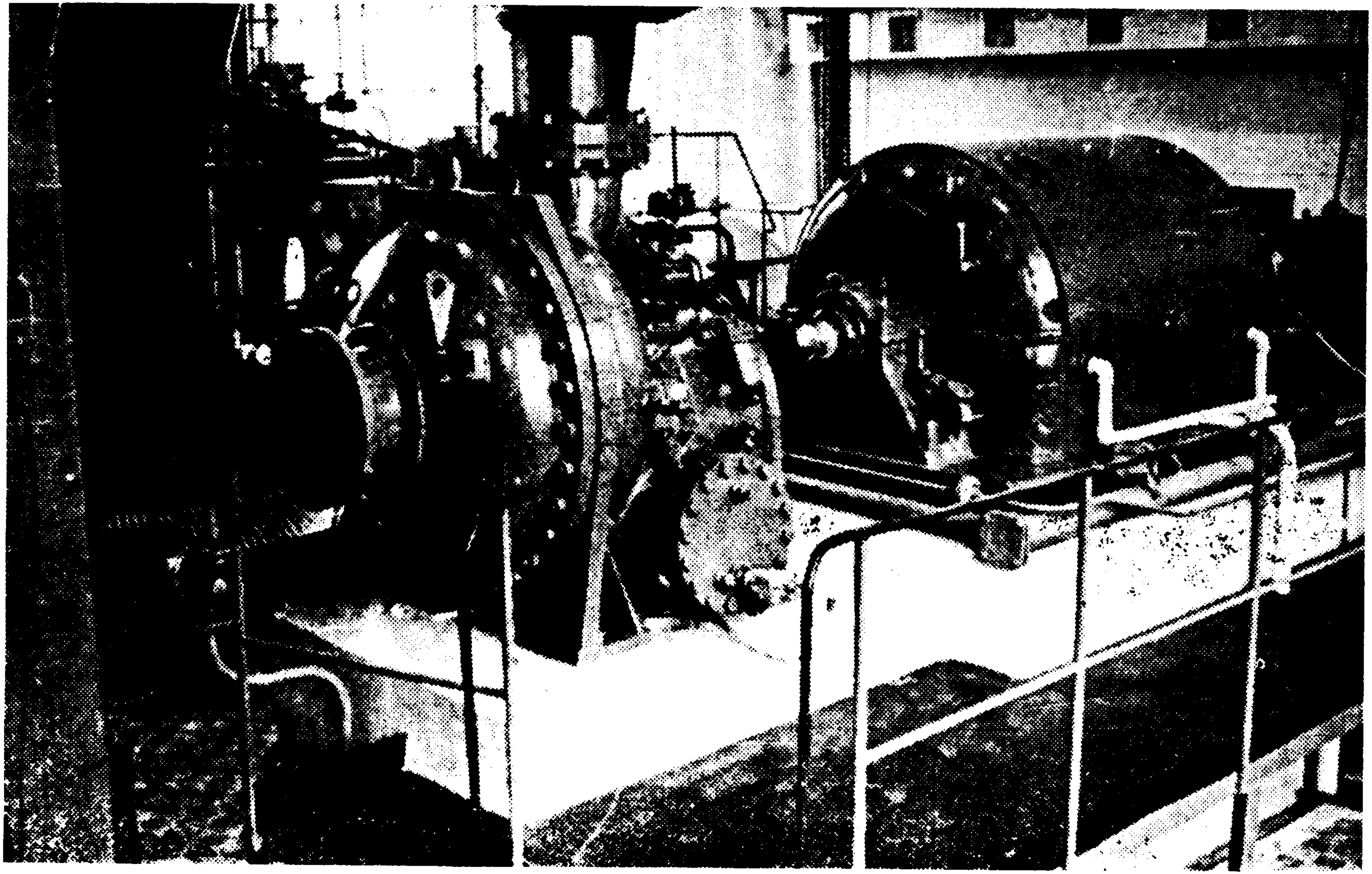


FIGURE 10.34

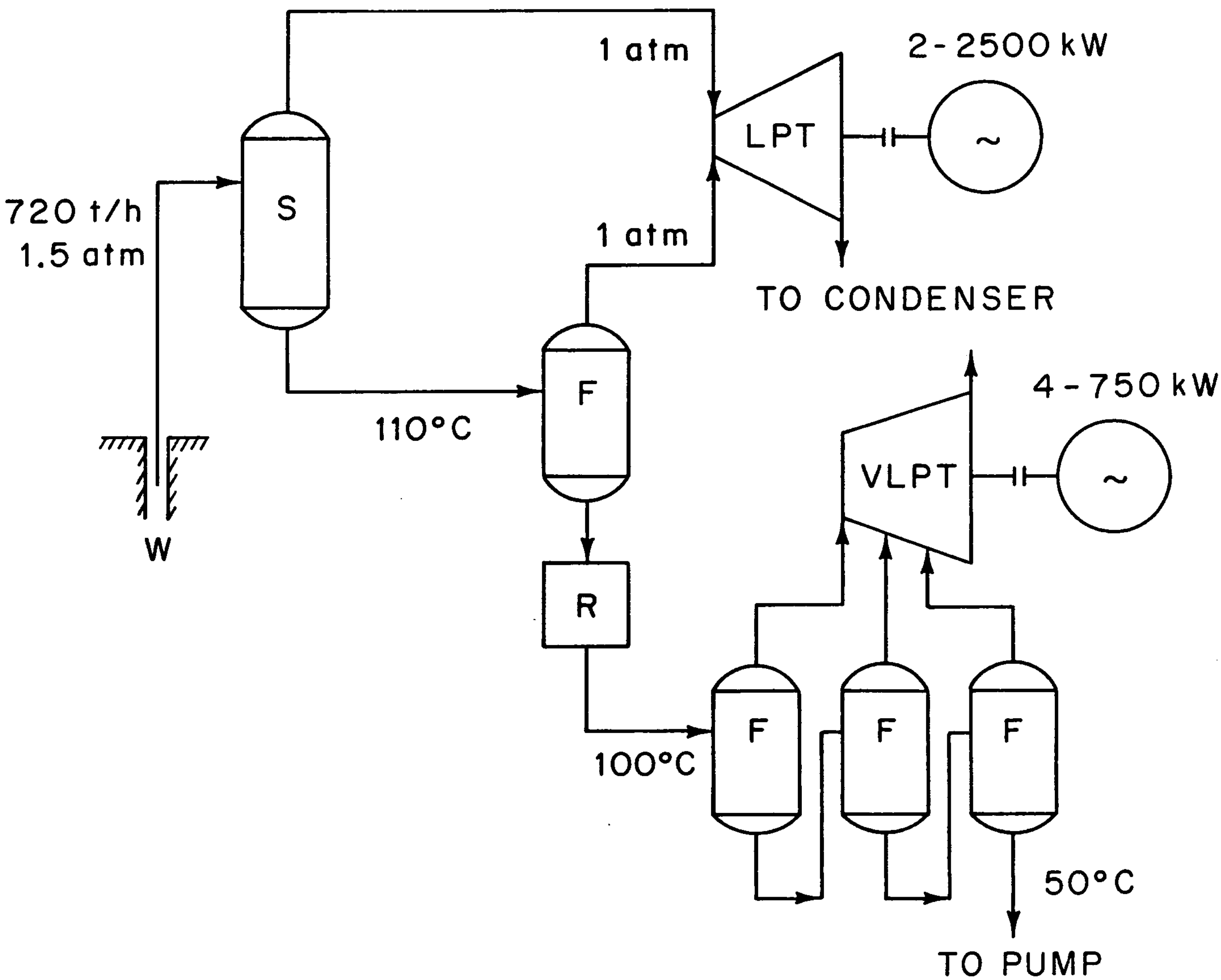

1 atm
2-2500 kW
LPT
~
720 t/h
1.5 atm
S
1 atm
TO CONDENSER
F
110°C
4-750 kW
VLPT
~
W
R
F
F
F
100°C
50°C
TO PUMP

FIGURE 10.35

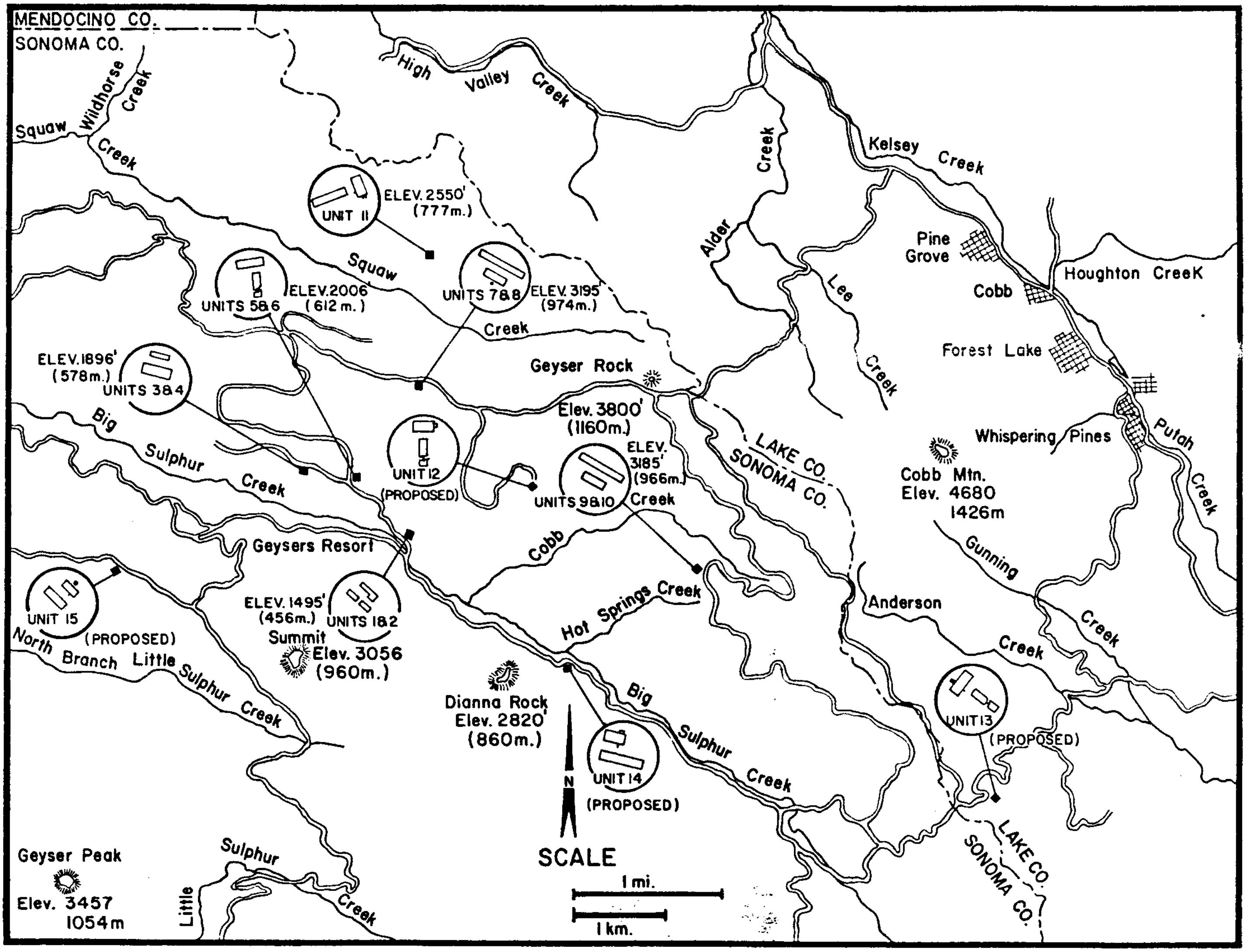

MENDOCINO CO.
SONOMA CO.
Squaw
Wildhorse Creek
Creek
High Valley Creek
Creek
Kelsey Creek
UNIT 11
ELEV. 2550' (777m.)
Pine Grove
Houghton CreeK
Cobb
Alder
Lee
Creek
Squaw
UNITS 5&6
ELEV. 2006 (612 m.)
UNITS 7&8
ELEV. 3195' (974m.)
Creek
Forest Lake
ELEV. 1896' (578m.)
UNITS 3&4
Geyser Rock
Big
Sulphur
Creek
Elev. 3800' (1160m.)
LAKE CO.
SONOMA CO.
Whispering Pines
Putah
Creek
UNIT 12
(PROPOSED)
UNITS 9&10
ELEV. 3185' (966m.)
Creek
Cobb Mtn.
Elev. 4680
1426m
Gunning
Geysers Resort
Cobb
Hot Springs Creek
Anderson
Creek
Creek
UNIT 15
(PROPOSED)
ELEV. 1495' (456m.)
UNITS 1&2
Summit
Elev. 3056 (960m.)
North Branch Little Sulphur Creek
Dianna Rock
Elev. 2820' (860m.)
Big
Sulphur
Creek
UNIT 13
(PROPOSED)
N
UNIT 14
(PROPOSED)
Geyser Peak
Elev. 3457
1054m
Sulphur
Creek
Little
SCALE
1 mi.
1 km.
LAKE CO.
SONOMA CO.

FIGURE 10.36

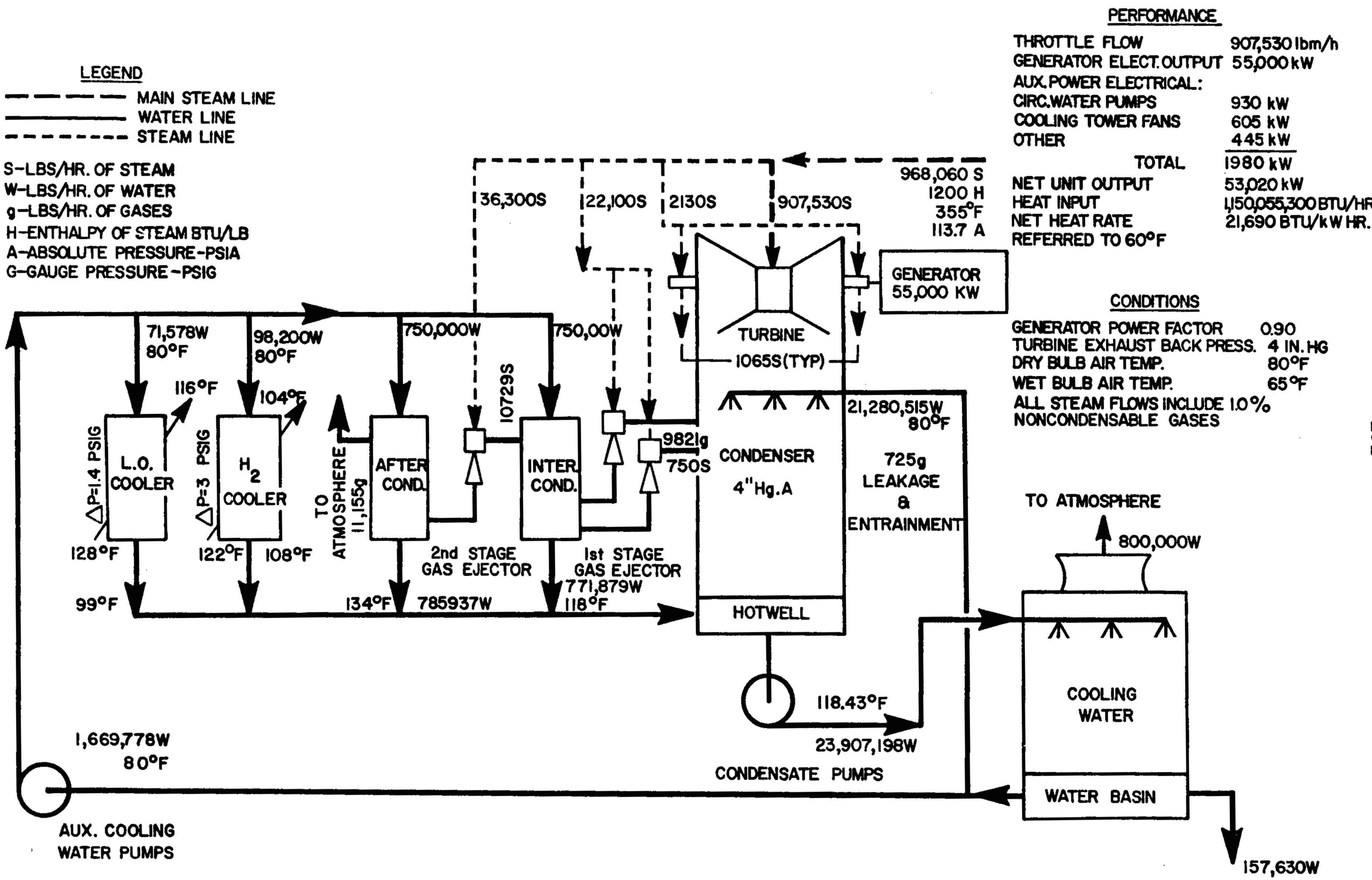

LEGEND
MAIN STEAM LINE
WATER LINE
STEAM LINE
S-LBS/HR. OF STEAM
W-LBS/HR. OF WATER
g-LBS/HR. OF GASES
H-ENTHALPY OF STEAM BTU/LB
A-ABSOLUTE PRESSURE-PSIA
G-GAUGE PRESSURE-PSIG
PERFORMANCE
THROTTLE FLOW 907,530 lbm/h
GENERATOR ELECT. OUTPUT 55,000 kW
AUX. POWER ELECTRICAL:
CIRC. WATER PUMPS 930 kW
COOLING TOWER FANS 605 kW
OTHER 445 kW
TOTAL 1980 kW
NET UNIT OUTPUT 53,020 kW
HEAT INPUT 1,150,055,300 BTU/HR.
NET HEAT RATE 21,690 BTU/kW HR.
REFERRED TO 60°F
CONDITIONS
GENERATOR POWER FACTOR 0.90
TURBINE EXHAUST BACK PRESS. 4 IN. HG
DRY BULB AIR TEMP. 80°F
WET BULB AIR TEMP. 65°F
ALL STEAM FLOWS INCLUDE 1.0% NONCONDENSABLE GASES
968,060 S
1200 H
355°F
113.7 A
36,300S
22,100S
2130S
907,530S
GENERATOR 55,000 KW
TURBINE
1065S(TYP)
71,578W
80°F
98,200W
80°F
750,000W
750,00W
116°F
104°F
10729S
ΔP=1.4 PSIG
L.O. COOLER
ΔP=3 PSIG
H2 COOLER
TO ATMOSPHERE 11,155g
AFTER COND.
INTER COND.
9821g
750S
CONDENSER 4"Hg.A
21,280,515W
80°F
725g LEAKAGE & ENTRAINMENT
128°F
122°F
108°F
2nd STAGE GAS EJECTOR
1st STAGE GAS EJECTOR
771,879W
118°F
99°F
134°F
785937W
HOTWELL
TO ATMOSPHERE
800,000W
COOLING WATER
118.43°F
23,907,198W
CONDENSATE PUMPS
1,669,778W
80°F
WATER BASIN
AUX. COOLING WATER PUMPS
157,630W

FIGURE 10.37

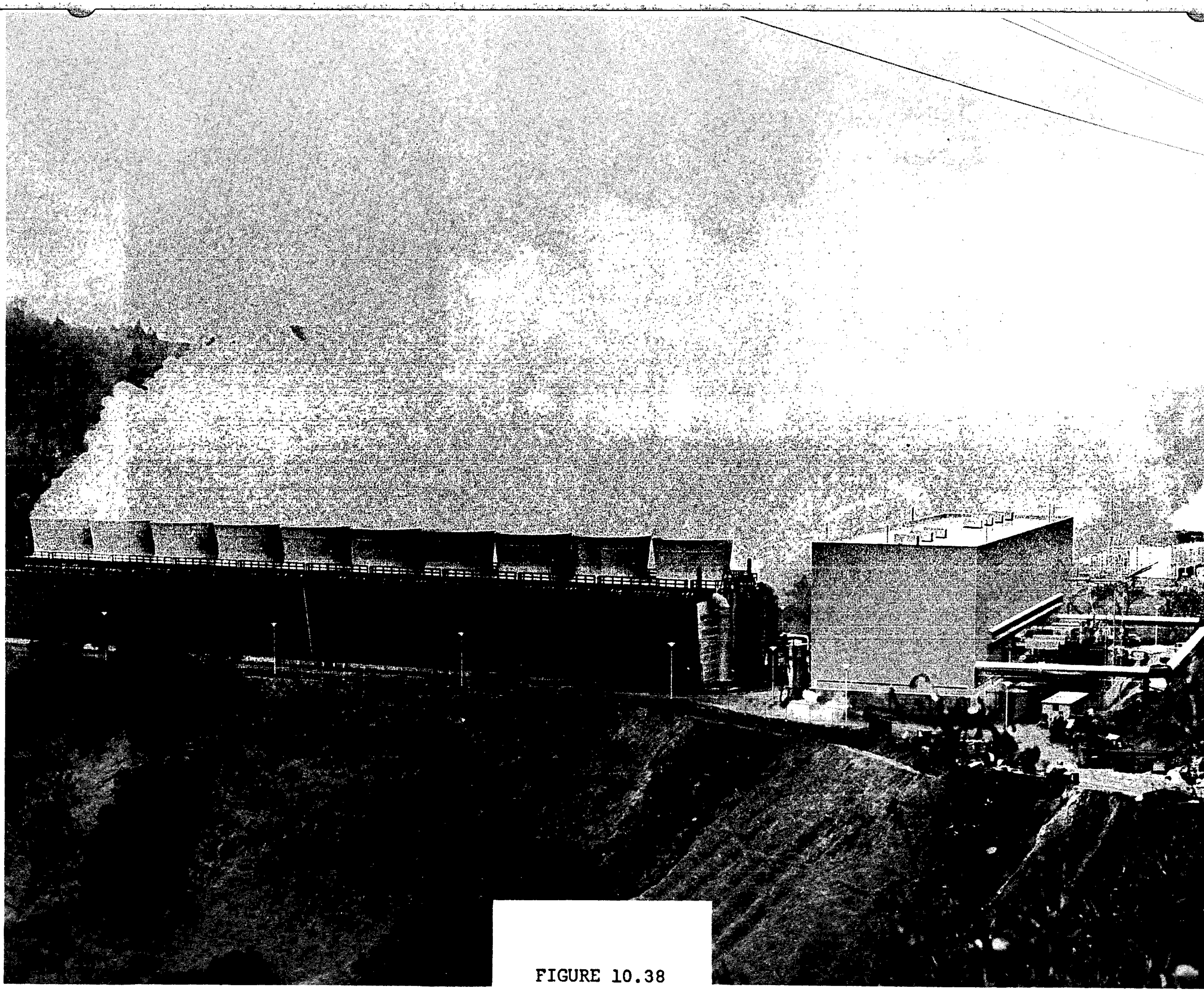


FIGURE 10.38

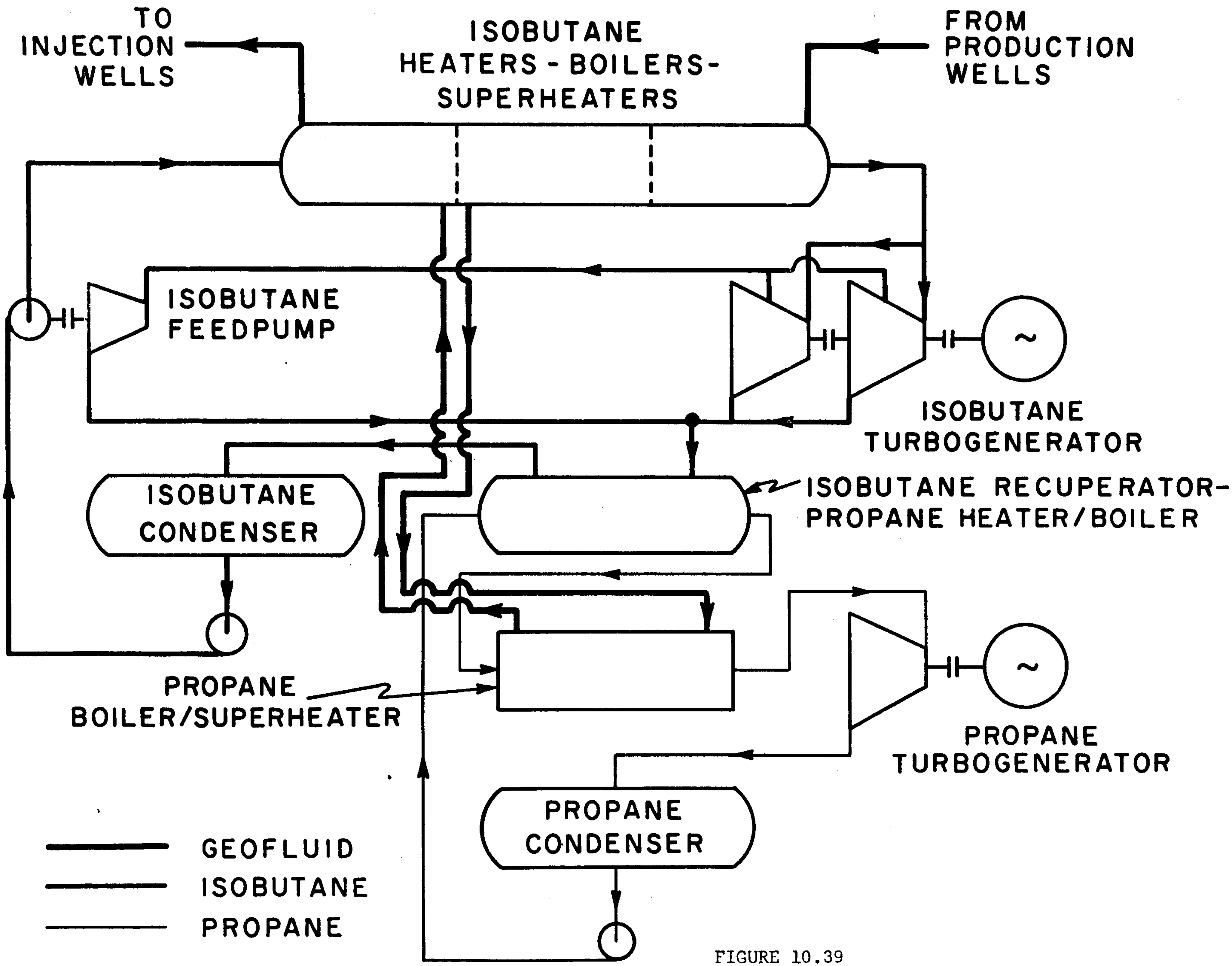

TO
INJECTION
WELLS
ISOBUTANE
HEATERS - BOILERS-
SUPERHEATERS
FROM
PRODUCTION
WELLS
ISOBUTANE
FEEDPUMP
ISOBUTANE
TURBOGENERATOR
ISOBUTANE
CONDENSER
ISOBUTANE RECUPERATOR-
PROPANE HEATER/BOILER
PROPANE
BOILER/SUPERHEATER
PROPANE
TURBOGENERATOR
PROPANE
CONDENSER
GEOFLUID
ISOBUTANE
PROPANE

FIGURE 10.39

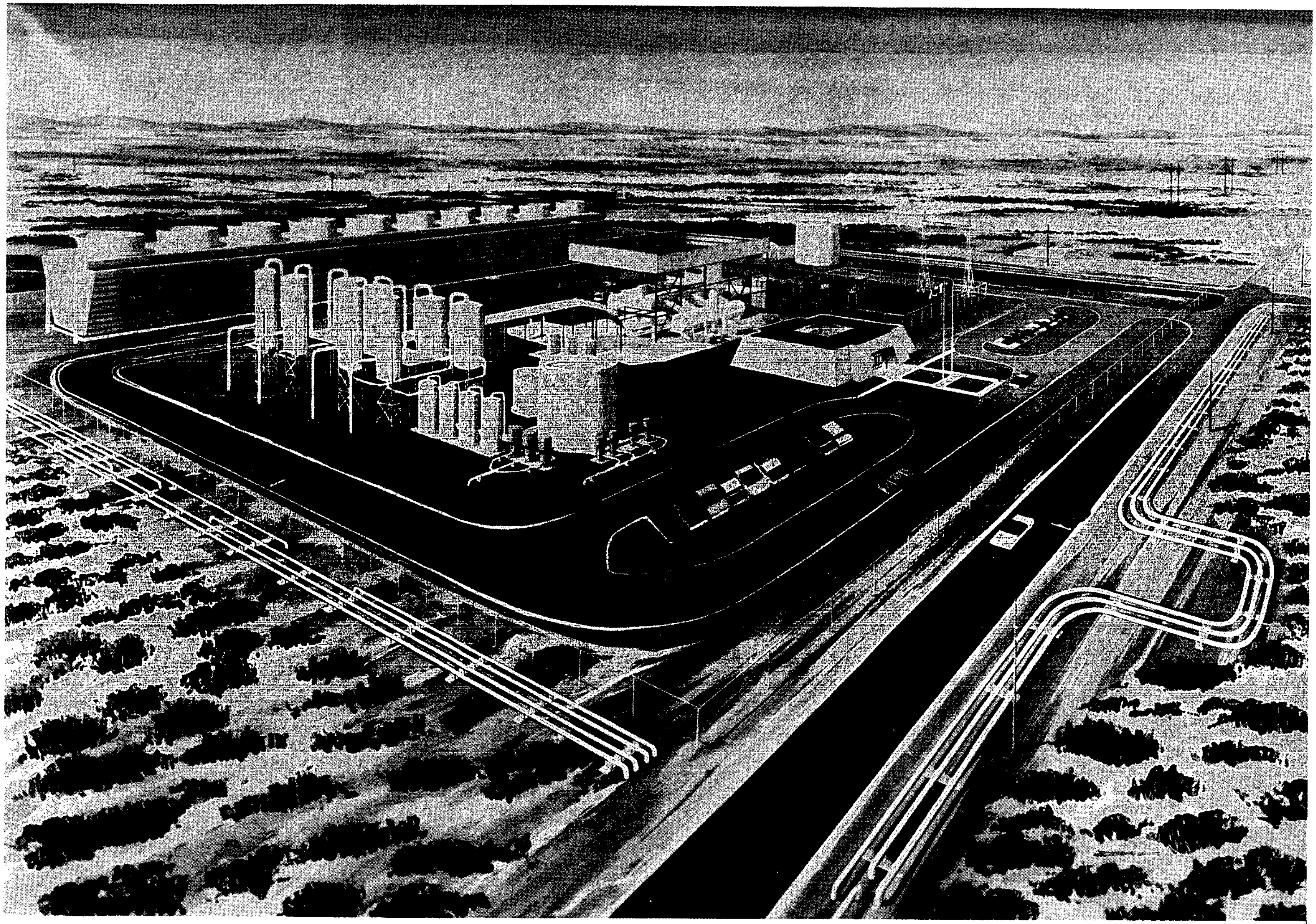


FIGURE 10.40

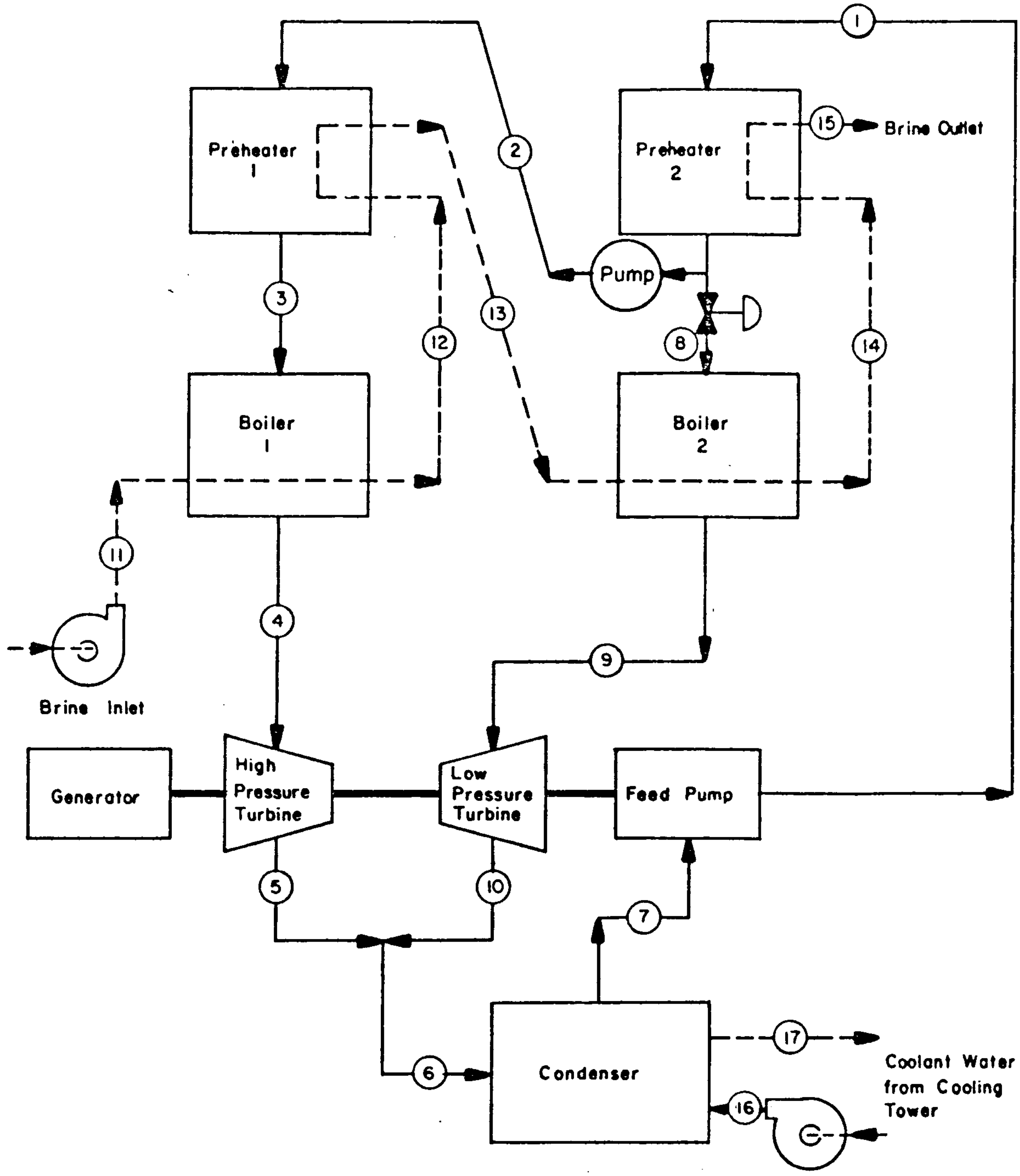

Preheater 1
Preheater 2
Brine Outlet
Pump
Boiler 1
Boiler 2
Brine Inlet
Generator
High Pressure Turbine
Low Pressure Turbine
Feed Pump
Condenser
Coolant Water from Cooling Tower
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17

FIGURE 10.41