WASTE HEAT REJECTION FROM GEOTHERMAL POWER PLANTS

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Waste heat rejection is a greater problem at geothermal power stations than at fossil or nuclear-fueled plants because the comparatively low temperature of the energy source results in relatively low thermal efficiencies for the cycle, and this means significantly more heat must be rejected per kilowatt of power generated. Further, conventional stations can be located at a source of cooling tower makeup water and the fuel brought to them, but geothermal plants must be built at the geothermal resource sites, which in the Western United States are often in areas where little or no water is available for consumptive use in power plants. Rejection of waste heat without the evaporation of water, that is, by transferring the heat to the atmosphere in dry coils, imposes significant penalties on the cycle performance and requires relatively large and expensive heat transfer surfaces. Such heat dissipation systems can cost as much as five times more per kilowatt than the heat rejection systems in fossil or nuclear stations.

The U. S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI) have recognized the constraints that waste heat dissipation can place on development of the geothermal power industry and have sponsored research and development programs to determine whether the problems can be mitigated. Some of the results of these programs have become available in the two years or more since Section 5 of the Sourcebook[1] covering waste heat rejection was written. Several of the programs, however, are just nearing completion of construction and the results will not be available until later in 1981. Some of the more significant developments in the field of waste heat rejection for geothermal power plants are as follows:

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1 Joseph Kestin, ed., Sourcebook on the Production of Electricity from Geothermal Energy, U. S. Government Printing Office, DOE/RA/4051-1, March, 1980.

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1. Phased Cooling at Magma's 10-MWe Power Station

The first large-scale demonstration in the United States of phased cooling will be at the Imperial Magma Corporation's 10-MWe binary geothermal power plant located at East Mesa, California. In this arrangement, the warm circulating water discharged from the turbine condenser during the day will be collected in a storage pond and then cooled at night when the conditions for heat dissipation to the atmosphere are more favorable. The cooled water will be stored in another pond for use the next day. Among the advantages of the concept are thought to be the conservation of water and providing a closer approach of the water temperature to the ambient wet-bulb temperature. Of course, by delaying the heat dissipation, great cooling capacity is required in the heat rejection equipment. These aspects will be evaluated when the plant goes into full operation, probably in March, 1981.

The Magma installation consists of about 25 acres of storage ponds and spray areas. There are three ponds and two spray areas. The desert-like soil conditions and terrain made the scooping out of the 20-ft deep ponds relatively inexpensive on a cubic yard basis, but their large size nevertheless made it a construction project of significant magnitude. The ponds are lined with a 30 to 40-mil-thick chlorinated polyethylene (CPE) sheeting reinforced with fiberglass. There have been few problems with the material itself to date, but the sealing of the seams presented some difficulties. The water spray nozzles used for cooling the water are installed over grade-level areas having gunnite surfaces pitched to drain into the storage ponds. This arrangement was thought to be less expensive than installing supports over the ponds for the nozzles and the long headers that are required, and it also provides some additional area for the water to be cooled by evaporation and by nighttime radiation. It was also originally thought that the spray areas would have a first cost less than that of cooling towers of the same cooling capacity, but actual construction experience at Magma has rasied some doubts as to this aspect. A detailed evaluation has not yet been made, however. Certainly the

availability of land at the Magma site for the spray areas may not be typical of other geothermal installations.

The performance of the heat dissipation system at the 10-MWe station will be followed with considerable interest. It should provide the first definitive answers regarding the merits of the phased-cooling concept when applied to geothermal power plants located in climates similar to that in the Imperial Valley of California.

2. Test of 15-MWe Wet/Dry Cooling Tower Module

A single-cell test module was operated for 15 months during 1979-80 at Southern California Edison's San Benardino Generating Station to determine the potential of wet/dry cooling towers for conserving water. The work was sponsored by a ten-member cooperative, which included the U. S. Department of Energy and the Electric Power Research Institute. The test module had a cooling capacity capable of handling about 15 MWe of power generation. The tower was manufactured by Ecodyne and was a cross-flow type, arranged with the water flowing first through the 1-in. in diameter finned tubes in the dry section and then through the splash fill of the wet section. The air flow was in parallel through the two sections, with the amount proportioned by motor-operated dampers. The single 28-ft in diameter fan, powered by a 250-hp motor at 135 rpm, served both sections. The ambient temperatures at San Benardino varied from a mean low of 38° dry-bulb/35°F wet-bulb temperature to a mean high of 95°F dry-bulb/64°F wet-bulb temperature. The wet/dry tower, on an annual-average basis, was judged to evaporate about 19% less water than a conventional wet, mechanical-draft cooling tower would have used when rejecting the same amount of heat under the same ambient conditions.[2]

Operating difficulties were experienced with the dampers and the damper-actuating mechanism. The damper pivot points stuck and the damper

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2 D. M. Burkhart, Test Report: Wet/Dry Cooling Tower Test Module, Southern California Edison for the Electric Power Research Institute, EPRI CS-1565, October 1980.

motor linkage was said to need redesigning. Significant fouling of the dry surfaces occurred due to dust, insects and pollen from the nearby agricultural fields. It was suspected that residual oil on the dry surfaces from the manufacturing processes may have contributed to the initial fouling. At the conclusion of the test the surfaces were cleaned with a water lance using 140°F water at 300 psi, a method that was judged to be about 90% effective in removing the fouling. Some trouble was also encountered with biological fouling in the wet section of the tower. All of these difficulties, however, appear to be amenable to straight-forward solutions and the wet/dry module was judged to be a viable concept for the conservation of water. Cost studies were not included in the report.

3. Ammonia Heat Transport System[3]

A facility has been constructed at the Kern Power Station of the Pacific Gas and Electric Company near Bakersfield, California, to demonstrate the use of ammonia to transport heat from a steam condenser to a dry cooling tower. The system, known as the Advanced Concepts Test (ACT), has a capacity of 10-MWe. The coil in the tower can be operated either dry or water-augmented. The steam condenser in which the ammonia is vaporized, has grooved tubes to enhance the heat transfer. The project is supported by the U. S. Department of Energy, the Electric Power Research Institute, and a consortium of utilities. Ben A. Johnson of the Battelle Pacific Northwest Laboratories, is one of the major participants in the project. Installation of the system is essentially complete and shakedown testing will probably be started in April, 1981.

The superior heat transport and transfer properties of ammonia, as compared to water, allow the air-cooled coil to be significantly smaller and less expensive. The system, however, interposes an additional heat exchange process and temperature difference, which increases the turbine back pressure. This project will be viewed with great interest because

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3. F. R. Zaloudek, L. J. Brown, and R. T. Alleman, Advanced Concepts Test Facility - Measurements and Suggested Test Plan, Battelle, Pacific Northwest Laboratories, EPRI CS-1530, September 1980.

it may demonstrate a method of reducing dry cooling costs at those potential geothermal power plant sites where there is no water for cooling tower makeup.

4. Tower System's Plastic Membrane Cooling Tower

Parallel with the study of ways to reduce the water consumption in wet cooling towers there should be study of arrangements to make more cooling tower makeup water available. If water treatment could be provided at low enough costs, water normally considered to be of too poor a quality for makeup could be obtained from such sources as geofluids, saline ground waters, sewage or industrial plant effluents, irrigation ditches, salt lakes, or polluted rivers. A new cooling tower concept recently marketed by Tower Systems, Incorporated, of Tacoma, Washington, may be a significant step in this direction. The tower, which is used in conjunction with a water treatment system specified by Tower Systems, has particular application at installations where makeup water quality is poor, there is a need to conserve water, and zero discharge of waste water is required.[4]

The tower consists of 5-mil Mylar sheets stretched tautly over frames standing about 15 to 20 ft high, and arranged with a non-splashing falling film of the "clean" water to be cooled flowing down one side of the membrane. On the other side is a downward-flowing film of "dirty" water that is partially evaporated into an upward-flowing air stream. The separation of the two water flows has led Tower Systems to term it a "binary cooling tower", or BCT. The packing density of the BCT is not as great as in towers having a splash fill and they are threfore larger in dimensions than conventional towers having the same heat dissipation capacity. When first introduced on the market, many thought that at last someone had developed a less expensive way to build cooling towers. Actually, however,

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4. W. G. Sanderson, R. L. Lancaster. and J. J. Bostjancic, The BCT Process - A Water Conserving Zero Discharge Cooling Technology, Tower Systems, Inc., Tacoma, WA (Paper presented at 42nd Am. Power Conf., April 23, 1980).

due to the relatively larger size, the reinforced concrete structure, and the fact that the towers are not yet manufactured in large quantity, the selling price is not the principal sales argument. The feature that is of most interest is the tower's ability to operate with many more cycles of concentration than can be tolerated in conventional towers and its adaptability to zero waste water discharge management.

The factors usually limiting the amount of concentration in cooling towers are: (1) corrosion, (2) scaling, (3) environmental impacts of drift, and (4) blowdown disposal. The BCT has limited corrosion problems because much of the water path is non-metallic. Scaling is controlled by the associated water treatment system and by the fact that the glossy surface of the plastic sheeting resists scale deposition to some extent. The drift rate is said to be significantly less than for conventional wet cooling towers. With regard to blowdown, the BCT cannot be directly compared to conventional wet cooling towers in that in the usual application of the BCT it is designed to concentrate the blowdown to very high levels of concentration (over 100,000 ppm) to enable it to be evaporated to dryness in solar ponds to achieve zero discharge of waste water.

The first commercial test of the BCT system was made in 1979 at the Las Vegas Sunrise Station of the Nevada Power Company.[5] The cooling tower makeup at this plant is supplied from secondary sewage treatment plant effluent. The water is first treated with lime in a clarifier to reduce the phosphates, has various inhibitors and biofouling control agents added, but after concentration by a factor of five in the cooling tower, the blowdown under current regulations is not acceptable for discharge into the Colorado River system via the Las Vegas Wash. Shortage of land for evaporation ponds led to investigation of the BCT system as a means of disposing of the blowdown on the site. The circulating water side of the BCT Mylar membrane operates in parallel with the existing cooling water

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5 Tower Systems, Inc., Final Test Report: MCT Pilot Plant Demonstration, Chemical Softening Mode, Nevada Power Company, Sunrise Station, August, 1979.

circuit. The air side of the membrane is supplied with blowdown water from the existing tower at about 5,000 ppm total dissolved solids (TDS) and concentrates it by a factor of about 20 to 100,000 ppm TDS. The system was reported to operate much as designed, with no significant corrosion, fouling problems, or insoluble deposits on the plastic surfaces, in sumps, or in the distribution systems.

A second commercial installation will be placed in service late in the summer of 1981 at Lakeland, Florida, at the C. B. McIntosh Generating station, Unit 3. It will be used in series with the existing cooling towers to treat waste water from the ash pond to take it to high levels of concentration prior to evaporation in solar ponds. This is being done to comply with zero waste water discharge regulations.

EG&G at Idaho Falls, Idaho, has drafted a proposal to study the BCT system at Raft River's 5-MWe geothermal power plant test facility, using saline water as the makeup source. A second phase of the proposed program would be to install a multi-celled larger system at some geothermal power plant that had makeup water supply problems. The proposal points out that the California State Water Resources Control Board has a policy of not approving use of inland water for power plant cooling unless the water is sufficiently saline to have little or no agricultural value. Further, the EPA strongly encourages energy development facilities to be designed to use water of a poorer quality. The EG&G proposal identifies several geothermal areas in which saline water, but not fresh water, would be available for cooling tower makeup.[6]

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6. L. G. Kragh, Consultant, Letter to J. F. Whitbeck, EG&G, Idaho Falls, ID, "Draft Program Plan to Study Binary Cooling Tower in Geothermal Applications Using High Silica Water Treatment Techniques", Nov. 6, 1980.

5. Enhanced-Surface Condenser Test at Raft River.

During 1980 a vertical, fluted-tube condenser with Admiralty-metal tubes was tested at the 60-kW facility at Raft River, Idaho, using a surface-type evaporator as a source of isobutane vapor. The performance was found to be within 60 to 100% of the predicted values based on heat transfer experiments made at the Oak Ridge National Laboratory.[7] In the earlier tests at ORNL fluted tubes were found to enhance the condensing film coefficient by factors of 4 to 6 over the performance of smooth tubes. In the tests at Raft River the agreement with the predicted results became better with time, suggesting that non-condensable gases were working their way out of the system, or perhaps that the tubes had a residual oil coating from the manufacturing process that was getting washed away. The condenser will next be tested by condensing isobutane vapor that was generated in a direct-contact boiler. This arrangement will more nearly simulate the amount of non-condensable gases and other conditions that would exist in an actual binary cycle application.[8]

6. Enhanced-Surface Vertical Condenser Test at East Mesa.

In 1981 a larger vertical condenser with fluted tubes will be tested in the 500-kWe Barber-Nichols facility at East Mesa, CA. It has carbon-steel fluted tubes, in a four-pass configuration with floating bottom head, that will test the effect that a tube bundle may have on the heat transfer performance. As in the Raft River tests, the condenser will first be tested using a surface-type evaporator to provide the isobutane vapor, since this will allow more direct comparison to the ORNL experimental results. It will then be tested when condensing isobutane vapor supplied by a direct-contact boiler. The condenser tests are scheduled to begin in the fall of 1981.[8]

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7. S. K. Combs, G. S. Mailen and R. W. Murphy, Condensation of Refrigerants on Vertical Tubes, ORNL/TM-5848, August 1978.

8. J. W. Michel and R. W. Murphy, Energy Division, Oak Ridge Natl. Lab., Condenser Designs for Binary Power Cycles, Proceedings 15th Energy Conversion Conference, Seattle, WA, Aug. 18-22, 1980.

7. Economic Study of Six Heat Rejection Systems by R. W. Beck, Assoc.

An economic evaluation of six different heat rejection systems for hydrothermal geothermal power stations was made in 1980 by R. W. Beck and Associates for the University of Utah.[9] The system arrangements, shown in Figure 1, all used isobutane as the working fluid in the power cycle. The systems incorporated either shell-and-tube or direct-contact condensers, and in one case a packed-bed direct-contact condenser was assumed. Conventional wet cooling towers, dry cooling towers, and evaporative condensers were employed, and both water and isobutane were investigated as condenser coolants.

The same energy conversion system was assumed for all the waste heat rejection arrangements studied. In this standard system, the geofluid transferred heat to the isobutane in a surface-type heat exchanger. The working fluid conditions at the turbine throttle were 550 psia and 290°F and the pressure in the turbine exhaust was 85 psia. Geothermal energy costs of $0.50 and $1.00 per million Btu's were studied, but only the fifty-cent cases are discussed here because the study showed that changing the "fuel" cost did not alter the relative rankings of the different heat rejection systems.

In each case study such parameters as the cooling range, approach temperature, and initial and terminal temperature differences, were optimized to produce the lowest net electrical power production cost. Capital cost data were taken from manufacturer's quotations and pricing guides, and construction costs were based on published information and data compiled by R. W. Beck and Associates. The fixed charges were taken to be 18% and a plant capacity factor of 80% was used.

The results of the study are summarized in Figure 1. (The energy conversion system is not shown in Figure 1 because the same system was common to all cases). The systems are listed in the order of ascending electrical

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9. Letter from E. Victor Derks, R. W. Beck and Associates, to Harold R. Jacobs, University of Utah, August 11, 1980.

Figure 1-a

50-MWe Binary Geothermal Power Plant Heat Rejection System Study[a]

System No. 1

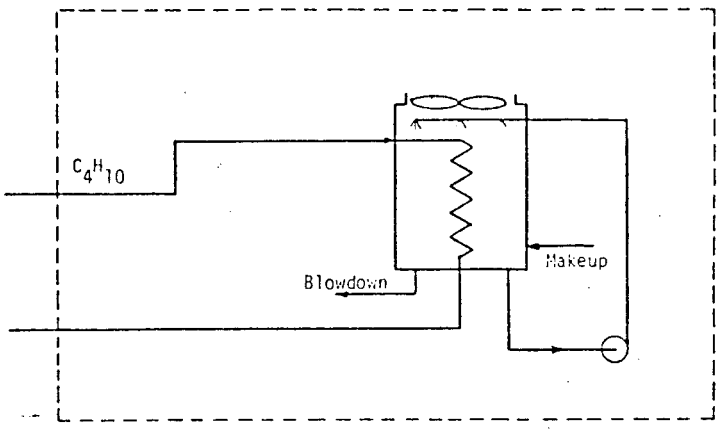
Geofluid flow rate
8×10^6 lb/hr

Avg. annual aux. load
13.5 MWe

Makeup water flow rate
4,558 acre-ft/yr

Plant capital cost
$862/net kWe

Busbar cost electricity
4.1 cents/kWh



System No. 2

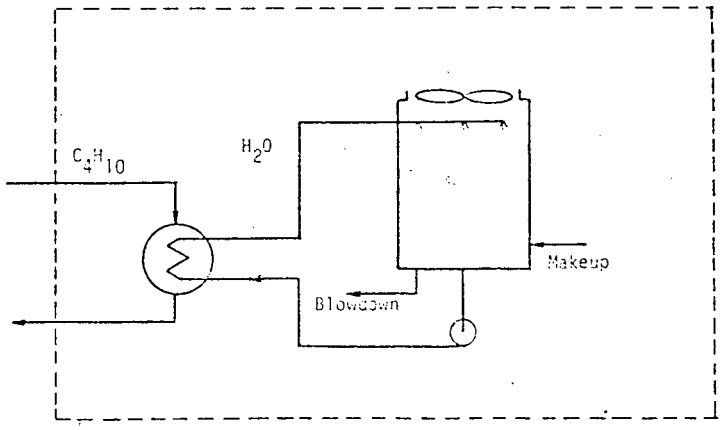
Geofluid flow rate
8.1×10^6 lb/hr

Avg. annual aux. load
13.7 MWe

Makeup water flow rate
3,147 acre-ft/yr

Plant capital cost
$1,030/net kWe

Busbar cost electricity
4.5 cents/kWh



System No. 3

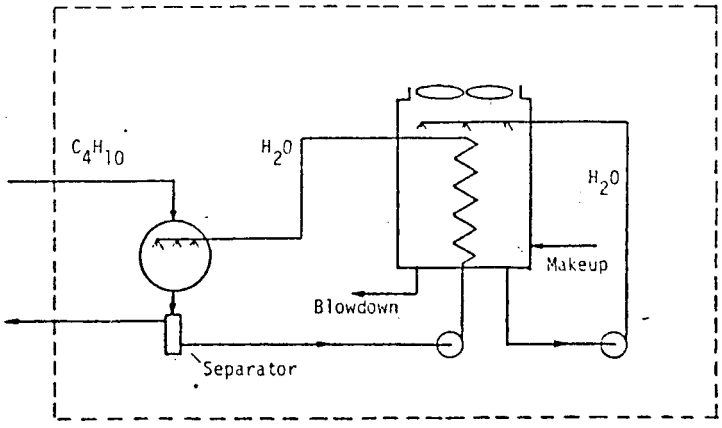
Geofluid flow rate
8.2×10^6 lb/hr

Avg. annual aux. load
16.2 MWe

Makeup water flow rate
4,749 acre-ft/yr

Plant capital cost
$1,068/net kWe

Busbar cost electricity
4.7 cents/kWh



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a Taken from letter R. W. Beck Assoc., Ref. 9. Based on geothermal energy cost of $0.50/$10^6$ Btu, fixed charge rate of 18% and 80% capacity factor.

b Acre-ft/yr x 1,233.482 = m^3/yr.

Figure 1-b

System No. 4

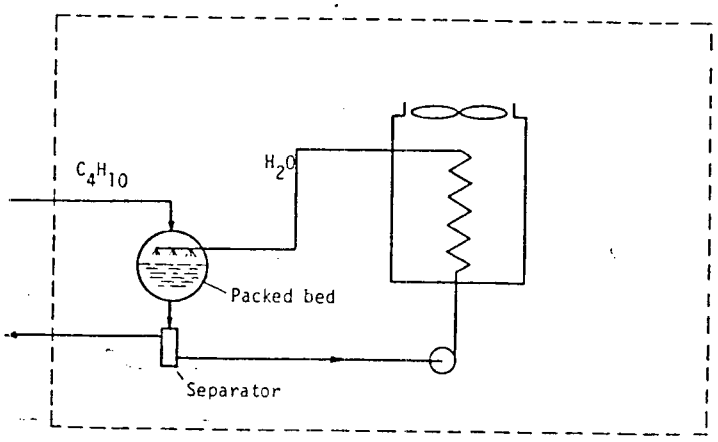
Geofluid flow rate
14 x 10^6 lb/hr

Avg. annual aux. load
26.3 MWe

Makeup water flow rate
(none)

Plant capital cost
$2,368/net kWe

Busbar cost electricity
5.6 cents/kWh



System No. 5

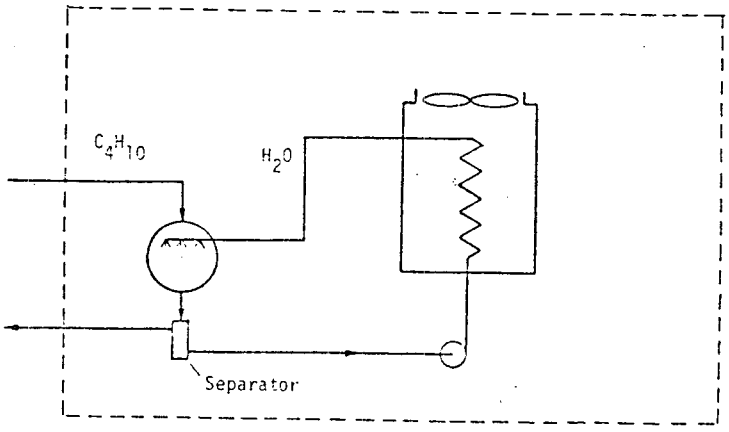
Geofluid flow rate
14.6 x 10^6 lb/hr

Avg. annual aux. load
28.8 MWe

Makeup water flow rate
(none)

Plant capital cost
$2,462/net kWe

Busbar cost electricity
5.7 cents/kWh



System No. 6

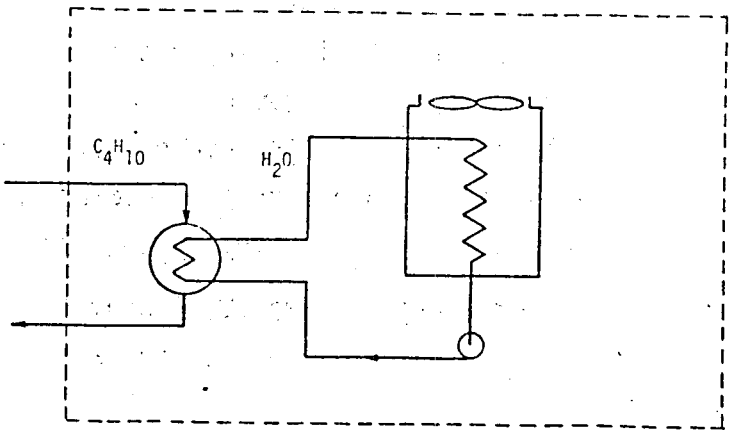
Geofluid flow rate
15.3 x 10^6 lb/hr

Avg. annual aux. load
30.5 MWe

Makeup water flow rate
(none)

Plant capital cost
$2,764/net kWe

Busbar cost electricity
6.1 cents/kWh



power production costs. The system providing the lowest cost was the one in which the isobutane vapor in the turbine exhaust is condensed directly inside a serpentine coil which is cooled on the outside by evaporating water into a counterflowing air stream. (This arrangement is variously called an "evaporative condenser", "Baltimore Air Coil type", or "hybrid type"). Unfortunately, the water consumption rate for this best-performing system was one of the highest of those studied, as will be further discussed below.

The second best, or No. 2 system, from a cost of power standpoint, was the base case system, in which isobutane vapor is condensed in a shell-and-tube heat exchanger with the circulating water cooled in a conventional wet mechanical-draft cooling tower. The Beck report points out that the results of the study of this system and the results of the No. 1 system are so similar that revising some of the judgements as to the input parameters could possibly reverse the rankings. A case in point is the water consumption rate, which in System No. 2 is about 45% less than that in System No. 1, in Figure 1. The amount of heat to be dissipated is roughly the same in both instances, but in the conventional cooling tower about 15 tp 20% of the energy is absorbed in sensible heating of the air stream, whereas in the evaporative condenser of System No. 1 it was assumed that all of the heat must be dissipated in the evaporation of water. The reason for this assumption was not explained in the Beck report but presumably is on the basis that the air flow near the exit of a conventional wet cooling tower is exposed to the incoming water temperature, which is usually higher than the ambient dry-bulb temperature, and an opportunity is thus provided for sensible heating. In the evaporative condenser the water flowing over the coils is recirculated and tends to approach the ambient wet-bulb temperature and makes sensible heating of the air less likely.

The third-ranked, or No. 3, system utilizes a direct-contact condenser with the heat given up to the cooling water dissipated in a wet coil arrangement similar to that used in System No. 2. As shown in Figure 1, the system consumes even a great amount of water than Systems 1 and 2.

The fourth ranked system with a packed-bed direct-contact condenser performs slightly better than the No. 5 system, which has the same arrangement but with a conventional direct-contact condenser. In both cases the water is cooled in a dry coil cooling tower. The more than 20% increase in the cost of electricity produced is primarily due to the high cost of the large amount of surface needed in the towers. Of great significance, however, is the fact that the systems require no makeup water.

The sixth-ranked system employs a surface-type condenser used in conjunction with a dry cooling tower. Even though this arrangement results in the highest electrical power production cost, it does not require makeup water and the isobutane losses will be less than in the direct-contact condensers used in Systems 4 and 5. It could thus be the best choice for many geothermal sites.

With the exception of System No. 1 in Figure 1, which condensed the isobutane directly, all the other systems discussed above used water as the condenser coolant. The Beck study also investigated use of isobutane to transport heat from the condenser to the cooling tower. This resulted in a 10 to 30% increase in the busbar cost of electricity, 20 to 50% greater capital costs, and 20 to 45% greater auxiliary power requirements. Since this arrangement is clearly not an attractive option, these cases were not included in Figure 1.

The Beck study is of considerable interest in that it provides a ranking for various heat dissipation schemes. Although there are obviously other considerations than power production costs, it is noteworthy that the evaporative condenser appears to be very competitive. It is also apparent that lack of water for cooling tower makeup always exacts a significant cost penalty.

8. Optimizing Wet/Dry Cooling Tower Designs.

Dynatech Company, of Cambridge, MA, did two studies in 1979-80[10,11] on wet/dry cooling towers for EPRI. One study developed an optimization methodology for base-loaded power stations and the other applied the technique to cycled, or varying capacity, stations at Phoenix, AZ, and Boston, MA. The computer programs determined the economic tradeoffs between loss of performance, size of the wet/dry towers, and the water consumption rates.

The cost of wet/dry cooling per unit of power production cost was found to be at least 50% greater for cycled plants than for base-loaded stations. Cooling water is thus 50% more valuable to a cycled plant. The report concluded that consideration should be given to designing the heat rejection system for base load conditions regardless of the anticipated plant capacity factor, because the additional total cost could be significantly less than the cost penalty associated with under-design of the cooling system.

The studies were made with fossil-fired power stations in mind and probably represent a sophistication not yet generally applicable to design of hydrothermal geothermal power stations. The developers of geothermal energy are generally more concerned at the present time with solving basic technical problems than with fine tuning the designs for maximum performance with varying plant capacity factors.

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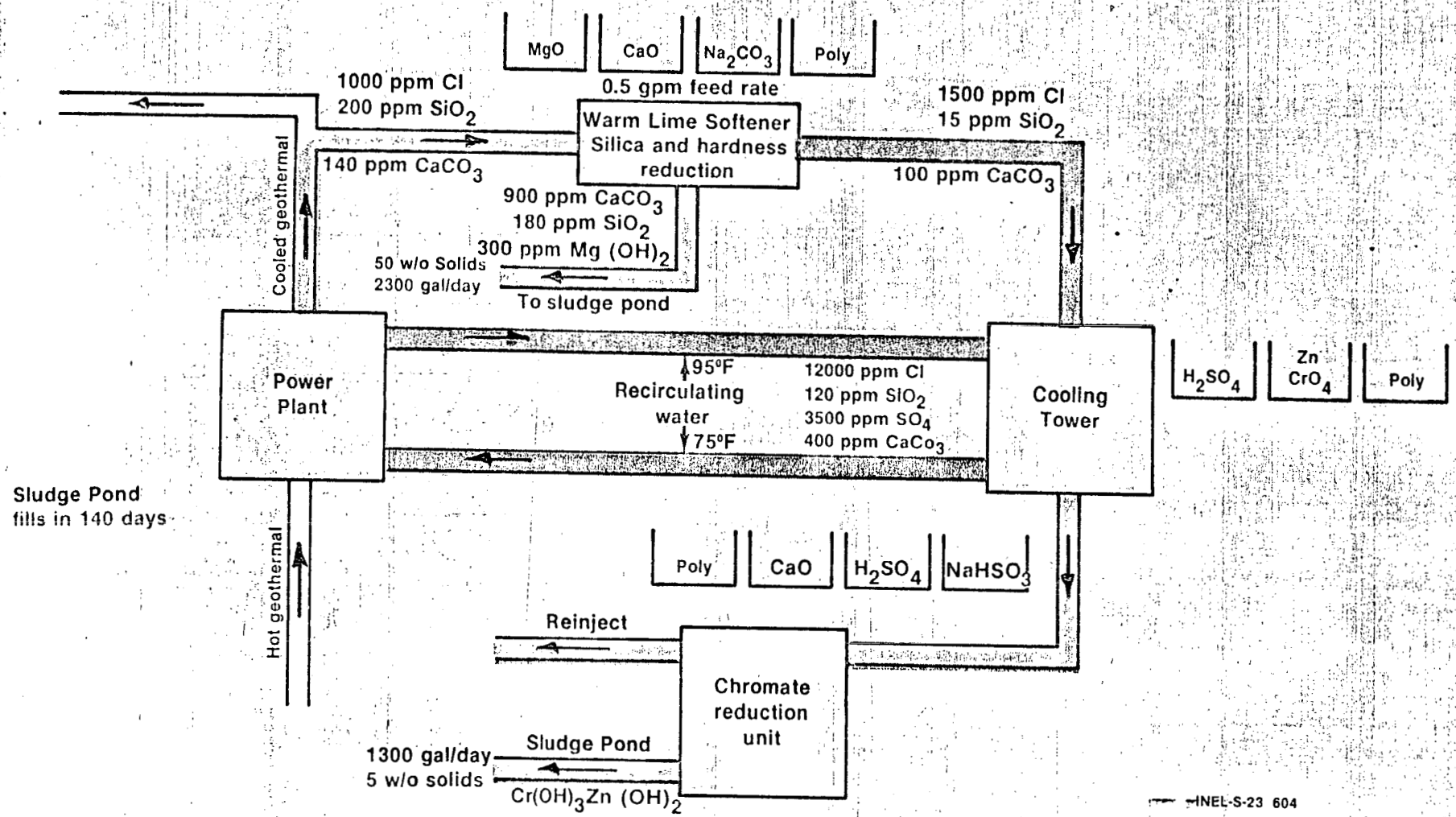
10. E. C. Guyer, D. L. Brownell, and R. A. Kack, Optimization-Simulation Methodology for Wet/Dry Cooling, Dynatech R/D Company, for the Electric Power Research Institute, EPRI FP-1096, May, 1979.

11. E. C. Guyer, and D. L. Brownell, Wet/Dry Cooling for Cycling Steam-Electric Plants, Dynatech R/D Company, for the Electric Power Research Institute, EPRI CS-1474, August, 1980.

APPENDIX O

5 MW Design Water Treatment System



RAFT RIVER WATER CHEMISTRY

Sample Source	Ph	Hardness as $CaCO_3$	Cl^-	F^-	Alkalinity as $CaCO_3$	SiO_2	Conductivity	SO_4	Na	Tentative Limits in Cooling Tower at 8 cycles of Concentration
RRGE-1	8.1	140	1000	7.9	40	180	2915	65	650	Ph 6.7-8.5
RRGE-2	8.0	80	747	3.8	42	150	1500	38	331	Hardness - 800
RRGE-3	7.5	552.5	2634	2.0	26	182	4950	59	1245	Cl Limit Undetermined
RRGP-5B	8.0	130	1089	3.2	40	140	2910	56	179	F - 10
RRGI-6	7.8	497.5	3619	2.8	66	96	8150	61	2020	Alkalinity - 200
RRGP-5	7.3	100	900	8.7	143		2150			SiO_2 - 100
RRGI-4	7.7	474	2250	6.8			6450			Conductivity/No Limit
Domestic Well-1	7.6	94.6	320	1.2	278	40	1429	80	387	1000 ppm SO_4
R. R.	7.9	297	233	0.88	140	40	1139			No Limit On Sodium

ROUGH COST OF USING GEOTHERMAL WATER FOR POWER PLANT COOLING - MILLS/kW-HR

ITEM	RESOURCE TEMPERATURE	
	290°F	360°F
CHEMICAL COST		
PRETREATMENT	1.6-5	1-3
CORROSION & SCALE	0.8-1.5	0.5-1
TOTAL	2.4-6.5	1.5-4
CAPITAL COST	APPROX. 2	1
TOTAL COST	4.4-8.5	2.5-5

NOTE:

(A) SLUDGE DISPOSAL/PONDING COST NOT INCLUDED
(B) INCREMENTAL CONDENSER MATERIAL COST NOT INCLUDED
(C) COST OF OPERATORS ASSUMED NEGLIGIBLE
(D) RAFT RIVER TYPE GEOFLUID
(E) MINIMUMS ACHIEVED BY DEVELOPMENT

APPENDIX P

SITE PHOTOGRAPHS

RAFT RIVER 5 MW DOUBLE-BOILING
PILOT BINARY PLANT

PHOTOGRAPHY BY
RONALD DIPIPPO

DATE OF PHOTOGRAPHS:
FEBRUARY 26, 1981

PLATE NO. 1

GENERAL VIEW OF PLANT SITE.

HEAT EXCHANGERS AND TURBINE INSTALLATION AT LEFT.

COOLING TOWER AND CONDENSATE TREATMENT FACILITY AT RIGHT.

WATER STORAGE (WHITE TANK), CONTROL BUILDING, AND SWITCHYARD AT CENTER-RIGHT.

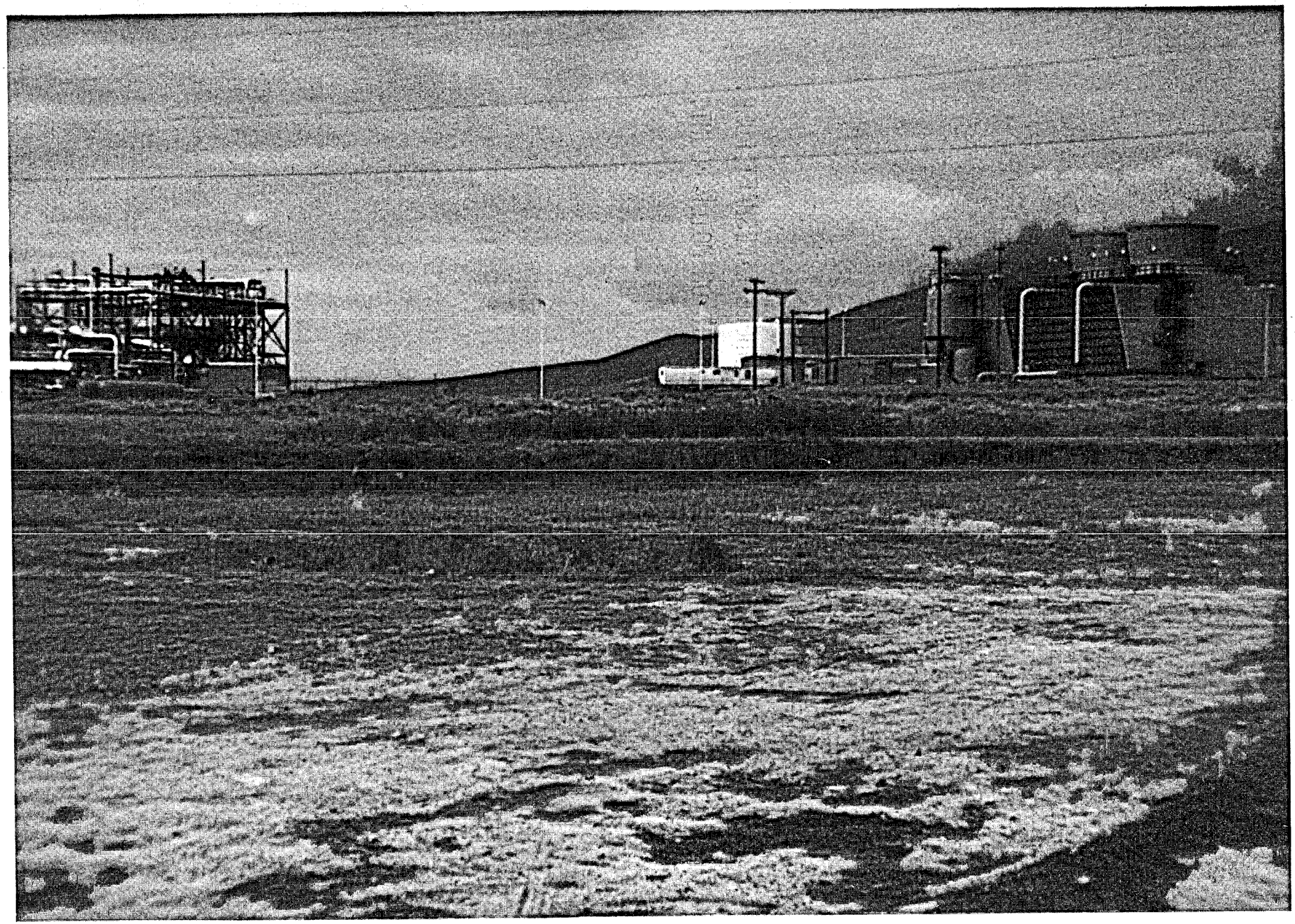


PLATE NO. 2

WELLHEAD EQUIPMENT FOR WELL RRGE-3.
ELECTRIC MOTOR FOR DRIVING DOWNHOLE LINESHAFT PUMP.
NOTE ENCRUSTATION OF SALT DEPOSITS ON MOTOR MOUNT.

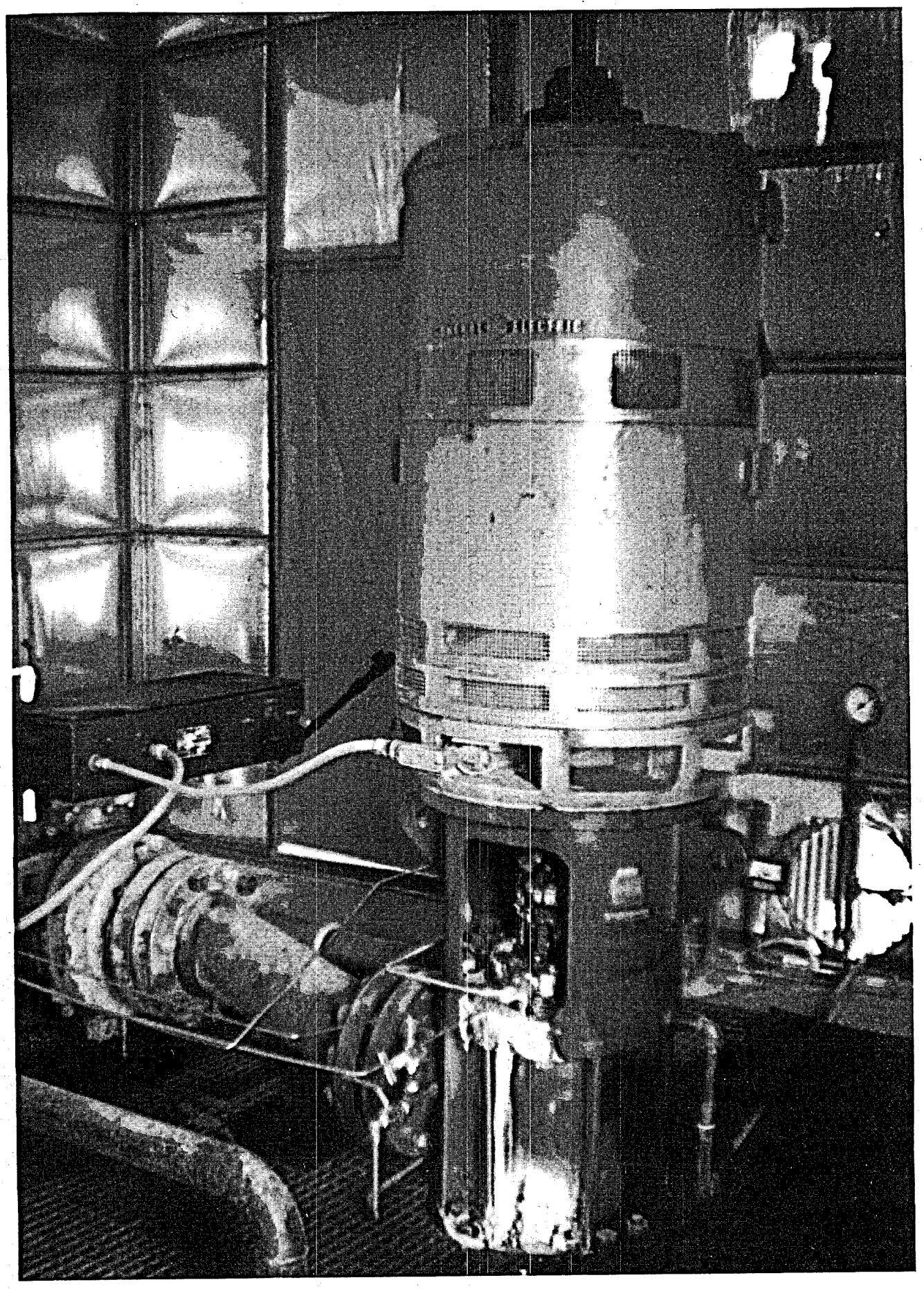


PLATE NO. 3

HEAT EXCHANGER ARRAY.

TWO HEATERS ON LOWER LEVEL ARE LIQUID ISOBUTANE ($I-C_4$) HEATERS, SHELL-AND-TUBE TYPE WITH GEOTHERMAL BRINE ON THE TUBE SIDE AND $I-C_4$ ON THE SHELL SIDE. THE HEATER AT FAR RIGHT IS THE LOW PRESSURE PREHEATER THROUGH WHICH ALL THE $I-C_4$ FLOWS. THE OTHER ONE IS THE HIGH-PRESSURE PREHEATER THAT HANDLES ABOUT 2/3 OF THE TOTAL $I-C_4$ FLOW.

TWO HEATERS ON THE UPPER LEVEL ARE $I-C_4$ BOILERS OF THE KETTLE-BOILER TYPE. THE ONE ON THE RIGHT IS FOR LOW PRESSURE: THE OTHER ONE IS FOR HIGH PRESSURE.

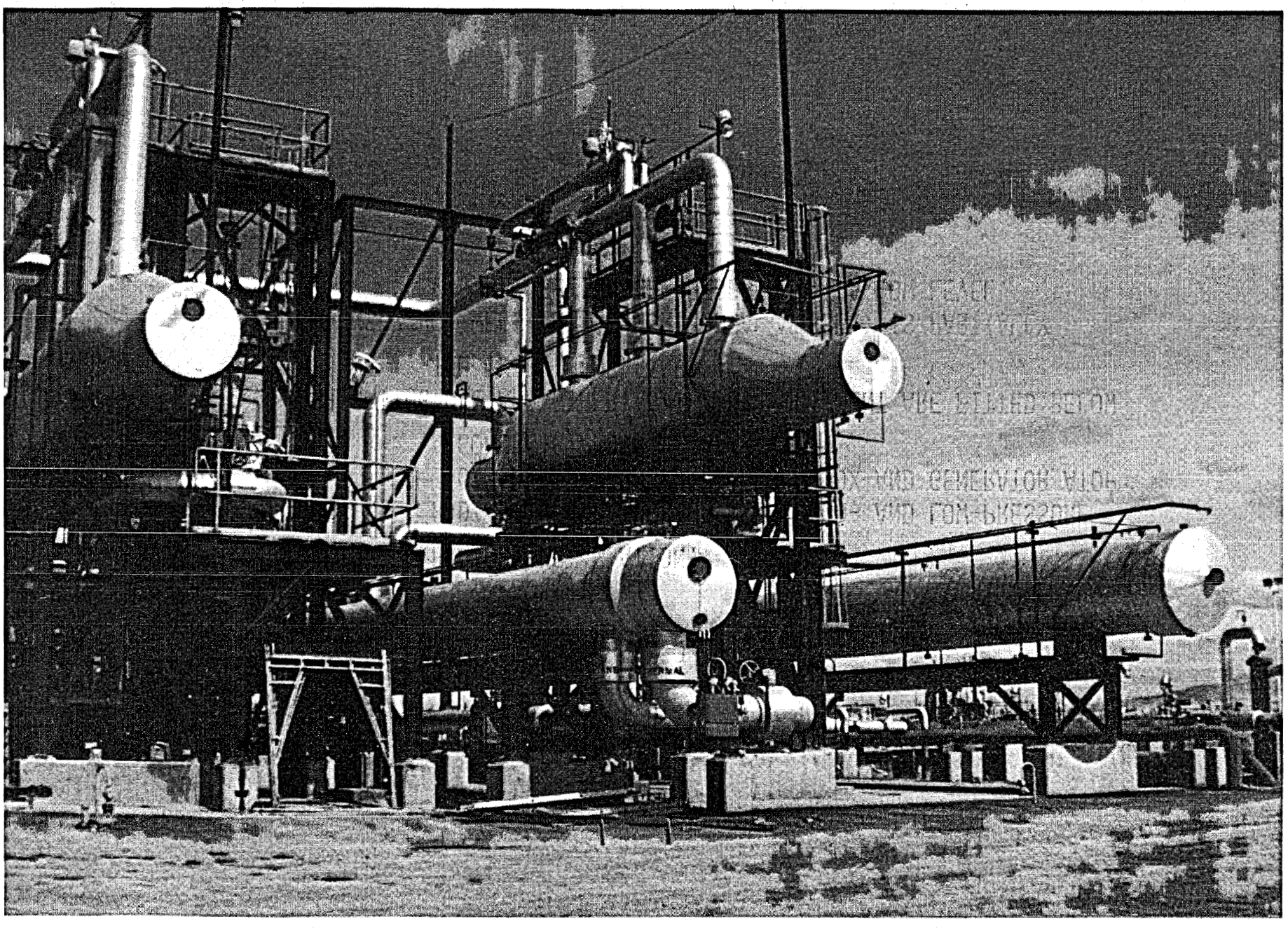


PLATE NO. 4

TURBINE-GENERATOR INSTALLATION.

TWO-STAGE, RADIAL-INFLOW TURBINE WITH HIGH- AND LOW-PRESSURE I-C_4 INLETS MOUNTED WITH GEARBOX AND GENERATOR ATOP A CONCRETE PEDESTAL.

LUBRICATING OIL AND OTHER AUXILIARY EQUIPMENT ARE FITTED BELOW THE TURBO-GENERATOR.

CONDENSER HOT WELL (LARGE HORIZONTAL VESSEL) IS PARTIALLY VISIBLE BEHIND THE PEDESTAL AT A LOW LEVEL.

PLATE NO. 5

CLOSE-UP VIEW OF DUAL-PRESSURE TURBINE WITH LARGE INDICATORS OF I-C_4 INLET VALVE POSITION.

COMMON EXHAUST PIPE MAY BE SEEN AT LEFT (LARGE DIAMETER PIPE LEADING OFF TO THE LEFT).

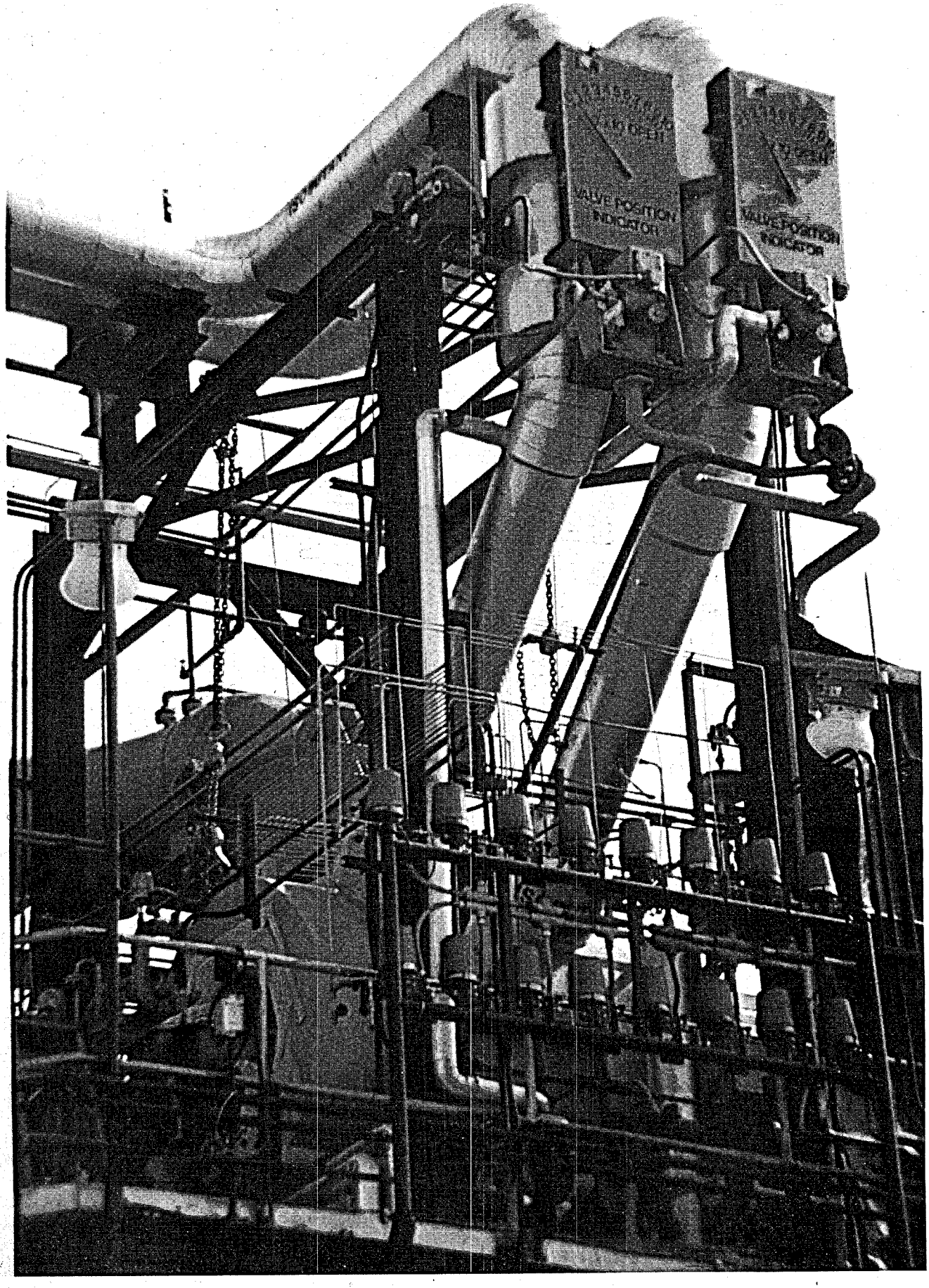

VALVE POSITION
INDICATOR
VALVE POSITION
INDICATOR

PLATE NO. 6

COOLING TOWER, PUMP HOUSE AND CONDENSATE TREATMENT FACILITY, WITH ELECTRICAL TRANSFORMER IN FOREGROUND.

TWO-CELL, MECHANICAL-INDUCED-DRAFT, CROSS-FLOW WATER COOLING TOWER.

CHEMICAL TREATMENT EQUIPMENT IS LOCATED IN ADJACENT BUILDING AT LEFT. LARGE VESSEL IS A HOLDING TANK FOR SLUDGE WHICH IS LATER TRANSFERRED TO OPEN-AIR HOLDING PITS.