SAN/RA 50239-SDG&E-0012

HEBER GEOTHERMAL BINARY DEMONSTRATION PROJECT

QUARTERLY TECHNICAL PROGRESS REPORT FOR THE PERIOD JULY 1, 1982 – SEPTEMBER 30, 1982

SDGE

San Diego Gas & Electric
Post Office Box 1831
San Diego, California 92112

Prepared for
The Department of Energy
Under Cooperative Agreement No. DE-FC03-80RA50239

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By

R. G. Lacy
R. F. Allen
J. R. Dixon
W. P. Hsiao
G. S. Liparidis
G. L. Lombard
T. T. Nelson
G. D. Van De Mark

San Diego Gas & Electric
Post Office Box 1831
San Diego, California 92112

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ABSTRACT

The purpose of this quarterly technical progress report is to document work completed on the nominal 65 Megawatt (Mwe gross) Heber Geothermal Binary Demonstration Project, located at Heber, California, during the period of July 1, 1982, through September 30, 1982. The work was performed by San Diego Gas & Electric Company under the support and cooperation of the U. S. Department of Energy, the Electric Power Research Institute, the Imperial Irrigation District, the California Department of Water Resources, the State of California, and the Southern California Edison Company. Topics covered in this quarterly report include progress made in the areas of Wells and Fluid Production and Injection Systems, Power Plant Design and Construction, Power Plant Demonstration, and Data Acquisition and Dissemination.

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SUMMARY

Recognizing the desirability of demonstrating the operation of the binary cycle process for commercial-scale electric production, San Diego Gas & Electric Company (SDG&E), the United States Department of Energy (DOE), the Electric Power Research Institute (EPRI), the State of California, the California Department of Water Resources (DWR), the Imperial Irrigation District (IID), and the Southern California Edison Company (SCE) joined together to carry out the Heber Geothermal Binary Demonstration Project.

The purpose of the Heber Binary Project is to design, construct, and operate a nominal 65 Mwe (gross) commercial-scale, binary cycle power plant and to demonstrate the technical and economic feasibility of geothermal power generation. The Project will be the first commercial-scale hydrothermal generating facility in the United States utilizing liquid-dominated resources and the binary energy conversion process. It is expected that information developed by this demonstration project will be applicable to a wide range of moderate-temperature, low-salinity hydrothermal reservoirs. Geothermal generation from the Project offers the possibility of displacing 525,000 barrels of oil per year that would otherwise have to be burned in Southern California. Figure 1 shows an artist's rendering of the Project and Figure 2 shows the location.

This report describes the Project's progress for the period of July 1, 1982, through September 30, 1982, in the areas of wells and fluid production development, engineering design and construction, and data acquisition and dissemination.

During this period three modifications to the Cooperative Agreement between DOE and SDG&E were executed. Modification A006 obligates DOE for their share of incremental Fluor costs during the extended Phase I effort. Modification M007 evokes Attachment O to OMB Circular A-110, thereby eliminating the need for DOE consent for procurements in most cases. Modification A008 definitizes Phase IIA and IIB through construction, obligates DOE funding through January 31, 1983, and extends the term of Agreement through June 1987.

The revised SDG&E/State Assignment Agreement was executed on July 15. This agreement assigns approximately 4.3% of the ownership interest and 1.7% of the cost responsibility from SDG&E to the State of California for their $2 million contribution to the Project. As a result of this agreement, the Imperial Irrigation District opted to reduce its ownership pro rata share by about 0.5% (see Figure 3).

Negotiations on Amendment 1 to the Geothermal Sales Contract were completed with Union, and Amendment 1 was executed on July 19. The package requesting DOE's consent to the Contract was transmitted to DOE on July 21, and SDG&E filed an Application with the California Public Utilities Commission (CPUC) for approval of the Contract on August 19. In September the DOE advised the Project that they did not believe the Contract submitted for their consent met the requirements of the Cooperative Agreement. Based on DOE's objections, SDG&E commenced further negotiations with Union. At

the CPUC, no action has been taken yet, but a project manager was named for the Application in September.

In the area of design, a significant change in maintenance philosphy of heat exchangers, condensers, and turbine was implemented in the hydrocarbon system. No on-line maintenance of the condensers and heat exchangers will be performed while the unit is in operation. This decision resulted in the elimination of the two 60 inch valves in the turbine exhaust and double block and bleed valving on the heat exchanger inlet and outlet piping. Functionally, the hydrocarbon condensate and booster pumps were combined in pairs or individual pumping units. Because of this double block and bleed valves have been designed to isolate these pump pairs for on-line maintenance without a plant shutdown.

The brine system operational function and performance requirements were defined. System warmup will be primarily a manual operation by operator-initiated action and set point adjustment of local control valves. A temperature increase of 50°F per hour was established starting with 150°F cold brine. Brine flow during operation will be controlled on demand signal from the heat exchanger outlet hydrocarbon temperature (305°F setpoint) and the hydrocarbon flow (variable). Because of the heat supplier's condition for maintaining brine flow above 80%, for downhole pump protection, the brine flow will remain unchanged under a condition of cooling water pump loss or plant-related turbine trip (other than the loss of brine return pumps).

A Brown Boveri Turbomachinery generator is being considered for use in lieu of the Electric Machinery generator originally proposed by the turbine generator supplier (Elliott). This proposed generator is electrically identical to the original. Acceptance for substitution is pending evaluation of data collected during factory acceptance tests, performed in late September.

Construction efforts focused on the preparation of the Site Development bid packages. The Site Development work was split into two phases: Phase I consisted mainly of earthwork and drainage, while Phase II consisted of building work and underground utilities.

Dravo Constructors, Inc. (DCI) was selected as the contractor for developing and implementing the Vendor Surveillance Program. Surveillance will be performed during the manufacturing of all sizable equipment that have historically necessitated such a program.

INTRODUCTION

The scope of the Heber Binary Project is to design, construct, and operate a commercial-size, binary cycle geothermal power plant at the Heber reservoir for a two-year demonstration period. The goal of the Project is to demonstrate the technical and economic feasibility, as well as the environmental acceptability, of geothermal power generation using the binary process. Our work plan for the Project consists of four major tasks, or Work Breakdown Structure (WBS) elements (see Figure 4), that are described below:

WBS 1.1. - WELLS AND FLUID PRODUCTION AND INJECTION SYSTEMS

Primary responsibility for this task has been assigned to the heat supplier. The task consists of well drilling, the construction of surface facilities for geothermal fluid production and injection, and operation of the field facilities to support plant operation.

WBS 1.2 - POWER PLANT DESIGN AND CONSTRUCTION

This task consists of the work by SDG&E, the architect/engineer, and a construction manager to manage the design, procurement, construction, and start-up of the power plant systems and the associated switchyard, distribution system, and the brine return pipeline. The task includes obtaining necessary permits, associated monitoring, design, procurement, construction, start-up, and project management activities.

WBS 1.3 - POWER PLANT DEMONSTRATION

This task consists of the work by SDG&E to operate the power plant for a two-year period to achieve the basic objectives of the Project. The task includes services, repairs, facilities, overhaul, cleaning, consumables, testing, spare parts, and the tools necessary to operate the plant in a safe and reliable manner.

WBS 1.4 - DATA ACQUISITION AND DISSEMINATION

This task consists of the work by SDG&E and a subcontractor in gathering, reducing, evaluating, and reporting on reservoir and plant performance data.

The WBS will serve several functions. It divides the work into discrete and manageable work packages which, taken in the aggregate, will constitute Project implementation. To some extent, it will dictate organizational lines, and will be an important management tool. It provides a method of accounting for all work that must be performed, and is the basis for manpower loading and scheduling. In addition, it will be used for cost and schedule control and progress audit.

WBS 1.1
WELLS AND FLUID PRODUCTION AND INJECTION SYSTEMS

WBS 1.1.1 - DESIGN AND CONSTRUCTION

OBJECTIVE:

This WBS element will be performed and funded entirely by the heat supplier. It will include work to design, build, and test production and injection systems necessary to deliver fluid from the reservoir to the power plant and, after use, return the fluid into the reservoir.

STATUS:

Negotiations on Amendment 1 to the Geothermal Sales Contract were completed with Union, and Amendment 1 was executed on July 19. The major impact of this amendment is to accelerate the installation of the full field facilities by six months over the brine delivery schedule under the original Contract. The package requesting DOE's consent on the Contract was transmitted to DOE on July 21, and SDG&E filed an Application with the California Public Utilities Commission (CPUC) for approval of the Contract on August 19.

In September, DOE advised the Project that they did not believe that the Geothermal Sales Contract submitted for their consent met the requirements of the Cooperative Agreement. Based on DOE's objections, SDG&E commenced further negotiations with Union. One of the main objects of the negotiations was to further accelerate the schedule for full field facilities installation. The schedule for brine delivery under both the original Contract and Amendment 1 calls for a period of operations with half of the field facilities installed before the remaining facilities are installed. The goal of these further negotiations with Union will be a second amendment to the Contract.

No action was taken at the CPUC on the Application in September, but a project manager was named for the Application. The CPUC was requested to act on the Application at the earliest possible time, so that the projected construction start date could be met and so the heat supplier could meet its contractual commitments.

In addition to the contract negotiations with the heat supplier, a series of technical interface meetings were held with Chevron, the reservoir operator. Engineering requirements grew critical enough that it became essential for Chevron to commence engineering in order to maintain the Project schedule. Because of the uncertainties of CPUC and DOE approval of the Contract and the need to maintain the Project schedule, an agreement was drafted which provides that SDG&E will indemnify Chevron for limited engineering work only if SDG&E does not obtain the necessary approvals from the CPUC and DOE. The implementation of this agreement was targeted to occur before the end of year.

WBS 1.2

POWER PLANT DESIGN AND CONSTRUCTION

WBS 1.2.1 - ENVIRONMENTAL STUDIES AND PERMITS

OBJECTIVE:

The objective of this WBS element is to obtain the necessary permits and provide environmental studies and monitoring to facilitate plant design and ensure compliance with government regulations for plant construction and operation.

STATUS:

Imperial County Air Pollution Control District (ICAPCD) Permit

On May 10, 1982, an application was filed with ICAPCD for an Authority to Contruct/Permit to Operate for the Heber plant. Normal plant air emissions included evaporation from the cooling towers, hydrocarbons, leaks from valves, flanges, pump seals, etc., and hydrocarbon, CO_2, and N_2 from the flare stack. On August 10, 1982 the ICAPCD issued the Permit to Construct, however, the permit stipulated the following conditions:

- All hydrocarbon relief valve emissions shall be vented through the flare stack.
- Metering of the relief valve emissions shall be conducted on a continuous basis at a point prior to flaring.
- The Air Pollution Control Officer (APCO) shall be appraised of the metered rates on a monthly total pounds basis.
- The APCO shall be notified of isobutane recharges on a monthly total pounds basis.
- SDG&E shall obtain offsets under the direction of the APCO upon a condition where hydrocarbon emissions exceed 250 lbs/day.

By setting these conditions and assuming the approximation of

monthly hydrocarbon losses = free leakage + flare stack leakage

the ICAPCD believed the free hydrocarbon leakage could be measured/ monitored. In a condition where the free leakage exceeded the 250 lbs/day limit, emission offsets would have to be obtained.

Since the flare header will be continuously purged with nitrogen, the continuous metering of the hydrocarbon relief emissions is not a straight forward procedure. The expected hydrocarbon in the purge mixture will be approximately 5000 ppm. Because of this low concentration, the ICAPCD's proposed measurement method would be restricted by the accuracy of flow instruments. The stipulated conditions were reviewed and a more plausible method for accomplishing this measurement was proposed.

Proposed method for measuring hydrocarbon leakage -- A gas meter can be used to monitor the nitrogen purge gas flow. At the same time the flow of the hydrocarbon-nitrogen mixture in the flare header can be sampled and analyzed to provide a ppm concentration of hydrocarbon present, thus making the hydrocarbon measurement periodic rather than continuous. To provide monthly rates of hydrocarbon flow to the flare, the periodic measurements can be averaged over the month. Since the average expected monthly losses would be approximately 3500 gallons (free and flare), it is unlikely the storage tank will be recharged on a monthly basis. Such relatively small losses would not warrant a truck delivery to the plant. However, by monitoring the storage tank level drop the storage loss could be approximated monthly. The difference between the storage loss and the loss to the flare would then represent an estimate of hydrocarbon leakage to the atmosphere.

If the calculated hydrocarbon emissions exceed 250 lbs/day, the pump stuffing boxes could be vented to the flare system to further decrease emissions by 25%. This could be accomplished in the field, if and when required, during a normal plant shutdown.

This proposal was presented to the ICAPCD and a meeting is scheduled on October 14, 1982, for further clarifications; preliminary communications indicate they will accept this alternate measuring method.

Meteorological Monitoring Program

Upon receiving the hydrogen sulfide (H_2S) monitor in late August, preparation began for the start of the meteorological monitoring program. Basically the program calls for at least one year of pre-operational data to be collected at the existing off-site met tower, to be followed by operational data collected at the plant site.

Pre-operational monitoring will include wind speed, wind direction, and H_2S concentration. Operation parameters to be monitored at the plant site will include wind speed, wind direction, H_2S, ambient temperature, and dew-point temperature. All five plant measurements will be inputs to the Data Acquisition System.

WBS 1.2.2 - POWER PLANT ENGINEERING, DESIGN, AND PROCUREMENT

OBJECTIVE:

The objective of this WBS element is to prepare engineering and design specifications and procure major equipment to build a nominal 65 Mw (gross) electrical geothermal power plant. Special studies also will be accomplished whenever required.

STATUS:

PROCESS/MECHANICAL ENGINEERING

Several changes in system criteria and requirements were implemented. These were based upon review, analysis, and evaluation of the process engineering development of performance, control, and operation of the power cycle. The major systems (brine, hydrocarbon, and cooling water) required modifications in order to meet these new requirements. The criteria and requirements will be covered in the following discussion as they pertain to the systems.

Hydrocarbon System

Much of the hydrocarbon system has remained relatively unchanged since the power cycle design review in June 1982, once the method of warming of the plant hydrocarbon heaters was established. See Figure 5 for the overall hydrocarbon system process.

A significant change in maintenance philosophy of heat exchangers, condensers, and turbine was implemented in the design of this system. No on-line maintenance of the condensers and heat exchangers will be performed while the unit is in operation; a plant shutdown will be required. This resulted in the elimination of two 60-inch valves in the turbine exhaust and double block and bleed valving on the heat exchanger inlet and outlet piping. Several underlying reasons resulted in this change of maintenance philosphy.

a. The reliability of heat exchangers of this particular design is considered high on the basis of past history with boiler feedwater heat exchangers and the rolled and welded tube-to-tubesheet connection to be utilized. Also considered were the materials of construction, moderately high brine and hydrocarbon pressures, and moderate operating temperatures. It was judged that the primary point of failure would be tube leakage at the tubesheet and these would be minimal due to the welded configuration.

b. It is not economical (heat cost versus revenue), to operate with only one heat exchanger train and the plant should be shutdown for heat exchanger repair.

c. Using double block and bleed valves on the turbine exhaust piping was prohibitive from a size and cost consideration and would offset revenue considerations. Condenser design is similar to the hydrocarbon heat exchangers with rolled and welded tube-to-tubesheet configurations. Therefore, expected reliability would be good and potential tube leakage would have a low probability (reference PL&G report SAN/RA50239-PLG-0180, dated June 1981).

d. The mean-time-to-repair the heat exchangers or the condensers could be reasonably low (reference PL&G report SAN/RA50239-PLG-0212, Revision 1, dated December 1981). Provisions have been made to facilitate the removal of the heads on the heat exchangers to minimize down time, labor, and equipment expenses.

e. Eliminating on-line maintenance of condensers and heat exchangers improves safety conditions. On-line maintenance requires the installation of blinds on the inlet/outlet piping of the condensers and/or heat exchangers. Because of the large line sizes (30 inch) and high pressures involved during such an operating scenario, the probability of hydrocarbon leakage is increased. Avoiding such an operating scenario eliminates this risk.

   PL&G recommended several approaches to improve overall plant availability which included valving out heat exchangers, either in pairs or individually. However, heat transfer performance and dynamic performance (i.e. pressure and temperature imbalance) of the heat exchangers would not allow achievement of the turbine throttle conditions unless costly control additions were made. The present system configuration will provide enough valving such that one train of heat exchangers may be isolated while the other remains in service. This provision could be used for special testing of the system equipment and/or the heat exchangers to define operational or performance problems prior to a shutdown for repairs.

Several operational/performance requirements for this system have been established which have simplified the design without jeopardizing equipment and/or hydrocarbon system performance.

a. The turbine bypass control valve and piping subsystem requirements will be limited to providing a means for bypassing 20% of the design hydrocarbon flow to the condenser prior to the synchronizing the turbine. Once the turbine-generator has been synchonized, the bypass control valve is closed. It is not used during a turbine-generator trip, loss of one or two hydrocarbon condensate/booster pump units, or any other plant trip mode. One of the major reasons for the reduction in the bypass provision is that the hydrocarbon design pressure is 850 psig, which is sufficient to "bottle" the working fluid pressure. Brine flow would not continue through the heat exchangers, but would be bypassed to the injection wells. This will be discussed in more detail later in this section of the report.

   It should be noted that control of the turbine bypass valve could be changed to open on a turbine trip, however, single hydrocarbon pump operation would have to be continued, which would increase the post trip load. The objective, however, is to maintain continuous operation of the downhole brine supply pumps for better realiability and allow return to service of the heat exchange system only on action by the control operator. This permits evaluation of the trip-related problems and a decision point to avoid potential damage to the system and equipment. The present approach also precludes the potential for scale deposition in the condensers due to over temperature if both cooling water pumps are dropped out during a trip.

b. Double block and bleed valves have been provided to isolate the booster/condensate pump pairs for on-line maintenance, that is, without requiring a plant shutdown. Figure 6 shows the locations of these valves.

Block and bleed valves are also required on the filter coalescers and the hydrocarbon transfer pump. The filter coalescers process 2% of design hydrocarbon flow to cleanup and continuously remove water from the system. As such the filter elements will require a change-out periodically. The transfer pump will be used to maintain liquid inventory in the condenser hotwells during start-up, normal, and shutdown operation.

The primary reason for providing these valves will be to allow continued operation of the plant while maintaining equipment which is easily isolatable, but which could require frequent maintenance.

c. Hotwell level control range was reduced from 10 feet normal level with 11 feet high/8 feet low levels to 6 feet normal level with 7 feet high/4 feet low levels. In so doing the liquid hydrocarbon inventory was reduced by 1000 barrels or 42,000 gallons. Storage requirement was also reduced by this amount.

As a result of the lower hotwell level, condensate pump net positive suction head available (NPSHA) was reduced. However, there is still a margin of 4.2 feet available NPSH over the required 19 feet at design point and a low hotwell level. Figure 7 shows details of relative elevations and variations of pump NPSHR versus flow. A lower normal hotwell also has the advantages of more ullage for swell on system heat up and surges during transient operation. The hydrocarbon liquid residence time is also shortened from 3 minutes to 1.7 minutes, however, this does not compromise pump and/or system operation since a means was provided to trip the condensate/booster pumps on decreasing hotwell level below the minimum of 4 feet. This feature should protect the pumps from operating with cavitation in the suction impeller.

d. Functionally, the hydrocarbon condensate pumps and booster pumps were combined in pairs or individual pumping units as shown in Figure 8. One condensate pump and one booster pump comprise a pump pair or operational pumping unit. Four pump pairs have the capability to achieve the maximum hydrocarbon flow requirement plus about 5% margin on rated discharge pressure for wear. This arrangement has several advantages: (1) Pump runout will be within industry accepted limits when one or more pump pairs trip as shown in Figure 9.

This provides inherent operational stabililty of the system and does not require additional controls to limit runout for pump protection. (2) Both condensate and booster pumps in any pair are protected if either of the pumps in a pair should trip. For example, if a condensate pump trips, the booster pump is also tripped. (3) The amount of piping, valves, and controls required to provide the pumps with the minimum flow capability was reduced by approximately 50% with the pump pair or unit approach rather than the headered approach. Figure 10 illustrates this difference. The minimum flow provision is required to protect the pumps from excessive wear and potential damage which occurs from high and unpredictable forces. These forces will act on bearings, shaft, wear rings, and wetted surfaces due to abnormal fluid velocities and internal hydraulic recirculation which could cause premature wear and failure. Usually, the minimum flow for a pump with closed, centrifugal impellers is 50% of the flow at the best efficency point. This is illustrated in Figure 11.

e. On plant-related turbine-generator trips, hydrocarbon flow will be automatically tripped and the hydrocarbon in the system between the pumps and the turbine stop valves will be bottled. An analysis confirmed that the maximum system pressure will be between 800 and 850 psia during this transient. The heat exchangers will be designed to handle this pressure. This approach simplifies the control logic substantially and at the same time precludes a return-to-service in automatic until Operations personnel have verified the trip cause and have performed corrective action and tests necessary to resume operation in a safe manner and without damage to equipment. Operator-initiated action will be required to restart the hydrocarbon pumps and synchronize the turbine-generator.

f. Start-up strainers have been added to the turbine inlet lines. These strainers will provide protection for the turbine blades and nozzle diaphrams from debris during initial turbine roll: These strainers will remain in place until start-up testing has been completed.

Brine System

The design of this system has developed substantially since February 1982. The operational function and performance requirements were defined. In addition the revised P&ID has been developed to the extent that the system piping and equipment layout is being implemented on the plant piping model. The following covers the major design issues involving operational concepts and criteria that have been resolved and implemented.

System Warmup -- The critical equipment that requires a controlled rate of warmup or temperature increase are the eight brine/hydrocarbon heat exchangers and the wetted surfaces of the brine return pumps. A rate of 50°F per hour for the heat exchangers was established and considered acceptable for stress distribution in the tubesheets, heads, tubes, and shells.

The process design has the required provisions to heatup the heat exchangers and system piping on both hydrocarbon and brine streams:

- One train at a time with the other off
- One train at a time with the other in service
- Both trains simultaneously, but will take more time due to extended cold-fill time

Piping and valves are also provided to warmup the brine return pumps independently and prior to warmup of the heat exchangers. This provision was necessary to accommodate the field operator's need to dispose of brine during the time production wells were being brought on for plant operation.

The warmup procedure involves the following very broad and general steps (refer to Figure 12):

- Fill the system with cold brine from storage until the system is full and completely vented,
- Circulate the cold brine through the system and continue venting,
- Established forced hydrocarbon flow at about 40% of design flow for one heat exchanger train,
- Start feed of hot brine to the cold recirculation stream and bleed same amount of mixed fluid to injection,
- Continue until operating temperatures have been achieved,
- Valve in hot brine supply, shut warmup feed down, valve in main injection piping, and shut down warmup bleed.

System Interface Requirements -- The brine heat exchange and return system physically interfaces with the brine field operational installation on the brine supply and injection systems (see Figure 13). As such, these physical interfaces, i.e., connections, impose dynamic operating requirements on the plant which must be addressed. Since March 1982, the brine supply and injection system dynamics and operating concepts have been identified, analyzed, evaluated, and accommodated in the design of the plant brine system and equipment.

System Head of Supply System/Plant System/Injection System -- Using data obtained from Chevron, vendors, the SDG&E/DOE proposal Volume III dated December 1979, and state-of-the-art hydraulic system analysis techniques, the integrated system head was calculated for various plant operational scenarios. System friction versus system flow is shown in Figure 14. Brine supply pressure characteristics at supply pump discharge versus flow is shown in Figure 15. The unusual shape of this curve is due to the well drawdown behavior versus pumped well flow and is based on Chevron data. As the flow demanded of the pumps is decreased, the total developed head of the pump increases; add to this the increasing static head of well fluid (decreasing drawdown) and the result is shown on the curves in Figure 16.

Figure 17 shows the net system head the brine return pumps must overcome to inject the desired brine flow. These curves are referenced to brine return pump total suction head. One significant point to recognize is that for flows up to about 10,000 gpm (Curve #3) and supply pumps operating to provide 300 psig at the wellhead, the plant brine return pumps are not needed. Another significant point is that this characteristic does not reduce the overall installed pump capacity. It does mean that plant auxiliary electrical load would be reduced and net power generation would be increased. This incremental increase in net power output will decrease as the brine flow increases to the design point.

The specification for flow and developed head for the brine return pumps will be based on these findings. The number of brine return pumps, their drives, and control will be optimized for a rangeability to cover the flow range from 10,000 gpm to 24,900 gpm, minimum flow, and runout. One candidate approach is to utilize four pumps, each rated for 25% of 24,900 gpm (end of run brine flow 24,900 gpm, 338°F) with hydraulic, variable-speed couplings and constant speed induction motors. The cost of brine, revenue, equipment efficiency, minimal technical risk, and impact on balance-of-plant design will be the major considerations in selecting the approach.

<u>Brine Supply and Injection Pipelines/Cold Fill and Warmup</u> -- No provisions have been made to fill these pipelines using plant equipment, except that the plant bypass could be used by the geothermal field operator to accomplish a cold fill. The warmup of these lines will be accomplished by reason that they will be in service during the plant brine system warmup operation.

It should be noted that nitrogen purge connections provided on the plant brine piping could also supply nitrogen gas to the supply and injection piping. The nitrogen would be used to purge the line of air during long shutdowns for cleaning, modifications, or other maintenance in order to minimize the potential for corrosion.

<u>Integrated Operation Requirements and Criteria</u> -- The field operator is requiring that brine flow variation be limited to 80% to 100% of rated downhole pumps capacity during normal operation. Normal operation is defined as load change transients, constant load operation, plant-related trips, and controlled plant shutdowns. Any of the above conditions apply whether we are operating on one or two heat exchanger trains.

The objective of this requirement is to minimize downhole pump problems and improve their reliability in order to achieve the expected plant availability of about 77%. It is evident that if the installed capacity of the downhole pumps is not achieved nor available, then the plant will not achieve its expected capacity or availability.

In order to meet the 80% to 100% brine supply pump capacity range, the heat exchanger-return pump bypass arrangement shown in Figure 18 was provided. Furthermore, the plant post-trip load forecast includes all brine supply pumps. That is following a plant trip, all brine supply pumps will remain on and will be discharging through the bypass line to the suction of the injection pumps. The injection pumps will also remain in operation following a trip.

The bypass line and the bypass pressure control valve are key elements in the design and integrated operation of the brine supply, heat exchange, and injection systems. The line and valves will be sized to accommodate the capacity of brine flow required at end-of-run conditions.

System design pressure will be 850 psig to cover the downhole pump discharge pressure transients. This pressure rating eliminates the need for pressure relief valves on the heat exchanger tube side, which was previously designed for 300 psig. Both the shell and tube sides of the brine/hydrocarbon heat exchangers have equal design pressure ratings.

The bypass control valve will be automatically controlled to modulate the amount of brine through the plant heat exchangers. On plant-related trips or loss of the IID system, the valve will open fully to handle the entire brine flow. The bypass system under all operating modes will be full of fluid and pressurized above the saturation pressure of the brine at 360°F to prevent flashing.

<u>Overall System Features</u> -- A simplified process flow diagram of the overall system, including supply and injection wells and process piping, is presented in Figure 19.

a. Cold Brine Supply/Storage/Cold Fill -- Cold brine can be provided to fill the plant brine system from the hot brine supply via a takeoff to the brine cooler. The cold brine produced in this manner will then be routed to the 25,000 gallon brine flash drum. No pump will be required to accomplish this operation since the available brine supply pressure, 250 psia, is sufficient to achieve the desired flow, approximately 100 gpm. This process will be initiated and monitoried locally by the operator and will be primarily a manual operation. Only the brine flow to the cooler will be controlled automatically by a flow controller with manual set point adjustment. All pressure, temperature, and flow indications will be local. It should be noted that this process could be accomplished with the plant in operation without significantly affecting the overall plant operation.

   Nitrogen gas purge was provided to minimize the level of dissolved oxygen in the cold brine. The drain to the brine sump was provided for tank cleanout and inspections. The take-off to supply the fill pump suction will be at some level above the brine storage tank boot so as not to introduce scale precipitates into the fill pump and/or brine system piping and equipment.

   Cold fill will be accomplished by the fill pump valved to discharge to the plant system. The cold fill operation will require about four hours per train. The proper number and location of valves, including piping, will be provided such that either train can be filled with the other in operation.

b. Warmup Circulation/Hot Brine Feed and Bleed -- Warmup circulation flow will be accomplished with a brine return pump regardless of whether the final number of pumps is three or four, which are presently under evaluation. Two brine return pumps will have the provisions necessary to operate either pump in this mode. Only one pump will be needed for the desired recirculation flow of about 3,500 gpm (one-train warmup) or 7,000 gpm (two-train warmup). A pressure control valve in the recirculation line returning to the system will be provided to maintain a stable system pressure during the warmup cycle. In a fixed-volume, closed-loop operation such as this, the pressure control valve will act as a surge control. A pressure differential controller will maintain the loop pressure at about 20 to 25 psia higher than the injection line to allow feed-and-bleed of brine during warmup. Control will be automatic, but with local set point adjustment. Operation and monitoring will be local, with local instrumentation.

c. Brine System Control -- Control of the brine system warmup was covered in previous sections. In summary, control will be primarily a manual operation by operator-initiated action and set point adjustment of local control valves. The fill pump will be operated from a local on/off station. When the recirculation process is initiated, the brine return pump selected for this operation will be started and controlled remotely to achieve the proper flow and discharge head.

When the plant is operating normally at loads above synchronizing flow, but less than or equal to maximum gross generator output, the brine flow is automatically controlled. In general, the brine flow will be controlled on demand signals from the heater outlet hydrocarbon temperature (305°F setpoint) and the hydrocarbon flow (variable). The hydrocarbon temperature will "fine-tune" the hydrocarbon/brine ratio control, which will also compensate for fouling in the heat exchangers.

On load increases, the brine flow will be picked up by either the hydrocarbon flow ratio control or the hydrocarbon vapor temperature. If the vapor temperature is not maintained, the load pickup will be automatically interrupted until this temperature is at or above 305°F. This feature will serve to protect the turbine from hydrocarbon liquid droplet impingement and potential damage.

The brine flow will remain unchanged under the following conditions:

- Loss of one cooling water pump, or

- Plant-related trip of the turbine-generator other than loss of brine return pumps.

During these conditions, a cutback in brine flow will be accomplished remotely by the control operators after evaluation of the event and its cause. This feature was provided primarily to maintain brine flow from the wells at or above the 80% level for downhole pump protection and reasonable return-to-service time. Plant-related trips will be frequent during start-up and the risk of exercising the downhole pumps will be excessive without this feature. Furthermore, this feature will provide reasonable assurance that the hydrocarbon throttle temperature will be above the 305°F required.

Four power actuated valves are provided in the brine inlet and outlet piping of the brine/hydrocarbon heat exchangers. The inlet valves will be either full-open or shut and serve to either isolate or line-up the heat exchanger train for impending operation. Isolation of the heat exchanger train(s) brine side could be initiated by a turbine-generator trip or under controlled conditions by remote operator action. The outlet valves function will be similar to the inlet valves, but with the additional feature that they can be position-modulated by the control operator. This feature was provided to allow the operating personnel to switch operation of the plant from one train to the other without a shutdown, only a load reduction. It will also provide a means to "balance" the brine-side system hydraulics so as to achieve equivalent thermal performance on the hydrocarbon side; specifically, equal hydrocarbon vapor outlet temperature, 305°F, and pressure, 575 psia. Obviously, the hydrocarbon system controls will allow flow adjustments to be made so as to achieve these desired throttle conditions.

Each of the brine return pumps will be provided with suction and discharge isolation valves for the purpose of on-line maintenance, controlled warm-up of the pumps, and placement in service. Check valves are provided to prevent reverse rotation of the pump on normal shutdown of any of the pumps for matching flow to unit load. These check valves would also prevent a pump start under reverse rotation, although this capability will be specified in the pump specification.

Cooling Water System

The physical design of this system, its function and interface with the hydrocarbon system and service water systems has not changed (see Figure 20). Some operational and control concepts; though, have been improved in the following areas:

Circulating Water Pump Discharge Valve Control -- Each main circulating water pump will have a discharge valve, which will be power actuated. Upon initiation of a pump start, the valve will remain in the closed position for a preset time before it begins to open. The underlying reason for this feature is to prevent hydraulic shock on pipe bends and condenser tubesheet. Any time the system is filled, either when the system is initially commissioned or following maintenance shutdowns, there will be air pockets in the system piping and equipment. Uncontrolled, random opening time on the pump discharge could sweep the air pocket at too high a rate, which would reduce or eliminate the "cushion" effect of the air as it compresses from the pump discharge fluid and pressure.

The technique of utilizing the entrapped air in the system to cushion the hydraulic loads imposed during a circulating water pump start is employed in typical once-through, utility cooling water systems. The air "bleed-off" or venting would be achieved at selected high point vents in the cooling water piping.

An analysis will be conducted to establish the required time delay in starting the valve actuation and the opening time required. The analysis is pending the selection of the main cooling water pump supplier.

Automatic Closure of Cooling Tower Blowdown Valve -- This valve will be used to control basin solids below 4000 ppm total dissolved solids in order to meet the NPDES permit limit. As such, this valve will be modulating as basin solids increase or decrease. However, it will never be fully open or closed when the plant is in operation. Therefore, when both cooling water pumps are off, this valve will receive a signal to close. Until recently, the valve logic had no such feature and when both pumps were off, the valve would have been open and as a result piping from the top of the condenser to the blowdown valve and piping from the valve to the top of the cooling tower would have been drained.

The logic required to shut the valve will be implemented using the cooling water pump starting controller contacts, a programmable controller (digital relay) and solenoid valves in the drive air to the valve actuator.

Power Actuated Condenser (Water-Side) Isolation -- Each condenser will have an inlet and outlet valve, both 54 inches in diameter. Initially, these valves were provided with gear operators for actuation, but now because of the large valve size, accessibility, anticipated high frequency of operation, ability to balance water flow through the two condensers operating in parallel, and limited number of field operators on a shift, the valves will be actuated with motor operators.

Cooling Water Pump On/Off Logic -- The planned on/off logic for these pumps will be as follows:

- Two pump operation -- The control room handswitch of one pump in the on or manual position. The handswitch for the second pump in standby (spring return). On a turbine-generator trip, the pump in manual remains on, the other trips.

- One pump operation -- The nonoperating pump selector switch is in standby and will start automatically if the operating pump trips.

Cooling Tower Fan Operation -- Tripping the cooling tower fans on loss of the plant was investigated as a means of reducing the post-trip electrical load carried by the Imperial Irrigation District system, and maximizing the amount of power available to maintain operation of the downhole brine pumps. It was determined that the cooling tower could achieve the specified approach to wet bulb of 20°F, with all cells flowing, no fans in operation, and one cooling water pump operating at design water flow. Approximately 2,500 horsepower could be allocated to operating the downhole brine pumps if the tower fans were tripped during a plant trip. During normal operation each cell will require a fan.

Hydrocarbon Unloading and Recovery System

Four areas of this major auxiliary system are covered in this report as they have a direct bearing on design, operation, and safety considerations.

Hydrocarbon Storage (Overall) -- A primary function of the system is to store the 90% isobutane/10% isopentane working fluid. Initially, a single sphere capable of storing the mixture was provided in the design. The sphere, with a total volume of 8,100 barrels (340,200 gallons), physically interfaced with the condenser hotwells (via the transfer subsystem), liquid/vapor recovery piping and equipment, and the unloading piping and equipment. The working fluid was to be delivered as a mixture with the proportions noted above.

The volume of the storage tank was decreased to 7,100 barrels (298,200 gallons) when analysis of the hotwell inventory, i.e. liquid level and residence time, and condensate pump operation showed that the nominal operating hotwell level could be reduced from 10 feet to 6 feet. This finding will result in some cost reductions associated with the sphere and working fluid inventory. However, safety and fire protection provisions, i.e. deluge system piping, hydrocarbon leak detection, flame detection, will not decrease.

The current single tank design exceeds the LPG tank capacity limitation stipulated in the California Occupational Health and Safety Orders. The Safety Orders limit tanks in non-refinery applications to 90,000 gallons. A design which incorporates multiple tanks under the 90,000 gallons limit would increase material and construction costs by about $500,000. The Project plans to apply for a variance from the capacity limitation of the Safety Orders from the Cal/OSHA Board. The first step in this variance procedure is to seek the concurrence of the local authorities for the single tank design prior to filing for an application. An initial meeting with the Acting Imperial County Fire Chief to discuss the fire protection system design, as well as the storage tank issue, will be held in early October.

The single sphere has design, operational, and cost advantages over the multiple-sphere (probably four) storage approach as shown in Table 1. It was concluded that these advantages are significant enough to warrant the effort of obtaining a variance.

Separate Hydrocarbon Component Storage/On-Site Mixing -- During a joint DOE/SDG&E/Fluor design review meeting in March 1982, it was recommended that provisions for separate storage of isopentane and the working fluid be incorporated in the design of the storage system. The primary reason was to have the capability to maintain the 90% mol isobutane/10% mol isopentane composition of the working fluid over a reasonably long period of operation, in the order of one year. At that time, there was no capability for adjusting the component percentages to the specified valves should the mixture, as delivered, be outside the tolerances of those that would be desired, less than ±1% mol.

After further evaluation of operational flexibility and the potential to obtain cycle performance data on a variation of working fluid composition, such provisions were made and the design revised as shown in Figure 21. The unloading system now has a 50,000 gallon vessel for storing isopentane. Pure components will be delivered to the site; pure isobutane will be loaded into the main 7,100 barrel-capacity sphere. On-site mixing will be accomplished by adding isopentane to the isobutane until the desired mixture, monitored with analyzers, is achieved.

Hydrocarbon Liquid Recovery -- Initially, the system was to receive liquid inventory from the main hydrocarbon system by means of static head differential between the main system and the liquid recovery system. This concept was abandoned because sufficient static head would not be achieved unless either the hydrocarbon system equipment and piping were elevated or the liquid recovery piping and equipment, were below grade, which would result in open pits. Neither approach was considered to be proper because the first would result in excessive cost for seismic design, platforms for valve operation, and piping material, and the second would compromise the safety of the plant by allowing the collection of "pockets" of working fluid vapor in the pits.

Forced or pumped liquid recovery, shown schematically in Figure 22, was selected to accomplish the function of transferring or recovering liquid from the main system during a shutdown of the unit for maintenance purposes. Four small vertical centrifugal pumps, strategically placed to minimize suction and discharge piping runs, will be used for the recovery operation. The discharges of these pumps will be manifolded and routed through the filter coalescers to the large storage sphere. The filter coalescers, which will filter 2% of the design hydrocarbon flow when the plant is operating, will also filter the liquid recovered so as to prevent accummulated particulates and water, that will "hide-out" in large equipment and piping, from contaminating the main storage sphere.

Vapor Recovery Compressor -- The recovery of working fluid existing in the vapor state within the system takes place after most of the liquid has been recovered. The vapor recovery compressor functions to recover the vapor and bring the pressure of the main hydrocarbon system and equipment to 2 psig. Initial design of the system provided for two 100% compressors, one of them in standby in the event the in-service compressor should fail. An analysis was conducted which compared the cost of hydrocarbon lost (flared-off) if no compressor were available versus the installed cost of the redundant compressor. The results showed that initial, installed cost of the backup compressor was equivalent to flaring approximately 60,000 gallons of liquid working fluid. In other words, the single vapor recovery compressor would have to fail about 67 times, based on 900 gallons lost per failure. This rate of failure, about three times per year for 20 years, is not realistic. Therefore, only one vapor recovery compressor will be provided for the vapor recovery system.

After liquid and vapor recovery operations have been completed, the balance of working fluid vapor remaining in the system is removed with a vacuum pump and flared.

Relief and Flare System

The function of this system is to safely dispose of hydrocarbon vapor produced by: the need to purge the main hydrocarbon system for maintenance; discharges from the safety relief valves; purge of the hydrocarbon storage vessels for maintenance; disposing of "out-of-spec" working fluid from the filter coalescers; and thermal relief valves when sections of piping and/or equipment are isolated for maintenance or operational reasons.

Of the above broad functional operations, the most critical will be the flaring of the various safety relief valve discharges since they will result in significant flow of hydrocarbon and heat release at the flare stack. As such, a significant effort to analyze the operational conditions and the resultant flow of hydrocarbon vapor to the flare was made. The findings were as follows:

- A relieving rate of 208,000 lbs/hr was calculated on the basis of a fire under the large storage sphere, a zero pressure rise once the relief pressure has been reached, and a base or uninsulated tank. It was also calculated that insulating the sphere with a material having a thermal conductivity of 4 btu/hr-ft^2-°F that insulating the relief rate could be reduced by 70% from 208,000 lbs/hr to 62,400 lbs/hr. The storage sphere, however, will not be insulated since the cost of insulation is far greater than the savings that would be realized in reducing the size of the sphere safety relief valves and their discharge piping runs to the relief header.

- The system design and operational complexity was simplified by removing the piping, which tied-in the discharge from the safety relief valves on the brine-side of the brine/hydrocarbon heat exchangers. The design criteria for depositing brine vapor generated from relieving brine to prevent overpressure in the heat exchangers will be discussed in the Brine Collection and Wastewater Disposal section.

Safety relief valves and discharge piping to the relief and flare system from the back-up recovery compressor were eliminated because the back-up compressor was removed from the design.

Brine Collection and Wastewater Disposal System

The purpose of this system is to collect brine, which has been drained from the brine return system equipment and piping. Excluded will be the brine drained from the 2.5 mile long injection pipeline, which will be designed, built, owned, and operated by the geothermal field operator. That portion of the system designated for wastewater disposal will function to collect oily water and oil from equipment, such as the turbine-generator, chemical wastewater from the chemistry laboratory, rainwater collected on-site, and waters used during maintenance which has become mildly contaminated and would be suitable for direct discharge to the Beech Drain via the rainwater sump and pumps.

Brine Collection System -- The initial system design concepts to achieve the intended purpose of this part of the system have been changed rather extensively as more requirements imposed by the brine return system and heat exchanger operation/maintenance were defined.

The system configuration shown in Figure 23 is the concept now being implemented and will serve to collect brine from the heat exchange and return system. The capability to relieve hot brine under design pressure, about 250 psia, is no longer required because the brine-side pressure rating of the heat exchangers has been changed from 300 psig to 850 psig. This change was made in order to meet high brine supply pump discharge pressure during low brine flow transients. The brine flash tank will be used to "flash-down" hot, 360°F, brine from the system should it be necessary to do so in an emergency. This tank will also store cold brine for filling up the heat exchange loop. A separate vent stack, about 50 feet high and 14" diameter, will be provided to dispose of brine vapor and noncondensables from the brine flash tank rather than discharge vapor-gas mixture to the flare stack. The tank was sized on the basis of anticipated, worst-case condition of a two-tube leak, 90 psia on downstream side of heat exchanger relief valve, 20 psia in the flash tank, and two-phase pipe flow between the relief valve and tank.

A brine collection sump will be provided to hold the equivalent volume of brine contained in one heat exchanger train and associated system piping. This brine will then be disposed of via a vacuum truck to an authorized disposal site. The brine disposal sump pump and booster pump, which would have been provided to dispose of waste brine, were eliminated. The reason for this action and the revised approach was to minimize corrosion of the injection pipeline.

Wastewater Disposal System -- Several changes to this system have been implemented because the functional requirements have been defined for the plant, environmentally and operationally.

a. A concrete berm will surround the sulfuric acid storage tank and will be sized to hold the full capacity of the tank. If a catastrophic failure of the tank should occur, the spillage within the berm will be disposed of by contract with a company experienced in chemical spill cleanup.

b. Oily water collection will be by several small sumps located under or adjacent to equipment, i.e., the turbine-generator uses substantial amounts of oil for lubrication and scaling. The oily water would then be disposed of by vacuum truck. This approach has eliminated the need for a central sump, sump pumps, oil/water separator, storage of water-contaminated oil for future disposal, and underground sump collection piping. It is expected that the sumps will need to be emptied only three to four times a year. The initial cost savings will be $43,000 in piping pumps and separator. The annual cost for maintaining the sumps is estimated to be between $500 and $1,000 per year.

c. Chemical wastes from the chemistry laboratory will be collected in a small sump, neutralized, and either trucked off-site or piped to the plant sanitary waste drain. This decision has not yet been made.

d. Rain water will be disposed of by the storm water collection system and sump pumps to the Beech Drain.

e. The septic tank and backing system to dispose of sanitary wastes has been eliminated. These wastes will be piped to the Heber Public Utility District (HPUD) sewage system.

Water Treatment and Distribution System

This system had initially encompassed the equipment necessary to provide potable water for sanitary and plant utility uses. The source was the plant make-up water supply, raw Colorado River water. In-plant distribution is also part of the system design.

The HPUD made it known to SDG&E that they were interested in providing the plant with potable water and sewerage services. HPUD provided a cost estimate for a 6" water supply extension, a 6" sewer line extension to the plant property, plus the cost of water. A cost evaluation of this alternative versus the cost of proposed plant equipment, operation cost, and maintenance cost was performed. The analysis showed that it was more economical to proceed with the HPUD alternative of installing a 6" water supply and 6" sewer.

Service Water System

The purpose of this system is to provide cooling for several plant auxilliary equipments such as lube oil coolers, generator hydrogen gas coolers, and other small, miscellaneous heat transfer equipment. A complete, up-to-date, listing of the various cooling equipment fed by the service water system is shown in Table 2, the present system process flow diagram.

The most significant change in the system design concept was from an open-loop to a closed-loop system with a supply (cold water) header and a return (hot water) header. From these headers, the various cooling loads are connected. This supplies temperature control for each individual cooling load without affecting the pressure and flow controls of the supply and return headers.

As more vendor information is made available, the system requirements on flow demand will be refined. At this time we believe that no further reduction in the service water flow and cooling requirements will be achieved. However, the refinements referred to above deal primarily with overall system control and cooling duty verifications. There is adequate margin on both service water flow, 15%, and on the heat transfer duty, about 20%, to cool the service water.

The service water will be cooled in plate heat exchangers, which could receive additional plates to increase heat transfer duty up to 40% without any increase in size of the equipment or space. This would not be possible with the standard tube and shell heat exchanger configuration.

Service water pump size was reduced by 50% from the initial estimate on the basis of investigation of requirements with potential vendors of plant major equipment prior to and during the bid process. As such, the number of service water circulation pumps was reduced from three 50% pumps to two 100% pumps.

One of the pumps will be for standby in the event the in-service pump fails. The standby pump could also be used for additional circulation capability during the summer months and unseasonally high temperatures impact the main cooling tower performance. The service water will be cooled with main cooling water via the service water cooler pumps located in the tower basin.

The service water system inventory will be maintained by make-up from the cooling water system make-up supply. Chemical treatment of the service water for corrosion inhibition and biological fouling will be done at the storage tank (25,000 gallon capacity), but fed from the chemical treatment systems that treat the main cooling water.

Diesel Generator System

The purpose and function of this system are unchanged, however, the requirements affecting the amount of plant equipment that must be transferred to this system during a complete separation from the IID electric system were evaluated and changed. This evaluation resulted in a significant reduction in size of the unit from 600 KW to 400 KW.

The equipment that will be powered by the diesel-driven generator are listed in Table 3. A 10% margin for future requirements and for running this equipment in the service factor range, between 1.1 to 1.15 times rated amperage.

As a result of the size reduction, the fuel oil storage tank, transfer pumps, and associated piping were eliminated. It was determined that sufficient fuel storage could be provided by the vendor's standard equipment. Fuel storage will provide 16 hours of full-load diesel generator output. Historically, IID system outages have lasted two to six hours with a frequency of about four to six times a year. In addition, there are several suppliers of diesel fuel in the Imperial Valley, which could dispatch bulk delivery of fuel within one or two hours on immediate request.

Plant Piping Model

The system designs discussed are now in the process of being modeled in 3/8"-to-the-foot scale model at the offices of Fluor. To date all of the systems and their related equipment, piping, and valves have been initiated, with the exception of the inert gas system and the miscellaneous gas sytem (hydrogen and carbon dioxide for the main generator).

The model reflects changes discussed in this report. Pictures of some of the key process areas modeled to date, are presented at the end of this report.

ELECTRICAL ENGINEERING

Auxiliary Electrical System

Detailed engineering and equipment procurement activities continued for the plant auxiliary electrical system. A simplified single-line diagram of major electrical system connections is shown in Figure 24. The technical constraints imposed by the need to start 4000 Hp induction motors were of primary consideration in developing this arrangement.

The decision to use a generator breaker in lieu of separate start-up and running auxiliary transformers was based on economic considerations. The "emergency" 480 volt bus will serve essential plant loads during normal auxiliary system maintenance or IID 34.5 KV system outages. Alternate supplies to this bus will be from the diesel generator and IID's 12.5 KV distribution lines.

Total auxiliary system load is estimated at 23 Mw for start-of-run and 29 Mw for end-of-run conditions. These numbers include the production island load which is supplied from the plant auxiliary electrical system via two 4160 volt feeders. Consequently, output power delivered through the main transformer to IID's 34.5 KV transmission lines will be true net unit output.

Transmission System Interface

SDG&E performed computer studies to estimate the voltage dip at the Calexico and Valley Substations while the 4000 HP motors are starting. IID found the estimated voltage dip to be acceptable. SDG&E also performed computer studies to investigate the transient impact on IID's transmission system immediately following a full-load plant trip. Preliminary indications are that the transient impact will not adversely affect IID's system.

Site Development-Electrical Package

Design work was completed for the electrical installations included in the site development package. This scope of work includes: ground grid; main and shop building power and lighting systems; streetlighting;

provisions for future installation of telephone communications in buildings; and a construction power distribution system.

Construction power will be supplied from IID's distribution lines via a 12 KV/480 volt transformer. This same supply will later be used as an alternate source for the auxiliary electrical system emergency bus.

CIVIL/STRUCTURAL ENGINEERING

Hydraulic Model

A hydraulic model study for the main cooling pumps intake structure will be conducted. The objective of the study is to verify all hydraulic characteristics and flow patterns to assure the satisfactory performance of the main cooling pumps. The model will also be a tool to optimize the preliminary layout of the intake structure, transition, and cooling tower basin.

All bids for the model study have been received and reviewed. Contract award is pending selection of the cooling tower and pump suppliers.

Turbine-Generator Pedestal

The top of the turbine-generator pedestal was raised to elevation (+) 4'-0" (mean sea level), which brings the total thickness of the concrete pedestal to about 14', including the foundation mat. The elevation is dictated by the requirements to maintain a gravity drain for the lube oil system and to avoid piping interferences at the operating deck level.

A solid concrete pedestal was chosen instead of a framing structure. It was decided that the massive form work required for the latter option would offset its saving in concrete.

Concrete Pipe Racks

Based on the cost-benefit evaluation performed by Fluor, site-cast, precast concrete pipe racks are to be used for the Project. Compared to the steel structure sprayed with cementitious fireproofing, the concrete alternative offers the following advantages:

- Lower installed cost
- Better durability
- Better fire resistance
- Better appearance

AVAILABILITY/RELIABILITY ENGINEERING

Pickard, Lowe & Garrick (PL&G) completed the last in their series of reports on the reliability and maintainability of major plant components. The last of these reports was on the principal valves. The majority of

PL&G's work was completed with the submittal of their availability assessment on the definitive design, the remainder of PL&G efforts centered on the completion of an availability assessment on the final design. The completion of this task will be dependent upon the finalization of the plant design.

QUALITY ASSURANCE

Vendor Surveillance Program

Dravo Utility Constructors, Inc. (Dravo) was selected as the contractor for developing and implementing the Vendor Surveillance Program (VSP). The primary objective of the program shall be to provide assurance to the Sponsors, through a documented record of in-plant inspections of vendor manufactoring processes, that equipment classified as Category I meets the technical requirements of the contract.

Category I-Equipment Classification -- Based upon the combined industry experience of SDG&E, Fluor, and Dravo, a Category I equipment list was developed, which was composed of equipment that has historically necessitated vendor surveillance. Supported by this experience, the Category I list includes the majority of equipment that meet one of the following criteria: (1) equipment which must operate to keep the unit on line, (2) equipment which has an impact on the immediate safety of personnel or other equipment, or (3) equipment which has a cost in excess of $100,000. The Category I list includes, but is not limited to:

- Hydrocarbon Turbine Generator
- Brine/Hydrocarbon Heat Exchangers
- Hydrocarbon Condensers
- Cooling Tower - Cooling Tower Fans and Motors, and Cooling Tower Fire Protection
- Brine Return Pumps and Motors
- Hydrocarbon Condensate Pumps and Motors
- Hydrocarbon Booster Pumps and Motors
- Main Cooling Water Pumps and Motors
- Fire Extinguishing Systems
- Main Transformer
- Auxiliary Transformer
- Generator Breaker
- 34.5 KV Power Circuit Breakers
- Medium Voltage Switchgear
- DAS-DCS Control Cabinets and Panels
- Diesel Generator
- Fire Pumps
- Brine and Hydrocarbon Prefabricated Piping
- Water Treatment Package

Vendor Surveillance Program Development -- The VSP was developed by starting with Dravo's standard vendor surveillance procedure and modifying it to reflect the Project's normal equipment procurement specification. The way the improved VSP shall work will be as follows:

A vendor surveillance plan shall be developed for each Category I equipment procurement. Surveillance plans shall primarily include a Source Inspection Requirements (SIR) list and a tentative schedule of source (vendor) inspections.

Procurement specifications will state minimum mandatory in-process factory testing to be performed by the vendors. In addition, equipment vendors will submit a list of shop inspections for SDG&E's review and selection of those inspections which SDG&E wishes to witness. This selection will be made by SDG&E's representatives (Dravo and Fluor), through an analysis of the procurement technical specification requirements and the vendor's manufacturing processes. The witnessing of selected shop inspections and tests shall provide maximum visibility of the vendor's compliance with the technical specification requirements. The SIR list shall identify required inspections or tests to be accomplished or witnessed by Dravo personnel. The method of verification, witness and hold points, and inspection instructions will also be defined on the SIR. Based upon information provided by SDG&E, Fluor, and the vendor, a tentative schedule of source inspections shall be developed for each piece of equipment. The resulting individual Category I equipment vendor surveillance plan shall consist of the following:

- Conference with each equipment vendor to discuss, coordinate, and schedule intended in-plant inspection activities.
- Periodic review and reporting to SDG&E of program status.
- In-plant inspection of vendor's manufacturing, testing, and in-house quality control procedures, and documentation of all inspections.
- Processing, coordinating, and compiling VSP documentation by equipment item for delivery in a orderly and timely manner.
- Final inspection, review, and technical acceptance.

Application of specific tasks to individual contracts shall depend on the criticality and cost of the items being procured.

PROCUREMENT

Turbine-Generator Contract

On August 9, 1982, the turbine-generator supplier (Elliott) offered a reduction to their contract price if an alternate generator produced by Brown Boveri Turbomachinery (BBT) was accepted. This generator, built by BBT as a standard Electric Machinery (EM) generator for the gas turbine market with no customer type specifications, has electrical characteristics identical to what was originally proposed by EM. In addition, this existing generator makes use of an EM design, carries the EM nameplate, and would be warranteed and serviced by them.

Elliott advised the Project of the total specification differences. In addition they advised that some of these differences would be eliminated for proper turbine interface or modified by EM to bring the generator more in line with the contract specification at no additional cost to the Project.

Following negotiation of the needed contract changes, submital of manufacturing documentation, certifications, inspection, and available test records, factory acceptance tests were conducted the week of September 20, 1982. Acceptance of the proposed substitution is pending review of data collected during these tests.

Procurement Status

Fluor issued bid evalautions/recommendations for SDG&E's approval on the following procurements:

- Fire Pumps
- Generator Breaker
- Non-Segregated Phase Bus
- Service Water Circulating Pumps
- Air Compressors and Dryers
- Brine/Hydrocarbon Heat Exchangers
- Hydrocarbon Condensers
- Hydrocarbon Condensate Pumps

WBS 1.2.3 - POWER PLANT CONSTRUCTION

OBJECTIVE:

The objective of this WBS element for Phase I is to provide construction input to the architect/engineer during the design of the power plant to allow construction in an orderly, cost effective manner. In Phase II, efforts will focus on actual construction of the geothermal binary power plant.

STATUS:

Reporting in this section includes progress made as construction input to the power plant design and preparation for actual construction.

During this period, the construction management effort was focused on preparation of Site Development bid packages. The Site Development work was split into two phases: Phase I consisted mainly of earthwork and drainage, while Phase II consisted of building work and underground utilities. Also, a bid package was prepared for Site Testing Services. Pursuant to this effort, the following list describes major tasks accomplished:

Document Review

Final reviews of Fluor design documents were performed on both Phase I and Phase II drawings and specifications. The main purpose of these reviews is to reduce the potential for contract changes during the course of performance of the work by lump sum contractors. Emphasis is placed on constructability, construction cost, contract interfaces, and correction of design errors. Reviews continued on miscellaneous documents for future contract packages.

Contract Administration

Contract documents for Site Development Phase I and Phase II were finalized including scope of work; special, general, and miscellaneous provisions; contract exhibits; detailing drawings; technical specifications; and prevailing wages. Documents were assembled, printed, and provided to those contractors who expressed an interest in bidding the work. A pre-bid meeting was held on Site Development Phase I to answer specific questions of the bidders. Addendums and letters of clarification were issued to further clarify bid documents. A consent package was prepared after Phase I bids were received and evaluated.

Document Development

Specifications and drawings were developed for laydown area grading, construction power distribution, and a temporary warehouse building.

Erection specifications were generated for the hydrocarbon storage sphere and cooling tower for inclusion into Fluor procurement documents.

Cost and Scheduling

Cost breakdown/progress billing forms were developed for the Site Development bid packages.

The Project Master Control Network (PMCN) was updated for inclusion into Site Development bid packages. This schedule is a bar chart form indicating timetable for all major activities for the entire project. Refer to Figure 25 for a summary of the construction schedule.

The Construction Detail Activity Schedules (CDAS) were developed for each of the bid packages. This schedule is a precedence network showing individual tasks within major activities.

The Fluor procurement logs were compared against the procurement activities of the PMCN.

Estimating

A fair cost estimate was completed for Phase I for use in the bid evaluation. Work was started on the Phase II estimate.

Field Work

A survey crew was dispatched to check contours within the site boundaries. Elevations were found to be reasonably close to those shown on contract drawings.

WBS 1.2.4 - POWER PLANT START-UP

OBJECTIVE:

The objective of this WBS element is to start-up, check-out, and test the completed power plant. This effort shall include the necessary personnel training and the correction of equipment or system problem areas identified during plant start-up.

STATUS:

During this period SDG&E continued to collaborate with Dravo's Power Plant Test and Operations personnel in reviewing and updating the Summary Start-up Procedures. This procedure outlines in general terms the activities and responsibilities of construction contractors and SDG&E Start-up Task Force. SDG&E in-house work continued on the start-up planning and procedures manual.

WBS 1.2.5 - PROJECT MANAGEMENT

OBJECTIVE:

The objective of this WBS element is to provide Project management by establishing interfaces and control between SDG&E, the heat supplier, the architect/engineer, the construction manager, other subcontractors, and the Sponsors; defining schedules and reporting progress based on actual accomplishments; finalizing procedures for management, engineering, start-up, and design, construction cost and scheduling, accounting, procurement, and reporting; providing cost control by combining estimating, recording, reporting, analyzing, forecasting, and trending of cost data; monitoring work package budget estimates and reporting progress; negotiating and administering Project agreements and contracts; coordinating legal, public information, geothermal heat supply, and procurement activities; and preparing, reviewing, and publishing information regarding the technical status, cost, and schedules of the Project.

STATUS:

Reporting in this section includes progress made in Project Management as indicated by the negotiation and execution of Project agreements and contracts, and by the accomplishment of establishing interface and control between SDG&E, the Sponsors, and Project subcontractors.

During this period, three modifications to the Cooperative Agreement between DOE and SDG&E were executed.

Modification A006 obligates DOE to their share of incremental cost, for the extended Phase I, covering the Fluor Power Services contract. This extension covers the period of June 1982 through August 1982, with the total Fluor extended cost being $1,534,000. Because Fluor's Phase I contract ended on June 1982 this interim "extended Phase I" modification was needed to cover engineering, design, and long-term procurement while the Phase II definitive estimate was being prepared for approval.

Modification M007 evokes Attachment O to OMB Circular A-110, thereby eliminating the need for DOE consent for procurements in most cases. This will reduce the procurement cycle time by as much as four weeks. This development is a direct result of a DOE examination of SDG&E procurement procedures, which concluded that SDG&E's procedures are consistent with government procurement policies. Performance under Attachment O will still require SDG&E to submit for consent any noncompetitive procurements (sole source) or scope of work changes to existing contracts that exceed a $5,000 value. Noncompetitive procurements of less than $5,000 will require the DOE contracting officer's verbal approval.

Modification A008 definitizes Project costs through construction (Phases IIA and IIB of Appendix A, Statement of Work, of the Cooperative Agreement). All subsequent components of Phase II, because of their irresolution at this time, will be negotiated at a later date. Additionally in this modification DOE obligates funding through January 31, 1983, and extends the term of the Cooperative Agreement to continue until June 30, 1987.

The revised SDG&E/State Assignment Agreement was executed on July 15. This agreement assigns approximately 4.3% of the ownership interest and approximately 1.7% of the cost responsibility from SDG&E to the State of California for their $2,000,000 contribution to the Project.

As a result of the State Assignment Agreement mentioned above, the Imperial Irrigation District opted to reduce its ownership pro rata share by about 0.5%. This agreement was executed by SDG&E on August 25.

The use or sale of power from the Heber power plant requires that it be transmitted over IID's 34.5 KV line between the Valley and Calexico Substations. Technical studies have indicated that the line must be upgraded for it to be capable of carrying the loads from the plant. An SDG&E/IID Heber Line Construction Agreement was drafted to provide for IID performing the line upgrade and billing the Project, through SDG&E as Project Manager, for the costs of the upgrade. The participants in the Project will receive credits on transmission charges from IID in return for the expenditures to upgrade the line. These principles come from the Heber Participation Agreement. The principles for handling the transmission charge credits are laid out in this Construction Agreement. The exact method of handling these credits will be dealt with in transmission service agreements the participants will establish with IID. This Agreement is scheduled for execution in January 1983.

An SDG&E/IID Heber Plant Connection Agreement was also drafted to provide for the physical arrangements for connecting the plant to IID's system, how the power flows will be metered, and what SDG&E's and IID's obligations are in terms of scheduling, receiving, and dispatching power production from the plant. This Agreement is also scheduled for execution in January 1983.

The Sponsors' Technical Committee met on July 14, in a combined meeting with representatives from SDG&E, Fluor, PL&G, and DOE Review Panel members. The following items were discussed: Project schedule, equipment procurement status, availability assessment, model development, and the power cycle review.

The Sponsors' Management Committee met on July 15, and were brought up to date on the following subjects: federal and state funding, state and IID agreements, pending modifications to the Cooperative Agreement, groundbreaking ceremony, engineering status, schedule status, and Project costs. In addition, they were asked to approve Amendment 1 to the Geothermal Sales Contract.

The House of Representatives Appropriations Subcommittee filed a report explaining the Energy and Water Development Appropriation bill, which makes appropriations for energy and water development for the fiscal year ending September 30, 1983. The report was adopted by the full Appropriations Committee on September 21, and included $30 million in Fiscal Year 1983 funds for the Heber Binary Project. It is expected that the bill will go to the full House of Representatives during a special session, which is likely to be held following the Thanksgiving Holiday. The Project expects that both the House and Senate will take final action on this bill early in December and complete a conference prior to the departure of Congressman Burgener. This would "bank" the entire $61 million for the Project.

WBS 1.3
POWER PLANT DEMONSTRATION

WBS 1.3.1 - DEMONSTRATION ACTIVITIES

OBJECTIVE:

The objective of this WBS element is to demonstrate reliable and economic geothermal power generation.

STATUS:

No activity occurred on this WBS during this reporting period.

WBS 1.4
DATA ACQUISITION AND DISSEMINATION

WBS 1.4.2 - DATA ACQUISITION, ANALYSIS, AND DISSEMINATION

OBJECTIVE:

The overall objective of the data management effort is to acquire, store, evaluate, and report Project data to the energy generation industry and to other parties interested in liquid-dominated geothermal power plant performance. The intended result is to stimulate commercial development of hydrothermal resources in the United States.

STATUS:

During this period the requirements for the data acquisition system, which were formulated earlier in the year, were incorporated into the Central Control System specification. Battelle/Pacific Northwest Laboratories began the preliminary design of their proposed systems for the detection of hydrocarbon in water/brine and water/brine in hydrocarbon. This design was reviewed by Fluor and SDG&E, and comments were forwarded to Battelle. Battelle will complete the design of the leak detection units, as well as fabricate and operationally test one of each type of unit. In addition to the work on the leak detection units, a similar design review was completed on the on-line corrosion monitoring system.

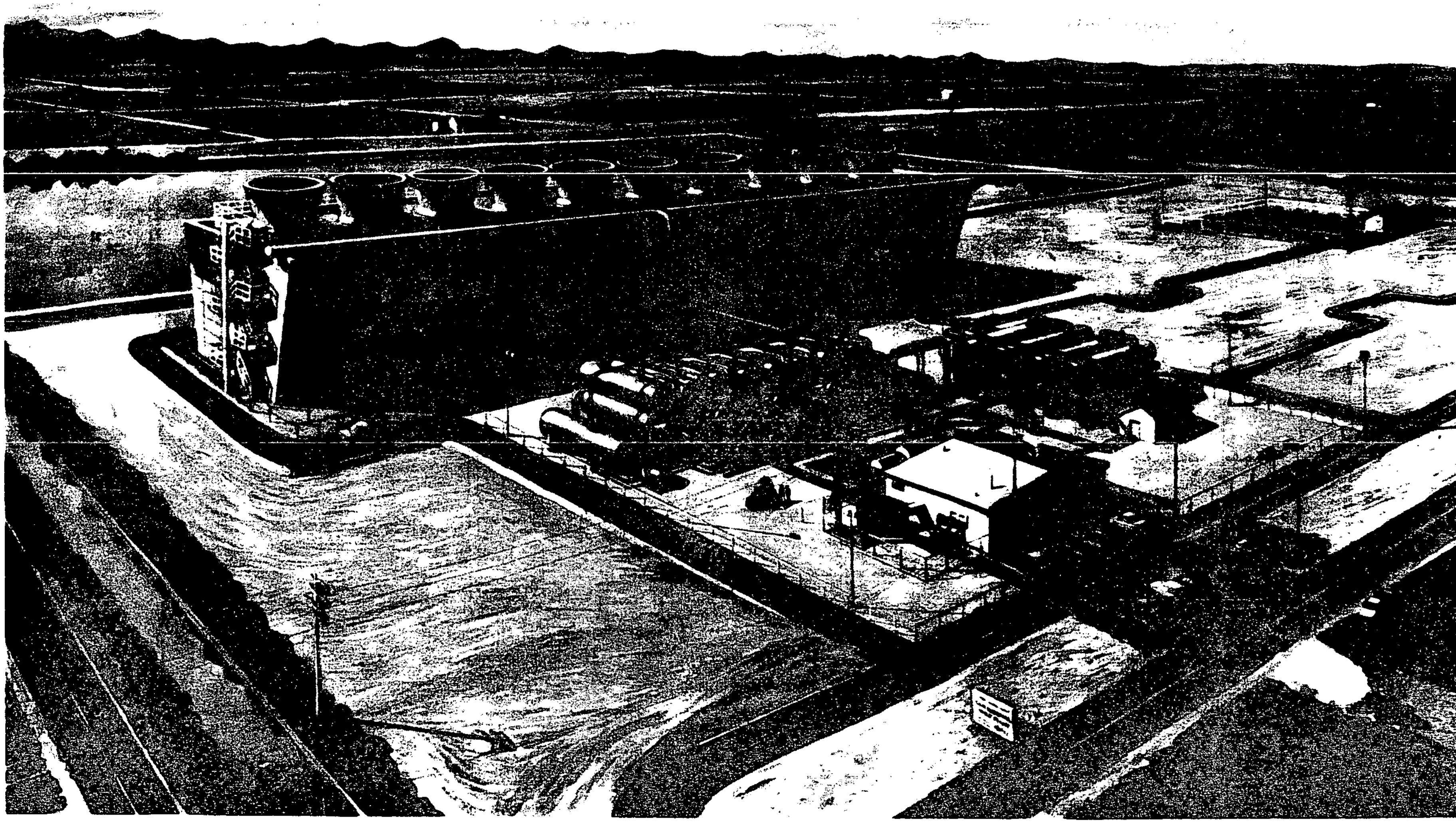


FIGURE 1
ARTIST'S RENDERING

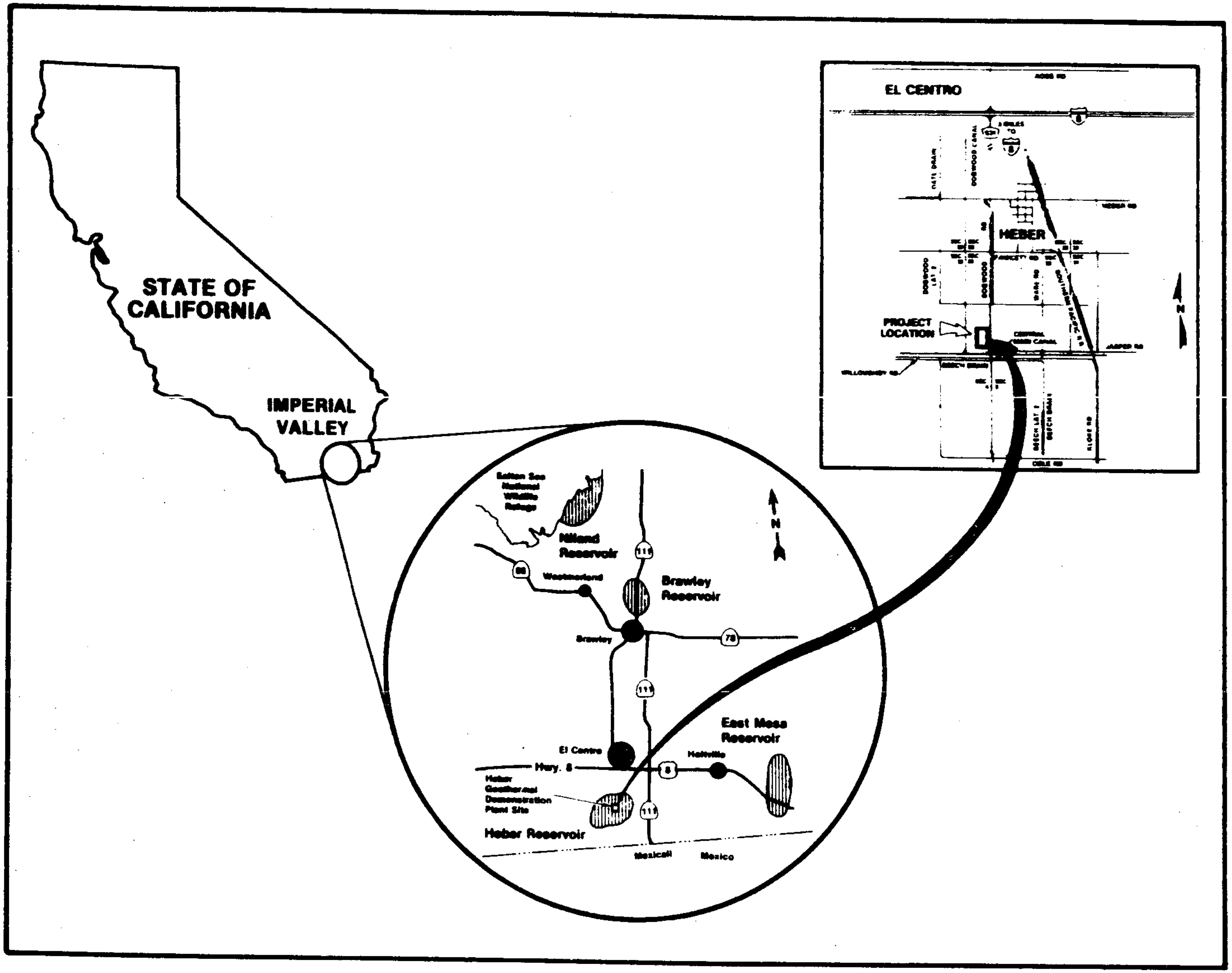


FIGURE 2
PROJECT LOCATION

SPONSOR	FUNDING	OWNERSHIP
U. S. DEPARTMENT OF ENERGY	50.0%	---
ELECTRIC POWER RESEARCH INSTITUTE	10.0%	---
SAN DIEGO GAS & ELECTRIC COMPANY	31.3%	82.5%
IMPERIAL IRRIGATION DISTRICT	3.8%	10.0%
DEPARTMENT OF WATER RESOURCES	1.2%	3.2%
STATE OF CALIFORNIA	1.7%	4.3%
SOUTHERN CALIFORNIA EDISON COMPANY	2.0%	---

FIGURE 3
FUNDING AND OWNERSHIP PARTICIPATION

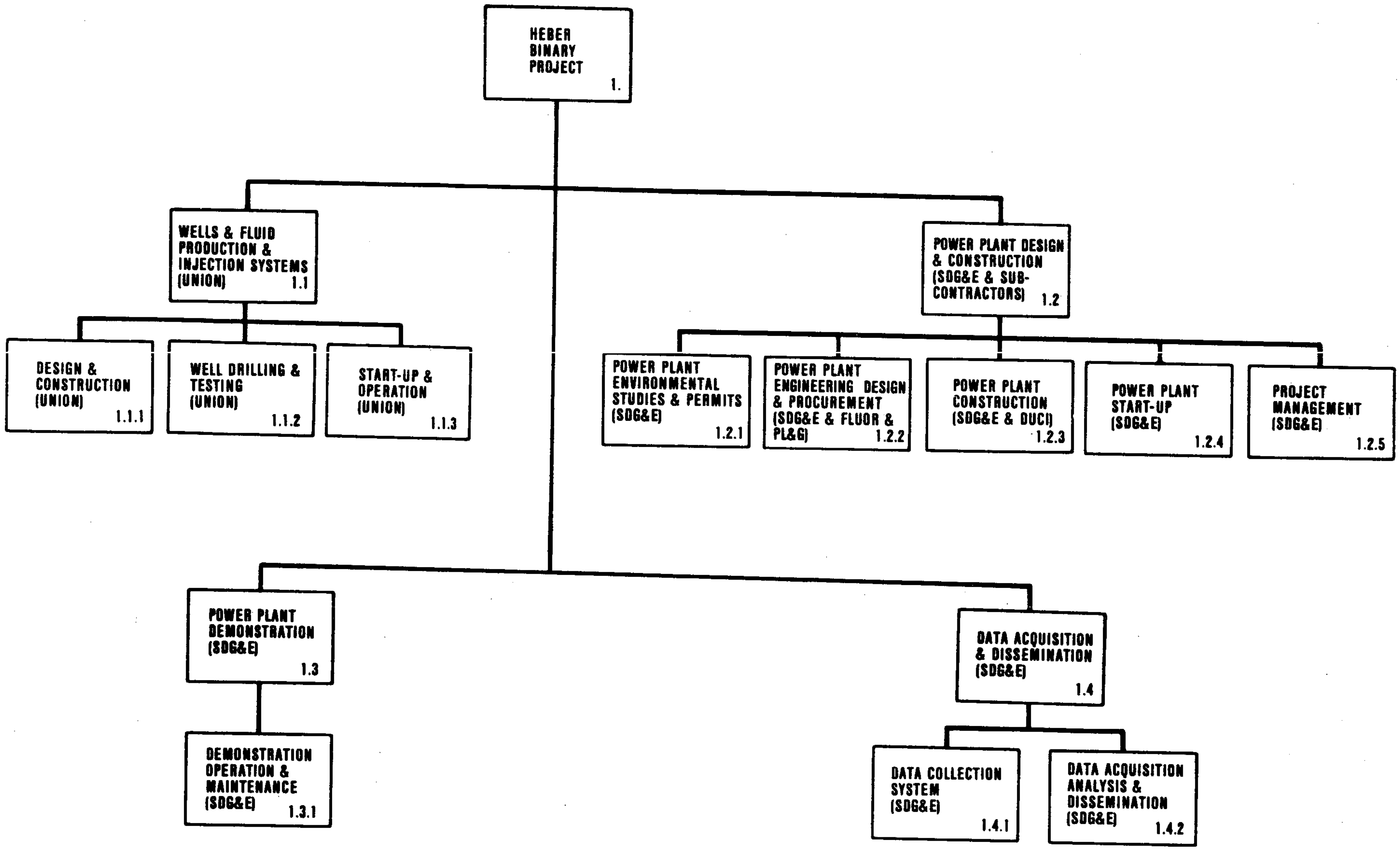


FIGURE 4
WORK BREAKDOWN STRUCTURE

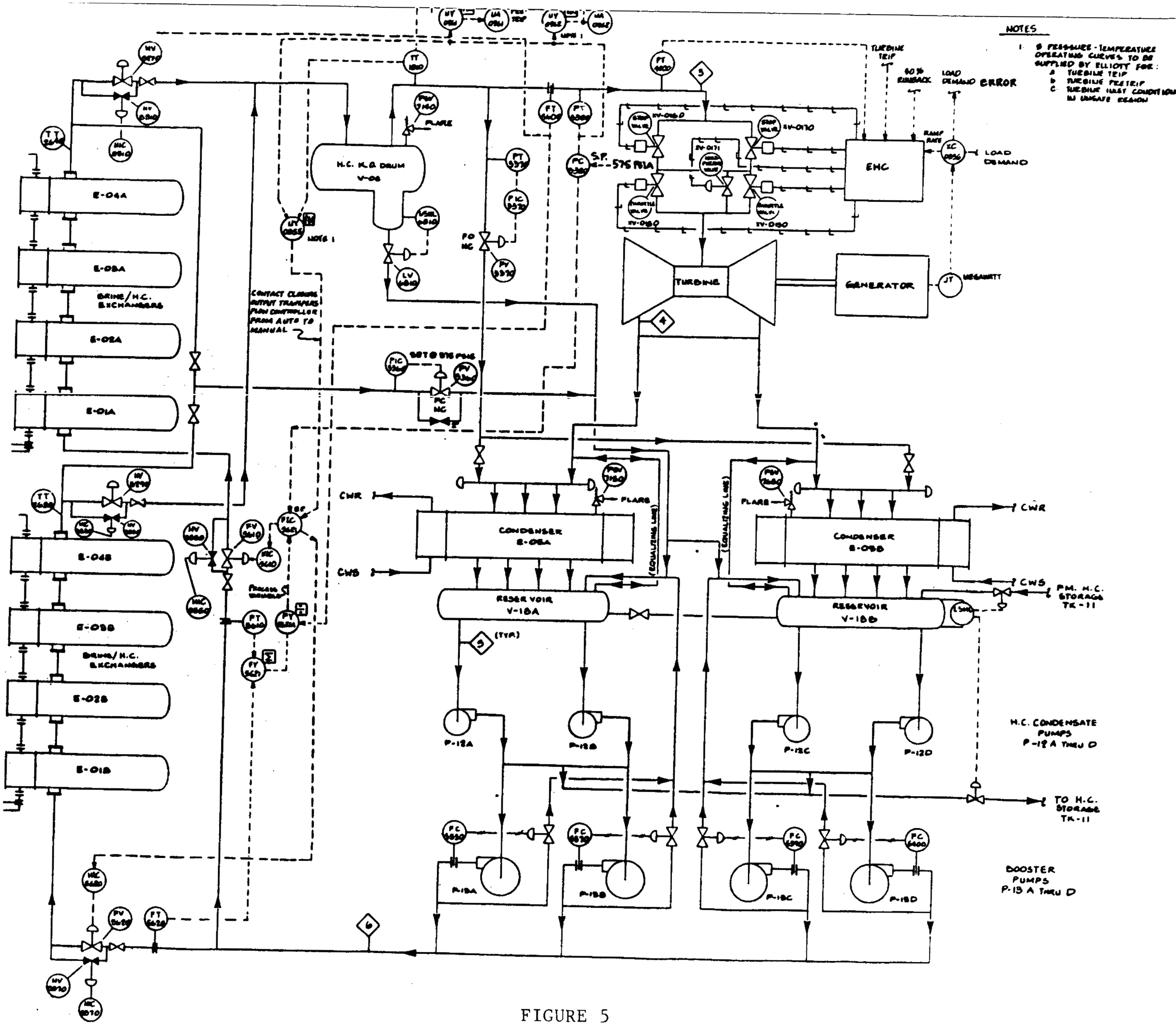


FIGURE 5
HYDROCARBON SYSTEM PROCESS FLOW DIAGRAM

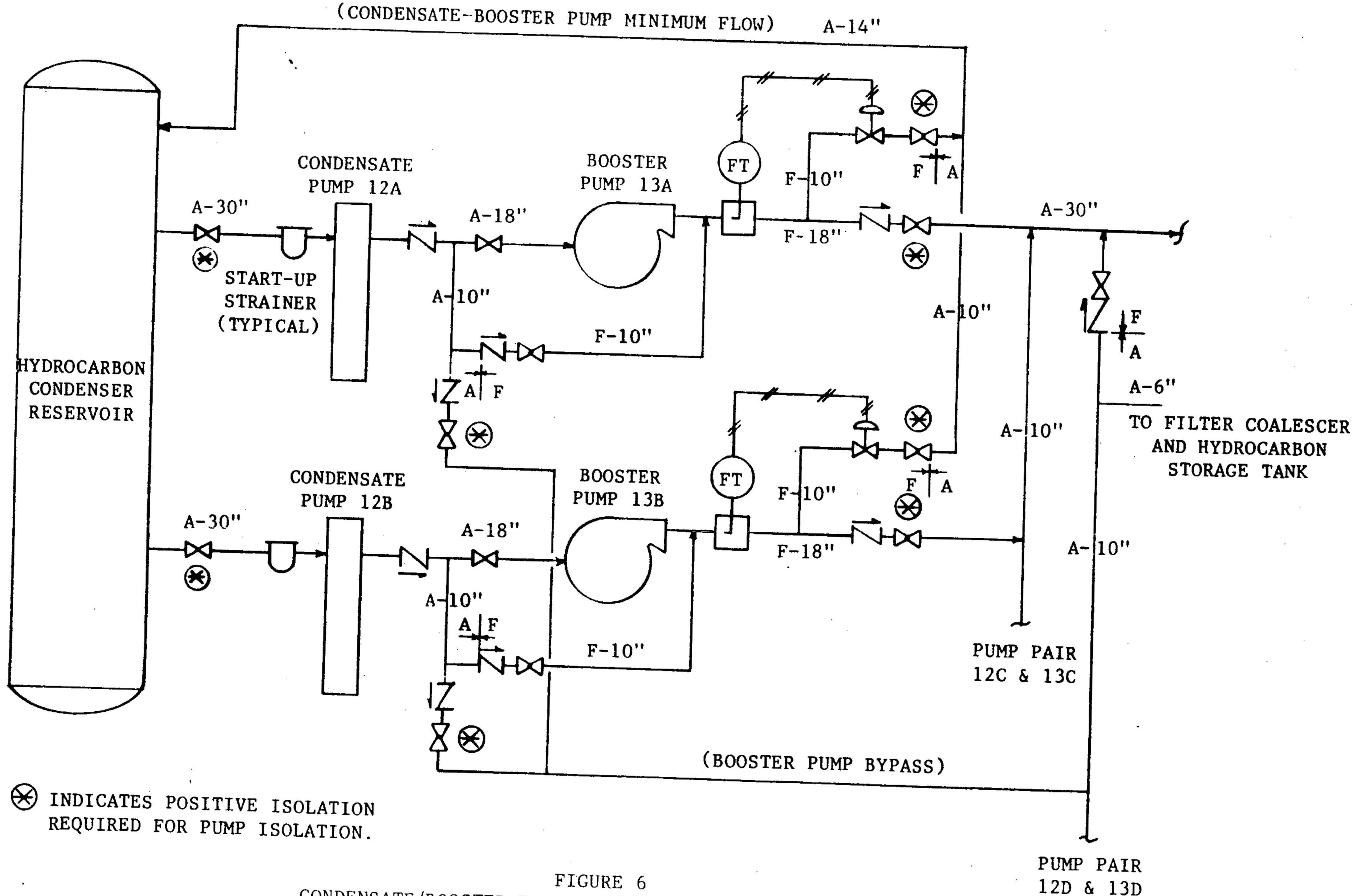


FIGURE 6
CONDENSATE/BOOSTER PUMP DOUBLE BLOCK AND BLEED VALVES

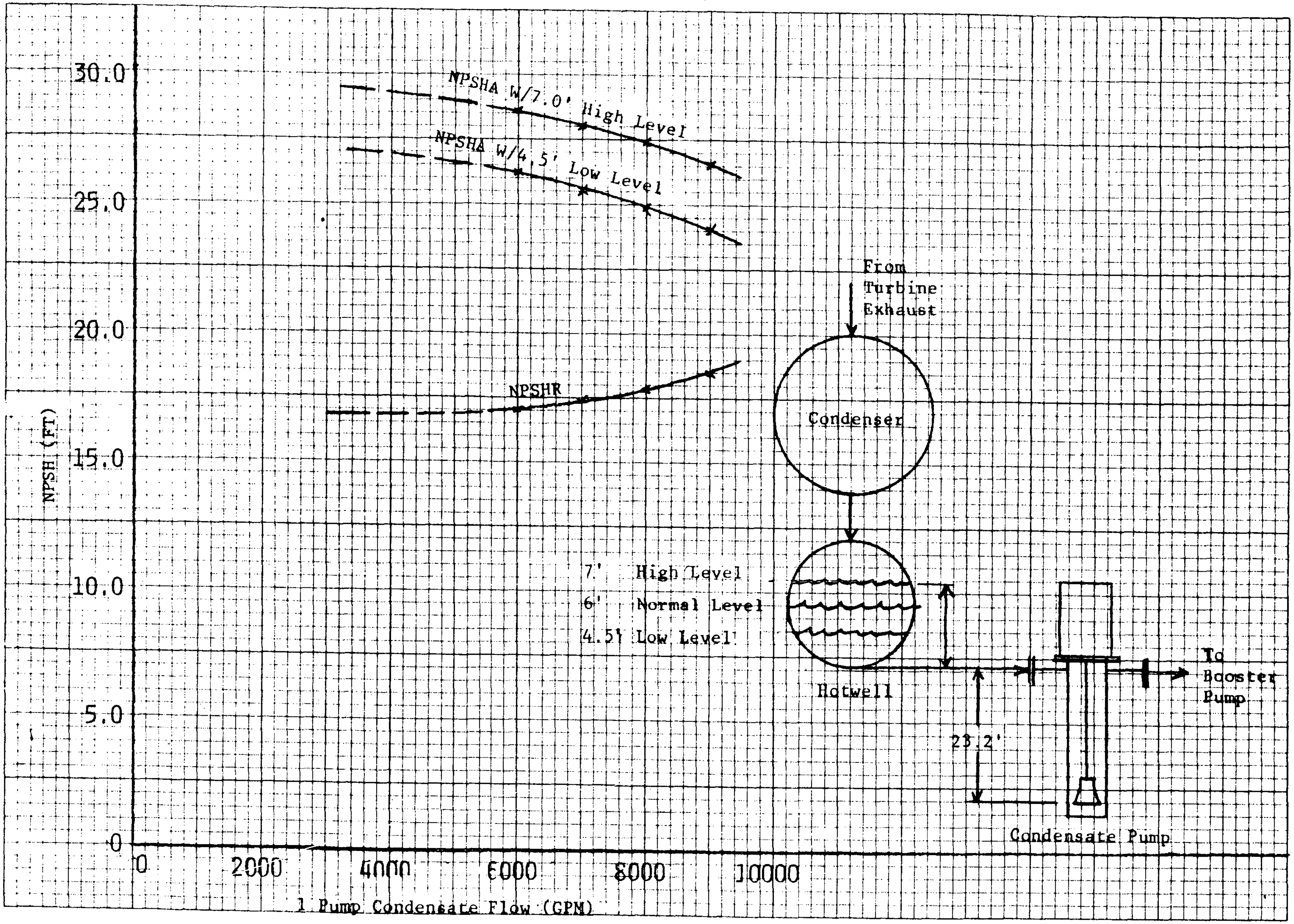


FIGURE 7
REDUCTION OF CONDENSATE PUMP NPSHA DUE TO LOWER HOTWELL LEVEL

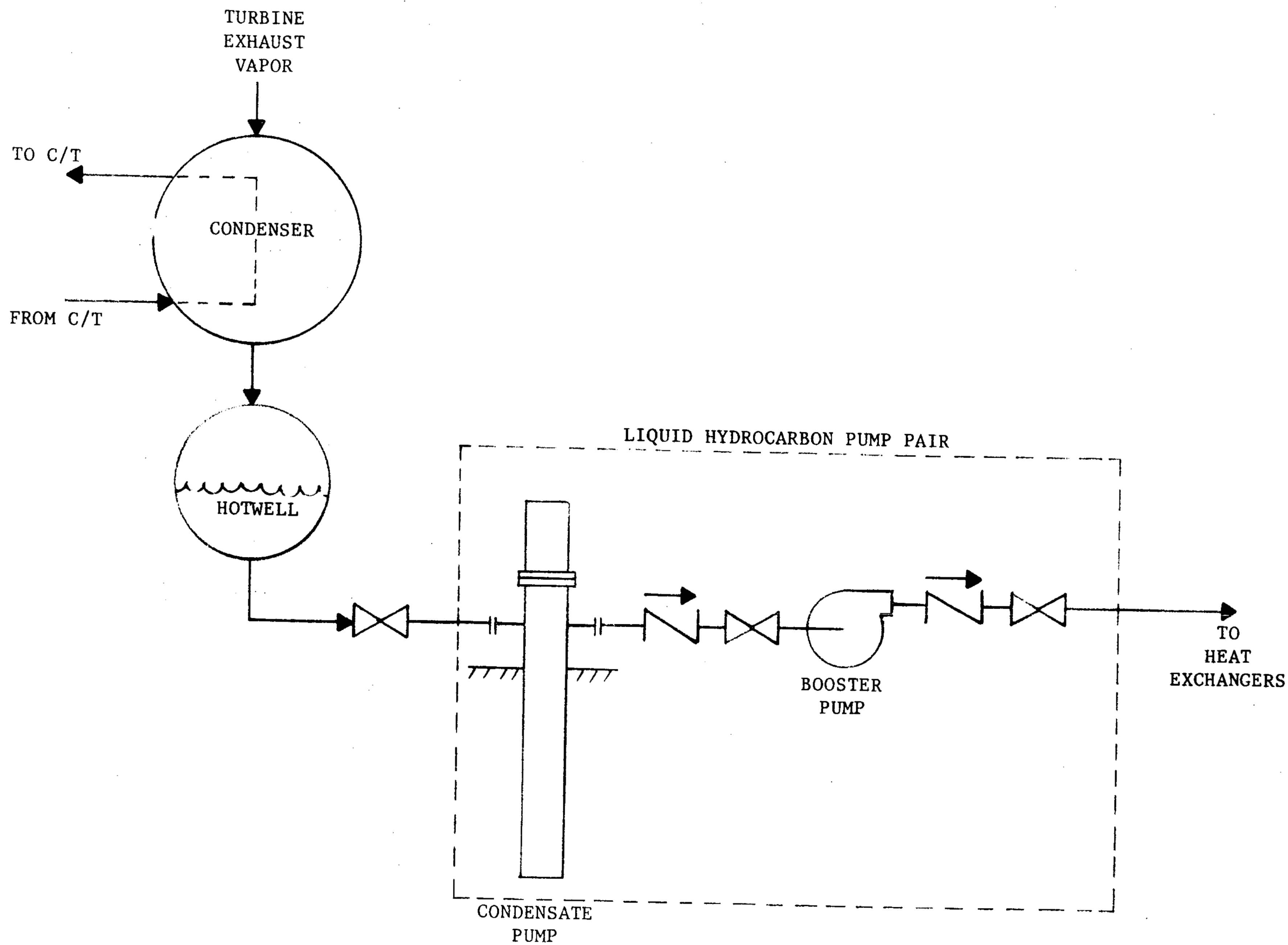


FIGURE 8
HYDROCARBON CONDENSATE/BOOSTER PUMP PAIR

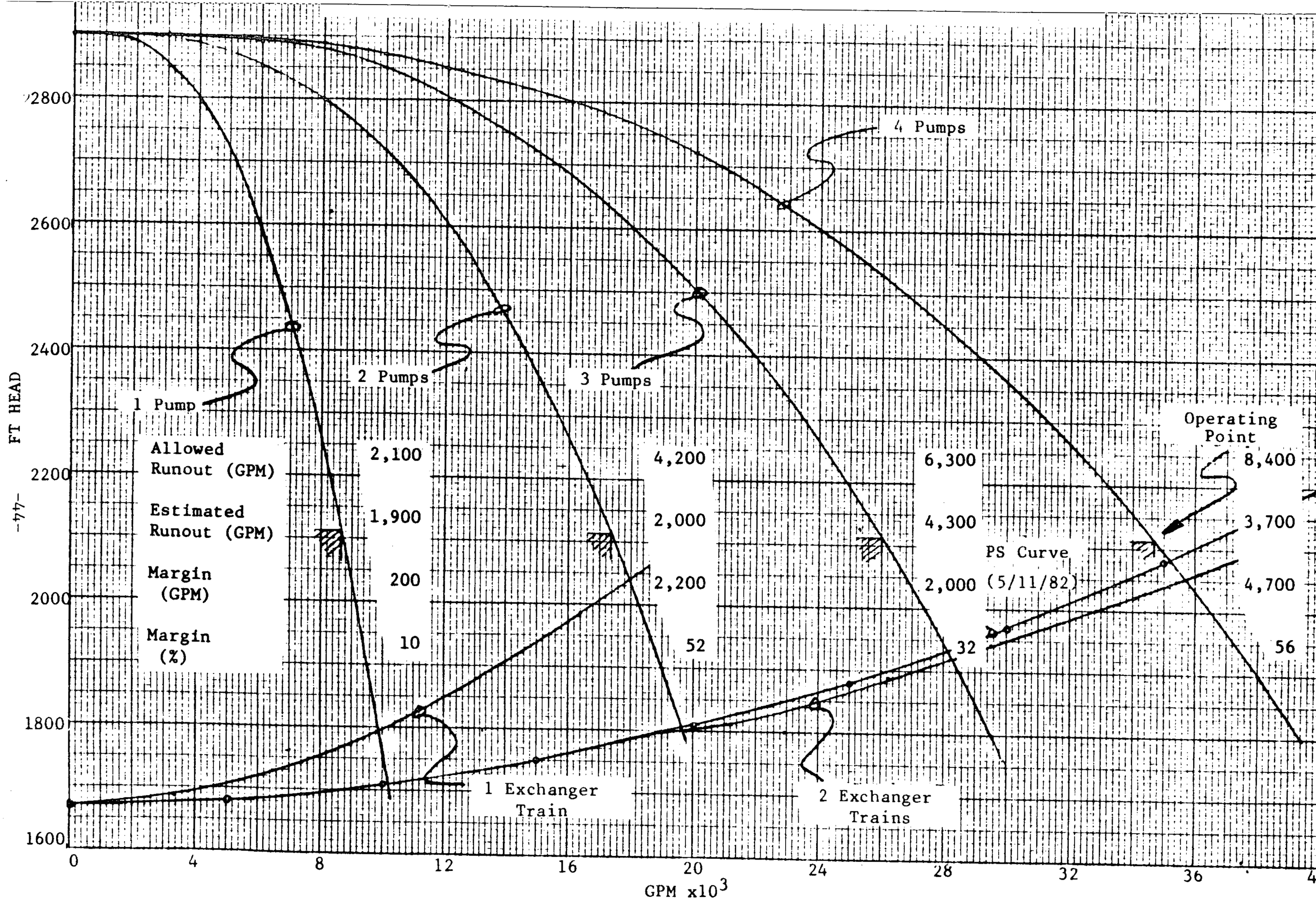


FIGURE 9
SYSTEM HEAD CURVE - HYDROCARBON BOOSTER PUMPS

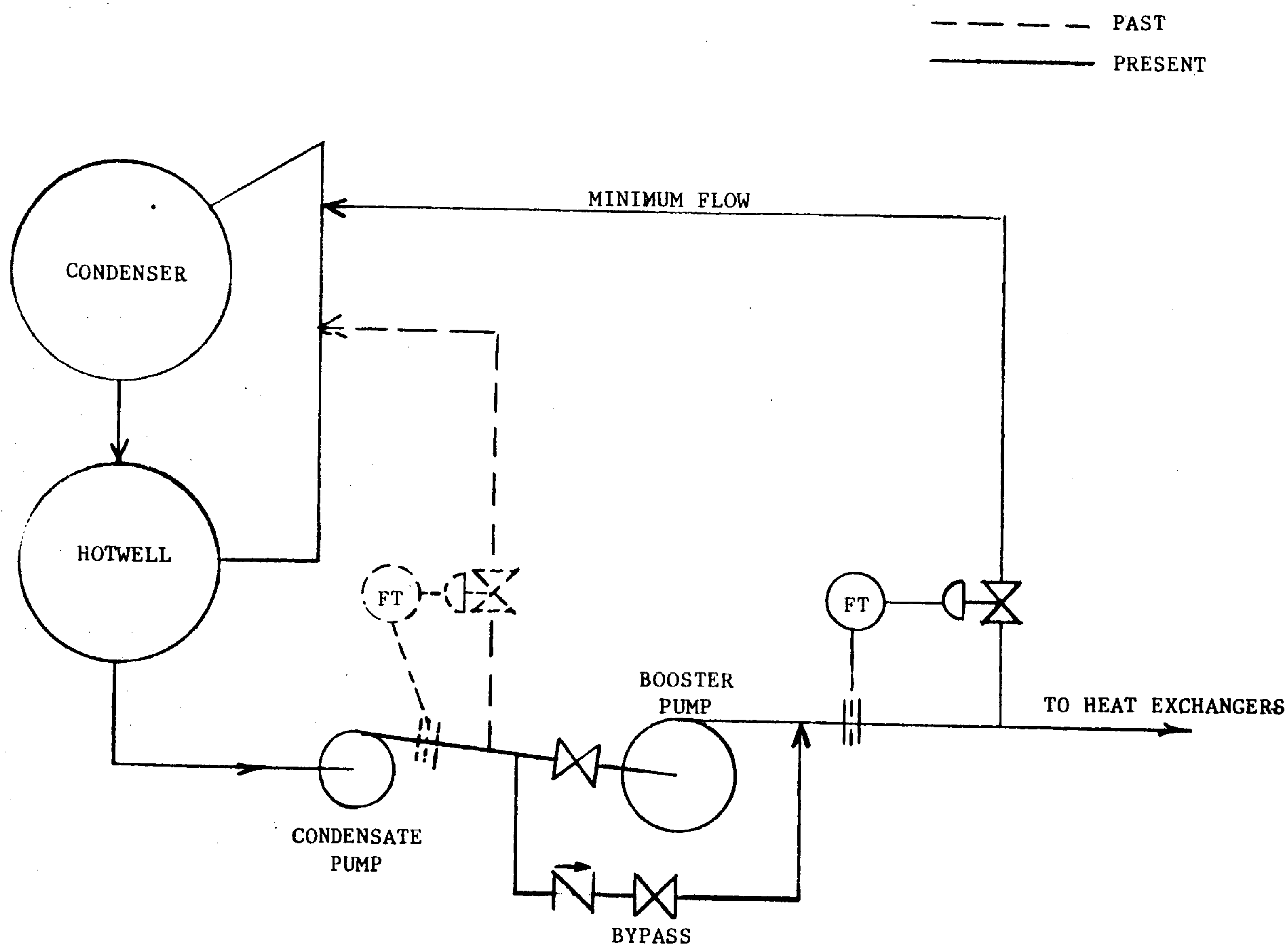


FIGURE 10
CONDENSATE/BOOSTER PUMP MINIMUM FLOW DESIGN

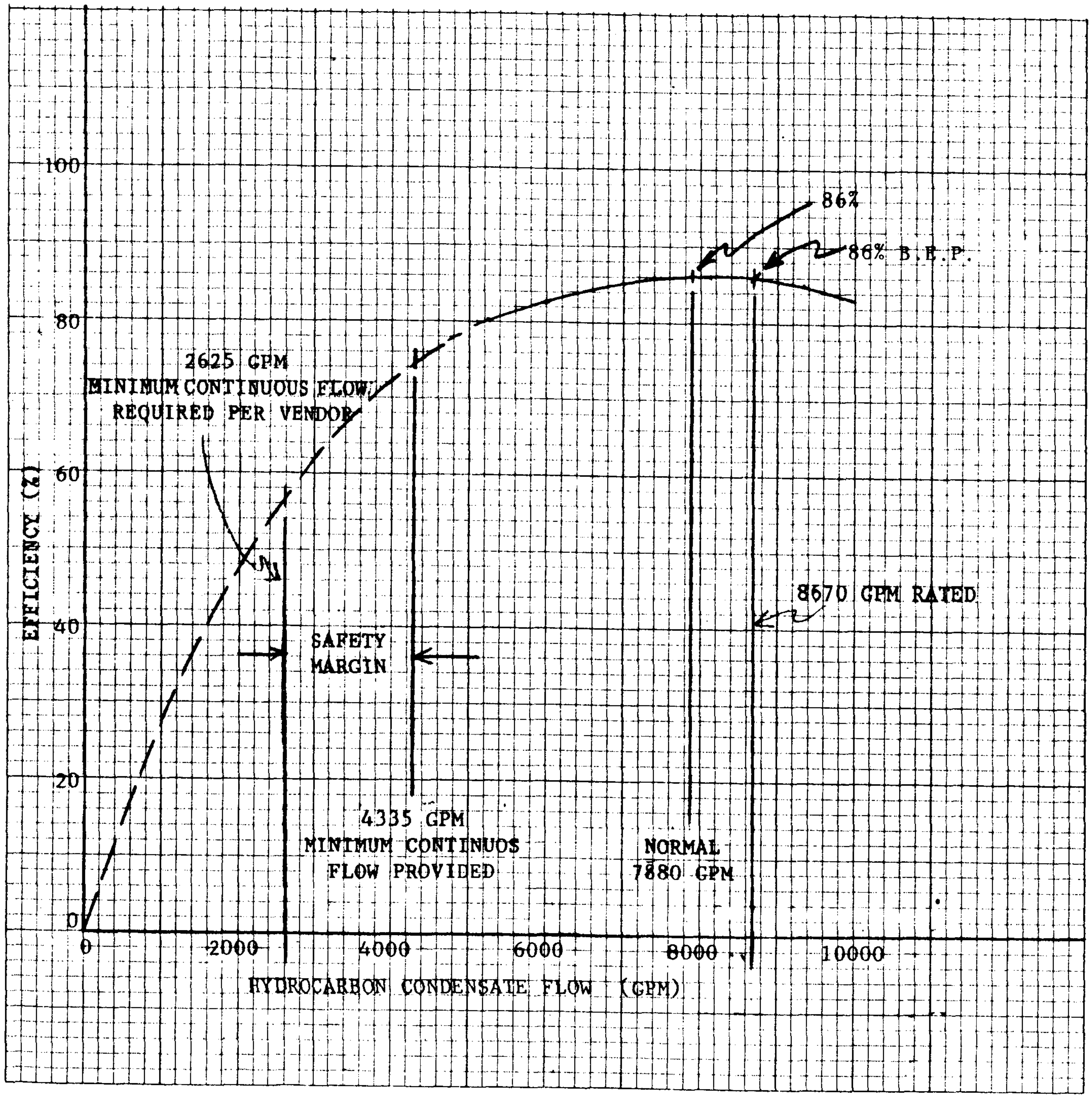


FIGURE 11
CONDENSATE PUMP MINIMUM CONTINUOUS FLOW

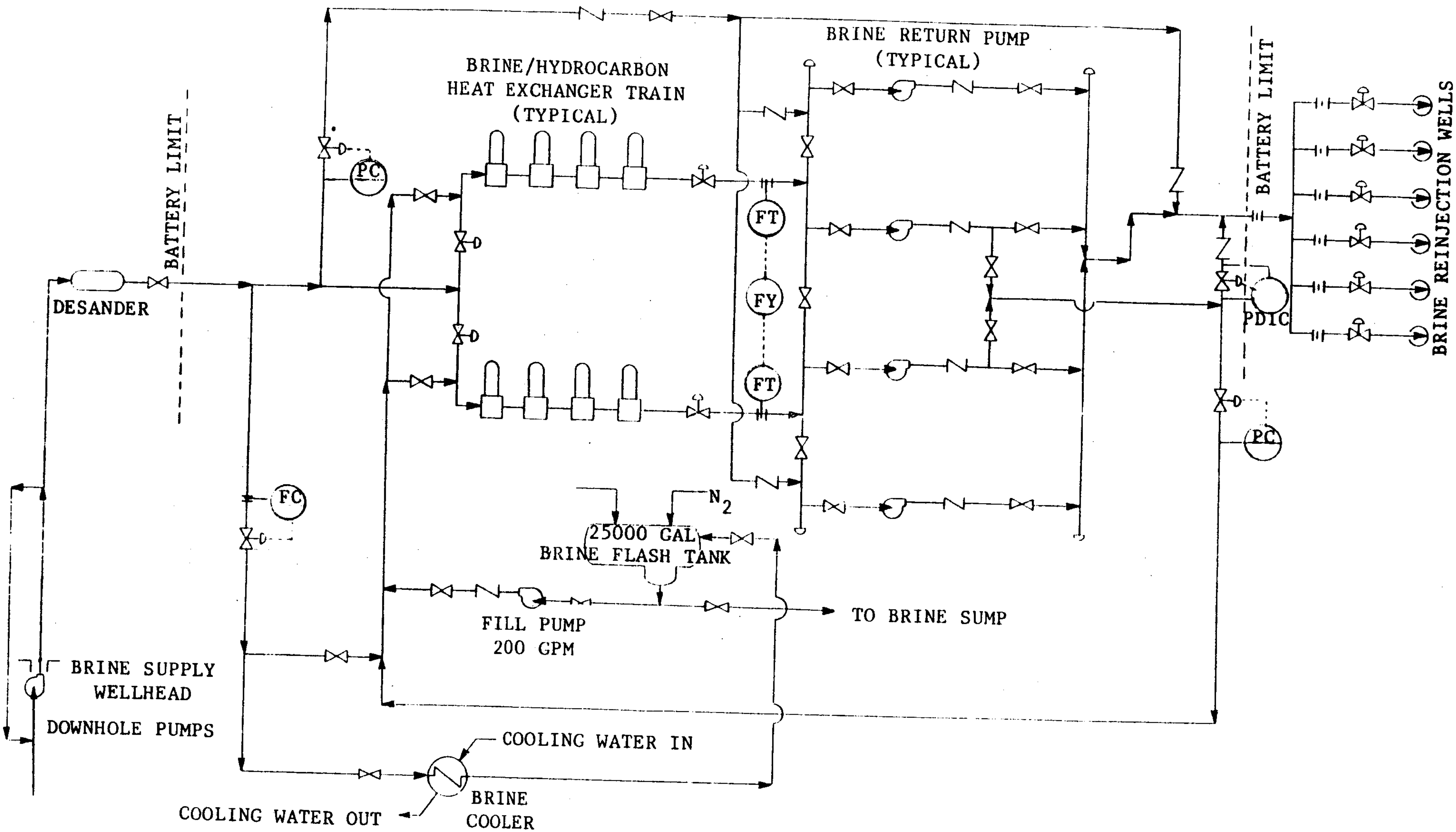
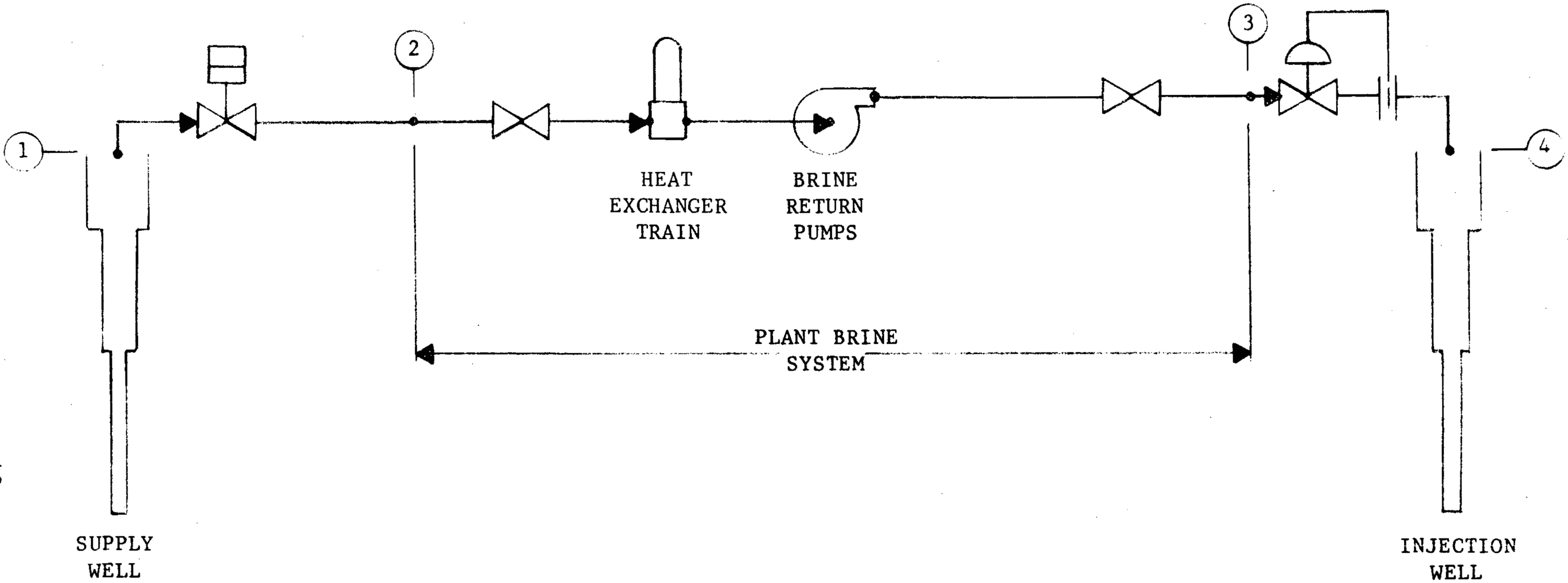


FIGURE 12
BRINE SYSTEM SCHEMATIC



(1) SUPPLY WELLHEAD

(2) INTERFACE WITH BRINE SUPPLY SYSTEM

(3) INTERFACE WITH BRINE INJECTION SYSTEM

(4) INJECTION WELLHEAD

FIGURE 13
BRINE SYSTEM INTERFACES - SUPPLY/HEAT EXCHANGE AND RETURN INJECTION

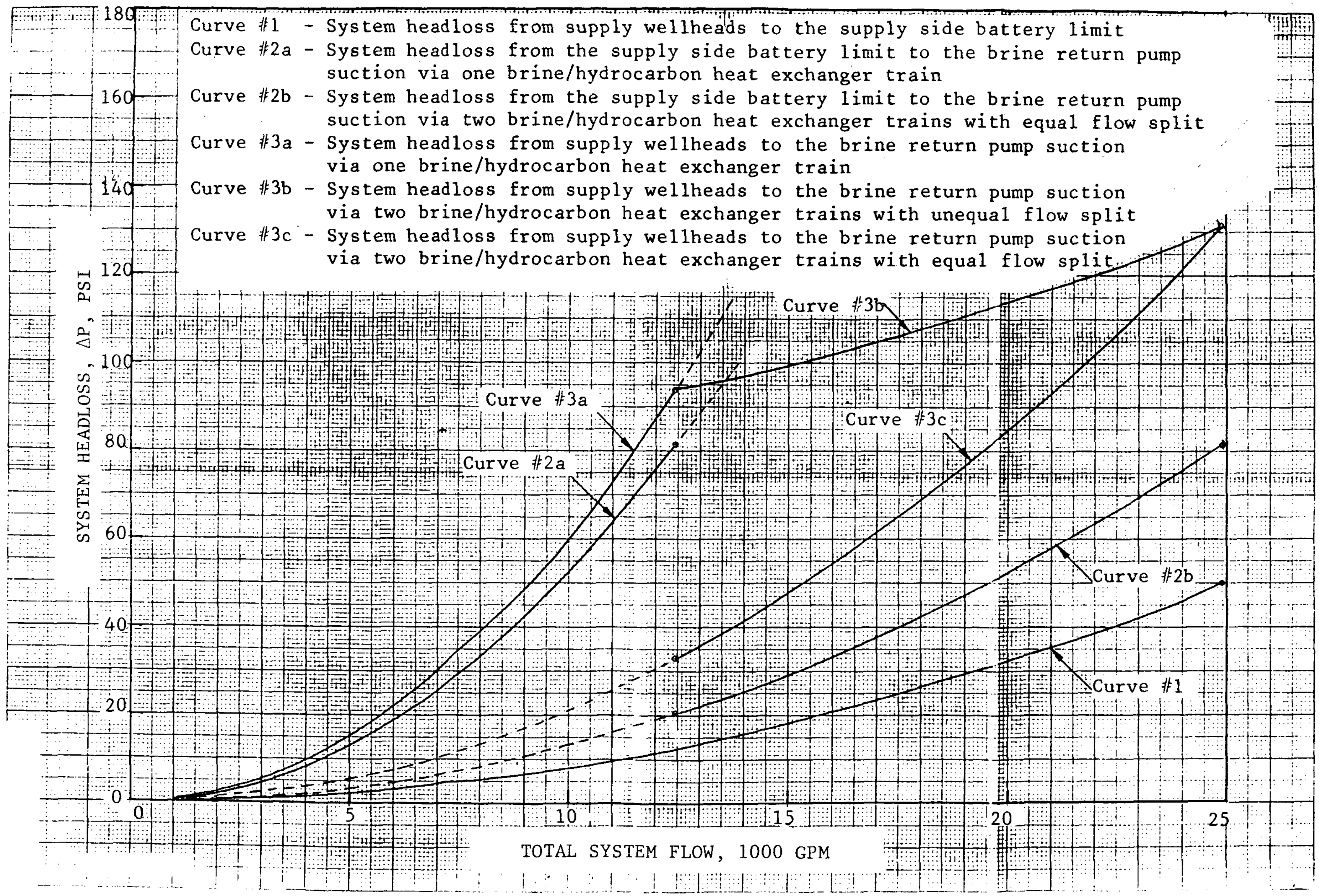


FIGURE 14
BRINE SYSTEM HEADLOSS VERSUS SYSTEM FLOW

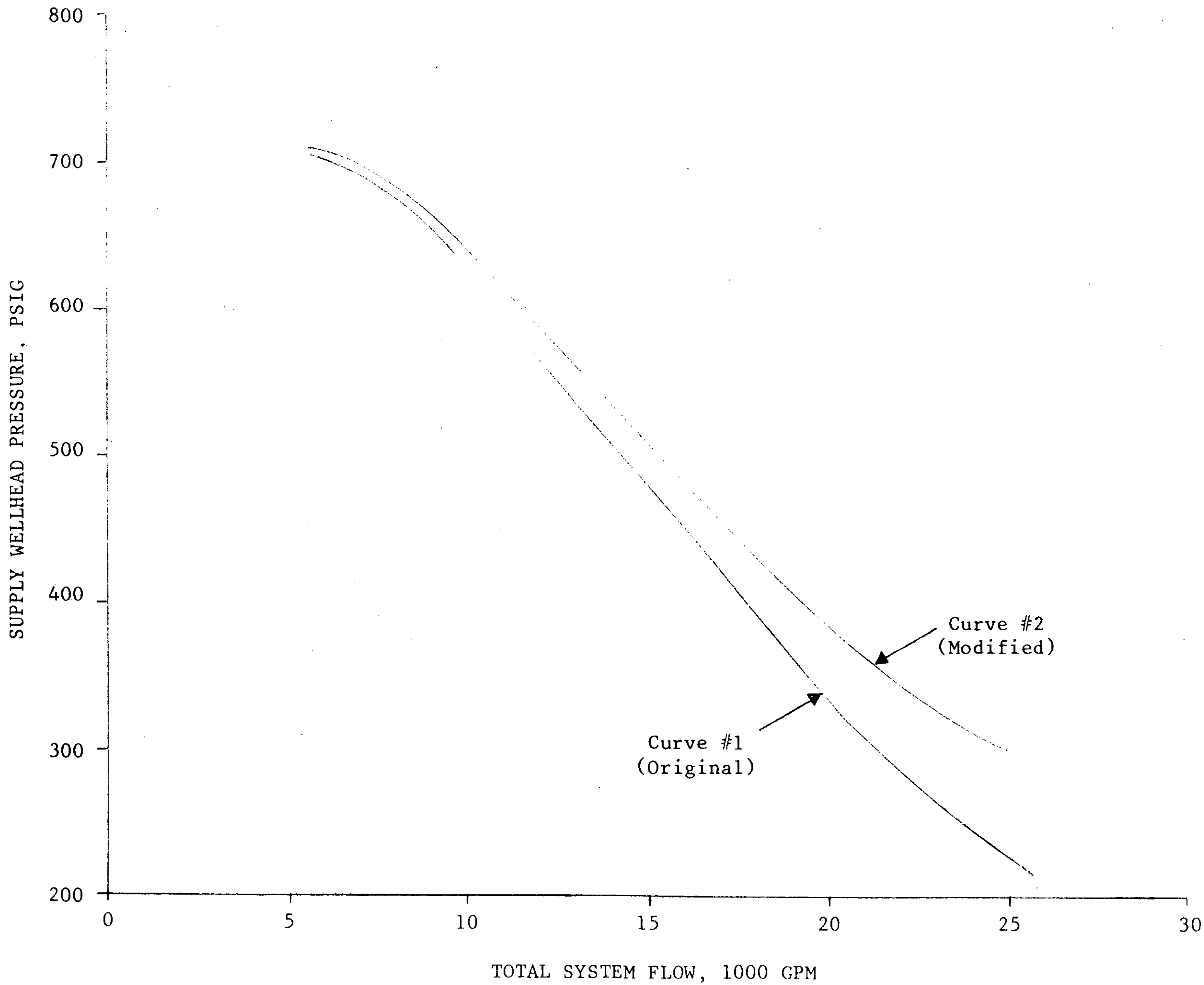


FIGURE 15
MODIFIED SUPPLY WELLHEAD PRESSURE CURVE VERSUS FLOW

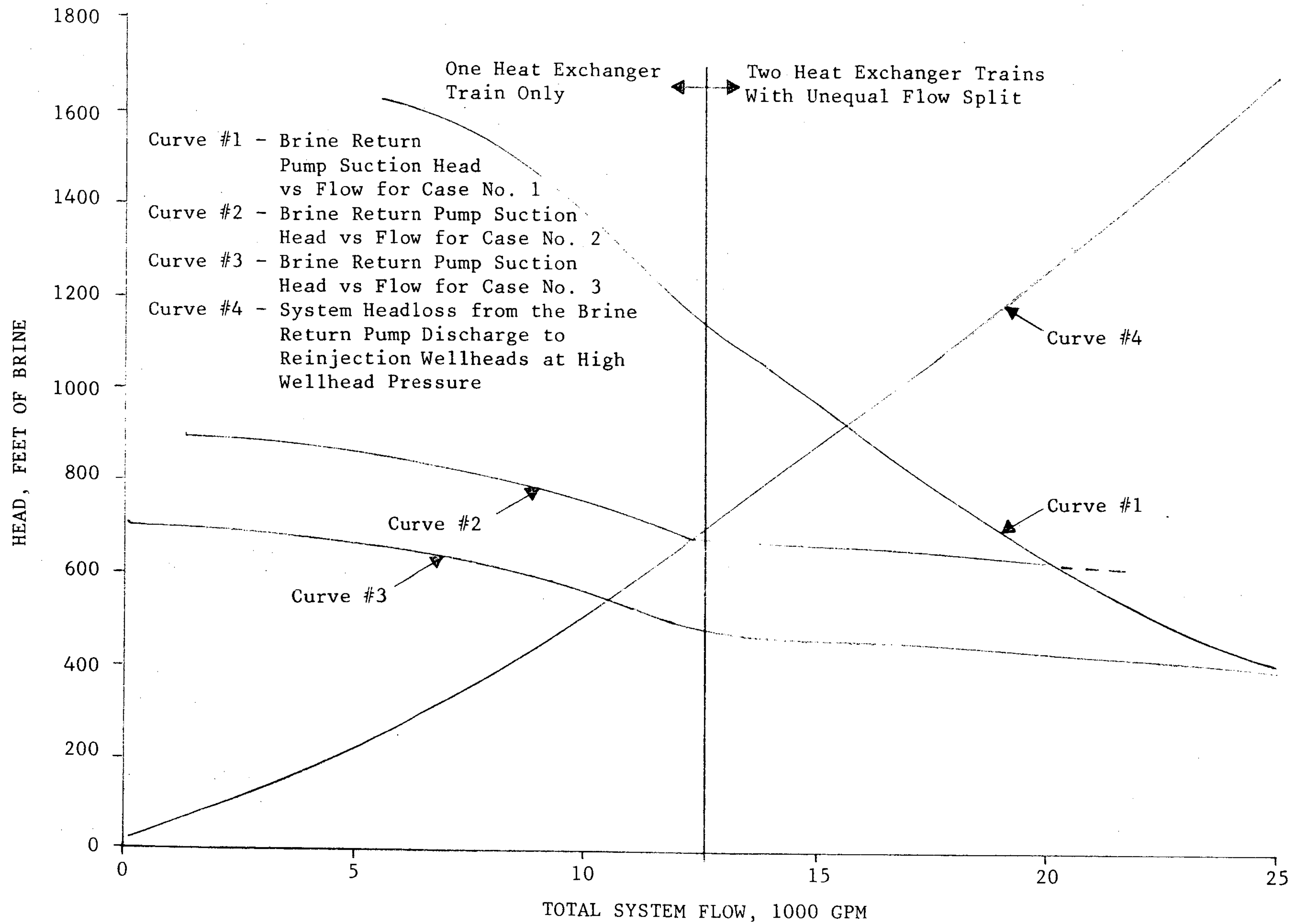


FIGURE 16
BRINE RETURN PUMPS - SYSTEM HEAD CURVES

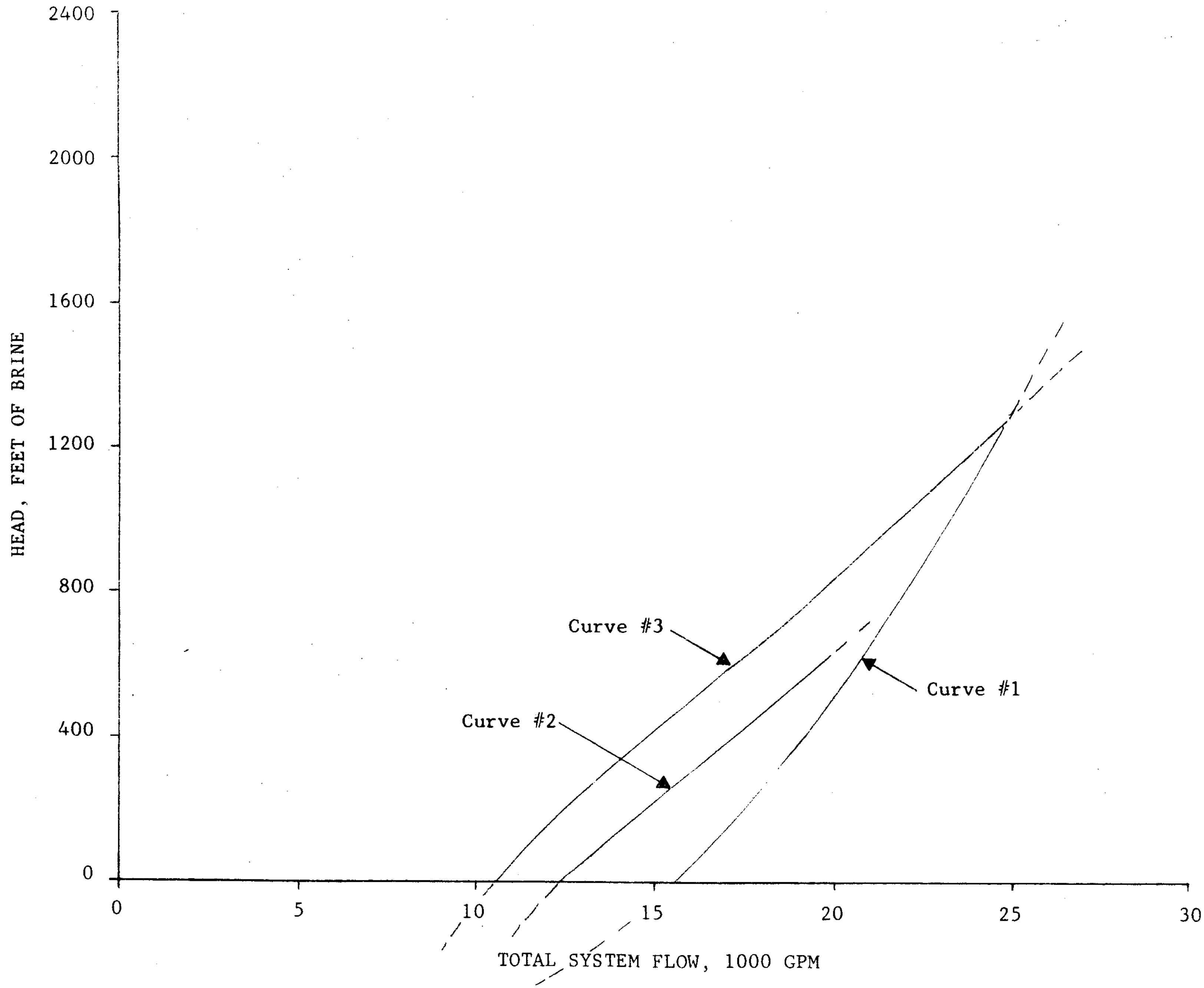


FIGURE 17
BRINE RETURN PUMP SUCTION - STATIC HEAD VERSUS FLOW

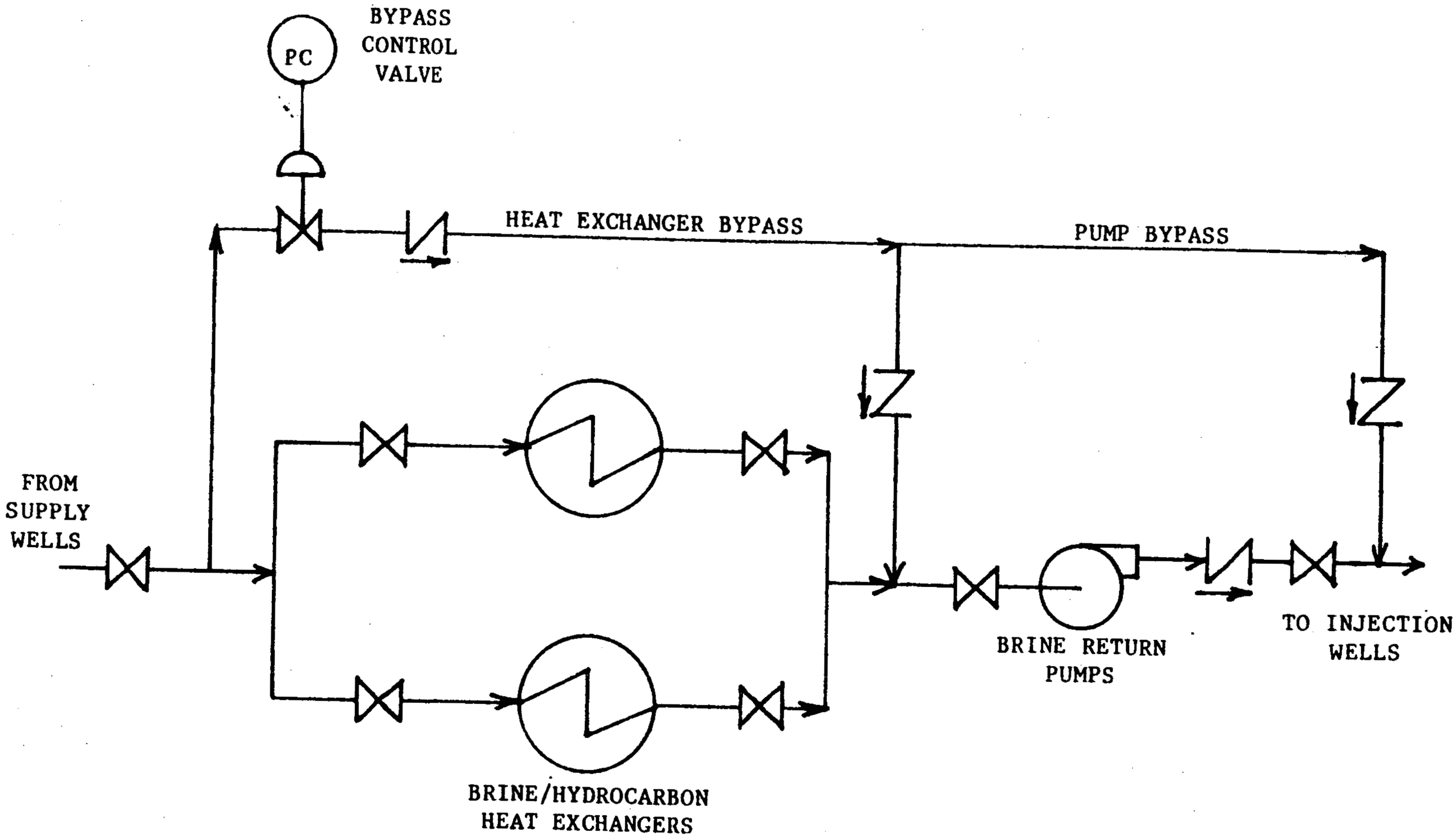


FIGURE 18
BRINE SYSTEM - BYPASS CONCEPT

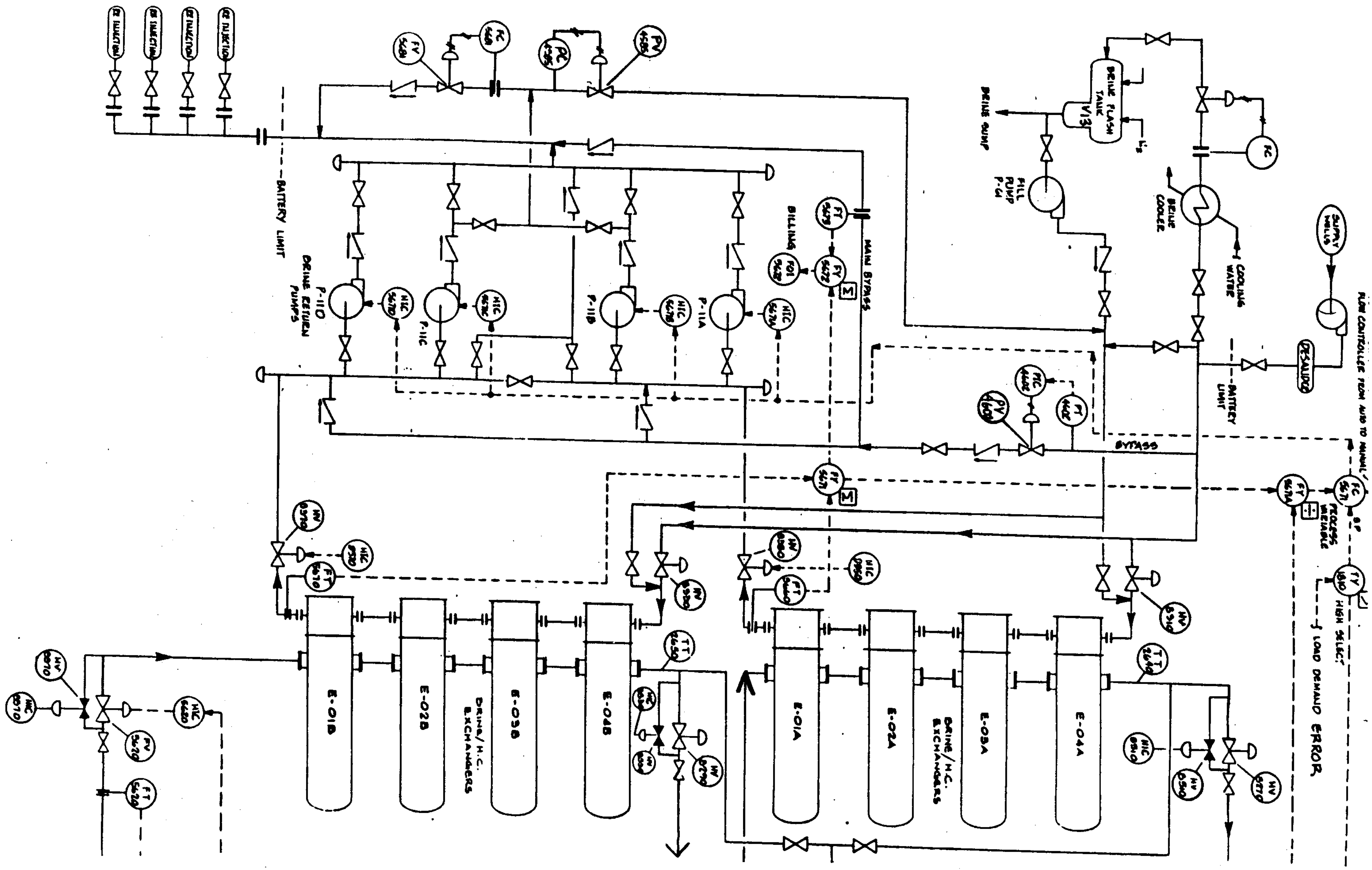


FIGURE 19
BRINE SYSTEM PROCESS FLOW DIAGRAM

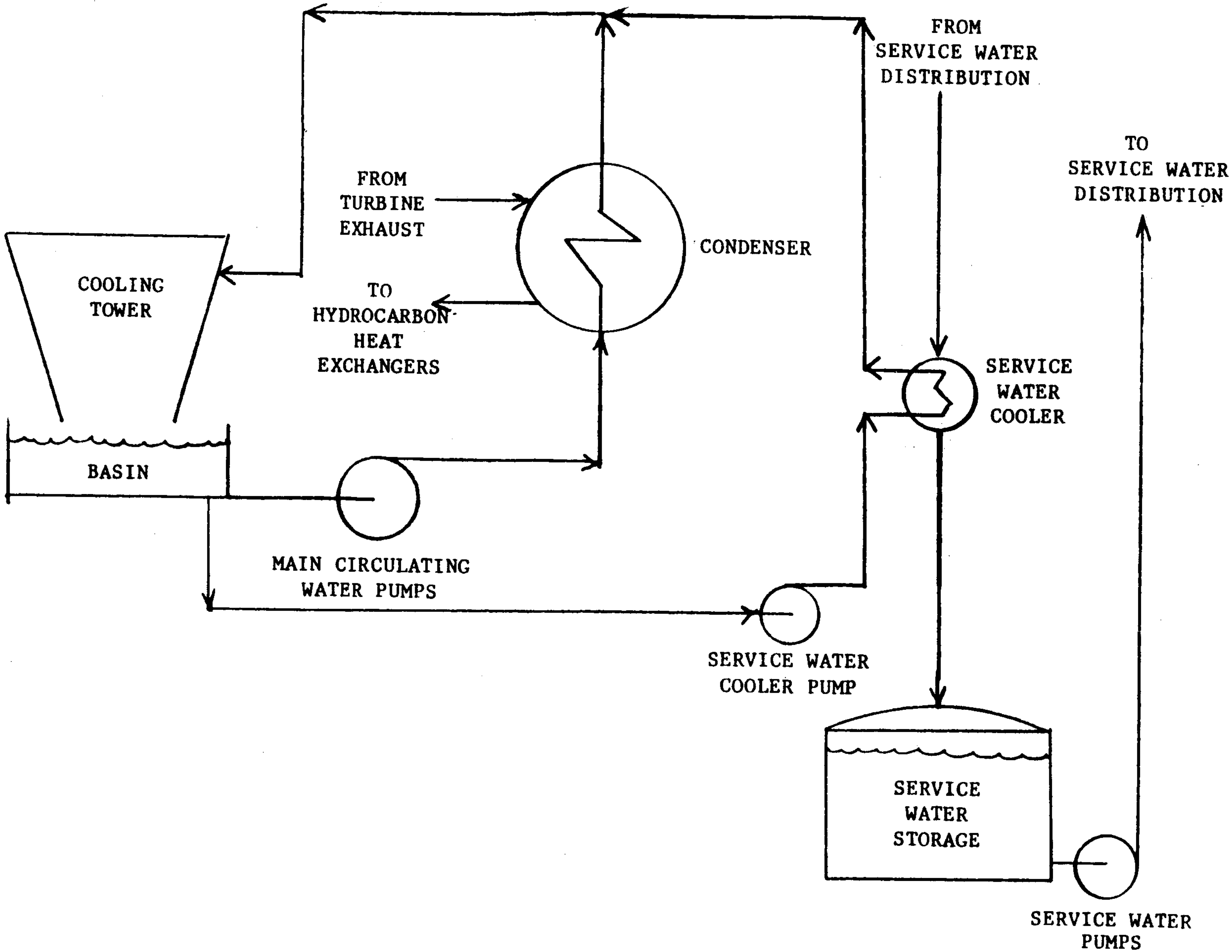


FIGURE 20
COOLING WATER SYSTEM INTERFACE

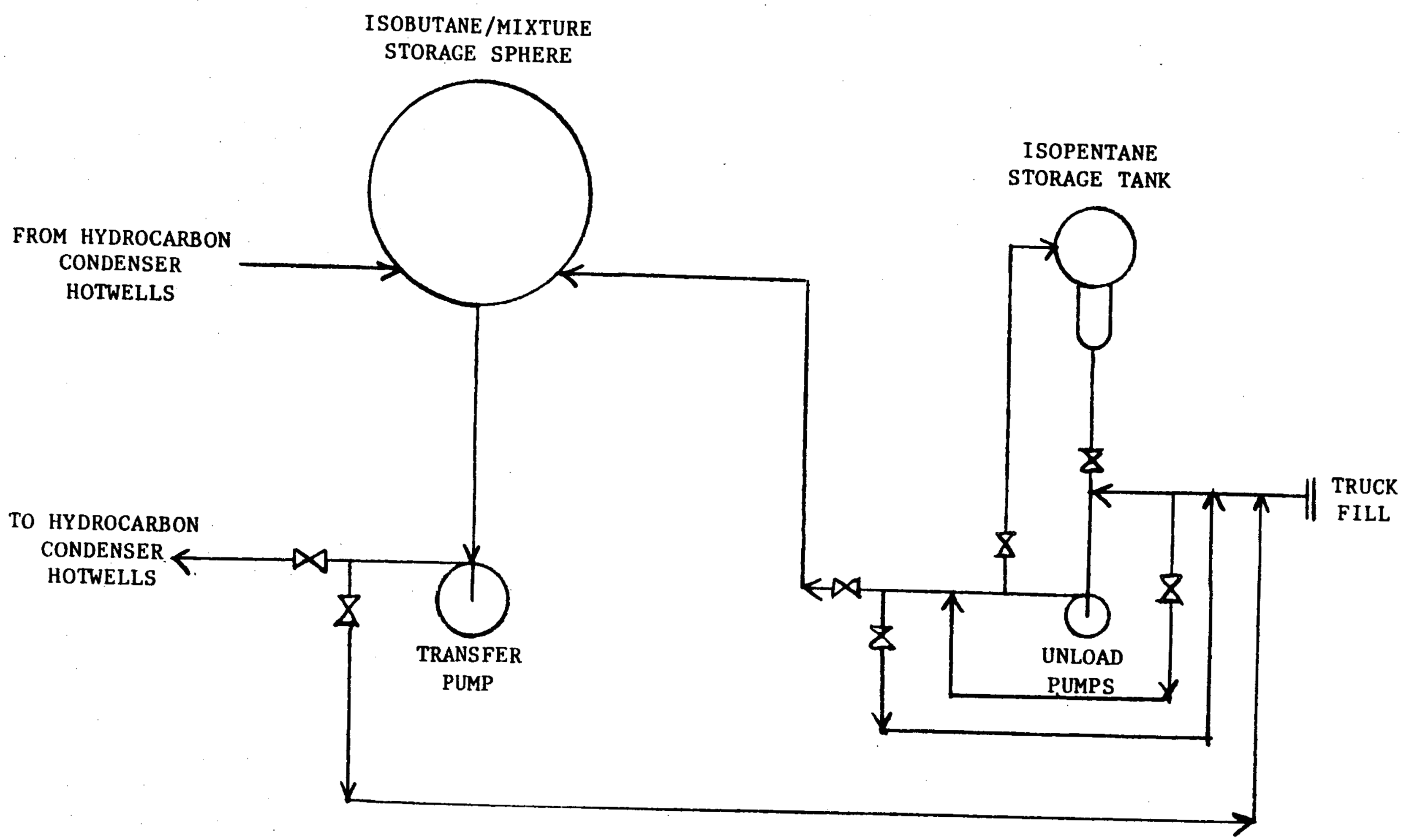


FIGURE 21
ISOBUTANE/ISOPENTANE STORAGE

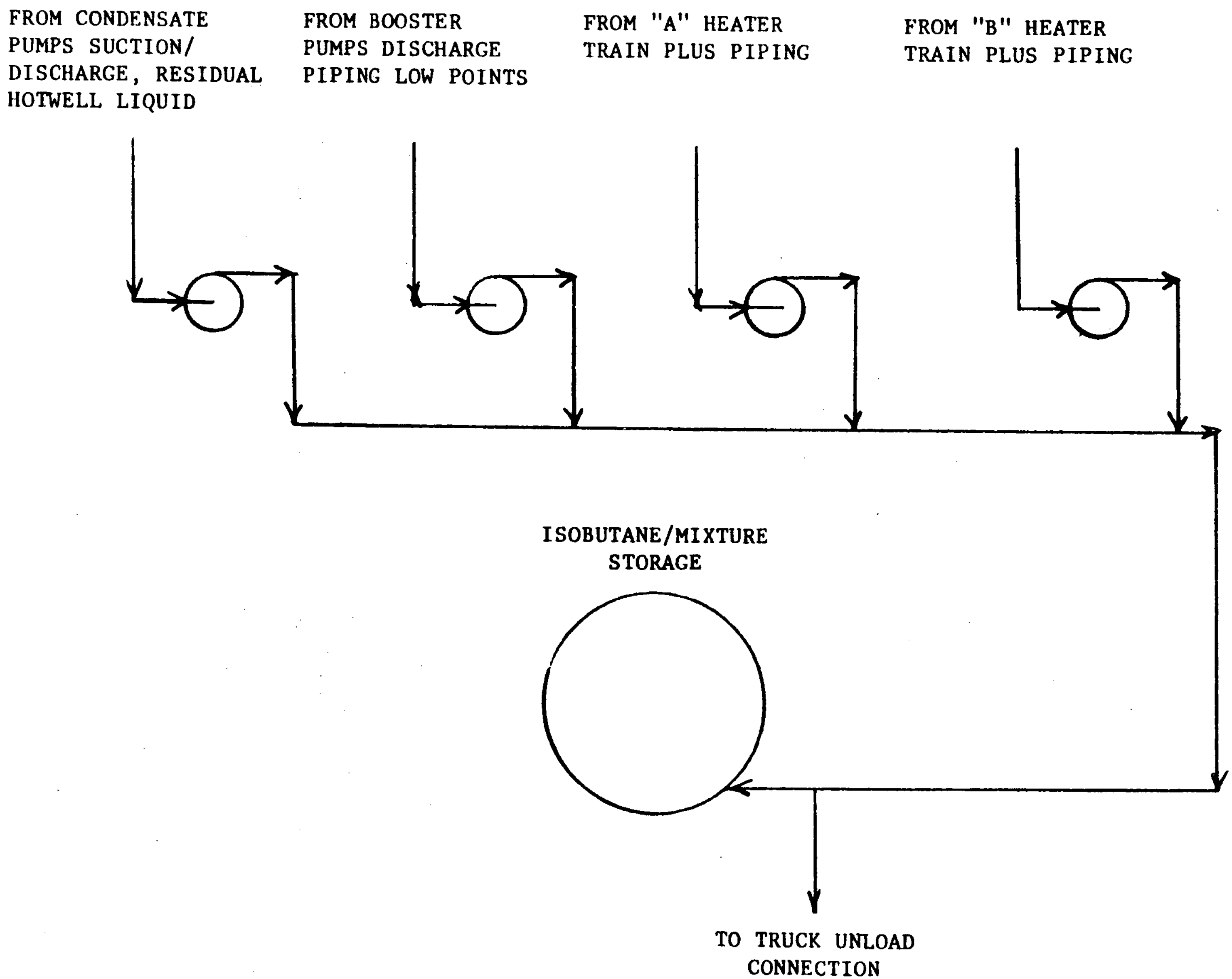


FIGURE 22
HYDROCARBON LIQUID RECOVERY SYSTEM

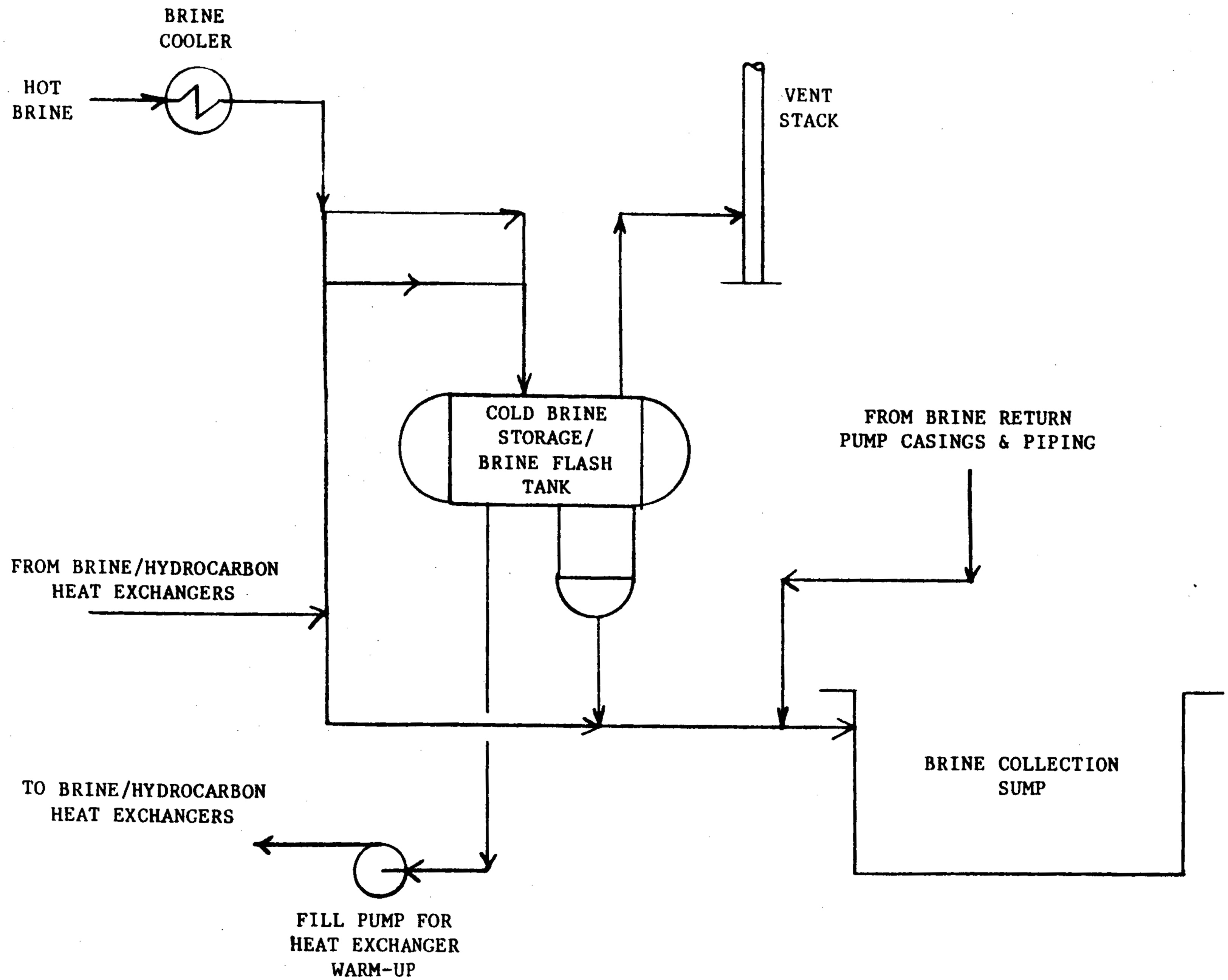


FIGURE 23
BRINE COLLECTION SYSTEM

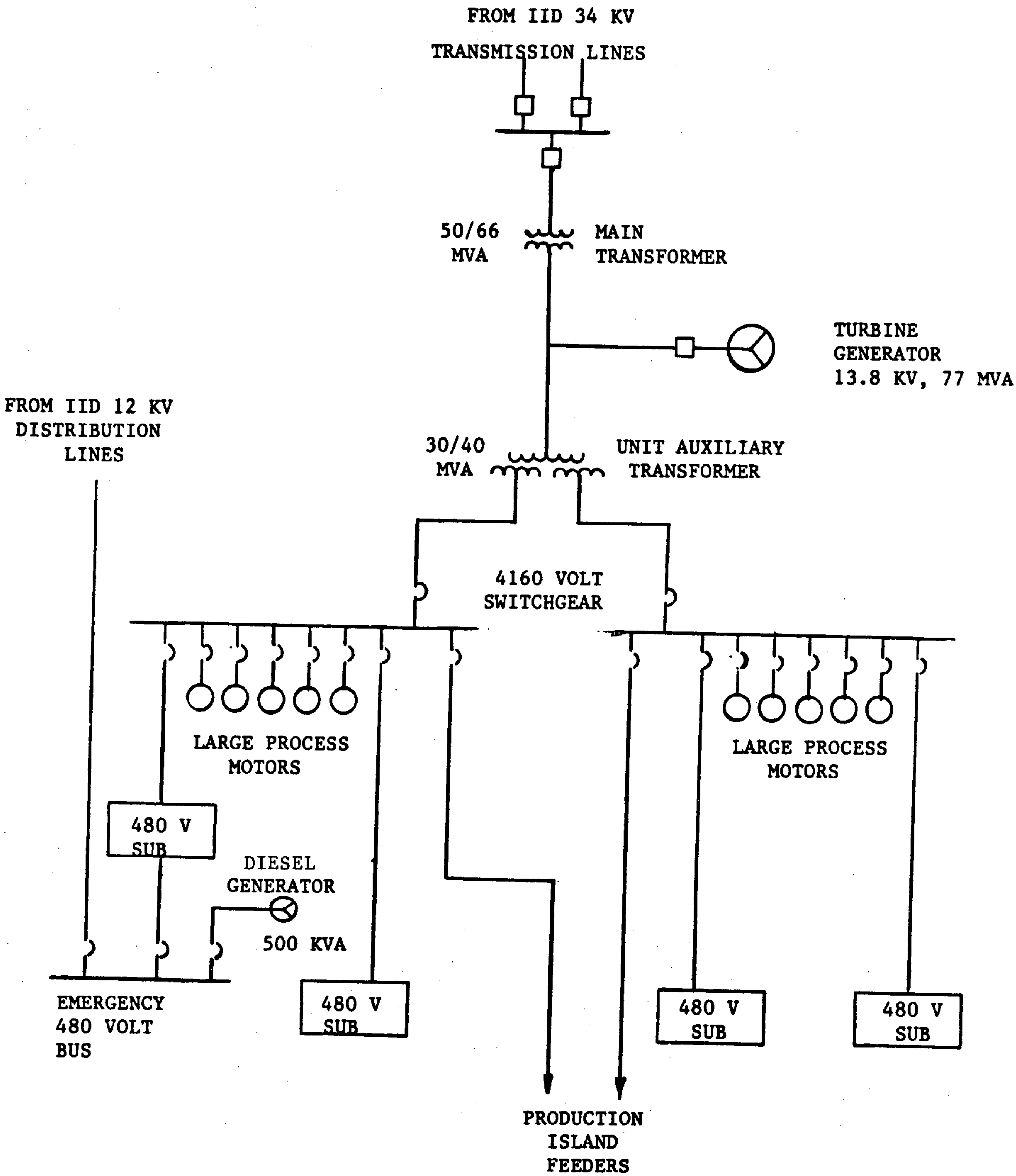
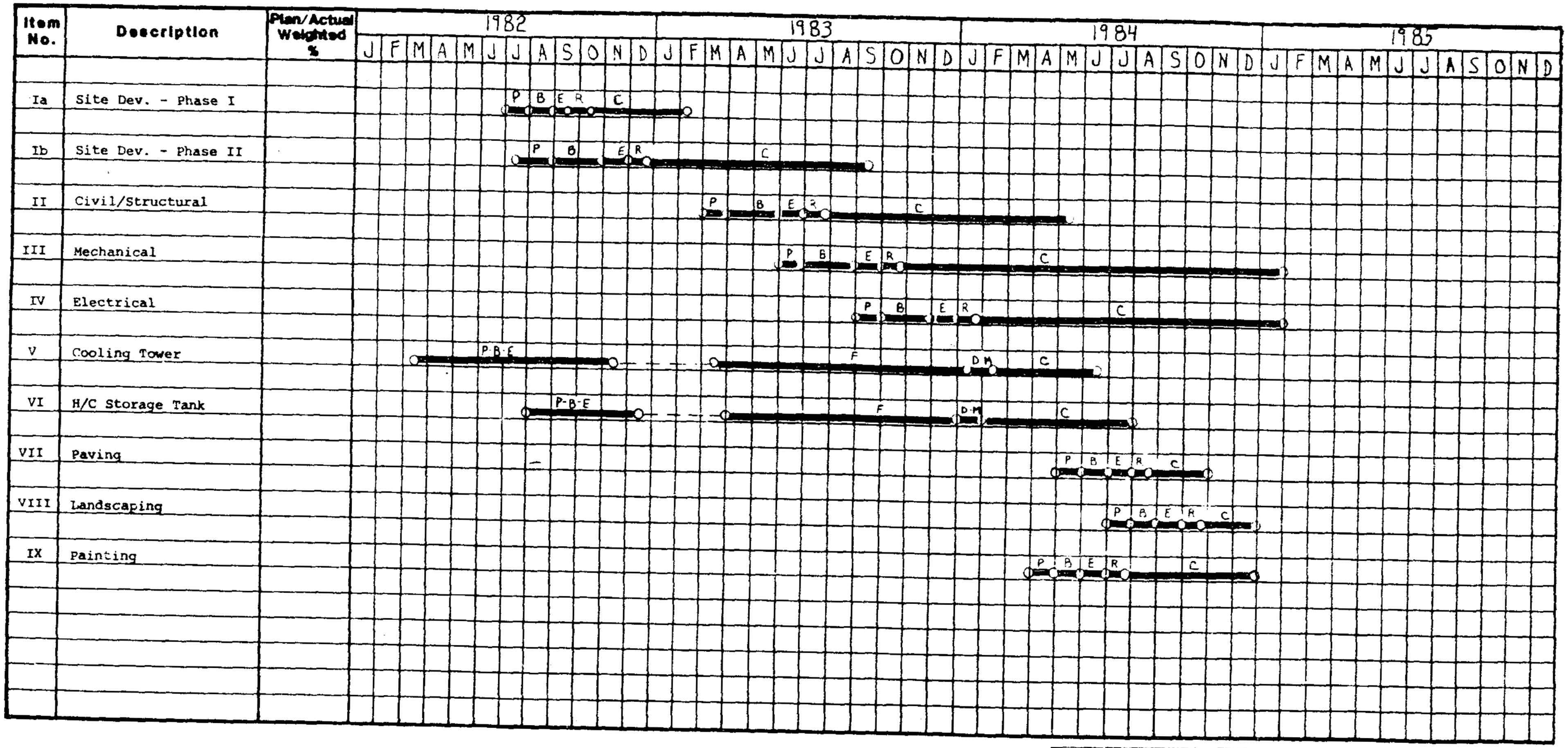


FIGURE 24
AUXILIARY ELECTRICAL SYSTEM - SINGLE LINE DIAGRAM



LEGEND

P - Prepare Bid Documents
B - Bid
E - Evaluate
M - Mobilize
C - Construction
F - Fabricate
D - Deliver
R - SDG&E Review

FIGURE 25
SUMMARY CONSTRUCTION SCHEDULE

FACTOR	1 SPHERE	4 SPHERES
Diameter	1.0	0.63/sphere
Plot Space	1.0	3.5
Fire Protection (Detectors, Deluge)	1 Lot	4 Lots
Relief Valves	2	8
Level Indication	1 Set	4 Sets
Piping Cost (Valves, Pipe, Fittings)	X	2X
Sphere Erection	Y	2Y

TABLE 1
HYDROCARBON STORAGE FACTORS - ONE VERSUS FOUR SPHERES

Turbine Lube Oil Cooler
Generator Lube Oil Cooler
Stop Valve Hydraulic Oil Cooler
Generator Hydrogen Cooler
Brine Return Pump(s) Lube Oil
Brine Return Pump(s) Hydro-viscous Coupling
Instrument Air Compressor(s) After-Cooler
Plant Air Compressor After-Cooler
HC Condensate Pump(s) Seal Oil Coolers
Booster Pump(s) Lube Oil & Seal Oil Coolers
HC Vapor Recovery Inter-stage & After-Coolers
HC/N_2 Vacuum Pump Seal & Bearing Water
HC/N_2 Vacuum Pump After-Cooler
HC Storage Tank Cooling System Condenser
Miscellaneous Corrosion Monitoring Stations

TABLE 2
SERVICE WATER SYSTEM - EQUIPMENT COOLING

Control Room Air Conditioner	1	100 HP
Emergency Lighting	Lot	50 KW
Critical Instruments	Lot	20 KW
Battery Charger (UPS)	Lot	30 KW
Instrument Air Compressor	1	40 HP
HC Storage Tank Condenser Pump	1	1 HP
Fire Water Jockey Pump	1	10 HP
Flare Air Blower	1	25 HP
Flare KO Drum Pump & Igniters	1	6 HP
Service Water Cooler Pump	1	90 HP
Service Water Circulation Pump	1	80 HP
TOTAL EXPECTED LOAD - - - - - - - - - - - - - -		363 KW

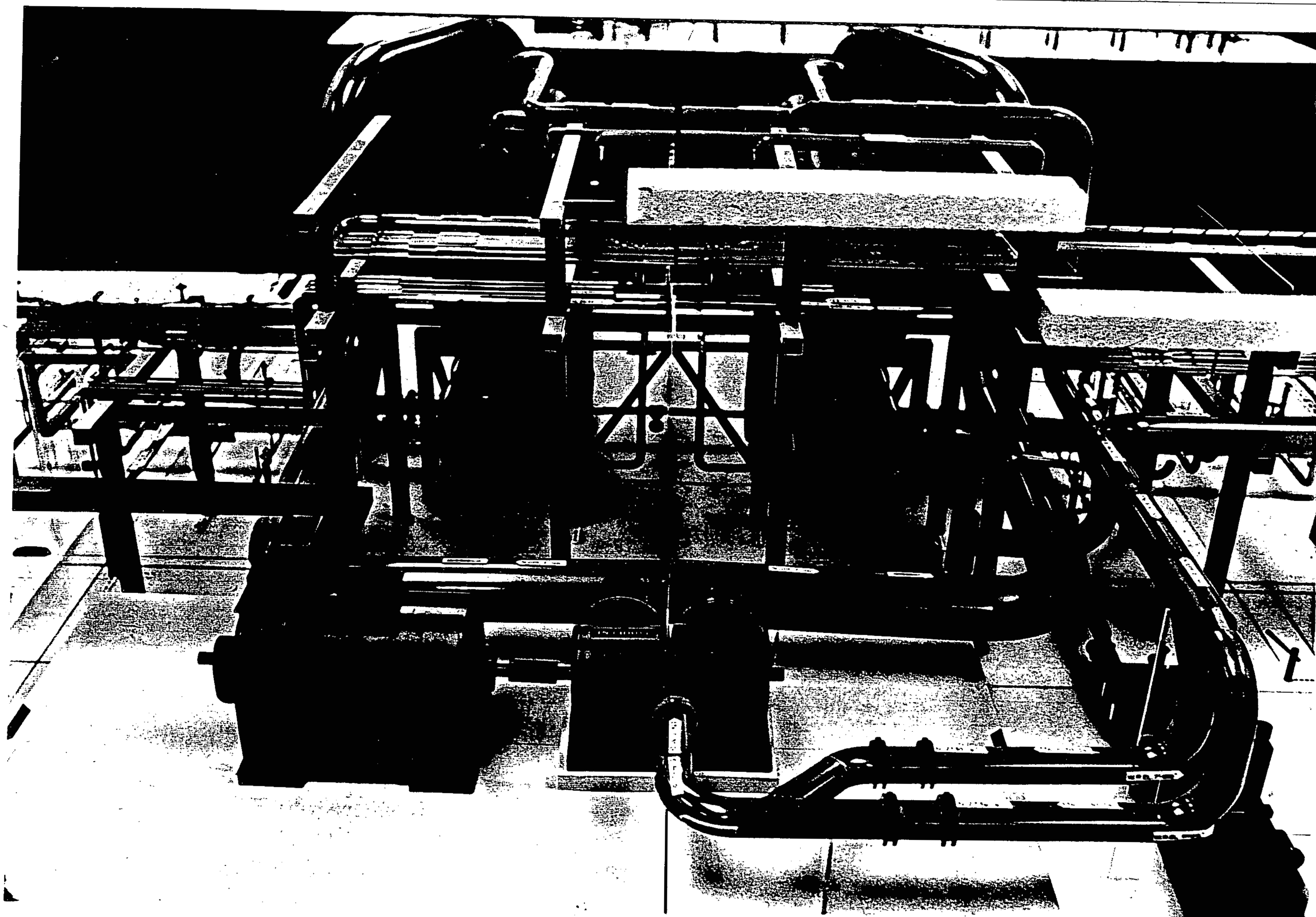
NOTES:

A - Diesel Generator rated for - - - - - - - - - - - - 400 KW

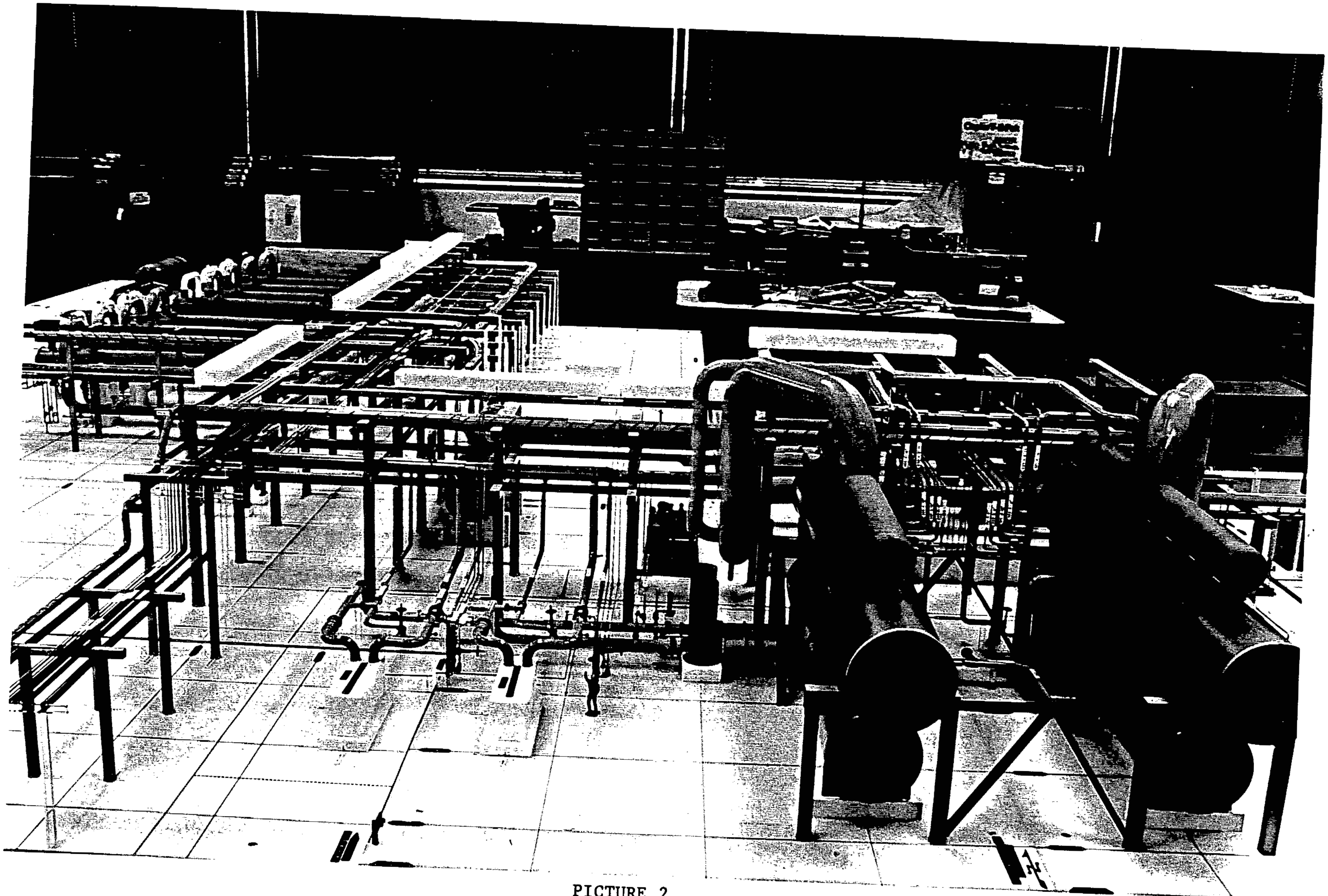
B - Margin = Rated - Expected - - - - - - - - - - - - 37 KW

C - Margin = $\frac{\text{Rated - Expected}}{\text{Expected}} \times 100$ - - - - - - - - 10.2%

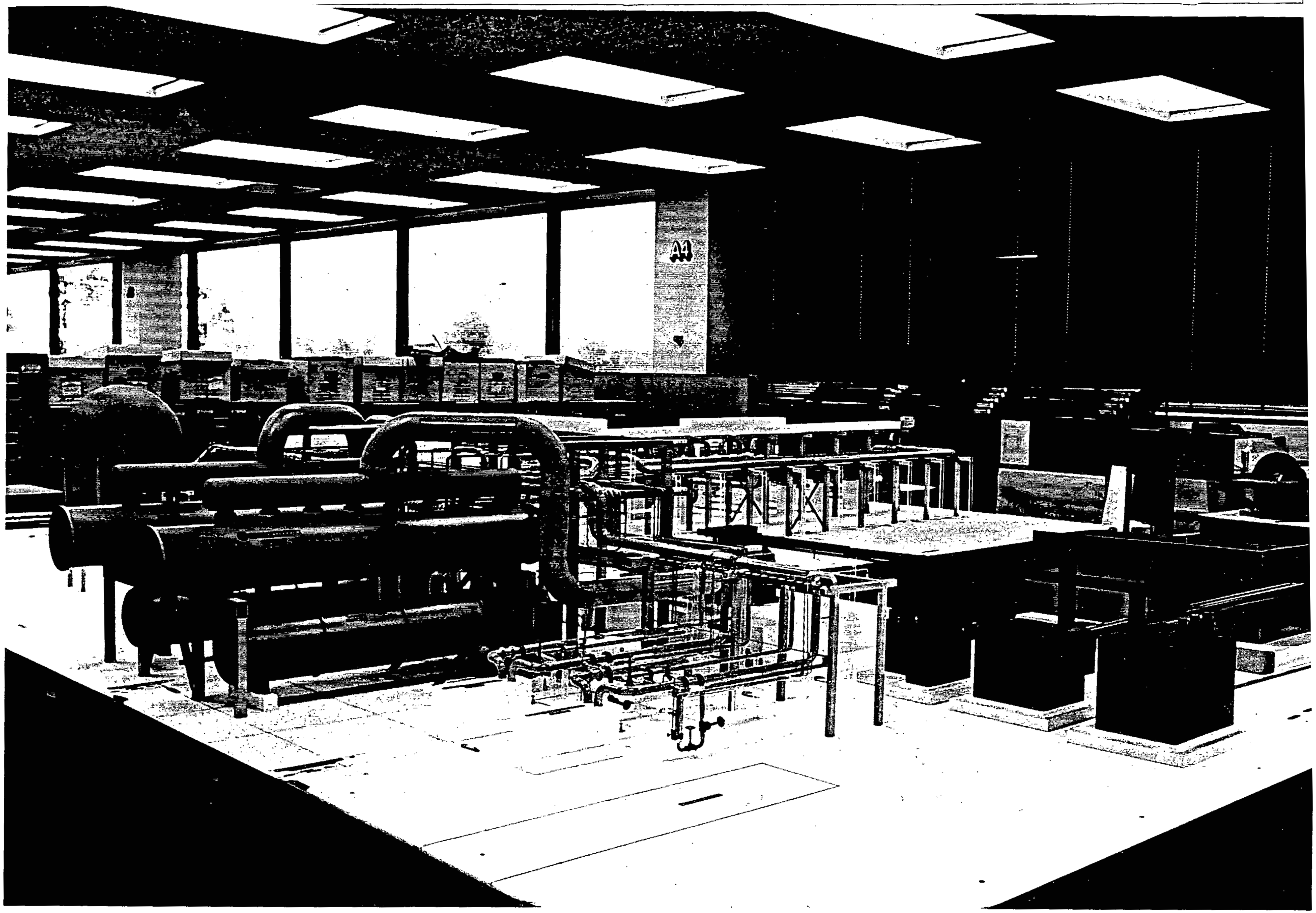
TABLE 3
DIESEL GENERATOR - LOAD LIST



PICTURE 1
TURBINE-GENERATOR (CONDENSERS IN THE BACKGROUND)



PICTURE 2
CONDENSERS AND CONDENSATE/BOOSTER PUMPS



PICTURE 3
TRANSFORMERS AND CONDENSERS (HYDROCARBON STORAGE SPHERE IN THE BACKGROUND)