Heber Geothermal Demonstration Power Plant

Keywords:
Geothermal
Power Plant
Design
Binary Cycle
Cycle Optimization
Working Fluid
Cost

EPRI ER-1099
Project 580-2
Final Report
June 1979

MASTER

Prepared by
Fluor Engineers and Constructors, Inc.
Irvine, California

ELECTRIC POWER RESEARCH INSTITUTE

Heber Geothermal Demonstration Power Plant

ER-1099
Research Project 580-2

Final Report, June 1979

Prepared by

FLUOR ENGINEERS AND CONSTRUCTORS, INC.
3333 Michelson Drive
Irvine, California 92730

Fluor Project Manager
S. G. Unitt

Prepared for

San Diego Gas & Electric Company
101 Ash Street
San Diego, California 92112

San Diego Gas & Electric Company Project Manager
J. W. Carroll

and

Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, California 94304

EPRI Program Manager
Vasel W. Roberts
Fossil Fuel and Advanced Systems Division

DISCLAIMER

DISCLAIMER

ORDERING INFORMATION

Requests for copies of this report should be directed to Research Reports Center (RRC), Box 50490, Palo Alto, CA 94303, (415) 961-9043. There is no charge for reports requested by EPRI member utilities and affiliates, contributing nonmembers, U.S. utility associations, U.S. government agencies (federal, state, and local), media, and foreign organizations with which EPRI has an information exchange agreement. On request, RRC will send a catalog of EPRI reports.

ABSTRACT

The Heber Geothermal Demonstration Power Plant Project was undertaken by the Electric Power Research Institute, San Diego Gas and Electric Company and others in order to accelerate geothermal development for power generation, and to establish the binary cycle technology as a proven alternative to the flashed steam cycle for moderate temperature hydrothermal reservoirs. The binary power plant would be a 45 MW net electrical facility deriving energy from the low salinity (14,000 ppm), moderate temperature (360°F, 182°C) Heber reservoir in Southern California.

The report describes the optimized baseline design established for the power plant, and documents the design and optimization work that formed the basis for the baseline design. The report also records the work accomplished during Phase II, Preliminary Design, and provides a base from which detailed plant design could be continued. Related project activities in the areas of licensing, environmental, cost and schedule are also described.

The approach used to establish the Phase II optimized baseline design was to 1) review the EPRI Phase I conceptual design and feasibility studies, 2) identify current design criteria and state-of-the-art technology, and 3) develop a preliminary design optimized to the Heber site based on utility standards.

The report shows that state-of-the-art technology can be adapted to the design of this type of power plant, with a good probability of successful demonstration of commercial readiness.

EPRI PERSPECTIVE

PROJECT DESCRIPTION

The results of the engineering and design effort for a geothermal demonstration plant are contained in the final report of Research Project 580-2. The results reported are from the second phase of a multi-phase, multi-participant project which was to include system definition, subsystem optimization, design, construction, and demonstration of a 45 MW (e) net binary cycle power plant. The demonstration plant was to be specifically optimized and designed for use with a low salinity moderate temperature hydrothermal resource near Heber, California. In mid-1978 it became clear that funding would not be adequate to complete the project, and the project was terminated on November 30, 1978. This report preserves the project results for future use and reference.

PROJECT OBJECTIVES

The broad objective of the project was to accelerate geothermal development for electricity generation by demonstrating the practical use of binary cycle technology for the commercial development of low salinity moderate temperature geothermal/ hydrothermal resources. This would provide a cost-effective alternative to direct flash systems in the lower temperature range. The objectives of this phase were to complete the engineering studies, a large part of the design, and procurement specifications for long lead items.

PROJECT RESULTS

Refinement of the optimization studies reconfirmed that the binary cycle is the best choice for the demonstration plant at Heber. Analysis showed that a binary cycle plant can be designed for the Heber geothermal reservoir to yield 10 to 15 percent higher plant efficiency than direct flash. This advantage alone makes the binary cycle a viable option in terms of lower busbar electricity cost; however, a second important advantage also contributed to its selection. The binary cycle requires about 28 percent less geothermal fluid than direct flash, and more energy per unit of brine mass flow is available for conversion to electricity. Lower fuel charge and busbar energy cost result. Although other moderate temperature reservoir conditions are likely to be different from those at Heber, similar advantages for the binary cycle are expected.

The resource company proposed two brine production options, each of which would result in different brine conditions at the plant interface which in turn would impact power plant design. It was postulated that brine production by spontaneous two-phase flow would have an economic advantage over pumped single-phase flow and might affect the choice of the binary cycle. This was not the case, and the pumped option was selected. The main disadvantage of the spontaneous flow option was that the resultant decrease in temperature and pressure of the brine entering the plant reduced plant performance.

The concept of tailoring binary cycle working fluids by mixing hydrocarbons to optimize cycle performance continues to appear valid. The optimum choice for the conditions at Heber was a mixture of 90 percent isobutane and 10 percent isopentane. One disadvantage of the hydrocarbon mixtures is that the vaporization and condensation lines are not uniquely defined. However, proper selection of the working fluid cycle should avoid potential problems in this area.

The cost of power from the plant was estimated to be 45 mils/kWh in constant 1977 dollars. Energy contributes 62 percent of the cost and O&M and capital investment contribute 15 and 23 percent respectively. The capital cost reported by the investigators was $860/kW installed in 1977, based on 45 MW (e) net. The installed cost is somewhat distorted by use of 45 MW (e) in the computation. Actually, the plant would deliver 45 MW (e) to the grid and 5 MW (e) to the field operator for which credit would be received. Thus, the plant could be viewed as having a 50 MW (e) capacity, in which case the installed cost is $774/kW.

The County of Imperial issued an environmental impact report for the plant in December 1977. There were no overriding considerations that would prohibit or delay construction of the demonstration plant. Agreements for heat purchase, power sales, and cooling water purchase were developed in principle, but were not actually signed into contract.

The binary cycle is expected to be the primary option for geothermal development for many utilities. The results from this project will be useful in comparative analyses and in choosing the technology option best suited to the geothermal resource and to individual utility needs consistent with lowest cost of power. The report provides insight into the binary cycle plant design decision process that will be helpful to others designing similar plants in the future. In addition, if the need and priority remain high for a commercial scale demonstration plant, the results can be used as a basis for restructuring a project to meet these objectives.

Vasel W. Roberts, Program Manager
Fossil Fuel and Advanced Systems Division

CONTENTS

Section		Page

ILLUSTRATIONS

TABLES

SUMMARY

The Electric Power Research Institute (EPRI), together with San Diego Gas and Electric Company, several other utilities and state government agencies joined in a common objective to construct, operate, and evaluate a 45 megawatt net capacity binary cycle geothermal demonstration power plant. The selected plant site is located six miles south of El Centro in the Imperial Valley of Southern California on the Heber hydrothermal reservoir. The project is identified as the Heber Geothermal Demonstration Power Plant.

Commitment to the project resulted from precursory studies that evaluated the importance of moderate temperature geothermal resources and binary technology, as well as the comparative economics of other more proven technologies, such as the direct flash cycle. These studies were performed for EPRI by Holt/Procon, under Phase I of the project, and were completed in 1976. Study results supported the conclusion that the binary cycle, using a saturated hydrocarbon as the working fluid, has significant potential for generating electric power at a cost that is lower than direct flash when operated on reservoirs in the low to moderate temperature range. Since approximately 80 percent of the known hydrothermal fields in the U.S. are in the moderate temperature range, having temperatures between 300°F (149°C) and 410°F (210°C), the binary cycle offers major near term potential in the development of geothermal power.

The binary cycle is a process in which heat is transferred from the geothermal brine to a secondary working fluid which is, in turn, vaporized and used to drive a turbine generator. The working fluid, upon leaving the turbine, is condensed and used over and over in a closed loop. The direct flash cycle refers to a process in which a portion of the geothermal brine is caused to flash into steam in flash vessels. The flashed steam is used to drive a turbine generator.

The binary cycle employs technology well established in the process industry and thus requires no technical breakthrough in its application to geothermal power

generation. The only impediment to its commercial use for electric power generation is that it has not been demonstrated in commercial size units.

The primary objectives of the Heber project are to accelerate geothermal development for power generation in the U.S., and to establish the binary cycle as a proven alternative to the flashed steam cycle.

Execution of the project was organized into six phases as follows:

PHASE I - Conceptual Design and Feasibility Studies
PHASE II - Preliminary Engineering and Design
PHASE III - Detailed Design and Procurement
PHASE IV - Construction and Mechanical Completion
PHASE V - Start-Up and Initial Testing
PHASE VI - Operation and Performance Evaluation

This report provides a summary of the preliminary design work accomplished during Phase II by Fluor Engineers and Constructors, Inc., (Fluor) under contract to SDG&E and The Ben Holt Company under subcontract to Fluor.

The objective of Phase II was to develop a preliminary power plant design optimized for operation on the Heber hydrothermal field using the Phase I study as the point of departure. The scope of work included:

- Review and evaluation of the Phase I studies
- Development of design criteria
- Optimization and final determination of critical process variables and plant design features
- Development of a baseline design optimized for the Heber site
- Development of project execution controls, budgets, schedules, and procedures

This work has been completed, although not in all cases, to the depth of detail planned at the outset due to project funding uncertainties. Because of the economic risks associated with this first of a kind plant, financing of the project was structured for 50 percent funding by the U.S. Department of Energy (DOE). In July of 1978, it was learned that DOE had elected to co-fund a lower risk higher temperature direct flash power plant and would not support the Heber binary plant as had been anticipated. Alternate funding could not be secured and in late 1978 the decision was made by the participants to terminate the project.

CRITERIA DEVELOPMENT AND OPTIMIZATION STUDIES

It was agreed at the beginning of Phase II that the Phase I EPRI sponsored studies would be used as the point of design departure for the power plant. A review of this work was undertaken by Fluor. Major conclusions from the baseline reviews are as follows:

- The thermodynamic base was valid but not optimum.
- Power cycle process and equipment efficiencies were considered to be optimistic.
- The power cycle system design developed for the Phase I conceptual design was valid but required optimization to meet current SDG&E project guidelines and criteria, and energy supply costs and criteria established by Chevron Resources Company.
- Additional work was needed to identify and reduce critical system pressure losses, improve equipment arrangements and lower the turbine deck height.

Binary Cycle Selection: The Phase I studies resulted in the selection of the hydrocarbon binary cycle as the preferred conversion cycle for the Heber plant. However, based on the Fluor review of this work, changes in energy supply economics, and other changes in design criteria, it was decided to reevaluate and confirm the binary cycle selection.

Three binary and two direct flash steam cycle cases were studied as follows:

- Binary Cycles

  Case I - Single-phase brine supply with 150°F (66°C) brine return temperature (EPRI Phase I Design)

  Case II - Two-phase brine supply with 150°F (66°C) brine return temperature

  Case III - Two-phase brine supply with 200°F (93°C) brine return temperature

- Direct Flash Steam Cycles

  Case IV - GE turbine and free flowing two-phase brine supply with 200°F (93°C) brine return temperature

  Case V - Elliott turbine and free flowing two-phase brine supply with 200°F (93°C) brine return temperature

Two direct flash cases were investigated as a result of a significant difference in the indicated capital cost and efficiency between two potential turbine generator suppliers.

From the study, Binary Case III was determined to produce the lowest net power cost. Subsequent to the completion of this work, revised energy supply guidelines were identified which tended to reduce much of the power cost differential favoring the two phase brine supply binary cases. However, the selection of the binary cycle remained valid. Also, while the cycle thermal efficiency for both cycles is nearly the same, the direct flash cycle requires approximately 38 percent more brine flow. This results from the need (for process reasons) to return the brine at a temperature approximately 50F° (28C°) higher than with the binary cycle.

Working Fluid Selection: A saturated hydrocarbon was selected from among several alternatives as the preferred working fluid for the Heber plant during the Phase I studies. During Phase II, this selection was reviewed and reconfirmed by Fluor. The working fluids evaluated were carbon dioxide, ammonia, halocarbons, and hydrocarbons.

Power Cycle Optimization: The power cycle developed during Phase I required a change out of the binary working fluid composition and the addition of brine/hydrocarbon heat transfer surface. This change was to occur at a time during the life of the plant when the brine temperature decayed to approximately 345°F (174°C). This concept was selected in order to take full advantage of the economics associated with an unrestricted brine return temperature and a projected end-of-run (30 year) brine supply temperature of 325°F (163°C).

During Phase II, it was established with Chevron that the end-of-run brine supply temperature would be 338°F (170°C) and that the brine return temperature could not be less than 150°F (66°C). These new conditions negated the economic advantages of deferring capital expenditure on equipment and changing out the working fluid composition during the plant life. Based on these new conditions, the power cycle was reoptimized to operate with a single working fluid composition for the life of the plant.

Also during the Phase II, EPRI engaged C. F. Braun to develop laboratory temperature-enthalpy test data for a representative hydrocarbon mixture, namely, 80 mol percent isobutane and 20 mol percent isopentane. This data contributed materially to the selection of the Benedict-Webb-Rubin (BWR) equation of state for power cycle process design calculations and the need to alter the turbine throttle conditions in order to avoid the formation of hydrocarbon liquid in the expansion path through the turbine.

Brine Supply: A single phase brine supply mode was selected during Phase I for the plant design. This produced favorable power cost economics as compared to other cycles and materially reduced the uncertainties associated with scaling and injection plugging that can occur when geothermal brines are allowed to flash.

During Phase II, preliminary information obtained from Chevron on the cost differential between single and two phase brine supply lead to further economic studies. Based on the new energy cost data, these studies lead to the conclusion that two phase flow resulted in a lower power cost. However, it was subsequently determined that the minimum brine delivery pressure necessary for efficient binary cycle operation resulted in a very unfavorable pressure/flow relationship for economic well operation. As a consequence, partial pumping would be required very early in the operational life of the plant. This caused the energy supply cost differential between single phase and two phase brine supply to converge and the economics reverted back to single phase pumped well operation.

Power Cycle Control: It has been established that the Heber plant will operate as a base load unit. The ability of the plant to support this operational mode involves the need for a turbine-generator speed/load governor system that is suitably responsive, and a power cycle control system that will maintain the necessary turbine throttle conditions, i.e., temperature, pressure, and flow. Responsibility for turbine speed/load control will be delegated to the turbine generator supplier. Maintaining required turbine throttle conditions is an integral part of the power cycle design.

Power cycle control involves three dependent variables. They are temperature and pressure of the binary fluid supplied to the turbine, and brine temperature leaving the unit. The independent variables available for control of the power cycle are brine flow and two of three working fluid flows.

As a part of the Phase II preliminary design effort, Fluor developed eight alternative power cycle control schemes. The most optimum of these schemes was selected for incorporation in the final power cycle design.

Cooling System: An ample supply of irrigation water is available for the first five years of plant operation. This will be utilized in wet cooling tower system. Alternate sources of cooling water make up are under investigation for operation beyond the initial five year period. The most likely alternative is agricultural drain water.

During Phase II, wet/dry cooling was investigated as an alternative to the all wet cooling tower system. Power cost economics would not support this cooling mode. Alternative wet cooling tower designs were also evaluated and an optimum selection was established.

Power Cycle Economizer: The use of an economizer in the power cycle to transfer waste heat in the turbine exhaust to the recirculating working fluid was studied and determined to be uneconomic for the Heber binary plant.

Hydrocarbon Pumping Configurations: The economics of high head horizontal pumps in series with low head NPSH pumps versus multiple high horsepower high head multistage vertical pumps (as proposed in the Phase I studies) were investigated. Study results marginally favor the use of horizontal pumps. Their use is proposed in order to minimize repetition of maintenance problems experienced by SDG&E with vertical multistage pumps.

Heat Transfer Materials Selection: During Phase I, several field tests were performed on the corrosion and scaling tendencies of carbon steel and titanium when exposed to Heber reservoir brine. Test results showed that carbon steel was a suitable shell and tube material for the brine/hydrocarbon heat exchangers.

Discussions with process and utility plant operators in the Imperial Valley lead to the conclusion that Admiralty metal would be a suitable tube material for the hydrocarbon condensers operating in a wet cooling tower system.

Turbine Piping Economics: During the Phase I study review, it was determined that power cycle performance was extremely sensitive to turbine exhaust piping pressure loss. One psi (7kP) of pressure drop between the turbine and the condenser has an equivalent annual cost impact of $47,000 (1977 pricing baseline).

During Phase II, a pressure drop optimization study was performed. Six configurations involving different numbers of condenser shells, the use of expansion joints, and both axial and radial inflow turbines were selected for investigation.

This study resulted in a preliminary optimum piping and equipment arrangement. It was also determined that a turbine deck in the order of 20 to 30 feet (6 to 9 meters) above grade is feasible, there is no economic incentive to the use of expansion joints, and that the economics are insensitive to type of turbine (axial versus radial).

Turbine Generator Development: During Phase II, EPRI contracted with Elliott Company and Rotoflow Corporation to develop conceptual designs, performance predictions, and preliminary costs for commercial size binary turbines. Based on this work both turbine concepts appear to be technically viable but are unproven in the commercial size established for the Heber plant.

A plant design employing two half capacity turbine generator trains was investigated (one axial and one radial) in the interest of broadening the demonstration benefits of the plant. This concept resulted in a projected plant cost increase on the order of 15 to 20 percent. Also, it appeared that the smaller machine size would compromise the commercial demonstration aspect of the plant. For these reasons, the concept was not recommended.

PHASE II BASELINE DESIGN

The Heber power plant is to be an outdoor type station, having a net power output of 45 MW_e (65 MW design gross capacity). The outdoor concept provides for all major plant equipment including the turbine generator to be installed outside so as to reduce capital cost and minimize safety hazards associated with the handling and containment of the hydrocarbon working fluid. The plant is to be designed for operation from a central control room. The power plant will be provided with complete utility services and support facilities, and be located on a site shared with the brine production facilities that will be owned and operated by Chevron Resources Company.

The power plant has a net thermal efficiency of approximately 11.2 percent, which will remain nearly constant over the 30 year design life of the plant. The reservoir temperature is predicted to decrease over the life of the plant from an initial temperature of 360°F (182°C) to an end of life temperature of 338°F (170°C). Geothermal brine flow over this temperature range will vary from about 7 million pounds per hour (3.2 MM KG/hr) to 9 million pounds per hour (4.1 MM KG/hr), which is about 38 percent lower than an equivalent capacity dual stage flash plant.

Auxiliary power requirements to sustain plant operation will vary over the plant life from 16.9 MW to 19.1 MW. The levelized busbar power cost is estimated to be 137 mills per KWH.

The Phase II baseline design is characterized by the following additional features:

- The binary working fluid is a saturated hydrocarbon mixture of 90 percent isobutane and 10 percent isopentane that will be used over the life of the plant.

- The plant will employ a hydrocarbon binary cycle tailored from a simple Rankine cycle. Electrical energy is produced by transfer of sensible heat from the hydrothermal fluid to the binary working fluid, which is in turn, used to drive the turbine-generator.

- Brine temperature from the reservoir is expected to decay to about 338°F (170°C) at the end of 30 years of plant operation with full reservoir development (400-500 MW).

- The brine enters a brine/hydrocarbon heat exchanger where it is cooled to about 160°F (71°C) by heat exchange with the binary working fluid. The brine is then pumped to the injection island. All brine removed from the reseroir is returned.

- The binary working fluid is heated under supercritical conditions in the brine/hydrocarbon heat exchangers to about 305°F (152°C). This supercritical hydrocarbon vapor is expanded in the turbine, discharging as a superheated vapor and is condensed by cooling water in shell and tube type heat exchangers (surface condensers).

- The turbine is directly connected to the generator and is to operate at a speed of either 1,800 or 3,600 rpm. Turbine throttle conditions are 575 psia and 305°F (3965 kPa/152°C).

- Cooling water makeup is provided from irrigation canals operated by the Imperial Irrigation District (IID).

- The electrical transmission system will be provided by IID. The power plant will interface with the IID system through a switchyard. The main power plant transformer connects the generator output to a 34.5 kV switchyard. A station service transformer connects the switchyard with in-plant loads at 4,160 volts. Metering is provided to determine plant gross power output, in-plant power consumption, and power delivered to Chevron for well pumping and other production island uses.

REMAINING TECHNICAL ISSUES

The remaining technical issues relating to the commercialization of the binary cycle envolve the application of state-of-the-art technology and there is no indicated need for any new technology development.

ENVIRONMENTAL AND LICENSING

The Heber project would be a precursor in the development of licensing and environmental guidelines for future commercial geothermal plants. Considerable effort was expended by and under the direction of SDG&E in the development of environmental impact assessment, permits and licenses for the Heber plant.

An Environmental Impact Report (EIR) was prepared for the power plant and brine production facilities. The EIR concludes that there would be no significant adverse impact as a result of the Heber plant and Imperial County certification was approved in June, 1978.

Since the power plant will have a net capacity of less than 50 MW, jurisdiction falls to the County of Imperial as the lead agency in conjunction with regulation over the use of privately owned land. Permits have been granted by the County covering a zone change and a conditional use permit to construct and operate the brine production facility and demonstration power plant.

ESSENTIAL CONTRACTS

Agreements have been established for the purchase of geothermal heat energy, cooling water make-up, and for the sale of electric power produced by the power plant. Heat energy will be purchased as delivered to the power plant boundary from Chevron Resources Company. Cooling water make-up will be purchased from the Imperial Irrigation District for the first 5 years of plant operation. An alternate source must be established for continued operation after 5 years. The most likely alternative will be agricultural drain water. Power produced by the plant will be sold to the Imperial Irrigation District.

PROJECT CONTROLS

Project implementation controls were developed to cover project execution procedures, quality assurance, and plant design. In additon, a complete Cost/Schedule Implementation Plan was developed to cover Phase III, Detailed Design and Procuement. This document has not been published but is on file with EPRI.

SCHEDULE AND COSTS

At the time of project termination initial power plant operation was scheduled for mid 1982 and the total installed cost (in as-spent dollars) was estimated to be $54.8 million. The levelized busbar cost of power is 137 mills/KWH based on a revenue requirements method of computation. This estimate is the total of the components representing heat (62 percent), operation and maintenance (15 percent) and plant capital investment (23 percent).

Section 1
INTRODUCTION

The Heber Geothermal Demonstration Power Plant Project was initiated in 1976 by the Electric Power Research Institute (EPRI). The primary purpose of the project was to accelerate geothermal development for electric power generation in the United States by developing a moderate temperature, low salinity, hydrothermal (hot water) power plant to demonstrate adaptation of power conversion technology, environmental control technology and the economics of power plant construction and operation. A second objective was to establish the so-called binary cycle technology as a proven alternative to the flash steam cycle for those applications where reservoir characteristics and site specific considerations make it more desirable. The documentation of technical studies, analyses and evaluations and the dissemination of that information for the benefit of the general public was also considered an important objective.

The plant as now conceived is to be of a commercial size and be located on the Heber known geothermal resource area (Heber) in the Imperial Valley of Southern California. The plant design is based on a binary energy conversion cycle where in a saturated hydrocarbon is utilized as a working medium. Geothermal fluid (brine) will be supplied from an adjacent production facility to be owned and operated by the Chevron Resources Company (Chevron). The hot brine will be delivered to the power plant boundary as a liquid. After the heat energy has been transferred from the geothermal fluid to the hydrocarbon working fluid in heat exchangers, the brine will be returned to Chevron at the plant boundary for injection into the Heber reservoir. The hydrocarbon will vaporize in the heat exchangers and then drive a turbine/generator to produce electrical energy. The energy produced by the plant will be delivered to the Imperial Irrigation District for marketing on its distribution system.

Because broad industry support was essential for EPRI participation, San Diego Gas & Electric Company (SDG&E) organized a consortium of utility and governmental agencies to participate in the project. The two types of participants were owners and contributors. SDG&E was project manager and the principal owner with 77 percent of the power plant output. The other plant owners included Imperial Irrigation District (10 percent), Los Angeles Department of Water and Power (10 percent), and Southern California Edison Company (3 percent). EPRI continued as a major contributor. Other contributors to the project included: Nevada Power Company; Portland General Electric; Republic Geothermal, Inc.; Geothermal Resources International, Inc.; California Department of Water Resources; and the California Energy Commission.

Implementation of the project was organized into six phases. Phase I was the conceptual design and feasibility studies performed by the Ben Holt Company (Holt) and Procon, Inc. (Procon) under contract to EPRI (1) and was completed in 1976. The current phase, Phase II, is the preliminary design and engineering of the binary power plant and includes process and facility definition, major system optimizations, special background studies, environmental reports, project planning, scheduling, budgeting, and related work. Phase III was to consist of detailed design and engineering, procurement, and detailed construction planning. Phase IV was to include power plant construction and mechanical integration of all systems and facilities. Phase V was to include power plant start-up and shakedown operations. Phase VI was to include operation and performance evaluation.

The objective of Phase II was to design a 45 MWe net binary cycle power plant optimized for, and to be located at, the Heber reservoir. The size, location and conceptual engineering design for the power plant were specified in EPRI's Phase I studies conducted by Holt/Procon. This prior work was used as the point of departure for the Phase II work.

The statement of work for Phase II divided the scope of work into eighteen tasks. These tasks were: 1) evaluate and select an architect/engineer; 2) prepare project control documents; 3) establish project management controls for detailed design; 4) perform preliminary design and engineering activities; 5) perform plant performance and design analysis; 6) recommend provisions for research and development; 7) prepare bidders lists and specifications; 8) apply for and obtain all required permits, licenses and approvals; 9) prepare drawing, engineering, procurement and construction schedules; 10) prepare capital cost estimates and perform economic analysis for busbar cost of power; 11) develop quality assurance and quality control procedures; 12) prepare list of long lead-time equipment; 13) prepare detailed construction drawings; 14) prepare equipment lists with applicable code requirements; 15) prepare preliminary subsystem and system testing, start-up and operating procedures; 16) conclude Environmental Baseline Data Acquisition (EBDA) program; 17) develop procedures for management reviews and report; and 18) prepare periodic reports and technical reviews.

The original period of performance for Phase II activities was from June, 1977 through February, 1978. The completion date was extended until December, 1978 in order to obtain the requisite funding from DOE for the project. Several tasks were initiated and some were completed. Tasks 1, 2, 3, 4, 8, 10, 11, 16, 17 and 18 were initiated. Only Tasks 1, 2, 3, 11, 16, 17 and 18 were completed.

The purpose of this Final Report is to preserve the results of engineering and design activities, cost and economic analyses, permitting processes, and other related project activities that evolved as a part of Phase II. Utilities will be able to reference and utilize this record in conjunction with the future development of similar projects. This report presents the results of the Phase II engineering/design work and other related efforts performed by Fluor Engineers and Constructors (Fluor) under contract to SDG&E; and, Holt under subcontract to Fluor. It also includes the results of related project activities accomplished by SDG&E, such as economic analyses of busbar cost of power, establishment of energy supply, power sales and cooling water supply agreements, development of environmental impact studies and reports, and acquisition of use permits.

The work accomplished confirmed the technical and economic incentives favoring the binary cycle, and the use of a hydrocarbon as the power cycle working fluid. It also identified the optimum thermodynamic power cycle, working fluid mixture, turbine throttle conditions, and geothermal fluid supply mode. Other work performed included the development of a detailed work breakdown structure complete with manhour and project cost budgets suitable for cost control and status reporting. Project and quality assurance procedures and a design guide were developed along with the cost/schedule progress tracking and status reporting system. A master schedule covering project activities under the six phases was developed. Capital cost estimates and busbar cost of power analyses were also performed.

The presentation of the results of the work performed during Phase II has been organized into eight major sections in this Final Report. This introductory section, Section 1, discusses the purpose and historical background of the project. The optimized baseline design developed for the power plant is described in Section 2 and is based on the studies and optimization work discussed in Section 3. Cost analyses and the project schedule are described in Section 4. Section 5 discusses several outstanding technical and engineering problems identified during the design development. The licensing and environmental efforts expended on the project are detailed in Section 6. The agreements and contracts essential to the operation of the power plant are summarized in Section 7. Section 8 discusses the procedures developed to administer and control the project. In addition to this Final Report, EPRI has on file all of the supporting engineering documentation for the results presented in the report.

Section 2
PHASE II BASELINE DESIGN

This section describes the baseline design developed during Phase II for the Heber binary power plant. The design is optimized and the optimization process, including trade-off studies is described in Section 3. The EPRI Phase I conceptual design was used as the point of design departure. The plant location is shown on Figures 2A and 2B.

2.1 GENERAL DESIGN REQUIREMENTS

The power plant will be an outdoor type station having a generating capacity of 45 MW_e net. A plant capacity of 45 MW was selected since a size approaching 50 MW was desired to demonstrate commercial operation but less than 50 MW would simplify the permitting progress. Under the outdoor type station concept all major plant equipment including the turbine generator unit will be installed outside. This will reduce cost and help to avoid safety hazards associated with the handling and containment of hydrocarbons. Utility services and support facilities such as administrative offices, shops, and warehouses required to fully support station operation are to be included. The station is to be located on a site shared with brine production facilities that will be owned and operated by the Chevron Resources Company (Chevron).

The plant is to be designed for operation from a central control center with minimum operating manpower. The power plant control center will also be the focal point for effective coordination of operations between the field and the grid.

The geothermal fluid production system and the energy conversion system are designed for operation under base load conditions. A major design objective is to accommodate an instantaneous interruption in full generator load without damaging equipment or brine wells.

FIGURE 2A

IMPERIAL VALLEY GEOTHERMAL RESERVOIRS LOCATION MAP

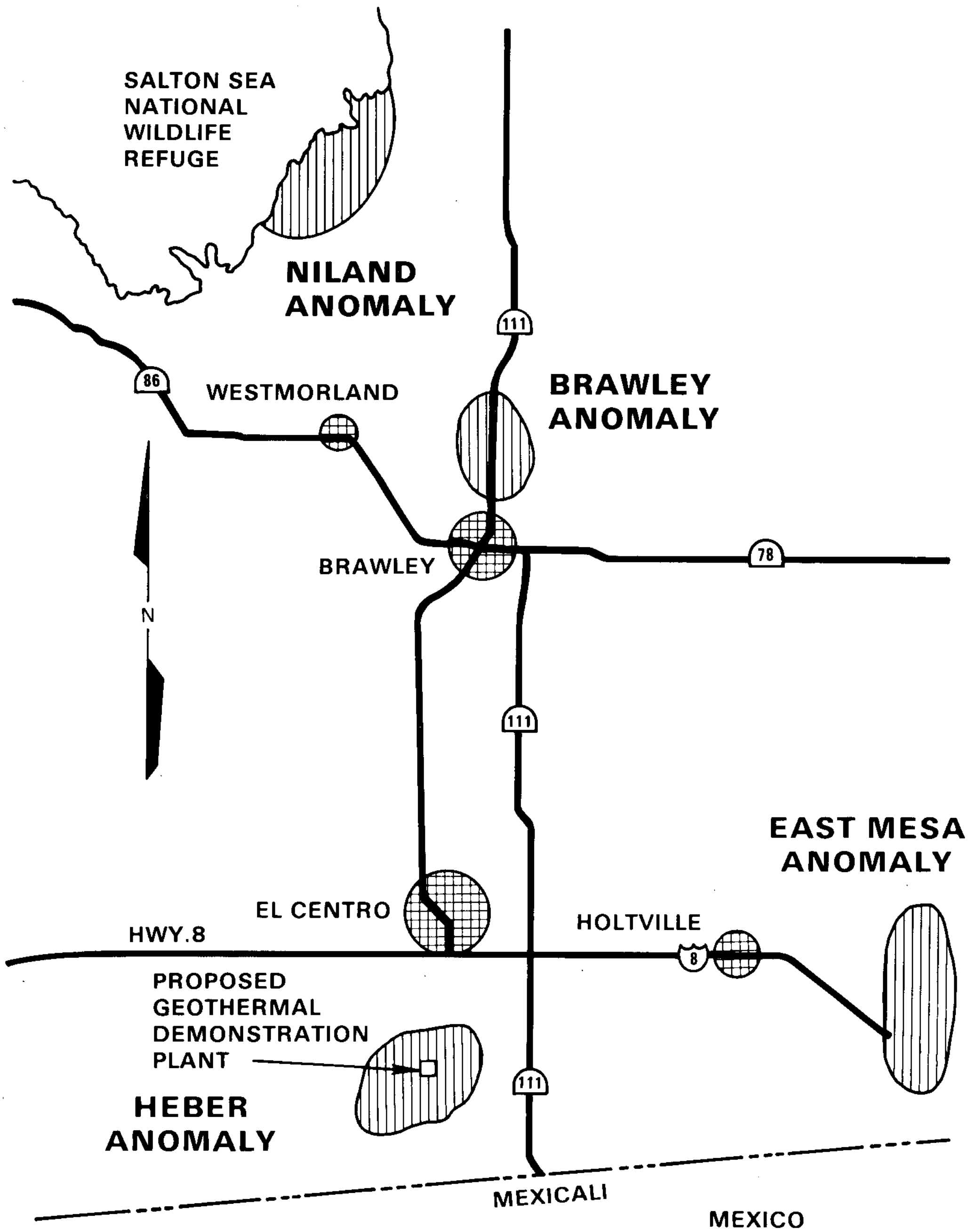
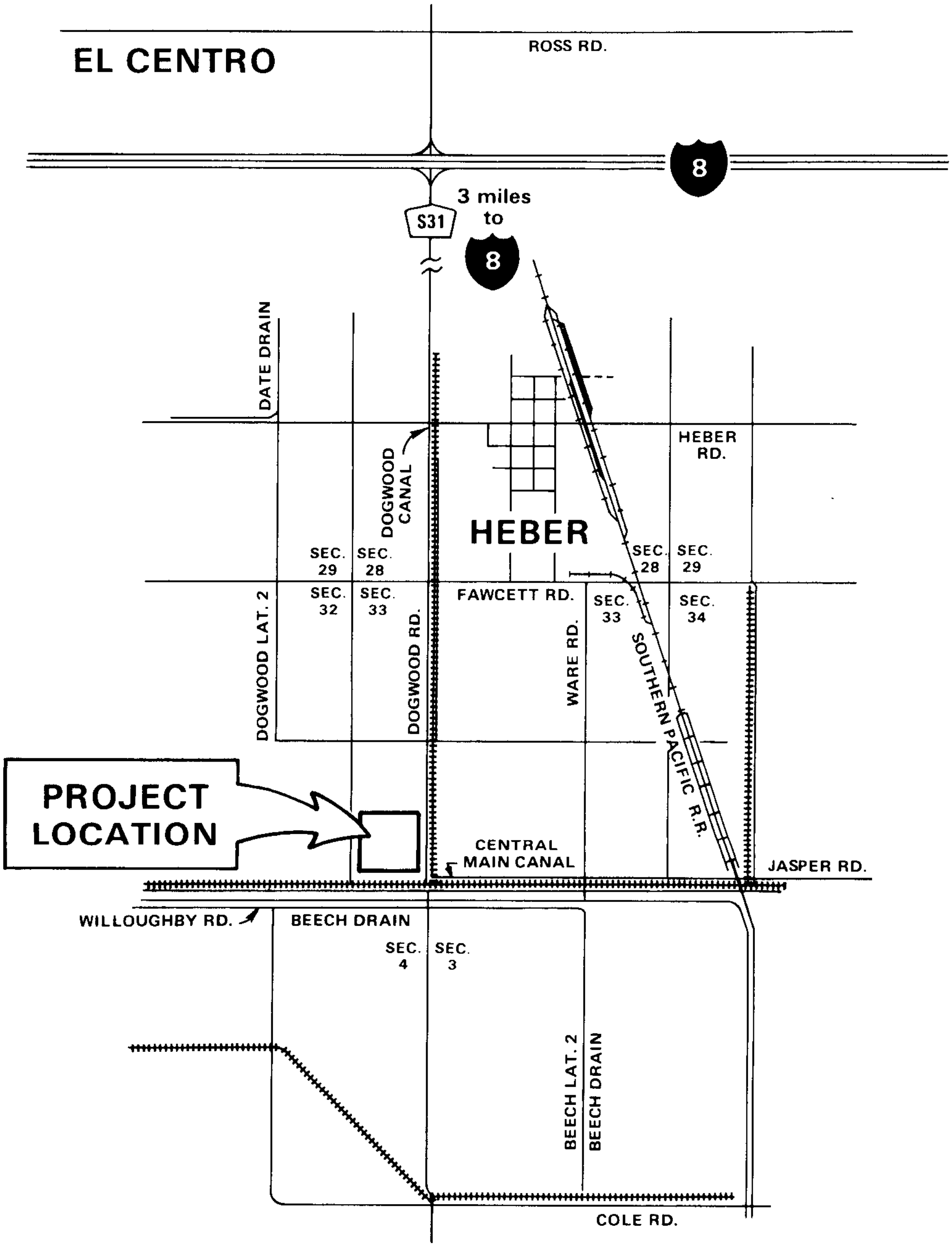


FIGURE 2B
PROJECT LOCATION
HEBER GEOTHERMAL
DEMONSTRATION PLANT



The facility is to be designed to avoid adverse impact on the surrounding environment. The hydrocarbon working fluid will be contained within the energy conversion system during all normal start-up operations and planned shutdown activities. All hydrocarbon vents and drains are to be piped to the hydrocarbon recovery system or the flare system so as to avoid release to the environment. Emergency venting of hydrocarbon will be through the flare system. Intermittent venting of water vapors from the brine system is to be controlled in a manner that avoids brine carry-over to adjacent agricultural areas. Drift from the cooling tower is to be controlled by the use of current state-of-the-art cooling tower drift eliminator designs. The design is to provide the most aesthetically acceptable appearance consistent with the technical, operational and economic requirements of the facility.

Conservation of water is a major consideration in the design of the plant for the following reasons:

- The power plant has a low thermal efficiency and this requires a disproportionately large heat rejection system as compared to a conventional power plant.
- Irrigation water for cooling is in short supply in the Imperial Valley and will only be available for the first five years of plant operation.
- Alternative supplies are only available from polluted sources that will require extensive and costly treatment prior to use for plant cooling water make-up.

Noise generated during normal operation is to be attenuated using current design practices such as acoustical insulated lagging and discharge silencers. Noise generated from venting, pressure relieving, and pressure reducing during start-up, normal, and emergency operations shall be attenuated in accordance with OSHA regulations.

A seismic investigation of the plant site region was performed for SDG&E by Fugro, Inc. of Long Beach, California. Their report "Geologic, Seismologic, and Earthquake Engineering Report for the Heber Geothermal Demonstration Plant, Heber, California" (16) was issued in December 1977. The geologic field reconnaissance reports no features readily attributable to active faulting or a seismic creep within four miles of the site. The report states that the facility is likely to experience significant vibratory ground motion during the thirty year life of the plant. Furthermore, the report indicates that a large magnitude earthquake is likely to occur along one of the two faults that are near the site during the plant's anticipated thirty year life.

Fugro reported that the maximum credible earthquake which would cause maximum shaking at the site would have a 0.7 g peak ground acceleration level. The acceleration level that would have a 50 percent probability of not being exceeded during the 30 year life of the plant is about 0.29 g for Maximum Probable Earthquake motion. The plant design is to be based on retaining operability after a 0.29 g seismic induced ground acceleration level; and, retaining structural integrity of critical equipment, systems and structures under a maximum peak ground acceleration level of 0.7 g.

2.2 OPERATING PLAN

The power plant will be owned by a consortium of utility companies and operated by SDG&E for the consortium. Hydrothermal fluid production and reinjection facilities will be operated by Chevron. Chevron will supply the geothermal fluid to the power plant boundary according to terms and conditions set forth in the energy supply agreement. SDG&E will return the spent brine to the power plant boundary at the pressure and temperature conditions specified by Chevron. Electric energy for operation of the Chevron production facility including downhole pumping is to be supplied by SDG&E from the station auxiliary power system. SDG&E is to be responsible for interfacing electrically with the Imperial Irrigation District (IID) system through an onsite switching station to be provided by SDG&E.

Compensation for power to operate the production and reinjection facilities, including pumping, is factored in the price of brine delivered to the power plant. To avoid the added cost of a separate substation, SDG&E has agreed to deliver power to the Chevron production island from the station auxiliary power system. This power will be metered and the cost will be credited against the price of geothermal energy supplied. Chevron will arrange for an independent power supply to operate their reinjection island since it will be located several miles from the power plant/production island site.

2.3 OPERATION OBJECTIVES

The three primary operation objectives of the Heber geothermal demonstration power plant operation are:

- To demonstrate the potential for producing electric power from a binary power cycle utilizing energy supplied from a liquid dominated moderate temperature geothermal resource.

- To reach a net power output of 45 MW_e and a reliable 70 percent on-stream availability within five years of operation.

- To demonstrate commercial operation in the following manner:

  --by conducting safe, reliable operation from a central control room utilizing a minimum number of operating personnel.

  --by proving that brine production and energy conversion systems are responsive to daily and seasonal load swings and are capable of withstanding instantaneous interruption of full generator load without damaging equipment or brine wells.

  --by operating within the prescribed environmental limits.

The power plant is to be designed to operate in a base load mode over a broad range of daily and seasonal system load demands. The plant will achieve the following objectives during the early life of the plant:

- Train operating and maintenance personnel.

- Demonstrate function of specific equipment.

- Calibrate and fine-tune instrumentation and control systems.

- Establish operating ranges and limits for systems and equipment.

- Determine brine production well capacity.

- Demonstrate safe operation.

- Evaluate equipment and process performance.

- Establish economic data.

- Demonstrate environmental acceptability.

- Provide information and technical data for use in designing future geothermal facilities.

2.4 PROCESS SYSTEM DESCRIPTIONS

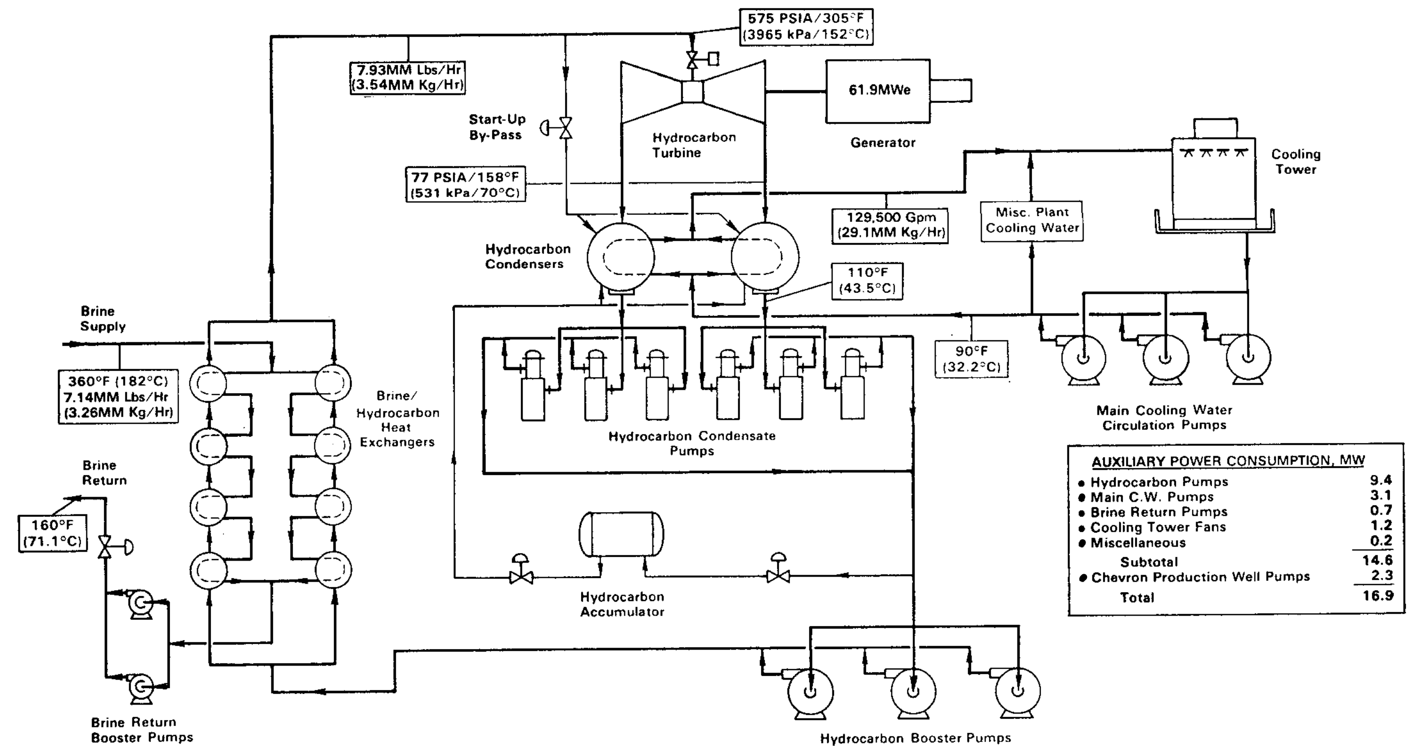
The plant consists of a main power cycle plus utility and other supporting auxiliary systems. The power cycle consists of a hydrothermal fluid loop and a hydrocarbon binary loop. The power cycle system design is based on a single-phase brine supply mode and a 90 mol percent isobutane and 10 mol percent isopentane hydrocarbon binary working fluid mixture for the thirty year plant design life.

2.4.1 Power Cycle

The power cycle process design is depicted on the accompanying start-of-run and end-of-run power cycle schematics, Figures 2.4.1A and B.

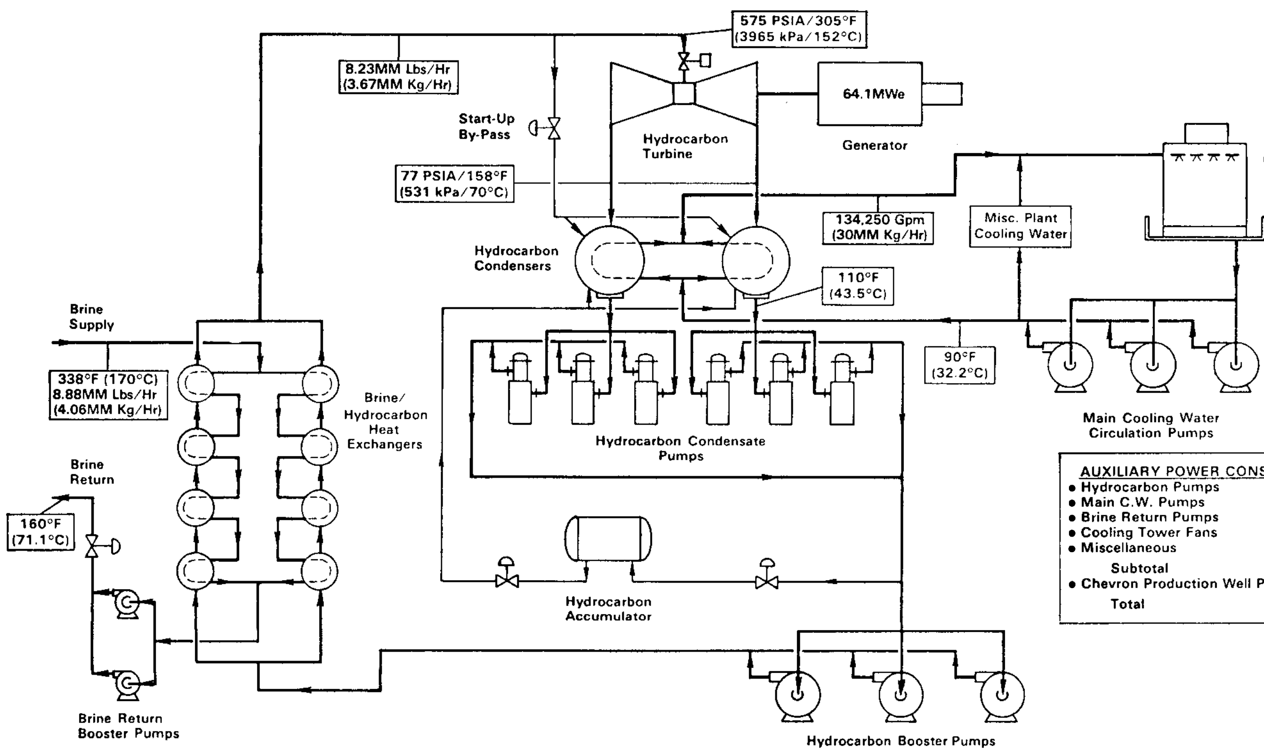
Brine System Loop

The purpose of the brine system loop is to provide an efficient and economic means of transferring heat energy contained in the geothermal fluid to the hydrocarbon working fluid.



AUXILIARY POWER CONSUMPTION, MW	
• Hydrocarbon Pumps	9.4
• Main C.W. Pumps	3.1
• Brine Return Pumps	0.7
• Cooling Tower Fans	1.2
• Miscellaneous	0.2
Subtotal	14.6
• Chevron Production Well Pumps	2.3
Total	16.9

FIGURE 2.4.1A
POWER CYCLE SCHEMATIC
(START OF RUN)
HEBER GEOTHERMAL DEMONSTRATION POWER PLANT



AUXILIARY POWER CONSUMPTION, MW	
• Hydrocarbon Pumps	9.7
• Main C.W. Pumps	3.2
• Brine Return Pumps	0.9
• Cooling Tower Fans	1.3
• Miscellaneous	0.2
Subtotal	15.3
• Chevron Production Well Pumps	3.8
Total	19.1

FIGURE 2.4.1B
POWER CYCLE SCHEMATIC
(END OF RUN)
HEBER GEOTHERMAL DEMONSTRATION POWER PLANT

This loop is to contain a bank of shell and tube heat exchangers arranged in a series/parallel configuration and manifolded to the brine supply and return piping in a manner that promotes flow balance among parallel exchanger trains by piping symmetry and equal friction losses. This configuration is shown in Figures 2.4.1A and B. The use of valves to achieve flow balance is to be avoided because of increased cost and the risk of not being able to benefit from on-stream maintenance due to the difficulties in achieving tight shutoff for safe maintenance isolation.

The exchanger configuration is to be finalized through contact with potential manufacturers during the detailed mechanical system design. The final configuration is to be confirmed during the equipment selection and award process. The performance rating of the exchangers is to be based on the end of run downhole temperature of 338°F (170°C). This temperature is estimated by the reservoir operator to be the worst condition, assuming full reservoir development.

Hot brine is to be provided by Chevron at the plant boundary interface at a pressure which will ensure liquid-phase conditions. The thermally spent brine is to be returned to the plant boundary at a minimum temperature of 160°F (71°C) in order to enable Chevron to meet the 150°F (66°C) temperature requirement at the well head in order to minimize reinjection well damage. Booster pumps are to be provided in the brine return system to maintain a minimum return pressure of 250 psia (1724 kPa) and a maximum return pressure of 300 psia (2068 kPa) at the plant boundary.

Catchments and trenches are to be provided to collect any spilled or leaking brine for transfer to either the production island or to a sump for disposal. Drains, vents, thermal expansion relief valves and instrument blowdowns on piping and equipment handling brine are to be discharged into a brine collection system.

Facilities for separating sand from the brine are to be provided by Chevron. These facilities are to be located on the production island.

Hydrocarbon System Loop

The hydrocarbon system loop provides for: 1) containment of the binary hydrocarbon working fluid, and 2) efficient transfer of energy from the brine loop to the hydrocarbon turbine. The system is to be designed so that the hydrocarbon can be raised to a pressure of approximately 575 psia (3965 kPa) and a temperature of 305°F (152°C) under supercritical conditions. The hydrocarbon expands through the turbine and is condensed under controlled conditions in a closed loop. The hydrocarbon temperature is maintained at the turbine inlet through the exchange with the brine in the brine/hydrocarbon heat exchangers. Design pressure levels are maintained within the hydrocarbon system by vaporization, expansion, condensation and pumping.

Several hydrocarbon pumping configurations were evaluated and are documented in Section 3 of this report. As a result of this evaluation, a series pumping system was selected as shown Figures 2.4.1A and B. The system includes vertical motor-driven condensate pumps that take suction directly from the hydrocarbon condenser hot wells. These pumps are to discharge to the suction of the high-head, motor-driven pumps which maintain the required pressure of 575 psia (3965 kPa) at the turbine inlet.

Alternative turbine exhaust piping and condenser configurations were evaluated and are also documented in Section 3. Based on the results of this evaluation, the system will utilize two condenser shells arranged in parallel and separately connected to the turbine exhaust nozzles as shown on Figure 2.4.1A and B. The final number of condenser shells is to be determined during the equipment selection process, during which time consideration is to be given to transportation and vapor distribution problems associated with large diameter shells. These considerations may cause the number of exchanger shells to be increased, thereby nullifying the cost advantages discussed in Section 3.

Cooling tower circulating water is to be used as the heat removal medium to condense the hydrocarbon as it exhausts from the turbine, also as shown on Figures 2.4.1A and B.

The number of hydrocarbon condensate and booster pumps required to operate in parallel is based on the two shell parallel condenser arrangement. Two sets of three nominal 50 percent capacity condensate pumps are planned for inclusion in the design. One set is to be utilized for each of the two parallel condensers.

The final determination as to the number of pumping units is to be made by evaluating the economics, performance, and technical suitability of competitive proposals.

A side stream (makeup/drawoff) hydrocarbon accumulator is to be provided in the system to accommodate volume changes within the system during load variations and to provide for liquid hydrocarbon storage during unit shutdowns. Feed to the accumulator is to be from the condensate pump discharge during periods of high level in the condenser hot well. Hydrocarbon makeup to the system is to be supplied from the accumulator to the condenser hot wells during periods of low levels in the condenser hot well.

Piping and exchangers are to be protected from overpressure by adequately sized relief valves that are arranged to discharge to the hydrocarbon condensers and/or the flare system.

Means for quick shutoff of hydrocarbon flow to the turbine during emergency conditions is to be provided in order to protect personnel and equipment. A quick-closing emergency trip valve is to be supplied by the turbine manufacturer for this purpose.

Thermal expansion and pressure drop are the controlling design parameters for determining the hydrocarbon exhaust piping configuration.

Adequately sized suction and discharge piping is to be appropriately manifolded, valved, vented, and drained to permit isolation of individual hydrocarbon pumps.

All liquid relief valves on pumps and accumulators are to discharge into the hydrocarbon condensers. Vapor reliefs are to discharge into the flare system.

Connections for purging and venting the low-pressure hydrocarbon vapor from lines and equipment during shutdown and hydrocarbon evacuation are to be provided at appropriate points in the piping system. Piping configurations are to be designed to minimize entrapment of hydrocarbon within the equipment and to expedite venting and purging operations.

The system is to be designed to accommodate and control load changes created by the variations in the brine system flow during start-up and normal operation. The system is also to be designed to accommodate instantaneous interruption of the hydrocarbon flow to the turbine under full load operation or upset conditions.

Turbine shaft seal leakage is to be vented to the hydrocarbon recovery system. Various types of sealing systems are available and final determination of recycling arrangements must await selection of a specific turbine supplier. The hydrocarbon recovery system is to be designed to recycle the amount of hydrocarbon recovered from the sealing oil in addition to the buffer gas required by the turbine manufacturer.

2.4.2 Hydrocarbon Relief and Flare System

Equipment design pressures are to be such that relief valve set pressures will be sufficiently high to accommodate pressure increases during normal or anticipated minor upset operating conditions. The hydrocarbon relief and flare system is designed to ensure that the hydrocarbon vapors are diverted into the flare system in the event that relieving becomes necessary. Some venting to the flare system is anticipated during purging and recharging operations.

The flare system is to consist of adequately sized relief valves, relief headers, and the accessory equipment necessary to ensure safety in handling any hydrocarbons discharged into the system. Condensate separated from the vapor in the flare knockout drum is to be pumped to a holding vessel.

A flow sensor is required to actuate the pilot flame ignition system upon presence of flowing vapor. A water seal prevents atmospheric air from entering the flare system during periods of zero flow. Hydrocarbon flow passes through the seal when the pressure in the flare header rises above atmospheric. Vapors are ignited as they emerge from the flare tip. The flare tip is to be at a sufficient elevation to ensure that plant personnel and equipment are not endangered by thermal radiation.

2.4.3 Hydrocarbon Storage System

The hydrocarbon storage system is to include unloading, transfer, and vapor recovery facilities. Desired mixtures of hydrocarbons are to be blended in a storage tank before being transferred into the hydrocarbon accumulator. A recovery system is to be provided to collect the vapors from the storage vessels and then compress, condense, and return the degassed hydrocarbon liquid to storage during recharging and other operations. Noncondensables are to be discharged to the flare system.

The transfer facilities are to be used to "pump out" hydrocarbon-containing equipment and systems when clearing them for inspection or maintenance. After pump-out operations are complete, purge gas is introduced into the equipment for purging of the hydrocarbon. The purge gas/hydrocarbon mixture is to be discharged into the flare system until purging is complete.

Air is to be purged to the atmosphere from the systems with inert gas. When the air/purge gas mixture reaches a predetermined purge gas concentration, hydrocarbon is to be introduced into the system and inert gas and hydrocarbon vented to the flare header until the desired hydrocarbon concentration is attained.

2.4.4 Inert Gas System

Nitrogen is to be used to exclude air and hydrocarbons from the hydrocarbon-containing equipment and systems during start-ups and shutdowns. Purging and blanketing operations will consume a significant amount of inert gas which must be distributed to all locations requiring purge gas during maintenance and operation. An adequately sized storage vessel is to be installed along with an evaporator, if required.

2.4.5 Fuel Gas System

Fuel gas will be required for the flare pilot ignition system, for gasification of liquid nitrogen, and possibly for space heating. An adequately sized and valved piping system is to be designed to distribute the required quantity of fuel gas at the pressure required by the user.

2.4.6 Cooling Water System

A multicell cooling tower is required to maintain the cooling water temperature at about 95°F (35°C) when the wet bulb temperature is at a maximum of 80°F (27°C).

Cooling water at a rate of approximately 140,000 gpm (31,797 m^3/hr) is to be circulated through the power plant for heat rejection. The major portion of the circulating cooling water is required by the hydrocarbon condensers. Cooling water supply and return lines are to be routed underground to and from the hydrocarbon condensers and are to be constructed of reinforced concrete.

The cooling water system is to be provided with facilities for automatically injecting environmentally acceptable dispersants and corrosion inhibitors into the circulating water. Bacteria and algae control is to be accomplished by the use of an automatic chlorination system. Side stream filters are to be considered if it becomes necessary to remove airborne solids and/or residual silt entrained in the makeup water.

A blowdown rate of about 700 gpm (159 m^3/hr) is anticipated for maintaining the quality of the cooling water. The cooling water circulation system is to be controlled at a total dissolved solids content of 4000 parts per million (ppm). The blowdown is to flow by gravity from the cooling tower basin to interface with a treatment system which will provide adequate treatment for ultimate discharge into an agricultural drain. Sampling points and a control system are to be provided for regulating blowdown flow.

Further investigation during detailed plant design may prove that a closed loop system is desirable for circulating cooling water through the generator hydrogen coolers, the oil coolers for the turbine and generator, the hydrocarbon recovery compressor condenser, and the plant and instrument air compressor aftercoolers.

2.4.7 Makeup Water and Water Treatment Systems

The source of raw water makeup is either the Central Main or Dogwood Canal which are adjacent to the plant site. The instantaneous raw water makeup requirement is approximately 3000 gpm (749 m^3/hr). This irrigation water originates at the Colorado River and contains concentrations of up to 900 ppm of total dissolved solids with significant quantities of entrained silt.

Pumps are to be provided to transport water from either canal to the silt removal ponds where silt is expected to accumulate at a rate of approximately 1,500 pounds (680 kg) per day. A coagulant is to be added to the raw water entering the pond to accelerate silt deposition. Because most of the silt will be deposited in a small area of one pond, desilting operations are to be conducted on a regular basis. The silt removal ponds are to be provided to impound sufficient water for approximately one day of full load operation as well as an adequate amount of reserve for fire fighting purposes. Dikes are to provide adequate free board above normal pond level.

Impermeable pond linings are to be provided from either properly conditioned soil available at or near the site or from commercially available man-made materials. Final selection of the lining is to be made after completion of the geotechnical investigation.

A sulphate-resistant concrete pump pit with removable trash gates is to be designed to receive water from either or both ponds. The fire water and makeup water pumps are to take suction from this pit. The flow system and pump pit are to be designed to provide sufficient water to all of the fire water pumps and one raw water makeup pump simultaneously.

2.4.8 Fire Protection Facilities

Water to the fire water system is to be transferred from the silt removal pond pump pit by a diesel-driven and an electric motor-driven pump. A small electric motor-driven jockey pump is to maintain pressure in the fire water system during periods of little or no flow. All three fire water pumps are to be provided with individual suction facilities in the pump pit of the silt removal pond. The main fire water pumps are to be monitored from the control room and equipped with automatic starting controls initiated by decreasing fire water pressure. The fire water system is to be designed in accordance with applicable insurance and state fire system standards. Deluge systems, activated by high local temperature conditions, are to be installed, as required, in hazardous areas. Monitors capable of spraying the turbine generator operating floor are to be operable from ground level.

A dry pipe deluge system is to be installed in the cooling tower. Water flow through this system is to be actuated by high temperature sensing devices located at strategic points.

Additional fire protection equipment to be installed throughout the facility includes:

- Portable fire extinguishers located throughout the facility.
- An automatic fire suppression system to protect the electrical switch control room.

The design of the fire protection facilities is to be reviewed and approved by the local fire authorities.

2.4.9 Potable Water System

The use of potable water is to be restricted to the sanitary facilities, showers, safety showers and eye wash stations. Irrigation canal water is to be used as the potable water source. A pump is to be installed at the irrigation canal water supply point to furnish raw water to potable water treatment tanks. Coagulant is to be injected into the raw water prior to its entering the treatment tanks. Desilted water will flow by gravity from the settling tank to a 24-hour holdup tank where it is to be chlorinated. Silt from the settling tank is to be returned by gravity to the canal water inlet at the silt removal ponds. Chlorinated potable water is to be supplied to the plant system by a potable water pump. Potable water is also to be furnished to the production island. An air padded tank is to be considered in order to allow intermittent operation of the potable water pump and to supply potable water for a reasonable time during power failure.

2.4.10 Sanitary Wastewater System

Sewage is to gravitate to septic tanks and then to tile drain fields for dispersal. Drain field design is to be based upon recommendations of the geotechnical investigation consultant.

2.4.11 Drainage Systems

Surface drainage from the plant is to drain from sloped pavement to swales at the edge of the concrete for surface discharge. Oily water from the pavement under the turbine generator structure and from the turbine generator oil console is to be collected in an underground piping system. This system is to discharge into a holding sump for oil removal then eventual release to the surface drainage system or disposal by other means.

2.4.12 Plant and Instrument Air System

One electric motor-driven and one diesel-driven reciprocating compressor are to supply instrument and plant air. This equipment is to be located under a roof cover. Each compressor is to be equipped with an air intake located at least 20 feet (6 meters) above ground level. The compressors are to be valved, vented, and drained to permit isolation of either machine. Controls are to be designed to ensure that either machine can function as the standby unit. Oil bath-type inlet filters are to be provided.

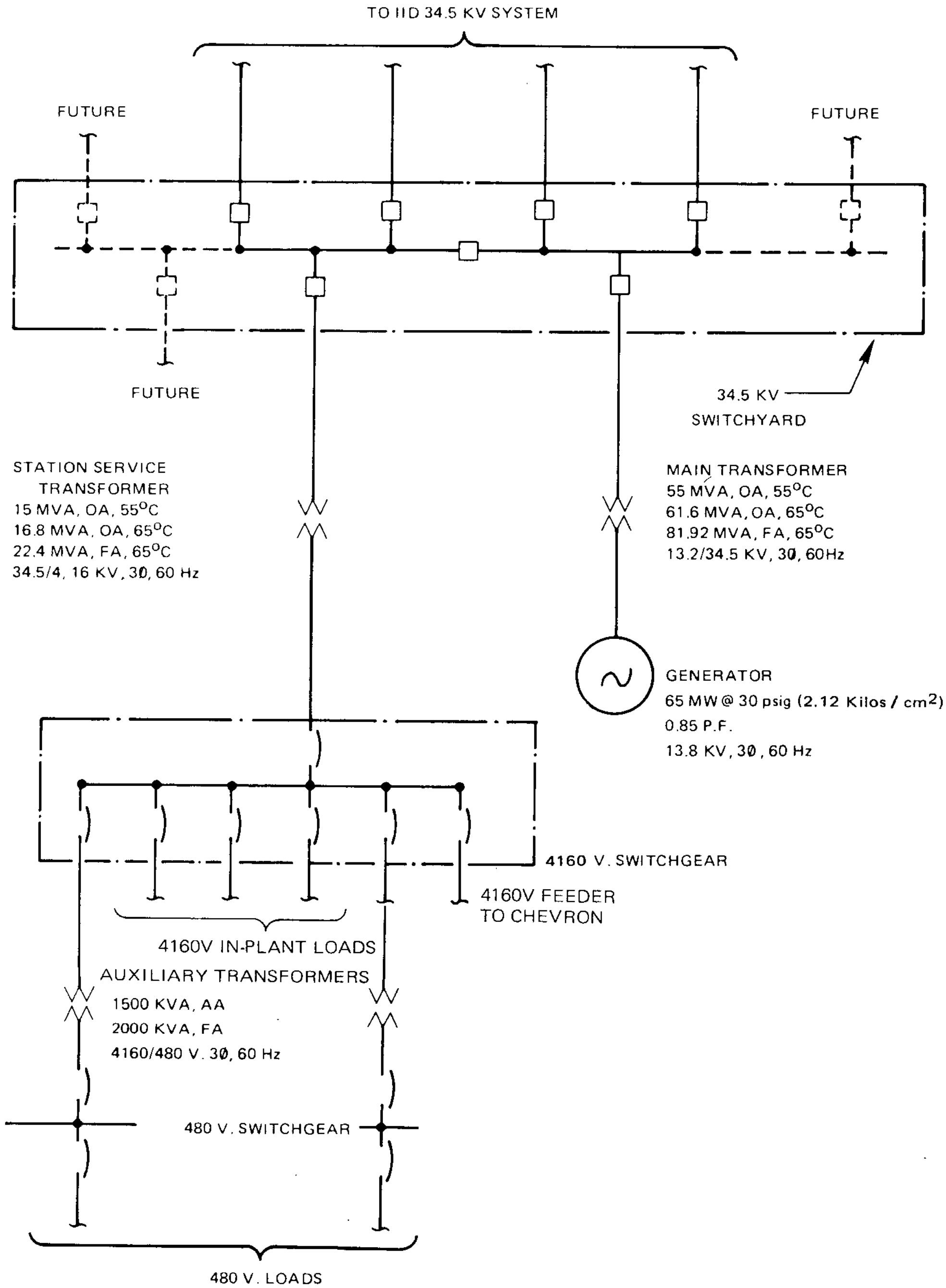
A plant air distribution system is to be provided to distribute air for general service throughout the facility. This system is to be designed to ensure that plant air can also be provided by portable compressors.

The inlet line to the instrument air header is to be equipped with a set of dual filters capable of reducing the quantity of entrained oil in the air to acceptable levels at ambient temperature. The air is to be processed through a refrigerated filter for drying to a suitable dew point. Automatic bypasses are to be provided for both the oil and refrigerated filters.

2.4.13 Electrical Transmission System and Main Switchyard

Two 34.5 kV transmission lines from the IID network are to loop through the power plant switchyard. The main bus is to be provided in two sections connected with a tie breaker. Four positions are required to accommodate the transmission lines. Two additional positions are required, one position for the 13.2/34.5 kV generator transformer and one position for the 34.5/4.16 kV station service transformer (see Figure 2.4.13).

FIGURE 2.4.13
PRELIMINARY ELECTRICAL ONE-LINE DIAGRAM



Open buswork is to be supported on a steel structure. Oil circuit breakers, disconnect switches, control equipment, protective relays, and all necessary ancillary equipment are to be located in the switchyard. Metering equipment for cost accounting purposes is to be provided at the transformer positions.

2.4.14 High-Voltage Electrical Systems

The generator is to produce 13,800-volt, 3-phase, 60-hertz power at the machine terminals. A segregated phase bus duct is to connect the machine to the 13.2/34.5 kV transformer. All necessary protective relaying is to be included in the design. All electrical operating functions are to be monitored and controlled from the control room. The generator transformer system is to be designed as a unit with a 34.5 kV circuit breaker between the transformer and the main bus.

A single 34.5/4.16 kV transformer is to be provided to supply total station service for the facility. All induction motors over 200 horsepower are to be connected to the 4160-volt system. Circuit breakers with appropriate metering and relaying equipment are to be located in the control building switch room. Any capacitors required for power factor improvement are to be located in nonelectrical hazard areas.

All 4160-volt protective relaying is to be integrated with protective relaying for the switchyard and transmission systems.

2.4.15 Low-Voltage Electrical Systems

A 480-volt, 3-phase, 60-hertz system is to provide electrical power to all process-associated motors rated 200 horsepower or less, to all exterior lighting, and to all welding machine receptacles.

Interior lighting, receptacles in buildings, and other low-power, single-phase equipment are to operate at 120/208 volts. Emergency lighting is to be provided by individual battery-powered units equipped with automatic recharging capability.

A 120-volt dc system is to be provided to supply power to various emergency oil pumps, to the turbine generator turning gear, and to selected instrumentation and controls. An adequately sized wet cell battery bank is to furnish power to the 120-volt dc system. Battery charge is to be maintained by a static-type rectifier powered from the 480-volt system. An inverter is to be furnished to supply power to the critical controls requiring alternating current.

2.4.16 Control Systems

Instrumentation and control systems are to be provided to monitor and control the operation of the power plant. Additional instrumentation and data acquisition capability is to be provided in order to thoroughly evaluate equipment and system performance during the demonstrative phase of operation. The power cycle control scheme is to be developed around the control concept described in Section 3. Special instrumentation and control systems are to be devised as the various flow diagrams are developed during detail design.

Electronic instrumentation and control system components are to be utilized, wherever practicable. The turbine generator governor/admission valve controls are to be a combination electronic hydraulic system. Trip circuits and bypasses for testing are to be provided to protect the plant systems against damage during emergency conditions. Deviation and absolute value alarm circuits are to monitor critical functions and energize alarms to warn operators of impending difficulties. The alarm system is to incorporate "first out" features in order to rapidly identify the cause of a trip-out situation.

Control room panels are to be desk-type consoles equipped with instruments and control devices that are highly visible and easily operated by the attending personnel. The control system is to be designed to ensure that all control activities that can be initiated in the control room can also be initiated from the corresponding local station.

2.5 MAJOR EQUIPMENT

2.5.1 Turbine Generator

The turbine generator is to be designed to operate as a base load unit in a central generating station environment. There will be occasional variations in the turbine generator load due to variations in the electrical network demand or seasonal demand. The generator system is to be designed to maintain frequency when operating as a single unit. Machine characteristics are also to be such that the unit can be operated with other generators connected into the power grid.

The turbine and generator are to be direct-connected for operation as a unit at a synchronous speed of either 1800 or 3600 revolutions per minute. If a turning gear is required by the manufacturer, it is to be equipped for automatic starting.

The turbine generator and auxiliary equipment are to be installed outdoors in an electrical hazard area classified Class 1, Division 2, Group D as defined in the National Electric Code. Outdoor equipment must be able to withstand ambient air temperatures of 120°F (49°C) and sun radiation heat to 180°F (82°C).

All parts of the turbine generator are to be accessible and removable for maintenance. Major turbine generator components are to be arranged in such a manner that a gantry crane can be utilized during maintenance.

The turbine generator is to be soleplate-mounted. All auxiliary systems such as oil consoles are to be baseplate-mounted for installation as an assembled unit. The equipment and structural anchors are to be capable of accommodating the seismic acceleration levels established for the area in addition to normal operating forces.

The turbine generator is to be designed to limit sound levels to 90 dBA or less as measured at a distance of three feet from any projection of the unit or from any enclosure.

Components are to be subjected to various tests at the factory. Such tests are to include, but not be limited to:

- Overspeed rotor assemblies.
- Hydrostatic tests.
- High potential test of stator and armature assemblies.

- Four-hour mechanical run of turbine and accessories.

The components of the turbine generator are to be inspected during the manufacturing and assembly processes by Purchaser Inspectors and Quality Assurance Personnel to ensure compliance with specifications and applicable standards.

The turbine generator is to be guaranteed by the manufacturer for capacity and performance in accordance with specifications. In addition, the vendor is to warrant the unit against incorrect designs, defective materials, poor workmanship, and failure from normal usage for a specified period of time.

2.5.2 Turbine

The turbine may be an axial flow or a radial in-flow machine with single or multiple cylinders. A single inlet nozzle is the most desirable arrangement. Downward oriented exhaust nozzles are required (see Subsection 3.12). The casing is to be either cast or fabricated steel and all split lines are to be leakproof. The rotor may be either "stiff" or "flexible" shaft design.

The turbine is to be equipped with sleeve or tilting pad friction-type journal bearings with force feed lubrication. The thrust bearing may be self-equalizing, double-acting with a removable thrust collar. Any other thrust control arrangement is to be reviewed and specifically approved prior to award.

Lube oil systems are to include a shaft-driven main pump, an ac motor-driven auxiliary pump, and a dc motor-driven emergency pump. The lube oil console is to be baseplate-mounted for installation as an assembly. Oil piping between the filter discharge and the inlet connections on the machine is to be stainless steel. The lubrication system for the turbine is to be separate from the generator lubrication system.

Lubricated or nonlubricated flexible couplings installed between turbine and generator or between multiple turbine casings are to be dynamically balanced.

The shaft sealing design is to prevent leakage of hydrocarbon to the atmosphere even when the shaft is at rest and the turbine casing is under pressure. In the event oil is employed for the shaft sealing system, it may be furnished by the lubrication system. The seal oil system is to be capable of recovering both hydrocarbon vapors and seal oil liquid for recycling to their respective systems. A buffered gas shaft seal arrangement is also acceptable. This system is also to be capable of recycling hydrocarbon leakage and buffering gas to their respective systems.

2.5.3 Generator

The generator is to be a 13,800-volt, 3-phase, 60-hertz machine capable of developing full load with a 0.85 power factor and 30 psig (2.12 kg/m^2) hydrogen pressure. The gas cooler arrangement must permit operation at 80 percent of rated kVA when one section of the coolers is shut down. The bearings are to be friction-type sleeves or tilting pad arrangement.

The generator is to be matched to the turbine physically and functionally and is to be hydrogen cooled. Windings are to be wye-connected and grounded through a distribution transformer with secondary resistance.

A static excitation system is to be provided. If the system requires the use of collector brushes on the generator shaft, the rigging must be suitable for installation in an area designated Class 1, Division 2, Group D for electrical hazards.

The lube oil system may include a shaft-driven main pump, an ac motor-driven auxiliary pump, and a dc motor-driven emergency pump. The lube oil console is to be baseplate-mounted for installation as an assembled unit.

Generator tests specified in Table 3 of ANSI standard C50.13 are to be conducted in accordance with IEEE Publication Number 115.

2.5.4 Turbine Generator Instrumentation and Controls

The turbine generator is to be equipped with a control system which will allow automatic operation and monitoring of electrical and mechanical performance from the control room. Additionally, the system must be designed to initiate appropriate action for protection of the unit during abnormal situations.

Auxiliary systems are to be equipped with instrumentation and controls to monitor performance and initiate appropriate remedial action during upset conditions.

The control system for the turbine generator is to provide immediate interruption of hydrocarbon flow to the turbine in an emergency shutdown situation, prevent shaft speeds in excess of 120 percent of synchronous speed during any trip situation, and provide smooth load changes from minimum to maximum generator output.

2.5.5 Pumps

Most of the station auxiliary power is consumed by pumping operations. Therefore, careful consideration must be given to the selection of this equipment in order to ensure optimum net power output.

Pump selection must be based on efficiency, initial cost, operating conditions, turndown capability, turndown requirements of the system, and operating costs. Shaft seals must be designed to contain the flammable fluids within the hydrocarbon system. The following general requirements are to be established for the plant pumping equipment.

Hydrocarbon Circulation Booster Pumps

The hydrocarbon circulation booster pumps are to be of the single-stage, double-suction type. The rotor assembly is to be supported between two journal bearings. Bearings are to be pressure lubricated and the thrust collar is to be removable. These pumps are to be equipped with a shaft-driven, gear-type oil pump and a separate lube oil console baseplate-mounted with all accessory equipment and interconnecting piping necessary for operation. Force feed lubrication may be furnished from the pump lube oil system.

The pump drivers are to be electric motors with a flexible coupling connecting the pump and motor shafts. The pump shaft is to be equipped with mechanical seals to contain the pumped fluid during operation and during periods when the shaft is at rest and the casing is under pressure.

The pumps and drivers are to be suitable for outdoor installation in a Class 1, Division 2, Group D area.

Hydrocarbon Condensate Pumps

The hydrocarbon condensate pumps are to be of the vertical multistage can-type directly connected to vertical-type motor drivers.

Mechanical seals are to be used to contain the pumped fluid during operation and when the shaft is at rest and the casing is pressurized.

Brine Return Booster Pumps

These pumps are to be horizontally split, single-stage, double-suction units supported on two journal bearings designed to accommodate their own thrust load.

Force feed lubrication for pump and motor, if necessary, may be provided by a shaft-driven, gear-type oil pump. A baseplate-mounted lubrication system is preferable.

Cooling Water Circulation Pumps

Cooling water circulation pumps are to be electric motor-driven, direct-coupled pumps. The casing is to be horizontally split with a single-stage, double-suction impeller. The rotor assembly may be supported between two antifriction bearings, one of which would accommodate pump thrust loads.

The pumps may be installed in a pit near the cooling tower basin.

Fire Water Pumps

A diesel-driven pump and an electric motor-driven pump are to provide water for the plant fire protection system. An electric motor-driven jockey pump is to maintain minimum required pressure on the fire water system when the fire water pumps are idle.

The fire water pumps, drivers, ancillary equipment and their installation are to be in accordance with the most recent edition of the National Fire Protection Association (FPA) Standard No. 20. The pump units are to be listed by the Underwriters' Laboratories, Inc. or approved by the Associated Factory Mutual Insurance Companies.

Special Requirements

A hydrostatic test of all pressure parts, a running test to verify predicted performance data and ascertain vibration levels, and an NPSH test is to be conducted on the hydrocarbon circulation booster pumps, the hydrocarbon condensate pumps, the brine booster pumps and the cooling water circulation pumps. Testing of the fire water pumps is to be in accordance with FPA Standard No. 20.

The hydrocarbon circulating booster and the hydrocarbon condensate pumps are to be suitable for outdoor installation in a Class 1, Division 2, Group D area.

The brine booster pumps and the cooling tower circulation pumps and drivers are also to be suitable for outdoor installation.

2.5.6 Cooling Tower

The cooling tower is to be designed with a 10F° (6C°) approach to the wet bulb temperature of 80°F (27°C). The cooling tower pumping system is to be designed to circulate about 140,000 gpm (31,792 m^3/hr) of water through the plant.

Final cooling tower selection is to be based on such factors as the capital cost, annual operating and maintenance costs, water consumption requirements, noise levels, appearance, height, and the effect of drift on adjacent property.

Determining the size of the cooling tower cells requires consideration of turndown characteristics as well as optimum fan characteristics since winter temperatures can approach 19°F (-7°C). Adjustable fan blades with electric motor drives are to be used for the induced draft tower. A fire suppression system is also to be provided.

2.5.7 Heat Exchangers

All heat exchangers are to be designed and manufactured in accordance with all applicable standards and codes. If practicable, all heat exchangers are to be assembled and hydrostatically tested at the manufacturing facility. Because of their physical size and weight, the hydrocarbon condensers will probably require field assembly.

Brine/Hydrocarbon Heat Exchangers

A multiple set of carbon steel heat exchangers is to be utilized to heat the hydrocarbon working fluid to about 305°F (152°C) with brine at an initial bottom hole temperature of about 360°F (182°C). The units are to be designed to heat the hydrocarbon to 305°F (152°C) when the brine temperature decreases to 338°F (181°C). The heat content is to be sustained by increasing the flow in order to maintain a constant brine return temperature.

Hydrocarbon Condensers

The hydrocarbon condensers are to be manufactured with carbon steel shells, admiralty metal tubes and water boxes of lined carbon steel. These condensers are to be of the shell and tube-type with internal vapor inlet distribution. The hot wells are to be designed to store approximately one minute of condensate flow.

Pressure losses incurred after the working fluid is exhausted from the turbine are critical to overall plant efficiency and must be minimized by proper design of the condenser and the interconnecting piping between the turbine and condenser.

The hydrocarbon pressure on the shell side will exceed the cooling water pressure in the tubes. The tube/tube sheet joint and the tubes are to be designed to minimize the risk of leakage of hydrocarbon to the water and subsequent release of hydrocarbon to the atmosphere via the cooling tower. As an additional precaution, a detector is to be installed in the cooling water return line to initiate an alarm signalling hydrocarbon leakage into the cooling water system.

2.5.8 Electrical Equipment

All transformers, switchgear and controllers for the 34.5 kV, 13.8 kV, 4160 volt, and 480 volt electrical systems are to be designed, manufactured, and tested in accordance with applicable sections of ANSI and NEMA standards.

Generator Transformer

The generator transformer is to transfer the gross output of the 13.8 kV generator to the 34.5 kV bus in the plant switchyard. This transformer is to be designed for outdoor installation with ambient temperatures of approximately 19°F (-7°C) in the winter and 120°F (49°C) in the summer and a sun radiation temperature of 180°F (82°C). The transformer is to be liquid immersed with a delta-connected, low-voltage winding and a wye-connected, solidly grounded high-voltage winding. The unit is to be provided with a tap changer and standard accessories.

Station Service Transformer

The 34.5 kV/4160 volt station service transformer is to be designed to handle the total station auxiliary power demand and also accommodate the power inrush for starting a motor rated at approximately 4000 hp.

This transformer is to be suitable for outdoor installation with ambient temperatures that range from 19°F (-7°C) in the winter to 120°F (49°C) in the summer and a sun radiation temperature of 180°F (82°C). The unit is to be liquid immersed, with a delta-connected high-voltage winding and a low resistance grounded wye-connected low-voltage winding. The unit is to be provided with a tap changer and standard accessories.

Auxiliary Transformers

The 4160/480 volt auxiliary transformers are to be strategically located throughout the plant to supply the power demand of the 480 volt distribution system.

The transformers may be located indoors or outdoors. These units are to be the ventilated dry-type with delta-connected high-voltage windings and solidly grounded wye-connected low-voltage windings. The transformers are to be equipped with a tap changer and a full complement of standard accessories.

Medium-Voltage Switchgear

Switchgear for the 4160-volt, 3-phase, 60-hertz distribution system is to be designed with continuous current and interrupting capability to satisfy the overall system requirements. This switchgear is to be suitable for indoor installation. The structures are to be metal clad freestanding dead-front steel cabinets that contain the power buses, removable power circuit breakers, and all necessary ancillary control devices.

Low-Voltage Switchgear

Switchgear for the 480-volt, 3-phase, 60-hertz distribution system is to be designed with continuous current and interrupting capability to meet the overall system requirements.

This switchgear is to be the indoor-type, metal enclosed freestanding dead-front steel structures that contain power buses, removable circuit breakers, and all necessary ancillary devices.

Medium-Voltage Controllers

Controller assemblies for the 4160-volt, 3-phase, 60-hertz distribution system are to be NEMA Class EZ with continuous current and interruptible capability to meet the overall system requirements. The assemblies are to be the indoor-type, metal enclosed freestanding dead-front steel structures that contain power buses, circuit breakers, and necessary ancillary devices.

Low-Voltage Motor Control Centers

Motor control centers for the 480-volt, 3-phase, 60-hertz distribution system are to be NEMA Class I with Type B wiring. This equipment is to be designed with continuous current and interrupting capability to meet the overall system requirements. Motor control centers are to be indoor-type, metal enclosed freestanding dead-front steel structures containing power buses, drawout circuit breaker-type combination starter units, drawout feeder circuit breakers, and all necessary ancillary devices.

Emergency Power Supply

A lead acid, battery-powered 120-volt dc system is to provide the energy for those items requiring an emergency power source. The batteries and charging equipment are to be sized to satisfy the requirements of the 120-volt dc system.

The equipment is to be suitable for indoor installation in metal enclosures containing power buses, circuit breakers/starters, and all ancillary equipment. The battery bank is to be enclosed in a separate room with adequate ventilation.

2.5.9 Pressure Vessels

All vessels for the Heber power plant are to be designed, manufactured, and tested in accordance with applicable portions of Section VIII of the ASME Boiler and Pressure Vessel Code and Safety Regulations of the State of California. Vessels requiring internal inspection are to be equipped with a six-inch (0.15 m) nozzle for cross ventilation of the unit during inspection and maintenance activities.

2.5.10 Water Treatment Packages

Package-type water treatment equipment mounted on baseplates for installation as an assembly is to be provided. Water treatment packages are to include:

- Coagulant feed for desilting canal water.
- Sulphuric acid feed for pH control of makeup water and cooling tower water.
- Chlorination facilities for bacteria and algae control in cooling water and potable water.
- Solid dispersant and corrosion inhibitor feed for cooling water.
- Coagulant feed for desilting raw potable water.

These packages are to be designed, manufactured, and tested, if required, in accordance with all applicable standards and codes for installation in the State of California. The use of manufacturer's standards during fabrication and assembly of packages is to be evaluated prior to release for fabrication.

2.5.11 Compressors

Hydrocarbon Recovery Compressor

A motor-driven, reciprocating compressor is to be utilized in the hydrocarbon recovery system. This compressor is to be purchased as a package unit complete with suction drums, heat exchangers, a closed loop jacket water system and all other ancillary equipment for operating the system.

The hydrocarbon recovery system is to be designed to handle hydrocarbons vented during start-up and shutdown of individual hydrocarbon equipment, charging and cleaning operations involving the entire hydrocarbon system, loading and normal operation of the hydrocarbon storage facilities, and operation of the turbine shaft sealing facilities.

Plant and Instrument Air Compressors

An electric motor-driven and a diesel-driven air compressor are to provide sufficient plant and instrument air to meet the requirements of the systems. The diesel-driven unit is to perform as the standby unit and its start-up is to be actuated by a low-pressure sensing device installed in the air header.

Each of these reciprocating compressors is to be a package-type unit with all ancillary equipment mounted on baseplates for installation as an outdoor assembly. A closed loop system is to be utilized for jacket cooling.

2.6 CONTROLS AND INSTRUMENTATION

2.6.1 Measurement

The following criteria apply to various classifications of measurements:

Flow Measurement

Energy conversion system flow instruments of the differential head-type utilizing a low permanent pressure loss annular primary element are preferred. Other types of primary flow elements are to be considered in accordance with the situation and economics involved.

Level Measurement

Differential pressure (D/P) transmitters are preferred to measure liquid level. External, displacer-type transmitters or controllers may be used where D/P devices are not practical. Float-type external level switches are preferred for alarms and shutdowns.

Temperature Measurement

Thermocouples are preferred for measuring process temperatures. The use of sheathed thermocouples is most desirable, but other types may be used when necessary.

Resistance temperature detectors are to be used for applications requiring higher accuracy than is available from thermocouples in the measurement range of -238°F to 932°F (-150°C to +500°C). Resistance temperature detectors are also preferred for differential temperature measurement.

Pressure Measurement

Ranges for pressure transmitters are to be in accordance with the process control requirements and are to be selected so that the normal pressure will be indicated or recorded between 50 percent and 75 percent of the span. Suppressed ranges are to be used on transmitters and controllers when maximum accuracy and control are required. Instruments are to have overrange protection to the maximum pressure to which they may be exposed.

Rotating Equipment Monitoring

Vibration of Mechanical Equipment

Continuous vibration monitoring (both radial and axial) and associated shutdown systems are to be installed on all critical rotating equipment.

Speed Instrumentation

Speed transmitters are to be of the "noncontact," magnetic pickup-type.

Temperature

The special applications of machinery temperature monitoring require careful consideration and the sensors are to be furnished by the selected equipment vendor.

2.6.2 Alarm and Shutdown Systems

Alarms

Conditions to be signalled by an alarm are classified as follows:

- Critical - Conditions that can create personnel hazards, damage major equipment or cause environmental pollution.
- Guides - Conditions that must not exceed established limits for a specified period of time.

Both visible and audible alarms are to be provided in an annunciator system. After the audible alarm has been silenced, the visible alarm is to remain until the abnormal condition is corrected.

Shutdown Systems

Shutdown systems are to be energized during normal operation; i.e., deenergized to trip.

It is preferable that shutdown devices including all transmitters, valves, current trips, and logic and relay cabinets be independent of control loops.

All shutdown systems are to be provided with a manual reset where local start-up or checking is necessary. The manual reset is to be locally-mounted near the equipment controlled.

2.6.3 Electronic Instruments

Miniature-type electronic instruments are to be panel-mounted with medium to high-density spacing. All electronic instrumentation systems are to be designed for computer compatibility including "clean" power supplies, proper grounding, and shielding.

The field signal transmission is to be a two-wire, 4 to 20 mA dc current, except for thermocouples, RTD's, analyzers, and other special instrument signals which may transmit directly to the control room in order to satisfy design considerations.

All control room instrumentation used for the remote control of equipment is to be provided with local auto-manual stations. The control room is to be provided with visual indications to signify that the systems are available for controlled operation.

2.6.4 Pneumatic Instruments

Pneumatic systems are to be utilized for local (noncontrol room-mounted) loops. Pneumatic instruments are to operate with a nominal 3 psig (0.21 kg/m^2) to 15 psig (1.03 kg/m^2) signal.

2.6.5 Control Valves

The flow rate to be used for determining the valve size is to be either the maximum determined by the process engineers or 1.5 times the specified normal flow, whichever is greater.

The determination of control valve sizes is to be based on the valve manufacturer's published engineering data for gases and vapors and the acceptance of the sizing pressure drop limitation for cavitating and flashing liquids.

Control valve bodies are not to be less than one-half the nominal pipe size.

Air actuators and spring return cylinders are to be specified for all valves indicating fail-safe action on the system flow sheet.

2.6.6 Control Panels

Central Control Panel

The central control panel is to be a shop-fabricated freestanding design utilizing the "medium to high-density" concept of instrument spacing.

The layout of the front of the panel is to be in accordance with good engineering practice with proper consideration given to accessibility for maintenance and operation. The general arrangement is to be in accordance with the following instructions:

- Alarms and indicators are to be placed in the top section.
- Controllers, recorders and indicators are to be placed in the middle section.
- Electrical equipment controls, comprised of pushbuttons, running lights, etc., are to be placed in the lower section (or bench portion) of the panel.

Local Panels

Local panels are to be generally of the vertical-type design and are to be suitable for unprotected outdoor installation. All devices mounted on local panels are to be watertight and the panel design is to provide the necessary dust protection. Local start and stop pushbuttons are to be mounted on local panels.

2.7 BUILDINGS

2.7.1 Main Building

The main building is to house the administrative offices, chemical laboratory, the instrument shop, main switchgear, central control room, and adequate sanitary and shower facilities for the occupants.

The entire building is to be pressurized to about 0.1 inch (2.5 mg/l^2) of water. Adequate air conditioning equipment is to be provided for the building. The use of "heat pumps" is to be considered for heating and air conditioning purposes.

The battery room may be a part of the main building, but direct access from the battery room to the pressurized portion of the main room is not to be provided. A separate ventilation system is to supply air to the battery area.

The chemical laboratory is to be provided within the confines of the main building. This laboratory is to be equipped in such a manner that those routine chemical analyses required to control the quality of the various waters used within the plant can be performed. The laboratory must also contain the equipment necessary for performing analysis on the hydrocarbon mixtures received, those in storage and those in the energy conversion system.

2.7.2 Shop Building

A prefabricated shop build is to be provided to perform normal maintenance functions. The building shall be fully air conditioned and include instrument/ electrical shop, machine shop/tool room, general maintenance/welding area, spare parts and supplies storage area, and washroom/shower facilities.

2.8 SILT REMOVAL PONDS

The quality of water in the Central Main Canal and the Dogwood Canal is such that about 1500 pounds (680 kg) of silt per day must be removed from the makeup water prior to its use in the cooling water system.

Two silt removal ponds are required in order to supply clear water makeup on a continuous basis. The ponds are to be designed to contain 24 hours of raw water supply plus an adequate reserve for fire protection to ensure a supply of fire water when irrigation canal water is not available. The pond design is to include a pump pit for the raw water makeup and fire water pumps. The pump pit is to be equipped with valved intakes from both ponds and is to be designed in such a manner that two fire water pumps and one makeup pump can operate simultaneously. The ponds can be converted for evaporation use in conjunction with alternative cooling water make-up sources at the end of the first five years of plant operation when irrigation water is no longer available.

2.9 PLANT LAYOUT

A preliminary layout of the power plant is shown on Figure 2.9. The power plant and production island occupy approximately 20 acres (80,938 m^2). As indicated on this drawing, the production island is located adjacent to the power plant to minimize heat and pressure losses during the transport of the brine.

The energy conversion equipment is shown positioned around the turbine generator to allow short runs of hydrocarbon piping, thereby decreasing the pressure losses. Clearance and accessibility for maintenance is also to be of primary consideration in the plant layout. The main building/control room is to be located in the vicinity of the major equipment to avoid excessive lengths of control loops and provide the operators with easy access to the equipment.

Silt removal pumps, cooling water makeup pumps, fire water pumps, and the cooling tower are to be located south of the energy conversion area. Cooling water circulation pumps are to be located in a pit between the energy conversion area and the cooling tower.

The hydrocarbon unloading and storage area is to be located west of the energy conversion area and adjacent to a plant road.

The flare stack is to be located in the pond area and provided with a safety circle radius of 170 feet (52 m) to ensure protection of personnel from thermal radiation of the flare during upset conditions.

The transformers and switchyard are to be located east of the energy conversion area and near the transmission lines that are to parallel Dogwood Road.

Paved roads are to encircle the plant and provide access to the various items of equipment during maintenance activities.

2.10 OPERATION AND MAINTENANCE

2.10.1 Manpower

Operational philosophy and manpower requirements are to be based upon SDG&E staffing philosophy for conventional steam generating stations.

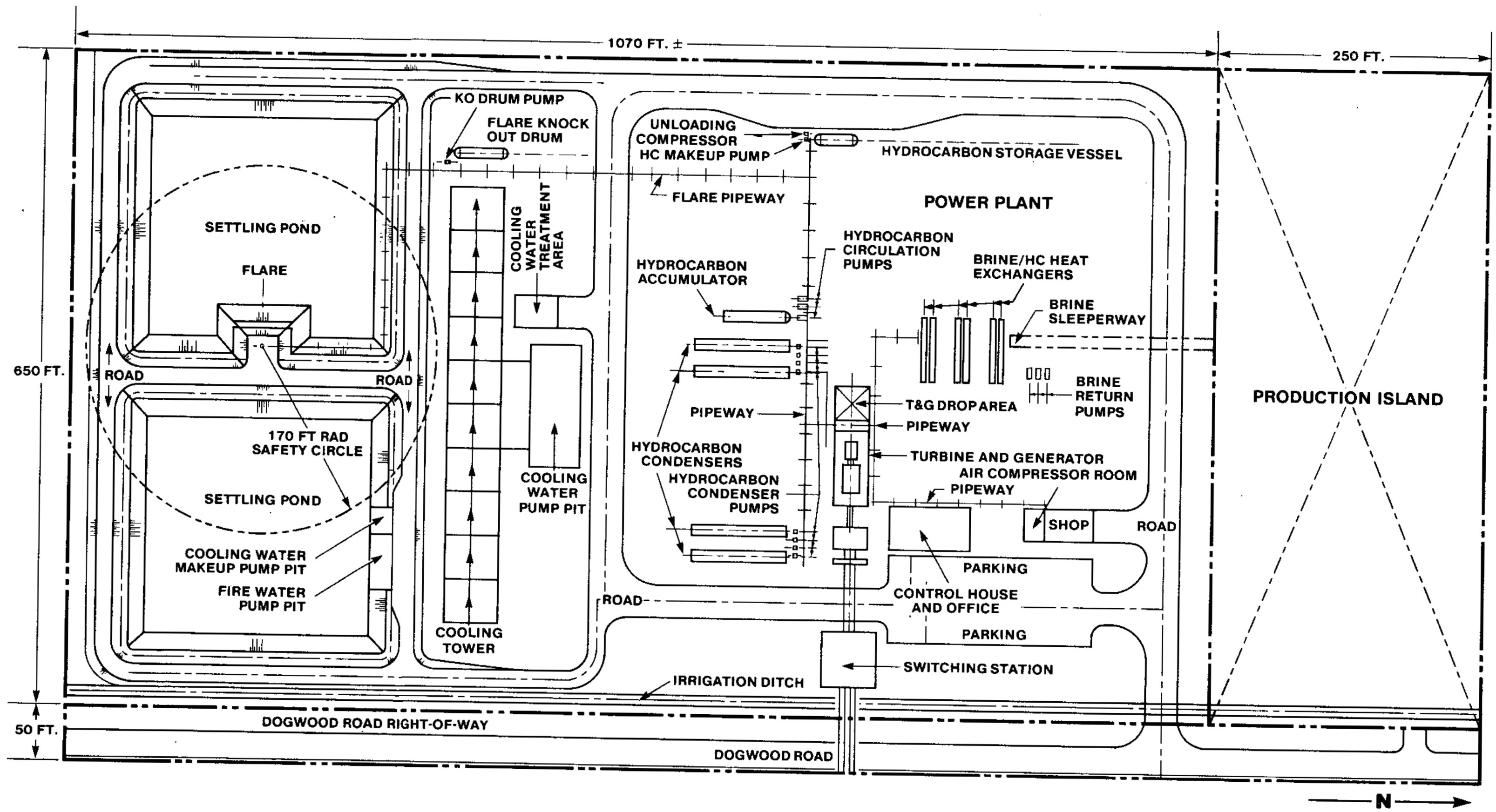


Figure 2.9 Plot Plan

The anticipated permanent staff is to include a plant superintendent, plant engineers, shift supervisors, shift operators, a chemist, a storekeeper, a maintenance foreman, maintenance mechanics, and clerks. Chevron Resources Company, the brine supplier, is to supply the manpower necessary to operate the brine production and reinjection facilities. Guard service is not anticipated to be necessary during normal plant operation.

Turnaround and maintenance activities will require intermittent increases in personnel, depending on the work demand. Subcontractors may be required during periods of high maintenance demand.

Additional personnel are to be temporarily assigned to the power plant during start-up and the test phases of the operation.

2.10.2 Operational Arrangement Concepts

The power plant equipment is to be arranged to occupy the minimum amount of land consistent with the constraints of equipment maintenance and piping design. The brine handling equipment is to be located as close to the production island as practicable. The energy conversion system is to be isolated to provide easy fire control access. The equipment is to be installed within close proximity to ensure that piping losses are maintained within practicable limits.

The turbine generator is to be an outdoor installation mounted on a foundation of minimum acceptable height based on an economic analysis of installation, maintenance, and operating costs. Maintenance accessibility is to be a major consideration in the arrangement of the installation. The use of overhead lines and overhead electrical conduits around the turbine is to be avoided in order to provide freedom of access.

Adequate clearance is to be provided for a gantry-type crane to be used during installation and maintenance activities. A drop area is to be provided on the turbine end of the foundation to enable components to be lowered to grade for maintenance or transportation to a shop.

All valves, controls, and instrumentation located in and around the turbine generator are to be accessible. All indicating and recording devices are to be readable from the operating floor.

Enclosed instrument and control panels located near the equipment are to be accessible for maintenance activities.

Heat exchangers are to be arranged for accessibility of tube cleaning and tube replacement activities. Pumps are to be installed in such a manner that operating activities, "in place" maintenance, and removal of major components or whole units for replacement or shop maintenance can be conducted with reasonable ease. Piping and electrical conduit around pumps is to be installed in such a manner that the use of hydraulic cranes (cherry pickers) for maintenance purposes is not unduly restricted.

Water handling equipment and systems are to be located at a reasonable distance from the energy conversion area. Pumps, valves, instrumentation, and controls are to be accessible for operating and maintenance activities.

The energy conversion area is to be covered with a hard surface capable of handling maintenance equipment such as hydraulic cranes and their loads, portable air compressors, and loaded trucks. Hard-surfaced areas are to be provided around equipment located beyond the energy conversion area for access by operators, maintenance personnel, and equipment.

Hard-surfaced roads are to be provided for access to the various items of equipment throughout the power plant. Such roads are to accommodate maintenance equipment, loaded trucks, and hydrocarbon tank trucks. Paved walkways are to provide direct access from one area to another for both operation and maintenance personnel.

Any areas covered by vegetation are to be irrigated to maintain growth and reduce the amount of fugitive dust within the power plant.

2.10.3 Maintenance Equipment

A gantry-type crane capable of lifting the heaviest single component of the turbine generator during maintenance activities is to be provided on the operating deck. This crane should be able to traverse the length of the operating deck and deposit loads into the drop area at the end of the turbine generator foundation.

An overhead crane is to be provided for handling one-ton chlorine cylinders in the water treatment area.

The possibility of purchasing mobile cranes for use during construction and subsequently for plant maintenance is to be evaluated.

The maintenance shop is to be equipped with a motorized overhead bridge crane capable of lifting the heaviest single component that the maintenance department anticipates handling in the shop.

Consideration is to be given to the installation of permanent maintenance aids, such as davits, for assisting in the removal of manways, relief valves, etc.

Removable covers providing shade for workers are to be furnished for those areas that require a significant amount of maintenance activity during overhauls.

2.11 RELIABILITY

A primary objective of the Heber power plant is to demonstrate a long-term availability factor of at least 70 percent.

Because the plant is a demonstration facility, equipment and controls are to be designed to protect the persons in and around the facility, to protect the environment, to safeguard the equipment from serious damage, and to maintain reliable operation at full load.

Items such as installed spare capacity, spare standby equipment, the capability of isolating equipment for maintenance while the plant is in operation, and duplicate control systems are to be evaluated with adequate consideration given to meeting the reliability objectives noted above.

Economic evaluation based on operating, maintenance, and initial cost factors are to be performed in selecting the amount of spare equipment to be provided in warehouse storage. The effect upon unit availability resulting from the loss of a pump, heat exchanger, or vessel is to be considered in selecting the amount of spare capacity to be initially installed.

Duplicate control systems should not be provided without a thorough investigation and evaluation of the need for such duplication. Direct pressure and temperature indications are to be provided as backup for control system components in critical service. Dual and/or separate level indications are to be provided where maintenance of levels is critical to the process or equipment.

2.12 SECURITY

The jobsite is to be fenced around the perimeter to limit access to the facility through prescribed gates only. Outlying areas and/or areas usually not inhabited by operators or maintenance personnel are to be adequately lighted to discourage intruders. Twenty-four hour a day security is to be provided by guards to protect the facility from intruders during construction.

Section 3
OPTIMIZATION STUDIES

This section reports the work performed as a part of the design development and optimization process. It includes review of the Phase I results that were developed by Holt/Procon under contract to EPRI and used as a point of departure for the work described in this section. Earlier work in Phase II was reported in EPRI Interim Report 1 dated August 1978(20) (EPRI ER-863, Project 580-2).

3.1 PHASE I RESULTS

Phase I consisted of a series of conceptual and economic feasibility studies performed by Holt/Procon (1, 2, 3, 6, 7). These studies were completed under EPRI Research Project No. 580-1.

3.1.1 Major Phase I Conclusions

The Phase I studies concluded that a geothermal power plant using low salinity hydrothermal fluid is feasible, and that a net plant output of about 50 MW_e would be an optimum capacity for a demonstration plant to confirm the technology, demonstrate the economics and stress the reservoir at the lowest project cost. The Heber reservoir in Imperial County, California, was selected as the best overall location for a demonstration geothermal power plant based on the information available in 1976. The choice was based on the following considerations:

- The Heber reservoir was one of the most extensively analyzed and best defined reservoirs in the United States.
- Conservative estimates of the Heber reservoir indicate a potential to supply on the order of 400 to 500 MW_e for 30 years.
- The Heber reservoir is a low salinity, moderate temperature resource typical of a majority of liquid-dominated hydrothermal reservoirs in the United States.

The binary cycle was selected as the preferable conversion process. This cycle was determined to be technically and economically feasible, and environmentally acceptable. The binary cycle was shown to be more economical than alternate processes studied (multi-stage flash steam and a hybrid cycle which is a combination of the flashed steam and binary cycles) for the Heber reservoir.

3.2 RESULTS OF PHASE I REVIEW

One of the first tasks in Phase II of the Heber project was to review the EPRI Phase I studies, analyze the conceptual design data and document Fluor's conclusions resulting from this evaluation.

The major conclusions from this evaluation are documented in a separate Fluor report(8) and in EPRI Interim Report 1(20) and summarized below:

- The Phase I thermodynamic data base was valid for the conditions assumed but would require further optimization to meet new criteria.

- The 12 percent cycle thermal efficiency derived during Phase I was considered optimistic compared to Fluor's estimate of 10 percent.

- The process system design as represented on the Holt/Procon Process and Instrument Diagram (P&ID) is valid for use as a baseline. However, further study would be needed to develop and optimize this design.

- Further work would be required to identify and minimize system pressure losses and improve cycle efficiency.

3.3 CYCLE SELECTION

As previously stated, the binary cycle was selected during Phase I as the preferred energy conversion process for the Heber power plant. However, during review of the Phase I design, SDG&E and Fluor identified additional criteria that suggested a need for further evaluation of the decision to use the binary cycle. Significant in this regard was the fact that 1) the energy cost had changed, 2) the end of run reservoir temperature had been revised upward and 3) the brine return temperature had to be controlled to a specified minimum. Also, Fluor's estimate of lower cycle efficiency provided further reason for confirming the binary cycle selection.

SDG&E, therefore, authorized Fluor to perform a special study (Work Package T002) (9) to evaluate and confirm the binary cycle for the Heber plant. The purpose and results of this study are summarized below.

The purpose of the conversion cycle study was to:

- Reevaluate the thermodynamic conversion cycle selection for the Heber site, comparing the binary cycle and the direct flash steam cycle.
- Incorporate current resource energy costs and refined design criteria, including revised estimates of mechanical and electrical efficiencies.
- Evaluate both cycles at a plant capacity of 45 MW_e net power output.
- Consider and compare the impact of using fully pumped wells to supply single (liquid) phase brine to the plant and unpumped or partially pumped wells to supply two-phase brine to the plant for binary cycle operation. The flash steam cycle would utilize unpumped wells.
- Reevaluate plant capital costs and operating costs.
- Determine the differential net power cost for each of the conversion cycle options.

Five conversion cycle cases were studied as follows:

Binary Cycle

Case I - Single-phase brine supply with 150°F (66°C) brine return temperature (EPRI Phase I design).
Case II - Two-phase brine supply with 150°F (66°C) brine return temperature.
Case III - Two-phase brine supply with 200°F (93°C) brine return temperature.

Direct Flash Steam Cycle

Case IV - GE Turbine, with free-flowing two-phase brine supply and 200°F (93°C) brine return temperature.

Case V - Elliott turbine, with free-flowing two-phase brine supply and 200°F (93°C) brine return temperature.

For binary Cases II and III brine would be supplied to the power plant as a two-phase mixture and steam separators were included in the plant cost.

For the direct flash steam cases, brine would also be supplied to the power plant as a two-phase mixture, with steam/brine separation occuring in two steam separators arranged in series.

Heat and material balances were developed for each of the five cases. Plant performance for the five cases is shown on Table 3.3.

Differential net power cost for the five cases is displayed on Figure 3.3. The "middle of run" discontinuity for Cases II and III results from a need to change out the working fluid composition and add capital equipment to maintain constant power output over the 30 year plant life with decreasing downhole temperature. This design approach was taken from the Phase I studies and is the subject of additional optimization work described in Subsection 3.5. Case I uses the same design approach but middle-of-run and end-of-run points were not developed.

The conclusions of this study were, 1) the binary cycle, Case III, produced a lower net power cost over the life of the plant than either of the direct flash cycles (See Figure 3.3), 2) the binary cycle, Case II, produced a lower power cost during the start-of-run period, and 3) both of the two-phase brine supply binary cases produced lower start-of-run power costs as compared to Case I.

However, based on subsequent studies, it was established that the available two-phase brine flow pressure associated with the brine price established for the Case III was too low for practical binary cycle operation. This problem is discussed further in Subsection 3.6. It was also later established that, although the brine cost to the plant would be computed on a heat removal basis, the pricing structure is such that minimum brine cost would be obtained by cooling the brine

TABLE 3.3

PLANT PERFORMANCE

(ENGLISH UNITS)

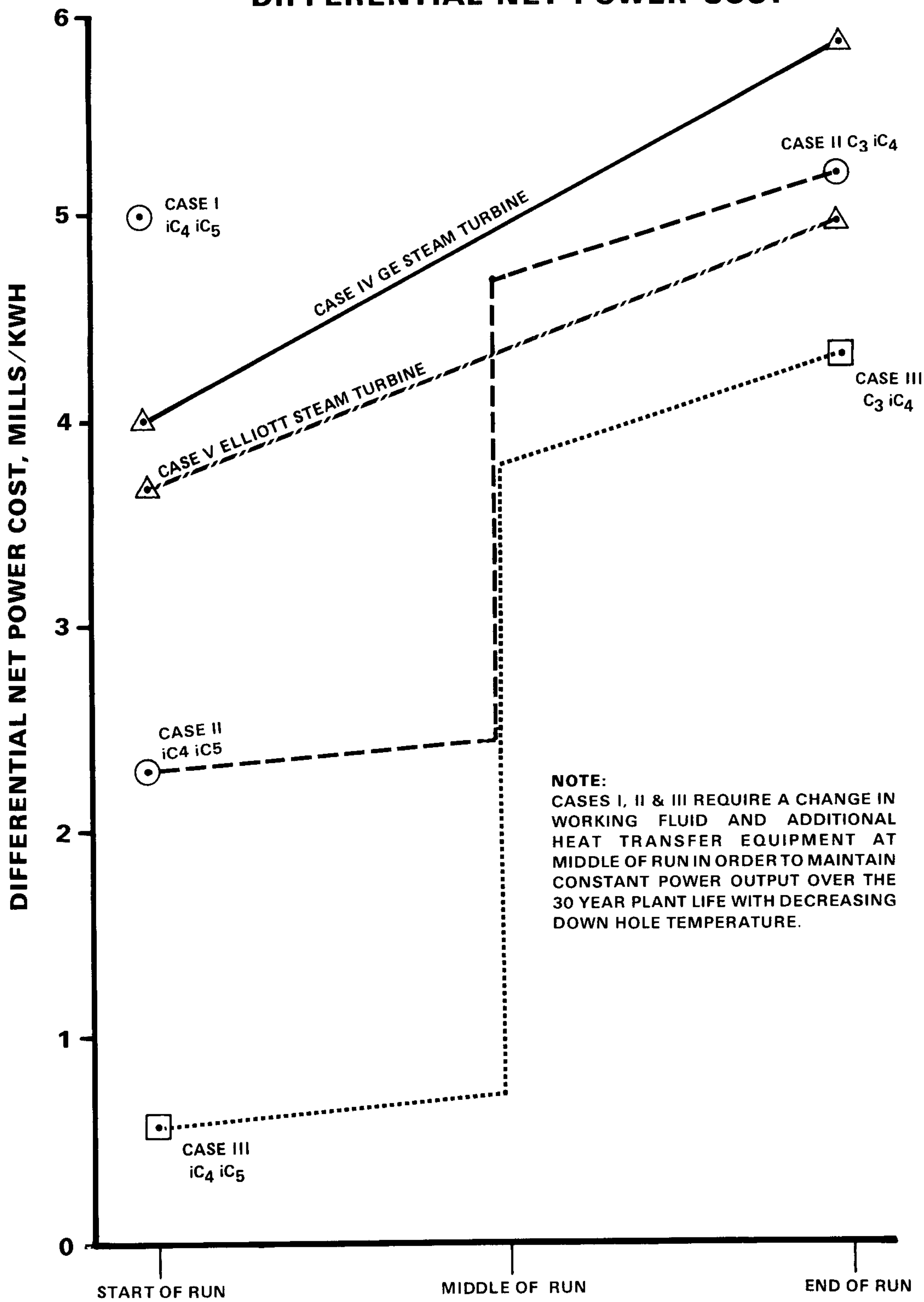
	CASE I	CASE II				CASE III		CASE IV		CASE V	
	START OF RUN	A START OF RUN	B MIDDLE OF RUN	C MIDDLE OF RUN	D END OF RUN	A START OF RUN	B END OF RUN	GEN ELEC START OF RUN	GEN ELEC END OF RUN	ELLIOTT START OF RUN	ELLIOTT END OF RUN
BRINE DATA											
FLOW $(10)^6$ lb/h	6.66	6.76	8.011	8.07	10.6	7.80	11.87	8.79	12.42	9.57	13.00
TEMP DOWNHOLE (^oF)	360	360	345	345	325	360	325	360	325	360	325
TEMP INTO PLANT (^oF)	360	340	325	325	305	340	305	340	305	340	305
TEMP OUT OF PLANT (^oF)	150	150	166	150	174	200	200	197	200	198	200
BRINE $\Delta H = Q_{in}$ (10^9)BTU	1.39	1.42	1.43	1.57	1.61	1.25	1.48	1.43	1.55	1.55	1.63
POWER DATA											
GENERATOR GROSS (MWe)	57.7	58.5	59.1	63.7	64.9	58.5	63.6	52.4	54.05	53.1	54.3
AUXILIARY LOADS (MWe)	12.7	13.5	14.1	18.7	19.9	13.5	18.6	7.4	9.05	8.1	9.3
PLANT NET (MWe)	45	45	45	45	45	45	45	45	45	45	45
PLANT EFFICIENCY %	11.05	10.81	10.73	9.78	9.54	12.28	10.37	10.73	9.91	9.91	9.42
CW CIRCULATION (1,000's GPM)	123	125	126	171	175	116	159	149	156	153	158

(METRIC UNITS)

	CASE I	CASE II				CASE III		CASE IV		CASE V	
	START OF RUN	A START OF RUN	B MIDDLE OF RUN	C MIDDLE OF RUN	D END OF RUN	A START OF RUN	B END OF RUN	GEN ELEC START OF RUN	GEN ELEC END OF RUN	ELLIOTT START OF RUN	ELLIOTT END OF RUN
BRINE DATA											
FLOW (MKg/h)	3.02	3.06	3.63	3.66	4.81	3.53	5.38	3.98	5.64	4.34	5.9
TEMP DOWNHOLE (^oC)	182	182	174	174	163	182	163	182	163	182	163
TEMP INTO PLANT (^oC)	182	171	163	163	152	171	152	171	152	171	152
TEMP OUT OF PLANT (^oC)	66	66	74.5	66	79	93	93	91.6	93	92.3	93
BRINE $\Delta H = Q_{in}$ (MW)	407	416	419	460	472	366	434	419	454	454	478
POWER DATA											
GENERATOR GROSS (MWe)	57.7	58.5	59.1	63.7	64.9	58.5	63.6	52.4	54.05	53.1	54.3
AUXILIARY LOADS (MWe)	12.7	13.5	14.1	18.7	19.9	13.5	18.6	7.4	9.05	8.1	9.3
PLANT NET (MWe)	45	45	45	45	45	45	45	45	45	45	45
PLANT EFFICIENCY %	11.05	10.81	10.73	9.78	9.54	12.28	10.37	10.73	9.91	9.91	9.42
CW CIRCULATION (M^3/h)	28,000	28,400	28,600	38,800	39,800	26,400	36,100	33,800	35,400	34,800	35,900

FIGURE 3.3

DIFFERENTIAL NET POWER COST



as close as possible to the 150°F (66°C) minimum brine reinjection temperature established by Chevron.

Case II suffered a similar temperature penalty, however, the return temperature problem was avoided, since a 150°F (66°C) brine return temperature was specified. Further work by the brine supplier, performed after this study was completed, identified the brine cost for an elevated brine supply pressure (see Subsection 3.6). This cost is considerably higher than the costs available for this study and closely approached the single phase brine feed cost.

Figure 3.3 shows two direct flash cases (Cases IV and V). Case IV utilizes a General Electric steam turbine, while Case V utilizes an Elliott steam turbine. The two curves represent the net power cost differential which could be expected from the two installations, recognizing differences in both turbine efficiency and capital cost.

These developments cause the binary cycle power cost to approach the power cost of the direct flash cycle. However, power costs still remain slightly lower and the selection of the binary cycle for the Heber plant remains valid. Also, the direct flash cycle requires approximately 38 percent more brine flow than the binary cycle. This results from the smaller differential temperature, i.e., 210°F (98.9°C) for the binary cycle versus 160°F (71.1°C) for the flash cycle. The binary cycle thermal efficiency is also about 10 percent higher than a direct flash cycle.

3.4 WORKING FLUID SELECTION

The objective of this study was to confirm the validity of the choice of working fluid that resulted from the Phase I study. The concept developed in Phase I was to use two hydrocarbon mixtures. A mixture of 80 mol percent isobutane and 20 mol percent isopentane was to be used for initial operation corresponding to brine supply temperatures of 360°F (182°C) down to 345°F (174°C) and turbine inlet conditions of 500 psia (3450 kPa) and 295°F (146°C). Condenser outlet conditions were 70.3 psia (484 kPa) and 104.4°F (40.2°C). At mid-run, the binary fluid was to change to 90 mol percent isobutane and 10 mol percent propane for brine temperatures below 345°F (174°C) down to an end-of-run temperature of 325°F (163°C) and turbine inlet conditions were set at 590 psia (4070 kPa) and 285°F (141°C). Condenser outlet conditions were 94.1 psia (648 kPa) and 105°F (40.5°C).

The first step in the validation process was to evaluate the earlier working fluid selection. These evaluations were performed with the following objectives:

- Assess alternate working fluids and reconfirm the selection of a hydrocarbon as the binary working fluid.

- Consider cycle efficiency, plant economics, safety and environmental criteria in the evaluation.

With these objectives in mind, Fluor initiated a study to investigate the use of water as the working fluid as an alternative to the hydrocarbon binary cycle and the direct flash steam cycle. The cycle evaluated would use a brine/water heat exchanger and a two-stage flash system to drive a steam turbine. This alternate was considered so as to include a nontoxic nonflammable working fluid in the comparison. The study showed that the direct flash steam cycle would have a higher overall plant efficiency than the water binary system. It also showed that the water binary system would produce a higher cycle efficiency than the hydrocarbon binary cycle; however, this required a higher brine return temperature, and a higher brine flow rate, resulting in a higher resource energy cost and a correspondingly higher power cost.

Other alternate binary cycle working fluids were studied in order to determine whether hydrocarbons were the best choice. This work was documented in a project report dated on January 11, 1978. The working fluids studied were: carbon dioxide, ammonia, halocarbons, and hydrocarbons.

The use of carbon dioxide and ammonia were eliminated from consideration based on their thermodynamic properties:

- Carbon dioxide has a critical temperature of 87.8°F (31°C) and will therefore not condense at the 90°F (32°C) or higher cooling water temperature.

- An ammonia cycle would require a working fluid pressure of about 1000 psia (6895 kPa) to provide efficient energy conversion. This would lead to substantially higher plant capital and operating costs. Also, although thermally stable, ammonia is highly toxic and flammable and therefore offers no safety or environmental advantages over the hydrocarbons or halocarbons.

The halocarbons were also studied as an alternative to hydrocarbons. The most competitive halocarbons were identified to be R114 and R12. These working fluids were also demonstrated to be less desirable than the hydrocarbons for the following reasons:

- Halocarbon thermodynamic properties, when compared to hydrocarbons, produce lower unit power output, as shown on Table 3.4:

TABLE 3.4
COMPARATIVE POWER OUTPUT

Working Fluid	Net Power Output MM KW/pound of brine/hr (KW/Mkg/hr)
Isobutane	8200 (18,100)
R12	6700 (14,800)
R114	7300 (16,100)

- The light aliphatic hydrocarbons proposed for a binary cycle are thermally stable at the 300°F (149°C), 550 psia (3780 kPa) working fluid conditions. Halocarbons will decompose in this regime, the rate depending on temperature and the presence of impurities, such as oil, which will accelerate the decomposition rate.

  Decomposition products may include highly corrosive hydrochloric and hydrofluoric acids, and in the presence of water or oxygen, phosgene gas may be formed.

  The report cites operating plant data indicating loss of halocarbon (R11) to decomposition at a rate of 0.6 to 1.0 percent per year. Additional losses occur as the result of leaks, start-up and shutdown operations, purging and venting.

- Halocarbons are generally nonflammable, resulting in a fire safety advantage over light hydrocarbons. However, in the presence of an externally-fueled fire (e.g., turbine oil), halocarbons may generate highly lethal phosgene gas and toxic acid vapors. Extensive experience exists in the safe handling of hydrocarbons in petroleum, chemical and natural gas industries. These existing design practices can be applied to the Heber plant design to assure safety.

- From an environmental viewpoint, hydrocarbons are preferable. In the event of an upset conditon, the hydrocarbon would be burned in a flare, producing carbon dioxide and water.

  The halocarbon cannot be flared due to the toxic nature of the combustion products.

- From a cost standpoint, the hydrocarbons are preferred. Commercial grades of isobutane cost about 30 cents per gallon ($79/cubic meter). R114 can be purchased in tank car lots for about $7.50 per gallon ($1,980/cubic meter). The initial charge cost for the hydrocarbon is about $30,000 as compared to $750,000 for the halocarbon.

Hydrocarbon was concluded to be the preferable choice for the Heber plant binary cycle working fluid.

3.5 POWER CYCLE OPTIMIZATION

Subsections 3.3 and 3.4 of this section have dealt with the selection of the conversion cycle (binary versus direct flash) and the selection of a binary cycle working fluid (hydrocarbon versus other fluids such as freon, ammonia, carbon dioxide, etc.). This section addresses the optimization of the power cycle conditions, i.e., turbine throttle and exhaust conditions, and the specific hydrocarbon working fluid mixture. The power cycle envolves the heating of the working fluid in the brine/hydrocarbon heat exchangers, expansion of the working fluid through the turbine, and condensing the working fluid as illustrated in Figures 2.4.1A and B.

3.5.1 Selection of a Suitable Equation of State

The Starling modified Benedict-Webb-Rubin (BWR) equation of state was used to analyze the power cycle conditions in the Phase I studies. There are a number of different equations of state that are currently in use for predicting the thermodynamics of hydrocarbon processes. Cycle performance estimates will vary depending on the particular set of equations used, and none of the equations have been rigorously correlated with actual hydrocarbons under the operational range of temperature and pressure conditions of interest for a binary cycle in conjunction with a moderate temperature geothermal reservoir. In recognition of this problem, EPRI contracted with C.F. Braun Company (Braun) to perform bench test temperature/enthalpy determinations for a representative hydrocarbon mixture, namely 80 mol percent isobutane and 20 mol percent isopentane.

The thermodynamic properties(19) experimentally determined by C.F. Braun for a mixture of 20 mol percent isopentane and 80 mol percent isobutane were analyzed by Fluor, Holt, Rotoflow and Elliott, among others. The Braun data, though incomplete for purposes of establishing an equation of state suitable for use in the design of the Heber binary plant, was useful in selecting an equation of state to be used for the plant design.

As part of Holt's analysis of the Braun data, the experimentally obtained enthalpy values of the mix were plotted against temperature with lines of constant pressure shown. Figures 3.5.1A and B are these plots (two figures are used for clarity). It is important to note that only the 80 psia (552 kPa) isobar shows a definite discontinuity at the dew point. The other dew points and all the bubble points were estimated from much less well defined inflection points.

Figure 3.5.1C shows a comparison of the Braun data and predictions using Starling's modified Benedict-Webb-Rubin (BWR) equation of state. This modification, published in 1973, is the one that was used for the Phase I studies. The bubble points and bubble point enthalpies are in good agreement for pressures of 300 psia (2069 kPa) and lower. However, dew points and values for pressures near the critical are not in good agreement.

Availability of the Braun data made it possible to compare dew points predicted by the several equations of state (including the Starling BWR used in Phase I) with laboratory test results. Figure 3.5.1D shows the loci of dew points as

FIGURE 3.5.1A
TEMPERATURE-ENTHALPY PLOT
(CF BRAUN TEST DATA)
CONSTANT PRESSURE

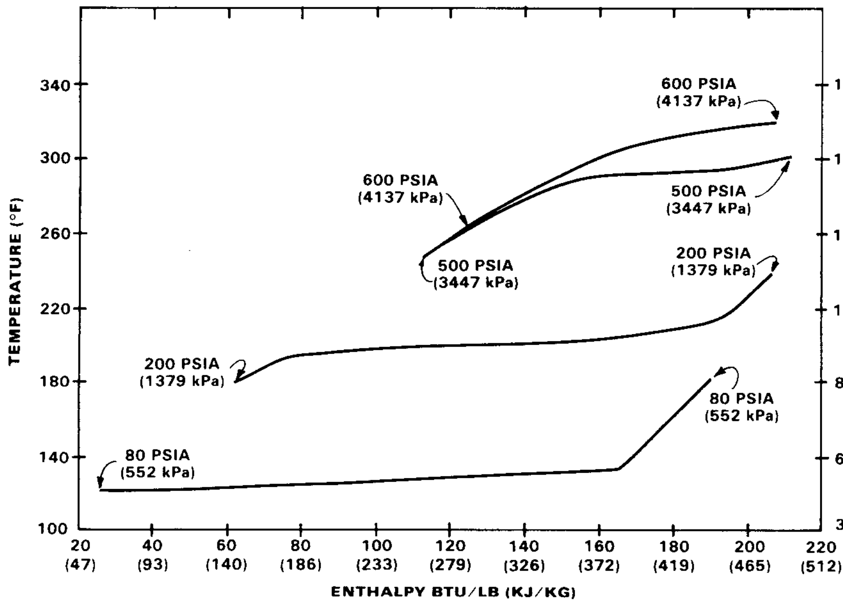


FIGURE 3.5.1B
TEMPERATURE-ENTHALPY PLOT
(CF BRAUN TEST DATA)
CONSTANT PRESSURE

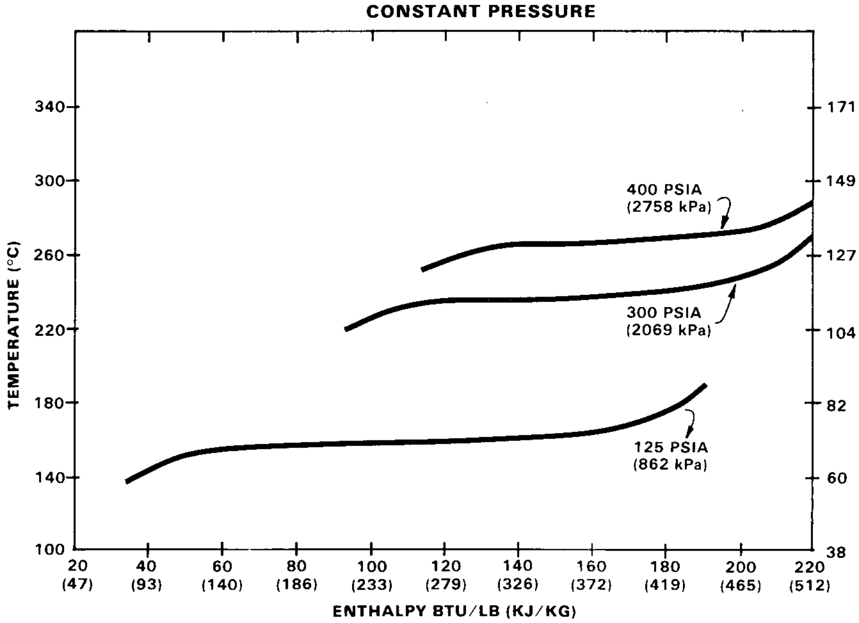


FIGURE 3.5.1C

TEMPERATURE-ENTHALPY COMPARISON
(BRAUN DATA VS. STARLING BWR)
CONSTANT PRESSURE

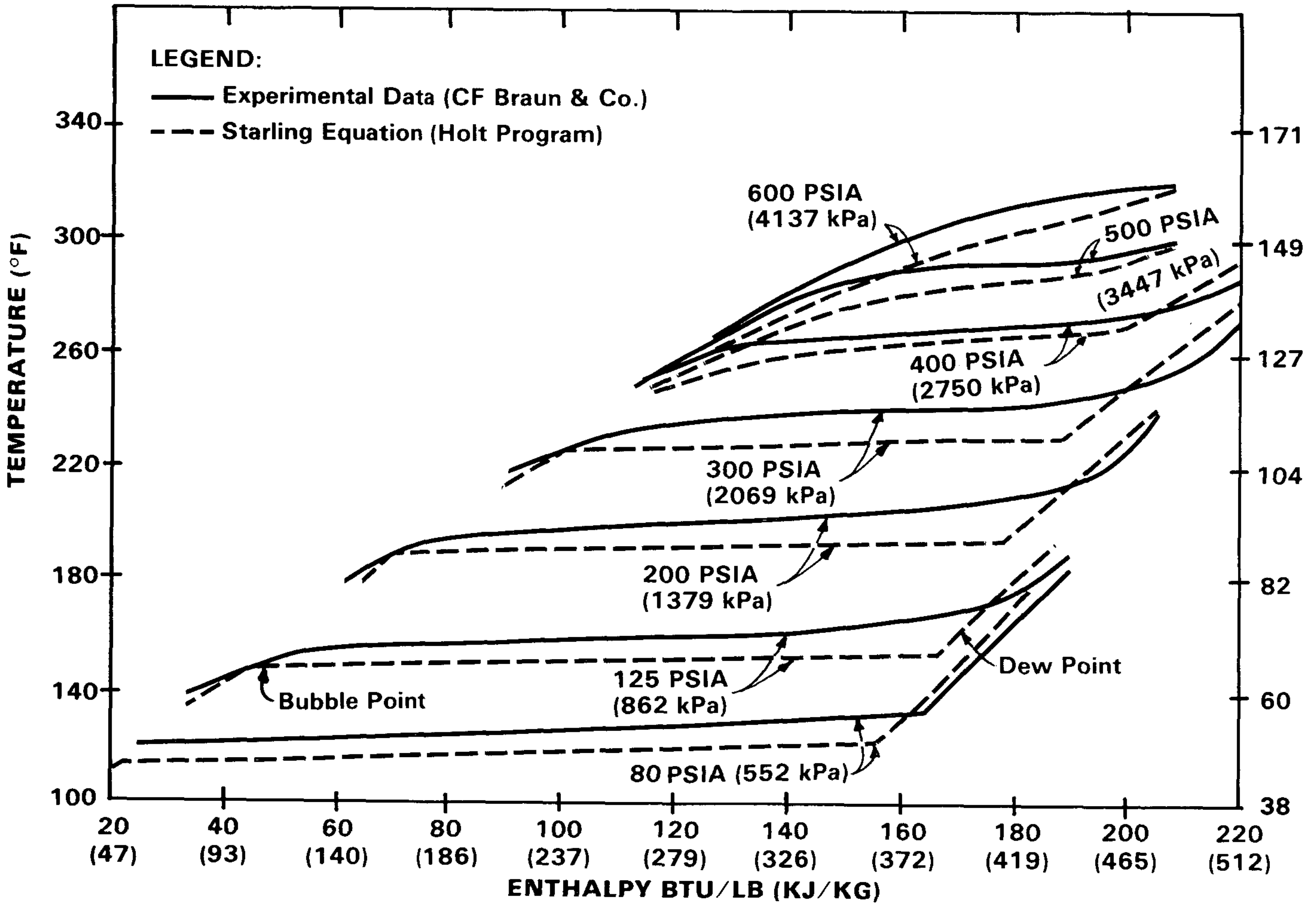
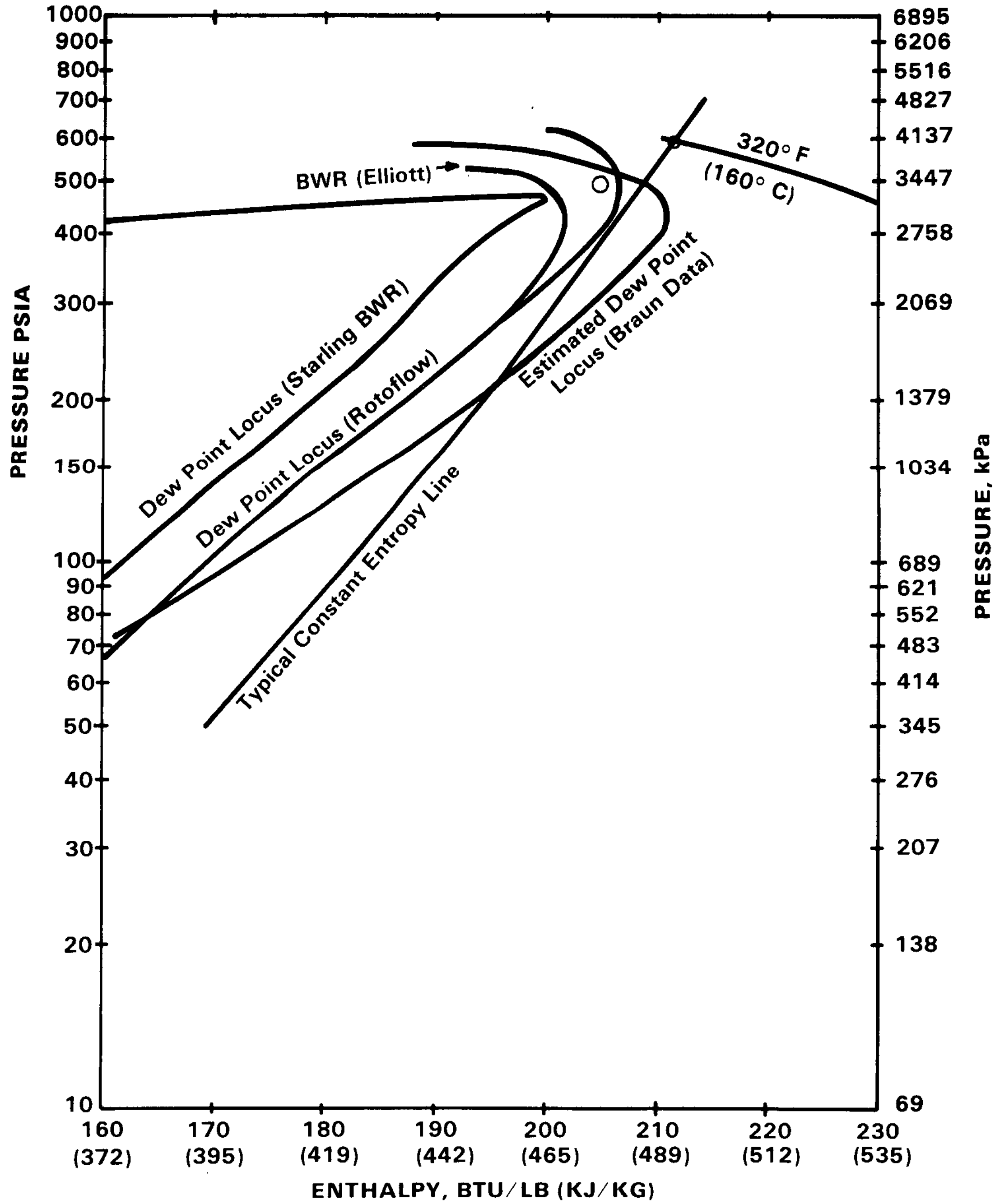


FIGURE 3.5.1D
COMPARISON OF BRAUN EXPERIMENTAL DATA WITH EQUATION OF STATE PREDICTIONS
80/20 PERCENT ISOBUTANE/ISOPENTANE



predicted utilizing different equations of state and the locus estimated from the Braun data. Elliott's BWR and Rotoflow's correlation, important in that both represent the thinking of potential suppliers of turbines for binary plants, agree reasonably well with one another. The loci of these predictions fall between the locus predicted by the Starling equation and the estimated locus derived from the Braun data.

The Starling predictions appear to be significantly different from the others. Furthermore, using a method that does not agree with those used by the turbine manufacturers could lead to uncertainties or discrepancies in the design basis for the hydrocarbon loop. Therefore, the decision was made to evaluate the binary plant design utilizing the BWR equation of state. This equation of state was selected because its locus of dew point prediction coincides with Elliott's BWR prediction and, for most of the range of pressures of interest, also coincides with Rotoflow's predictions.

3.5.2 Preliminary Cycle Optimization

Following the completion of Phase II special study T002 (Subsection 3.3), additional information on brine supply were obtained from Chevron. Significant in this regard was the determination that the terminal (end of 30 years) reservoir design temperature would be 338°F (170°C) versus 325°F (163°C) used in the Phase I(3) study, and that the brine reinjection temperature was to be 150°F (65.6°C) minimum. Based on this information, the decision to use a different equation of state for the hydrocarbon working fluid and changes in cycle design criteria dealing with component efficiencies and pressure drop assumptions, it was necessary to reoptimize the power cycle.

Assumptions for this study were as follows:

- Hydrocarbon mixtures to be considered were 80/20 isobutane/isopentane, 90/10 isobutane/propane and pure isobutane.

- Cycle calculations to be based on a two-phase brine supply with 5 percent by weight steam.

- Net busbar power output to be 45 MW_e, including brine return booster pump power but excluding Chevron brine production well power.

- Minimum brine return temperature to be 160°F (71°C) at plant boundry to insure compliance with Chevron requirements of 150°F (66°C) minimum at wellhead.

- Minimum brine/hydrocarbon heat exchanger approach (pinch) to be 10°F (5.6°C).

- Hydrocarbon condensation temperatures: 105°F (40.5°C) for mixtures.
  110°F (43°C) for pure isobutane.

- Initial reservoir temperature, 360°F (182°C).

- Terminal reservoir temperature 338°F (170°C).

Figures 3.5.2A, B, C and D show comparative plant performance for the three hydrocarbon mixtures. Results and conclusions from this work are summarized as follows:

- The 80/20 mixture of isobutane/isopentane was optimum over the entire range of reservoir downhole temperatures 360°F (182°C) to 228°F (170°C).

- The 80/20 mixture requires the lowest brine flow, hydrocarbon circulation rate, and cooling water flow, and consequently, results in the lowest cost power plant and requires the least number of geothermal wells.

3.5.3 Final Cycle Optimization

Reevaluation of the 20-80 mix power cycle (500 psia and 295°F turbine throttle, 3,448 kPa and 146°C) described in Subsection 3.5.2 utilizing the BWR equation of state shows for the start-of-run conditions (brine at 360°F, 182°C) that the net power output of the cycle was not significantly different; in fact, it was slightly higher than the output predicted with the Starling correlation. However, differences were apparent (as seen by Figure 3.5.3A) in the predicted dew point and in

FIGURE 3.5.2A
POWER PLANT THERMAL EFFICIENCY VERSUS RESERVOIR TEMPERATURE (STARLING BWR)

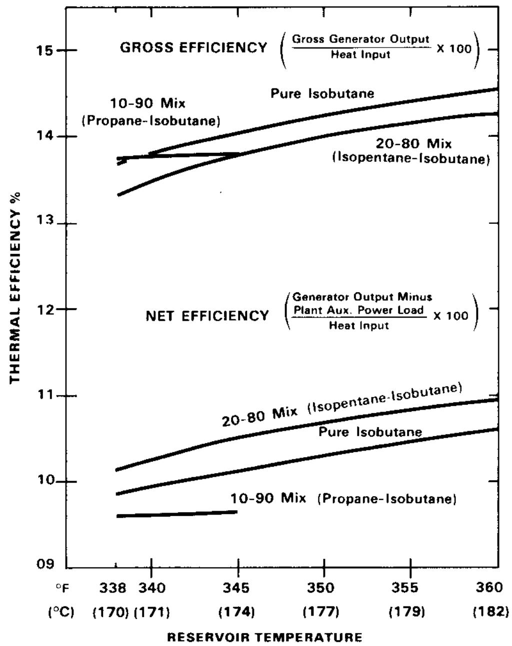


FIGURE 3.5.2B
HYDROCARBON CIRCULATION RATE VERSUS RESERVOIR TEMPERATURE (STARLING BWR)

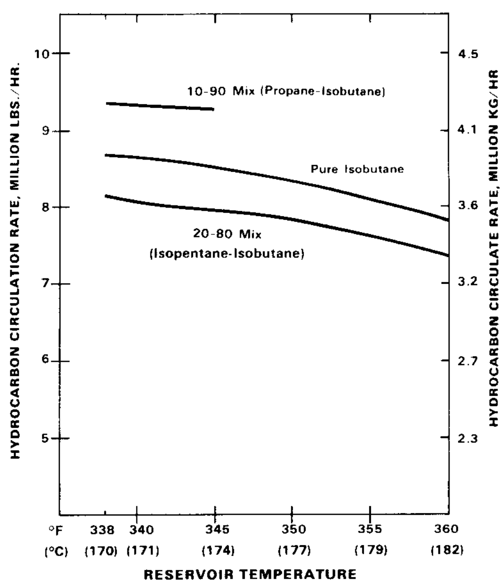


FIGURE 3.5.2C
BRINE FLOW RATE
VERSUS
RESERVOIR TEMPERATURE
(STARLING BWR)

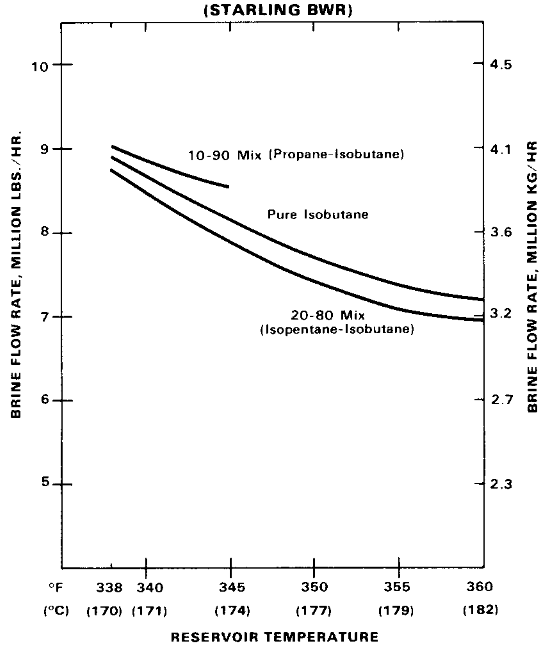


FIGURE 3.5.2D
COOLING WATER CIRCULATION RATE
VERSUS
RESERVOIR TEMPERATURE
(STARLING BWR)

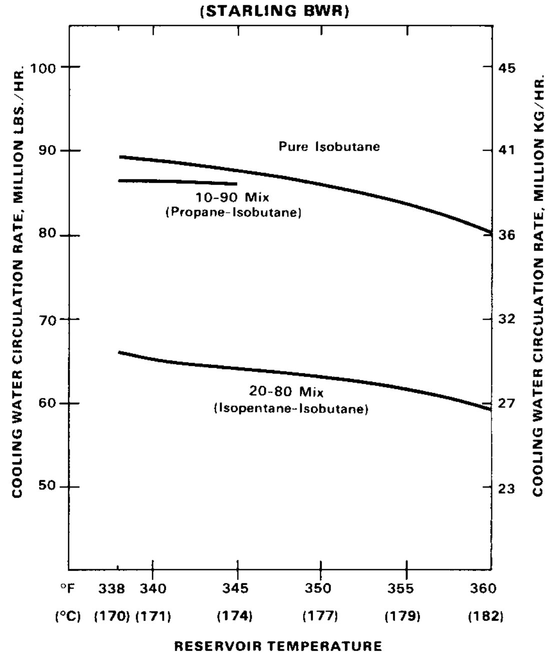
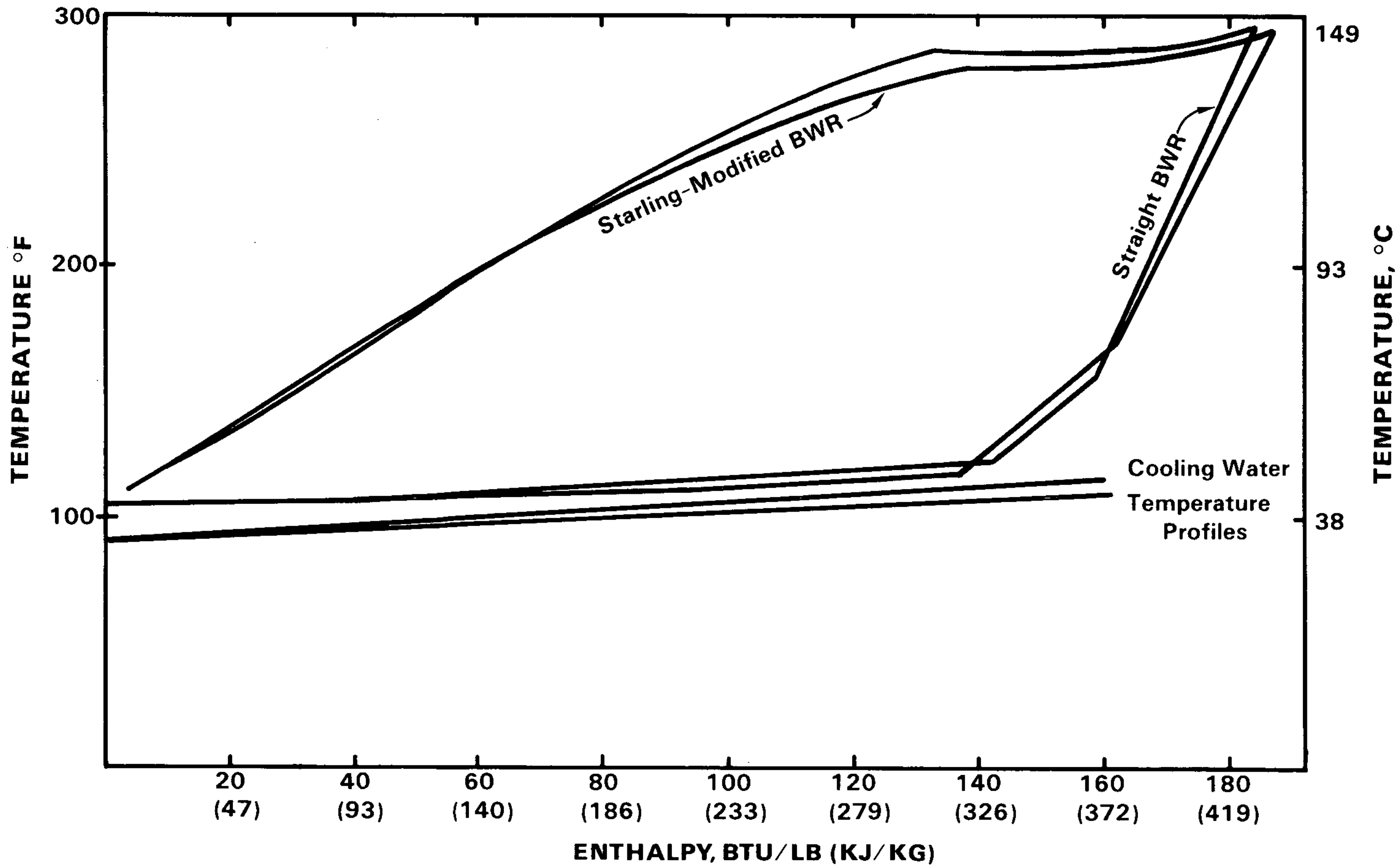


FIGURE 3.5.3A

POWER CYCLE PREDICTION UTILIZING BWR AND STARLING EQUATIONS OF STATE

20% ISOPENTANE — 80% ISOBUTANE

500 PSIA/295°F (3447 kPa/146°C)



the predicted heating curve. These discrepancies are, not surprisingly, of the same type and magnitude as those observed when comparing Starling's predictions with the Braun data (Figure 3.5.1C). In addition, there was concern that the turbine inlet conditions that had been selected utilizing the Starling correlation would fall so close to the predicted BWR two-phase region that some undesirable fluid condensation could occur inside the turbine. This point is illustrated in Figure 3.5.1D. The circle shown at about 205 Btu/lb (477 kJ/kg) and 500 psia (35.28 kg/cm^2) represents the turbine throttle conditions as predicted by Starling and BWR (both estimates are within one Btu/lb (2.3 kJ/kg) of one another). The constant entropy path (parallel to the typical constant entropy line shown in the graph) passes away from the Starling locus of dew points but it does touch the BWR locus. If the latter situation were to occur in an operating plant, depending on how far to the left of the locus the path passes, condensation inside the turbine will occur. This condensation could cause erosion and/or loss of efficiency, especially in an axial flow turbine. Consequently, a more thorough study was carried out to reevaluate the conclusions of the preliminary optimization.

The same design criteria used for the preliminary optimization were used again, except for the change in brine delivery mode. Consistent with latest information from Chevron and with the results discussed in Subsection 3.6, the brine was assumed to be supplied from single phase pumped wells and to be delivered at the plant boundary at 200 psia (1379 kPa).

Binary power cycles utilizing 20-80 and 10-90 isopentane-isobutane mixes and pure isobutane were studied over the full range of bottom hole brine temperature (360°F, 182°C to 338°F, 170°C).

As in the previous study, the three major power plant flow rates, (i.e., brine, hydrocarbon and cooling water) were calculated along with gross and net thermal efficiencies. These estimates have been plotted in Figures 3.5.3B, C, D and E. The 10-90 propane-isobutane mix, which in the preliminary cycle optimization did not show any advantage, was not investigated in the final optimization. Two changes in criteria reduced the economic attractiveness of this mix since it was initially proposed(21). These were the 160°F (71°C) minimum brine discharge temperature and the reduction in the expected temperature decline of the resource during the life of the power plant.

FIGURE 3.5.3B

POWER PLANT THERMAL EFFICIENCY VERSUS RESERVOIR TEMPERATURE (BWR)

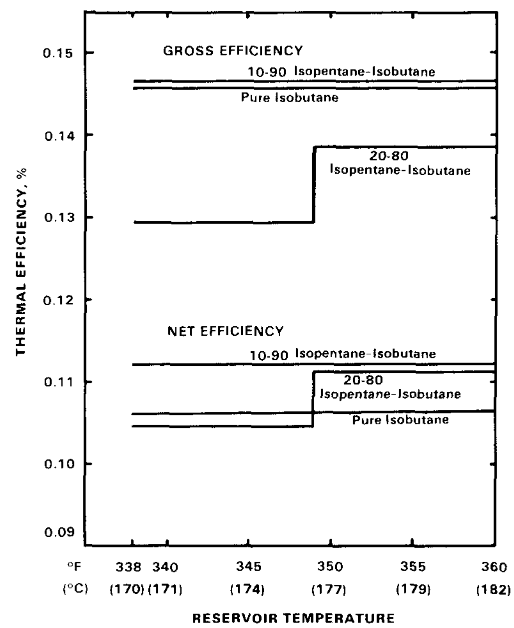


FIGURE 3.5.3C

HYDROCARBON CIRCULATION RATE VERSUS RESERVOIR TEMPERATURE (BWR)

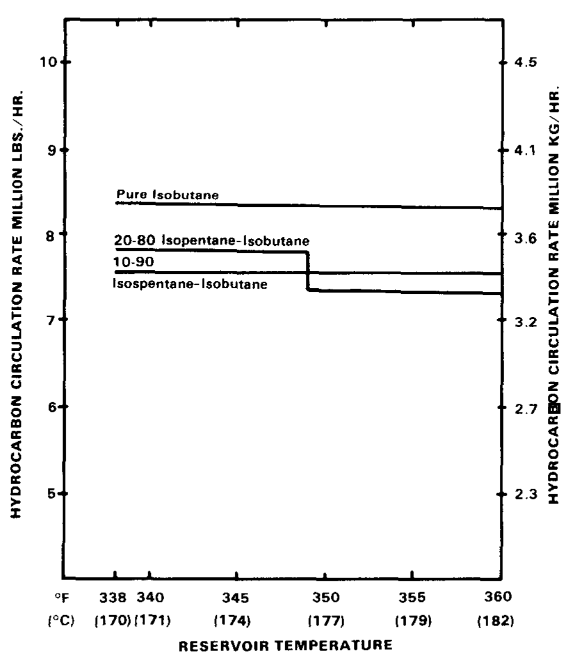


FIGURE 3.5.3D

BRINE FLOW RATE VERSUS RESERVOIR TEMPERATURE (BWR)

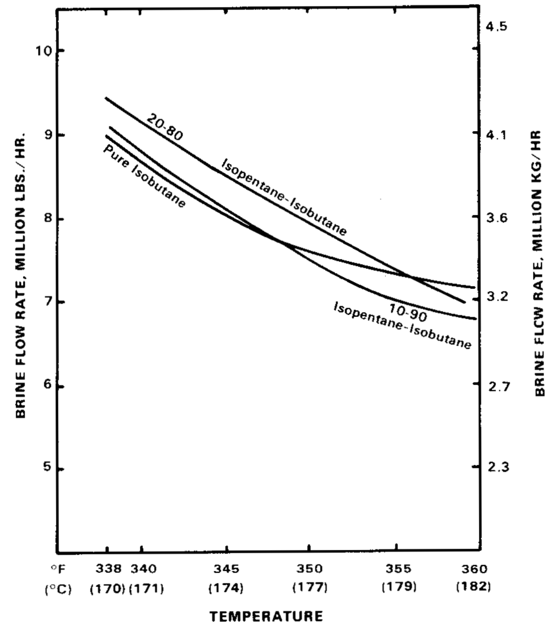
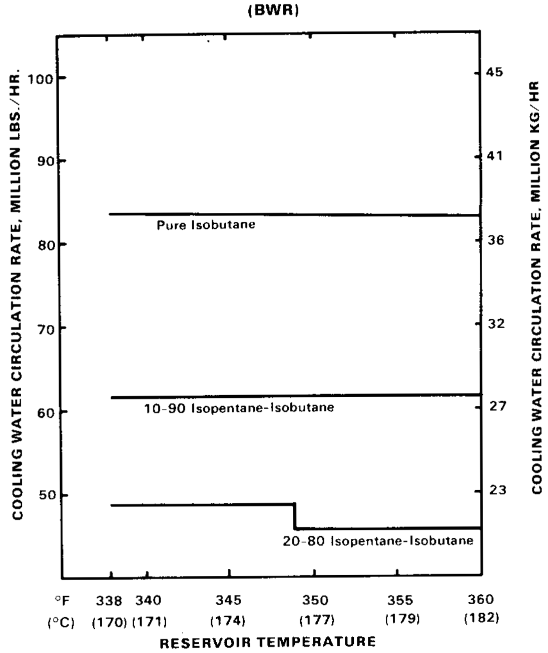


FIGURE 3.5.3E

COOLING WATER CIRCULATION RATE VERSUS BOTTOM HOLE TEMPERATURE (BWR)



The final optimization started by selecting turbine throttle conditions for the 20-80 mix that would reduce the risk of condensation inside the turbine. For start-of-run operation, the best conditions were found to be 475 psia (3275 kPa) and 295°F (146°C). However, this cycle has a disadvantage. The new heating curve forces the dicharge of brine at higher temperatures, thus requiring proportionately higher flow rates.

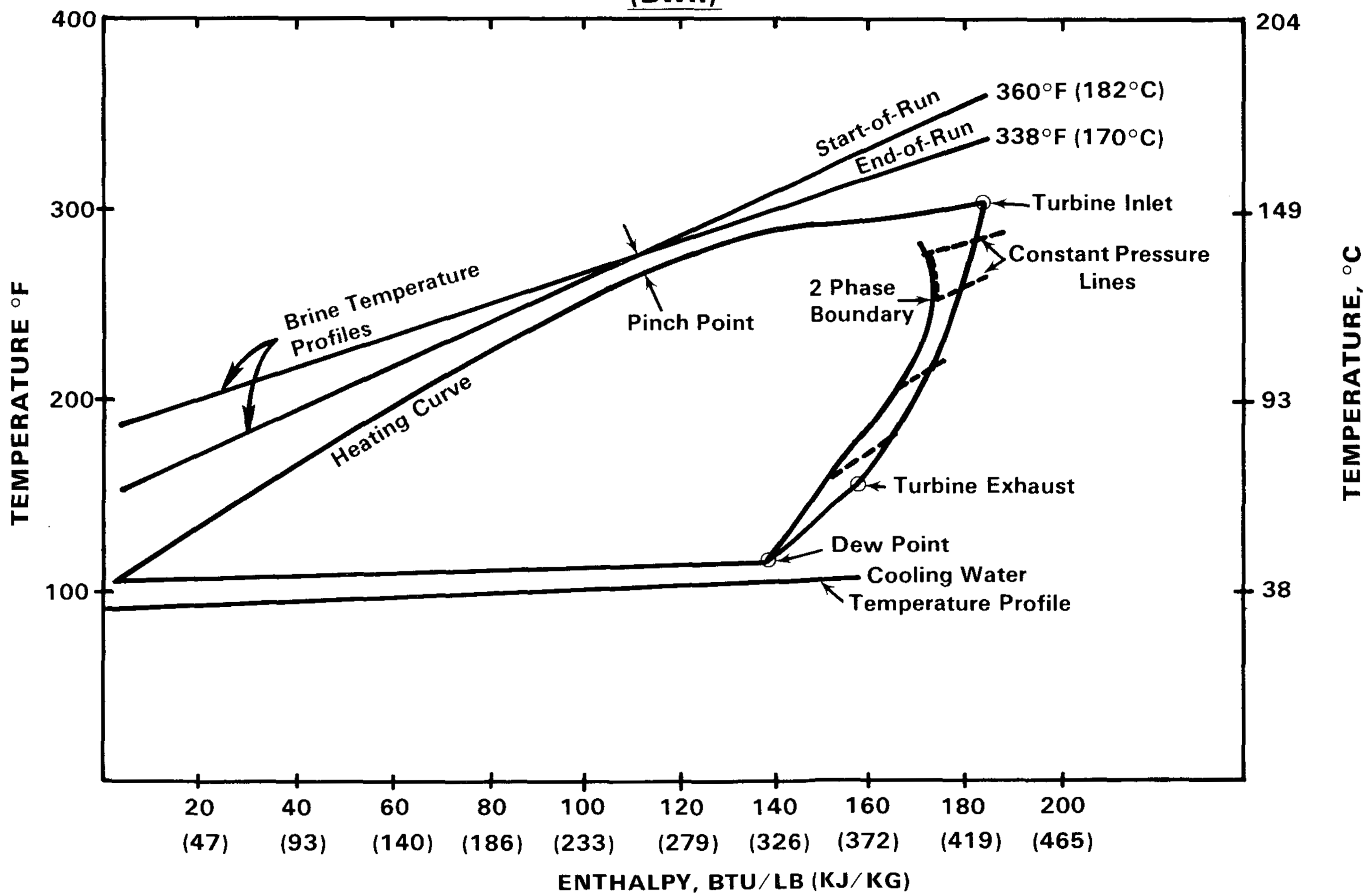
In order to keep the brine flows close to previously estimated optimum values, a change in operating conditions would be required after about 15 years of operation. A reduction in pressure and temperature to 400 psia (2758 kPa) and 278°F (137°C) was found to be the best way of attaining this goal. The lines, labeled 20-80 mix, in Figures 3.5.3B, C, D and E, depict this two cycle operation over the 30-year life of the plant.

Although cycle optimization with the same fluid over the life of the plant could be achieved for every few degrees that the brine temperature is expected to drop, this is hardly a realistic way to predict power plant operation. Each change in cycle conditions would require changes in pump head, in equipment capacity, and most important in pressure ratio across the turbine; making it difficult to operate the plant efficiently without major expenditures for equipment additions or modifications. Furthermore, the possibility that the brine temperature might fluctuate over periods of time, or might be different than presently predicted, makes it imperative to design the plant so that it can operate efficiently over the full range of expected brine temperatures without requiring any equipment changes. Therefore, it was decided to search for one cycle that could be used throughout the life of the plant permitting both efficient operation of the equipment in the hydrocarbon loop and efficient utilization of the brine. The results were the two additional cycles presented in Figures 3.5.3B, C, D and E utilizing a 10-90 (isopentane-isobutane) and pure isobutane.

Conclusions are that the 10-90 mix cycle with 575 psia (3965 kPa) and 305°F (152°C) turbine throttle conditions should be selected for optimum power plant operation throughout the 30-year life of the plant. The selected power cycle is illustrated in Figure 3.5.3F.

The inherent flexibility of the binary power plant concept, which allows considerable latitude to the plant designer as well as to the future plant operator,

FIGURE 3.5.3F
OPTIMIZED POWER CYCLE
10% ISOPENTANE — 90% ISOBUTANE
TURBINE THROTTLE CONDITIONS — 575 PSIA/305°F (3965 kPa/152°C)
(BWR)



has been demonstrated by the optimizations done for the Heber plant. After changing the equation of state and moving the turbine throttle conditions away from the two phase region, the new operating conditions, as far as major circulation rates and thermal efficiencies are concerned, are almost identical to those previously established during the Phase I study. The pressure at the turbine throttle was increased by 75 psia (517 kPa) but this still remains below the anticipated design pressure.

3.6 BRINE SUPPLY

Several studies were performed relative to the brine supply system. The Phase I studies were based on brine supply from single phase pumped wells. From further assessment of this work, it was determined that the energy supply pricing structure had changed from earlier concepts as a result of information developed for SDG&E by Chevron pursuant to their energy supply agreement. A study was performed to evaluate the impact of this pricing on the process selection (binary versus direct flash steam)(9) using single-phase and two-phase brine supply wells. The results of this study are discussed in Subsection 3.3.

As the result of continuing reservoir development work by Chevron, it was subsequently determined that free-flowing two-phase brine supply wells are not economically feasible because of their unfavorable pressure/flow relationship. Consequently, it would be necessary to employ downhole pumps to provide economic two-phase well flow rates at a pressure necessary to support binary cycle operation.

For this reason, a brine supply optimization study was undertaken to determine the economics of single phase pumped wells and two phase partially pumped wells using the energy supply conditions provided by Chevron as shown on the following table:

TABLE 3.6A

ENERGY COST

Supply Mode	Supply Pressure psia	Energy Cost Cents/MM Btu
Single Phase Flow	200	66
Two Phase Flow	75	56 (through 1986)
		61 (1987 +)
Two Phase Flow	85	58 (through 1983)
		63 (1984 +)

Consideration of two phase flow at a supply pressure of 95 psia was dropped because well pumping would be required from the start and the energy cost would approximate that of single phase flow.

Flow configurations for single phase and two phase brine supply employed in the study are shown in Figures 3.6A and B. Brine flow rates and plant capital costs are shown in Tables 3.6B and C.

TABLE 3.6B

BRINE FLOW RATE, LBS/HR (KG/HR)

	Two-Phase 75 psia (517 kPa)	Two-Phase 85 psia (586 kPa)	Single-Phase 200 psia (1379 kPa)
Start @ 360°F	7,100,000	7,000,000	6,800,000
(182°C)	(3,220,000)	(3,170,000)	(3,080,000)
15 Years Later			
@ 340°F	7,600,000	7,700,000	7,800,000
(171°C)	(3,450,000)	(3,500,000)	(3,540,000)

FIGURE 3.6A
SINGLE PHASE BRINE SUPPLY
(PHASE II BASELINE DESIGN)

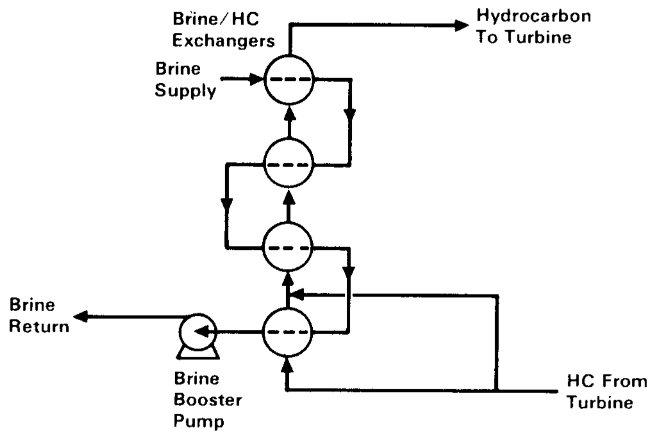


FIGURE 3.6B
TWO PHASE BRINE SUPPLY

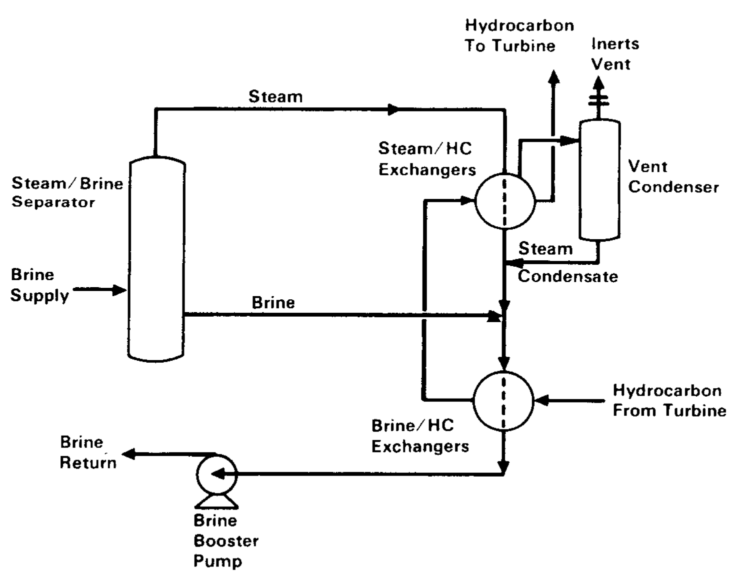


TABLE 3.6C
ESTIMATED CAPITAL COST
VERSUS
BRINE SUPPLY OPTION
(Instantaneous 1977 Dollars)

Two-Phase 75 psia (517 kPa)	Two-Phase 85 psia (586 kPa)	Single-Phase 200 psia (1379 kPa)
$35,000,000	$34,500,000	$32,600,000

From Figure 3.6C, it is shown that during the first few years of the plant life, the two-phase brine feed system results in lowest busbar power cost, with both the 75 psia (517 kPa) and 85 psia (586 kPa) two-phase supply. However the savings is only about one mill per KWH lower cost.

During the period of plant life between year 5 and year 12, all three feed conditions produce approximately equivalent (within 1/2 mill) busbar cost. At plant life beyond year 12, the 75 psia (517 kPa) two-phase feed case becomes more attractive, but the difference between the cases remains at less than one mill per KWH through year 18.

In the two-phase feed cases, considerably more equipment and controls are required than in the single-phase case to separate the steam from the brine, remove noncondensable gases from the steam, and remove sand from the brine. Indications are that these additional steps will complicate operation and adversely affect plant reliability. In fact these factors could result in additional operating expenses (i.e., for sand removal and steam lost in the noncondensable vent) which would more than offset the estimated $800/day difference (at 70 percent availability) in busbar cost at one mill/KWH.

3.7 POWER CYCLE CONTROL

A process sketch of the binary cycle, showing the three process variables which must be controlled for proper plant operation, is shown as Figure 3.7A. The flow of binary fluid to the turbine is controlled by a speed/load governor control system, and is outside the scope of this discussion.

FIGURE 3.6C
DIFFERENTIAL POWER COST AS A FUNCTION OF BRINE DELIVERY OPTIONS

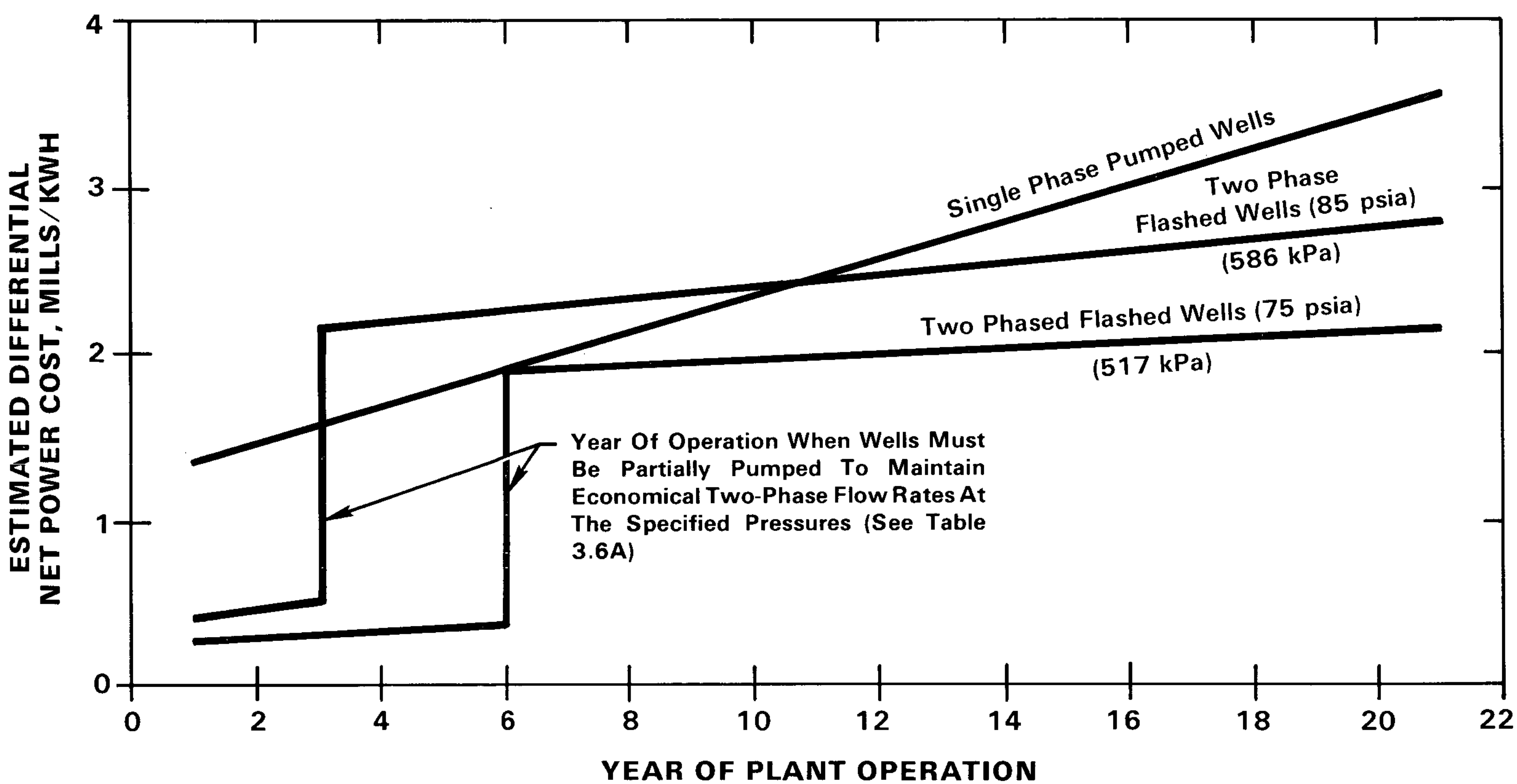
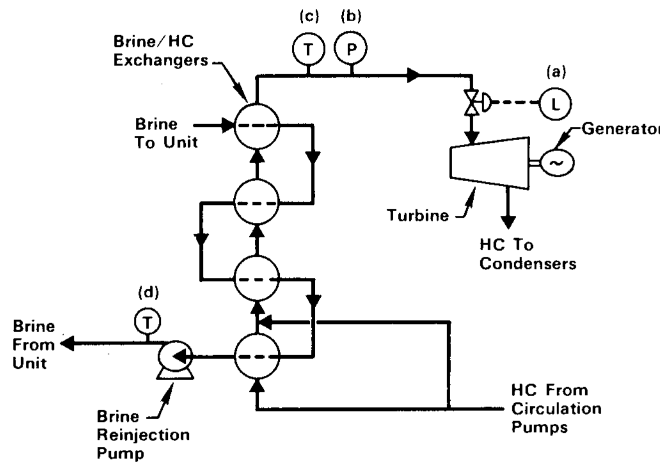


FIGURE 3.7A

POWER CYCLE CONTROL VARIABLES

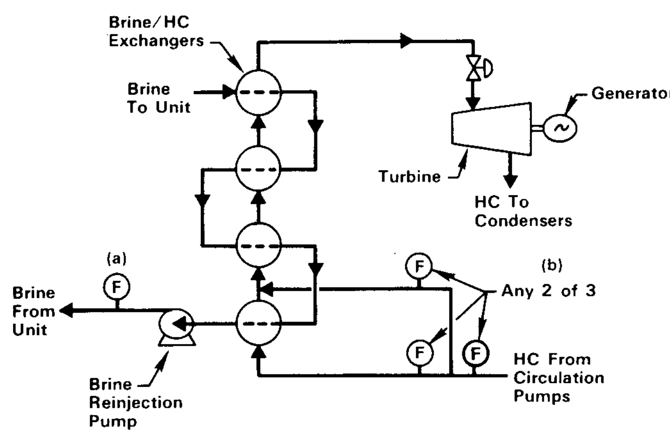


VARIABLES TO BE CONTROLLED:

(a) = Turbine Generator Load
(b) = Hydrocarbon Temp. To Turbine Throttle
(c) = Hydrocarbon Press. To Turbine Throttle
(d) = Brine Return Temperature

FIGURE 3.7B

POWER CYCLE CONTROL VARIABLES



VARIABLES WHICH CAN BE CONTROLLED:

(a) = Brine Return Flow
(b) = Any Two of the Three Flows Indicated

The temperature and pressure of the binary hydrocarbon working fluid to the turbine throttle valve will be controlled to insure operation in the supercritical or vapor phase. The temperature of the brine exiting the brine/hydrocarbon heat exchanger train will be held above the temperature at which the brine solution would begin to precipitate solids. This temperature has been identified by Chevron to be 150°F (66°C) at the reinjection wellhead.

These three dependent variables (temperature and pressure of the binary fluid to the turbine throttle valve, and temperature of brine from the unit) require that three independent control variables be utilized. The independent variables available for control are shown on Figure 3.7B. They are the brine flow and any two of the three hydrocarbon flows shown, i.e., total flow, flow to the complete exchanger train, and bypass flow around a portion of the exchanger train.

Of the many possible control schemes for the power cycle system, the scheme shown on Figure 3.7C, appears to yield the highest potential for maintaining the binary turbine throttle conditions and the brine return temperature at desired values. In this scheme, brine flow and total hydrocarbon circulation follow the flow of hydrocarbon to the turbine by ratio control. The ratios are trimmed to maintain desired throttle conditions.

On a load increase, throttle flow will increase causing brine flow and hydrocarbon flow to linearly increase. Minor variations in flow instrument response will be corrected by a reset action of the ratio control points as either the throttle pressure and/or temperature drift from set point. The hydrocarbon bypass valve will be directly controlled by the brine return temperature. Any movement of the bypass valve will not alter the total hydrocarbon flow to the system, as the ratio flow controller will compensate by either opening or closing the main hydrocarbon flow valve. The scheme works in the same manner on a load decrease, with reversed action.

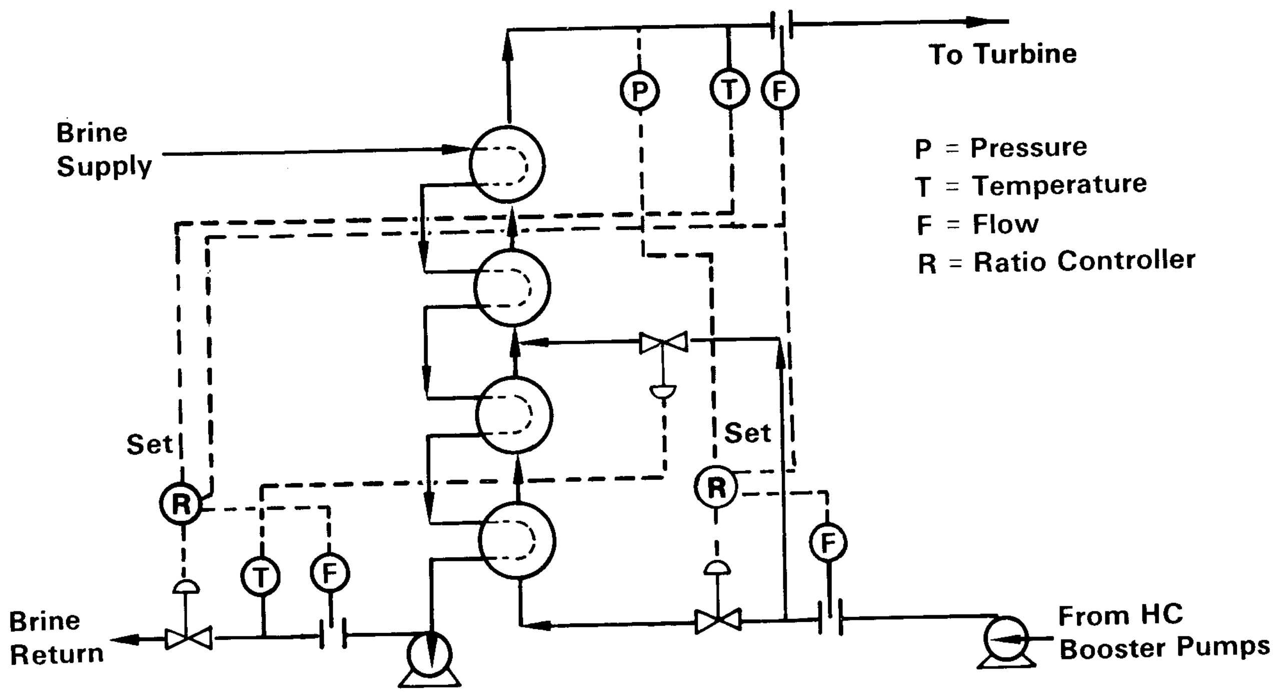
3.8 COOLING SYSTEM

The Heber power plant will require substantial amounts of cooling water during operation. The considerations for supplying cooling water and treatment of this water have therefore been carefully studied. Present estimates of plant water usage are as follows:

FIGURE 3.7C

POWER CYCLE CONTROL

(PHASE II BASELINE DESIGN)



- Approximately 140,000 gpm (31,792 m^3/hr) of treated cooling water will be circulated through the plant, with the major user being the hydrocarbon condensers.

- Makeup water flow is estimated at 2,300 gpm (523 m^3/hr) at a yearly average plant availability of 70 percent. Normal makeup at full plant output is 3,300 gpm (750 m^3/hr).

Present commitments between SDG&E and IID will provide the plant cooling water for the first five years of operation from the Central Main Canal or the Dogwood Canal. These water supply sources are from existing irrigation systems and contain up to 900 ppm total dissolved solids and large quantities of entrained silt.

SDG&E, IID and others are investigating alternate water supply sources for plant operations beyond the initial five years. The most viable source at present is the agricultural drain water system which IID has agreed to furnish for the operating life of the Heber plant. The final decision on the suitability of the agricultural drain water will be based on further evaluation of alternate sources and assessment of the environmental effects of using these water supplies.

3.8.1 Cooling Water Treatment

Irrigation canal water will require a fairly conventional water treatment system. Change over to the agricultural drain water supply will require extensive treatment for plant use. The present water treatment system includes the following features:

- Large settling ponds for silt removal. Silt is estimated to accumulate at between one and two tons per day (907 and 1,814 kg/d).

- Sulfuric acid treatment to remove dissolved carbonates (pH adjustment) prior to entering the cooling tower basin.

- At the cooling tower basin, further treatment is performed consisting of chemical injection and filtration.

As part of Fluor's Optimization Studies(18), alternate methods for removing silt from the incoming water were investigated, producing the following results:

Method	Annual Cost
Settling Ponds	$155,000
Hydroclones	$185,000
Gravity filters	$203,000
Pressure filters	$210,000
Clarifier	$245,000

Based on this evaluation settling ponds will be employed.

3.8.2 Wet versus Wet/Dry Cooling

R.W. Beck and Associates (Beck) were engaged to develop parametric analyses on varying combinations of wet and wet/dry cooling systems for the Heber plant using their computerized program developed in conjunction with similar studies they performed under contract to EPRI. The criteria for this work is identified in Interim Report I (20).

The Beck study indicates that a "wet/dry" system could be employed at Heber. However, the climatological history at Heber leads to an evaluation showing the "all wet" system to be economically more attractive. As can be seen from Figures 3.8.2A and B, a cost increase (penalty) of 7 to 18 mills/KWH would result from use of the "wet/dry" system compared to the more economical "all wet" system, and is associated with a 60-92 percent annual average load on the "dry" system. This cost increase translates into 19-57 percent busbar cost penalty. The Beck estimates of makeup water usage for 0-100 percent average load on the dry system is shown on Figure 3.8.2C.

Under an agreement between IID and SDG&E, cooling water will be supplied from the IID canal system for the first five years of plant operation. It was anticipated that makeup water will cost in the order of 20 cents per thousand gallons (5.3 cents per cubic meter). As seen from Figure 3.8.2A, this cost is far below the cost that would be required to justify a wet/dry cooling mode.

FIGURE 3.8.2. A
R. W. BECK STUDY
RANGE OF COST PENALTY OF "WET/DRY" SYSTEM VERSUS "ALL WET" SYSTEM

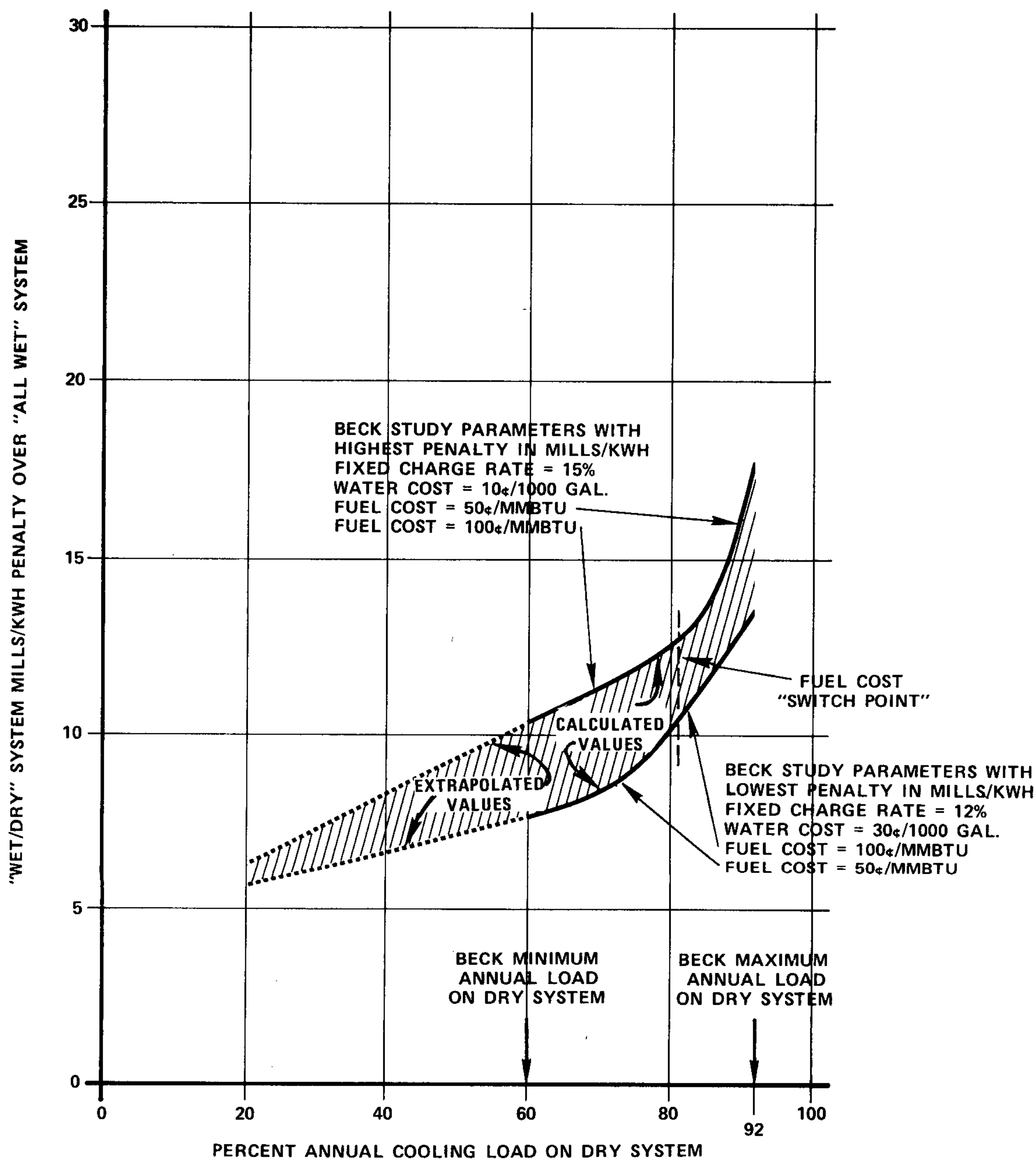


FIGURE 3.8.2. B
R. W. BECK STUDY
RANGE OF PERCENT COST PENALTY OF "WET/DRY" SYSTEM VERSUS "ALL WET" SYSTEM

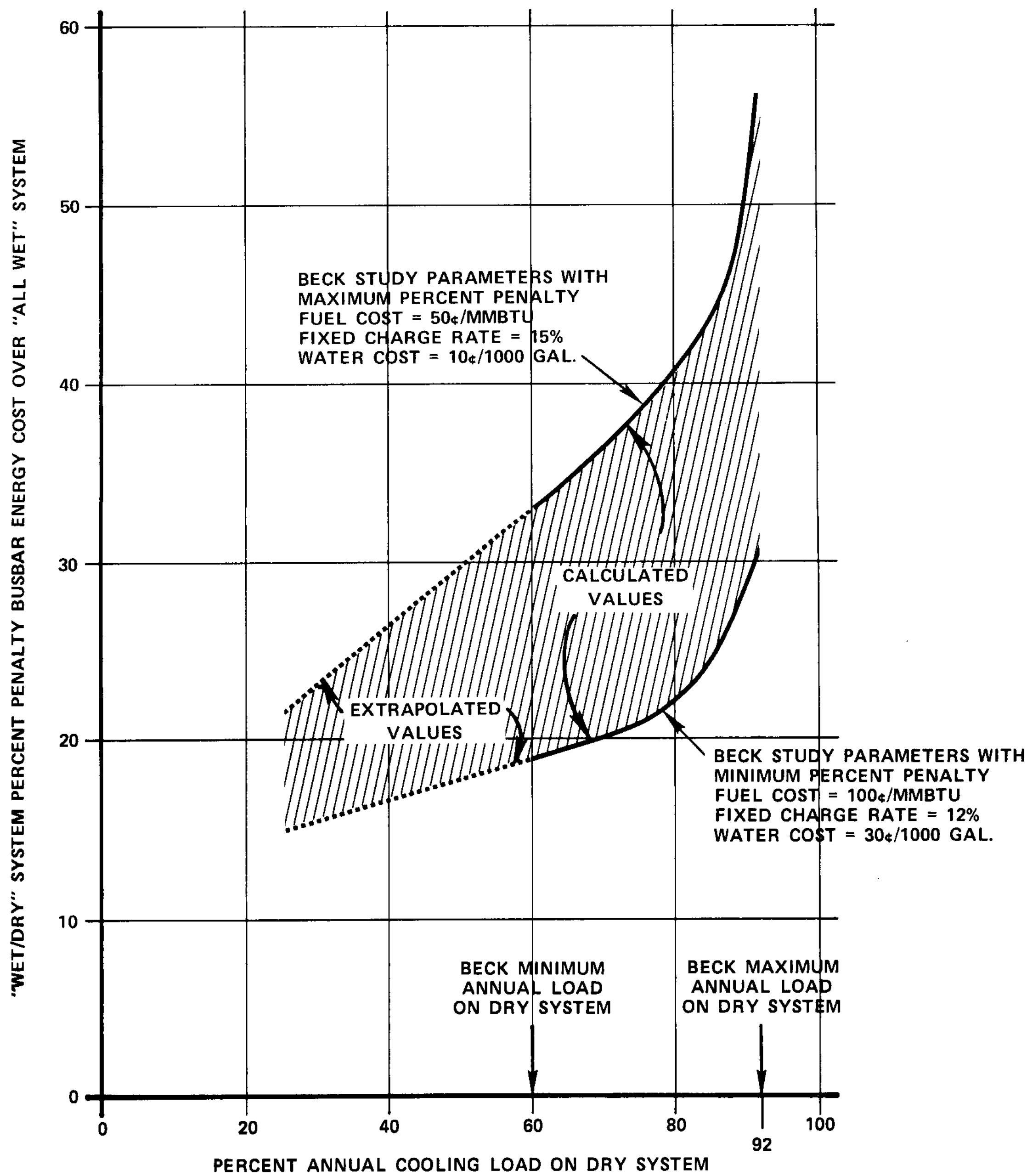
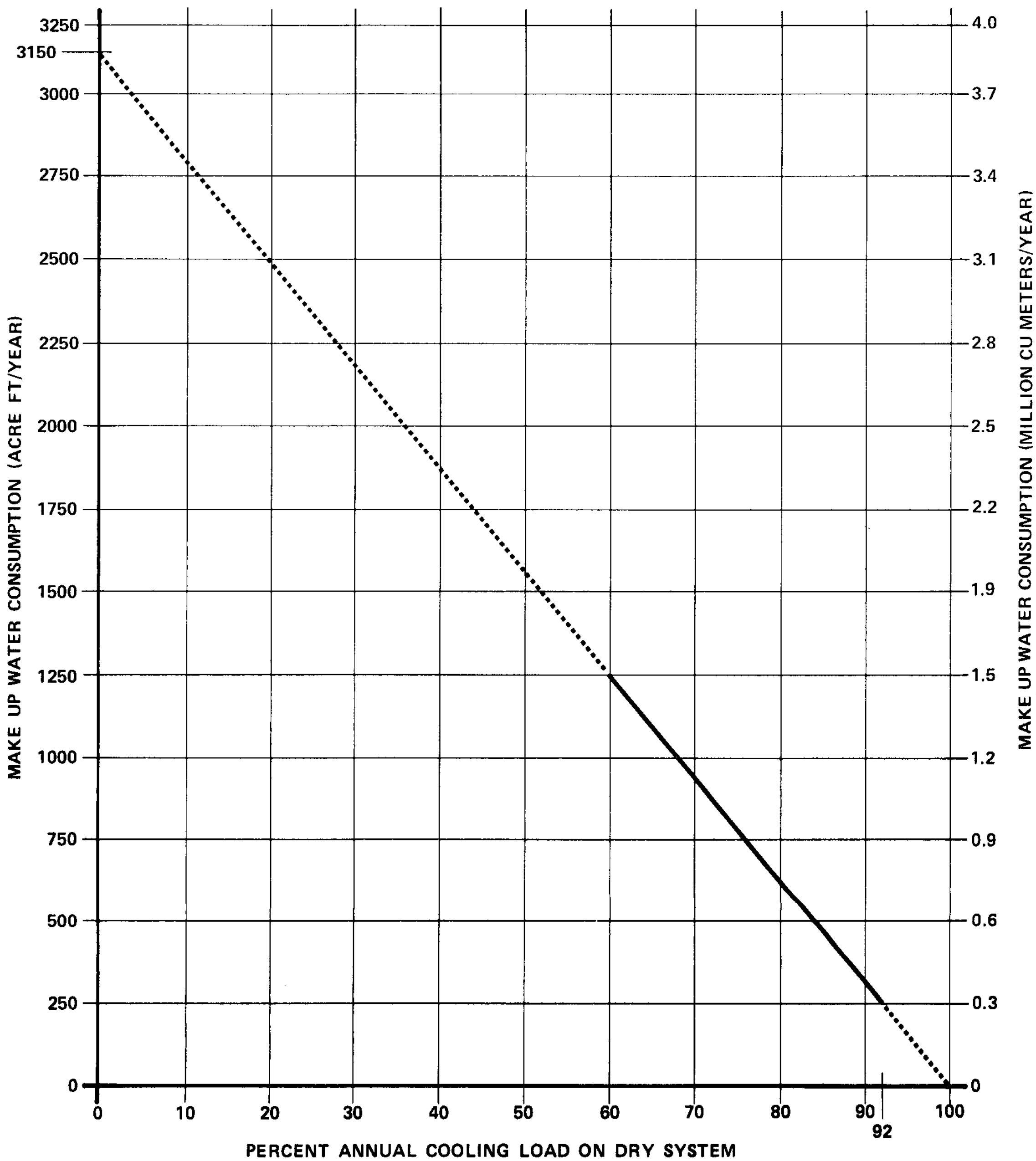


FIGURE 3.8.2. C
R. W. BECK STUDY
MAKE UP WATER CONSUMPTION VS PERCENT ANNUAL COOLING LOAD ON DRY SYSTEM



3.8.3 Cooling Tower Optimization

The high summer ambient temperature conditions at Heber combined with the very low power cycle thermal efficiencies results in the need for a disproportionately large and costly plant heat rejection system as compared to a conventional thermal power plant. Because of this and the requirement for maximum power output in the summer months, a preliminary cooling tower optimization was undertaken to establish tower selection criteria that would result in minimum annual cooling cost. Design conditions used in the study were as follows:

Wet Bulb Temperature	80°F (26.7°C)
Cooling Water Rise	20F° (11C°)
Approach to Wet Bulb Temperature	10°F (5.6°C)
Fixed Charge Rate	(0.1532) X (Total Capital Cost)

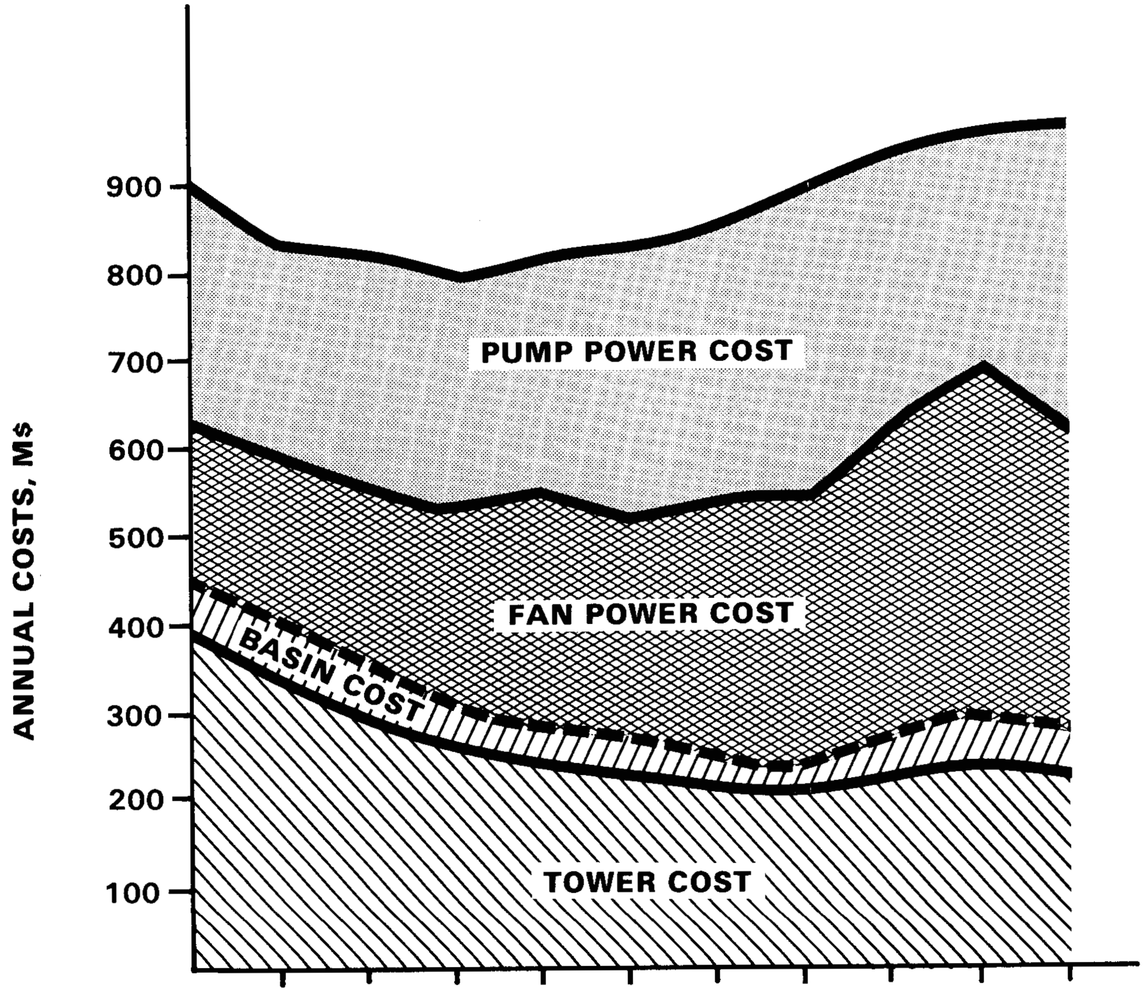
Design data and costs were obtained from two major cooling tower suppliers for eleven different tower selections. This information was used to establish the annualized capital cost of the cooling tower and basin, and the annualized operating cost for fans and pumping power.

From Figure 3.8.3A, it is seen that the optimum cooling tower is selection number 4. This tower consists of 10 cells and a basin area of 26,600 sq. ft. (2,471 m^2). Each cell has a 115 horsepower (85.8 kW) fan. The tower requires a static pumping head of 35 feet (10.7 meters).

3.9 POWER CYCLE ECONOMIZER

Hydrocarbon vapor exhausts from the turbine at a temperature of 150-170°F (66-77°C). In a unit not utilizing an economizer, this vapor flows directly to the hydrocarbon condensers, as shown on Figure 3.9A. A flow scheme was developed to conserve a portion of the heat in this stream by passing it through a heat exchanger where it would indirectly contact liquid hydrocarbon from the circulating pumps, adding preheat to the stream, as shown on Figure 3.9B. The effect of this additional heat exchanger on the brine/hydrocarbon heat exchanger temperature-enthalpy profile is shown on Figure 3.9C.

FIGURE 3.8.3A
ANNUAL OPERATING COST VS. TOWER DESIGN



C.T. Selection	1	2	3	4	5	6	7	8	9	10	11
H/P Fan	62	65	72	115	142	141	194	198	229	187	197
Basin Area M Sq.Ft.	27	29.2	25.2	20.6	18.6	16.7	14.8	13.2	16.2	18.5	14.8
No. Cells	15	15	14	10	10	9	8	8	8	11	9
kW/Fan	46	48	54	86	106	105	145	148	171	139	147
Area, M m^2	2.5	2.7	2.3	1.9	1.7	1.6	1.4	1.2	1.5	1.7	1.4

FIGURE 3.9A

BINARY CYCLE HYDROCARBON FLOW SCHEMATIC WITHOUT ECONOMIZER

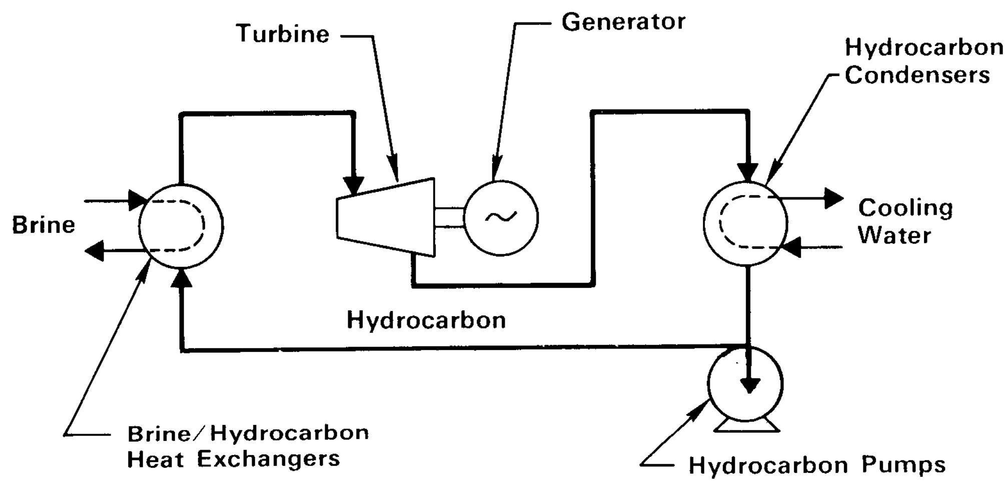


FIGURE 3.9B

BINARY CYCLE HYDROCARBON FLOW PATH WITH ECONOMIZER

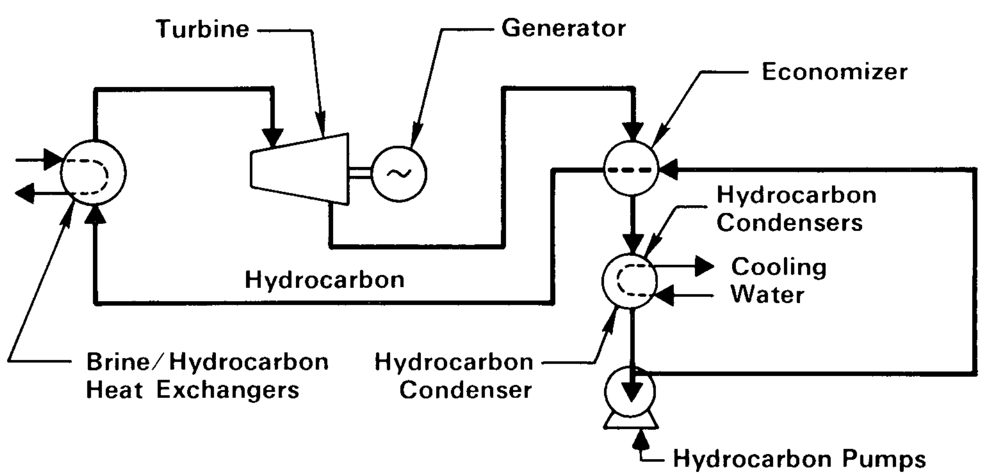
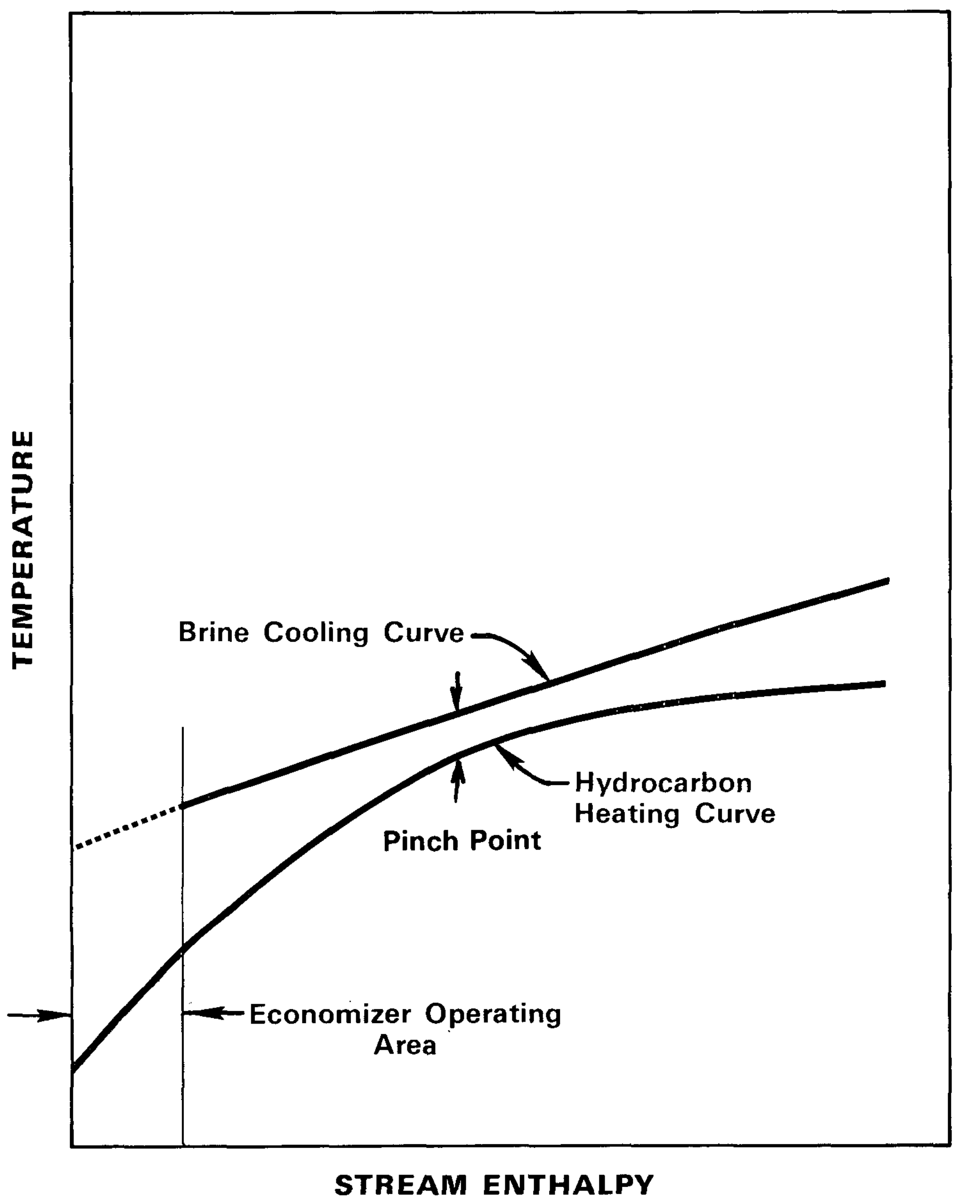


FIGURE 3.9C

BRINE/HYDROCARBON HEAT EXCHANGER HEATING/COOLING PROFILE (TEMPERATURE/ENTHALPY DIAGRAM)



For the economic analysis of an economizer installation, an increase of 0.5 psi (3.4 kPa) turbine backpressure and a hydrocarbon circulating pump discharge pressure increase of 5 psi (34 kPa) were assumed. Heat balance calculations indicate that the unit, without an economizer, would discharge brine at 160°F (71°C). The incorporation of an economizer results in a brine return temperature increase to 173°F (78°C) at start-of-run and 185°F (85°C) at end-of-run, 30 years later. This brine return temperature increase occurs because the brine/hydrocarbon heat exchanger "pinch point" occurs midway through the heating curve (see Figure 3.9C). The effect of the brine outlet temperature increase is to limit the economic usefulness of the economizer, since the brine supply contract requires payment for all brine as if it were cooled to the contract temperature basis i.e., 150°F (66°C) at the reinjection wells. Returning the brine at a higher temperature receives no credit.

The capital cost for a unit with an economizer was found to be approximately $1.4 million higher than a unit without an economizer. At a fixed charge rate of 15.32 percent per annum, this equates to a fixed charge in excess of $214,000 per year. Brine cost savings during the initial operating year is $205,000, falling to no savings by year 15. Since the proposed economizer never shows a positive cash flow, it will not be incorporated into the Heber plant design.

3.10 HYDROCARBON PUMPING CONFIGURATIONS

The Phase I conceptual design proposed the use of 2,000 horsepower (1,491 kW) multistage vertical pumps operating in parallel to maintain hydrocarbon circulation in the binary loop. Utility industry experience with similar equipment in the 300-500 horsepower (224-373 kW) range has produced a poor operational record. Based on their own experience with this type of equipment, SDG&E suggested that alternative configurations be investigated. This section provides a discussion of three alternatives evaluated and a summary of their comparative economics.

Figures 3.10A, B and C show the basic concept and details of the alternatives described below.

Alternate I comprises seven (6 normally operating plus one spare) 13-stage vertical pumps with a capacity of 4,700 gpm (1,067 m^3/hr) each. The multistage vertical pumps would have an operating efficiency of approximately 81 percent, and would

FIGURE 3.10A
HYDROCARBON CIRCULATION
PUMP CONFIGURATIONS
ALTERNATE I

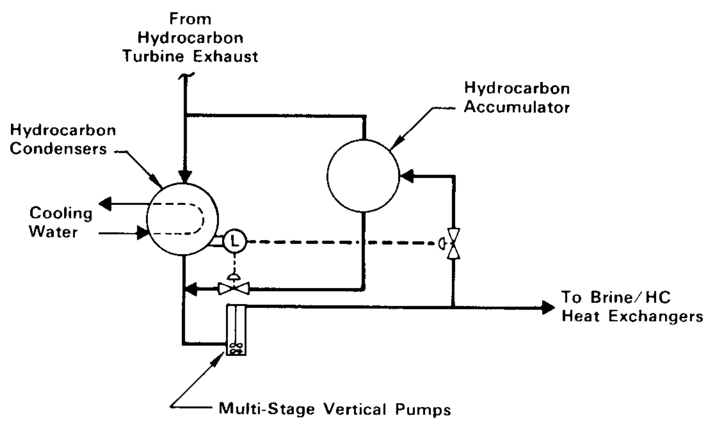


FIGURE 3.10B
HYDROCARBON CIRCULATION
PUMP CONFIGURATIONS
ALTERNATES II & III

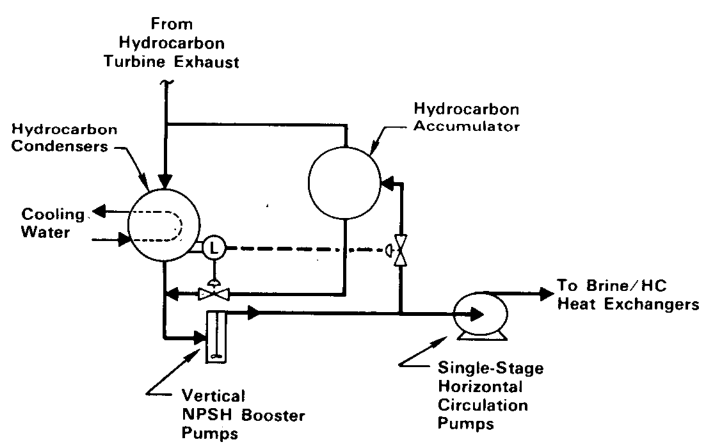
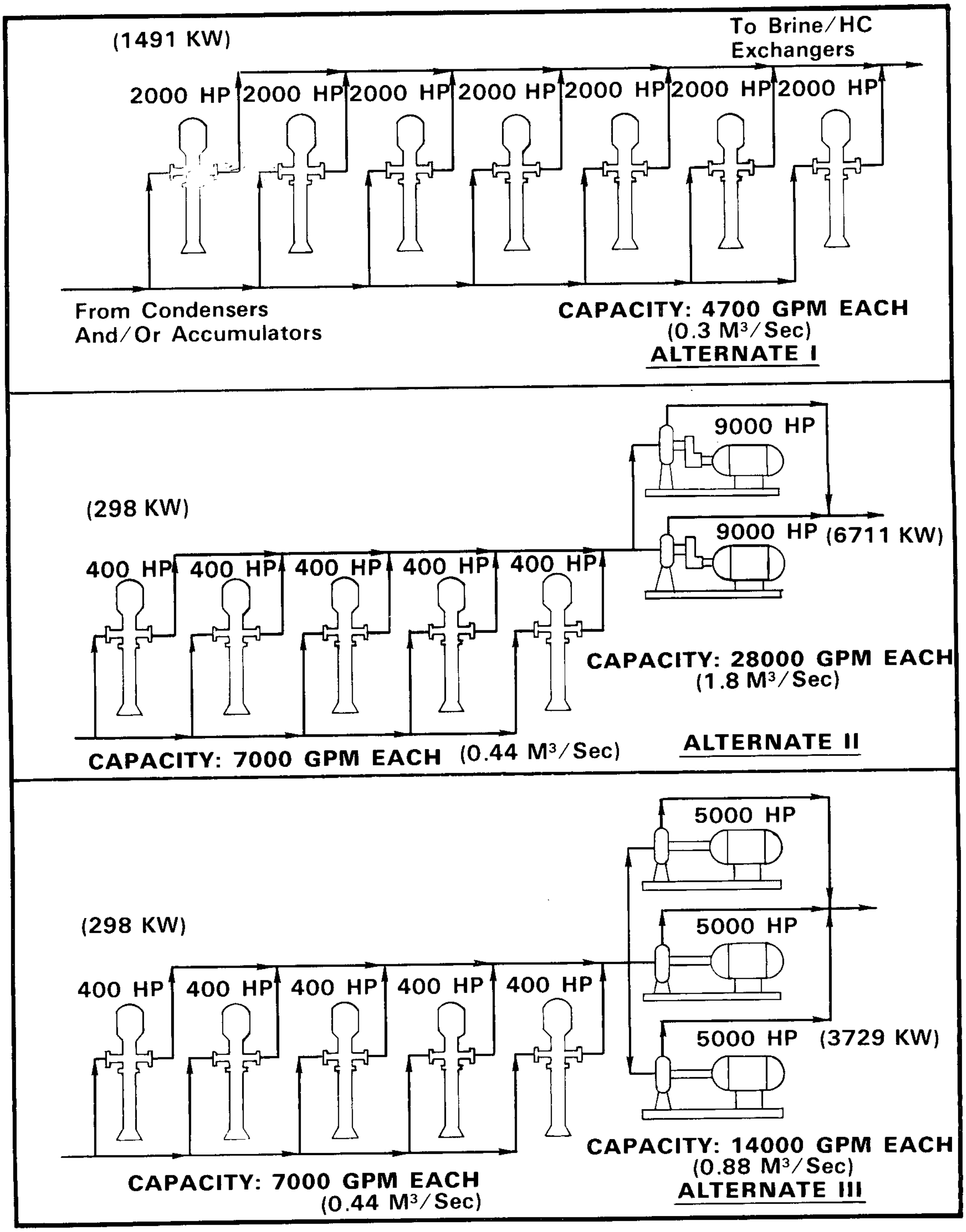


FIGURE 3.10C

HYDROCARBON CIRCULATION PUMPING CONFIGURATIONS



be driven with 2,000 HP electric motors having 95 percent efficiencies. The uninstalled capital cost of each of the seven units would be approximately $144,200.

Alternate II comprises five (4 operating plus one spare) 7,000 gpm, (1,590 m^3/hr) 2-stage vertical NPSH booster pumps, followed by two (1 operating plus 1 spare) single-stage horizontal circulation pumps. The NPSH booster pumps have operating efficiencies of 80 percent and are driven by 400 HP (298 kW) motors with 93 percent efficiencies. Uninstalled cost of the NPSH booster pumps and motors is $64,500 per unit. The single-stage main circulation pump has an operating efficiency of 86 percent, and is driven by a 9,000 HP (6,711 kW) motor with a 97 percent efficiency. A speed increasing gear is required with this unit; its efficiency is 97 percent. The uninstalled cost of each pump, gear and motor set is $420,000.

Alternate III utilizes the same NPSH booster pump setup as Alternate II. The three main pumps (2 operating plus one spare) have 86 percent operating efficiencies and are driven with 96 percent efficient 5,000 HP (3,729 kW) motors. No gear is required for these units.

Alternate I appears to have the advantage of flexibility for turn-down operations, when compared to the other two alternates. The six operating pumps yield 17 percent turn-down steps, compared to no steps for Alternate II and a 50 percent step for Alternate III. The main operational disadvantage is that all excess flow would be pumped to full discharge pressure, approximately 550 psia (3795 kPa), and then let down to suction pressure across a control valve. This is not the case in Alternates II and III, where letdown would occur at the NPSH booster pump discharge pressure of approximately 100 psia (690 kPa).

Alternate III appears to be the most reliable configuration, and should require the least maintenance. The low head NPSH pumps should require less maintenance than the high head vertical pumps of Alternate I. The Alternate III main pump does not require a gear, which could be a high maintenance item.

Alternate II appears to be the second most attractive from a maintenance and reliability viewpoint. Alternate I appears the least attractive from a maintenance viewpoint. The 13-stage vertical pumps are believed to be difficult to maintain and involve a heavy lift to remove the impeller assembly for inspection and maintenance.

The economics for the three cases are essentially equal. Alternate I has the lowest annualized capital cost of $310,000/year. Case II is $450,000/year and Case III is $490,000/year. Annual power cost (at 40 mills/KWH) for Case III is lowest at $1.8 million/year. Case II is $1.83 million/year and Case I is $1.91 million/year. Total annual costs for power and capital range from $2.22 million to $2.32 million per year, with Cases I and III being essentially equal at $2.22 million and $2.25 million/year.

Alternate III is recommended for incorporation into the Heber plant as it offers good economics, reliability and maintainability. The economics for Alternate III will improve with plant life (as mills/KWH increase because of brine cost escalation), as it is the highest efficiency configuration.

3.11 HEAT TRANSFER MATERIALS SELECTION

3.11.1 Brine/Hydrocarbon Heat Exchanger

Both carbon steel and titanium tubes are expected to demonstrate a 30 year life in Heber brine (based on Electric Power Research Institute, Research Project 846-1, Geothermal Heat Exchanger Tube Material Test under flowing conditions at Heber(11), California, the Ben Holt Co., June 1977). Admiralty was found to degrade on exposure to Heber brine.

The shell side of the heat exchanger will be exposed to the binary hydrocarbon fluid only. At the Heber unit design temperature, carbon steel will exhibit a life in excess of 30 years.

A carbon steel shell exchanger with titanium tubes would cost approximately 2.5 times as much as the same exchanger with carbon steel tubes. Since the use of titanium tubes appears to exhibit no advantage, the lower cost carbon steel option was chosen for the final design.

3.11.2 Hydrocarbon Condenser

The hydrocarbon condenser will have binary fluid hydrocarbon on the shell side. Carbon steel will provide a design life in excess of 30 years for the shell side.

The tube side of the exchanger will also be exposed to plant cooling water. Carbon steel, Admiralty and titanium were considered for this service.

Industry experience in the Imperial Valley indicates, with the best cooling water treatment systems available, a 6-7 year life could be expected for carbon steel tubes. Water quality requirements proposed to be imposed on the Heber plant will not allow the use of an effective carbon steel corrosion inhibition system. Carbon steel tube life under the proposed water quality standard would be considerably less than on year. Both Admiralty and titanium tubes are expected to have a service life in excess of 30 years, even with the regulated substandard water treatment system.

The heat exchanger costs for a carbon steel shell exchanger with Admiralty tubes is approximately 1.4 times higher than for a carbon steel tube unit. Titanium tubes increase the premium to approximately 2.5 times higher than an all carbon steel unit.

In order for the lower capital cost of an all carbon steel unit to be economically competitive with an Admiralty tube unit, an expected life of 17 years would be required at a 15 percent carrying charge. A 15 year expected life would be required at a 23 percent carrying charge. Because the required economical life cannot be met, carbon steel was dropped from further consideration.

Both Admiralty and titanium will satisfy an estimated life requirement of 30 years. The initial cost of the Admiralty tubed carbon steel exchanger is considerably less than a similar unit with titanium tubes. The Admiralty tubed carbon steel shell exchanger was therefore selected for the final design.

3.12 TURBINE PIPING ECONOMICS

During a review of the EPRI/Holt conceptual/feasibility studies it became apparent that the turbine exhaust piping configuration could significantly affect cycle performance. One psi (7 kP) of pressure drop between the turbine exhaust flange and the condenser inlet has an equivalent annual cost impact of $47,000. Several factors contribute to the problem of minimizing this effect as follows:

- The need for very large hydrocarbon condensers operating at elevated pressure and temperature to reject approximately 90 percent of the heat energy input to the plant.

- Very large diameter (up to 74 inches or 1.9 meters) exhaust piping to handle required hydrocarbon circulation under thermally induced stress forces.

- Safety hazards associated with a system containing a large volume of flammable fluid under pressure.

These considerations established the need to optimize factors influencing the relationship between plant costs and energy consumption. They are influenced by:

- Turbine deck height
- Piping configuration
- Use of expansion joints
- Radial versus axial turbines
- Number of condenser shells

3.12.1 Study Case Descriptions

Six cases (identified herein as A through F) were selected for investigation(18), five involving an axial flow turbine and one involving a radial flow turbine. "Case A" reflects the equipment selections and piping configurations established in the EPRI Phase I study. Following is a brief description of each case.

"Case A"

This case was developed using an axial flow turbine and the Phase I conceptual study. The equipment elevations correspond to the Holt design. The equipment was relocated to improve piping layout and access requirements. In the Phase I study, eight (8) hydrocarbon condensers are located above four hydrocarbon accumulators, exhaust piping block valves are employed at the condensers, and the exhaust piping is connected to top inlet nozzles on the condensers. Thermal expansion of the piping is accommodated by the piping configuration. The condenser location above the accumulators set the turbine deck height at approximately 45 feet (14 meters) above grade.

"Case B"

This case is also based on an axial flow turbine and the Phase I study. However, the condensers have been reduced in number from eight to four and have been located as close to grade as possible. The exhaust piping is manifolded above the condensers and the block valves are eliminated. Deletion of the block valves in the exhaust piping and the location of the condensers at grade reduces the turbine deck height to 35 feet (14.3 meters) above grade. The piping configuration will accommodate thermal expansion.

"Case C"

This case is based on an axial flow turbine and two (2) hydrocarbon condensers with side inlet nozzles. The hydrocarbon condensers are located as close to grade as possible. Because of the size of the hydrocarbon condensers 15 feet (4.5 meters) in diameter by 80 feet (32.7 meters) long, shipping could be a problem. The turbine deck height is lowered to approximately 27 feet (11 meters) above grade, which is set by the condensers close location to grade and the use of side inlet nozzles. The piping thermal expansion is accommodated by the piping configuration.

"Case D"

Three preliminary studies were conducted using expansion joints in the exhaust piping to accommodate thermal expansion. This case reflects the best of these and has one expansion joint in each exhaust line at the turbine nozzle. The expansion joints allow the hydrocarbon condensers to be located very close to the turbine generator structure. This case uses an axial flow turbine and two condensers with inlet connections on the side. As in "Case C" the size of the condensers will create shipping problems. Because of the condensers being located close to grade with side inlet nozzles, the turbine deck height will be about 29 feet (9 meters) above grade. This elevation is 2 feet (0.6 meters) higher than "Case C," because of the expansion joint overall length. The exhaust piping configuration is reduced significantly with the use of expansion joints.

"Case E"

"Case E" is based on an axial flow turbine and 4 hydrocarbon condensers with side inlet nozzles. It appears that the condensers for this case will be at least two or three feet (0.6 or 0.9 meters) smaller in diameter than for Cases C, D and F. This will reduce the problem of shipping. The turbine deck height is approximately 20 feet (6 meters) above grade with minimum turbine exhaust piping and the condensers located as close to grade as possible.

Thermal expansion is accommodated by piping configuration.

"Case F"

This case is based on a radial flow turbine with three (3) hydrocarbon condensers in the exhaust piping. Three shells were chosen to match the turbine exhaust flow pattern. The inlet nozzles are on the side of the condensers. The condensers for this case are larger in diameter than in "Case E." The turbine deck height is approximately 21 feet (6 meters) above grade with the condensers located as close to grade as possible and with the minimum turbine exhaust piping. Thermal expansion is accommodated by piping configuration.

These cases are summarized in the following table:

TABLE 3.12.1
TURBINE PIPING CASE SUMMARY

Case	A	B	C	D	E	F
Turbine						
Style	Axial	Axial	Axial	Axial	Axial	Radial
Deck Height	45 Ft (14 M)	35 Ft (11 M)	27 Ft (8 M)	29 Ft (9 M)	20 Ft (6 M)	21 Ft (6 M)
Condensers						
Number	Eight	Four	Two	Two	Four	Three
Location	Above Grade	At Grade	At Grade	At Grade	At Grade	At Grade
Nozzle Orientation	Top	Top	Side	Side	Side	Side
Piping						
Expansion Joints	No	No	No	Yes	No	No
Block Valves	Yes	No	No	No	No	No
Pressure Loss	2.19 psi (15 kP)	2.60 psi (18 kP)	1.77 psi (12 kP)	1.32 psi (9 kP)	2.29 psi (16 kP)	0.92 psi (6kP)

3.12.2 Economics

A cost comparison of the six cases is tabulated in the following tables:

TABLE 3.12.2A

TURBINE PIPING CAPITAL COST COMPARISON

Capital Costs (Direct Field Costs, Dec.' 77 Dollars)

Case	A	B	C	D	E	F
Piping	$ 856,000	$ 810,000	$ 732,000	$ 759,000	$ 792,000	$ 762,000
Expansion Joints	N/A	N/A	N/A	124,000	N/A	N/A
Condensers	3,600,000	3,250,000	3,078,000	3,078,000	3,250,000	3,178,000
Total	$4,456,000	$4,060,000	$3,810,000	$4,061,000	$4,042,000	$3,940,000

TABLE 3.12.2B

TURBINE PIPING ANNUAL COST COMPARISON

Annual Costs (Dec. '77 Dollars)

Case	A	B	C	D	E	F
Fixed Chgs. @15.21%	$ 632,660	$ 621,990	$ 583,690	$ 622,150	$ 619,230	$ 603,610
*Performance Penalty	102,930	122,200	831,190	620,040	107,630	43,240
Total	$ 785,590	$ 744,190	$ 666,880	$ 684,190	$ 726,860	$ 646,850

*At $47,000/year/psi ($6,714/year/kP) pressure loss

3.12.3 Results and Conclusions

Results:

- The radial flow turbine ("Case F") has the lowest annual cost impact as compared with five axial flow turbine exhaust system configurations.

- "Case C" employing two hydrocarbon condensers has the least annual impact among the five axial flow turbine configurations evaluated.

Conclusions:

- Piping and layout problems are about the same regardless of the type of turbine employed, and the differential cost impact is minimal.

- In order to maintain exhaust flow symmetry (thrust balance) two or four condenser shells are required for the axial turbine while three or six shells are necessary for the radial turbine.

- Because of weight limitations, the use of two or three condenser shells will necessitate field tubing.

- The large diameters of the two and three shell condensers may involve special transportation problems.

- Any one of the cases studied can be accommodated on the proposed site.

- A turbine deck height on the order of 20-30 feet (6-9 meters) is feasible.

- There is no economic incentive to use expansion joints in the exhaust piping.

- Bottom outlet turbine exhaust connections are preferred in order to avoid interference with the gantry crane and to avoid the need of major pipe removal for turbine maintenance.

Subsequent to the completion of this study, an additional case was evaluated involving locating the turbine generator at grade and employing top exhaust connection(s) from the turbine. The performance penalty for this case corresponds closely to Case B.

The capital cost is reduced by approximately $75,000 through the elimination of the turbine pedestal. However, this has only a minor effect on the fixed annual cost and does not change the above noted results and conclusions.

This case presents several disadvantages including:

- The need to dismantle large piping for turbine maintenance combined with the added cost and hazards of employing breakout flanges.

- Piping arrangement layout problems to allow gantry crane access for turbine and generator maintenance.

3.13 TURBINE-GENERATOR DEVELOPMENT

The optimized baseline design turbine-generator performance requirements are highlighted below. Also, the development work performed for EPRI by Elliott and Rotoflow, and the proposed use of two half-capacity turbines is briefly summarized.

3.13.1 Turbine-Generator Performance Characteristics

- Gross Output: 65 MW_e
- Synchronous Speed: 1800 or 3600 rpm
- Working Fluid: isobutane/isopentane (90/10 mol percent)
- Approximate Throttle Conditions: 575 psia (3,965 kPa) and 305°F (152°C)
- Estimated Full Throttle Flow: 7.8×10^6 lbs/hr (3.5 Mkg/h)
- Estimated Turbine Efficiency: 83 percent
- Generator Output: 65 MW_e at 13,800 volts, 3-phase, 60 hertz
- Generator Cooling: Hydrogen
- Turbine Options: axial flow or radial inward flow machine with single or multiple cylinders.

3.13.2 Axial Flow Turbine Study

The Elliott Company performed a study for EPRI to evaluate an axial flow turbine design for geothermal applications(12). A brief summary of this study follows:

- A 65 MW_e turbine-driven generator is feasible for the hydrocarbon mixtures anticipated for the Heber plant.

- The turbine considered is a single cylinder, double flow, three stage, 3600 rpm machine directly coupled to a 13,800 volt, two pole, hydrogen-cooled generator.

- The turbine is designed to operate within the superheat region of the Mollier charts for 80/20 isobutane/isopentane and 90/10 isobutane/propane mixtures.

- No new materials of construction would be required.

- Turbine aerodynamics are subsonic, and the stages are adapted from gas and steam turbine vane profiles.

- Well proven turbine shaft seal designs are available that will keep the gas within the system and avoid hazardous leakage conditions.

- Control schemes are based on current practices. Further studies of control response requirements are recommended.

3.13.3 Radial Inflow Turbine Study

The Rotoflow Corporation performed a study for EPRI to evaluate a radial inflow turbine design for geothermal applications(13). A brief summary of this study follows:

- An inward radial flow hydrocarbon turbine is feasible for the Heber plant.

- The turbine considered uses a 50-inch (1.3 meter) diameter double wheel installed in a horizontally split cylinder with single inlet and exhaust connections. The turbine drives a generator operating at 3600 rpm, 13,800 volts delivering 65 MW_e.

- The radial inflow blade design would be optimized for the binary fluid selected. Rotoflow maintains that the blade design can accommodate expansion through the wet regions of the Mollier charts without mechanical problems.

- Scaleup of wheel size is required from a single wheel, 10,000 horsepower (7.5 MW) design to the 2-wheel, 87,000 horsepower (64.8 MW) design required for Heber.

- This turbine uses high strength, journal-type bearings, thrust load control on thrust bearings, and stiff shaft construction.

- Control system components used are consistent with performance of conventional steam turbine controls.

3.13.4 Half Capacity versus Full Capacity Turbines

From the conceptual design studies performed for EPRI by the Elliott Company and the Rotoflow Corporation, it appears that both turbine concepts (axial and radial) are technically viable but unproven in the commercial size established for the Heber plant. In keeping with the project objectives, operation of a large machine is, therefore, needed to establish commercial acceptance.

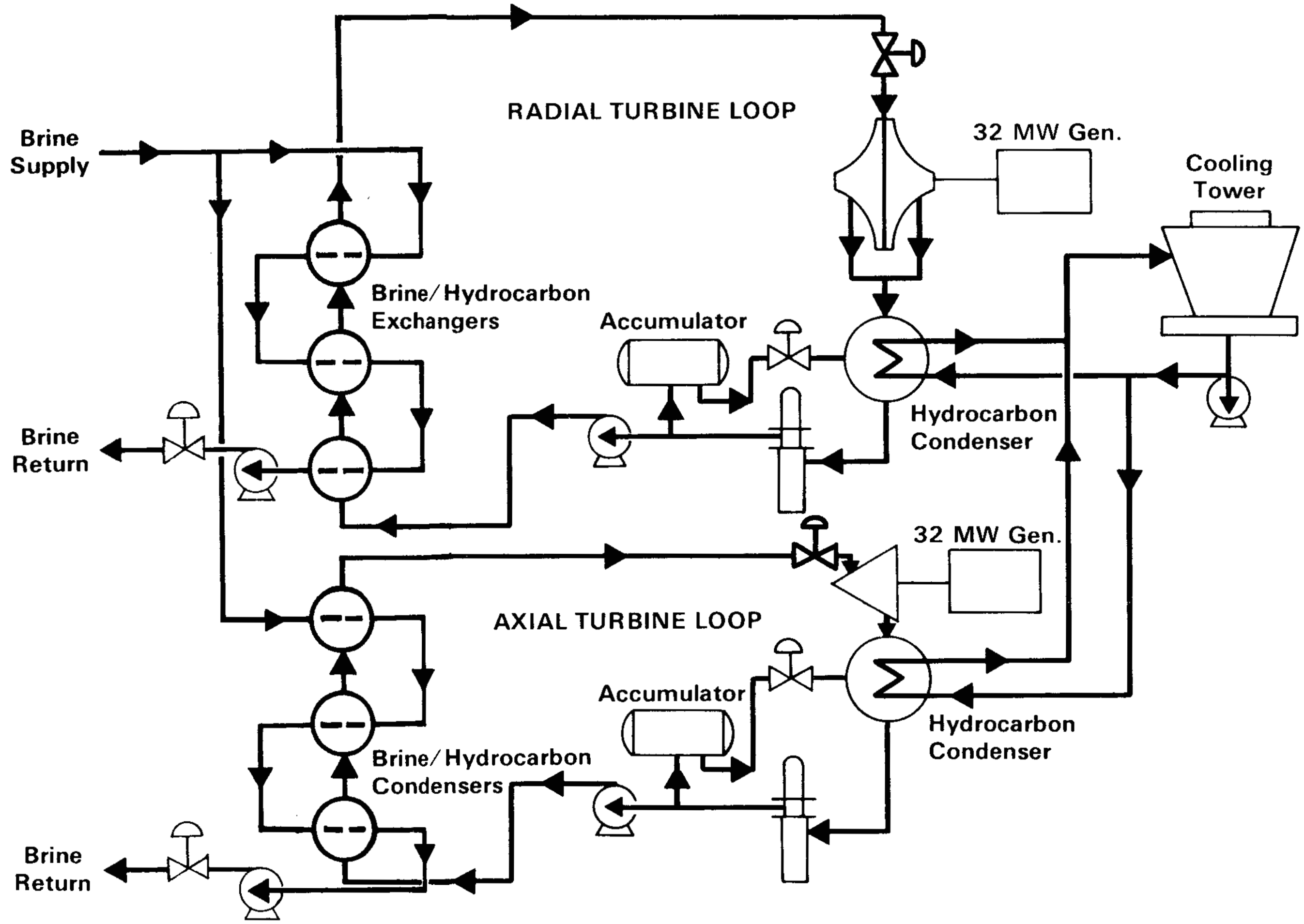
Under the project ground rules, one turbine will be purchased for installation in the plant. Thus, only one turbine concept (axial or radial) would be demonstrated. To avoid this problem, consideration was given to an alternative plant design involving the use of two half capacity turbine generators (one axial and one radial) each with its own hydrocarbon loop and controls(17). This concept is shown on Figure 3.13.4A.

The advantages of this concept are:

FIGURE 3.1 3.4A

HEBER GEOTHERMAL DEMONSTRATION POWER PLANT

POWER CYCLE SCHEMATIC - TWO HALF CAPACITY T-G UNITS



- Failure Risk Mitigation: If one turbine experiences extended problems and is inoperable, plant operation can be continued.

- Additional Data Available: Both turbine concepts are demonstrated.

- Operational Flexibility: Plant can be operated on either turbine or with one turbine load-blocked while the other one is subjected to experimental testing.

Disadvantages are:

- Turbine Capacity: Machine size would be well below commercially attractive capacity and not fully representative of a commercial size unit.

- Plant Complexity: Two train concept would involve more equipment to operate and maintain, and would make operational control more complex.

- Costs: The economy of scale is in the direction of high cost intensity resulting in a plant capital cost impact in the order of 15 to 20 percent.

Because of the cost intensity of two half capacity turbines, a decision was made by SDG&E to use one full capacity turbine generator unit.

Section 4

COST ANALYSES AND SCHEDULE

This section describes the total Project Schedule and depicts the overall project execution plan in barchart form with major milestones identified. The results of economic studies and busbar cost of power are also presented based on the program logic reflected in the Project Schedule.

4.1 PROJECT SCHEDULE

The schedule prepared in January, 1978 had a target completion date for the power plant of mid-1981. This completion date was extended one year in order to secure cost sharing from the Department of Energy (DOE) geothermal commercialization program (Expression of Interest and Program Opportunity Notice). DOE announced in July, 1978 that the Heber project would not receive federal funding. However, if the Heber binary cycle project had been selected, process engineering/design and procurement activities would have commenced in September, 1978. The current Project Schedule was developed assuming the initiation of these activities in September, 1978.

The major activities and milestones of each phase are depicted on the Project Schedule shown in Figure 4. The schedule represents the overall project plan in barchart form. The basis for the project plan are the individual work packages and critical path schedules developed for the project scope of work. This schedule reflects a completion window that begins with detailed mechanical systems engineering in September, 1978, and ends with construction mechanical completion and start-up in early 1982 with operation by July, 1982.

The current Project Schedule was developed to accommodate major involvement by SDG&E Engineering in the development and review of mechanical system packages. For this reason the critical path schedule flows through the completion of systems engineering, the release of major equipment procurement, and the receipt of vendor data to sustain the detailed design development and not through major equipment deliveries. The turbine generator unit is anticipated to have the longest delivery (20 to 24 months).

The economic evaluations described in the remainder of this section employed the schedule logic and representative time periods presented in Figure 4.

4.2 CAPITAL COST ESTIMATE

The installed investment for the power plant will include direct and indirect capital costs. The total capital investment represents the capital necessary to install the process equipment with all auxiliaries that are needed for complete plant operation. The direct capital costs involve the expenditures in the areas of project implementation and planning, licensing and environmental, engineering/design and procurement, construction, and start-up. The indirect capital investment is composed of escalation and allowance for funds during construction (AFDC) accumulated prior to plant operation.

Various levels of detail can be employed for estimating capital investment. The preliminary or predesign cost estimate developed for this report is based on sufficient data to permit the estimate to be budgeted with a probable accuracy of ±20 percent. This type of estimate is important because it permits comparison of alternative designs. The project employed a work breakdown structure to define and control the work plan. Each major work breakdown element defined all of the tasks necessary to accomplish an identifiable scope of work. The Project Implementation and Planning element included SDG&E project management functions, including the technical, financial and scheduling aspects. The Licensing and Environmental element was composed of the SDG&E effort concerning licensing, permitting and environmental impact reporting. The Engineering/Design and Procurement element involved optimization studies, preliminary and detailed engineering/design and procurement as performed by Fluor Engineers and Constructors and SDG&E. The Ben Holt Company also provided engineering support services to the technical efforts. Construction management and erection of the facility to be done by Fluor Engineers and Constructors and SDG&E comprised the construction element. The start-up element involved the plant checkout and start-up to be done by SDG&E.

Preliminary estimates of the major cost elements of the project are as shown in Table 4.2. The fixed costs are depicted in 1977 dollars and include a 15 percent contingency for all elements except for construction which has a 20 percent contingency. Equipment and materials costs include California sales tax at 6 percent.

FIGURE 4
PROJECT SCHEDULE

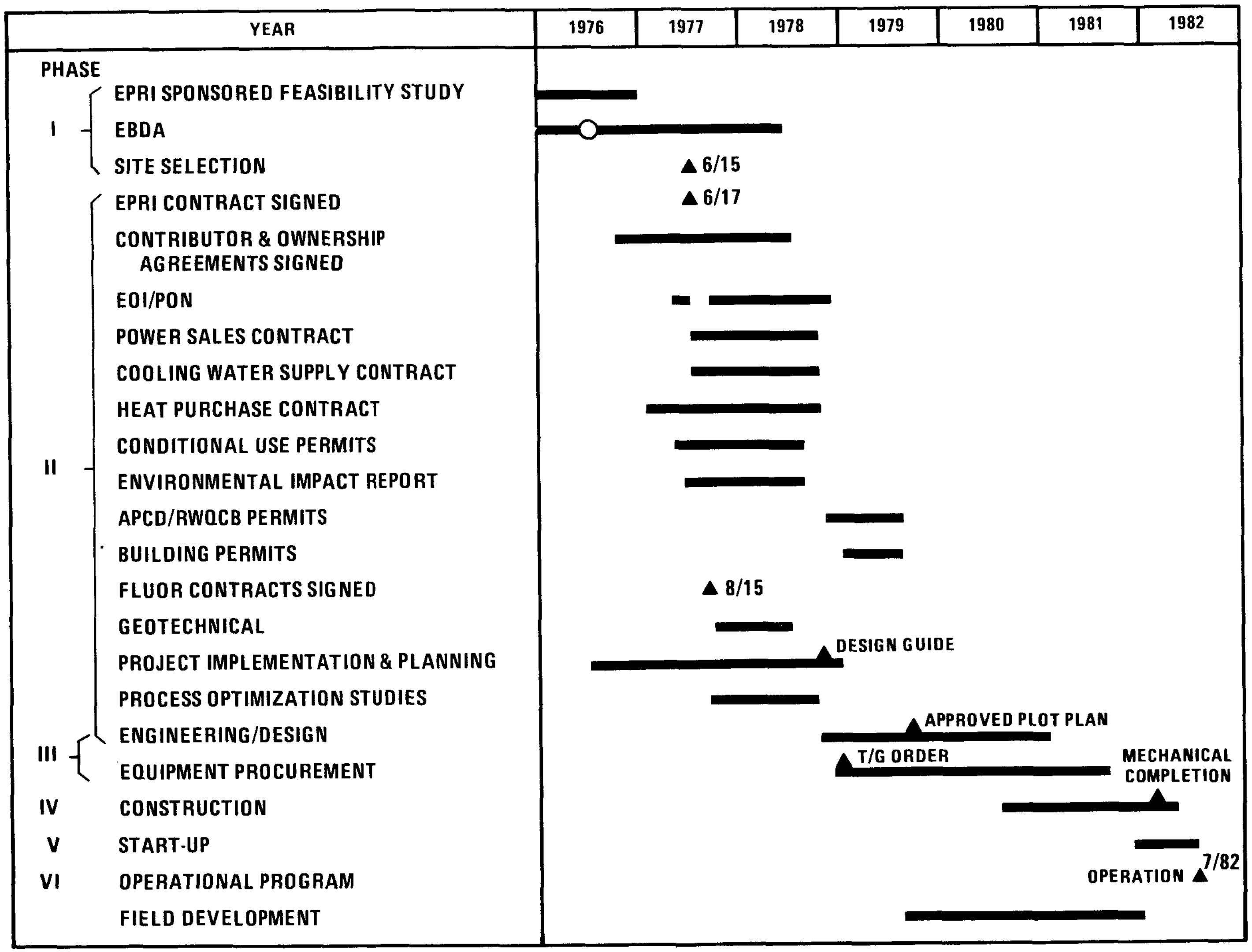


TABLE 4.2
CAPITAL COST ESTIMATE
($*Million)

Project Implementation and Planning	0.92	
Licensing and Environmental	0.16	
Engineering/Design and Procurement	5.96	
Construction	29.63	
Start-up	0.58	
Brine Injection Line	1.45	
Direct Cost:	$38.70	($860/kw)
Escalation	10.89	
AFDC	4.99	
Installed Cost:	$54.58	($1213/kw)

Notes:

(1) Direct costs in 1977 dollars.
(2) Direct cost elements include contingency of 15% except construction which is 20%.
(3) Escalation rates are 8% for labor and 6% for material.
(4) Includes 6% California sales tax on equipment and material.
(5) Net capacity: $45MW_e$ to IID distribution system.

The brine injection line has been included as a separate element in the direct cost estimate. It had been proposed that the project pay all costs associated with the design, engineering, and construction of the pipeline in exchange for a favorable reduction in the price of geothermal heat from the reservoir operator. The corresponding pricing agreement is discussed in more detail in Section 4.3.

The total fixed capital investment for the power plant amounts to $38.70 million in 1977 dollars. This represents $860/kw for a 45 MW_e (net) binary power plant to be operational in 1977.

The fixed costs are estimated from cost data available for immediate use - 1977 base year. Because equipment and material prices change considerably with time, an escalation component has been included to correctly represent the installed capital cost. The $10.89 million escalation component of the indirect costs is based upon SDG&E's corporate estimates for increases in labor and material indices experienced on other construction activities. These annual rates are 8 percent and 6 percent for labor and material, respectively.

The last element of the capital cost estimate is the allowance for funds during construction (AFDC) component of the indirect costs. AFDC, also termed interest during construction, represents the carrying costs accumulated on expenditures from initiation until operation of the power plant and amounts to $4.99 million. The allowable rate varies from 6 to 7 percent per annum during this period of time based on SDG&E's financial condition.

The total installed capital cost for the power plant is estimated to be $54.58 million and is based on the schedule logic discussed in Section 4.1 and the financial conditions associated with a private utility. This represents $1213/kw for a 45 MW_e net binary plant to be operational in mid-1982.

4.3 OPERATION AND MAINTENANCE (O&M) COSTS

The cost of operating and maintaining the power plant is directly connected with the production of electricity and, therefore, included in the busbar cost of power. These expenses, as considered here, are divided into three classifications as follows: 1) fixed costs, 2) variable costs, and 3) energy costs. The fixed and variable costs have been estimated based on SDG&E's current staffing for its oil-steam power plants, as modified to reflect the experience gained in operating the Niland Geothermal Loop Experimental Facility. Energy expenses are based on the negotiated agreements with the heat supplier, Chevron Resource Company.

The annual fixed O&M costs include a considerable amount of expense for operation and maintenance to keep the plant in efficient operating condition. These expenses include supervisory, clerical and operating labor; maintenance labor; overhead on labor involving medical services, employee benefits and social security; maintenance materials; accruals for major overhauls; and general items such as insurance and property taxes. Maintenance materials have been estimated by multiplying the installed capital cost by 0.7 percent. Major overhaul costs are based on a 30 day overhaul every two years. The breakdown of the fixed expenses is shown in Table 4.3A, and it totals $1,607,000 in 1977 dollars.

TABLE 4.3A

SUMMARY OF OPERATION AND MAINTENANCE COSTS

(1977 Dollars)

Annual O&M Costs		
Fixed Costs		
Direct Labor - Operation	$ 340,000	
Maintenance	125,000	
Subtotal	$ 465,000	
Administrative and General @ 110%	512,000	
Total Labor	$ 977,000	
Maintenance Materials		
- Annual	$ 380,000	
- Major Overhauls	250,000	
Total Materials	$ 630,000	
TOTAL FIXED COSTS	$1,607,000	$1,607,000
Variable Costs		
Operation Materials	$ 390,000	
Typical Plant Capacity Factor - 70%		
Total Variable Costs (0.70 x $390,000)	$273,000	$ 273,000
TOTAL O&M COSTS		$1,880,000

Variable costs include estimates for the cost of cooling water and operating supplies which reflect the long-term capacity factor of the plant. Cooling water makeup diverted from one of the fresh water canals would be purchased from the Imperial Irrigation District and amount to approximately $320,000 for 5300 acre-feet (6.54 MM m^3) annually. (The unit price reflects anticipated increases to be applied to industrial activities in the Imperial Valley.) The cost estimates reflect continued use of fresh water because no engineering has yet been performed on the use of alternative sources. Operating supplies are the many miscellaneous materials needed to keep the plant functioning efficiently such as charts, lubricants, water treatment and test chemicals, and office supplies. The total variable expenses are estimated to amount to $370,000 per year at full load. Based on a long-term capacity factor of 70 percent, the total annual variable O&M costs would total $273,000 in 1977 dollars as indicated on Table 4.3A.

The total fixed and variable O&M costs amount to $1,880,000 annually. These costs are estimated to escalate at 7 percent per annum from the 1977 base year.

The project would have purchased geothermal heat energy from the reservoir developers, represented by Chevron Resources Company. The exact terms and conditions of the heat purchase agreement have not been completed as yet; however, an agreement has been reached as to the pricing method that will be used.

The "fuel" or energy charge would be separated into fixed and variable portions. The fixed portion would be paid regardless of the capacity factor achieved by the plant and represents a minimum fuel charge. The variable portion would be paid in direct relation to fuel used; i.e., to the capacity factor achieved by the plant. The total fuel charge would be the sum of the fixed and variable charges. In addition, both portions would escalate from mid-1977 according to rates based on U.S. Government - compiled statistical indices. The basis for the pricing agreement, with SDG&E's estimates of escalation rates, is shown in Table 4.3B.

TABLE 4.3B

BASIS FOR PRICING OF GEOTHERMAL ENERGY

Base Heat Price[1]:	$\$0.66/10^6$ Btu extracted from brine	
Base Year:	Mid-1977	
Fixed[2] and Variable Charge Percentages:	First two years:	50% fixed 50% variable
	Thereafter:	75% fixed 25% variable
Escalation Estimate:	Fixed charge:	7% per annum
	Variable charge:	9% per annum

NOTES:

(1) Assumes injection pipeline included in power plant capital costs.

(2) The fixed fuel charge is calculated as the given percentage of the fuel charge that would be paid if the plant were to operate at 100 percent capacity.

The heat purchase agreement specified that the power plant would supply electrical power to the brine production facilities primarily for the downhole pumps. This capacity would be included in the station auxiliaries requirements.

The energy usage would be metered and a credit applied to the fuel charges. The average annual credit is estimated at $2.7 million based on a long-term capacity factor of 70 percent.

4.4 BUSBAR COST OF POWER

Business enterprises employ various methods for comparing alternative proposals involving the receipt or expenditure of money. SDG&E has elected to measure levelized revenue requirements as its method of comparing the financial effects of proposed projects. This method has the advantage of allowing the comparison of alternatives involving costs that differ in timing or amounts or both. This levelized revenue requirement is developed by restating costs through discounting methods to an annuity over a certain predetermined period.

For a power plant, revenues are required to recover fuel and O&M costs, pay all taxes, depreciate the capital investment, and provide a return on that investment at SDG&E's rate of return. Power production costs must be normalized to allow comparison of power plants of different size. A unit cost of power (in mills/kwh) is simply the total revenue requirements for a year divided by the amount of electrical energy generated in that year. Since the costs of operating the plant will be continually rising due to escalation, and continually varying because of changes in capacity factor, the yearly busbar cost of power will not be constant. Therefore, to compare different generation alternatives, the levelized unit cost of energy is determined by first discounting the annual revenue requirements, and dividing by the appropriate annuity factor. The resultant value is the levelized revenue that must be earned in each year of the plant's operating life to recover capital costs, and to pay all taxes, fuel and O&M costs. Dividing this levelized revenue requirement by the levelized energy generated annually yields the levelized unit cost of production.

The financial parameters utilized to calculate the revenue requirements are SDG&E corporate assumptions and are tabulated in Table 4.4A. The primary parameters used in developing the busbar cost of power from the plant have all been discussed previously and are shown in Table 4.4B. The resultant levelized busbar cost is 137 mills/kwh. This is the total of the components representing heat (62 percent), O&M (15 percent), and plant capital (23 percent). The first year (1982) cost at a 40 percent capacity factor is 95 mills/kwh; if a 75 percent capacity factor could be achieved, the busbar cost would be reduced to 64 mills/kwh.

TABLE 4.4A

FINANCIAL ASSUMPTIONS USED IN
DETERMINING REVENUE REQUIREMENTS

Book Depreciation Life (years)	30
Federal Tax Depreciation Life (years)	15
State Tax Depreciation Life (years)	15
Debt Ratio (%)	50
Common Stock Ratio (%)	35
Preferred Stock Ratio (%)	15
Cost of Debt (%)	9.0
Rate of Return on Common Stock (%)	14.5
Rate of Return on Preferred Stock (%)	9.0
Federal Tax Rate (%)	46.0
State Tax Rate (%)	9.0
Property Tax Rate (%)	1.0
Investment Tax Credit (%)	5.0
Discount Factor (%)	10.93

TABLE 4.4B

BUSBAR COST OF POWER

Assumptions:

Power Level	45 MW_e (net)
Installed Cost	$54.58 million
Operational Date	July, 1982
Capacity Factor (yearly)	40%, 50%, 60%, 70% there-after
Operating Life	30 years
Heat Cost (1977 $)	
Base Price	$0.66/mm Btu
Fixed Portion (yearly)	50%, 50%, 75% there-after
Escalation (fixed and variable)	7% and 9%
O&M Costs - Excluding Energy (1977 $)	
Base Cost	$1.88 million/year
Escalation	7%

Levelized:

Heat Cost	(62%)	85 mills/kwh
O&M Cost	(15%)	20
Plant Capital Cost	(23%)	32
Base Busbar Cost	(100%)	137 mills/kwh

The 1977 busbar cost from the power plant would be approximately 45 mills/kwh (in 1977 constant dollars) with a capacity factor of 75 percent. This compares with nuclear energy busbar costs of 25 mills/kwh and oil-fired costs of 33 mills/kwh (also 1977 dollars and 75 percent capacity factor). If escalation effects are integrated into the cost estimates, the cost of energy from the geothermal power plant becomes competitive with comparable oil-fired generation costs in the late 1980's. This transition is primarily due to the fact that the fuel contribution to the busbar power costs for the geothermal power plant is 62 percent and escalates at a (negotiated) composite rate of 7 to 9 percent; while for an oil-fired power plant, the fuel contribution is 84 percent and escalates at a rate of 9 to 10 percent. However, nuclear energy costs escalate at a slower pace than oil fired costs, because the fuel component of nuclear busbar cost is a smaller fraction of the whole, and geothermal costs at Heber do not gain an advantage relative to nuclear costs.

Sensitivity studies on the 137 mills/kwh base busbar costs of power were performed by varying the primary parameters. The results are summarized in Table 4.4C. As expected, the parameters which influence the heat component (62 percent of the base levelized cost) have the greatest impact. These impacts are 8 to 9 mills for a 10 percent change in the base heat price, 12 to 15 mills for a plus or minus change of 1 percent in the heat escalation rates and 10 to 15 mills for a plus or minus change of 10 percent in the long-term capacity factor. The parameter which has a surprisingly small influence is the installed cost of the power plant. A 10 percent variation in that cost has only a 3 mill impact on the busbar cost.

TABLE 4.4C

SENSITIVITY OF BUSBAR COST (MILLS/KWH)

Levelized Busbar Cost	137
Base Heat Price	
Plus 10%	146
Minus 10%	129
Heat Escalation Rates	
Up 1%	152
Down 1%	125
Long Term Capacity Factor	
60%	152
80%	127
Economic Life	
20 years	124
Reservoir Temperature	
Constant 360°F (182°C)	133
Installed Cost	
Plus 10%	140
Minus 10%	134

Section 5

REMAINING TECHNICAL ISSUES

The design of the Heber power plant systems and equipment will be accomplished, for the most part, using existing state-of-the-art technology. Design aspects requiring special study based on requirements peculiar to the Heber facility have been studied in detail.

Feasibility studies, development tests and optimization studies have been performed for these site-specific design aspects. The studies are discussed in Section 3, Optimization Studies, and the outstanding problems with related solutions are summarized below.

5.1 TURBINE-GENERATOR DESIGN

The hydrocarbon turbine is a key element in the binary conversion process system. Many relatable designs exist, but a unit of the size selected for the Heber plant, using the specific binary fluid, has not been previously built.

The feasibility studies performed by the Elliott Company and Rotoflow Corporation (Subsection 3.13) indicate high confidence in the design, manufacture, and operation of a unit to meet Heber requirements.

The axial-flow turbine design would be based on principles used in design of existing steam turbines and centrifugal and axial hydrocarbon compressors. The radial inflow hydrocarbon expander design would be based on existing commercial equipment in the gaseous fluid turbo-expander field.

Some uncertainty remains relative to thermodynamic behavior of the hydrocarbon working fluid as it is expanded through the turbine and condensed. However, the C.F. Braun enthalpy bench tests(19) have served to minimize this problem. As discussed in Subsection 3.5 (Power Cycle Optimization) the BWR equation of state correlates well with the laboratory data and with the equations of state employed by Elliott Co. and Rotoflow and will be used by Fluor/Holt for the detailed design of the power cycle.

Based on the foregoing, expansion through the Mollier diagram wet regions is unlikely. However, both Elliott (axial) and Rotoflow (radial inflow) contend that some moisture can be accommodated with no noticeable effect on turbine performance.

Other design features that have been handled successfully in other applications but require demonstration for this application involve turbine shaft sealing and turbine speed/load control governor systems. Also, in the case of the radial turbine, size/capacity scaleup is a factor. At this time, the largest wheel diameter in service is in the order of 12 inches (0.3 meters). However, machines having a wheel diameter up to 53 inches (1.3 meters) are in production and will have been operated in advance of the Heber schedule. The turbine would require a wheel diameter in the range of 50 inches (1.3 meters).

The plan is to issue a performance specification for procurement of the turbine-generator set to obtain competitive bids. The turbine performance will be specified in terms of inlet/outlet temperatures and pressures and the gross generator output specified. The bid responses will be evaluated to determine the machine most suitable for the power plant, taking into account both capital cost and operating efficiency.

Three suppliers indicate willingness to furnish the turbine generator required for the power plant. They have expressed interest in submitting commercial competitive quotations with guarantees for meeting specified mechanical and performance criteria.

5.2 HYDROCARBON CONDENSERS

Subsection 3.12 (Turbine Piping Economics) discusses the sensitivity of turbine exhaust piping configuration and condenser arrangement on plant performance. Much of the problem stems from the large amount of heat transfer surface (approximately 1.15 million square feet (106,835 square meters) required to reject approximately 90 percent of the heat energy transferred from the geothermal fluid to the binary working fluid to a cooling tower.

As seen from the results of the above referenced study (Subsection 3.12), the optimum turbine exhaust system configuration involves two condenser shells and a single side stream hydrocarbon accumulator vessel. The conceptual study(3) involves the use of eight condenser shells arranged in groups of two and mounted over four hydrocarbon accumulator vessels arranged in parallel.

A potential problem with the optimum arrangement results from the size and weight of the two condenser configurations. Under this concept, each shell would be in the order of 15 feet (5 meters) in diameter by 80 feet (24 meters) and weigh approximately 450 tons (408 MKg). Preliminary information indicates that rail and highway limitations would necessitate field tubing. There also could be a problem with the shell diameter although indications are this could be handled by highway transport.

A fallback position would be to use a four condenser configuration. This would reduce the shipping clearance problem and possibly allow shop tubing.

Another problem assocaited with the condensing equipment involves the predictability of heat exchange performance. Vapor distribution in this size equipment may become a problem that could materially affect current preliminary sizing and heat transfer effectiveness.

For the above reasons, it is recommended that several alternates be identified at the time of bidding (Phase III) so as to provide a basis for final optimization taking into account transportation problems, the cost of field versus shop tubing, and the impact of heat transfer performance or shell size.

5.3 MATERIALS OF CONSTRUCTION

The selection of appropriate materials of fabrication for the power plant equipment was studied in detail. The studies were mainly addressed to the materials used in the brine supply and cooling water supply systems. Specific tests were performed during earlier studies on materials subjected to flow of Heber brine. Operating data was reviewed for equipment subjected to Colorado River water to assess performance under simulated operating conditions. Material studies are further discussed in Subsection 3.11.

Materials for application within the hydrocarbon binary fluid system are not conidered of a special nature. Materials used for commercial hydrocarbon system equipment will be selected for this service, and performance has been well demonstrated.

5.4 COOLING WATER SUPPLY

SDG&E has an agreement with IID for supplying plant water for the first five years from existing irrigation systems. Arrangements for water supply after five years have been under consideration.

The alternative supply from the agricultural drain water system may require future modifications to the water conditioning system.

Additional study is recommended during Phase III to evaluate the economics of using agricultural drain water and the impact this will have on the plant cooling system and land requirement.

Section 6

ENVIRONMENTAL AND LICENSING STUDIES

The Heber Geothermal Demonstration Power Plant Project, in addition to establishing the technical and economic feasibility of geothermal energy conversion, will be a precursor in the development of licensing and environmental bases for future commercial geothermal plants. Considerable effort has been expended, under the direction of SDG&E, in the development of environmental impact assessment, permits and licenses for this facility.

6.1 ENVIRONMENTAL IMPACT REPORT

Original environmental studies were performed by SDG&E for EPRI(14) and published in February, 1977. This report provided the baseline environmental data for the Heber power plant design.

A draft environmental impact report (EIR) was prepared by VTN Consolidated, Inc., of Irvine, California for the County of Imperial Planning Department and was issued in December, 1977(15).

This draft EIR addresses the impact of:

1. Chevron Resources Company development and utilization of the geothermal resource located in and around Heber, California.

2. Chevron Resources Company construction and operation of a production island, a transportation pipeline, and a reinjection facility to extract heat from the geothermal resource.

3. San Diego Gas and Electric construction and operation of a demonstration facility near Heber that would utilize the heat extracted from the geothermal resource for the production of electrical power.

The description of the Heber power plant used in the EIR is similar to that in Section 2 of this report. The EIR, however, more fully described the hydrothermal fluid production, transmission, and reinjection facilities.

Data presented in the EIR indicates that the Heber anomaly has been rather well defined as to the depth, characteristics, composition, potential, and capacity of the resource. Fifty test wells have been drilled to an average depth of 5500 feet (1,576 meters). Productivity and injectivity test results are reported as favorable to geothermal development. It appears to Chevron that the Heber Reservoir should yield about 400 MW_e of recoverable energy at well depths of 10,000 feet (3,048 meters).

The production island proposed by Chevron would consist of 13 to 14 wells. Six production wells would be drilled to the 2,000 to 4,000 foot (610 to 1,220 meter) levels, six more to the 4,000 to 6,000 foot (1,220 to 1,830 meter) levels and one to the 10,000 foot (3,048 meter) level. Hydrothermal brine from all wells would be manifolded into a single pipeline for transmission to the adjacent power plant.

Chevron proposes that all brine cooled in the power plant process be transported by pipeline to the periphery of the geothermal resource for reinjection into the reservoir at no less than 150°F (66°C). This carbon steel pipeline would be at grade for the two mile run to the reinjection island. It is reported that the line and a trench for containing any leakage would slope towards the reinjection facility. The brine supplier indicates that the cooled brine would be reinjected into the reservoirs consistent with the production pattern. Thus, reinjection wells would be drilled to the same depths as the production wells. It appears that half as many reinjection wells as production wells would be required. Additional pumping may be necessary at the reinjection island to return brine to levels below 4,000 feet (1,220 meters).

All wells, according to the brine supplier, would be drilled during daylight to minimize any possible distraction to the populace. It is proposed to use conventional oil well drilling equipment with proven techniques for preventing leakage of brine and/or gas into the atmosphere.

Shutdown and abandonment of any of the wells would be in accordance with existing California Division of Oil and Gas Regulations.

The EIR describes the existing environment and discusses the mitigations necessary for minimizing the effect of all of the geothermal demonstration facilities upon the environment.

The design of the plant must take into consideration the effect the facility may have upon the physical, biological, and socioeconomic settings of the surrounding area.

The environmental impacts and mitigations for the power plant are discussed below.

6.1.1 Physiography and Topography

The selected site is in the Imperial Valley which is now predominately agricultural in nature. Irrigation water is imported from the Colorado River. All drainage is to the Salton Sea. The design of influent water equipment must be such that large quantities of entrained silt can be removed from the water prior to use in the plant. Facilities for the disposal of these large quantities of silt must also be included in the design. Facility effluents must be suitably treated for discharge into the dead ended Salton Sea. The design must consider the high visibility of the plant from the town of Heber and the effect noise levels and the flare system may have upon the populace.

6.1.2 Seismicity

Earthquake records maintained for the past fifty years indicate that the Imperial Valley/Heber Geothermal Reservoir area is characterized by high regional seismicity. Earthquakes of magnitude 4.5 or less on the Richter Scale are common. Twelve earthquakes of 6.0 or greater magnitude have occurred since 1890. The facility should be designed to remain operable during a seismic event with a 0.29 g peak ground acceleration and remain structurally sound during a 0.7 g peak ground acceleration event. Containment of the hydrocarbon working fluid within the energy conversion equipment and pipng is of major importance. Although no specific data is available for the area around the Heber Geothermal Reservoir, studies performed for other geothermal locations in the Imperial Valley indicate a correlation between microearthquake activity and geothermal anomalies. The Environmental Baseline Data Acquisition Report(14) contains the following statements about earthquakes in geothermal areas of the Imperial Valley:

"Shocks are generally smaller in magnitude and more frequent in geothermal areas than other areas in the same tectonic setting.

Faults related to the microearthquakes often serve as plumbing conduits for circulating brines.

Earthquake focal depths are usually higher in geothermal areas than in outside areas. This implies that microearthquakes are probably related to the geothermal process."

The design of the process must include controls on brine temperature consistent with those limits imposed by the brine supplier. The magnitude of the effect of disturbing the geothermal reservoir conditions is unknown but it appears that some increase in seismic activity may occur. Design conditions for the brine/hydrocarbon process should take into account possible variations of temperature, pressure quality of brine.

6.1.3 Subsidence

Recent data suggests that the Heber area is moving up slightly relative to El Centro but that the dominant motion of the area has been a downward tilting to the north and east. The area is monitored for subsidence. Bench marks must, by law, be established in the geothermal reservoir area. As a measure to minimize subsidence, the design must be such that all of the brine will be returned to the reservoir.

There appears to be no recorded subsidence of the area caused by agricultural operations.

6.1.4 Geology and Geophysics

It appears that no additional design considerations beyond those already discussed are required because of the geology and geophysics associated with the area.

6.1.5 Soils

A detailed investigation of the soil at the selected plant site must be made to develop specific criteria for the design of this facility. Preliminary investigation indicates that special design provisions may be necessary due to the expansive nature of the soils. The surface soils have been under cultivation for some time and may have to be stripped to a depth of 6 inches (0.15 meters). Subsurface soils are generally saturated with water from irrigation or capillary action. The clay soils are essentially saturated at shallow depths and cannot be permitted to dry during construction. Light to moderately loaded structures can probably be supported on continuous foundations. Heavy or vibrating structures will probably require driven pile foundations. The soil may be satisfactory for the construction of leakproof reservoirs. Detailed investigation of proposed reservoir sites, however, may reveal shallow sandy or silt layers that would necessitate stabilization of clay linings or the use of impervious membranes. The corrosion characteristics of the soil are such that preventive measures must be taken for both concrete and steel that may come in contact with the soil.

6.1.6 Hydrology

Annual rainfall averages less than 3 inches (0.08 meters). Localized summer thundershowers have drenched the area with over 5 inches (0.13 meters) of rain in a 49 hour period. Monthly rainfall reached 7 inches (0.18 meters) at the City of Imperial in September 1939. Sheet flow runoffs of up to 6 inches (0.15 meters) experienced in the City of El Centro during a storm in September 1939 are unlikely at the selected plant site because of natural and man-made drainage features. Surface runoff design must be capable of handling water desposited by a severe summer storm similar to the one in 1976. Runoffs from the site would flow to the Salton Sea through normal or man-made drainage features.

Ground water movement is inhibited by the types of soils in the area. Well water yield is poor and of inferior quality. Water for use in the plant would have to come from the irrigation system. The New River channel is about 1.5 miles (2.4 KM) to the southwest of the plant site. The bottom of the channel is about 35 feet (10.5 meters) below sea level whereas the surrounding land lies at 10 feet (3 meters) below sea level. The natural drainage from the plant site is the Alamo River about nine miles east of the site. Local agencies anticipate a maximum flood flow in the New River of about 5000 cubic feet per second (509,700 m^3/hr). The flood rate anticipated for the 100 year storm has not yet been estimated. The New River channel near the plant site is calculated to handle a flow of 112,000 cfs (11.42 MM m^3/hr).

It appears that the design need not consider inundation of the site by flood waters from the New River. Threat of major flooding of the site as a result of irrigation canal malfunction is considered to be remote. Flooding caused by malfunctioning of the agricultural drains is also considered to be remote. Design, however, must await the results of a detailed site investigation prior to finalization. The Colorado River is the source of all irrigation, municipal and industrial water used in the area. Analyses of Colorado River water at Imperial Dam during 1972/73 indicate average figures for the following items; pH - 8.0, sodium (NA) - 145 mg/l, bicarbonate (HCO_3) - 174 mg/l, sulphate (SO_4) - 336 mg/l, chlorine (CL) - 128 mg/l, total dissolved solids 856 mg/l, total hardness - 360. Because of the upward trend in river water salinity, the EPA has established a program for controlling TDS at about 880 mg/l below the Imperial Dam. Water treatment design will revolve about the above analyses.

Effluent from the facility would be discharged into the agricultural drains which flow into the New or Alamo Rivers and thence to the Salton Sea. The water in the agricultural drains contain total dissolved solids (TDS) in the range of 5000 mg/l. The waters in both rivers and the Salton Sea are protected. Although effluent limitations are not in existence at this time, the California Regional Water Control Board, Colorado River Basin issues waste water discharge permits for the area. This Regional Board is active in water quality control and has established nondegradtion as the basic aim. Quality of effluent must be a major consideration in the design of this facility. It is planned to discharge cooling tower blowdown water with less than 5000 mg/l of TDS into these drains. The design must consider the effects that surface runoff and cooling tower blowdown may have upon the quality of water in the agricultural drains.

6.1.7 Climatology

The selected site is in the Southeast Desert Air Basin of California. Prevailing winds are from the west. The rainy season is November through March with an annual average precipitation rate of about 3 inches (0.08 meters) over a period of

16 hours of rainfall. Maximum temperatures reach about 119°F (48.4°C) during the summer. A winter minimum temperature of 19°F (-7°C) was recorded in January 1937 at Imperial. Although monthly mean temperatures for winter run as high as 42.3°F (5.6°C), temperatures of 31°F (-0.56°C) or below were recorded on eleven days for each of the months of December 1974, January and February, 1975. The design of static water piping systems should consider the effect of these temperatures.

Atmospheric stability conditions for the area indicate poor dispersions potential for airborne pollutants especially during the winter months. These climatic conditions should be considered in design of the flare stack and cooling tower. An environmental monitoring station was installed at the selected plant site in mid-June 1976. Data was collected by instrument booms located at elevations of 33 feet (10 meters) and 195 feet (59 meters) above grade for twelve months. This data is available for study when design of the plant commences.

6.1.8 Air Quality

The quality of the air in the Imperial Valley is described as pristine. Dust from agricultural operations appears to be the most prevalent airborne solid pollutant. The predominate sources of gaseous airbone pollutants are motor vehicles and engine driven agricultural equipment. Both the Air Pollution Control District of Imperial County and the California Air Resources Board operate air quality and meterology stations in the area.

Regulations for the district pave been promulgated and various sections are pertinent to geothermal operations. Such regulations concern the:

opacity of emissions;
quantity of dust, fumes or particulate material;
quantity of sulphur compounds;
quantity of combustion contaminants;
discharge of nuisance contaminants;
sulphur content of fuels;
discharges from fuel burning equipment.

Data acquisition programs for determining background quantities of potential contaminants associated with geothermal operations should be complete in time for inclusion in the design of this facility. Such contaminants include hydrogen sulphide, ammonia, sulfate aerosols and traces of metals.

Meeting established and future air quality criteria should be considered during the design of the hycrocarbon brine, coolant, and stationary diesel driven equipment in the facility.

6.1.9 Ambient Sound Levels

In the spring of 1976, five sound measuring stations were established in the area around the proposed jobsite. One station was located near an existing geothermal well in the vicinity of the proposed production wells. Another was located in downtown Heber. The data from all but the station located near the potential jobsite indicates higher noise levels than the L_{DN} 55 dB identified by the EPA as the limit to protect health and welfare. The noise levels at the jobsite location were in the 50 to 55 dB range. Regulatory agencies are active in noise abatement. It appears that noise attenuation should be a design consideration for this facility.

6.1.10 Adverse Impacts

Impacts due to well drilling and operation as well as those adverse impacts identified as unavoidable are now discussed.

Unavoidable adverse biological impacts discussed in the EIR are the loss of acreage for agricultural purposes, the effect of salinity upon adjacent areas and the discharge of heated water to the agricultural drainage system.

Those unavoidable adverse impacts associated with the geological and seismic setting by the EIR are the tectonically induced subsidence, uplift, and horizontal movement of the region.

Hydrologically unavoidable adverse impacts identified in the EIR are the minor contamination of ground water from septic tank drain fields, the minor modifications to drainage patterns during construction, the depletion of available water suppliers by the cooling tower and facility consumption, and the minor effect on agricultural drainage waters.

The EIR discusses the impact of well drilling and well operations upon the air resources of the area. The overall conclusion appears to be that hydrogen sulphide releases to the atmosphere during drilling, well testing, and operations would occur but that the impact upon air quality would be negligible. The report identified those unavoidable adverse impacts upon air resources as: 1) vehicular pollutants; 2) minimal amounts of hydrogen sulphide released from the hydrothermal reservoir; 3) steam plumes as wells are brought into service; 4) and the visibility of the drilling rigs. Some deleterious effects on the environment appear to be unavoidable in spite of anticipated adherence to limits established by the various air quality regulatory agencies.

Although conformance to noise attenuation regulations established by various agencies is anticipated, some environmental deterioration can be expected due to noise that cannot effectively be mitigated.

Several unfavorable adverse impacts upon the aesthetics of the area are identified in the EIR. These are: 1) the short term presence of two 150 foot (46 meter) drilling rigs; 2) the 18 month period of power plant and brine pipeline construction; 3) the intrusion of power plant structures, vapor plumes and additional electrical transmission lines into the local skyline; and 4) the change in character from agriculutural to industrial.

The unavoidable adverse impacts associated with socioeconomic resources by the EIR are identified herein.

Land Use - Long term commitment of agricultural lands for industrial use.

Aesthetic effect upon populace by character of industrial site versus current agricultural nature of the land.

Community Services and Facilities - Some unquantifiable but extra short term demands during drilling and construction activities.

Transportation Systems - Periodic disruptions in traffic patterns and a long term increase in local traffic volume.

The report indicates that no unavoidable impacts have been identified that would adversely effect: Zoning and Community Plans, Population, Local Economy, Housing, Health and Safety, if all applicable codes and regulations are met. It appears that no unavoidable adverse impacts are identified for the cultural resources of the area since no such resources are reported on the proposed sites of the facilities.

The EIR contains an outline of various effluent and environmental measurement and monitoring programs. Programs were undertaken prior to the start of the proposed activity in the areas of biology, geology and seismicity, hydrology, air and noise and socioeconomic and cultural resources. Various programs are identified for operation while project activities are under way.

Biology - Conditions at and around the proposed facilities are such that no further programs appear to be necessary at this time beyond those required for hydrological purposes.

Geology and Seismicity - Monitoring networks will continue to furnish data for subsidence related to fluid production and geothermally induced seismicity.

Hydrology - The Regional Board is expected to establish effluent requirements as well as monitoring and reporting programs for discharges from the facilities.

Air and Noise - Air quality and meterology data acquisition will continue into 1978. An as yet unspecified air quality monitoring program will be performed during the operation of the power plant.

Socioeconomic - Applicable OSHA and NFPA regulations are expected to be met during all phases of drilling, construction and operation of the facilities. Self monitoring by all parties as well as periodic inspections by various governmental agencies are anticipated. Hydrogen sulphide monitoring and pipeline inspection will be conducted by Chevron.

Cultural - No programs are anticipated, but discovery of a cultural resource during site activities may precipitate a program at that time.

The EIR discusses restoration and reclamation plans and policies. It appears that abandoned wells would be sealed off in accordance with existing California Division of Oil and Gas Regulations. Brine transportation pipelines and supports would have to be removed. All above grade equipment and foundations would be removed, contaminated soil replaced, the area leveled to grade and prepared for possible agricultural use.

6.1.11 Conclusions

Alternatives to the proposed power plant and possible future expansion are discussed in the report. These include:

Taking no action or delaying the proposed action;

Implementing the proposed power plant at an alternative location;

Developing alternative project design concepts;

Developing alternative uses of the geothermal resource;

Utilizing alternative energy resources in lieu of the proposed utilizations of geothermal energy resources.

The EIR indicates that the various alternatives discussed are not viable enough to obviate the construction of the Heber power plant and its support facilities.

The EIR concludes that there would be no significant adverse environmental impacts as a result of the Heber power plant and that most of the potential minor impacts could be mitigated. Certification and adoption of the final Environmental Impact Report by Imperial County was approved in June 1978.

6.2 REGULATORY APPROVAL

The California Energy Commission (CEC) resolved that it considered the Heber project a "reasonable concept of promoting geothermal development." Since the plant is less than 50 MW_e, net, it was SDG&E's position that it does not fall within the CEC jurisdiction.

On this basis, the County of Imperial had the role of lead agency in conjunction with its responsibility for regulation of the use of privately owned land, through the issuance of conditional use permits. In order to gain regulatory approval from the County of Imperial, three specific permits had to be approved by the Imperial County Board of Supervisors. These are:

- A zone change application for Geothermal (G) Overlay Zone of 7320 acres (30 million square meters) around Heber;
- A Conditional Use Permit Application to construct and operate the necessary facilities to extract, transport, and inject the geothermal resources; and
- A Conditional Use Permit Application to construct and operate a geothermal demonstration power plant.

The issuance of these permits was dependent upon certification of an Environmental Impact Report in compliance with the California Environmental Quality Act (CEQA).

SDG&E and Chevron worked with the County of Imperial to obtain the permits for this 45 MW_e net plant and, further, to lay the groundwork for future development of the Heber field. Imperial County has pioneered the concept of geothermal zoning by adopting a Geothermal Element to its General Plan. The County, SDG&E, and Chevron took the next step through the preparation of the anomaly-wide EIR for the Heber area.

The significance of the anomaly-wide EIR was its consideration of the impacts associated with development of the anomaly beyond the Heber power plant to approximately 400 MW_e. The EIR was the basis for Imperial County's adoption of a "G-Overlay Zone" for the anomaly. In granting such a zoning application, the County specified the level and manner of acceptable future development of the anomaly. County consideration of the use permit applications for the Heber power plant was held concurrently with the consideration of the "G-Overlay" zoning and all were approved in June 1978.

The EIR will serve as the environmental disclosure required to obtain other permits. They are:

- Air quality permit from the local Air Pollution Control District, as administered by the Deputy Agricultural Commissioner of Imperial County for emissions from the cooling tower and hydrocarbon flare system;

- Building and grading permit from the Chief Building Inspector of Imperial County Department of Public Works;

- Waste water discharge permit from the State of California Colorado River Basin Regional Water Quality Control Board for discharge of cooling tower blowdown to the agricultural drain;

- Health and safety approvals from the Environmental Health Division of the County of Imperial Health Department, and from the Imperial County Fire Marshall;

- Easement and right-of-way agreements from the Imperial County Road Department for access roads with ingress/egress from a county road; and,

- Encroachment agreement for construction of facilities to obtain water for the plant from the Imperial Irrigation District.

Section 7
ESSENTIAL CONTRACTS

7.1 HEAT PURCHASE AGREEMENT

The heat energy purchase agreement to be entered into with Chevron Resources Company provides that Chevron will deliver to the Heber plant a firm contract quantity of useful heat as needed to operate the plant. Brine temperature and pressure conditions at the inlet and exit point of the plant are specified. The exact terms and conditions of the heat purchase agreement have not been completed; however, an agreement has been reached as to the pricing method that will be used. In its present form, the agreement provides for a demand/commodity rate in cents per million Btu's of useful heat for single phase brine flow. This price of $.66/MM Btu is quoted in 1977 base year dollars and will escalate in future years based on U.S. government - complied statistical indices. The demand/commodity breakdown provided for is 50%/50% for the first two years, and 75%/25% thereafter, calculated at 100% plant capacity factor.

The cost of electric power for operation of the production wells and brine reinjection to the reservoir is included in the base cost of energy. Chevron will operate and maintain the brine supply and injection facilities including pipelines and will be responsible for reservoir management operations and liabilities stemming from any environmental impacts associated with those operations. Power for operation of the production island will be supplied to Chevron by SDG&E from the station auxiliary power system. This power will be metered and the cost will be credited against the cost of energy supplied by Chevron.

7.2 POWER SALES AGREEMENT

The proposed Heber Power Sales Agreement between IID and SDG&E is prepared for execution by the utilities at this time. The basic concepts of the agreement embody the following:

- SDG&E will sell its share of electric energy generated by the Heber power plant to IID.

- IID will accept all energy delivered by SDG&E.

- A base price for energy sales will have an escalation factor applied which will reflect changes in the Wholesale Price Index for electric power (such escalation factor to be computed from the day of contract execution).

- The term of the contract is to be for five years from plant start-up, or until the plant is declared "commercial."

Los Angeles Department of Water and Power also planned to enter into an agreement with IID under essentially the same terms and conditions. Southern California Edison Company is in the process of negotiating a separate agreement with the District for power sales and exchanges.

7.3 WATER PURCHASE AGREEMENT

The Imperial Irrigation District supplies Colorado River water to the Imperial Valley agricultural, domestic and industrial users through an extensive system of canals and feeder ditches. IID has agreed to supply the Heber plant with up to 5300 acre feet (6.54 MM m^3 per year) of fresh Colorado River water for cooling cycle makeup for up to five years of plant operation. After this time, another source of cooling water must be used. Price will be IID's current rate for water commodity charge at the time of delivery. An assessment of sources and their availability indicates that agricultural runoff (drain) water will be available. IID has committed to supply the lifetime water requirements of the Heber plant from the agricultural drains. During the first five years, plant modifications necessary to accommodate irrigation drain water will be evaluated and the plant will be converted to utilize this source.

Section 8
PROJECT CONTROLS

Project controls that were developed to support the engineering and design effort are discussed in this section. These related activities included the development of Project Procedures, a Project Design Guide, and Quality Assurance Procedures.

8.1 PROJECT PROCEDURES

To document the procedures required to administer and control the Heber project, Fluor initiated preparation of a Project Procedure Manual. This document has undergone two iterations and is ready for implementation. The systems and procedures established by the Project Procedure Manual are outlined below:

- Provides a description of the project organization of Fluor and SDG&E, defines responsibilities of project members and defines communication and interface procedures.

- Describes the management control system procedures including cost and schedule controls, cost estimating, preparation of schedules and reporting.

- Identifies scheduled project review and design review meetings.

- Defines the various project correspondence used for project communications and documentation of performance and progress. The project documentation includes letters, conference notes, telephone call confirmations and related documents.

- Establishes a project file index and a document distribution chart.

- Provides a method for documentation, assignment and control of action items.

- Establishes procedures for engineering and design controls. These include use of the Design Guide, design calculations, drawing and specification preparation, approval and issuance and design coordination systems.

- Provides methods for control of vendor-generated data.

- Describes the Quality Assurance Program and references related procedures in the Quality Assurance Manual.

- Provides procedures for cost accounting, including a detailed cost code of accounts.

- Future sections will be added to define procurement and construction procedures.

8.2 DESIGN GUIDE

The need for a document to provide a consolidated basis for design for the power plant was identified, and the preparation of this document was assigned as a joint Fluor/SDG&E effort. The purpose of this document is as follows:

- To collect all project design criteria in one document, so all project participants will use a common design basis.

- Through the process of documentation and review of the design criteria, assurance is provided that the detailed design implementation will satisfy overall project objectives.

- Changes in design philosophy and implementation, resulting from design reviews or other conferences, will be incorporated in the Design Guide. This will provide a means to consolidate the ongoing changes in design philosophy in a centralized document.

- SDG&E will approve the basic Design Guide and any subsequent changes. This will assure agreement has been reached in the design objectives for the project.

The Design Guide will include the following data:

- A description of the project, including basic project design objectives and associated risks.
- A definition of the project interfaces.
- A description of the operating plans for the plant.
- Project schedules, including requirements for licensing and permits.
- A summary of studies and optimizations performed or planned for the project.
- A section defining the general project design objectives. This section provides the design requirements for each power plant system, major items of equipment, buildings and structures. Also included are requirements for plant operation and maintenance, reliability, regulatory requirements and plant safety.
- A section will be added to describe the actual design of the power plant systems and equipment after detailed design of the systems has been completed and approved.

8.3 QUALITY ASSURANCE

The Quality Assurance Manual to be used by Fluor for the power plant was prepared and submitted to SDG&E for review. Subsequent meetings were conducted by Fluor and SDG&E Quality Assurance personnel to establish agreement on the extent and philosophy of quality assurance activities for the project. The manual has been approved and is ready for implementation. The Quality Assurance Program considers the following objectives, which are further defined in the Quality Assurance Manual.

- To provide the procedures and review/audit systems required to assure that design, procurement and construction of the power plant will provide a high quality product conforming to established design criteria and other program guidelines and sound engineering practices.

- To familiarize and indoctrinate project personnel in the Quality Assurance Program objectives, procedures and requirements.

- To interface with other project control systems, including those defined in the Procedure Manual and the Design Guide, to assure uniformity and conformance with project requirements.

- To establish procedures for assigning quality levels to structures, systems and equipment based on an evaluation of their importance in contributing to plant safety, performance, reliability, and maintainability.

- To provide an independent review and audit agency to assess the quality of ongoing work and conformance to established procedures.

- Initial emphasis will be on the engineering and design control procedures. Quality assurance procedures as applied to procurement and construction will be developed prior to initiating those project phases.

Section 9
REFERENCES

1. Holt/Procon, Feasibility Study of a Low Salinity Hydrothermal Demonstration Plant, prepared for EPRI, April, 1976.

2. Holt/Procon, Energy Conversion and Economics for Geothermal Power Generation at Heber, California; Valles Caldera, New Mexico; and Raft River, Idaho - Case Studies, prepared for EPRI as a report under Reference 1, November 1976.

3. Holt/Procon, Preliminary Design Manual for a Geothermal Demonstration Plant at Heber, California, prepared for EPRI, Research Project 580, September, 1976.

4. Holt/Procon, Implementation Plan for a Geothermal Demonstration Plant at Heber, California, prepared for EPRI, December, 1976.

5. Holt/Procon, Preliminary Environmental Assessment of Geothermal Power Generation at Heber, California, Volumes I and II, prepared for EPRI, April, 1976.

6. Holt/Procon, Geothermal Demonstration Plant, Continuing Design Studies, prepared for EPRI, March, 1977.

7. Holt/Procon and Geonomics, Inc., Geothermal Demonstration Plant Executive Summary, EPRI Research Project 580-1, issued as a report under Reference 2, March, 1977.

8. Fluor Engineers and Constructors, Work Package B001 Report, Process, Equipment, and Electrical Review, November, 1977.

9. Fluor Engineers and Constructors, Special Study T002 Report, Flashed Steam versus Binary (HC) Cycles, October, 1977.

10. San Diego Gas and Electric Company, Test and Evaluation of a Geothermal Heat Exchanger, EPRI ER-376, September, 1975.

11. The Ben Holt Company, Geothermal Heat Exchanger Test at Heber, California, RP-846-1, EPRI ER-572.

12. The Elliott Company, Axial Flow Organic Turbine Study, RP-923-1, EPRI ER-513.

13. Rotoflow Corporation, Radial Inflow Organic Turbine Study, RP-923-3, EPRI ER- (number not yet assigned).

14. San Diego Gas and Electric Company, Geothermal Environmental Studies, Heber Region, Imperial Valley, California, Environmental Baseline Data Acquisition, Research Project 556-1, prepared for EPRI, February, 1977.

15. VTN Consolidated, Draft Environmental Impact Report, prepared for County of Imperial Planning Department, re: Geothermal Demonstration Project, issued December, 1977.

16. Fugro, Inc., Geologic, Seismologic, and Earthquake Engineering Report for the Heber Geothermal Demonstration Plant, Heber, California, prepared for San Diego Gas and Electric Company, December, 1977.

17. Fluor Engineers and Constructors, Inc., Special Study T003, Hydrocarbon Turbines, April, 1978.

18. Fluor Engineers and Constructors, Inc., Optimization Studies Report, March, 1978.

19. C.F. Braun Co., Enthalpy Measurements for a Mixture 80 mol Percent Isobutane and 20 mol Percent Isopentane, performed for EPRI.

20. Heber Geothermal Demonstration Power Plant, Interium Report 1, August, 1978, EPRI ER-863, Project 580-2.

21. Topical Report, EPRI ER-670, Project 580, February, 1978.