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**REPORT ON
PRELIMINARY ENGINEERING STUDY
FOR
INSTALLATION OF AN AIR-COOLED STEAM CONDENSER
AT
BRAWLEY GEOTHERMAL PLANT, UNIT NO. 1**

**Prepared For
SOUTHERN CALIFORNIA EDISON COMPANY
ROSEMEAD, CALIFORNIA**

MARCH 1982

S-81014

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Engineering • San Francisco

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Date	12 March 1982	Job No.	S-81014-00
Attention		MR. LARRY JOHNSON, PROJECT ENGINEER	
Re:			
PRELIMINARY ENGINEERING STUDY FOR INSTALLATION			
OF AIR-COOLED STEAM CONDENSER			
BRAWLEY GEOTHERMAL PLANT - UNIT NO. 1			

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Prepared for
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ROSEMEAD, CALIFORNIA

Prepared by
ROGERS ENGINEERING CO., INC.
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San Francisco, California 94111

MARCH 1982

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1.0

INTRODUCTION

1.1

The Brawley Geothermal Project comprises a single 10 MW nominal geothermal steam turbine-generator unit which has been constructed and operated by the Southern California Edison Company (SCE). Geothermal steam for the unit is supplied through contract by Union Oil Company which requires the return of all condensate. The Imperial Irrigation District (IID) purchases the electric power generated and provides irrigation water for cooling tower make-up to the plant for the first five years of operation, commencing mid-1980.

Because of the unavailability of irrigation water from IID in the future, SCE is investigating the application and installation of air cooled heat exchangers in conjunction with the existing wet (evaporative) cooling tower with make-up based on use of 180 gpm (nominal) of the geothermal condensate which may be made available by the steam supplier.

1.2

A preliminary engineering study was completed in mid-1981 which considered the use of an air cooled heat exchanger installed for operation in series flow with the existing wet (evaporative) cooling tower water circulating system at the Brawley Geothermal Plant. The

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air cooled heat exchanger was to be optimized so as to economically reduce the cooling tower make up to the 180 gpm (or less) of plant geothermal steam condensate.

- 1.3 This preliminary engineering study has as its purpose the development of the requirements for the installation and operation of an air cooled steam condenser (ACSC) in parallel flow with the water cooled main steam condenser. The turbine exhaust steam is then to be controlled so that the split of condensation in the ACSC and the existing water cooled condenser will not exceed use of the nominal maximum 180 gpm condensate as cooling water make up.

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2.0 SCOPE OF PRELIMINARY ENGINEERING

2.1 The scope of this preliminary engineering study includes the following elements:

2.1.1 Review of the criteria and operating data available from the Brawley Geothermal Plant and make initial determination of the applicability of an air cooled steam condenser (ACSC) installation within the guidelines and parameters established by SCE.

2.1.2 Prepare plant heat balance used in design optimization calculations for the ACSC.

2.1.3 Preparation of initial design optimization of the ACSC for development of preliminary equipment specification.

2.1.4 Obtain equipment bids from at least three suppliers.

2.1.5 Review of bids and development of any missing data so that proposed equipment is considered representative and suitable as specified.

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- 2.1.6 Preparation of drawings of each separate equipment system bid to permit development of a definitive estimate of each system installed cost. The installed cost estimate for each of the systems will be developed and evaluated by SCE.
- 2.1.7 Preparation of a control system description.
- 2.1.8 Preparation of a list of major equipment and materials for equipment installation.
- 2.1.9 Preparation of an electrical single line diagram and listing of electrical materials and proposed equipment for the electrical installation.
- 2.1.10 Preparation of a preliminary P&ID of the proposed ACSC as related to the existing cooling system.

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3.0

SUMMARY OF PRELIMINARY DESIGN PARAMETERS

3.1

The air cooled steam condenser (ACSC) shall be specified to handle the turbine steam at the maximum allowable exhaust flange pressure of 6" Hg Abs.

3.2

The ACSC installation shall be designed to operate in parallel with the water cooled main condenser.

3.3

The main water cooled steam condenser shall be operated with a constant flow of water specified to hold the water side velocity near the original design. The specified flow is 12,740 gpm which is used in the design calculations.

3.4

The cold water off tower temperature shall not exceed 94°F. This is the maximum temperature which is permitted for proper performance of the station auxiliaries and can be accomplished by reducing the loading of turbine heat into the water cooled main steam condenser or restarting wet tower fans.

3.5

The plot of the annualized ambient dry bulb temperature data shown in Appendix Figure A has been developed from the Imperial Valley Conservation Research Center and is used to develop the annualized gross power capability.

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- 3.6 The net power will include the debit for the existing plant auxiliary power loads and the new fan power loads calculated in the equipment design optimization.
- 3.7 Wet and dry bulb temperatures shown in Appendix Figures B, C and D are used to check test wet tower evaporation relative to calculated wet tower heat loading.
- 3.8 The use of geothermal condensate shall be controlled on a 24 hour basis; i.e., the amount of condensate used over a 24 hour period shall not exceed the nominal 180 gpm (43% of the condensate generated in that same 24 hour period).
- 3.9 The following features pertinent to the design, installation and operation of the proposed wet/dry cooling system or the ACSC were incorporated into the Brawley Geothermal Project during the original construction of the Plant.
- 3.9.1 Two feet additional depth has been included in the cooling tower basin which provides approximately 47,000 gallons additional volume as surge availability during "worst" day conditions.

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- 3.9.2 The instrument air compressor shelter was extended southward a sufficient distance to provide space for installation of an electric power load center panel for the ACSC fan motors and controls.
- 3.9.3 An underground conduit was stubbed out underground from Pullbox F and G for future electric power cable routing to the instrument air compressor shelter.
- 3.9.4 The south road was re-routed further south to provide space for the ACSC installation.
- 3.9.5 A 4-inch stainless steel condensate line was extended from the main condensate pump area to the northwest side of the wet cooling tower and terminated with a blank flange.
- 3.9.6 The cooling water circulating pumps were epoxy coated to provide corrosion resistance when circulating geothermal condensate.

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4.0 SUMMARY OF CONCLUSIONS

4.1 Basis for ACSC Design

Initial preliminary specifications for the air cooled steam condenser used for quotation requests were developed using the average maximum geothermal condensate make-up of 180 gpm (as in the case of the wet/dry cooling system study) and based on 56% loading factor with estimated de-rating values for predicted performance higher inlet air temperatures. Derating values provided by manufacturers in their quotations proved more conservative at the higher operating inlet air temperatures than the estimated values used in the initial specification. Revaluation of the calculations indicates a loading factor up to 66% can probably be used economically.

At final design the purchase specifications for the ACSC should be revised to provide for this loading. Estimated cost for this added capability is approximately \$400,000 - which has not yet been confirmed by a manufacturer.

Manufacturers solicited were: GEA Power Cooling Systems, CE Lummus-Heat Transfer Division and Hudson Products Corporation.

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4.2 ASCS Application

4.2.1 Based on the design parameters established for the ACSC operating conditions, the application of the ASCS at Brawley Geothermal Unit 1 is technically feasible and will permit use of the nominal 180 gpm of geothermal condensate as cooling water make up except under "worst" day conditions. Reduction in plant output will be required if the plant condensate retention (make-up requirement) is held to the maximum stipulated.

4.2.2 The plant area available for the ACSC installation is adequate as shown on the layout drawings. However, because of its configuration, an extremely long extension of the large diameter turbine exhaust at high level is required which is a high cost element in this installation.

All the construction features included in the initial plant construction program to service the proposed wet/dry cooling system are available and adequate for the ACSC installation.

4.3 The annualized power generation available from the plant under the ACSC operation is very close to that available from the wet/dry cooling system as shown in the body of this report.

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4.4 Economic feasibility has not been included in the scope of this study of the ACSC and cannot be completed without development of capital and operating costs.. SCE will develop the capital and budget costs for this project based on the drawings and data provided in this report.

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5.0 SYSTEM DESCRIPTION

5.1 General

The system described in this section is the result of a preliminary engineering study for the retrofit installation of an air cooled steam condenser (ACSC) at the Brawley Geothermal Unit Number 1. This ACSC will operate in parallel with the existing evaporative cooling system to achieve full heat rejection at reduced water consumption levels. The system is designed so that the power plant can operate without the need for an external water supply (such as the New River) by using portion of the condensate generated from the geothermal steam for makeup to the evaporative cooling tower. Heat that cannot be rejected in the evaporative tower as a result of its reduced capacity will be rejected by direct steam condensing in the ACSC. The following paragraphs describe the salient features of the retrofit system installation and operation.

5.2 General System Operation

Exhaust steam from the steam turbine enters a duct which contains a steam diversion valve. Exhaust steam will generally be at approximately 6 inches of Hg, but may be at or near 4 inches on the coolest

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days of the year. When the diversion valve is closed, all steam is directed to the ACSC. When the valve is fully opened, steam flows to both the main condenser and the ACSC. Steam directed to the main condenser is condensed on the shell side of the condenser. Condensate formed collects in the main condenser hot well and is either returned to the steam supplier or used as makeup for the evaporative wet cooling tower. The wet cooling tower serves all power plant auxiliaries and the main condenser. Makeup water to replace the water evaporated and the water blowdown is provided from the condensate hot well of the main condenser. Cooling water from the basin is pumped to the main condenser and also to the heat exchangers for auxiliary equipment cooling.

Steam diverted to the ACSC is passed through a series of finned tubes for direct condensing by fan generated air flow. Condensate formed is returned to the main condenser.

Air and noncondensable gases are collected in both the main condenser and the ACSC. Gases that are collected in the ACSC are first passed through a gas boost steam jet ejector to raise the gas pressure, and then passed into the main condenser for eventual passage through the existing two ejector stages. Motive steam for the booster jet at the ACSC is also obtained from the main steam system to the plant.

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An automatic control system is designed to regulate the split of heat rejection exhaust steam flow between the wet condenser and the ACSC systems in order to control the consumption of geothermal condensate in the wet cooling system. If steam condensate continues to exceed contractual supply, the control system reduces turbine load in the ACSC at that time.

5.3 System Installation

The general arrangement of the retrofit installation of the ACSC at Brawley Unit No. 1 is shown on the enclosed drawings. The drawings reflect the basic differences in arrangement required by the equipment of the various manufacturers who supplied preliminary bid information.

The following paragraphs provide a brief description of the required construction features.

5.3.1 Turbine Exhaust Steam Duct

The existing turbine exhaust steam duct must be modified to provide space for the installation of a diverter valve at the top of the main condenser and a spool piece to provide a nozzle for return of

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the noncondensable gases from the ACSC. The existing duct will have to be raised to accommodate the above items and will require a spool piece at the top turbine exhaust connection.

The exhaust duct will then be extended to the ACSC at its new elevation along the routes shown on the drawings. Expansion joints will be required at elbow locations as indicated on the drawings. The supports for the duct are located on the drawings and for preliminary design are fabricated from pipe. Final design optimization may alter this selection.

The duct has been sized conservatively at 60 inch diameter as being adequate for pressure drop and flow considerations for the preliminary application. Final design will depend on equipment selected and could therefore vary from the size selected for this study.

5.3.2 Noncondensable Gas, Condensate, and Steam

The noncondensable gas, condensate and steam piping required for the ACSC, are routed to parallel the turbine exhaust duct but will require additional supports along their length since the span for these pipes is less than required for the exhaust steam duct. This additional support is provided by open web steel joist or from the exhaust duct.

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5.3.2.1 The noncondensable gas separated at the ACSC is collected by a steam jet ejector located at the unit and the discharge is taken to the new spool piece connection provided at the main condenser. Preliminary size of the noncondensable gas duct is 14 inch diameter.

5.3.2.2 The motive steam for the steam jet ejector for the noncondensable gas is taken from the auxiliary steam line in the main condenser area and routed to the ACSC as shown on the drawings. This line has been sized at 1 1/2 inch diameter.

5.3.2.3 The condensate return line from the ACSC is a gravity line 4 inch diameter and necessarily runs at lower level than the other line servicing the ACSC. It connects to an existing nozzle at the main condenser hot well.

5.3.3 Condensate Make-up Line

The condensate make-up line is a 4 inch diameter stainless steel line presently installed from the main condensate line in the main condenser area to the northwest corner of the wet cooling tower and will need to be extended to the basin in accordance with the PandID drawing D-03-001.

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5.3.4 Electrical System

The electrical system comprises the extension of 4160 volt power cables from the existing switchgear in the Plant Control Room to a new pad mounted 500 kVA - 4160/480V transformer near the southwest corner of the instrument air compressor shelter via an existing conduit stub-out of Pullbox F and G. 480 volt feeders will be extended from the transformer to the new motor control center in the air compressor shelter. The new motor control center contains the main circuit breaker, fan motor starters, lighting transformer and breakers. Feeders will be installed underground via a new pullbox from the motor control panel to the ACSC unit for all power, lighting and controls connections.

5.3.5 Proposed Control System

The proposed control system is basically an electronic system using a microprocessor unit which will be installed in the existing Plant Control Room. The microprocessor unit will take signals from electronic devices or transducers providing electronic signals for various control functions required as described below.

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The proposed control system would make use of a Micon P-200 micro-processor based controller.

5.3.5.1 The following inputs would be required from remote transducers:

- a) Condensate flow (pulses from existing magnetic flow meter)
- b) Wet cooling tower make up flow (pulses from new magnetic flow meter)
- c) Wet cooling tower basin level (4-20 ma from new P/I transducer)
- d) Turbine back pressure (4-20 ma from new absolute pressure transmitter)
- e) Ambient temperature (4-20 ma from new RTD and R/I transducer)
- f) Water cooled condenser cooling water supply temperature (4-10 ma from new RTD and R/I transducer)
- g) Water cooled condenser cooling water discharge temperature (4-20 ma from new RTD and R/I transducer)
- h) Steam pressure (4-20 ma from new P/I transducer)

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5.3.5.2 The outputs from the controller would control the following:

- a) Wet cooling tower basin level valve (via solenoid LY-730)
- b) Generator load (via new motorized potentiometer in governor load control circuit)
- c) Turbine trip
- d) Steam flow diversion valve (via 4-20 ma signal to electropneumatic positioner)
- e) ACSC fans (via 4-20 ma signal to new electronic switches)

5.3.5.3 The basic system would be set up to keep the steam flow diversion valve closed to the water cooled condenser as long as the air cooled steam condenser (ACSC) is able to handle steam flow without a rise in turbine back pressure. As the ambient temperature increases the capability of the ACSC will decrease causing the turbine back pressure to increase. This increase in back pressure will be used to open the steam flow diversion valve to the water cooled condenser and thereby control the back pressure.

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A continued increase in back pressure after the steam flow diversion is fully open will cause the controller to reduce generator load to prevent the back pressure from exceeding 6" Hg.

If the ambient temperature exceeds 110°F the rising ambient temperature signal will be used to change the set point of the turbine back pressure controller and reduce generator load in order to conserve condensate make-up to the cooling tower basin.

When the ambient temperature goes below a preset point, the ACSC fans will be turned off in sequence to switch the cooling load from the ACSC to the wet condenser and to conserve power in the ACSC fans.

A reduction in steam pressure below the turbine minimum rating will change the set point of the turbine back pressure controller to force a reduction in generator load.

The system does not include provision for controlling the fans on the cooling water tower. In normal operation, only one fan would be run. On extremely hot days, the operator could elect to start the second cooling tower fan to increase power output early in the day by sacrificing turbine operation later in the day when the avail-

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able condensate runs out. The portion of the condensate that is available for use by the power plant will be totalized by the controller and compared with the amount actually used for make-up to the cooling tower. The counters will automatically be reset once every 24 hours at a time when excess condensate is being generated. The excess of available condensate over the amount required for make-up will be accumulated in the counters. When the total available condensate for the day has been used, the level control valve for the cooling tower basin will be closed. The level in the cooling tower basin will be allowed to drop until additional condensate is available. If the cooling tower basin level starts to drop too early in the day, the generator load will be reduced. If the level reaches the minimum, the turbine will be tripped. The turbine will be restarted after the daily reset of the condensate and make-up counters.

5.3.6 Water Treatment

The introduction of geothermal steam condensate as make up into the plant cooling system at the wet cooling tower will result in aerated condensate rather than aerated irrigation water. The aerated condensate will require different treatment than is presently provided for the make up water system in order to insure that existing carbon steel piping and non-alloy components are protected from corrosion.

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6.0 EQUIPMENT AND SUB-SYSTEM MATERIALS LIST

The following is a listing of major equipment and materials required for the installation of an air cooled steam condenser at SCE's Brawley Geothermal Plant Unit 1.

- 6.1 Air-cooled steam condenser and new noncondensable gas steam ejector (erected basis).
- 6.2 Turbine exhaust piping system, 304 stainless steel duct with 3/8" wall consisting of the following 304 stainless steel elements:
- a) 66-inch square by 40-inch long turbine exhaust hood make-up spool (Sketch SK-41-003).
 - b) 66-inch diameter "tee" to the air-cooled steam condenser into the system (Sketch SK-41-003).
 - c) 66-inch diameter butterfly valve with pneumatic operator and electropneumatic positioner.
 - d) 66-inch diameter by 24-inch long make-up spool with 14-inch nozzle (Sketch SK-41-004).

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- e) One 66-inch O. D. by 60-inch O. D. reducer.
- f) Three 60-inch diameter expansion joints, each with butt-weld ends and eight 321 stainless steel convolutions.
- g) 60-inch diameter elbows and duct sections, and smaller diameter connecting steam ducts as shown on Rogers' Sketches, Nos. SK-04-002 through SK-04-006, and Nos. SK-41-001 through SK-41-005. Ductwork runs from turbine exhaust to inlet of water-cooled condenser and to inlet of air-cooled steam condenser.

6.3 304 stainless steel noncondensable gas suction line from air-cooled steam condenser to new steam ejector. This is a nominal 16-inch O. D., Schedule 10-line, as shown on Project Drawings.

6.4 304 stainless steel noncondensable gas return line from new noncondensable gas ejector to water-cooled steam condenser. This is a 14-inch O. D. Schedule 10-line as shown on Project Drawings.

6.5 Motive steam supply line to new noncondensable gas ejector. 1 1/2-inch Schedule 40 carbon steel from existing 6-inch auxiliary steam line (Sketch SK-41-001) to new ejector.

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6.6 Condensate return line from air-cooled steam condenser to water-cooled condenser hot well. 4-inch Schedule 40, 316 stainless steel.

6.7 Instruments and Control

- a) Programmable Controller
Powell Industries, Inc.
Process System Division
MICON P-200
- b) Electronic absolute pressure transmitter for turbine back pressure
(PT-68)
- c) Electronic temperature transmitter with RTD for ambient temperature (TT-500)
- d) Electronic temperature transmitter with RTD for cooling water temperature (TT-525)
- e) Electronic pressure transmitter for steam pressure (PT-310)
- f) Magnetic flow transmitter with slow element for cooling tower make-up flow (FT-115) - similar to existing FT-110

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- g) Pneumatic to current transducer for cooling tower level signal (LY-730A)
- h) Electronically controlled motorized potentiometer for governor load control
- i) Electronic alarm unit with 6 individually adjustable contacts for air-cooled steam condenser fan control
- j) Turbine trip
- k) Steam flow diversion valve (via 4-20 ma signal to electropneumatic positioner).

NOTE: Items shown on Instrument Loop Diagram 40-001 and not listed above are either existing or are included in programmable control Item A above.

6.8 Electrical Systems

- 6.8.1 One Motor Control Center, 480 volt, 3-phase, 3-wire, 22,000 ampere short circuit capacity, with main bus rated 600 amperes. NEMA Type 1 gasketed enclosure for indoor service, with NEMA Class II, Type B wiring and containing the following items built in:

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- a) Main circuit breaker, 3-pole, 600 amperes, with incoming lugs for 2-500 MCM copper cables, per phase.
- b) 6 combination motor starters, full voltage start, nonreversing, single speed, NEMA size 3, with magnetic only circuit breaker, and with control power transformer.
- c) 1 lighting transformer, 15 kVA, 480-120/208V, 3-phase, dry type.
- d) 1 circuit breaker, 480 volt, 30 ampere, 3-pole, for lighting transformer.
- e) 1 lighting panelboard, 100 ampere main bus, with 12-20 ampere branch circuit breakers and door.
- f) 1 ground detector composed of:
 - 3 potential transformers, 480-120 volt, single phase, connected grounded wye to broken delta, and 3 indicating lights, a resistor, and an alarm relay.

6.8.2 One station-use transformer, power, 500 kVA, 3-phase, 4160-480/277 volt, with 4 2-1/2% taps, oil insulated, for outdoor service. Both

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terminal compartments shall be suitable for XLPE or EPR insulated single conductor, shielded cable.

- 6.8.3 One circuit breaker, 4160 volt, 1200 ampere to add to existing motor control center.
- 6.8.4 Electrical cable, rated 5,000 volts, single conductor, No. 2 AWG, shielded, insulated with XLPE or EPR and as shown on Project Drawings.
- 6.8.5 Electrical cable, rated 600 volts, single conductor, unshielded, insulated with XLPE or EPR and as shown on Project Drawings.
- 6.9 Supports and support structures for condensers and piping (Refer to SK-42-001).
- 6.10 Extension of 4-inch 316 stainless steel condensate line to cooling tower basin.

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7.0

DESIGN AND CONSTRUCTION SCHEDULE

The final design and construction schedule for the project is shown on Schedule A. The total time required from start of engineering and continuing through procurement, construction, testing and start up is estimated to require one year. Longest term equipment delivery was for the ACSC which will pace the project. Quotations received from three manufacturers solicited in this study varied from 20 weeks to 52 weeks.

Schedule A is based on the shorter term delivery. A six week period has been allowed for engineering prior to quotation request for this item with award being made seven weeks later.

The modification of the existing turbine exhaust duct should be closely coordinated with plant operations to minimize plant down time. It would be desirable to install the modified duct during a scheduled plant shutdown period if at all possible. Modification of the duct could be tailored to that arrangement.

A - ANALYSIS OF BIDS COMPLETE
 B - BASIS OF DESIGN RECEIVED
 C - CONSTRUCTION START
 D - DRAFTING START
 E - ENGINEERING START

F - CONSTRUCTION COMPLETE
 G - TESTING COMPLETE
 H -
 I - ISSUED FOR CONSTRUCTION
 J -

K -
 L - LAYOUT DRAWING COMPLETE
 M - MATERIAL TAKEOFF
 N -
 O - ORIENTATION COMPLETE

P - FOREIGN PRINTS RECEIVED
 (P) - FOREIGN PRINTS APPR'D & RET.
 Q - QUOTES RECEIVED
 R - REQUEST FOR QUOTES
 S - SPECS. COMPLETE

T - START TEST
 U - UNDERGROUND COMPLETE
 V - MATERIAL DELIVERED TO JOB
 W -
 X -

ROGERS JOB NO. S-81014
 CLIENT W. O.
 PROJECT AIR COOLED STEAM CONDENSER
 PLANT BRANLEY GEOTHERMAL PLANT

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8.0 GENERAL DISCUSSION

8.1 Design Considerations

In order to develop a heat rejection system that meets the operating criteria an optimization procedure is necessary. In general, the first step taken was to determine the maximum amount of heat that could be rejected from the existing evaporative cooling system with the available makeup from condensate. This heat rejection capacity was determined for a number of "typical" days at Brawley, including the typical summer day, typical hottest day, typical winter day, and typical coldest day. Knowledge of the capability of the evaporative cooling system provided a basis for sizing the ACSC.

The following criteria were used in selecting the design of the ACSC:

- The ACSC design is based on the turbine operating at 6 inches of Hg back pressure.
- The ACSC is designed to reject 56% of the total heat rejected by the turbine at full power output and 6 inches of Hg.
- The ACSC is sized at an ambient air temperature of 84°F.

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- The ACSC design must employ the minimum amount of heat transfer area and fan horsepower, thus minimizing capital investment and maximizing net plant power output.

The selected design criteria means that the ACSC can reject more than 56% of the heat load (at 6 inches of Hg) at temperatures below 84°F (such as the time frame from November to February/March), and less than 56% of the load above 84°F. At temperatures above 84°F (36% of the time during the year), either the evaporative system will have to pick up more than 44% of the load, or the turbine load will have to be reduced. Since the ACSC has not been specified to handle the full load steam flow, the maximum load it can handle is estimated at 74% when the ambient air temperature falls below 70°F. See Figure III.

If either the design temperature or size were increased, the ACSC would have increased capacity, resulting in more time that the power plant can operate at full power. The increase in revenue from power sales is accompanied by increased power losses from large (or more) fans, and higher capital costs. An analysis was performed with a variety of different ACSC designs to determine this economic cross-over point.

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Detailed design information (and budgetary estimates) was subsequently provided by ACSC vendors, once the design points were established. Design information was provided by three companies: GEA Power Cooling Systems, Lummus-Heat Transfer Division, and Hudson Products Corporation.

8.2 Preliminary Design Optimization

8.2.1 Design Heat Load Conditions

The design heat load used in the optimization calculations are shown on Appendix Figure 1. The values include the small plant auxiliary loads used in the previous wet/dry design plus the expected variable loads which vary with turbine and steam ejector conditions at 4" Hg Abs., 5" Hg Abs and 6" Hg Abs turbine exhaust flange pressure. It should be noted that the values have been rounded to the nearest million Btu/Hr. Thus the optimization calculations are kept reasonably consistent in the points used in the study.

8.2.2 Initial selection of split for the ACSC was made by trials which checked the cooling water evaporation at various turbine loads plus the plant auxiliaries dependent on the cooling water tower. The preliminary calculations showed that up to 51% load could be applied

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to the cooling water tower and the evaporation check for a winter condition would not exceed 180 gpm. Similar checks showed that at 44% load the typical summer day evaporation at this load was less than 180 gpm. A worst day check at 44% load indicated the evaporation would be over 180 gpm. The overage could be balanced at 180 gpm by decreasing the cooling tower basin inventory for the day. On this initial check basis the preliminary heat load for the ACSC was assigned at 56% of turbine load @ 6" Hg Abs exhaust flange pressure.

8.2.3 Methodology of Optimization

While soliciting the preliminary equipment bids, the initially assigned ACSC loading of 56% turbine load was checked by the following method.

The final selection of turbine heat loading and inlet air for the air cooled steam condenser is accomplished by determining the annual net power produced. The following calculation elements are maintained consistent throughout the design points studied.

- (i) The dry bulb data from Appendix Figure A is used to determine the annual operating hours split for each design.

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- (ii) Trial calculations of cold water approach temperature were made for one and two fan operation of the existing wet cooling tower. The Cooling Tower Institute method was used because the cooling hot water temperature is far below the original design point.
- (iii) The cold water temperature is limited to a maximum of 94°F as was developed in the wet/dry preliminary engineering study.
- (iv) The yearly operating hours were specified as 8,000. The calculations were developed for air inlet temperature of 78°F, 84°F and 90°F. At each inlet temperature condition the turbine heat loading into the air cooled steam condenser was varied incrementally at 56%, 66% and 70%.

For the nine selected points the equipment size and air fan electric power requirements were estimated.

The heat transfer coefficients and air temperature log mean temperature difference applied were typical to industry standards and literature references for this type of service. The gross annual-

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ized electric power was calculated and the net power to sales was calculated by subtracting the existing auxiliary power loads and the new air cooling fan loads.

8.2.4 Conclusions from Preliminary Optimization Study

The first optimization check was made for the air inlet design of 84°F at 56%, 66% and 70% turbine loadings. The initial method of de-rating the ACSC above the 84°F point was by LMTD ratio. These checks indicated that compared to the wet/dry annualized gross generation of 9,839 kW/Hr. the ACSC/CWSC (cooling water steam condenser) system would operate approximately as follows:

84° Inlet Air Design Constant (LMTD De-rate)

<u>% Turbine Load to ACSC</u>	<u>Annualized Gross Generation Calc kW/Hr.</u>	<u>Ratio to Wet/Dry</u>
56	9,600	0.976
66	9,784	0.994
70	9,834	0.999

Also the calculated net power to sales was as follows: (LMTD De-rate)

<u>% Turbine Load to ACSE</u>	<u>10⁶kWh /Yr.</u>	<u>10⁶ \$ @ 50 Mils</u>	<u>10³ \$ Δ</u>
56	69.2	3.460	+55
66	70.3	3.515	+15
70	70.6	3.530

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Vendor bid de-rating factors at 84°F design inlet were found to be more conservative at the higher operating temperatures for the inlet air. Therefore calculations were redone to cover the nine points selected. The results are shown on Figure II in the Appendix.

The vendor de-rating values were used for 78°F and 90°F by extrapolation using curves plotted at near parallel slope to the 84°F inlet design. For comparison to the above the initial calculations by the vendor de-rate prediction is shown below.

<u>% Turbine Load to ACSC</u>	<u>10⁶ kWh/Yr.</u>	<u>10⁶ \$ @ 50 Mils</u>	<u>10³ \$ Δ (a)</u>
56	68.4	3.420	
			+60
66	70.1	3.480	
			+10
70	70.5	3.490	

- (a) Possible improvement by ACSC fan cut-off during winter is not included in the analysis since it is dependent upon characteristics of the ACSC purchased. However, additional revenue to sales resulting from fan cut-off is in the order of \$15,000 per year.

From Figure II it is estimated that some \$400,000 would be required to increase the ACSC rating from 56% to 66% LOADING capability, or approximately 7 years simple return on investment ratio.

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From the values shown on Appendix Figure II, the net power to sales is not improved by increasing the design past 84°F to 90°F. There is a much larger improvement by using 84°F instead of 78°F. For the 84°F the design gross generation compared to the wet/dry cooling system is as follows:

Annualized Power Generation Rate

<u>Calculated at</u>	<u>ACSC kW/Hr.</u>	<u>Wet/Dry kW/Hr.</u>	<u>Ratio</u>
56%	9,504	9,839	0.966
66%	9,755	9,839	0.991
70%	9,818	9,839	0.998

To be nearly comparable to the wet/dry cooling system study additional ACSC capability is probably economically justified up to the 66% loading point. As calculated the sales value drops to a low value between 66% and 70% loading.

8.3 System Operation

The operation of the parallel heat rejection system can best be described by reference to some "typical" atmospheric conditions.

8.3.1 Typical Hottest Day

On the hottest day, turbine back pressure will always be at 6 inches of Hg. Early in the day, when the ambient temperature is below

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84°F, the ACSC is operated at maximum capacity to conserve condensate which will be required in elevated quantities later in the day. Power output at this time is at 10 megawatts. As the temperature rises toward 84°F, the capacity of the ACSC to reject heat approaches 56%, causing more and more steam to be diverted to the main condenser. At 84°F, the ACSC is rejecting approximately 56% of the heat and the wet tower, with one fan operating rejects 44% of turbine load plus auxiliaries. At wet bulb temperatures typical for this part of the day (68-75°F), the evaporation rates are around 165 gpm. Above 84°F, the capacity of the ACSC falls below 56%, tending to drive more heat load to the wet tower. This increases the cooling water temperatures. When the cold water temperature reaches 94°F, no more heat load can be diverted to the wet tower without turning on a second fan. The second fan will enable the wet tower to reject heat at higher ambient temperatures, but may result in excessively high evaporation rates. For this reason, a more likely choice would be to leave one fan operating and begin to shed turbine load after the cold water temperature reaches 94°F.

At this point, less power is being generated, since the ACSC is limited by size and the wet tower is limited by the cold water temperature. As the temperature continues to rise, the total power output continues to decline. At 110°F the wet tower heat load is

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reduced to handle all auxiliary heat only, and the entire turbine load is diverted to the ACSC. Total power output is below 3,000 kW at these elevated temperatures. The wet tower is operated with auxiliaries only to conserve condensate. Even with these precautions, the evaporative tower consumes over 47% of the condensate generated over the 24 hour period.

After the peak temperatures of the hottest day have past, turbine load can gradually be increased as ambient temperatures drop. Usually late in the evening, power output can be restored to 100%.

The control system monitors a number of critical parameters during this worst day operation to ensure safe operation of the system. These include: turbine back pressure, cold water temperature, minimum cooling tower basin water level, and the ratio of total condensate evaporated to total condensate made. If these parameters exceed established limits, system operation is adjusted automatically.

8.3.2 Typical Summer Day

On a typical summer day, system operation is similar, but with a few important differences. First, condensate evaporation can be limited

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to 43% of condensate made over the day. Second, power output during this day averages 9.200 kW. Third, wet tower operation is not curtailed to only handle the auxiliary heat load since 110°F is not reached.

All fans on the ACSC operate throughout this day, and one fan operates on the wet tower, as in the hottest day.

8.3.3 Typical Winter Day

As the ambient temperature decreases, the heat rejection capability of the ACSC fan exceeds the 56% design number. Because of this greater capability, the operator has to choose between several alternatives as the temperature drops.

- 1) Maximum heat load could continue to be rejected in the ACSC at rated load and 6 inches Hg back pressure, thereby reducing heat load to the wet tower and condensate evaporation.
- 2) Maintain heat rejection capacity in both systems, allowing back pressure to fall below 6 inches of Hg. If steam is available it may be possible to generate power over rated output.

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- 3) Maintain rated output and operate the wet tower at its maximum rate (not to exceed condensate evaporation of 43%), and reduce ACSC heat load accordingly by shutting down ACSC fans.

Alternative 1) is not optimum since more net power is generated per unit output with wet tower heat rejection than with ACSC rejection. The reason for this lies in the greater parasitic fan power on the ACSC. Alternatives 2) and 3) are both acceptable operationally, but 3) may be more desirable in case of limited steam availability.

In general, operation of the system during the cooler parts of the year is not limited by heat rejection capability. If the steam supply is adequate, power output can be maintained at or above rated, with operating back pressures from ~ 3.5 to 6 inches of Hg, depending upon ambient conditions.

8.4

Preliminary Considerations for Controlling Split of Turbine Heat Load

By holding the cooling water flow in the main water cooled steam condenser (WCSC) constant it is possible to determine the heat flow into this unit by measuring the water temperature rise through the condenser (i.e. hot water temperature off minus cold water temperature from the cooling tower).

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Because the main water cooled condenser is operating well below the design temperature this unit will run at reduced pressure compared to the ACSC. Therefore to force the steam into the ACSC a flow diversion valve must be included in the steam connection into the water cooled condenser.

At the specified design of the air cooled steam condenser heat flow into this unit varies in relationship to the ambient air temperature.

Basic system to check control of desired plant generation load.

Two curves have been developed based on process consideration for implementing this basic part of the control system. The curves as developed are designed to minimize cooling water make up requirements.

The loading for the ACSC is shown on Figure III. A similar loading for the WCSC is shown on Figure IV. This curve is developed from trials comparing cooling tower evaporation with loading at various conditions. The curves are to be used as follows. (NOTE: This narrative describes the steps required and does not consider the required hardware or alternative system of control for final automation).

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Procedure Steps:

- a) Measure ambient air temperature °F
- b) Enter Fig. III at °F ambient, read ACSC % load
- c) Enter Fig. IV at °F ambient, read water cooled condenser load
- d) Test for minimum load to the water cooled condenser
i.e. for desired load of 100%
 $100 - \text{ACSC LOAD} = \text{VALUE}$
If Fig. IV LOAD read is less than VALUE use Fig. IV LOAD for
water cooled condenser
If VALUE is less than Fig. IV LOAD, use VALUE for water cooled
condenser
- e) Use selected (minimum) LOAD and enter Fig. V and read required
cooling water temperature rise for water cooled condenser.
- f) Modulate steam diversion valve to split steam flow between ACSC
and the water cooled condenser.

At higher ambient air temperature the ACSC load handling capability is rather low. Therefore above 109°F the overall plant output must be dropped to conserve cooling water make up. At this point because of the need to hold the cold water temperature to less than 94°F,

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both wet tower fans will be required under worst day conditions (from about 12 Noon to 6:00 P. M.). Wet tower evaporation will then be about 0.58 fraction of the condensate produced.

8.4.1 Alternative Load Splitting Strategies

As noted above, with plant load reduced (to about 48%) the wet tower evaporation is above the "across the board" 0.43 as make-up fraction proposed by SCE in the initial project coordination meeting.

8.4.1.1 Alternative I

If it were required that this cooling tower make up fraction be reduced an alternative is to provide two speed fans for the wet tower. A condensate retention fraction of 0.53 is calculated. This can be further reduced by using the water in the cooling tower basin by level reduction, to about 0.41 fraction retained by the power plant.

The basin level can be recovered in one to two days of 48% plant load operation at typical summer day conditions.

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8.4.1.2 Alternative II

Adjust contractual condensate split so that it does not cover worst day condition. It should be noted that during winter conditions more condensate will be returned than the 0.43 fraction proposed.

Winter Conditions Alternative

For typical winter conditions one or two fans can be turned off on the ACSC to increase net power to sales. See Figure III.

8.4.2 Sensing Equipment Required

Ambient air temperature

Cold water off cooling water tower

Hot water off main water cooled steam condenser

Turbine exhaust hood pressure

Plant steam pressure

Cooling tower basin level

Condensate flow 24 hr. (total 1)

Cooling tower make up flow 24 hr (total 2)

$2 \div 1 = \text{FRACTION RETAINED by Power Plant}$

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8.4.3 Recommended Preliminary Control System

The recommended preliminary control system is an augmentation of the preliminary requirements described in 8.4 above. That procedure should be used for achieving all steam flow splits as required to meet total desired load.

The program and hardware of the proposed preliminary control system are described in Section 5.3.5 herein.

8.4.4 Winter Weather Schedule

ACSC fans may be stopped as shown on Fig. III. This curtailment will increase net power to sales.

8.4.5 Other Limits

- a) Cold water off cooling tower. If temperature rises to 94°F start and run second fan. When temperature falls below 92°F stop one fan. Repeat cycle as required. (Probable occurrence from 12 Noon to 6:00 P. M. on Worst Day.
- b) Increase in Turbine Exhaust Flange Pressure - Decrease total turbine load in 1-2% increments until corrected.

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- c) Decrease in Turbine Exhaust Pressure - Shut off fans on ACSC one at a time until corrected.
- d) Condensate production and make up to the cooling tower will be continuously measured. A daily reporting of the fraction retained at the power plant will be recorded.

8.5 Additional Considerations

8.5.1 The proposed ACSC is designed for parallel operation with the existing water cooled steam condenser. A preliminary study was made to ascertain if it would be feasible to operate the proposed ACSC in series flow. It was found that the large size of both the steam feed and residual uncondensed steam and noncondensable gas ducting were very costly compared to cost of the required steam diversion valve and smaller piping needed for parallel flow operation. This study considers only the parallel flow operation with steam flow diversion system.

8.5.2 Maximizing the condensate returned to the steam supplier falls below the desired 0.57 fraction (1.0 - 0.43 retained) proposed. Several strategies were tried. A near success was only achieved by increasing the size of the ACSC. The size may outrun the proposed plot

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area. An alternative is suggested in Section 5.0. By changing the cooling tower fan drives to two speed motors the evaporation can be reduced during the worst day conditions when the cold water temperature rises above 94°F. This change has been designed and the cost estimated in the wet/dry system preliminary engineering study. This option should be re-examined if the ACSC system is selected for final design.

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9.0

LIST OF DRAWINGS

<u>Drawing No.</u>	<u>Title</u>
D-03-001	Preliminary P&ID
SK-40-001	Instrument Loop Diagram
SK-04-001	General Arrangement - GEA Condenser
SK-04-002	General Arrangement - Hudson Condenser
SK-04-003	General Arrangement - Lummus Condenser
SK-04-004	Elevation - GEA Condenser
SK-04-005	Elevation - Lummus Condenser
SK-04-006	Elevation - Hudson Condenser
SK-41-001	Piping Plan
SK-41-002	Piping Plan
SK-41-003	Piping Plan
SK-41-004	Piping Sections
SK-41-005	Piping Sections
SK-42-001	Pipe Supports
SK-17-001	Electrical Single Line Diagram - GEA Condenser
SK-17-002	Electrical Single Line Diagram - Hudson Condenser
SK-17-003	Electrical Single Line Diagram - Lummus Condenser

Appendix!

DESIGN DATA

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Reference: S-81014

FIGURE I

DESIGN HEAT LOAD CONDITIONS

AUXILIARY LOADS

	<u>Flow gpm</u>	<u>Rise F</u>	<u>10⁶ Btu/hr.</u>
Building Air Conditioning	60	6	0.18
Lube Oil Cooler	132	4	0.26
Gen. Air Cooler	264	6.7	0.88
Vac. Comp. Cooler	204	13.0	1.3
Inst. Air Comp. Cooler	20	3.2	0.03
SUB SUM:			2.65
Intercondenser and New Ejector			14.35
SUB SUM:			17.0

10⁶ Btu/hr. - ROUNDED VALUES FOR DESIGN CALCULATIONS

Turbine Exhaust Pressure Inch Hg. Abs.	-	<u>4</u>	<u>5</u>	<u>6</u>
Auxiliaries 10 ⁶ Btu/hr.		17	14	13
Turbine Load		176	183	*192
Total Cooling Tower Load		189	197	205

*Turbine load to air cooled steam condenser = 104.6 Btu/hr.
Turbine load to main c. w. exchanger = 87.4 Btu/hr.

FIGURE II
SUMMARY OF AIR COOLED
STEAM CONDENSER OPTIMIZATION

S-810.14

CODE - DESIGN INLET AIR POINT

□ 90°F

○ 84°F

△ 78°F

ANNUAL NET KW TO SALES 106

70

69

68

67

66

50

60

70

% LOADING @ DESIGN

4-82

TO: CH. NCHE
KEUFFEL & ESSEX CO. MADE IN U.S.A.

FIGURE III
ACSC LOADING VS AMBIENT AIR °F BE 11 DEC 81

5-81014

% AIR COOLED STEAM CONDENSER LOADING FROM TURBINE

ACSC
SCHEDULE
ALL FANS ON.

TWO FANS OFF, FOUR RUN
(3 OFF / 6 RUN)

ONE FAN OFF, FIVE RUN
(2 OFF / 7 RUN)

+ WINTER

AMBIENT AIR TEMPERATURE °F

TO CH. NCHE
KEUFFEL & ESSER CO. MADE IN U.S.A.

FIGURE V

5-81014
BF 11 DEC 81

COOLING WATER
TEMPERATURE RISES
VS TURBINE LOADING

OF RISE IN COOLING TOWER TOTAL WATER FLOW

OF RISE IN MAIN CONDENSER

% TURBINE LOADING INTO MAIN WATER COOLED CONDENSER

FIGURE C

TYPICAL SUMMER
JULY 7, 1978

JOB No. S-81014

BF
ROGERS ENGINEERING

FIGURE D
TYPICAL WINTER
NOV 1, 1978
JOB No. S-81014
BF
ROGERS ENGINEERING

APPENDIX 2 -
CALCULATIONS

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SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

HEAT BALANCE

SHEET NO. XP-1A OF
JOB NO. 5-81014
BY PF DATE 10 DEC 81
CHKD. BY DATE

ORIGINAL TURBINE STEAM FLOW 191,800 $\frac{LB}{HR}$ @ 4"
AMMENDED BY TWX 19 JAN 79 TO 188,500 $\frac{LB}{HR}$ @ 4"
OVERALL TURBINE EFF ~ 0.717

EXH PRESSURE 4" Hg Abs
1.96 PSIA

5" Hg Abs
2.46 PSIA

6" Hg Abs
2.95 PSIA

TURBINE

INLET 90.3 PSIA

HIN = 1188 SIN = 1613

Steam FLOW 188,500

197,500

206,100

Isentropic outlet $\frac{BTU}{LB}$ 935.5

947

957

Isentropic drop 252.5

241

231

Actual drop @ E=0.717 181.0

172.8

165.6

Calculated outlet

Ave $\frac{BTU}{LB}$ 1007.0

1015.2

1022.4

C.W. UNIT

CONDENSER

OUTLET PRESS/EQUILIB F 1.5/(116)

2.0/(126.1)

2.3/(131)

OUTLET TEMP OF EQ STEAM PS 103/(1.038)

114/(1.43)

122/(1.789)

DALTONS LAW R = 2.25

2.51

3.5

N.C. GAS MOLS/HR 54

54

54.1

AIR " " 4

4

4.3

Calc Steam " " 130.5

145.6

204.4

" " LB/HR OUT 2350

2620

3680

" " CONDENSED 184,740 $\frac{LB}{HR}$ (120°F)

195,450 $\frac{LB}{HR}$ (120°F)

204,660 (128°F)

COND. Δh 919

927.4

926.4

TURB DUTY 10^6 BTU 170

181

190

GLAN SEAL " 2

2

2

TOTAL @ TURB " 172

183

192

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SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

SHEET NO. XP-1B OF

JOB NO. S-8101K

BY BF DATE 10 DEC 81

CHKD. BY DATE

<u>AUX LOADS</u>	DESIGN 4"		4"	5"	6"
	FLOW	RISE	106 BTU/HR		
	gpm	°F			
BLDG AIR COND	60	6	0.18		
LUBE OIL COOLER	132	4	0.26		
GEN AIR COOLER	264	6.7	0.88		
VAC. COMP COOLER	204	13.0	1.3		
1st ST. AIR COMP. COOLER	20	3.2	<u>0.03</u>		
SUB SUM			2.65		
INTERCONDENSER	930	30	<u>13.95</u>		
SUB SUM			16.60		

APPROX VALUE SUMMARY

TURBINE LOADING $\frac{\text{BTU}}{\text{HR}}$	16	14	13
TO MAIN CONDENSER	<u>172</u>	<u>183</u>	<u>192</u>
TOTAL HEAT TO COOLING TOWERS	188	197	205

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SUBJECT SCE

AIR COOLED STEAM CONDENSER

Ref Sheet 2

SHEET NO. XP-2 OF

JOB NO. S-81014

BY BF DATE 17 Sept 81

CHKD. BY DATE

HEAT LOAD TO CW TOWER

will be all auxiliary plus about

3,000 $\frac{\text{LB}}{\text{HR}}$ steam from booster steam on

new AIR COOL COND.

Therefore Main Condenser on

6" Back pressure case will

have a duty of about $192 + 3.3 = 195.3 \times 10^6 \frac{\text{BTU}}{\text{HR}}$

note this value used to check evaporators

Also note Lillie Hoffmann Tower

used Munters Packing

Original $4\frac{1}{2}$ was 11363 two fans $\pm$ 2.726 one fan

Munters packing has been modified but have

used original performance chart to determine

cold off using C.T. Institute system

ORIGINAL FAN SPEC WAS 88,000 $\frac{\text{LB}}{\text{HR}}$ AIR (2 FANS)

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SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P3 OF JOB NO. 5-81014BY PF DATE 18 Sept 81CHKD. BY DATE

ORIGINAL DESIGN

		MOL/HR	Ave
TURBINE EXHAUST	(11)		
	191,800 Steam	10655	Mol
	3,840 CO ₂	87	WT
	200 AIR	7	
	195,840	10749	18.22

$$\text{Molar Vol @ 1.96 PSIA \& 125^\circ\text{F}} = 379 \times \frac{14.7}{1.96} \times \frac{585}{520} = 3197.8$$

$$\frac{10749 \times 3197.8}{3600} = 9548 \frac{\text{FT}^3}{\text{SEC}}$$

$$P = \frac{18.22}{3197.8} = 0.0057$$

$$66 \text{ NOM ID} = 5.5 \text{ ft} = 23.75 \text{ FT}^2 \text{ Flow Area}$$

$$\left(\frac{\text{ALL AS VAPOR}}{\text{VAPOR}} \right) \text{ Superficial Vel} = 9548 \div 23.75 = 402 \text{ ft/sec}$$

$$Re = \frac{6.31 \times 195,840}{66 \times 0.012} = 1.56 \times 10^6 \quad f = 0.012$$

$$\Delta p_{s1/100} = 0.02 \quad \text{about } 100 \text{ Eq. ft.}$$

for Same superficial Velocity

$$\text{@ } 6'' \text{ TURB EXH} \quad 2.95 \text{ PSIA \& } 140^\circ\text{F}$$

$$\text{Molar Volume} = 379 \times \frac{14.7}{2.95} \times \frac{600}{520} = 2179.1 \frac{\text{FT}^3}{\text{mol}}$$

$$\text{New Steam @ } 6'' = 20,100 = 11561 \text{ MOL/HR} \quad 18.20$$

N.C. GAS	3,840	87
AIR	200	7
TOTAL	212,140	11655

$$(11655 \times 2179.1) \div 3600 = 7054 \div \text{Superficial Vel } 402 = 17.54 \text{ ft}$$

$$\text{@ } 4'' \quad 190,500 \text{ Steam} = 10583 + 87 + 7 = 10677.3 \text{ MOL/HR}$$

$$(10677.3 \times 3197.8) \div 3600 = 9484.4 \div 402 = 23.59 \text{ FT}^2$$

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SUBJECT BRAWLEYAIR COOLED STEAM CONDENSER
(ACSC)SHEET NO. 74 OFJOB NO. 5-81014BY RF DATE 18 Sept 81

CHKD. BY DATE

DUCT ϕ FOR FULL FLOW@ TURB EXHAUST of 4"
Area Calc 23.59
I.d. Calc 66"

5"

6"

17.54

57"

 ρ
Apsi/100

0.0057

~ 0.0066

0.0083

0.022

~ 0.024

0.036

for
Split Flow

@ 56% to ACSC

I.d. Calc

Apsi/100

13.2

9.8

48"

48"

48 42

0.039

~ 0.046

0.027 0.052

Use 66" for full & 48" for split Apsi/100 ~
Area/FT 23.74 12.56

Series Flow steam

from air cooled condenser 44%

DALTONS N.C. GAS Steam

N.C. GAS

Air

LB/HR

MOLE/HR

LB/HR

2.68 in

84390

4688

91560

5087

3830

213

3760

209

3840

87

3840

87

200

7

200

17

92,260

4995

99,360

5390

Ave h.d.wt

18.47

18.43

~ Mol wt

3561

2337

0.0052 ρ 0.0079 ρ FT³/sec

4938

3499

 $\div 400 = A$

12.34

8.75

For FULL cd
FLOW Return Duct use 42" for Cost

48"

40"

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. 15 OF JOB NO. 5-81214BY RF DATE 21 Sept 81CHKD. BY DATE

SPLIT CASE 56% TO AIR UNIT

△ REV 29 Sept

TURB & GLAND	4"	MD/HR	5"	6"
Steam	190,200		199,500	208,100
56%	106,510		111,720	116,540
@ PSIA & °F	1.5 103		1.8 114	△ 2.3 122
EXIT Steam	2350	130.5	2,620	145.6 3,680 ✓ 204.4 △
N.C. GAS	2,380	54	2,380	54 2,380 54.1
AIR	124	4	124	4 124 4.3
DALTON R	2.25		2.51	2.29 3.5 △
CONDENSATE	104,160		109,100	114,230 262.8
ft ³ /sec	0.467		0.49	0.514
gpm	210		220	230
TOTAL				
VAPOR OUT	4854	188.5	5,124	203.6 6184 262.8
Ave Mol Wt	25.75 ✓		25.17	23.53
Molar Vol	4027		3417	2711
ρ	0.0064		0.0074	0.0087
ft ³ /sec	210		193	198
Area @				
300 ft/sec	0.70		0.64	0.66
id calc	12"		12"	12"

Condensate Line 4"

USE A VAPOR LINE OF 14" TO BOOSTER JET

JET Steam RATE

Based ~ 2.0 SIA (103 mm Hg To 2.6 (134 mm Hg):

LB MOTIVE PER LB AIR = 0.30

PRES MULTIPLIER 1.15 SIZE EFF ~ 1.12 ±

262.8 x 2.9 ~ 7600 LB/HR AIR x 0.35 1.15 x 1.12 ~ 3000 ¹⁰ HR

JET & GASES EXIT LINE ~ 263 + 167 = 430 MOLES/H.

Molar Volume @ 170°F & 2.6 PSIA = $379 \times \frac{14.7}{2.6} \times \frac{630}{520} = 2596$ (430 MOLES/HR x 2596) ÷ 3600 = 310 ft³/secArea @ 300 ft/sec 1.03 FT² id ~ 14" TO MAIN COND.

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SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. PGA OF JOB NO. 5-81014BY B. F. Farn DATE 21 Sept 81CHKD. BY DATE Ref E-03-012

	<u>gpm</u> <u>Flow</u>	<u>°F</u> <u>Rise</u>	<u>gpm x R</u>
BLDG AIR UNIT COND	60	6	
LUBE OIL COOLER	132	4	
GEN AIR COOLER	264	6.7	
VAC. COMP COOLER	204	13.0	
INST. AIR COMP. COOLER	20	3.2	

Ref Calc Sht XP-1

@ 6" Abs Exh

TURBINE Duty 192 x 10⁶3.3 x 10⁶ = for jet195.3 x 10⁶ BTU/HR

÷ 500 = 390,600

FULL LOAD TO

C.W. CONDENSER

2	680	7.9	5372	
Add INTER	930	30	27,900	
SUM	1610	20.67	33272	CONSTANT BASE

W.C. MAIN COND 12,740 12.26 156,240 40% to Wet

SUM TO C.W.T 14,350 13.21 189,512

12,740 12.88 164,052 42% to Wet

14,350 13.75 197,324

12,740 13.49 171,864 44% to WET

14,350 14.30 205,136

12,740 14.10 179,675 46% to WET

14,350 14.84 212,948

12,740 14.72 187,488 48% to WET

14,350 15.38 220,760

12,740 15.33 195,300 50% to Wet

14,350 15.93 228,572

12,740 15.64 199,206 51% to Wet

14,350 16.20 232,478

12,740 11.65 148,428 38% to Wet

14,350 12.66 181,700

12,740 11.03 140,616 36% to Wet

14,350 12.1 173,888

12,740 10.42 132,804 34% to Wet

14,350 11.57 166,076

12,740 9.81 124,992 32% to Wet

14,350 11.03 158,264

12,740 9.20 117,188 30% to Wet

14,350 10.48 150,452

Rogers

SUBJECT BRAWLEY
ACSC

SHEET NO. P6B OF
JOB NO. 5-61-14
BY RF DATE 7 DEC 81
CHKD. BY DATE

CWT	R _{max}		
1,640	17.70	33,272	390,600
12740	-0-	-0-	-0%-
14350	2.3	33,272	
12740	1.36	17,445	19% LOAD
14,350	3.5	50,717	
12740	10.73	136,710	35%
14,350	11.8	169,982	
12740		171,864	44
14,350	14.3	205,136	
12740	13.8	175,770	45
14350	14.6	209,042	
12740	13.18	167,958	43
14350	14.0	201,230	
12740	12.26	156,240	40
14,350	13.2	189,510	
12740	6.75	85,932	22
14350	8.3	119,204	
12740	2.46	31,248	8
14350	4.5	64,520	
12740	1.2	15,624	4
14350	3.4	48,896	
12740	6.44	82,026	21
14350	8.0	115,298	
12740	8.58	109,368	28
14350	9.9	142,640	
12740	10.11	128,898	33
14350	11.3	162,170	
12740	4.29	54,684	14
14350	6.1	87,956	
12740	18.4	234,360	60
14350	18.6	267,632	
12740	16.86	214,830	55
14350	17.29	246,102

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM COND.SHEET NO. P. 7 OF JOB NO. 2-81014BY B. Fraser DATE 21 Sept 81CHKD. BY DATE

WORST DAY			ONE FAN		TWO FANS	
CWT PERFORMANCE $\oplus$			L/G 2.726		L/G 1.363	
TEMP °F			RANGES		COLD OFF	
			74 / 12		APPROACH	
TIME	DRY	WET	APPROACH		COLD OFF	
MID	85	67	23/21	90/88	13/12	80/79
2A	80	68	22/20	90/88	13/12	81/80
4	80	67	23/21	90/88	13/12	80/79
6	84	69	21/20	90/89	12/11	81/80
8	98	79	16/15	95/94	8/8	86/86
10	109	80	16/15	96/95	8/7	88/87
12N	117	82	16/14	98/96	8/7	90/89
2P	118	83	15/14	98/97	8/6	91/89
4	116	83	15/14	98/97	7/6	90/89
6	113	84	14/13	98/97	7/7	91/91
8	100	76	18/15	94/91	10/9	86/85
10	92	72	20/18	92/90	11/10	83/82
TYPICAL SUMMER						
12MID	88	70	22/19	92/89	12/11	82/81
2A	79	70	22/19	92/89	12/11	82/81
4	74	71	20/19	91/90	12/11	83/82
6	73	68	22/20	90/88	13/12	81/80
8	76	69	21/20	90/89	12/11	81/80
10	90	73	20/18	93/91	11/10	84/83
12N	99	75	19 1/2 / 17	94 1/2 / 92	9 1/2 / 8 1/2	84 1/2 / 83 1/2
2P	104	74	20/18	94/92	10/10	84/84
4	108	76	18/17	94/93	10/9	86/85
6	108	75	19 1/2 / 17	94 1/2 / 92	9 1/2 / 8 1/2	84 1/2 / 83 1/2
8	104	74	20/18	94/92	10/10	84/84
10	95	68	22/20	90/88	13/12	81/80

 $\oplus$ USING COOLING TOWER INSTITUTE CHARTS

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P8 OF JOB NO. S-81014-BY B. Fraser DATE 22 Sept 81CHKD. BY DATE

CHECK WET TOWER EVAPORATION @ 44% POINT

WORST DAY $R = 14.30$ L/G one fan = 2.726

TIME	TEMP °F		ENTHALPY		GRAINS		ΔWi
	DRY	WET	IN	OUT	IN	OUT	
12 MID	85	67	31.6	70.6	70	295	225
2A	86	68	32.4	71.4	74	300	226
4	80	67	31.6	70.6	78	295	217
6	84	69	33.3	72.3	82	305	223
8	98	79	41.6	80.6	120	355	235
10	109	80	43.7	82.7	108	362	254
12N	117	82	45.9	84.9	108	375	267 -
2P	118	83	47.0	86.0	114	380	266 -
4	116	83	47.0	86.0	118	380	262 -
6	113	84	48.2	87.2	130	388	258 -
8	100	76	39.6	78.6	96	342	246
10	92	72	35.8	74.8	86	318	232

12 POINTS $\Sigma = 2911 \div 12 = 242.5$ AVE

$$\frac{\text{LB EVAP}}{\text{MIN}} = 242.5 \times \frac{44,000}{7,000} = 1524.8 \div 8.34 = 182.8 \text{ gpm} \quad \text{OK}$$

TRY 2 FANS FROM 12N - 6P

ENTHALPY		GRAINS		ΔWi
IN	OUT	IN	OUT	
45.9	65.4	108	275	167
47.0	66.5	114	277	163
47.0	66.5	118	277	159
48.2	67.7	130	282	152

$$4 \text{ POINTS } \Sigma 641 \text{ ave } 160.25 \times \frac{88,000}{7000} = 2014.5 \div 8.34 = 241.6 \text{ gpm}$$

$$8 \text{ POINTS } \Sigma 1858 \text{ ave } 232.25 \times \frac{44,000}{7000} = 1459.9 \div 8.34 = 175 \text{ gpm}$$

$$\text{FOR MIX } (16 \times 175) + (8 \times 241.6) = \text{ave } 197.2$$

$(197.2 - 180) \times 1440 = 24,800$ gal evaporation above allowable for day
This is acceptable.

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

SHEET NO. 89 OF

JOB NO. 5-81014

BY BR DATE 23 Sept 81

CHKD. BY DATE

CHECK WET TOWER EVAPORATION @ 44 % POINT

CONDITIONS FOR JUNE 1978 R=14.30 ONE FAN

TYPICAL SUMMER DAY $\frac{W}{G} = 2.726$

	TEMP °F		ENTHALPY		GRAINS		ΔW _i
	DRY	WET	IN	OUT	IN	OUT	
12 MID	88	70	34.6	73.1	82	310	228
2A	79	70	34.1	73.1	94	310	216
4	74	71	35.0	74.0	110	315	205
6	73	68	32.4	71.4	95	300	205
8	76	69	33.3	72.3	95	305	210
10	90	73	36.7	75.7	95	322	227
12N	99	75	38.6	77.6	92	335	243
2P	104	74	37.7	76.7	78	330	252
4	108	76	39.6	78.6	84	343	259
6	108	75	38.6	77.6	78	335	257
8	104	74	37.7	76.7	78	330	252
10	95	68	32.4	71.4	60	300	240

$$12 \text{ POINTS } \leq 2794 \div 12 = 232.8$$

$$232.8 \times \frac{44,000}{7,000} = 1463.5 \div 8.34 = 175.5 \text{ gpm OK}$$

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P.10 OFJOB NO. 5-81014BY RF DATE 23 Sept 78

CHKD. BY DATE

CHECK WET TOWER ON WINTER DAY @ 44% POINTS
 CONDITIONS FOR 7 NOV 78 R=14.30 4G=2.726 (one fan)

	TEMP °F		ENTHALPHY		GRAINS		AWC	COLD OFF
	DRY	WET	IN	OUT	IN	OUT		
12 MID	61	47	18.7	57.7	26	232	206	78
2A	59	52	21.4	60.4	46	242	196	84
4	54	48	19.2	58.2	40	235	195	79
6	53	47	18.7	57.7	40	234	194	78
8	70	54	22.6	61.6	36	247	211	84
10	83	60	26.5	65.5	40	272	232	87.
12N	90	62	27.9	66.9	44	277	233	87
2P	90	61	27.2	66.2	40	273	233	86
4	88	61.4	27.4	66.4	43	272	230	86.4
6	72	56.5	24.2	63.2	44	258	214	85.5
8	66	49.5	20.0	59.0	27	238	211	82.5
10	62	61	27.2	66.2	78	273	195	86

12 POINTS Σ 2550 $\div$ 12 = 212.5

$212.5 \times \frac{44000}{7000} = 1335.7 \div 8.34 = 160 \text{ gpm}$ OK

Check @ same conditions @ 46% POINT R=14.83 COLD OFF

12 MID	18.7	59.1	26	237	211	77
2A	21.4	61.8	46	247	201	85
4	19.2	59.6	40	235	195	82
6	18.7	59.1	40	237	197	81
8	22.6	63.0	36	257	221	86
10	26.5	66.9	40	275	235	88
12N	27.9	68.3	44	284	240	89
2P	27.2	67.6	40	281	241	88
4	27.4	67.8	43	282	239	87.4
6	24.2	64.6	44	268	224	86.5
8	20.0	60.4	27	242	215	83.5
10	27.2	67.6	78	281	203	88

12 POINTS Σ 2622 $\div$ 12 = 218.5

$218.5 \times \frac{44000}{7000} = 1373.4 \div 8.34 = 164.7$ OK

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SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P.11 OF

JOB NO.

BY DATE

CHKD. BY DATE

CHECK WET TOWER ON WINTER DAY @ 48% POINT
Ref SHT P 10 R=15.39 L/G=2.726

	ENTHALPHY		GRAINS		AWL	COLD OFF
	IN	OUT	IN	OUT		
12 MID	18.7	60.7	26	242	216	same at 48% point see sheet P10
2A	21.4	63.4	46	258	212	
4	19.2	61.2	40	245	205	
6	18.7	60.7	40	244	204	
8	22.6	62.6	36	253	217	
10	26.5	68.5	40	285	245	
12N	27.9	69.9	44	294	250	
2P	27.2	69.2	40	288	248	
4	27.4	69.4	43	289	246	
6	24.2	66.2	44	275	231	
8	20.0	62.0	27	250	223	
10	27.2	69.2	78	288	210	

$$12 \text{ POINT } \Sigma 2767 \div 12 = 230.6$$

$$230.6 \times \frac{44,000}{7,000} = 1418 \div 8.34 = 170 \quad \text{OK}$$

Check @ 50% POINT

R=15.9

L/G 2.726

12 MID	18.7	62.2	26	250	224
2A	21.4	64.9	46	270	224
4	19.2	62.7	40	254	214
6	18.7	62.2	40	251	211
8	22.6	66.1	36	275	239
10	26.5	70.0	40	295	255
12N	27.9	71.4	44	300	246
2P	27.2	70.7	40	296	256
4	27.4	70.9	43	296	253
6	24.2	67.7	44	282	238
8	20.0	63.5	27	257	230
10	27.2	70.7	78	296	218

$$12 \text{ POINTS } \Sigma 2808 \div 12 = 234$$

$$234 \times \frac{44,000}{7,000} = 1470.9 \div 8.34 = 176.4 \quad \text{OK}$$

Rogers

SUBJECT BRAWLEYSHEET NO. 912 OF JOB NO. 5-81014BY P. E. J. AM DATE 2-3 Sept 81CHKD. BY DATE AIR COOLED STEAM CONDENSERCheck Wet Tower @ 51% POINT WINTER DAYR = 16.20L/G = 2.726ONE FAN

			ENTHALPHY		GRAINS			COLD OFF
	DRY	WET	IN	OUT	IN	OUT	AWI	
12M10	61	47	18.7	62.9	26	254	228	82
2A	59	52	21.4	65.6	46	275	229	86
4	54	48	19.2	63.4	40	258	218	83
6	53	47	18.7	62.9	40	254	214	82
8	70	54	22.6	66.8	36	275	239	87
10	83	60	26.5	70.7	40	294	254	89
12N	90	62	27.9	72.1	44	305	261	90
2P	90	61	27.2	71.4	40	300	260	89
4	88	61.4	27.4	71.6	43	302	259	89 1/2
6	72	58.5	24.2	68.4	44	295	251	88 1/2
8	66	49.5	20.0	64.2	27	266	239	84 1/2
10	62	61	27.2	71.4	78	301	223	83 1/2
								89

12 POINT E = 2875 ÷ 12 = 239.6 $239.6 \times \frac{44,000}{7,000} = 1506.1 \div 8.34 = 180.6$ OK

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P13 OFJOB NO. S-81014BY RF DATE 29 Sept

CHKD. BY DATE

STEAM CONDENSING CURVE

STEAM FLOW IN 116,540 = 56% OF FULL TURBINE LOAD @ 6"

INLET ENTHALPHY ave 1022.4 @ 6" Condensate @ 128

		<u>96</u>	COND.		ESTIMATE	
	<u>Lb/HR</u>	<u>Δh 926.4</u>	<u>MoL/HR</u>	<u>MoL% N.C. & AIR</u>	<u>AVE PRESS</u>	<u>TEMP °F</u>
STEAM	116,540	6474.4	0.89	R	PSIA	
① N.C.	2380	54.1		110.86	2.7	~ 136.8
AIR	124	4.3		F°		
	<u>119,044</u>	<u>6532.8</u>				
STEAM	56,000	3111.1	1.84		2.6	~ 135.
N.C.	2380	54.1		53.27		
② AIR	124	4.3				
	<u>58,504</u>	<u>3169.5</u>				
Steam	6,000	333.3	14.9		2.5	~ 128.2
③ N.C.	2380	54.1		5.71		
AIR	124	4.3				
	<u>8,504</u>	<u>391.7</u>				
Steam	4000	222.2	20.8		2.4	~ 124.0
④ N.C.	2380	54.1		1.9		
AIR	124	4.3				
		<u>280.6</u>				
Steam	3680	204.4	22.2		2.3	~ 122
⑤ N.C.	2380	54.1		2.29		
AIR	124	4.3				
		<u>262.8</u>				

1-2 - Heat Dnty $\sim (116,540 - 56,000) 926.4 = 56.1 \times 10^6 \frac{\text{BTU}}{\text{HR}}$

2-3 $\sim (56,000 - 6,000) 926.4 = 46.3 \quad "$

3-4 $(6,000 - 4,000) \times (1022.4 - 92) = 1.9 \quad "$

4-5 $4000 - 3,680 \times (1022.4 - 90) = 0.3 \quad "$

Neglect Steam & Gas Cooling

Σ 104.6

ROGERS ENGINEERING CO., INC.

111 PINE STREET
SAN FRANCISCO, CA.

CALCULATION COVER SHEET

Job No. S-81014DISCIPLINE PROCESSCalc. No. P-IINo. of Sheets 214

Three P18 - P35

TITLE BRAWLEY STUDY

SUBJECT

AIR COOLED STEAM CONDENSER

STATEMENT OF PROBLEM

CHECK OPTIMIZATION AT VARIOUS AIR INLET TEMPERATURES

SOURCES OF DATA

PRELIMINARY HEAT BALANCE FOR DUTY TO AIR COOLED UNIT
STEAM CONDENSING CURVE

SOURCES OF FORMULAE & REFERENCES

PROPOSED POWER SALES VALUESPRELIMINARY CALC ☒FINAL CALC ☐

SUPERSEDES CALC NO. _____

0	PRELIMINARY OPTIMIZATION	AFRAN	800+81				
REV. NO.	REVISION	CALCULATION BY	DATE	CHECKED BY	DATE	APPROVED BY	DATE

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P14A OFJOB NO. 5-81014BY BF DATE 6 Oct 81

CHKD. BY DATE

CHECK OPTIMIZATION AT VARIOUS AIR INLETS

Heat Duty vs TEMP

STEAM		N.C. GAS
DUTY	104.0	0.6
FRAC. DUTY	0.9943	0.0057
°F IN	OUT	OUT
140	128	122
124	78.26	78°F INLET AIR RISE = 46
16	49.74	44 Δt's
33.74/29.75	5.74/46.81	Δt/LMTDS
29.58	0.27	WT/LMTD = 29.85 BHP
AIR = $104.6 \div (0.24 \times 46) = 9.47 \times 10^6 \text{ LB/HR}$ (2.1 FADIS K1252a = 263)		
FIN AREA @ STAB OF 7.5 = $104.6 \div (7.5 \times 29.85) = 0.467 \times 10^6 \text{ FT}^2$		

		128	122
140			
124	84.23	84°F INLET AIR RISE = 40	
16	43.77	38	
27.77/27.59	5.77/40.82		
27.43	0.23	27.66 WT/LMTD	BHP
AIR = $104.6 \div (0.24 \times 40) = 10.9 \times 10^6 \text{ LB/HR}$ (2.42 FADIS K1252a = 303)			
FIN AREA = $104.6 \div (7.5 \times 27.66) = 0.504 \times 10^6 \text{ FT}^2$			

		128	122
140			
124	90.19	90°F INLET AIR RISE = 34	
16	37.81	32	
21.91/25.48	5.81/34.82		
25.33	0.20	25.53 WT/LMTD	BHP
AIR = $104.6 \div (0.24 \times 34) = 12.8 \times 10^6 \text{ LB/HR}$ (2.85 FADIS K1252a = 356)			
FIN AREA = $104.6 \div (7.5 \times 25.53) = 0.546 \times 10^6 \text{ FT}^2$

Rogers

SUBJECT BRAWLEY
ACSC

SHEET NO. 14B OF
JOB NO. S-81014
BY B.F. DATE 9 DEC 81
CHKD. BY DATE

54°F

DERATE ABOVE DESIGN USING LMTD RATIO
FROM DESIGN SHEET FOR P16A

			↓ RATIO	56%	66%	70%
84	LMTD	27.68		100	100	100
				+ CWT @ 44	44	44
90		25.43	0.92	95	105(100)	108(100)
100		21.44	0.77	87	95	98
104		19.73	0.71	84	91	94
110		16.98	0.61	78	84	87
80		28.76	1.039			
70		32.74	1.18			
60		32.36	1.17

Rogers

SUBJECT BRAWLEY

ACSC

SHEET NO. 14C OF

JOB NO. S-81014

BY BE DATE 6 OCT 81

CHKD. BY DATE

LMTD DERATE CHECK

Calc Elec Output

84°F INLET AIR DESIGN @ 56% LOADING
OF
INLET AIR
84

OPER HR
8000
SPLIT FOR
TEMP. INTERVAL
1000 S

Period
KW
1000 S
51,200

KW@DERATE
10,000 - 0 - 10,000

5120 51,200

84	0.64	10000	10000	9655	460	9269
96	0.24	9800	0.95	9310		
				8831	1200	10597
100	0.09	9600	0.87	8352		
				8208	320	2626
104	0.05	9600	0.84	8064		
				7776	400	3110
110	<0.01	9600	0.78	7488		
11						76802

EXISTING PLANT AUX 703 KW X 8000

NEW ACSC FANS 246 KW X 8000

Kw to Sales

(5624)
(1968)
69,210

GROSS HOURLY
WETDRY $\frac{9600}{9839} = 0.976$

Rogers

SUBJECT BRAWLEY
ACSC

SHEET NO. 140 OF
 JOB NO. 5-81014
 BY BF DATE 6 OCT 81
 CHKD. BY DATE

LMTD DERATE CHECK

CALL ELEC OUTTURN

<u>°F</u>	<u>INLET AIR</u>	<u>DESIGN</u>	<u>LOADING</u>	<u>OPER HR</u>	<u>PERIOD</u>
<u>84</u>	<u>0.64-0.60</u>	<u>66%</u>	<u>KN @ derate</u>	<u>8000</u>	<u>PERIOD</u>
<u>84</u>	<u>10000</u>		<u>SPWT FOR</u>	<u>8000</u>	<u>KW</u>
<u>84</u>	<u>10000</u>	<u>0-10000</u>		<u>TEMP. INTERVAL</u>	<u>1000S</u>
<u>90</u>	<u>9800</u>	<u>1.0</u>	<u>9800</u>	<u>5120</u>	<u>51208</u>
<u>90</u>	<u>9800</u>	<u>1.0</u>	<u>9800</u>	<u>960</u>	<u>9504</u>
<u>100</u>	<u>9600</u>	<u>0.95</u>	<u>9120</u>	<u>9460</u>	<u>11352</u>
<u>104</u>	<u>9600</u>	<u>0.91</u>	<u>8736</u>	<u>1200</u>	<u>11352</u>
<u>110</u>	<u>9600</u>	<u>0.84</u>	<u>8064</u>	<u>8928</u>	<u>2857</u>
			<u>8480</u>	<u>720</u>	<u>2857</u>
			<u>8480</u>	<u>400</u>	<u>3360</u>
			<u>2</u>		<u>78273</u>
	<u>EXIST AUR</u>	<u>203 KW</u>	<u>X 8000</u>		<u>(5624)</u>
	<u>NEW ACSC FANS</u>	<u>290 KW</u>	<u>X 8000</u>		<u>(2320)</u>
	<u>KW TO SALES</u>				<u>70329</u>

GROSS HOURLY 9784 = 0.994
wet / dry 9839

Rogers

SUBJECT BRAWLEY
ACSC

SHEET NO. 14E OF
 JOB NO. 3-81014
 BY HE DATE 6/27/81
 CHKD. BY DATE

LMTD DERATE CHECK
 CALL ELECTRIC OUTTURN

84°F INLET DESIGN @ 70% LOADING

°F INLET AIR	KW @ DERATE		OPEN HRS 8000 SPLIT FOR TEMP INTERVAL	Period KW 1000S
84	10,000	-0-	5120	51,200
84	10,000	-0 10000		
90	9800	1.0 9800	9900 960	9504
100	9600	0.98 9408	9604 1200	11525
104	9600	0.94 9024	9216 320	2949
110	9600	0.87 8352	8688 400	3475
				<u>78653</u>
Exit Air 203 KW x 8000				(5624)
New ACSC FANS 308 KW x 8000				(2464)
1KW to Sales				<u>20565</u>

GROSS HOURLY $\frac{9832}{9839} = 0.999$
 wet/dry

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

DERATE CHECK per Vendor data

SHEET NO. PISA OF
 JOB NO. 5-81614
 BY REDA DATE 9 DEC 81
 CHKD. BY DATE

DERATE FOR 78°F DESIGN

NEGLECT N.C. GAS DUTY & TEMP. ① ② X 56 ACHE % OF FULL

INLET AIR

78

Steam 140

AIR $\frac{124}{16}$

128 R L
 78 E M
 50 34 / 29.83 T
 0

① X 56 ACHE % OF FULL
 L + 44 CWT % OF FULL
 M T
 D X
 R ② POINT
 A X + LOAD
 T 56 TOTAL 100 100
 0 56 + 44 = 100 100 100

90

140
 $\frac{124}{16}$

128
 90 34
 38 22 / 25.43

0.74
 0.85

70

100

140
 $\frac{124}{16}$

128
 100 24
 28 22 / 21.44

0.52
 0.72

43 + 44 = 87

53 + 44
 57 + 44

97
 100

104

140
 $\frac{124}{16}$

128
 104 20
 24 8 / 19.73

0.43
 0.66

33 + 44 = 77

43 + 44
 47 + 44

87
 91

110

140
 $\frac{124}{16}$

128
 110 14
 18 2 / 16.98

0.30
 0.57

29 + 44 = 73

39 + 44
 43 + 44

83
 87

22 + 44 = 66

32 + 44
 36 + 44

76
 80

APPROX DERATE PER
 BID DATA AVERAGE

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P158 OFJOB NO. 5-81-14BY RFM DATE 9 DEC 81

CHKD. BY _____ DATE _____

CALC. ELECTRIC OUTTURN78°F INLET AIR DESIGN ± 5% LOADING

TEMP °F	ANNUAL INLET AIR FRACTIONS	EST. KW (FULL)	AIR COND. EFFECT (1)	DERATE (2)	KW @ DERATE
78	0.50 - 0.50	10,000			10,000
78	0.50		-0-		
	0.26				9263
90	0.24	9800	0.87		8526
	0.15				7959
100	0.09	9,600	0.77		7392
	0.04				7175
104	0.05	9,600	0.73		7008
	0.05				6672
110	<0.01	9600	0.66		6336

OPER 8000 HRS/YR	PERIOD
SPLIT FOR	KW
TEMP. INTERVAL	1000 S

78	0.50 - 0.50	10,000		10,000	4000	40,000
78	0.50		-0-			
	0.26			9263	2080	19,267
90	0.24	9800	0.87	8526		
	0.15			7959	1200	9,551
100	0.09	9,600	0.77	7392		
	0.04			7175	320	2,296
104	0.05	9,600	0.73	7008		
	0.05			6672	400	2,669
110	<0.01	9600	0.66	6336		

	Σ	73,783
EXISTING PLANT AUXILIARIES 703 KW X 8000	=	5,624
NEW CONDENSER FANS 263 BHP ~ 213 KW X 8000	=	1,704
KW TO SALE	=	66,455

- ① DERATE DUE GEN. AIR COOLER VS COLD WATER TEMPERATURE
2 FANS REQ'D ABOVE 110 WHICH IMPROVES CAPABILITY
- ② BASED ON EFFECT OF AVAILABLE AIR RISE X LMTD RATIO FOR
ACHE AT OFF DESIGN INLET ASSUMING HOLDING TERMINAL
AIR OUT DIFFERENCE CONSTANT. AIR LOAD + CWT LOAD % = DERATE
SEE CALC. SHEET P15A, 16A & 17A

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

SHEET NO. 155 OF

JOB NO. 5-81014

BY BF DATE 9 DEC 81

CHKD. BY DATE

CALC ELECTRIC OUTTURN				8000	
78°F INLET AIR DESIGN @ 66% LOADING				OPER	PERIOD
KW DERATE				HRS FOR	KW
TEMP OF				INTERVAL	1000'S
INLET AIR					
78	0.50 - 0.50	10,000		4000	40,000
78	0.26	10,000	- 0 - 10,000		
			9753	2080	20,286
90	0.15	9800	0.97 9506		
			8929	1200	10,715
100	0.04	9600	0.87 8352		
			8160	320	2,611
104	0.05	9600	0.83 7968		
			7632	400	3053
110		9600	0.76 7296		
				Σ	76,665
EXISTING AUX 203 x 8000					(5,624)
FANS 251 KW x 8000					(2,008)
Net for Sale					69,033

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

SHEET NO. 15D OF

JOB NO. 5-81014

BY RF DATE 9 DEC 81

CHKD. BY DATE

CALL ELECTRIC OUTTURN					8000	
78°F INLET AIR DESIGN & 70% LOADING					OPER HRS	PERIOD
KW DERATE					FOR	KW
TEMP °F					INTERVAL	1000's
INLET AIR 0.						
78	0.50-50	10000			4000	40,000
78		101000	- 0 -	10,000		
				9,900	2080	20,592
90		9800	0.10	9,800		
				9268	1200	11,122
100		9600	0.91	8736		
				8544	320	2,734
104		9600	0.87	8352		
				8016	400	3,206
110		9600	0.80	7680		
					2	77,654
EXISTING AUX 703 X 8000						(5,624)
FANS 266 KW X 8000 HRS						(2,128)
Net for Sale						70,175

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P.16A OFJOB NO. 5-81.14BY BF DATE 9 DEC 71CHKD. BY DATEDERATE CHECK FOR VENDOR DATA
DERATE FOR 84°F DESIGN

INLET AIR

84

Steam 140

124

16

128

84

44

AT/LMTD

28/27.68.

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X 56

444 = 50% LOAD

VENDOR DATA
DERATE

POINT

TOTAL ALLOWANCE

LOAD %

66 70

56 + 44 = 100 100 100

90

140

124

16

128

90

38

34

0.85.

22/25.43. 0.92.

100

140

124

16

128

100

28

24

0.60

12/21.44 0.77

104

140

124

16

128

104

24

20

0.50

8/19.73 0.71

110

140

124

16

128

110

18

14

0.35

2/16.98 0.61

TURB 5.5"

80

137

120

17

128

80

45

40

1.0

28/18.76 1.039

TURB 4.5"

70

130

110

20

120

70

50

40

1.0

30/32.74 1.18

TURB 3.5"

60

120

100

20

109

60

49

40

1.17

29/32.36 1.17

Rogers

SUBJECT BRAWLEY
AIR COOLER STEAM CONDENSER

SHEET NO. P.16B OF
 JOB NO. S-21014
 BY A. Frank DATE 9
 CHKD. BY DATE

CALL. ELECTRIC OUTTURN					OPER 8000HR/YR	PERIOD
84°F INLET AIR DESIGN @ 56% LOADING					SPLIT FOR TEMP	KW
TEMP °F	ANNUAL	EST KW	AIR COND. EFFECT	KW @	INTERVAL	1000'S
INLET AIR FRACTIONS (FULL) (1)			FRAC. LOSS (2)	DERATE		
84	0.64 - 0.64	10,000	- 0 -	10,000	5,120	57,200
84	0.64			10,000		
	0.12			9557	968	9,175
90	0.24	9,800	0.93	9114		
	0.15			8541	1200	10,249
100	0.09	9,600	0.83	7968		
	0.04			7776	320	2,488
104	0.05	9,600	0.79	7584		
	0.05			7296	400	2918
110	< 0.01	9,600	0.73	7008		
					=	76030
EXISTING PLANT AUXILIARIES 703 KW x 8000					=	(5624)
NEW CONDENSER FANS 303 BHP x 246 KW x 8000					=	(1968)
KW TO SALES					=	68438

NOTES SEE CALL SHEET P-15B

$$76030 \div 8000 = 9504 \text{ HOURLY}$$

SUBJECT BRAWLEY
AIR COOLED STEAM CONDENSER

SHEET NO. 16C OF
 JOB NO. 5-81014
 BY BF DATE 9 DEC 91
 CHKD. BY DATE

CALL ELECTRIC OUTTURN						PERIOD
84°F INLET AIR DESIGN @ 66% LOADING						Kw
8000 OPER						1000'S
TEMP OF	KW DERATE		HRS FOR		INTERVAL	
INLET AIR						
84	0.64	10,000			5120	51200
84	0.64		-0-	10,000		
				9,400	960	9504
90	0.24	9,800	1.0	9800		
				9364	1200	11237
100	.09	9,600	0.93	8928		
				8736	320	2796
104	0.4	9,600	0.89	8544		
				8256	400	3302
110		9,600	0.83	7968		
						78039
EXIST AUX 703 X 8000						(5624)
FANS 290 KW X 7 8000						(2320)
Kw to Sales						70095
78039 ÷ 8000 = 9755 HOURLY

AIR COOLED STEAM CONDENSER

SHEET NO. 160 OF
JOB NO. 5-81014
BY BF DATE 7 DEC 81
CHKD BY DATE

CALC ELECTRIC OUTTURN					8000	PERIOD
84°F INLET AIR DESIGN @ 70% LOADING					OPER HRS	KW
TEMP °F			KW	DERATE	FOR INTERVAL	1000'S
INLET AIR						
84	0.64	10000			5120	51200
89			-0-	10,000		
				9,900	960	9504
90		9800	1.0	9,800		
				9,556	1200	11467
100		9600	0.97	9312		
				9120	320	2918
104		9600	0.93	8928		
				8640	400	3456
110		9600	0.87	8352		
				Σ		78545
EXIST	AWK	703 X 8000				(5624)
FANS		308 KW X 800				(2464)
		KW TO SALES				70457
78545 ÷ 8000 = 9818						Kowley

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

SHEET NO P17A OF

JOB NO. 5-E1014

BY RF DATE 9 DEC 81

CHKD. BY DATE

DERATE CHECK PER VENDOR DATA

DERATE FOR -90°F DESIGN

INLET AIR

90

Steam 140

124

16

128

90

38

R
I
S
E

L
M
T
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34

22/25.43

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X 56

+44 = % OF LOAD

POINT

TOTAL ALLOWABLE

ACHR
LOAD % ACH 70

58+44 = 100 100 100

100

140

124

16

128

100

28

24

12/21.44

0.71

0.84

45+44 = 89

104

140

124

16

128

104

24

20

8/19.73

0.59

0.78

41+44 = 85

110

140

124

16

128

110

18

14

2/16.98

0.41

0.67

34+44 = 78

TURB 5.5"

80

137

114

23

125

80

45

34

22/32.78

1.0

1.29

44+44 = 88

48

72

88

92

VENDOR DATA
DERATE

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

SHEET NO. P17B OF

JOB NO. S-81014

BY B. Fraser DATE 3 DEC 81

CHKD. BY DATE

CALC. ELECTRIC OUTTURN

90°F INLET AIR DESIGN & 56% LOADING

TEMP ANNUAL EST KW AIR COND KW @
INLET AIR FRACTIONS FULL LOAD(1) FRAC. LOSS(2) DERATE

OPER 8000HR/YR PERIOD
SPLIT FOR KW
INTERVAL 1000 S

90	0.76	-0.76	9800	-0-	9800	6080	59,584
90	0.76	0.15	9600	0.89	9800	1200	11,006
					9172		
100	0.09	0.04	9,600	0.85	8544	320	2673
					8352		
104	0.05	0.05	9,600	0.78	8160	400	3,130
					7824		
110	<0.01		9,600		7488		

Σ

76,393

EXISTING PLANT AUXILIARIES 703 KW X 8000 =

(5,624)

NEW CONDENSER FANS N 356 BHP N 289 KW X 8000 =

(2,312)

KW TO SALES

68,457

NOTES: SEE CALL SHEET P15B

Rogers

SUBJECT BRAWLEY
AIR COOLED HEAT EXCHANGER

SHEET NO. P.17C OF
JOB NO. S-8101.4
BY B.F. DATE 9 DEC 81
CHKD. BY DATE

CALC ELECTRIC OUTTURN						
90°F INLET AIR DESIGN @ 66% LOADING						
TEMP °F			KW DERATE	80000 PER HRS FOR PERIOD	PERIOD KW 1000'S	
INLET AIR						
90	0.76	9,800			6080	59584
90			-0-	9800		
				9652	1200	11582
100		9,600	0.99	9504		
				9312	320	2980
104		9,600	0.95	9120		
				8784	400	3514
110		9,700	0.88	8448		
						<hr/>
						77660
						(5,624)
Exit AUX 203 X 8000						(2,728)
FANS 341 KW X 8000						69,308
Net to Sales

Rogers

SUBJECT BRAWLEY
AIR COOLED STEAM CONDENSER

SHEET NO. D17D OF
JOB NO. S-81014
BY BF DATE 9 DEC 81
CHKD. BY DATE

CALC ELECTRIC OUTTURN					8000	
90°F INLET AIR DESIGN @ 70% LOADING					OPER HRS	
KW					FOR PERIOD	
DERATE						
TEMP °F						
INLET AIR						
90	0.76	9800			6080	59584
90			-0-	9800		
				9700	1200	11,640
100		9600	1.0	9600		
				9552	320	3057
104		9600	0.99	9504		
				9168	400	3667
110		9600	0.92	8832		
						77,948
EXIST AUX 703 x 8000						(5,624)
FANS 361 KW x 8000						(2,888)
Net to Sales						69,436

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P19 OFJOB NO. S-81014BY RF DATE 5 DEC 81

CHKD. BY DATE

CHECK ON WORST DAY AT CONTROL SPECIFIC POINTSFANS - ONE L/G = 2.726 TUB $\frac{1}{4}$ = 1.363

TIME	TEMP °F		ENTHALPHY		R-	No	GRAINS		AWI	Calc gpm
	DRY	WET	IN	OUT			IN	OUT		
12 MID	85	67	31.6	69.1	13.75	1	70	290	220	165.8
2A	86	68	32.4	69.9	13.75	1	74	295	221	166.6
4	80	67	31.6	70.6	14.3	1	78	295	217	163.5
6	84	69	33.3	70.8	13.75	1	82	296	214	161.3
8	98	79	41.6	79.1	13.75	1	120	340	220	165.8
10	109	80	43.7	79.7	13.2	1	108	345	237	178.6
12N	117	82	45.9	63.9	13.2	2	108	260	152	229.1
2P	118	83	47.0	65.0	13.2	2	114	265	151	227.6
4	116	83	47.0	65.0	13.2	2	118	265	147	221.6
6	113	84	48.2	66.2	13.2	2	130	272	142	214.0
8	100	76	39.6	75.6	13.2	1	96	320	224	168.8
10	92	72	35.8	73.3	13.75	1	86	310	224	168.8

12 POINT Σ = 2231.5 $\div$ 12 = 186.0 gpm Ave

CHECK FOR TYPICAL SUMMER DAY

TIME	TEMP °F		ENTHALPHY		R-	1	GRAINS		AWI	Calc gpm
	DRY	WET	IN	OUT			IN	OUT		
12 MID	88	70	34.1	71.5	13.75		82	300	218	164.3
2A	79	71	34.1	71.5			94	300	206	155.2
4	74	71	35.0	72.5			110	308	198	149.2
6	73	68	32.4	69.9			95	295	200	150.7
8	76	69	33.3	70.8			95	295	200	150.7
10	90	73	36.7	74.2			95	315	223	168.1
12N	99	75	38.6	76.0			92	325	233	175.6
2P	104	74	37.7	73.7	13.2		78	314	236	177.9
4	108	76	39.6	75.6			84	330	246	185.4
6	108	75	38.6	74.6			78	324	246	185.4
8	104	74	37.7	73.7			78	320	242	182.4
10	95	68	32.4	69.9	13.75		60	295	235	177.1

12 POINTS Σ 2022 $\div$ 12 = 168.5

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSED

SHEET NO. P20 OF

JOB NO. S-81014

BY BF DATE 5 DEC 81

CHKD. BY DATE

CHECK ON WINTER DAY AT CONTROL SPECIFIC POINTS
OF

TIME	°F		ENTHALPY		FANS	NO	GRAMS		GPM	Calc
	DRY	WET	IN	OUT R-			IN	OUT AWT		
12 MID	61	47	18.7	62.0	15.9	1	26	250	224	168.8
2A	59	52	21.4	64.7	15.9		46	265	219	165.1
4	54	48	19.2	62.5	15.9		40	250	210	158.3
6	53	47	18.7	62.0	15.9		40	248	208	156.8
8	70	54	22.6	61.6	15.4		36	248	212	159.8
10	83	66	26.5	64.0	13.75		40	260	220	165.8
12N	90	62	27.9	65.3			44	270	226	170.3
2P	90	61	27.2	64.7			40	265	225	169.6
4	88	61.4	27.4	64.9			43	265	222	167.3
6	72	56.5	24.2	66.2	15.4		44	272	228	171.8
8	66	49.5	20	63.3	15.9		27	250	223	168.1
10	62	61	22.2	70.5	15.9	1	78	295	217	163.5

Σ 12 POINTS = 1985.2 ÷ 12 = 165.4 Ave

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

SHEET NO. 221 OF
 JOB NO. S-81014
 BY BR DATE 5 DEC 81
 CHKD. BY DATE

CHECK STEAM CONDENSED AT CONTROL SPECIFIC POINTS

WORST DAY TURB @ 6" Hg Abs - Steam Condensed Flow $\approx$ 205,000 $\frac{LB}{HR}$

TIME	°F	C.W.T.	ACHE	Σ	AUX Steam COND $\approx$	STEAM LIMITING PERIOD, LB	
12M	85	42	56	98	106	213,900	427.8
2A	86	42	56	98	104	↓	427.3
4	80	44	64	108		218,000	436.0
6	84	42	56	98		213,900	427.8
8	98	42	30	72		160,600	321.2
10	109	40	14	54		123,700	247.4
12N	117	40	4	44		103,200	206.4
2P	118	40	3	43		101,100	202.2
4	116	40	5	45		105,200	210.4
6	113	40	8	48		111,400	222.8
8	100	41	26	67		150,300	300.6
10	92	42	40	82		181,100	362.2

CONDENSATE = $\left[3,792,000 \frac{LB}{DAY} \div (1440 \times 8.34) \right] \times 43 = 135.8 \text{ gpm Ave}$
 ≈ 315.8

CALL EVAP $[-1186.0 + 135.8 = 50.2 \text{ gpm Short Ave} \times 1440 = 72,280 \text{ gal short}]$

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P22 OF
JOB NO. S-21014
BY RF DATE DEC 81
CHKD. BY DATE

check for TYPICAL SUMMER DAY AT CONTROL SPECIFIC POINTS

TIME	CWT		ACHE Σ		Steam LIMITING Packed $\frac{L}{HR}$
	DRY	% LOAD	% LOAD	% LOAD	
12M	88	42	46	88	193,400
2A	79	42	66	108	218,000
4	74	42	76	118	↓
6	73	42	76	118	
8	76	42	72	114	
10	90	42	44	86	
12N	99	42	24	66	148,300
2P	104	40	20	60	136,000
4	108	40	14	54	123,700
6	108	40	14	54	↓
8	104	40	20	60	
10	95	42	34	76	168,800

CONDENSATE 4,192,400 $\div (1440 \times 8.34) \times 0.43 = 149.7 \text{ gpm Ave}$ Calc EVAP $[-168.7 + 149.7 = 18.8 \text{ gpm Short} \times 1440 = 27,072 \text{ gal Short}]$

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

SHEET NO. P23 OF

JOB NO. 5-81014

BY BE DATE 7 DEC 81

CHKD. BY DATE

check for typical WINTER DAY at control specific points

TIME	DRY	CWT		ACHE		PERIOD	LB/HR
		% LOAD		% LOAD			
12 MID	61	51		60	111	218,000	
2 A	59	51		60			
4	54	51		60			
6	53	51		60			
8	70	48		60			
10	83	42		60			
12 N	90	42		44	86	189,300	
2 P	90	42		44			
4	88	42		48	90	197,500	
6	72	48		60	108	218,000	
8	66	50		60	110		
10	62	51		60	111		

CONDENSATE $[5,076,200 \text{ LB/DAY} \div (1440 \times 8.34)] \times 0.43 = 181.7 \text{ AVE}$

Calc EVAPORATION $(-165.4 + 181.7) = 16.3 \text{ LONG}$

$\times 1440 = 23,472 \text{ gal LONG}$
each DAY

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

SHEET NO. P24 OF

JOB NO. S-81014

BY BE DATE 7 DEC 81

CHKD. BY DATE

Check Worst Day @ 84°F & 66% of Load at Design

TIME	DRY	CWT	ACHE		
12M	85	42	63	100+	218,000
2A	86		59		
4	80		70+		
6	84		66		
8	98		39	81	179,000
10	109	42	23	65	146,200
12N	117	40	8	48	111,400
2P	118				
4	116				
6	113				
8	100	41	36	77	170,800
10	92	42	50	92	201,600

$$4030.4 [1440 \times 8.34] \times 0.43 = 144.3$$

$$186.0 - 144.3 = 41.7 \text{ short } 1440 = 60048 \text{ gal short}$$

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

SHEET NO. P25 OF

JOB NO. 5-81014

BY BF DATE 7 DEC 81

CHKD. BY DATE

Check For Typical Summer Day @ 90°F DESIGN (56 Load)

TIME	DRY				
12M	88	42	61	100+	218,000
2A	79				
4A	74				
6	73				
8	76				
10	90		56	98	213,900
12N	99		35	77	170,800
2P	104	40	26	66	148,300
4	108		18	58	131,900
6	108			58	
8	104		26	66	148,300
10	95	42	43	85	187,200

$$0.85 \text{ Condenser } 4444.6 \div [1,440 \times 8.34] \times 0.43 = 159.1 \text{ gpm Ave}$$

$$\text{EVAP } 168.5 - 159.1 = 9.4 \text{ gpm Ave Short}$$

$$\times 1440 = 13,536 \text{ gal Short ea Day}$$

Rogers

SUBJECT BRAWLEY
AIR COOLED STEAM CONDENSER

SHEET NO. P28 OF
 JOB NO. S-81014
 BY BF DATE 7 DEC 81
 CHKD. BY DATE

Check Typical Summer Day @ 84°F ± 66% of Load at Des. gn

TIME	DRY				
12 MID	88	42	57	99	215,900
2 A	79		70	100+	218,000
4	74			↓	↓
6	73			↓	↓
8	76			↓	↓
10	90		53	95	207,700
12 N	99	↓	38	80	177,000
2 P	104	40	30	70	156,500
4	108	↓	24	64	144,200
6	108		24	↓	↓
8	104	↓	30	70	156,500
10	95	42	44	86	189,300

Condensate $4526.6 \div [(1440 \times 8.34)] \times 0.43 = 162.0 \text{ gpm Ave}$

EVAP $\sim 168.5 + 162.0 = 6.5 \text{ gpm short} \times 1440 = 9360 \text{ gal day short}$

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P27 OF JOB NO. S-81014BY BF DATE 7 DECCHKD. BY DATE

Check Typical Summer Day @ 84°F & 70% of load @ Design

TIME	DRY	CWT ACHE					
12 MID	88	42	38	62	100	100+	218,000
2 A	79						218,000
4	74						
6	72						
8	76						
10	90		36	58	94		205,700
12 N	99			42	78	84	185,200
2 P	104	40		30	66	70	156,500
4	108			28	64	68	152,400
6	108			28		68	
8	104			30	66	70	156,500
10	95	42	38	48	86	90	197,500

0.88

$$4617 \div [1440 \times 8.34] \times 0.43 = 165.3$$

$$\text{EVAP} - 168.5 + 165.3 = 3.2 \text{ gpm Short} \times 1440 = 4608 \text{ gal Short}$$

0.86

$$4485.8 \div [1440 \times 8.34] \times 0.43 = 160.6$$

$$\text{EVAP} - 153.9 + 160.6 = 6.7 \text{ LONG OK}$$

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P28 OF JOB NO. S-81014BY BF DATE 7 DEC 81CHKD. BY DATE

Check on WORST DAY AT Reschedule on CWT

TIME	°F		ENTHALPY		R	FANS No	GRAINS		Calc gpm
	DRY	WET	IN	OUT			IN	OUT Δwci	
12 MID	85	67	31.6	66.1	12.66	1	70	270 200	150.7
2A	86	68	32.4	66.9	↓	1	74	275 201	151.5
4	80	67	31.6	66.1		1	78	270 192	144.7
6	84	69	33.3	67.8		1	82	280 198	149.2
8	98	79	41.6	76.1		1	120	325 205	154.5
10	109	80	43.7	76.7	12.1	1	108	330 222	167.3
12 N	117	82	45.9	62.1	↓	2	108	250 142	214.0
2P	118	83	47.0	63.4		2	114	260 146	220.
4	116	83	47.0	63.4		2	118	260 142	214.
6	113	84	48.2	64.6		2	130	263 133	200.5
8	100	76	39.6	72.6	↓	1	96	310 214	161.3
10	92	72	35.8	70.3	12.66	1	86	296 210	158.3

 $\Sigma 2086 \div 12 = 173.8$ gpm Ave EVAP.

Check Typ Summer Day Similar Reschedule

TIME	DRY	WET	IN	OUT	R	1	IN	OUT	Δwci	gpm
12 M1	88	70	34.1	71.5	12.66	↓	82	300	218	164.3
2A	79	71	34.1	71.5	↓	↓	94	300	206	155.2
4	74	71	35.0	72.5		↓	110	308	198	149.2
6	73	68	32.4	69.9		↓	95	295	200	150.7
8	76	69	33.3	70.8		↓	95	295	200	150.7
10	95	73	36.7	74.2	↓	↓	95	318	223	168.1
12 N	99	75	38.6	76.0		↓	92	325	233	175.6
2P	104	74	37.7	73.7	12.1	↓	78	314	236	172.9
4	108	76	39.6	75.6	↓	84	330	246	185.4	
6	108	75	38.6	74.6	↓	78	324	246	185.4	
8	104	74	37.7	73.7	↓	78	320	242	182.4	
10	95	68	32.4	69.9	12.66	↓	60	295	235	177.1

 $\Sigma 2022 \div 12 = 168.5$ gpm Ave

Rogers

SUBJECT BRAWLEY
AIR COOLED STEAM CONDENSER

SHEET NO P29 OF
 JOB NO. S-810.14
 BY BF DATE 7 DEC 81
 CHKD. BY DATE

Check Worst Day : Day @ 84°F & 70% of Load at Design
 Resealed

	DRY	CWT	ACHE				
12 MID	85	4238	68	100	100	+	218,000
2A	86		66				218,000
4	80		74				
6	84		70				
8	98		39	77	81		179,000
10	109	4236	23	59	65		146,200
12N	117	4038	8	46	48		111,400
2P	118						
4	116						
6	113						
8	100	41	40	78	81		179,000
10	92	4236	50	86	92		201,600
							189,300

Condensate $4046.8 \div [1440 \times 8.34] \times 0.43 = 144.9$ Ave

EVAP $-1860 + 144.9 = 41.1 \times 1440 = 59,184$ gal / short

OR
 Condensate $3936.2 \div [1440 \times 8.34] \times 0.43 = 140.9$

EVAP $-173.8 + 140.9 = 32.9 \times 1440 = 47,376$ SHORT

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

SHEET NO. P30 OF

JOB NO. S-81014

BY BE DATE 7 DEC 81

CHKD. BY DATE

Check For Worst Day @ 90°F Design & 50% Load
& 70% Load

		Resched.					
TIME	DRY	↓	↓	↓			
12M	85	423868	100+	100	218,000	218,000	
2A	86	42	66	↓	↓	↓	↓
4	80	44	79	↓	↓	↓	↓
6	84	42	70	↓	↓	↓	↓
8	98	42	385280	90	177,000	197,500	
10	109	4036	173157	67	129,800	150,300	
12N	117	38	8	48	46	111,400	107,300
2D	118	↓	↓	↓	↓	↓	↓
4	116	↓	↓	↓	↓	↓	↓
6	113	↓	↓	↓	↓	↓	↓
8	100	41	334974	87	164,700	191,300	
10	92	4236	526694	100+	205,700	218,000	

$$3989.6 \left[(1440 \times 8.34) \right] \times 0.43 = 142.8 \text{ Ave}$$

$$142.8 - 186 = 43.2 \times 1440 = 62,208$$

$$4116.6 \left[(1440 \times 8.34) \right] \times 0.43 = 147.4$$

$$147.4 - 173.8 = 26.4 \times 1440 = 38016$$

Rogers

SUBJECT BRAWLEYAIR COOLED STEAM CONDENSERSHEET NO. P31 OF JOB NO. 5-81014BY PF DATE 70.5.21CHKD. BY DATE

Check on Worst Day at Reduced Power loading 48%

TIME	°F DRY	CWT %LOAD	ACHE %LOAD	Σ %LOAD	CONDENSATE PERIOD LB	
					111,400	222.8 gpm Ave
12M	85	0	48	48		
2A	86	0	48			
4	86	0	48			
6	84	0	48			
8	98	19	29			
10	109	35	13			
12N	117	44	4			
2P	118	45	3			
4	116	43	5			
6	113	40	8			
8	100	22	26			
10	92	8	40			

TIME	DRY	Wet	ENTHALPHY		R	FANS No	GRAINS		AwL	EVAP CALC gpm
			IN	OUT			IN	OUT		
12M	85	67	31.6	37.9	2.3	1	70	125	55	41.5
2A	86	68	32.4	38.7			74	130	56	42.2
4	80	67	31.6	37.9			78	129	51	38.4
6	84	69	33.3	39.6			82	135	53	39.9
8	98	79	41.6	51.1	3.5		120	292	172	129.6
10	109	80	43.7	75.9	11.8		108	324	216	162.8
12N	117	82	45.9	65.3	14.3	2	108	270	162	244.1
2P	118	83	47.0	66.9	14.6	2	114	280	166	250.2
4	116	83	47.0	66.1	14.0	2	118	270	152	229.1
6	113	84	48.2	66.2	13.2	2	130	270	140	211.0
8	106	76	39.6	62.2	8.3	1	96	250	154	116.1
10	92	72	35.8	48.1	4.5	1	86	180	94	70.8

12 POINTS = $1575.7 \div 12 = 131.3$ Ave EVAP $131.3 - 28 = 103.3 \div 222.8 = 0.46$ Required frac (MIN) $131.3 \div 222.8 = 0.589$

Rogers

SUBJECT FRAWLEY
AIR COOLED STEAM CONDENSER

SHEET NO. P32 OF
 JOB NO. 5-81014
 BY EF DATE 7 DEC 81
 CHKD. BY DATE

CHECK ON WORST DAY @ Reduced Power loading (48%)
 using 2 speed CWT fan to cut evaporation

TIME	DRY WET	ENTHALPHY			NO FANS	GRAINS			Calc gpm
		IN	OUT	R		IN	OUT	AwI	
12M			37.9	2.3	1				41.5
2A			38.7						42.2
4			37.9						38.4
6			39.6						39.9
8			57.1	3.5					129.6
10			75.9	16.8					162.8
12N		45.9	71.8	14.3	①	108	300	192	197.3
2P		47.0	73.5	14.6		114	320	206	211.7
4		47.0	72.4	14.6		118	305	187	192.2
6		48.2	72.1	13.2		130	302	172	176.7
8		39.6	62.2	8.3					116.1
10		35.8	48.1	4.5					70.8

$$\Sigma = 1420.2 \div 12 = 118.3$$

① $\frac{1}{4} \sim 1.812$ AIR FLOW $\sim 60,000$ LB/HR

$$118.3 \div 222.8 = .53$$

$$118.3 - 28 = 90.3 \div 222.8 = 0.41 \quad \text{by using SURGE}$$

Rogers

SUBJECT BRAUNLEY
AIR COOLED STEAM CONDENSER

SHEET NO. 233 OF
 JOB NO. 3-31014
 BY B.F. DATE 7 DEC 81
 CHKD. BY DATE

Check for typical Summer Day @ 48% LOADING

TIME	°F		ENTHALPY		R	No FANS	GRAINS		AWC	Colc EVAP gpm
	DRY	WET	IN	OUT			IN	OUT		
12M	88	70	34.1	40.4	2.3	1	82	140	58	43.7
2A	79	71	34.1	40.4			94	140	46	34.7
4	74	71	35.0	41.3			110	145	35	26.3
6	73	68	32.4	38.7			95	130	35	26.3
8	76	69	33.3	39.6			95	136	41	30.9
10	90	73	36.7	46.0	3.4		95	168	73	55.0
12N	99	75	38.6	60.4	8.0		92	243	151	113.8
2P	104	74	37.7	64.7	9.9		78	265	187	140.9
4	108	76	39.6	70.4	11.3		84	295	211	159
6	108	75	38.6	69.4	11.3		78	290	212	159.8
8	104	74	37.7	64.7	9.9		78	265	187	140.9
10	95	68	32.4	49.0	6.1	1	60	183	123	92.7

$$1024 \div 12 = 85.3 \text{ gpm Ave EVAP}$$

$$85.3 \div 222.8 = 0.38 \text{ Required frac (MIN)}$$

$$222.8 \times 0.43 = 95.8$$

$$95.8 - 85.3 = 10.3 \text{ Recovery}$$

$$\frac{28}{10.3} \text{ Deficit} = 1$$

Rogers

SUBJECT BRAWLEY

AIR COOLED STEAM CONDENSER

SHEET NO. P34 OF

JOB NO. 5-21014

BY R.F. DATE 7 DEC 71

CHKD. BY DATE

Check For Typical Summer Day @ 48% Loading

TIME	°F	CWT	ACHE	Σ	Periced LB	
	DRY	%LOAD	%LOAD	%LOAD		
12M	88	- 0 -	48	48	111,400	222.9 gpm Ave
2A	79	- 0 -				
4	74	- 0 -				
6	73	- 0 -				
8	76	- 0 -				
10	90	4	44			
12N	99	21	27			
2P	104	28	20			
4	108	33	15			
6	108	33	15			
8	104	28	20			
10	95	14	34

Rogers

SUBJECT BRAWLEYSHEET NO. P-35 OFJOB NO. 5-81014BY PF DATE 11 Dec 81CHKD. BY DATE

ACSC
CHECK FOR WORST DAY & RECOVERY SCHEDULE
WORST DAY

TIME	DRY	Fig 7 MAX	100% -ACSC	CWT MAX NET	2 LOADING	CONDENSATE CALC	gpm CALC
12 MID	85	54	46	43.6 +	97.6	213,080	426.2
2A	86	52	48	43.4 +	95.4	208,570	417.1
4	86	58	42 +	45	100.0	218,000	436.0
6	84	56	44	44 +	100.0	218,000	436.0
8	98	30	70	40.1 +	70.1	156,700	313.4
10	109	14	34 + (1)	37.2	48.0	48 - ACSC 111,400	222.8
12N	117	4	44	35.0 +	39.0	93,000	186.0
2P	118	3	45	34.7 +	37.7	77,300	154.6
4P	116	5	43	35.2 +	40.2	95,400	190.8
6	113	8	40	36.0 +	44.0	103,200	206.4
8	100	26	22 +	39.6	48.0	111,400	222.8
10	92	41	7 +	42	48.0	111,400	222.8

$$12 \text{ POINTS} = 3434.9 \div 12 = 286.2$$

TIME	IN	OUT	R	FANS	GRAINS	calc gpm
12 MID	31.6	70.0	14.1	1	70 294 224	168.8
2A	32.4	70.8	14.1	1	74 300 226	170.3
4	31.6	68.9	13.7	1	78 288 210	158.3
6	33.3	72.0	14.2	1	82 304 222	167.3
8	41.6	77.6	13.2	1	120 335 215	162.0
10	43.7	75.3	11.6	1	108 320 212	159.8
12N	45.9	62.0	11.8	2	108 250 142	214.0
2P	47.0	62.9	11.7	2	114 255 141	212.5
4	47.0	63.2	11.9	2	118 257 139	209.5
6	48.2	64.7	12.1	2	130 264 134	202.0
8	39.6	62.2	8.3	1	96 250 154	116.1
10	35.8	47.0	4.1	1	86 173 87	65.6

$$12 \text{ POINTS } 2006.2 = 167.2 \text{ Ave}$$

$$167.2 \div 286.2 = 0.58$$

Rogers

CHECK

SUBJECT BRAWLEYACSCSHEET NO. P-36 OFJOB NO. 2-81014BY P.F. DATE 11 DEC 81

CHKD. BY DATE

TYPICAL SUMMER ON RECOVERY SCHEDULE

TIME	DRY	FI 97 MAX ACSC	48% - ACSC	CWT MAX MET POWER SCHED	2 LOADING	CALC CONDENSATE	CALC gpm
12 MID	88	48	-0-	43.6	48	111,400	222.8
2A	79	59	-0-	43.4			
4	74	63	-0-	45			
6	73	64	-0-	44			
8	76	62	-0-	40.1			
10	90	44	4	37.2			
12N	99	29	19	35.0			
2P	104	20	28	34.7			
4	108	15	23	35.2			
6	108	15	23	34.8			
8	104	20	28	39.6			
10	95	35	13	42			

AVE = 222.8

TYP SUMMER CHECK

TIME	ENTRANCE	ALPHA	R	F	A	GRAINS	Calc
	IN	OUT			N	IN	OUT Awi gpm
12 MID	34.1	40.4	2.3	1		82	140 58 43.7
2A	34.1	40.4				94	140 46 34.7
4	35.0	41.3				110	145 35 26.4
6	32.4	38.7				95	132 37 27.9
8	33.3	39.6				95	135 40 30.1
10	36.7	46.0	3.4			95	165 70 52.8
12N	38.6	58.8	7.4			92	233 141 106.3
2P	37.7	64.7	9.9			78	263 185 139.4
4	39.6	62.8	8.5			84	255 171 128.9
6	38.6	61.8	8.5			78	250 172 129.6
8	37.7	64.7	9.9			78	270 192 144.7
10	32.4	48.2	5.8			60	182 122 91.9

12 POINTS = 956.4 = 79.7 Ave

$$79.7 \div 222.8 = 0.36$$

$$\text{WORST-1} = (167.2 + 79.7) \div (344.1 + 222.8) = 0.44$$

$$\text{WORST-2} = (167.2 + 159.4) \div (344.1 + 445.6) = 0.41$$

Rogers

SUBJECT BRAWLEYSHEET NO. D-37 OF JOB NO. S-81014BY BF DATE 11 DEC 81CHKD. BY DATE ACSC -
CHECK ON REVISED PRELIM. SCHED.
TYPICAL SUMMER

		100% CWT		MAX		CALL	CALL
		FIG 7	ACSC	NET		CONDENSATE	gpm
		MAX	CWT	POWER	Σ LOADING		
TIME	DRY	ACSC		SCHED			
12M	88	48	52	42.8 +	90.8	199,100	398.2
2A	79	59	41 +	45.3	100.0	218,000	436
4	74	63	37 +	46.6	100.0		
6	73	64	36 +	46.9	100.0		
8	76	62	38 +	46.0	100.0		
10	90	44	56	42.3 +	86.3	189,900	379.8
12N	99	29	71	39.9 +	68.9	154.2	308.4
2P	104	20	80	38.5 +	58.5	132,900	265.8
4	108	15	85	37.4 +	52.4	107,400	214.8
6	108	15	85	37.4 +	52.4	107,400	214.8
8	104	20	80	38.5 +	58.5	132,900	265.8
10	95	35	65	40.9 +	75.9	168.6	337.2

$$\Sigma 12 \text{ POINTS} = 4128.5 \div 12 = 344.1$$

60%

TYP SUMMER EVAP CHECK FANS

TIME	ENTHALPHY			R	GRAINS			Calc
	IN	OUT			IN	OUT	Aw	
12MID	34.1	72	13.9	1	82	294	212	159.8
2A	34.1	71.2	13.6		94	300	206	155.3
4	35.0	68.4	12.26		110	285	175	131.9
6	32.4	65.4	12.1		95	268	173	130.4
8	33.3	67.6	12.6		95	280	185	139.4
10	36.7	74.3	13.8		95	316	221	166.6
12N	38.6	74.3	13.1		92	316	224	168.8
2P	37.7	72.3	12.7		78	306	228	171.8
4	39.6	73.4	12.4		84	310	226	170.3
6	38.6	72.4	12.4		78	306	228	171.8
8	37.7	72.3	12.7		78	306	228	171.8
10	32.4	68.3	13.16		60	284	224	168.8

$$\Sigma 12 \text{ POINTS } 1906.7 \div 12 = 158.9$$

$$158.9 \div 344.1 = 0.46$$

Rogers

SUBJECT BRAWLEY
ACSC

SHEET NO. P-38 OF
 JOB NO. S-81014
 BY BF DATE 11 DEC 81
 CHKD. BY DATE

CHECK TYP WINTER DAY

TIME	DRY	Fig 7 MAX ACSC	CWT 100 - ACSC	CWT MAX NET POWER	Z LOADING	CALC CONDENSATE	Calc gpm
12 MID	61	53	47 +	50.2	100	218,000	436
2A	59	53	↓	50.6	↓	↓	↓
4	54	53	↓	51.7	↓	↓	↓
6	53	53	↓	51.8	↓	↓	↓
8	70	53	↓	47.8	↓	↓	↓
10	83	56	44 ↓	44.2	↓	↓	↓
12 N	90	44	56	42.3 +	86.3	189,900	379.8
2P	90	44	56	42.3 +	86.3	↓	↓
4	88	48	52	42.8 +	90.8	199,100	398.2
6	72	53	47 +	47.2	100.0	218,000	436
8	66	53	↓	48.8	↓	↓	↓
10	62	53	↓	49.9	↓	↓	↓

Σ 12 POINTS = 5081.8 ÷ 12 = 423.5 Ave gpm

TIME	ENTHALPY IN OUT	R F A N S	GRAINS IN OUT ΔW/L
12 MID	18.7 55.6	15.0 1	26 216 190
2A	21.4 62.3	↓	46 250 204
4	19.2 60.1	↓	40 240 200
6	18.7 59.6	↓	40 235 195
8	22.6 67.5	↓	36 258 222
10	26.5 67.4	↓	40 280 240
12 N	27.9 65.5	13.8	44 267 223
2P	27.2 64.8	13.8	40 265 225
4	27.4 65.3	13.9	43 266 223
6	24.2 65.1	15.0	44 268 224
8	20 60.9	15.0	27 243 224
10	27.2 68.1	15.0	78 280 202

12 POINT ΔW/L = 2572 ÷ 12 = 214.3 × $\frac{1.4}{7}$ ÷ 8.34 = 161.5 gpm

161.5 ÷ 423.5 = 0.38

Rogers

SUBJECT BEWLEY

ACSC

SHEET NO. P-39 OF

JOB NO. 5-81014

BY AF DATE 15 DEC 81

CHKD. BY DATE

WORST DAY RECHECK

TIME	DRY	Fig 7 MAX ACSC	100 - ACSC	CWT		LOADING
				MAX	NET POWER	
12 MID	85	55	45	43.6	+	98.6
	86	53.7	46.3	43.4	+	97.1
	80	58	42 +	45		100.0
	84	53	44	44	+	100.0
	98	41	59	40.1	+	81.1
	109	29.5	70.5	37.2	+	66.7
	117	20	80	35.0	+	55.0
	118	18.5	81.5	34.7	+	53.1
	116	21	79	35.2	+	56.2
	113	24.5	75.5	36.0	+	60.5
	100	39.4	60.6	39.6	+	79.0
	92	47	53.0	42	+	89

12 POINTS = $936.4 \div 12 = 78 \times 436 = 340$ gpm
condensate

Rogers

SUBJECT ORAWLEYALSCSHEET NO. P.40 OF JOB NO. 581014BY BF DATE 15 DEC 81CHKD. BY DATE

TYP. SUMMER DRY CHECK

		Fig 7 MAX	100-ALSC	Fig 6	LOAD
TIME	DRY	ALSC			
12M.	88	51	49	42.8 +	93.8
2A	79	59	41 +	45.3	100.0
4	74	63	37 +	46.6	100.0
6	73	64	36 +	47.0	100.0
8	76	62	38 +	46.2	100.0
10	90	49	51	42.3 +	91.3
12N	99	40	60	39.5 +	79.5
2P	104	35.5	64.5	38.5 +	74.0
4	108	30.5	69.5	37.4 +	67.9
6	108	30.5	69.5	37.4 +	67.9
8	104	35.5	64.5	38.5 +	74.0
10	95	44	56	41 +	85.0

$$12 \text{ POINTS } 1033.4 \div 12 = 86.1 \times 436 = 375$$

$$1681.5 \div 375 = 0.449$$

	IN	OUT	R	FANS	GRAINS
TIME					IN OUT
12M	88	134.1	72.0	13.9	82 304 222
2A		34.1	73.9	14.6	94 313 219
4		35.0	75.6	14.9	110 323 213
6		32.4	73.3	15.0	95 305 210
8		33.3	73.9	14.9	95 313 218
10		36.7	74.3	13.8	95 315 220
12		38.6	74.3	13.1	92 315 213
2P		37.7	72.3	12.7	78 304 226
4		39.6	73.7	12.5	84 313 229
6		38.6	72.7	12.5	78 306 228
8		37.7	72.3	12.7	78 304 226
10		32.4	68.9	13.4	60 270 210

$$12 \text{ POINTS } = 2634 \div 12 = 219.5 \times 165.4 \text{ gpm}$$

$$165.4 \div 375 = 0.44$$

APPENDIX 3 -

DRAWINGS

- NOTE:**
- 1.) SEE DWG. E-03-013 FOR CONTROL OF AIR-COOLED STEAM CONDENSER (ACSC)
 - 2.) SEE DWG. D-40-001 FOR INSTRUMENT LOOP DIAGRAM.

ROGERS ENGINEERING CO., INC. ENGINEERS & ARCHITECTS 111 PINE STREET, SAN FRANCISCO, CALIF. 94111						SOUTHERN CALIFORNIA EDISON CO. ROSEMEAD, CALIFORNIA		BRAWLEY GEOTHERMAL PLANT - UNIT No. 1 AIR COOLED STEAM CONDENSER STUDY	
SCALE: NONE DATE OCT 7, 1981						APPROVED: _____ DATE _____		PRELIMINARY P&ID	
DR. <i>RS</i> CHK. <i>KKS</i> ENG. <i>BF</i> APPROVED <i>JMG</i>						JOB NO. S-81014		D-03-001	
REV. DATE REVISION DR. CHK. RECO. APPR. CLIENT APPR.						0		0

REFERENCE DRAWINGS		REV.	DATE	REVISION	ENGR.	CHK.	DATE	REVISION	ENGR.	CHK.	DATE
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2											
3											
4											
5											
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7											

ROGERS ENGINEERING CO., INC.
ENGINEERS - ARCHITECTS
101 PINE STREET, SAN FRANCISCO, CALIFORNIA 94111

SOUTHERN CALIFORNIA
EDISON CO.
ROSE MEAD, CALIFORNIA

BRAWLEY GEOTHERMAL PLANT - UNIT NO. 1
AIR-COOLED STEAM CONDENSER STUDY
INSTRUMENT LOOP DIAGRAM

SCALE: NONE DATE: 11/17/01

DR. R. CHK. ENGR. APPROVED

APPROVED

DATE

REV. 10

1-110/18-00

SK-40-001

REV. 0

- NOTES:
1. EQUIPMENT, BLDG'S. & PIPING ARE EXISTING.
 2. APPROXIMATE DIMENSIONS MAY BE OBTAINED BY SCALING DRAWING.
 3. SEE ELECTRICAL DRAWINGS FOR ELECTRICAL EQUIPMENT RATINGS AND CIRCUIT SIZING.
 4. "A", "B" & "C" INDICATE PIPE SUPPORT TYPES. SEE DWG. SK-42-001

ROGERS ENGINEERING CO., INC. ENGINEERS • ARCHITECTS 101 FINE STREET, SAN FRANCISCO, CALIFORNIA 94104										SOUTHERN CALIFORNIA EDISON CO. ROSBEMERD, CALIFORNIA										DRAWLEY GEOTHERMAL PLANT - UNIT No. 1 AIR COOLED STEAM CONDENSER STUDY GENERAL ARRANGEMENT GEA CONDENSER																																																	
										SCALE 1" = 20'-0" DATE _____ BY _____ CHK _____ ENG _____ APPROVED _____										APPROVED _____ DATE _____ _____ _____										JOB NO. _____ SK - 04 - 001										REV. _____																																							
REFERENCE DRAWINGS										REV. DATE										REVISION										ENG. CHK. DES. DATE										REV. DATE										REVISION										ENG. CHK. DES. DATE																			
1										1										2										3										4										5										6										7

- NOTES:
1. EQUIPMENT, BLDG'S. & PIPING ARE EXISTING.
 2. APPROXIMATE DIMENSIONS MAY BE OBTAINED BY SCALING DRAWING.
 3. SEE ELECTRICAL DRAWINGS FOR ELECTRICAL EQUIPMENT RATING AND CIRCUIT SIZING.
 4. "A", "B", "C" INDICATE PIPE SUPPORT TYPES. SEE DWG. SK-42-001.

<div> <div> ROGERS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 311 FINE STREET, SAN FRANCISCO, CALIFORNIA 94111 </div> <div> SOUTHERN CALIFORNIA EDISON CO. ROSEMERE, CALIFORNIA </div> </div>										BRAWLEY GEOTHERMAL PLANT - UNIT NO. 1 AIR COOLED STEAM CONDENSER STUDY GENERAL ARRANGEMENT HUDSON CONDENSER	
SCALE 1" = 20'-0"										JOB NO. S-81014	
DATE _____										REV.	
APPROVED _____										SK-04-002	
REFERENCE DRAWINGS											
REV. DATE											
REVISION											
ENG. CHK. DATE											
REVISION											
ENG. CHK. DATE

- NOTES:**
1. EQUIPMENT, BLDG'S & PIPING ARE EXISTING.
 2. APPROXIMATE DIMENSIONS MAY BE OBTAINED BY SCALING DRAWING.
 3. SEE ELECTRICAL DRAWINGS FOR ELECTRICAL EQUIPMENT RATING AND CIRCUIT SIZES.
 4. 'A', 'B' & 'C' INDICATE PIPE SUPPORT TYPES. SEE DWGS. SK-42-001

REFERENCE DRAWINGS				REVISION				REVISION			
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100				101				102			

ROGERS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 111 FIVE STREET, SAN FRANCISCO, CALIFORNIA 94101		SOUTHERN CALIFORNIA EDISON CO. ROSMERE, CALIFORNIA		BRAWLEY GEOTHERMAL PLANT - UNIT No. 1 AIR-COOLED STEAM CONDENSER STUDY GENERAL ARRANGEMENT LUMINUS CONDENSER	
SCALE 1" = 20'-0" DATE _____ DR. _____ CHK. _____ ENG. _____		APPROVED _____ DATE _____		JOB NO. 6-81014 SK-04-003 REV. _____

SECTION ③
01/01

												<div> <div>ROGERS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 111 FINE STREET, SAN FRANCISCO, CALIFORNIA 94102</div></div>		<div>SOUTHERN CALIFORNIA EDISON CO. ROSEMEAD, CALIFORNIA</div>		<div>BRAWLEY GEOTHERMAL PLANT - UNIT No. 1 AIR COOLED STEAM CONDENSER STUDY ELEVATIONS GEA CONDENSER</div>																																																																			
												SCALE 1/8" = 1'-0"		DATE		APPROVED		DATE		JOB NO. 5-81014		SK - 04 - 004		REV.																																																											
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SECTION B
03/09

										ROGERS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 111 FINE STREET, SAN FRANCISCO, CALIFORNIA 94111		SOUTHERN CALIFORNIA Edison CO. ROSEMEAD, CALIFORNIA		BRAWLEY GEOTHERMAL PLANT - UNIT No. 1 AIR COOLED STEAM CONDENSER STUDY ELEVATIONS LUMMUS CONDENSER																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																															
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SECTION **D**
02/04

<div> ROGERS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS <small>111 FINE STREET, SAN FRANCISCO, CALIFORNIA 94101</small> </div>										SOUTHERN CALIFORNIA EDISON CO. ROSEMead, CALIFORNIA		BRADLEY GEOTHERMAL PLANT - UNIT No. 1 AIR COOLED STEAM CONDENSEE STUDY ELEVATIONS HUDSON CONDENSEE	
SCALE: 1/4" = 1'-0" DATE: 12-14-61										APPROVED: _____ DATE: _____		JOB NO. 13-01014 SK - 04-006	
<div> <div> REFERENCE DRAWINGS 1 </div> <div> REVISION 2 </div> <div> REVISION 3 </div> </div>

PLAN
3/8" = 1'-0"

										ROGERS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 111 FINE STREET, SAN FRANCISCO, CALIFORNIA 94111		SOUTHERN CALIFORNIA EDISON CO. ROSEMEAD, CALIFORNIA		BRAWLEY GEOTHERMAL PLANT - UNIT NO. 1 AIR COOLED STEAM CONDENSER STUDY					
										SCALE 3/8" = 1' - 0"		DATE		APPROVED		DATE		PIPING PLAN			
										DR. B. E. CHIL		ENR.		APPROVED				JOB NO. S-61014			
REFERENCE DRAWINGS										REV.		DATE		REVISION		ENR.		DATE		REVISION	
1																		SK - 41 - 001		REV.

										<div><div> </div><div>ROGERS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 941 FINE STREET, SAN FRANCISCO, CALIFORNIA 94111</div></div>										SOUTHERN CALIFORNIA EDISON CO. ROSBAD, CALIFORNIA										BRAWLEY GEOTHERMAL PLANT - UNIT No. 1 AIR COOLED STEAM CONDENSER STUDY																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																									
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SECTION B
3/8" = 1'-0"

												<div><div> </div><div>ROGERS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 211 FINE STREET, SAN FRANCISCO, CALIFORNIA 94111</div></div>		SOUTHERN CALIFORNIA EDISON CO. ROSEMEAD, CALIFORNIA		BRAWLEY GEOTHERMAL PLANT - UNIT No. 1 AIR COOLED STEAM CONDENSER STUDY																			
												SCALE 3/8" = 1'-0"		DATE		APPROVED		DATE		PIPING SECTIONS															
												DR. G. L. CHIL.		ENG.		APPROVED		JOB NO. 5-51014		SK - 41 - 004		REV.													
REFERENCE DRAWINGS												REV.		DATE		REVISION		ENR.		CHK.		DATE		REV.		DATE		REVISION		ENR.		CHK.		DATE

SECTION C
5/8" x 1'-0"

												<div> <div>ROGERS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 111 FINE STREET, SAN FRANCISCO, CALIFORNIA 94104</div></div>		<div>SOUTHERN CALIFORNIA EDISON CO. ROSEMEAD, CALIFORNIA</div>		<div>DRAWLEY GEOTHERMAL PLANT - UNIT NO. 1 AIR COOLED STEAM CONDENSER STUDY</div>															
												SCALE 3/8" = 1'-0"		DATE 12-20-61		APPROVED		DATE		PIPING SECTIONS											
												DR. E. E. CHILDS		ENR.		APPROVED				JOB NO. S-51014		SK-41-005		REV.							
REFERENCE DRAWINGS												REV.		DATE		REVISION		ENR.		CHK.		DATE		REVISION		ENR.		CHK.		DATE

SUPPORT TYPE "A"

SUPPORT TYPE "C"

SUPPORT TYPE "B"

<div> ROGERS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 111 FINE STREET, SAN FRANCISCO, CALIFORNIA 94111 </div>										SOUTHERN CALIFORNIA EDISON CO. ROSEMEAD, CALIFORNIA		BRAWLEY GEOTHERMAL PLANT - UNIT No. 1 AIR COOLED STEAM CONDENSER STUDY PLAN, ELEVATIONS & DETAILS PIPE SUPPORTS		
SCALE 1/2" = 1'-0" DATE 12-14-61										APPROVED _____ DATE _____		JOB NO. 5-B1014 SK - 42 - 001 REV. _____		
<div> <div> REFERENCE DRAWINGS </div> <div> REVISION </div> </div>

NOTES:

1. NUMBER INDICATES NEMA STARTER SIZE
2. NUMBER INDICATES MOTOR RATED HORSEPOWER
3. ADJUSTABLE MAGNETIC TRIP ONLY
4. GROUND DETECTOR & RESISTOR

PLAN

FRONT ELEVATION
MOTOR CONTROL CENTER

REFERENCE DRAWINGS		REVISION		REVISION		REVISION		REVISION		REVISION	
1		2		3		4		5		6	
ROGERS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 171 FINE STREET, SAN FRANCISCO, CALIFORNIA 94111		SOUTHERN CALIFORNIA EDISON CO. ROSEMEAD, CALIFORNIA		BRAWLEY GEOTHERMAL PLANT - UNIT No. 1 AIR COOLED STEAM CONDENSER STUDY ELECTRICAL SINGLE LINE DIAGRAM GEA CONDENSER		JOB NO. S-81014		SK - 17 - 001		REV. 1	
SCALE NONE		DATE		APPROVED		DATE					
DR. G. L. CHIL		ENG. [Signature]		APPROVED [Signature]

ROGERS ENGINEERING CO., INC. ENGINEERS - ARCHITECTS 915 FINE STREET, SAN FRANCISCO, CALIFORNIA 94111										SOUTHERN CALIFORNIA EDISON CO. ROSEMEAD, CALIFORNIA										DRAWERY GEOTHERMAL PLANT - UNIT NO. 1 AIR COOLED STEAM CONDENSER STUDY ELECTRICAL SINGLE LINE DIAGRAM GEOTHERMAL CONDENSER									
										SCALE NONE DATE _____ DR. CHK. CHK. <i>ENG. [Signature]</i> APPROVED <i>[Signature]</i>										APPROVED _____ DATE _____ _____										_____ _____									
REFERENCE DRAWINGS										REMOVE DISCONNECT SW. & ADD CKT. BKR.										REVISION										REVISION									
REV. DATE										REV. DATE										REV. DATE										REV. DATE									