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FINAL REPORT - TECHNICAL DATA

VOLUME I - SECTIONS 1 - 8

PGandE GEYSERS RETROFIT PROJECT

UNITS 1 - 12

S-79007

August 24, 1979

ROGERS
Engineering • San Francisco

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In reply refer to:
S-79007

24 August 1979

Mr. J. P. Finney
Pacific Gas and Electric Company
77 Beale Street, Room 1901
San Francisco, CA 94106

Subject: Final Reports
PGandE Geysers Retrofit Project, Units 1-12

Dear Mr. Finney:

We are transmitting to you ten copies of the reports. They are titled:

Executive Summary
Condensed Final Report
Final Report Technical Data Volume 1
Final Report Technical Data Volume 2

These reports represent many weeks of conferences with you and your staff, and discussion of materials presented in previous reports. We do feel that this group of reports can serve your many needs.

It has been a pleasure to work with you on this phase of the project, and we look forward to serving Pacific Gas and Electric Company on additional assignments.

Yours very truly,

H. I. Rogers

H. I. Rogers
Acting Project Manager
Vice President

HIR:ee

Encls. 10 sets

cc: R. P. Wischow w/encls.

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FINAL REPORT - TECHNICAL DATA

PGandE GEYSERS RETROFIT PROJECT

Job No. S-79007

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PGandE GEYSERS RETROFIT PROJECT

1.0 INTRODUCTION

The firm of Rogers Engineering Co., Inc. is submitting herewith a cost benefit analysis for Pacific Gas and Electric Company on the hydrogen sulfide abatement systems required at Units 1-12 of the Geysers.

1.1 Purpose

The purpose of this work is to demonstrate whether there is a cost benefit to Pacific Gas and Electric Company in replacing the present iron catalyst/caustic/peroxide system used in the direct contact condenser units with an alternative approach using surface condensers and the Stretford System for hydrogen sulfide abatement.

1.2 Scope of Study

This work is limited to consideration of Units 1 thru 12, and shall use as much as possible data already prepared by PGandE, and with concurrence and cooperation of the various departments of PGandE with respect to the design, construction, and operations of the Geysers Project.

To evaluate the cost and time involved in installing the alternative abatement system (surface condenser/Stretford Process), it was necessary to prepare new process flow sheets, physical arrangements of equipment, cost estimates and construction schedules. It is important to note that for this report the design is a concept. If this project proceeds to final design and purchase of equipment, it will be necessary to pursue the engineering details to a much greater extent than allowed in the scope of work for this report.

2.0 SUMMARY AND RECOMMENDATIONS

This section is prepared as an executive summary of the whole report. It also has the recommendations in brief form. Details of all data follow in the body of the report. This conceptual report is to justify the method and approach to assist in making a decision concerning H_2S abatement on Units 1 through 12.

2.1 General Economic Viewpoint

The overview of economic techniques, cost estimate method and economic design selection alternatives are presented. Generally the regular Pacific Gas and Electric GM estimate format has been followed. The accounts are the normal plant accounts used by plant accounting. The economic analysis must be done with equivalent alternatives and is performed using the level annual revenue requirement technique. The GM estimates are prepared in June 1979 dollars and also with estimated escalation to June 1982 the center of gravity of expenditures. General Construction, Engineering, Electric Operations, and Planning and Research all contributed to various aspects of the costs and economics. All figures in the summary are in June 1979 dollars unless otherwise noted. Also all economic analysis is performed in 1979 dollars as requested.

2.2 Existing Abatement

The existing units with the iron catalyst/caustic/peroxide H_2S abatement are presented so that a common base could be established for later comparison. Additional capital costs, operating and maintenance costs and capacity factors are addressed. It is understood that a fully implemented iron catalyst/caustic/peroxide system presently meets the air pollution board requirements. This existing abatement system is Alternative 1, the defender, and the retrofit with surface condensers and Stretford system vent gas treatment is Alternative 2, the challenger.

Analysis of the overall Geysers Power Plant capacity factor shows it to be decreasing. The highest calculated annual capacity factor was 81 percent and the lowest 65 percent to date. It is not possible to attribute all changes in capacity factor to abatement. Full time, complete abatement has only been on a relatively short time on a few units. The capacity factor can be stated for past plant operations and projections made from trends established. Recognizing the limitations of analyzing the total plant capacity factors versus those for analyzing individual units or groups of units, the calculated annual capacity factor range for the abated group and the unabated group is 62-76 percent and 68-84 percent respectively. The

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existing abatement system will be evaluated at both 60 and 70 percent capacity factors in the cost analysis. The long term mature unabated existing plants have demonstrated an ability to achieve 80 percent and even 85 percent. Capacity factor data is developed in Section 4.1.3.

The capital cost to implement the iron catalyst/caustic/peroxide abatement system fully on all units is estimated to be 14.9 million dollars over and above the 18.9 million already invested in the abatement facilities. See Table 4-9.

The costs for chemicals will amount to an estimated 10 million dollars per year and is included as part of the operating cost. Maintenance costs are estimated to be about double the unabated units.

Although this abatement method is very severe on the plant equipment it is estimated that continued high maintenance will keep the plants going. Replacement in kind is not envisioned.

2.3 Alternative Abatement

The alternative, considered in this report, to the iron catalyst/caustic/peroxide abatement is the retrofit of units 1 through 12 with surface condensers and the installation of various Stretford process plants to treat the vent gases and remove the sulfur. Various combinations of Stretford process plants are studied.

Recent tests at Unit 15 are not conclusive with respect to the Surface Condenser/Stretford abatement system meeting the air pollution requirements. However, it is believed this approach will prove satisfactory with further experience.

Each typical unit has been studied with regard to performance, equipment arrangement, and capital cost estimates. The typical units are:

Typical	Typical For
1	1 and 2
3	3 and 4
5	5, 6, 7, 8, 9 and 10
11	11 and 12

In a few cases individual units were addressed since there were arrangement or performance differences which affected costs.

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The capacity factor for the retrofit is dependent on the natural long term capacity factor of the power plant unit in combination with the Stretford units capacity factor. In Sections 4.1.3 and 5.0 the respective capacity factors are presented. Two overall capacity factors are used in the economic evaluation: 80 and 85 percent.

The total capital cost estimate is in the standard GM Form. This whole report is conceptual in nature as the final designs and drawings are not made. Telephone quotations of major equipment were obtained and field investigations by qualified persons developed the other costs. In the following tabulation, the GM 1979 is without escalation and GM with escalation is to June 1982.

COST TO RETROFIT WITH SURFACE CONDENSERS AND STRETFORD PROCESS

Surface Condenser Retrofit

Unit	GM 1979	GM With Escalation
1	$ 2,042,712	$ 2,631,912
2	2,042,712	2,631,912
3	3,899,308	5,012,558
4	3,899,308	5,012,558
5	6,066,641	7,798,667
6	6,066,641	7,798,667
7	6,066,641	7,798,667
8	6,066,641	7,798,667
9	6,066,641	7,798,667
10	6,066,641	7,798,667
11	12,116,789	15,576,132
12	12,116,789	15,576,132
Subtotal	$ 72,517,464	$ 93,233,206
Stretford Systems		
1-6	$ 17,572,146	$ 22,588,993
7, 8, 11	17,464,697	22,450,867
9, 10	5,634,310	7,242,906
12	5,916,141	7,605,199
Subtotal	$ 46,587,294	$ 59,887,965
Total	$119,104,758	$153,121,171

Engineering, Procurement and Construction critical path schedules have been developed to determine the length of time required to implement the retrofit on each typical unit. Also, of critical importance to the economic evaluation is the required unit outage time to implement the retrofit. Generally, each total project takes 30 months from the start of engineering to end of restart of the unit. Outage times range from 8 - 11 months for specific units.

2.4 Cost Benefit Analysis

This is a comparison of the existing iron catalyst/caustic/peroxide system with the retrofit of units with surface condenser/Stretford Process in terms of 1979 dollars. The retrofit units with the

Stretford Process is considerably more economic. The closest the iron method comes is 1.43 times the retrofit evaluated cost. The level annual revenue requirement is about 36,644,000 dollars for the surface condenser/Stretford Process retrofit and 52,240,000 dollars for the iron catalyst/caustic/peroxide method. The estimated minimum benefit is 15,596,000 dollars per year.

The largest cost factor in the evaluation is the cost of energy due to the iron catalyst/caustic/peroxide system's anticipated capacity factor. The second largest cost is cost of chemicals to keep the iron system operating and the third largest cost in the analysis is the capital to retrofit the units with surface condensers and install the Stretford units.

2.5 Overall Recommendation

The overall recommendation is to proceed with a series of projects to retrofit all existing Units 1-12 with surface condensers and various combinations of Stretford processes based upon the information in this study.

There is an economic sequence of the subprojects as described in Section 6 of this report. The timing economics are based upon a 10 percent difference in capacity factor between existing and retrofit abatement. The capacity factor is the largest single factor in determining the timing. The economic sequence shows Units 9 & 10 operational in 1981, Units 7, 8 and 11 operational in 1983, and Units 1, 2, 3, 4, 5, 6 and 12 operational in 1984.

2.6 Professional Services

The estimated professional services costs are included in each individual unit's cost estimate under Account 365, Other Engineering. The engineering services total based upon the 1979 total construction cost of 119.1 million is 7.1 million dollars.

If the economic timing sequence is followed Units 9 & 10 and the associated Stretford engineering, procurement and construction support services needs to start immediately. The retrofitting of Units 9 & 10 and the subsequent restarting the units must be delayed one year past the economic time because of delivery time of condenser and the required installation time. All other units can follow the economic timing.

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3.0 GENERAL ECONOMICS

The economic techniques, cost estimate methods and design selection parameters which apply in general to work performed in this report. Each area of costs or economics has assumptions and ground rules in order for the results to be consistent. These will be explained as applicable to this report. The cost benefit analysis follows the general economic conditions. The results of each system to be compared are analyzed on the Level Annual Revenue Requirement (LARR) basis. This method and factors are discussed in Appendix A.

3.1 Economic Evaluation

There are two periods of time in which economic evaluations take place in this report. The first evaluation is early in the process and affects the basic design parameters and conditions. These could be called design trade-offs or design selection analyses. These tend to be very rough approximations to eliminate unnecessary alternatives to be addressed in detail. The second economic evaluation is the final comparison (cost benefit analysis) which includes all the details of each alternative.

The Engineering Planning Department, Generation Planning Section was consulted in the preparation and the determination of techniques and factors used in economic evaluations of different generation plans. The overall method is a level annual revenue requirement (LARR) technique. All economic quantities must be converted to LARR before comparison. LARR takes into account escalation, cost of capital, and other items. In generation planning, single life values for LARR are utilized rather than perpetual values.

The following areas each have levelizing factors which were provided by Generation Planning.

- -Account 314 Capital, Single Life, 30 Years
- -Operation & Maintenance, 30 Years
- -Power Values, 30 Years and Single
- -Geysers Steam, 30 Years

Appendix "E" explains these factors in more detail.

3.2 Cost Estimate Accounts

The cost estimates have been prepared by categories, and are the same accounts used by Pacific Gas and Electric for GM estimates. Only the following accounts are included by the nature of this project work.

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Account	Description
51-20	Structures and Improvements
52-50	Main Steam Piping
54-20	Condensate System
54-29	H_2S Abatement Facilities
54-30	Circulating Water System
54-40	Lube Oil System
54-70	Instrumentation
55-30	Control and Power Connection
55-60	Auxiliary Electrical Equipment - Station Power
56-10	Compressed Air System
365	Engineering and Other Cost Allocations

The detailed cost figures are in June 1979 dollars. These are modified, due to escalation and project timing as a result of the schedule prepared. Separate subtotals are established for the total of direct costs, the total with GM overheads and indirects, and the total with escalation.

3.3 Cost Estimates

The cost estimates include equipment and material; installation labor with overheads, profit and indirects; Account 365-Engineering and other allocatable costs; escalation; and the GM factor. Each will be briefly discussed as they apply to the detailed estimates which follow.

3.3.1 Major Equipment

Suppliers of the major equipment, condensers, pumps, and Stretford licensors were contacted by telephone and followed up by transmittal of pertinent equipment data sheets. In the majority of cases, vendors were contacted who have had some experience in the special problems associated with geothermal plants.

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The following items in the detailed cost estimate are adjusted quoted figures:

- Condensers and Ejectors
- Condensate Pumps
- Circulating Water Pump
- Stretford Equipment

The Material and Equipment column is a combination of adjusted quoted costs, estimated bulk materials, six percent use tax, and twenty percent for unestimated items since this is a conceptual cost estimate. The estimate assumes that Pacific Gas and Electric will purchase all major equipment and supply it to the contractor for installation, as has been the practice at the Geysers Plant. The costs in the estimate for each piece of major equipment reflect our best judgment as to the eventual bid on the "selected" equipment data sheets.

3.3.2 Installation Cost

The estimated installation cost is the cost anticipated to be charged by an outside contractor to perform the removal of the old and installation of the new equipment. Most of the larger project construction work at the Geysers has been done by outside contractors and this guide has been used in preparation of this estimate. This decision affects the labor overheads and labor efficiency as well as the general overheads of a GM factor.

The estimated materials and labor shown on the detailed estimates are based upon the conceptual layout drawings and field investigations at the site for each installation. There is judgment used whenever making such an estimate, and this estimate has been prepared by people who have been a part of other geothermal plant construction. The General Construction Department has assisted with suggestions on various factors included in the estimates.

In consultation with General Construction about contractor performance and costs at the Geysers certain figures were developed for use in this conceptual report. The current labor direct rates show a $15 per hour to be an overall good concept estimate direct labor cost. The labor efficiency has been estimated to be 60 percent and has been used in the estimate. The contractor overhead includes his profit, overheads and all indirect expenses. It has been estimated that 55 percent is a good value from past Geysers' experience in contractor bidding.

In addition to the above basic parameter discussions a twenty percent contingency has been included in the direct man-hours for this conceptual estimate. The labor man-hours shown in detailed estimates are derived as follows:

Man-hours	= Basic Estimate	x	One Divided By Efficiency	x	Contingency
2.0	= 1.0	x	1.67	x	1.2

3.3.3 Account 365

The costs shown in Account 365 are the direct allocatable costs to a given project such as field construction activities, general office engineering and other engineering. All the costs have been lumped into the three above subdivisions. Also, previous Geyser GM's were studied both as estimates and as final plant accounting to determine the appropriate numbers. The past range is from 14 to 18 percent of the total direct charges. Since these cost estimates developed in this report are for fairly complex project modifications, a twenty percent figure is considered appropriate for this estimate.

3.3.4 GM Factor

The GM Estimate preparation is the last step in the cost estimate process. The GM estimate is used to get funds approved for the project. Engineering Services in consultation with Engineering and General Construction puts the final GM numbers together. Engineering Services has been consulted in the methods and factors used in preparation of GM estimates.

The GM factor is a function of whomever does the construction. The estimates prepared here are based upon an outside contractor doing the construction. The following factor is applied to the direct costs.

<u>Factor Development</u>

Item	Percent of Direct Cost
Indirects:	
Indirects	0.0
General Overheads:	
General Engineering & Administration	16.0
Allowance for Funds During Construction	3.7 - 5.0
Ad Valorem Taxes	1.0 - 2.0
Total GM Factor	20.7 - 23.0%

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The allowance for funds during construction is a function of the construction period; the general engineering and administration; and the direct costs. The Ad Valorem tax is a function of the direct dollar cost of the project. Pacific Gas and Electric S. P. 112.6-1, Appendix A, effective 10/16/78 has been used in determining the factor. Each estimate summary indicates the percentage used for the GM factor.

3.3.5 Escalation

The GM estimate total includes escalation, and it is separated out as a definable item. The rate of escalation was derived from Economics and Statistics Department escalation report for Autumn 1978. All the detailed cost estimates are June 1979 dollars. The escalation time assumes one year or June 1980 to start engineering and procurement, and two additional years to the center of gravity of dollar disbursements for a project (3 years of escalation). The escalation was calculated at the stated compound percent applied to the sum of the direct costs plus the GM factor costs.

3.3.6 Project Differential Cost

It is often helpful to have a magnitude feeling for the GM estimated cost total in terms of level annual revenue requirement. This figure in mills per kilowatthour is presented with each cost estimate summary.

3.4 Design Selection Evaluation

Certain economic evaluations which were made at the very beginning of the design apply in general and are presented here.

3.4.1 Cooling Tower and Circulating Water Flow

It is assumed that no additional major investment is required to return the cooling tower capability to design condition beyond regular maintenance. Thus, the only design trade-off to maximize power is to increase circulating water flow until pumping costs or size of the circulating water piping limit the retrofit space considerations. This required an examination of field cooling tower test data, along with pumping and piping considerations to set the estimated capability for operating vacuum after retrofit.

3.4.2 Condensing and Gas Cooling Limitations

Once the cooling tower return water and off tower temperature have been assigned preliminary values as shown by para. 5.4.1, the specification of the surface type heat exchangers must then consider two factors:

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(a) The terminal temperature difference (TTD) which is the steam inlet temperature minus the condenser outlet water temperature and

(b) the cold gas outlet temperature minus the condenser inlet water temperature.

As the specified TTD is lowered, the turbine operating back pressure is also lowered, the turbine output is increased, and the condenser size and cost rises. For surface type exchangers, the Standards of the Heat Exchanger Institute recommends a lower TTD limit of 5°F. Table 3.1 (study for Unit 1) shows that the increased power output will more than offset the condenser cost. However, the specification for TTD was increased to 7.8°F (Unit 1) in order to reduce the condenser to a size suited to the available installation space. A similar methodology was used for all units in the retrofit study.

As the gas cooling temperature is lowered (assuming turbine back pressure is held constant), two conditions influence vacuum system specification.

(a) A colder temperature will decrease the inlet pressure available to the vacuum system steam jet ejectors, and

(b) at the same time the steam vapor entrainment carried by the noncondensable gas flow is reduced.

The combination of these two factors results in an overall increase in motive steam requirement as the cold gas temperature is allowed to rise. Table 3.2 (Study for Unit 1) shows that when a cost of steam is assigned to the motive steam it is desirable to specify lower cold gas temperatures. Throughout the study, cold gas temperatures were adjusted to avoid oversizing the condensers.

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TABLE 3.1

TYPICAL ECONOMIC ANALYSIS

MAIN CONDENSER - UNIT 1

STEAM END APPROACH (TTD)

Study Case Item	A	B
TTD °F	7.8	5
Condenser Cost (1)	0	$376,800
Calc. Power Output Increase	0	190 kW
ECONOMIC EVALUATION		
Difference in Capital (2) (Cost)	0	(54,700) $/yr.
Difference in Energy (3) (Revenue)	0	86,500 $/yr.
Advantage (Capital over Energy)		$31,800 $/yr.

(1) Capital Installed

(2) Annualized Capital Installed per Year Value

(3) System Level Annualized Power per Year Value

This table indicates that it is economic to buy a condenser for a lower TTD °F to increase electrical energy generated from the plant. The advantage is 31,800 level annual dollars per year. However, 7.8°F was used for conceptual design because of condenser space limitations.

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TABLE 3.2

TYPICAL ECONOMIC ANALYSIS

MAIN CONDENSER - UNIT 1

NONCONDENSABLE GAS END APPROACH

Study Case Item	A	B	C	D
Noncondensable Gas Outlet °F	95	105	115	119
Difference in Heat Exch. Cost (1)	$17,700	$ 9,300	$ 2,700	0
Steam to Jet Difference (2)	0	$14,400	$47,200	$67,500
TOTAL DIFFERENCES (3)	$17,700	$23.700	$49,900	$67,500

(1) Annualize Capital Installed
(2) Steam Fuel Level Annualized Value
(3) Annualized Basis

This table indicates that cooling of the noncondensable gases is "economic", if a cost is assigned to motive steam. However, in real life, the jet steam is not a cost factor. The capital cost is less in case D and the designs reflect this relationship.

3.5 Installation Labor Cost Sensitivity

As all recognize in the construction industry, the labor productivity, the labor pay rate and the contractor overhead and profit vary depending on time of bid, overall conditions and the specific project requirements. Since this is a conceptual design report, some knowledge of what difference these variations of parameters can make in total project cost is worth studying. Cost sensitivity analysis was performed on the Unit 1 estimate to demonstrate the total cost vulnerability to parameter variation. This vulnerability is also a function of the labor to equipment and material ratio. The labor material ratio, excluding Account 365, vary from 0.365 to 0.558. Using a value of about 0.42, the following sensitivities to total project cost are observed:

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Labor Efficiency %	Total Project Cost (per Unit)
50	1.058
60	1.000
70	0.957

Labor Rate $/hr.	Total Project Cost (per unit)
13.50	0.971
15.00	1.000
16.50	1.030

Labor Overhead %	Total Project Cost (Per Unit)
45	0.981
55	1.000
65	1.019

As observed these changes in total cost are small as compared with:

Escalation	1.2.85
Contingency	1.20

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4.0 EXISTING ABATEMENT SYSTEM

Methods to control the hydrogen sulfide emissions from the Geysers Power Plant were initiated in 1971. The addition of a metal catalyst (ferric iron) to the circulating cooling water was selected for large scale tests at Units No. 1 and 2. Currently, in addition to the iron sulfate catalyst, caustic soda and hydrogen peroxide are being introduced on a full-time basis to maximize the abatement on Units 3, 4, 5, 6, 11 and 12. Additionally interim abatement on Units 2, 8, 9, 10 is being used at specified times.

4.1 Existing Conditions

It is our understanding, that Units 1, 2, 7, 8, 9 and 10 operate under a variance to the air pollution standards, and the iron catalyst/caustic/hydrogen peroxide system will accomplish the level of abatement required by the Air Pollution Board.

4.1.1 Historic Abatement

The historic data of time and type of abatement is important when evaluating the existing units. The abatement methods have affected the power plant unit operations and the equipment in each unit so treated. Table 4-1 summarizes by unit the abatement facilities installed to date. Each unit has a varying amount of abatement, and it was put on at differing times in the useful life of the equipment. The units which are not being abated 100% of the time are only abated when the air pollution officer requests. Up to this point in the concept study, we could not determine how many hours per year Units 2, 8, 9 and 10 abatement have actually been operating.

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TABLE 4-1

H_2S HISTORIC ABATEMENT

Unit	Commercial Operation	H_2S Abatement	Remarks
1	9/25/60	-	None
2	3/19/63	6/78	June-Oct. Interim Time Iron Catalyst
3	4/28/67	12/76 1/79	100% Time Iron Catalyst 100% Time Iron Catalyst with Caustic and Hydrogen Peroxide
4	11/ 2/68	9/76 1/79	100% Time Iron Catalyst 100% Time Iron Catalyst with Caustic and Hydrogen Peroxide
5	12/15/71	1/78 1/79	100% Time Iron Catalyst 100% Time Iron Catalyst with Caustic and Hydrogen Peroxide
6	12/15/71	1/78 1/79	100% Time Iron Catalyst 100% Time Iron Catalyst with Caustic and Hydrogen Peroxide
7	8/18/72	-	None
8	11/23/72	6/78	June-Oct Interim Time Iron Catalyst
9	10/15/73	6/78	June-Oct Interim Time Iron Catalyst Plus Caustic
10	11/30/73	6/78	June-Oct Interim Time Iron Catalyst Plus Caustic
11	5/31/75	1/77 1/79	100% Time Iron Catalyst 100% Time Iron Catalyst Caustic and Hydrogen Peroxide
12	3/1/79	3/79	100% Time Abatement Iron Catalyst and Caustic, Hydrogen Peroxide

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4.1.2 Existing Abatement

The existing units have the following abatement facilities installed as of June 1979:

Unit 1 - No permanent abatement equipment - only abatement testing program
Unit 2 - Operating intermittently using only ferric iron
Unit 3 - Using ferric iron, caustic and hydrogen peroxide-continuous abatement
Unit 4, 5 & 6 - Same as Unit 3
Unit 7 - Up stream EIC and Coury Process - tests continuing
Unit 8 - Intermittent abatement only ferric iron
Unit 9 - Intermittent abatement only ferric iron with caustic
Unit 10 - Same as Unit 9
Unit 11 - Continuous abatement using ferric iron, caustic and hydrogen peroxide
Unit 12 - Same as Unit 11

4.1.3 Capacity Factor

Geysers power plant units are operated as a base load plant, that is they are on line and fully loaded all the time regardless of system load. Therefore, the capacity factor is indicative of how well a unit is performing. Many factors affect the capacity factor, and it is difficult to indicate the exact causes of a low capacity factor even though outage and curtailment records are kept.

Two questions are of greatest importance. What has been the highest capacity factor at which existing units have operated unabated? What has been the capacity factor of H_2S abated units since abatement has started? These are difficult questions, and it is not possible to attribute all changes in capacity factor to abatement. Full time complete abatement has been only on a relatively small number of units and for a short period of time. The capacity factor can only be "stated" for the past plant operations and what they are operating at today.

Available capacity factor data has been analyzed by statistical methods: least square, mean, and median. It is essential to build confidence in a tool before it is used for predictions. The following Table 4-2 illustrates the accuracy of the methods to approximate the annual capacity factor. The mean is the average value of capacity factor taking into account all the capacity factor values. The median is the statistically calculated capacity factor value at which an equal number of capacity factor values occur below and above the calculated value.

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Many calculations and combinations of calculations have been made to study capacity factors of individual units and of the overall Geysers plant. Tables 4-2, 4-3 and 4-4 are summaries of part of the analysis. Trends have been statistically developed (least squares) from Table 4-3 using 1975 through 1978 data and 1975 through April 1979 data. Table 4-5 (graph of least squares trend) indicates the capacity factor trend of the overall Geysers total plant and the subset of units with abatement.

The capacity factor difference between existing units abated and unabated has been addressed by others and was not a part of this conceptual work. However based on the results in this report, the economic evaluations have been made at 60 and 70 percent capacity factor for abated units with the iron/caustic/peroxide abatement and 80 and 85 percent capacity factors for units with surface condenser/ Stretford abatement.

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TABLE 4-2

COMPARISON OF METHODS

ANNUAL CAPACITY FACTOR ANALYSIS
(1977)

Unit	Actual[1] Annual Capacity Factor	-----------Calculated----------- Least Square	Mean	Median
1	67.7	67.7	67	65
2	86.3	86.3	85	85
3	57.2	57.4	57	60
4	76.1	76.1	75	78.3
5	87.5	87.5	87	95.7
6	78.0	77.7	77	85
7	83.8	83.8	83	90
8	82.4	82.5	82	88
9	92.0	92.0	92	92.9
10	95.2	95.2	94	95
11	74.0	74.0	74	77.5
A	-	-	84	80.0
B	-	-	84	89.6
C	-	80.0	79	85.8

[1]Annual capacity factor from Operating Dept.

A Combination of Units 3, 4, 5, 6, 11 (Existing Abatement)
B Combination of Units 1, 2, 7, 8, 9, 10 (Not Abated)
C All units combined

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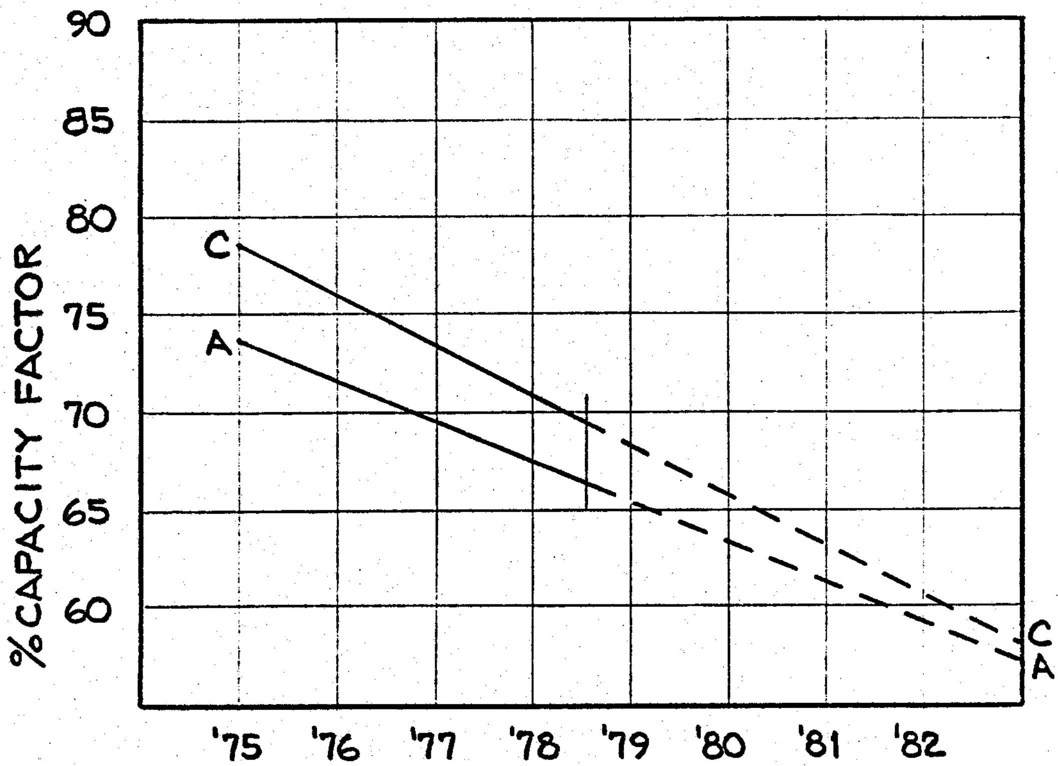
TABLE 4-3
ANNUAL CAPACITY FACTORS
(Least Square)

Units	1975	1976	1977	1978	1979*
1	76	78	67	50	68.3
2	53	76	85	67	58.3
3	74	70	57	38	44.5
4	53	65	75	52	48.3
5	84	86	87	82	62.0
6	82	90	77	84	59.5
7	79	88	83	78	62.0
8	77	90	82	59	82.0
9	90	87	92	78	90.8
10	95	86	94	77	97.8
11	47	71	74	54	68.3
A	68	76	74	62	56.5
B	78	84	84	68	76.4
C	74	81	79	65	67.3

TABLE 4-4
ANNUAL CAPACITY FACTORS
(Median)

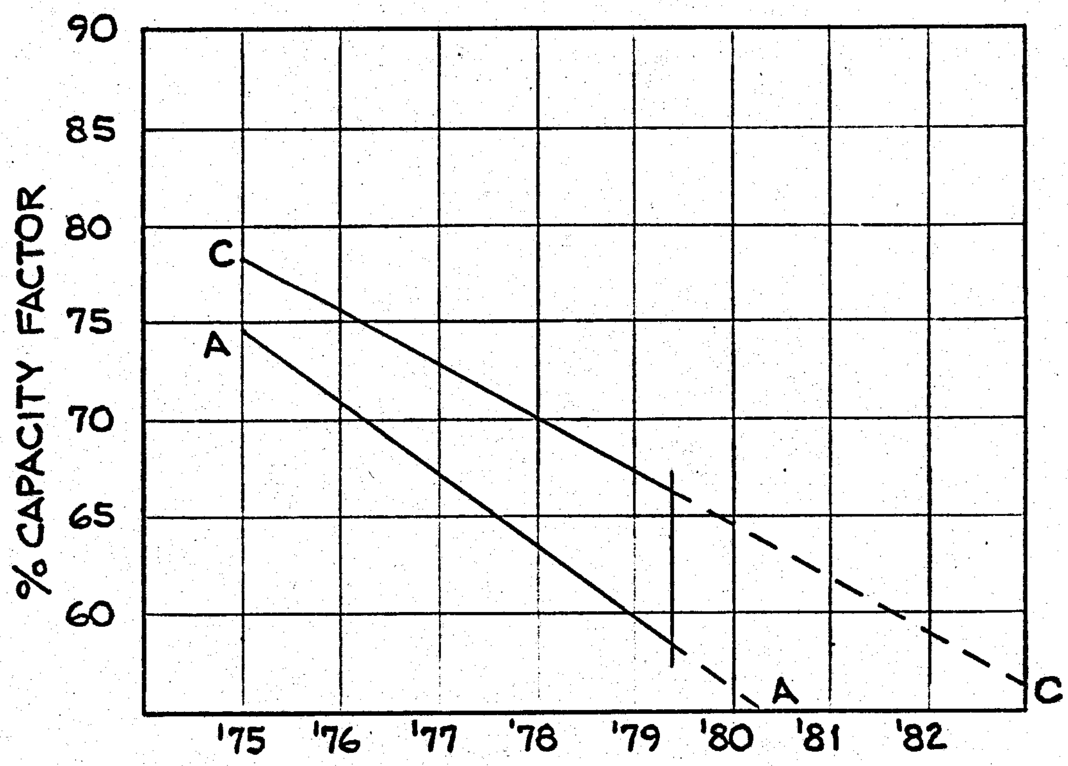
Units	1975	1976	1977	1978	1979*
1	80.0	86.0	65.0	57.0	68.3
2	52.8	85.0	85.0	75.0	55.0
3	80.0	75.0	60.0	35.0	30.0
4	55.0	68.8	78.3	50.0	45.0
5	91.7	92.1	95.7	83.3	50.0
6	95.0	93.3	85.0	86.3	55.0
7	87.5	89.0	90.0	76.7	75.0
8	86.5	91.7	88.0	72.5	85.0
9	91.7	93.8	92.9	87.5	90.0
10	96.3	92.9	95.0	85.0	97.5
11	45.0	80.0	77.5	70.0	60.0
A	79.0	82.5	80.0	71.7	60.0
B	86.3	90.0	89.6	75.7	80.0
C	83.5	88.2	85.8	74.5	69.0

*Developed from partial year data



DATA 1975 – 1978

LEGEND
C – TOTAL PLANT
A – ABATED UNITS



DATA 1975 - 4/79

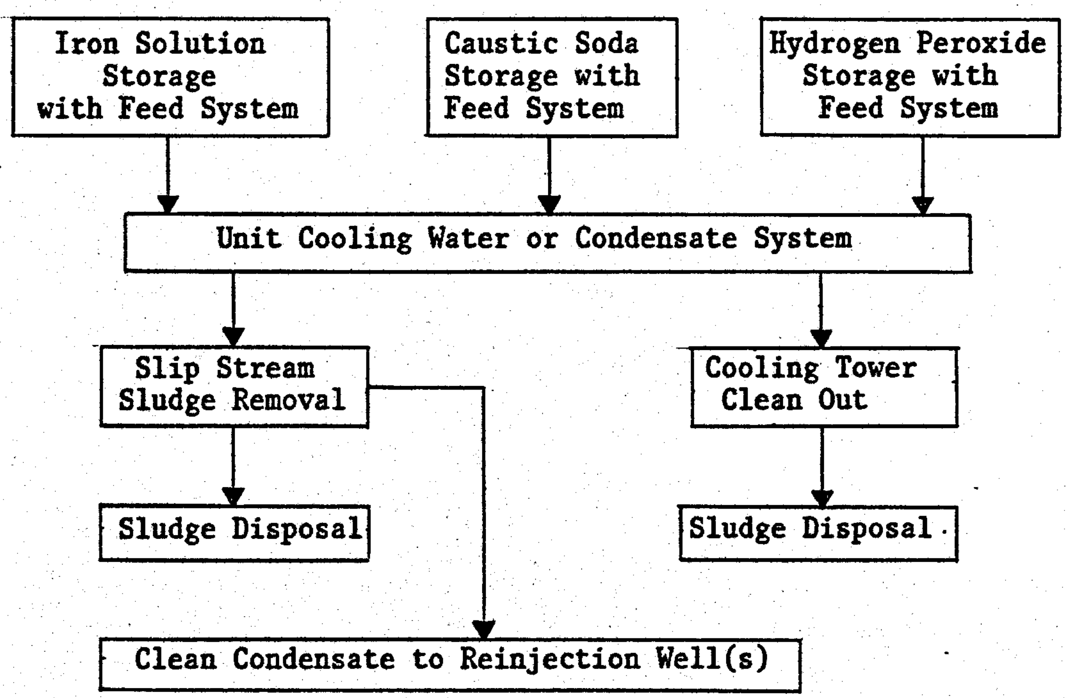
ROGERS ENGINEERING CO., INC. 111 PINE STREET SAN FRANCISCO, CALIF. 94111	CAPACITY FACTOR STATISTICAL TRENDS	DRAWING NO. TABLE 4-5	REV.
JOB NO. S-79007		SHEET OF	

DG-023

4.2 Overall Process

In order to compare the existing abatement system as applied to the direct contact condensers, the chemical feed (budget data) was examined for Units 3, 4, 5, 6, 11 and 12. The molar ratio of ferric iron, caustic soda and hydrogen peroxide were compared with the mols of hydrogen sulfide in the incoming steam and an average chemical input ratio was developed. For the purposes of this report, these chemical values can then be prorated for all Units 1 thru 12, so as to cost out the placement of a continuous abatement program onto each unit, which theoretically could provide the abatement necessary to meet the air quality standards.

The overall process for each of the first twelve units in block diagram is as follows:



The chemical requirements for each unit are summarized in Table 4-6 and 4-7. The chemical quantities required are dependent on the units' capacity factor. Two capacity factor levels are presented: the 60 percent which plants are now operating, and the 70 percent which is anticipated to be the long range best capacity factor obtainable with this abatement system.

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TABLE 4-6

IRON CATALYST ABATEMENT CHEMICALS
(60 Percent Capacity Factor)

Unit	Iron #/hr.	NaOH 100% #/hr.	H_2O_2 Gal./hr.	Sludge yd.^{3}/yr.
1	12.8	14.2	22.8	180
2	12.8	14.2	22.8	180
3	58.4	67.9	109.5	1,367
4	58.4	67.9	109.5	756
5	116.8	135.8	219	1,451
6	146.0	135.8	219	2,073
7	90.6	100.9	162.5	1,267
8	41.6	56.1	90.4	670
9	22.4	25.0	40.2	313
10	27.3	30.4	49.0	382
11	219.0	271.6	438	3,622
12	110.7	123.3	198.7	1,549
Total	916.8	1,043.1	1,681.4	13,810

TABLE 4-7

IRON CATALYST ABATEMENT CHEMICALS
(70 Percent Capacity Factor)

Unit	Iron #hr.	NaOH 100% #/hr.	H_2O_2 Gal/hr.	Sludge yd.^{3}/hr.
1	14.9	16.6	26.6	210
2	14.9	16.6	26.6	210
3	68.1	79.2	127.8	1,595
4	68.1	79.2	127.8	882
5	136.3	158.4	255.5	1,693
6	170.3	158.4	255.5	2,418
7	105.7	117.7	189.6	1,478
8	48.5	65.4	105.5	782
9	26.1	29.2	46.9	365
10	31.8	35.5	57.2	446
11	255.5	316.9	511.0	4,226
12	129.2	143.8	231.8	1,807
Total	1,067.4	1,216.9	1,961.8	16,112

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4.3 Operations

As described in 4.2, Overall Process, above the chemical feed ratios between unit hydrogen sulfide feed input and chemicals, sludge production, etc. can be applied to the capacity factor (each unit separately) and thence calculate the related cost for operating chemicals, sludge disposal.

TABLE 4-8

IRON CATALYST/CAUSTIC/PEROXIDE
CHEMICAL COSTS
(1979 Dollars Per Year)

Units	60% Capacity Factor	70% Capacity Factor
1	$ 131,500	$ 153,400
2	131,500	153,400
3	632,200	737,600
4	627,000	731,500
5	1,214,400	1,416,800
6	1,256,400	1,465,800
7	882,500	1,029,600
8	490,900	572,700
9	216,100	252,100
10	272,100	317,400
11	2,432,400	2,837,800
12	1,076,800	1,256,300
Total	$9,363,800	$10,924,400

4.4 Capital Cost

For the purpose of this report, the actual field installation costs were examined for the existing abatement facilities. (Units 3, 4, 5, 6, 11 and 12). These costs were then prorated and projected for facility costs for each unit (1, 2, 7, 8, 9 and 10) which do not have complete abatement installations. The existing column was derived from GM Estimate 186422R2, and the Research and Development allocation for caustic and peroxide facilities, all except for Unit 12, which is based on Unit 11. The "additional capital" is the estimated amount required to bring all existing units up to a common level of abatement using the iron catalyst/caustic/ peroxide systems. These costs are estimated in June 1979 dollars.

Table 4-9 is a summary of the past and additionally required capital costs for the iron/caustic/peroxide abatement system.

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TABLE 4-9

EXISTING H_2S ABATEMENT CAPITAL COST
(Dollars x 1,000)

Unit	Existing	Additional GM 1979	Total
1 & 2	-	2,302	2,302
3 & 4	$ 4,950	-	4,950
5 & 6	2,415	-	2,415
7 & 8	-	6,327	6,327
9 & 10	-	6,327	6,327
11	5,794	-	5,794
12	5,794		5,794
Totals	$18,953	$14,956	$33,909

The GM Estimate total for the additional is calculated as follows:

Item	Dollars x 1000
Direct Costs	$12,391
GM Factor @ 20.7%	2,565
Sub Total (GM 1979)	$14,956
Escalation @ 28.55%	4,270
Total GM Estimate	$19,226

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4.5 Remaining Life

Effect of Existing Abatement on Equipment Life

One problem developed by the existing abatement is that oxidation of the sulfur cannot be selectively stopped when free sulfur is produced. The reaction also produces some sulfites and sulfates. The existing equipment was constructed using 304 SS, and the expected equipment life was probably over 50 years. With the addition of the existing abatement system however, the sulfites, sulfates and oxygen corrode 304 SS in a manner described as "pit" corrosion.

Corrosion testing was initiated in about 1973, and the initial findings were reported by Dodd and Ham on 22 January 1975.

Tubular Type Heat Exchangers and Piping

The corrosion data without iron catalyst in the cooling water indicate very little loss of metal from 304 SS; measured value less than 0.0001 inch/year. With iron, the general corrosion increased to 0.0007 inch/year and the pitting action was at a rate of 0.005 inch/year on an unsensitized specimen. Assuming that 22 gauge heat exchanger tubing is the thinnest construction material and that a 30% thickness loss is allowable prior to replacement, the following can be calculated:

Normal life expectancy:
    22 Ga. is 0.028 inch thick
    $0.028 \times 0.30 = 0.0084$ allowable loss
    $0.0084 \div 0.0001$ inch/year = 84 years
With iron $0.0084 \div 0.0007 = 12$ years
With iron and pitting $0.0084 \div 0.005 = < 2$ years

Based on the above values, it might be necessary to replace some tubular type heat exchanger tubes on every unit turnaround (2 year interval), and some piping may require patching. Testing has also been conducted on Carpenter alloy 20 cb 3, and the test data indicate this material is not corroded by the sulfur acids. Thus, equipment replacement should be based on the use of this alloy, which will give an additional useful life of over fifty years in this type of H_2S abatement service. This replacement has been accounted for in this study by doubling the regular replacement cost.

Cooling Tower

The effect of the sulfur acids and excess iron and sulfur sludge on the cooling tower is such that a complete reconditioning will be required every unit turnaround (2 year interval). During this 2 year run, it is estimated that the cold water temperature will increase 1°F. The result will be an increase in turbine exhaust hood pressure of 0.075 psi (0.15 in. Hg Abs.). The resulting loss in turbine heat drop will be 2.175 Btu/lb. steam flow. Assuming 77% overall turbo-generator efficiency, the power loss will be about 0.0005 kW/lb. steam flow. This figure will be used to calculate the generation capacity loss during the run. It is included in Table 6-1 and associated tables.

Pumps

It is assumed that all pumping requirements for cooling water and auxiliary water will not be affected during the operation between turnaround.

4.6 Existing Abatement System Summary

This section presents the parameters involved with retrofitting the existing Units 1-12 with the iron oxide/caustic/peroxide. As this is the condensed report only the results are presented of the most significant elements. See Table 4-10.

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TABLE 4-10
ALTERNATIVE 1: EXISTING ABATEMENT

Unit	Design Gross kW	Net kW	Annual Annual MWH @ 60%	Annual Annual MWH @ 70%	GM Estimated Cost 1979	O & M Cost 1979 $/yr. @ 60%	O & M Cost 1979 $/yr. @ 70%	Schedule (Months)
1	12,500	12,098	63,587	74,185	2,302,000	155,300	172,700	-
2	12,500	12,115	63,676	74,289		155,300	172,700	-
3	27,500	26,500	139,284	162,498		747,800	831,400	-
4	27,500	26,500	139,284	162,498		740,900	823,800	-
5	55,000	53,020	278,673	325,119		1,435,400	1,595,900	-
6	55,000	53,020	278,673	325,119		1,484,200	1,650,200	
7	55,000	53,020	278,673	325,119	6,327,000	1,042,300	1,158,900	-
8	55,000	53,020	278,673	325,119		579,300	644,100	-
9	55,000	53,020	278,673	325,119	6,327,000	255,200	283,700	-
10	55,000	53,020	278,673	325,119		321,400	357,300	-
11	110,000	106,000	557,136	649,992		2,874,400	3,195,900	-
12	110,000	106,000	557,136	649,992		1,272,300	1,414,600	-
CT. DED.			(13,878)	(16,191)	-	-	-	
Total	630,000	607,333	3,178,263	3,707,977	14,956,000	11,063,800	12,301,200	

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5.0 ALTERNATIVE ABATEMENT

Section 4.0 discussed existing means of H_2S abatement employed at the Geysers Power Plant. This section treats the technical aspects, cost estimates and scheduling of an alternative system which would consist of surface condensers and the patented Stretford process for treatment of the noncondensable gases drawn from the condensers.

As a part of this retrofit/alternative abatement concept study, Rogers has submitted Milestone Report No. 1 dated June 4, 1979 and Milestone Reports No. 2 and 3 dated June 29, 1979. These reports, essentially progress reports, discussed study work accomplished toward conceptual design and economic assessment of replacing existing condensers with surface condensers and auxiliaries and installing Stretford process units and associated piping, blowers, etc.

This section presents those portions of the progress reports dealing with process design, design parameters and selected criteria, system installation and equipment arrangement, and cost estimates. A section on scheduling has been added. Since the previous reports were to advise PGandE of progress on the study effort, and were prepared while work was still ongoing, they were of necessity incomplete in some aspects and subject to revision and updating as more data was acquired. Thus the material from the progress reports incorporated herein will differ in some ways from the earlier presentations, and additions, deletions and some reorganization will be noted.

A determination of design steam flows, noncondensable gas contents and analyses of the noncondensable gases to be used in the study work was required early in the study period. Accordingly, a meeting was held May 11, 1979, during which values were agreed upon for study purposes. This meeting was documented in Project Conference Note #23 which is included in Appendix A and is applicable to the various units as indicated. The data presented in the conference note was used as "agreed", for the purposes of this report. These values should be updated during final design for two reasons:

(1) Union Oil Company plans to update its analyses on the "actual" pipeline network during 1979.

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(2) The required unit total steam flow must be adjusted to the actual design conditions required by the "values bid" for the exchangers and vacuum ejectors.

The following Sections 5.1, 5.2 and 5.3 treat those aspects of the proposed retrofit concerned with installing surface condensers and related equipment in the Geysers Power Plant, Units 1-12. Section 5.1 discusses Unit 1 under 5.1.1, Unit 2 under 5.1.2 and Units 3 and 4 under 5.1.3. In each case, the discussion includes process design selection, equipment arrangement and installation and the estimated cost. Section 5.2 presents similar information for Units 5-10 with Unit 5 considered typical for all units in most respects. There is a small difference in cooling tower performance between Units 5 & 6 and 7-10 and some differences in equipment arrangement also exist between these groupings of units. Section 5.3 treats Units 11 & 12 which are identical in configuration although differing in performance due to a lower noncondensable gas content in steam at Unit 12.

Sections 5.4 through 5.7 discuss the vent gas abatement process, equipment and costs with Sections 5.4 presenting a general overview of the considerations involved in selecting a limited number of alternatives for further study. Sections 5.5, 5.6 and 5.7 present the alternative and selected schemes for Units 1-6, 7, 8 & 11 and 9, 10 & 12 respectively.

This section concludes with a discussion of construction schedule in 5.8.

The capacity factor of the retrofit power plant units with surface condensers is estimated to be the same as the long term mature unabated capacity factor of existing units. This factor has been demonstrated to be approximately 80 percent overall for units 1-12 and it is anticipated it could reach 85 percent in the long term. Both of these values are used in the economic evaluations of section 6. In Section 4.1.3 is a discussion of the existing plant capacity factors.

5.1 Replace Condenser and Auxiliaries, Units 1-4

Units 1 and 2 are each rated at 12.5 MW gross (for study purposes) and Units 3 and 4 each at 27.5 MW gross. For study purposes, it was intended all work for Unit 1 would be appli-

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cable to Unit 2 and similarly, Unit 3 effort applicable to Unit 4. This assumption proved satisfactory for Units 3 and 4, but the Unit 2 cooling tower was found to perform approximately at design rating while the Unit 1 tower is 4-5°F below design rating. This difference affects design parameters and overall unit performance and results in different material balances as shown on the process flow diagrams. In addition to the process differences, physical layout of the units resulted in differing equipment arrangement and installation. Accordingly, the following paragraphs will reflect some differences between Units 1 and 2, but the discussion of Unit 3 is applicable to Unit 4.

5.1.1 Unit 1

Unit 1 was designated as typical for 1 and 2. The basic overall discussion is therefore presented here. In Section 5.1.2, Unit 2 variances are discussed.

5.1.1.1 Selected Process Design

The process parameters are here discussed as they apply to Unit 1 typical.

5.1.1.1.1 Noncondensable Gas Values

Original base reference design point was 0.75% by wt. noncondensable gas in the steam. Based on updated field data which was reported in PCN #23 and agreed upon by PGandE, the design value was set at 0.5% by wt. for Units 1 and 2. The gas composition is shown in detail in Appendix A. The average mol wt. is 30.3.

5.1.1.1.2 Field Test Data for Cooling Water Tower

The cooling water tower for Unit 1 was tested when clean on 5 April 1977. At a test condition of 45°F wet bulb, with a circulating water flow of 13,530 gpm and a range of 36.4°F, the approach to wet bulb was 32.6°F. The results of this test indicates that the tower is 4 - 5°F below design rating.

5.1.1.1.3 Base Reference Design Point

The Unit 1 Data Book Heat Balance Diagram for 100% Maximum Guaranteed Load is the Base Reference Design Point. The calculated gross power output will be based on essentially the same turbine throttle flow at the retrofit conditions. Net power

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output will be determined on the basis of the new station auxiliary power requirements. The Unit 1 Process Flow Diagram, PD-001, for conversion of the present system shows the expected Unit performance after retrofit.

5.1.1.1.4 Main Condenser Cooling Water System Limitations

The cooling water tower for Unit 1 by field test is 4 - 5°F below rating. For a set approach in a cooling tower, more water can be circulated as the range is reduced (tower, hot water on temperature is reduced). An increase in turbine output can also be achieved because a lower exhaust pressure can be attained when a constant terminal temperature difference between the hot water and the incoming steam is maintained. However, as the range is reduced the water circulation system piping may need to be larger and/or the pumping power increased, which will reduce the unit net power output. For Unit 1, at the base reference design point of 65°F wet bulb the approach must be relaxed from a design of 15.6°F to 20°F and the range reduced from about 40°F to 38°F. This results in a turbine exhause pressure of 5.0 inches Hg Abs. Although a lower range would be desirable to reduce exhaust pressure the resulting increase in circulating water power requirements and pipe size would execeed the economic balance point for the retrofit of Unit 1.

5.1.1.1.5 Condensing and Gas Cooling Limitations

The existing direct contact exchange system can achieve temperature approaches of 4°F on the mixed steam-water condensate outlet and about 6°F on the noncondensable gas outlet. For the surface type heat exchanger the terminal temperature difference might be specified down to 5°F and some economic considerations and tradeoffs have been discussed in Section 3.4.2 and illustrated in Table 3.1. For Unit 1 a terminal temperature difference of 7.8°F was used.

It would be desirable on the gas cooling end to achieve low outlet temperatures so as to minimize the motive steam requirements for the 1st stage steam jet ejector. These economic trade-offs have also been discussed in Section 3.1. The main condenser outlet temperature approach has been relaxed to 33°F for Unit 1. The relaxation of this approach was mostly a consideration of consistency with what surface condenser manufacturers will guarantee using their standard design procedures. The interaction between the cooling water tower approach and range are the major factors in determining turbine exhaust pressure at the base design reference point. This methodology maximizes the power expected after retrofit.

5.1.1.1.6 Intercondenser

The gas steam mixture is condensed and cooled at a pressure near 5 psia. At this pressure the condensation and cooling design temperatures are not as sensitive to main condenser approach conditions, basically because of high steam gas inlet saturation temperatures. With the specified cooling water range and approach the temperature differences specified are 37°F and 25°F respectively at steam gas inlet and outlet.

5.1.1.1.7 Aftercondenser

The steam gas mixture is condensed and cooled at 14.1 psia. Similar design conditions as applied to the intercondenser prevail. The temperature differences specified are 77°F and 25°F respectively at the steam gas inlet and outlet. Since it is desirable to hold the aftercondenser outlet gas steam mixture at a low temperature so as to minimize the steam carry-over into the Stretford process no attempt was made to use series flow cooling water, (first into the intercooler and then into the aftercooler).

5.1.1.1.8 Steam Jet Ejectors

These units are specified to handle the noncondensable gas and steam vapor carry-over from the main and intercondenser at the pressure and temperature specified for subject equipment.

5.1.1.1.9 Cooling Water Pumps

The existing cooling water system is of the "open type" utilizing a cold well and a hot well. Because the condenser supply pump was purchased with just enough differential head to supply the main barometric condenser when it is at design vacuum and 110% of full load, this pump cannot be reused in a "closed" design. Similarly, the cooling tower return pump was purchased with just enough differential head to feed the cooling water tower and cannot be used in a "closed" design which is desirable to avoid losing the condenser outlet pressure static head. For Unit 1, once the cooling water head balance is specified the system curve can be estimated for the retrofitted "closed" system. The two half-sized pumps required can be arranged in the existing wells by equalizing the hot and cold well compartments as shown on Drawing No. PD-001. At this time with the direct contact system two sources of warm water enter the hot well. These two streams will be directed to the hot well of the new shell and tube condenser.

5.1.1.1.10 Condensate Pumps

The new main condenser hotwell will collect the condensate from the turbine exhaust and the inter- and aftercondensers. Since the total condensate flow is not large (600 gpm) it is practical to consider a pump that can operate under reduced pressure (full vacuum suction) with a minimum NPSH requirement. Several manufacturers supply pumps which can operate at an NPSH of 6-10 feet without resorting to the "canned" type configuration required for large flows. The total differential head noted in the Data Sheet is based on pumping from the expected condenser operating vacuum into the cooling water tower return header at system design head.

5.1.1.1.11 Process Flow Diagram

The Cooling Cycle Conversion Process Flow Diagram, PD-001, shows the material balance at the suggested retrofit conditions. Table 5.1-1 shows a comparison summary of the original Reference Design Base Point and the Conversion Retrofit.

5.1.1.1.12 Equipment Data Sheets

The Equipment Data Sheets associated with the conversion equipment for Unit 1 are included in Appendix "A". These Flow/ Thermodynamic Information Sheet, Exchanger Specification Sheets for Unit 1 Main Condenser, Intercondenser, Aftercondenser, and the Data Sheets for the Condensate and Circulating Water Pumps and Drivers.

5.1.1.1.13 Notes on Equipment Specifications and Selection

Suppliers of the equipment discussed herein were contacted by telephone followed up by transmittal of pertinent equipment data sheets. In the majority of cases, vendors were contacted who have had some experience in the special problems associated with geothermal plants.

Because of space limitations, a limit of 30 ft. on length of tubing in main condenser and 20 ft. in the inter- and aftercondensers was specified.

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On a first pass basis, rather than specifying cleanliness factors according to Heat Exchange Institute practice, TEMA fouling factors of 0.0001 on shell side and 0.001 on tube side were specified. As a result of PGandE's direction on May 22, cleanliness factors of 70% have been used in the final system concept, for the main steam condenser only.

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TABLE 5.1-1

COMPARATIVE SUMMARY

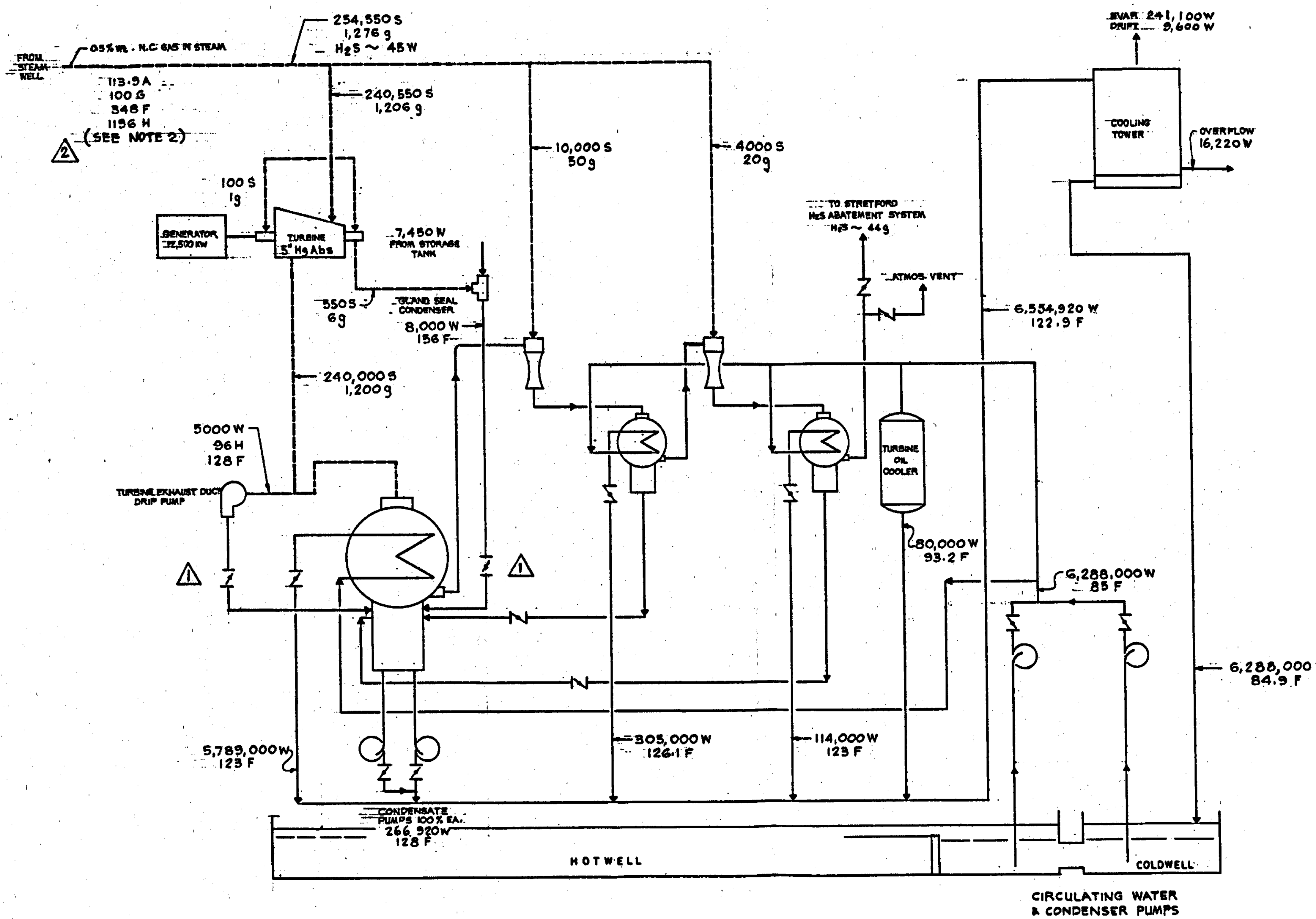
UNIT 1

	Base Reference Design Point	Conversion Retrofit
Throttle Flow lbs./hr.	240,550	240,550
Noncondensable Gas % Wt.	0.75	0.5
Gross Generator Electric Output kW	12,500[2] [3]	11, 845[1]
Auxiliary Power (Electric) kW		
Cooling Tower Fans	96.2	96.2
Exciter	69.0	69.0
Miscellaneous	7.8	7.8
Circ. Water & Cond. Pumps	229.0	313.0
Noncondensable Gas Blower	-	20.0
Net Unit Output kW	12,098	11,339
Heat Input Btu/Hr. (Ref. to 60°F)	293×10^6	297.3×10^6
Net Heat Rate Btu/kWh	24,215	26,200
Turbine Exh. Inch Hg Abs	4	5
Wet Bulb	65.0	65.0
C. W. T. Range/Approach °F	40/15	38/19.9

[1]For expected gross output after retrofit, multiply actual field gross output of unit by retrofit derating factor of 0.9476

[2]Recent field pressures differ from the plant data book values. For consistency, data book values have been used for comparisons.

[3]If it is desired to use actual field gross output, the "base design point" net will change by the difference between the stated gross in this study and the actual gross. Also the gross conversion retrofit will change. Use the derating factor to get the actual gross output after retrofit, and the net will be reduced per the design point calculation.



PERFORMANCE

THROTTLE FLOW — 240,550 #/HR.
GENERATOR ELEC. OUTPUT — 11,845 KW(1)
AUXILIARY POWER (ELECTRICAL)
CIRC. WATER & COND. PUMPS — 313 KW
COOLING TOWER FANS — 96.2 KW
EXCITER & MISC. — 76.8 KW
NON COND. GAS BLOWER — 20 KW
TOTAL 506 KW

NET UNIT OUTPUT — 11,339 KW
HEAT INPUT — 297 x 10⁶ BTU/HR
NET HEAT RATE — 26,200 BTU/KWHR
REFERRED TO 60°F

CONDITIONS

GENERATOR POWER FACTOR — 1.0
CONDENSER BACK PRESSURE — 5.0 Hg
DRY BULB AIR TEMPERATURE — 75°F
WET BULB AIR TEMPERATURE — 65°F

GAS SHOWN ENTERING COOLING TOWER IS AIR ABSORBED BY WATER

GASES TO-AND FROM COOLING TOWER DO NOT INCLUDE COOLING AIR BUT ONLY THAT WHICH IS ABSORBED AND DEGASSED.

ANY AIR ABSORBED IN COOLING WATER IN HOTWELL IS NOT INCLUDED

LEGEND

MAIN STEAM LINE
WATER LINES
STEAM LINES
GAS LINES
S POUNDS PER HOUR STEAM
W POUNDS PER HOUR WATER
g POUNDS PER HOUR GASES
F DEGREES FAHRENHEIT
H STEAM ENTHALPY
A PRESSURE PSI ABSOLUTE
G PRESSURE PSI GAGE

NOTES

(1) FOR EXPECTED GROSS OUTPUT, MULTIPLY ACTUAL FIELD OUTPUT OF UNIT BY RETROFIT DERATING FACTOR OF 0.9476

2 (2) RECENT FIELD PRESSURES DIFFER FROM PLANT DATA BOOK VALUES. DATA BOOK VALUES USED FOR COMPARISONS.

2 (3) SEE TABLE 5.1-1 IN REPORT.

REFERENCE DRAWINGS

	REVISION			
2	REISSUED FOR FINAL REPORT	EA	BF	
1	ISSUED FOR FINAL REPORT	EA	BF	
0	ISSUED FOR REPORT	CO.	BF	

ROGERS ENGINEERING CO., INC.
ENGINEERS • ARCHITECTS
111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94111

SCALE NONE DATE 5-31-79
DR. C.O. CHK. ENG. BF APPROVED

APPROVALS
DATE
DATE

PG and E RETROFIT PROJECT
UNIT No. 1 CONVERSION
PROCESS FLOW DIAGRAM

JOB NO. 579007 PD-001 2

5.1.1.2 Installation and Equipment Arrangement

5.1.1.2.1 Main Condenser

Field measurements were taken to check clearances and accessibility around and to the equipment and these measurements formed the basis for the arrangement developed and shown on Drawing SK-007. It was important to ascertain that no interference will exist between the proposed new condenser installation and the main steam lines for Units 1 and 2 and that all exits from the turbine bulding are unobstructed.

Surrounding equipment and fence locations determined the main condenser location and orientation. The lowest point of the main condenser shell should be 15' above grade which will permit vehicle traffic around the plant as exists now and fulfill the requirement for the hot well and the associated pump equipment located above grade. This suggested layout assumes an even number of cooling water passes. The cooling water system would connect to the nearest existing water well taken the shorter distance from the condenser water box. The existing turbine exhaust duct will be cut at a point above grade and the downstream ducting will be utilized as much as possible in the connection to the condenser inlet.

5.1.1.2.2 Intercondenser, Aftercondenser and Ejectors

The existing steel structure would be utilized to support the intercondenser, aftercondenser and ejectors.

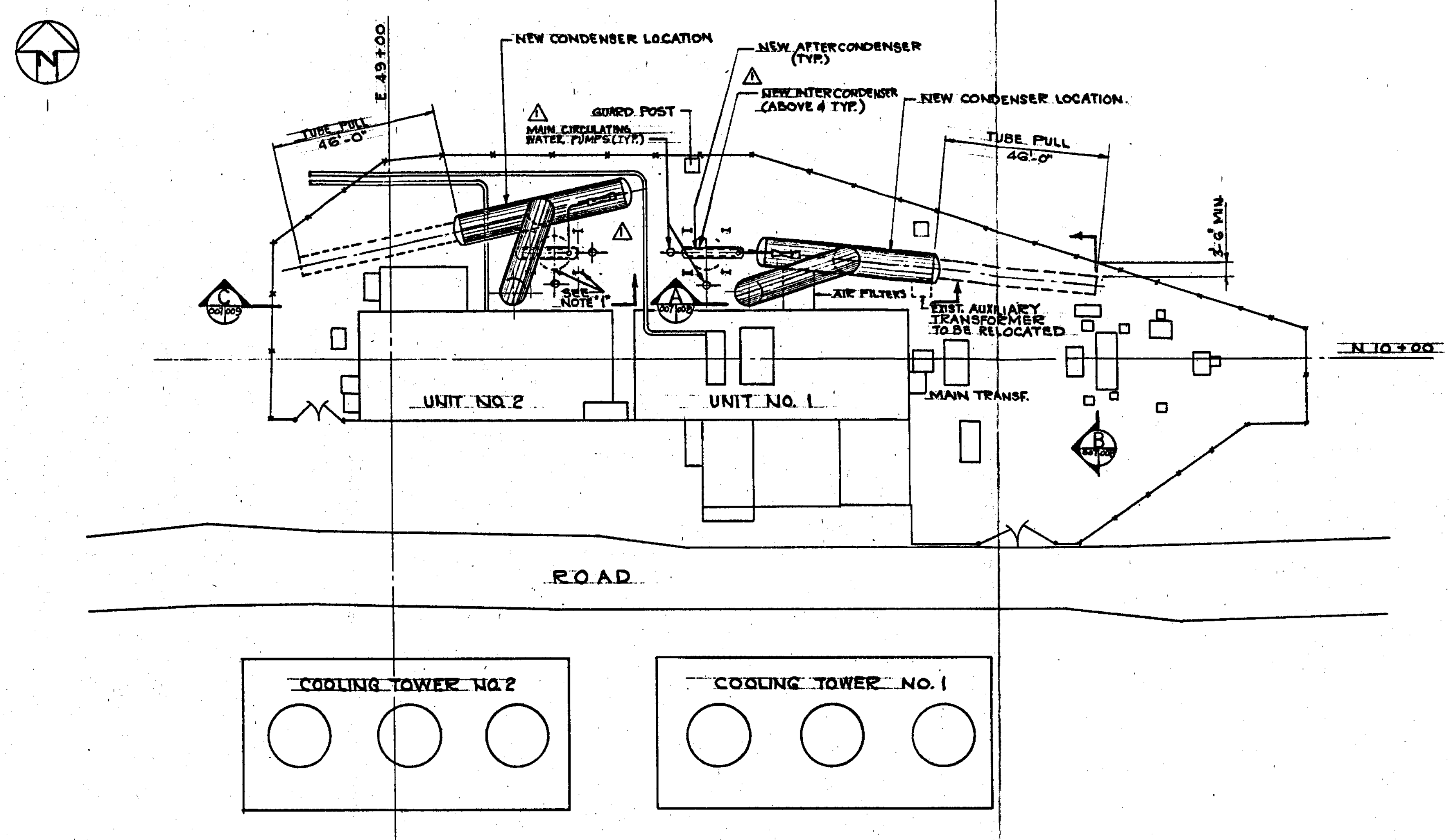
5.1.1.2.3 Pumps

The existing condensate and circulating water pumps do not meet the new requirements for the shell and tube condenser and will have to be removed. The new circulating water pumps will be located in such a way that the existing wet well will be utilized with the existing hot well and cold well modified to allow free communication between the two sections and allow the installation of two circulating water pumps (Refer to Drawings SK-007, SK-008 and SK-009.) A small ~ 12 gpm drip pump which has been used to pump the hot water to the existing hot well will have its discharge routed to the new surface condenser hot well. As shown in the cooling water system drawings the condensate pumps will discharge into the circulating water return header to the cooling tower.

Rogers

5.1.1.2.4 Site Plan

The Site Plan (SK-007) included herein indicates the new conversion equipment locations superimposed on the existing building and equipment locations.



SITE PLAN UNIT 1 & 2

1" = 20'-0"

NOTES:

1. BAROMETRIC CONDENSER AND EXISTING INTER, AFTER CONDENSERS AND EJECTORS, ALONG WITH STRUCTURAL STEEL WILL BE REMOVED. AS MUCH OF THE STRUCTURAL STEEL AS POSSIBLE WILL BE USED ON THE RETROFIT.

REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.
1		9/20/79	ISSUED FOR FINAL REPORT	RS	LFW		
0		5/31/79	ISSUED FOR MILESTONE REPORT #1	H-E.	LFW		

REFERENCE DRAWINGS

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

SCALE AS SHOWN DATE 5-30-79

DR. Hagele CHK. LFW ENG. EJM. APPROVED

APPROVALS

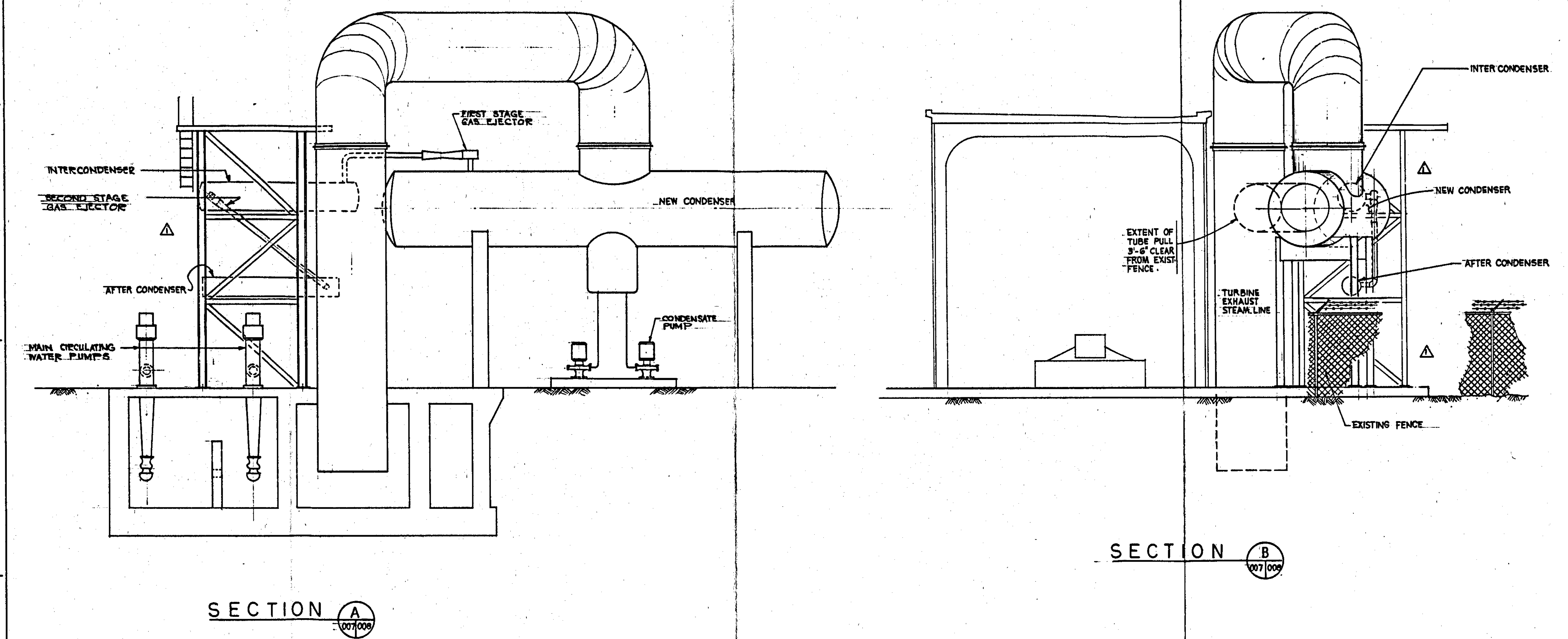
DATE
DATE

PG and E RETROFIT STUDY
UNITS 1 & 2
SITE PLAN

JOB NO. S79007

SK-007

1



REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO.	APPR.
1		9/20/79	ISSUED FOR FINAL REPORT	RS	LFW		
0		5/30/79	ISSUED FOR MILESTONE REPORT #1	G.O.	LFW		

REFERENCE DRAWINGS

ROGERS ENGINEERING CO., INC.
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111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94111

SCALE 3/16" = 1'-0" DATE 5-30-79

DR. G.O. CHK. LFW ENG. PJM APPROVED

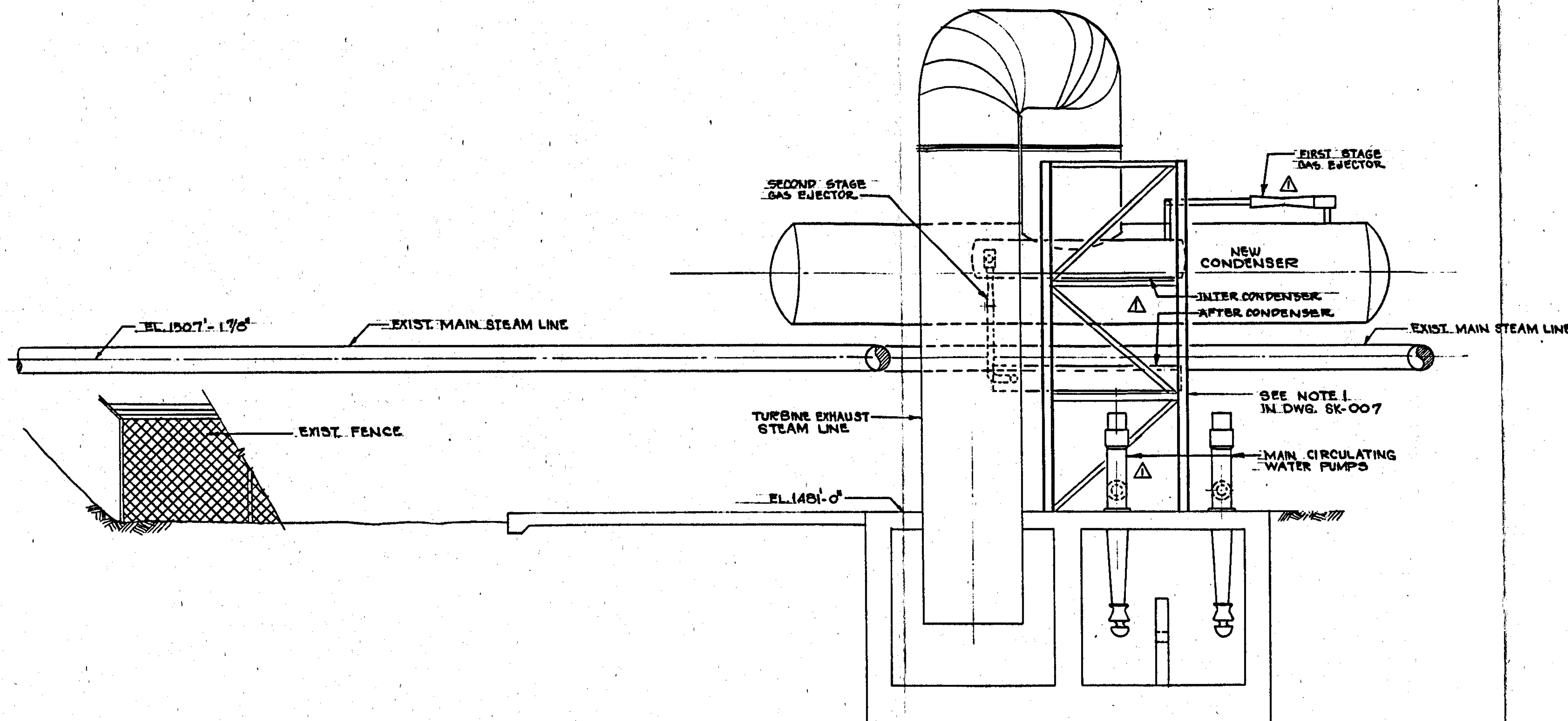
APPROVALS

DATE

DATE

PG and E RETROFIT STUDY
UNITS 1 & 2
SECTIONS A & B

JOB NO. S79007 SK-008 1



SECTION C
3/16" = 1'-0"
007 009

REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.
1		9/.../79	ISSUED FOR FINAL REPORT	RS	LFW		
0		5/31/79	ISSUED FOR MILESTONE REPORT #1	H.E.	LFW		

REFERENCE DRAWINGS

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

SCALE 3/16" = 1'-0" DATE 5-30-79
DR. Hagob CHK. LFW ENG. PJM APPROVED

APPROVALS
DATE
DATE

PG and E RETROFIT STUDY
UNITS 1 & 2
SECTION C

JOB NO. S79009
SK-009
1

Rogers

5.1.1.3 Cost Estimate

Section 3 of this report discusses methods and parameters employed in preparing cost estimates for the retrofit project. The following summary cost estimate and the backup detail on succeeding pages adhere to the guidelines in Section 3, and as noted have been prepared according to typical PGandE format.

TABLE 5.1-2

SUMMARY COST ESTIMATE - UNITS 1 & 2 (UNIT 1 TYPICAL)
(Each Unit)

Account	Description	Equip. & Mat'l	Labor	Total
54-20	Condensate System	$ 690,124	$282,354	$ 972,478
54-30	Circ. Water System	264,576	80,932	345,508
54-70	Instrumentation	16,790	18,171	34,961
55-30	Control & Power Conn.	3,943	17,472	21,415
55-60	Station Power System	19,716	16,214	35,930
365	Engineering & Other	282,120	0	282,120
	Subtotals	$1,277,269	$415,143	$1,692,412
GM Factor (20.7%)				350,300
	Subtotal (GM 1979)			$2,042,712
Escalation (28.55%)				589,200
	Total GM Estimate			$2,631,912

Project Differential Cost

The capital involved to accomplish the retrofit for Unit 1 using a surface condenser will require a level annual revenue of 3.77 mills per kilowatthour.

ROGERS ENGINEERING CO.,INC. COST ESTIMATE

JOB NAME-UNIT NO 1 JOB NO.-S79007 CLIENT-P G AND E ESTIMATE DATE- 16 JULY 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-21-1	CONDST PMP EXC&BKFL	318.	6989.	301.	7307.
54-21-2	CONDST PMP CONCRETE	382.	5591.	240.	5973.
54-22-1	TBN EXT PIPNG STEELW	1908.	6989.	301.	8897.
54-22-2	RMV PART SUPT STRUCT	636.	5591.	240.	6227.
54-23-1	RMV CONDSR	3816.	39138.	1683.	42954.
54-23-2	COND M,INT,AFT&EJTR	555864.	0.	0.	555864.
54-23-3	COND STEEL WORK	6360.	27956.	1202.	34316.
54-23-4	COND MECH	1272.	83867.	3607.	85139.
54-24-1	CONDST PMP MECH	30528.	6989.	301.	37517.
54-25-1	COND PIPING & MISC	5088.	22365.	962.	27453.
54-25-2	CONDST PMP PIPING EQ	6360.	34945.	1503.	41305.
54-25-3	TBN EXT PIP MECH	77592.	41934.	1804.	119526.
ACCOUNT TOTAL		690124.	282354.	12144.	972477.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-31-1	CW PMP CONCRETE	1272.	16773.	721.	18045.
54-31-2	CW PIPING EXCV&BKFL	636.	8387.	361.	9023.
54-33-1	CW PIPING & EQ	45792.	31450.	1353.	77242.
54-34-1	CW PMP MECH	216240.	18730.	806.	234970.
54-39-1	RELOCATE FIRE MAIN	636.	5591.	240.	6227.
ACCOUNT TOTAL		264576.	80932.	3481.	345508.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-74 1	INSTMT CONDST SYS	11448.	8387.	361.	19835.
54-74-2	INSTMT CW SYS	5342.	9785.	421.	15127.
ACCOUNT TOTAL		16790.	18171.	782.	34962.

ROGERS ENGINEERING CO., INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111
JOB NO. S-79007
DG-023

TABLE 5.1-6
COST ESTIMATE DETAIL
UNIT 1 SURFACE CONDENSER

DRAWING NO. REV.

SHEET 1 OF 2

ROGERS ENGINEERING CO.,INC. COST ESTIMATE

JOB NAME-UNIT NO 1 JOB NO.-S79007 CLIENT-P G AND E ESTIMATE DATE- 16 JULY 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
55-33-1	AUX TRNSF W & CBL	2798.	10483.	451.	13282.
55-32-1	AUX TRNSF COND & DUC	1145.	6989.	301.	8134.
ACCOUNT TOTAL		3943.	17472.	752.	21416.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
55-61	RELOCATE AUX TRNSF F	191.	1677.	72.	1868.
55-63	RELCT AUX TRANSF	445.	4193.	180.	4639.
55-64-1	CW PMP ELECTRICAL	16536.	6989.	301.	23525.
55-64-2	CONDST PMP ELECT	2544.	3355.	144.	5899.
ACCOUNT TOTAL		19716.	16214.	697.	35930.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL	
365-1	CONSTRUCTION FIELD	70560.	0.	0.	70560.	
365-2	GENERAL ENGINEERING	42360.	0.	0.	42360.	
365-3	OTHER ENGINEERING	169200.	0.	0.	169200.	1
ACCOUNT TOTAL		282120.	0.	0.	282120.	2

ROGERS ENGINEERING CO., INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111

JOB NO. S-79007

DG-023

TABLE 5.1-6
COST ESTIMATE DETAIL
UNIT 1 SURFACE CONDENSER

DRAWING NO. REV.

5.1.2 Unit 2

5.1.2.1 Selected Process Design

The variances from Unit 1 typical pertaining to Unit 2 are here presented.

5.1.2.1.1 Noncondensable Gas Values

Same as Unit 1 - 0.5% wt. in steam

5.1.2.1.2 Field Test Data for Cooling Water Tower

This cooling tower was completely rebuilt and it is assumed that when clean that it will be capable of design rate operation.

5.1.2.1.3 Base Reference Design Point

Same as Unit 1 Data Book. The Unit 2 Conversion Process Flow Diagram PD-002 shows the expected unit performance after Retrofit.

5.1.2.1.4 Main Condenser Cooling Water System Limitations

The Unit 2 cooling water tower at the base design point of 65°F wet bulb is expected to be close to meeting design. The approach has been relaxed from 15°F to 15.9°F and the range dropped from 40°F to 39°F. This results in turbine exhaust pressure of 4.8 inches Hg Abs compared to the Unit 1, 5 inches Hg Abs.

5.1.2.1.5 Condensing and Gas Cooling Limitations

Since the Unit 2 cooling water is cooler it is possible that the turbine exhaust pressure could be lowered to about 4.3 inches Hg Abs. However, to insure meeting a more severe installation space problem the exhaust pressure was held at 4.8 inches Hg Abs and the temperature differences specified are 10.2°F and 29.1°F respectively for the terminal temperature difference and the gas cooling outlet.

5.1.2.1.6 Intercondenser

With specified cooling water range and approach the temperature differences specified are 38°F and 29.1°F respectively at the gas steam inlet and outlet using parallel flow cooling water.

Rogers

5.1.2.1.7 Aftercondenser

The differences specified are 82°F and 29.1°F respectively at the gas steam inlet and outlet using parallel flow cooling water.

5.1.2.1.8 Steam Jet Ejectors

These units are specified to handle the noncondensable gas and steam vapor carry-over from the main and intercondensers at the pressure and temperature specified for subject equipment.

5.1.2.1.9 Cooling Water Pumps

Two pumps will be required almost identical to Unit 1.

5.1.2.1.10 Condensate Pumps

Two pumps will be required almost identical to Unit 1.

5.1.2.1.11 Process Flow Diagram

The Cooling Cycle Conversion Process Flow Diagram, PD-002, shows the material balance at the suggested retrofit conditions. Table 5.1-2 shows a comparison summary of the original Reference Design Base Point and the Conversion Retrofit.

5.1.2.1.12 Equipment Data Sheets

The Equipment Data Sheets associated with Unit 2 are included in Appendix "A".

Rogers

TABLE 5.1-3

COMPARATIVE SUMMARY

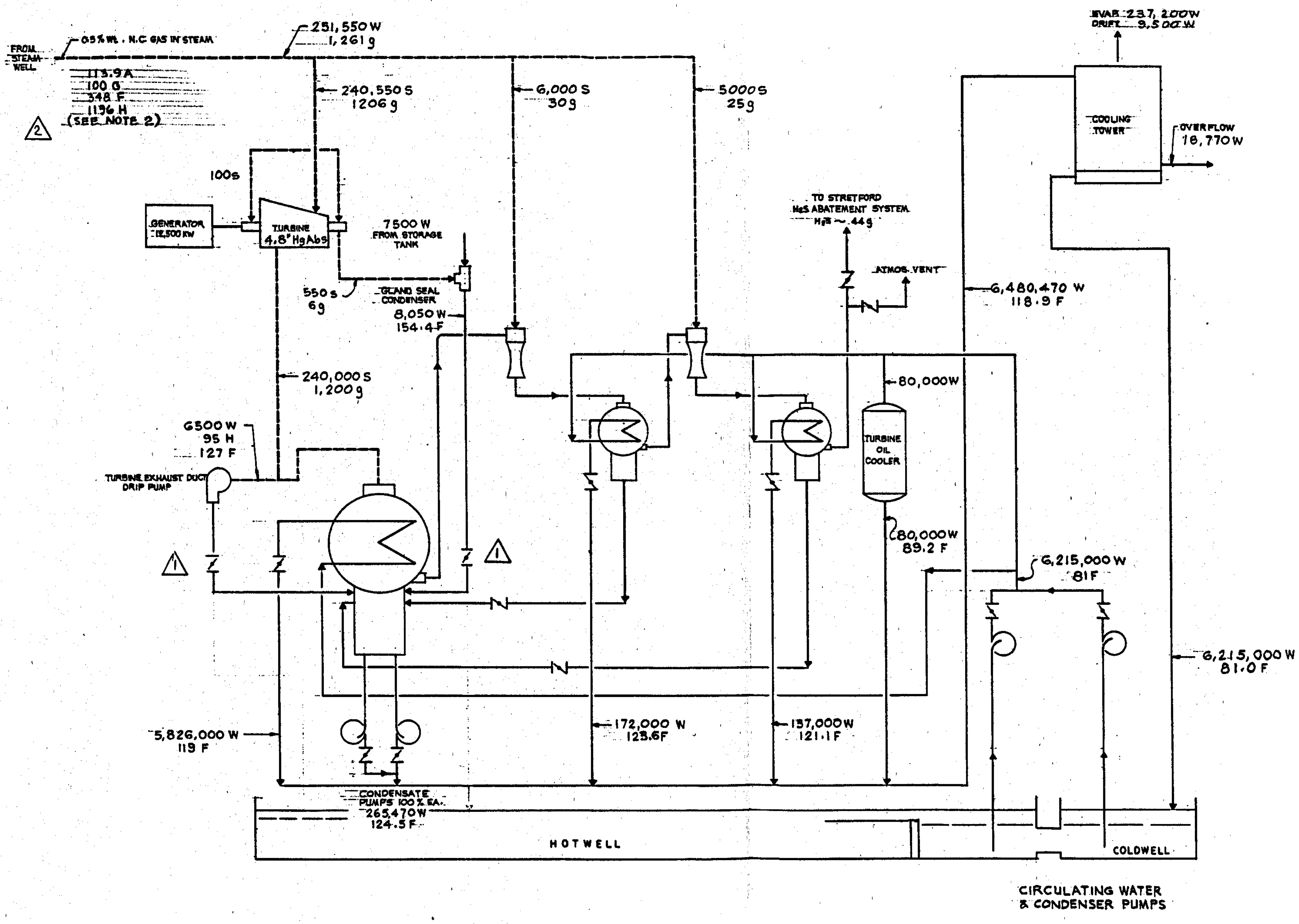
UNIT 2

	Base Reference Design Point	Conversion Retrofit
Throttle Flow lbs./hr.	240,550	240,550
Noncondensable Gas % Wt.	0.75	0.5
Gross Generator Electric Output kW	12,500[2 3]	11, 974[1]
Auxiliary Power (Electric) kW		
Cooling Tower Fans	115	115
Miscellaneous	35	35
Circ. Water & Cond. Pumps	235	309
Noncondensable Gas Blower		20
Net Unit Output kW	12,115	11,495
Heat Input Btu/Hr. (Ref. to 60°F)	293×10^6	294×10^6
Net Heat Rate Btu/kWh	24,180	25,580
Turbine Exh. Inch Hg Abs	4	4.8
Wet Bulb	65.0	65.0
C. W. T. Range/Approach °F	40/15	39/15.9

[1]For expected gross output after retrofit, multiply actual field gross output of unit by retrofit derating factor of 0.9579

[2]Unit 2 was assumed to have the same gross as Unit 1 because of the contractual stipulations in the scope of work. For comparison, this is good as it shows the difference in cooling tower performance.

[3]If it is desired to use actual field gross output the "base design point" net will change by the difference between the stated gross in this study and the actual gross. Also the gross conversion retrofit will change. Use the derating factor to get the actual gross output after retrofit. The net will be reduced as per the design point calculation.



PERFORMANCE

THROTTLE FLOW — 240,550 #/HR
GENERATOR ELEC. OUTPUT — 11,974 KW (1)
AUXILIARY POWER (ELECTRICAL)
CIRC. WATER & COND. PUMPS — 309 KW
COOLING TOWER FANS — 115 KW
MISC. — 35 KW
NON COND. GAS BLOWER — 20 KW
TOTAL 479 KW

NET UNIT OUTPUT — 11,495 KW
HEAT INPUT — 294×10^6 BTU/HR
NET HEAT RATE — 25,560 BTU/KW HR
REFERRED TO 60°F

CONDITIONS

GENERATOR POWER FACTOR — 1.0
CONDENSER BACK PRESSURE — 4.8 Hg
DRY BULB AIR TEMPERATURE — 75°F
WET BULB AIR TEMPERATURE — 65°F

GAS SHOWN ENTERING COOLING TOWER IS AIR ABSORBED BY WATER

GASES TO AND FROM COOLING TOWER DO NOT INCLUDE COOLING AIR BUT ONLY THAT WHICH IS ABSORBED AND DEGASSED.

ANY AIR ABSORBED IN COOLING WATER IN HOTWELL IS NOT INCLUDED

LEGEND

- MAIN STEAM LINE
- WATER LINES
- STEAM LINES
- GAS LINES

S POUNDS PER HOUR STEAM
W POUNDS PER HOUR WATER
g POUNDS PER HOUR GASES
F DEGREES FAHRENHEIT
H STEAM ENTHALPY
A PRESSURE PSI ABSOLUTE
G PRESSURE PSI GAGE

2 NOTES:

(1) FOR EXPECTED GROSS OUTPUT, MULTIPLY ACTUAL FIELD OUTPUT BY RETROFIT DERATING FACTOR 0.9579.

~~(2) UNIT 2 WAS ASSUMED THE SAME GROSS OUTPUT AS UNIT 1, BECAUSE OF CONTRACTUAL STIPULATIONS IN THE SCOPE OF WORK. FOR COMPARISONS THIS IS GOOD BECAUSE IT SHOWS DIFFERENCE IN COOLING TOWER PERFORMANCE.~~ 2

(3) SEE TABLE 5.1-2 IN REPORT.

REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.
2			REISSUED FOR FINAL REPORT	RS	BF		
1			ISSUED FOR FINAL REPORT	EA	BF		
0			ISSUED FOR REPORT #1	CO.	BF		

REFERENCE DRAWINGS

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

SCALE NONE DATE 5-31-79
DR. G.O. CHK. ENG. BF APPROVED

APPROVALS
DATE
DATE

PG and E RETROFIT PROJECT
UNIT No. 2 CONVERSION
PROCESS FLOW DIAGRAM

JOB NO. S79007 PD-002 2

5.1.2.2 Installation and Equipment Arrangement

The Site Plan (SK-007) and equipment arrangement drawings (SK-008 & 009) presented earlier are for both Units 1 and 2. As seen, the geometry of the plant does not allow an identical arrangement for Unit 2 as for Unit 1. Relocation of the existing auxiliary transformer is necessary to provide required clearances to the fence and other equipment, and the main condenser will have a different orientation. Other than this, the layouts differ in minor respects only.

5.1.2.3 Cost Estimate

Refer to Table 5.1-2, Summary Cost Estimate for Unit 1. The cost for retrofitting Unit 2 is considered essentially the same as for Unit 1.

Rogers

5.1.3 Units 3 and 4

5.1.3.1 Selected Process Design

5.1.3.1.1 Noncondensable Gas Values

Original base reference design point was 1.0% wt. noncondensable gas in the steam. Based on updated field data the agreed value is now 0.8% wt. The gas composition is shown in detail in Appendix A. The average mol wt. is 32.4.

5.1.3.1.2 Field Test Data for Cooling Water Tower

The cooling tower for Unit 4 was tested 20 May 1969, when clean. At a wet bulb of 60.9°F, with a circulating water flow of 21,860 gpm and a range of 37.3°F the approach to wet bulb was 17.9°F. This test indicates the tower is at design rating. Unit 3 cooling water tower is of similar design. The last test on Unit 3 tower was 25 August 1978 and indicated that the system was not thoroughly cleaned of iron oxide since performance was poor. For this report it will be assumed both Units 3 and 4 cooling water towers can be cleaned to achieve design ratings.

5.1.3.1.3 Base Reference Design Point

The Data Book Heat Balance Diagram for Maximum Guaranteed Load is the base reference design point. The calculated gross power will be based on essentially the same turbine throttle flow at the retrofit conditions. Net power will then be calculated based on the additional station auxiliary power requirements. The Unit 3 conversion Process Flow Diagram, PD-003, shows the expected Unit performance after retrofit.

5.1.3.1.4 Main Condenser Cooling Water System Limitations

The Unit 3 cooling tower at the base design of 65°F wet bulb is expected to meet a design approach of 15°F with the range relaxed from 40°F to 39.4°F. To obtain the lowest turbine exhaust flange pressure it is proposed to use for the main condenser an 8°F terminal temperature difference. A gas cooling outlet approach of 34°F is proposed to keep the first vacuum jet ejector and intercooler system from being grossly oversized.

5.1.3.1.5 Intercondenser

With the specified cooling water tower range and approach, the temperature differences specified are 41°F and 30°F respectively at the gas steam inlet and outlet.

5.1.3.1.6 Aftercondenser

The temperature differences specified are 81°F and 30°F respectively for the steam gas inlet and outlet.

5.1.3.1.7 Steam Jet Ejectors

These units are specified to handle the noncondensable gas and steam vapor carryover from the main- and intercondensers at the pressures and temperatures specified for subject equipment.

5.1.3.1.8 Cooling Water Pumps

The existing cooling water system is of the "open" type utilizing atmospheric vented hot and cold wells. Two new pumps will be specified and the system revised to a "closed" type to reduce pumping power requirements. The hot and cold wells will be rearranged for use as a common supply of cold water. As with Unit 1 there are two small warm water streams that will be added to the main condenser hotwell.

5.1.3.1.9 Condensate Pumps

These units are specified to remove the approximate 1,000 gpm of condensate from the main condenser. The total differential head required is based on pumping from expected vacuum into the cooling water tower return header at system design head.

5.1.3.1.10 Process Flow Diagram

The conversion Process Flow Diagram, PD-003, shows the material balance at the suggested retrofit conditions. Table 5.1-3 shows a comparison summary of the original Reference Design Base Point and the conversion retrofit.

5.1.3.1.11 Equipment Data Sheets

The Equipment Data Sheets associated with the conversion equipment for Units 3 and 4 are included in Appendix A. The Flow/Thermodynamic Information Sheet is only prepared for Unit 3. Exchanger Specification Sheets have been prepared for Unit 3

Rogers

Main Condenser, Intercondenser, Aftercondenser, as well as Data Sheets for the Condensate and Main Water Circulating Pumps and Drivers.

5.1.3.1.12 Notes on Equipment Specifications and Selection

Comments in Section 5.1.1.1 for Unit 1 apply generally to Units 3 and 4.

TABLE 5.1-4

COMPARATIVE SUMMARY

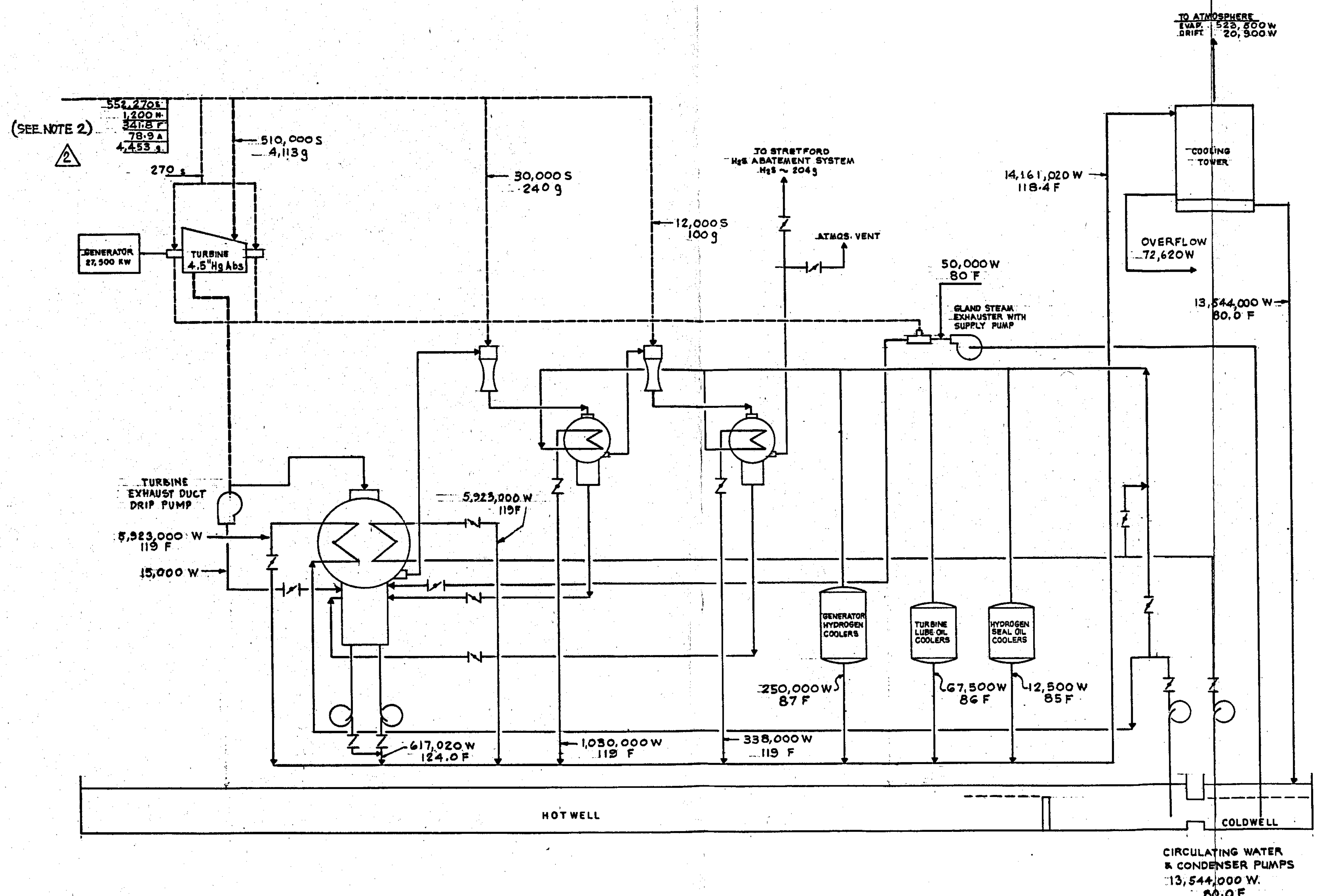
UNIT 3 OR 4 (Unit 3 Typical)

	Base Reference Design Point	Conversion Retrofit
Throttle Flow lbs./hr.	509,600	510,000
Noncondensable Gas % Wt.	1.0	0.8
Gross Generator Output kW	27,500[2] [3]	26, 817[1]
Auxiliary Power (Electric) kW		
Cooling Tower Fans	310	310
Miscellaneous	100	100
Circ. Water & Cond. Pumps	590	721
Noncondensable Gas Blower		25
Net Unit Output kW	26,500	25,661
Heat Input Btu/Hr.	630×10^6	648×10^6
Net Heat Rate Btu/kWh		25,300
Turbine Exh. Inch Hg Abs	4	4.5
Wet Bulb	65.0	65.0
C. W. T. Range/Approach °F	39/15	38.4/14.9

[1]For expected gross output after retrofit, multiply actual field gross output of unit by retrofit derating factor of 0.975

[2]Recent field pressures differ from the plant data book values. For consistency, data book values have been used for comparisons.

[3]If it is desired to use actual field gross output the "base design point" net will change by the difference between the stated gross in this study and the actual gross. Also the gross conversion retrofit will change. Use the derating factor to get the actual gross output after retrofit. The net will be reduced as per the design point calculation.



PERFORMANCE

THROTTLE FLOW — 510,270 #/HR.
GENERATOR ELEC. OUTPUT — 26,817 KW (1)
AUXILIARY POWER (ELECTRICAL)
- CIRC. WATER & COND. PUMPS — 721 KW
- COOLING TOWER FANS — 310 KW
- MISC. — 100 KW
- NON COND. GAS BLOWER — 25 KW
- TOTAL 1,156 KW

NET UNIT OUTPUT — 25,661 KW
HEAT INPUT 648 × 10^6 BTU/HR
NET HEAT RATE 25,300 BTU/KWHR
REFERRED TO 60°F

CONDITIONS

GENERATOR POWER FACTOR — 0.80
TURBINE EXHAUST BACK PRESSURE — 4.5 Hg
WET BULB AIR TEMPERATURE — 65°F
ALL STEAM FLOWS INCLUDE NON-CONDENSABLE GASES

LEGEND

MAIN STEAM LINE
WATER LINE
STEAM LINE
GAS LINE
S POUNDS PER HOUR OF STEAM
W POUNDS PER HOUR OF WATER
g POUNDS PER HOUR OF GASES
F DEGREES FAHRENHEIT
H ENTHALPY OF STEAM BTU/LB
A ABSOLUTE PRESSURE PSI
G GAUGE PRESSURE PSIG

NOTES:

(1) FOR EXPECTED GROSS OUTPUT, MULTIPLY ACTUAL FIELD OUTPUT BY RETROFIT DERATING FACTOR OF 0.975

(2) ~~RECENT FIELD PRESSURES DIFFER FROM PLANT DATA BOOK VALUES. DATA BOOK VALUES USED FOR COMPARISONS.~~

(3) ~~SEE TABLE 5.1-3 IN REPORT~~

2		REISSUED FOR FINAL REPORT	RS	BF		
1		ISSUED FOR FINAL REPORT	EA	BF		
0		ISSUED FOR REPORT	CO	BF		
NO.	ZONE DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.

REFERENCE DRAWINGS

ROGERS ENGINEERING CO., INC.
ENGINEERS · ARCHITECTS
111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94111

SCALE NONE DATE 5-31-79
DR. CO. CHK. ENG. BF APPROVED

APPROVALS
DATE
DATE

PGandE RETROFIT PROJECT
UNIT No. 3 CONVERSION
PROCESS FLOW DIAGRAM

JOB NO. S79007 PD 003 2

5.1.3.2 Installation and Equipment Arrangement

5.1.3.2.1 Condensers

The dimensions verifications in the field were based on design drawings obtained from PGandE and the drawings showing the proposed location of the shell and tube condenser and the associated equipment. It should be noted that the location and configuration of the turbine exhaust duct of Unit 3 is different from Unit 4. Therefore, the principle of the proposed modification is the same but not the detailed execution.

The passageway between the turbine building and the cooling tower has been kept clear, being the main artery of this plant, and exits from the turbine building to this area are unobstructed as well. The lowest point of the main condenser shell should be 15'-0" above grade. With the assumed main condenser length of 46'-0" it appears sufficient space is available to install the new equipment. The total required length including tube pulling area is 100'-0". This allows a clearance from the property cyclone fence of 4'-0".

The intercondenser, aftercondenser and ejectors can be mounted in the existing steel structure occupied by the corresponding equipment to be removed.

5.1.3.2.2 Pumps

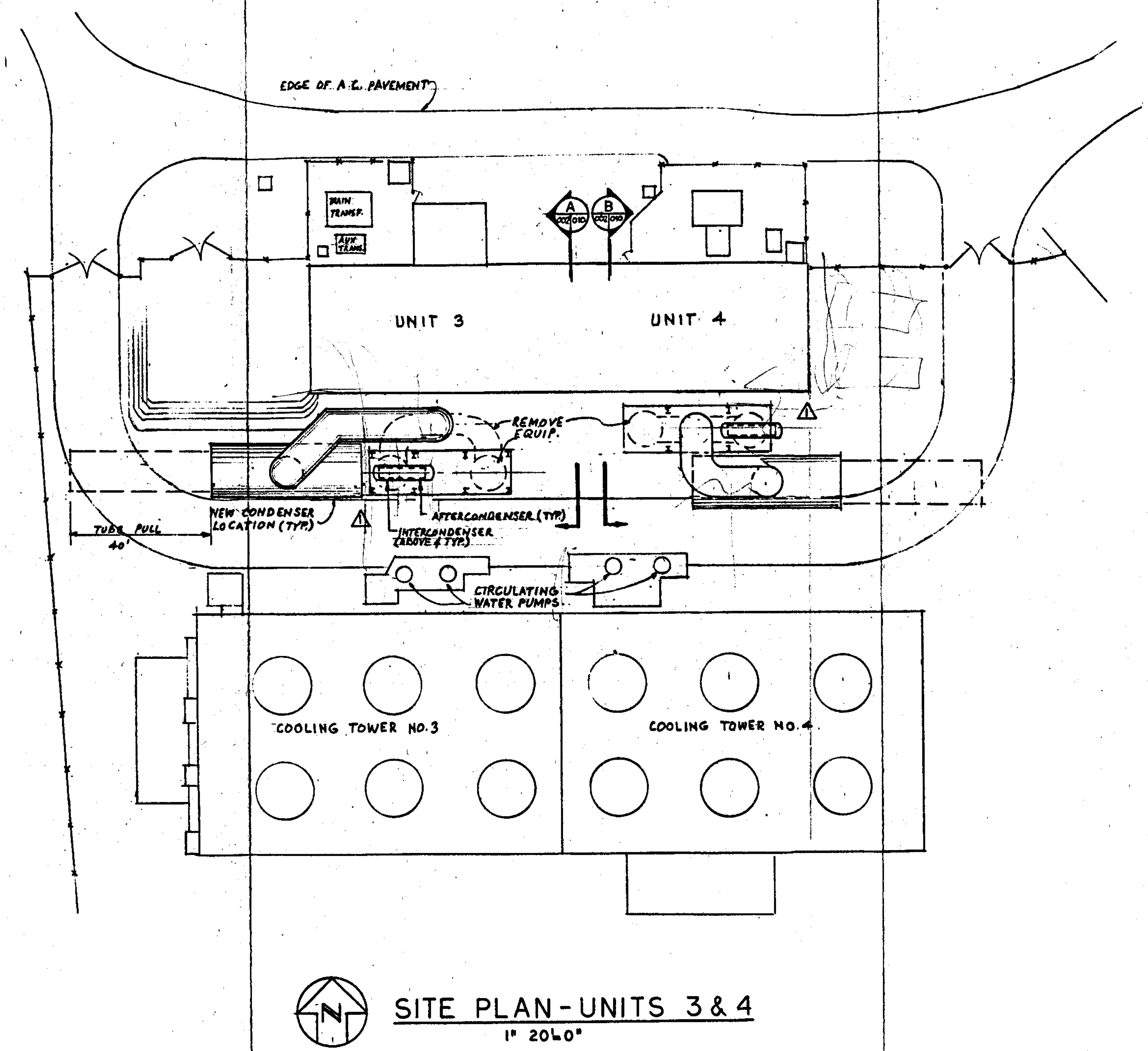
The existing condensate pump will be removed and replaced by a horizontal centrifugal pump as specified. As shown in the cooling water system diagram the condensate pumps will discharge into the circulating water return header to the cooling tower. The existing hot and cold well require modification to allow free communication between the two wells and also allow the installation of two circulating water pumps. (Refer to PD-003) A small ~ 30 gpm existing drip pump delivering drips to the existing hot well will have its discharge rerouted to the new shell condenser drip pot.

5.1.3.2.3 Miscellaneous

The east corner of the power building of Unit 4 has some equipment retired in place. This machinery will require removal before new equipment can be installed.

5.1.3.2.4 Site Plan - Units 3 and 4

Included herein is a Site Plan (SK-002) for Units 3 and 4, indicating the new conversion equipment locations superimposed upon the existing equipment and building locations.



SITE PLAN - UNITS 3 & 4

1" = 20'-0"

REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.
1		7/31/79	ISSUED FOR FINAL REPORT	RS	LFW		
0		5/31/79	ISSUED FOR MILESTONE REPORT #1	E.A.	LFW		

REFERENCE DRAWINGS

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

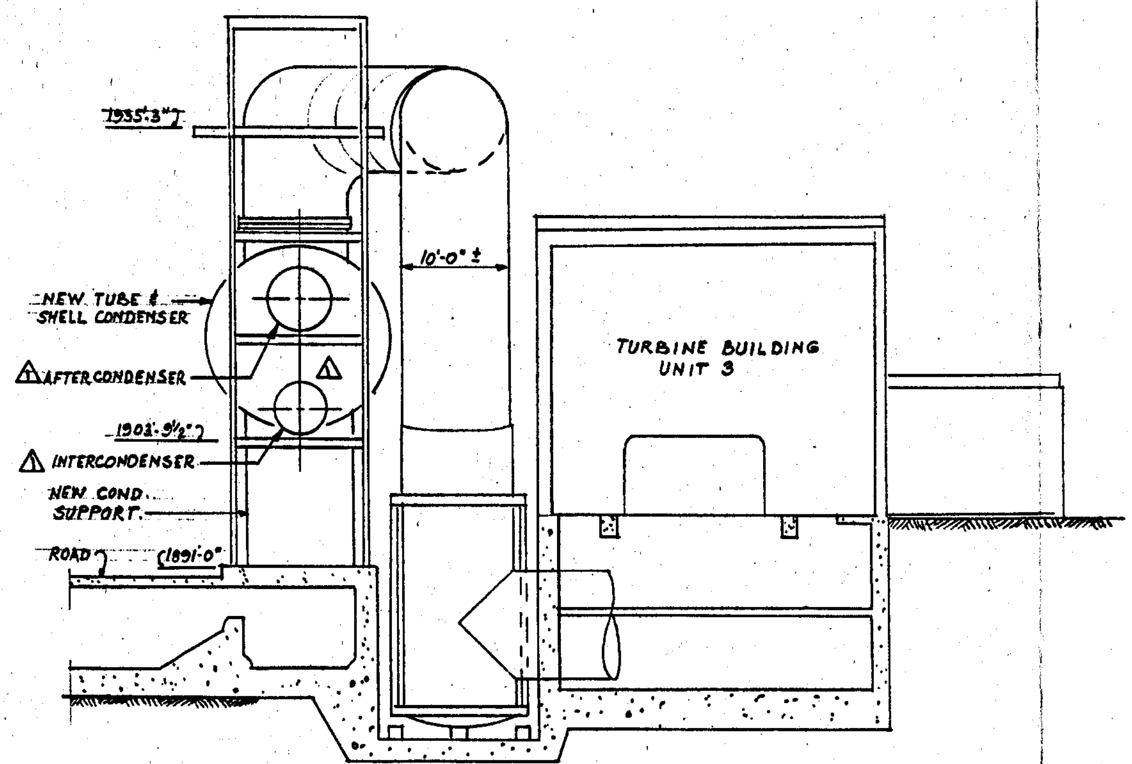
SCALE 1" = 20'-0" DATE 5-29-79
DR. E.A. CHK. LFW ENG. EJM APPROVED

APPROVALS

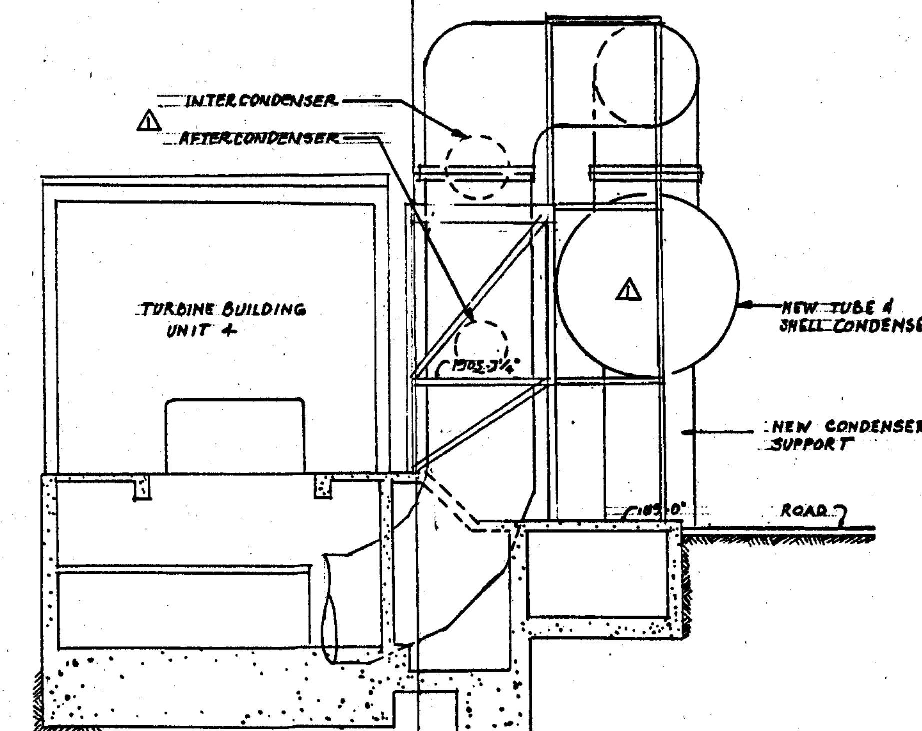
DATE
DATE

P G and E RETROFIT STUDY
UNITS 3 & 4
SITE PLAN

JOB NO. S-79007 | SK-002 | 1



SECTION A 002 010
UNIT 3



SECTION B 002 010
UNIT 4

		1		9/29/79	REISSUED FOR FINAL REPORT	RS	LFW		
SK-002	SITE PLAN	0		5/30/79	ISSUED FOR MILESTONE REPORT #1	E.A.	LFW		
REFERENCE DRAWINGS		REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.

ROGERS ENGINEERING CO., INC.
ENGINEERS • ARCHITECTS
111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94111.

SCALE NONE DATE 5-31-79
DR. E.A. CHK. LFW ENG. EJM APPROVED

APPROVALS
DATE
DATE

PG and E RETROFIT STUDY
UNITS 3 & 4
SECTIONS A-A & B-B

JOB NO. S-79007 SK-010 1

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5.1.3.3 Cost Estimate

Section 3 of this report discusses methods and parameters employed in preparing cost estimates for the retrofit project. The following summary cost estimate and the backup detail on succeeding pages adhere to the guidelines in Section 3, and as noted have been prepared according to typical PGandE format.

TABLE 5.1-5

SUMMARY COST ESTIMATE - UNITS 3 & 4 (UNIT 3 TYPICAL)
(Each Unit)

Account	Description	Equip. & Mat'l	Labor	Total
54-20	Condensate System	$1,392,331	$514,200	$1,906,532
54-30	Circ. Water System	521,138	167,253	688,392
54-70	Instrumentation	19,080	19,352	38,432
55-60	Station Power System	39,432	19,352	58,784
365	Engineering & Other	538,440	0	538,440
	Subtotals	$2,510,422	$720,157	$3,230,579
	GM Factor (20.7%)			668,730
	Subtotal (GM 1979)			$3,899,308
	Escalation (28.55%)			1,113,250
	Total GM Estimate			$5,012,558

Project Differential Cost

The capital involved to accomplish the retrofit using a surface condenser will require a level annual revenue of 3.18 mills per kilowatthour.

ROGERS ENGINEERING CO., INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111
JOB NO. S-79007
DG-023

TABLE 5.1-7
COST ESTIMATE DETAIL
UNIT 3 SURFACE CONDENSER

ROGERS ENGINEERING CO.,INC. COST ESTIMATE

JOB NAME-UNIT NO 3 JOB NO.-S79007 CLIENT-P G AND E ESTIMATE DATE- 17 JULY 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-21-1	CONDST PMP CONCRETE	636.	9676.	416.	10312.
54-21-2	CONDST PMP EXC &BKFL	763.	17278.	743.	18041.
54-22-1	TBN EXT PIPNG STLWK	5088.	17278.	743.	22366.
54-22-2	RMV PRT SUPT STRUCTR	1272.	11058.	476.	12330.
54-23-1	RMV CONDENSER	6360.	71877.	3092.	78237.
54-23-2	COND STEELWORK	15264.	55290.	2378.	70554.
54-23-3	COND MECH	3180.	172782.	7432.	175962.
54-23-4	COND M,INT,AFT &EJTR	1097100.	0.	0.	1097100.
54-24-1	CONDST PMP MECH	50880.	20734.	892.	71614.
54-25-1	COND PIPNG &MISC	16536.	48379.	2081.	64915.
54-25-2	CONDST PIPNG & EQPT	15264.	20734.	892.	35998.
54-25-3	TBN EXT MECH &PIP MT	179988.	69113.	2973.	249101.
ACCOUNT TOTAL		1392331.	514200.	22116.	1906532.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-31-1	CW PMP CONCRETE	3816.	44232.	1902.	48048.
54-31-2	CW PIPNG EXC &BKFL	1526.	20734.	892.	22260.
54-33-1	CW PIPNG PIPE &EQPT	69960.	55290.	2378.	125250.
54-34-1	CW PMP MECH	445200.	41468.	1784.	486668.
54-39-1	RELOCATE FIRE MAIN	636.	5529.	238.	6165.
ACCOUNT TOTAL		521138.	167253.	7194.	688392.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-74-1	INSTMT CONDST SYS	11448.	9676.	416.	21124.
54-74-2	INSTMT CW SYS	7632.	9676.	416.	17308.
ACCOUNT TOTAL		19080.	19352.	832.	38432.

DRAWING NO.

REV.

SHEET 1 OF 2

ROGERS ENGINEERING CO.,INC.   COST ESTIMATE

JOB NAME-UNIT NO 3   JOB NO.-S79007   CLIENT-P G AND E   ESTIMATE DATE- 17 JULY 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
55-64-1	CW PMP ELECTRICAL	34344.	13823.	595.	48167.
55-64-2	CONDST PMP ELECT	5088.	5529.	238.	10617.
ACCOUNT TOTAL		39432.	19352.	832.	58784.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
365-1	CONSTRUCTION FIELD	134640.	0.	0.	134640.
365-2	GENERAL ENGINEERING	80760.	0.	0.	80760.
365-3	OTHER ENGINEERING	323040.	0.	0.	323040.
ACCOUNT TOTAL		538440.	0.	0.	538440.

TABLE 5.1-7
COST ESTIMATE DETAIL
UNIT 3 SURFACE CONDENSER

ROGERS ENGINEERING CO., INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111

JOB NO. S-79007

DG-023

DRAWING NO.   REV.

SHEET 2 OF 2

5.2 Replace Condenser and Auxiliaries - Units 5-10

Units 5-10 are rated at 55 MW gross, and for study purposes, Unit 5 is considered typical for Unit 6 as well and Unit 7 is typical for Units 7-10.

The format for a portion of this section will be noted as differing from Section 5.1, which treated Units 1-4, in that a performance specification for purchase of the necessary condensing equipment was developed and is presented herein. Condensate pump and motor data sheets are included in Appendix B. Other subsections remain in the same format.

5.2.1 Selected Process Design

The difference between Units 5 and 6 and Units 7-10 is a 1/2°F difference in cold water temperature out of the cooling towers. The same equipment specification applies to all six units, and the differences in performance are reflected in Tables 5.2-1 and 5.2-2.

5.2.1.1 Noncondensable Gas Values

The original base design reference value was 1.0% wt. Tabulated below are the agreed values for this study report.

Unit	% wt. in Steam Noncondensable Gas
5	0.8
6	0.8
7	0.5
8	0.5
9	0.5
10	0.5

5.2.1.2 Field Test Data for Cooling Water Tower

The Post Overhaul Performance Test for Unit 5 data was examined for the 1976, 1977 and 1978 test periods. It was estimated that for the retrofit conceptual design an approach of 15.5°F could be obtained at a range of 37.7°F by a thorough cleaning of the cooling tower during the retrofit turn around. Similarly for Units 7 thru 10 it was estimated that an approach of 16.0°F could be obtained at a range of 37.6°F.

In order to prepare preliminary specifications for the entire surface condenser and steam jet ejector system the conceptual design was performed at a turbine exhaust of 4.3 inches of Hg Abs. (2.11 psia). It was assumed that the various equipment suppliers would respond to the specification by submitting proposals which would allow adjusting the conceptual design toward conditions of maximized power (as limited by the cooling tower). The conceptual design is shown on Drawing No. PD-004.

5.2.1.3 Base Reference Design Point

The Data Book Heat Balance Diagram for Maximum Guaranteed Load is the base reference design point. The calculated gross power will be based on essentially the same turbine throttle flow at the retrofit conditions. Net power will then be calculated based on the additional station auxiliary power requirements. The Units 5-10 conversion Process Flow Diagram shows the expected Unit performance after retrofit.

5.2.1.4 Specification of Equipment for Conversion from Direct Contact to Surface Type Exchangers

5.2.1.4.1 Performance Requirements

Generation capability to be maximized within the constraints imposed by the existing cooling water tower capability, the availability of area for tube sheets and space for tube length and the desirability of maintaining a turbine throttle steam flow near existing conditions of 907,530 lbs./hr. Supplier shall be responsible for complete design of condensing and vacuum system components for maximum power generation.

5.2.1.4.2 Steam Conditions

Turbine Inlet	Steam Jet Inlet
Enthalpy Btu/lb. - 1,200	
Entropy Btu/lb. x R - 1.608	
Pressure psia - 113.7	90 psig
Temperature °F - 355	355

Turbine exhaust (existing, for reference only)
Pressure-psia (in. Hg Abs.) - 1.964 (4.0)
Enthalpy - Btu/lb. - 990 (calculated)
Gross Power @ 4 in. Hg Abs. - 55,000 kW

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5.2.1.4.3 Noncondensable Gas Conditions

Unit	% Wt. in Steam	Ave. Mol. Wt.
5 or 6	0.8	31.9
7 thru 10	0.5	29.4

5.2.1.4.4 Air Leakage Allowance

Units 5 thru 10 - 440 lb./hr. each

5.2.1.4.5 Constraints

Cooling Water Availability (Best Preliminary Values)

Main Condenser

Unit	Item	
5 or 6	Cold °F	80.5
	Rise °F	37.5
	Flow gpm	43,000
7 thru 10	Cold °F	81.0
	Rise °F	37.5
	Flow gpm	43,000

Intercondenser

Unit	Item	
5 or 6	Cold °F	80.5
	Rise °F	37.5
	Flow gpm	2,900
7 thru 10	Cold °F	81.0
	Rise °F	37.5
	Flow gpm	2,700

Aftercondenser

5 or 6	Cold °F	80.5
	Rise °F	37.5
	Flow gpm	1,200
7 thru 10	Cold °F	81.0
	Rise °F	37.5
	Flow gpm	1,000

Main, Inter- and Aftercondenser Gas Cooling Exit Temperatures Preferred.

Units	Condenser	
5 thru 10	Main	114°F
	Inter	110°F
	After	110°F

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Space Availability

Unit	Item
5 thru 10	Main Condenser (Note 1) Preferred Design Flow Split - Two Inlets and Two Outlets Passes - Two Tube Sheet Area - 35 sq. ft. x 4 Each End Tube Length - 40 ft. Maximum - 34 ft. Minimum Hot Well ~ 20 Ft. x 34 Ft. x 9" Minimum Depth Inter- or Aftercondenser Tube Length - 16 Ft. Maximum Passes - Three Preferred

NOTE 1: Existing condenser (Information Only) Opening approximately 10 ft. x 15 ft. and transists to a hemispherical section of 11 ft. radius by 30 ft. long. This upper section 22 ft. wide x 30 ft. long extends 12 ft. deep terminating in a flat bottomed hotwell. See SK-11 for equipment arrangement with surface condenser.

5.2.1.4.6 Construction

Main Condenser
- Pressure
  - Shell Side - Full Vacuum to 15 psig
  - Tube Side - 75 psig
- Temperature
  - Shell Side - 150°F
  - Tube Side - 150°F
- HEI Cleanliness Factor - 70%
- Tubes - 22 Ga x Δ pitch x size (3/4", 7/8" or 1")
- Materials
  - Shell 304L SS Clad Steel
  - Internals - All 304L SS
  - Tube Sheets - All 304L SS
  - Tubes - 304L SS
  - Water Box Covers - Carbon Steel, Coal Tar Epoxy Lined
  - Code Requirements
    - Heat Exchanger Institute
    - ASME - Tube Side Only

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Inter- or Aftercondensers
Pressure
Shell Side - Full Vacuum to 40 psig
Tube Side - 75 psig
Temperature
Shell Side - 210°F
Tube Side - 150°F
TEMA Fouling Resistance - Total 0.0011
Tubes - 3/4" x 22 Ga x Δ pitch
Materials
Shell, internals, tube sheets and tubes - All 304L SS
Water Channel Covers - Carbon Steel, Coal Tar Epoxy Lined
Code Requirements
ASME
TEMA Class "C"

Steam Jets
Pressure - Full Vacuum - 90 psig
Temperature °F - 355
Materials - All 304L SS

5.2.1.4.7 Information Required With Bid

Supplier shall provide following data for proper evaluation of his proposal.

Unit		Item
5 and/or 6	a.	Turbine Exhaust Pressure - psia (in. Hg Abs)
separately	b.	Main Steam Condenser Number of Tubes - Size - Length
7 thru 10	c.	Intercondenser Shell Size - Number of Tubes - Length
	d.	Aftercondenser Shell Size - Number of Tubes - Length
	e.	Steam Vacuum Ejectors Each Stage - Motive Steam Flow Proposed lb./hr.

Weight and Budget Price Separately for Each Item

Expected Delivery Time - Weeks

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TABLE 5.2-1

COMPARATIVE SUMMARY

UNIT 5 OR 6 (Unit 5 Typical)

	Base Reference Design Point	Conversion Retrofit
Throttle Flow lb./hr.	907,530	907,530
Noncondensable Gas % Wt.	1.0	0.8
Generator Electric Output kW	55,000	54,101 (1)
Auxiliary Power (Electric) kW		
Cooling Tower Fans	605	605
Miscellaneous Total	445	445
Circ. Water & Cond. Pumps	930	981
Noncondensable Gas Blower	-	65
Net Unit Output kW	53,020	52,005
Heat Input Btu/Hr. (Ref. to 60°F)	$1{,}150 \times 10^6$	$1{,}140 \times 10^6$
Net Heat Rate Btu/kWh	21,690	21,920
Turbine Exh. Inch Hg Abs	4	4.3
Wet Bulb	65.0	65.0
C. W. T. Range/Approach °F	38.4	37.7/15.5

(1) For expected gross output, multiply actual field output of unit by retrofit derating factor of 0.9837

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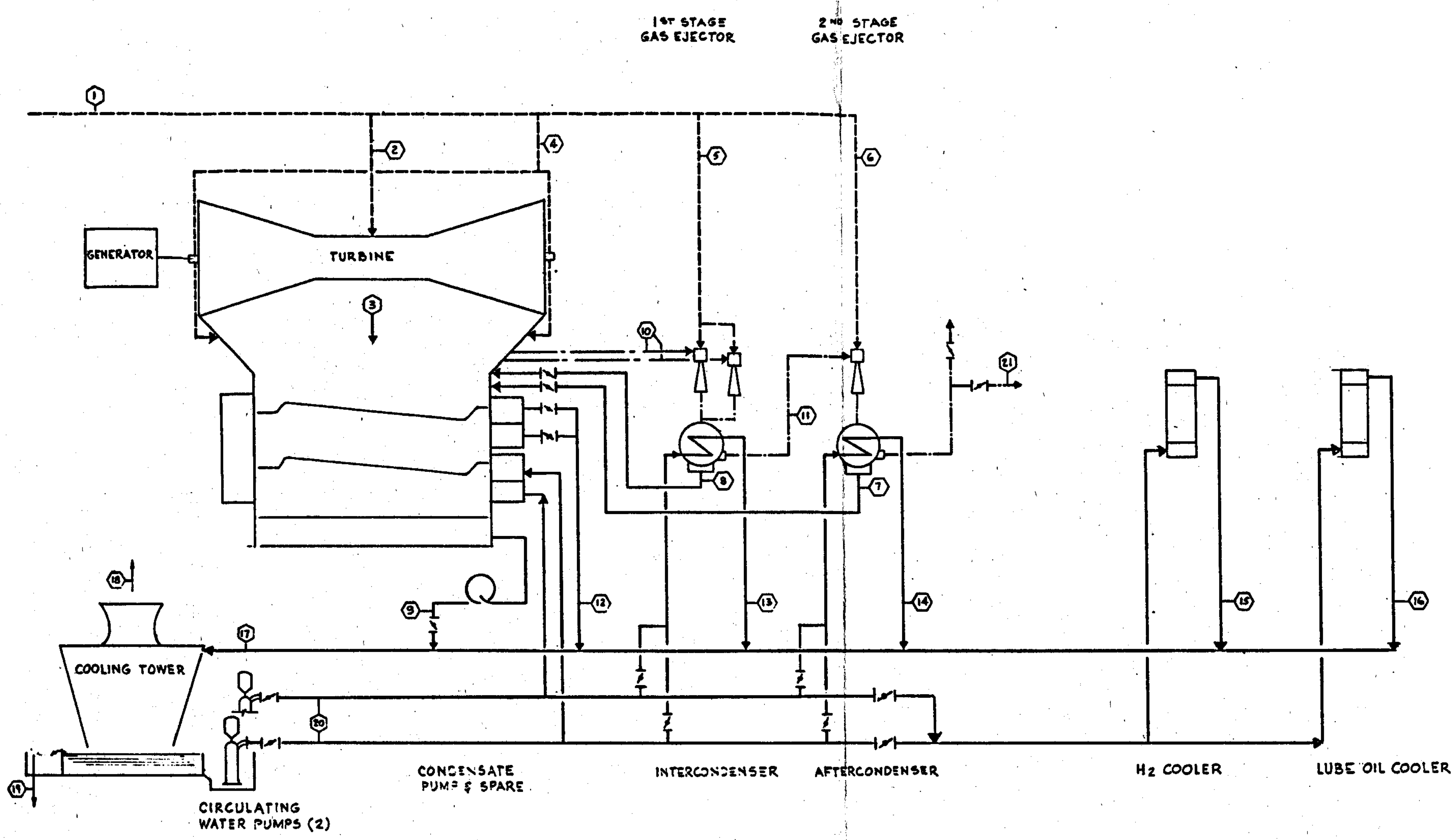
TABLE 5.2-2

COMPARATIVE SUMMARY

UNITS 7 THRU 10 (Unit 7 Typical)[2]

	Base Reference Design Point	Conversion Retrofit
Throttle Flow lb./hr.	907,530	907,530
Noncondensable Gas % Wt.	1.0	0.5
Generator Electric Output kW	55,000	54,101[1]
Auxiliary Power (Electric) kW		
Cooling Tower Fans	605	605
Miscellaneous Total	445	445
Circ. Water & Cond. Pumps	930	973
Noncondensable Gas Blower[2]	-	90
Net Unit Output kW	53,020	51,988 (2)
Heat Input Btu/Hr. (Ref. to 60°F)	$1,150 \times 10^6$	$1,114 \times 10^6$
Net Heat Rate Btu/kWh	21,690	21,430
Turbine Exh. Inch Hg Abs	4	4.3
Wet Bulb	65.0	65.0
C. W. T. Range/Approach °F	40.4	37.6/16.0

[1]For expected gross output, multiply actual field output of unit by retrofit derating factor of 0.9837
[2]No Noncondensable Gas Blower Debit for Units 9 & 10 - Net = 52,078



STREAM NO.	MOL. WT.	UNIT	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
FLOWS IN LB/HR.		5 OR 6																					
STEAM	18	↓	972,660	907,530		2,130	42,000	21,000				12,110	1,590										470
NON CONDENSABLE GAS	31.9	↓	7,844	7,319		15	340	170				7,319	7,659										6,275
AIR	29	↓										440	440										440
CONDENSATE		↓							21,120	52,520	969,060			21,500,000	1,450,000	600,000	98,200	72,000	24,689,260	855,500	113,560	23,720,200	
COOLING WATER		↓																					
PRESSURE PSIA		↓	113.7		2.11																		
ENTHALPY BTU/LB		↓	1200		993.5																		
TEMPERATURE °F		↓	355								125.0			118.0	118.0	118.0	102.5	99.5	118.2		80.5	80.5	
		7 THRU 10																					
STEAM	18	↓	950,660	907,530		2,130	30,000	11,000	11,770	37,330	893,110	8,420	1,090										320
NON CONDENSABLE GAS	29.4	↓	4,776	4,560		.11	150	55				4,710	4,765										3,821
AIR	29	↓										440	440										440
CONDENSATE		↓																					
COOLING WATER		↓												21,500,000	1,350,000	500,000	88,200	72,000	24,460,400	866,500	81,700	23,370,200	
PRESSURE PSIA		↓	113.7		2.11																		
ENTHALPY BTU/LB		↓	1200		993.5																		
TEMPERATURE °F		↓	355								125.0			118.5	118.5	118.5	103.0	100.0	118.6		81.0	81.0	

MAXIMUM H_2S VALUES: UNIT 5 317, UNIT 6 407

MAXIMUM H_2S VALUES: UNIT 7 278, UNIT 8 155, UNIT 9 69, UNIT 10 84

REFERENCE DRAWINGS

REVISION

ISSUED FOR FINAL REPORT E.A. BF

ISSUED FOR REPORT #1 E.A. BF

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

SCALE NONE DATE 6-7-79

DR. E.A. CHK. ENG. BF APPROVED

APPROVALS

PG and E RETROFIT STUDY
UNITS 5 THRU 10 CONVERSION
PROCESS FLOW DIAGRAM

JOB NO. S 79007 PD-004 1

5.2.2 Installation and Equipment Arrangement

5.2.2.1 Units 5 and 6

Units 5 and 6 are mirror imaged turbine-generator units except for the cooling towers and associated piping between the towers and condensers. Equipment location, clearances, and accessibility were field checked on June 11, 1979, and verified against Drawings SK-013, -014 and -015. These drawings are included herein and show the layout of the new equipment locations.

5.2.2.1.1 <u>Main Condenser</u>

Because of the location of the cooling towers, the intake and discharge to the main condenser will be located on the same end of the condenser. The condenser will have a split flow two pass tube bundle arrangement and two supply lines to facilitate the cleaning of half the condenser tubes at a time when necessary.

The condenser duty requirements should be satisfied with the current condenser shell size and configuration. However, the centerline of the condenser tube arrangement must be shifted 1 ft-6 inches inside the condenser shell to ensure column line clearance and tube pulling space. The condenser shell must also be shifted toward the cooling towers approximately 6 ft-6-inches for attachment of the water boxes to the condenser shell. In addition, excavation for a dry pit will be required in front of the condenser and outside the power building to insure adequate tube pulling space.

Due to these condenser modifications, the turbine exhaust flange to the condenser neck connection will be shifted off center approximately 3 1/2 ft. No problem is foreseen in reconnecting to the turbine hood.

Existing condenser cooling water inlet piping can not be used. Attachment of new inlet water piping to the condenser will be positioned at the bottom of the inlet water boxes. The need for circulating water pumps and smaller condensate pumps offset from the tube pull space will preclude the use of existing discharge piping from the condenser. All new piping will be constructed of techite for underground service and stainless steel for piping above grade.

The present location of the auxiliary cooling water and fire pumps is satisfactory. The existing condensate pumps will be removed.

5.2.2.1.2 Intercondenser and Ejectors

The existing intercondenser and ejectors will be removed. The new surface type intercondenser and new first stage jet ejectors will be located to the southeast corner of the power building for Unit No. 5 (southwest for Unit No. 6) at elevation 3,211 ft. to allow for tube pulling space in front of the main condenser. New support steel will be required.

5.2.2.1.3 Aftercondenser and Ejector

The existing aftercondenser and ejectors will be removed. The new surface type aftercondenser and new second stage jet ejectors will be located and stacked below the intercondenser at elevation 3,202 ft. to allow for tube pulling space in front of the main condenser. New support steel will be required.

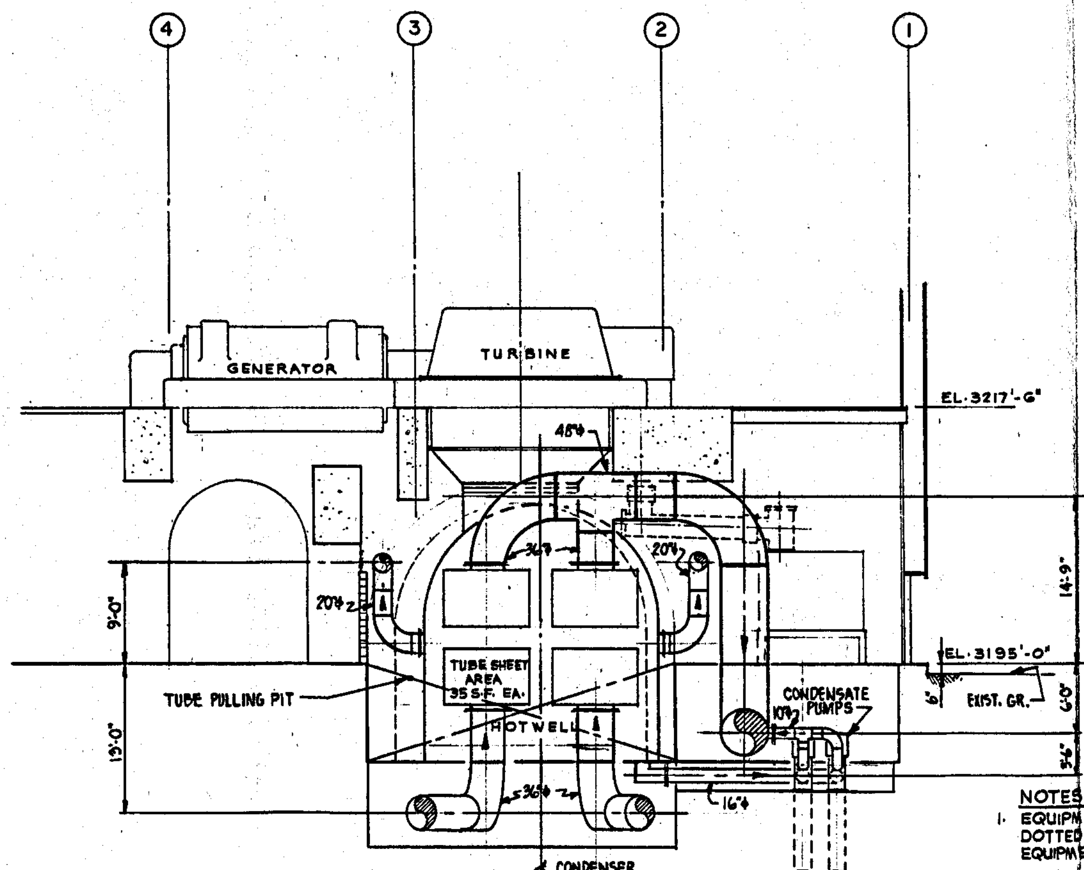
5.2.2.1.4 Condensate Pumps

New condensate pumps have been sized and located based on the system and tube pulling requirements for the shell and tube condenser. The new location is in front of the lube oil coolers inside the power building at elevation 1,995 level to facilitate the necessary piping and sump location. The existing condensate pumps are of proper size and capacity to function as the new circulating water pumps.

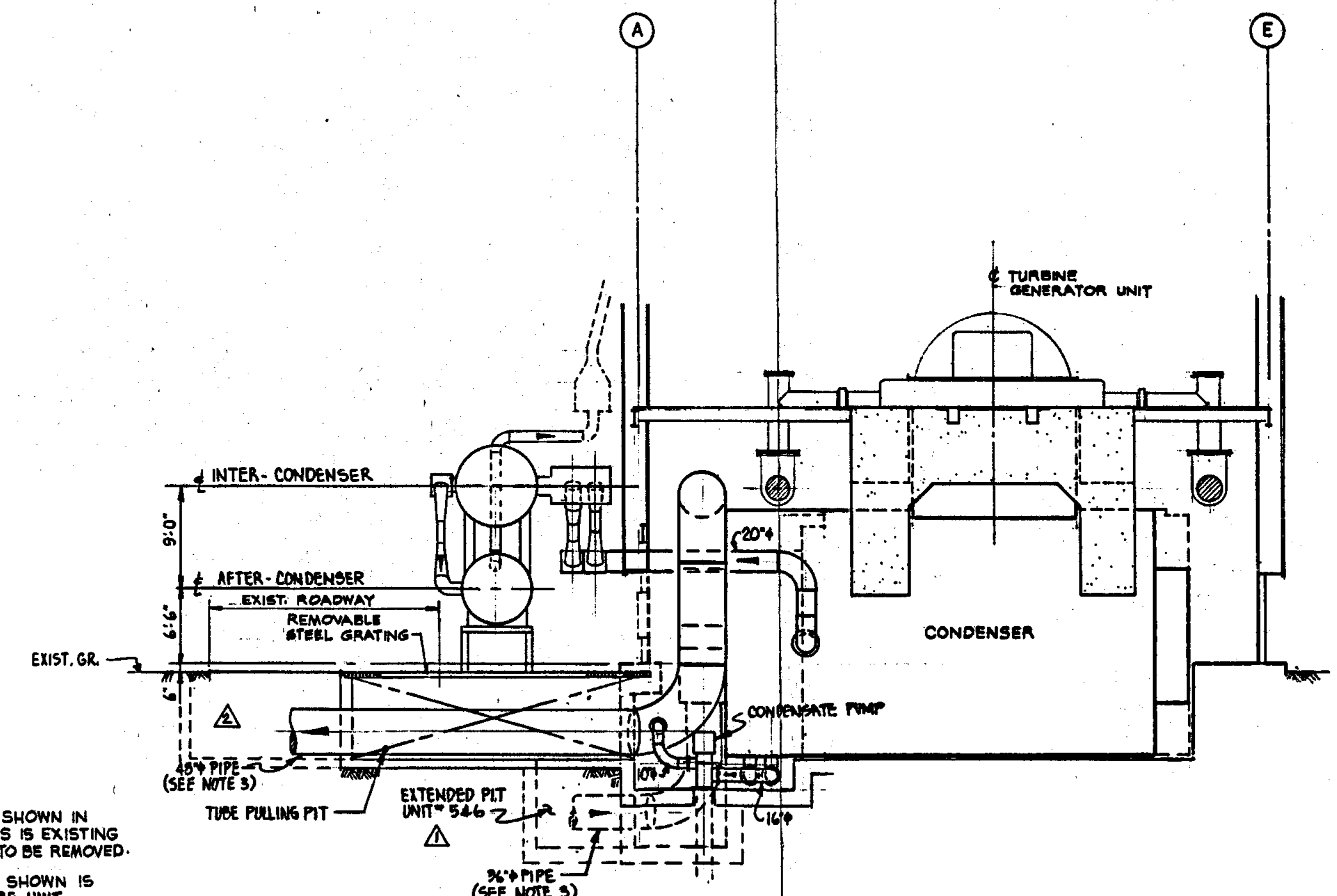
5.2.2.1.5 Circulating Water Pump

The existing sumps in the cooling towers and connecting piping to the condenser will not be used. The new circulating water pumps and wet pit will be located near the cooling tower riser and the piping routed to the condenser without interference to other equipment or condenser tube pulling space. The existing condensate pumps as stated above can be used as circulating water pumps. In this mode the pump shaft can be shortened to take advantage of the new NPSH requirements and reduce excavation for the wet pit.

A wet pit diffuser will be used to reduce the fluid velocity of cooling tower basin discharge water to the cooling water pump wet pit. This will eliminate wet pit vortexing around the pumps.



SECTION A 012 013 014



SECTION B 012 013 014

NOTES:

1. EQUIPMENT SHOWN IN DOTTED LINES IS EXISTING EQUIPMENT TO BE REMOVED.
2. CONDENSER SHOWN IS 34 FOOT TUBE UNIT
3. (2) ALL UNDERGROUND PIPES TO BE FR.PIPE
4. ELEVATIONS GIVEN ARE FOR UNITS 7&8

		◇							
		2		9/12/79	REISSUED FOR FINAL REPORT	Rs	LFW		
		1		7-12 1979	REVISED & REISSUED FOR FINAL REPORT	G.O.	Rs	LFW	
(2) SK-014	PLAN AT ELEVATION 2006'-0" (UNITS 5&6)								
SK-012	PLAN AT ELEVATION 3207'-6" (UNITS 7&8)	0		6-28 1979	ISSUED FOR MILESTONE REPORT #2	G.O.	Rs	LFW	
REFERENCE DRAWINGS		REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.

ROGERS ENGINEERING CO., INC.
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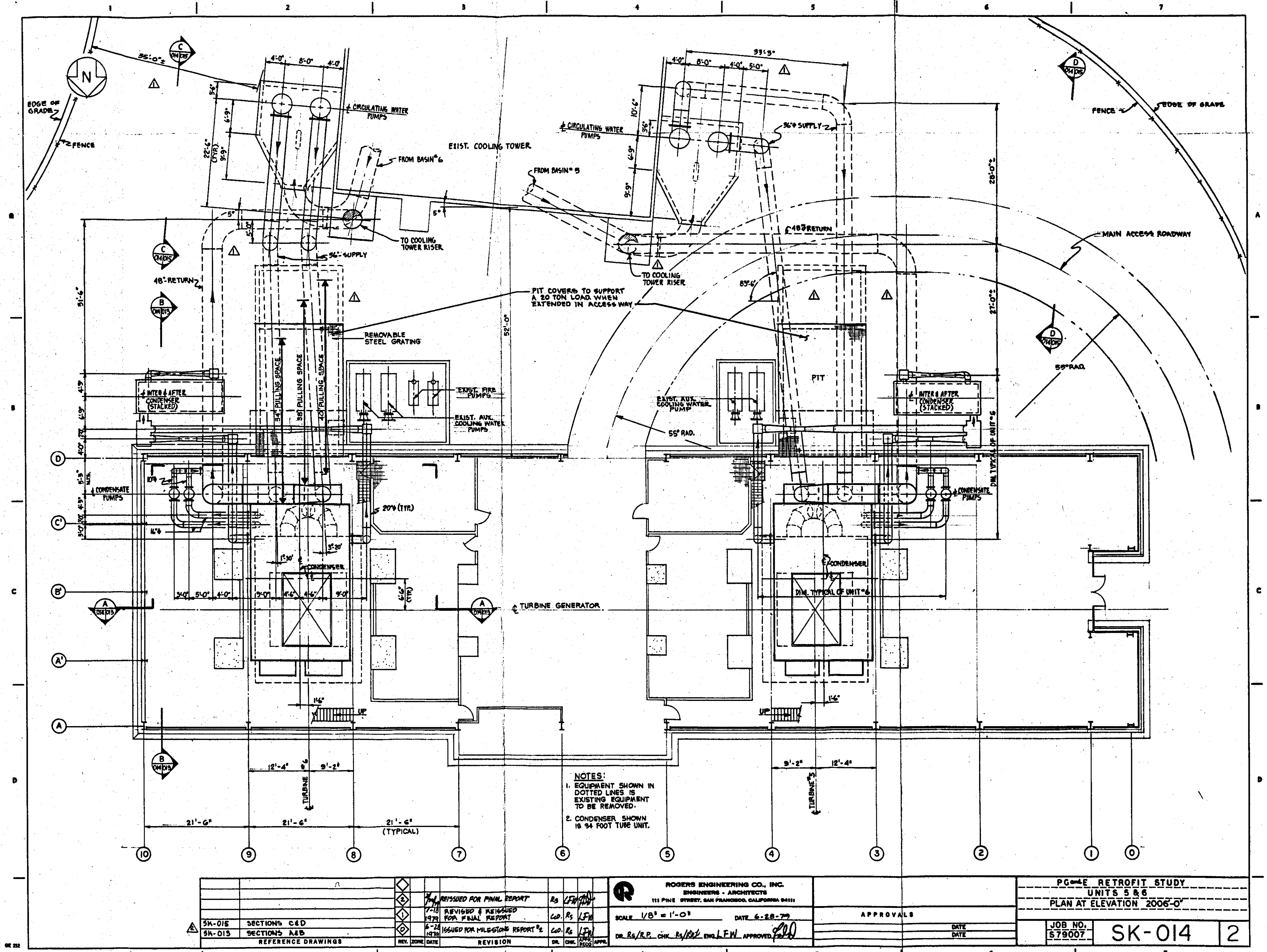
111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94111

SCALE 1/8" = 1'-0" DATE 6-28-79
DR. R.S./R.P. CHK. Rs/ ENG. LFW APPROVED

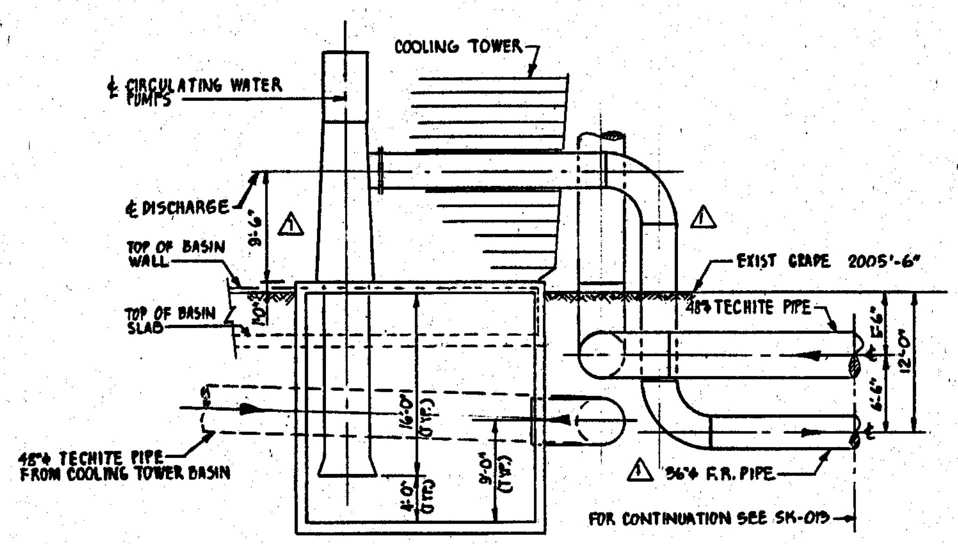
APPROVALS
DATE
DATE

PG and E RETROFIT STUDY
UNITS 5 THRU 10
SECTIONS A & B

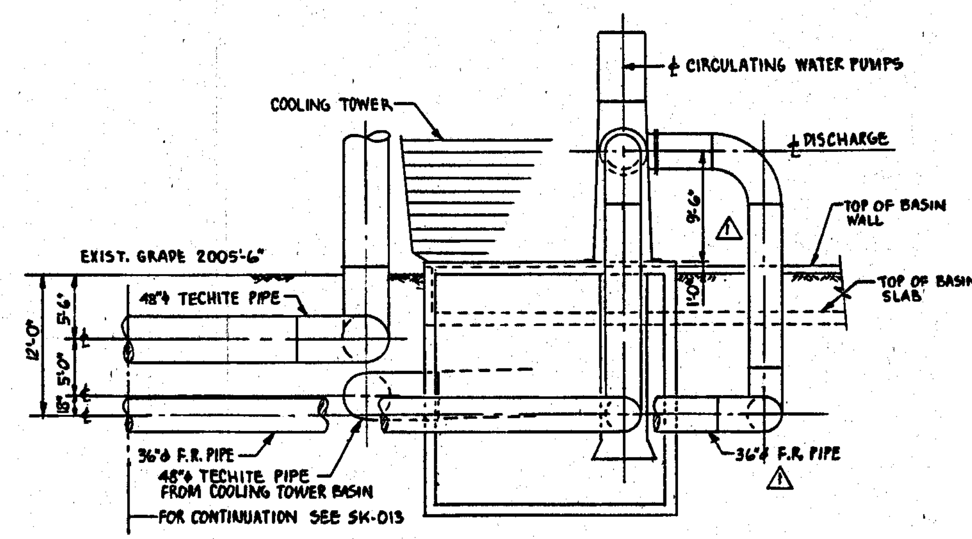
JOB NO. S79007 | SK-013 | 2



EDGE OF GRADE
FENCE
EXIST. COOLING TOWER
℄ CIRCULATING WATER PUMPS
FROM BASIN #6
FROM BASIN #5
TO COOLING TOWER RISER
36" SUPPLY
48" RETURN
36"⌀ SUPPLY
48"⌀ RETURN
PIT COVERS TO SUPPORT A 20 TON LOAD WHEN EXTENDED IN ACCESS WAY
REMOVABLE STEEL GRATING
34' PULLING SPACE
38' PULLING SPACE
40' PULLING SPACE
EXIST. FIRE PUMPS
EXIST. AUX. COOLING WATER PUMPS
EXIST. AUX. COOLING WATER PUMP
PIT
MAIN ACCESS ROADWAY
55' RAD.
℄ INTER & AFTER CONDENSER (STACKED)
℄ CONDENSATE PUMPS
℄ CONDENSER
DIM. TYPICAL OF UNIT #6
℄ TURBINE GENERATOR
℄ TURBINE #6
℄ TURBINE #5
UP
NOTES:
1. EQUIPMENT SHOWN IN DOTTED LINES IS EXISTING EQUIPMENT TO BE REMOVED.
2. CONDENSER SHOWN IS 34 FOOT TUBE UNIT.
21'-6"
21'-6"
21'-6" (TYPICAL)
SK-015 SECTIONS C&D
SK-013 SECTIONS A&B
REFERENCE DRAWINGS
REISSUED FOR FINAL REPORT
7-18 1979 REVISED & REISSUED FOR FINAL REPORT
6-28 1979 ISSUED FOR MILESTONE REPORT #2
REV. ZONE DATE REVISION DR. CHK. APPR. RECO APPR.
ROGERS ENGINEERING CO., INC.
ENGINEERS - ARCHITECTS
111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94111
SCALE 1/8" = 1'-0"
DATE 6-28-79
DR. RS/R.P. CHK. RS/KB ENG. LFW APPROVED
APPROVALS
DATE
DATE
PG and E RETROFIT STUDY
UNITS 5 & 6
PLAN AT ELEVATION 2006'-0"
JOB NO. 579007
SK-014
2



SECTION C (014 | 015)



SECTION D (014 | 015)

NOTES:

1.) PUMP PIT IN ACCORDANCE WITH HYDRAULIC INSTITUTE STD'S.

REFERENCE DRAWINGS	
SK-014	PLAN AT ELEVATION 2006'-0"

REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.
2		9/20/79	REISSUED FOR FINAL REPORT	RS	LFW		
1		7-18 1979	REVISED & REISSUED FOR FINAL REPORT.	GO	RS		
0		6-28 1979	ISSUED FOR MILESTONE REPORT #2	GO.	RS		

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SCALE 1/8" = 1'-0" DATE 6-22-79

DR. RS/RP CHK. RS ENG. LFW APPROVED

APPROVALS

DATE

DATE

PG and E RETROFIT STUDY
UNITS 5 & 6
SECTIONS C & D

JOB NO. S79007

SK-015 2

Rogers

5.2.2.2 Units 7-10

Units 7 and 8 are mirror imaged turbine-generator units housed in the same power building. Units 9 and 10 are similarly arranged. A field check on June 12, 1979 confirmed building and equipment location as they appear on Drawings SK-012, -013 and -016. These drawings are included herein and show the layout of the new equipment locations.

5.2.2.2.1 <u>Main Condenser</u>

The modifications to Units 7 through 10 to replace the existing condenser with surface condensers are in general identical to the changes on Units 5 and 6. This includes shifting of the condenser centerline the same distance to provide adequate tube pulling space along with condensate pump removal and modification to condenser intake and discharge piping. In addition, excavation is required in front of the condenser for tube pulling space.

5.2.2.2.2 <u>Intercondenser and Ejectors</u>

The modifications to Units 7 through 10 are the same as for Units 5 and 6.

5.2.2.2.3 <u>Aftercondenser and Ejectors</u>

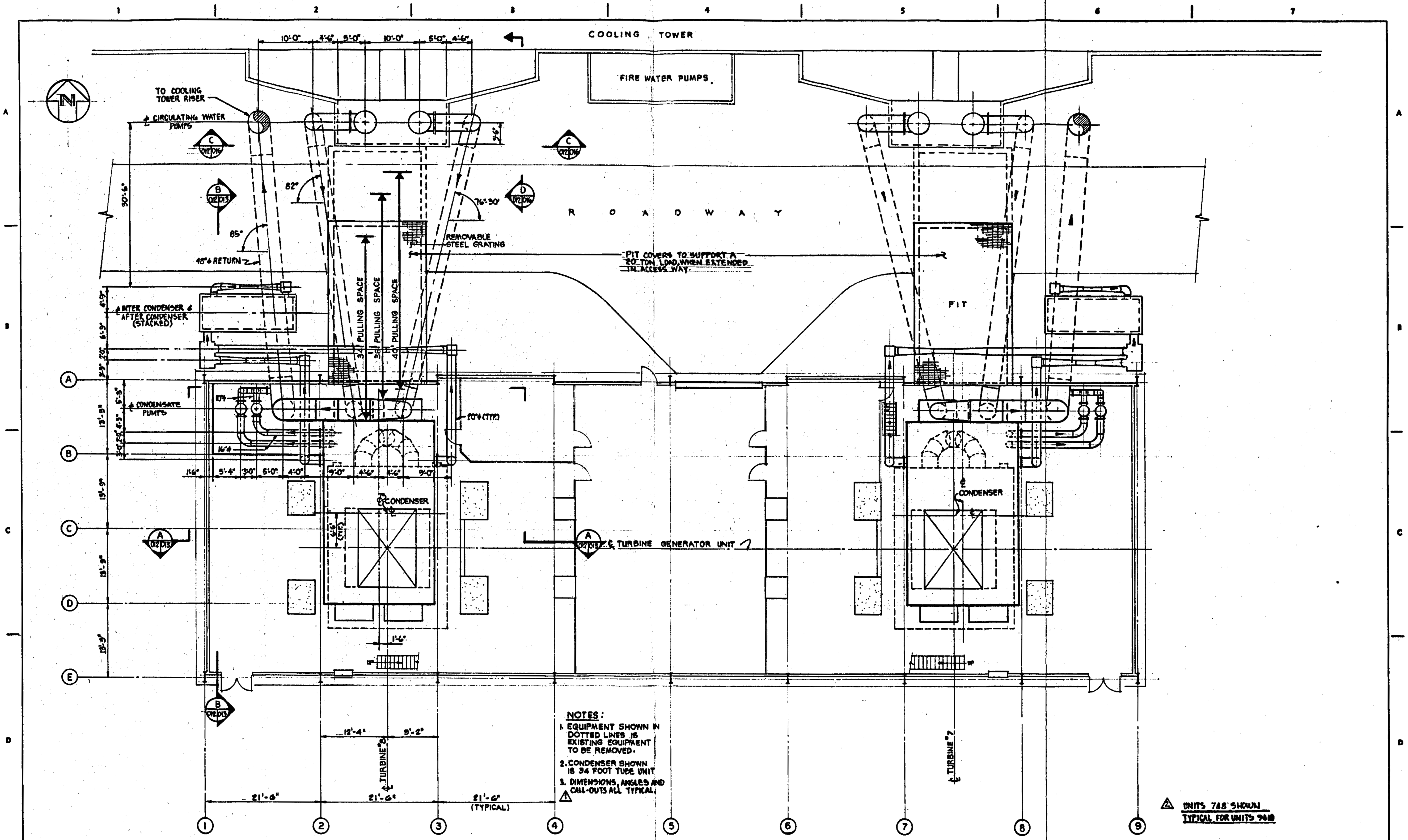
The modifications to Units 7 through 10 are the same as for Units 5 and 6.

5.2.2.2.4 <u>Condensate Pumps</u>

The new condensate pumps will be placed in the same relative location as for Units 5 and 6. To do this the auxiliary cooling water pumps will be relocated. The existing condensate pumps again will function as the new circulating water pumps.

5.2.2.2.5 <u>Circulating Water Pumps</u>

The existing cooling tower sump locations can be used but the connecting discharge piping to the condenser requires rerouting. The new circulating water pumps will be located just outside the cooling tower at the existing cooling tower sump locations. Piping from the cooling water pumps will be routed to the condenser with due consideration to layout clearances and condenser tube pulling space. A wet pit diffuser again will be used to reduce turbulence near the circulating water pump suction. As for Units 5 and 6, the condensate pumps will be modified for use as circulating water pumps.



		◇							
		2		7/79	REISSUED FOR FINAL REPORT	Rs	LFW		
		1		7-6 1979	REVISED & REISSUED FOR FINAL REPORT	G.O.	Rs	LFW	
SK-016	SECTIONS C&D	0		6-28 1979	ISSUED FOR MILESTONE REPORT #2	G.O.	Rs	LFW	
SK-013	SECTIONS A&B								
REFERENCE DRAWINGS		REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.

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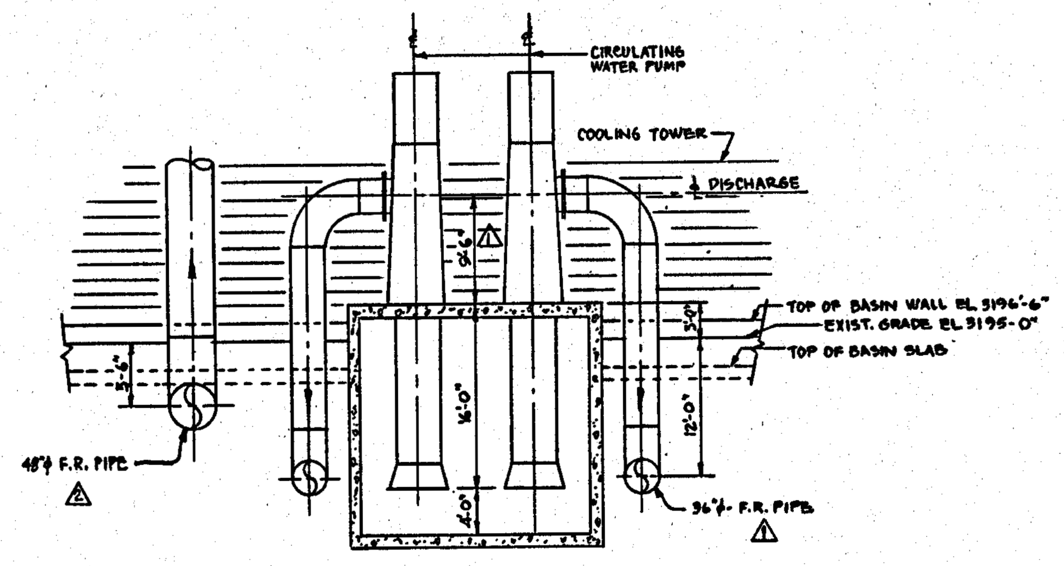
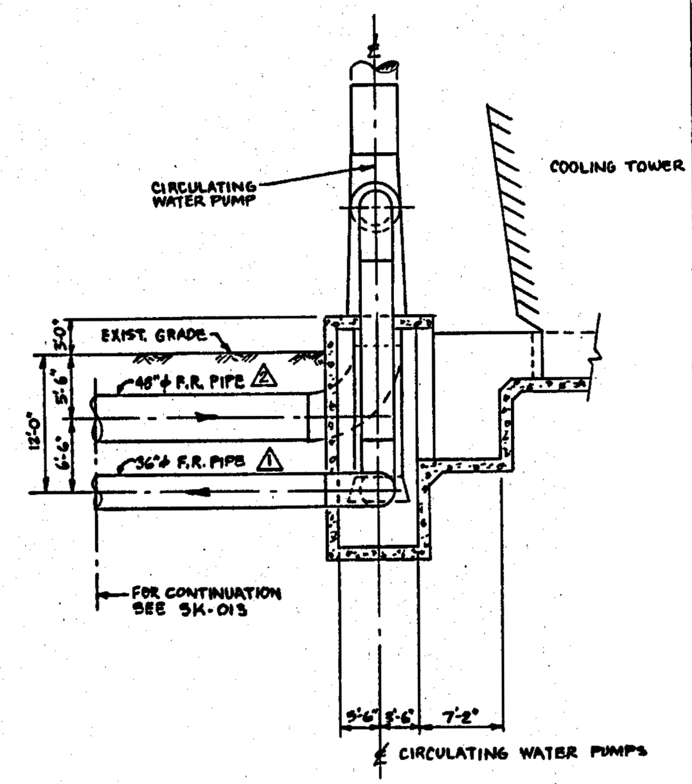
APPROVALS
DATE
DATE

PG and E RETROFIT STUDY
UNITS 7 & 8
PLAN AT ELEVATION 3207'-6"

JOB NO. S79007 SK-012 2



SECTION C (012/016)



SECTION D (012/016)

NOTES:
(1) PUMP PIT IN ACCORDANCE WITH HYDRAULIC INST. STD'S.

UNITS 7 & 8 SHOWN
TYPICAL FOR UNITS 9 & 10

SK-012	PLAN AT ELEVATION 3207'-6"	2		9/22/79	REISSUED FOR FINAL REPORT	RS	LFW	
		1		7-18 1979	REVISED & REISSUED FOR FINAL REPORT	Go	RS	LFW
		0		6-25 1979	ISSUED FOR MILESTONE REPORT # 2	Go.	RS	LFW
REFERENCE DRAWINGS		REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO / APPR.

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DR. R.P./R.S. CHK. RS/10P ENG. LFW APPROVED

APPROVALS
DATE
DATE

PG and E RETROFIT STUDY
UNITS 7 & 8
SECTIONS C & D

JOB NO. S79007 SK-016 2

5.2.3 Cost Estimate

Section 3 of this report discusses methods and parameters employed in preparing cost estimates for the retrofit project. The following summary cost estimate and the backup detail on succeeding pages adhere to the guidelines in Section 3, and as noted have been prepared according to typical PGandE format.

TABLE 5.2-3

SUMMARY COST ESTIMATE UNITS 5 THROUGH 10 (UNIT 5 TYPICAL)
(Each Unit)

Account Total	Description	Equipt & Mat'l	Labor	
51-20	Building	$ 0	$ 14,910	$ 14,910
54-20	Condenser System	2,241,646	969,926	3,211,572
54-30	Circ. Water System	224,508	318,696	543,204
54-70	Instruments	25,440	20,501	45,941
55-60	Station Power	34,344	86,430	120,774
365	Engineering & Other	960,000	0	960,000
	Subtotals	$3,485,938	$1,410,463	$4,896,401
	GM Factor (23.9%)			$1,170,240
	Subtotal (GM 1979)			$6,066,641
	Escalation (28.55%)			1,732,026
	Total GM Estimate			$7,798,667

Project Differential Cost

The capital involved to accomplish the retrofit for Unit 5 using a surface condenser will require a level annual revenue of 2.44 mills per kilowatthour.

ROGERS ENGINEERING CO.,INC. COST ESTIMATE

JOB NAME-UNIT 5 JOB NO.-S79007 CLIENT-P G AND E ESTIMATE DATE- 29 JUNE 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
51-22-1	REMOVE BLDG CONCRETE	0.	14910.	641.	14910.
ACCOUNT TOTAL		0.	14910.	641.	14910.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL	
54-21-1	COND PUMP CONCRETE	1908.	9319.	401.	11227.	
54-21-2	COND PUMP EXC & BKFL	2290.	16773.	721.	19063.	
54-21-3	TUBE PULL PIT	44520.	83867.	3607.	128387.	
54-22-2	RMV AUX COND STRUCT	2544.	3494.	150.	6038.	
54-22-3	AUX COND STRUCTURE	19080.	46593.	2004.	65673.	
54-23-1	COND SYSTEM EQUIP R	30528.	93186.	4008.	123714.	
54-23-2	REMVOE STEAM JETS	0.	1491.	64.	1491.	
54-23-3	REMOVE AUX CONDSRS	0.	8387.	361.	8387.	
54-23-4	REMOVE STEAM PIPE JE	0.	466.	20.	466.	
54-23-5	CONDENSER QUOTE	1844400.	0.	0.	1844400.	1
54-23-6	CONSENSER IN PLACE	50880.	465930.	20040.	516810.	
54-23-7	CONDENSER TRANSITION	31800.	32615.	1403.	64415.	
54-23-8	CONDENSER EQUPT R	63600.	32615.	1403.	96215.	
54-24-1	REMOVE COND PUMPS	0.	4659.	200.	4659.	
54-24-2	COND PUMP QUOTE	82680.	0.	0.	82680.	
54-24-3	COND PP SET IN PLACE	3816.	23297.	1002.	27113.	
54-25-1	REMOVE MN CND PIPE R	2544.	16773.	721.	19317.	
54-25-2	REMOVE AUX COND PIPE	0.	3727.	160.	3727.	
54-25-3	REMOVE NC GAS PIPE	0.	4659.	200.	4659.	
54-25-4	COND PIPING	35616.	32615.	1403.	68231.	
54-33-1	REMOVE CW PIPING	0.	5591.	240.	5591.	
54-25-4	COND MISC PIPING	25440.	83867.	3607.	109307.	
ACCOUNT TOTAL		2241646.	969926.	41717.	3211572.	3

ROGERS ENGINEERING CO., INC.
111 PINE STREET
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JOB NO. S-79007

DG-023

TABLE 5.2-4
COST ESTIMATE DETAIL
UNIT 5 SURFACE CONDENSER

DRAWING NO. | REV.

SHEET 1 OF 2

ROGERS ENGINEERING CO.,INC. COST ESTIMATE

JOB NAME-UNIT 5 JOB NO.-S79007 CLIENT-P G AND E ESTIMATE DATE- 29 JUNE 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-31-1	CW PUMP CONCRETE	15264.	18637.	802.	33901.
54-31-2	CW PIPING TRENCH	5088.	27956.	1202.	33044.
54-33-2	CW PIPING	152640.	186372.	8016.	339012.
54-33-3	CW PIPING EQUIPT R	10176.	9319.	401.	19495.
54-34-1	REMOVE CW PUMPS	0.	3727.	160.	3727.
54-34-2	CW PUMP QUOTE REWORK	29256.	0.	0.	29256.
54-34-3	CW PUMP SET IN PLACE	11448.	69890.	3006.	81338.
54-39-1	RELOCATE FIRE H.CAB	636.	2796.	120.	3432.
ACCOUNT TOTAL		224508.	318696.	13707.	543204.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-74-1	INST CONDENSARE SYS	15264.	10250.	441.	25514.
54-74-2	INST CW SYSTEM	10176.	10250.	441.	20426.
ACCOUNT TOTAL		25440.	20501.	882.	45941.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
55-64-1	REMOVE COND PPS ELEC	0.	23297.	1002.	23297.
55-64-1	CW PUMP STARTERS	6360.	20967.	902.	27327.
55-64-2	COND PUMP STARTERS	7632.	8387.	361.	16019.
55-64-3	COND PP POWER SUPPLY	5088.	11648.	501.	16736.
55-64-4	ELECTRIC POWER SUPLY	15264.	8154.	351.	23418.
55-64-5	REMOVE CW PPS ELECT	0.	13978.	601.	13978.
ACCOUNT TOTAL		34344.	86430.	3717.	120774.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
365-1	CONSTRUCTION FIELD	240000.	0.	0.	240000.
365-2	GENERAL ENGINEERING	144000.	0.	0.	144000.
365-3	OTHER ENGINEERING	576000.	0.	0.	576000.
ACCOUNT TOTAL		960000.	0.	0.	960000.

ROGERS ENGINEERING CO., INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111

JOB NO. S-79007

DG-023

TABLE 5.2-4
COST ESTIMATE DETAIL
UNIT 5 SURFACE CONDENSER

DRAWING NO. REV.

SHEET 2 OF 2

5.3 Replace Condenser and Auxiliaries - Units 11 and 12

Units 11 and 12 are each rated at 110 MW gross with two turbines in tandem driving a single alternator in each unit. These units are essentially identical, and Unit 11 was investigated for study. Differences in performance due to a lower noncondensable gas content in the steam at Unit 12 are reflected in Tables 5.3-1 and 5.3-2.

5.3.1 Selected Process Design

5.3.1.1 Noncondensable Gas Values

See Steam Conditions and noncondensable gas values in Section 5.3.1.3.2 and 5.3.1.3.3.

5.3.1.2 Field Test Data for Cooling Water Tower

The Results of Post Overhaul Performance Test for Unit 11 of September 18, 1978 was received. It was estimated that for the retrofit conceptual design an approach of 16.0°F could be obtained at a 38°F range by a thorough cleaning of the cooling tower during the retrofit turnaround. A similar methodology as was used on Units 5 through 10 was used to prepare the conceptual design at a turbine exhaust of 4.3 inches of Hg Abs (2.11 psia). The conceptual design is shown on Drawing No. PD-005.

5.3.1.3 Specification of Equipment for Conversion from Direct Contact to Surface Type Exchanger

5.3.1.3.1 Performance Requirements

Generation capability to be maximized within the constraints imposed by the existing cooling water tower capability, the availability of area for tube sheets and space for tube length and the desirability of maintaining a turbine throttle steam flow near existing conditions of 1,808,000 lbs./hr. Supplier shall be responsibile for complete design of condensing and vacuum system components for maximum power generation.

5.3.1.3.2 Steam Conditions

	Turbine Inlet	Steam Jet Inlet
Enthalpy Btu/lb.	1.200	
Entropy Btu/lb. x R	1.606	
Pressure psia	113.4	90 psig
Temperature °F	355	355

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Turbine exhaust (existing for reference only)
Pressure-psia (in. Hg Abs.) - 1.964 (4.0)
Enthalpy - Btu/lb. - 989.3 (calculated)
Gross Power @ 4 in. Hg Abs. - 110,000 kW

5.3.1.3.3 Noncondensable Gas Conditions

Unit	% Wt. in Steam	Ave. Mol. Wt.
11	0.85	35.6
12	0.5	35.6

5.3.1.3.4 Air Leakage Allowance

Units 11 or 12 - 930 lb./hr. each

5.3.1.3.5 Constraints

Cooling Water Availability (Best Preliminary Values)

Main Condenser

Unit	Item	
11 or 12	Cold °F	81.0
	Rise °F	38.0
	Flow gpm	85,000

Intercondenser

Unit	Item	
11	Cold °F	81.0
	Rise °F	38.0
	Flow gpm	5,300
12	Cold °F	81.0
	Rise °F	38.0
	Flow gpm	4,000

Aftercondenser

Unit	Item	
11	Cold °F	81.0
	Rise °F	38.0
	Flow gpm	2,200
12	Cold °F	81.0
	Rise °F	38.0
	Flow gpm	1,200

Rogers

Main, Inter- and After Condenser Gas Cooling Exit Temperatures Preferred.

Units	Condenser	
11 or 12	Main	114°F
	Inter	110°F
	After	110°F

Space Availability

Unit	Item
11 or 12	Main Condenser (Note 1)
	Preferred Design
	Flow Split - Two Inlets and Two Outlets
	Passes - 2 (4 for perpendicular configuration)
	Tube Sheet Area - 45 sq. ft. x 2 Each End
	55 sq. ft. x 2 Each End
	Tube Length - 48 ft. Maximum
	- 40 ft. Minimum
	Hot Well ~ 20 Ft. x 34 Ft. x 20" Minimum Depth
	Inter- or Aftercondenser
	Tube Length - 16 Ft. Maximum
	Passes - Three Preferred

NOTE 1: Existing condenser (Information Only) Two openings approximately 14 ft. x 15 ft. and transists to a hemispherical section of 25 ft. radius by 48 ft. long. This upper section 25 ft. wide x 48 ft. long extends 11 ft. deep terminating in a flat bottomed hotwell. See SK-14 for equipment arrangement with surface condenser.

5.3.1.3.6 Construction

Main Condenser
- Pressure
  - Shell Side - Full Vacuum to 14.6 psia
  - Tube Side - 75 psig
- Temperature
  - Shell Side - 150°F
  - Tube Side - 150°F
- HEI Cleanliness Factor - 70%
- Tubes - 22 Ga x Δ pitch x size (3/4", 7/8" or 1")

Rogers

Materials
Shell 304L SS Clad Steel
Internals - All 304L SS
Tube Sheets - All 304L SS
Tubes - 304L SS
Water Box Covers - Carbon Steel, Coal Tar Epoxy Lined
Code Requirements
Heat Exchanger Institute
ASME - Tube Side Only

Inter- or Aftercondensers
Pressure
Shell Side - Full Vacuum to 40 psig
Tube Side - 75 psig
Temperature
Shell Side - 210°F
Tube Side - 150°F
TEMA Fouling Resistance - Total 0.0011
Tubes - 3/4" x 22 Ga x Δ pitch
Materials
Shell, internals, tube sheets and tubes - All 304L SS
Water Channel Covers - Carbon Steel, Coal Tar Epoxy Lined
Code Requirements
ASME
TEMA Class "C"

Steam Jets
Pressure - Full Vacuum - 90 psig
Temperature °F - 355
Materials - All 304L SS

5.3.1.3.7 Information Required With Bid

Supplier shall provide following data for proper evaluation of his proposal.

Unit		Item
11	a.	Turbine Exhaust Pressure - psia (in. Hg Abs)
separately	b.	Main Steam Condenser
	c.	Intercondenser
		Shell Size - Number of Tubes - Length
		Shell Size - Number of Tubes - Length
	e.	Steam Vacuum Ejectors
		Each Stage - Motive Steam Flow Proposed lb./hr.

Rogers

Weight and Budget Price Separately for Each Item

Expect Delivery Time - Weeks

Rogers

TABLE 5.3-1

COMPARATIVE SUMMARY

UNIT 11

	Base Reference Design Point	Conversion Retrofit	
Throttle Flow lb./hr.	1,808,000	1,808,000	
Noncondensable Gas % Wt.	1.0	0.85	
Generator Electric Output kW	110,000	108,147	(1)
Auxiliary Power (Electric) kW			
Cooling Tower Fans	1,242	1,242	
Miscellaneous Total	982	982	
Circ. Water & Cond. Pumps	1,776	2,194	
Noncondensable Gas Blower			(2)
Net Unit Output kW	106,000	103,729	
Heat Input Btu/Hr. (Ref. to 32°F)	$2,266 \times 10^6$	$2,314 \times 10^6$	
Net Heat Rate Btu/kWh	21,376	22,310	
Turbine Exh. Inch Hg Abs	4.0	4.3	
Wet Bulb	65.0	65.0	
C. W. T. Range/Approach °F	40.4	38/16.0	

(1) For expected gross output, multiply actual field output of unit by retrofit derating factory of 0.983

(2) No Noncondensable Gas Blower at Unit 11

Rogers

TABLE 5.3-2

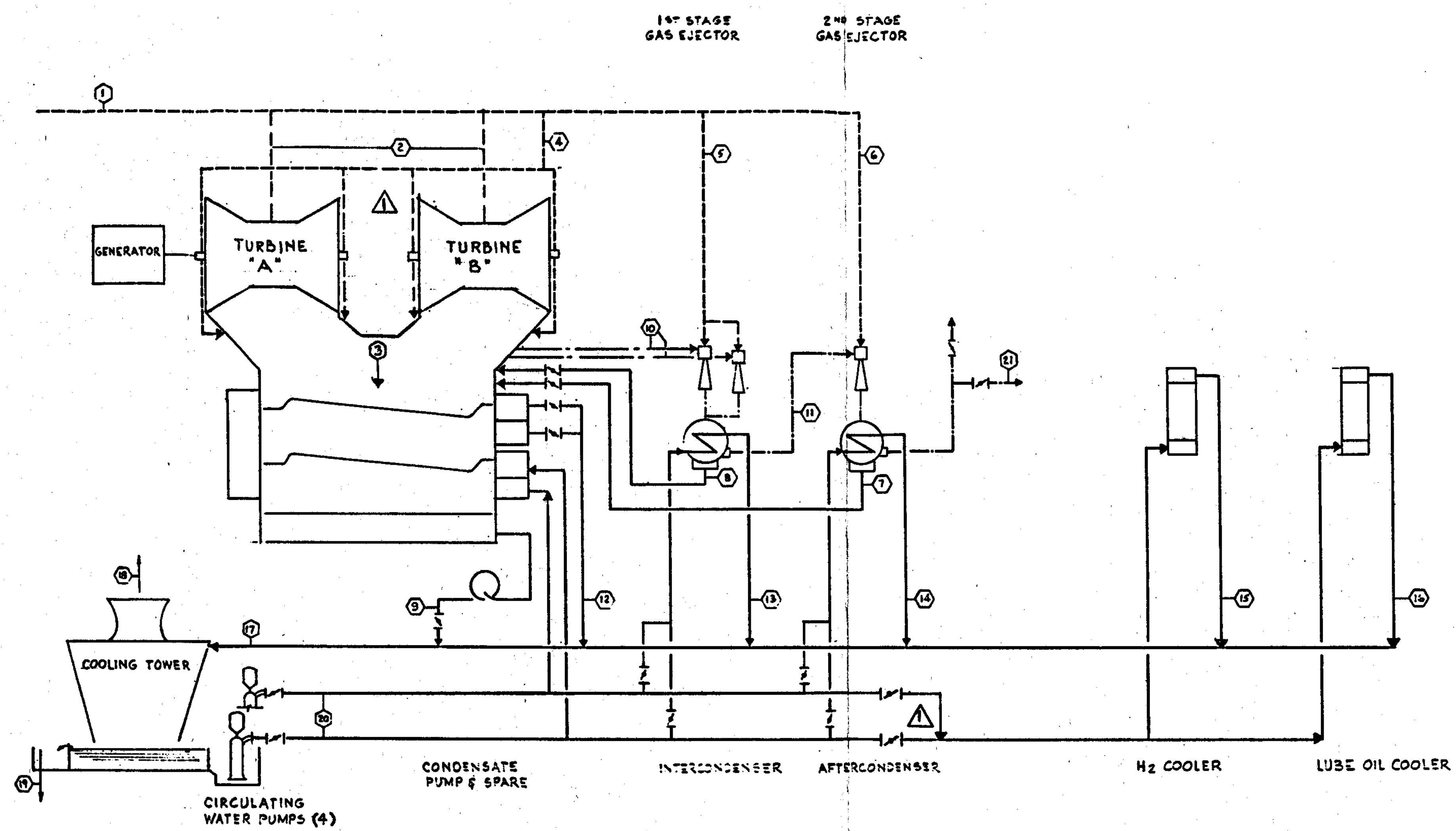
COMPARATIVE SUMMARY

UNIT 12

	Base Reference Design Point	Conversion Retrofit
Throttle Flow lb./hr.	1,808,000	1,808,000
Noncondensable Gas % Wt.	1.0	0.5
Generator Electric Output kW	110,000	108,147 (1)
Auxiliary Power (Electric) kW		
Cooling Tower Fans	1,242	1,242
Miscellaneous Total	982	982
Circ. Water & Cond. Pumps	1,776	2,122
Noncondensable Gas Blower		(2)
Net Unit Output kW	106,000	102,801
Heat Input Btu/Hr. (Ref. to 32°F)	$2,266 \times 10^6$	$2,255 \times 10^6$
Net Heat Rate Btu/kWh	21,376	21,940
Turbine Exh. Inch Hg Abs	4.0	4.3
Wet Bulb	65.0	65.0
C. W. T. Range/Approach °F	40.4	38/16.0

(1) For expected gross output, multiply actual field output of unit by retrofit derating factory of 0.983

(2) No Noncondensable Gas Blower at Unit 12



STREAM NO.	MOL. WT.	UNIT	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
FLOWS IN LB/HR.		11																					
STEAM	18		1928,260	1,808,000		4,260	78000	38,000				23,140	9,040										890
NON CONDENSABLE GAS	35.6		16536	15,500		36	670	330				15,500	16,170										13,228
AIR	29											930	930										930
CONDENSATE									40,150	38,100	1,923,110												
COOLING WATER														42,263,000	2,663,000	1,105,000	350,000	277,500	48,581,610	1,738,800	184,310	46,658,500	
PRESSURE PSIA			113.4		2.11																		
ENTHALPY BTU/LB			1200		992.8																		
TEMPERATURE °F			355								125.0			119.0	119.0	119.0	103.0	100.0	119.0		81.0	81.0	
		12																					
STEAM	18		1,879,260	1,808,000		4,260	49,000	18,000				14,230	1,850										550
NON CONDENSABLE GAS	35.6		9,447	9,090		21	246	80				9,090	9,335										7,558
AIR	29											930	930										930
CONDENSATE									19,300	61,380	1,874,450												
COOLING WATER														42,475,000	1,700,000	551,000	350,000	277,500	42,307,950	1,689,600	184,850	45,339,500	
PRESSURE PSIA			113.4		2.11																		
ENTHALPY BTU/LB			1200		992.8																		
TEMPERATURE °F			355								125.0			119.0	119.0	119.0	103.0	100.0	119.0		81.0	81.0	

MAXIMUM H_2S VALUE — UNIT 11: 797

MAXIMUM H_2S VALUE — UNIT 12: 170

REFERENCE DRAWINGS — REVISION

1 — ISSUED FOR FINAL REPORT — EA — BF
0 — ISSUED FOR REPORT #1 — EA — BF

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ENGINEERS - ARCHITECTS
111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94111

SCALE NONE — DATE 6-7-79
DR. E.A. — ENG. BF — APPROVED

APPROVALS — DATE — DATE

PG and E RETROFIT STUDY
UNIT 11 & 12 CONVERSION
PROCESS FLOW DIAGRAM

JOB NO. S 79007 — PD-005 — 1

5.3.2 Installation and Equipment Arrangement

Units 11 and 12 are identical turbine-generator units, each housed in its own power building at two different sites. Equipment location and other dimensions were field checked on June 12, 1979 and verified against Drawings SK-019 and -020. These drawings are included herein and show the new equipment locations.

5.3.2.1 Main Condenser

Two conceptual arrangements were studied. First with the condenser tubes parallel to the T-G shaft and secondly with the condenser tubes perpendicular to the T-G shaft. The first and second arrangements are shown on SK-017 with SK-018 and SK-019 with SK-020 respectively.

For either arrangement the cooling water flow is split to allow tube clean out while operating near one half turbine flow. The condenser supplier's response indicated a two pass water flow and a four pass water flow would be the probable configuration for the first and second arrangements respectively.

For the parallel arrangement, a major equipment removal is required involving relocation of the entire turbine lube oil system, instrument air compressor and battery room to accommodate the tube pulling area. For the perpendicular arrangement this would not be required. For either arrangement removal of the condensate pumps is required.

For either main condenser conceptual arrangement all the following are essentially handled in the same manner.

5.3.2.2 Intercondenser and Ejectors

The existing intercondenser and ejectors will be removed. The new surface type intercondenser and new first stage jet ejector will be located to minimize the vacuum piping size. New support steel will be required.

5.3.2.3 Aftercondenser and Ejectors

The existing aftercondenser and ejectors will be removed, and the surface type aftercondenser will be located adjacent to the intercondenser on new supports.

Rogers

5.3.2.4 <u>Condensate Pumps</u>

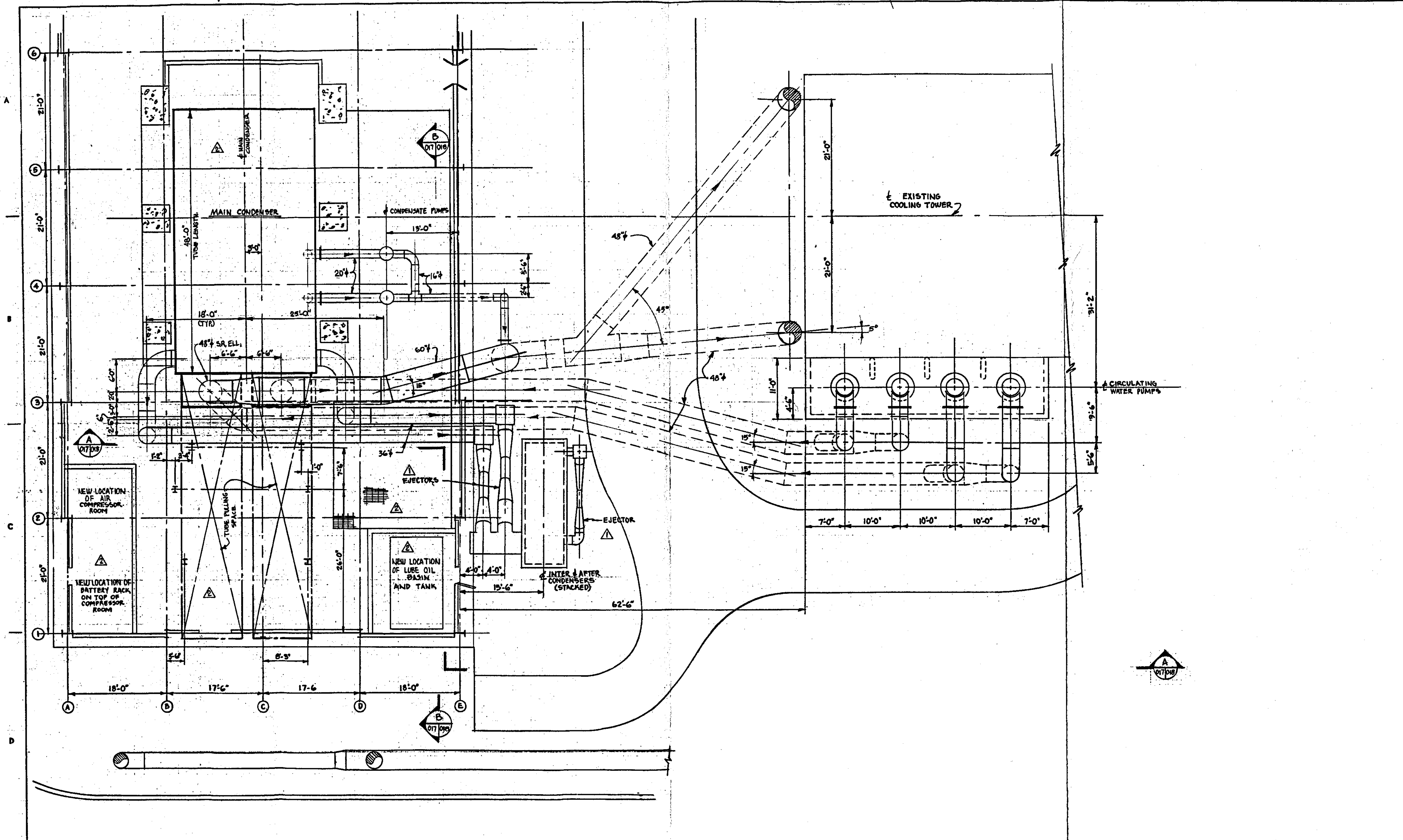
The four existing condensate pumps will be removed and two new condensate pumps located in the basement adjacent to the condenser inside the power building. The four existing condensate pumps will be used as circulating water pumps for the new system configuration.

5.3.2.5 <u>Circulating Water Pumps</u>

The four circulating water pumps will be located at the west end of the cooling tower near the cooling tower sump. Each pair of pumps will supply water to half the condenser. Cold well water will flow by gravity to the circulating water pump wet pit where a diffuser will reduce vortices before entering the pump suction. After rework to satisfy additional head requirements, the existing condensate pumps can be used as circulating water pumps for the new circulating water system.

5.3.3 Cost Estimates

Section 3 of this report discusses methods and parameters employed in preparing cost estimates for the retrofit project. The following summary cost estimate and the backup detail on succeeding pages adhere to the guidelines in Section 3, and as noted have been prepared according to typical PGandE format.



			REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.
			2		9/22/79	REISSUED FOR FINAL REPORT	RS	LFW		
			1		7-18 1979	REVISED & REISSUED FOR FINAL REPORT	CLO	RS	LFW	
2	SK-018	SECTIONS A & B	0		6-28 1979	ISSUED FOR MILESTONE REPORT #2	CLO	RS	LFW	
	REFERENCE DRAWINGS									

ROGERS ENGINEERING CO., INC.
ENGINEERS - ARCHITECTS
111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94108

SCALE 1/8" = 1'-0" DATE 6-26-79

DR. RS/RP. CHK. RS. ENG. LFW APPROVED

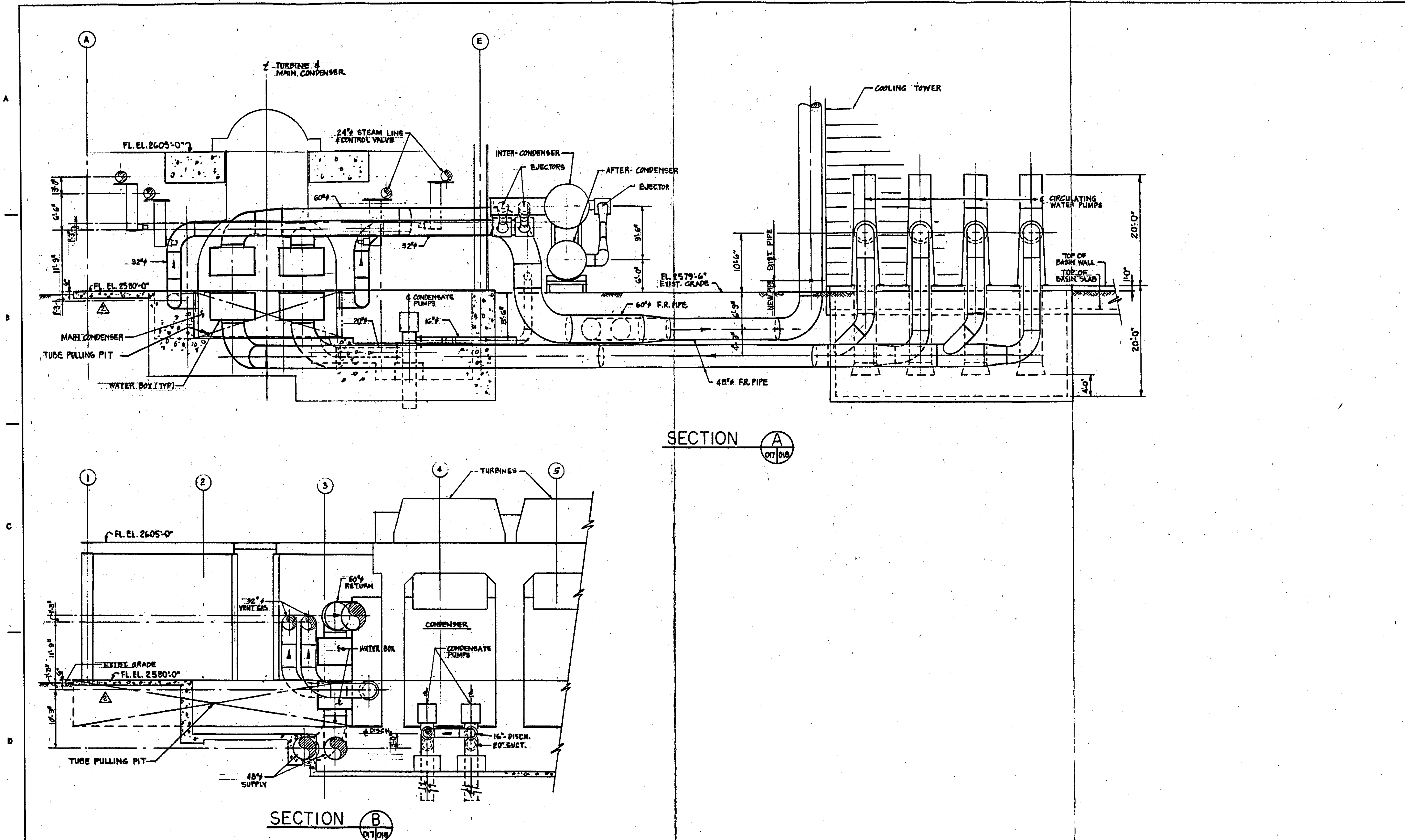
APPROVALS

DATE

DATE

PG and E RETROFIT STUDY
UNIT 11
TWO PASS CONDENSER PLAN
ELEVATION 2580'-0"

JOB NO. S79007 | SK-017 | 2



SK-017	PLAN AT ELEVATION 2580'-0"	2		9/24/79	REISSUED FOR FINAL REPORT	RS	LFW	
		1		7-18 1979	REVISED & REISSUED FOR FINAL REPORT	G.O.	RS	
		0		6-25 1979	ISSUED FOR MILESTONE REPORT # 2	G.O.	RS	
REFERENCE DRAWINGS		REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO / APPR.

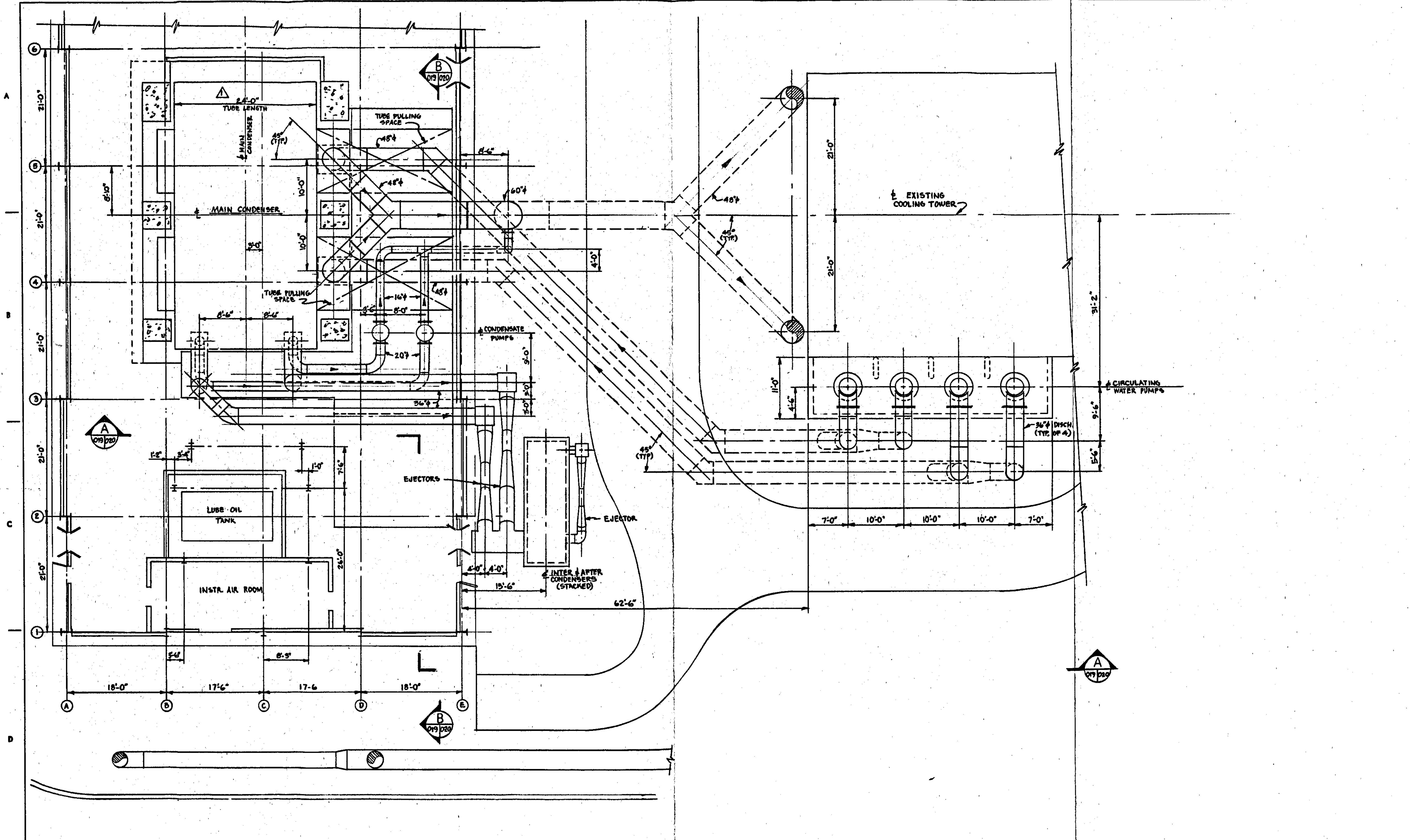
ROGERS ENGINEERING CO., INC.
ENGINEERS • ARCHITECTS
111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94108

SCALE 1/8" = 1'-0" DATE 6-25-79
DR. RS./R.P. CHK. RS/DL ENG. LFW APPROVED

APPROVALS
DATE
DATE

PG and E RETROFIT STUDY
UNIT 11 & 12
SECTIONS A & B

JOB NO. S79007 | SK-018 | 2



		1			REISSUED FOR FINAL REPORT	RS	LFW		
SK-020	SECTIONS A&B (FOUR PASS)	0		7-18 1979	ISSUED FOR FINAL REPORT	GO.	RS	LFW	
REFERENCE DRAWINGS		REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.

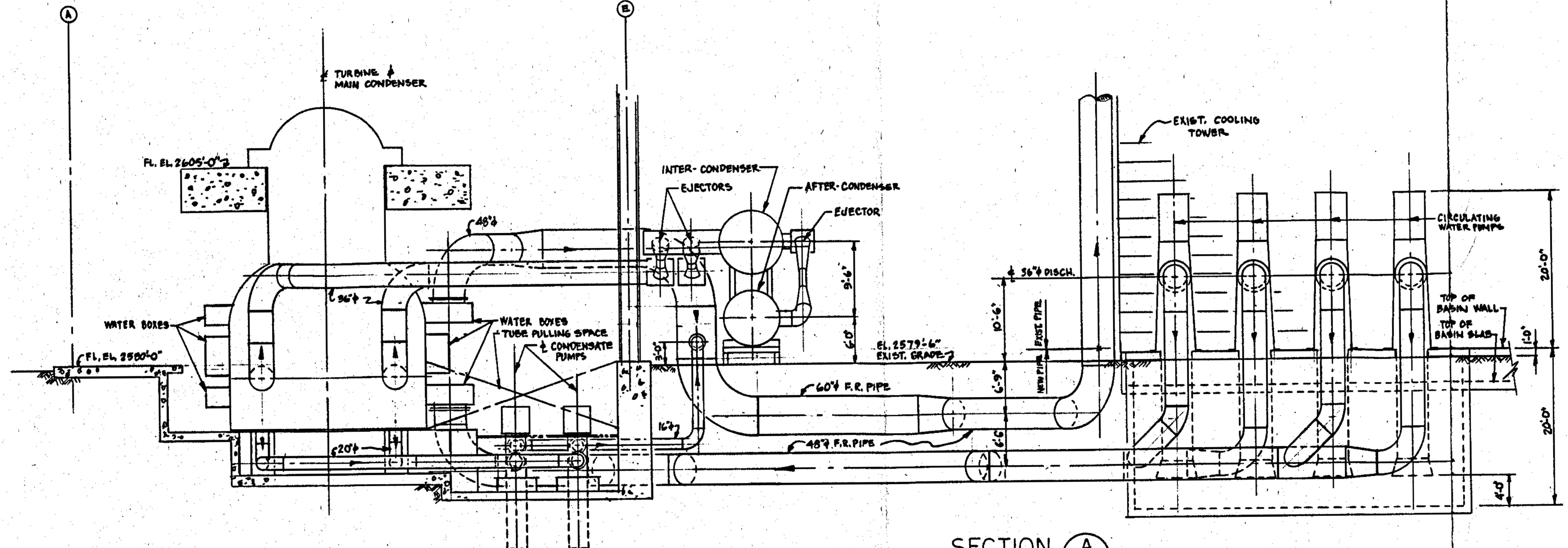
ROGERS ENGINEERING CO., INC.
ENGINEERS · ARCHITECTS
111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94105

SCALE 1/8"=1'-0" DATE 7-12-79
DR. RS CHK. ENG. LFW APPROVED

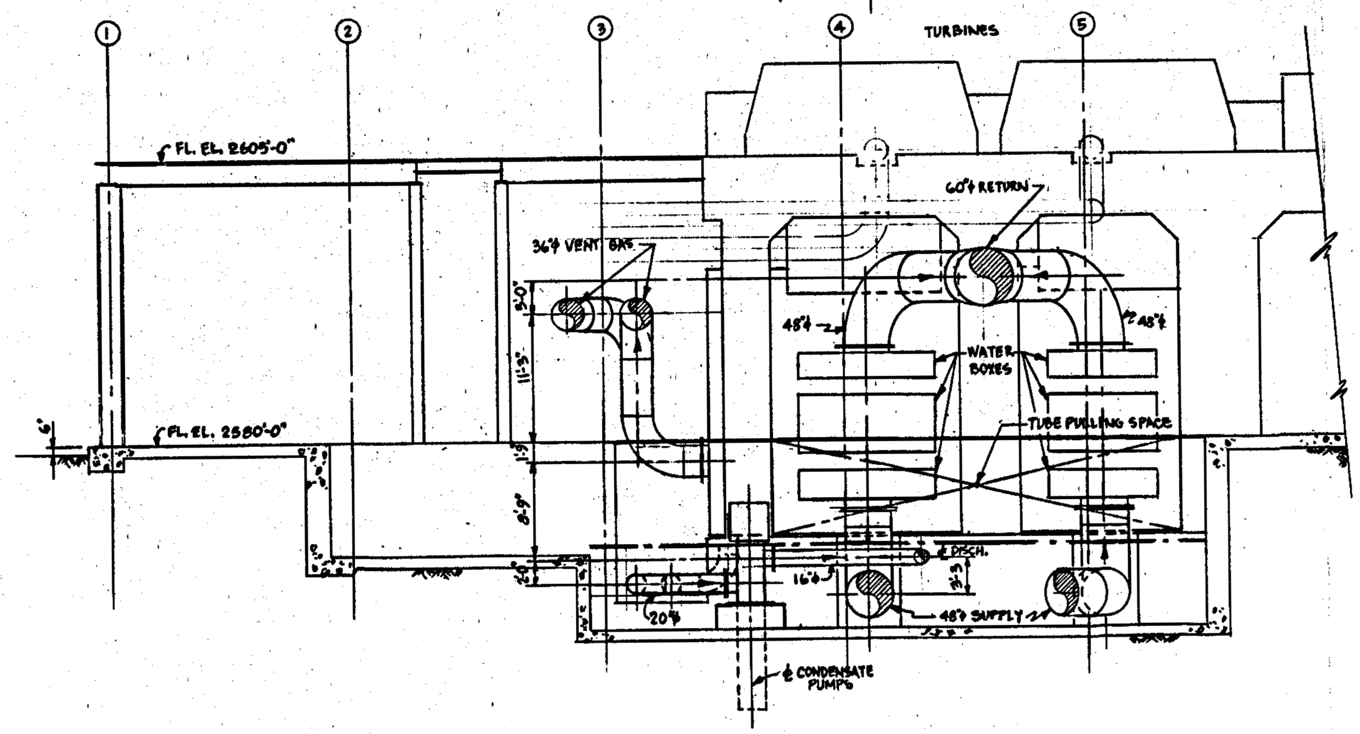
APPROVALS
DATE
DATE

PG and E RETROFIT STUDY
UNIT 11
FOUR PASS CONDENSER PLAN
ELEVATION 2580'-0"

JOB NO. S79007 SK-019 1



SECTION A (019/020)



SECTION B (019/020)

△	SK-019	PLAN AT ELEVATION 2580'-0" (FOUR PASS)
	REFERENCE DRAWINGS	

REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.
1			REISSUED FOR FINAL REPORT	RS	LFW		
0		7-18 1979	ISSUED FOR FINAL REPORT	GD.	RS	LFW	

ROGERS ENGINEERING CO., INC.
ENGINEERS - ARCHITECTS
111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94109

SCALE 1/8" = 1'-0" DATE 7-12-79

DR. RS CHK. DAV ENG. LFW APPROVED

APPROVALS

DATE
DATE

PG and E RETROFIT STUDY
UNITS 11 & 12
FOUR PASS CONDENSER SECTIONS

JOB NO. S79007

SK-020

1

GE 212

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TABLE 5.3-3

SUMMARY COST ESTIMATE - UNIT 11
(Tube Bundle Parallel to Turbine Shaft)

Account	Description	Equipt. & Mat'l	Labor	Total
51-20	Building	$ 19,080	$ 147,700	$ 166,780
54-20	Condenser System	4,437,245	1,557,138	5,994,383
54-30	Fire Water System	1,102,570	838,208	1,940,778
54-40	Lube Oil System	22,642	80,140	102,782
54-70	Instrumentation	35,107	46,593	81,700
55-60	Station Power	70,087	47,059	117,146
56-10	Compressed Air System	10,812	67,560	78,372
365	Engineering & Other	1,696,320	0	1,696,320
	Subtotals	$7,393,862	$2,784,398	$10,178,260
	GM Factor (23.0%)			2,340,999
	Subtotal (GM 1979)			12,519,259
	Escalation (28.55%)			3,574,248
	Total GM Estimate			$16,093,507

Project Differential Costs

The capital involved to accomplish this retrofit project using a surface condenser with tube bundle parallel to the turbine axis will require a level annual revenue of 2.52 mills per kilowatthour.

The detailed backup to the summary is presented by accounts and sub-accounts in Table 5.3-5.

Table 5.3.4 is the summary cost estimate for a surface condenser axis perpendicular to the turbine axis. This cost is slightly less than the parallel cost and is used in further analysis as recommended for Units 11 & 12. A detailed cost backup is also included. The telephone quotes for the parallel two pass condenser were the same as the perpendicular four pass condenser.

Rogers

TABLE 5.3-4

SUMMARY COST ESTIMATE - UNIT 11
(Tube Bundle Perpendicular to Turbine Shaft)

Account	Description	Equipt. & Mat'l	Labor	Total
51-20	Building	$ 11,448	$ 33,547	$ 44,995
54-20	Condenser System	4,437,245	1,557,138	5,994,383
54-30	Circ. Water System	1,107,912	850,322	1,958,234
54-70	Instrumentation	34,471	41,937	76,405
55-60	Station Power	67,416	37,274	104,690
56-10	Compressed Air System	2,544	27,956	30,500
365	Engineering & Other	1,641,841	0	1,641,841
	Subtotals	$7,302,877	$2,548,171	$ 9,851,048
	GM Factor (23.0%)			$ 2,265,741
	Subtotal (GM 1979)			12,116,789
	Escalation (28.55%)			3,459,343
	Total GM Estimate			$15,576,132

Project Differential Costs

The capital involved to accomplish this retrofit project using a surface condenser with the tube bundle perpendicular to the turbine axis will require a level annual revenue of 2.44 mills per kilowatthour.

The detailed backup to the summary is in Table 5.3-6.

ROGERS ENGINEERING CO., INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111
JOB NO. S-79007
DG-023

TABLE 5.3-5
COST ESTIMATE DETAIL - UNIT 11
SURFACE CONDENSER (PARALLEL)

DRAWING NO.
REV.
SHEET 1 OF 3

ROGERS ENGINEERING CO.,INC. COST ESTIMATE
JOB NAME-UNIT 11 JOB NO.-S79007 CLIENT-P G AND E ESTIMATE DATE- 18 JULY 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL	
51-21-1	RMV BLDG CONC FL/WLL	1272.	18637.	802.	19909.	
51-21-2	RMV STR STL COLS	636.	46593.	2004.	47229.	
51-21-3	CONST LO SUMP & RES	1272.	13978.	601.	15250.	
51-21-4	INSTALL BLDG STR STL	4452.	34945.	1503.	39397.	
51-21-5	CONST TUBE PULL PIT	11448.	33547.	1443.	44995.	
ACCOUNT TOTAL		19080.	147700.	6353.	166780.	1

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL	
54-21-1	COND PUMPS EXC & BFL	4070.	27956.	1202.	32026.	
54-21-2	COND PUMPS CONC	3562.	16773.	721.	20335.	
54-22-1	SUP STRUCT INT/AFT/E	22896.	55912.	2405.	78808.	
54-22-2	RMV SUP STR INT/AFT	0.	9319.	401.	9319.	
54-23-1	RMV CONDENSER	3816.	130460.	5611.	134276.	
54-23-2	R CRANE	38160.	16308.	701.	54468.	
54-23-3	EQ COND M/INT/AFT/EJ	3816000.	0.	0.	3816000.	3
54-23-4	INSTALL M COND MECH	76320.	838674.	36072.	914994.	
54-23-5	R CRANE/EQUIP	63600.	32615.	1403.	96215.	
54-23-6	INSTL INT/AFT/EJ	2544.	46593.	2004.	49137.	
54-24-1	RMV COND PUMPS MECH	0.	18637.	802.	18637.	
54-24-2	EQ CONDS PUMPS QUOTE	139920.	0.	0.	139920.	
54-24-3	INSTALL COND PUMP ME	6360.	39604.	1703.	45964.	
54-25-1	RMV COND PIPING	3816.	37274.	1603.	41090.	
54-25-2	R CRANE	2544.	3727.	160.	6271.	
54-25-3	RMV NC GAS PIPING	890.	9319.	401.	10209.	
54-25-4	RMV MISC SMALL PIPE	890.	9319.	401.	10209.	
54-25-5	NC GAS PIPING	101760.	107164.	4609.	208924.	
54-25-9	CONDS PIPING	89040.	93186.	4008.	182226.	
54-25-6	EQ TURB EXH CONN	57240.	0.	0.	57240.	
54-25-7	INSTALL TURB EXH CON	1272.	60571.	2605.	61843.	
54-25-8	R CRANE	2544.	3727.	160.	6271.	
ACCOUNT TOTAL		4437245.	1557138.	66974.	5994383.	5

ROGERS ENGINEERING CO., INC. COST ESTIMATE

JOB NAME-UNIT 11 JOB NO.-S79007 CLIENT-P G AND E ESTIMATE DATE- 18 JULY 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL	
54-32-1	RMV COLD WELL	1272.	13978.	601.	15250.	
54-32-2	CONST COLDWELL	25440.	104834.	4509.	130274.	
54-33-1	CW PIPING	788640.	577753.	24850.	1366393.	1
54-33-2	R CRANE/EQUIP	3816.	4659.	200.	8475.	
54-34-1	EQ CW PUMPS REWRK	254400.	0.	0.	254400.	
54-34-2	INSTALL CW PUMPS ME	20352.	116483.	5010.	136835.	
54-34-3	R CRANE	7632.	9319.	401.	16951.	
54-39-1	RELOCATE FHC & PIPG	1018.	11182.	481.	12200.	
ACCOUNT TOTAL		1102570.	838208.	36052.	1940778.	1

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-41-1	CONS CONC BERM & STR	509.	22365.	962.	22873.
54-43-1	RELOCATE LO RES & EQ	1272.	9319.	401.	10591.
54-43-2	R CRANE	2544.	3727.	160.	6271.
54-43-3	MOD & EXT PIPING SYS	18317.	44729.	1924.	63046.
ACCOUNT TOTAL		22642.	80140.	3447.	102782.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-74-1	INSTR COND SYS	19080.	18637.	802.	37717.
54-74-2	INSTR CW SYS	15264.	18637.	802.	33901.
54-74-3	INSTR LUBE OIL SYS	636.	4659.	200.	5295.
54-74-4	INSTR COMP AIR SYS	127.	4659.	200.	4787.
ACCOUNT TOTAL		35107.	46593.	2004.	81700.

ROGERS ENGINEERING CO., INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111
JOB NO. S-79007

TABLE 5.3-5
COST ESTIMATE DETAIL - UNIT 11
SURFACE CONDENSER (PARALLEL)

DRAWING NO. REV.

DG-023

ROGERS ENGINEERING CO, INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111
JOB NO. S-79007
DG-023

TABLE 5.3-5
COST ESTIMATE DETAIL - UNIT 11
SURFACE CONDENSER (PARALLEL)

DRAWING NO. REV.
SHEET 3 OF 3

ROGERS ENGINEERING CO.,INC. COST ESTIMATE
JOB NAME-UNIT 11 JOB NO.-S79007 CLIENT-P G AND E ESTIMATE DATE- 18 JULY 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
55-64-1	COND PUMP ELECT	20352.	6057.	261.	26409.
55-64-2	CW PUMPS ELECT	47064.	31217.	1343.	78281.
55-64-3	RELOCATE LO ELECT	1526.	3727.	160.	5254.
55-64-4	RELOCATE COMP A ELEC	382.	2330.	100.	2711.
55-64-5	RELOCATE DC BATT SYS	763.	3727.	160.	4491.
ACCOUNT TOTAL		70087.	47059.	2024.	117146.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
56-11-1	CONST CONC BLK ROOM	6360.	27956.	1202.	34316.
56-13-1	RELOCATE COMP AIR EQ	636.	9785.	421.	10421.
56-13-2	R CRANE	1272.	1864.	80.	3136.
56-13-3	MOD & EXT C A PIPING	2544.	27956.	1202.	30500.
ACCOUNT TOTAL		10812.	67560.	2906.	78372.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL	
365-1	CONSTRUCTION FIELD	424080.	0.	0.	424080.	
365-2	GENERAL ENGINEERING	254400.	0.	0.	254400.	
365-3	OTHER ENGINEERING	1017840.	0.	0.	1017840.	1
ACCOUNT TOTAL		1696320.	0.	0.	1696320.	1

ROGERS ENGINEERING CO.,INC. COST ESTIMATE

JOB NAME-UNT11 PD JOB NO.-S79007 CLIENT-P G AND E ESTIMATE DATE- 18 JULY 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
51-21-5	CONST TUBE PULL PIT	11448.	33547.	1443.	44995.
ACCOUNT TOTAL		11448.	33547.	1443.	44995.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL	
54-21-1	COND PUMPS EXC & BFL	4070.	27956.	1202.	32026.	
54-21-2	COND PUMPS CONC	3562.	16773.	721.	20335.	
54-22-1	SUP STRUCT INT/AFT/E	22896.	55912.	2405.	78808.	
54-22-2	RMV SUP STR INT/AFT	0.	9319.	401.	9319.	
54-23-1	RMV CONDENSER	3816.	130460.	5611.	134276.	
54-23-2	R CRANE	38160.	16308.	701.	54468.	
54-23-3	EQ COND M/INT/AFT/EJ	3816000.	0.	0.	3816000.	3
54-23-4	INSTALL M COND MECH	76320.	838674.	36072.	914994.	
54-23-5	R CRANE/EQUIP	63600.	32615.	1403.	96215.	
54-23-6	INSTL INT/AFT/EJ	2544.	46593.	2004.	49137.	
54-24-1	RMV COND PUMPS MECH	0.	18637.	802.	18637.	
54-24-2	EQ CONDS PUMPS QUOTE	139920.	0.	0.	139920.	
54-24-3	INSTALL COND PUMP ME	6360.	39604.	1703.	45964.	
54-25-1	RMV COND PIPING	3816.	37274.	1603.	41090.	
54-25-2	R CRANE	2544.	3727.	160.	6271.	
54-25-3	RMV NC GAS PIPING	890.	9319.	401.	10209.	
54-25-4	RMV MISC SMALL PIPE	890.	9319.	401.	10209.	
54-25-5	NC GAS PIPING	101760.	107164.	4609.	208924.	
54-25-6	EQ TURB EXH CONN	57240.	0.	0.	57240.	
54-25-7	INSTALL TURB EXH CON	1272.	60571.	2605.	61843.	
54-25-8	R CRANE	2544.	3727.	160.	6271.	
54-25-9	COND PIPING	89040.	93186.	4008.	182226.	
ACCOUNT TOTAL		4437245.	1557138.	66974.	5994383.	5

ROGERS ENGINEERING CO, INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111

JOB NO. S-79007

DG-023

TABLE 5.3-6
COST ESTIMATE DETAIL - UNIT 11
SURFACE CONDENSER (PERPENDICULAR)

DRAWING NO. REV.

SHEET 1 OF 2

ROGERS ENGINEERING CO., INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111
JOB NO. S-79007
DG-023

TABLE 5.3-6
COST ESTIMATE DETAIL - UNIT 11
SURFACE CONDENSER (PERPENDICULAR)

ROGERS ENGINEERING CO.,INC. COST ESTIMATE
JOB NAME-UNT11 PD JOB NO.-S79007 CLIENT-P G AND E ESTIMATE DATE- 18 JULY 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL	
54-31-1	C W PUMP FOUNDATION	6360.	23297.	1002.	29657.	
54-32-1	RMV COLD WELL	1272.	13978.	601.	15250.	
54-32-2	CONST COLDWELL	25440.	104834.	4509.	130274.	
54-33-1	CW PIPING	788640.	577753.	24850.	1366393.	1
54-33-2	R CRANE AND EQUIP	3816.	4659.	200.	8475.	
54-34-1	EQ CW PUMPS (REWORK)	254400.	0.	0.	254400.	
54-34-2	INSTALL CW PUMPS ME	20352.	116483.	5010.	136835.	
54-34-3	R CRANE	7632.	9319.	401.	16951.	
ACCOUNT TOTAL		1107912.	850322.	36573.	1958234.	1

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-74-1	INSTR COND SYSTEM	19080.	18637.	802.	37717.
54-74-2	INSTR CW SYSTEM	15264.	18637.	802.	33901.
54-74-3	INSTR COMP AIR SYS	127.	4659.	200.	4787.
ACCOUNT TOTAL		34471.	41934.	1804.	76405.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
55-64-1	COND PUMP ELECT	20352.	6057.	261.	26409.
55-64-2	CW PUMPS ELECT	47064.	31217.	1343.	78281.
ACCOUNT TOTAL		67416.	37274.	1603.	104690.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
56-13-3	MOD & EXT CA PIPING	2544.	27956.	1202.	30500.
ACCOUNT TOTAL		2544.	27956.	1202.	30500.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL	
365-1	CONSTRUCTION FIELD	410460.	0.	0.	410460.	
365-2	GENERAL ENGINEERING	246276.	0.	0.	246276.	
365-3	OTHER ENGINEERING	985105.	0.	0.	985105.	
ACCOUNT TOTAL		1641841.	0.	0.	1641841.	1

DRAWING NO. REV.
SHEET 2 OF 2

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5.4 Hydrogen Sulfide Abatement, Units 1-12

This section is introductory to detailed discussions of the hydrogen sulfide abatement vent gas process (Stretford) site studies. It provides a general overview of the initial site selection process, a discussion of Stretford capital costs, operating and maintenance costs, and a summary of the conclusions and recommendations.

5.4.1 Abatement Site Alternatives

A large number of generating unit and Stretford unit combinations and Stretford unit locations could be devised to provide H_2S abatement for the Geysers Power Plant, Units 1 - 12. Due to terrain, location and size of generating units and other physical features at the Geysers, only a few arrangements are feasible and were selected for investigation in this study.

Due to the relatively close proximity of Units 1 & 2, 3 & 4 and 5 & 6, and ease of access between these units, it was apparent that consideration should be given to servicing them with one Stretford unit. These units constitute a power block of slightly less than 200 MW gross which was felt to be of reasonable size for grouping with one Stretford unit.

Unit 11 and Units 7 & 8 form a power block of slightly more than 200 MW gross, and a connected series of steam lines from the well field provides a right-of-way between these locations along with a cleared route and the possibility of modifying existing pipe supports to accommodate the Stretford gas lines. Because of these factors, consolidation of H_2S abatement for these units also appeared logical, and the study proceeded accordingly.

Unit 12 and Units 9 & 10 combined are of the same gross capacity as the combination of Units 7, 8 and 11. Additionally, these units are in the same general area of the Geysers Power Plant and thus were considered for grouping for off-gas treatment by one Stretford unit. Further study indicated that considerations of terrain and communication between Units 9 & 10 and Unit 12 render separate units at each location more practical and economical.

5.4.2 Development of Stretford Capital Costs

Quotations for the cost of the Stretford facilities were solicited from the three Stretford process licensees, R. M. Parsons

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Co., J. T. Pritchard, and Peabody Engineering. Both Parsons and Pritchard supplied cost data for the Stretford process. The cost includes a one time royalty payment which was not segregated.

The information received from Parsons was used for the economic trade-off studies for the Stretford consolidations and site selections. Parsons provided cost estimates for complete, installed Stretford process units. However, these costs were not for units installed at the Geysers, but rather were based on a "curve estimate" of composite costs for Stretford units in many locations. Parsons' quotations include uncertainty limits of -10% to + 30% for every Stretford unit. The highest capital cost value (+30%) was utilized for the Stretford facilities in this study.

To estimate the cost of a Stretford unit installed at the Geysers, the total cost of the Stretford facility was divided into two categories as suggested by Pritchard, installation labor cost and material cost. The cost of the initial loading of chemicals was added to the material category, and a use tax charged on this material total. The labor portion is increased by factors used to account for higher labor costs at the Geysers. These two separate material and labor costs were added back together to estimate the total cost of a Stretford unit installed at the Geysers.

Parsons has stated that where individual Stretford units are located at each power plant, the scheduled outage of the power plant is sufficient to service the Stretford facility. However, when multiple power plants are tied to a single Stretford unit, this scheduled outage time is not available to service the Stretford facility. Thus, for these consolidated systems, the estimated cost of the Stretford unit was increased by 20% to account for equipment redundancy necessary to approach a 100% capacity factor.

5.4.3 Stretford Operating and Maintenance Costs

R. M. Parsons Co. supplied a detailed breakdown of the operating and maintenance costs of the Stretford abatement process. These values were converted to a levelized annual cost of O & M, which entered into the economic comparison of alternative Stretford unit consolidations.

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Parsons estimates that the maintenance cost of a Stretford facility is 2% of the capital cost of a Stretford unit. They also provided steam, electricity, and chemical operating requirements for the Stretford Process as summarized in the following table.

TABLE 5.4-1

STRETFORD OPERATING COSTS

Unit	Steam (lbm/hr.)	Electricity (kW)	Daily Chemical Cost ($ - Not Levelized)
Individual Units			
1, 2	400	N. S.	72.74
3, 4	1,700	N. S.	345.75
5, 6	3,200	N. S.	646.25
7, 8	2,000	N. S.	395.82
9, 10	800	N. S.	139.79
11	3,500	N. S.	700.40
12	1,000	N. S.	153.49
Consolidated Units			
1-6	5,300	1,065	1064.66
7, 8, 11	5,500	1,095	1087.89
9, 10, 12	1,500	300	293.20
9, 10, 12, 14	3,900	N. S.	773.86

N. S. - Not Stated

5.4.4 Electrical Service at Stretford Units

Two alternatives were considered for power service to the Stretford facilities; 1) Utilizing the power plant 480 volt auxiliary bus, and 2) installing two independent transformers similar to the existing auxiliary transformers connected to one of the power plant generators and to the 21 kV distribution line now in use in some parts of the Geysers area.

The major problems with using the auxiliary bus are reliability, transformer capacity, and voltage drop. Since a single Stretford facility serves several power plants, failure of the power supply to the Stretford is not tolerable. Thus, the recommended electrical service to the Stretford facilities entails a prime and standby source.

The estimated electrical demands for the Streford facilities were obtained from R. M. Parsons Co. The Stretford facilities require electrical service at 480 volts. Lighting requirements are included in these Stretford loads. Parsons has stated that the largest motor will not exceed 200 hp.

The electrical demands for the Stretford facilities are summarized in Table 5.4-2 and Table 5.4-3. The kilowatt demand, estimated kVA demand based on an assumed 0.85 power factor, and the closest standard transformer size if an independent power supply is provided are shown in Table 5.4-2. Table 5.4-3 shows existing transformer capacities and station auxiliary power demand after retrofit plus Stretford power requirements.

The recommended electrical service to a Stretford facility serving Units 1-6 is shown in Drawing SK-032. Likewise, Drawing SK-034 diagrams the electrical service to a Stretford facility located at Unit 11, which would receive the vent gases from Units 7, 8 and 11. Drawing SK-033 gives the preferred electrical service to a local Stretford plant at Units 9 and 10. The electrical service to a local Stretford facility at Unit 12 is shown in Drawing SK-035.

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TABLE 5.4-2

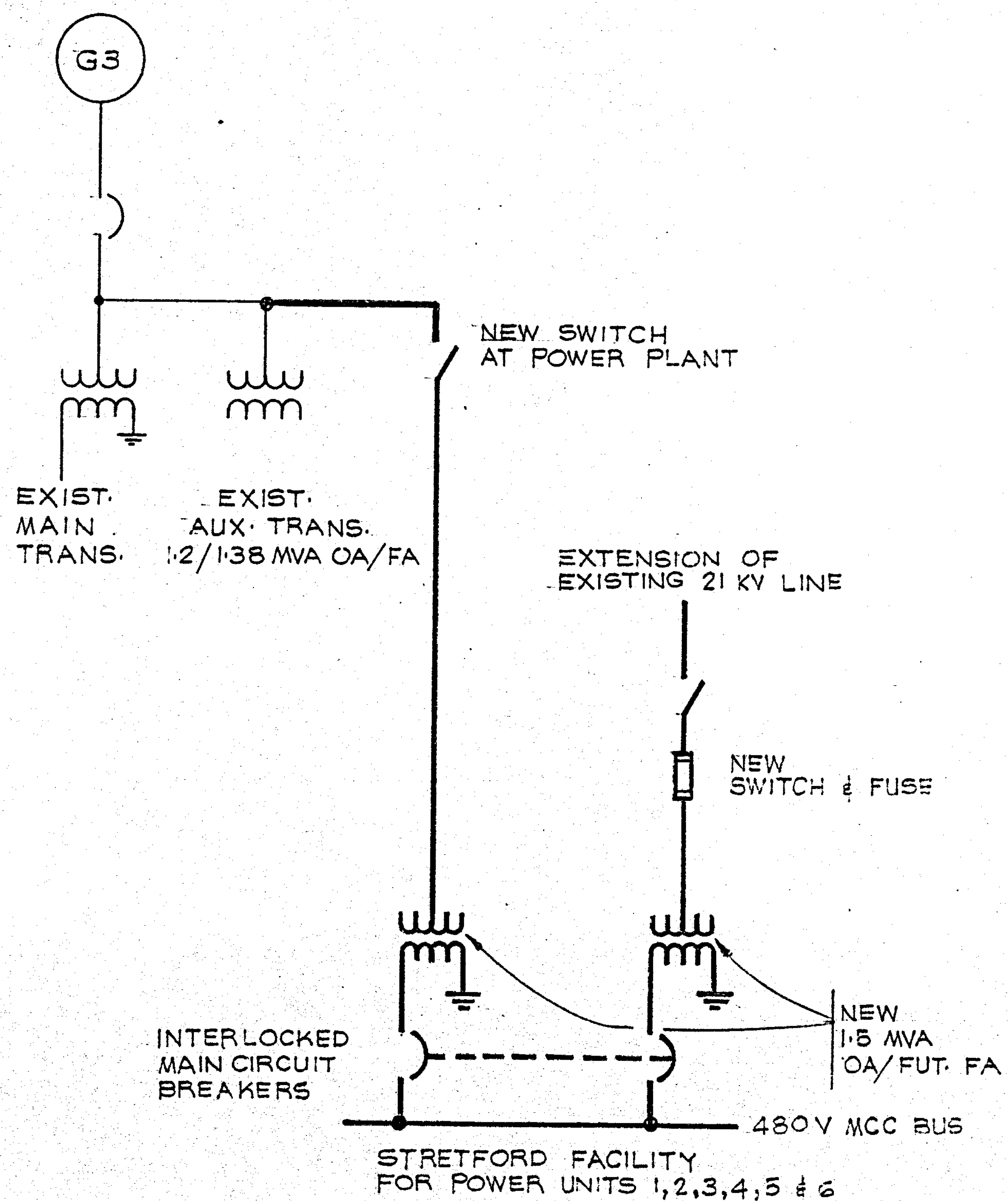
Stretford Facility Serving	Estimated Demand kW	Minimum Transformer Requirements-Stretford Facility, kVA	Closest Standard Size for an Oil Insulated Transformer kVA
Units 1 thru 6	1065	1252	1500 OA[1] or 1000 kVA OA/FA (1288 kVA max.)[2]
Units 7, 8 and 11	1095	1288	1500 OA or 1000 kVA OA/FA (1288 kVA max.)
Units 9 & 10	143	179	225 OA
Unit 12	157	196	225 OA

[1]Self cooled rating at 55°C rise.
[2]Rating with fans and if 65°C temperature rise is utilized.

TABLE 5.4-3

Stretford Facility Serving	Supplied From Power Plant	Existing Auxiliary Transformer Max. Capacity kVA	Existing Load kVA	Estimated Load After Retrofit kVA	Estimated Load for Stretford kVA	Total Load kVA
Units 1 thru 6	Unit 3	1,546[1]	1,185	1,375	1,252	2,627[3]
Units 7, 8 & 11	Unit 11	3,750[2]	2,327	2,382	1,288	3,670
Units 9 & 10	Unit 9	3,000[2]	1,849	1,846	179	2,025
Unit 12	Unit 12	3,750[2]	2,286	2,402	196	2,598

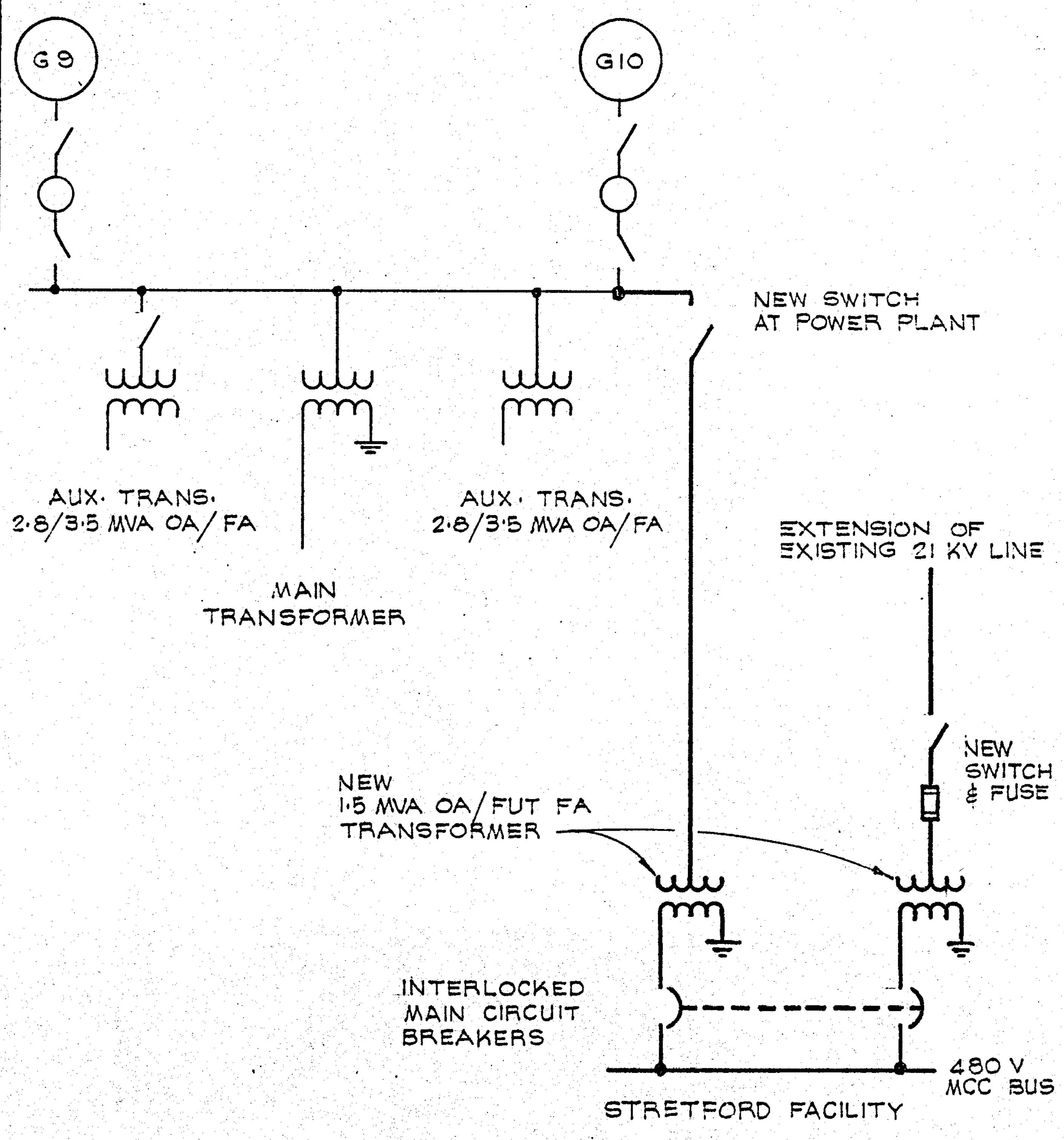
[1]With fans at 65°C rise, 1,380 kVA without fans. Single Line Diagram, Unit 3 indicates provision for fans.
[2]With fans at 65°C rise. Requires addition of fans if Stretford Facility is supplied from auxiliary transformer.
[3]In excess of existing auxiliary transformer capacity. Separate transformers are required.



No.	Date	Description	Ck.	R.App	C.App
1	8/24/79	REDRAWN - FINAL REPORT			

ROGERS ENGINEERING CO., INC. 111 PINE STREET SAN FRANCISCO, CALIF. 94111	PROPOSED ELECTRICAL SERVICE TO STRETFORD LOCATION-NEAR UNIT 3	DRAWING NO SK-032	REV. 1
JOB NO. S79007	Client / Date	SHEET OF	

DG-022



No.	Date	Description	Ck.	R.App	C.App
1	8/24/79	REDRAWN - FINAL REPORT			

ROGERS ENGINEERING CO., INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111

PROPOSED ELECTRICAL SERVICE TO STRETFORD LOCATION - UNIT 9 & 10

DRAWING NO	REV.
SK - 033	1

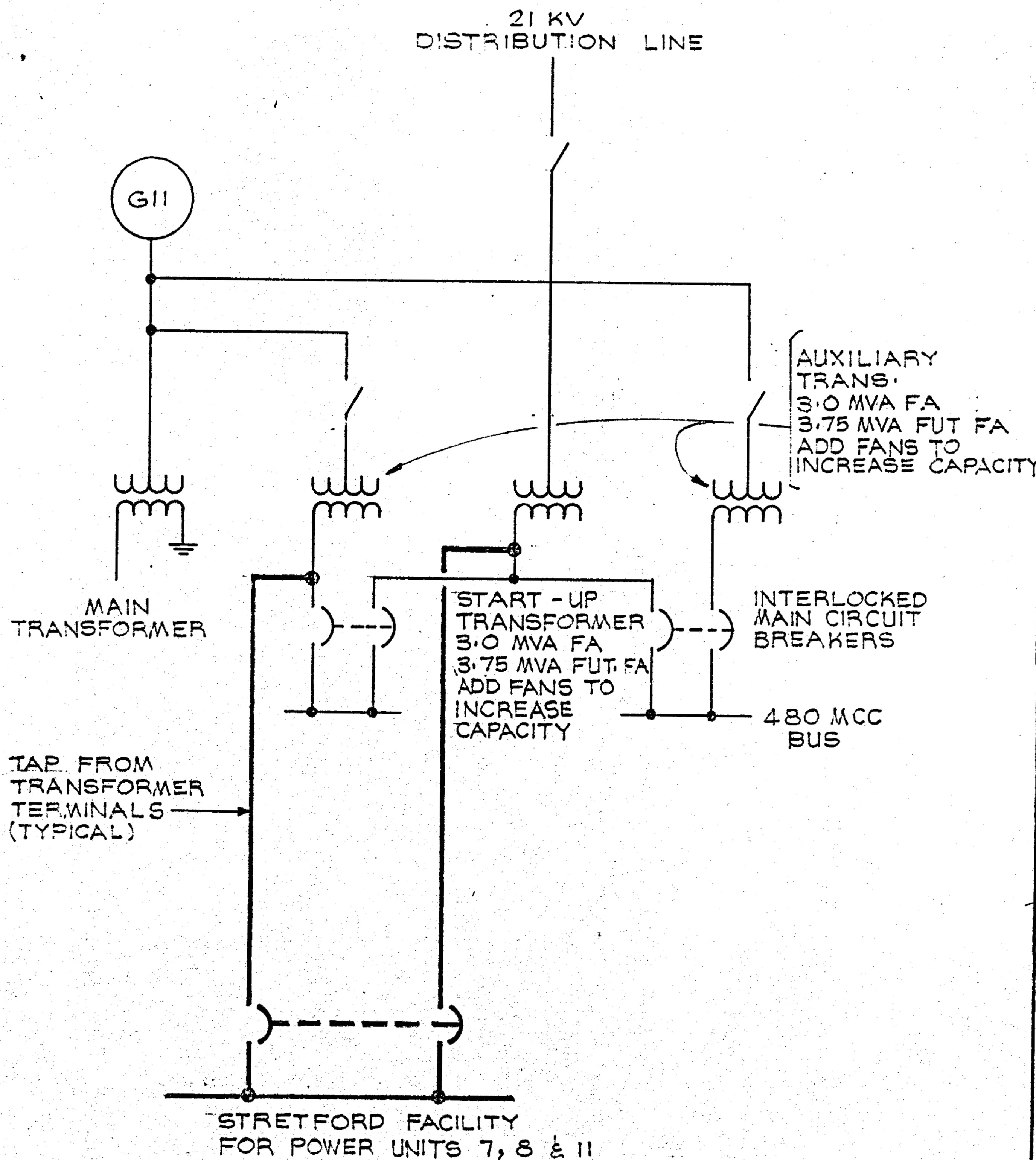
JOB NO. S79007

Client

Date

SHEET OF

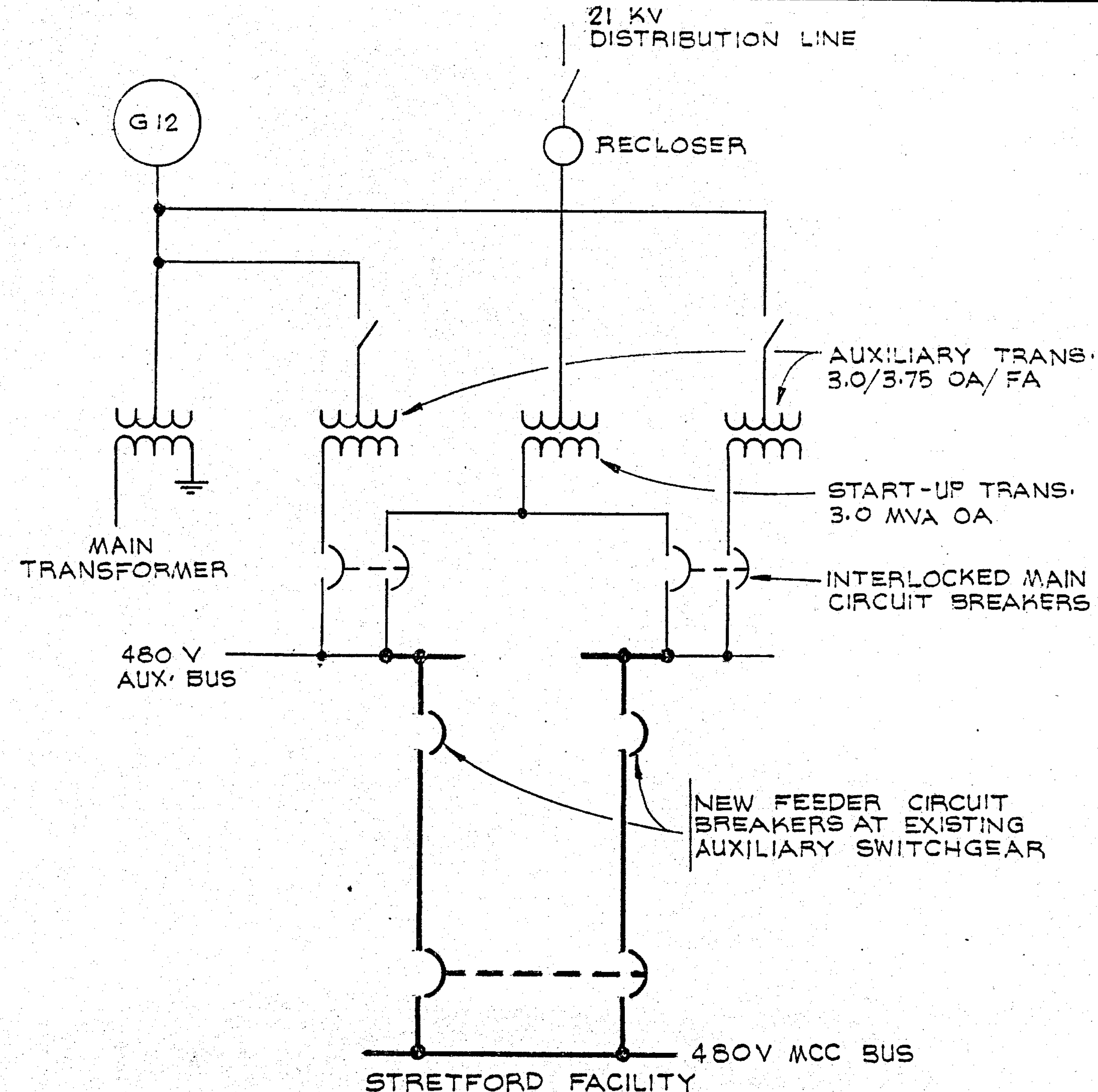
DG - 022



No.	Date	Description	Ck.	R.App	C.App
1	8/24/79	REDRAWN - FINAL REPORT			

ROGERS ENGINEERING CO., INC. 111 PINE STREET SAN FRANCISCO, CALIF. 94111	PROPOSED ELECTRICAL SERVICE TO STRETFORD LOCATION - UNIT 11	DRAWING NO SK - 034	REV. 1
JOB NO. S79007	Client / Date	SHEET	OF

DG - 022



No.	Date	Description	Ck.	R.App	C.App
1	8/24/79	REDRAWN - FINAL REPORT			

ROGERS ENGINEERING CO., INC. 111 PINE STREET SAN FRANCISCO, CALIF. 94111	PROPOSED ELECTRICAL SERVICE TO STRETFORD LOCATION - UNIT 12	DRAWING NO SK - 035	REV. 1
JOB NO. S79007	Client Date	SHEET OF	

DG - 022

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5.4.5 Conclusions and Recommendations

5.4.5.1 Units 1-6

1) Units 1-6 should be served by a common Stretford facility. This system results in a lower levelized annual cost than individual Stretford units located at each power plant.

2) The site at the Union Oil Company surplus yard near Unit 3, or another potentially available site near Units 5 and 6, should be utilized for the location of the Stretford unit for the most economical placement. The advantages of these sites, as opposed to the alternative area adjacent to Unit 4, are: a) lower levelized annual cost, b) reduced loss of total generating capacity during construction, and c) increased flexibility in the construction schedule.

3) Individual Gas Scrubbers

Further study is required before a definite recommendation can be made regarding this approach. Preliminary investigation does indicate advantages for such a system(s), and it should be studied further prior to a final selection of the H_2S abatement system for the Geysers Power Plant.

5.4.5.2 Units 7, 8, and 11

1) A common Stretford facility should be utilized to process the noncondensable gases from Units 7, 8 and 11. The consolidation results in a lower levelized annual cost than individual Stretford units located at each power plant.

2) The recommended site for the Stretford facility is at Unit 11, provided that the Stretford licensee is willing to redesign the equipment plot plan to fit into the long narrow space adjacent to the cooling tower. The advantage of this Stretford location over the alternative site at Unit 7 and 8 is a lower levelized annual cost due to reduced noncondensable gas piping requirements and smaller blower energy costs.

5.4.5.3 Units 9, 10, and 12

1) Individual Stretford facilities should be located at each power plant unit to process the noncondensable gases from

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Units 9, 10, and 12. This arrangement results in a lower levelized annual cost than a single consolidated Stretford unit.

2) Enlarging the Stretford facility at Unit 14 has a slight economic advantage over the individual Stretford units. However, the consolidation of 330 MW of generating capacity with a single Stretford unit, and the hazardous terrain and complex piping network, makes this combination unattractive.

5.5 Vent Gas Abatement - Units 1-6

Several alternatives of Stretford facilities for removing the hydrogen sulfide from the vent gas discharged from Units 1-6 were studied. The various alternatives considered and discussed in detail in successive sections are: 1) Processing the vent gas from Units 1-6 at a common Stretford facility. Two different locations for the Stretford facility were evaluated under this alternative; 2) installing individual Stretford units at each power plant location; 3) erecting gas absorbers at each power plant and pumping the scrubbing solution to a central Stretford facility.

5.5.1 Selected Design Quantities

The noncondensable gas and H_2S flow rates utilized for this study are summarized in Table 5.5-1. These flow rates are consistent with an aftercondenser exhaust gas temperature of 120°F. The gas temperature affects the total flow rate due to the variation in water vapor flow rate caused by the change in partial pressure with temperature.

TABLE 5.5-1

DESIGN NONCONDENSABLE GAS FLOW RATES

	Total (lbm/hr)	H_2S (lbm/hr)
Units 1 and 2	2,839	90
Units 3 and 4	9,726	428
Units 5 and 6	17,680	800
Units 1 - 6	30,245	1,318

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5.5.2 Stretford Process Variations

Three alternative Stretford process variations for treating the vent gas from Units 1-6 were considered in this study; 1) Constructing a single large Stretford facility accommodating the gases from all six power generating units. The gases would be pressurized with stainless steel gas blowers located at each power plant and transported via stainless steel pipe to the common Stretford facility. 2) Building three separate Stretford units near the power plants, serving only the adjacent power plant. 3) Locating gas scrubbers at each of the three power plants and pumping the Stretford liquid solution to a single large Stretford facility for solution regeneration.

5.5.2.1 Consolidated Stretford Unit with Gas Blowers

With this Stretford process variation, gas blowers would be located at each of the three power plants. The blowers would provide the native force to propel the gases through stainless steel piping to the Stretford facility. In every case, a 100% standby blower would be installed to provide backup should the primary blower fail. Also, sophisticated blower controls would be required with a gas bypass loop so that the blower would continue to operate in the event of a forced or scheduled outage of one of the generating units located at each plant. The controls would also have to shut down the blowers and power plant if the stainless steel pipe should rupture, spilling lethal hydrogen sulfide gas.

5.5.2.2 Individual Stretford Units

The alternative of installing an individual Stretford unit at each of the three power plant locations was found to be substantially more expensive than the consolidated Stretford facility. The savings realized by eliminating the gas blowers and connecting pipeline do not compensate for the penalty of higher Stretford unit capital costs. The approach of individual Stretford units does allow for greater flexibility in the operation of the abatement facility and power plants. However, the increased operational flexibility would not appear advantageous considering the cost penalty incurred. Additional problems with installation of individual Stretford units are associated with the extensive site preparation required at the Unit 1 and 2 and the Unit 5 and 6 sites.

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5.5.2.3 Individual Gas Scrubbers

The alternative of erecting gas absorbers at each power plant and circulating the scrubbing solution to a central Stretford facility was evaluated for Units 1-6.

Essentially, the concept entails relocating the gas absorber from the large Stretford facility to the individual power plants. The Stretford process downstream of the gas absorber section would be unchanged. Then, for the system, regenerated Stretford solution is pumped from the central Stretford facility to the absorber at each power plant. The noncondensable gas is scrubbed with the solution in the absorber. The H_2S rich solution is then pumped back to the Stretford unit for processing.

This system has some apparent advantages over the consolidated system with high grade blowers and a stainless steel collection network. Smaller diameter carbon steel pipe could be used for the liquid circulation system as opposed to the noncondensable gas pipe. This savings is partially offset by the fact that two liquid lines must run between the Stretford facility and the power plant, a supply and a return line. Another advantage of the liquid circulation concept is that some of the pumping energy could be recaptured from the liquid stream with a regenerative hydraulic turbine. The individual absorber system would also be inherently safer for operating personnel since there would be no dangerous H_2S gas released in the event of a pipeline break.

The levelized annual cost of the gas scrubber system was compared to the costs of the alternative gas blower consolidated system and the individual Stretford units discussed in previous sections. The levelized annual cost associated with the gas scrubber system is documented in Table 5.5-5.

This analysis indicates little difference in the levelized annual costs of the individual gas scrubber concept and the gas blower systems. Though the gas scrubber system cannot be preferentially recommended at this point, the liquid circulation approach does merit further investigation in a final design stage.

5.5.2.4 Cost Comparison of Stretford Process Variations

The three Stretford process variations are compared on an economic basis in Tables 5.5-2, 5.5-4 and 5.5-5. Note that

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constructing individual Stretford units is the most expensive alternative and can be eliminated. The gas blower and gas scrubber approaches were both evaluated based on locating the consolidated Stretford facility adjacent to the Unit 4 cooling tower. The annual levelized costs for these alternative Stretford process variations are very close. The gas scrubber approach is economically attractive but would require further detailed study before it could be preferentially recommended. The gas blower approah is considered to be the economic approach at this time taking all factors into account. The gas blower approach is studied and costs developed in greater detail in the following subsections.

TABLE 5.5-2

COST ITEMS ASSOCIATED WITH STRETFORD LOCATION AT UNIT 4

Consolidated Stretford Facility at Unit 4
Stretford Maintenance (2% of Capital)
Stretford Chemical Cost Including Salt Purge
Stretford Steam Cost (5,300 lbm/hr.)
Stretford Electrical Energy Cost (1,065 kW)
Noncondensable Gas Blowers Installed Cost at Units 1 & 2 and 5 & 6
Noncondensable Gas Blower Electrical Energy Cost (115 kW)
Noncondensable Gas S. S. Piping Installed Cost
Removal of Existing Abatement Equipment at Unit 4

Total Levelized Annual Cost	$3,519,698

TABLE 5.5-3

COST ITEMS ASSOCIATED WITH STRETFORD LOCATION AT UOC SCRAP YARD

Consolidated Stretford Facility at Union Oil Company's Scrap Yard
Stretford Maintenance (2% of Capital)
Stretford Chemical Cost Including Salt Purge
Stretford Steam Cost (5,300 lbm/hr.)
Stretford Electrical Energy Cost (1,065 kW)
Noncondensable Gas Blowers Installed Cost at Units 1 & 2, 3 & 4, and 5 & 6
Noncondensable Gas Blower Energy Cost (110 kW)
Noncondensable Gas S. S. Piping Installed Cost
Decrease in Replacement Energy Cost Due to Shorter Construction Schedule (Deduct)

Total Levelized Annual Cost	$3,247,365

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TABLE 5.5-4

COST ITEMS ASSOCIATED WITH INDIVIDUAL STRETFORD UNITS

Stretford Facility at Unit 1 & 2	
Stretford Facility at Unit 3 & 4	
Stretford Facility at Unit 5 & 6	
Total Stretford Maintenance (2% of Capital)	
Total Stretford Chemical Cost Including Salt Purge	
Total Stretford Steam Cost (5,300 lbm/hr.)	
Total Stretford Electrical Energy Cost (1,065 kW)	
Noncondensable Gas S. S. Piping Installed Cost	
Removal of Existing Abatement Equipment at Unit 4	
Total Levelized Annual Cost	$4,253,967

TABLE 5.5-5

COST ITEMS ASSOCIATED WITH INDIVIDUAL GAS SCRUBBERS

Consolidated Stretford Facility at Unit 4 (less scrubbers)	
Scrubbers at Unit 1 & 2, Unit 3 & 4, and Unit 5 & 6	
Excess Chemical Inventory in Pipelines	
Stretford Maintenance (2% of Total Capital)	
Stretford Chemical Cost Including Salt Purge	
Stretford Steam Cost (5,300 lbm/hr.)	
Stretford Electrical Energy Cost (1,065 kW)	
Liquid C. S. Piping Installed Cost	
Pumps Including Regenerative Turbines	
Pump Net Electrical Energy Cost	
Removal of Existing Abatement Equipment at Unit 4	
Total Levalized Annual Cost	$3,421,604

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5.5.3 Consolidated Stretford Sites for Units 1-6 with Gas Blowers

An economy of scale exists for the capital cost of the Stretford units which results in a substantial savings for consolidating the first six power plants with a central Stretford facility.

5.5.3.1 Site At Units 3 and 4 Drawing SK-006 (Alternative No. 1)

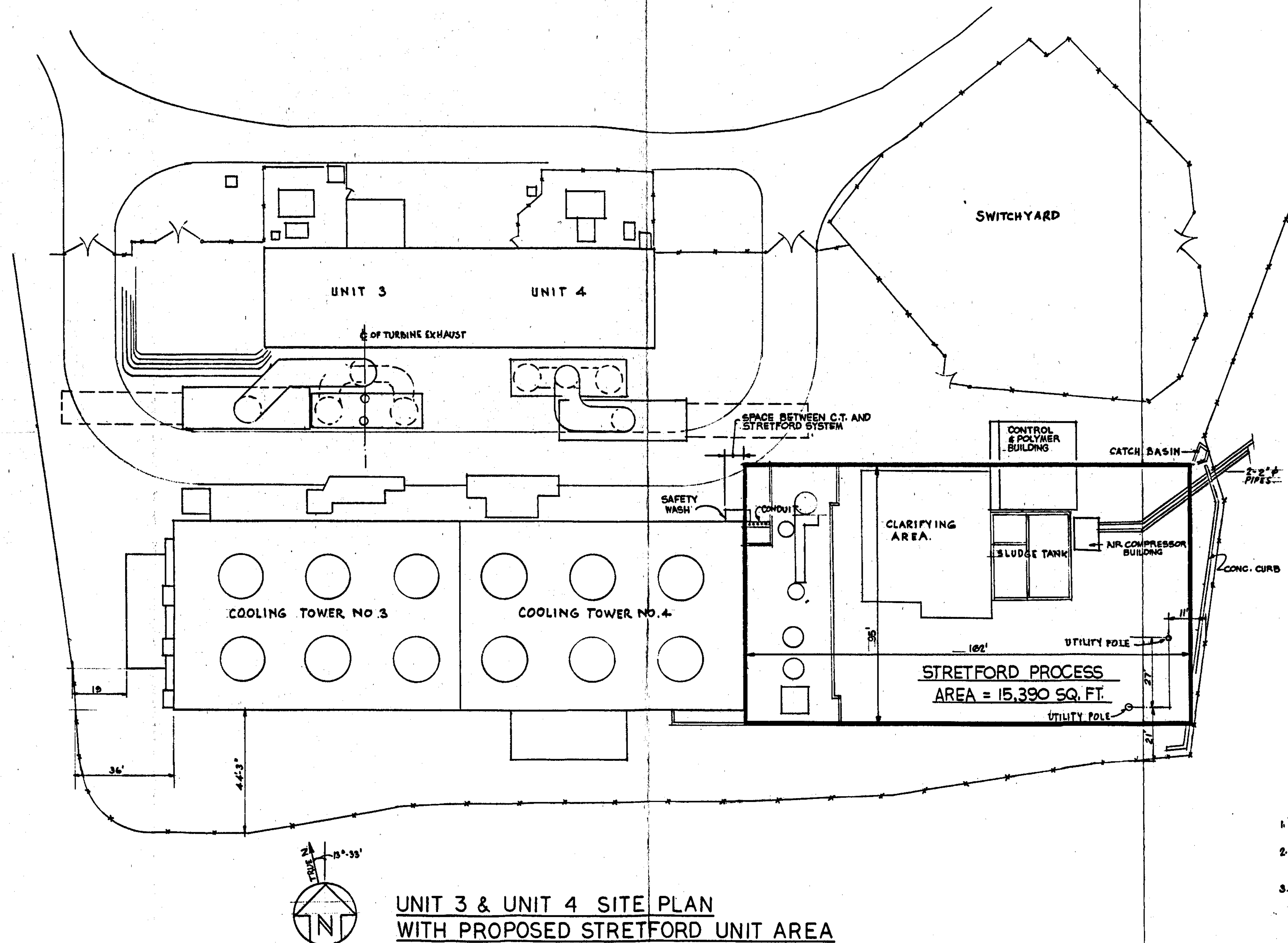
A Streford facility of the size quoted by the vendors could be located due east of the Unit 4 cooling tower where an existing abatement facility is currently operating. Note from Drawing SK-006 that the dimensions of the Stretford unit would have to be modified to allow for clearance between the Unit 4 cooling tower and the Stretford facility. Sufficient area is available between the existing abatement facility and the fence along the southern border of the power plant to allow for expansion of the Stretford process in this direction to provide the desired open space near the cooling tower.

The existing abatement facility serves Units 3, 4, 5 and 6. Thus, it is assumed that these power plants would have to be shut down during the construction of the Stretford unit if the existing abatement system is removed. The net loss in generating capacity is affected by the construction schedule which influences the site selection. If the Stretford unit were located at this site the condenser replacement at Units 3, 4, 5 and 6 would be scheduled concurrently with the Stretford construction. The condensers at Units 1 and 2 would be replaced at a later date after Units 3, 4, 5 and 6 are back on the electrical grid. There is a cost savings associated with the decrease in energy replacement cost with a reduced overall electrical generation outage time which can be achieved by locating the Stretford facility other than at the existing abatement area.

5.5.3.2 Site At Union Oil Co. Surplus Equipment Yard

Drawing SK-005A & B (Alternative No. 2)

The second site considered for the construction of a Stretford facility is located southwest of Units 5 and 6. Union Oil Company is currently using this parcel to store surplus equipment, thus, this site would require that the appropriate rights-of way be secured from Union Oil Co. A second disadvantage of this site is that the soil is geologically unstable. This would required more extensive site preparation and perhaps more



UNIT 3 & UNIT 4 SITE PLAN WITH PROPOSED STRETFORD UNIT AREA

NOTES:

1. STRETFORD UNIT TO BE PLACED IN INDICATED AREA.
2. AREA 15,390 SQ. FT RESULTS FROM DIMENSIONS 95' x 162' AS REPORTED BY PARSONS FOR STRETFORD EQUIPMENT.
3. REMOVE EXISTING EQUIPMENT.

REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.
1		6/18/79	ISSUED FOR MILESTONE REPORT #3	G.O.			
0		5/31/79	ISSUED FOR MILESTONE REPORT #1	E.A.	[illegible]	LFN	[illegible]

REFERENCE DRAWINGS

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

SCALE 1" = 20'-0" DATE 5-25-79

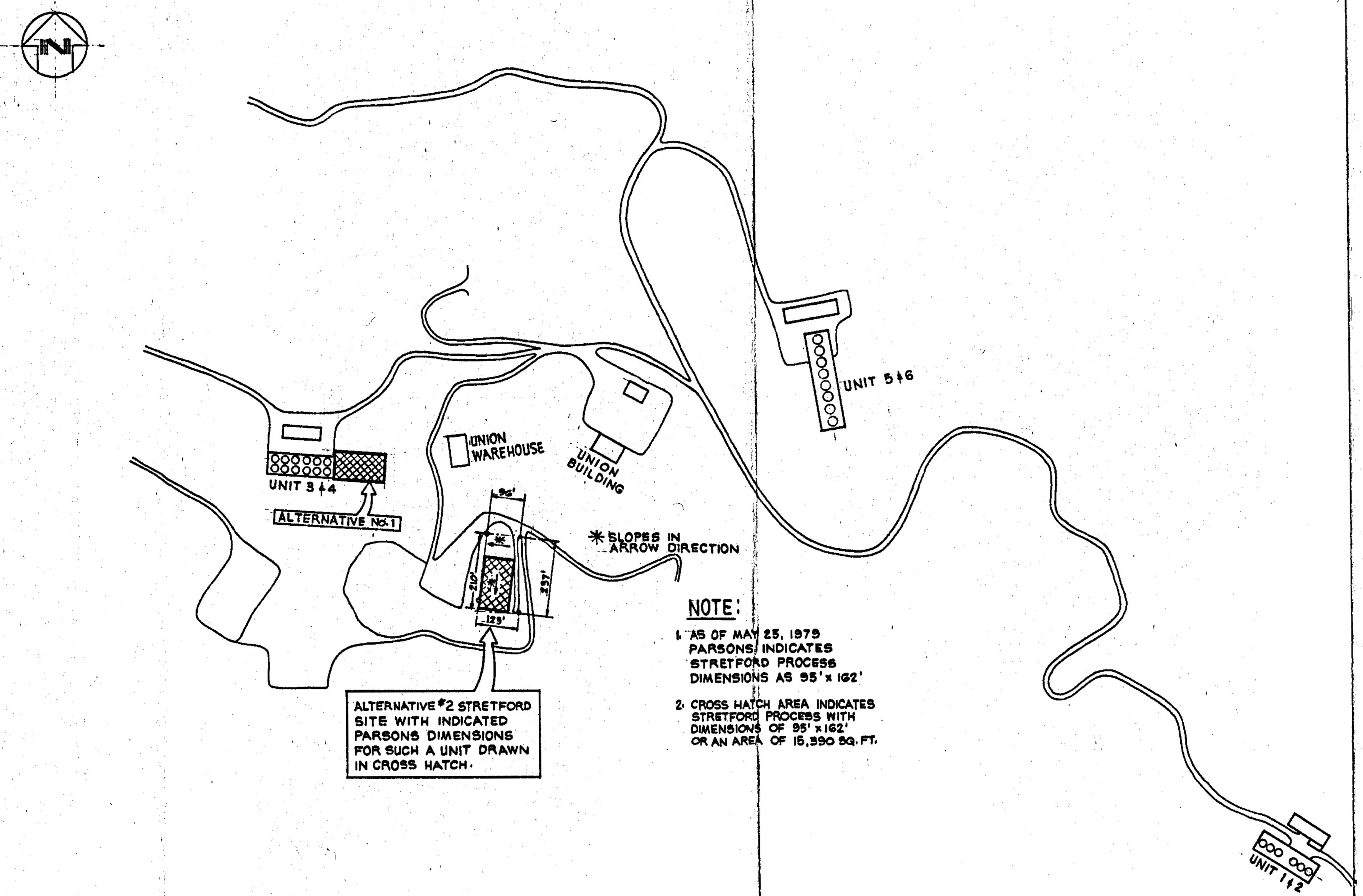
DR. E.A. CHK. LFN ENG. EJM APPROVED [illegible]

APPROVALS

DATE
DATE

PG and E RETROFIT STUDY
UNITS 1 THRU 6
SITE PLAN - STRETFORD ALTERNATIVE No. 1
CONSOLIDATION OF UNITS 1 THRU 6

JOB NO. S 79007 — SK-006 — 1



NOTE:

1. AS OF MAY 25, 1979 PARSONS INDICATES STRETFORD PROCESS DIMENSIONS AS 95' x 162'
2. CROSS HATCH AREA INDICATES STRETFORD PROCESS WITH DIMENSIONS OF 95' x 162' OR AN AREA OF 15,390 SQ. FT.

REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.
0		6/18/79	ISSUED FOR MILESTONE REPORT #3	G.O.	LFW	LFW	[illegible]

REFERENCE DRAWINGS

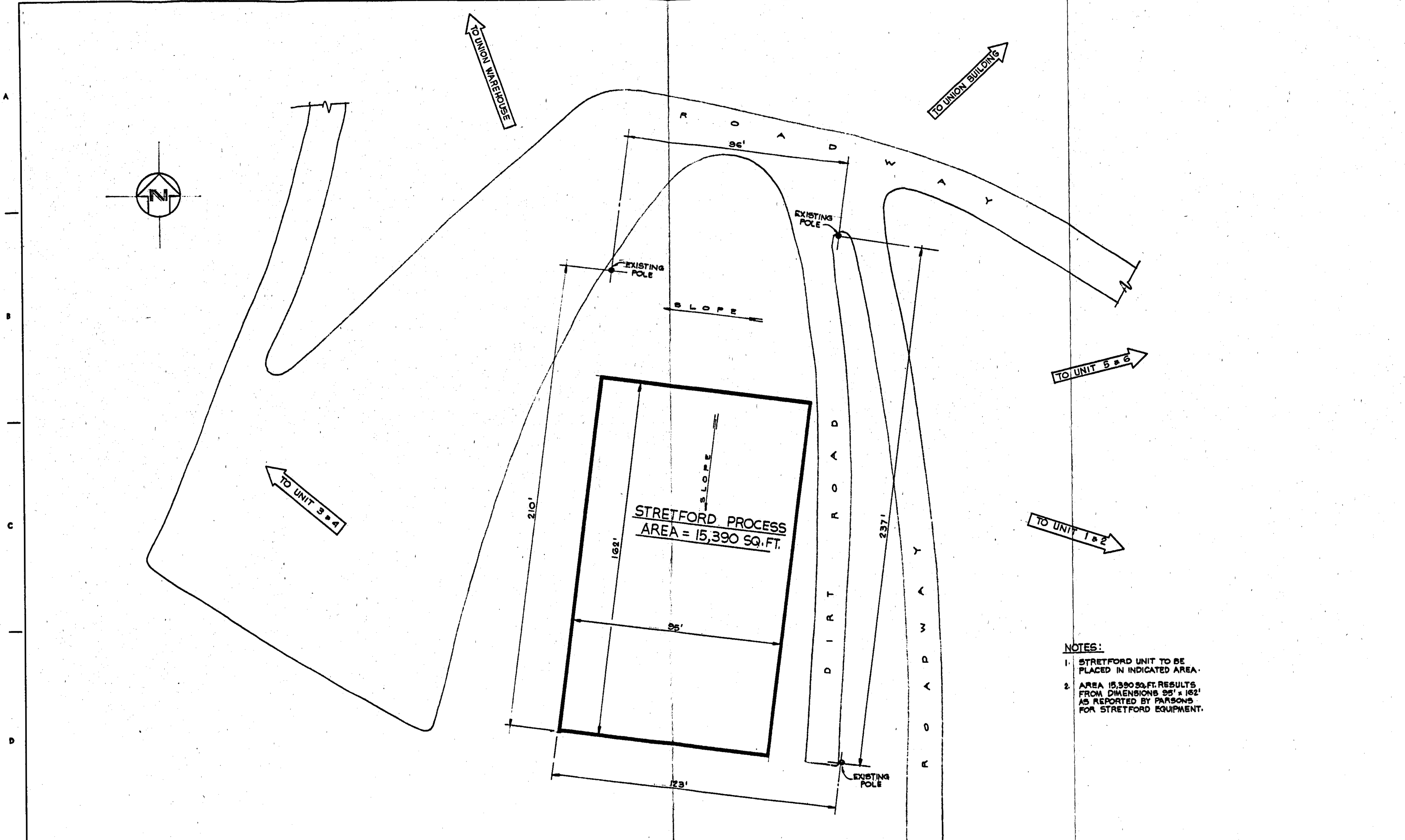
ROGERS ENGINEERING CO., INC.
ENGINEERS - ARCHITECTS
111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94111

SCALE 1" = 200' DATE 6-18-79
DR. G.O. CHK. LFW ENG. EJM APPROVED [signature]

APPROVALS
DATE
DATE

PG and E RETROFIT STUDY
UNITS 1 THRU 6
SITE PLAN-STRETFORD PLANT LOCATIONS ALTERNATIVE No. 1 & 2
CONSOLIDATION OF UNITS 1 THRU 6

JOB NO. S79007
SK-005A | 0



NOTES:

1. STRETFORD UNIT TO BE PLACED IN INDICATED AREA.
2. AREA 15,390 SQ.FT. RESULTS FROM DIMENSIONS 95' x 162' AS REPORTED BY PARSONS FOR STRETFORD EQUIPMENT.

REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO.	APPR.
0			ISSUED FOR MILESTONE REPORT #3	CcO	JZS	LFW	

REFERENCE DRAWINGS

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

SCALE 1" = 20' DATE 6-27-79
DR. CcO. CHK. LFW ENG. JZS APPROVED [signature]

APPROVALS
DATE
DATE

PG and E RETROFIT STUDY
UNITS 1 THRU 6
SITE PLAN STRETFORD ALTERNATIVE No. 2
CONSOLIDATION OF UNITS 1 THRU 6

JOB NO. S79007

SK-005B 0

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complex equipment foundations, for the construction of a Stretford facility in this area.

The site remains attractive for the following reasons, however. First, the proximity to Units 5 and 6, the largest noncondensable gas contributor of the three power plants, would reduce the piping costs. The capital cost of the blowers would partially offset this savings since a blower would be required at Units 3 and 4 to transport the gases to the Stretford unit. There would also be a slight savings in blower power requirements due to the reduced transit distance from Units 1, 2, 5 and 6.

The second reason that the scrap yard site is attractive is that the Stretford facility would be constructed without interrupting the operation of Units 3, 4, 5 and 6 simultaneously as is required for the site at Unit 4 where existing abatement equipment is located. One possible construction schedule for the scrap yard site would be to replace the condenser at Units 5 and 6 while the Stretford facility is being constructed. After Units 5 and 6 and the Stretford unit are completed, Units 3 and 4 would then be retrofitted. The condenser at Units 1 and 2 would be replaced after Units 3 and 4 are again generating power.

5.5.3.3 Site Comparison

Two alternative sites for the location of the large Stretford facility were considered in this study; 1) The area due east of the Unit 4 cooling tower where the existing abatement facility is located, and 2) between Units 3 & 4 and Units 5 & 6 where Union Oil Co. is currently storing surplus equipment.

An economic comparison of the two alternative sites is contained in Tables 5.5-2 and 5.5-3. This analysis indicates an economical advantage of a Stretford facility located at the Union Oil Co.'s surplus equipment yard.

5.5.4 Select System Cost Detail

Table 5.5-6 summarizes the GM cost of installing a Stretford facility at the Union Oil Co. surplus equipment yard. This estimate includes the installation of the required gas blowers and stainless steel piping.

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TABLE 5.5-6

SUMMARY COST ESTIMATE

STRETFORD UNIT FOR POWER PLANT UNITS 1-6

Account	Description	Equip. & Mat'l	Labor	Total
54-29	H_2S Abatement	$11,872,723	$1,164,545	$13,037,268
365	Engineering & Other	1,394,520	0	1,394,520
	Subtotals	$13,267,243	$1,164,545	$14,431,788
	GM Factor (21.76%)			$ 3,140,357
	Subtotal (GM 1979)			$17,572,146
	Escalation (28.55%)			5,016,847
	Total GM Estimate			$22,588,993

The detailed development of the cost estimate is presented in Table 5.5-7.

ROGERS ENGINEERING CO.,INC. COST ESTIMATE

JOB NAME-STRFD 1-6 JOB NO.-S79007 CLIENT-P G AND E ESTIMATE DATE- 18 JULY 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-293-1	EQ STRETFORD 1-6	10108840.	0.	0.	10108840.
54-293-2	EQ BLOWER 1&2	44520.	0.	0.	44520.
54-293-3	INSTALL BLOWER	139920.	55912.	2405.	195832.
54-293-4	EQ BLOWER 3&4	50880.	0.	0.	50880.
54-293-5	INSTALL BLOWER 3&4	152640.	55912.	2405.	208552.
54-293-6	EQ BLOWER 5&6	76320.	0.	0.	76320.
54-293-7	INSTALL BLOWER 5&6	184440.	65230.	2806.	249670.
54-297-1	NC GAS PIPE 1-6	534240.	0.	0.	534240.
54-297-2	INSTALL PIPE 1-6	101760.	838674.	36072.	940434.
54-291-1	FOUNDATION BLWR 1&2	890.	4193.	180.	5084.
54-291-2 F	OUNDATION BLWR 3&4	890.	4193.	180.	5084.
54-291-3	FOUNDATION BLWR 5&6	890.	4193.	180.	5084.
54-293-18	R CRANE,TRUCKS 1-6	31800.	18637.	802.	50437.
54-294-1	EQ UNIT 3 ELEC	65126.	0.	0.	65126.
54-294-2	INSTALL & MISC MTL	26076.	63832.	2745.	89908.
54-296-1	GAS BLWR 1&2 ELEC	5724.	2982.	128.	8706.
54-296-4	GAS BLWR 3&4 ELEC	3053.	1864.	80.	4917.
54-296-3	GAS BLWR 5&6 ELEC	13992.	4659.	200.	18651.
54-299-1	CONTROLS BLOWER 1&2	101760.	13978.	601.	115738.
54-299-2	CONTROLS BLOWER 3&4	108120.	13978.	601.	122098.
54-299-3	CONTROLS BLOWER 5&6	120840.	16308.	701.	137148.
ACCOUNT TOTAL		11872723.	1164545.	50088.	13037269.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
365-1	FIELD CONSTRUCTION	651840.	0.	0.	651840.
365-2	GENRL ENG	391080.	0.	0.	391080.
365-3	OTHR ENGINEERING	351600.	0.	0.	351600.
ACCOUNT TOTAL		1394520.	0.	0.	1394520.

ROGERS ENGINEERING CO., INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111

JOB NO. S-79007

DG-023

TABLE 5.5-7
COST ESTIMATE DETAIL
STRETFORD INSTALLATION, UNITS 1 - 6

DRAWING NO.

REV.

SHEET 1 OF 1

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5.6 Vent Gas Abatement - Units 7, 8 and 11

Units 7, 8 and 11 were grouped together in this study due to the geographic proximity of the power plants and the magnitude of their combined generating capacity. It was thought that the physical location of the power plants was such that a capital savings in the cost of a large Stretford facility could offset the increased piping costs. This is verified in later sections of this report. Two different Stretford locations and the alternative of building individual Stretford units are compared in Tables 5.6-2, -3, and 4. This comparison was used to select one alternative for further study.

5.6.1 Selected Design Quantities

The noncondensable gas and H_2S flow rates utilized for this study are summarized in Table 5.6-1.

TABLE 5.6-1

DESIGN NONCONDENSABLE GAS FLOW RATES

	Total (lbm/hr)	H_2S (lbm/hr)
Units 7 and 8	11,282	490
Unit 11	18,649	867
Unit 7, 8 and 11	29,931	1,357

5.6.2 Stretford Process Variations

5.6.2.1 Consolidated Stretford with Gas Blowers

The Stretford process variation of installing gas blowers to transport the vent gases to a common Stretford facility serving Units 7, 8 and 11 was evaluated. The gas blower and piping system would be similar to the recommended installation for Units 1-6 discussed in Section 5.5.2.1.

5.6.2.2 Individual Stretford Units

The Stretford unit capital costs quoted by the vendors are such that an overall cost advantage over individual Stretford units can be realized by combining Units 7, 8 and 11 with a common Stretford facility. A comparison of individual Stretford units located at each power plant versus the single Stretford facil-

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ity serving Units 7, 8 and 11 is included in Tables 5.6-4 and 5.6-3. Note that the consolidated Stretford facility has the least expensive annualized cost and is the recommended vent gas abatement installation discussed in the following section.

TABLE 5.6-2

COST ITEMS ASSOCIATED WITH STRETFORD LOCATION AT UNIT 8

Consolidated Stretford Facility at Unit 8
Stretford Maintenance (2% of Capital)
Stretford Chemical Cost Including Salt Purge
Stretford Steam Cost (5,500 lbm/hr.)
Stretford Electrical Energy Cost (1,095 kW)
Noncondensable Gas Blowers Installed Cost at Unit 11
Noncondensable Gas Blower Energy Cost (150 kW)
Noncondensable Gas S. S. Piping Installed Cost

Total Levelized Annual Cost	$3,618,195

TABLE 5.6-3

COST ITEMS ASSOCIATED WITH STRETFORD LOCATION AT UNIT 11

Consolidated Stretford Facility at Unit 11
Stretford Maintenance (2% of Capital)
Stretford Chemical Cost Including Salt Purge
Stretford Steam Cost (5,500 lbm/hr.)
Stretford Electrical Energy Cost (1,095 kW)
Noncondensable Gas Blowers Installed Cost at Units 7 and 8
Noncondensable Gas Blower Energy Cost (90 kW)
Noncondensable Gas S. S. Piping Installed Cost
Removal of Existing Abatement Equipment at Unit 11

Total Levelized Annual Cost	$3,559,894

TABLE 5.6-4

COST ITEMS ASSOCIATED WITH INDIVIDUAL STRETFORD UNITS

Stretford Facility at Unit 7 & 8
Stretford Facility at Unit 11
Total Stretford Maintenance (2% of Capital)
Total Stretford Chemical Cost Including Salt Purge
Total Stretford Steam Cost (5,500 lbm/hr.)
Total Stretford Electrical Energy Cost (1,095 kW)
Noncondensable Gas S. S. Piping Installed Cost
Removal of Existing Abatement Equipment at Unit 11

Total Levelized Annual Cost	$3,863,323

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5.6.3 Consolidated Stretford Sites

Two alternative sites for the location of the Stretford facility serving Units 7, 8 and 11 were considered.

5.6.3.1 Site at Units 7 and 8
Drawing SK-0027 (Alternative No. 2)

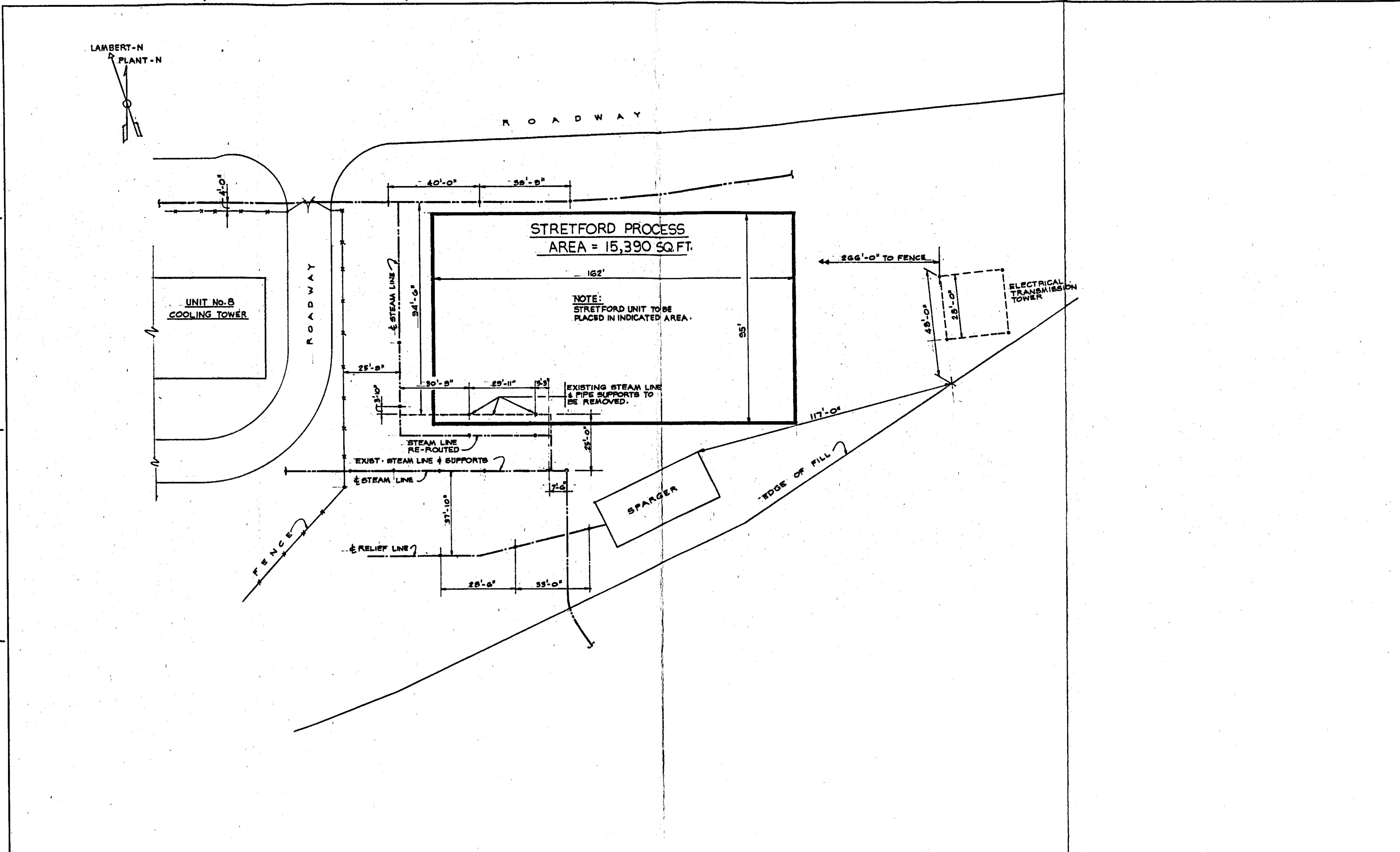
The level area located east of the Unit 8 cooling tower is an attractive site for a Stretford facility. This site would require a minimal amount of preparation prior to the installation of the abatement unit. This proposed site is not currently occupied by any abatement equipment and, hence, would not adversely affect the total generating capacity outage time.

5.6.3.2 Site at Unit 11
Drawing SK-0028 (Alternative No. 1)

The proposed Stretford site at Unit 11 requires the removal of the existing abatement equipment at this location. There is a small cost penalty associated with the removal work. However, since the time required to replace the condenser at Unit 11 exceeds the construction schedule of the Stretford facility there is not an additional penalty for lost power generation due to the removal of the existing abatement equipment.

The physical dimensions of the Stretford unit quoted by the vendors are such that the abatement unit would not fit into the long narrow area adjacent to the cooling tower. Further interaction with the process licensees would be required to ascertain whether the Stretford unit could be redesigned into a longer, narrower configuration. Otherwise, the main steam supply line and sparger pit would have to be relocated. A small portion of the hillside would also have to be leveled to accommodate a Stretford unit with the quoted dimensions.

The advantage of locating the Stretford facility adjacent to Unit 11 is that the size of the pipeline from Unit 7 and 8 would be smaller for this site selection than for the alternative location. This is due to the fact that total noncondensable gas flow rate from Unit 11 is 1.65 times the discharge from Units 7 and 8. A savings in blower energy cost would also be realized for the site at Unit 11. This results in a lower levelized annual cost for the Stretford site at Unit 11. A listing of the cost items associated with the two alternative sites is contained in Table 5.6-2 and Table 5.6-3.



		REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.
		0		7/18/79	ISSUED FOR MILESTONE REPORT #3	C.O.	JF	LFW	
REFERENCE DRAWINGS									

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111 PINE STREET, SAN FRANCISCO, CALIFORNIA 94111

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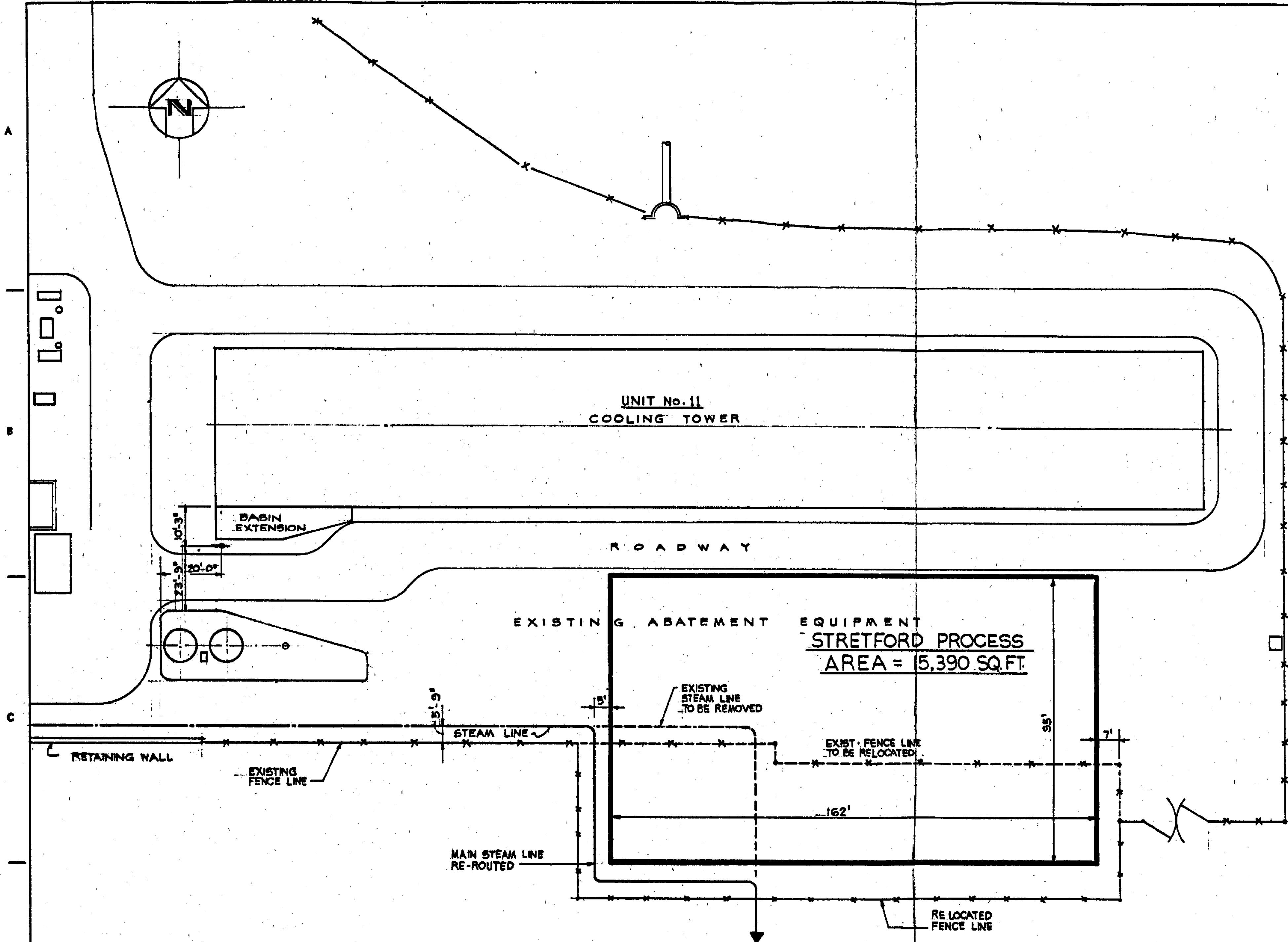
DATE

PG and E RETROFIT STUDY
UNITS 7 & 8 SITE
SITE PLAN-STRETFORD ALTERNATIVE No. 2
CONSOLIDATION OF UNITS 7 8 & 11

JOB NO. S79007 SK-027 0



NOTES:

1. STRETFORD UNIT TO BE PLACED IN INDICATED AREA AFTER RE-LOCATION OF EXISTING FENCE AND MAIN STEAM PIPING.
2. AREA 15,390 SQ.FT. RESULTS FROM DIMENSIONS 95' × 162' AS PER REPORTED BY PARSONS FOR STRETFORD EQUIPMENT.

REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.
0		4/18/79	ISSUED FOR MILESTONE REPORT #3	GO.	JF	LFW	

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DATE

PG and E RETROFIT STUDY
UNIT No. 11 SITE
SITE PLAN-STRETFORD ALTERNATIVE No. 1
CONSOLIDATION OF UNITS 7, 8 & 11

JOB NO: S79007
SK-028
0

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5.6.4 Cost Estimate

The estimated GM cost for a consolidated Stretford facility located at Unit 11 (the recommended alternative) is given in the following summary cost estimate Table 5.6-5. This estimate is detailed in the computer output in Table 5.6-6. All of the associated capital and installation costs are included in the estimate.

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TABLE 5.6-5

SUMMARY COST ESTIMATE

STRETFORD UNIT FOR POWER PLANT UNITS 7, 8 & 11

Account	Description	Equip. & Mat'l	Labor	Total
54-29	H_2S Abatement	$11,789,716	$1,323,707	$13,113,423
365	Engineering & Ohter	1,230,120	0	1,230,120
	Subtotals	$13,019,836	$1,323,707	$14,343,543
	GM Factor (21.76%)			$ 3,121,154
	Subtotal (GM 1979)			$17,464,697
	Escalation (28.55%)			4,986,170
	Total GM Estimate			$22,450,867

ROGERS ENGINEERING CO.,INC. COST ESTIMATE

JOB NAME-STRFD 11 JOB NO.-S79007 CLIENT-P G AND E ESTIMATE DATE- 18 JULY 79

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
54-291-4	FOUNDATION BLWR 7&8	890.	4193.	180.	5084.
54-293-8	FQ STRETFORD 7-8-11	10528909.	0.	0.	10528909.
54-293-9	EQ BLOWER 7&8	63600.	0.	0.	63600.
54-293-10	INSTALL BLOWER 7&8	165360.	65230.	2806.	230590.
54-293-20	CH2M REMOVAL AT 11	19080.	139779.	6012.	158859.
54-294-1	EQ UNIT 11 ELEC	11194.	0.	0.	11194.
54-294-2	INSTALL ELECT & MISC	50880.	52184.	2244.	103064.
54-296-1	GAS BLWR 7&8 ELEC	2162.	2330.	100.	4492.
54-297-3	NC GAS PIPE 7-8-11	674160.	0.	0.	674160.
54-297-4	INSTALL PIPE 7-8-11	127200.	1025046.	44088.	1152246.
54-293-19	R CRANE,TRUCKS 7-11	31800.	18637.	802.	50437.
54-299-4	CONTROLS BLWR 7&8	114480.	16308.	701.	130788.
ACCOUNT TOTAL		11789716.	1323707.	56934.	13113423.

ITEM NO.	DESCRIPTION	MATL&EQPT	INSTALL	MANHOURS	TOTAL
365-1	CONST FIELD	655200.	0.	0.	655200.
365-2	GENRL ENG	393360.	0.	0.	393360.
365-3	OTHR ENGINEERING	181560.	0.	0.	181560.
ACCOUNT TOTAL		1230120.	0.	0.	1230120.

ROGERS ENGINEERING CO., INC.
111 PINE STREET
SAN FRANCISCO, CALIF. 94111
JOB NO. S-79007
DG-023

TABLE 5.6-6
COST ESTIMATE DETAIL
STRETFORD INSTALLATION, UNITS 7, 8 & 11

DRAWING NO. REV.

SHEET 1 OF 1

5.7 Vent Gas Abatement Units 9, 10 and 12

The geographical proximity of Units 9 and 10 to Unit 12 made it desirable to consider combining these power plants with a common Stretford facility. As with the consolidation of Unit 7, 8 and 11, an economic trade-off study was initiated to determine whether the capital savings in the cost of the large Stretford facility would offset the increased expenditure for piping and associated costs. Two different locations for this Stretford unit and the associated costs are compared. The alternatives of constructing individual Stretford units, and of enlarging the Stretford unit under construction at Unit 14 to accommodate the noncondensable gases from Units 9, 10 and 12 are also evaluated.

5.7.1 Selected Design Quantities

The noncondensable gas and H_2S flow rates utilized for this study are summarized in Table 5.7-1.

TABLE 5.7-1

DESIGN NONCONDENSABLE GAS FLOW RATES

	Total (lbm/hr)	H_2S (lbm/hr)
Units 9 and 10	11,282	78
Unit 12	11,124	95
Units 9, 10 and 12	22,406	173

5.7.2 Stretford Process Variations

5.7.2.1 Consolidated Stretford with Gas Blowers

The cost of consolidating Units 9, 10 and 12 with a single large Stretford facility was evaluated. This would require stainless steel blowers to transport the gas to the Stretford facility. The blower design requirements are discussed in Section 5.5.2.1.

5.7.2.2 Individual Stretford Units

Vendor quotations were obtained from the Stretford process licensees that enabled the comparison of individual Stretford units to a single consolidated abatement facility serving Units

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9, 10 and 12. The items that were included in this economic comparison and the resulting levelized annual cost are provided in Table 5.7-4.

Note that the cost of building individual Stretford units at each power plant is lower than the cost of consolidating Unit 9, 10 and 12 with a central Stretford unit. Thus, the recommended abatement system for Units 9, 10 and 12 is to construct individual Stretford units at each of the two power plants.

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TABLE 5.7-2

COST ITEMS ASSOCIATED WITH STRETFORD LOCATION AT UNIT 9 & 10

Consolidated Stretford Facility at Unit 9 & 10	
Stretford Maintenance (2% of Capital)	
Stretford Chemical Cost Including Salt Purge	
Stretford Steam Cost (1,500 lbm/hr.)	
Stretford Electrical Energy Cost (300 kW)	
Noncondensable Gas Blowers Installed Cost at Unit 12	
Noncondensable Gas Blower Electrical Energy Cost (72 kW)	
Noncondensable Gas S. S. Piping Installed Cost	
Total Levelized Annual Cost	$1,932,089

TABLE 5.7-3

COST ITEMS ASSOCIATED WITH STRETFORD LOCATION AT UNIT 12

Consolidated Stretford Facility at Unit 12	
Stretford Maintenance (2% of Capital)	
Stretford Chemical Cost Including Salt Purge	
Stretford Steam Cost (1,500 lbm/hr.)	
Stretford Electrical Energy Cost (300 kW)	
Noncondensable Gas Blowers Installed Cost at Units 9 and 10	
Noncondensable Gas Blower Energy Cost (72 kW)	
Noncondensable Gas S. S. Piping Installed Cost	
Removal of Existing Abatement Equipment at Unit 12	
Total Levelized Annual Cost	$1,954,064

TABLE 5.7-4

COST ITEMS ASSOCIATED WITH INDIVIDUAL STRETFORD UNITS

Stretford Facility at Unit 9 & 10	
Stretford Facility at Unit 12	
Total Stretford Maintenance (2% of Capital)	
Total Stretford Chemical Cost Including Salt Purge	
Total Stretford Steam Cost (1,800 lbm/hr.)	
Total Stretford Electrical Energy Cost (300 kW)	
Noncondensable Gas S. S. Piping Installed Cost	
Removal of Existing Abatement Equipment at Unit 12	
Total Levelized Annual Cost	$1,726,500

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TABLE 5.7-5

COST ITEMS ASSOCIATED WITH STRETFORD ENLARGEMENT AT UNIT 14

Cost of Enlarging Unit 14 Stretford Facility
Stretford Maintenance Due to Units 9, 10 and 12
Stretford Chemical Cost
Stretford Steam Cost (1,500 lbm/hr.)
Stretford Electrical Energy Cost (300 kW) (Incremental)
Noncondensable Gas Blowers Installed Cost at Units 9, 10 and 12
Noncondensable Gas Blower Energy Cost (145 kW)
Noncondensable S. S. Piping Installed Cost

Total Levelized Annual Cost	$1,656,524

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5.7.3 Consolidated Stretford Sites

The feasibility of locating the Stretford abatement equipment at either power plant locations was evaluated. This consolidated Stretford unit would serve Units 9, 10 and 12.

5.7.3.1 Site at Units 9 and 10 (Drawing SK-030)

A level area suitable for the placement of a Stretford facility exists just north of the Unit 9 and 10 cooling tower within the PGandE fence line. The steam pressure relief sparger pit and associated piping is located in this area and would need to be relocated prior to the installation of the Stretford facility. This site would not require the removal of existing abatement equipment.

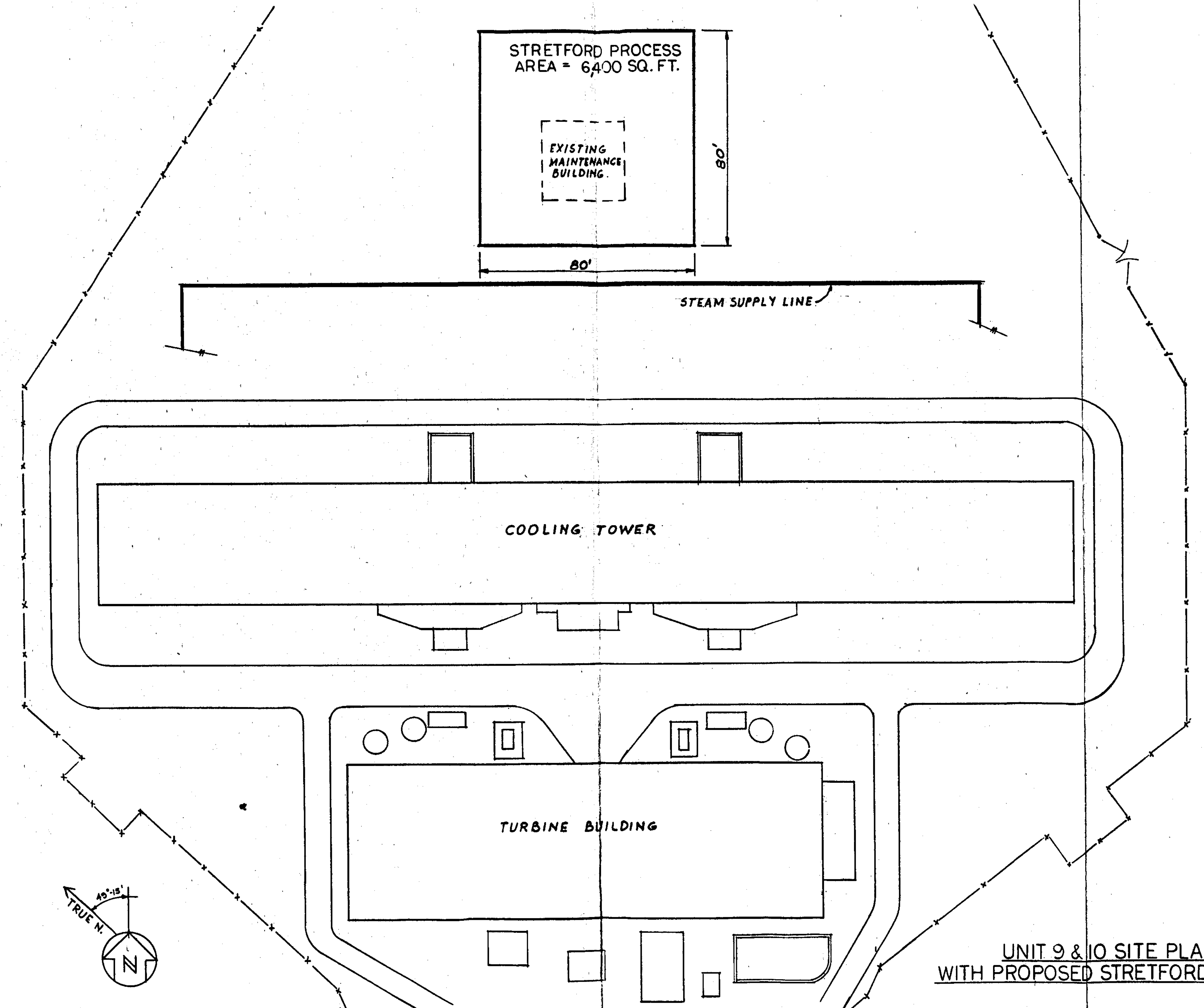
The noncondensable gas flow rate from Units 9 and 10 is nearly the same as the noncondensable gas output from Unit 12. Then for all practical purposes there is no blower and piping cost advantage associated with either power plant location. The pipe size and blower capital and operating costs do not depend on the location of the Stretford unit.

5.7.3.2 Site at Unit 12 (Drawing SK-029)

The site available for construction of the Stretford facility at Unit 12 coincides with the location of the existing abatement equipment adjacent to the cooling tower. Thus, there is a small cost penalty associated with this site due to the cost of removing the existing equipment. However, since the estimated construction time for replacing the condenser in Unit 12 exceeds the time required to remove the existing abatement equipment and construct the Stretford facility, there is no additional power generation loss caused by this equipment removal. Thus, there is no significant difference in the levelized annual costs of the two alternative site locations. Table 5.7-2 and Table 5.7-3 compare these estimated costs.

5.7.3.3 Combining Units 9, 10 and 12 with Unit 14

The possibility of enlarging the Stretford facility under construction at Unit 14 to accommodate the noncondensable gases from Units 9, 10 and 12 was considered in this study. Parsons has stated that the capacity of the Unit 14 Stretford unit



NOTES:
1. STRETFORD UNIT TO BE PLACED IN INDICATED AREA.
2. REMOVE EXISTING BUILDING AND EQUIPMENT.

UNIT 9 & 10 SITE PLAN
WITH PROPOSED STRETFORD UNIT AREA

REFERENCE DRAWINGS	REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO.	APPR.
	1		8/27/79	ISSUED FOR FINAL REPORT	E.A.	JES	LFW	

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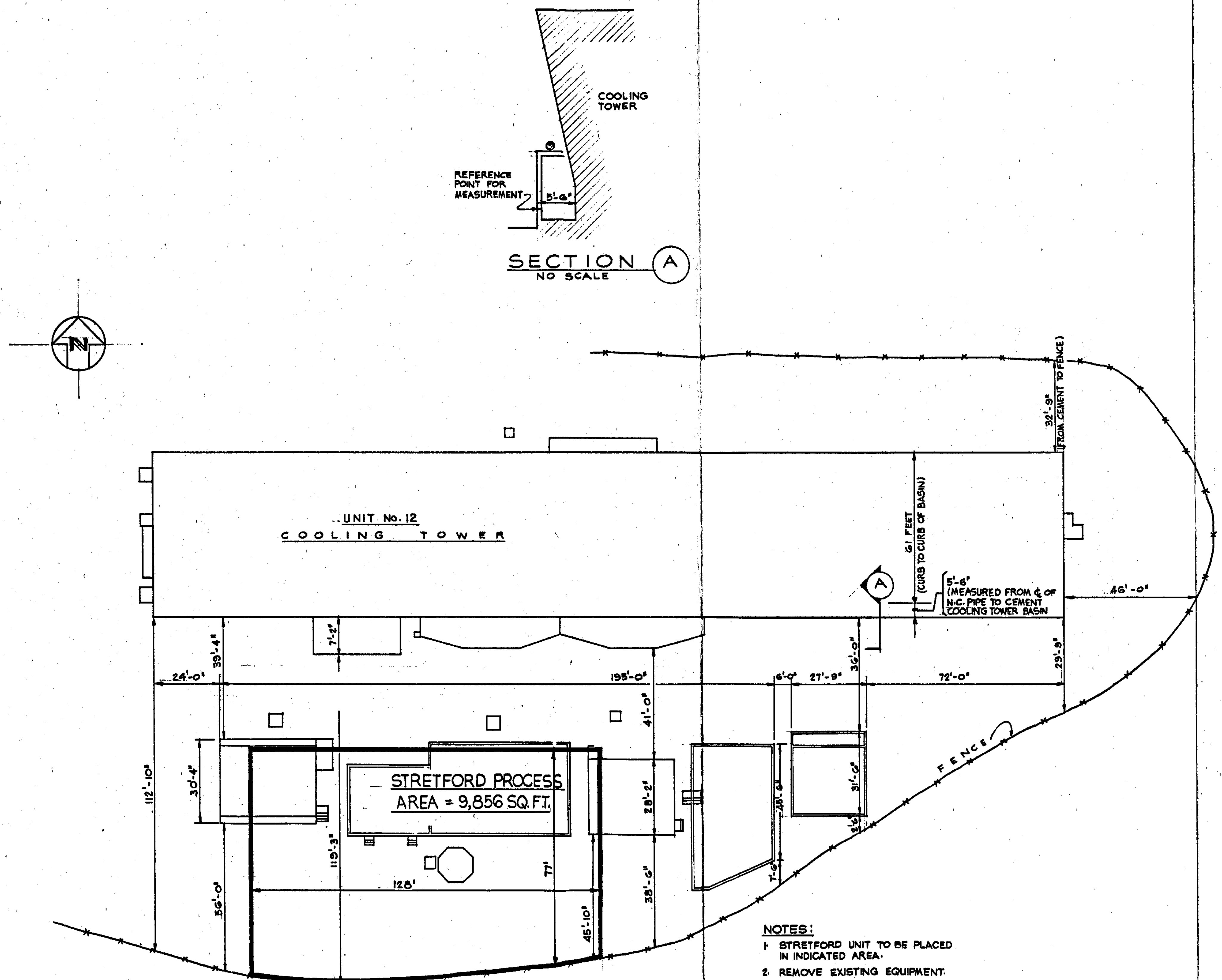
DR. E.A. CHK. JES ENG. LFW APPROVED

APPROVALS
DATE
DATE

PG and E RETROFIT STUDY
UNITS 9 & 10
STRETFORD PROCESS AREA

JOB NO. S-79007 SK-030 1



NOTES:

1. STRETFORD UNIT TO BE PLACED IN INDICATED AREA.
2. REMOVE EXISTING EQUIPMENT.
3. STRETFORD PROCESS AREA IS BASED ON A RECTANGLE AND NOT THE FENCE CONTOUR.

REV.	ZONE	DATE	REVISION	DR.	CHK.	APPR. RECO	APPR.
1		7/20/79	ISSUED FOR FINAL REPORT	E.A.	JJT	LFW	
0		7/18/79	ISSUED FOR MILESTONE REPORT #3	C.O.	JF	LFW	LFW

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DATE

PG and E RETROFIT STUDY
UNIT No. 12 SITE
SITE PLAN - STRETFORD PROCESS PLANT

JOB NO. S79007
SK-029
1

GE 212

could indeed be enlarged without increasing the physical dimensions of the abatement unit. The levelized annual cost of this consolidation along with the items that contribute to this cost are included in Table 5.7-5.

This cost estimate indicates that the alternative of enlarging the Stretford facility at Unit 14 would yield the lowest levelized annual cost of the considered Stretford arrangements. However, the difference between the levelized cost for the Stretford enlargement at Unit 14 and individual Stretford facilities (the closest alternative) is not large. The abatement system with individual Stretford units has a number of advantages that offset this levelized annual cost difference.

There is greater operating flexibility realized with individual Stretford units since Units 9, 10, 12 and 14 would not depend on a single Stretford unit. A loss of generating capacity of 330 MW would result in the event of a forced outage of the Stretford facility. This dependency would not exist with individual Stretford facilities. Also, the extensive noncondensable piping network for Units 9, 10 and 12 down to Unit 14 would be eliminated. This pipeline traverses very steep terrain and poses a safety hazard in the event of pipe breakage. Thus, individual Stretford facilities located at each of the power plants remains the recommended alternative.

5.7.4 Cost Estimate

The GM cost of installing Stretford facilities at Units 9 and 10 and at Unit 12 are given in the following cost estimate summary Tables 5.7-6 and 5.7-7. Computer outputs giving detail on each of these estimates are also included Table 5.7-8.

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TABLE 5.7-6

SUMMARY COST ESTIMATE

STRETFORD UNIT FOR POWER PLANT UNITS 9 & 10

Account	Description	Equip't & Mat'l	Labor	Total
54-29	H_2S Abatement	$ 3,584,280	$620,703	$ 4,204,983
365	Engineering & Other	422,407	0	422,407
	Subtotals	$ 4,006,687	$620,703	$ 4,627,390
	GM Factor (21.76%)			$ 1,006,920
	Subtotal			$ 5,634,310
	Escalation (28.55%)			$ 1,608,596
	Total GM Estimate			$ 7,242,906

TABLE 5.7-7

SUMMARY COST ESTIMATE

STRETFORD UNIT FOR POWER PLANT UNIT 12

Account	Description	Mat'l & Equip.	Labor	Total Dollars
54-29	H_2S Abatement	$ 3,763,567	$651,751	$ 4,415,318
365	Engineering & Other	443,536	-	443,536
	Subtotal	$ 4,207,103	$651,751	$ 4,858,854
	GM Factor (21.76%)			1,057,287
	Subtotal (GM 1979)			$ 5,916,141
	Escalation (28.55%)			1,689,058
	Total GM Estimate			$ 7,605,199

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5.8 Construction Schedule

In order to schedule and carry out the Surface Condenser/ Stretford Process retrofit project at the Geysers Power Plant, Units 1 through 12, a planning document will be required. In satisfaction of this need for a planning document, four separate and independent CPM networks have been developed that are representative of the various typical unit conversions and a typical Stretford installation.

For the retrofit project, Units 1 & 2 are representative of Units 3 & 4 in terms of schedule. Units 5 & 6 are representative of Units 7 & 8 and 9 & 10, and Unit 11 is representative of Unit 12.

5.8.1 Basic Activities

The entire retrofit construction project will involve the following basic activities.

Removal of existing condensers

Installation of surface condensers and auxiliaries at each of Units 1-12.

Installation of Stretford units at locations as recommended and/or determined.

Installation of gas blowers and connecting noncondensable piping or installation of gas absorbers, pumps and connecting piping for regenerated liquid.

5.8.2 Activities and Schedules

These CPM Networks include not only the construction activities, but also all major activities associated with design and major equipment/material procurement required prior to construction. The start date of all of the above mentioned networks is June 1, 1980 as a matter of convenience and is not intended to represent a recommended or planned start date. All of the above CPM networks were analyzed utilizing the Boeing Computer Services software package called Project/2 and associated Boeing computer hardware. Working schedules, sorted by late start, and a complete network listing of activities and precedences have been prepared for Units 1 & 2, Units 5 & 6, Unit 11, and a Stretford installation. The anticipated unit outage times due to actual construction, removal and retrofit activities are also indicated in the associated CPM Networks.

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5.8.3 Unit Outage Duration

The unit outage time or unit down time is indicated by the time differences between the beginning construction activity which requires the unit to be out and the plant re-start up after retrofit. Table 5.8-1 indicates the number of the beginning construction activity, the description of that activity, and the late start date as scheduled. This table also indicates the number of the plant re-start up activity, the description of that activity, and the late finish date as scheduled. It is to be noted that the unit outage time is in calendar months utilizing a 5 day work week with an 8 hour day. This unit outage time might be reduced by the use of overtime and increased manpower.

With the indicated unit outage times for the typical units, as shown in Table 5.8-1, it may be seen that Units 1 & 2 and 3 & 4 have an outage time of 8 months each, Units 5 & 6, 7 & 8 and 9 and 10, 9-1/3 months, Units 11 and 12, 11 1/3 months each, and a Stretford installation, 8-2/3 months. It should be noted the above outage times are without regard to interfaces between retrofit of the various power plant units and construction of the Stretford facilities.

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TABLE 5.8-1

UNIT OUTAGE TIMES FOR TYPICAL RETROFIT UNITS
AS INDICATED BY CPM NETWORKS AS ANALYZED BY PROJECT/2 COMPUTER SOFTWARE

Typical Units	Beginning Construction Activity: Activity Number	Beginning Construction Activity: Activity Description	Beginning Construction Activity: Scheduled Late Start Date	Ending of Plant Re-Start Up Activity: Activity Number	Ending of Plant Re-Start Up Activity: Activity Description	Ending of Plant Re-Start Up Activity: Scheduled Late Finish Date	Unit Outage Time
1 & 2	395010	Remove CW and Condensate Pumps	7 April '82	399005	Plant Re-Start Up & Equip. Test After Retrofit	6 Dec. '82	8 Months
5 & 6	395005	Remove Direct Contact Condensers	19 Jan '82	399005	Plant Re-Start Up & Equip. Test After Retrofit	27 Oct. '82	9 1/3 Months
11	395030	Disconnect NC-CW Connections to Condensers and Steam Connections to Turbine	17 Feb. '82	399010	Plant Re-Start Up & Equip. Test After Retrofit	27 Jan. '83	11 1/3 Months
Stretford Process	195005	Remove Water Processing Equipment from Site	13 April '82	399010	Connection to Units 1 thru 6 (Typical)	5 Jan. '83	8 2/3 Months

5.8.4 Activity Interrelationships

As noted in this report the Stretford installation for Units 1-6 and 9 & 10 do not require removal of existing abatement equipment. Thus, for these units, the only scheduling interface between retrofit of the power plants and installation of the Stretford units and interconnecting piping is that a Stretford unit should be ready for service when the first power plant unit served by a given Stretford installation has been retrofitted and is ready for startup.

The Stretford installations at Unit 11 (which will also serve Units 7 & 8) and Unit 12 require removal of existing abatement equipment before construction of the Stretford unit can begin. Further each unit must be taken out of service when demolition of the existing abatement equipment begins. As noted above, downtime to retrofit Units 11 & 12 is estimated to be 11-1/3 months each while the scheduled time to install a Stretford unit is 8-2/3 months. Thus, to minimize plant downtime, the first activity in construction of the Stretford unit (removal of existing abatement equipment) should not begin until the plant has been shut down to begin condenser retrofit work, but it should begin no later than approximately 2-2/3 months after this time. With respect to Units 7 & 8, the only interface is that the Stretford installation at Unit 11 be complete when the first of these units is ready for startup after retrofit.

5.8.5 Schedule Summary

The schedule summary relates three very important schedule items. The total project time is from start of design right through restarting the units for commercial operation. The construction time is the total time that construction is underway, and the unit out of service time is that portion of the construction time which the unit can't operate due to the construction work. Table 5.8-2 presents the tabulations as scheduled in this conceptual study.

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TABLE 5.8-2

SCHEDULE SUMMARY
(Time in Months)

Unit	Total Project	Construction	Unit Out of Service
(Surface Condenser Retrofit)			
1 & 2	28	9.0	8.0
3 & 4	28	9.0	8.0
5 & 6	30	10.5	9.3
7 & 8	30	10.5	9.3
9 & 10	30	10.5	9.3
11	32	12.0	11.3
12	32	12.0	11.3
(Stretford Installation)			
1-6	30	9.3	8.7
7, 8, 11	30	9.3	8.7
9, 10	28	8.3	7.7
12	28	8.3	7.7

The actual scheduling and sequencing of retrofitting the various units and constructing the Stretford units and associated piping is very complex and is treated in detail in Section 7.

These schedules can provide the starting of project control to get the overall projects done on time.

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6.0 COST BENEFIT ANALYSIS

The cost benefit analysis is where the alternatives are compared. At this point it is necessary to put the alternatives on a common basis in order for comparisons to be made. The benefits are defined as the difference in cost between the alternatives. The existing direct contact condenser system with the iron catalyst/caustic/peroxide is Alternative 1 and defender. The retrofit of units with surface condensers and the addition of Stretford units to process the vent gases is Alternative 2 or the challenger. The study is to show the economics of continuing with the existing defender or to convert and implement the challenger system in terms of 1979 dollars.

6.1 Capacity Factor (Cost Benefit Analysis)

Capacity factors of the units are being used to analyze the annual electrical output from a unit. The first discussions of capacity factor were presented in Section 4.1.3.

6.1.1 Alternative 1 (Iron/Caustic/Peroxide System)

This system has indicated a decrease in capacity factor. There are also many other reasons for capacity factor changes; however, at this time it appears that the iron catalyst/caustic/peroxide system and direct contact condensers could operate at a 60 percent capacity factor or lower. With continued operating experience and improvements to the system it appears a 70 percent capacity factor could eventually be achieved for the mature system. Both 60 and 70 percent will be used in comparisons.

6.1.2 Alternative 2 (Surface Condensed/Stretford System

This system should have the power plants capable of operating at their intrinsic or natural capacity factor. This was indicated by experience to be 80 percent and with a mature system to be 85 percent. Both figures are used in the economic analysis.

The capacity factors of the vent gas processing equipment (Stretford) affects the Units capacity factor. As discussed in Section 5.4 of the technical data, Volume 1, the Stretford unit cost has been increased from the normal to provide a design that has zero forced outages in the case of combined units and for individual units such that they are available all the time a separate power plant unit is available. Therefore, the Stretford units (the vent gas processing) are not anticipated to impact plant capacity factors.

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6.2 Unit Energy (Cost Benefit Analysis)

The net kilowatt hours available for the bulk power system is of paramount importance when making comparisons. The design base reference point net kWh for each unit is used for this calculation. Alternative 1 energy is the base net kW times the hours indicated by the capacity factors. Alternative 2 energy is reduced from the base kW due to the retrofit. This new output times the hours indicated by capacity factor is the energy from the retrofit units. The Stretford energy is indicated at the bottom separately. Alternative 1 has a cooling tower deduct based upon Section 4.5, Table 6.1. The alternative which generates the least energy has to make up the difference for economic evaluation purposes. The bulk power system supplies this energy and at its 100 percent capacity factor energy cost. This reduction in capacity factor and output is considered to be increased forced outages and unpredictable, therefore the system energy cost includes capacity and energy in the energy cost number.

TABLE 6-1

ANNUAL ENERGY OUTPUT

	Alternative 1		Alternative 2	
Capacity Factor Unit MWh/yr.	60%	70%	80%	85%
1	63,587	74,185	79,464	84,430
2	63,676	74,289	80,557	85,592
3	139,284	162,498	179,832	191,072
4	139,284	162,498	179,832	191,072
5	278,673	325,119	364,451	387,229
6	278,673	325,119	364,451	387,229
7	278,673	325,119	364,332	387,103
8	278,673	325,119	364,332	387,103
9	278,673	325,119	364,963	387,773
10	278,673	325,119	364,963	387,773
11	557,136	649,992	726,933	772,366
12	557,136	649,992	720,429	765,456
Cooling Tower	-13,878	-16,191	0	0
Stretford	0	0	-21,021	-21,021
Total MWh/hr.	3,178,263	3,707,977	4,133,518	4,393,177

Alternative 1 has the lowest energy output when compared to Alternative 2. Therefore, Alternative 1 for economic comparisons must have a replacement energy cost element. This replacement energy need

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continues for the life of the facility and is represented by a level annual cost. Since the replacement energy is a function of the capacity factor of the alternative, four cases are developed. Table 5-4, Alternative 1 - Replacement Energy and Cost, summarizes the replacement energy costs by case.

TABLE 6-2

ALTERNATIVE 1 - REPLACEMENT ENERGY AND COSTS

Case	Alt. #1 Capacity Factor	Alt. #2 Capacity Factor	MWh/yr.	Level Annual $/yr.
1	60%	80%	955,255	50,290,144
2	60%	85%	1,214,914	63,960,094
3	70%	80%	425,541	22,402,937
4	70%	85%	685,200	36,072,888

6.3 Operations and Maintenance

The operations and maintenance cost must be estimated for each alternative to form a basis for comparison. The difference between alternatives is presented.

6.3.1 Alternative 1 (Defender)

The maintenance is estimated to be twice that of the base unabated plant, Section 4.5. The maintenance is assumed for this study to be constant for both capacity factors. From historic data projected (FPC Form 1 year ending 1978 escalated one year), the unabated plant maintenance difference for Alternative 1 is estimated to be:

Level Annual Maintenance $/yr. 3,723,000

This alternative also has a direct operating expense for the chemicals required for the system. The level annual dollars per year are estimated for the capacity factors:

Capacity Factor	Level Annual $/yr.
60%	20,506,700
70%	23,924,400

6.3.2 Alternative 2 (Challenger)

The power plant itself is estimated to require the same operations and maintenance as the unabated base plant; however, this alternative has the vent gas processing facilities (Stretford Units). These operations and maintenance costs are estimated to be:

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TABLE 6-3

STRETFORD OPERATIONS AND MAINTENANCE
(Level Annual $/yr.)

Maintenance	$1,217,160
Chemicals	1,564,004
Steam	105,569
Electricity	1,646,021
Total	$4,532,754 $/yr.

6.4 Capital Cost

The capital costs have been estimated in Sections 4.0 and 5.0 for the respective alternatives 1 and 2. For economic evaluations in 1979 dollars, the level annual dollars per year are segregated by alternative.

6.4.1 Alternative 1 (Defender)

Not all the existing units have the full abatement. For comparison they are all brought up to full abatement. The estimated capital cost was presented in Section 4.4 and in terms of 1979 dollars the level annual $/year are estimated to be:

Capital	2,191,000 $/year

6.4.2 Alternative 2 (Challenger)

The required capital expenditures are in two areas for this alternative. The first is retrofitting the power plants with surface condensers, and the second is the Stretford process. These capital costs are given in Section 5. The following is the 1979 level annual dollars per year required:

Retrofit	10,623,808 $/yr.
Stretford	6,825,038
Total Capital	17,448,846 $/yr.

6.5 Replacement Energy During Construction

Schedules for the work of Alternative 2 have been presented in Section 4.1. This summary table is from that data. The Unit down time is required in the economic evaluation to account for all cost. If a plant has two units, both are out at the same time and the total time is the out of service time.

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TABLE 6-4

ALTERNATIVE 2 - SUMMARY
REPLACEMENT ENERGY DURING CONSTRUCTION

Units	Construction Outage Months	Level Annual Replacement Cost \$/yr.
1- 2	8.0	\$ 475,607
3- 4	8.0	1,041,062
5- 6	9.3	2,421,382
7- 8	9.3	2,421,383
9-10	9.3	2,421,383
11	11.3	2,941,000
12	11.3	2,941,000
Total		\$14,662,815

6.6 Economic Evaluation

This subsection is the main purpose of the whole report; to compare on a cost basis the alternatives for H_2S abatement. The Alternative 1 is the iron/caustic/peroxide abatement with existing direct contact condensers. The Alternative 2 is to retrofit all units with surface condensers and provide Stretford processes for the vent gases. The benefit is defined as the difference in costs between alternatives.

Three types of economic evaluations have been requested. They are: level annual revenue requirements, present worth, and constant dollars. All three give the same resultant choice; however, the numbers are in different units or kinds of units. In this report, the major analysis is by the level annual approach and the other methods are touched only slightly.

The capacity factors over the long term are the most significant factor as they affect the two biggest cost items: replacement energy and treatment chemicals. Evaluation "A" compares Alternative 2 (surface condenser/ Stretford) at 80 percent capacity factor with Alternative 1 (iron/caustic/ peroxide) at both 60 and 70 percent capacity factors. Evaluation "B" compares Alternative 2 at 85 percent capacity factor with Alternative 1 at both 60 and 70 percent capacity factors.

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6.6.1 Level Annual Analysis

This evaluation is the summary of all the costs developed in this report. It is done by the level annual revenue requirement method. The dollar amounts in the table are thousands of dollars per year on a level annual basis, and are from the report sections indicated by the numbers in parenthesis. This evaluation is in 1979 dollars.

TABLE 6-5

LEVEL ANNUAL ECONOMIC EVALUATION "A"
(thousands of $/yr. 1979)

Alternative:		1	1	2
(5.6)	Capacity Factor	60%	70%	80%
(5.7)	Energy (Replacement)	$50,290	$22,402	-
(5.10)	Energy (Replacement During Construction)	-	-	$14,663
(5.8)	Operation & Maintenance	24,230	27,647	4,533
(5.9)	Capital	2,191	2,191	17,448
	Total $1,000/yr.	$ 76,711	$52,240	$36,644
	Comparison "Per Unit"	2.09	1.43	1.00

TABLE 6-6

LEVEL ANNUAL ECONOMIC EVALUATION "B"
(thousands of $/yr. 1979)

Alternative:		1	1	2
(5.6)	Capacity Factor	60%	70%	85%
(5.7)	Energy (Replacement)	$ 63,960	$36,073	-
(5.10)	Energy (Replacement During Construction	-	-	$14,663
(5.8)	Operation & Maintenance	24,230	27,647	4,533
(5.9)	Capital	2,191	2,191	17,448
	Total $1,000/yr.	$ 90,381	$65,911	$36,644
	Comparison "Per Unit"	2.47	1.80	1.00

Alternative 2 is observed to be the lowest level annual cost in all four cases. The conditions and the per unit multiple cases are summarized below. The "per unit" multiple is defined as the base value divided into the compared value, where the base value is the lowest cost alternative. The per unit multiple is the number of times the most economical alternative is better than Alternative 1 for those conditions.

TABLE 6-7

SUMMARY COMPARISON

Case	Alt. 1 Cap. Fac.	Alt. 2 Cap. Fac.	Per Unit Multiple
1	60	80	2.09
2	60	85	2.47
3	70	80	1.43
4	70	85	1.80

TABLE 6-8

CASE DIFFERENCE SUMMARY (L.A.)

Case	Alt. 1 Cap. Fac.	Alt. 2 Cap. Fac.	Difference in $/yr. L.A.
1	60	80	40,067,000
2	60	85	53,737,000
3	70	80	15,596,000
4	70	85	29,267,000

There is a very large difference between Alternative 2 and Alternative 1 in level annual dollars per year. The smallest of the differences occurs in Case 3, 15,596,000 $/yr. level annual. It is worthwhile to study the sensitivity of the difference to various assumptions. The largest component in the evaluation is replacement energy. Decreasing the energy cost twice by 10 percent per kWh gives the following information.

Per Unit Replacement Energy Cost	Level Annual	Difference
1.0	22,402,000	0
0.90	20,145,100	-2,256,900
0.80	17,906,800	-4,495,200

Decreases in replacement energy by significant amounts only change the difference slightly. 15.6 million is needed to make the alternatives equal in cost.

The second largest cost is chemical requirements of the iron/caustic/peroxide system. Both a 20 percent increase and decrease are presented. A negative number decreases the difference. Again the difference for the chemical sensitivity is small compared to the case difference of 15.6 million.

Per Unit Chemical Cost	Level Annual	Difference
1.0	27,647,000	0
0.8	22,117,000	-5,530,000
1.2	33,177,000	+5,530,000

The third largest cost is the capital to install the surface condenser and the Stretford units. A 20 percent change in the capital cost only created a difference of 3.4 million dollars for evaluation purposes.

Per Unit Capital Cost	Level Annual $/yr.	Difference
1.0	17,448,000	0
0.8	13,958,400	-3,489,600
1.2	20,937,600	+3,489,600

Within the limits of the current analysis, it appears that a capacity factor difference between existing abatement and the alternative abatement (surface condenser/Stretford) of 3.6 or greater justifies the expenditures to change the abatement method.

If one were to take all the three major cost elements and add the differences stated above in the greatest way against Alternative 2 the total would amount to 13,514,000 million dollars per year. The difference between Alternative 2 and 1 is 15,596,000 million dollars per year. Therefore, Alternative 2 is solidly the most economic.

6.6.2 Present Value Comparison

To make comparisons with some previous work done by others it has been requested to present the "present values" of the cases and the elements. The results are the same; however, the units of the quantities are different. The present values are the 1979 dollars

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with all future expenditures converted to 1979 dollars. Table 5-13 summarizes the benefits (difference in cost) of each Alternative 2 case (surface condenser/Stretford) over Alternative 1 (iron/caustic/peroxide) cases as stated.

TABLE 6-9

PRESENT VALUE ECONOMIC EVALUATION "A"
(1979 thousands of dollars)

Alternative:	1	1	2
Capacity Factor %	60	70	80
Energy Replacement $	437,303	194,800	-
Energy Replacement During Construction $	-	-	127,504
Operation & Maintenance $	210,695	240,408	39,426
Capital $	19,052	19,052	151,721
Total $	667,050	454,261	318,651

TABLE 6-10

PRESENT VALUE ECONOMIC EVALUATION "B"
(1979 thousands of dollars)

Alternative	1	1	2
Capacity Factor %	60	70	85
Energy Replacement $	556,174	313,678	-
Energy Replacement During Construction $	-	-	127,504
Operation & Maintenance $	210,695	240,408	39,426
Capital $	19,052	19,052	151,721
Total $	785,921	573,138	318,651

TABLE 6-11

CASE DIFFERENCE SUMMARY (PV)

Case	Alt. 1 Cap. Fac.	Alt. 2 Cap. Fac.	Difference in PV
1	60	80	$348,399,000
2	60	85	467,270,000
3	70	80	135,609,000
4	70	85	254,487,000

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6.6.3 Constant Dollar Analysis

The constant dollar analysis is a useful and equivalent version of the level annual revenue requirement method; however, in periods of sustained general inflation the value of current dollars declines with time in real terms and the current dollar analysis eliminates the effects of general inflation which gives results more easily compared to present day costs. This method does not eliminate the effect of real price changes.

The constant dollar factor applied to the escalated costs was obtained from Generation-Planning and was from their latest Power Values Memo to management dated September 12, 1978.

The constant dollar approach works from escalated dollar values. All the previous economic comparisons did not work from escalated costs. 1982 was used as the year to escalate all values to before applying the constant dollar factor for a 30 year life operation to get 1979 constant dollars. The following tables are 1979 constant dollars. As predicted the results are the same as the previous two analyses.

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TABLE 6-12

CONSTANT DOLLAR EVALUATION "A"
(Thousands of $/yr. 1979)

Alternative:	1	1	2
Capacity Factor %	60%	70%	80%
Energy (Replacement) $/yr.	36,383	16,207	-
Energy (Replacement During Construction) $/yr.	-	-	10,608
Operation & Maintenance $/yr.	16,131	18,406	3,017
Capital $/yr.	1,490	1,490	11,867
Total $/yr.	54,004	36,103	25,492

TABLE 6-13

CONSTANT DOLLAR EVALUATION "B"
(thousands of $/yr. 1979)

Alternative:	1	1	2
Capacity Factor %	60%	70%	85%
Energy (Replacement) $/yr.	46,273	26,098	-
Energy (Replacement During Construction $/yr.	-	-	10,608
Operation & Maintenance $/yr.	16,131	18,406	3,017
Capital $/yr.	1,490	1,490	11,867
Total $/yr.	63,894	45,994	25,492

TABLE 6-14

CONSTANT DOLLAR CASE DIFFERENCE SUMMARY

Case	Alt. 1 C. F.	Alt. 2 C. F.	Difference Construction Dollars
1	60	80	28,512,000
2	60	85	38,402,000
3	70	80	10,611,000
4	70	85	20,502,000

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7.0 RECOMMENDATIONS

It has been shown that there is an economic benefit to converting from the existing abatement to an abatement system which utilizes surface condensers and the Stretford Process for vent gas treatment. The economic analysis was done on an overall Geysers Power Plant basis. Since the overall project of retrofitting Units 1-12 with surface condensers and installing selected Stretford units was economic is there an economic benefit to doing the individual sub-projects in a prescribed sequence? The recommendations of this section relate to the timing of unit retrofitting.

Retrofitting the existing Units 1-12 with surface condensers is only part of the project. Various Stretford facilities are built as part of the program. The economics of power plant groupings and Stretford unit size and groupings was presented in the Technical Data Volume 1, Section 5.4 through 5.7. As it turns out groupings of about 200 MW of power plant units had about the same vent gas processing requirements and proved economic except for power plant Units 9-10 and 12 where 9-10 would have its own Stretford as would Unit 12. A power plant unit retrofitted must feed the vent gas into a Stretford unit before the power plant can operate. Therefore for timing economic studies each power plant unit or combination and its associated Stretford unit was considered as a subproject to evaluate construction timing.

7.1 Timing Analysis Method

The method has many variables that inter-relate to provide a relationship which gives a cost for construction timing. Most all the variables are functions of time themselves, each varying in a different manner. The following factors have been combined in a specific way to address the question of how long should the existing abatement continue operations before the retrofit surface condensers/ Stretford be operational? The factors are:

a) the chemical costs associated with the iron/caustic/peroxide's operation;

b) the energy cost of operating the existing units at a lower capacity factor than is anticipated by the retrofit;

c) the capital cost of retrofitting with surface condensers and installing Stretford units;

d) the replacement energy during construction of the retrofit and Stretford units when the power plant unit is out of service;

e) the energy output increase after retrofit due to higher anticipated capacity factor operation;

f) the operation and maintenance costs associated with new retrofit units and Stretford processes.

Table 6-15 shows all the factors described above and is the summary of the timing analysis calculations for the alternative abatement being constructed in period 3, 1982. Period 0 is June 1979. The present worth is the difference in cost, in 1979 dollars, between continuing with the existing abatement and installing and operating the surface condensers and the Stretford units. Previous analysis in Section 6.6 was on a levelized basis. Table 6-15 is not levelized but treats each individual cost element in the year it occurs. Table 6-15 is a more precise look at the details for timing purposes.

The method places the construction first in period 0, then period 1, etc. The present worth starts out positive which means the alternative abatement is more expensive and decreases continually and eventually goes negative which means the existing abatement has become more expensive. This crossover period from positive to negative is then the economic period to have the retrofit condenser units and the Stretford start operation. Table 6-16 shows the construction in the 4th period and the present worth negative. These two tables specify the period most economic for the specified construction, between period 3 and 4.

The input information and all the variables are presented in Appendix A since the information on power values (energy costs), escalation rates are considered in-house management figures.

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TYPICAL
TIMING ECONOMICS

DRAWING NO. Table 6 - 15
REV. 0
SHEET OF

-EXISTING ABATEMENT-				-ALTERNATIVE ABATEMENT-			
Period	Capital	Energy	Oper. & Maint.	Capital	Energy	Oper. & Maint.	Period
0	0.	.481E+07	.450E+07	0.	0.	0.	0
1	0.	.486E+07	.439E+07	0.	0.	0.	1
2	0.	.461E+07	.428E+07	0.	0.	0.	2
3	0.	0.	0.	.579E+07	.448E+08	0.	3
4	0.	0.	0.	.373E+07	-.528E+07	.157E+07	4
5	0.	0.	0.	.327E+07	-.493E+07	.152E+07	5
6	0.	0.	0.	.286E+07	-.483E+07	.147E+07	6
7	0.	0.	0.	.250E+07	-.449E+07	.142E+07	7
8	0.	0.	0.	.219E+07	-.430E+07	.137E+07	8
9	0.	0.	0.	.202E+07	-.393E+07	.132E+07	9
10	0.	0.	0.	.179E+07	-.375E+07	.128E+07	10
11	0.	0.	0.	.156E+07	-.365E+07	.124E+07	11
12	0.	0.	0.	.136E+07	-.333E+07	.119E+07	12
13	0.	0.	0.	.119E+07	-.315E+07	.115E+07	13
14	0.	0.	0.	.103E+07	-.301E+07	.111E+07	14
15	0.	0.	0.	.899E+06	-.286E+07	.107E+07	15
16	0.	0.	0.	.780E+06	-.269E+07	.104E+07	16
17	0.	0.	0.	.101E+07	-.257E+07	.999E+06	17
18	0.	0.	0.	.896E+06	-.243E+07	.964E+06	18
19	0.	0.	0.	.770E+06	-.231E+07	.930E+06	19
20	0.	0.	0.	.664E+06	-.219E+07	.897E+06	20
21	0.	0.	0.	.568E+06	-.208E+07	.866E+06	21
22	0.	0.	0.	.488E+06	-.197E+07	.835E+06	22
23	0.	0.	0.	.418E+06	-.188E+07	.806E+06	23
24	0.	0.	0.	.358E+06	-.177E+07	.778E+06	24
25	0.	0.	0.	.305E+06	-.168E+07	.750E+06	25
26	0.	0.	0.	.262E+06	-.160E+07	.724E+06	26
27	0.	0.	0.	.222E+06	-.152E+07	.698E+06	27
	0.	.143E+08	.132E+08	.369E+08	-.275E+08	.260E+08	

Present Worth 8020770.

	-EXISTING ABATEMENT-			-ALTERNATIVE ABATEMENT-			
Period	Capital	Energy	Oper. & Maint.	Capital	Energy	Oper. & Maint.	Period
0	0.	.481E+07	.450E+07	0.	0.	0.	0
1	0.	.486E+07	.439E+07	0.	0.	0.	1
2	0.	.461E+07	.428E+07	0.	0.	0.	2
3	0.	.533E+07	.414E+07	0.	0.	0.	3
4	0.	0.	0.	.562E+07	.444E+08	0.	4
5	0.	0.	0.	.327E+07	-.493E+07	.152E+07	5
6	0.	0.	0.	.286E+07	-.483E+07	.147E+07	6
7	0.	0.	0.	.250E+07	-.449E+07	.142E+07	7
8	0.	0.	0.	.219E+07	-.430E+07	.137E+07	8
9	0.	0.	0.	.191E+07	-.393E+07	.132E+07	9
10	0.	0.	0.	.176E+07	-.375E+07	.128E+07	10
11	0.	0.	0.	.157E+07	-.365E+07	.124E+07	11
12	0.	0.	0.	.137E+07	-.333E+07	.119E+07	12
13	0.	0.	0.	.119E+07	-.315E+07	.115E+07	13
14	0.	0.	0.	.104E+07	-.301E+07	.111E+07	14
15	0.	0.	0.	.904E+06	-.286E+07	.107E+07	15
16	0.	0.	0.	.786E+06	-.269E+07	.104E+07	16
17	0.	0.	0.	.683E+06	-.257E+07	.999E+06	17
18	0.	0.	0.	.888E+06	-.243E+07	.964E+06	18
19	0.	0.	0.	.784E+06	-.231E+07	.930E+06	19
20	0.	0.	0.	.673E+06	-.219E+07	.897E+06	20
21	0.	0.	0.	.581E+06	-.208E+07	.866E+06	21
22	0.	0.	0.	.497E+06	-.197E+07	.835E+06	22
23	0.	0.	0.	.427E+06	-.188E+07	.806E+06	23
24	0.	0.	0.	.366E+06	-.177E+07	.778E+06	24
25	0.	0.	0.	.313E+06	-.168E+07	.750E+06	25
26	0.	0.	0.	.267E+06	-.160E+07	.724E+06	26
27	0.	0.	0.	.229E+06	-.152E+07	.698E+06	27
	0.	.196E+08	.173E+08	.327E+08	-.226E+08	.244E+08	

Present Worth -2394969.

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TYPICAL
TIMING ECONOMICS

DRAWING NO. Table 6 - 16

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7.2 Timing Study Results

The timing studies were performed using a 10 percent difference in capacity factor between the existing abatement and the surface condenser/Stretford alternative abatement. There are four subprojects studied:

a) Power Plant Units 7, 8 and 11 with Stretford at Unit 11.

b) Power Plant Units 1, 2, 3, 4, 5 and 6 with a Stretford unit near Unit 3.

c) Power Plant Unit 9 and 10 with a Stretford at 9 or 10.

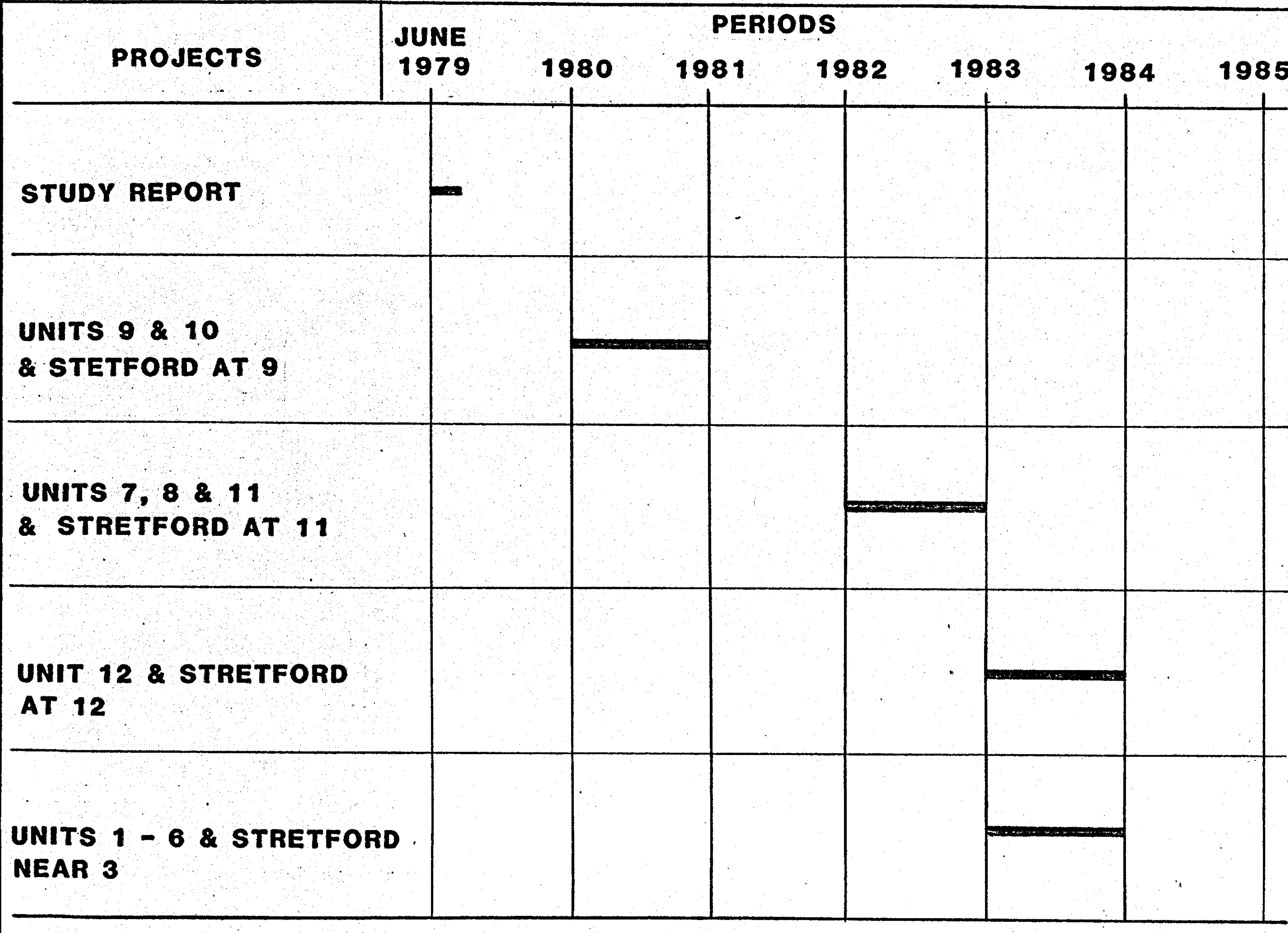
d) Power Plant Unit 12 with a Stretford at Unit 12.

The studies showed with a 10 percent capacity factor difference the subprojects should be implemented in the following order, the first at the top of the list. The third and fourth have the same timing.

1) Power Plant Units 9 and 10 and Stretford
2) Power Plant Units 7, 8 and 11 and Stretford
3) Power Plant Units 1, 2, 3, 4, 5 and 6 and Stretford
4) Power Plant Unit 12 and Stretford

A bar graph is presented in Table 6-17 which indicates the economic period to have the alternative abatement facilities come on the line.

A sensitivity analysis on the timing as it relates to capacity factor difference between the existing and the alternative showed very interesting results. If the capacity factor difference is as great as 15 percent then economically the projects should be put in as fast as possible (instantaneously). If the capacity factor difference is 5 percent the timing moves out about 4 years. Capacity factor differences are again very significant and are probably the most significent single element in the timing economics.



MOST ECONOMIC PLANT START-UP PERIODS

ROGERS ENGINEERING CO., INC.
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JOB NO. S 79007

MOST ECONOMIC PLANT START-UP PERIODS

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7.3 Geysers Power Plant Available Capacity

Economics are not the sole governing element in making a decision nor are they in developing schedules. However, if the economics were followed here is a table which would approximate the available capacity from the total Geysers' plant. Only Units 1-12 are considered.

TABLE 7-1

AVAILABLE CAPACITY DURING CONSTRUCTION
(Units 1-12 only)

Year	Net MW Before	Under Construction MW	Net MW After	Available MW
1979	607	0	0	607
1980	501	106	0	501
1981	501	0	104	605
1982	289	212	104	393
1983	0	289	312	312
1984	0	0	593	593

Rogers

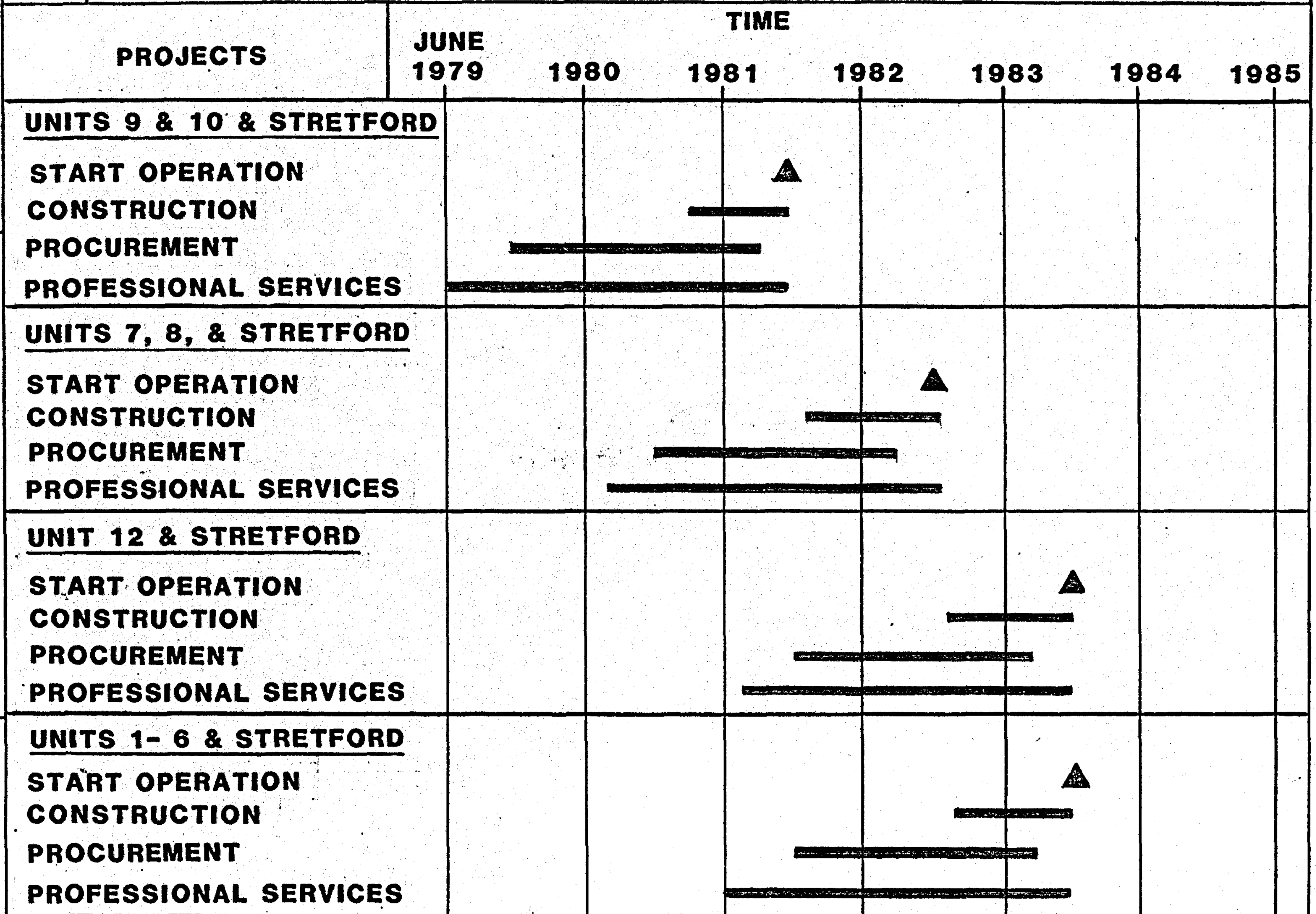
8.0 PROFESSIONAL SERVICES

A format for proceeding with the retrofitting of the existing power plant Units 1-12 with surface condensers and Stretford vent gas processing units is described here. In previous sections details of the overall objective have been discussed. This section brings the schedules for engineering, procurement and construction together with the economic timing of each sub-project, Table 8-1. The timing in Table 8-1 for the sub-project Units 9 & 10 and Stretford is deferred one year past the first economic year because engineering, equipment delivery and construction times are too great starting in June 1979 to get it accomplished for January 1981 start up.

This bar graph schedule Table 8-1, shows a coordinated effort and logical progression of accomplishing the projects. It also shows procurement as a very significant element in the overall plan. We feel this schedule can be maintained as the preliminary details indicated in Section 5.8 and Appendices A, B, C and D of the Final Report Technical volumes.

As part of the plan for organizing and arranging the accomplishment of the overall project, it is important to realize that in preparing the cost estimate for the project the estimates were so done to include the full GM costs. That is Account 365 "Engineering and Other Allocatable Costs" (field construction costs - general construction, general engineering, general office, and engineering other-professional services by consultant) are included in the direct costs and then the GM factor for general and administration has been added. The plan, governed by timing and costs, shows that the project should get underway very soon.

To culminate this section Table 8-2 represents the time and economic scheduled restart up of the retrofit units. It shows all units completed by June 1984.



RETROFIT PROJECTS - ENGINEERING, PROCUREMENT, & CONSTRUCTION SCHEDULE

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RETROFIT PROJECTS
ENGINEERING, PROCUREMENT,
& CONSTRUCTION SCHEDULE

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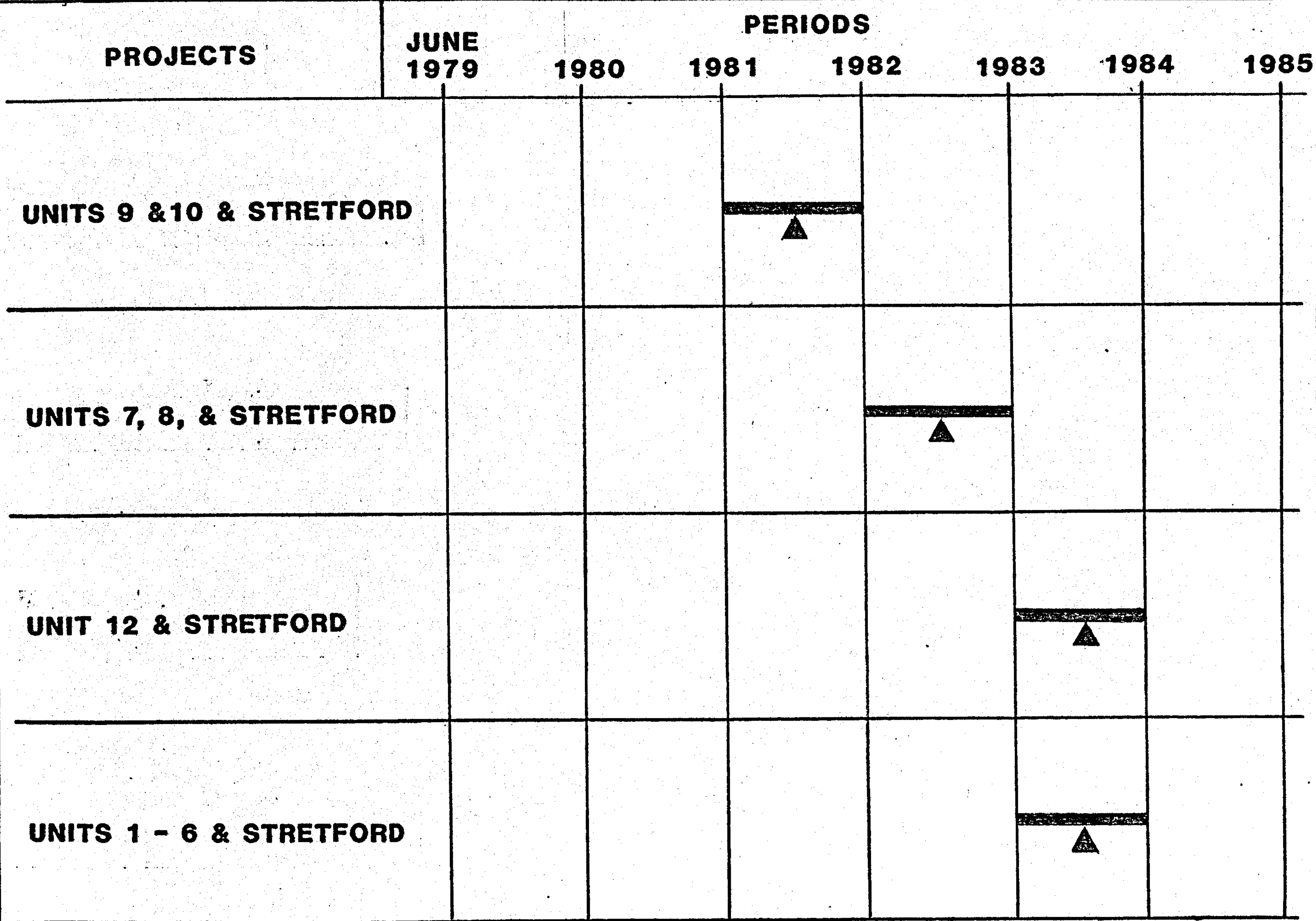

RETROFIT UNITS - PROPOSED START-UP PERIODS

▲ UNIT START-UP

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RETROFIT UNITS
PROPOSED START-UP PERIODS

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