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Cool-Water Coal-Gasification Program, First Annual Progress Report

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Research Project 1459

Interim Report, July 1982

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ABSTRACT

This report presents current status information on the Cool Water Coal Gasification Program, a private industry jointly funded effort to design, build, and operate a 100 MW coal-based power plant to demonstrate new integrated gasification combined cycle (IGCC) technology at a commercial scale. Background on the project is provided and the organizational structure is discussed. Planned facilities are described quite extensively, and a number of relevant drawings are included. Design issues are identified and plant operating and control requirements are addressed. The expected plant performance is indicated for normal and special test conditions.

The project cost estimate and present funding support are briefly summarized. The progress of the engineering work and the overall project status are reported. The regulatory process and permit history are reviewed. Plans regarding plant testing, as currently defined, are also discussed.

As the Cool Water effort proceeds, EPRI intends to publish annual reports updating the project progress.

EPRI PERSPECTIVE

PROJECT DESCRIPTION

The Cool Water Coal Gasification Program is an undertaking of a number of private entities to design, construct, and operate the nation's first integrated gasification-combined-cycle (IGCC) power plant to supply electricity to a utility system. The demonstration plant, comprising commercial-scale components and subsystems, will be located at the existing Cool Water generating station of Southern California Edison Co. (SCE) near Barstow, about halfway between Los Angeles and Las Vegas in the Mojave Desert. Organizations presently sharing in the funding of the $300 million effort are EPRI, SCE, Texaco Inc., Bechtel Power Corp., General Electric Company (GE), Japan Cool Water Program Partnership (JCWP), and the Empire State Electric Energy Research Corp. (ESEERCO).

The plant will utilize an oxygen-blown Texaco gasifier that is sized to convert 1000 tons of Utah coal per day to a medium-Btu syngas. After particulate and sulfur removal, the syngas will be used to fuel a GE combined-cycle unit that employs a slightly modified Frame-7 combustion-turbine-electric generator, a heat recovery steam generator (HRSG), and a steam turbine-electric generator. The net plant output, after serving auxiliary loads and accounting for power supplied to an "over-the-fence" air separation unit that will provide the oxygen needed for gasification, is expected to be 90 to 100 MW, depending on operating conditions.

The project under RP1459 is being conducted in phases as follows:

- Phase I--Preliminary Engineering and State Permits
- Phase II--Final Engineering
- Phase III--Procurement and Construction
- Phase IV--Operation and Testing
- Phase V--Completion

PROJECT OBJECTIVES

For almost 30 years in a large number of plants worldwide, Texaco has licensed commercially its Synthesis Gas Generation Process for use with oil or natural gas feed. The Texaco Coal Gasification Process, which was born out of the initial experience with this oil-partial oxidation technology, has received greatly increased emphasis as a result of the recent national move toward more coal use to promote energy self-sufficiency and has been extensively tested on the small and large pilot plant scale. Specifically, a wide range of coals and other solid feedstocks have been processed in Texaco's 15-ton-per-day Montebello (Los Angeles) unit over the last decade, and Ruhrchemie, a West German chemical firm, has successfully operated a 165-ton-per-day Texaco gasifier at Oberhausen since 1978. The latter unit has logged over 10,000 hours of operation, including runs of about 500 hours each on Pittsburgh No. 8, Illinois No. 6, and Utah coal (the Cool Water design coal). One of the main objectives of the Cool Water project will be to identify and rectify scale-up problems that might occur with operation of the gasification process at the 1000-ton-per-day level; i.e., resulting from a six-fold increase in size.

Essentially, all of the other elements of the IGCC system have individually achieved successful operation in one application or another at the size proposed for Cool Water. However, some of the process segments--e.g., the sulfur-removal facilities and the "over-the-fence" air separation unit--have traditionally been required to operate almost exclusively at only a steady-state level. Furthermore, the degree and number of direct interrelationships among the various components of the IGCC system are rarely present in existing conventional practice. A key goal of the project will be to verify the operability and controllability of the overall heavily integrated system in both steady-state and load-following modes and under startup, shutdown, and emergency conditions.

Equipment and system reliability is another area to be specifically addressed at Cool Water in order to provide important failure rate and repair data. Efficiency and costs are to be carefully evaluated to confirm or, if necessary, to correct projections for commercial plants. Extensive monitoring of environmental performance is also to be carried out in compliance with the project permit conditions and to develop information for future planning.

In order to demonstrate the feedstock flexibility of the gasification process, several coals, including both eastern and western varieties, are expected to be tested. During the course of operations, detailed operating, maintenance, and safety procedures, which can be applied to future plants, will be developed and refined.

In short, it is the intent of the parties in the Cool Water project to obtain a comprehensive package of real plant data on a commercial scale. This information will allow decisions and plans for future application of IGCC technology to be made with a high level of confidence and substantially reduced technical and financial risk.

PROJECT RESULTS

Phase I, Preliminary Engineering, was completed in December 1979 upon receipt of the state environmental permit from the California Energy Commission. Phase II, Final Engineering, was then initiated, with Bechtel being selected as the project engineer-constructor. After several trade-off studies were conducted and a final plant configuration was selected, detailed engineering design work commenced. GE was chosen to supply the combined-cycle equipment and to lead the integrated control system development activities. A decision was made to utilize the Selexol® process, licensed by the Norton Company, for the removal of sulfur compounds from the coal-derived fuel gas. It was agreed that recovery of this sulfur would be accomplished using the Claus process, licensed by Amoco Oil Co., and the Claus tail gas would be treated for further sulfur removal in a Shell Claus Off-Gas Treating (SCOT) unit, licensed from Shell Development Co. The engineering design of the Claus and SCOT facilities was subcontracted by Bechtel to Ford, Bacon, & Davis.

An arrangement was negotiated with Airco, Inc., whereby they will build a commercial air separation unit adjacent to the project facilities in order to supply oxygen on an "over-the-fence" basis. Combustion Engineering, Inc., was selected to manufacture the gasifier and the syngas coolers, the latter being the largest and most critical process vessels in the plant.

Phase III, Procurement and Construction, was released to proceed in December 1981. As of May 1982, all major equipment had been ordered, site clearance work was completed, and initial underground civil construction activity was well under way. Also, by that date, Phase II engineering work was 60% finished. Phase III is scheduled for completion by October 1984, including a four-month plant shakedown period after construction has ended. Phase IV, Operations and Testing, will then proceed and continue for a period of about six and one-half years, to be followed by Phase V, consisting of the sale of all or part of the facilities for future use "in-place," dismantling for reuse elsewhere, or demolition and sale for salvage.

With regard to funding, EPRI agreed in February of 1980 to share in the project cost along with SCE and Texaco. Bechtel and GE formalized their commitment to participate in the financing of the effort in September of that year. When in July of 1981 additional contributions had not yet been secured to cover the full funding requirement, commencement of construction was temporarily postponed and the project was essentially placed in a holding pattern. In December 1981, the EPRI Board of Directors approved an immediate increase in the Institute's funding level and agreed to a major commitment to underwrite a substantial portion of the remaining funds required to allow the project to proceed. This action, along with increased commitments from the other participants and the addition of two new cofunders, did indeed permit a release of the "holds" placed on procurement and construction. The agreed-upon funding closure plan was formally implemented in February 1982 when the necessary amendments to existing participation agreements were executed and new contracts covering the contributions by JCWP and ESEERCO also went into effect.

The foregoing discussion of the project status represents an interim summary of the results obtained to date in this major alternate energy effort. Annual progress updates on design and construction will be issued as EPRI public reports during Phase III, and in Phase IV these reports will continue, presenting plant operating results, along with a comparison against projections and objectives.

Thomas P. O'Shea, Project Manager
Advanced Power Systems Division

ACKNOWLEDGMENTS

Input for this report was received from virtually all of the organizations participating in the Cool Water Coal Gasification Program. The individuals named below were directly involved in the actual preparation of the various sections of the document and a number of other members of the overall project team provided necessary and constructive editorial comment. The conscientious efforts of all whose time and energy went into the production of this comprehensive project report are very much appreciated and gratefully acknowledged.

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CONTENTS

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ILLUSTRATIONS

TABLES

DRAWINGS

SUMMARY

This document comprises the first annual EPRI Progress Report on the Cool Water Coal Gasification Program. This project is the focal point of the EPRI Clean Gaseous Fuels Program (CGF) and its successful implementation is the primary goal in the current CGF Five-Year Plan. EPRI's and the utility industry's strong commitment to gasification combined-cycle (GCC) as a future coal-based power option, as well as their recognition of the need to first demonstrate this new generation alternative at a commercial scale, are evidenced by the substantial EPRI funding share in the Cool Water effort. This funding share represents the largest contribution ever made by the Institute to a single project.

Formulation of the Program was begun in early 1978 by Southern California Edison (SCE) and Texaco. During 1980 EPRI, Bechtel and General Electric (GE) executed contracts to share in the Program funding with SCE and Texaco. Subsequently, these parties were joined by the Japan Cool Water Program Partnership (JCWP) and the Empire State Electric Energy Research Corporation (ESEERCO), who have agreed to also co-fund the project. A breakdown of the co-funders' contributions is provided in Section 7 of this report. The rights of Program participants and sponsors, relative to their funding contribution levels, are discussed in Section 3.

The primary governing body for the Program is the Board of Control, comprised of a representative from each of the participant organizations. Reporting to the Board of Control is a Management Committee, also consisting of participant representatives. The day-to-day activities are coordinated by the Program Manager (a Texaco employee), with the assistance of a Program Office staff made up of participants' personnel.

The Cool Water Program encompasses the design, construction, testing and operation of the nation's first integrated GCC plant on a commercial scale. The demonstration unit, designed for a coal feed rate of 1000 tons per day, is to be built at the site of SCE's existing 600 MW Cool Water Generating Station, located near Daggett, California, about 120 miles northeast of Los Angeles. The plant is expected to produce from 90 to 100 MW of net power, depending on the process

conditions achieved. Table S-1 provides an estimate of plant performance under three different operating conditions, each of which is based on the design using Utah coal as feed. Significantly lower heat rates are projected for commercial plants where larger, more efficient reheat steam turbines are expected to be employed and certain other improvements are anticipated to be implemented.

The objectives to be met in the Cool Water Program include:

- Demonstration of acceptable system and equipment performance at a commercial scale
- Confirmation of system compliance with environmental criteria
- Verification of controllability of the integrated plant under all operating conditions, including steady-state, load-following, start-up, shutdown and emergency
- Assessment of equipment and system reliability
- Demonstration of feedstock flexibility
- Preparation of operating, maintenance, safety and training procedures which could be applied to future plants
- Development of a complete economic and technical data base for use in commercial application decision-making and future plant designs

The demonstration plant will include subsystems for coal receiving, storage and transfer, grinding and slurrying, gasification and gas cooling, sulfur removal and recovery, resaturation and reheating, power generation, waste water treating and other ancillary support facilities. Coal will be delivered by rail from the Southern Utah Fuel Co. (SUFCO) mine in unit trains. From silo storage, it will be conveyed to the grinding section and prepared with water as a slurry before being fed into the gasifier through a specially designed burner. Oxygen (to be supplied at Cool Water from an "over-the-fence" air separation plant) is also fed to the gasification reactor. Partial oxidation reactions between the coal, water and oxygen produce a medium-Btu raw product gas consisting mainly of carbon monoxide, hydrogen, carbon dioxide and steam. This very high temperature product gas exits the gasifier and passes through syngas coolers, where most of its sensible heat is recovered by generating high pressure saturated steam, before being water-scrubbed for separation of entrained carbon and/or ash particles. Most of the ash in the coal, after being melted into a slag in the high temperature reactor environment, is solidified in a quench water sump below the gasifier before being removed for disposal.

After further cooling, the gas is routed to a Selexol unit where 97 percent of the sulfur is removed, primarily as hydrogen sulfide and carbonyl sulfide. These sulfur constituents are then converted to elemental sulfur in a conventional Claus plant, whose tail gas is treated in a Shell SCOT unit for removal of remaining acid gases. The sulfur will be disposed of or, perhaps, sold.

The clean, cool product gas from the Selexol unit passes through a water saturator, a heater and a surge/knock-out drum before entering a GE Frame 7 combustion turbine, which drives an electric generator. The moisture added in the saturator aids in minimizing the formation of nitrogen oxides in the gas turbine by limiting the combustor flame temperature. Supplemental steam injection is also planned for NO_x emissions control. The exhaust gas from this turbine is released to the atmosphere, after being cooled in a heat recovery steam generator (HRSG) where high pressure saturated steam is generated and is then superheated, along with the steam produced in the syngas coolers in the gasification section. The superheated steam flows to a steam turbine which also drives an electric generator. A more detailed description of the Program facilities can be found in Section 5 of this report.

The current Program cost estimate is $300 million (in actual dollars, i.e., including escalation). A breakdown of this estimate is provided in Section 7.

The Cool Water project has been structured as follows:

- Phase I - Preliminary Engineering and State Environmental Permits
- Phase II - Final Detailed Engineering
- Phase III - Procurement and Construction
- Phase IV - Operation and Testing
- Phase V - Completion and Dismantling/Disposal (if necessary)

Phase I was completed at the end of 1979 when the California Energy Commission approved the construction and operating permit for the demonstration plant. At the beginning of 1980, Bechtel was selected as the Engineer-Constructor and Phase II was started. As of May 1982 this detailed design phase is approximately 60 percent complete and is expected to continue through mid-1983. Phase III was initiated in December 1981 and orders for all long-delivery equipment items have been placed. Bids are in hand for most of the other plant equipment and site clearance work has commenced. Major supplier/licensor decisions made include:

- GE will supply the combined-cycle equipment and certain other electrical items (in addition to performing integrated controls design and cycle development and definition services)

- The Selexol sulfur removal process is being licensed from Norton Company

- The Claus process for sulfur recovery is licensed from Amoco Oil Company

- Shell Development Co. is the licensor for the SCOT tail gas treating process

- Ford, Bacon and Davis (Texas) is carrying out the engineering design of the sulfur recovery and tail gas treating facilities

- Combustion Engineering is the supplier of the gasifier vessel and syngas coolers

- Airco Inc. has been selected to supply the oxygen required in the gasification process on an "over-the-fence" basis

- Foxboro has been chosen to provide the distributed control system and data acquisition system

Construction of the demonstration plant is expected to be complete in the first half of 1984 and, after a short "pre-demonstration" period allowed for initial start-up and shakedown, Phase IV, the formal test and operations program, is anticipated to begin in the latter half of 1984. During Phase IV, long-term performance and reliability assessment is planned on the design Utah coal, as well as several short term tests using other coals, including high-sulfur eastern varieties. EPRI has already nominated Illinois No. 6 coal, with a sulfur content of 3.5 percent, as its candidate for testing. Various materials tests and regular evaluations of plant economics are also planned during Phase IV. In addition, a comprehensive environmental monitoring and surveillance program will be conducted during the operations period in accordance with the requirements of the permit issued by the California Energy Commission. The type and frequency of environmental measurements currently envisioned are identified in Section 10 of this report.

The operations and test period is planned to continue for six and one-half years. Accordingly, Phase IV will be complete in early 1991. At that time a decision will be made as to whether SCE wishes to purchase the plant and operate it commercially, another party desires to purchase it (presumably requiring relocation), or whether it should be dismantled and sold for salvage.

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Table S-1

OVERALL PLANT PERFORMANCE

(SUFCO COAL)

	Initial Operation	Anticipated Future Operations	
	1	2	3
Coal in (lb/hr)	83,820	83,820	87,108
(tpd)	1,006	1,006	1,045
Coal Heating Value (Btu/lb., HHV)	12,277	12,277	12,277
Water Usage (gpm)			
- To Combined-Cycle Condenser	190	140	150
- Cooling Tower Use	863	863	928
- Gasification/slurry Make-up	79	123	135
Heat in Coal (Btu/hr. x 10^6, HHV)	1,029.1	1,029.1	1,069.4
Gross Dry Clean Fuel Gas Produced (lb/hr)	157,080	155,370	155,500
Heat in Clean Fuel Gas (Btu/hr x 10^6, HHV)	750	767	842
Total High Pressure Steam (lb/hr)	407,720	394,240	398,300
Total Medium Pressure Steam (350 psig) Produced (lb/hr)	1,660	1,660	1,710
Estimated Expected Gross Power Generated (kw)	115,950	118,750	123,100
Electrical Auxiliary Power Consumed			
- Balance of Plant (kw)	6,020	6,120	6,240
- Oxygen Plant (kw)	17,980	16,424	15,880
Estimated Expected Net Performance			
- Net Power Generated (kw)	91,950	96,210	100,980
- Net Plant Heat Rate (Btu/kw-hr)	11,190	10,700	10,600
- Overall Net Plant Efficiency (%) (coal-to-busbar)	30.5	31.9	32.2

Note: All cases above are based on site elevation of 2,000 ft. and ambient temperature of 80F. Column 1 represents initial "normal" operation, reflecting 99.5% O_2 purity, slurry containing approximately 60% coal with no pre-heating, and supplemental steam injection at the gas turbine for NO_x control. Columns 2 and 3 represent target performance at future test conditions. Both columns are based on 95% O_2 purity, the addition of slurry heating, and the elimination of steam injection, but column 3 also assumes increased slurry concentration.

Section 1

INTRODUCTION

The electric utility industry, as a major user of oil and natural gas, has recognized the need for alternate energy sources. Their search has focused on the technologies that would provide an environmentally acceptable way to use a broad range of domestic coals, which are in abundant supply.

One way in which coal can be used in an environmentally acceptable manner is by gasification. The gaseous product (syngas) from coal gasification has many uses. It can be used in steam boilers and gas turbines to generate electricity, and can be used to fuel process heaters and furnaces in industrial complexes. It can also serve as a primary feed source for manufacturing petrochemicals such as methanol, ammonia, acetic acid and alcohols, as well as high-purity hydrogen and synthetic crude oil.

Analyses by the Electric Power Research Institute (EPRI), the Engineering Societies Commission on Energy (ESCOE), the Department of Energy (DOE), the General Electric Company (GE), and others indicate that electricity produced by a gasification plant integrated with a gas and steam turbine combined-cycle offers several attractive advantages versus conventional power plant technology, i.e., coal-fired boiler/steam turbine using flue gas desulfurization. These include:

- Use of readily available high-sulfur coals
- Lower air pollution emissions
- No sludge disposal requirement
- Lower water use
- Lower solid waste production
- Potentially lower cost of electricity
- Potentially higher plant efficiency
- Reduction in oil usage through retrofit potential

It is the goal of the Cool Water Coal Gasification Program to demonstrate the attractive environmental and economic characteristics of an integrated gasification combined-cycle (IGCC) power generation plant on such a scale and in a time frame that will lead to widespread commercial acceptance by the late 1980's.

The following sections of this report provide an overall description of the Cool Water Coal Gasification Program, its management structure, the IGCC concept and plant facilities, and the status of the Program through the year 1981.

Section 2

BACKGROUND

Southern California Edison thoroughly studied the coal technologies which have, or are projected to have, commercial capabilities in the near term and which could also meet California's emission and effluent requirements. They concluded that the gasification of coal to produce clean-burning medium Btu gaseous fuel for use in boilers and combustion turbines merited further investigation. In early 1978, SCE and Texaco Inc., signed a letter of intent to jointly perform preliminary engineering studies for a commercial scale 1000 tons-per-day coal gasification system linked with a 100 MW combined-cycle electric generating plant. Linking of the gasifier and the combined cycle unit was expected to produce electrical energy at an efficiency comparable to conventional direct-fired coal combustion plants. SCE's Cool Water Generating Station near Daggett, California was selected as the site where adequate land, water and rail facilities for coal delivery and other plant support facilities were available.

Subsequently, an EPRI-funded study was conducted by the Ralph M. Parsons Company to perform the conceptual design of the coal gasification-combined cycle power system. Preliminary design information, performance and emissions data, and project costs and schedules were developed for the construction of the proposed plant. A final report was issued in August 1978 (EPRI Report No. AF-880). The results of this study were used by SCE and Texaco to structure a program for a commercial scale integrated gasification combined-cycle power plant.

Southern California Edison filed a Notice of Intention (NOI) for certification of the site and the project with the State of California Energy Resources Conservation and Development Commission (CEC). Thereafter SCE's Preliminary Environmental Assessment (PEA), dated October 12, 1978, was filed with the CEC. On November 25, 1978, the CEC issued its order converting the NOI proceeding to an Application for Certification (AFC) pursuant to the Coal Gasification Generation Act (Public Resources Code Section 25650, et. seq.). The California Energy Commission issued a draft Environmental Impact Report for public comment in October 1979 and granted a construction permit in December 1979.

SCE and Texaco entered into an "Agreement", dated July 31, 1979, for the purpose of designing, constructing and operating a 100MW integrated gasification combined-cycle (IGCC) power plant based on the data and costs developed during the R. M. Parsons study. The project, known as the Cool Water Coal Gasification Program, would entail the gasification of 1000 tpd of coal using the Texaco Process. Overall project cost was originally estimated at $300 million.

In January 1980, Bechtel Power Corporation was selected as the prime engineer/constructor for the Program. Engineering began in February 1980 at Bechtel's Houston Office. Later that year, Bechtel entered into a Participation Agreement with the Program to contribute $25 million toward the funding. In February 1980, EPRI evidenced its dedication to the Program by committing $50 million. This was the largest single project commitment in EPRI history.

Also during February 1980, Program personnel were assigned to provide overall coordination and liaison with Bechtel. The Program Office is staffed by representatives from the various participating organizations as described later in Section 3 of this report.

On August 19, 1980, SCE received approval of a Certificate of Public Convenience and Necessity from the California Public Utility Commission.

In September 1980, a participation agreement and supply contract was signed with General Electric Company to become a participant, at $25 million, to supply the combined-cycle equipment and to take the lead in design of the integrated plant controls and in thermal cycle development and definition.

Airco, Inc., was selected in November 1980 to design, construct and operate an "over-the-fence" Air Separation Plant at the Cool Water site for the supply of oxygen and nitrogen. This oxygen supply approach effectively reduced the Program capital requirements to $275 million. However, subsequent delays in securing the necessary Program funding resulted in an increase in the cost estimate to its present level of $300 million.

At the end of 1981, when sources still had not been identified for all of the necessary funds required to complete the project, the existing participants agreed on a funding closure plan which allowed a decision to be made to proceed with Phase III, Procurement and Construction. The funding closure plan involved increased financial commitments from the present participants, the most substantial of which was that of EPRI, bringing its contribution to a level of $105 million, and also included anticipated commitments of $35 million from new parties. These new party commitments, which have since been contractually secured, are comprised of $30 million from the Japan Cool Water Program Partnership (JCWP) and $5 million from the Empire State Electric Energy Research Corp. (ESEERCO). Section 7 of this report provides a breakdown of the sources of project funding under the closure plan.

Section 3

PROGRAM ORGANIZATION AND MANAGEMENT STRUCTURE

PROGRAM ORGANIZATION

The Cool Water Program has been formed as a joint venture of participants and sponsors. Current parties sharing in the funding include:

- Southern California Edison
- Texaco
- Electric Power Research Institute
- Bechtel
- General Electric
- JCWP (Japan Cool Water Program Partnership)
- ESEERCO (Empire State Electric Energy Research Corp. - special contributor)

The Texaco/Edison Agreement is the basic contractual document for the venture and provides for joint ownership of the plant by each present and subsequent party to the Agreement. Each party owns an individual percentage interest equivalent to its degree of participation.

Under terms of the Agreement, each participant agrees to commit a minimum of $25 million to the Program and to assume a proportionate share of all Program costs. Each sponsor agrees to commit a minimum of $5 million to the Program. All participants, other than EPRI, are subject to unlimited liability for capital costs, and participants indemnify sponsors for liability incurred in excess of their established funding contribution.

Southern California Edison has agreed to provide the Program with free use of the plant site and water, free access to the site, and to supply coal to the Program at no cost. Texaco Development Corporation, a wholly owned subsidiary of Texaco, has agreed to provide the Program royalty-free use of its gasification process technology.

Participants also share in capital recovery (except SCE), Program decisions, receive full technical information developed during the Program, share in any license royalties resulting from technology developed under the Program, and receive the right to nominate a coal of their choice for testing in the plant.

Additionally, participants are granted a reduction in the license fee for any future use of the Texaco Coal Gasification Process for combined-cycle power generation. SCE is granted a special license fee consideration for its use.

Sponsors also share in capital recovery but only up to one-half their contribution. They also receive full technical information and a lesser reduction in license fees for use of the Texaco Coal Gasification Process for combined cycle power production.

These obligations and rights are summarized in Tables 3-1 and 3-2.

Table 3-1

PARTICIPANT OBLIGATIONS AND RIGHTS

Obligations

- Capital commitment - $25 million minimum
- Shares in all Program costs

Rights

- Shares in capital recovery
- Shares in Program decisions
- Full technical information
- TCGP royalty fee reduction
- Other Program royalty sharing
- Special coal test without fee
- Have Engineers and Technicians trained
- Special tests of process, material, or equipment
- Publicize participation

Table 3-2

SPONSOR OBLIGATIONS AND RIGHTS

Obligation

- Capital commitment - $5 million minimum

Rights

- Shares to one-half capital recovery
- Full technical information
- TCGP royalty fee reduction
- Special coal test for a fee
- Publicize sponsorship

Participating organizations in the Cool Water Coal Gasification Program have joined the Program because of their interest in achieving early commercialization of coal gasification combined-cycle plants and have demonstrated strong management and technical qualifications which complement one another. The tasks to be completed are similar to those the Participants have performed on other process plants and power generating facilities. However, the uniqueness of this first-of-a-kind facility requires higher levels of interaction between the major Program suppliers, especially during the engineering and planning activities. This has been recognized in establishing the Program work structure and organization.

PROGRAM MANAGEMENT STRUCTURE

The overall management structure for the Cool Water Coal Gasification Program is shown in Figure 3-1. The Board of Control is the governing body and the Management Committee is the operations group. Each participant has the right to assign an individual to each group to represent the participant's organization in all Program matters.

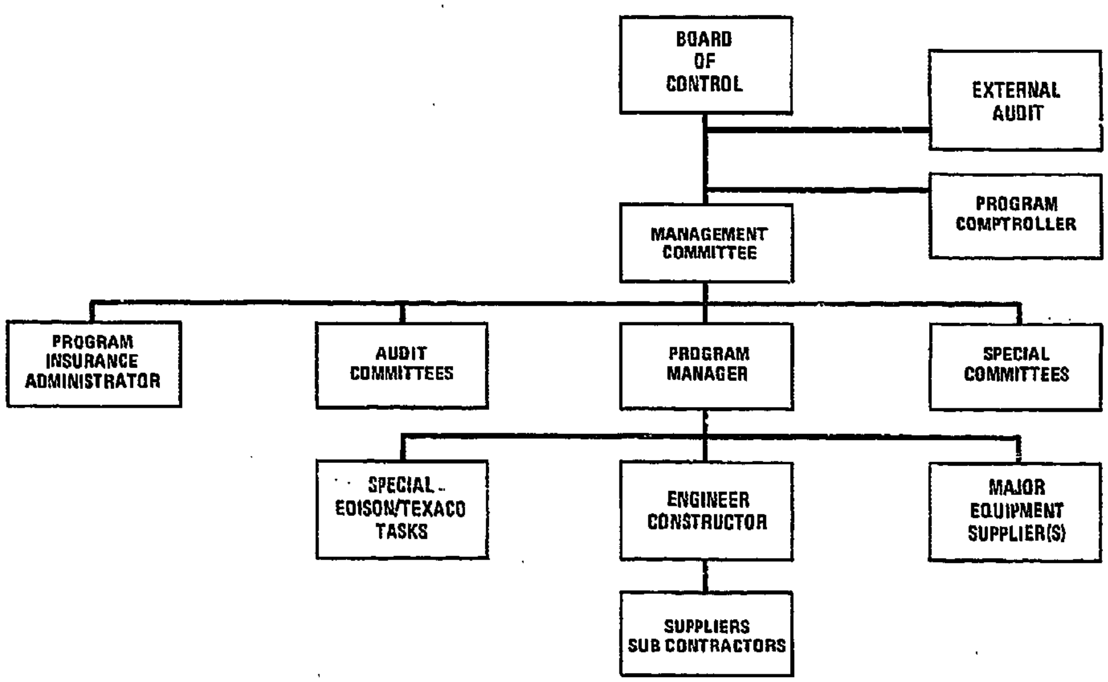


Figure 3-1. Cool Water Program Management Structure

Board of Control

The Board of Control is comprised of one representative from each participant. Each participant has one vote. A two-thirds vote of the Board Members, without a dissenting vote by Texaco or SCE, is required for all decisions. Current members of the Board are shown in Table 3-3.

The Board of Control performs the following duties:

- Establishes the Program objectives.
- Reviews and approves Program concepts, budgets (including overruns), progress, changes in the scope of work, responsibilities of the parties, and recommendations of the Management Committee and Program Comptroller.
- Reviews and approves new and substitute participants and sponsors.
- Considers any other matter deemed necessary for the full and complete operation of the Program.

The meetings of the Board of Control are called by the Chairman and are scheduled on a quarterly basis or more frequently, as necessary. The chairmanship rotates on an annual basis between Texaco and SCE.

The Management Committee, a Comptroller and an External Auditor all report to the Board of Control.

The Program Comptroller has been appointed by SCE and is responsible for receiving, disbursing and accounting for Program funds and revenues. The Arthur Anderson Company has been selected as the External Auditor.

Management Committee

The Management Committee is a working team reporting to the Board of Control. It has the responsibility for carrying out the directives of the Board of Control for contracting, engineering, procuring, constructing, operating and maintaining, and the final disposal of the plant.

The Management Committee is comprised of one member from each participant. Each member has one vote. Committee decisions and directions require a two-thirds vote; if SCE or Texaco cast a dissenting vote, the matter must be submitted to the Board of Control for resolution. Each Management Committee member may be supported by additional representatives of the participants for working subgroups as required to provide technical expertise to the Management Committee.

The Management Committee meets at least monthly or more often as established by its chairman. The chairmanship rotates on an annual basis between SCE and Texaco. Current members of the Management Committee are shown in Table 3-4.

The Management Committee performs the following functions:

- Reviews and makes recommendations for all items which require approval of the Board of Control
- Reviews and approves all other items not requiring Board approval including, but not limited to, technical aspects for achieving Program objectives, operating budgets and schedule
- Monitors and directs the Program Manager
- Initiates and maintains a Program control system
- Carries out other tasks and duties as assigned by the Board of Control

Table 3-3

COOL WATER PROGRAM BOARD OF CONTROL

Name	Affiliation
J.L. Dunlap	Vice President, Alternate Energy Department, Texaco Inc.
L.T. Papay	Vice President, Advanced Engineering, Southern California Edison
D.F. Spencer	Director, Advanced Power Systems Division, Electric Power Research Institute
E.F. Phelps	General Manager, Energy Applications Program Department, General Electric Company
L.G. Hinkelman	Vice President, Bechtel Power Corporation
K. Fujimori	Managing Director, Tokyo Electric Power Company (representing JCWP)

Table 3-4

COOL WATER PROGRAM MANAGEMENT COMMITTEE

Name	Affiliation
T.L. Reed	Project Manager, Engineering and Construction Division, Southern California Edison
W.R. Siegart	Senior Staff Coordinator, Alternate Energy Department, Texaco Inc.
N.A. Holt	Program Manager, Clean Gaseous Fuels, Electric Power Research Institute
D.R. Plumley	Manager, Coal Gasification Combined Cycle Projects, General Electric Company
J. DeDivitis	Division Manager, Engineering, Refining & Chemical Division, Bechtel Petroleum Inc.
S. Araki	Chief Researcher, Engineering R&D Center, Tokyo Electric Power Co. (representing JCWP)

The Program Manager, the Program Insurance Administrator and other special task-oriented committees report to the Management Committee.

The Program Manager and The Program Office

Day-to-day operation and management of the Program is the responsibility of the Program Manager. The present Program staff level stands at 13 engineers, an accountant, a procurement representative and clerical support. The staff is expected to increase as additional participants join the Program. All participants, even those without a specifically defined technical role in the Program, may have representatives at the Program Office.

All design input from the participants to the Engineer/Constructor is handled by the Program Office. The Program Office exercises the necessary degree of control over the work and handles the engineering and procurement approval responsibility for the Program, as well as the accounting, funds collection and disbursement, cost control and scheduling.

The present Program Office organization is illustrated in Figure 3-2.

An auxiliary Program Field Office has been established at the jobsite. This office is headed by a Program Construction Manager under the general direction of the Program Manager, as shown in Figure 3-3. The Program Field Office performs the Program's engineering and inspection responsibilities at the jobsite. Field accounting, funds disbursement, and construction auditing are also provided at the Program Field Office. Some personnel from the field construction office will be retained for the permanent plant operating and maintenance organization.

As the Home Office engineering nears completion, the Program Office may be consolidated at the job site during final construction and into initial plant operations. Key personnel from the engineering office will be at the jobsite during the final construction and start-up phase to contribute their expertise.

Participant Responsibilities

In addition to being part of the management structure of the Program, many current participants have subcontract responsibilities in the engineering, construction and/or equipment supply areas. Each of these responsibilities reflects their

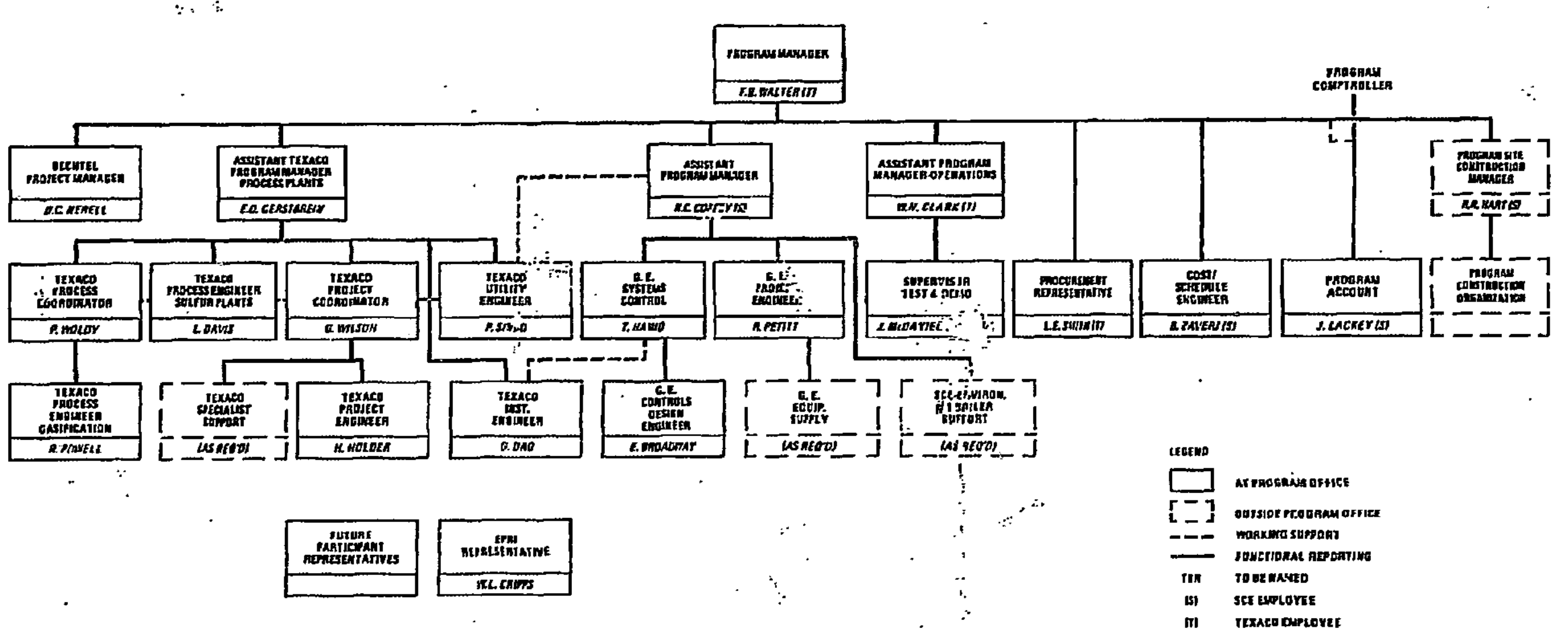


Figure 3-2. Program Office Organization - Engineering Phase

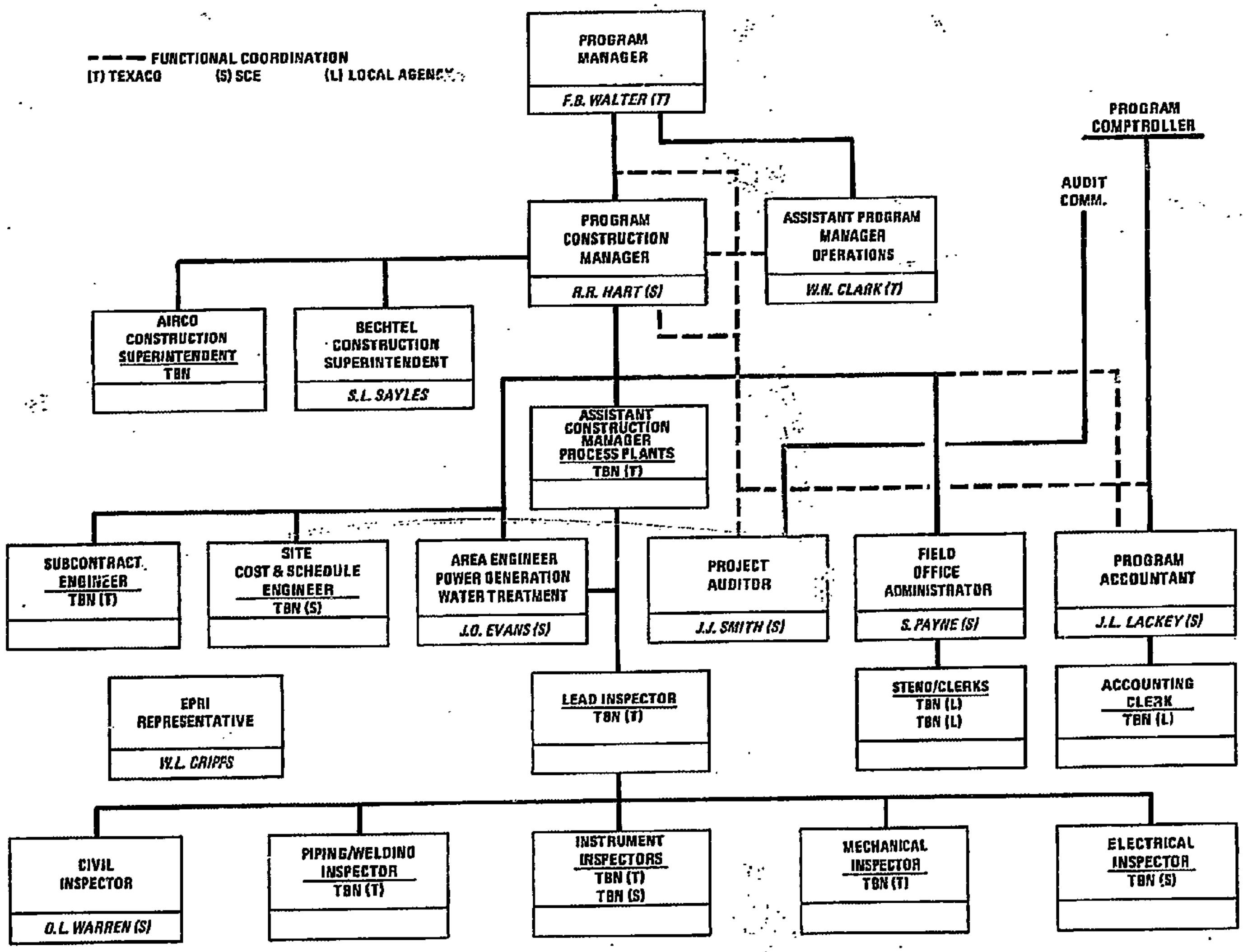


Figure 3-3. Program Field Office Organization - Construction Phase

background, expertise and capabilities in providing the services necessary to accomplish the overall Program tasks.

The participants' responsibilities are identified in Figure 3-4. In providing these services, these organizations are under the direction of the Program Manager.

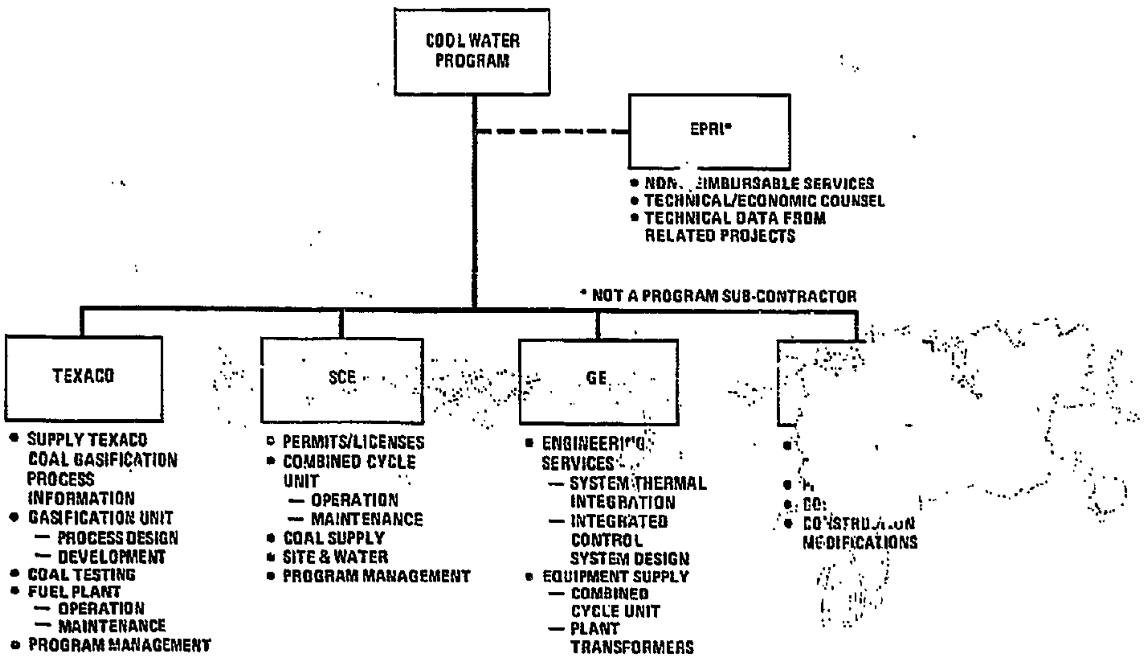


Figure 3-4. Responsibilities of Program Participants

Section 4

GENERAL PROJECT DESCRIPTION

The Cool Water Coal Gasification Program encompasses the design, construction, start-up and operation of a commercial-scale, integrated coal gasification-combined-cycle electric generating facility. The intent of the Program is to confirm, at a commercial scale, that coal can be utilized as a fuel (via gasification) for combustion turbine/combined cycle plants and conventional boilers to produce power in an environmentally superior manner while satisfying electric utility requirements for reliability, economy and compatibility. The system is being designed to operate as an integrated gasification combined-cycle plant, although provisions are being included for firing and testing the performance of the synthesis gas in an existing 65 MW boiler.

Specific objectives include:

- Demonstration of the integrated coal gasification-electric power generation technology on a commercial scale (1000 tons coal/day)
- Demonstration of system compliance with environmental regulations
- Demonstration of system compatibility with utility systems and standards. Of primary interest are specific operating performance including start-up, shutdown and dynamic load following capability over a wide operating range, thermal operating efficiency, reliability of the integrated system and its components, and availability and operational safety at a high capacity factor
- Demonstration of the feasibility of adapting various hardware components (burners, combustors, etc.) to the gasification/electric power generation process
- Demonstration of operational flexibility with a variety of coal feedstocks
- Development of precise capital and operating/maintenance costs and procedures to permit a thorough analysis of the economic competitiveness of the system with other energy alternatives for use in the 1980's and beyond
- Development of design and scale-up criteria for planned future applications of the technology
- Evaluation of performance of existing boiler when firing coal-derived syngas

- Facilitation of utility operator training. On-the-job training and experience and operating procedures and manuals derived therefrom will ensure a smooth transition from demonstration plant to future use of the technology.

The work to be performed in the Program has been divided into five phases, as shown in Figure 4-1, and takes into account the normal complexities associated with the design, construction, start-up and operation of a coal-based power plant.

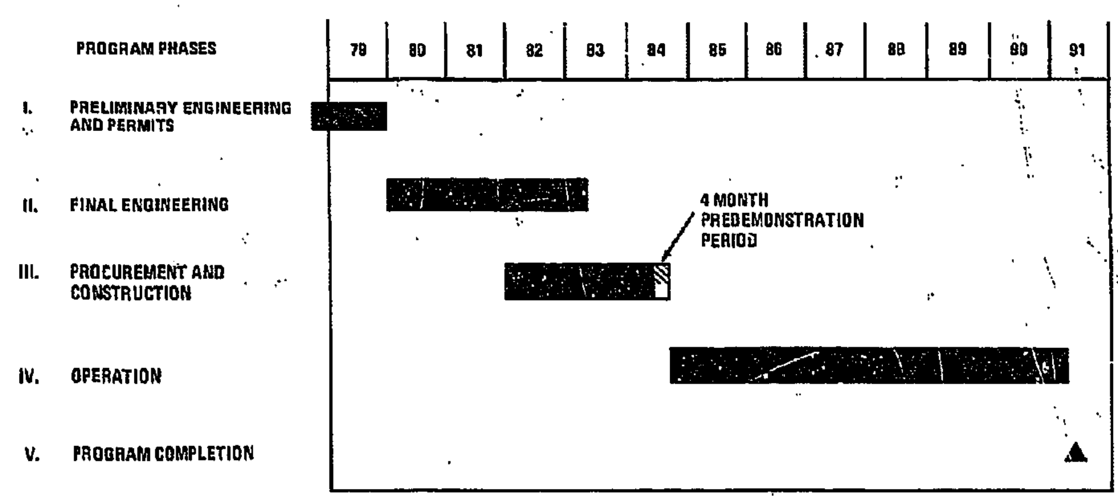


Figure 4-1. Program Schedule

The types of activities to be carried out in each phase are identified below and are representative of the nature and general content of the work required to design, build and operate facilities of this type.

Phase I (Preliminary Engineering and Permits) has been completed and Phases II and III (Final Engineering, Procurement and Construction) are in progress. Phase IV (Operation) is planned to begin in late-1984, after a suitable shakedown period (Pre-demonstration). The venture is planned to terminate in early 1991, at which time it is anticipated that Southern California Edison may exercise its option, as defined in the joint venture agreement, to purchase the plant as an energy resource for their system.

PHASE I - PRELIMINARY ENGINEERING

The Preliminary Engineering phase of the program began in 1978 and was completed when the California Energy Commission granted the environmental permit in December 1979.

Phase I work included:

- The 1978 preliminary design study performed by Ralph M. Parsons Company with EPRI funding
- Texaco tests at the 15 tpd Montebello pilot plant and preliminary conceptual design studies
- Investigation of regulatory permit requirements and preparation and submittal of a Notice of Intent for Approval of Site and Related Facilities, including supplemental environmental data
- Initial solicitation of participants

Preliminary Design Study

An EPRI-funded study was conducted by Ralph M. Parsons Company to perform the preliminary design of a coal gasification combined-cycle demonstration plant. Included were project costs and schedules, preliminary design information and performance and emissions data for the proposed plant (published as EPRI Report AF-880).

During the study, design data was developed for the major systems and included preparation of:

- Overall plant process schematic diagram
- Site and plot plans
- System design basis
- Process descriptions and flow diagrams
- Preliminary process and mechanical specifications
- Material (including utility) and energy balances
- Project cost estimates and schedules

Coal Gasification Pilot Plant Tests

In 1978 and 1979, coal gasification tests relating to this program were performed at Texaco's Montebello Research Laboratory facilities. The objectives of the tests were to determine the feasibility of utilizing low sulfur Western coal in the

Texaco gasifier, obtain preliminary engineering design data and perform environmental measurements to determine the environmental acceptability of the gasification process. The information obtained from the performance of these tests was used in the preliminary engineering studies and, subsequently, as technical data for submittal to the California Energy Commission in the certification activities.

Permitting and Regulatory Activities

In July 1978, a Notice of Intent (NOI) was submitted to the California Energy Commission (CEC) and accepted. A petition to convert and expedite the Cool Water Demonstration Project to Application for Certification (AFC) was approved in October 1978.

Following submittals by SCE and Texaco of technical information addressing site acceptability and various other concerns, hearings were conducted and the AFC was approved by the CEC on December 21, 1979.

In November 1979, the California Public Utilities Commission (CPUC) application for Certificate of Public Convenience and Necessity (CPCN) was submitted. A decision on the CPCN from the CPUC was received August 19, 1980. For both of these applications, engineering, environmental and economic analyses were performed.

A Prevention of Significant Deterioration (PSD) permit application was filed with the EPA. SCE began obtaining the required one year of monitoring data on the existing site local environment in late 1979 and had submitted all data to the EPA by the end of 1980. With California standards being generally more stringent than federal regulations, no major problems were foreseen in obtaining the PSD permit. The PSD permit was approved by the EPA on December 9, 1981.

Solicitation of Participants

Though solicitiation of participants and sponsors is not an engineering activity, a significant number of business and technical presentations have been made to a variety of potential industrial and utility sponsors by Texaco, SCE, EPRI, Bechtel and GE during Phase I and Phase II of the Program and these activities are continuing in Phase III.

PHASE II - FINAL ENGINEERING

The Final Engineering phase, which began on February 1, 1980, covers the engineering and detailed design of the plant, preparation of construction drawings and specifications, development of procurement specifications for material and equipment and preparation of operating, testing and maintenance procedures. This phase is estimated to last until the end of 1982.

In the initial months of this phase certain identified options concerning the system configuration were evaluated, with the aim of firming up the basic plant design arrangement.

The Program coal, a Utah low sulfur bituminous, had been selected and process data runs were made at Texaco's Montebello Research Laboratories providing the data necessary to complete the process design. Further testing to obtain confirmatory data was performed at the 165 tpd Ruhrchemie facility in Oberhausen, West Germany, in late 1980.

Specifications for major gas plant compone ts were developed and issued. Bid packages for these components were prepared and vendor selections made.

Major engineering efforts are proceeding on one of the key subsystems, the integrated control system. The performance of this system, compatible with utility system practices, represents an important commercial development required of the Cool Water Program.

While procurement is primarily a Phase III activity, some limited procurement, involving long delivery major equipment and confined for the most part to vendor engineering, was authorized during Phase II.

Phase II Work included the following:

- Perform plant configuration studies including:
    - -- Steam cycle alternatives - Review of the suggested steam cycle with consideration given to steam conditions, heat recovery, steam generator duty and oxygen plant compressor drive alternatives
    - -- Plant control - Analysis of the plant control system to project the load-following characteristics, need for fuel gas surge tank and ability to transfer to a standby fuel

p

- -- Auxiliary steam - Consideration for use of steam from existing on-site units, the combined cycle unit on standby fuel, or the addition of a new auxiliary boiler for start-up
- -- Water consumption/balance - Analysis of total plant water requirements and methods of recycle of blowdown, fines underflow, etc.
- -- Ash disposal - Determination of ash disposal or alternate uses and economic considerations associated with same
- -- Plant emissions - Emissions testing and monitoring with full-scale combustor to project air quality emissions
- -- Test program - Development of a detailed test program including a description of locations and types of data to be gathered, schedule of program and statement of objectives for all test modes. The purpose of the test program will be to verify technical design, operational controls and environmental effects
- -- Operating requirements - Identification of O&M requirements including personnel, start-up and shutdown times

- Perform gasification studies including:

  - -- Syngas cooler - Optimization of syngas cooler system design
  - -- Sulfur removal - Selection of the optimum method of sulfur removal to achieve a minimum 97-percent-efficient system for the design coal and for EPRI's high sulfur Illinois No. 6 test coal
  - -- Sulfur recovery - Determination of the most effective sulfur recovery plant to be used in conjunction with the sulfur removal to achieve a minimum 97-percent-efficient system for the design coal and for EPRI's high sulfur Illinois No. 6 test coal
  - -- Oxygen storage - Determination of the benefits of providing oxygen surge tank and storage capacity for periods of plant shutdown
  - -- Coal preparation - Consideration of methods to achieve, handle and maintain proper coal slurry concentrations. Study included actual tests of various types of grinding/slurrying equipment

- Perform soils investigations and prepare report
- Prepare plant design criteria, process flow diagrams
- Prepare heat and material balances, plot plans, piping and instrument diagrams, electrical one-lines, material selection guides and major equipment specifications and data sheets
- Obtain quotes on major equipment, select vendors and begin vendor engineering

- Prepare plant model
- Perform final engineering, including the preparation of design drawings, construction drawings, equipment specifications and construction specifications
- Prepare critical path method schedule for Phase III
- Formulate operations plan for Phase IV
- Prepare progress reports for the participants, as required

PHASE III - FINAL PROCUREMENT AND CONSTRUCTION

Phase III, which began in December 1981, encompasses the procurement of the remaining equipment and materials, the construction of the plant and a pre-demonstration period. This pre-demonstration period is planned to allow complete shakedown of the plant in the integrated mode, gasification plus combined cycle operation, prior to proceeding into the long-term operation period of Phase IV.

With the beginning of Phase III, previously selected major equipment vendors were released for materials and fabrication and procurement of bulk materials began. Field construction was also started in December 1981.

Bechtel, the Engineer-Constructor, under the direction of the Program Office, provides the following:

- Procurement Services, including development of bidders' lists, preparing inquiries, obtaining and evaluating quotations, recommending awards, inspection and expediting, publication of periodic status reports of major equipment and materials
- Construction Services, including direct hire and subcontracting construction labor, field engineering, field supervision, temporary construction facilities, procurement of field construction equipment and consumables; monitoring and reporting construction progress versus schedule, conducting of equipment and systems tests at conclusion of construction
- Pre-operational Testing Services, including procedures, materials and service engineers to assist Texaco and SCE personnel in preoperational cleaning, equipment testing and systems checkout prior to the pre-demonstration period

After completion of pre-operational testing a pre-demonstration period, presently planned to last four months, will be initiated. This will allow sufficient time to "debug" the facility prior to committing the plant to long-term, high capacity operation. Specific activities will include:

- Initial start-up of fuel plant with corresponding production of first fuel gas
- Operation of combined cycle on distillate fuel
- Integrated operation of fuel plant and combined cycle at partial loads
- Operation of integrated facility at rated conditions
- Preliminary load following tests of integrated facility to assess response to electric power generation demand
- Preliminary evaluation of performance and economics at normal and off-normal operation conditions

PHASE IV - TESTING AND OPERATION

Following the pre-demonstration period, long-term plant operation is scheduled to begin in late-1984 and last for six and one-half years.

Work efforts in Phase IV will include:

- Operation of all plant facilities in accordance with pre-established plans to achieve project objectives
- Conducting of special process and equipment tests
- Testing of performance on various coals, including EPRI's test coal
- Maintenance of all equipment and systems
- Inspection of plant and equipment at regular intervals
- Monitoring of plant emissions and environmental performance
- Reporting on operations progress and economic performance

During the planned six and one-half year period of operation, an average capacity factor of 77 percent has been established as a goal. On a period basis, target capacity factors shown in Table 4-1 have been identified in order to achieve this goal.

Table 4-1

TARGET CAPACITY FACTORS

First Four Quarters	50%
Next Four Quarters	73%
Next Four Quarters	80%
Next Fourteen Quarters	85%
Average for 26 Quarters	77%

Operation and maintenance of the facility during this period will be a joint effort of Texaco and SCE and the electricity produced will be delivered to SCE's system. Southern California Edison will supply the coal and will pay the Program a fee for its processing into synthesis gas. This fee will pay for the Program's operation and maintenance costs and will repay to each participant (except SCE) its net capital contributions to the Program on a proportionate basis with the actual plant capacity factor achieved versus the target capacity factor.

Initially, operation of the facility will be on the design coal, a low sulfur Utah bituminous. Subsequently, participant coal will be utilized to demonstrate at commercial scale feedstock flexibility of the gasification combined-cycle system. EPRI has selected Illinois No. 6 with 3.5 percent sulfur as its candidate coal and it is anticipated that other participants will also nominate coals expected to be used in subsequent commercial facilities.

Since this plant represents unique integration of several processes and constitutes a single prototype for many future plants, it is imperative that plant performance measurements and equipment testing and monitoring procedures be more comprehensive than for a normal commercial facility. These requirements will be met through the definition of a rigorous, comprehensive test plan, through performance of heat and mass balances on all major systems, extensive data logging and thorough equipment surveillance.

As presently contemplated, a Program operations schedule is summarized in Figure 4-2. This schedule allows at least two years for Program coal performance and long-duration testing, the equivalent of six months of alternate coal tests which would be completed over a two-year period, with the remaining time allotted to long-term operation using the Program coal.

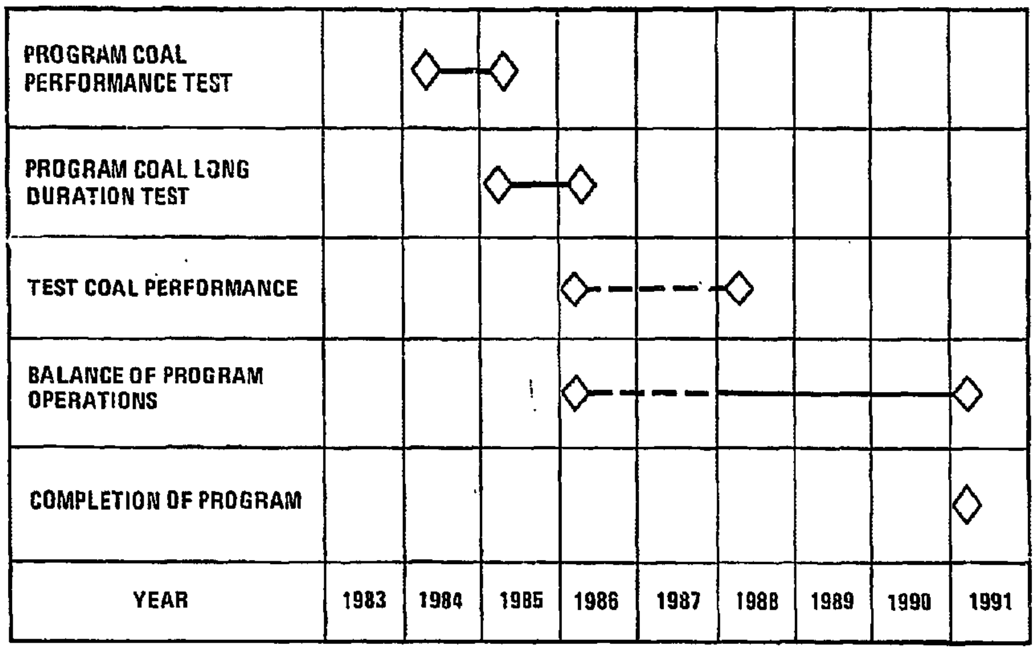


Figure 4-2. Cool Water Coal Gasification Program Operations Schedule

The long-duration test operations using the Program coal will focus on the determination of the long-term reliability of the process and the durability of process equipment (such as the gasifier refractory). The process will be operated in its optimum configuration as determined during the preceding Program coal performance test phase. Plant operations will again be monitored thoroughly to determine such information as plant heat rates, environmental impact and operating life of critical process equipment. An important task will be the monitoring of materials using suitable measurements and inspections of the materials during forced outages and scheduled shutdowns. Training of operating personnel will also be addressed.

Following the completion of performance and long-duration operations using the Program coal, a series of tests will be performed using coals selected by the participants of the Program. The plant operations using test coals will follow an abbreviated version of the Program coal performance test program. Short-term performance tests will be conducted with each coal to determine optimum process operating criteria. Following these tests, the process will be operated continuously for several weeks to obtain heat and mass balance data similar to the previous Program coal tests. These tests will also yield performance data such as plant heat rates.

PHASE V - PROGRAM COMPLETION

After completion of the planned six and one-half year operation period, it is anticipated that the joint venture will be terminated. The Texaco/SCE agreement provides distinct options for Program completion, including:

- SCE's purchase of the total plant for inclusion as an electric generating facility resource. SCE has the right of first refusal for the plant
- Another utility purchasing the total plant for operation at the Cool Water Generating Station or dismantling and relocation
- SCE could purchase a portion of the plant if no offer for the total plant is received
- If neither SCE nor other parties purchase the plant or portions thereof, then the Program will salvage the plant and return the plant site to its original condition

Section 5

PROCESS AND PLANT DESCRIPTION

GENERAL

Coal will normally be delivered to the plant by rail in unit trains and will be unloaded from each hopper car and conveyed to storage. The coal will then be crushed and ground to the required size, slurried with water and fed to the refractory-lined gasifier. In the gasifier, the coal and water will be reacted with oxygen (in an exothermic reaction), producing a raw synthesis gas consisting primarily of hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), and steam. Within the gasifier the coal ash will be melted into slag, which will be subsequently quenched with water and removed through a pressurized lockhopper system. The synthesis gas produced will be cooled in the radiant and convection gas coolers to produce saturated steam (which will be superheated in the combined cycle unit heat recovery steam generator), thus recovering and utilizing much of the process waste heat.

The synthesis gas will pass through a wet scrubbing system to remove particulates and is then cooled to ambient temperature prior to sulfur removal. Sulfur compounds, consisting primarily of hydrogen sulfide (H_2S), will be removed in a Selexol physical solvent sulfur removal system. A Claus sulfur conversion system and a SCOT (Shell Development Co.) tail gas treating unit will receive a H_2S stream from the sulfur removal unit for conversion to elemental sulfur for disposal or sale. The synthesis gas from the sulfur removal system will then be delivered to the combustion turbine-generator after saturation with water for NO_x suppression.

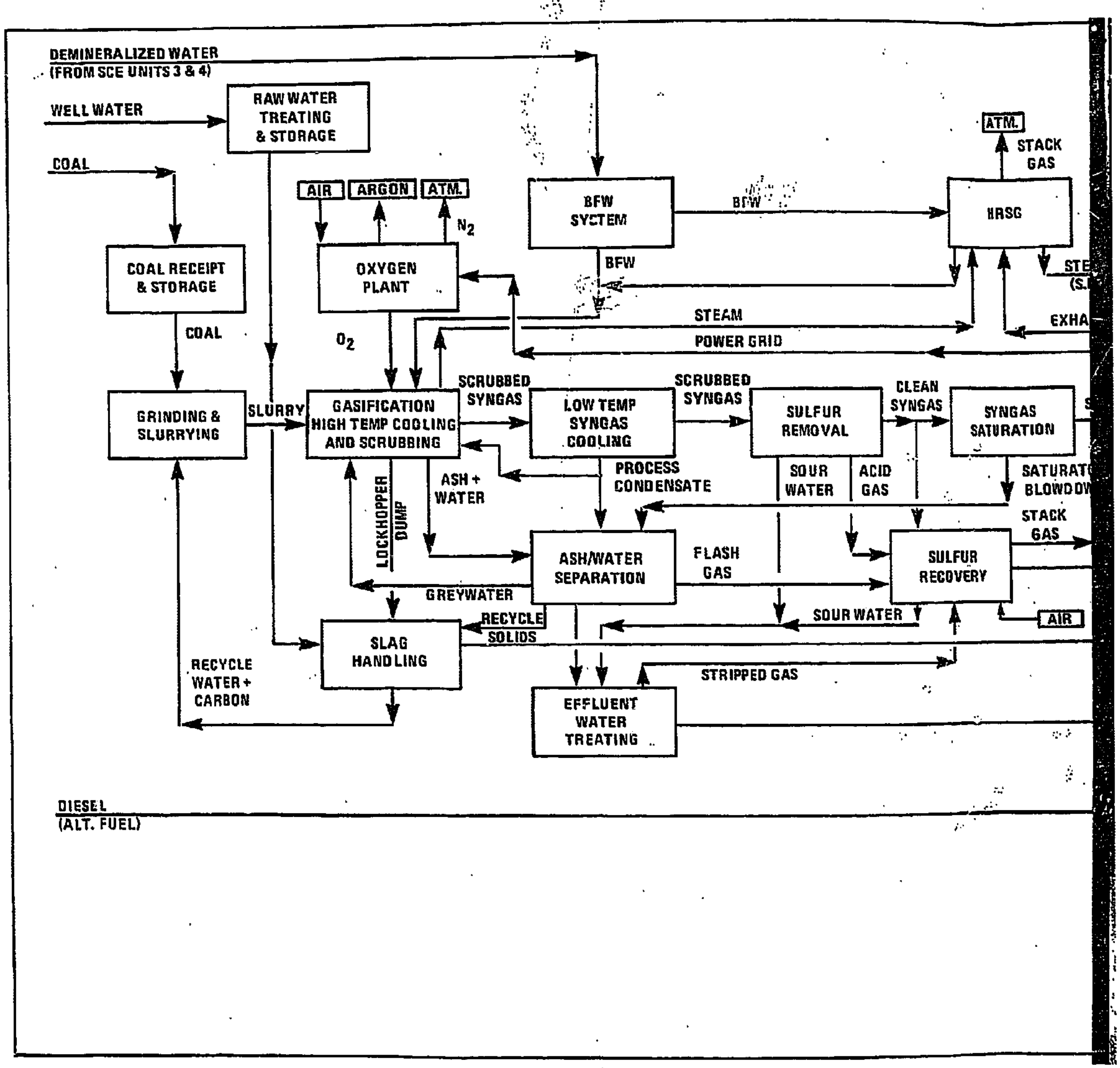
The combined cycle generating system includes a gas turbine generating unit of approximately 65 MW capacity. The gas turbine will be designed to operate primarily on the synthesis gas although provisions are made for firing a standby (start-up) diesel fuel oil. A steam turbine will be operated on superheated steam produced in the heat recovery steam generator, thereby increasing the overall efficiency of the integrated gasification-electric generation system. After being cooled in the heat recovery steam generator, the combustion turbine exhaust will be vented to the environment. An overall block flow diagram of the system is shown in drawing B73-SK-110. A more detailed flow diagram of the integrated gasification combined cycle process is presented in drawing B73-SK-100 (sheets 1 and 2). Drawings C20-SK-116 and C20-SK-115 show the overall site plan and plot plan, respectively.

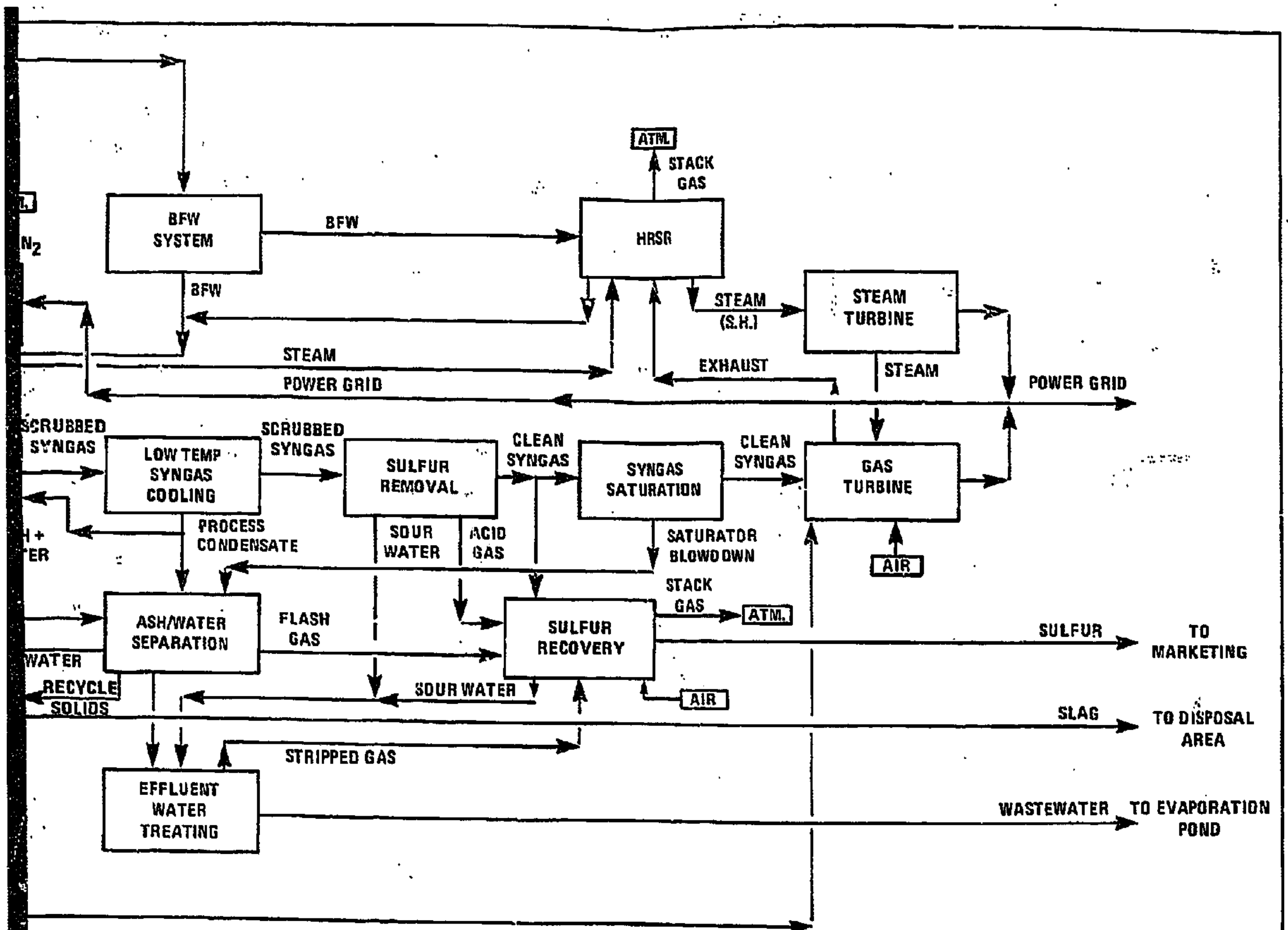
The coal selected as the normal operating coal (Program coal) is a high grade Utah bituminous coal from the Southern Utah Fuel Co. (SUFCO) mine. A summary of the coal's characteristics is shown in Table 5-1.

Table 5-1

PROGRAM COAL CHARACTERIZATION
(Typical)

Proximate Analysis, wt%	
Moisture	10.00
Ash	9.45
Volatile Matter	36.05
Fixed Carbon	44.50
	100.00
Ultimate Analysis, wt%	
Moisture	10.00
Carbon	63.2
Hydrogen	4.3
Nitrogen	1.05
Sulfur	0.45
Ash	9.45
Oxygen	11.55
	100.00
Higher Heating Value	
As received:	11,150 Btu/lb


DEMINERALIZED WATER
(FROM SCE UNITS 3 & 4)
WELL WATER
RAW WATER TREATING & STORAGE
COAL
AIR
ARGON
ATM.
N_2
BFW SYSTEM
BFW
HRSG
ATM.
STACK GAS
COAL RECEIPT & STORAGE
OXYGEN PLANT
STEAM
POWER GRID
O_2
GRINDING & SLURRYING
SLURRY
GASIFICATION HIGH TEMP COOLING AND SCRUBBING
SCRUBBED SYNGAS
LOW TEMP SYNGAS COOLING
SULFUR REMOVAL
CLEAN SYNGAS
SYNGAS SATURATION
PROCESS CONDENSATE
ASH + WATER
LOCKHOPPER DUMP
SOUR WATER
ACID GAS
ASH/WATER SEPARATION
FLASH GAS
SULFUR RECOVERY
STACK GAS
GREYWATER
RECYCLE SOLIDS
SLAG HANDLING
SOUR WATER
AIR
RECYCLE WATER + CARBON
STRIPPED GAS
EFFLUENT WATER TREATING
DIESEL
(ALT. FUEL)



BECHTEL
HOUSTON

COOL WATER COAL GASIFICATION PROGRAM

BLOCK FLOW DIAGRAM

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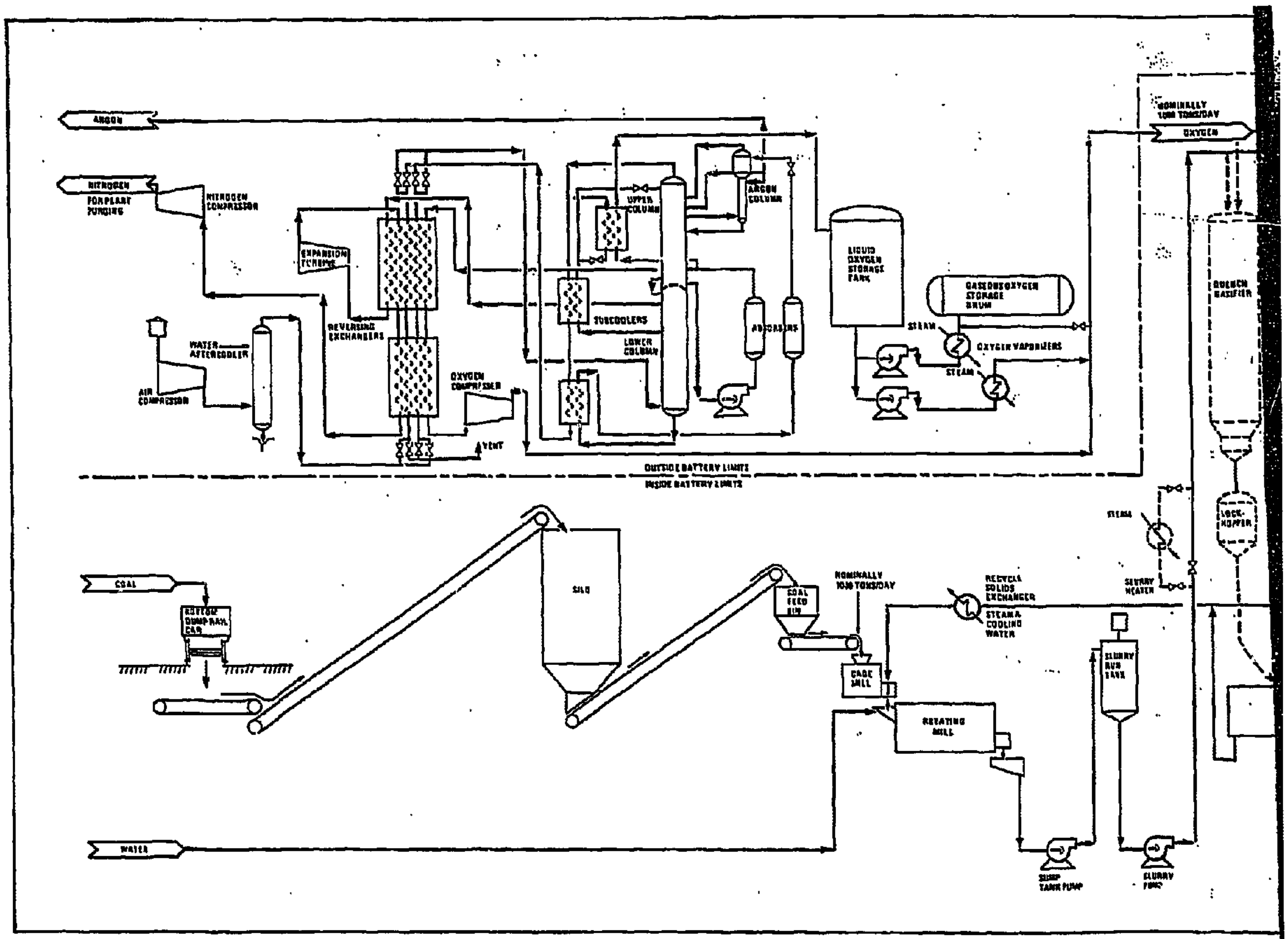
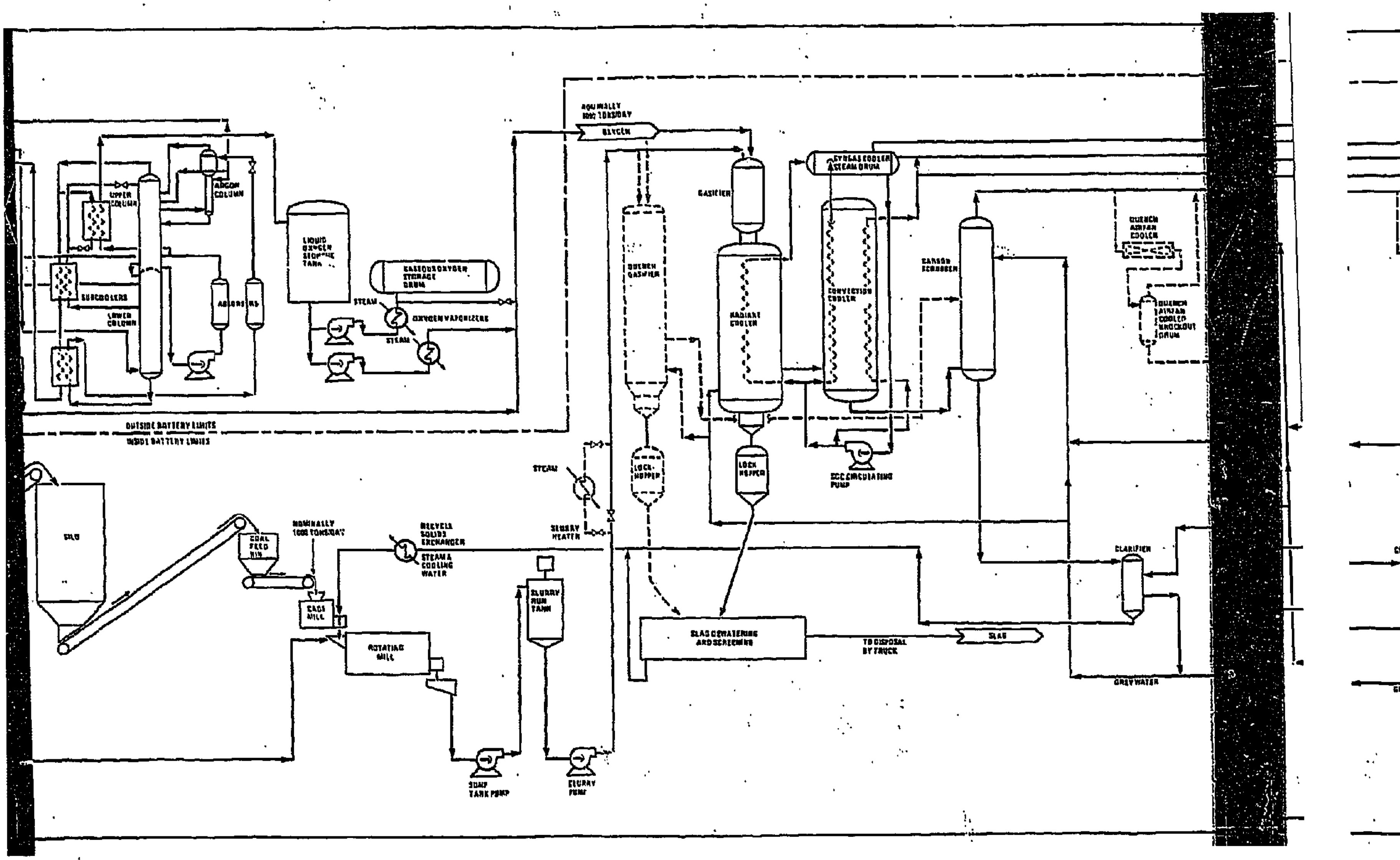
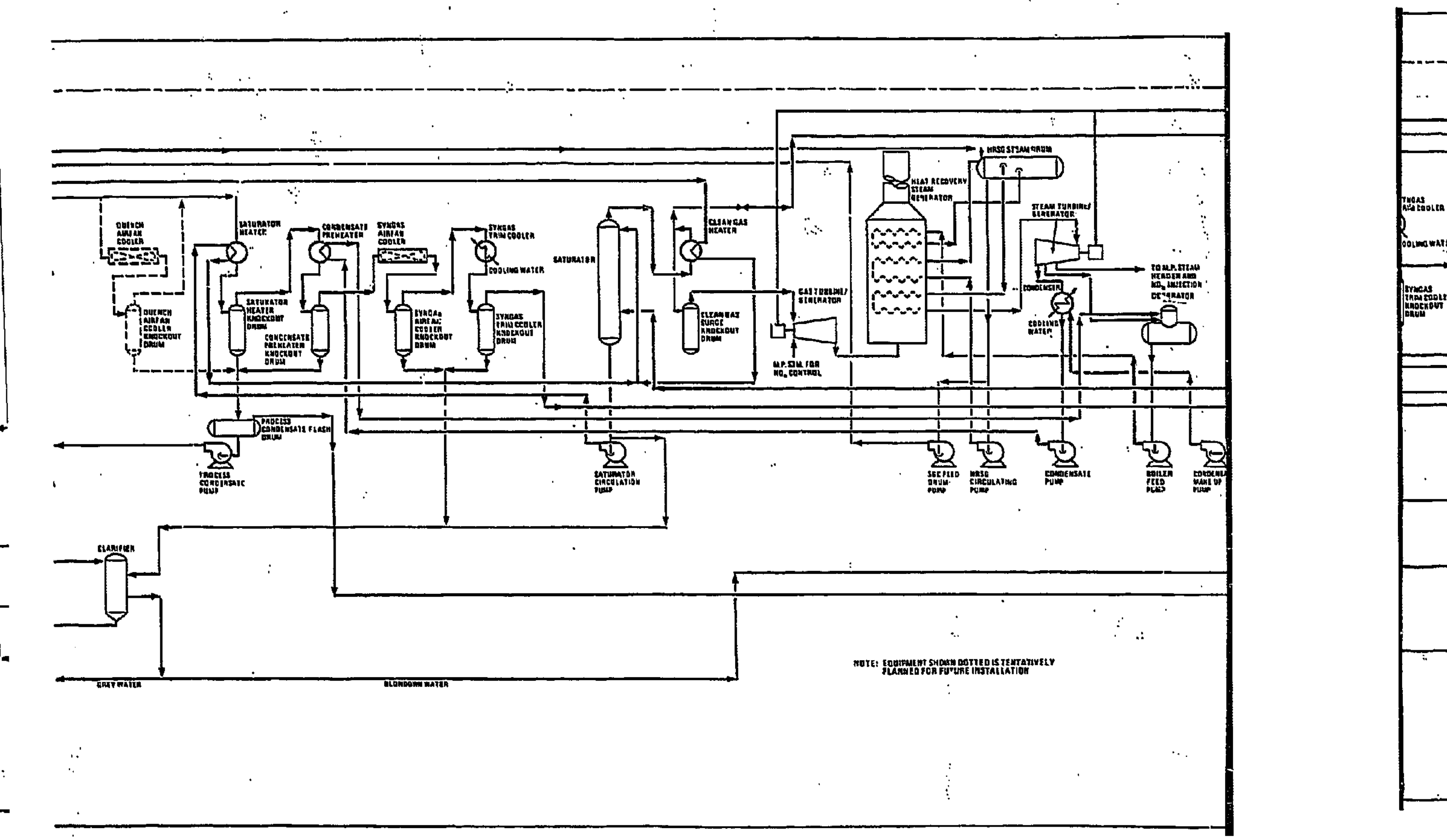
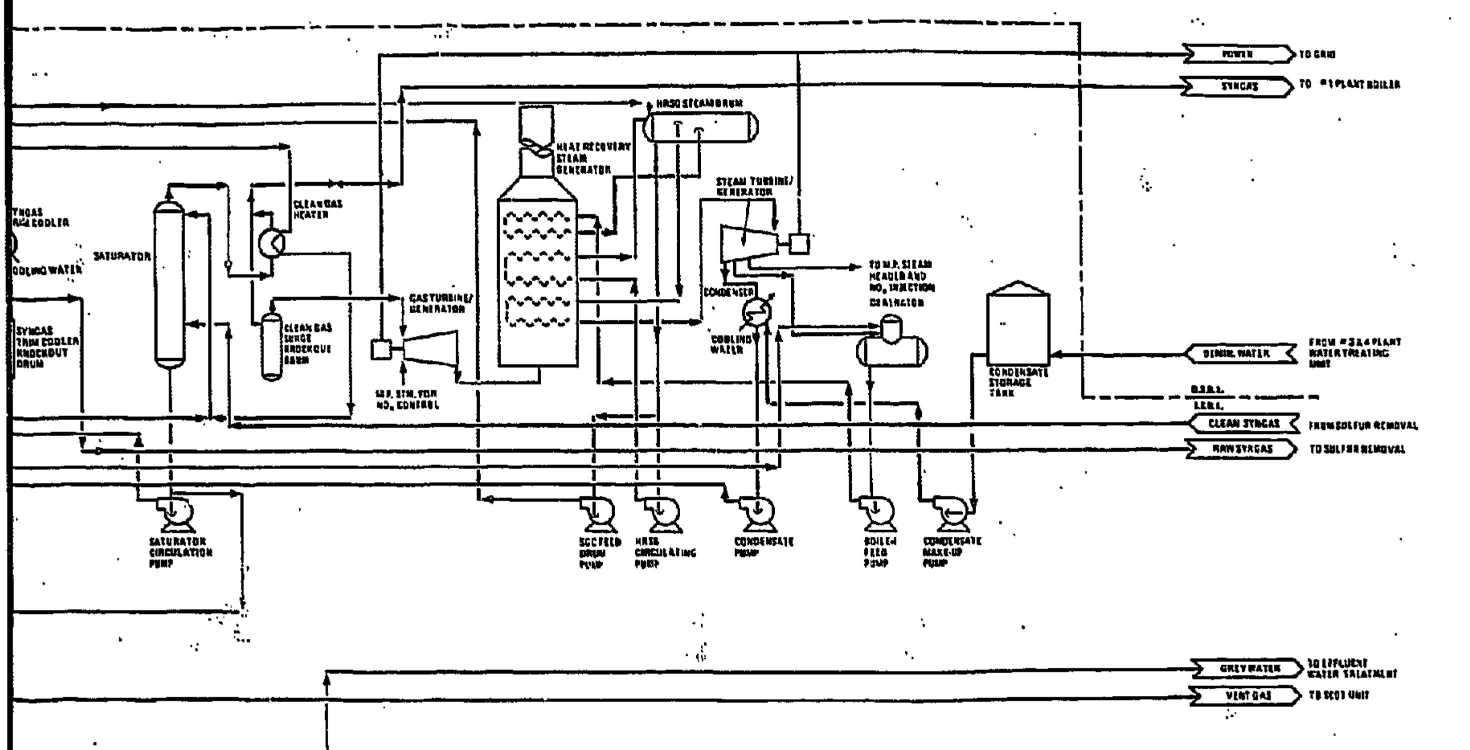

ARGON
NITROGEN
FOR PLANT PURGING
NITROGEN COMPRESSOR
EXPANSION TURBINE
REVERSING EXCHANGERS
WATER AFTERCOOLER
AIR COMPRESSOR
OXYGEN COMPRESSOR
VENT
UPPER COLUMN
ARGON COLUMN
SUBCOOLERS
LOWER COLUMN
ABSORBERS
LIQUID OXYGEN STORAGE TANK
GASEOUS OXYGEN STORAGE DRUM
STEAM
OXYGEN VAPORIZERS
NOMINALLY 1000 TONS/DAY
OXYGEN
QUENCH GASIFIER
OUTSIDE BATTERY LIMITS
INSIDE BATTERY LIMITS
LOCK-HOPPER
SLURRY HEATER
COAL
BOTTOM DUMP RAIL CAR
SILO
COAL FEED BIN
NOMINALLY 1000 TONS/DAY
CAGE MILL
RECYCLE SOLIDS EXCHANGER
STEAM & COOLING WATER
SLURRY RUN TANK
WATER
SUMP TANK PUMP
SLURRY PUMP


UPPER COLUMN
ARGON COLUMN
SUBCOOLERS
LOWER COLUMN
ABSORBERS
LIQUID OXYGEN STORAGE TANK
GASEOUS OXYGEN STORAGE DRUM
STEAM
OXYGEN VAPORIZERS
STEAM
OUTSIDE BATTERY LIMITS
INSIDE BATTERY LIMITS
GASIFIER
QUENCH GASIFIER
RADIANT COOLER
SYNGAS COOLER STEAM DRUM
CONVECTION COOLER
CARBON SCRUBBER
QUENCH AIR FAN COOLER
QUENCH AIR FAN COOLER KNOCKOUT DRUM
LOCK-HOPPER
LOCK HOPPER
SCC CIRCULATING PUMP
STEAM
SLURRY HEATER
SILO
COAL FEED BIN
CAGE MILL
ROTATING MILL
STEAM & COOLING WATER
SLURRY RUN TANK
SUMP TANK PUMP
SLURRY PUMP
SLAG DEWATERING AND SCREENING
TO DISPOSAL BY TRUCK
SLAG
CLARIFIER
GREY WATER


QUENCH AIRFAN COOLER
QUENCH AIRFAN COOLER KNOCKOUT DRUM
SATURATOR HEATER
SATURATOR HEATER KNOCKOUT DRUM
CONDENSATE PREHEATER
CONDENSATE PREHEATER KNOCKOUT DRUM
SYNGAS AIRFAN COOLER
SYNGAS AIRFAN COOLER KNOCKOUT DRUM
SYNGAS TRIM COOLER
COOLING WATER
SYNGAS TRIM COOLER KNOCKOUT DRUM
SATURATOR
CLEAN GAS HEATER
CLEAN GAS SURGE KNOCKOUT DRUM
GAS TURBINE/ GENERATOR
M.P. STM. FOR NO_x CONTROL
HEAT RECOVERY STEAM GENERATOR
HRSG STEAM DRUM
STEAM TURBINE/ GENERATOR
CONDENSER
COOLING WATER
TO M.P. STEAM HEADER AND NO_x INJECTION
DEAERATOR
PROCESS CONDENSATE FLASH DRUM
PROCESS CONDENSATE PUMP
SATURATOR CIRCULATION PUMP
SGC FEED DRUM PUMP
HRSG CIRCULATING PUMP
CONDENSATE PUMP
BOILER FEED PUMP
CONDENSATE MAKE UP PUMP
CLARIFIER
GREY WATER
BLOWDOWN WATER
NOTE: EQUIPMENT SHOWN DOTTED IS TENTATIVELY PLANNED FOR FUTURE INSTALLATION



NOTE: EQUIPMENT SHOWN DOTTED IS TENTATIVELY PLANNED FOR FUTURE INSTALLATION

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COOL WATER COAL GASIFICATION PROGRAM

OVERALL PROCESS FLOW DIAGRAM OXYGEN PLANT, COAL HANDLING AND SLURRYING, GASIFICATION, POWER GENERATION

JOB No	DRAWING No	REV
13478	B73 - SK - 100 SHEET 1 OF 2	0

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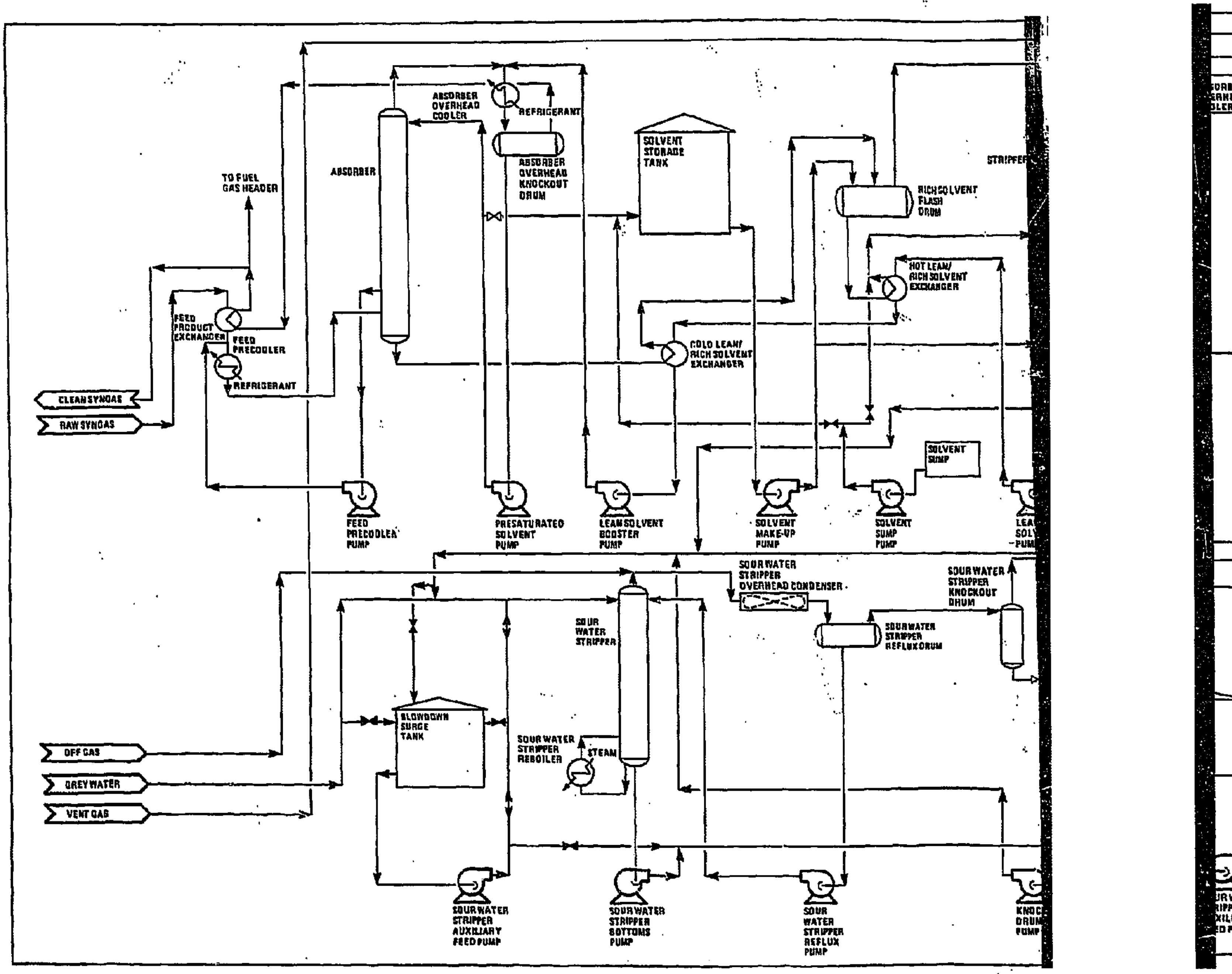
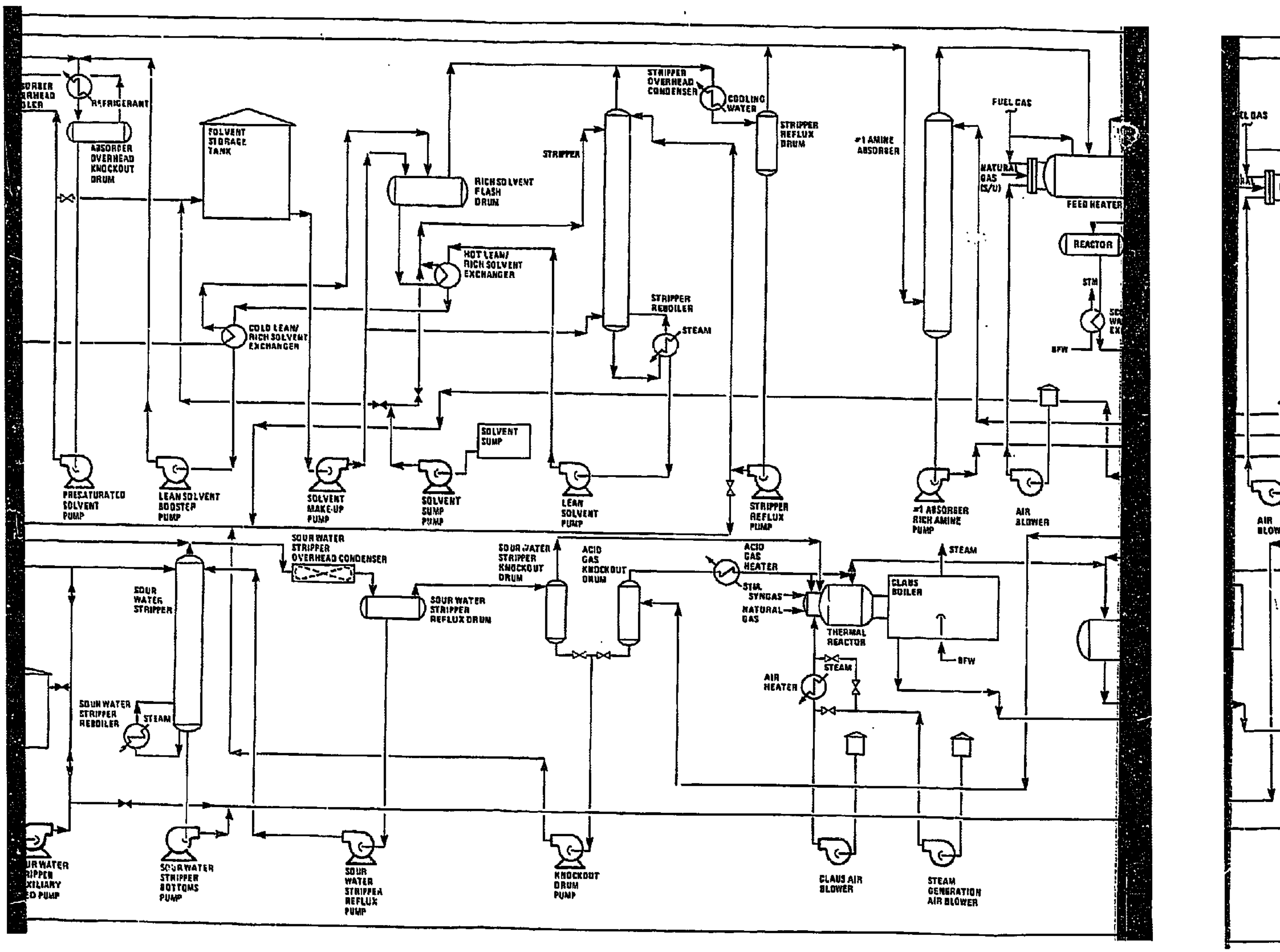
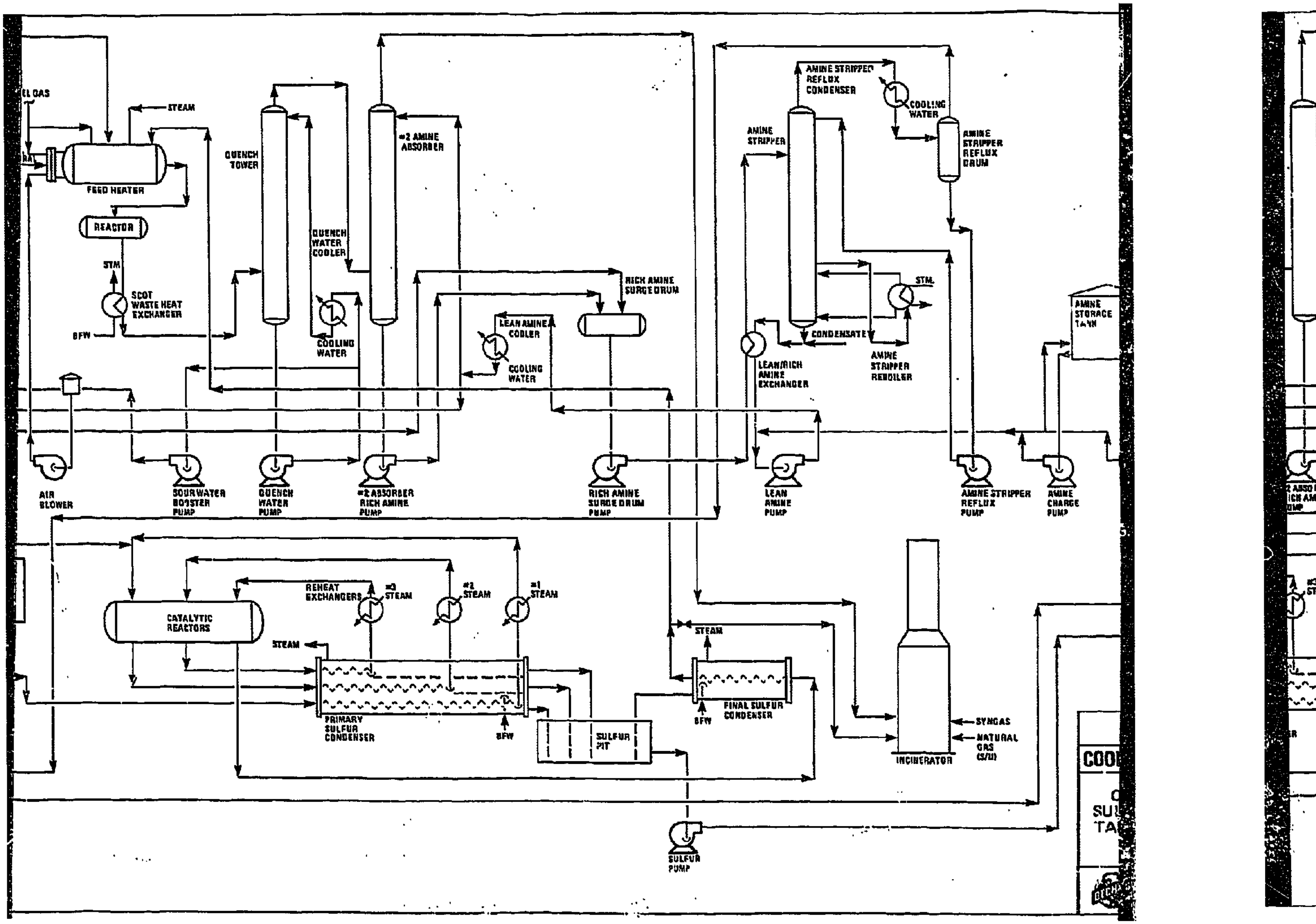
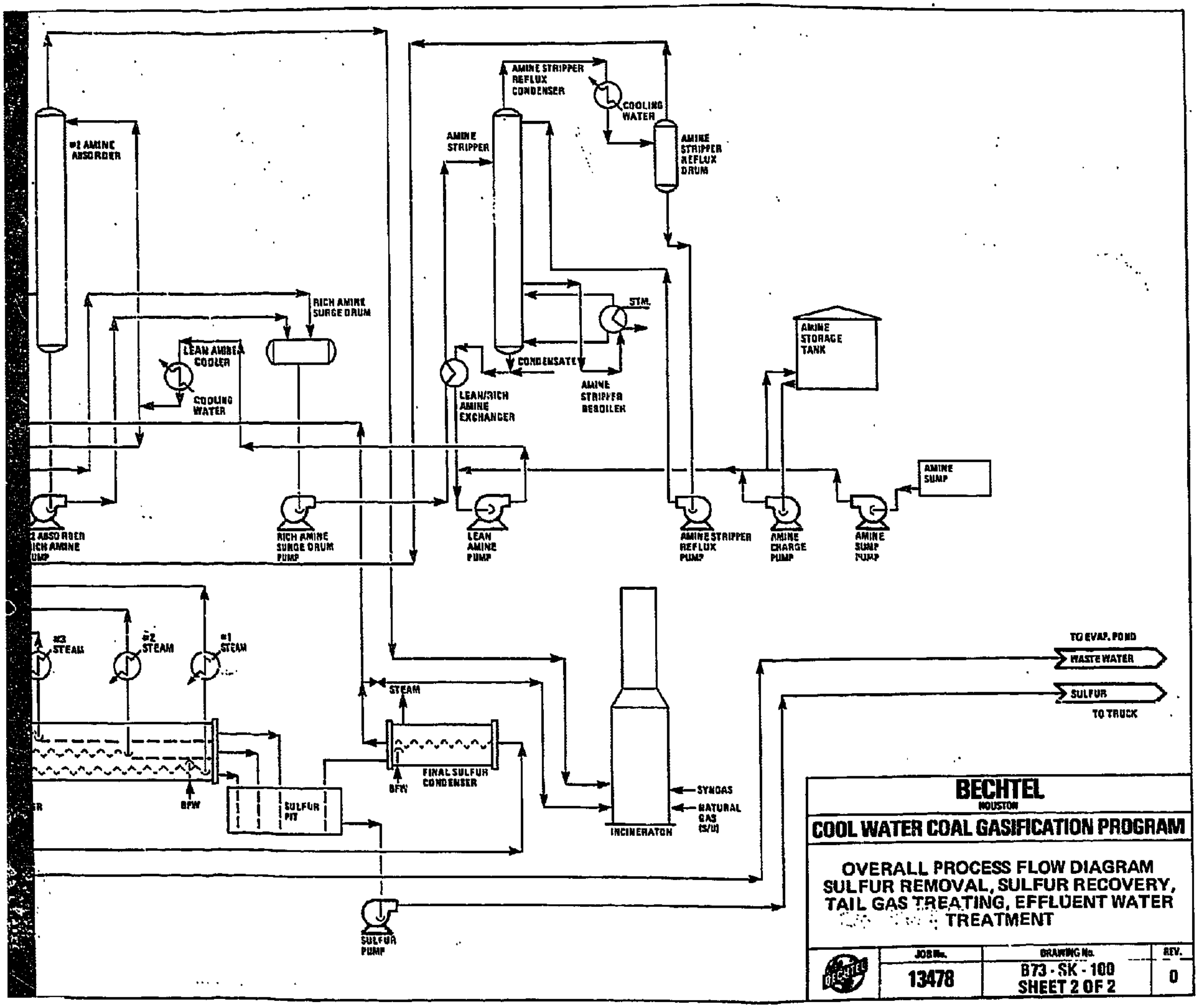

ABSORBER OVERHEAD COOLER
REFRIGERANT
ABSORBER OVERHEAD KNOCKOUT DRUM
SOLVENT STORAGE TANK
STRIPPER
RICH SOLVENT FLASH DRUM
TO FUEL GAS HEADER
ABSORBER
HOT LEAN/ RICH SOLVENT EXCHANGER
FEED PRODUCT EXCHANGER
FEED PRECOOLER
REFRIGERANT
COLD LEAN/ RICH SOLVENT EXCHANGER
CLEAN SYNGAS
RAW SYNGAS
SOLVENT SUMP
FEED PRECOOLER PUMP
PRESATURATED SOLVENT PUMP
LEAN SOLVENT BOOSTER PUMP
SOLVENT MAKE-UP PUMP
SOLVENT SUMP PUMP
SOUR WATER STRIPPER OVERHEAD CONDENSER
SOUR WATER STRIPPER KNOCKOUT DRUM
SOUR WATER STRIPPER
SOUR WATER STRIPPER REFLUX DRUM
BLOWDOWN SURGE TANK
SOUR WATER STRIPPER REBOILER
STEAM
OFF GAS
GREY WATER
VENT GAS
SOUR WATER STRIPPER AUXILIARY FEED PUMP
SOUR WATER STRIPPER BOTTOMS PUMP
SOUR WATER STRIPPER REFLUX PUMP

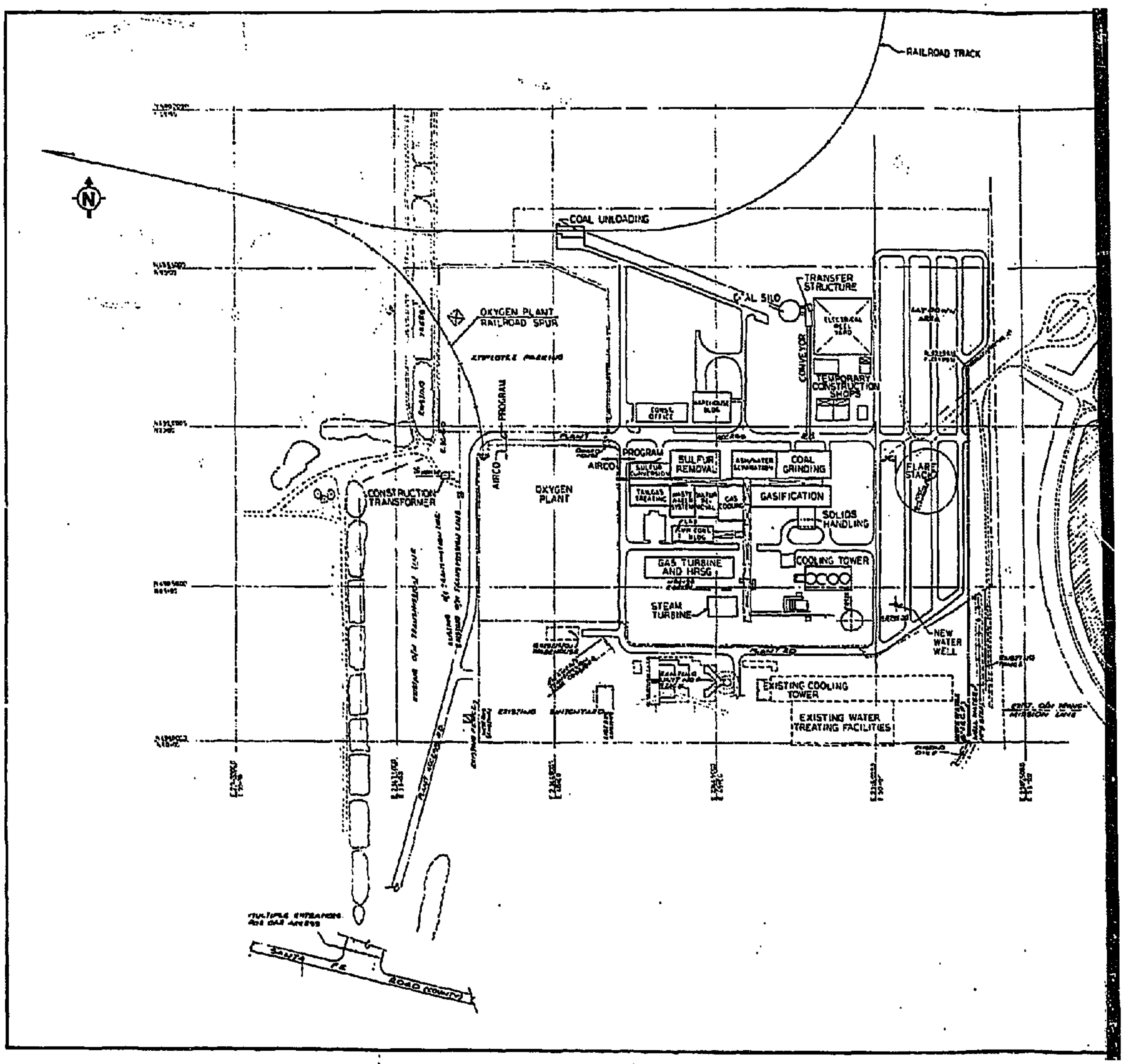

REFRIGERANT
ABSORBER OVERHEAD KNOCKOUT DRUM
SOLVENT STORAGE TANK
RICH SOLVENT FLASH DRUM
HOT LEAN/ RICH SOLVENT EXCHANGER
COLD LEAN/ RICH SOLVENT EXCHANGER
STRIPPER
STRIPPER OVERHEAD CONDENSER
COOLING WATER
STRIPPER REFLUX DRUM
STRIPPER REBOILER
STEAM
#1 AMINE ABSORBER
FUEL GAS
NATURAL GAS (S/U)
FEED HEATER
REACTOR
STM
BFW
SOLVENT SUMP
PRESATURATED SOLVENT PUMP
LEAN SOLVENT BOOSTER PUMP
SOLVENT MAKE-UP PUMP
SOLVENT SUMP PUMP
LEAN SOLVENT PUMP
STRIPPER REFLUX PUMP
#1 ABSORBER RICH AMINE PUMP
AIR BLOWER
SOUR WATER STRIPPER OVERHEAD CONDENSER
SOUR WATER STRIPPER
SOUR WATER STRIPPER REFLUX DRUM
SOUR WATER STRIPPER KNOCKOUT DRUM
ACID GAS KNOCKOUT DRUM
ACID GAS HEATER
STM.
SYNGAS
NATURAL GAS
THERMAL REACTOR
CLAUS BOILER
STEAM
BFW
AIR HEATER
SOUR WATER STRIPPER REBOILER
SOUR WATER STRIPPER BOTTOMS PUMP
SOUR WATER STRIPPER REFLUX PUMP
KNOCKOUT DRUM PUMP
CLAUS AIR BLOWER
STEAM GENERATION AIR BLOWER

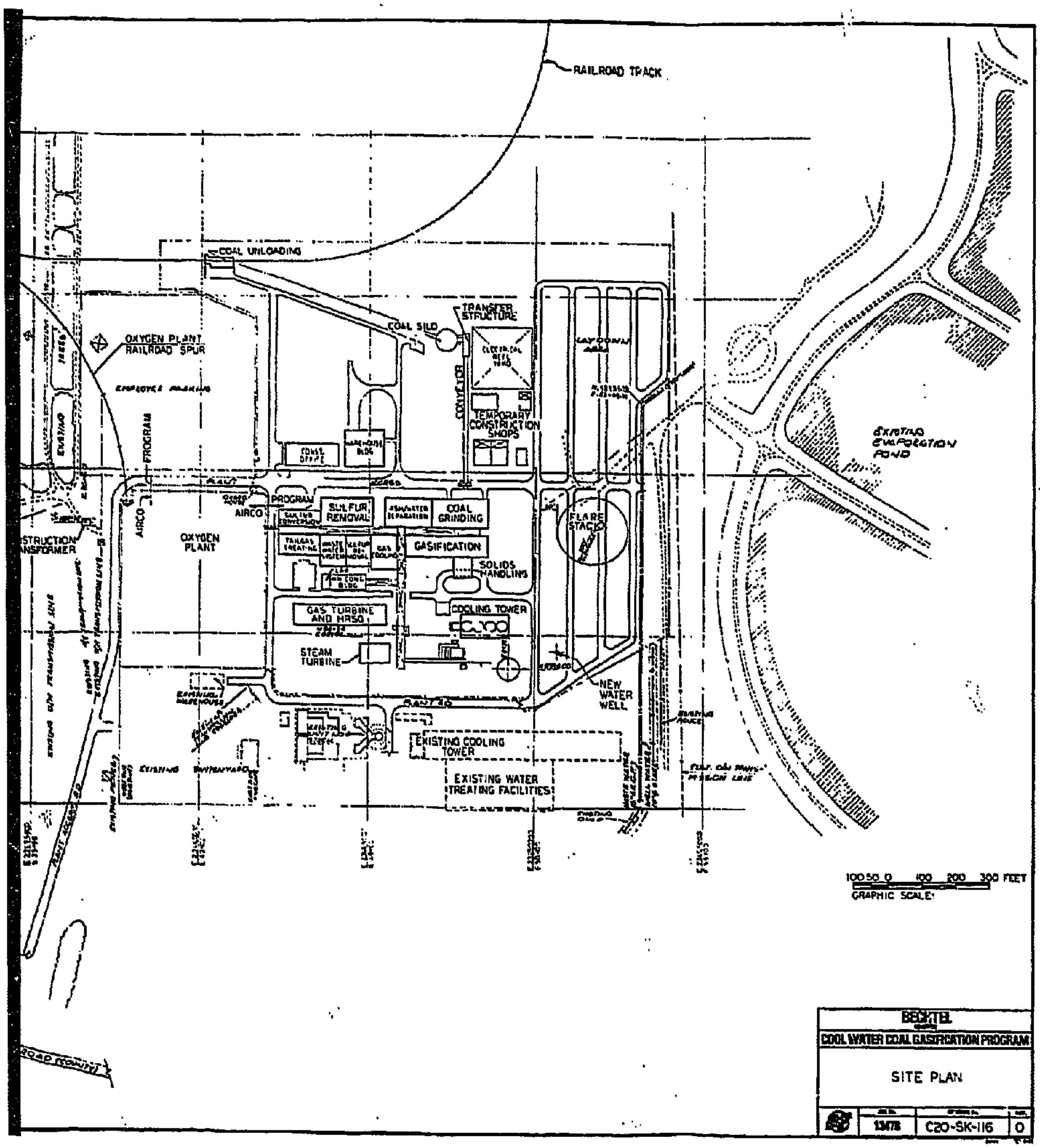
p


FUEL GAS
STEAM
FEED HEATER
REACTOR
STM
SCOT WASTE HEAT EXCHANGER
BFW
QUENCH TOWER
QUENCH WATER COOLER
COOLING WATER
#2 AMINE ABSORBER
RICH AMINE SURGE DRUM
LEAN AMINE COOLER
COOLING WATER
AIR BLOWER
SOUR WATER BOOSTER PUMP
QUENCH WATER PUMP
#2 ABSORBER RICH AMINE PUMP
RICH AMINE SURGE DRUM PUMP
AMINE STRIPPER REFLUX CONDENSER
COOLING WATER
AMINE STRIPPER
AMINE STRIPPER REFLUX DRUM
STM.
CONDENSATE
AMINE STRIPPER REBOILER
LEAN/RICH AMINE EXCHANGER
AMINE STORAGE TANK
LEAN AMINE PUMP
AMINE STRIPPER REFLUX PUMP
AMINE CHARGE PUMP
CATALYTIC REACTORS
REHEAT EXCHANGERS
#3 STEAM
#2 STEAM
#1 STEAM
STEAM
PRIMARY SULFUR CONDENSER
BFW
SULFUR PIT
STEAM
FINAL SULFUR CONDENSER
BFW
INCINERATOR
SYNGAS
NATURAL GAS (S/U)
SULFUR PUMP
COO
SU
TA

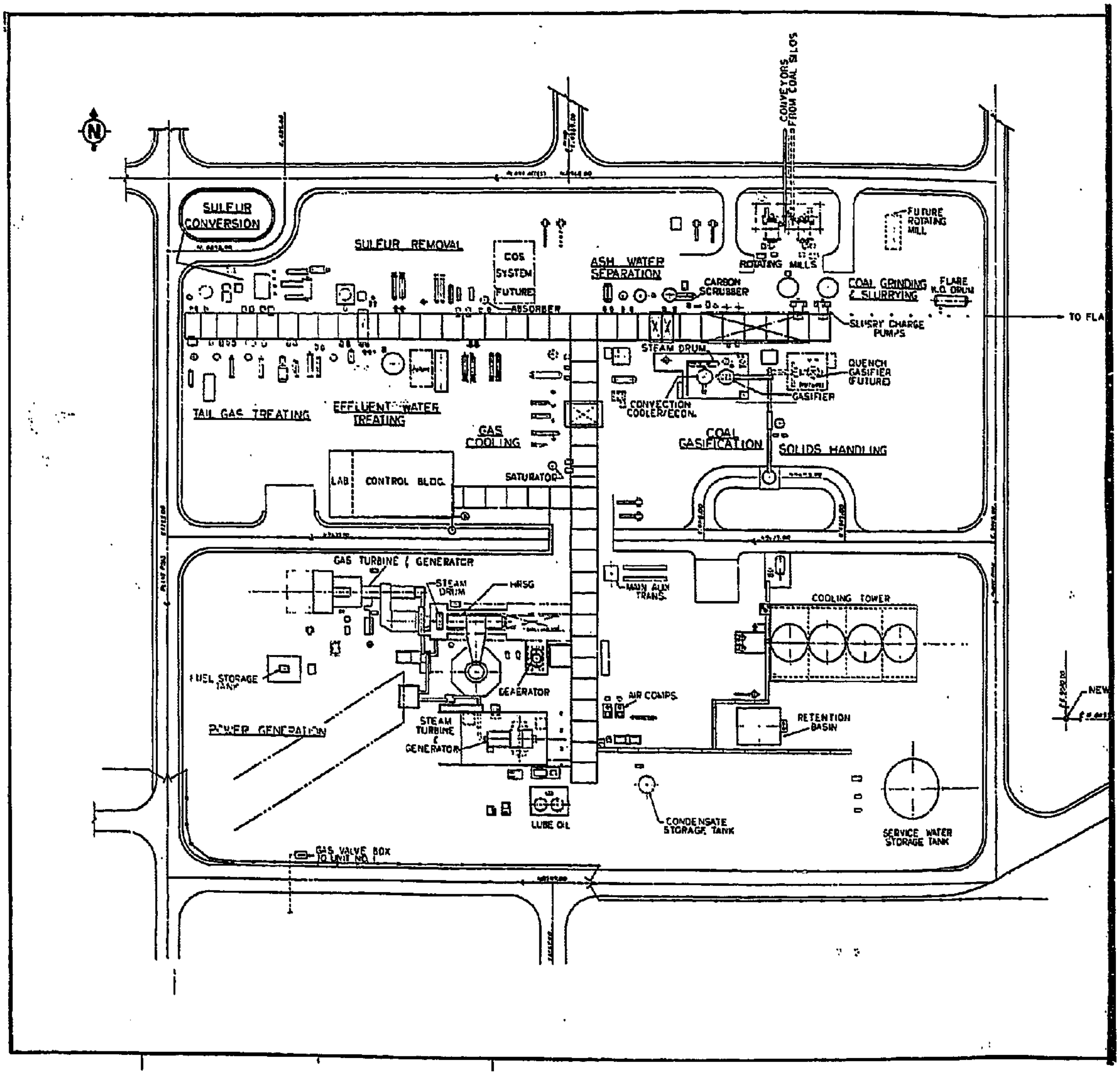


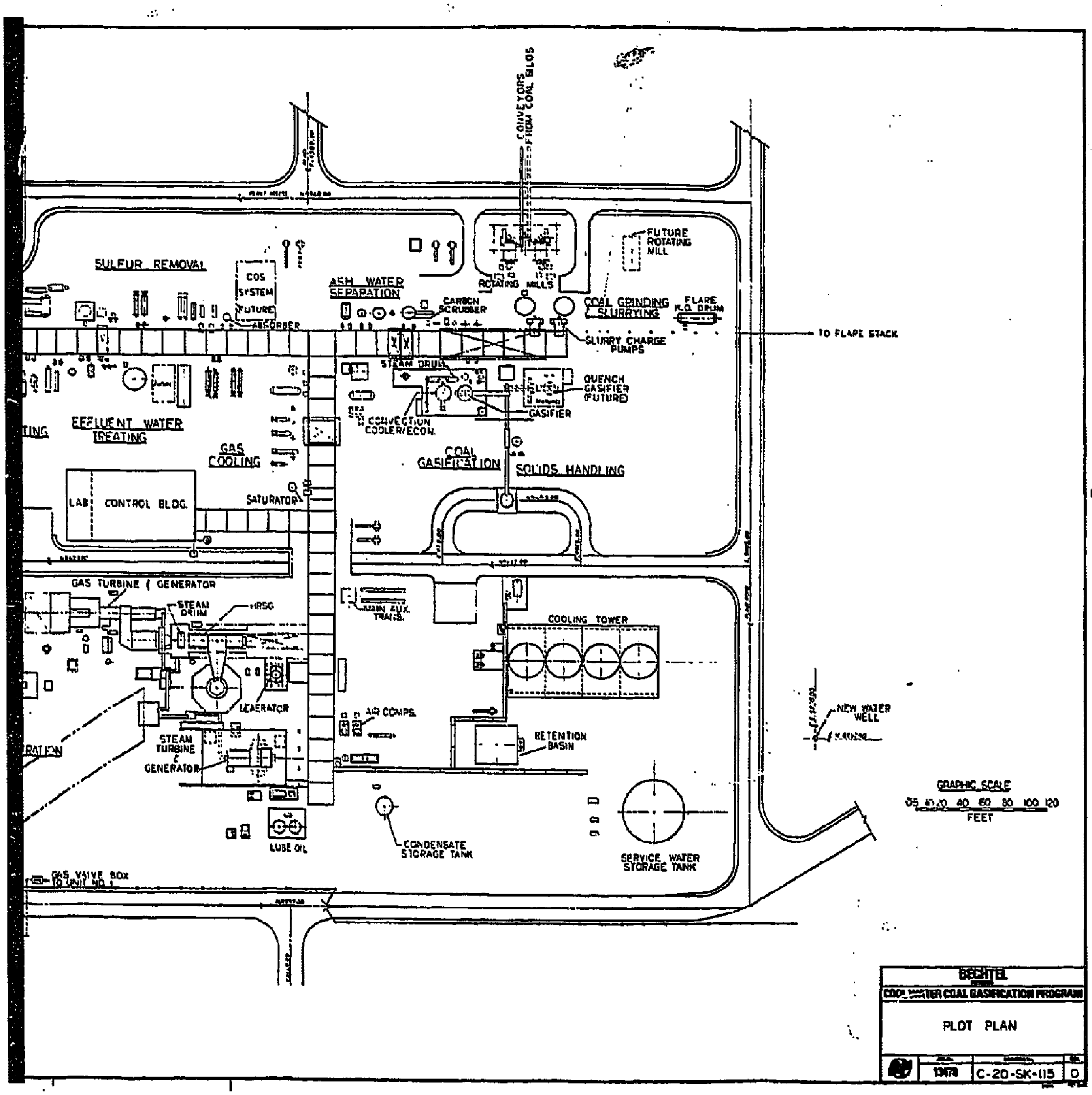
#2 AMINE ABSORBER
RICH AMINE SURGE DRUM
LEAN AMINE COOLER
COOLING WATER
AMINE STRIPPER REFLUX CONDENSER
COOLING WATER
AMINE STRIPPER
AMINE STRIPPER REFLUX DRUM
STM.
CONDENSATE
LEAN/RICH AMINE EXCHANGER
AMINE STRIPPER REBOILER
AMINE STORAGE TANK
AMINE SUMP
RICH AMINE SURGE DRUM PUMP
LEAN AMINE PUMP
AMINE STRIPPER REFLUX PUMP
AMINE CHARGE PUMP
AMINE SUMP PUMP
#3 STEAM
#2 STEAM
#1 STEAM
BFW
STEAM
FINAL SULFUR CONDENSER
BFW
SULFUR PIT
SYNGAS
NATURAL GAS (S/U)
INCINERATOR
TO EVAP. POND
WASTEWATER
SULFUR
TO TRUCK
SULFUR PUMP
BECHTEL
HOUSTON
COOL WATER COAL GASIFICATION PROGRAM
OVERALL PROCESS FLOW DIAGRAM
SULFUR REMOVAL, SULFUR RECOVERY,
TAIL GAS TREATING, EFFLUENT WATER
TREATMENT
JOB No.
13478
DRAWING No.
B73 - SK - 100
SHEET 2 OF 2
REV.
0


RAILROAD TRACK
COAL UNLOADING
OXYGEN PLANT
RAILROAD SPUR
EMPLOYEE PARKING
TRANSFER
STRUCTURE
CONVEYOR
TEMPORARY
CONSTRUCTION
SHOPS
PROGRAM
AIRCO
OXYGEN
PLANT
SULFUR
REMOVAL
COAL
GRINDING
GASIFICATION
SOLIDS
HANDLING
FLARE
STACK
CONSTRUCTION
TRANSFORMER
GAS TURBINE
AND HRSG
COOLING TOWER
STEAM
TURBINE
NEW
WATER
WELL
EXISTING COOLING
TOWER
EXISTING WATER
TREATING FACILITIES



RAILROAD TRACK
COAL UNLOADING
OXYGEN PLANT RAILROAD SPUR
COAL SILO
TRANSFER STRUCTURE
CONVEYOR
TEMPORARY CONSTRUCTION SHOPS
PROGRAM
AIRCO
OXYGEN PLANT
CONSTRUCTION TRANSFORMER
SULFUR REMOVAL
COAL GRINDING
GASIFICATION
SOLIDS HANDLING
FLARE STACK
GAS TURBINE AND HRSG
COOLING TOWER
STEAM TURBINE
NEW WATER WELL
EXISTING COOLING TOWER
EXISTING WATER TREATING FACILITIES
EXISTING EVAPORATION POND
100 50 0 100 200 300 FEET
GRAPHIC SCALE
BECHTEL
COOL WATER COAL GASIFICATION PROGRAM
SITE PLAN
13478
C20-SK-116
0


N
SULFUR CONVERSION
SULFUR REMOVAL
COS SYSTEM FUTURE
ABSORBER
ASH WATER SEPARATION
CARBON SCRUBBER
CONVEYORS FROM COAL SILOS
ROTATING MILLS
FUTURE ROTATING MILL
COAL GRINDING & SLURRYING
FLARE K.O. DRUM
SLURRY CHARGE PUMPS
STEAM DRUM
QUENCH GASIFIER (FUTURE)
GASIFIER
CONVECTION COOLER/ECON.
TAIL GAS TREATING
EFFLUENT WATER TREATING
GAS COOLING
COAL GASIFICATION
SOLIDS HANDLING
LAB
CONTROL BLDG.
SATURATOR
GAS TURBINE & GENERATOR
STEAM DRUM
HRSG
MAIN AUX TRANS.
COOLING TOWER
FUEL STORAGE TANK
DEAERATOR
AIR COMPS.
POWER GENERATION
STEAM TURBINE & GENERATOR
RETENTION BASIN
LUBE OIL
CONDENSATE STORAGE TANK
SERVICE WATER STORAGE TANK
GAS VALVE BOX TO UNIT NO. 1


CONVEYORS FROM COAL SILOS
FUTURE ROTATING MILL
SULFUR REMOVAL
COS SYSTEM FUTURE
ASH WATER SEPARATION
CARBON SCRUBBER
ROTATING MILLS
COAL GRINDING & SLURRYING
FLARE K.O. DRUM
TO FLARE STACK
ABSORBER
SLURRY CHARGE PUMPS
STEAM DRUM
QUENCH GASIFIER (FUTURE)
GASIFIER
CONVECTION COOLER/ECON.
EFFLUENT WATER TREATING
GAS COOLING
COAL GASIFICATION
SOLIDS HANDLING
LAB
CONTROL BLDG.
SATURATOR
GAS TURBINE & GENERATOR
STEAM DRUM
HRSG
MAIN AUX. TRANS.
COOLING TOWER
DEAERATOR
AIR COMPS.
NEW WATER WELL
STEAM TURBINE & GENERATOR
RETENTION BASIN
GRAPHIC SCALE
FEET
LUBE OIL
CONDENSATE STORAGE TANK
SERVICE WATER STORAGE TANK
GAS VALVE BOX TO UNIT NO. 1
BECHTEL
COOL WATER COAL GASIFICATION PROGRAM
PLOT PLAN
C-20-SK-115
0

In addition to the Program coal, which will be the predominant plant feedstock, other Western coals and Eastern coals will be processed (each for about a 30- to 60-day period). Each Participant has been granted the right to run its coal and each Sponsor can arrange to have its coal run to demonstrate feedstock flexibility in the commercial scale plant components. Sufficient sulfur removal and recovery capability, for example, has been incorporated into the design to permit environmentally acceptable operation on coals with as little as 0.35 wt% sulfur or with as much as 3.5 wt% sulfur, as in the EPRI Illinois No. 6 candidate coal.

The quantity of syngas produced will be approximately 70 million standard cubic feet per day. A typical syngas composition is shown in Table 5-2.

Table 5-2

SYNGAS ANALYSIS FOR PROGRAM COAL

	Untreated Gas Mol. %*	Clean Gas Mol. %*
CO	41.34	43.53
H_2	36.38	38.33
CO_2	21.42	17.39
CH_4	0.10	0.11
Ar	0.16	0.17
N_2	0.44	0.47
H_2S	0.15	15 ppm
COS	0.01	55 ppm
Heating Value (Btu/SCF, HHV)		265.2

*Dry Basis

EXISTING SITE FACILITIES

The site of the Integrated Coal Gasification-Combined Cycle Project is Southern California Edison's Cool Water Ranch property in the Mohave Desert region of San Bernardino County (see Figure 5-1). This property is comprised of 2,500 acres, of which the existing station occupies approximately 16 acres. A photograph of the site is shown as Figure 5-2.

The site presently includes two steam electric generating units and two combined cycle units. Units 1 and 2 are conventional oil/gas-fired steam plants with respective capacities of 65 MW and 81 MW. Unit 1 was completed in 1961 and Unit 2 in 1964. Units 3 and 4 are combined cycle units which each use two gas turbines, two waste heat boilers and one steam turbine. The units each produce 236 MW of power and became operational in June and August 1978, respectively.

GCC PLANT SECTIONS

Coal Receiving, Storage and Handling

A complete coal handling facility will be provided for receiving, unloading and storing coal delivered by rail and for transferring the coal to the plant. Drawing 873-SK-101 presents the process flow diagram for this system. All conveyors will be enclosed in walk-through tube type galleries. Dust control, a combination of suppression and collection, will be provided throughout the coal handling system to control fugitive dust.

The coal will be delivered to the plant by train in bottom dump cars with a capacity of 100 tons each. The coal will have a nominal size of 2 inch x 0 inch. Railroad tracks and a track unloading hopper will be provided to accommodate up to 85 cars at one time.

The coal will be unloaded at the track hopper, which will unload one bottom dump car at a time. An enclosure will be provided over the track hopper, also enclosing the car shaker which assists in unloading the coal. The 42-inch-wide unloading conveyor will carry coal from the track unloading hopper to the coal storage silo fill system at a rate of 1,200 tons per hour (tph). The head pulley for the conveyor will be located in the silo fill system enclosure. A magnetic separator will be provided to remove tramp iron from the coal stream. These rejects will be chuted to a tote box at grade. Periodic truck removal of the tote box accumulation will be made.

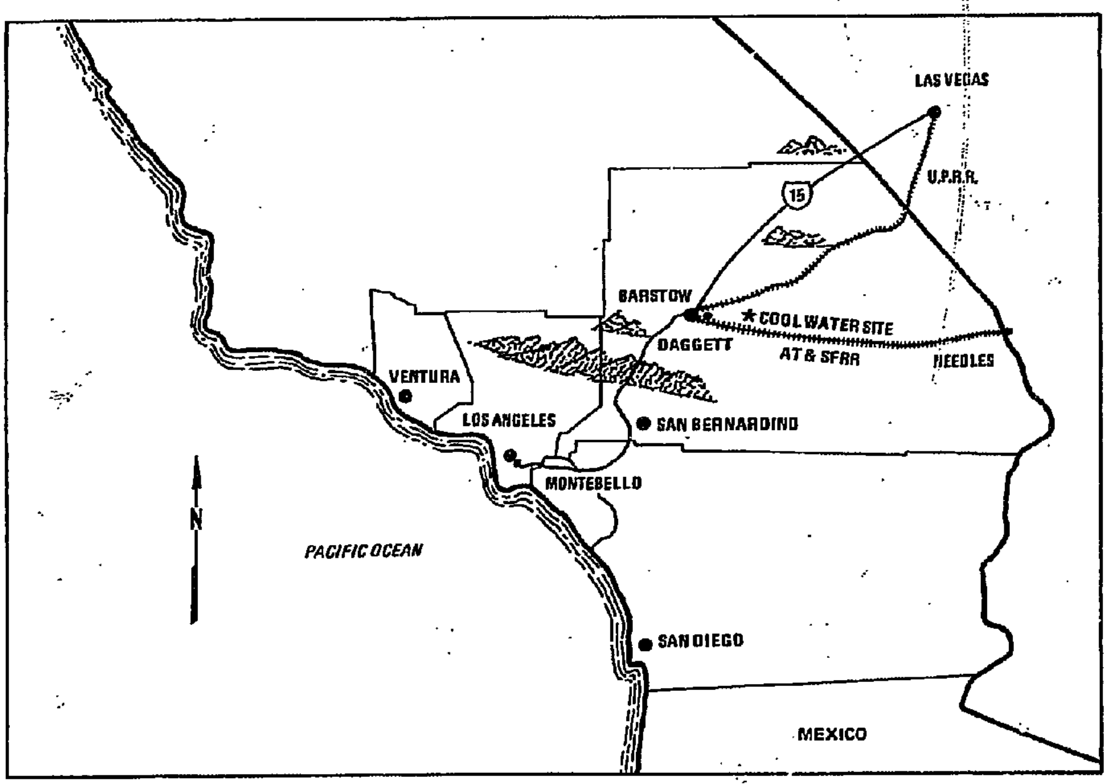


Figure 5-1. Site Location

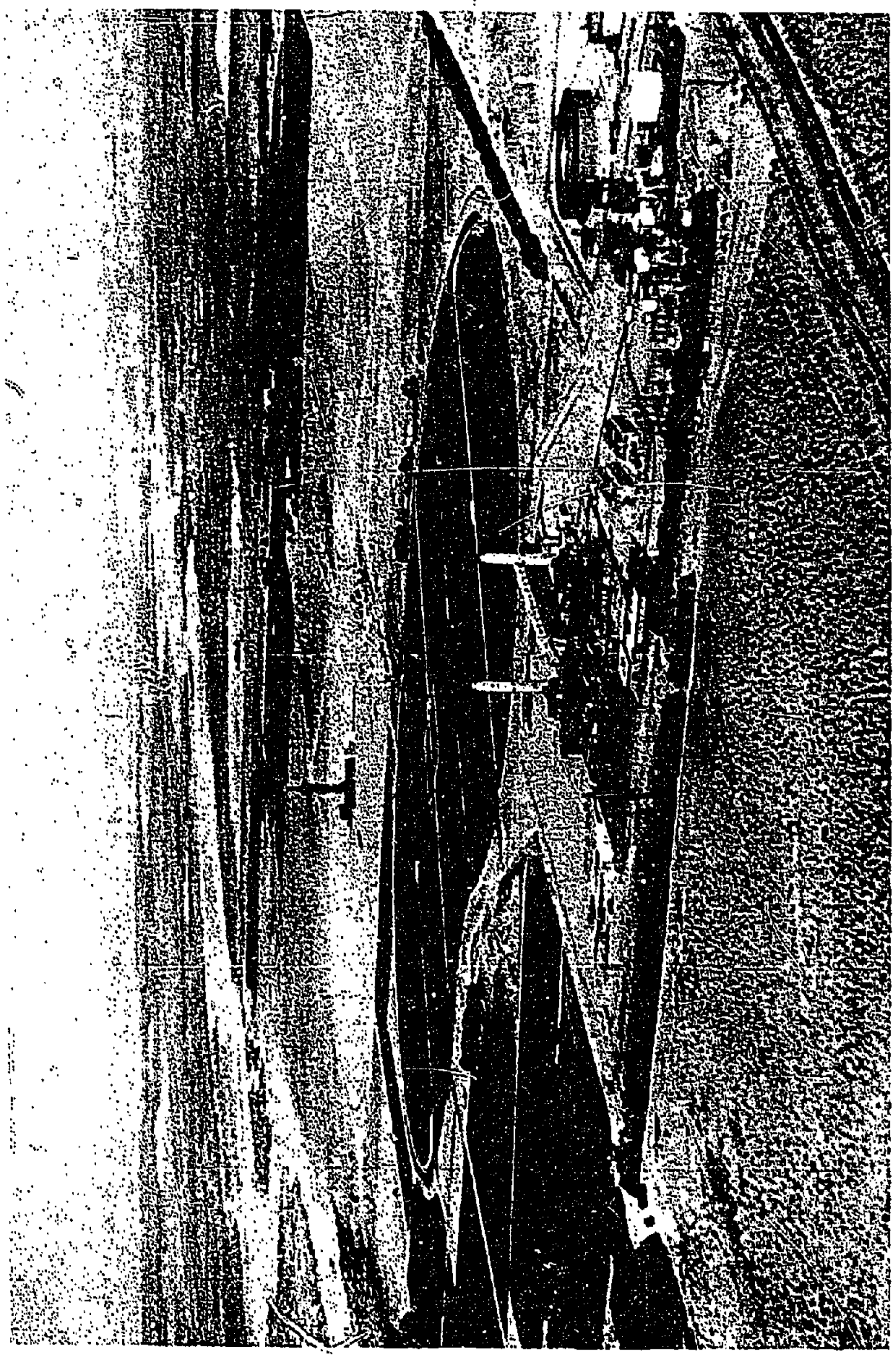
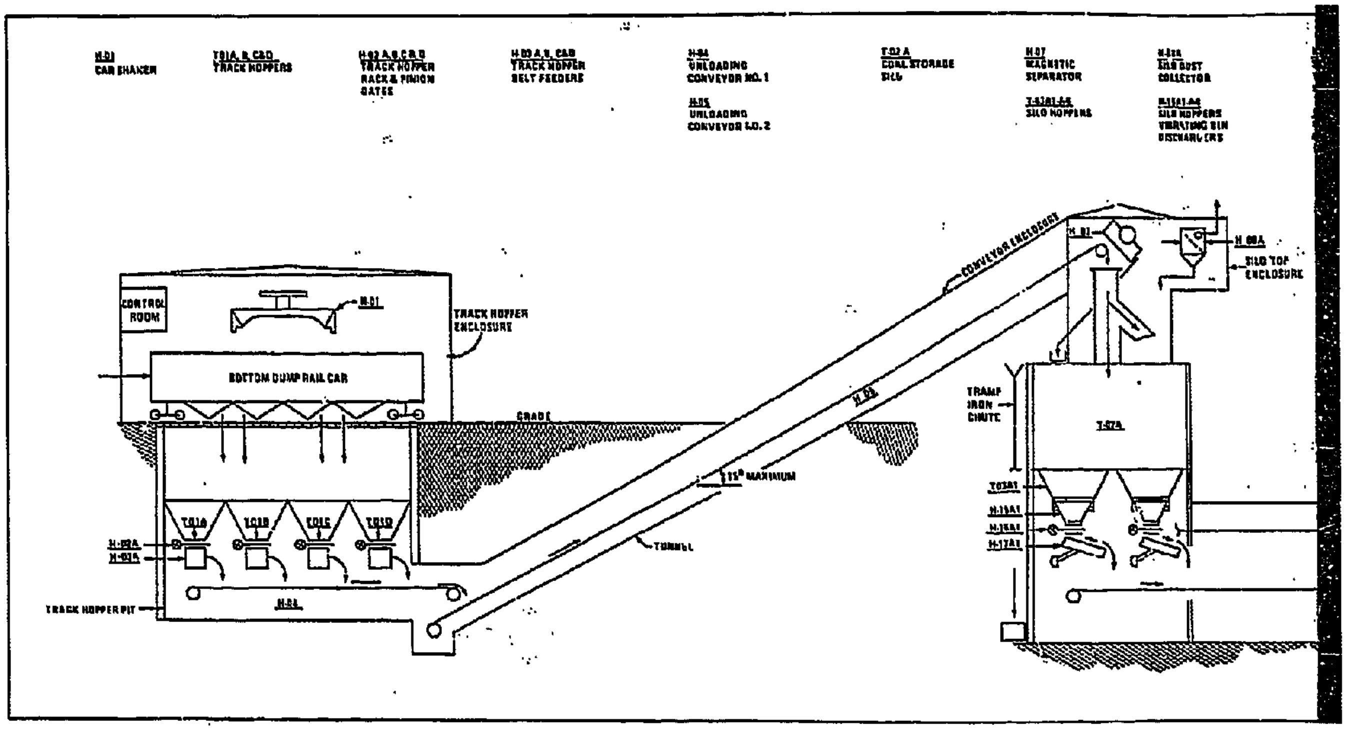
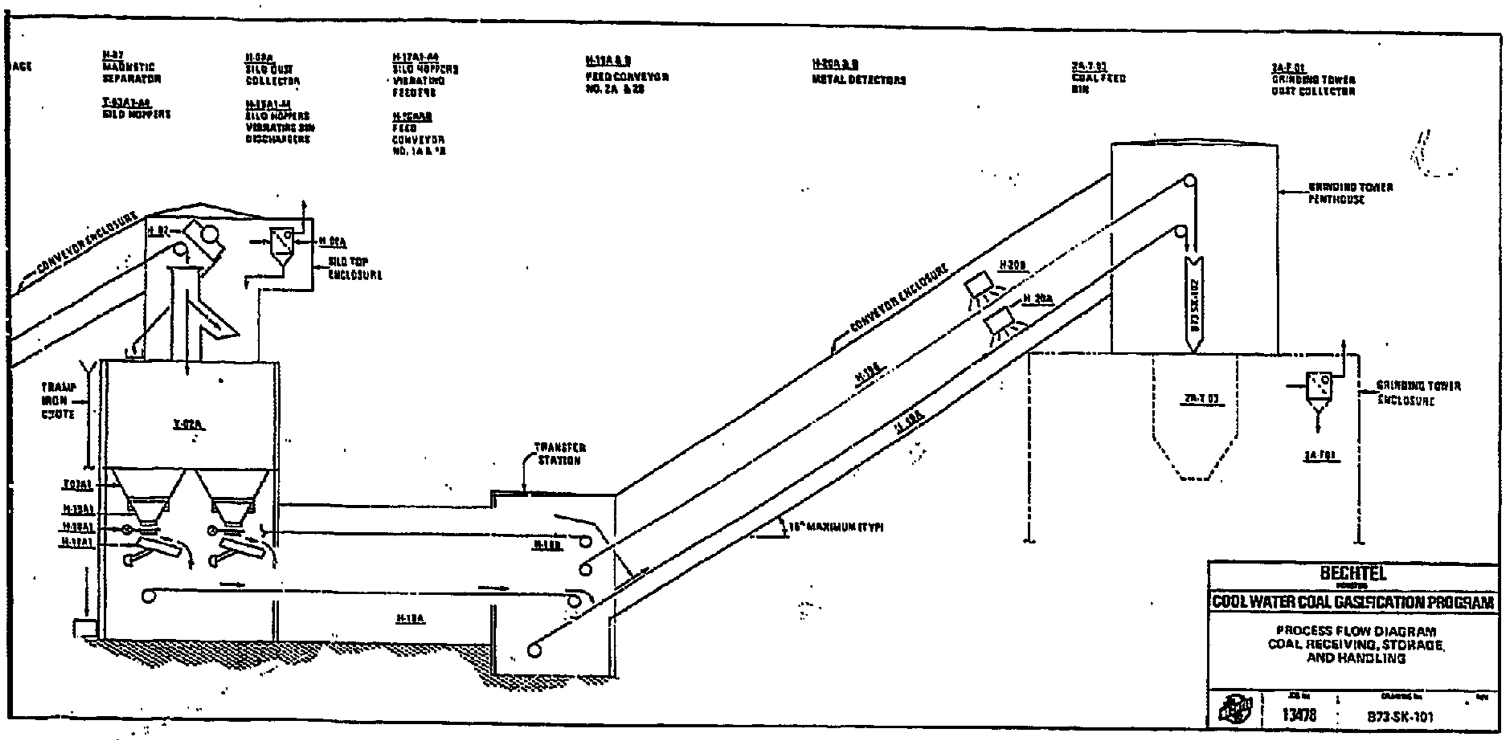


Figure 5-2. Site Photograph



CAR SHAKER
TRACK HOPPERS
TRACK HOPPER RACK & PINION GATES
TRACK HOPPER BELT FEEDERS
UNLOADING CONVEYOR NO. 1
UNLOADING CONVEYOR NO. 2
COAL STORAGE SILO
MAGNETIC SEPARATOR
SILO HOPPERS
SILO DUST COLLECTOR
SILO HOPPERS VIBRATING BIN DISCHARGERS
CONTROL ROOM
TRACK HOPPER ENCLOSURE
BOTTOM DUMP RAIL CAR
GRADE
CONVEYOR ENCLOSURE
SILO TOP ENCLOSURE
TRAMP IRON CHUTE
MAXIMUM
TUNNEL
TRACK HOPPER PIT


MAGNETIC SEPARATOR
SILO HOPPERS
SILO DUST COLLECTOR
SILO HOPPERS VIBRATING BIN DISCHARGERS
SILO HOPPERS VIBRATING FEEDERS
FEED CONVEYOR
FEED CONVEYOR NO. 2A & 2B
METAL DETECTORS
COAL FEED BIN
GRINDING TOWER DUST COLLECTOR
CONVEYOR ENCLOSURE
SILO TOP ENCLOSURE
TRAMP IRON CHUTE
TRANSFER STATION
CONVEYOR ENCLOSURE
GRINDING TOWER PENTHOUSE
GRINDING TOWER ENCLOSURE
15° MAXIMUM (TYP)
BECHTEL
COOL WATER COAL GASIFICATION PROGRAM
PROCESS FLOW DIAGRAM
COAL RECEIVING, STORAGE,
AND HANDLING
13478
873-SK-101

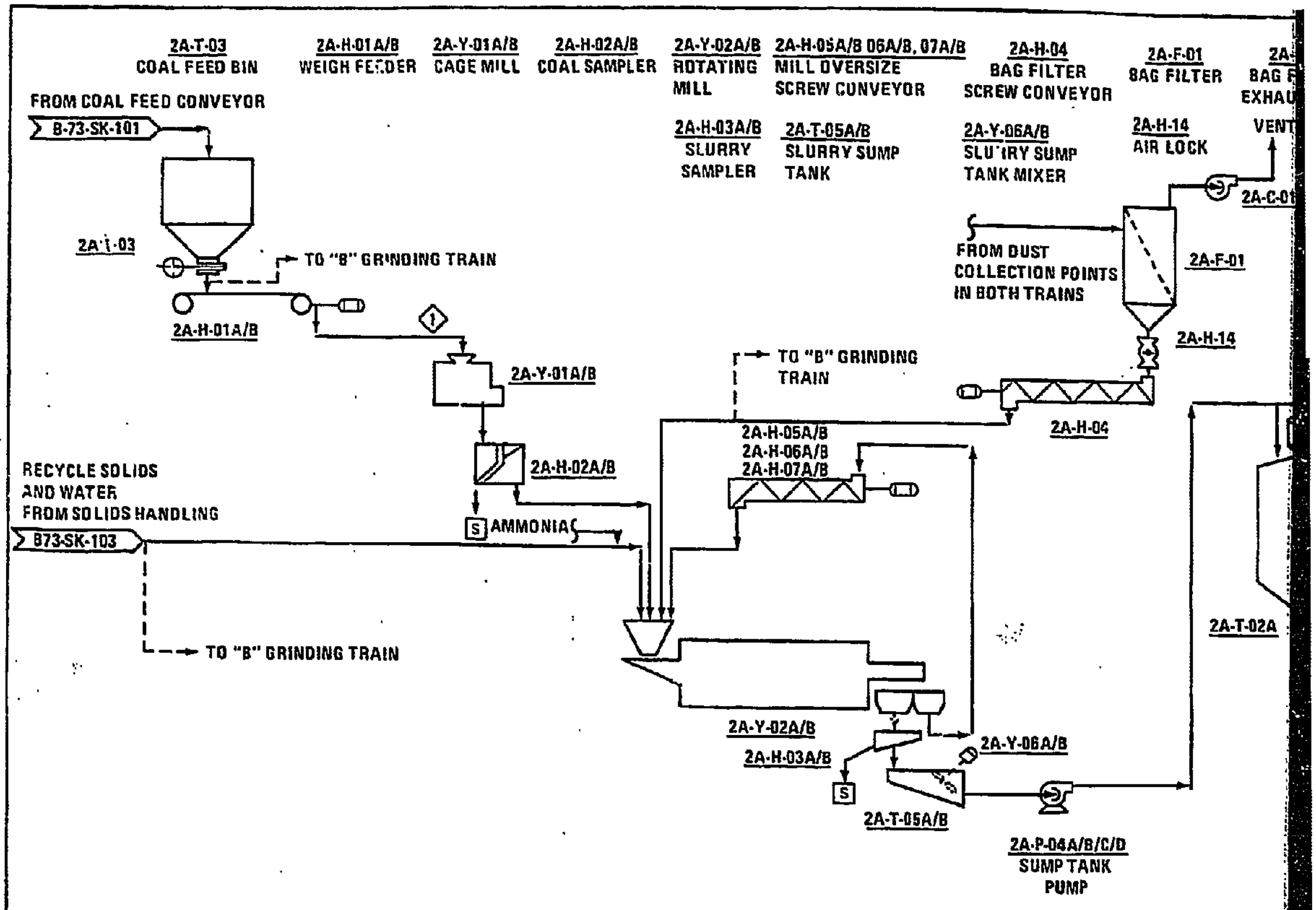
The system is planned to include two coal storage silos. The entire silo fill system will be enclosed. A dust collection system will be provided to capture fugitive dust generated by the filling operation and to minimize internal combustible atmospheres. Each storage silo will have a live capacity of 6,000 tons. The bottom of each silo will have four outlets with a bin activator, a rack and pinion shutoff gate and a vibrating feeder with a capacity of 200 tph at each outlet.

Two 100-percent-capacity silo outlet horizontal feed conveyors will transfer coal from the silo to the transfer house, onto a rising feed conveyor and then to a 50-ton-capacity grinding feed bin. The rising feed conveyor, along with a back-up feed conveyor, will be installed in a tube type gallery. Feed conveyors will be 24 inches wide with a capacity of 200 tph each.

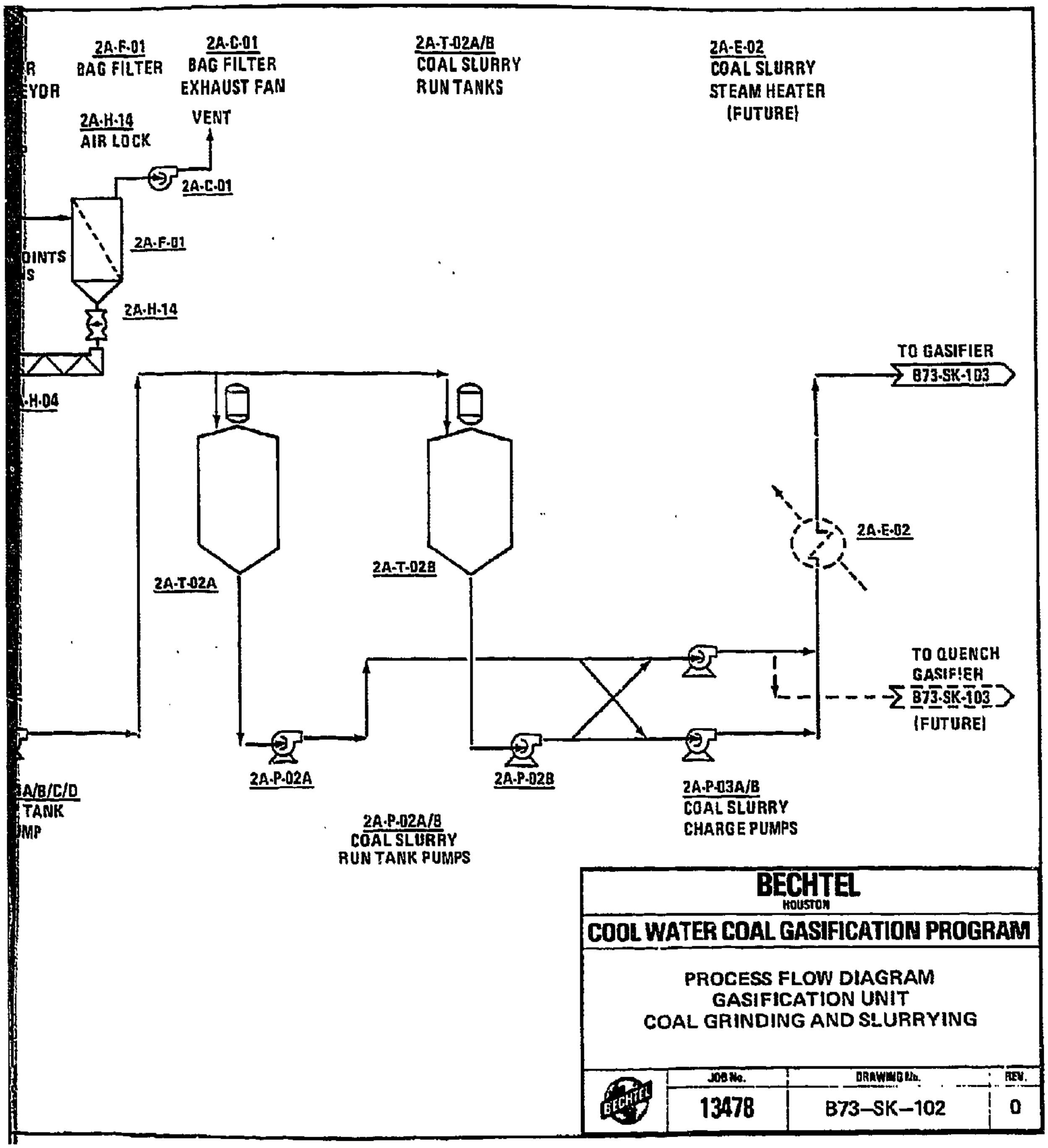
Coal Grinding and Slurrying

The coal grinding and slurrying system consists of two full-size trains of equipment to ensure continuity of operation. It is designed with flexibility to produce either a coarse grind or a fine grind specification. Each train is designed to process 1,000 tpd of coal feed (dry basis) and recycled fine ash and slag to produce the coarse grind specification, or 500 tons per day (tpd) of coal feed (dry basis) to produce a finer grind specification. One additional mill can be added at a later date to provide spare capacity for the fine grind operating mode if field operating experience establishes economic justification. The process flow diagram is shown in drawing B73-SK-102.

Raw coal is carried via two parallel belt conveyors from the live storage silo into a 50-ton-capacity grinding feed bin. Coal is withdrawn from the feed bin and fed to a cage mill by a variable speed weigh feeder. The cage mill is sized and powered to reduce the maximum feed size to nominally 100 percent smaller than 3/4-inch or to 100 percent smaller than 4-mesh (U.S.). The crushed coal is fed into a wet grinding rotating mill to produce the final grind distribution. In the future, this mill may be modified if finer grind product is desired. The rotating mill is powered by a variable speed drive in order to allow for constant product particle size distribution at varying feed rates (60 to 100 percent of design).



STREAM NUMBER	1
STREAM NAME	COAL FEED
COMPONENT, LB/HR	
COAL	79378
CARBON	–
ASH	8560
WATER	12620
TOTAL, LB/HR	100558
TEMPERATURE, °F	AMBIENT
PRESSURE, PSIA	ATM.


R
EYOR
2A-F-01
BAG FILTER
2A-C-01
BAG FILTER
EXHAUST FAN
2A-H-14
AIR LOCK
2A-T-02A/B
COAL SLURRY
RUN TANKS
2A-E-02
COAL SLURRY
STEAM HEATER
(FUTURE)
VENT
2A-C-01
OINTS
S
2A-F-01
2A-H-14
-H-04
TO GASIFIER
B73-SK-103
2A-E-02
2A-T-02A
2A-T-02B
TO QUENCH
GASIFIER
B73-SK-103
(FUTURE)
A/B/C/D
TANK
MP
2A-P-02A
2A-P-02B
2A-P-03A/B
COAL SLURRY
CHARGE PUMPS
2A-P-02A/B
COAL SLURRY
RUN TANK PUMPS
BECHTEL
HOUSTON
COOL WATER COAL GASIFICATION PROGRAM
PROCESS FLOW DIAGRAM
GASIFICATION UNIT
COAL GRINDING AND SLURRYING
JOB No.
13478
DRAWING No.
B73–SK–102
REV.
0

An automatic sampler is provided at the feed of the rotating mill. Screw conveyors are provided to recycle the oversize product from the rotating mill outlet screen back to the mill feed. The ground product is discharged into a sump tank and transferred by slurry pumps into either one of the two run tanks.

An automatic control system measures and controls the coal feed rate (lb/hr), measures the amount of recycled carbon, accounts for the amount of moisture in the coal (lb/hr) and calculates the additional amount of make-up water required at the rotating mill. The water valve is controlled in feed-forward fashion. The sump tank discharge slurry is measured with density meters in order to guarantee consistency and proper coal/water ratio and to adjust the water feed rate in cascaded feedback fashion.

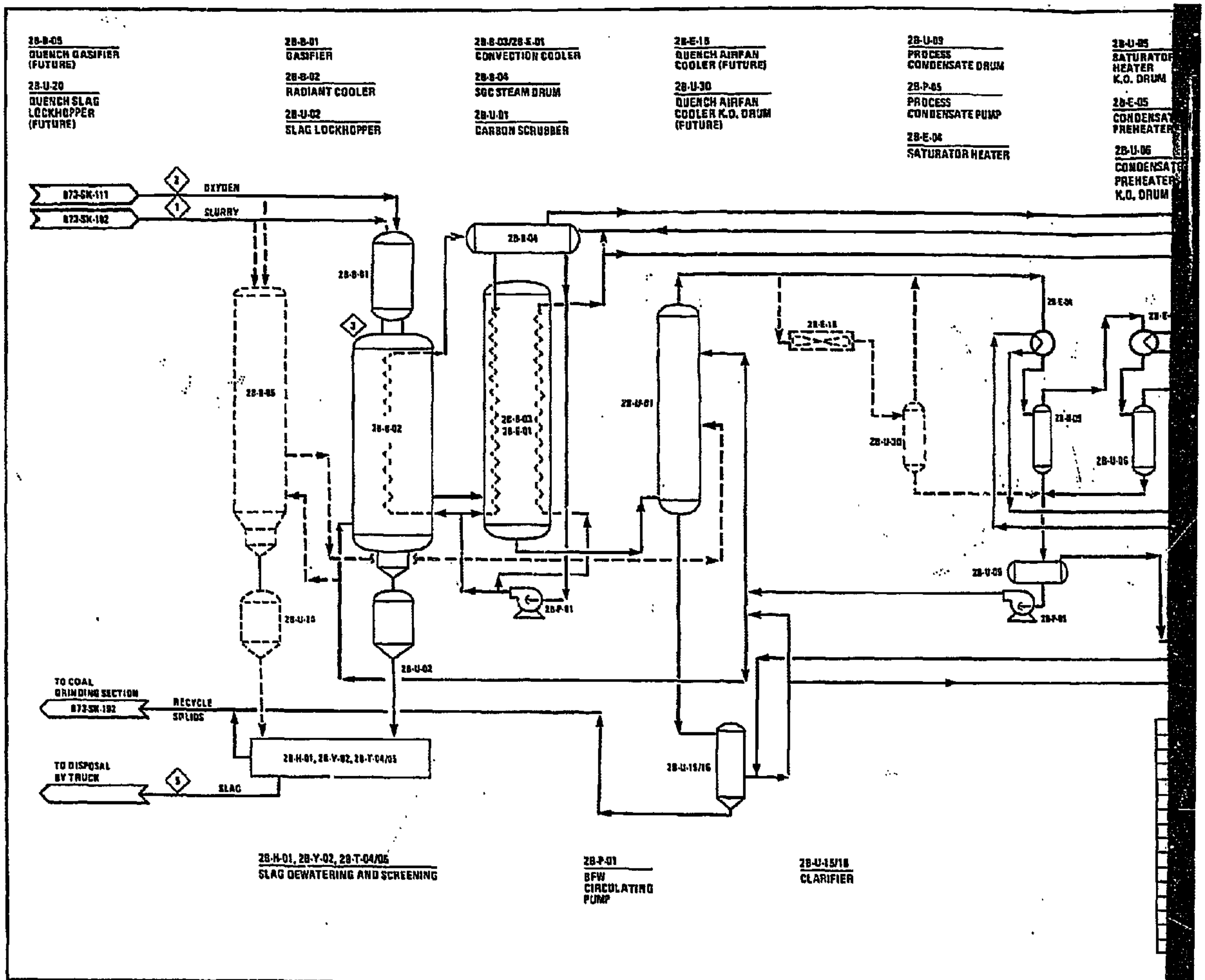
The slurry run tanks are provided with agitators to keep the solids suspended and to provide a uniform coal slurry to the gasifier. The system is designed to operate with both tanks full. One tank serves as a stand-by while simultaneously charging and discharging the other tank. A transfer pump is used to withdraw the slurry from the run tank and feed it to one of two high pressure, positive-displacement-type charge pumps. The charge pump is used to pump the slurry through a (future) steam slurry preheater prior to charging the gasifier.

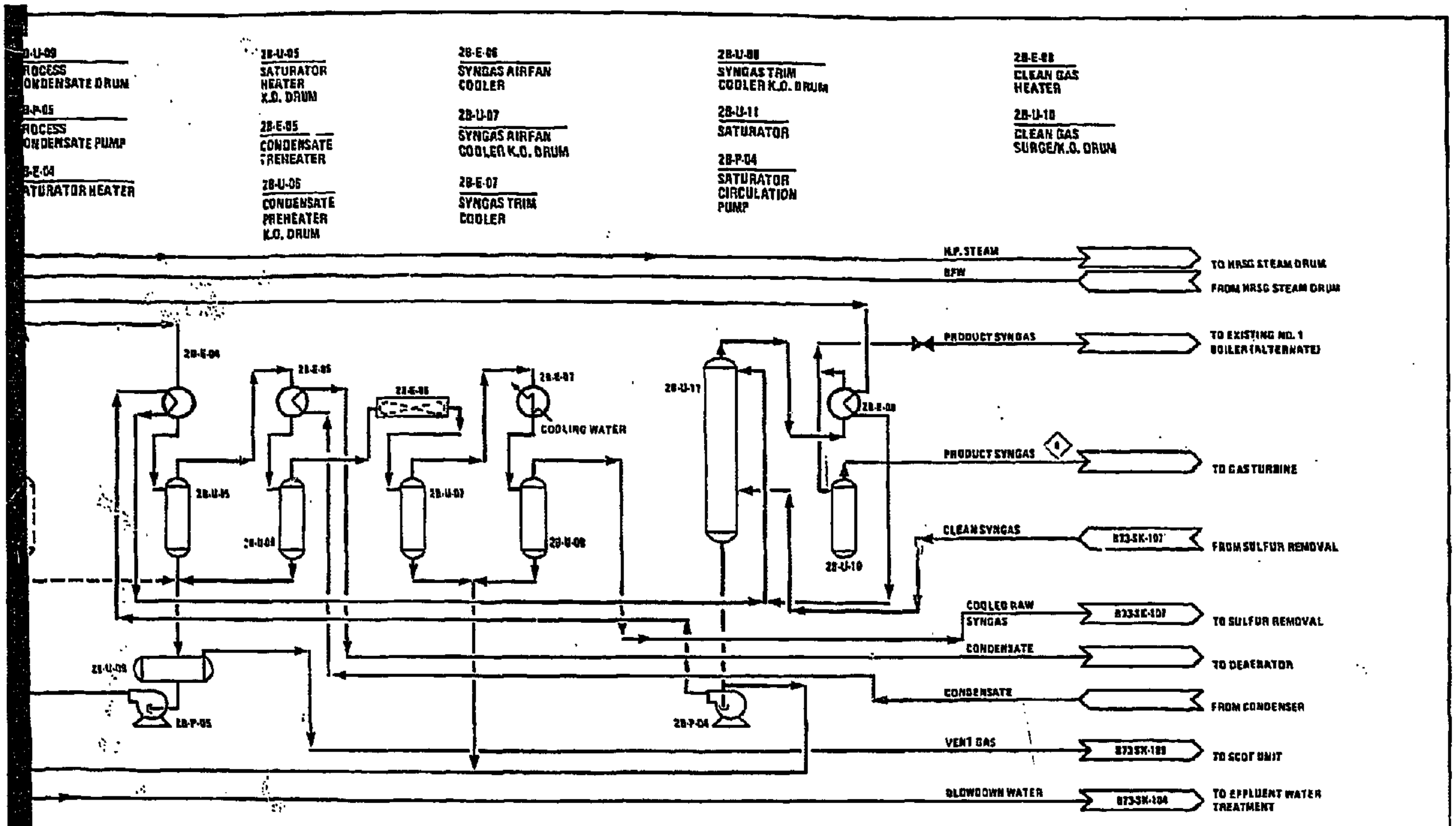
Coal Gasification

The coal gasification system includes the coal gasifier, the cooling of the syngas and, finally, the syngas saturation and superheating. A process flow diagram of the gasification system is shown in drawing B73-SK-103.

The coal slurry feed, consisting of fresh ground coal together with recycled fine slag and carbon, has a total solids content of 50 to 65 percent by weight.

The coal-water slurry is fed through a specially developed burner into a refractory-lined gasifier reactor. Partial combustion with oxygen takes place at a pressure of 600 psig and a temperature in the range of 2,300 to 2,800F to produce gas consisting mainly of CO, H_2, CO_2 and steam. Most of the sulfur in the coal is converted to H_2S and the balance is converted to COS. Nitrogen and argon from the oxygen feed, along with most of the nitrogen from the coal, appear in the gas. The gas contains a small amount of methane, some unconverted carbon and all of the ash not removed in the form of slag. The gas is essentially free of uncombined oxygen.


28-B-05
QUENCH GASIFIER (FUTURE)
28-U-20
QUENCH SLAG LOCKHOPPER (FUTURE)
28-B-01
GASIFIER
28-B-02
RADIANT COOLER
28-U-02
SLAG LOCKHOPPER
28-B-03/28-E-01
CONVECTION COOLER
28-B-04
SGC STEAM DRUM
28-U-01
CARBON SCRUBBER
28-E-15
QUENCH AIRFAN COOLER (FUTURE)
28-U-30
QUENCH AIRFAN COOLER K.O. DRUM (FUTURE)
28-U-09
PROCESS CONDENSATE DRUM
28-P-05
PROCESS CONDENSATE PUMP
28-E-04
SATURATOR HEATER
28-U-05
SATURATOR HEATER K.O. DRUM
28-E-05
CONDENSATE PREHEATER
28-U-06
CONDENSATE PREHEATER K.O. DRUM
873-SK-111
873-SK-102
OXYGEN
SLURRY
TO COAL GRINDING SECTION
RECYCLE SOLIDS
TO DISPOSAL BY TRUCK
SLAG
28-H-01, 28-Y-02, 28-T-04/05
SLAG DEWATERING AND SCREENING
28-P-01
BFW CIRCULATING PUMP
28-U-15/16
CLARIFIER



STREAM NUMBER	1	2	3	4	5
STREAM NAME	SLURRY FEED	OXYGEN FEED	RAW SYNGAS	CLEAN SYNGAS	SLAG
TOTAL FLOW, LB/HR	163,590	84,780	–	205,360	8,550
TEMPERATURE, °F	140	300	–	380	120
PRESSURE, PSIA	–	965	–	400	14
CO MOL/HR	–	–	3,384	3,378	–
H_2	–	–	2,738	2,735	–
CO_2	–	–	1,591	1,284	–
H_2O	3,723	–	3,052	2,403	–
	–	–	4	4	–
Ar	–	–	46	45	–
N_2	–	–	126	126	–
H_2S	–	–	10	22 ppm	–
COS	–	–	48 ppm	35 ppm	–
TOTAL, MOL/HR	3,723	–	10,951	9,975	–
SOLIDS, LB/HR	98,518	–		–	–

BECHTEL
HOUSTON

COOL WATER COAL GASIFICATION PROGRAM

PROCESS FLOW DIAGRAM
GASIFICATION

JOB No.	DRAWING No.	REV
13478	873 - SK - 103	0

The upper section of the gasifier is a refractory-lined chamber in which the coal slurry and oxygen are combined and the partial oxidation reactions take place. Hot raw syngas and molten slag will be discharged from the bottom of the reaction chamber to a radiant cooler. Hot syngas will be cooled in the radiant cooler that generates 1,600 psig saturated steam. The bulk of molten slag will solidify in the radiant cooler and drop into a lockhopper at the bottom of the radiant cooler. The slag will be removed through a lockhopper system. The raw syngas is cooled further by generating 1,600 psig steam in a convection cooler. Although not included in the present design, cool syngas may be recycled to the inlet of the convection cooler to moderate the inlet gas temperature. The gas will then exchange additional heat with boiler feedwater.

The gas then enters the carbon scrubber where most of the fine particulate material is removed. The syngas is contacted with water to remove particulate material. The last traces of particulate material in the gas are entrained in the water and the gas is completely saturated at this point.

The essentially particulate-free syngas flows on to further heat exchange. First, the gas is cooled in a saturator heater by exchanging heat with saturator circulating water and then is further cooled by a condensate heater. The gas then flows to an air cooler and a trim water cooler where it is cooled to a final temperature of about 100F. Water is removed from the gas in condensate separators following each cooler. The cooled, particulate-free gas flows from this point to the Selexol unit for sulfur removal. Condensate from the gas-cooling operations is pumped back to the carbon scrubber.

The Selexol unit removes most of the sulfur-bearing compounds. Upon leaving the Selexol unit, the dry syngas goes to the saturator where a counter-current flow of hot water saturates the syngas at about 325F. The water added at this point provides the bulk of that water required by the combustion gas turbine for the reduction of NO_x emissions. After saturation, the syngas is superheated against economized boiler feed water. About 80F of superheat is needed for the protection of the gas turbine.

A spare quench gasifier train may be added in the future as a backup to the main gasifier and syngas coolers. Instead of cooling the syngas by generating high pressure steam, the hot syngas from the quench gasifier would be cooled by direct water contact in the quench chamber. This quenched gas would flow to the carbon scrubber for particulate removal. It would then be further cooled by an air-fan cooler before entering the main cooling train upstream of the saturator heater.

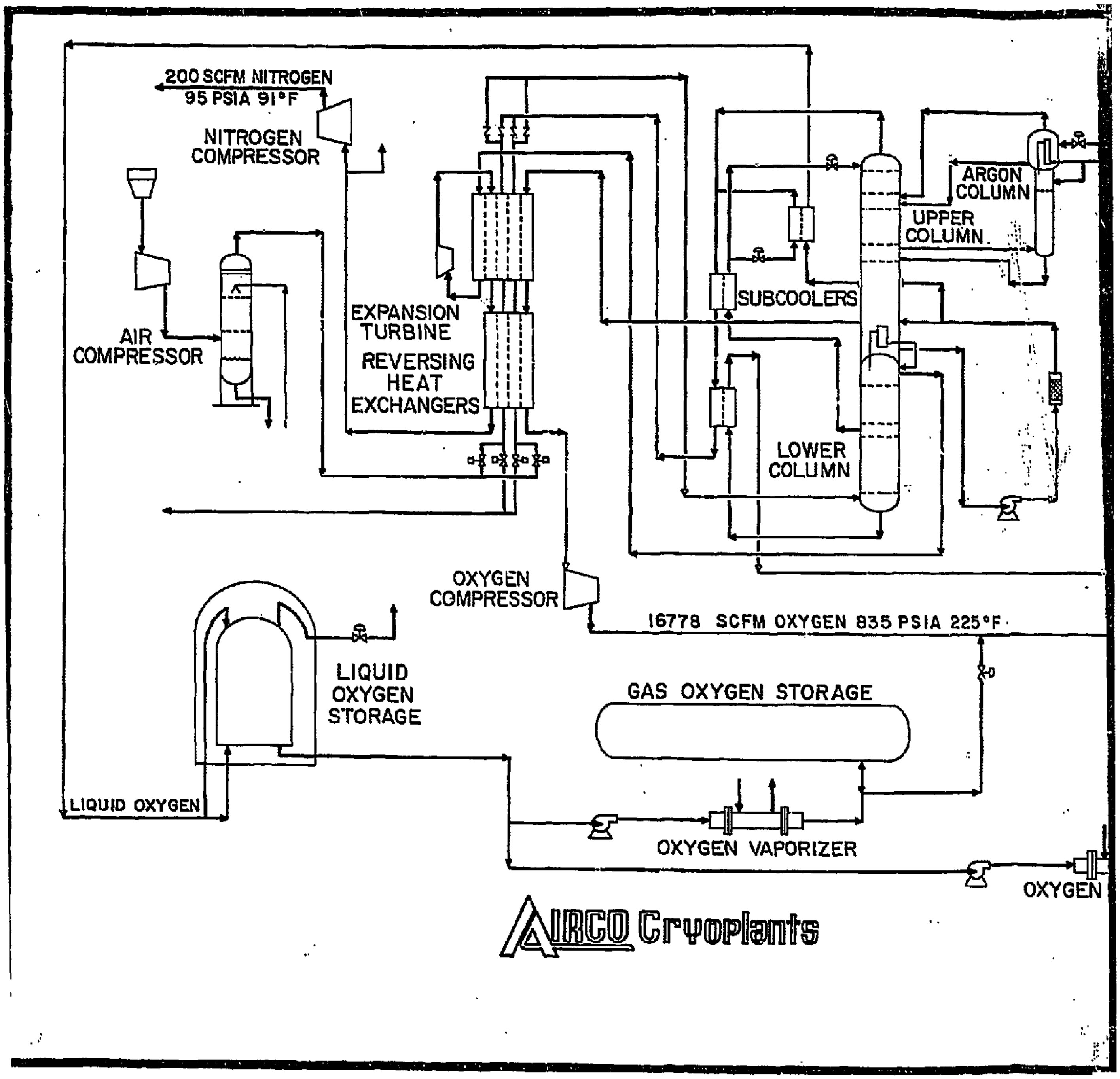
Oxygen Plant

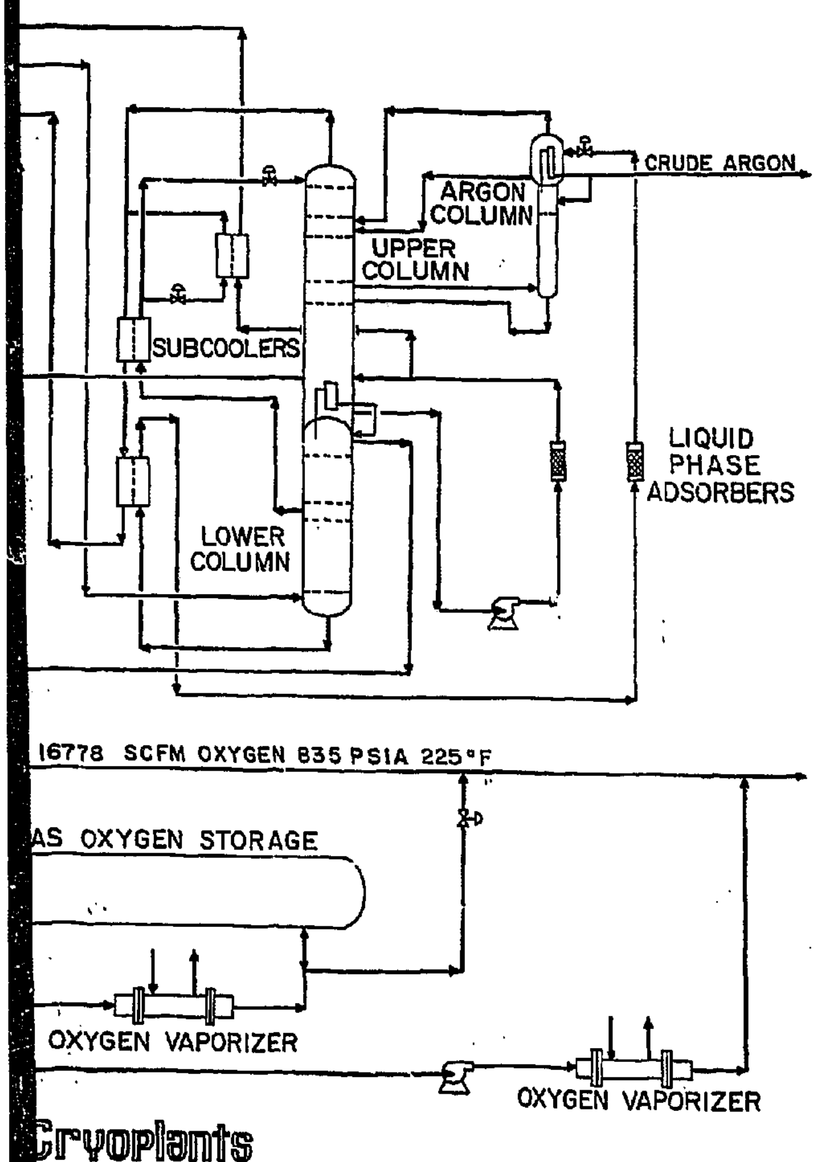
Oxygen will be received by pipeline from a nominal 1,000 tpd oxygen plant owned and operated by Airco, Inc., and located adjacent to the Cool Water Plant. Oxygen will be at 99.5 volume percent purity. Nitrogen will be supplied at various pressure levels and 98.0 volume percent purity. The Airco Plant will be able to deliver these two products to the Cool Water Plant at the product specifications with a 98 percent minimum on stream reliability factor. Should the oxygen plant shut down, 30 minutes of oxygen vapor storage as well as 24 hours of liquid storage will be provided. Process controls will be designed to ensure integration of the oxygen plant operation with the coal gasification plant. The oxygen plant will be capable of load-following demand of the gasification plant up and down from 60 percent to 100 percent of rated capacity without the use of oxygen storage or venting. A process flow diagram of the oxygen plant is shown in drawing 873-SK-111.

Gasification Process Effluent Water Treatment

The gasification process effluent water consists of a number of streams purged from the gasification process to limit the build-up of dissolved minerals in the gasifier circulating water system. Before being discharged to the evaporation pond, this water is stripped of dissolved H_2S, NH_3, and CO_2. The primary sources of effluent water are blowdown from the grey water system, the SCOT unit, and the Selexol unit. The flash gas from the grey water system combines with the stripped overhead vapor. The system is designed to process up to 80 gpm of water with a residual NH_3 concentration of about 200 ppm in the stripper bottoms. The overhead vapors are routed to the Claus plant for further processing. A process flow diagram of the unit is presented in drawing 873-SK-104.

The system consists of a sour water stripper, a thermosyphon steam reboiler, an airfan overhead condenser and associated pumps and controls. A 40,000-gallon sour water storage tank provides stripper feed surge capacity.


200 SCFM NITROGEN
95 PSIA 91°F
NITROGEN COMPRESSOR
AIR COMPRESSOR
EXPANSION TURBINE
REVERSING HEAT EXCHANGERS
SUBCOOLERS
ARGON COLUMN
UPPER COLUMN
LOWER COLUMN
OXYGEN COMPRESSOR
16778 SCFM OXYGEN 835 PSIA 225°F
LIQUID OXYGEN STORAGE
GAS OXYGEN STORAGE
LIQUID OXYGEN
OXYGEN VAPORIZER
OXYGEN
AIRCO Cryoplants



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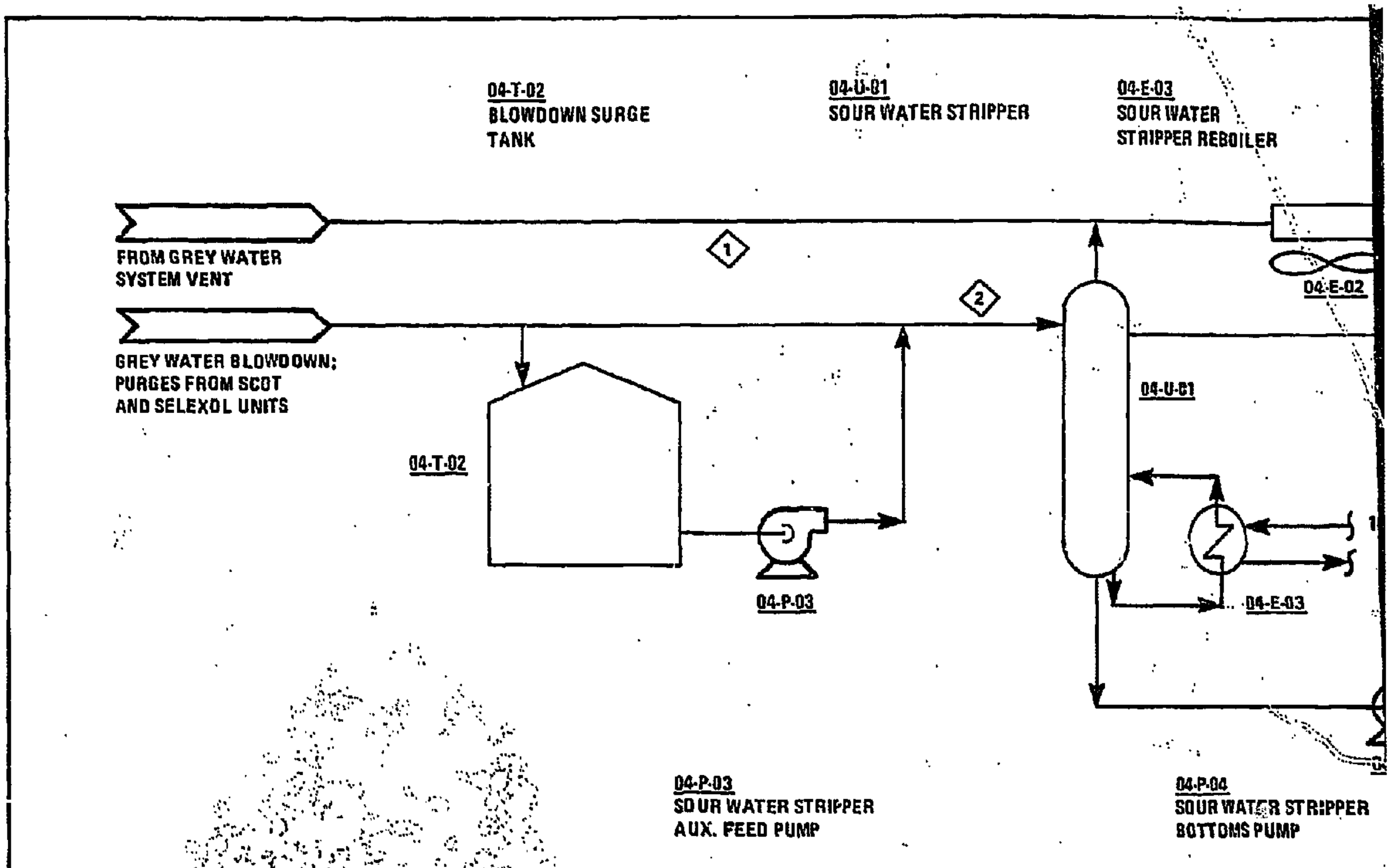
COOL WATER COAL GASIFICATION PROGRAM

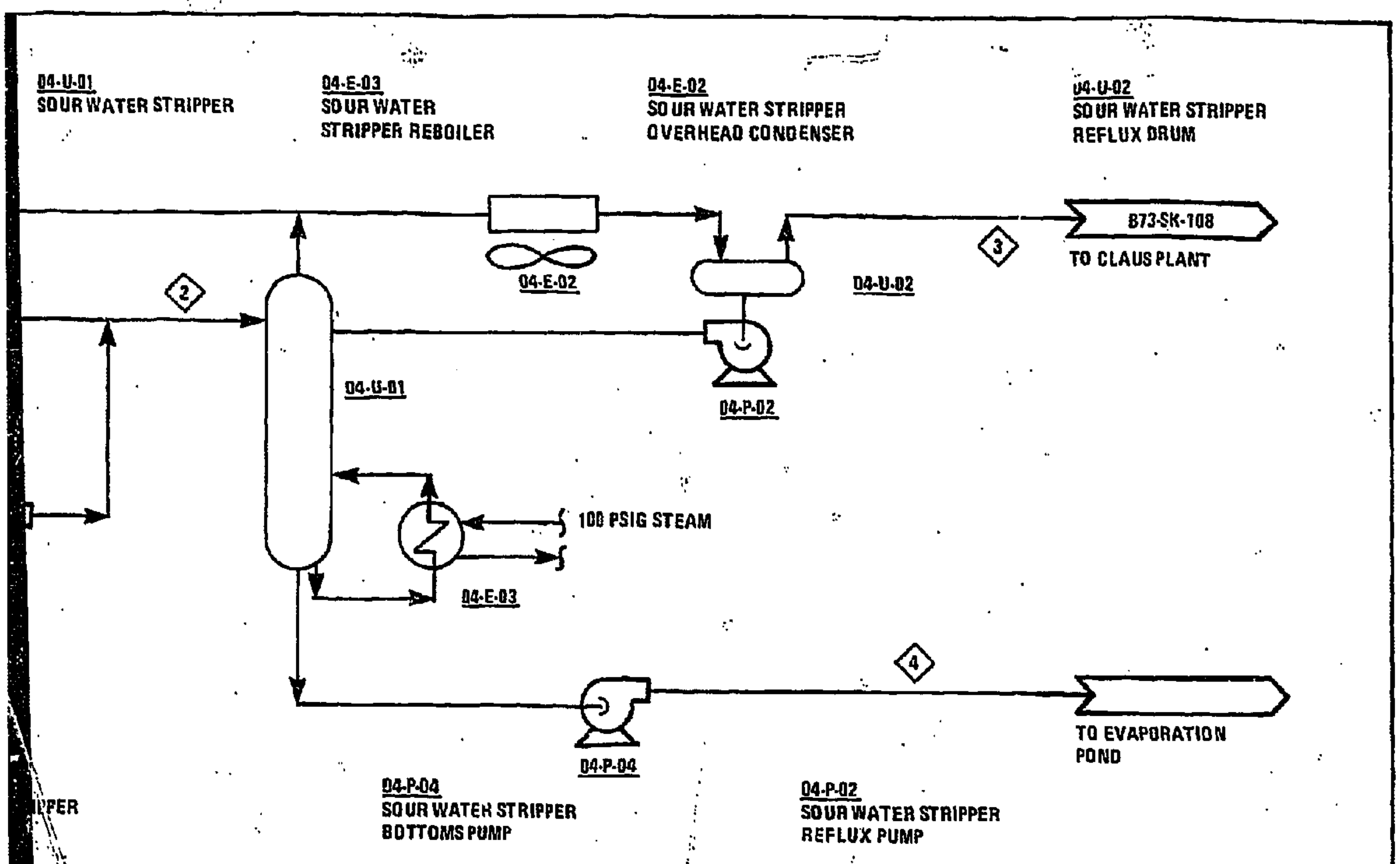
PROCESS FLOW DIAGRAM
OXYGEN PLANT

JOB No.	DRAWING No.	REV.
13478	B73-SK-111	0



STREAM NUMBER	1	2	3	4
STREAM NAME	GREY H_2O SYSTEM VENT	STRIPPER FEED	GAS. TO CLAUS PLANT	STRIPPER BOTTOMS
TOTAL FLOW, LB/HR	1447	40666	1447	40666
TEMPERATURE, °F	250	228	180	262
PRESSURE, PSIA	30	30	28	72
H_2O, MOLS/HR	48.96	2220.30	12.43	2256.83
NH_3	–	12.70	12.23	0.47
H_2S	0.16	0.09	0.22	0.02
CO_2	12.00	10.16	22.15	0.01
CO	1.00	–	1.00	–
H_2	2.00	–	2.00	–
SOLIDS	–	1000 ppm	–	1000 ppm
TOTAL, MOLS/HR	64.11	2243.25	50.03	2257.33

p



4
STRIPPER BOTTOMS
40666
262
72
2256.83
0.47
0.02
0.01
—
—
1000 ppm
2257.33

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COOL WATER COAL GASIFICATION PROGRAM

PROCESS FLOW DIAGRAM
GASIFICATION PROCESS EFFLUENT
WATER TREATMENT

JOB No.	DRAWING No.	REV.
13478	B73-SK-104	0

Ash and Slag Handling

Fly ash water from the radiant cooler, lockhopper and carbon scrubber contains fine ash and unconverted coal. These streams go to the clarifier where solids and water are separated. The recovered grey water is stored. Grey water return pumps are furnished to recycle the recovered grey water. The fly ash slurry is recycled to the coal grinding section.

Slag from the lockhoppers is fed to a slag sump. A screen classifier separates the coarse slag from the finer material which contains some unburned carbon. Coarse slag from the screen classifier is discharged to a slag bin and then transported by truck to an onsite disposal area. The fine carbon-containing material from the screen classifier is discharged to a recycle solids storage tank for recycling back to the coal grinding plant.

Sulfur Removal (Selexol)

A Selexol unit is provided to remove sulfur compounds from the syngas. Selexol is a proprietary process of the Norton Company for selective gas purification. In this application, it is designed to remove 97 percent of the H_2S and COS from the fuel-gas product, based on gasifying a design coal containing 0.7 percent by weight of sulfur, while removing only a minimum of the CO_2. This process employs a refrigerated solvent for sulfur absorption from the syngas in a counter-current trayed absorber column. Cooled gas at high pressure enters the absorber and contacts a counter-current stream of lean Selexol solvent. The hot, lean solvent is pumped through two exchangers which cool the solvent prior to introduction to the absorber. Ammonia refrigeration is used to cool the lean solvent. The purified gas passes from the unit as product gas. The rich solvent from the absorber bottom is fed to the stripper where the absorbed acid gas is stripped from the Selexol solvent. The overhead gas is the acid-gas feed to the sulfur conversion plant. Drawing B73-SK-107 presents the process flow diagram for the Selexol unit.

As an alternate case, coal containing 3.5 percent weight of sulfur could be used as feed to the coal gasification unit. In this case, 97 percent of the combined H_2S plus COS is removed from the fuel gas product by the Selexol sulfur removal system. The gas is treated to reduce H_2S and COS from 1.20 percent (1.14 percent H_2S, 0.06 percent COS) to 0.04 percent. The CO_2 content decreases from 19.6 percent to 15.4 percent. The acid gases, containing 17.4 percent combined H_2S and COS, are released to the Claus sulfur recovery unit for further processing.

Sulfur Recovery

Sulfur Conversion/Tail Gas Treating Plant. This plant consists of two sections: a modified Claus-type unit and a SCOT tail gas unit. The absorber in the SCOT unit first concentrates the H_2S in the acid gas which then flows to the Claus unit where most of the H_2S is converted to elemental sulfur. The tail gas from the Claus unit is further processed in the SCOT unit. Process flow diagrams of the two sections are shown in drawings 873-SK-108 and 873-SK-109.

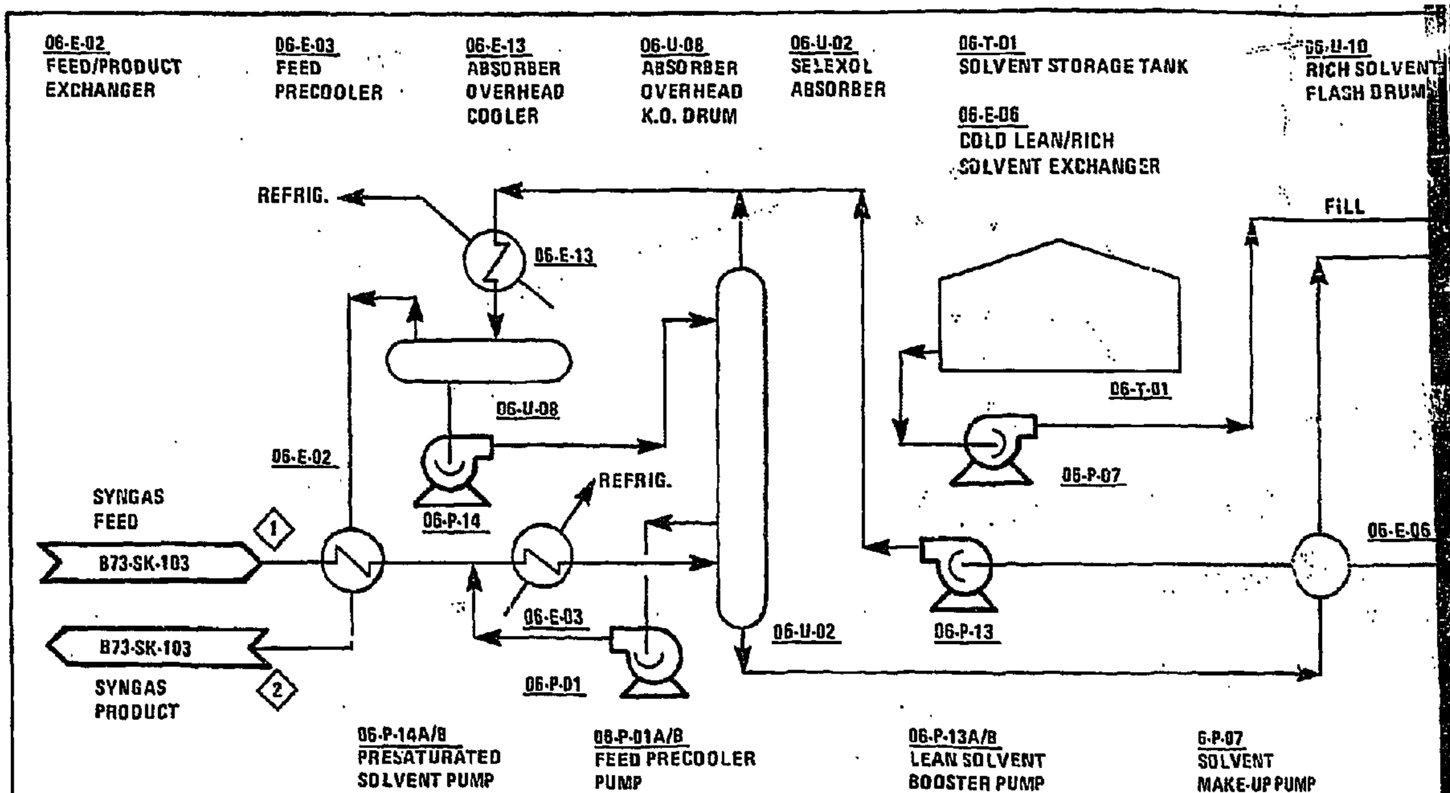
Claus Sulfur Conversion Unit. Combustion air is supplied by an air blower and is controlled automatically in proportion to the rate of acid-gas fed to maintain a ratio of H_2S/SO_2 at 2:1 in the converters. A gas analyzer in the plant tail gas line monitors the H_2S/SO_2 ratio and feeds back a signal to the air controller for close adjustment of air requirements.

The combustion gas containing sulfur, H_2S and SO_2 is cooled in the boiler tubes by generating medium pressure steam. The gas then passes to the first condenser. The first condenser cools the gas by generating more medium pressure steam. The gas is then reheated in the first reheater before entering the first converter.

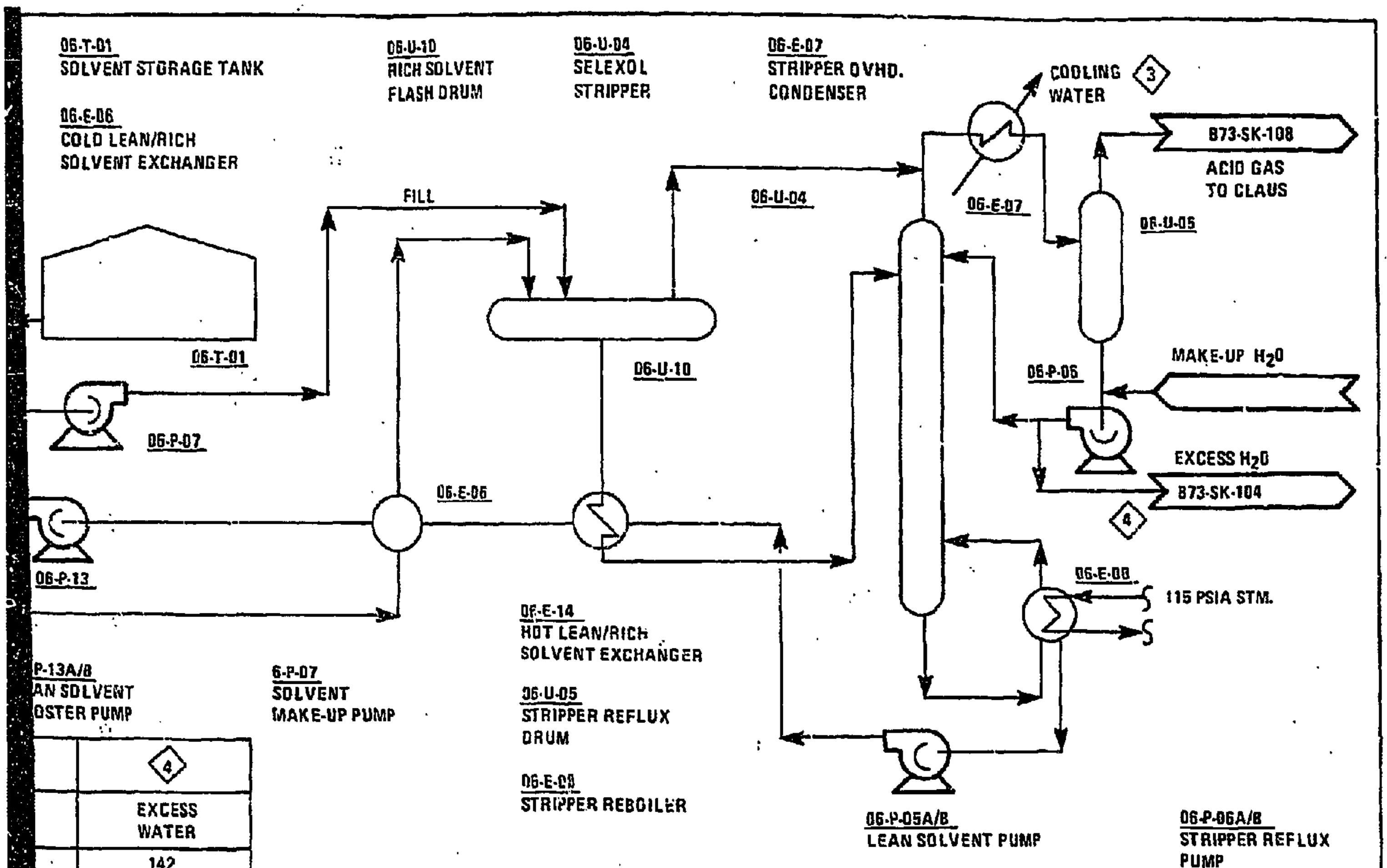
Most of the sulfur is produced in the first converter which is indicated by a larger temperature rise across this bed than in the other two stages. The gas then flows to the second sulfur condenser where the sulfur is condensed and drained to the sulfur pit. The second and third stages have similar reheaters, catalyst converters and condensers. The tail gas from the final condenser is then fed to the SCOT tail gas treating unit (TGTU).

All sulfur that is produced drains into the sulfur pit which is used for storage. The sulfur product is pumped from the pit to a truck-loading rack to be sold as a liquid product.

Equipment sizing in the catalytic reaction section of the Claus plant is governed chiefly by the quantity of gas flowing through the plant, and is affected only to a secondary extent by the H_2S content. With either low-sulfur or high-sulfur coal the acid gas separated by the Selexol process is mainly CO_2, in about the same quantity. Thus, the catalytic section of the Claus plant can be made large enough to handle the acid gas from high-sulfur coal with very minor added



STREAM NO.	1	2	3	4
STREAM NAME	SYNGAS FEED	SYNGAS PRODUCT	ACID GAS	EXCESS WATER
TOTAL FLOW, LB/HR	176117	162073	13902	142
TEMPERATURE, °F	100	85	100	100
PRESSURE, PSIA	513	450	28	98
COMPONENTS, MOL/HR				
H_2S	9	0.22	8.78	–
COS	0.53	0.35	0.18	–
CO_2	1585	1284	301	–
CO	3383	3378	5	–
N_2 + AR	171	170.8	0 2	–
H_2	2737	2735	2	–
CH_4	4	3.98	0.02	–
NH_3	0.07	0.03	0.04	–
H_2O	19	0.3	13.8	7.9
TOTAL	7908.60	7572.68	328.02	7.9



	4
	EXCESS WATER
	142
	100
	98
	–
	–
	–
	–
	–
	–
	–
	–
	7.9
	7.9

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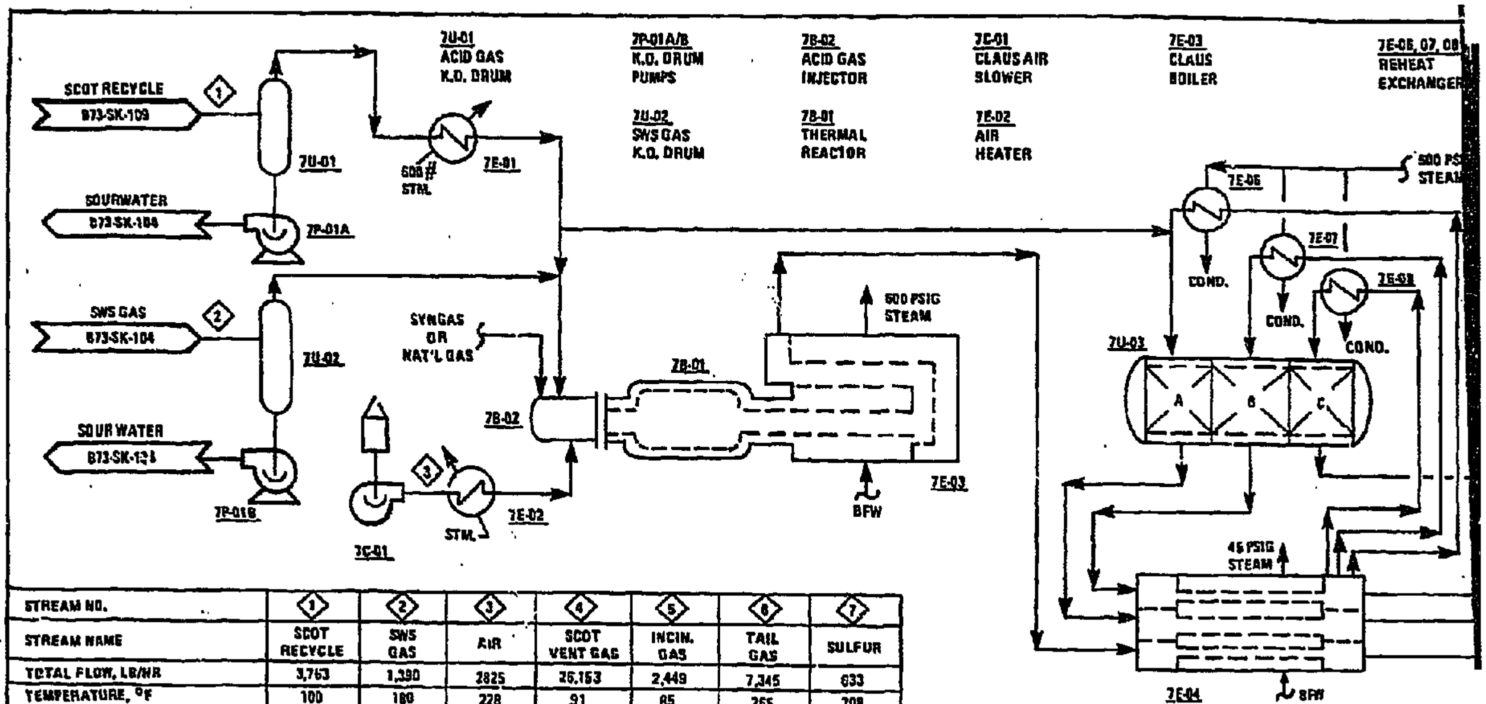
COOL WATER COAL GASIFICATION PROGRAM

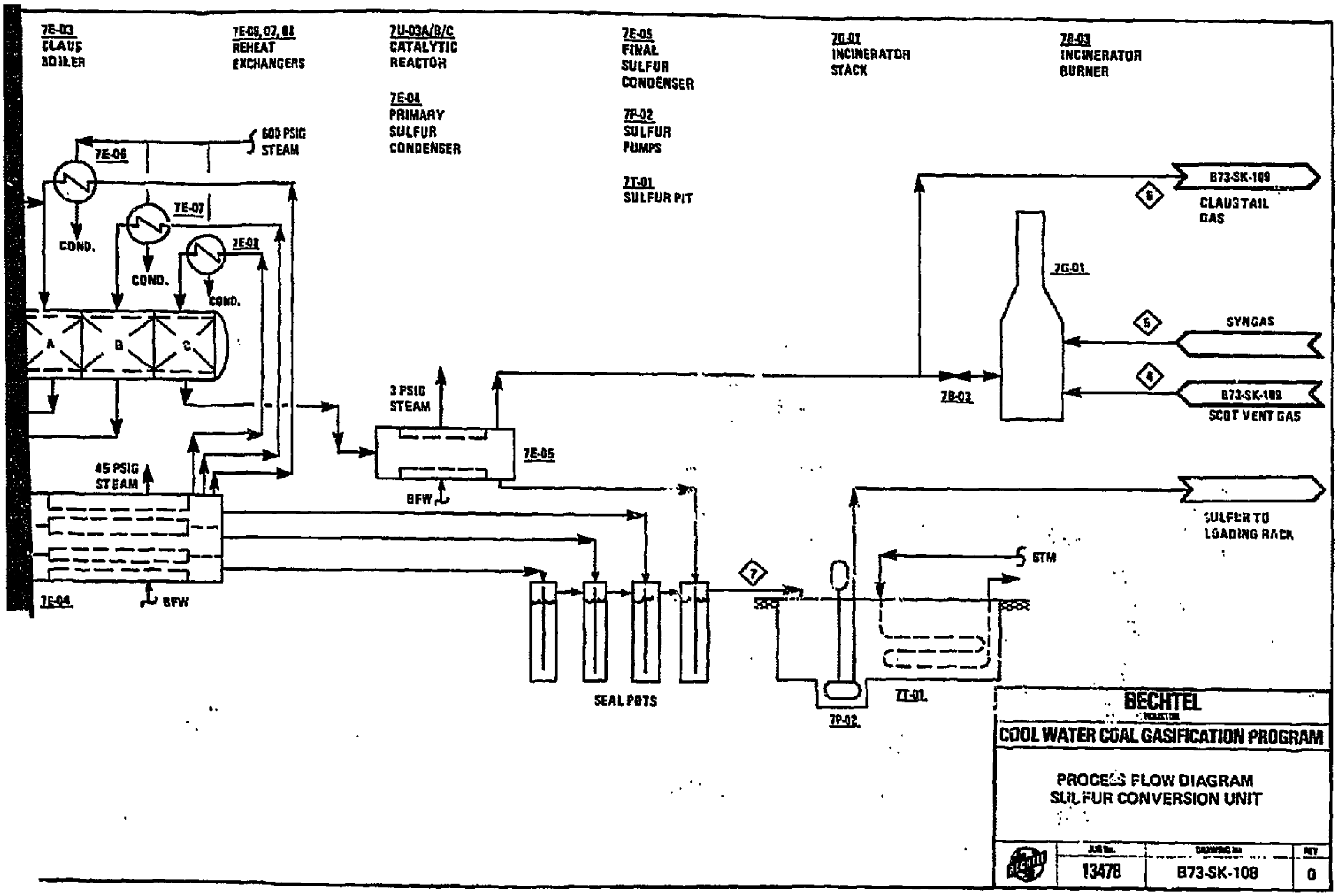
PROCESS FLOW DIAGRAM
SULFUR REMOVAL UNIT

JOB No	DRAWING No	REV
13478	B73-SK-107	0



STREAM NO.	1	2	3	4	5	6	7
STREAM NAME	SCOT RECYCLE	SWS GAS	AIR	SCOT VENT GAS	INCIN. GAS	TAIL GAS	SULFUR
TOTAL FLOW, LB/HR	3,763	1,390	2825	26,153	2,449	7,345	633
TEMPERATURE, °F	100	180	228	91	85	265	308
PRESSURE, PSIA	26	28	32	14	74	18	14
COMPONENTS, MOL/HR							
H_2S	20.60	0.24	–	0.05	–	1.15	–
CO_2	68.15	20.90	–	486.95	19.11	90.13	–
SO_2	–	–	–	–	–	0.58	–
COS	–	–	–	0.03	–	–	–
SULFUR	–	–	–	–	–	0.26	19.74
NH_3	0.04	11.24	–	–	–	–	–
N_2	–	–	–	144.48	2.57	82.32	–
CO	–	1.00	–	–	51.42	–	–
H_2	–	2.00	–	16.71	40.98	–	–
H_2O	3.40	13.00	–	35.41	–	54.96	–
TOTAL	92.19	48.46	–	683.83	114.08	229.40	19.74

NOTE: MATERIAL BALANCE SHOWN FOR 0.7% SULFUR COAL



7E-03 CLAUS BOILER
7E-06, 07, 08 REHEAT EXCHANGERS
7U-03A/B/C CATALYTIC REACTOR
7E-04 PRIMARY SULFUR CONDENSER
7E-05 FINAL SULFUR CONDENSER
7P-02 SULFUR PUMPS
7T-01 SULFUR PIT
7G-01 INCINERATOR STACK
7B-03 INCINERATOR BURNER
600 PSIG STEAM
7E-06
7E-07
7E-08
COND.
COND.
COND.
A
B
C
3 PSIG STEAM
45 PSIG STEAM
7E-05
BFW
BFW
7E-04
6
B73-SK-109
CLAUS TAIL GAS
7G-01
5
SYNGAS
4
B73-SK-109
SCOT VENT GAS
7B-03
SULFER TO LOADING RACK
STM
7
SEAL POTS
7P-02
7T-01
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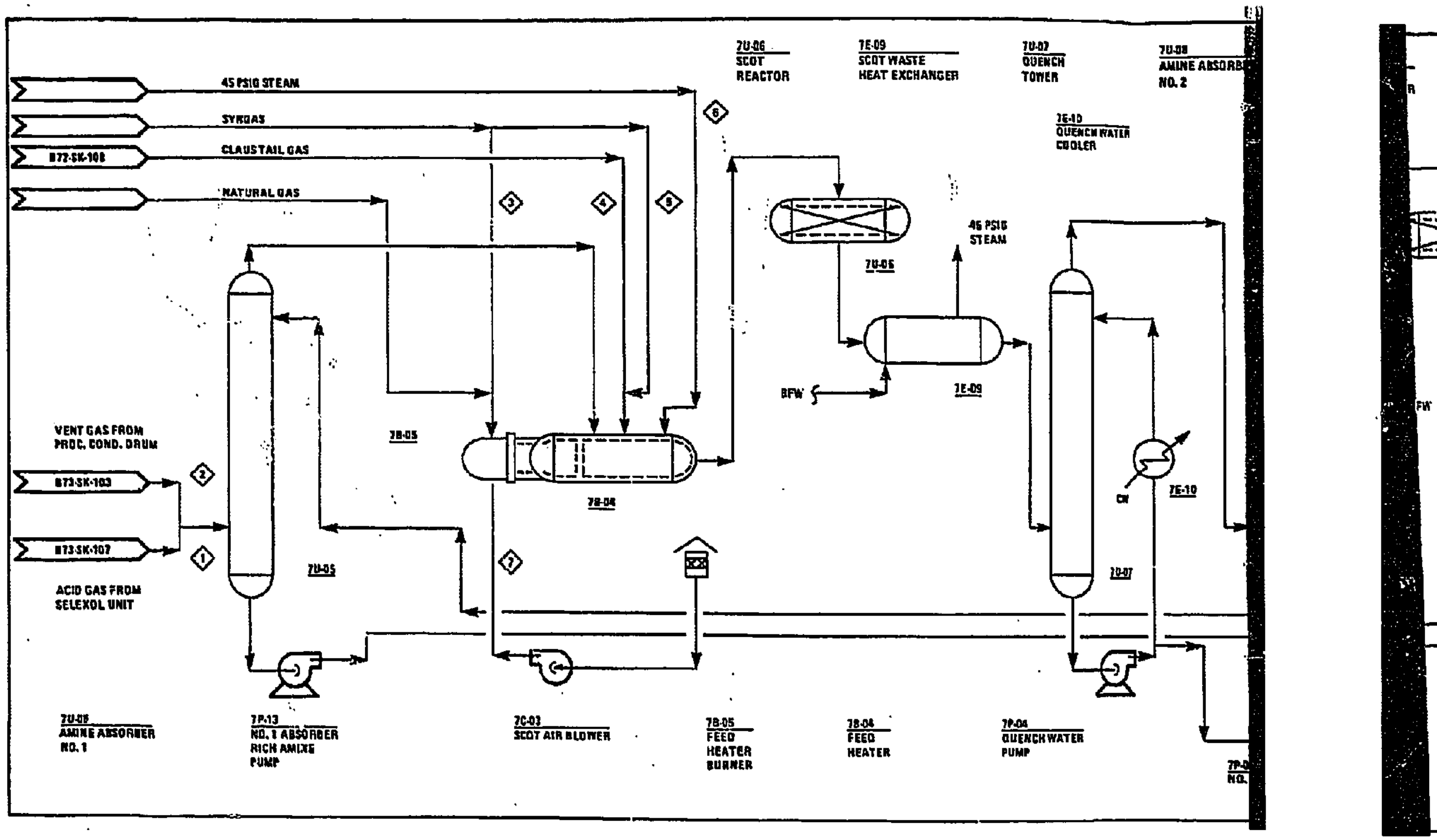
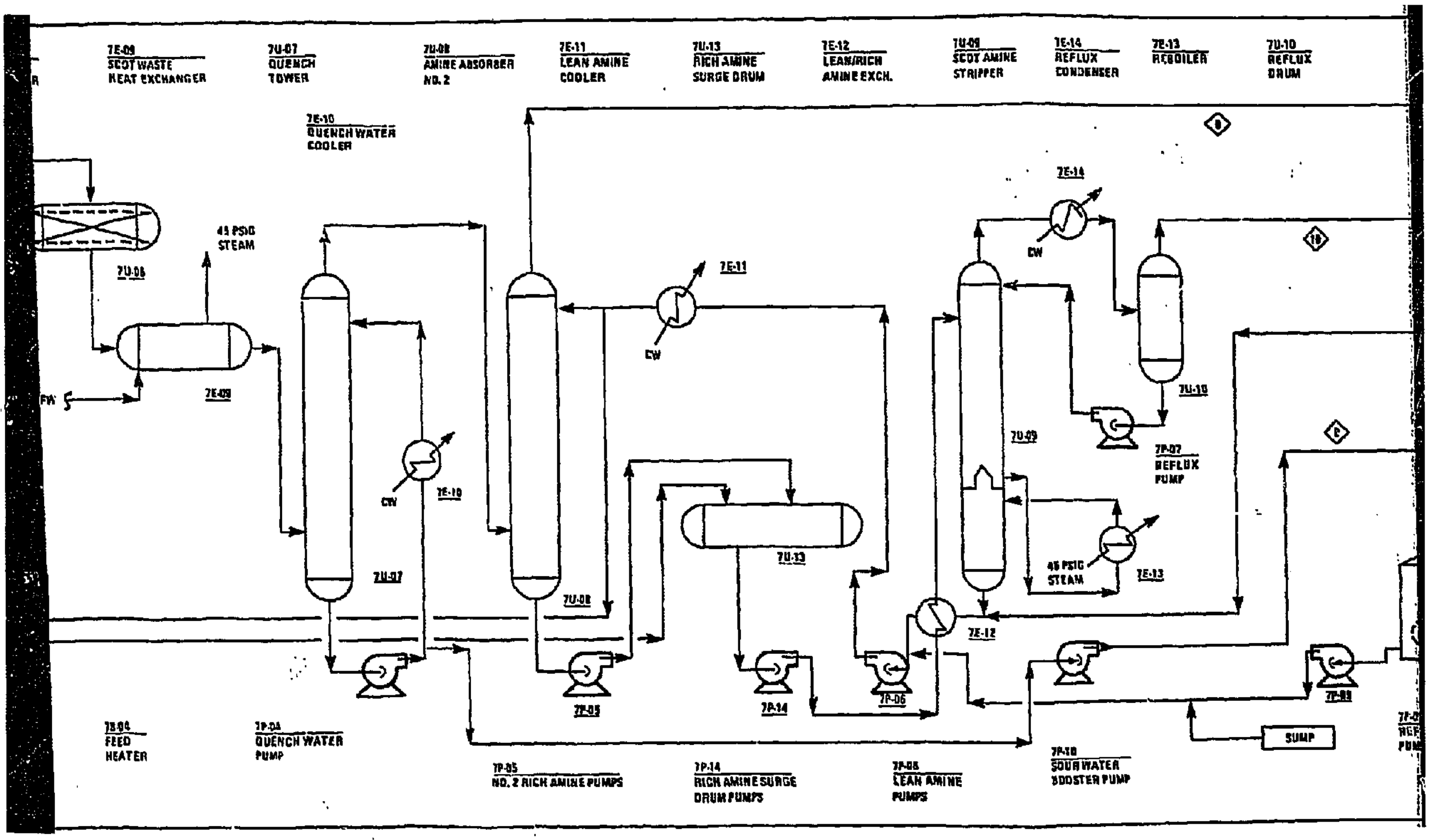
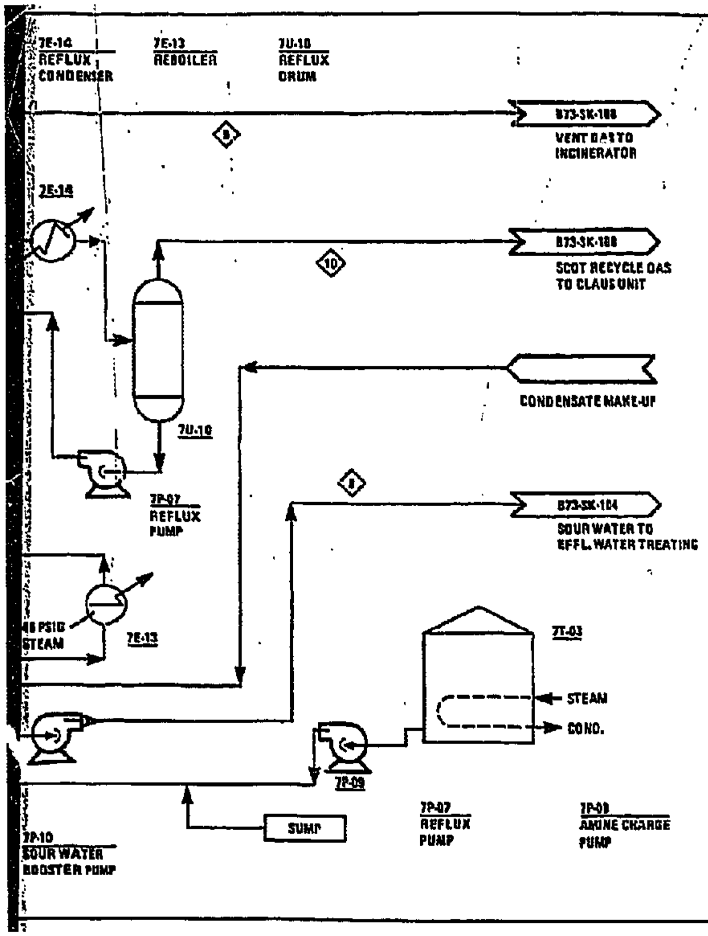
COOL WATER COAL GASIFICATION PROGRAM
PROCESS FLOW DIAGRAM
SULFUR CONVERSION UNIT
JOB No.
13478
DRAWING No.
B73-SK-108
REV
0



45 PSIG STEAM
SYNGAS
CLAUS TAIL GAS
NATURAL GAS
VENT GAS FROM PROC. COND. DRUM
ACID GAS FROM SELEXOL UNIT
7U-06 SCOT REACTOR
7E-09 SCOT WASTE HEAT EXCHANGER
7U-07 QUENCH TOWER
7E-10 QUENCH WATER COOLER
45 PSIG STEAM
BFW
CW
7U-05 AMINE ABSORBER NO. 1
7P-13 NO. 1 ABSORBER RICH AMINE PUMP
7C-03 SCOT AIR BLOWER
7B-05 FEED HEATER BURNER
7B-04 FEED HEATER
7P-04 QUENCH WATER PUMP

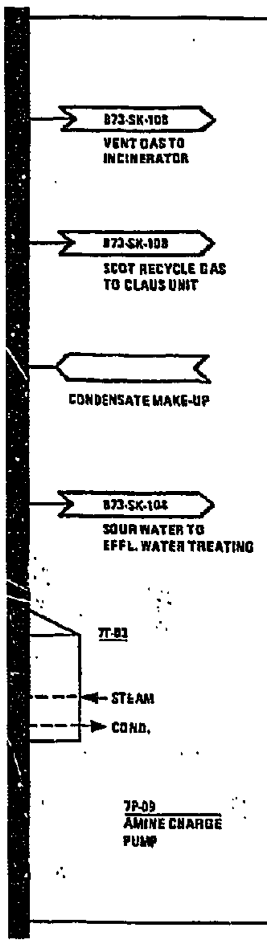


SCOT WASTE HEAT EXCHANGER
7U-07 QUENCH TOWER
AMINE ABSORBER NO. 2
7E-11 LEAN AMINE COOLER
7U-13 RICH AMINE SURGE DRUM
7E-12 LEAN/RICH AMINE EXCH.
SCOT AMINE STRIPPER
7E-14 REFLUX CONDENSER
7E-13 REBOILER
7U-10 REFLUX DRUM
7E-10 QUENCH WATER COOLER
45 PSIG STEAM
CW
FW
7P-07 REFLUX PUMP
SUMP
FEED HEATER
QUENCH WATER PUMP
7P-05 NO. 2 RICH AMINE PUMPS
7P-14 RICH AMINE SURGE DRUM PUMPS
LEAN AMINE PUMPS
SOUR WATER BOOSTER PUMP



STREAM NO.	1	2	3	4	5	6
STREAM NAME	ACID GAS	VENT GAS FROM FL. DR.	SYNGAS TO 78-05	CLAUS TAIL GAS	SYNGAS TO 78-04	45 PSIG STEAM
TOTAL FLOW, LB/HR	19,941	53	863.	7,348	106	5,000
TEMPERATURE, °F	100	140	70	265	70	291
COMPONENTS, MOL/HR						
H_2S	18.22	0.02	–	1.15	–	–
CO_2	424.50	1.11	7.02	90.13	0.87	–
SO_2	–	–	–	0.58	–	–
COS	0.45	–	–	–	–	–
SULFUR	–	–	–	0.28	–	–
NH_3	0.04	TR	–	–	–	–
N_2	0.26	–	0.90	82.32	0.11	–
CO	10.88	0.10	17.82	–	2.19	–
H_2	3.65	0.10	14.43	–	1.78	–
CH_4	0.03	–	0.03	–	–	–
O_2	–	–	–	–	–	–
H_2O	18.11	–	–	54.98	–	277.53
TOTAL	474.14	1.33	40.20	229.40	4.95	277.53

NOTE. MATERIAL BALANCE SHOWN FOR 0.7% SULFUR COAL



STREAM NO.	1	2	3	4	5	6	7	8	9	10
STREAM NAME	ACID GAS	VENT GAS FROM FL. DR.	SYNGAS TO 78-86	CLAUS TAIL GAS	SYNGAS TO 78-04	45 PSIG STEAM	AIR	SOUR WATER	SCOT VENT GAS	SCOT RE-CYCLE GAS
TOTAL FLOW, LB/HR	19,541	53	863	7,349	108	5,000	2,221	5,664	26,163	3,763
TEMPERATURE, °F	100	140	70	265	70	291	200	135	91	100
COMPONENTS, MOL/HR										
H_2S	18.22	0.02	–	1.15	–	–	–	TRACE	0.05	20.80
CO_2	424.50	1.11	7.02	50.33	0.87	–	–	TRACE	486.95	68.15
SO_2	–	–	–	0.58	–	–	–	–	–	–
COS	0.45	–	–	–	–	–	–	–	0.03	–
SULFUR	–	–	–	0.26	–	–	–	–	–	–
NH_3	0.04	TR	–	–	–	–	–	–	–	.04
N_2	0.26	–	0.90	82.32	0.11	–	60.82	–	144.48	–
CO	10.88	0.10	17.82	–	2.19	–	–	–	–	–
H_2	3.65	0.10	14.43	–	1.78	–	–	–	16.71	–
CH_4	0.03	–	0.03	–	–	–	–	–	0.03	–
O_2	–	–	–	–	–	–	16.17	–	–	–
H_2O	16.11	–	–	54.98	–	277.53	–	314.36	35.41	3.40
TOTAL	474.14	1.33	40.20	[illegible]	4.96	277.53	76.99	314.36	683.68	92.19

NOTE: MATERIAL BALANCE SHOWN FOR 0.7% SULFUR COAL

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COOL WATER COAL GASIFICATION PROGRAM

PROCESS FLOW DIAGRAM
SCOT TAIL GAS TREATING UNIT

JOB No.	DRAWING No.	REV.
13478	B73-SK-109	0

investment in steam generation for sulfur condensation. Tne Claus plant will recover about 96 percent of input sulfur from a coal feed containing 0.7 wt% sulfur and 97 percent from a 3.5 wt% sulfur coal.

SCOT Tail Gas Treating Unit. The SCOT unit serves two purposes. It first concentrates the H_2S in the acid gas from the Selexol unit. After the Claus unit has removed most of this H_2S, the SCOT unit reduces the amount of sulfur compounds in the Claus tail gas to a level below the allowable atmospheric emissions limits. The unit consists of three sections: a hydrogenation section to convert sulfur compounds to H_2S, a water quench section and an amine absorption unit for removal of the H_2S from the tail gas before incineration. The acid gas stream from the amine stripper recycles to the Claus Plant.

Power Generation

The power plant will use the clean gas produced by the gasification plant as fuel to be burned in a combustion turbine to generate electricity. The exhaust from the combustion turbine is used by the heat recovery steam generator (HRSG) to produce steam which is combined with the steam produced by the gasification plant syngas coolers. Process steam will be provided to the sulfur removal and recovery plants. The total steam produced by the HRSG and the gasification plant is used to produce additional electricity via a steam turbine.

Major components of the power plant consist of the following:

- Combustion Turbine Generator
- Heat Recovery Steam Generator (HRSG)
- Steam Turbine Generator

Combustion Turbine Generator. The combustion turbine generator is a base-mounted, simple cycle, turbine generator unit rated at 88,625 kVA at .80 power factor, 3 phase, 60 Hertz and 13,800 volts.

Because fuel gas produced by the coal gasification plant is a medium Btu gas, the standard combustion turbine will have to be modified. The modifications required in order to burn medium gas efficiently and cleanly are as follows:

- New fuel nozzles
- New fuel gas supply system to accommodate the high volume of gas required

Several design configurations of the new nozzle were fabricated and checked in a testing facility built for this purpose. During the testing, light-off capability, mechanical performance, thermal performance, emission performance and design capability of the new parts were analyzed and final designs were selected.

The combustion turbine generator consists of inlet and exhaust plenums, control cab, accessories compartment, turbine compartment and the generator excitation compartment including a water-air cooled generator. Diesel fuel will be used during gas turbine start-up and shutdown. Steam injection will be used for NO_x emission control. Provision will be made to install a future air pre-cooler to improve the efficiency of the gas turbine. A complete heating, ventilating, air-conditioning and fire protection system will be provided for the gas turbine.

The combustion turbine generator is also provided with a remote combustion turbine starting and supervisory control panel that will be located in the central plant control room.

Heat Recovery Steam Generator. The heat recovery steam generator (HRSG) is designed in accordance with the ASME Boiler and Pressure Vessel Code, Section I. The HRSG is designed to utilize the hot exhaust gas from the combustion gas turbine to generate a continuous and sufficient supply of superheated steam at a pressure of 1,450 psig and temperature of approximately 950F. The HRSG is composed of three convection sections: the superheater, evaporator and economizer.

The superheater is composed of rows of tubes in multiple passes connecting the inlet and outlet headers. Steam flow through the superheater is counterflow to the exhaust gas flow for auxiliary heat transfer. The evaporator is a multiple-row, two-pass evaporator which provides for unrestrained tube expansion through the use of free-floating return bends (U-bend type construction) at the end of the evaporator. The U-bend design also provides balanced steam output from the parallel circuit in the evaporator. The U-bend tubes are welded to two groups of large vertical headers, which in turn are welded to still larger horizontal inlet and outlet manifold headers. The inlet header is connected to the HRSG circulating pump discharge and the outlet header is connected to the HRSG steam drum. This arrangement provides maximum resistance to thermal shock and gives quick start capability.

The economizer provides counter-flow heat transfer between the water and the exhaust gases. The connecting pipe between the steam drum and economizer, referred to as a "Hartford Loop", prevents the draining of water from the economizer during operation, start-up and shutdown.

The HRSG produces approximately one-fourth of the total saturated steam produced by the overall plant (the other three-quarters are produced by the syngas cooler). The HRSG superheats the combined saturated steam (approximately 1,550 psig) produced by the HRSG and syngas cooler to about 950F.

Steam Turbine-Generator. The steam-turbine-generator is a standard, base-mounted unit, rated at approximately 67,000 kVA at 0.90 power factor, 3-phase, 60-Hertz, 13,800 volts. The steam turbine is a single-casing condensing arrangement consisting of a single-flow, high-pressure section and single-flow, low-pressure section. The unit is designed for rated throttle steam conditions of 1,365 psig and 1,000F, and for 2.5 inches of Hg(Abs.) back pressure. The turbine casing is equipped with two uncontrolled extractions to supply medium and low-pressure steam.

The steam produced by the HRSG unit passes through the steam turbine to generate additional electrical power in the combined-cycle arrangement. The normal operating mode consists of the steam turbine operating on inlet pressure control to accept all steam produced by the HRSG unit. A variable inlet pressure control optimizes the thermal efficiency of the turbine and minimizes erosion problems which could occur if the inlet steam temperature dropped below the desired level.

The range of operation on inlet pressure control approximates 25 percent to 100 percent of rating. During start-up, the high-pressure (main steam) bypass valve discharges steam directly to the condenser to establish initial flows and pressure levels. This bypass valve is also used during shutdown to allow the turbine to be tripped while operating at a relatively high temperature.

The steam turbine control system (STC) incorporates turbine auto start logic, control of turbine acceleration and loading, generator synchronization and steam pressure control b_ the bypass valves and steam turbine. In addition, the turbine generator monitoring and protective circuits are incorporated into the STC.

The steam turbine and bypass valve system includes the following features:

- Inlet stop valve
- Multiple cam-operated control valves with hardened leak-off bushings and valve stems
- High-pressure steam bypass valve with actuator and position feedback device
- Motorized drain valves for turbine casing, steam seal system, and above/below stop valve seats
- Automatic steam seal system
- Shaft packing vent system with blower and after condenser
- Turbine control system (STC) - Incorporates automatic starting, loading, stopping, monitoring, and protective functions. The high-pressure bypass, turbine main control, stop valve and synthetic gas cooler bypass to condenser are under STC control
- High-pressure hydraulic system with fire resistant fluid, duplex pumps, coolers, filters and integral fluid conditioning unit
- Electronic overspeed governor and trip with solenoid trip and exerciser for on-line testing
- Lube oil system with tank, pumps, coolers, valves, vapor extractor, gauges, pressure and temperature devices
- Turning gear, motor-operated with provisions for automatic or manual engaging and cranking
- Metal lagging for high-temperature parts of the turbine, with vibration dampening material sprayed on inside surfaces as required by design

Steam, Condensate and Boiler Feedwater System

To maximize efficiency and to minimize cost of the overall plant, an integrated coal gasification/power plant steam, condensate and boiler feedwater system is provided.

The steam production system is composed of the syngas cooler (SGC) and the heat recovery steam generator (HRSG). High pressure saturated steam (1,600 psig) is produced by the SGC and is transferred to the HRSG drum. The HRSG produces high pressure saturated steam (1,550 psig) in its evaporator section by utilizing the hot combustion turbine exhaust gases. Both the saturated HRSG and SGC steam are superheated in the HRSG's superheater section to a temperature of approximately

950F at a pressure of 1,450 psig. This superheated steam is then used by the steam turbine generator for electric power generation.

The steam turbine has two uncontrolled steam extractions. The higher pressure (250-300 psia) extraction provides medium pressure steam at a temperature of approximately 600F. This medium pressure steam is desuperheated to 500F and used by the combustion turbine for NO_x control and in the gasification process area. The lower pressure (21-31 psia) extraction provides low pressure steam to the deaerator for feedwater deaeration.

Some of the medium pressure steam is let down and desuperheated to 115 psia for use primarily in the Selexol and sour water stripper reboilers. This steam is further reduced to a 59 psia steam level used wholly within the sulfur conversion/tail gas treating unit. This unit also produces steam at several levels. Sulfur condensers produce 600 psig steam both for internal use and for export into the medium pressure steam header. Some 59 psia steam is also produced. An 18 psia steam header receives steam from a sulfur condenser and from flashed boiler blowdown. The header floats on the deaerator pressure.

Because of the large duties of the power plant turbine generator, most of the steam consumed by the plant will be condensed and recovered. Condensate recovered from the vacuum system is collected in the condenser hotwell where make-up from the condensate transfer system is added. The condensate is then pumped through the condensate heater where it picks up heat from the syngas being cooled and into a deaerator where it is mixed with returning hot condensate from process users in the gasification plant and deaerated by low-pressure steam. The deaerated feedwater is then pumped to the boilers for steam production and to gasification plant users by constant speed pumps. The syngas cooler steam generator receives the major portion of its feedwater via the HRSG steam drum. Intermediate and low pressure users are supplied through a pressure reducing station located in the gasification plant header. Facilities are provided to add chemical treating agents and an oxygen scavenger to the deaerated boiler feedwater supply. Blowdown water from boilers is discharged into the cooling tower basin where it is used as partial make-up to the circulating water system.

Plant Electrical Systems

The integrated plant electrical system consists of the following three divisions:

- 13.8 kV generator main transformers and connections to the existing 230 kV transmission switchyard
- 4.16 kV power system, main auxiliary transformers and connections to the 13.8 kV generation
- The power supply to the integrated plant auxiliary loads at various voltage levels

The electrical main one-line diagram is shown in drawing E40-SK-113. Each of the three divisions is described in the following subsections.

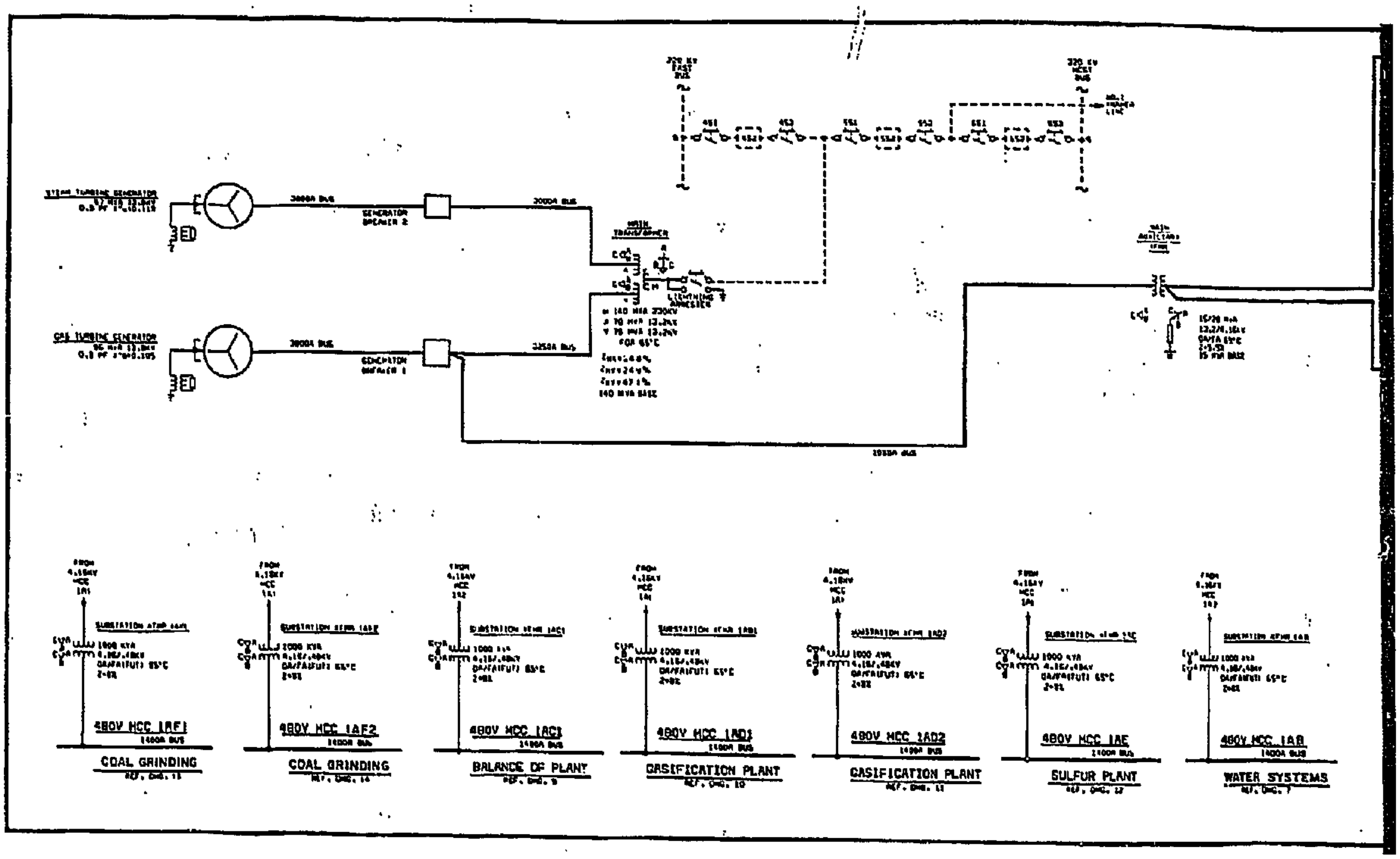
13.8 kV Generation. The 13.8 kV generation consists of a gas turbine generator and a steam turbine generator, each wye-connected and grounded through a distribution type transformer loaded by a resistor on the secondary side. Each generator will be provided with excitation and voltage regulation systems, field application equipment, the required current and potential transformers, associated controls, surge protection, synchronizing, protective relaying, metering and alarm circuits. The excitation system will have a high speed response.

Generator Connections to Existing 230 kV Transmission Switchyard. Each 13.8 kV generator will be connected to a 13.8 kV delta winding of the three-winding main transformer through a generator synchronizing outdoor air circuit breaker by means of a metal-enclosed, 15 kV cable bus.

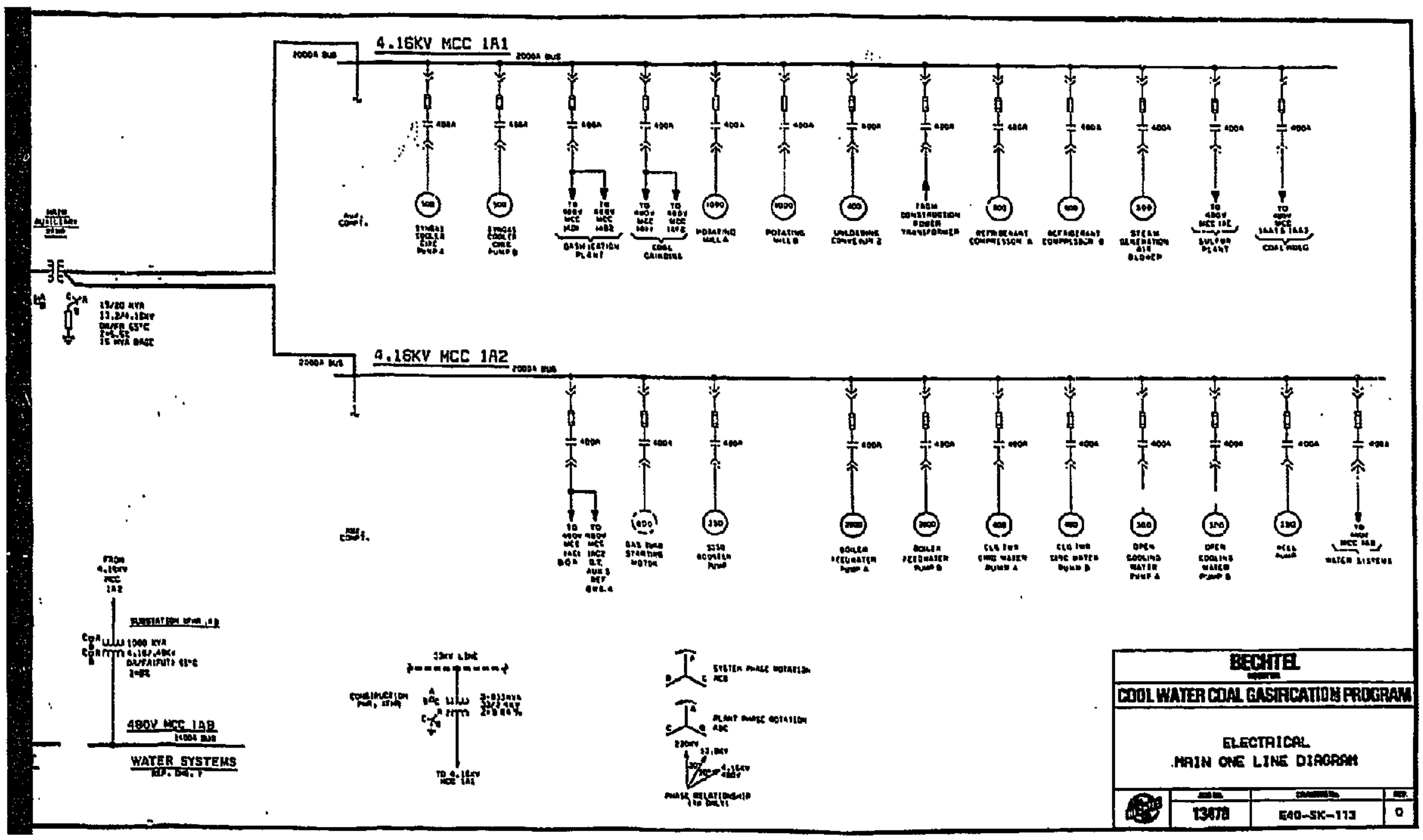
The 230 kV wye winding of the main transformer will be connected by an overhead power line to a spare position in the existing 230 kV transmission switchyard. The connection will require the installation of a 230 kV power circuit breaker with its required disconnects.

Each 13.8 kV generator system, including the main and main auxiliary transformers and the 230 kV power circuit breaker, will be provided with the required current and potential transformer, lightning and surge protection, synchronizing check, protective relaying, metering and alarm circuits.

4.16 kV Power System. The 4.16 kV power system can be supplied 4.16 kV power from either of the following two sources:



480V MCC 1AF1
COAL GRINDING
480V MCC 1AF2
COAL GRINDING
480V MCC 1AC1
BALANCE OF PLANT
480V MCC 1AD1
GASIFICATION PLANT
480V MCC 1AD2
GASIFICATION PLANT
480V MCC 1AE
SULFUR PLANT
480V MCC 1AB
WATER SYSTEMS


4.16KV MCC 1A1
2000A BUS
4.16KV MCC 1A2
GASIFICATION PLANT
COAL GRINDING
ROTATING MILL A
ROTATING MILL B
FROM CONSTRUCTION POWER TRANSFORMER
REFRIGERANT COMPRESSOR A
STEAM GENERATION AIR BLOWER
SULFUR PLANT
COAL HDLG
BOILER FEEDWATER PUMP A
BOILER FEEDWATER PUMP B
OPEN COOLING WATER PUMP A
OPEN COOLING WATER PUMP B
WATER SYSTEMS
480V MCC 1AB
WATER SYSTEMS
33KV LINE
SYSTEM PHASE ROTATION ACB
PLANT PHASE ROTATION ABC
PHASE RELATIONSHIP
BECHTEL
COOL WATER COAL GASIFICATION PROGRAM
ELECTRICAL
MAIN ONE LINE DIAGRAM
13478
E40-SK-113
0

- From the gas turbine-generator through the main auxiliary transformer

- From the 230 kV power system through the main transformer and the main auxiliary transformer

The power supply to the 4.16 kV power system will be from the main auxiliary transformer. This transformer will be connected to the gas turbine-generator 13.8 kV bus on the load side of the generator 13.8 kV air circuit breaker. It will be delta-wye-connected with the neutral grounded through a resistor sized to limit the ground current to approximately 400 amperes. The main auxiliary transformer will be within the differential protection zone of the main transformer.

All motors larger than 200 hp will be powered from the 4.16 kV motor control center (MCC) with their controlling equipment located in the MCC. The controlling equipment for each 4.16 kV motor will consist of a combination disconnecting fused switch and an electrically operated controller with:

- Overload current protection for the motor
- AC control transformers supplying the control circuits
- Ground protection
- Thermal overload protection
- Wattmeter and ammeter

Power to each of the 480-volt MCC unit substations will be supplied from the 4.16 kV supply buses through a 4.16/.48 kV delta-delta connected transformer. A ground-detecting circuit will be furnished for each 480-volt bus. Each motor that is supplied from a 480-volt MCC unit substation will be controlled by a combination manually operated, magnetic-trip circuit breaker and an electrically operated starter. The nonrotating loads and equipment with integral controls will be fed through a manually operated, thermal-magnetic circuit breaker.

The 125-volt dc system will consist of one 125-volt dc battery, with a main 125-volt dc distribution panel, and two 480-volt battery chargers. Each battery charger will be furnished to float-charge its battery and supply the normal continuous dc control load. The dc system will be ungrounded and equipped with a ground detector for continuous monitoring of ground-fault current.

The battery will be sized to handle the following combined loads:

	Operating Duration (hrs.)
• The steam turbine generator emergency oil pump	1
• Control and indication	1.5
• Vital instrument UPS system	1.5

A 120-volt ac vital instrumentation power supply bus will be provided to serve vital plant ac instrumentation and controls, and will normally be powered by the dc/ac inverter (UPS system).

A separate 120-volt ac regulated bus will be provided for loads requiring regulated ac supply. In addition, this source will be used as a backup supply for the vital instrumentation power supply bus in case of inverter failure.

Instrumentation and controls requiring unregulated ac power will be fed from distribution transformers and panels mounted in the 480-volt MCC's as required.

Lighting and low-energy auxiliary loads will be supplied from the 120/208-volt or from 277/480-volt solidly grounded lighting system. Lighting for each plant operating area will be supplied from at least two circuits fed from separate power sources to prevent complete loss of lighting on failure of equipment or wiring. Locally mounted wall packs will provide emergency lighting for exits and critical areas. Outdoor lighting will be provided for operating areas and will include parking lot lighting and road lighting to match the existing installation at the Cool Water site.

The electrical design for each unit will be based on centralized controls for monitoring and protection with a minimum of local control stations and switches.

The steam turbine and the combustion turbine generator units will be capable of operating in parallel with each other and the 230 kV grid system. The controls provided will maintain the required output, frequency, voltage and continuity of service demand. These controls will also provide protection to plant personnel and equipment under all operating conditions. To obtain operating reliability, the basic design of electrical equipment will be such that the necessity for interlocks is minimized and the requirement for control functions is also minimized. Control devices and monitoring devices necessary for start-up, shutdown, normal and emergency operations will be provided in the control room.

Protection of electrical equipment will be accomplished by means of coordinated relay systems, fuses and circuit breaker or contactor operations.

An automatic and manual synchronizing system will be provided with:

- Speed matching
- Voltage matching
- Breaker closing

Each generating unit, the main transformer and the main station auxiliary transformer will be provided with protection which includes:

Each generating unit:

- Differential (unit and transformer)
- Negative sequence overcurrent
- Overexcitation
- Loss of field
- Generator ground
- Generator field ground
- Stator over temperature
- Synchrocheck
- Reverse power
- Primary and backup lockout relays

Main, auxiliary and reserve power transformers:

- Differential
- Phase overcurrent
- Neutral overcurrent
- Sudden (fault) pressure
- Overtemperature
- Lockout relay

The 4,160-volt bus will be provided with voltage actuated bus differential protection, bus overcurrent and under-voltage protection.

The grounding system will be a ground grid, consisting of buried bare copper cable meshes and ground wells with copper anodes installed below the water table low level. The grid will extend throughout all areas, including interconnections to the existing grounding grid for Units 3 and 4 generators and the switchyard. All electrical equipment, all switchgear ground buses, all electrical motors, building columns, transformer and generator neutrals will be connected to this grounding grid.

Communications Systems. Telephone sets and public address speakers similar to the existing plant equipment, and all wiring and raceways will be provided for intraplant communication. All locations, including the switchyard and outlying areas dictated by the overall plant operation requirements, will be covered.

OTHER SUPPORTING SYSTEMS

Flare System

The flare system disposes of excess gas during start-up, emergency relief and abnormal operational transients. At start-up, the syngas stream vents to the flare on pressure control until the gas turbine switches entirely to syngas firing. Syngas is also vented to the flare for brief periods during abnormal operation when gasifier syngas production exceeds turbine demand. This too, is on pressure control. Should an upset condition require emergency relief, a flare knockout drum will first separate out any liquid water and the remaining gas will then burn in the flare. The water is pumped back to the grey water system.

Cooling and Make-up Water Systems

The integrated plant cooling water system provides cooling water to remove the heat loads generated in the power generation equipment and the coal gasification plant. It consists of the following subsystems:

- Cooling tower
- Circulating water system
- Closed cooling water system
- Chlorination system

Each of the subsystems is described in the following sections:

The cooling tower circulating water system utilizes a mechanical-draft, evaporative cooling tower to remove approximately 392.8 x 10^6 Btu/hr of heat from the power plant condensers, closed cooling water system and auxiliary equipment in the coal gasification plant. Clarified water, averaging approximately 810 gpm, is provided by the plant well water system to the cooling tower basin to compensate for losses caused by drift, evaporation and blowdown from the cooling tower. Blowdown from the steam, condensate and boiler feedwater system is routed to the cooling tower basin to provide part of make-up and to minimize water consumption. The circulating water system consists of the mechanical-draft cooling tower, two half-capacity circulating water pumps, two full-capacity open cooling pumps and the necessary piping, controls and instrumentation.

The closed-loop cooling water system is designed to remove 21 x 10^6 Btu/hr of heat load generated by the gas turbine, steam turbine and the coal gasification auxiliary equipment. Cooling water is supplied to the various equipment at 95F and the heated cooling water is returned to the shell side of the cooling water heat exchangers at 105F. The total design flow for the closed cooling water system is 4,140 gpm. Circulating water at 81F is used to remove the heat load from the tube side of the cooling water heat exchangers. Makeup to the closed cooling water system to compensate for leakage losses is provided by the combined cycle condensate system. The system consists of an atmospheric cooling water surge tank, two half-capacity cooling water heat exchangers, three half-capacity cooling water pumps, a manual chemical feeder and a closed-loop piping network with connections to the coal gasification plant and the power plant.

The chlorination systems equipment is housed in a separate chlorination building located adjacent to the plant main cooling tower. The chlorinators, control panel and leak detector are in an enclosed and ventilated chlorinator room. The evaporator, expansion chamber, chlorine cylinders and one-ton containers are in the adjacent evaporator room. Liquid chlorine flows from the manifold of the one-ton containers to the evaporator of the main cooling tower basin chlorination system and the service water storage tank chlorination system. Gaseous chlorine flows from the 150-pound gas cylinders to the potable water chlorination system.

The main cooling tower chlorination system is an automatic chlorine injection type where liquid chlorine flows into an evaporator, then to a chlorinator with injector and finally into the cooling tower basin via a diffuser.

The service water storage tank chlorination system is a continuous type where chlorine flows into a 150-pounds-per-day-capacity chlorinator with an injector.

The potable water chlorination system is a continuous type where gaseous chlorine flows into a 20-pounds-per-day-capacity chlorinator with an injector.

Plant Water System. The plant water system is designed to meet the overall water requirements for the integrated coal gasification/power generation plant. The plant water system consists of the following subsystems:

- Well water supply system
- Potable water system
- Service water system
- Demineralized water and condensate system
- Chemical injection system
- Waste disposal system

The well water supply system provides a supply of raw water to the service water, potable water, circulating water and firewater systems. The system consists of a single water well, a supply line, and a control system dedicated to the integrated coal gasification/combined-cycle power plant as well as three deep wells, pumps, piping and controls which already exist to supply SCE Cool Water Units 3 and 4. Well water discharged from the well pump is distributed to three locations: the service water storage tank, the circulating water system cooling tower basin and the potable water storage tank.

The potable water system provides a continuous supply of water for emergency eyewash showers and various domestic uses. The system consists of a potable water storage tank, two potable water pumps, piping and controls.

The service water system provides a continuous supply of chlorinated water for plant utility uses. The service water system consists of a service water storage tank, two service water pumps, piping and the necessary controls and instrumentation. Service water is distributed to the various plant users by the service water pumps which take suction from the service water storage tank. Normal full load operation will have one pump in service with the other as standby.

The demineralized water and condensate system shares a large demineralized water storage tank and a common spare demineralized water transfer pump with SCE Units 3 and 4. The SCE Units 3 and 4 demineralization system maintains a 24-hour supply of demineralized water in this tank for SCE Units 3 and 4 and Cool Water GCC Plant full-load operation should the demineralization system fail. Under normal conditions, the transfer pumps maintain the level of the integrated coal gasification/combined-cycle condensate storage tank.

The chemical injection system provides for the addition of sulfuric acid and a proprietary corrosion inhibitor to the circulating water system. Chlorine is also added to the various water systems as described in the preceding section. The sulfuric acid is added to maintain a pH between 8.0 and 9.0. Each of the chemical injection systems has a bulk storage tank and dedicated metering pumps.

A waste disposal system is provided to collect and transfer to the evaporation pond waste drains from the power generation area (other than cooling tower blowdown and the sour water stripper bottoms which discharge directly to the evporation pond). The power generation chemical waste system consists of three headers discharging into the retention basin. Power generation oily waste flows to an oil waste sump containing two progressing cavity pumps which pump to a coalescing plate oily waste separator. From the separator, the waste flows by gravity to the retention basin. Accumulated waste water is transferred from the retention basin to the evaporation pond with two retention basin centrifugal sump pumps. Lines leading to the evaporation pond are all headered together so that only one line actually runs to the evaporation pond. Any sludge accumulating in the retention basin is removed periodically.

Plant Air

The compressed air system provides instrument air which is clean, oil-free and dried to a dew point of -40F, at a maximum pressure of 125 psig for pneumatic instruments and controls. This system also provides clean, oil-free (but not necessarily dry) air for maintenance air base stations located throughout the plant.

The compressed air system consists of two identical nonlubricated reciprocating skid-mounted air compressors each rated at 669 scfm, two air receivers, two air dryers each rated at 600 scfm, and all necessary instruments, valves and piping.

The air compressors are provided with a lead-and-follow control arrangement in which the lead compressor runs continuously and maintains the pressure within the set pressure range by loading and unloading. The follow compressor will start automatically when the lead compressor is no longer able to maintain the set pressure range.

Auxiliaries

The proper and efficient operation of the integrated coal gasification/combined cycle power plant requires other auxiliary systems in addition to the systems previously described. The following paragraphs briefly describe these systems.

Nitrogen. Nitrogen requirements for Cool Water have been identified for three pressure levels.

- Low Pressure - 80 psig
- Intermediate Pressure - 250 psig
- High Pressure - 1000 psig

The basic use of nitrogen is for purge and blanketing of the equipment. The major uses by system are:

- Low pressure system - 80 psig
  - --Blanket grey water system
  - --Purge lockhopper flush drum
  - --Purge flare stack
  - --Pressure air cannons and coal feed hopper and slag bin
  - --Purge from the carbon scrubber through to fuel skid of the gas turbine on start-up
  - --Purge the gasifier, syngas cooler and carbon scrubber following shutdown
  - --Supply inert gas to the SCOT Unit for catalyst conditioning
  - --Blanket entire system including HRSG on extended shutdown
- Intermediate Pressure System - 250 psig
  - --Purge the gas turbine fuel skid piping system following a fuel switch.

- High Pressure System - 1,000 psig

  --Purge the gasifier burner

  --Purge the temperature measuring devices on the gasifier

  --Seal the shaft on the fly ash dump valve at the bottom of the syngas convection cooler riser

The above systems will consume an average of 110 scfm. The available nitrogen supply from the Airco Oxygen Plant is 200 scfm at 80 psig at design rate. The details of the system(s) for supplying the different pressure levels required and the high instantaneous rates of purge are currently under investigation.

<u>Natural Gas</u>. Natural gas is required continuously for the flare system pilot, space heating, furnace pilots and laboratory uses. It is also used in the gasifier warm-up as well as in the Claus/SCOT Unit start-up and shutdown when syngas is not available. The gas will be supplied through a tie-in with the natural gas distribution system in the existing Cool Water facility.

<u>Diesel</u>. The diesel fuel system supplies diesel fuel to the combustion gas turbine as an alternate fuel for both start-up and shutdown operations. The diesel fuel system will be interconnected with the existing diesel fuel system of SCE Units 3 and 4, and will utilize existing Units 3 and 4 transfer pumps to transfer from the existing diesel fuel oil tank to a new 500-gallon surge tank. A skid-mounted fuel forwarding pump supplies fuel from the surge tank to the gas turbine fuel distribution system at the required flow rate and conditions. In addition to the pump, the fuel forwarding skid includes a strainer, electric fuel heaters, control components and a flow meter.

<u>Lube Oil</u>. A lube oil conditioning system is provided for the collection, storage, purification and transfer of lube oil for use in the combustion and steam turbine lube oil systems.

The lube oil conditioning system consists of a clean oil storage tank, a dirty oil storage tank, a centrifuge-type oil purifier, a lube oil transfer pump, a lube oil unloading pump, and all necessary instruments, valves and interconnecting pipe.

Lube oil is transferred from the unit reservoir to the dirty oil tank by the positive displacement-type lube oil unloading pump and is returned from the clean oil tank to the reservoir by the lube oil transfer pump via the purifier.

Moisture and particulate contaminants are removed from the turbine lube oil by the purifier which is a self-contained unit with built-in feed and discharge pumps.

Slag Disposal. Slag produced in the gasification process is separated from the main process and conveyed to a slag surge bin. From there it is trucked to an onsite disposal area. This disposal area is enclosed by a dike and lined to prevent seepage. An underdrain detection system allows periodic inspection for liner leakage.

Evaporation Pond. Waste water from the integrated coal gasification/combined cycle power plant will be routed to the existing evaporation pond. The 130 acre pond is designed for an evaporation rate of 80 inches per year and will accommodate the increased load.

Fire Protection

The fire protection system consists of an electric-motor-driven fire water pump, a combination service water/fire water storage tank with 200,000 gallons dedicated fire water portion, and an underground piping loop serving fire hydrants and hose racks and reels, with monitors and deluge systems protecting major plant hazards. The coal silo and gas turbine are protected with CO_2.

The fire water system is maintained at 100 psig through a connection to the service water system. During a fire, the service water/fire water storage tank supplies fire water through the electric fire pump. If service or well water is unavailable or the electric fire pump fails, a normally closed valve may be opened to tie-in with the SCE Units 3 and 4 fire water loop, which makes over 1,000,000 gallons of cooling tower water available as fire water supply via the SCE Units 3 and 4 electric- and diesel-driven fire pumps.

Deluge water systems will protect the lube oil reservoir, coal handling system and coal grinding train. When the plant is down, the wood structure cooling towers are automatically sprayed with water to prevent drying, thus reducing the potential for fire.

Pollution Control Facilities

Coal will be delivered to the site by train. The rail cars will be open on top; however, the coal will be sprayed at the source of shipment with a sealing compound to reduce the possibility of fugitive dust. Once on site, the cars, which will be of the bottom dump type, will unload the coal inside an enclosure. The coal will be transported to enclosed storage silos via a covered belt conveyor system. The demonstration project will not utilize any dead storage piles.

All coal handling systems will use enclosures and vacuum exhaust dust collectors in conjunction with a spray type dust suppression system to minimize coal dust problems.

Ash residue particulates are removed from the gas by scrubbing with water. This results in particulate loadings of the order of 1 mg/Nm^3. Following this washing step, the water saturated gas is cooled to 100F, with the condensed water being separated. The gas is then passed through a sulfur removal process in which it is contacted with a liquid solvent. Together, these steps should reduce particulates by well over 99 percent, i.e., no measurable particulates are anticipated in the gas turbine fuel.

In addition to resaturation of the gas, supplementary steam will be injected into the gas turbine to reduce NO_x. It is estimated that this will effect an NO_x reduction by 70 percent.

The Claus sulfur and SCOT tail gas unit will remove 99.6 percent of the sulfur fed into the system on design coal at design rate.

The sulfur pit will be covered and fugitive sulfur compound emissions will be collected by an eductor and incinerated in the tailgas incinerator unit.

The evaporation pond is designed to contain all liquid waste without loss from leakage or underflow and be adequately protected against overflow, washout or inundation. The pond is lined and monitoring wells allow visual inspections for liner leakage.

The slag disposal area will be lined and have a seepage underdrain detection system with sumps to allow inspection for liner leakage. The area will be enclosed by a 3-meters-high dike with a minimum top width of 12 feet.

Buildings

The main control building will be a single story pre-engineered metal building 130 feet long by 60 feet wide with an eave height of 16 feet and a cast-in-place reinforced concrete slab. The building is designed to provide space for the following:

- Control room area including the control room, kitchen, instrument shop, watch engineer office and two offices
- Laboratory area including a laboratory office, the laboratory, and a separate grinding room for grinding slag and coal samples.
- Electronic areas including an electronic equipment room, electrical equipment room and battery room
- Support areas including a women's restroom and change room, a men's restroom and change room, a janitor's closet storage, and vestibules

The construction office building will be a single story pre-engineered metal building 175 feet long by 60 feet wide with an eave height of 14 feet and a cast-in-place reinforced concrete slab. The building is designed to provide space for the following areas:

- Construction office personnel
- Conference room
- Men and women's restrooms
- Janitor's closet

This building will be converted to the main office building at completion of the plant construction.

The warehouse will be a pre-engineered metal building 120 feet long by 100 feet wide with an eave height of 22 feet and a cast-in-place reinforced concrete slab. This building will initially be used as a construction warehouse and converted to a maintenance shop and warehouse facility at completion of the plant construction. The building is designed to provide space for:

- Office and restrooms
- General tool, piping and electrical issue rooms
- Warehouse area and loading dock
- Mezzanine storage area
- Spare parts storage area

The chlorination shed will be a pre-engineered metal building 40 feet long by 40 feet wide with an eave height of 14 feet and a cast-in-place reinforced concrete slab on grade. The building is designed to provide space for:

- Chlorination control area (enclosed and ventilated)
- Chlorine cylinder storage area (sheltered open area)
- Chlorine equipment area (sheltered open area)

The track hopper enclosure will be a steel framed engineered structure to cover the coal train track hopper. Exterior walls and roof will be constructed of uninsulated metal siding and roofing. The building will be designed to provide:

- Dust suppression and collection system
- Coal handling system control area including a control room (air-conditioned), HVAC area, restroom and janitor's closet

SYSTEM DESIGN CONSIDERATIONS

Achieving specific technical objectives is essential for the successful commercial application of this power system. These include:

- The full scale design and reliable operation of those major equipment components and subsystems which will be incorporated into the commercial plant design
- Achieving a performance level which can be reliably and convincingly extrapolated to competitive levels through proven and/or low technical risk system modifications in the commercial plant design
- Demonstrating flexible plant operation and control throughout all operating modes consistent with power grid maneuvering requirements and plant operator capabilities
- Demonstrating low environmental impact
- Developing an operating experience data base which can be applied to commercial plant training and procedures

The essential features to meet the above objectives are being incorporated into the Cool Water demonstration plant configuration. Design requirements, anticipated performance, plant integration characteristics and operational requirements are discussed below and in the sections that follow.

Plant Configuration and Design Requirements

Because of the significant sensible heat in the raw gas (25 to 30 percent of the coal input energy) it is essential that as much of this energy as possible be recovered and efficiently converted to power. In addition, due to the significant amounts of unreacted steam in the raw gas, efficient low temperature heat utilization is an important requirement.

The high temperature reducing atmosphere of the raw gas, with sulfur gas constituents, introduced material considerations in the raw fuel gas stream heat recovery boilers (synthesis gas coolers, SGC) requiring that maximum metal temperature limits be observed. Maintaining saturated steam conditions of 1,600 psi (604F) in these components provides an effective design which can hold SGC metal temperatures below maximum levels and can be practically integrated with the gas turbine heat recovery steam generator (HRSC) producing superheated steam at 935F which results in efficient steam conditions. The commercial configuration of the IGCC plant will incorporate modular gasifier/SGC and gas turbine/HRSG trains with a single steam turbine. The SGC configuration will be similar to Cool Water, generating saturated steam since metallurgical requirements will be the same. Thus, operating experience with the Cool Water SGC equipment will be directly applicable to follow-on commercial plant designs, even though the HRSG would have to be modified for steam reheat.

The relative availability of high and low temperature heat in the gasifier and gas turbine exhaust systems requires a proper selection of the steam equipment configuration and steam conditions in order to efficiently match the individual heating duties with the capabilities of the respective heat sources. Studies indicate a performance benefit for operation at higher steam pressure levels, to obtain greater steam production, within the constraints of the HRSG superheating capability. This is particularly important in selecting the conditions for reheat units associated with larger scale plants. This consideration has been incorporated into the selection of the Cool Water design point resulting in an SGC operating pressure of 1,600 psi which is considerably higher than conventional combined cycle steam conditions.

The division of economizing loads between the two heat sources is designed to take thermal advantage of the relatively large quantities of lower temperature heat in the HRSG exhaust. The relatively high cost of fuel gas heat recovery surface and the small quantities of heat below steam generating gas temperatures and above gas dewpoint limitations, makes the recovery of low temperature fuel gas heat in the SGC a prime candidate for future cost/performance trade-off studies with commercial configurations.

Variations in gasifier operation (e.g., temperature, cold gas efficiency, etc.) resulting from utilizing different coal feedstocks or changes in slurry conditions can have a significant influence in the design in order to assure reliable operation of the steam system under these conditions. Variations in the proportion of chemical and sensible heat in the fuel gas changes the relative steam loads in the SGC and HRSG, resulting in changes in steam turbine temperatures and flow. Thus a richer gas, (higher Btu/lb) requiring a lower gasifier exit temperature, could produce significantly less steam than a more lean gas operating with higher gasifier exit temperatures. These conditions may come about by changes in slurry concentration, oxygen-to-coal ratios, different coal types, or as equipment matures.

Significant imbalance of SGC steam production and HRSG superheat or economizing capability at any operating point can result in unacceptable steam turbine throttle conditions, economizer steaming, throttle steam over-temperature or inefficient quenching of SGC steam through excess feedwater subcooling. Such conditions must be accommodated by providing sufficient equipment design margin and proper control coordination for the anticipated range of operating conditions to ensure acceptable and reliable operation. This results in equipment selection which will trend in the direction of reliable operation at off-design point conditions, at some compromise in optimum performance. The Cool Water steam system design has incorporated features into the equipment and control to demonstrate this flexibility and coordination.

Under low total steam conditions, the throttle temperature approaches the gas turbine exhaust temperature. Thus, maximum steam temperature is controlled by proper coordination of the gas turbine inlet guide vanes which automatically limits these maximum steam temperatures by adjustment of the total gas turbine flow and thus turbine exhaust temperatures. Since these conditions can vary significantly over the ambient range, this factor must also be considered.

Reliable steam turbine operation requires that throttle steam conditions (e.g., temperature, pressure and flow) are properly coordinated such that last stage moisture and temperature limits are satisfied at all sustained operating points.

Such considerations, for example, result in the requirement for variable steam pressure operation at reduced plant loads. Since SGC steam generation changes disproportionately to HRSG steam, the proper variable steam pressure versus load schedule must be coordinated to prevent excessive turbine exhaust moisture levels.

There are similar considerations for larger commercial plant steam system designs although the operating conditions, and even configuration (e.g., reheat), may be different. This control coordination approach is applicable to commercial configuration plants and will be implemented and demonstrated in the Cool Water design.

A significant portion of the latent and low temperature energy in the raw gas can be efficiently recovered through fuel gas preconditioning prior to combustion. Moisturizing and heating the fuel gas through a low temperature direct contact water heater (reheat-resaturator) provides a means of transferring this energy at high availability in the basic cycle. This moisture contributes significantly to lowering the formation of NO_x in the turbine exhaust. Current gas turbine combustion designs incorporate moisture injection to achieve low NO_x levels, as required at the Cool Water site (43 ppmv in the exhaust). Fuel gas moisturizing through use of low temperature energy versus steam injection from turbine extraction, results in significant cycle performance improvement. The intermediate Btu value of the gas and the added fuel gas moisture at the gas turbine combustors results in a significant increase in gas turbine output and additional fuel flow requirements to bring the moisture to turbine inlet conditions. Proper coordination and control of this moisturing and heating is important in meeting acceptable gas turbine combustion system fuel moisture superheat and flow control requirements and in preventing interactions in the plant load control loops. Further optimizing of overall cycle conditions can improve the performance resulting from this feature on larger scale plants. This feature will be of increasing benefit permitting efficient operation at low NO_x emissions as gas turbine inlet temperatures increase to higher levels.

The use of intermediate Btu fuel gas in the gas turbine has several design implications. This fuel will require modification of the turbine fuel nozzles, fuel gas piping arrangement and fuel gas control valve design. However, due to the combustion characteristics of the gas and the relatively small variation of composition over the expected operating conditions and fuel types, only minor modification to the on-base combustion liners are anticipated. A large diameter fuel gas piping harness arrangement with an off-base fuel valve skid is being designed for the Cool Water unit.

The relatively high fuel hydrogen content results in adiabatic flame zone temperatures somewhat higher (e.g., 50F) than those resulting from the use of natural gas or distillate oil. Since the production of "prompt" NO_x is increased with higher temperature, this necessitates somewhat more moisture at a given load to achieve a given NO_x level than with conventional fuels. This effect, particularly with the higher gas turbine firing temperatures of future commercial plants is a significant incentive for fuel gas saturation.

To minimize new development risk at Cool Water, the gas turbine combustion system will utilize a modified version of the commercial combustion and fuel nozzle arrangement. Combustion liner air cooling pattern modifications are being made to maintain long combustor life and proper hot gas temperature profiles, and a new fuel nozzle will be incorporated.

The combustion system will have dual fuel (e.g., No. 2 oil and medium Btu gas) capability. The gas turbine fuel control system will be modified with several features including: automatic fuel transfer, fuel pressure regulation capability and direct load control capability when operating in the turbine lead mode.

The gas turbine combustor fuel and moisture flow is five times greater compared to the use of natural gas or oil. Due to this increased turbine mass flow, gas turbine pressure ratios and turbine/compressor thrust mismatches will be somewhat higher, resulting in maximum gas turbine load limit considerations. Proper matching of the fuel plant capability within these constraints, which occur at lower ambient conditions, is an additional system design parameter. Maximum load limit conditions are not anticipated to be a significant factor over the load range at Cool Water, since the plant is normally fuel supply limited.

The gas turbine will have dual gas/oil fuel capability, although operation on oil fuel is only planned for unit start-up and shutdown. However, for commercial plant application, dual fuel operation is of value in maintaining plant load carrying capability, particularly through short term outage of fuel plant equipment.

Sufficient margin is being incorporated in the Cool Water gas turbine HRSG and steam turbine designs to accommodate increased loading anticipated from potential process improvements and increased fuel processing capability with the Cool Water plant design.

Plant operation at high capacity factors is anticipated at Cool Water, with a target average of 77 percent over a six and one-half year project operating period. To achieve this goal, equipment modifications, redundancies and carefully planned operating and maintenance procedures are being implemented at Cool Water. To demonstrate combined cycle running reliability consistent with Project availability goals and commercial base load power generation requirements, a combined cycle 1,500-hour mean time between failures (MTBF) goal, with high turbine starting reliability, has been established and a comprehensive preventive maintenance program is to be developed.

INTEGRATED PLANT CONTROL

The central control room contains dedicated control panels or consoles for the gas producing train and the combined cycle equipment. Detailed operation of the equipment is accomplished at these positions, including the placing of various equipment in a state of readiness prior to a start-up and operation. Figure 5-3 shows a conceptual layout of the main control room.

Once readiness is achieved, the seat of normal operation will shift to an integrated station control console. The integrated control performs the functions of overall plant operation including start-up, shutdown, normal operation and operation mode changes. The integrated station control console includes start/stop, open/close, indication adjustments as required to perform the control positions. After start-up, the individual dedicated controls panels are utilized only in the event of significant sub-system upset. The integrated plant control concept is illustrated in Figure 5-4.

In addition to providing a direct manipulative operator interface, the integrated console and its associated cabinets provide CRT displays for operation guidance and informational support, plant load control, plant fuel gas pressure control and coordination of plant protective functions.

Plant Load/Pressure Control

The plant load/pressure control, which is a part of the integrated station control, performs the functions of adjusting the power output of the combined cycle plant in response to changes in load demand, and the regulation of the fuel gas pressure at the discharge of the fuel plant. This is accomplished by coordinating the fuel gas production of the fuel plant with the gas consumption of

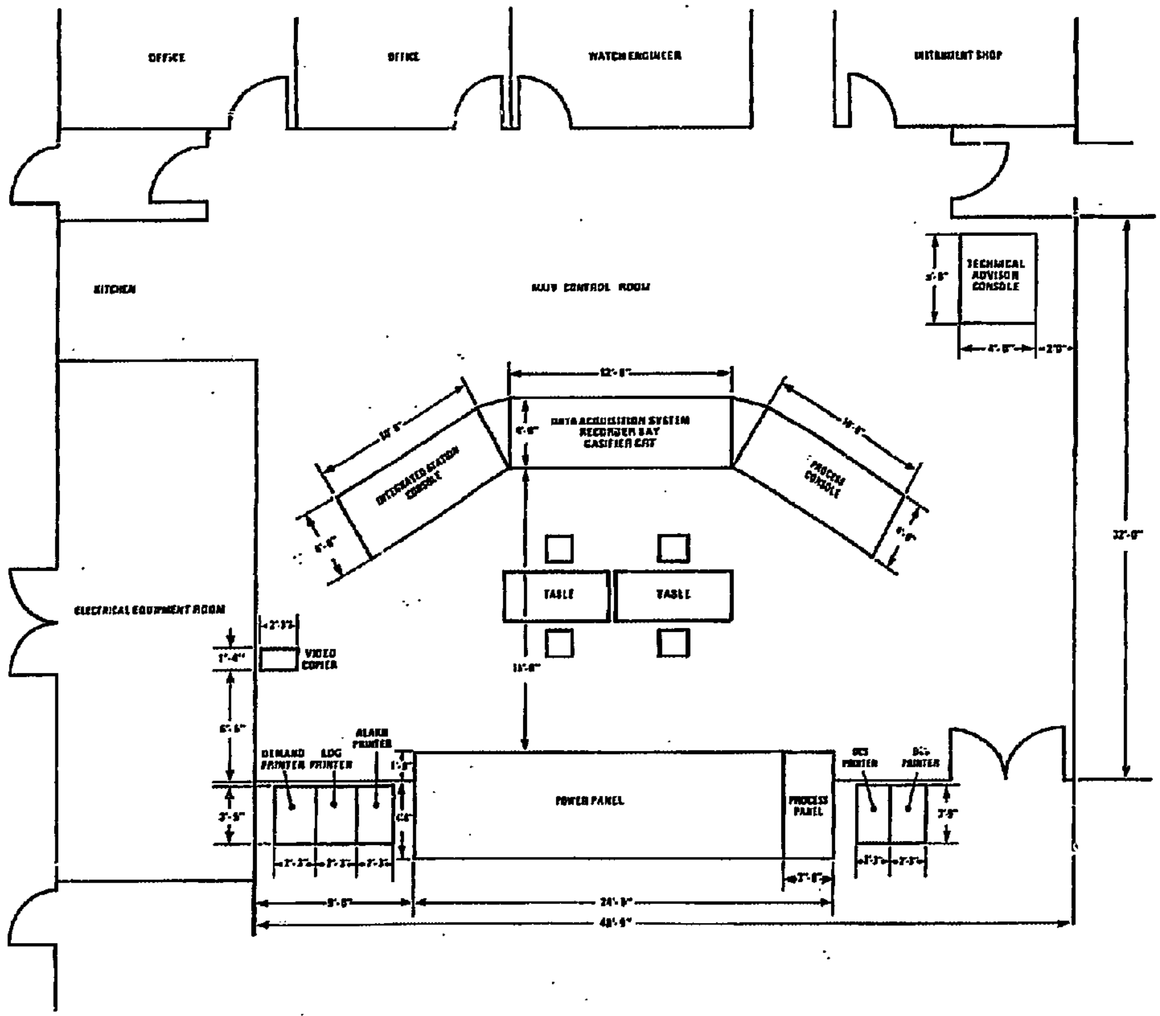


Figure 5-3. Main Control Room Plan

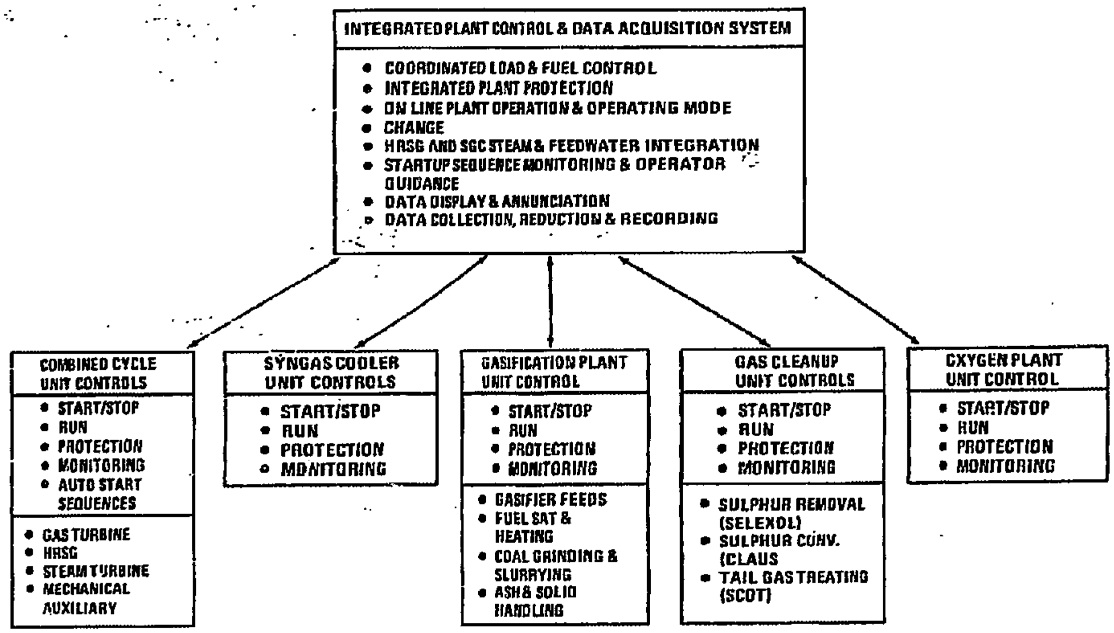


Figure 5-4. Control and Data Acquisition Systems

the combined cycle power plant and requires that the plant load/pressure control interface with and coordinate the operation of the gasifier, gas turbine and oxygen plant through their respective control systems.

Three modes of plant load/pressure control are being implemented for evaluation of integrated gasification-combined cycle plant operation. These are the turbine-lead, gasifier-lead and coordinated control modes of operation. (See Figures 5-5, 6 and 7)

- Turbine Lead Mode - In the turbine-lead mode, changes in plant power output are initiated by changing the fuel flow to the gas turbine. This action is followed by a change in gas fuel production by the gasifier which is controlled to maintain the required fuel plant pressure. Use of the fuel gas system intrinsic storage provides rapid response to overall system demand excursions.

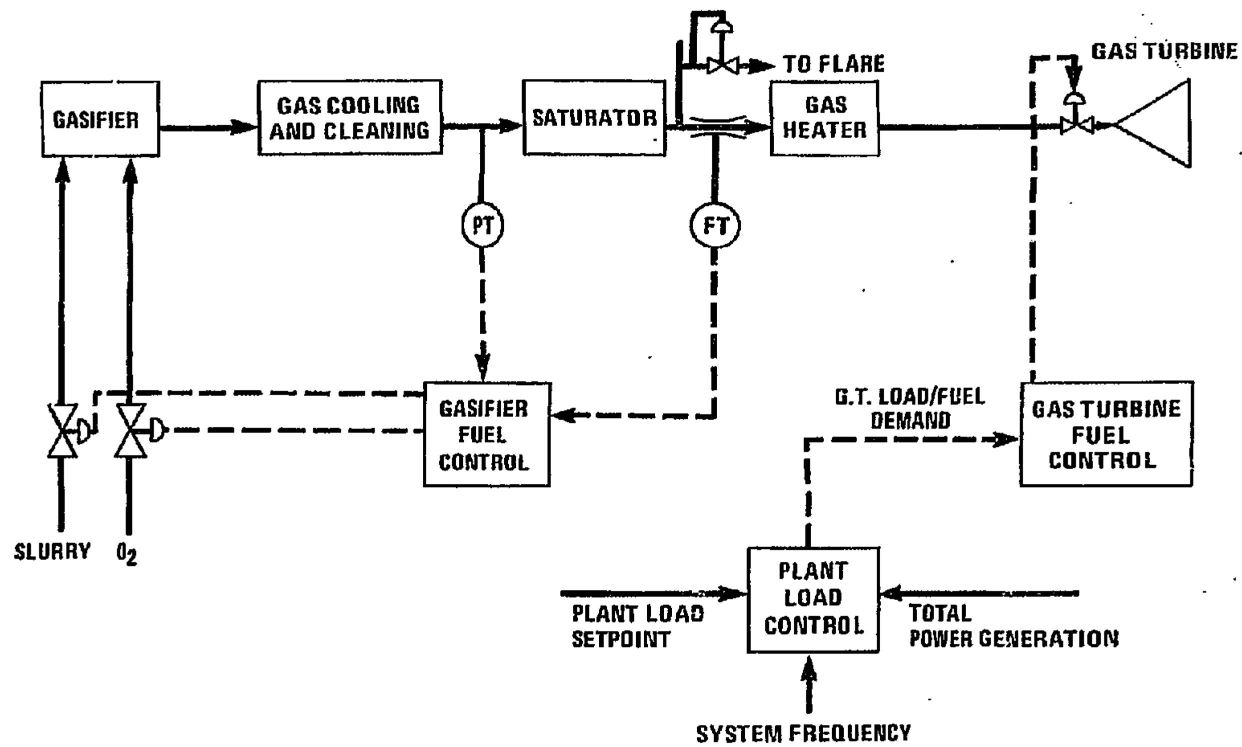
- Gasifier Lead Mode - In the gasifier-lead mode, changes in plant power output are initiated by first changing the fuel gas generation of the gasifier. The gas turbine control system regulates the flow of fuel gas to the turbine to regulate the pressure at the discharge of the fuel plant.

- Coordinated Control Mode - This mode of operation is similar to the turbine-lead mode in that changes in plant power output are initiated by changing the fuel flow to the gas turbine. The gasifier is controlled to maintain the required pressure in the gas fuel plant. The distinguishing features of this mode are the use of a feed forward signal to the gasifier to adjust the fuel gas production rate in anticipation of a change in fuel plant pressure, and the use of a feedback signal to the turbine fuel control signal to limit the rate of change of fuel consumption by the gas turbine as a result of an extensive change in fuel plant pressure. It is expected that this mode will provide the most favorable dynamic load response capability for the integrated plant, while minimizing the pressure transients which may occur in the fuel gas plant.

The controls are being designed for the operator to conveniently transfer to any of the three modes.

Operation Guidance

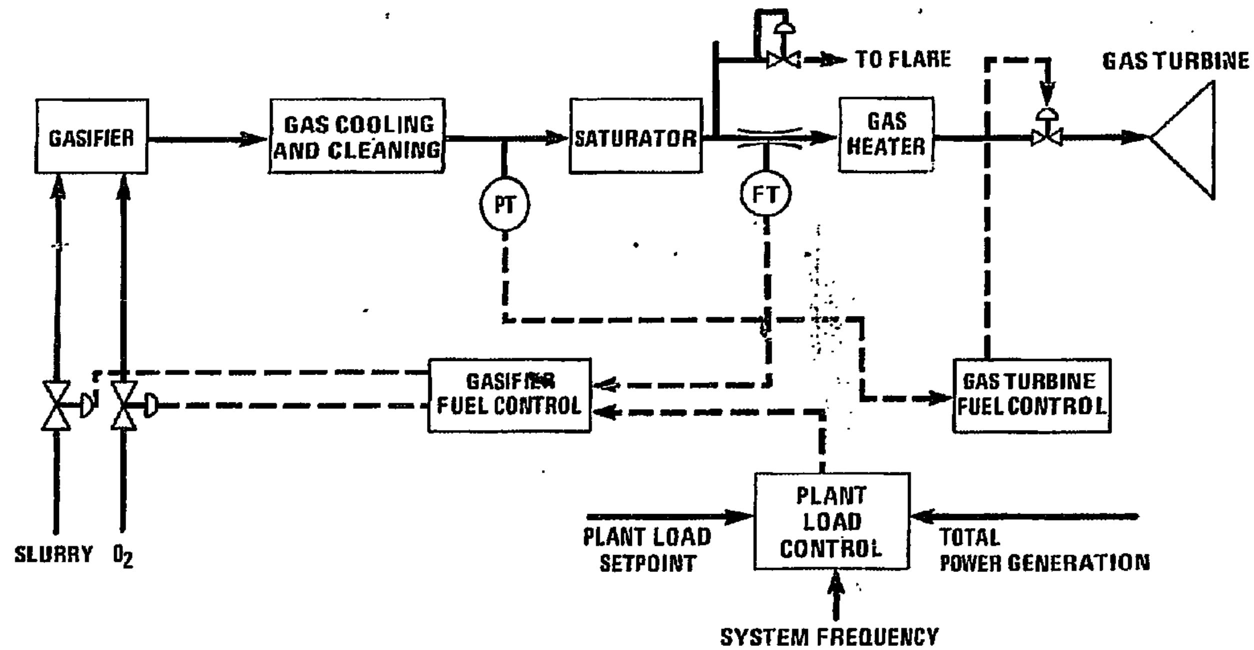
In addition to the operator manual interface at the integrated station control console, an operation guidance function is being provided. This is designed to provide visual guidance and information support, with the goal of simplifying operation. The display of information is by video (CRT) and an alpha-numeric printer. Operator requests are made via a keyboard.



LOAD CHANGES AND FREQUENCY REGULATIONS ARE ACCOMPLISHED BY:

- CHANGING THE FUEL DEMAND ON G.T. IN RESPONSE TO THE PLANT LOAD CONTROL
- THE CHANGE OF THE GASIFIER FEED FLOW (OXYGEN AND SLURRY) AS A FUNCTION OF THE RESULTING CLEAN GAS PRESSURE/FLOW CHANGE

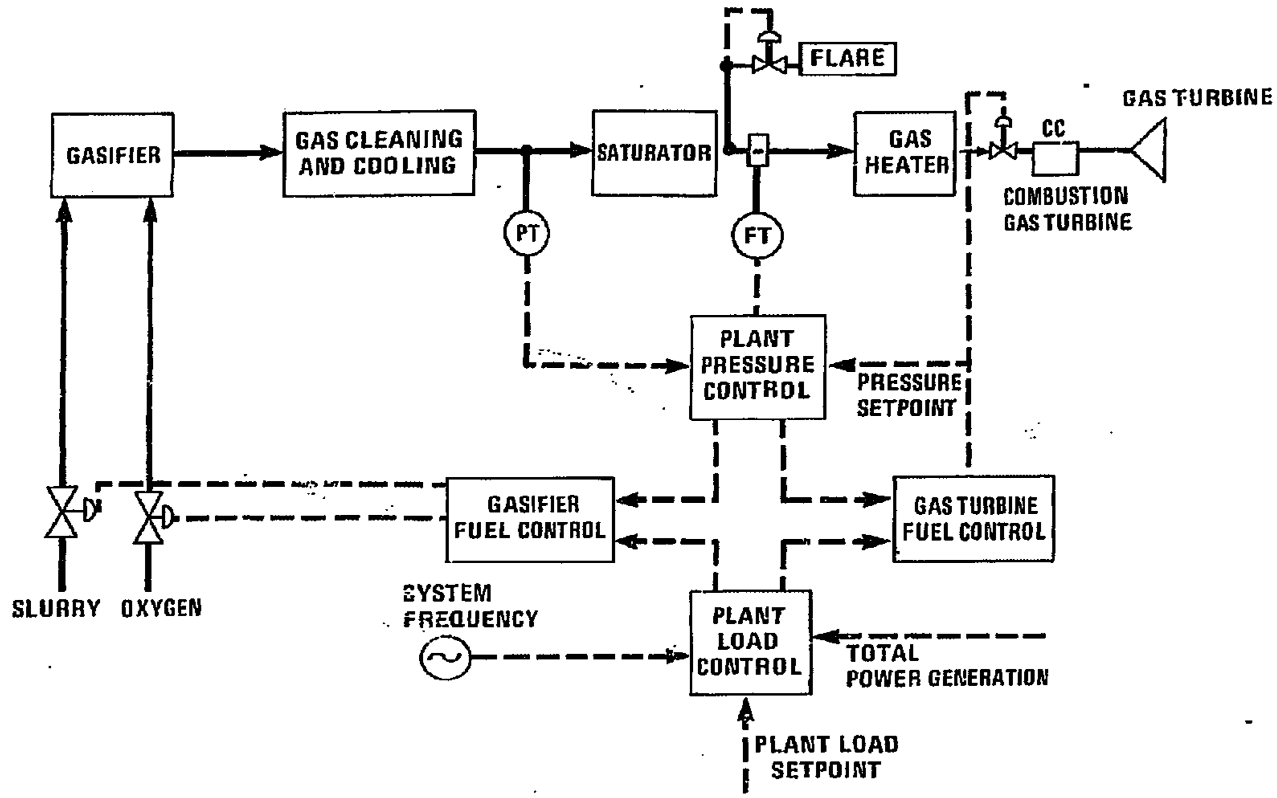
Figure 5-5. Integrated Plant Control - Turbine Lead Mode



LOAD CHANGES AND FREQUENCY REGULATIONS ARE ACCOMPLISHED BY:

- CHANGING THE GASIFIER FEED FLOW (OXYGEN AND SLURRY) IN RESPONSE TO THE PLANT LOAD CONTROL
- CONTROLLING THE RESULTING CHANGE IN SYNGAS PRESSURE BY MODULATING THE GAS TURBINE FUEL GAS CONTROL VALVE.

Figure 5-6. Integrated Plant Control - Gasifier Lead Mode



- GASIFIER FEED FLOW IS PRIMARILY ON THE CLEAN GAS PRESSURE CONTROL
- LOAD DEMAND SIGNAL IS DIRECTED TO GAS TURBINE FUEL FLOW CONTROL
- FEED–FORWARD AND CROSS–COUPLING CONTROL SIGNALS USED TO MINIMIZE TRANSIENT FUEL PRESSURE VARIATIONS

Figure 5-7. Coordinated Plant Control

The content of operation guidance includes:

- Sequence Monitoring - This will guide the operator through plant start-ups, shutdowns and major mode changes. This may be done by checklists, instructions, graphic displays, or a combination of the above. Where feasible, direct coordinated operation of start-up/shutdown actions and subsequences are being implemented.

- Operating Information - This operator aid will use current and recent historical plant data to provide graphic displays, operating snapshots, performance data and printed logs.

Plant Protective Coordination

In addition to the primary protective functions provided by the individual equipment controls, station level protective coordination is being implemented in the integrated plant control system. The major objective of this protective system is to reduce the probability of a shutdown of the entire plant or large portions of the plant as a result of a limited equipment failure.

The integrated-protection system interfaces directly with and operates through the individual equipment protective systems. Alarm and trip signals generated by the individual unit controls are communicated to the integrated-protective system along with equipment status information. Based upon the operational status of the plant at the time of an alarm, or equipment trip, the integrated-protective system initiates signals to other unit control systems in the plant which may be ultimately impacted by the equipment failure. These signals, as appropriate, initiate start-up of auxiliary equipment, effect transfer of equipment operating modes, change controller set-points and initiate equipment shutdowns. These signals are directed at isolating the effects of equipment fault, keeping as much of the plant operating as possible and placing the equipment in a state that would allow the most rapid restoration of the previous plant operating condition.

To eliminate potential problems with control system redesigns maximum use is being made of existing system equipment controls. This includes the combined cycle power plant equipment and other existing plant subsystem controls. The power plant controls will be a combination of electronic analog and microprocessors.

A commercially available distributed system is being utilized in the control of the fuel plant and the integrated plant control system. A distributed control system utilizing microprocessors affords greater flexibility for control loop configuration changes and modifications than is available with a conventional analog system. This is a highly desirable feature for a new process system design which has limited operating experience.

The system control is accomplished by several microprocessor units linked to a central operator's console, having CRT and keyboard, by a communications line (data highway) consisting of a multiplexed digital information transmission system. Dual, redundant data highways and several CRT's and keyboards will be used for system security and reliability.

<u>Control Analysis</u>

To aid in the control system development and to more fully understand the plant process variable interactions, a dynamic simulation study of the Cool Water configuration has been conducted as a joint technical effort among Program participants. This simulation incorporates dynamic digital mathematical models of all major system components programmed in a flexible software system that provides expedient modification and modular model development, while selected subsystem studies proceed in parallel.

The results have been encouraging, indicating no major control problems or instability characteristics which cannot be solved by state-of-the-art control logic and hardware. The relatively large volumes of fuel gas in the fuel system heat exchangers, scrubbers and piping at intermediate Btu heating values, and at high pressure relative to the gas turbine combustion, give an inherent system storage capability which results in small fuel system pressure variations over a wide range of plant maneuvering. Proper implementation of coordinated fuel pressure/gas turbine control appears to result in a responsive power plant with flow and pressure excursions well within design limits.

A goal of the control and protection system is to attain a high running reliability. To achieve this objective, isolation of control and protection circuits with sufficient instrumentation redundancy to ensure high reliability and equipment protection is being implemented.

POWER SYSTEM REQUIREMENTS

Normal daily operation and control of a bulk power system requires a continual adjustment of power generation to match changes in load connected to the power system. In addition, daily operation frequently requires the power system to respond to abrupt losses of connected generation either through loss of units or of transmission facilities. In a great majority of loss of generation cases, the power system is capable of maintaining service to all of its customers through good design and operating practices; this loss of generation without loss of customer service is a near-normal condition.

In order to equalize load following duty imposed on individual units in the system, and to prevent serious load-generation mismatches when given units are incapable of response, it is important that every prime mover supplying a large power system be capable of supporting its share of regulating and load following duty imposed by the power system over the life of the unit. These regulating requirements include the capability to change generation over short periods of time (seconds and minutes), and over longer periods of time (hourly, daily and weekly), under normal and abnormal operating conditions.

Thus, the network places load demand on individual plants to satisfy:

- Frequency regulation
- Tie-line regulation
- Load following

These demands cover a wide spectrum of load magnitude and duration requiring different response rates to satisfactorily meet the power system requirements.

Loss of Generation-System Islanding - Emergency Conditions

Under certain infrequent circumstances, a disturbance on a large interconnection may result in a portion of the interconnection breaking into one or more electrical islands. Generating units vary in their capability to control frequency under island conditions. Differences in the capability of units to regulate frequency are not normally observed in a large interconnection because units having poor frequency regulation characteristics are supported by units having better characteristics.

The power system frequency must be regulated under emergency conditions in an isolated or split-off system. The island's generation must be able to promptly change power output to maintain generation-load balance in the face of abrupt changes. The range of requirements imposed upon the island generation is a rapid change of power output under governing control to arrest the frequency transient, followed by up to 2.5 percent MW (rating) per minute under a close plant operator control. The consequences of not meeting this requirement include:

- Additional load shedding manually
- Cascading outages of other units or "blackouts"
- Extended time to restore service or to resynchronize with system
- Damage to equipment at off-normal frequencies

The Cool Water Test Plan will incorporate plant tests to demonstrate the inherent capability of the IGCC plant in meeting these requirements.

Load Following Capability

The plant shall contribute electrical power with the response desired of an advanced generating plant operated on a large interconnected electrical grid. The required response is more demanding than that expected of existing plants and represents anticipated needs in segments of the electric utility industry.

The target plant response capability shall encompass all of the response sets presented in the table below, when operating anywhere within its acceptable load range as combined-cycle or simple-cycle.

Table 5-3

LOAD FOLLOWING CAPABILITY

	FREQUENCY REGULATION(1)		TIE-LINE THERMAL BACKUP(2)		DAILY LOAD FOLLOWING(3)	
Magnitude of Change % of Rating	2	5	7	12	20	50
Response Rate Required % Rating per Minute	20	10	7	6	5	2.5
Time to Accomplish Minutes	0.1	0.5	1	2	4	20

1. Frequency regulation provided primarily by gas turbine governor action.
2. Contingency mode
3. Normal operation

Load Turndown

The plant will be designed for stable, sustained operation on gas fuel at as low a plant electrical load as possible, within the physical constraints of the various equipment, while maintaining all plant auxiliaries. A full-speed, zero electrical load test will be implemented.

When operating at maximum turndown, the plant shall be operated on its normal control equipment with ability to respond to load demands.

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Load Rejection Performance

As a test, the plant electrical generators will be disconnected from load by the opening of circuit breakers. On this occurrence, whether at full or partial load, a minimum of the plant operating equipment shall trip. Equipment shall recover from the load loss transient in a condition such that the generators can be resynchronized to the electrical line and the plant reloaded. This shall be true whether one or both generators suffer this disconnection. During these transients the gas producing train will minimize the flaring of gas.

DATA ACQUISITION SYSTEM

A computerized plant data acquisition system is being implemented for data collection, display and reporting. The computer is not utilized in the control of the plant, but is utilized for such functions as operator start-up/shutdown basis and display of major plant process loop conditions. The computer will have capacity for storage and retrieval of large volumes of data. The data acquisition system will extend and improve the operator/ plant interface. However, the plant operation and control will be independent of the computer.

The data acquisition system will provide support for:

- Engineering analysis of plant operation and performance by way of several logs (periodic, trip, demand, etc.)
- Plant test implementation and performance (steady state and dynamic) evaluation
- Operator guidance through color video display

Plant maneuvering and load following capability will be tested as part of a comprehensive overall Project Test Program. Each major component's response characteristics will be checked by subjecting it to controlled changes. All pertinent variables will be recorded in the plant data acquisition system to permit subsequent analysis and evaluation.

Section 6

PLANT PERFORMANCE PROJECTIONS

Planned plant operation on a variety of coal feedstocks in addition to extended runs under various process conditions (e.g., slurry ratios, preheat, etc.) is expected to result in a range of fuel gas output up to the gas turbine maximum of approximately 840 MM Btu/Hr at the site conditions of 80F and 2,000 feet altitude. The gasifier temperature and cold gas efficiency corresponding to an individual operating condition changes the relationship of sensible to chemical energy, causing some variation in gas and steam turbine outputs, coal and oxygen inputs, as well as overall plant performance. Table 6-1 indicates the range of performance anticipated under different fuel plant operating conditions at Cool Water. In addition, the performance level estimated for future commercial plant designs is shown in Table 6-2.

The Cool Water plant configuration has not been optimized to achieve maximum performance level. The relatively small size of the system, in addition to the defined program operating period, confines the selection of equipment and operating conditions, resulting in compromises in performance. The steam system configuration has been specified at lower level, non-reheat conditions. The modifications for more advanced reheat steam systems effect mainly the gas turbine heat recovery steam generator and steam turbine designs. Operation requirements with reheat steam turbines are known and have relatively little impact on fuel plant equipment, configuration, or operating conditions and are not considered essential for demonstration of the IGCC concept.

In order to achieve operating flexibility, some fuel plant equipment is being included with additional design margins for demonstration purposes. Subsequent refinement of this system equipment will result in improved cost/performance benefit in follow-on designs.

The oxygen supply at Cool Water will be provided by an on-site air separation plant producing gaseous products for commercial sale. This requirement results in gaseous purity requirements beyond that necessary for gasification needs. Studies have indicated performance incentives and TCGP process capabilities to utilize

Table 6-1

COOL WATER PERFORMANCE

	NET OUTPUT (MW)	NET HEAT RATE (Btu/kWh)
Initial Operation		
(750 MM Btu/Hr of clean syngas)(1)	92.0	11,200
Future Operation		
(767 MM Btu/Hr of clean syngas)(2)	96.2	10,700
(842 MM Btu/Hr of clean syngas)(3)	101.0	10,600

NOTES:

(1) Represents expected initial operating performance.

(2) Represents target test performance after tentative addition of slurry preheat operation with 95% O_2 purity, and elimination of supplemental steam injection for NO_x control.

(3) Further efficiency improvement based on future test with higher slurry concentration.

Table 6-2

LARGE REFERENCE PLANT DESIGN
COMMERCIAL PLANT PERFORMANCE

GAS TURBINE INLET TEMPERATURE	PLANT SIZE (MW)	NET HEAT RATE (Btu/kWh)
1,985	500 to 1,000	9,200 - 9,500
2,100	"	8,650 - 8,850
2,600	"	8,250 - 8,450

oxygen of lower purity (e.g., 95 percent). There are additional performance benefits in thermal integration with the air separation plant. These features can be implemented readily in commercial applications to derive these benefits.

Large scale reference plant configurations incorporating the Texaco oxygen-blown coal gas process have been studied and reported. The performance of these plants is based on projections of fuel plant performance on Illinois No. 6 coal which will be a test coal in the Cool Water Program. The results of the study conducted by General Electric are indicated as the Large Reference Plant Design in Table 6-2. This reference plant incorporates current state-of-the-art gas turbines with a 1,450 psig 935/935F reheat system and the basic Texaco coal gasification fuel system features to be demonstrated at Cool Water.

Section 7

COST ESTIMATE AND FUNDING

BASIS & ASSUMPTIONS

The funding and subscription target for the Cool Water Program was initially based on the principles contained in the Texaco-SCE Agreement, together with the conceptual design study performed by the Ralph M. Parsons Company in which the costs of designing and constructing the demonstration plant were estimated.

The estimated capital cost for the Program was $292 million. This estimate was originally prepared in mid-1978 by the Parsons Company and [illegible] updated by Bechtel, the Program Engineer-Constructor, and [illegible] organizations incurring reimbursable costs. This [illegible] costs expected to be spent in Phases I, II and III, including ope[illegible]ce expenses for the pre-demonstration period referred to in Sect[illegible]

The current estimate indicates that the total capital cost for the project is now $294 million, as shown in Table 7-1. The basic difference in the estimates is the change in the oxygen plant from an internal to an "over-the-fence" supply, the use of existing SCE facilities for water treatment, the resolved trends and the escalation associated with a scheduled completion approximately two years later than envisioned in the Parson's report. Based on these projected costs, the Program subscription target is now set at the $294 million figure.

PROGRAM FUNDING PLAN

As discussed previously, the Cool Water Coal Gasification Program has been established as a joint venture of participants and sponsors who own an undivided percentage interest in the project equivalent to the degree of their capital cost contribution. Each participant commits a minimum of $25 million to the Program and agrees to assume a proportionate share of all Program costs. Each sponsor agrees to commit a minimum of $5 million to the Program and agrees to assume a proportionate share of all program costs up to the amount of their subscription.

Table 7-1

CURRENT COST ESTIMATE

(Escalated for Mid-1984 Construction Completion)

		$1,000
I.	**Bechtel**	
	Coal Receiving, Storage & Handling	12,623
	Coal Grinding & Slurrying	8,407
	Coal Gasification	46,445
	Oxygen Plant Interface	128
	Gasification Effluent Water Treatment	849
	Sulfur Removal	5,019
	Sulfur Conversion	9,759
	Combined Cycle Plant & Auxiliaries	42,271
	Unit #1 Pipeline & Boiler Modification	1,099
	Evaporation Pond	1,080
	Flare System	359
	Interconnecting Piping & Electrical	7,162
	Plant Electrical	5,108
	Steam, Condensate, & Fdwtr. System	2,501
	Plant Water Systems	4,862
	Other Supporting Systems	5,667
	DIRECT FIELD COST	153,339
	Field Distributables	25,018
	Start-up Assistance	3,557
	SUBTOTAL	181,914
	Field Contingency	25,987
	TOTAL FIELD COST	207,901
	Bechtel Engineering & Home Office	37,255
	Engineering Contingency	1,983
	SUBTOTAL	247,139
II.	SCE, Texaco, and GE Reimbursable Costs	28,506
III.	Miscellaneous	1,124
IV.	Start-Up & Operator Training	5,583
V.	Pre-demonstration Period	9,317
VI.	Contingency (Non-Bechtel Scope)	2,331
	Non-Bechtel Total	46,861
	TOTAL Program Budget	294,000

SOURCE OF FUNDS

Sufficient funds have been committed to the Program (see Table 7-2) to allow procurement and construction activities to proceed. However, other alternate funding sources are still being pursued and interested parties are being encouraged to join the existing co-funders in this major demonstration project.

Table 7-2

COOL WATER FUNDING

SCE	\$ 25.0M (1)
Texaco	\$ 45.0M
EPRI (current commitment)	\$ 65.0M
(additional future obligation)	\$ 40.0M
GE	\$ 30.0M
Bechtel	\$ 30.0M
JCWP	\$ 30.0M
	\$265.0M
Additional Contributors	
ESEERCO	\$ 5.0M
	\$270.0M
Other Future Funds (may be borrowed)	\$ 24.0M
	\$294.0M

(1) This figure does not include some \$6.0M of "other" facilities contributions made by SCE.

Section 8

PROGRESS REPORT AND SCHEDULES

PILOT PLANT TESTS

Montebello

The Cool Water Program sponsored pilot unit runs at Texaco Inc.'s Montebello Research Laboratory. The purpose of these runs was to confirm the Program coal (SUFCO Coal) as an acceptable feedstock and to obtain certain data necessary for the detailed design of the Cool Water Gasification Unit.

Pilot unit operations involved a total of nine separate runs broken down into five groups. The amount of coal gasified was approximately 300 tons. The first group involved a series of variable studies to select optimum conditions for future testing. The second group was a series of runs to explore the variables involved in recycling the lockhopper fines. Additional time was spent testing modifications made in the recycle system. These runs were followed by five continuous on-stream days during which environmental data were collected. The final group of runs was conducted to determine the minimum operable temperature of the gasifier.

During all test runs, routine samples required to establish a material and energy balance from the gasification system were obtained. Special environmental testing was performed only during the five-day continuous run with the Selexol System for acid gas removal in operation.

Operating data from the 15 tpd pilot unit confirmed the process design basis, and analytical data on the effluent streams reaffirmed the environmental acceptability of the process.

Oberhausen

In addition to the pilot unit tests, demonstration tests were carried out under Texaco sponsorship at the 165 tpd coal gasification facility within the Ruhrchemie Plant in Oberhausen, West Germany. The objectives of the demonstration tests were to further confirm the operability of the Texaco process on Program coal, and to gather operating, environmental and materials data on a larger scale unit.

The Ruhrchemie Plant operated well on Program coal. It ran for 22 days, as planned, and processed 3,480 tons of coal. The coal slurried easily, and was found to be very reactive, leading to efficient gasification. The data from the tests were turned over to the Texaco Engineering Department for further support of the Cool Water process design.

ENGINEERING

Engineering for the Cool Water Project started February 26, 1980. The EPRI final report of August 1978 (AF-880 "Preliminary Design Study for an Integrated Coal Gasification Combined-Cycle Power Plant") provided a viable preliminary definition of the plant. Twelve trade-off optimization studies were approved to start the engineering phase and results of ten of these studies were formally approved by the Management Committee in August 1980. Two of the studies were subsequently canceled. Studies formally completed were:

Definition of Equipment to Allow Stand Alone Gasifier Operation

A system for operation of the gasifier system without the gas turbine or the steam turbine combined-cycle in operation was developed and a cost estimate prepared for the necessary valving, piping, etc. An evaluation of this "freestanding fuel plant" indicated that it would be cost effective. The syngas produced is to be fired in the existing SCE No. 1 Boiler at the Cool Water Station.

Cycle Definition and Performance With, Versus Without, a Gas Saturator

An analysis was made of the most efficient method of introducing moisture into the gas turbine combustors for NO_x suppression. The alternatives investigated were direct steam injection or water evaporation into the syngas as it is being reheated following sulfur extraction. The additional expense of installing a water saturator tower and its pump and heat exchange system was warranted based on the increase in net power generation.

Oxygen Plant Driver Selection (Steam Versus Electric)

The comparison of drives involved not only an analysis of the cost of motors versus steam turbine drivers, but an evaluation of the overall effect on net plant power production. Also involved were the problems of start-up with a steam system compared to the relative ease of starting an electric system with motor drivers. In the final analysis it was determined that the higher efficiency of the large steam turbine and its generator in the combined-cycle part of the plant was sufficient justification to use motor drives in the oxygen plant and maximize steam to the combined-cycle.

Oxygen Storage Requirements

The typical oxygen plant has a high operating on-stream factor. Unscheduled down periods per year amount to no more than 75 hours, or less than one percent. An analysis of data supplied by two major oxygen suppliers indicated that between 65 and 95 percent of the unscheduled down time events were for minor repairs that required less than 12 hours in one case and less than 14 hours in the other. One-half of the down time events averaged 3 hours and with the oxygen plant in a "cold" standby condition the plant restart was quite rapid. The gasifier cannot be held for long periods in a "hot" condition without the use of considerable fuel gas, and any extended interruption in oxygen flow will bring the plant off-stream and require depressuring of the gasifier and heat recovery system. In order to minimize this type of shutdown, a study was made to determine the economic feasibility of providing oxygen storage on which the gasification system would operate while minor repairs were being made to the oxygen plant. Such a storage system was incorporated into the plant design and will consist of high pressure gaseous oxygen for immediate use, during which time a liquid oxygen system with a vaporizer can be brought on-stream to supply oxygen for 24 hours of operation.

Desired Oxygen Plant Purity Level

A merchant oxygen plant will normally supply oxygen with a purity of 99.5 percent minimum. In the gasification process this level of purity is not required and a study was made of the overall economics of the combined oxygen and synfuels plant with oxygen purity between 90 percent and 99.5 percent. The final analysis indicated that an intermediate purity of 95 percent was optimum. The savings in the oxygen plant more than offset the increased cost in the synfuels plant resulting from the incremental nitrogen dilution. However, since the "across-the-fence" oxygen supply arrangement subsequently developed for Cool Water also involves recovery of Argon and other gases for outside sale, the purity will be 99.5 percent.

Alternative Sulfur Removal Processes

Several systems were considered for sulfur removal from the syngas. The design target of 97 percent was set for the plant to remove sulfur in the form of H_2S and COS. Preliminary data on investment, operating costs, maintenance, operability, proven installations and plant flow schemes were obtained from three licensors of such processes. The evaluations for the Cool Water Plant indicated that the Selexol process licensed by the Norton Company was best suited for the process requirements and this installation.

Alternative Sulfur Conversion Processes

A conventional Claus plant with tail gas treating was considered for conversion of the recovered sulfur to elemental sulfur. Three licensor-designers submitted system descriptions, investment estimates, utilities and chemical costs. Overall sulfur recovery is 99.6 percent of the sulfur fed into the system. A system using a modified SCOT tail gas treating process licensed by Shell Oil Company and the Claus process for sulfur recovery licensed by Amoco Oil Company was selected as being the best combination for the Cool Water Project. Integrating the Claus and SCOT sections was very beneficial to the process. Using a feed absorber on the SCOT unit to concentrate the H_2S from approximately 4 percent to above 20 percent reduced the size of the Claus equipment and greatly improved the operability. The SCOT section has a conventional absorber on the tail gas for final clean up before incineration and discharge to the atmosphere.

Cooled, Versus Uncooled, Gasifier Refractory

A study was made to establish a refractory cooling system for the gasifier. It was determined that cooling the gasifier refractory may improve its life but the concept needs data for verification and proper cooling equipment design. The current design does not include provisions for cooling the gasifier refractory.

Gasifier Configuration

The basic configuration of the gasification system was studied in detail. Factors evaluated were stream time, maintainability, equipment investment, installed cost, maintenance costs, operability and construction completion schedules. These considerations were defined with seven case studies as follows:

- Single Train
- Single Train with Gas Recycle
- Single Train with Unconnected Spare Gasifier
- Dual Train with Common Scrubber and Recycle Compressor
- Dual Train with Two Scrubbers and Common Recycle Compressor
- Single Train with Space for Future Train
- Single Train with Spare Quench Gasifier

An analysis of the cases indicated that the demonstration Program goals would be best served by the single train with the spare quench gasifier installed. However, because of funding limitations, the quench gasifier has been only partially engineered and is on hold for possible future installation.

Coal Grind Size

The experiences in coal gasification have shown that the grind, i.e. size and distribution, of the coal particles has an effect on the efficiency of the carbon conversion. A series of tests were made on the selected program coal to determine which type of system would be able to produce the fineness and distribution required. The basic equipment tested on samples of the Program coal were 4- and 6-row impact cage mills and conventional rotating mills. The rotating mill tests were run wet so that the discharge product would be of the correct slurry concentration. The final analysis indicated that the Cool Water system should have parallel grinding trains with a 2-row impact cage mill for initial reduction of the incoming coal and a wet second stage rotating mill to make the final grind. In order to make a finer grind, the rotating mills of both trains could be modified and run in parallel, and the cage mills could be converted to 4-row.

The final design engineering started at the completion of the studies with 20 Bechtel engineering personnel assigned from the Houston Office. Engineering manpower was increased, in accordance with a planned build-up, to 157 by the end of September 1981. Peak manpower was planned for October 1981 with a continually reducing manpower loading planned from November through the construction phase, which was scheduled for completion in December 1983. Due to delays in completing the project funding, this plan has been revised to conform to new schedule requirements corresponding to construction completion by June 1984. Progress through December 1981 is reported in the following paragraphs.

Specifications are essentially complete for major equipment, materials, installation and construction. Program specifications are basically Bechtel specifications modified to incorporate applicable Texaco requirements. All specifications are submitted to the Program Office for comments and/or approval, and to-date 172 out of a total of 186 have been approved.

Permanent plant materials and equipment are procured by the Home Office (Houston). A total of 211 material requisitions and subcontracts are scheduled to be issued. Bids have been received on 116 of these, which cover most of the major equipment and bulk quantities such as earthwork, concrete, reinforcing steel, structural steel, piping and valves, electrical cable and raceway. The bids are either in the evaluation stage or have been approved for purchase. Forty-four suppliers have sent review packages to Bechtel. Of the 1,464 drawings submitted, 734 have been returned with statusing. These 1,464 drawings include those issued for information which are not returned to the vendors.

Drawings are issued for construction as they are completed and applicable Program approvals received. A total of approximately 1,000 drawings are planned; 580 have been started and 296 have been issued for construction. Instrument data sheets, hanger drawings and piping isometrics are not included in the 1,000 drawing total. Process Flow Diagrams (PFD), Piping and Instrument Diagrams (P&ID's), electrical single lines and vessel drawings are essentially complete. Extensive work is complete in the civil area to comply with early construction activities, such as rough grading, earthwork, underground utilities and major foundations.

In accordance with California Energy Commission (CEC) requirements, specific civil and structural drawings are to be submitted to the County Engineer for approval prior to construction. These drawings are scheduled to be submitted in packages as the design for the appropriate structure, foundation, or drainage plan is completed. A total of 27 packages are scheduled and 15 have been transmitted to SCE for submittal to the CEC.

The critical path for the plant is the design, fabrication and installation of the gasifier and its components, including the radiant and convection cooler vessels, steam drums, connecting piping and the structural supports for the system. Combustion Engineering (CE) is designing and fabricating the vessels and associated equipment. Engineering is 90 percent complete for the CE scope.

The coal receiving, handling and storage system is in the detailed design stage with Jeffrey Manufacturing having the engineering and scope of supply for all mechanical and electrical equipment. This includes the coal unloading and feed hoppers, conveyors and their supporting structures, dust control and ventilation systems and associated controls.

General Electric has engineering responsibility for the gas turbine, steam turbine, electric generators, heat recovery steam generator (HRSG), power transformers and other associated equipment. In addition to furnishing the power generating equipment they have system design and controls engineering responsibilities that interface with Bechtel's engineering in the integrated plant control areas. GE engineering is 49 percent complete in the system and control scope.

Engineering and procurement for the sulfur recovery plant is under contract to Ford, Bacon and Davis (Texas) (FBDT) and administered by Bechtel. The FBDT scope is 49 percent complete, including model work.

Engineering is 24 percent complete for the oxygen supply plant, which is being engineered, designed, supplied and constructed by Airco, Inc. Airco will operate their air separation plant, and sell oxygen to the gasification plant.

A 3/8-inch-per-foot scale model of the plant (see Figure 8-1) is being prepared and piping and instrument installations have started on 14 of the model base tables. All of these tables have undergone the 10 percent completion review by the Program Office, and five tables have passed the 50 percent review point. The control room and solids handling model tables will be started when designs in these areas are finalized. Also, two tables are being prepared by FBDT for the sulfur recovery plant and these received the initial 10 percent review in September. There will be 18 tables when the model is complete, including the two FBDT tables.

Extensive use has been made of computer programs in engineering design, drafting of PFD's, P&ID's, electrical schematics, piping isometrics developed from the scale model and piping and valve material quantity controls. In addition, computer programs have been utilized to maintain status logs for engineering tasks, specifications, material requisitions and drawings. These logs supply the

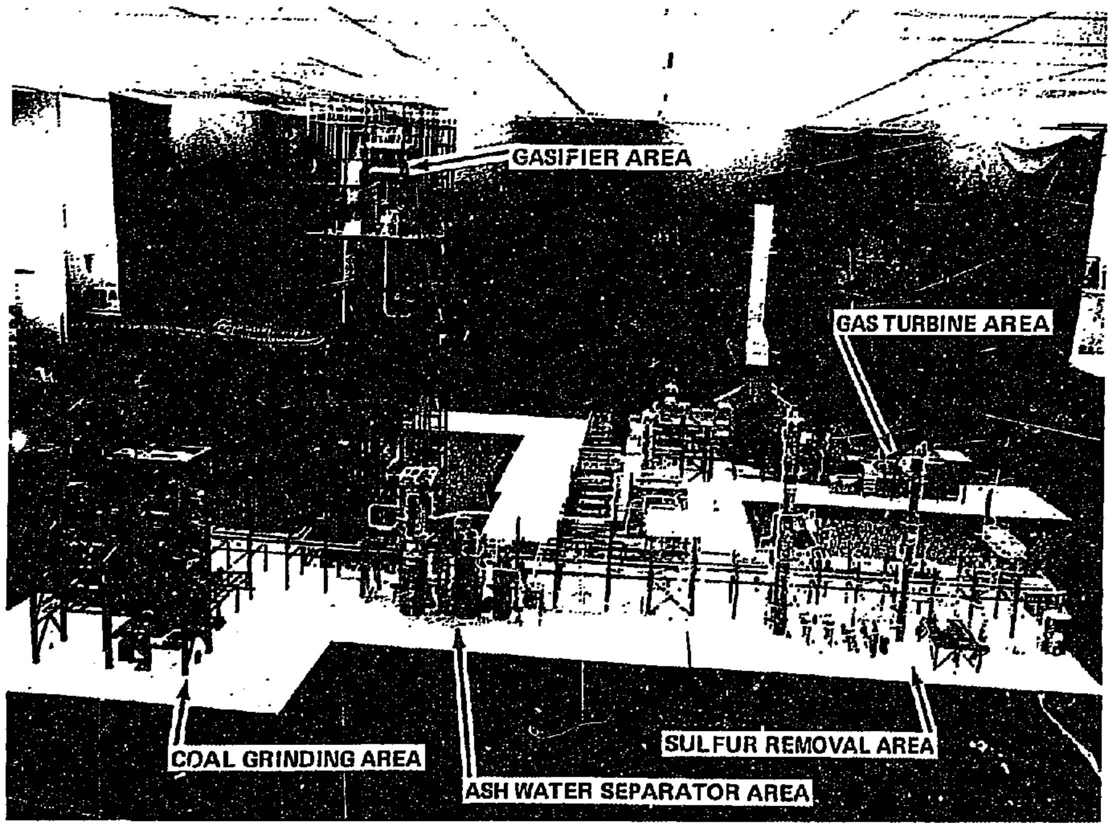


Figure 8-1. Plant Model

data base from which progress is monitored and controlled with regard to meeting engineering budgets and schedules.

As of December 18, 1981 Engineering was 49 percent complete (see Figure 8-2).

PROCUREMENT

Procurement services for the apparatus, construction material and equipment for the project, including purchasing, subcontracting, expediting, traffic, receiving, inspection and order/contract administration, are being performed by Bechtel. Procurement activities are performed in accordance with Program Procurement Procedures, Bechtel's corporate policy and manuals and specific guidelines requested by the Program.

A Project Procurement Team, located in Houston, was formed in April 1980. This group consisted of 10 personnel, representing purchasing, expediting and inspection, as of late 1981. In addition to the Home Office team, a field procurement manager and warehouse supervisor were assigned to the project. A temporary office was rented in Barstow, California, and bids were solicited for office trailers, furniture, supplies, etc. Trailers were subsequently purchased and are now in place at the plant site.

At inception of the project, Bechtel committed to giving small, local and minority owned businesses an opportunity to participate. Meetings were held with Operation Second Chance (OSC) in San Bernardino to review the scope of work and qualification procedures. A list of items to be purchased by Field Procurement was presented and OSC assistance requested to identify qualified bidders in the area. Whenever possible, OSC-recommended vendors are being given an opportunity to bid.

Permanent plant materials and equipment are procured by the Home Office. All long lead items and process equipment have been ordered and the remaining requisitions are primarily for lesser equipment, instrumentation and bulk materials.

As of October 30, 1981 purchasing was approximately 50 percent complete and the Program had approved 81 orders.

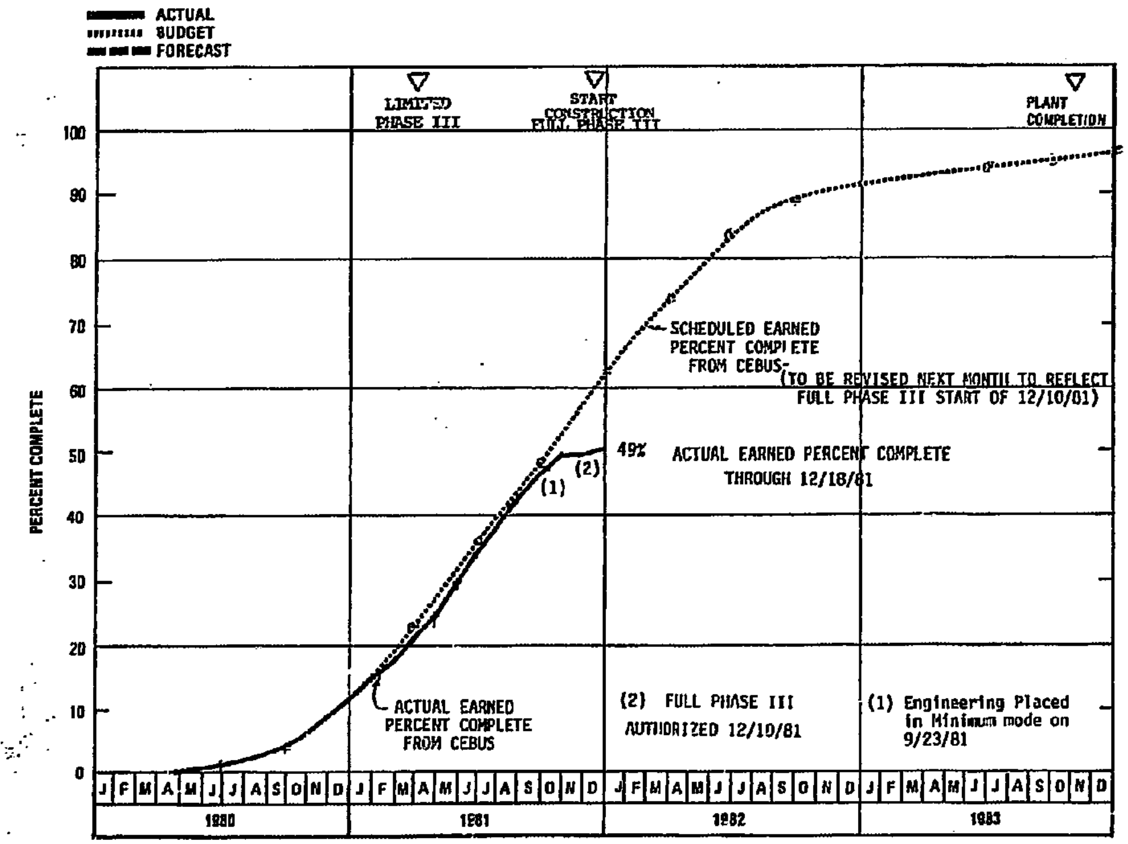


Figure 8-2. Cool Water Coal Gasification Program - Engineering Percent Complete

CONSTRUCTION

The nucleus of the field non-manual organization was assembled in the Houston Office in Spring 1981 for an expected July 1, 1981 construction start. This field staff reviewed project drawings, specifications, schedules and procedures prepared by the home office and started field procurement documents.

Subcontract bids were received on the office building/warehouse concrete slab and plumbing. The electrical subcontract package for buildings was formulated and the construction equipment package was prepared for Program review. Bid packages for portable toilet facilities, radio equipment, vehicles, warehouse pallet rack and bin shelving and heavy rigging were also developed.

Field purchasing procedures have been completed and approved by the Program. The draft of the field organization and procedure manual is complete and being furnished to site contractors.

The field non-manual organization, after being released for other assignments pending completion of the project funding, has now been re-assembled consistent with the construction release given in December 1981.

OPERATIONS PLANNING

The Program Management Committee has established an Operations Planning Committee to oversee detailed operations planning and to provide operational input into the Program engineering function. Each participant is represented on this committee.

The Operations Planning Committee performs the following functions:

- Provides operating comments on selected design items
- Reviews and makes recommendations concerning operating and maintenance organizational structure
- Functions as a planning group for interfacing new IGCC Plant into existing Cool Water site operations
- Reviews and comments on various training programs, including those for staff, operators and maintenance personnel
- Reviews and makes operational comments concerning IGCC plant start-up planning

At the end of 1981, the Program had filled two key slots within the plant operating organization. Mr. Wayne N. Clark of Texaco was appointed Plant Manager of the Integrated Gasification Combined-Cycle (IGCC) Plant, and also functions as chairman of the Operations Planning Committee. Mr. John McDaniel of EPRI was appointed Supervisor of Test and Demonstration and Chairman of the Test Plan Committee.

It is presently planned that Mr. Clark will assume the responsibilities of Program Manager once the Program engineering and construction is complete and emphasis shifts to operations.

The preliminary Cool Water IGCC operating organization is shown in Figure 8-3. It should be noted that the staffing number is higher than that expected for future plants because this is a first-of-a-kind demonstration plant. The staffing requirements for the plant will be reviewed on an annual basis.

MILESTONE SCHEDULE

Figure 8-4 shows a summary of scheduled project milestones. This Milestone Schedule shows Phase II and Phase III activities through the Predemonstration Period. The fabrication, delivery and erection of the Gasifier and Syngas Coolers are the critical path activities. The schedule reflects a Start of Construction on December 15, 1981 and a first Btu production date of June 1, 1984.

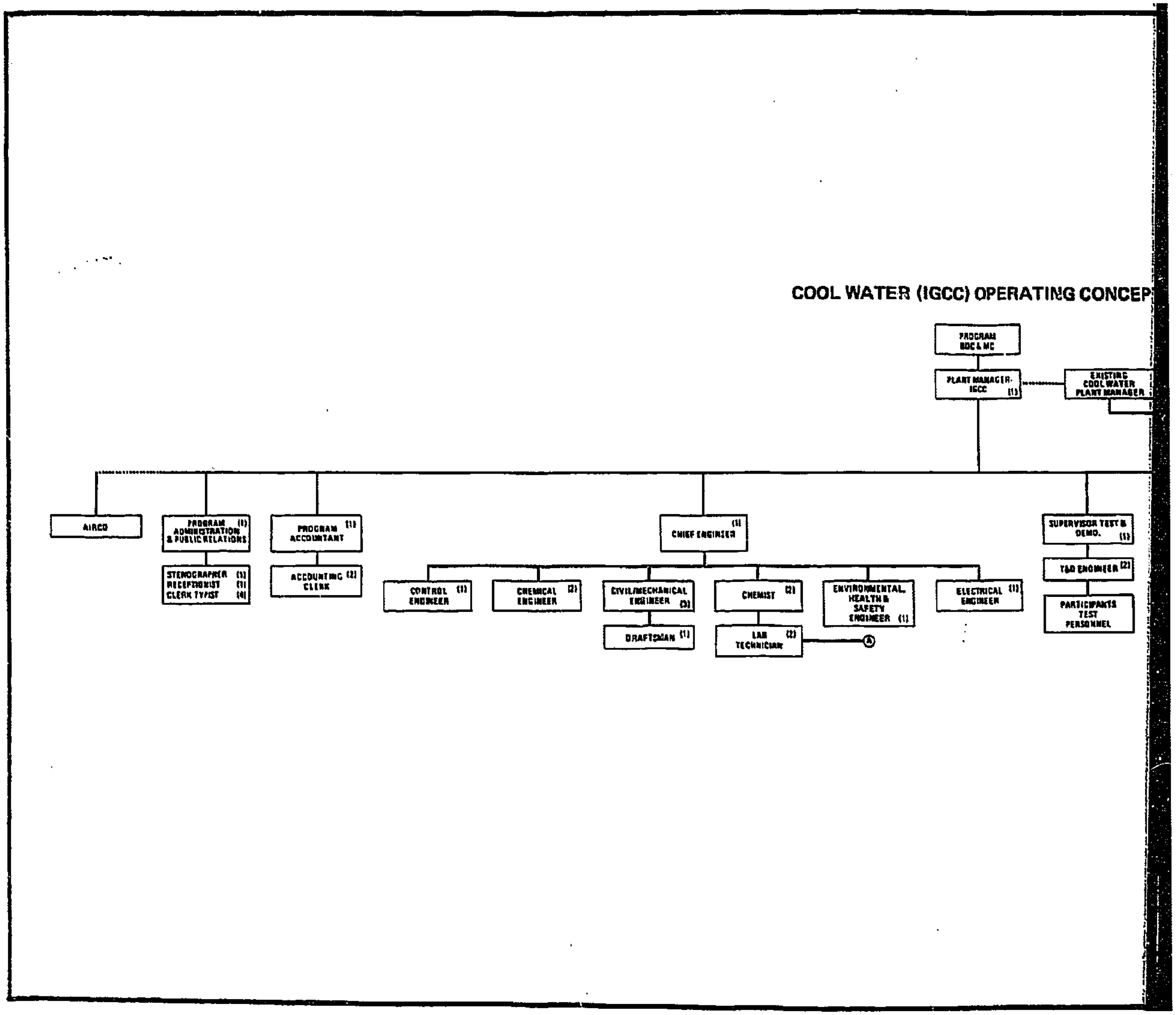
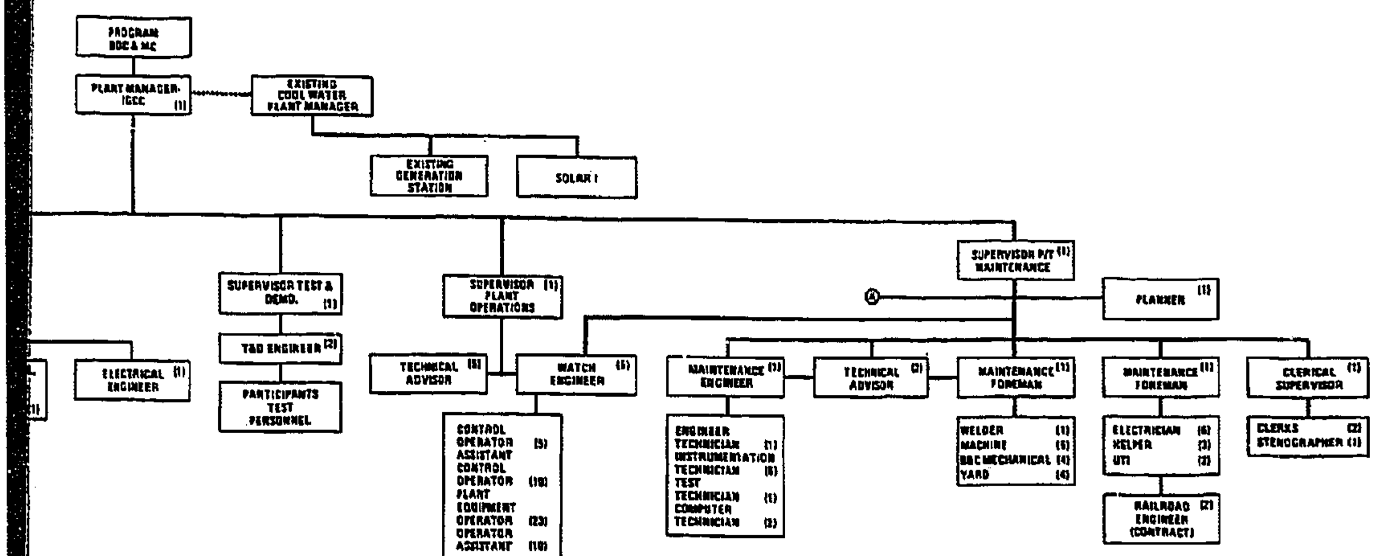


Figure 8-3. Cool Water (IGCC) Operating Concept

R (IGCC) OPERATING CONCEPT



ADMINISTRATION/PUBLIC RELATIONS/ACCOUNTING	TOTAL = 11
ENGINEERING	TOTAL = 17
OPERATIONS	TOTAL = 59
MAINTENANCE	TOTAL = 48
	GRAND TOTAL = 135

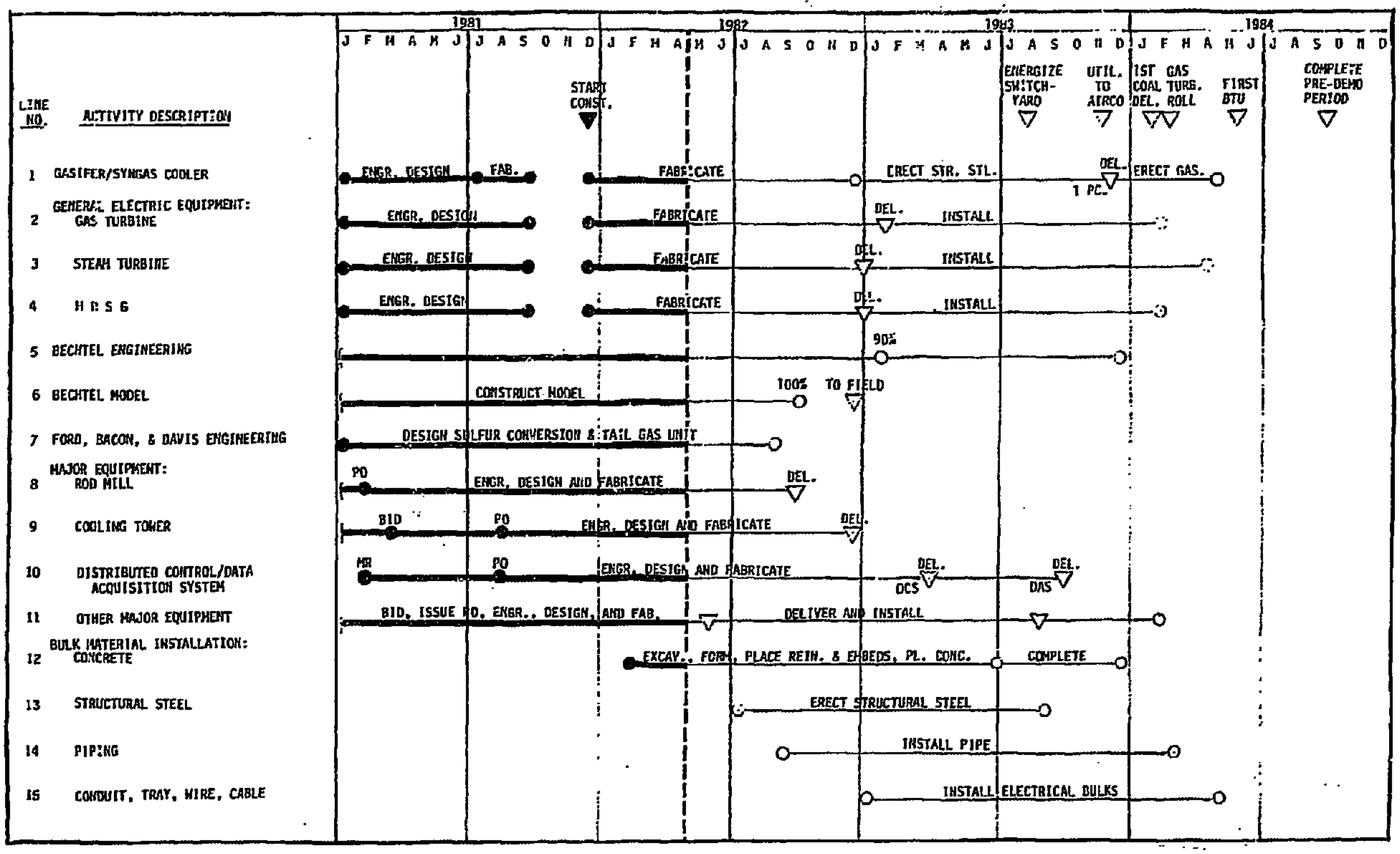


Figure 8-4. Interim Summary Milestone Schedule

Section 9

REGULATORY REQUIREMENTS

OVERVIEW OF THE REGULATORY REVIEW PROCESS

The California Energy Commission (CEC) is the lead agency in the State from which approval must be received to construct a power plant. The first phase for obtaining approval is the submission of a Notice of Intention (NOI) and the second phase is the Application for Certification (AFC). Both the NOI and the AFC phases of the CEC process involve public information meetings, workshops and public hearings. The hearings cover the full range of issues including need, design, environmental impacts, safety, rates and financial issues. The NOI is a site screening phase of at least three alternative sites; the AFC is a detailed review of one site approved through the NOI. It is during the AFC phase that the Environmental Impact Report is prepared by the CEC. Other state and local agencies, including (for example), the California Public Utilities Commission (CPUC), the Air Resources Board (ARB), and the local Air Pollution Control Districts (APCD's), participate in the CEC process. The "Permit to Construct" received from the CEC is in lieu of all other state, local and federal permits to the extent permitted by law. Therefore, the CEC represents a "one-stop shop" for most permits, except the CPUC and the U.S. Environmental Protection Agency (EPA). The CPUC does issue a permit, in addition to that issued by the CEC, which addresses the rate and financial aspects of a project. In addition, a Prevention of Significant Deterioration (PSD) air quality permit must be obtained from the EPA. Therefore, these three permits represent the primary approvals required to construct a power plant. Past regulatory activities are shown in Table 9-1.

SUMMARY OF THE CALIFORNIA ENERGY COMMISSION (CEC) PERMIT PROCESS

An NOI was filed with the CEC on July 13, 1978 for three alternative sites including the Cool Water site. Public information hearings had been held and issues were being defined when the California Legislature passed a law (SB 2066) exempting coal gasification-based electricity generation demonstration projects from the CEC's NOI requirements. Therefore, in October 1978, SCE petitioned the CEC to convert the NOI to an AFC. SCE's petition was granted and the Cool Water site was pursued in detail through the AFC phase. In December 1979 the CEC

Table 9-1

REGULATORY ACTIVITIES

COAL GASIFICATION DEMONSTRATION PROJECT

	Date
Filed NOI with California Energy Commission (CEC)	7-13-78
CEC issued Certificate of Acceptance of NOI	7-21-78
Procedural Conference with CEC	8-17-78
Advised CEC of SCE's desire to participate in expedited process for Project and requested EIR be prepared prior to AFC	8-23-78
Public Workshop - Air Quality (San Bernardino)	9-07-78
Public Workshop - Public Health, Solid Waste, and Water Supply (San Bernardino)	9-28, 29-78
Senate Bill 2066, Coal Gasification Generation Act signed into law	9-29-78
Public Information Hearing (Barstow)	10-05-78
Public Information Hearing (San Bernardino)	10-06-78
Filed petition with CEC to convert NOI to AFC	10-12-78
CEC granted petition converting NOI proceedings to AFC	10-25-78
Transmitted "Preliminary Environmental Assessment" to CEC	11-03-78
Transmitted "Proposed Monitoring and Mitigating Program" to CEC	11-21-78
Position Statement Workshop (San Bernardino)	3-7, 8, 9-79
Public Workshop (San Bernardino)	4-17-79
CEC distributed Draft EIR	4-26-79
Prehearing Conference (San Bernardino)	5-07-79
Public Hearing (Newberry Springs)	5-07-79
SCE filed motion with CEC to suspend adjudicatory Hearings	5-15-79
Workshop on Draft EIR (Barstow)	5-30-79
SCE filed motion to cancel suspension	6-28-79

Table 9-1 (Continued)

CEC Prehearing Conference (San Bernardino)	9-07-79
CEC Distributed "Revised Draft EIR"	10-26-79
Filed for "Certificate of Public Convenience and Necessity with California Public Utility Commission (CPUC)	11-09-79
Hearings on Final AFC Report	11-20-79
CEC Issues final EIR	12-05-79
Final Decision on AFC by CEC	12-21-79
Obtained Final Certification from the CPUC	8-19-80
Filed for EPA PSD Permit	9-12-80
EPA PSD Permit Issued	12-09-81

approved the construction of the Cool Water Coal Gasification Demonstration facility subject to numerous conditions outlined in the CEC's final decision and Third Prehearing Conference Statement. These conditions involve design requirements to mitigate various environmental impacts, as well as worker health and safety aspects of the Project.

SUMMARY OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC) PROCESS

An application was filed with the CPUC in November 1979 requesting a Certificate of Public Convenience and Necessity for the project. Public hearings were held in February and March 1980, after which the Commission issued a decision granting a certificate for the Cool Water Coal Gasification Program in August 1980. After a series of petitions of reconsideration and clarification by both Southern California Edison (SCE) and the CPUC, the Commission issued, on June 16, 1981, an order of clarification with conditions which SCE accepted. The main thrust of the decision was that SCE may recover its capital contribution through Energy Cost Adjustment Clause (ECAC) during the demonstration period to the extent that "avoided cost" revenues exceed project costs, including plant O&M costs, coal costs and processing fees. If SCE has not recovered all project costs, including its capital contribution, at the end of the demonstration period, it may apply for recovery of those costs, plus a factor computed at the "allowance for funds used during construction" (AFUDC) rate accrued during the demonstration period.

SUMMARY OF THE ENVIRONMENTAL PROTECTION AGENCY'S (EPA'S) PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT PROCESS

A PSD monitoring program was estabished at the Cool Water site in October 1979. One year of monitoring data is required to establish ambient air quality conditions. On September 12, 1980 an application was filed with the EPA for a PSD permit. The intent of this application was to show that construction of this facility would not prevent the attainment of the national ambient air quality standards and that best available control technology is being utilized. The EPA declared the application complete on May 29, 1981 and issued the approved PSD permit on December 9, 1981.

The PSD application summarized the anticipated emissions of a number of pollutants. Those pollutants for which a National Ambient Air Quality Standard exists are shown in Table 9-2. All other pollutants regulated under the Clean Air Act are summarized in Table 9-3.

Table 9-2

PRIMARY PLANT EMISSIONS

	0.7 % S Coal		3.5 % S Coal	
	Incin-erator	HRSG	Incin-erator	HRSG
SO_2, lb/hr	4.4	35	196	176
NO_x, lb/hr	0.1	140	0.1	140
Particulates, lb/hr	Negli-gible	2.8	Negli-gible	13.6
CO, LB/HR	Negli-gible	77	Negli-gible	77
Hydrocarbons, lb/hr	Negli-gible	4.4	Negli-gible	4.4

The San Bernardino County Desert Air Pollution Control District has placed a number of restrictions on plant emissions. Rule 468 limits SO_2 emissions to 198.5 lb/hr from the sulfur recovery/tail gas treating unit. For the 0.7 percent sulfur coal the unit must also conform to Best Available Control Technology (BACT). Carbon monoxide emissions are limited to 2,000 ppm by Rule 409. The rate shown in the table corresponds to less than 100 ppm. Rule 67 requires that fuel burning equipment (i.e., GT/HRSG) meet the following restrictions: 140 lb/hr of NO_x, 200 lb/hr of SO_2, and 10 lb/hr of combustion contaminants (particulates). Although this rule has been superseded, the EPA and the ARB still consider this rule part of the State Implementation Plan.

ENVIRONMENTAL PERMIT CONDITIONS AND MONITORING

Permit Conditions imposed on the Program by the CEC and the CPUC are summarized in the attached listings (Tables 9-4 and 9-5) of certification conditions for both construction and operation. Planned monitoring of plant emissions and effluents is discussed in Section 10 and is summarized in Table 10-2.

Table 9-3

MISCELLANEOUS PLANT EMISSIONS

Pollutant	Emissions (Tons/Yr.)	Significant Level (Tons/Yr.)
Asbestos	0	0.007
Beryllium	0.00007	0.0004
Mercury	0.00014	0.1
Vinyl Chloride	0	1
Fluorides	0.2	3
Sulfuric Acid Mist	20.2*	7
Hydrogen Sulfide (H_2S)	0	10
Total Reduced Sulfur (incl. H_2S)	0	10
Reduced Sulfur Compounds (incl. H_2S)	0	10

*Estimated as suspended particulates occurring during a year when 3.5% S coal is tested for a two-month period and 0.7% S coal is run for the remainder of the year. This is a conservative estimate assuming up to 10% of the total sulfur emissions from the HRSG appear as "sulfuric acid mist". Actual mist (particulate) emissions are likely to be lower.

Table 9-4

CERTIFICATION CONDITIONS
CONSTRUCTION

No.	Description	Agency	Agency Approval	CEC Approval	Remarks
1.	Construction Worker Health and Safety Program	CEC / Cal OSHA	1/28/81	*6/30/81	Construction Worker Safety and Health Program Program approved by Cal OSHA letter dated 1-28-81. CC to CEC
2.	Operational Worker Safety and Health Program	CEC / DHS			Draft of operational worker safety and health plan filed with CEC (CC to DHS) 1-26-81. Received written comments from CEC on 6-26-81. Will incorporate comments into final worker safety and health plan prior to operation of plant.
3.	Grading, Excavation and Backfill Plans	CEC / County Department of Bldg. & Safety		*6/30/81	Filed with CEC and copy to S.B. County Department of Bldg. & Safety 1-29-81. Five additional sets submitted on 7-13-81 to S.B. County Building & Safety Department by their request.
4.	Final Engrg. Dwgs., Specs and Calculations	CEC / County Department of Bldg. & Safety		*150 days after submittal	Filing of these documents required 150 days prior to installation of structural components.
5.	Drainage Control Berm Design	CEC / County Department of Bldg. & Safety		*6/30/81	Filed as part of Flood Control Plan with CEC and copy to S.B. County Department of Bldg. & Safety 1-29-81. Five additional sets submitted on 7-13-81 to S.B. County Building & Safety Department by their request.
6.	Use of Non-Fresh Water	CEC	Complete		Edison reached a conditional agreement dated 5-20-81 with the City of Barstow to use the Barstow slug water for Units 1 & 2 provided it does not affect operation in any way. Copy sent to CEC 5-26-81.

Table 9-4 (Continued)

CERTIFICATION CONDITIONS
CONSTRUCTION

No.	Description	Agency	Agency Approval	CEC Approval	Remarks
7.	Closure & Maintenance of Disposal Sites & Evaporation Ponds	CEC State Regional Water Quality Control Board	4/14/81 Complete	--	Approved by California Regional Water Quality Control Board, Lahontan Region 4-14-81. Approval sent to CEC 8-7-81.
8.	Wind Erosion Control Plan	CEC	1/22/81	--	Filed with CEC 1-29-81 along with a copy of a letter of acceptance from Apple Valley Office.
9.	Environmental Surveillance and Monitoring Program	CEC Calif. Dept. of Health Services			Two copies of a draft of the description of the Environmental Surveillance and Monitoring/Worker Health and Safety Program Plan filed with CEC 1-26-81. Received written comments from CEC on 6-26-81. Will incorporate comments into final monitoring and surveillance plan prior to operation of plant.
10.	Rule 213 Offset Requirements	CEC ARB EPA	Complete		The Project has been granted an exemption under Rule 213(f) (2) (B). The CEC, ARB and EPA have transmitted correspondence concurring with the exemption.
11.	FAA Notification	FAA	**5/28/81		Final determination approval received from FAA on 5-28-81. Notified CEC 8-7-81.

* The Commission has 90 days in which to review submittals. If the commission does not order otherwise within 90 days, the applicant may proceed with construction 150 days following submittal. The dates shown in the assumed CEC approval column are 150 days after submittal.

** This determination expires 12-20-82. Must notify FAA 60 days prior to expiration for renewal. Also must notify FAA 5 days prior to the gasifier structure reaching its greatest height during construction.

Table 9-5

CERTIFICATION CONDITIONS
OPERATIONS

No.	Description	Agency	Filing Date	Remarks
1.	Worker Safety & Health Program	CEC / Cal OSHA	90 days prior to start-up.	Must be reviewed and approved by Cal OSHA prior to filing with CEC.
2.	Facility Design Safety Code Compliance	CEC	90 days prior to start-up.	
3.	Handling, Storing, and Disposal of Hazardous Wastes	CEC	150 days prior to start-up.	Dept. of Health approval required prior to filing with CEC.
4.	Testing of Product Wastes	CEC / Dept. of Health Services	180 days after start of operations.	
5.	Final Monitoring and Surveillance Plan	CEC	150 days prior to start-up.	Plan to include expected dates for tests and availability of results.
6.	Noise Survey - Machinery and Equipment	CEC	90 days after operations.	
7.	Noise Survey - Employee Protection	CEC	90 days after start-up.	
8.	Fire Protection Program	CEC	90 days prior to start-up.	
9.	Combined Cost Report	CPUC	1 year after commencement of operations.	Order #9 of CPUC Decision #93203.
10.	Report on Capital Cost and Coal Expense	CPUC	36 days prior commencement of operation after predemonstration period.	Order #11 of CPUC Decision #93203.
11.	Fire Protection Program	CEC / County Fire Wardens Office	30 days prior to scheduled start of operations.	

Section 10

TEST AND DEMONSTRATION PLANS

GENERAL

Cool Water is a demonstration plant with objectives somewhat different from those of a normal commercial venture. In 1979, the Management Committee created the Test Plan Committee (comprised of participant representatives) and charged it with developing testing and data acquisition procedures (including environmental assessment) to achieve project objectives.

The contractual project objectives within the Test Plan Committee (TPC) scope are demonstration of:

- Integrated operation at commercial scale
- Compliance with environmental regulations
- Acceptable start-up, shutdown, load following capability, reliability, availability and safety
- Adapting hardware (burners; combustors, etc.) to gasification/power generation
- Flexibility for a variety of feedstocks

For each objective, the TPC will see to it that plant performance is quantified and documented with high quality data and analysis.

The Cool Water operating organization will include a technical staff to do the necessary testing, analysis and reporting. This Test and Demonstration Staff will be under the direction of the Test and Demonstration Supervisor who will report to the Cool Water IGCC Plant Manager. The Supervisor will also chair the TPC. The TPC will identify the needed tests and procedures, and will direct the Supervisor to scope each test and develop a cost estimate. The TPC will then seek approval from the Management Committee. Once approved by the Management Committee, the responsibility for detailed definition, execution, data evaluation and reporting of results will flow through the Plant Manager to the Supervisor. The Supervisor will coordinate the test execution with plant operations, maintenance and engineering.

TEST PLAN OUTLINE

There are four types of evaluations defined for Cool Water:

- Performance evaluations at steady state, e.g., heat rate
- Material evaluations
- Special environmental tests
- Plant dynamics and control evaluations

These evaluations will be conducted at different frequencies and intensities depending on the phase of operation. For the purpose of the Test Plan, the phases of operation are:

- Pre-demonstration
- SUFCO coal operation at the beginning of project Phase IV
- Operation on participant test coals
- Balance of program operation on SUFCO coal

Additionally, special tests may be conducted and evaluations will take place if there are any major equipment or control modifications.

Table 10-1 provides a preliminary summary of the elements of the Test Plan.

PLANNED TESTS AND EVALUATIONS

System (Steady State)

Objectives to be addressed in these tests are the following:

- Make timely identification of any system performance deterioration
- Characterize system performance over the life of the project
- Establish a data base for steady state model validation
- Conduct valid acceptance tests for package systems

The performance of all plant systems or plant process sections will be regularly monitored and compared to "Expected" or "Design" performance. Plant systems of interest are:

- Carbon, ash, grey water, slurry preparation
- Gasification

Table 10-1

PRELIMINARY
COOL WATER TEST PLAN

Cool Water Phase of Operation	Steady State Performance Evaluation: At Normal Operating Point	Steady State Performance Evaluation: At Special Operating Points	Dynamic and Control Evaluations	Materials Evaluations: General Metallurgy	Materials Evaluations: Syngas Cooler Entry/Inspect	Materials Evaluations: Refractory	Failure Analysis	Special Environmental Tests
1. Pre-demonstration (4 months)	N/A (Normal Operating Point Not Defined)	Continuous	As Required for Controller Tuning	Inspect During Forced Outage Coupon Tests at End of Phase	After 4 mo. Operation (at end of pre-demonstration	Inspect During Forced Outage In Depth Based on Wear Rate	Yes	No
2. SUFCO Coal Beginning of Phase IV (6 months)	Each Week	15 Points at Start-up 5 Points Each Mo. Thereafter	Yes	Inspect Per Schedule During Forced Outage. Coupon Tests Before First Alt. Coal Test	Before First Alt. Coal Test	During Forced Outage, In Depth Based in Wear Rate, Cold Inspection Before First Alt. Coal Test	Yes	1(2) At Normal Conversion 1 at Low Conversion
3. Alternate Test Coals	N/A	10 Points	Minimum	No	Based on Fouling	Based on Wear Rate	Yes	1 At "Normal" Conversion
4. Special Tests				IF APPLICABLE				
5. Balance of Program Operation	Each Month	5 Points Each 6 Mo.	No	Per Schedule When Plant Down	Annually or Based on Fouling During Forced Outage	Based on Wear Rate During Forced Outage	Yes	No

(1 point = 24 hrs. at a single steady operating Condition)

- Syngas cooling
- Carbon scrubbing, final cooling
- Sulfur removal
- Tail gas clean up
- Resaturator, gas turbine, HRSG
- Steam/BFW and steam turbine
- Cooling water
- Oxygen

These evaluations will consist of four steps:

- Data gathering
- Heat and material balance calculation
- Expected performance calculation
- Comparison/evaluation

Sufficient plant data will be taken to calculate high quality heat and material balances and to identify major operating parameters of all the listed plant process sections. All major mass and energy flows into and out of each process section will be measured directly, wherever feasible. Much of the necessary data will be automatically taken on the data acquisition system. In order that the data will be of acceptable accuracy, all involved measurement devices will be calibrated on a regular schedule.

Most data acquisition for the material balances will be automatic. Flows will be automatically integrated (totalized) and temperatures, pressures and compositions will be time averaged. These values will be stored at reasonable time intervals or on demand to enable subsequent calculation of balances over periods of particular interest and for longer term accounting and monthly reporting calculations. Texaco typically calculates a balance for every four-hour operating period and this practice will be maintained at least through the start-up and testing phases of the project.

All major heat and mass inputs and outputs of each process section will be directly measured, but the balances will not close perfectly due to unavoidable measurement errors. Closure will be achieved by statistical techniques, limiting adjustment of each variable to the maximum expected measurement error. A record will be kept of the variable adjustments made to close the balances. These variable adjustments should be normally distributed. If they are not, some systematic measurement error is indicated or some assumption is invalid. The instrumentation will be checked and, if faulty, repaired or recalibrated. If the instrumentation is operating properly and the error persists, the heat and mass balance assumptions will be modified.

Process conditions inevitably vary from the design point, most frequently through variations in feedstock or production rate. In order to evaluate the plant performance as determined by the balance calculations, some reference point is needed which will account for the most significant of these variations. To accommodate this need, some type of steady-state model of each process system will be made. Model input data will be flow rates, compositions and conditions of streams entering the modeled process unit. The model will calculate the expected process unit output streams. The first plant balances after start-up and individual equipment test performance evaluation data will be used for validation. Once the models have been validated, process unit inputs from selected heat and mass balances will be fed to the model along with the other necessary process parameters such as solvent circulation rates, etc., and the predicted unit performance, e.g., the output stream flows and compositions, will be calculated. The models will also be exercised at the plant design conditions.

For each process unit performance evaluation, i.e., for selected heat and mass balance periods, actual performance in key areas will be compared to the predicted performance and design performance. Representative results shall be reported in the monthly operation summaries. When significant variances occur between expected and observed performance, the source of the variance will be identified, possibly through more detailed equipment performance evaluations. If performance has changed, the model parameters will be adjusted. Records of all parameter adjustments will be permanently retained.

<u>Dynamic Tests</u>

Objectives addressed in these types of tests will include:

- Determine if the dynamic performance of the integrated gasification combined cycle system and of certain critical subsystems and components meets the load following requirements of a power generation system
- Evaluate various control strategies during normal system operation and system emergencies
- Provide a data base for validation of dynamic system models so the Cool Water dynamic performance can be extrapolated to full scale plants

The integration of several process units into an operable power plant is one of the significant challenges of the Cool Water Project. A dynamic model of the plant is being generated based on the "design" control configuration. Dynamic tests of the plant will be used to validate this model. Subsequently, model modifications, plant control system modifications and further plant tests will be used to realize the essential operability and the full dynamic potential of the gasification combined cycle configuration.

Generally, a dynamic test will be staged with personnel directing the test. The data acquisition computer will be programmed to collect 300 to 500 points of pertinent data at relatively rapid rates for a short period prior to the start and for an appropriately longer period after the start, through the completion of the test. The testing system will also be arranged for unstaged tests with automatic triggering on plant events so as to collect similar dynamic data which occur during normal operation of the plant.

The data collected will be selectively plotted by the data acquisition system for visual analysis and for comparison to results predicted by the dynamic simulation models. This will allow identification of any dynamically deficient equipment and provide information for the corrections.

Materials and Equipment Tests

This aspect of the Program is intended to:

- Document performance and the operating environment of all Cool Water materials of construction
- Determine the cause and find solutions for all unexpected materials problems
- Optimize the cost effectiveness and reliability of certain key materials such as gasifier refractories and syngas cooler metals

Due to the specialized nature of materials work and its criticality to reliable cost effective plant design and operation, a materials group is expected to be established with a representative from each participant to develop and oversee the materials testing and evaluation program.

It is anticipated that much of the most important materials evaluation work will take place during forced outages to minimize plant down time.

The materials testing and evaluation program will consider four areas:

- General Metallurgical
- Syngas Cooler
- Refractory
- Failure Analysis

General metallurgical evaluations will be integrated into the routine plant inspection, maintenance and safety program. They will consist of regular inspections (visual, ultrasonic, x-ray, etc.) and the placement and periodic removal and testing of corrosion coupons at well defined places in the plant. Plant sections most subject to this type of evaluation are the syngas cooling, reheating and saturation, the grey water system and the gas turbine buckets.

In addition to regular inspection points and corrosion coupons, special efforts will be made to sample and characterize tube deposits in the syngas coolers. Fouling factors will be measured regularly and watched closely. Sootblowing will be optimized. Because of the high temperature application, if the design tube materials prove unsatisfactory, special probes will be used for alternate material testing.

The refractory lining of the gasifier vessel must withstand very severe conditions of slag attack at high temperature. The life of the refractory will be an important factor in the economics of the plant. Therefore, measurements of wear rate, visual inspections and photographic records will be made as plant outages occur. If the original refractory materials are unsatisfactory, test panels of different materials will be installed. The cost effectiveness of all refractory materials tested will be determined.

Upon failure of any piece of plant equipment, a qualified member of the plant technical staff will make a detailed in-situ inspection, including photographs, measurements and observations. For certain types of failure or failure of certain critical equipment, additional specific actions will be taken. In most cases, the failed parts will be retained in a benign atmosphere (a plastic bag with desiccant and/or filled with nitrogen) for an appropriate failure analysis. Complete records of the failure will be retained including process conditions at the time of the failure.

Environmental Tests

These tests are intended to:

- Characterize the environmental acceptability of the plant
- Establish an environmental data base for future IGCC plants

Careful environmental monitoring will be conducted over the life of the project to characterize the environmental impact of the plant. Emphasis will be on effluent streams, e.g., slag, waste water, sulfur emissions, NO_x, etc., but any high internal recycles of noxious compounds will also be identified. Trace element balances will be conducted on each coal type tested in the gasifier.

Detailed methodology to meet permitting requirements is outlined in Table 10-2.

In addition to this regular environmental monitoring, special environmental tests will be conducted on the design coal and on participants' test coals at carefully selected operating conditions. The object of these tests will be to gather sufficient data so environmental performance can be predicted for the test coals in most likely commercial plant configurations. Included in such tests will be complete feedstock and effluent characterization and characterization of key internal recycle streams. Also, special environmental monitoring of the gas turbine will be required during NO_x emission reduction tests.

Table 10-2

COOL WATER COAL GASIFICATION PROGRAM
SUMMARY OF ENVIRONMENTAL MEASUREMENTS

System	Measurement Location	Measurement Description
Sulfur Recovery Tail Gas Treatment	Tail Gas Vent	Continuous: SO_2, Flow Rate Non-Continuous: Particulates, NO_x, CO, Hydrocarbons, Particle Size, Trace Elements, Radionuclides, Polycyclic Aromatic Hydrocarbons, Hydrocarbons, Sulfur Species, Nickel Carbonyl
Combined Cycle Unit	Heat Recovery Steam Generator Flue Gas Exhaust Stack	Continuous: SO_2, NO_x, CO, CO_2, Flow Rate Non-Continuous: Particle Size, Trace Elements, Radionuclides, Polycyclic Aromatic Hydrocarbons, Particulates, SO_3, Hydrocarbons
Slag and Waste Water Storage	Ambient Air in Vicinity of Storage Site	Non-Continuous: Ammonia, Sulfur Species, Radionuclides, Polycyclic Aromatic Hydrocarbons
	Slag Leachate and Groundwater	Non-Continuous: Trace Elements, NH_4^{+} -2, NO_3^{-1}, CN^-, S^{-2}, SO_3^{-2}, SO_4^{-2}, F^-, Cl^-, Br^-, COD, TOC, Phenols, Formate, Radionuclides
Plant Vicinity	Worst Case Impact Area and Nearby Receptor Areas-Ambient Air and Soil	Continuous: SO_2, O_3, NO, NO_2, Meteorological Data 24-hour Samples: Total Suspended Particulates Size
		Non-Continuous: Polycyclic Aromatic Hydrocarbons, Trace Elements, Radionuclides
Cooling Tower	Top of Stacks.	Non-Continuous: Particulates and Particle Size, Trace Elements, Flow Rate

NOTES:

1. "Continuous denotes measurements which are performed using automatic instrumentation and recorded around the clock; "Noncontinuous" designates measurements performed periodically by the manual collection and analysis of process material samples.
2. Sulfur Species include H_2S, COS, CS_2, methyl mercaptan, ethyl mercaptan, dimethylsulfide, and others to be determined.
3. Periodic noise measurements will be performed at plant property line.
4. Input coal to be analyzed for trace elements and radionuclides (noncontinuous).
5. Raw gas before and after acid gas removal to be analyzed for particulates, trace elements and radionuclides (noncontinuous), sulfur species.

Section 11

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