Section 6

INTEGRATED GASIFICATION/COMBINED-CYCLE (IGCC) ELECTRICAL POWER PRODUCTION: A RAPIDLY EMERGING ENERGY ALTERNATIVE

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Cool Water design confirmations, to date, have far exceeded initial projections. The concept has rapidly become a reality and in the authors' opinions, should be considered a viable option for the next base-load generating station needed.

Each of us can easily identify with the successes of and need for proven power production alternatives; oil, gas, nuclear and coal-fired generating facilities. However, each has its own distinct drawback(s); security of supply, socioeconomic ramifications and environmental considerations. IGCC, if proven, (and it shall be) has the capability to positively address each of these drawbacks or disadvantages.

SECURITY OF SUPPLY

The United States is the "Saudi Arabia" of Coal. Proven domestic reserves are conservatively estimated to represent 300 years supply at current levels of consumption and the availability of supply within this country, should never become a function of geopolitical concern. Should this technology become an export commodity (it is already showing great promise for Europe and Asia) the United States' potential position as a major exporter of coal would be enhanced and our balance of payments correspondingly improved.

SOCIOECONOMIC RAMIFICATIONS

Public concern over potential socioeconomic implications connected with nuclear and conventional coal plants, real or imagined, has adversely impacted existing alternatives. Small groups of concerned citizens have been able to add astronomical capital burdens to nuclear and direct coal-fired electrical production facilities. Coal gasification via the Texaco proprietary gasification process utilized at Cool Water has escaped this phenomenon since the process has evolved with a major emphasis on environmental concerns, and produces reduced/negligible pollutants.

ENVIRONMENTAL CONSIDERATIONS

The nature of the process used at Cool Water is environmentally advantageous. The coal gasification process occurs at very high temperatures, ranging from 2300 to 2800°F. Tars, phenols and other potential pollutants are not formed and/or do not survive the high gasifier temperatures. In a direct coal-fired plant, a utility burns the coal to provide steam to drive a turbine and then attempts to clean up significantly larger volumes of combustion gases and solid wastes. In the integrated gasification combined-cycle process utilized at Cool Water, we clean-up most of these potential waste by-products before the fuel is consumed to produce power.

Among additional IGCC advantages to be addressed in this paper are:

- Modularity
- Minimized land-use requirements
- Minimized water requirements (water savings/less waste water treatment is anticipated in mature IGCC plants)
- Cogeneration opportunities
- Coproduction opportunities
- Learning curve opportunities

IGCC is a concept whose time has come and whose product shall serve us well.

HISTORY AND FUNDING

Texaco Inc. (Texaco) which has for over 30 years been working to perfect its proprietary gasification technology and Southern California Edison Company (SCE), among the most innovative of utilities in the search for alternative power sources, began preliminary discussions in 1977 about the possibility of utilizing integrated gasification combined-cycle technology for the commercial production of electricity.

The Cool Water Coal Gasification Program was formally initiated in July, 1979, upon execution of the original Texaco/SCE agreement which has since been amended to provide for, among other things, invaluable contributions of capital and expertise by other Participants (see Table 1 and Figure 1 for capital funding and Participant Program Functions, respectively). The Electric Power Research Institute (EPRI), Bechtel Power Corporation (Bechtel), and General Electric Co. (GE) joined the effort in 1980 followed by the Japan Cool Water Program Partnership (JCWP) in early 1982. (The JCWP is a consortium of interested Japanese industrial organizations led by Tokyo Electric Power Co., Inc., the world's largest utility company.) Two non-equity Contributors, the Empire State Electric Energy Research Corp. (ESEERCO) and Sohio Alternate Energy Development Co., also joined the project at a lower level of funding to respectively support certain research and obtain access to particular information regarding the gasification process to be utilized by the Program. All of the capital costs were thus funded by private industry.

In July, 1983, the Program was the first recipient of a commitment from the United States Synthetic Fuels Corporation (SFC). This support, in the form of a Price Guarantee, will be available during the ongoing five-year commercial demonstration phase (1984-1989) while the plant is sustaining scheduled but inordinate expenses in an endeavor to prove the process to be commercially viable and to further improve the emerging technologies being utilized. Among the unusual expenses being borne by this first-of-a-kind facility are those associated with persuading suppliers to dedicate equipment and facilities to deliver materials, etc., to a unit in a remote location that has no prior commercial experience upon which contract delivery rates, etc., might be based.

The Price Guarantee will provide up to a maximum of $120 million in support at times when adverse market conditions do not allow the Program to generate adequate product revenue to offset the cost of syngas production. This is an important production incentive to encourage the Program to adequately test the Plant's operability under varying conditions utilizing a wide range of coal feedstocks.

The Price Guarantee was conditioned upon the Plant's passage of an exceptionally difficult ten-day Acceptance Test, designed to prove that IGCC had the potential to benefit this nation's consumers. The test parameters were successfully surpassed well ahead of schedule in June, 1984.

The Program has now begun a five-year demonstration period on behalf of its joint owners. SCE will purchase and operate the Plant (assuming economic viability and regulatory permit availability) for the subsequent 15 years. The SFC will have an opportunity to recoup any price support payments made in the first five-year phase during the extended operational period, through sharing in net revenues of the latter stage. The original concept of an approximate $300 million plant was later pared to a $284 million dollar capital budget. Final capital costs, being gathered as this paper is written, are anticipated to be only $263 million.

A relatively good economic environment and effective cost management have contributed to the downward revisions of the Project's costs.

ENGINEERING AND CONSTRUCTION

Detailed engineering began in February, 1980, and project funding was assured in December, 1981. Bechtel immediately began site preparation on SCE property adjacent to that Participant's Cool Water Generating Station in the Mojave Desert, approximately mid-way between Los Angeles and Las Vegas. SCE had acquired the property once owned by the Cool Water Ranch, and carrying a deed restriction requiring use of the name Cool Water. This location, like any other, has both advantages and disadvantages for industrial construction. Desert winds, sandstorms, heat and logistical problems associated with the remote location complicate construction and operation endeavors. Conversely, the absence of severe winter conditions enhance the same activities. Most importantly, this location gives the Program an excellent opportunity to prove what it knows to be an environmentally superior process for utilizing coal in one of the most ecologically sensitive areas of this nation. It is believed that if one can obtain the necessary permits to construct and then sucessfully operate a coal based facility in Southern California, one should be able to do it most anywhere.

The Program has subsequently decided to add a spare gasifier ("quench" type) to enhance its capacity factor. As this paper is written, construction of that unit is on schedule for a March, 1985, completion.

PROGRAM MANAGEMENT STRUCTURE

The overall management structure for the Cool Water Coal Gasification Program is shown in Figure 2. The Board of Control is the governing body (functioning much as a Board of Directors of a publicly held company) and the Management Committee has an oversight function for Program activities. Each Participant has the right to assign an individual to each group to represent the Participant's organization in all Program matters. The Contributors (ESEERCO & Sohio) have restricted participational rights with respect to the Program's management.

Day-to-day construction, operation and management of the Program is the responsibility of the Program Manager. Engineering and Construction organizations are not addressed in this paper, since the main Plant is physically complete and the spare "quench" type gasifier is rapidly nearing completion.

Of interest, however, is the operating organization structure shown in Figure 3. This independent organization, reporting to the Program Manager, is capable of handling day-to-day operations internally. Second generation plants would not have as large a staff, since many of the 135 positions depicted are involved in preparation of safety, operational and administrative manuals, and test and demonstration projects which will provide an established data base for second generation plants. In addition, extensive monitoring and reporting requirements (including daily, monthly and annual reports submitted to Participant companies and the SFC) require substantial man-hours.

PROGRAM OBJECTIVES

The Program's principal objectives during the five-year demonstration phase are as follows:

- 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
- Assessment of equipment and system reliability
- Preparation of operating, maintenance, safety, and training procedures which could be applied to future plants
- Development of a complete economic and technical data base
- Demonstration of feedstock flexibility

Test and demonstration objectives are among the unusual expenses to which this first-ever plant is subjected. A second-generation plant would realize capital and operating savings, above and beyond the inherent modular efficiencies of scale (to be addressed at the end of this paper).

The Program coal is a specified Utah run-of-mine coal with approximately 0.5 weight percent sulfur. The Program will, however, test up to eight other coals nominated by Participant and Contributor entities (one being an Illinois #6, nominated by EPRI, which contains 3.5 weight percent sulfur). An overall objective is to prove that the Program can utilize United States coal reserves in an optimal manner, given this nation's particular environmental concerns and resource capabilities. The Plant has been designed to process a range of coals with sulfur contents from 0.35 to 3.5 percent.

PROCESS DESCRIPTION

The Plant utilizes an oxygen-blown Texaco gasifier to convert 1,000 tons of coal per day to a medium - Btu syngas. After cleanup, this gas is burned in a combustion turbine to produce electricity. In addition, steam is produced by extracting heat from the hot product gas in syngas coolers (waste-heat boilers) and from the gas turbine exhaust gas in the heat recovery steam generator (HRSG). Steam from both sources is combined and superheated in the HRSG and then utilized in the steam turbine to produce additional electricity. A simplified block diagram of the CWCG process is shown in Figure 4.

COAL RECEIVING, HANDLING AND SLURRY PREPARATION

Coal is delivered to the plant by rail in unit trains, bottom-dumped from each hopper car, and conveyed to storage. An enclosure is provided over the track hopper containing a dust suppression and collection system to minimize coal dust emissions. An enclosed unloading conveyor carries coal from the unloading hopper to two-6,000 ton enclosed coal storage silos. A dust collection system is provided to capture fugitive dust generated during the filling operation. Coal is transferred out of the bottom of each silo onto a horizontal feed conveyor, onto a rising feed conveyor, and then to a grinding feed bin. All conveyors are enclosed and have dust collection systems to minimize coal dust emissions.

The coal from the grinding feed bin is crushed in a cage mill and pulverized in a wet grinding rotating mill. Recycled fine ash and slag from the gasifier may also be ground with the feed coal. The ground product is discharged into a sump tank and transferred by slurry pumps into one of two gasification run tanks. A transfer pump withdraws the slurry from the run tank and feeds it to one of two high-pressure, positive-displacement charge pumps. The charge pump is used to pump the slurry into the gasifier.

COAL GASIFICATION, SYNTHESIS GAS COOLING AND CARBON SCRUBBER

The coal-water slurry is fed through a specially developed burner into the refractory-lined gasifier. Partial combustion with oxygen takes place at a pressure of 600 PSI and a temperature in the range of 2300 to 2800°F to produce a medium Btu synthesis gas (syngas) consisting mainly of CO, H_2, CO_2, and steam (see Table 2 for clean syngas composition). Fuel-bound sulfur is converted primarily to H_2S with some COS formed. Fuel-bound nitrogen is largely converted to molecular nitrogen with some ammonia formed.

The gas contains a small amount of methane, some unconverted carbon, and slag. Hot gas is first cooled in a radiant cooler that generates 1600 PSI saturated steam. The slag droplets solidify and drop into a water sump at the bottom of the vessel where a lockhopper system is used for its removal.

The raw syngas is then cooled further in a convection cooler, generating additional 1600 PSI saturated steam and preheating the boiler feed water.

A quench gasifier is being added to provide for continuity of operation if the main gasifier is not available. Quench gasifier operation is similar to main gasifier operation except heat recovery via the 1600 PSI steam generators is not provided in the quench system. Instead, the hot raw syngas is immediately quenched with water as soon as it leaves the gasifier and the syngas then goes directly to the carbon scrubber.

In the carbon scrubber, essentially all of the fine particulate material is removed by direct scrubbing with water. The syngas is cooled to about 100°F by successive heat exchange with saturator circulating water, condensate, air, and cooling water. Water is removed from the gas in condensate separators following each cooling step. A portion of this condensate is pumped back to the carbon scrubber while the remainder is sent to ash/water separation. The cooled syngas flows to the sulfur removal unit where sulfur compounds are absorbed.

The clean fuel gas goes to a saturator where it is contacted with hot water. The moisture added at this point provides the majority of the water required to reduce NOx formation in the gas turbine (an alternate system of steam injection at the gas turbine is also available for this purpose). The fuel gas is then superheated against economized boiler feed water.

SLAG/ASH/WATER SEPARATION

Flyash water from the radiant cooler and carbon scrubbing sections is routed to a settler where solids and water are separated. The recovered water, known as "grey water", is used for recycle to the gasification area. A portion of the grey water is flashed and discharged to evaporation ponds. The settler bottoms are routed to the slag sump.

Slag from the lockhopper is fed to the slag sump. The slag from the sump is dewatered, discharged to a slag bin and transported by truck to the slag disposal area. The water is recycled back to the coal grinding section. Single-pass carbon conversion has been running in excess of 99 percent on the Utah bituminous coal, so the screen classifier (intended to separate fine high carbon content slag for recycle to the gasifier) has not yet been utilized.

SULFUR REMOVAL (SELEXOL)

Sulfur-containing gases are removed from the cooled product gas in a Selexol Unit designed to remove H_2S and COS from the raw syngas while minimizing CO_2 removal.

Cooled syngas is passed upward through a trayed absorber column while contacting a counter-current flow of chilled Selexol solvent. Rich solvent from the absorber bottom is fed to a stripper where the absorbed acid gases are stripped from the solvent. The stripped acid gases are routed to the sulfur recovery section. The lean solvent is cooled by heat exchange with ammonia refrigerant and is recycled to the absorber. The sulfur removal unit is considered a pollution control system because it removes sulfur species which would otherwise be oxidized to SO_2 in the gas turbine.

GAS TURBINE

The superheated clean fuel gas from the saturator and clean gas heater flows to the gas turbine where it is combusted with air. Steam injection is also provided (as an alternate to the saturator) to help reduce NOx emissions. The turbine generates approximately 65 MW of 13,800 volt electric power. The hot exhaust gas from the turbine is routed to the heat recovery steam generator.

HEAT RECOVERY STEAM GENERATOR (HRSG)

Exhaust gas from the gas turbine is cooled by producing 1450 PSIG steam, superheated to approximately 950°F. The HRSG is composed of three sections: the superheater, evaporator, and economizer. Steam raised in the HRSG is combined with that produced by the syngas coolers prior to the superheater section; the combined, superheated steam passes into the steam turbine-generator. The cooled flue gas passes through the HRSG stack and into the atmosphere.

STEAM TURBINE-GENERATOR

Steam from the HRSG is utilized in the steam turbine to produce approximately 55 MW of additional 13,800 volt electric power. In addition, steam for use in other locations throughout the plant is extracted at various pressure levels. The steam turbine is of the condensing type, with condensate recovered from the vacuum system being collected in a condenser hotwell where makeup water is added.

ADDITIONAL SUPPORT SYSTEMS

The Cool Water Plant has additional support systems which are discussed below:

1. Flare System

   The flare system disposes of excess gas during startup, emergency relief, and abnormal operational transients. A knockout drum is provided for the separation of any liquid prior to flaring. The water is pumped back to the secondary sump.

   Since the flare destroys species which would otherwise be emitted as pollutants (e.g., CO, H_2S, COS), the flare system is a pollution control system. The flare exhaust is an intermittent emission from the plant.

2. Cooling Tower

   The plant cooling tower is of the mechanical-draft evaporating type, and serves to remove heat from the power plant condensers, closed cooling water system, and auxiliary equipment in the Coal Gasification Plant. Clarified makeup water is provided by the Plant well water system. Additional makeup water is obtained from blowdown streams from the steam, condensate, and boiler feedwater system. Cooling water is treated to control corrosion, scale, and fouling. Cooling tower blowdown is routed to the plant evaporation pond with no discharge to ground or surface water.

3. Oxygen Plant

   Oxygen is supplied to the gasifier from an "across the fence" cryogenic air separation plant which also provides the IGCC Plant's nitrogen requirements. A separate cooling tower is provided for the oxygen plant and its blowdown is routed to the evaporation pond. The oxygen plant supplies 99.5 percent purity product. The CWCGP gasification process does not require oxygen of this advanced purity, but its production allows the air separation plant (Airco) to produce argon which is sold for incremental revenue.

SULFUR RECOVERY/TAIL GAS TREATING

This system consists of two sections: A Claus Unit and a modified SCOT Tail Gas Unit. Acid gas from the Selexol stripper and flash gases evolved as the grey water stream is reduced in pressure are routed to the SCOT Unit where H_2S is removed from the gas stream in an amine absorber. The H_2S is stripped from the amine solution and routed to the Claus Unit.

In the Claus Unit, a portion of the acid gas is combusted in air to form SO_2. The $H_2S:SO_2$ ratio is controlled at 2:1. The gas is cooled and passes through a condenser for the removal of liquid sulfur. After reheating, the gas enters the first of three catalyst conversion stages. Each stage consists of a reheater, reactor, and condenser. The tail gas from the final condenser is fed to a SCOT catalytic reactor where residual SO_2 is reduced to H_2S and then to a second absorber in the SCOT Tail Gas Treating Unit. The treated gas is routed to the gas turbine or an incinerator for destruction of the remaining reduced sulfur species and any remaining ammonia or organics. The liquid sulfur that is produced flows into a sulfur storage pit and is then pumped into the buyer's truck, F.O.B. Plant.

PROCESS WASTE WATER TREATMENT

The gasification process effluent water consists of a number of purge streams removed from the process to limit the buildup of dissolved minerals in the gasifier circulating water system. The principal sources of process effluent [illegible] grey water system and ammonia-laden condensate from the gas cooling equipment. Minor additional periodic sources are the SCOT Unit and the Selexol Unit. The grey water system blowdown is flashed to remove dissolved gases and routed directly to the evaporation pond. The ammonia laden condensate along with the SCOT and Selexol blowdown water is steam-stripped for the removal of dissolved gases (primarily H_2S and NH_3). The stripper overhead vapor, combined with grey water system flash gas, is routed to the Claus Unit. The stripped wastewater is routed to the evaporation pond which has an impermeable clay liner to provide containment of wastewater from the Plant.

SLAG DISPOSAL

The slag pit is equipped with an impermeable clay liner and an underdrain system with sumps so that the pit can be monitored for leakage. Ultimately it is anticipated that the slag will be sold commercially as a by-product.

ELECTRICAL POWER SALES

The Cool Water Coal Gasification Plant's electrical output (approximately 111 MW net) is transmitted to SCE's existing grid where it is sold pursuant to a CWCGP/SCE agreement.

PLANT PERFORMANCE TO DATE

The Plant was completed ahead of schedule and under budget on April 30, 1984. The commissioning and integrated operation of all Plant systems has since been completed with outstanding success.

Below are but a few of the major accomplishments versus objective dates since:

	Objective Date	Achieved
First Btu	6/01	5/07
Initial Electrical Production	6/25	5/20
10 Day SFC Acceptance Test Completion	8/01	6/23

The gasifier was first fired on May 7 and Plant commissioning was completed in only 47 days. In September, 1984, (only four months after initial startup) the Plant achieved a capacity factor greater than 71 percent, an operational achievement that would be envied by many conventional power plants utilizing mature technologies.

As this paper is being written, the Plant is running at essentially design capacity and has just broken yet another record for length of continuous run. The latest full month's production figures available follow:

	February 1985	Cumulative*
Coal Gasified (tons dry)	20,834	128,360
Gasifier Operations (hrs)	496.5	3,036.1
Gross Electricity Generated (kwh)	51,515,000	292,130,000
Capacity Factor	65.5%	41.6%
On-Stream Factor	73.8%	50.6%

*Commercial Production June 24, 1984 - February 28, 1985

These are remarkable statistics considering a new plant utilizing emerging technologies.

One of the Program's objectives is to establish a realistic basis for determining the cost of electricity from a mature IGCC power plant. It is now believed that we should have enough data to provide a reliable figure sometime during the final quarter of 1985.

In the interim, a recent EPRI study indicates that the process utilized at Cool Water will produce power in a mature plant for approximately 10% less than a direct coal-fired plant with scrubbers. An analysis of production costs for 1984 reflects a very promising trend; i.e., an average reduction in production costs of over 24% during each of the five months during the period for which data is available. It is too early for the Program to make definitive statements, however, we believe that EPRI's projections are conservative.

During the remainder of the five-year operational test and demonstration phase, an extensive test plan is to be carried out. The Program is expected to test at least eight alternate coals nominated by Participants and Contributors (an Illinois #6 has already been nominated by EPRI, containing 3.5 percent sulfur). The Plant is designed to process a range of coals with sulfur contents 0.35 to 3.5 percent. Elements of the test plan include steady state, materials and dynamic tests.

ENVIRONMENTAL ASPECTS

The overall emissions from the coal gasification plant approach or improve upon those which can be achieved with a combined-cycle unit fueled by natural gas, and will be within current Federal and California standards. A comparison of US EPA New Source Performance Standards for coal fired plants and CWCG plant data attained to date is presented below:

Air Pollutant Emissions

US EPA NSPS Pollutant	(Coal)	Plant Data Attained to Date*
NOx	0.60 lb/10^6	0.059 lb/10^6 Btu
SO_2	70-90% Removal And 0.6-1.2 lb/10^6 Btu	97% Removal And 0.034 lb/10^6 Btu
Particulates	0.030 lb/10^6 Btu	0.0013 lb/10^6 Btu

*Based on Coal Feed Rate of One (1) Billion Btu/Hour

We have encountered fewer difficulties than one would expect in the start up of a new plant. Most of the problem areas to date have been minor and easily corrected. One would anticipate that most of these problems would be associated with the gasifier/combined-cycle equipment in a first-ever commercial application. Ironically, these systems have been most reliable. An analysis of the 24 plant runs made from commercial production date through the end of 1984 indicates that the gasifier and combined-cycle systems were the cause of shut downs in only one instance each.

CAUSE OF UNIT SHUTDOWNS
(June 24 - December 31, 1984)

	Shutdowns	Percentage
Gasifier	1	4
Power Block (Combined-Cycle)	1	4
Procedural Errors	2	8
Oxygen Plant	2	8
Safety System Faults	4	17
Radiant Sump/Lockhopper	4	17
Boiler Feed Water	5	21
Slurry Charge Pump*	5	21
Total	24	100

*Pump or Slurry 2; Controls 3

Much has been learned in each of these gasifier runs which will allow greater operational efficiencies for the future. One of the most recent runs is a good illustration.

- This run was characterized by a rapid startup; 4-3/4 hours from gasifier light-off to full plant operations with electricity being generated in both the gas and steam turbines/generators. Sulfur removal/recovery reached design specifications (97/90%) during the run.

- The emergency oxygen back-up system was tested for the first time as a result of a trip of the oxygen compressor at the supplier's plant. Back-up systems consist of a 30 minute gaseous supply followed by a 24 hour liquid supply at the design 1000 TPD rate. Excellent coordination between the Program's personnel and those of the oxygen supplier kept production losses at near minimal levels.

- The gaseous back-up system was brought on-line smoothly and the gasifier ramped down to 57% capacity and approximately 500 PSIG within 10 minutes to conserve oxygen. The liquid back-up system was lined-up for delivery. However, the oxygen plant personnel were able to restart the compressor and bring the plant back on-line 5 minutes before the gaseous back-up supply was exhausted and the gasifier was ramped back to design within minutes with electrical production increasing accordingly.

- The gasifier was on-line for 443.9 hours (18.5 days) during this run resulting in production of 43,752 MWH from the syngas. The run was terminated because of a controller malfunction due to an air-conditioning problem.

PROSPECT FOR FUTURE IGCC APPLICATIONS

Recent EPRI studies conclude that the IGCC plants are competitive in cost and environmentally superior to conventional coal-fired plants with back-end cleanup. EPRI has been conducting comparison studies for over eight years. The environmental advantages of IGCC plants include:

- Higher sulfur removal capabilities
- Reduced NOx emissions
- Higher particulate removal
- Reduced solid waste disposal
- Less water use for electrical generation
- Reduced land requirements

Among economic factors, second generation IGCC plants are projected to be more efficient than conventional coal-fired plants with flue gas clean-up. Modules in the 200 to 250 MW size range allow utility capacity additions in small and/or phased increments, thus conserving capital and matching the demand growth. The modular nature of the facilities lead to high potential availability, resulting in lower revenue requirements as IGCC plants can be dispatched at higher capacity factors. Lower-priced (higher sulfur) coals can also be used, reducing fuel expenses.

SCE's studies of a potential IGCC plant for California's Eastern desert confirm the EPRI conclusions. SCE considers IGCC plants competitive with conventional coal plants and offering substantially greater financial and operational flexibilities.

Coal gasification integrated with combined-cycle electric generation provides a flexible multi-energy concept which can also be configured to produce process energy for cogeneration applications or to provide feedstock for chemicals production. Steam at various conditions or clean intermediate Btu fuel gas can be withdrawn at multiple points in the Plant. Thus, IGCC, with additional process equipment, has the flexibility to produce power, heat, fuel gas or chemical feedstock in various proportions. IGCC plants are also suitable for alternative financing mechanisms. Since there is an option for generation of electricity along with other industrial products, third-party equity participation can be considered.

The IGCC alternative is relatively low on the learning curve. Much of that yet to be discovered at CWCGP should add to the attractiveness of integrated gasification/combined-cycle technology, a rapidly emerging energy alternative.

TABLE 1

PROGRAM CAPITAL FUNDING
(Millons of Dollars)

Participants	Committed Funds
SCE	25
Texaco	45
EPRI	69
Bechtel	30
GE	30
JCWP	30
Subtotal	229
Contributors	
ESEERCO	5
Sohio	5
Program Loan	24
Subtotal	34
TOTAL COMMITMENT	263

TABLE 2

CLEAN SYNGAS COMPOSITION

Component	Mol % (Dry Basis)
CO	42.5
H_2	38.2
CO_2	18.6
CH_4	0.3
Ar & N_2	0.4
H_2S & COS	50 PPM

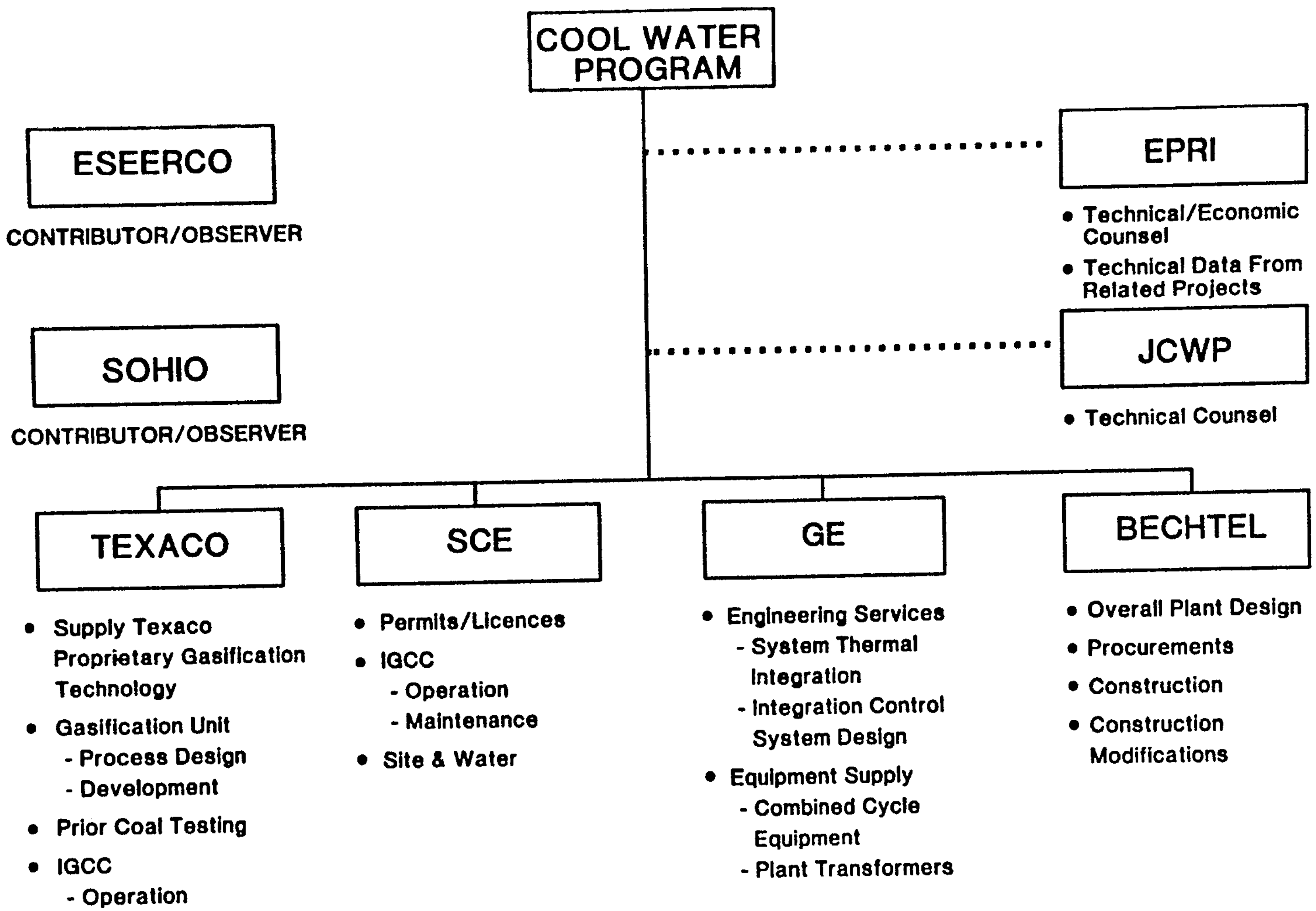
COOL WATER PROGRAM
ESEERCO
CONTRIBUTOR/OBSERVER
SOHIO
CONTRIBUTOR/OBSERVER
EPRI
• Technical/Economic Counsel
• Technical Data From Related Projects
JCWP
• Technical Counsel
TEXACO
• Supply Texaco Proprietary Gasification Technology
• Gasification Unit
- Process Design
- Development
• Prior Coal Testing
• IGCC
- Operation
SCE
• Permits/Licences
• IGCC
- Operation
- Maintenance
• Site & Water
GE
• Engineering Services
- System Thermal Integration
- Integration Control System Design
• Equipment Supply
- Combined Cycle Equipment
- Plant Transformers
BECHTEL
• Overall Plant Design
• Procurements
• Construction
• Construction Modifications

FIGURE 1

PROGRAM MANAGEMENT STRUCTURE
Cool Water Coal Gasification Program

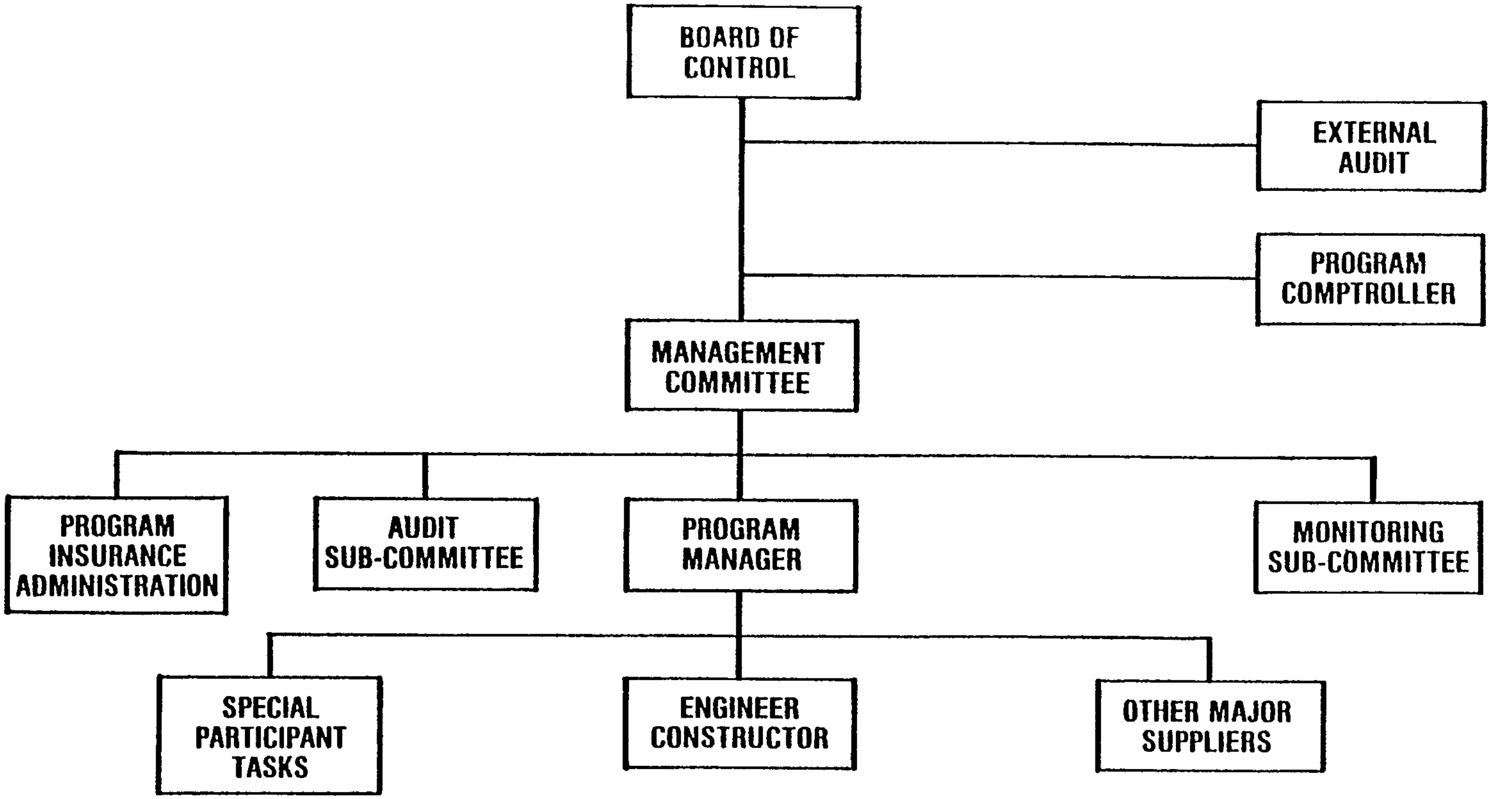

FIGURE 2

OPERATING ORGANIZATION

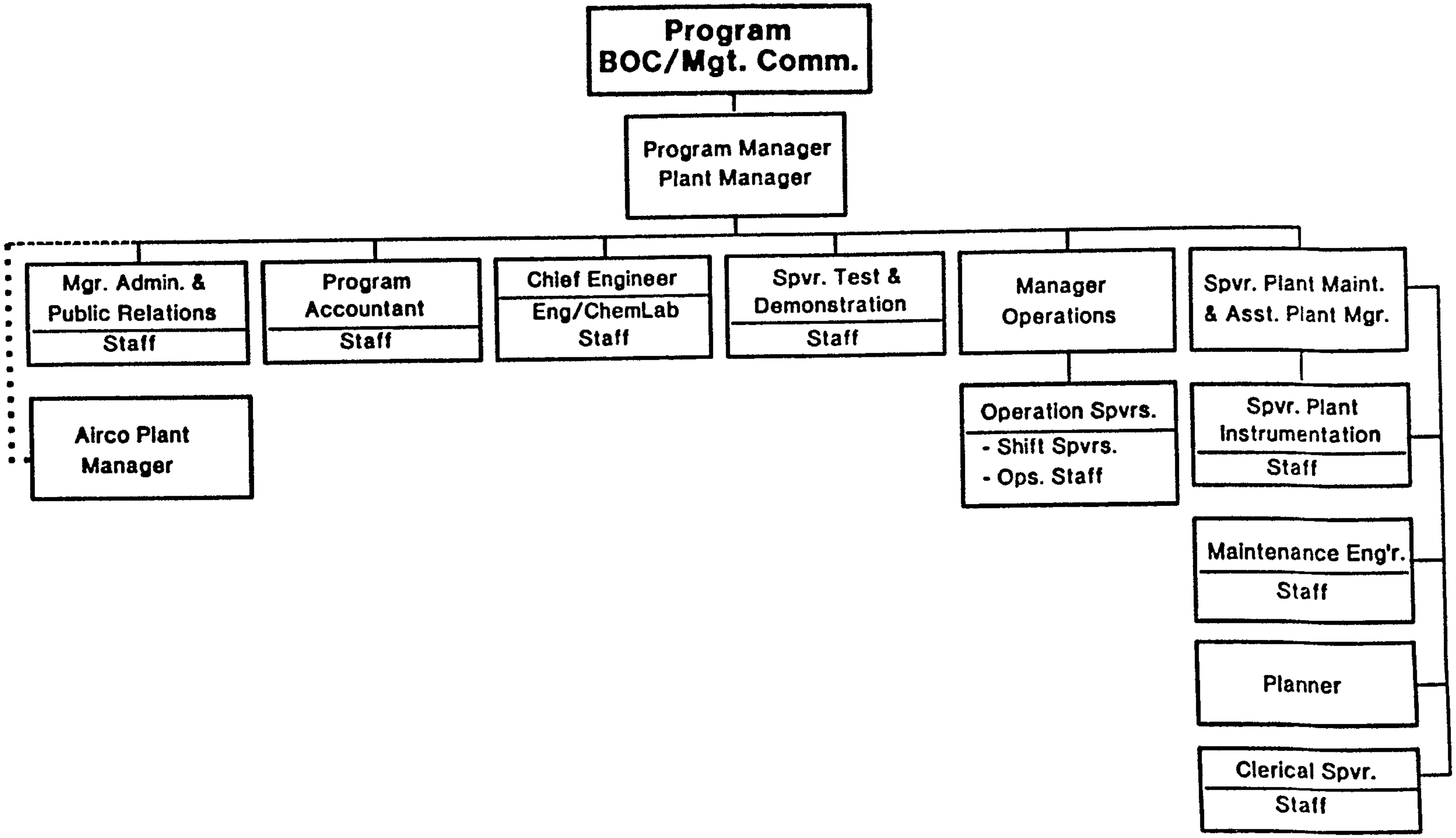

FIGURE 3

COOL WATER COAL GASIFICATION PROGRAM
BLOCK FLOW DIAGRAM

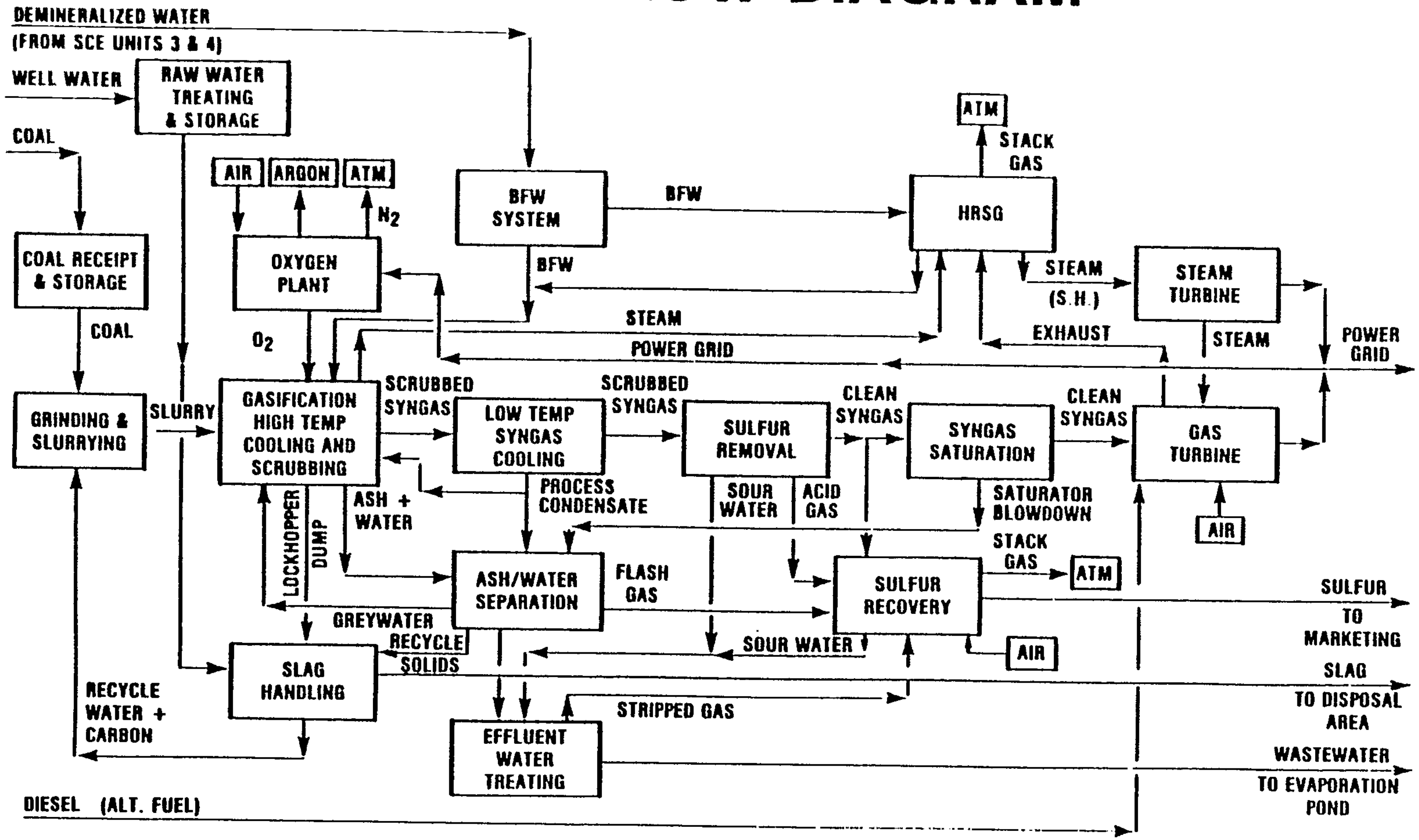

FIGURE 4