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A REPORT OF THE

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AND

Council of Scientific & Industrial Research (India)

FEASIBILITY ASSESSMENT of COAL INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) POWER TECHNOLOGY FOR INDIA

FINAL REPORT

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Section 1

INTRODUCTION

In India, coal plays a very important role for power generation. Essentially, all the power generated from coal is based on the PC (pulverized coal) plant. As both the economy and power demand in India have grown rapidly in recent years, the Government of India is looking for alternatives to the PC plant to use coal more efficiently and cleanly. The Integrated Gasification Combined Cycle (IGCC) plant has been identified as one of these alternatives.

In early 1987, the Ministry of Energy of the Government of India formed an Expert Group to review various coal gasification processes available globally and to identify a technology for setting up an IGCC demonstration plant in India. The Expert Group visited various coal gasification plants in India and abroad in July 1987 and submitted a finding report in January 1988.

A major finding of the Export Group was that all the gasification plants abroad were processing coal or lignite with substantially lower ash content than the Indian coal. The Indian coal typically has an ash content in the 40% range. Most of the process licensors had very little experience or test data with coal in this ash content range.

As recommended by the Expert Group, funding was acquired from the United States Government (mainly through the U.S. Agency of International Development and Trade and Development Program) for a program to estimate the gasifier performance for the high ash Indian coal and perform a techno-economic evaluation of the IGCC technology based on the estimated performance. The Council of Scientific & Industrial Research (CSIR) of the Government of India undertook the overall project responsibility. Bechtel Corporation in San Francisco was chosen as the U.S. engineering consultant and M/s. Projects & Development India Ltd., Sindri, was chosen as the Indian engineering agency. Many technical experts from both the government and private sectors in India also participated and contributed to this study.

In the following subsections, the major objectives of this study are described; related background information such as the coal resources, power generation, incentives to use IGCC, and current gasification development in India are provided; and a brief discussion on the organization of this report is also provided.

1.1 STUDY OBJECTIVES

The Expert Group has identified five gasification processes which are in an advanced stage of development and might be applicable for the high ash Indian coal. These processes include the Shell, Texaco, KRW, Dow, and BGL gasifiers. An initial screening study reduced the group to the first three gasifiers. A self-developed moving bed gasifier in India similar to the Lurgi process was later added as the fourth study case.

The major objectives of this study are to evaluate and rank these four gasification processes, compare their economics with the PC plant, and to establish an overall commercialization program for the IGCC technology in India.

The economics are to be established through a conceptual design of the IGCC plant. The technology evaluation will also address risk factors associated with each process.

Based on the processes selected, a preliminary design and cost estimate for an IGCC demonstration project will be prepared for project approval and fund appropriation by the Government of India.

1.2 BACKGROUND

1.2.1 Coal Resources in India

India has a substantial coal reserve, at a total of 176 billion tonnes excluding lignite. Annual coal production is about 192 million tonnes. About 60% of the coal produced is for power generation.

Bulk of the reserve consists of low grade coal with high ash content. With increased mechanization and open cast mining, the coal ash content is expected to continue to increase. Coal for future power generation in India will have 35-45% ash as compared to 10-15% in the United States or Europe.

The ash in Indian coal is generally refractory in nature and is characterized as long slag. It consists mainly of silica, alumina, and iron and has a very low content of calcium, magnesium, sodium, and potassium. Therefore, the ash is very abrasive and has a very high fusion temperature.

1.2.2 Power Generation in India

The total current power generation capacity in India is 60,000 MW. The required capacity by 1995 is projected to be 100,000 MW. About 65% of the current power generation is coal based. It is expected to continue at this percentage level in the future. Therefore, coal occupies a pivotal position in the national power supply.

Essentially, all coal power plants in India are PC plants. The high ash content and abrasive nature of ash found in Indian coal has led to severe equipment erosion and low availability of these plants. It also meant a higher performance requirement for the electrostatic precipitator for particulate removal.

1.2.3 Incentives to Use IGCC in India

PC plants, after decades of development and operation in India, have reached the peak efficiency attainable with little improvement potential. Currently, these plants are operated without sulfur and NO_x emission control. Whereas efforts to effectively control dust emission have begun, technologies for reducing sulfur and NO_x are yet to be introduced. If they are implemented, the PC plant cost will be increased significantly.

IGCC plants, in comparison with PC plants, are known to have the following advantages:

- o Higher efficiency
- o Lower water consumption
- o Less project gestation time
- o Flexibilities for small module construction and phased construction
- o Lower emissions even if the PC plant is equipped with FGD

While the PC plant has reached its peak efficiency, the IGCC plant can further improve its efficiency if more advanced materials are developed for the gas turbine to operate at a higher firing temperature. The lower water consumption is a very important factor as water resources are scarce in India.

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For Indian coal, the IGCC plant has an added advantage of being less susceptible to performance deterioration caused by the ash. IGCC will become increasingly more attractive in India as the ash content in Indian coal continues to increase in the future.

1.2.4 Status of Coal Gasification in India

India has long been interested in coal gasification. Two commercial K-T gasification plants have been in operation in the 900 t/d fertilizer plants at Ramagundam and Talcher. They are the first two four-headed K-T gasifiers set up in the world. A unit based on the Winkler fluid bed gasification system was in operation in Neyveli, processing lignite for the production of urea.

Interest in coal gasification continues today. The CSIR laboratories have been engaged in developmental work on gasification for three decades. Central Fuel Research Institute, Jealgora, installed a down-draft gasifier, a cross-draft producer, and a powdered coal gasification unit (about 25 kg/h) and a 110 kg/h K-T entrained bed gasifier. In 1962, a 0.8 m diameter moving bed pressure gasifier (19 t/d) was set up and gasification characteristics of eight coals were studied. A moving bed pressure gasifier of 1.3 m diameter (24 t/d) has been in operation at the Indian Institute of Technology of Chemical Technology, Hyderabad, since 1983.

The 24 t/d PDU (Process Development Unit) can be operated either as an oxygen-blown or air-blown unit. Extensive tests have been done in this PDU with coals having an ash content ranging from 15 to 35%. To determine the impact of ash content and to provide a design basis for the moving bed case for the present study, tests were carried out at this PDU with 1,200 t of the design coal, using oxygen-steam and air-steam as the gasification media. Effects of the operating pressure and steam-oxidant ratio on the performance of the process were studied.

Studies on reactivity of char towards carbon dioxide and steam were also conducted using the char obtained from this coal. It was clearly established from the PDU tests and the reactivity tests that the high ash coal is an acceptable feedstock for the moving bed gasification process. The tests showed that a reasonable carbon conversion can be achieved in the process; the ash content does not have significant impact on the gas composition; and the residual carbon in ash is within an acceptable range.

Bharat Heavy Electricals Limited (BHEL) has a 150 t/d IGCC demonstration plant at Trichy based on a self-developed air-blown moving bed gasifier similar to the Lurgi gasifier. This plant can produce a total of 6.2 MW and has been in operation since 1988. BHEL has also a 18 t/d PDU at Hyderabad based on fluidised bed gasification.

1.3 **REPORT ORGANIZATION**

This report is composed of nine sections; this section, Introduction, is the first.

In Section 2, a summary of the report is provided.

In Section 3, the design bases for the IGCC plant such as plant location, plant capacity, coal composition, ambient conditions, emission standards, etc are presented.

In Section 4, the rationale behind the selection of processes or process schemes in both the fuel gas and power generation blocks of the IGCC plant are discussed.

Sections 5 and 6 present the design, overall performance, and cost estimate for the IGCC and PC plants, respectively. The overall performance includes plant efficiency and a summary of the plant resource requirements, byproducts produced, and emission inventory. The cost estimate includes capital requirements and costs of generation. Other information provided includes project construction schedule and plant layout requirements. In Section 5, risk factors associated with IGCC plant are also identified and discussed.

In Section 7, the IGCC and PC plant efficiency and cost data presented in Sections 5 and 6 are compared. A relative ranking of the gasification technologies based on both technical and economic considerations is provided. Conclusions are drawn as to whether IGCC is a viable power generation option for the high ash Indian coal and which gasification processes are to be recommended.

Section 8 presents the preliminary design and cost estimate of the IGCC demonstration plant.

Section 9 discusses the necessary commercialization steps and strategy for IGCC plants in India.

Included at the end of the report are a list of the references used, and appendices containing equipment lists and specifications for the four IGCC study cases and the demonstration plant.

Section 2

SUMMARY

Coal is a major energy source for power generation in India. Most coal in India has a very high ash content (in the 40% range). A feasibility study was conducted jointly by an Indian team and Bechtel under USAID (U.S. Agency of International Development) funding to evaluate the use of this high ash coal for IGCC (Integrated Gasification Combined Cycle) power generation. The Indian study team consists of technical experts from both the government and private sectors. The major objectives of this study were to screen and rank various gasification processes, compare the economics with a PC plant, and to establish an overall demonstration and commercialization program for the IGCC technology in India.

2.1 IGCC PLANT DESIGN

A conceptual design was prepared for a mine mouth IGCC plant located at the North Karanpura coal field of Bihar State in eastern India.

The fuel gas production is sized to fully load two GE 9F gas turbines at the 29.5 C average ambient temperature with 5% excess capacity. The total net power produced from this IGCC plant is approximately 600 MW.

The design coal is a non-caking, unwashed, run-of-mine coal from the Dakra seam. The coal, on as-received basis, has 38.8% mineral matter, 18% moisture, a higher heating value of 3332 Kcal/kg, and an ash fusion temperature (fluid, under reducing atmosphere) of more than 1500 C. It represents the typical coal feedstock which would be available for future power generation in India.

The plant is designed with a minimum 70% sulfur removal. The NOx emission is based on 75 ppmv corrected for 15% oxygen.

There are four study cases, corresponding to the use of Shell, Texaco, KRW, and the moving bed gasifiers. The gasifiers are oxygen blown in the first two cases and air blown in the other two cases.

Shell, Texaco, and KRW provided the necessary gasification process packages and cost data for the first three cases. The moving bed is a self-developed technology similar to the Lurgi process. The design data were derived from the 24 t/d PDU test conducted by the Council of Scientific & Industrial Research (CSIR) at Hyderabad, India.

The major design features of each case are described below.

2.1.1 Shell Case

A block flow diagram of this case is shown in Figure 2-1.

Due to the high ash fusion temperature of the coal, limestone is added to the gasifier as a fluxing agent. The coal and limestone are dried to 2% moisture and milled to -88 μ before feeding to the gasifier.

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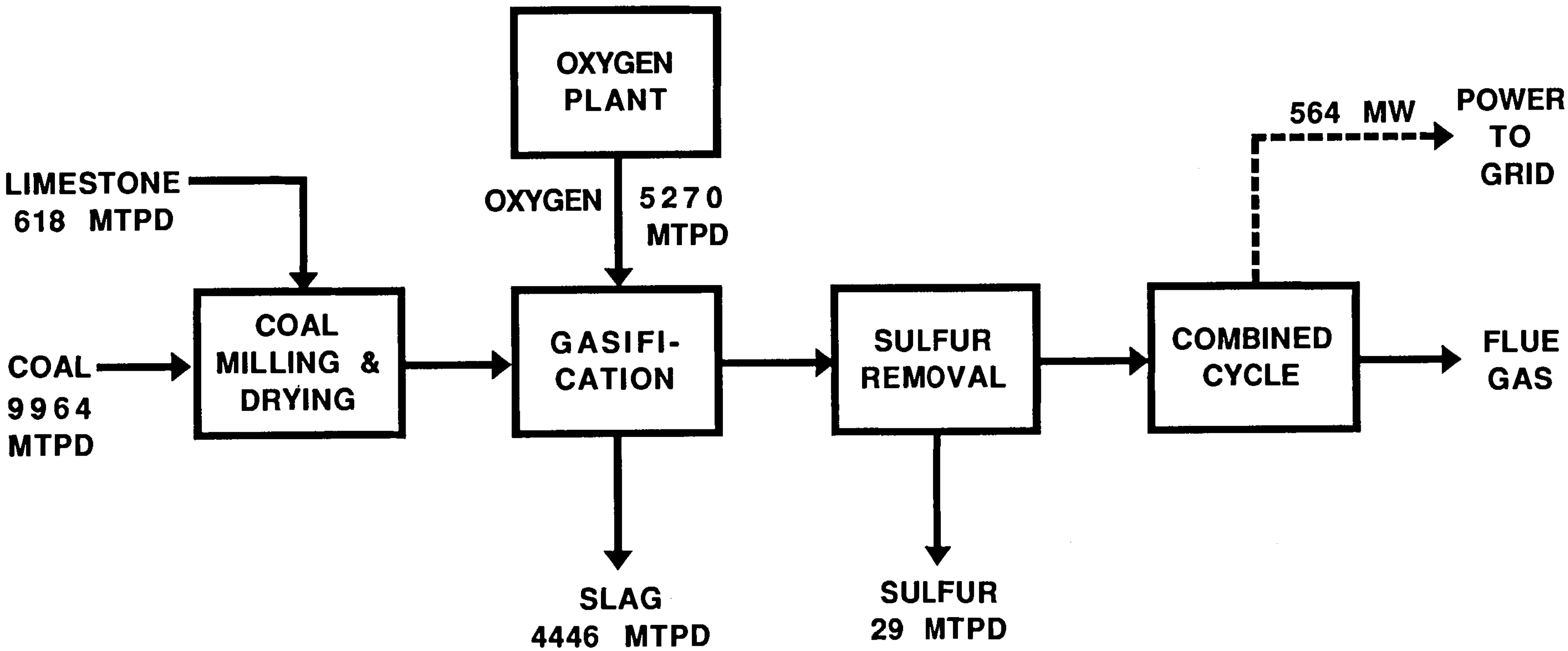

Figure 2-1 BLOCK FLOW DIAGRAM IGCC PLANT (SHELL CASE)

Four gasifiers with no spare are used. Each gasifier has a capacity of 2500 t/d. As the coal has a high ash content and the ash is highly abrasive, the coal milling unit has four operating and two spare trains and uses ball mills. Four air separation trains, each producing 1320 t/d oxygen at 98% purity, provide the necessary oxidant for the gasification process.

The raw gas produced is cooled to generate high pressure superheated steam, wet scrubbed to remove particulates, and sent for sulfur removal and recovery by a combined use of Sulfinol-M and Claus processes. The clean gas is then fed to the combined cycle plant.

The combined cycle plant has two trains. Each train consists of one gas turbine, one HRSG (heat recovery steam generator), and one steam turbine. The GE 9F gas turbine used is a 50 cycle version of the 7F gas turbine. This advanced gas turbine is selected to take advantage of the recent turbine efficiency improvement and to demonstrate the full potential of IGCC plant.

Steam injection is required in the gas turbine to control NOx emission. As IGCC plant is most likely to operate as a base load plant; no bypass damper is provided to allow single cycle operation. The HRSG uses a dual pressure design with maximum steam integration with the gasification plant. The steam turbine is a reheat turbine operated under 103 kg/cm2 a/538 C/538 C steam condition.

Facilities are also provided for coal receiving and handling, disposal of the gasifier slag, raw and cooling water supply, waste water treatment, electrical distribution, and other supporting facilities.

2.1.2 Texaco Case

A block flow diagram of this case is shown in Figure 2-2.

The coal is wet ground into -420 μ to form a slurry feed required for the gasifier. The slurry formed has a 68% solid concentration. Texaco elected to operate the gasifier at a higher temperature without limestone injection as the fluxing agent. This is to avoid further addition of mineral matter and minimize the amount of slurry water to be evaporated in the gasifier.

Due to the high ash content of the design coal and limited capacity of slag lockhopper valve currently available, Texaco chose to use seven gasifiers without spare and limit the capacity of each gasifier to 1800 t/d. Because of the large number of gasifiers used, Texaco further decided to use the quench instead of the waste heat boiler mode of operation in order to minimize the capital requirement.

The coal grinding and slurrying unit has seven operating trains without spare. Four air separation trains, each producing 1860 t/d oxygen at 98% purity, provide the necessary oxidant for the gasification process.

The quenched raw gas is cooled to generate low pressure steam, wet scrubbed to remove particulates, and sent for sulfur removal and recovery. The Texaco gas contains a significant amount of CO2. A highly selective process licensed by Dow (Gas/SPEC SS-2) is used for the sulfur removal to minimize the CO2 capture. As the acid gas produced is low in sulfur concentration, Parson's Selectox process is used instead of Claus

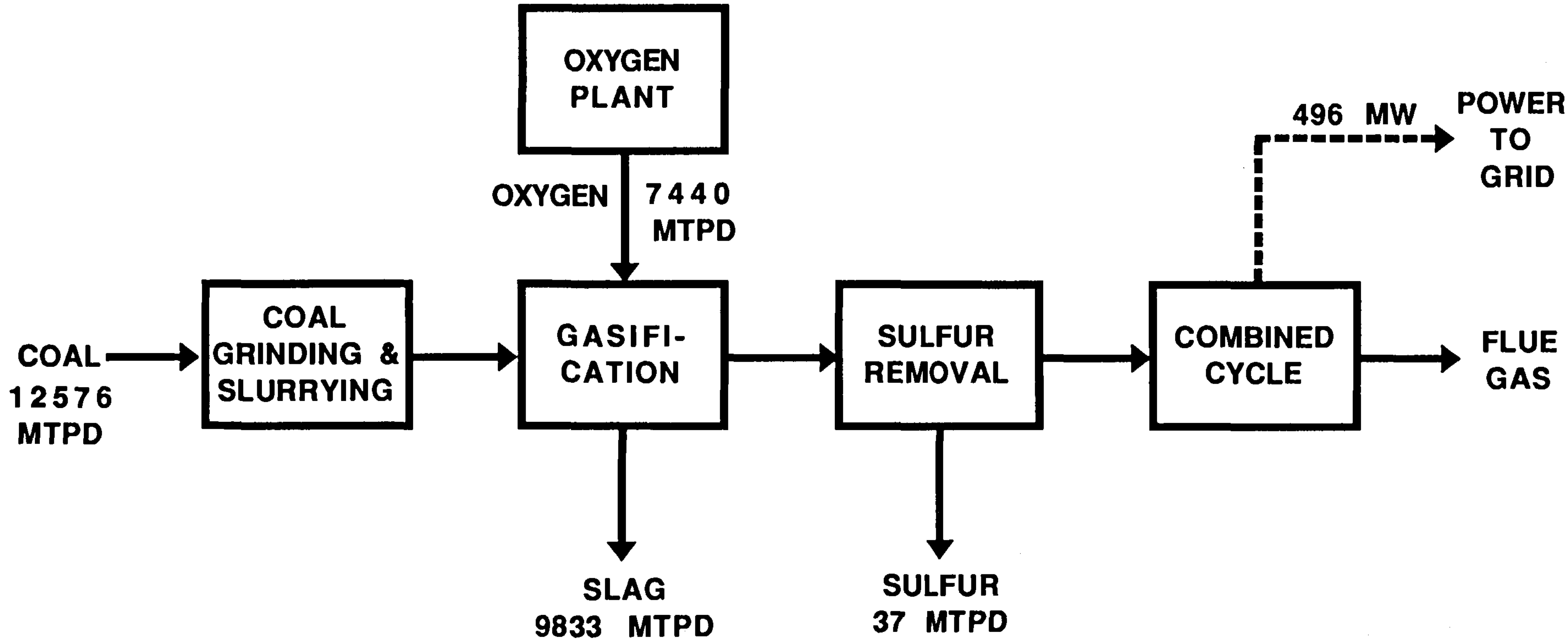

Figure 2-2 BLOCK FLOW DIAGRAM IGCC PLANT (TEXACO CASE)

for the sulfur recovery. The clean gas is then fed to the combined cycle plant.

The combined cycle design is very similar to that described above for the Shell case except no steam injection or fuel gas saturation is required for NOx control. The large amount of CO_2 in the fuel gas acts as a diluent in the turbine combustor to suppress the flame temperature and thus reduce the NOx formation.

2.1.3 KRW Case

A block flow diagram of this case is shown in Figure 2-3.

The coal is dried to 5% moisture and crushed to -6 mm before feeding to the gasifier. Air extracted from the gas turbine is boost compressed to provide the necessary oxidant for the gasification process. Six gasifiers without spare, each of 1500 t/d capacity, are used. The coal crushing unit has two trains, one operating and one spare.

Limestone is injected to the gasifier for in-bed sulfur capture. The raw gas produced is cooled down to 538 C by generating high pressure saturated steam. Hot gas cleanup based on ceramic filters is used to remove particulates before this fuel gas is fed to the gas turbines. Ash removed from the gasifier contains calcium sulfite (CaS) which is oxidized into disposable calcium sulfate in an ash sulfation unit.

The combined cycle design is very similar to that described above for the Shell case except no steam injection is required for NOx control. The large amount of N_2 in the fuel gas acts as a diluent in the turbine combustor to suppress the flame temperature and thus reduce the NOx formation.

2.1.4 Moving Bed Case

A block flow diagram of this case is shown in Figure 2-4.

As the moving bed gasifier has limited capability to consume coal fines, sized coal (6 to 50 mm) is assumed to be available at a premium price and can be fed to the gasifier without further preparation. Air is extracted from the gas turbine and the balance is drawn from a separate compressor. Both these streams are boosted to the required pressure and fed to the gasifiers. Process steam required for the gasification is drawn from the steam turbine and fed to the gasifiers along with the steam generated in the jacket of the gasifiers. Fourteen gasifiers without spare, each of 770 t/d capacity, are used.

The raw gas produced is cooled and scrubbed to remove particulates. Gas liquor condensed out during the cooling process is removed of tar and oil before it is sent for additional treatment. The tar and oil separated are used as fuel in a boiler to generate high pressure superheated steam for power generation.

Similar to the Texaco case, the moving bed gas contains a significant amount of CO_2. Therefore, the same sulfur removal and recovery processes used in the Texaco case are adopted for this case. The clean gas is then fed to the combined cycle plant.

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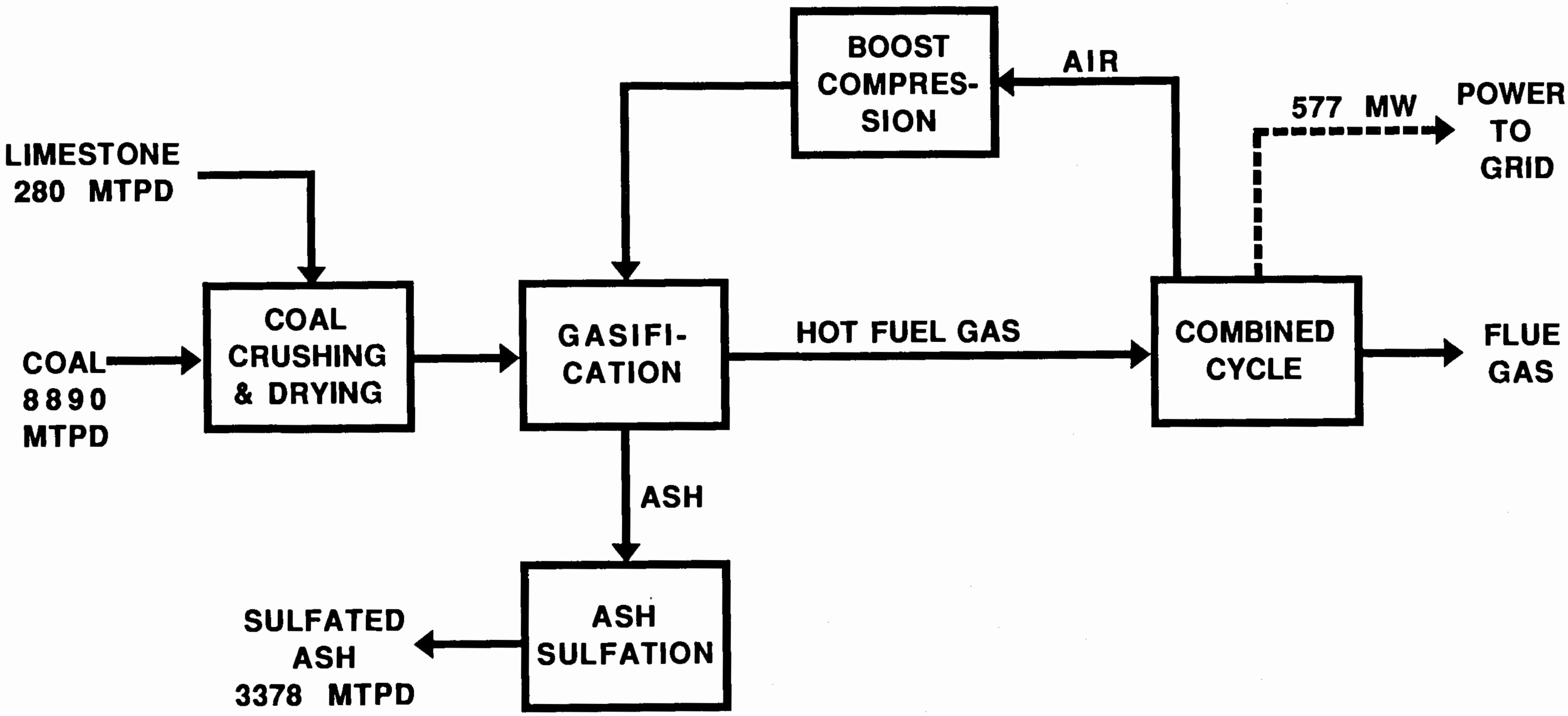

Figure 2-3 BLOCK FLOW DIAGRAM IGCC PLANT (KRW CASE)

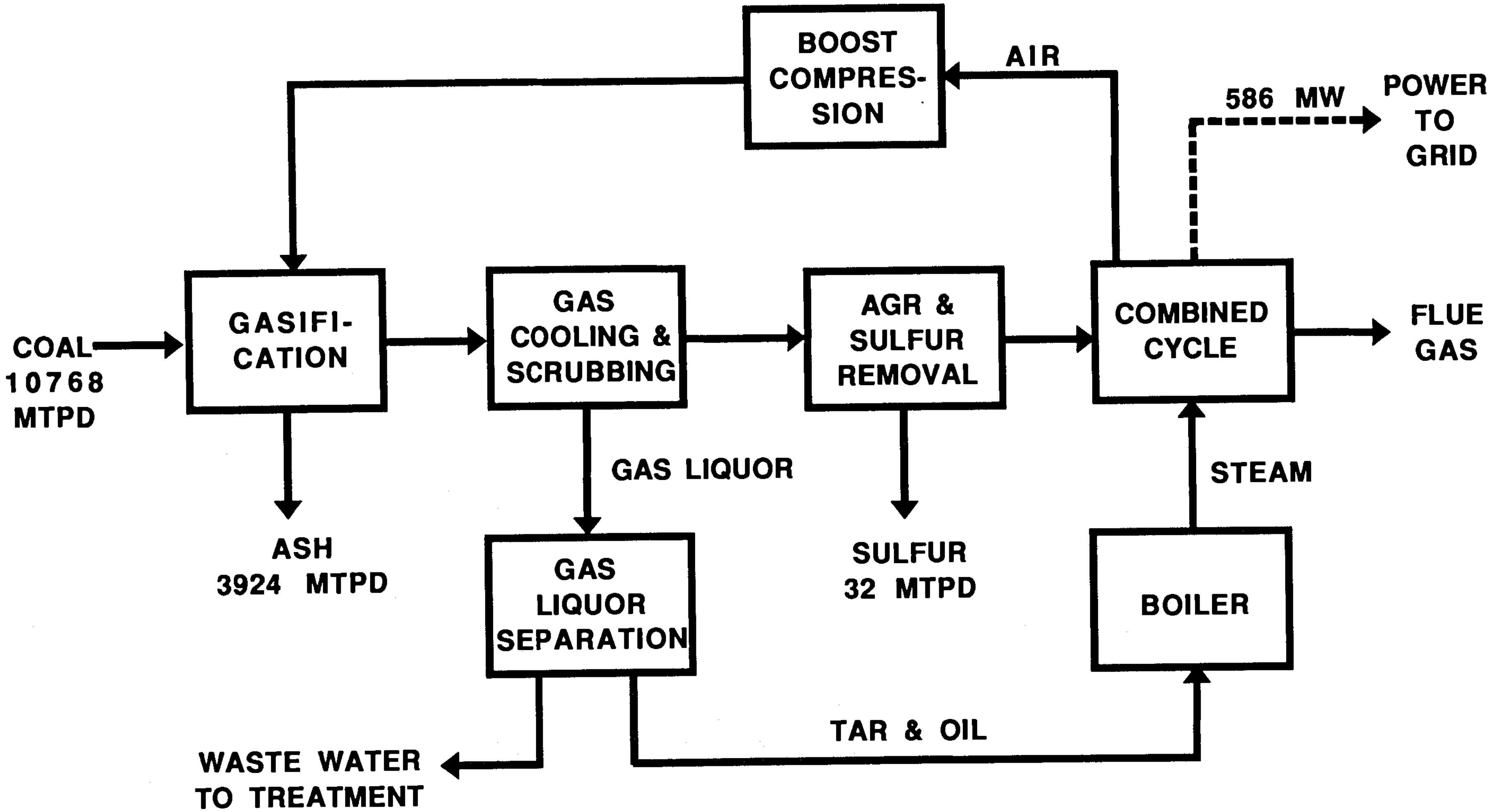

Figure 2-4 BLOCK FLOW DIAGRAM IGCC PLANT (MOVING BED CASE)

The combined cycle design is very similar to that described above for the Shell case. As in the Texaco case, the high CO_2 content of the fuel gas requires no steam injection or saturation for NO_x control.

2.1.5 Status of Different Gasification Technologies

Of the four gasification processes considered in the present study, a 250 t/d plant based on Shell process has been in operation in Deer Park (near Houston in the United States), and a 250 MW IGCC plant is being installed in the Netherlands. A number of gasification plants based on Texaco process have been in operation for the production of fertilizers, methanol, and oxo-chemicals in the United States, Germany, and Japan. The 100 MW IGCC plant in Cool Water, California is also based on this process. No large scale plants have been set up based on KRW process. A PDU was set up at Waltz Mill (near Pittsburgh in the United States) but it has now been dismantled. Commercial scale moving bed gasifiers are in operation in many countries for the production of fuel gas and synthesis gas. Around 200 gasifiers have been set up based on the moving bed process, and the 170 MW IGCC plant operated at Luenen, Germany, during 1972-1977 was the first IGCC demonstration plant in the world.

2.2 COMPARISON OF IGCC AND PC PLANTS

2.2.1 Performance Comparison

Summarized in Table 2-1 are the plant resource requirements, power outputs, heat rates, and efficiencies for the four IGCC cases in comparison with a PC plant both with and without FGD (Flue Gas Desulfurization). Data for the PC plant were extracted from a recent 2x500 MW design conducted by National Thermal Power Corporation, Ltd (NTPC) for the same coal feedstock and plant location.

Figure 2-5 shows the relative heat rates among all the cases with PC plus FGD as the base.

Comparison Among IGCC Technologies

Table 2-1 indicates that the Texaco case consumes substantially more coal and has a higher heat rate than other three IGCC cases. This is because the slurry feed system of the Texaco gasifier suffers severe thermal penalty when a high ash coal is used. Another reason is that Texaco chose to use the quench operating mode for the gasifier as discussed above. It is estimated that if the waste heat boiler mode is used, the heat rate can be improved by 20%.

In future studies, coal washing should be considered for the Texaco gasifier. The washing directly increases the gasifier thermal efficiency. It also removes the capacity bottleneck caused by the ash lockhopper valve. Only with washed coal, can Texaco be competitive with other gasifiers.

The moving bed case has a better heat rate than the Texaco case. But this heat rate is higher than those of the Shell and KRW cases. This is because the moving bed case requires a large quantity of steam injected to the gasifier to avoid ash clinkering.

The KRW case has the best heat rate among all cases. The major reasons are:

- o The gasifier is operated at low temperature and thus has a relatively high cold gas efficiency

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Table 2-1

PLANT PERFORMANCE COMPARISON

	IGCC Plant				PC Plant	
	Shell	Texaco	KRW	Moving Bed	No FGD	With FGD
Plant Resources Requirements						
Coal (as received), MTPD	9,964	12,576	8,890	10,768	10,886	10,886
Limestone, MTPD	618	0	280	0	280	280
Raw Water, m3/h	1,324	2,224	1,019	1,698	2,754	3,000
Plant Output, MW						
Gross Power Generated						
Gas Turbine	392.2	396.5	350.4	368.3	0.0	0.0
Steam Turbine	308.4	258.0	280.2	271.8	600.0	600.0
Total	700.6	654.5	630.6	640.1	600.0	600.0
In-Plant Power Consumption	136.2	158.3	53.4	54.4	42.0	51.0
Net Power to Grid	564.4	496.2	577.2	585.7	558.0	549.0
Heat Rate, Kcal/kwh						
HHV Basis	2,451	3,519	2,138	2,514	2,708	2,753
LHV Basis	2,330	3,345	2,033	2,427	2,575	2,617
Overall Thermal Efficiency, %						
HHV Basis	35.1	24.4	40.2	34.2	31.8	31.2
LHV Basis	36.9	25.7	42.3	35.4	33.4	32.9
Sulfur Byproduct, MTPD	29	37	0	32	0	0

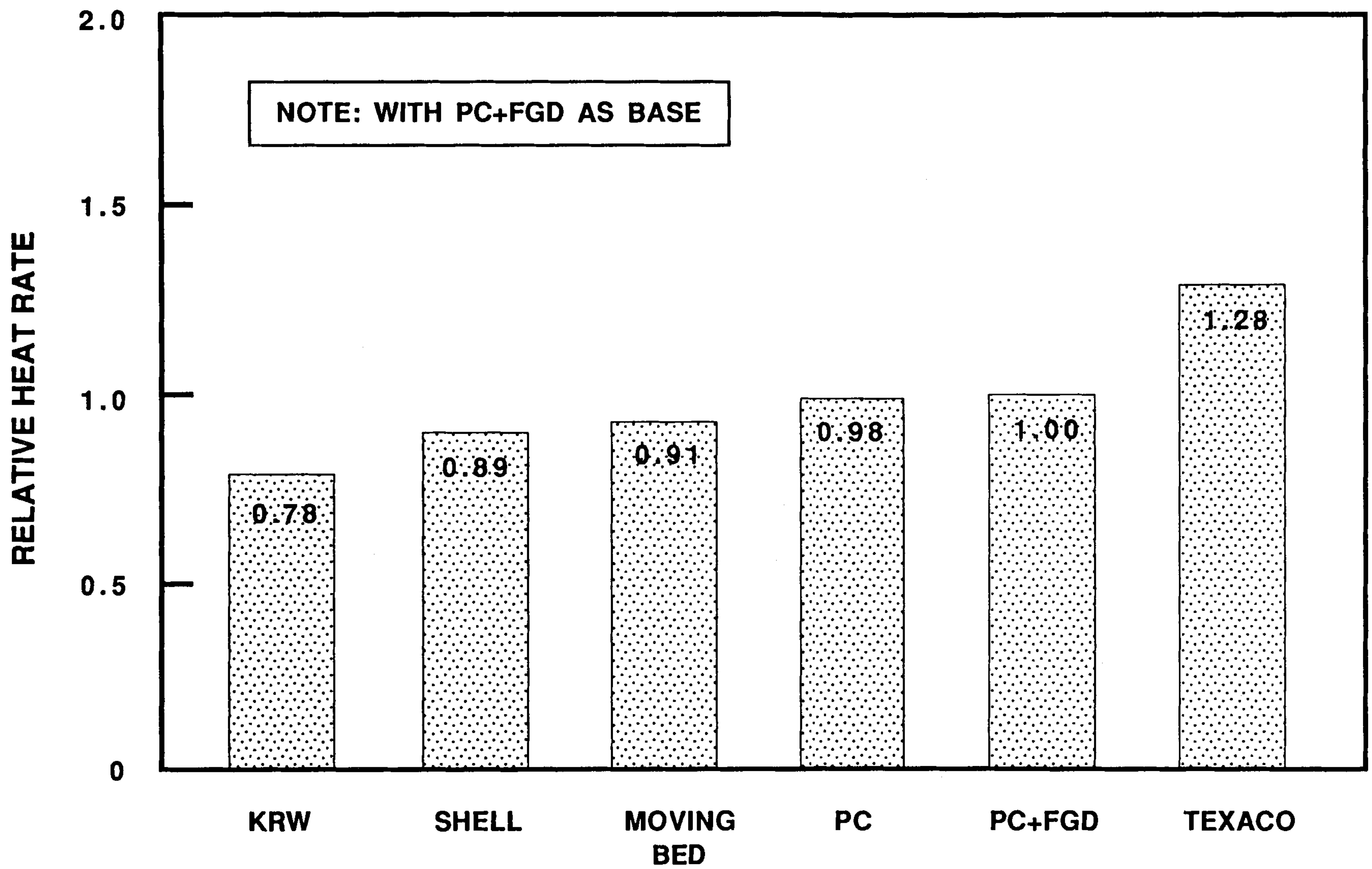

Figure 2-5 RELATIVE HEAT RATE

- o The gasifier uses in-situ sulfur capture
- o The gasifier uses hot gas cleanup for particulates removal
- o There is air integration between the gasifier and gas turbine.

Comparison with PC Plants

Figure 2-5 shows all the IGCC technologies except the Texaco case have better heat rates than the PC plant. The difference between the KRW case and PC plant is quite substantial.

All the IGCC plants use less water than the PC plant as shown in Table 2-1.

2.2.2 Cost Comparison

Summarized in Table 2-2 are the capital requirements and costs of generation for the four IGCC cases in comparison with a PC plant both with and without FGD. The capital requirements include plant cost, engineering and fees, and owner's cost.

Figure 2-6 shows the relative capital requirements with PC plus FGD as the base. A similar chart for the costs of generation at 5500 h/y operation is shown in Figure 2-7.

Bechtel developed the costs under U.S. conditions for the first three IGCC cases, and the Indian study team translated them into India conditions by adjusting the labor rate and productivity and applying the necessary sales taxes, custom fees, and shipping costs. The Indian team developed directly the cost for the moving bed case. Costs for the PC plant were estimated based on the same NTPC design mentioned above but scaled down to a 600 MW capacity level in order to be consistent with the IGCC cases.

The cost of power generation was calculated based on a standard operating cost estimate procedure and project financing structure used in India.

Comparison Among IGCC Technologies

The Shell case has a very high capital requirement. This is because it has a very high operating temperature and requires very large and expensive waste heat boilers. The Texaco case, even though it requires no syngas cooler as a result of the quench operation, has about the same capital requirement as the Shell case because its lower plant efficiency requires substantially more coal to be processed.

The moving bed case has a lower capital requirement than the Shell and Texaco cases because (1) it is air blown without the requirement of an expensive air separation plant and (2) the low product gas temperature from the gasifier resulting from the countercurrent flow reactor used minimizes the waste heat recovery requirement. The KRW case has the lowest capital requirement because it operates at low temperature, uses in-bed sulfur capture and hot gas cleanup, and has no air separation plant.

Comparison with PC Plants

Figures 2-6 and 7 indicate that all the IGCC cases are more capital

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Table 2-2

COST COMPARISON
(4th Q, 1989 Pricing)

	IGCC Plant				PC Plant	
	Shell	Texaco	KRW	Moving Bed	Without FGD	With FGD
Net Power Output, MW	564.4	496.2	577.2	585.7	558.0	549.0
Total Capital Required, Rs Crores	2,055	2,059	1,460	1,529	1,065	1,278
Unit Capital, Rs/kW Net	36,418	41,500	25,292	26,103	19,084	23,276
Cost of Generation, Paise/kwh						
@ 5500 h/y operation	146.0	170.2	103.8	115.5	86.7	102.2
@ 6000 h/y operation	135.4	158.1	96.5	107.6	81.4	95.6
@ 7000 h/y operation	118.8	139.2	85.0	95.3	73.0	85.4
@ 7400 h/y operation	113.4	133.0	81.3	91.3	70.3	82.1

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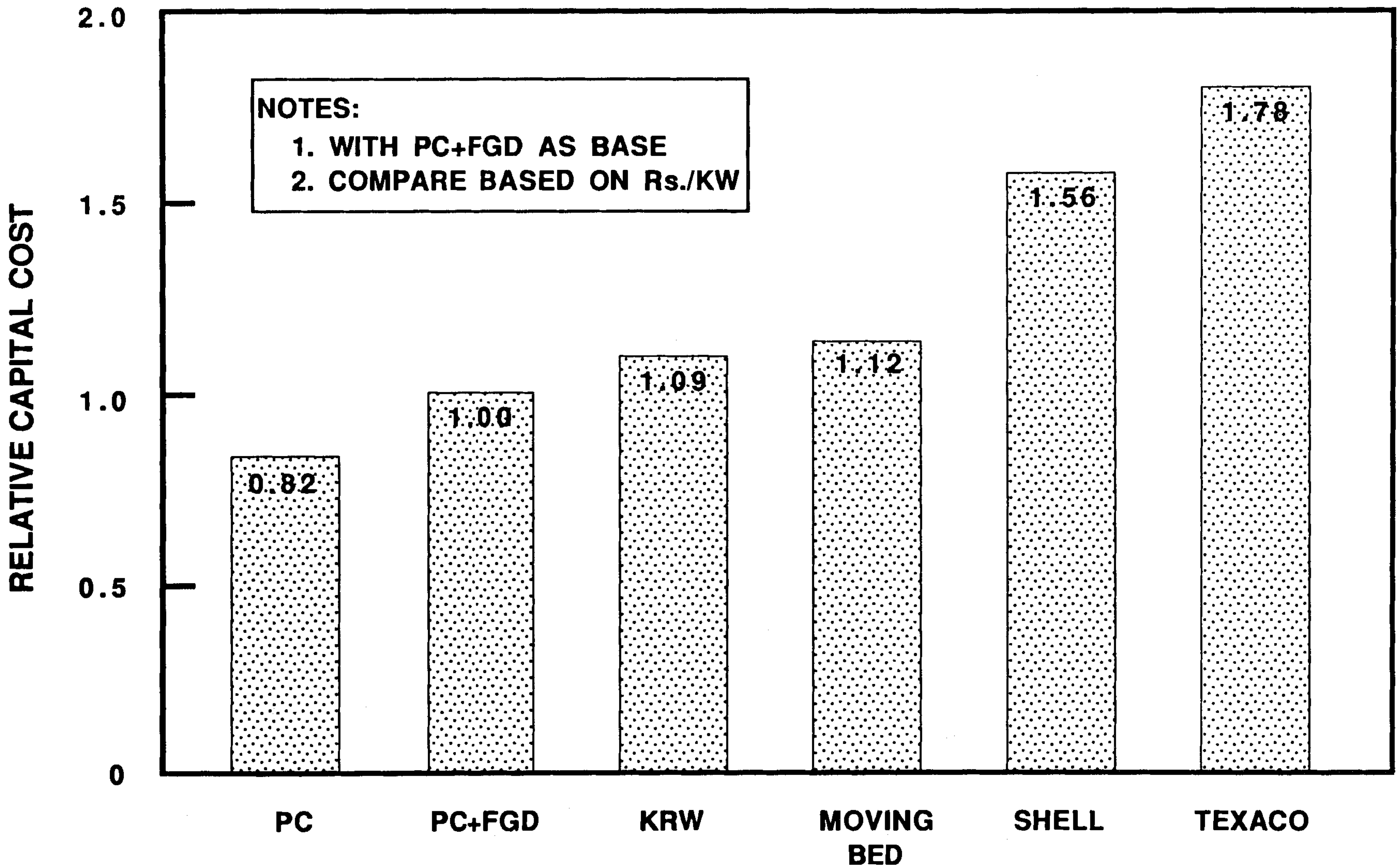

Figure 2-6 RELATIVE CAPITAL COST

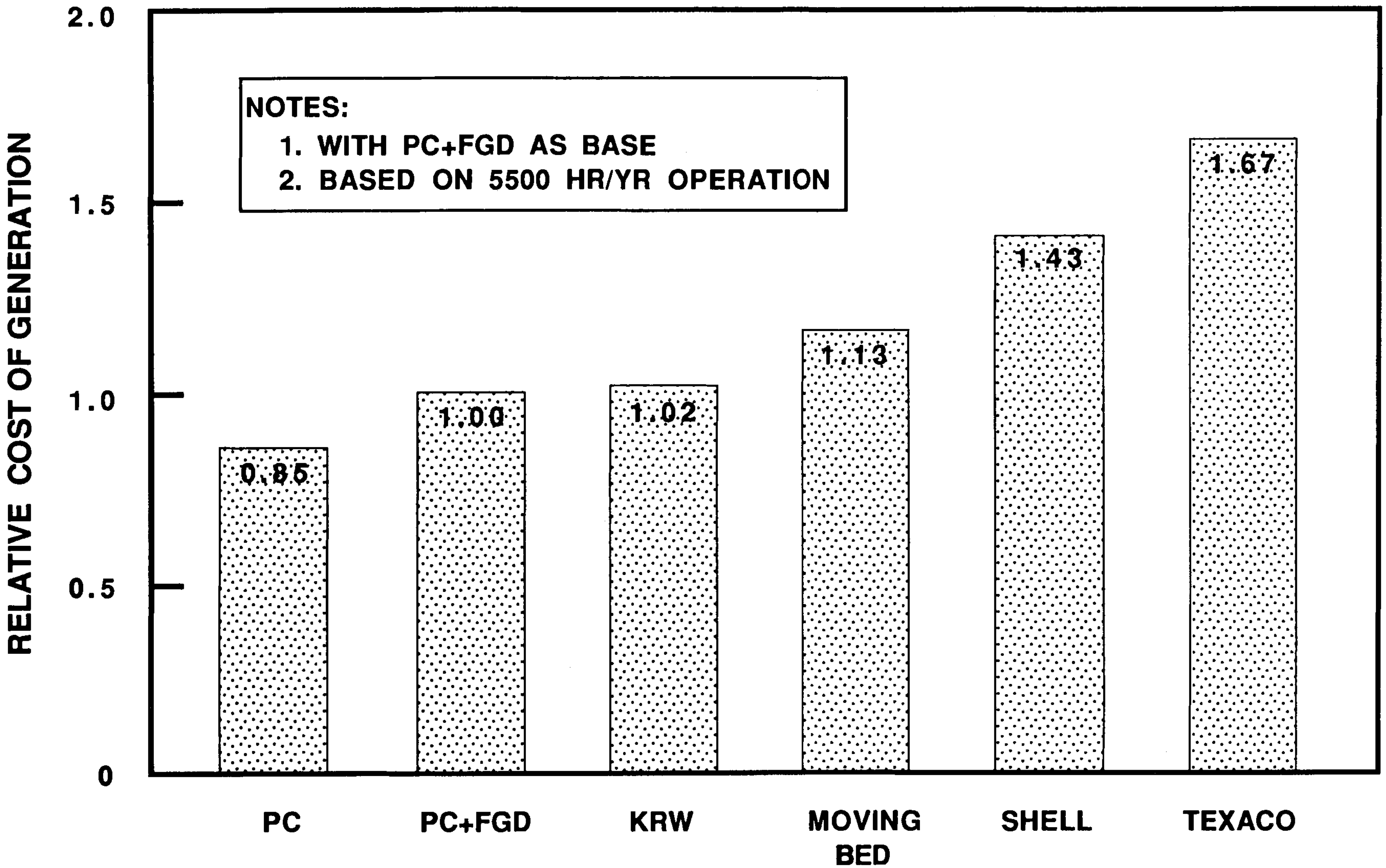

Figure 2-7 RELATIVE COST OF GENERATION

intensive and have higher costs of generation than the PC plant without FGD. The KRW and moving bed cases are, however, cost competitive with the PC plant with FGD.

In Table 2-2, the costs of generation are compared at four levels of plant operation hours. As most of the IGCC cases are thermally more efficient than the PC plant, the differences in cost of generation between IGCC and PC reduce as plant operation hours increase.

As IGCC plant usually consists of multiple trains in both the process and power blocks, it is expected to have a higher plant availability than the PC plant. A preliminary availability analysis conducted in this study indicates the present IGCC plant design can achieve 85% availability or about 7400 h/y plant operation. At this operating level, the cost of generation in the KRW case is actually lower than that of the PC plant without FGD if the PC plant is operated less than 6000 h/y.

2.2.3 Conclusions

This study shows IGCC is a viable power generation option for the high ash Indian coal. In comparison with PC plant, it has superior heat rate at comparable cost of generation. In addition to the better heat rate, IGCC also offers lower emissions, less water consumption, higher plant availability, and flexibilities for modular construction and phased construction. Therefore, IGCC can be an attractive power generation alternative in the future for India.

Among the four IGCC technologies, the KRW gasifier or similar fluidized bed gasification processes, such as U-Gas, is most attractive to use for the high ash Indian coal.

The KRW gasifier, however, has several technical uncertainties. This gasifier has been proven only on a pilot scale. The in-bed sulfur capture and hot gas particulates removal have been tested but only with limited experience. The ability to achieve a high CaS conversion in the ash sulfation unit has not been demonstrated.

The moving bed gasifier, on the other hand, is commercially proven and has been tested for Indian coal. Even though it is less efficient and more costly than the fluidized bed technology, it is considered equally attractive to use for the high ash Indian coal.

The Shell technology has an attractive heat rate and is very close to commercialization. But as it has a very high capital requirement, it probably does not warrant further consideration.

Because of the severe penalties imposed by its slurry feed system on both the heat rate and capital cost, the Texaco technology is not recommended.

2.3. IGCC DEMONSTRATION/COMMERCIALIZATION PLAN IN INDIA

The first step in India's commercialization plan of IGCC is to build a demonstration plant. The target date to fully demonstrate the technology is currently set for 1995. The Government of India has a budget provision in the 8th Five Year Plan for the demonstration plant.

Several potential sites for the demonstration plant have been screened and evaluated. The final site selected is the Delhi Electric Supply Undertaking (DESU) Indraprastha Power Station. This power station currently has six natural gas fired GE 6B gas turbines (30 MW each) in simple cycle operation. A plan has been initiated to convert them to combined cycle operation by adding HRSG and steam turbine facilities. For the demonstration project, one of the gas turbines will be retrofitted with coal gas from an ash agglomerating fluid bed gasifier.

In addition to the gas turbine units, the Indraprastha Power Station also has several PC units producing 278 MW power in total. The existing coal receiving, handling, storage, and primary crushing facilities can be used for the gasifier. The demonstration plant can also take advantage of existing infrastructures in the power station to minimize the capital requirements. The total capital required was estimated to be 89 Rs crores.

Potential users of IGCC in India include NTPC, various state electricity boards, captive power plants, and small power generation units in private sectors. The first few applications probably will be in the private sector, particularly those plants burning high cost fuels. Therefore, the initial market would be for retrofitting.

Section 3

STUDY BASES

This section presents the plant design bases. The cost estimate bases and economic analysis criteria are discussed in Sections 5 and 6.

3.1 SITE DATA

3.1.1 Location

The plant is at a mine mouth site in the Piparwar block of North Karanpura coal field (Figure 3-1). It is situated in the Hazaribag District of Bihar State in eastern India. The Damodar River flows through the southeastern boundary of the Piparwar block.

3.1.2 Elevation

The site is generally flat. The average elevation is 457.2 m above MSL (409 m minimum and 464 m maximum).

3.1.3 Seismic Zone

The site is in seismic zone 2.

3.1.4 Ambient Temperature and Pressure

The maximum temperature in the summer is 50 C. The minimum temperature in winter is 1C. The average temperature is 29.5 C and will be used as the design dry bulb temperature. The design wet bulb temperatures is 27 C. The corresponding relative humidity is 80%.

The ambient pressure is 720 mm Hg.

3.1.5 Wind Pressure

The wind pressure as a function of height is as follows:

Height, m	Wind Pressure, kg/cm^2
0-30	150
50	167
100	191
150	207

3.1.6 Land Availability

There is no land availability problem at the proposed plant site.

3.1.7 Rainfall

Average monthly rainfall during the monsoon (June to October) is 198.87 mm. The daily rainfall in the wettest month (August) is 19.55 mm. The maximum daily rainfall recorded is 249.2 mm on June 24, 1911.

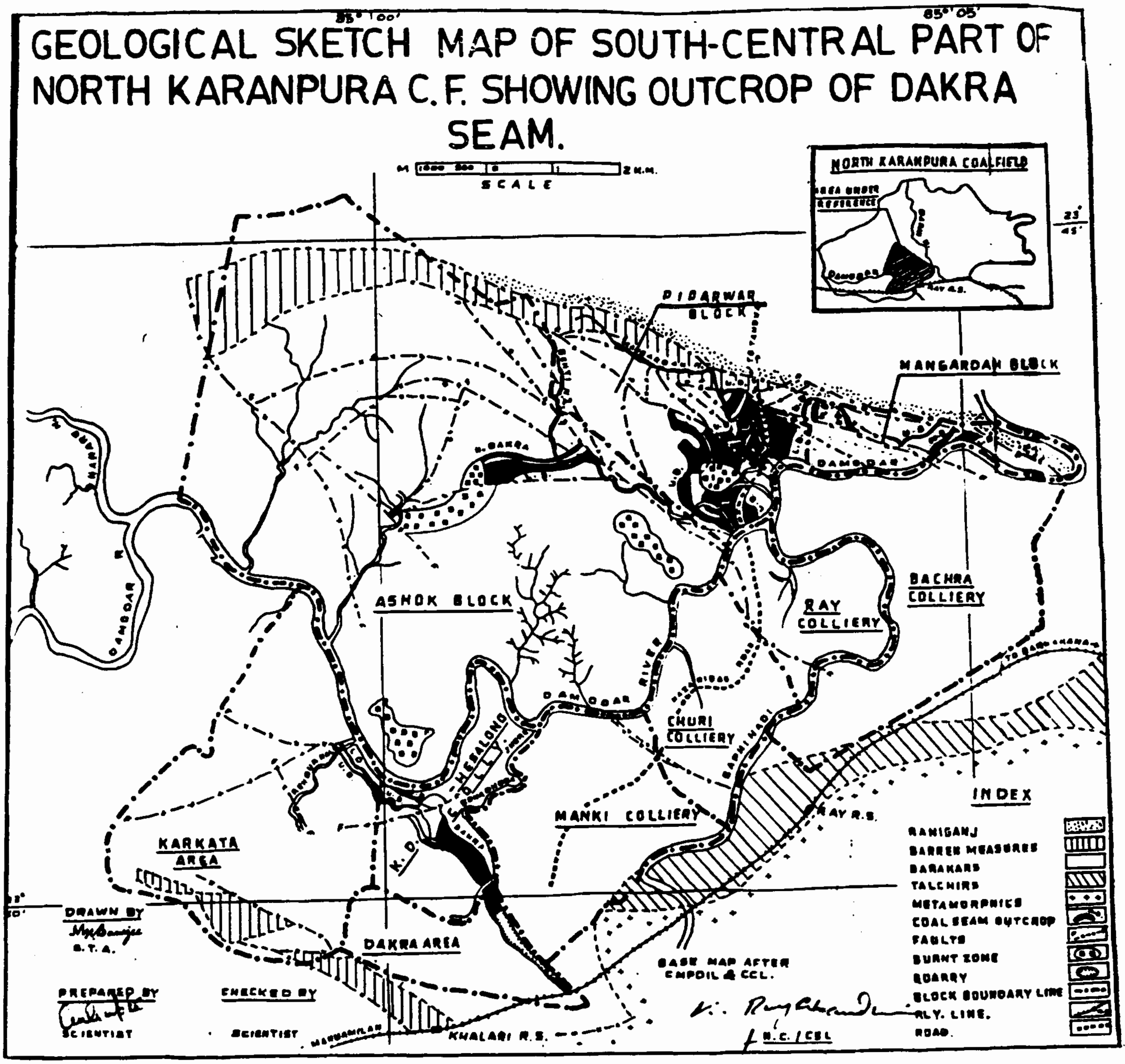

Figure 3-1 Plant Location Map

3.1.8 Soil Condition

The soil consists of hard moorum and weathered rock up to 17-20 m underlain by hard rock. Piling is normally not required.

3.1.9 Existing Infrastructure

The site is connected by a metalled road with Hazaribag. The Barkakana-Barwadih line of the Eastern Railway is 15-20 km from the site.

3.1.10 Water Availability and Quality

Raw water is available from the Damodar River. The water quality is as follows:

pH	7.2-7.3
TSS, mg/l	15-185
TDS, mg/l	100-130
BOD_5 at 20 C, mg/l	0.5-0.9
COD, mg/l	74-82
Chloride, mg/l	28
Nitrate (as N), mg/l	0.2-0.26
Sulphate (as SO_4), mg/l	14-68
Flouride (as F), mg/l	0.2-0.5

3.1.11 Limestone Availability and Characterisation

Limestone is available locally for the power plant use and will be delivered to the plant by truck. The limestone has the following composition (after calcination):

	wt%
CaO	41-45
MgO	3-5
SiO2	7-9
Al2O3	2-3

3.2 **COAL RESOURCE DATA**

The design coal is a high ash, noncaking, unwashed, run-of-mine coal from open cast mining of the Dakra seam in North Karanpura coal field. It is delivered to the power plant through a merry-go-round rail system. The delivered coal has the following properties.

3.2.1 Proximate Analysis and Calorific Value

	As Received, wt%	Dry Basis, wt%	Dry, Ash Free, wt%
Moisture (a)	18.0	--	--
Mineral Matter			
Ash	34.8	42.5	--
Crystal Water	3.5	4.3	--
CO_2 in Carbonates	0.5	0.6	--
Volatile Matter	17.1	20.8	44.6
Fixed Carbon	26.1	31.8	55.4
Total	100.0	100.0	100.0

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Calorific Value, Kcal/kg			
HHV	3 332	4 058	7 715
LHV	3 168	3 857	7 333

(a) The residual moisture after air drying is 5.8 wt% measured at 60% relative humidity and 40 C.

3.2.2 Ultimate Analysis

	As Received, wt%	Dry Basis, wt%	Dry, Ash Free, wt%
Moisture	18.0	--	--
Mineral Matter			
Ash	34.8	42.5	--
Crystal Water	3.5	4.3	--
CO_2 in Carbonates	0.5	0.6	--
C	35.8	43.6	82.9
H	2.1	2.5	4.8
N	0.8	0.9	1.8
S	0.3	0.4	0.7
O	4.2	5.2	9.8
Cl	trace	trace	trace
Total	100.0	100.0	100.0

3.2.3 Caking Properties, Grindability, and Size Consist

The coal has a swelling index of 0 and its LTGK coke is classified as type A.

The Hardgrove grindability is 45.

The coal received has a 200 mm top size. The fines (less than 6 mm) content is 25-35%.

3.2.4 Carbonisation Assay

The Gray King low temperature carbonization at 600 C produces the following assay:

Coke, kg/tonne dry coal	788.8
Tar, litre/tonne dry coal	70.6
Liquor, litre/tonne dry coal	75.9
Ammonia, kg/tonne dry coal	1.2
Gas, Nm^3/tonne dry coal	72.8
Oil Point, C	400
Gas Point, C	380

3.2.5 Ash Fusion Temperatures

The coal has very high ash fusion temperatures. Under mildly reducing atmosphere, the initial deformation temperature is 1400 C. The hemispherical and flow temperatures are above the 1500 C measuring limit. Under oxidizing atmosphere, all the three ash fusion temperatures are above 1500 C.

3.2.6 Ash Analysis

	Mean, wt%	Range, wt%
SiO_2	59.4	56.8-59.8
Al_2O_3	29.1	28.0-31.7
Fe_2O_3	4.1	4.5- 5.6
TiO_2	2.2	1.8- 2.8
P_2O_5	0.5	0.5- 0.8
SO_3	0.2	trace-0.6
CaO	1.1	1.4- 2.2
MgO	0.8	1.0- 1.8
Na_2O	0.3	0.2- 1.9
K_2O	1.1	0.2- 1.9
Unaccounted	1.2	
Total	100.0	

3.3 **PLANT OPERATION REQUIREMENTS**

3.3.1 Plant Size and Operating Life

Both the IGCC plant and PC plant are to be designed for approximately 600 MW net power output. In the IGCC case, this is equivalent to using two General Electric MS9001F (9F) gas turbines. The gasification unit is to be sized to fully load the gas turbines at the 29.5 C average ambient temperature with an additional 5% margin on throughput.

The plant operating life requirement is 25 years.

3.3.2 Sparing Requirement

The plant will be spared to achieve an overall plant availability of 85%.

3.3.3 On-Site Storage Requirement

Since the plant is at mine mouth, dead storage of coal is not necessary. The live storage requirement is 15 days of coal consumption.

Any sulfur byproduct will be produced, stored, and trucked out in solid form (block) for sale.

3.3.4 Alternate Fuel

No natural gas or fuel oil is to be used as alternate fuel for the IGCC plant. However, fuel oil is available as startup fuel.

3.3.5 Plant Cooling

Due to the site high ambient temperature, air cooling is not cost effective. Water cooling based on mechanically induced draft cooling tower will be used. The design cooling water supply temperature is 33 C. The cooling tower will use 5 cycles of concentration.

3.3.6 Electrical Distribution

Electrical power is to be generated at 16-17 kV at 50 Hz with a tolerance of -5% to +3% on frequency. For distribution, the voltage is to be stepped up to

220 kV. On-plot power consumption will be 0.4 kV for drivers less than 150 kW, 6.6 kV for drivers over 150 kW.

3.3.7 Stack Height and Other Structure Limitation

The stack height is to be 32 m or 1.25 times the height of the tallest structure in the plant, whichever is greater.

3.4 ENVIRONMENTAL REQUIREMENTS

3.4.1 Air Emission

Current air emission standards in India (in micrograms/Nm^3 ambient air at a distance of 20 times the height of stack) are:

	Industrial Area	Resd. & Rural Area	Sensitive Area
SO_2	120	80	30
NOx	120	80	30
Particulates	500	200	100

These standards can not be applied without an extensive dispersion modelling effort which is beyond the current study scope. Therefore, the following point of source emission limits are adopted for this study:

Particulates	150 mg/Nm^3 at stack discharge
NOx	75 ppmv at 15% oxygen
Sulfur	minimum 70% removal

3.4.2 Water Discharge

The water discharge limits are:

pH	5.5-9
TSS, mg/l	100
BOD, mg/l	30
COD, mg/l	250
Oil and Grease, mg/l	10
Phenolic, mg/l	1
Cyanide, mg/l	0.2
Sulfide, mg/l	2

3.4.3 Solids Waste Disposal

No on-site solids waste disposal is to be provided. All the wastes are to be slurried or trucked to an off-site disposal area.

3.4.4 Noise Limitation

The noise limits are 85 dbA at 1 m from equipment and maximum 90 dbA in very special cases.

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Section 4

TECHNOLOGY SELECTION CRITERIA

This section presents the technology selection rationale and design considerations for both the process and power generation facilities of the IGCC plant.

4.1 PROCESS AREA

4.1.1 Gasifier Selection

To select the proper gasifiers for study, Bechtel has screened five gasification processes as shown in Table 4-1.

These five processes represent the state of the art of gasification technology. They have been demonstrated either on a commercial scale or large pilot plant scale.

For each process, Bechtel has inquired of the respective process developer their willingness to provide a process package for this study, whether they require coal samples for characterization and coal test, their experiences with Indian coal, secrecy agreement requirements, and willingness to participate in the IGCC demonstration plant in India.

Dow indicated they would participate in this study only if washed coal is used. The mineral matter in Indian coal is intrinsically mixed with carbonaceous matter and is very difficult to be removed by washing. As this study is mainly interested in using raw coal, the Dow gasifier was not further considered.

British Gas and Lurgi indicated that the high ash content in Indian coal was not acceptable for the BGL gasifier. They recommended to consider their dry bottom Lurgi or CFB (circulating fluid bed) gasifier.

The CFB gasifier is still in the early developing stage and was not further considered. The dry bottom Lurgi gasifier is a viable candidate. But as India is developing their own Lurgi-type moving bed gasifier, it was decided the Indian team will provide the design and cost estimate for this gasifier.

The remaining three gasifier developers (Texaco, Shell, and KRW) all showed interests to participate. These three gasifiers and the moving bed gasifier constitute the four IGCC study cases.

4.1.2 Design Considerations of Shell Gasifier

Due to the high ash content of Indian coal and abrasiveness of the ash, the choice of coal grinding mill is a major design consideration for the Shell gasifier.

A roller mill or a bowl mill can not survive this very abrasive service. A rod mill is not applicable because it gives a coarser particles than what is required. A ball mill was selected for this study.

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Table 4-1

GASIFIER SELECTION

	TEXACO	SHELL	KRW	DOW	BGL
CONTACT	BILL PRESTON	F. SCHRIJVERS	M. BLINN	D. SUNSTROM	B. THOMPSON
WILLING TO PROVIDE PROCESS PACKAGE	YES	YES	YES	NO	NO
PROCESS PACKAGE DELIVERY SCHEDULE	4-6 WEEKS	6-12 WEEKS	6 WEEKS	--	--
REQUIRE COAL TEST	NO	NO	NO	--	--
REQUIRE COAL SAMPLE	NO	NO	NO	--	--
EXPERIENCE WITH INDIAN COAL	YES (30% ASH)	NO	NO	--	--
REQUIRE SECRECY AGREEMENT WITH INDIA	NO	NO	NO	--	--
REQUIRE SECRECY AGREEMENT WITH BECHTEL	NO	NO	NO	--	--
WILLING TO PARTICIPATE DEMONSTRATION PLANT	FEEL NOT NECESSARY	FEEL NOT NECESSARY	YES	--	–
COMMENTS			AIR BLOWN, HOT GAS CLEANUP	WILLING TO DO FOR WASHED COAL	ASH LEVEL NOT ACCEPTABLE, RECOMMEND DRY BOTTOM & CFB

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4.1.3 Design Considerations of Texaco Gasifier

The Texaco gasifier can be operated either under a waste heat boiler mode or a quench mode. The waste heat boiler mode requires more capital and is less reliable to operate but it provides a better heat rate for the IGCC plant.

With the high ash content of Indian coal and limited capacity of the slag lockhopper valve currently available, a large number of gasifiers is required (7 units in total). Due to the loss of economy of scale, the cost penalty of using waste heat boiler is further compounded. Based on this consideration, Texaco has chosen to use the quench mode.

This choice, however, leads to a very poor heat rate for the Texaco case. This is discussed in detail in Section 5.2.1.

The Texaco gasifier is penalized thermally by the coal high ash content more than other gasifiers due to the slurry feed system used. To avoid further increase of mineral feed to the gasifier, Texaco has elected to operate the gasifier at a very high temperature without limestone addition as a fluxing agent.

Even without limestone addition, the thermal penalty remains to be very severe. As concluded in Section 5.2.1, the Texaco gasifier can become competitive only when the coal is washed first to reduce ash content.

4.1.4 Design Considerations of KRW Gasifier

The KRW gasifier used in this study is an air-blown gasifier with limestone injection for in-bed sulfur capture. The air is extracted from the compressor of the gas turbine. Hot gas cleanup based on ceramic filter is used for particulates removal from the product gas. The gas is delivered to the gas turbine at 538 C.

This process scheme was chosen because it gives the best performance and lowest cost based on KRW's past experience. Many of the process concepts involved in this scheme, however, are not commercially proven and face many technical uncertainties. They are discussed in more details in Section 5.4.2.

4.1.5 Design Considerations of Moving Bed Gasifier

The moving bed gasifier used in this study is an air-blown gasifier having 3.7 m ID with a gas generation capacity of about 60,000 Nm^3/h. Sized coal (6-50mm) delivered from the mines is the feed to the gasifiers. Around 83% of the air requirement is met by the air extracted from the gas turbine and the rest from an auxiliary compressor. About 42% of the process steam is extracted from the HP-stage of the steam turbine and is mixed with the MP steam generated in the jacket of the gasifier.

Preheating of the clean fuel gas from the acid gas removal unit to 145 C is done in a gas-gas heat exchanger by cooling the crude gas to 146.5 C from 155 C.

Tar and oil produced during the gasification are used to raise steam in auxiliary boilers, which is, in turn, used to produce additional power in steam turbines.

Excess gas-liquor separated from the condensate streams is subjected to air-stripping for removal of ammonia followed by biological treatment for removal of phenols. The stripped ammonia is absorbed in dilute sulphuric acid producing ammonium sulphate as a useful by-product.

4.1.6 Acid Gas Removal and Sulfur Recovery

The Texaco gas contains a significant amount of CO_2. As a result, a highly selective acid gas removal process licensed by Dow (Gas/SPEC SS-2 process) was chosen to minimize the CO_2 removal and maximize the gas turbine gas flow.

The Shell gas, in comparison, has a very low CO_2 content. A less selective process (Sulfinol-M process) was chosen for the acid gas removal.

In the Shell case, the acid gas produced has sufficient sulfur concentration to use a Claus unit for sulfur recovery. In the Texaco case, the sulfur concentration is too low to sustain sulfur combustion in the Claus unit and the Selectox process licensed by Parson was selected for the sulfur recovery. The Selectox process conducts sulfur combustion catalytically at reduced temperature to permit the use of diluted feed.

The KRW gasifier uses in-bed sulfur capture. There are no acid gas removal and sulfur recovery facilities required for this case.

For the moving bed case, the sulfur concentration in the gasifier gas is very low as a result of nitrogen dilution from the air-blown operation. Similar to the Texaco case, the Dow Gas/SPEC SS-2 process and Selectox process were chosen for the acid gas removal and sulfur recovery, respectively.

4.2 **POWER GENERATION AREA**

4.2.1 Gas Turbine Selection

A list of the major industrial gas turbines supplied by various turbine manufactures is shown in Table 4-2. It includes both 50 and 60 cycles gas turbines and conventional and advanced gas turbines.

As the electrical system in India is 50 cycles, the gas turbine selection is limited to the machines of this cycle. Furthermore, it was decided to use an advanced gas turbine (1260 C firing temperature) to take advantage of recent turbine efficiency improvement and to demonstrate the full potential of IGCC plant.

Based on these selection criteria, GE's 9F gas turbine was chosen for this study. The 9F turbine is a 50 cycles version of GE's 7F machine. It is currently being developed and tested jointly by GE and Alsthom in France. This turbine will be commercially available in 1991. Several units of this machine have already been ordered by Japanese utilities.

4.2.2 NO_x Emission Control

The Shell gasifier has very limited low grade heat available for fuel gas saturation. Therefore, steam injection is usually the scheme for NO_x control.

The Texaco gasifier, on the other hand, has abundant low grade heat and fuel gas saturation is usually the recommended scheme for NO_x control. However, the high ash content of Indian coal and the slurry feed used in this gasifier have resulted in a very high CO_2 content in the gas. This eliminates the need for

Table 4-2

GAS TURBINE SELECTION

VENDOR	CYCLE	FIRING, C	MW	HEAT RATE*	YEAR AVAILABLE	COMMENTS
GE						
6B	50	1,093	40	2,737	COMMERCIAL	
7F	60	1,260	150	2,490	COMMERCIAL	
9E	50	1,093	116	2,598	COMMERCIAL	
9F	50	1,260	200	2,519	1991	JOINTLY WITH ALSTHOM
WH/MHI						
W501F	60	1,260	145	2,520	1990	
MW 701	60	1,093	127	2,553	COMMERCIAL	
KWU						
V64.3	50	1,093	60	2,583	COMMERCIAL	
V84.2	60	1,049	94	2,535	COMMERCIAL	
V84.3	60	1,210	132	2,432	?	
V94.2	50	1,093	150	3,077	COMMERCIAL	
V94.3	50	1,093	200	2,485	COMMERCIAL	
UTC						
FT8	60	1,160	25	2,284	COMMERCIAL	
TP 8	50	1,160	50	2,284	COMMERCIAL	
BBC						
TYPE 8	50	1,093	49	2,626	COMMERCIAL	
TYPE 11N	60	1,093	83	2,604	COMMERCIAL	
TYPE 13	50	1,093	100	2,620	COMMERCIAL	
TYPE 13E	50	1,082	146	2,526	COMMERCIAL	
GT15	50	?	145	?	?	

* BASED ON LHV (KCAL/KWH), NATURAL GAS FIRING WITHOUT NOX STEAM INJECTION

fuel gas saturation because CO_2 acts as a diluent in the gas turbine to suppress the combustion flame temperature and reduce the NO_x emission.

The KRW and moving bed gasifiers require neither fuel gas saturation nor steam injection for NO_x control. This is because these gasifiers are air blown. The high nitrogen content in product gas has the same effect as CO_2 for NO_x suppression.

4.2.3 Bypass Damper

In this study, it was decided not to use a bypass damper between the gas turbine and HRSG. This eliminates the damper gas leakage. Thus, a higher plant efficiency can be achieved.

However, without the bypass damper, the combined cycle plant loses the simple cycle operation capability. The effects on overall plant availability have been taken into account in the availability analysis presented in Section 5.4.1.

4.2.4 Bottoming Cycle Design Considerations

The bottoming cycle chosen for this study is a dual pressure reheat steam cycle (102 kg/cm^2 abs/538 C/538 C). This cycle has been found from previous studies to be optimum in an IGCC plant size range of this study.

Section 5

IGCC PLANT EVALUATION

This section presents the plant design, thermal efficiency, emission inventory, cost estimate, project lead time, and plant layout of the four IGCC cases.

5.1 PLANT DESCRIPTION

5.1.1 Shell Case

An overall block flow diagram of the IGCC plant using the Shell gasifier is shown in Figure 5-1. The number of operating and spare trains used is indicated for each of the major process and power blocks in Figure 5-1. The major stream flows (at the 29.5 C annual average ambient temperature) are shown in Table 5-1. An overall utility summary based on the same ambient temperature is shown in Table 5-2. Equipment lists are shown in Appendix A. A description of the plant facilities is as follows.

Coal Transportation System

The coal shall be brought from open cast mines of Magadh Block of North Karanpura coal fields located at a distance of about 8 km from the site.

It is proposed to adopt a Merry-Go-Round (MGR) system of rail transport for transporting coal to the plant from the mine. Coal shall be loaded from the fast loading station at the mine terminal and unloaded into the underground RCC track hooper at the plant end. Coal wagons fitted with pneumatically operated bottom discharging doors shall be employed. Both loading and unloading of the coal shall take place while the rake moves at pre-set creep speed. The provisions include rail lines of 20 km, wagons, signalling and telecommunication, in-motion weigh bridges, etc.

Coal Receiving, Primary Crushing, and Storage (Plant 1)

A flow diagram of this plant is shown in Figure 5-2. The plant is designed to operate at 2 shifts a day and 5 days a week in conformance with the operating schedule of coal mines.

Raw coal of size 200 mm x 0 is delivered from the mine by a merry go round rail system at an assumed rate of 1000 tph. The coal is crushed to the 50 mm x 0 size required for further milling and drying in the Shell gasification plant. The crushing uses two standard cone crushers which are designed to crush tough coals and rocks. Conventional coal crushers were rejected for this application in view of the extremely high coal ash content and high ash silica content. A scalping screen is provided ahead of each crusher to remove fines from the received coal.

The crushed coal is delivered to a distribution bin from where the coal is directed, in the desired proportion, to one or more of the following three destinations:

- o A large storage yard
- o A small day-storage pile
- o Directly to downstream plants, thus avoiding multiple handling

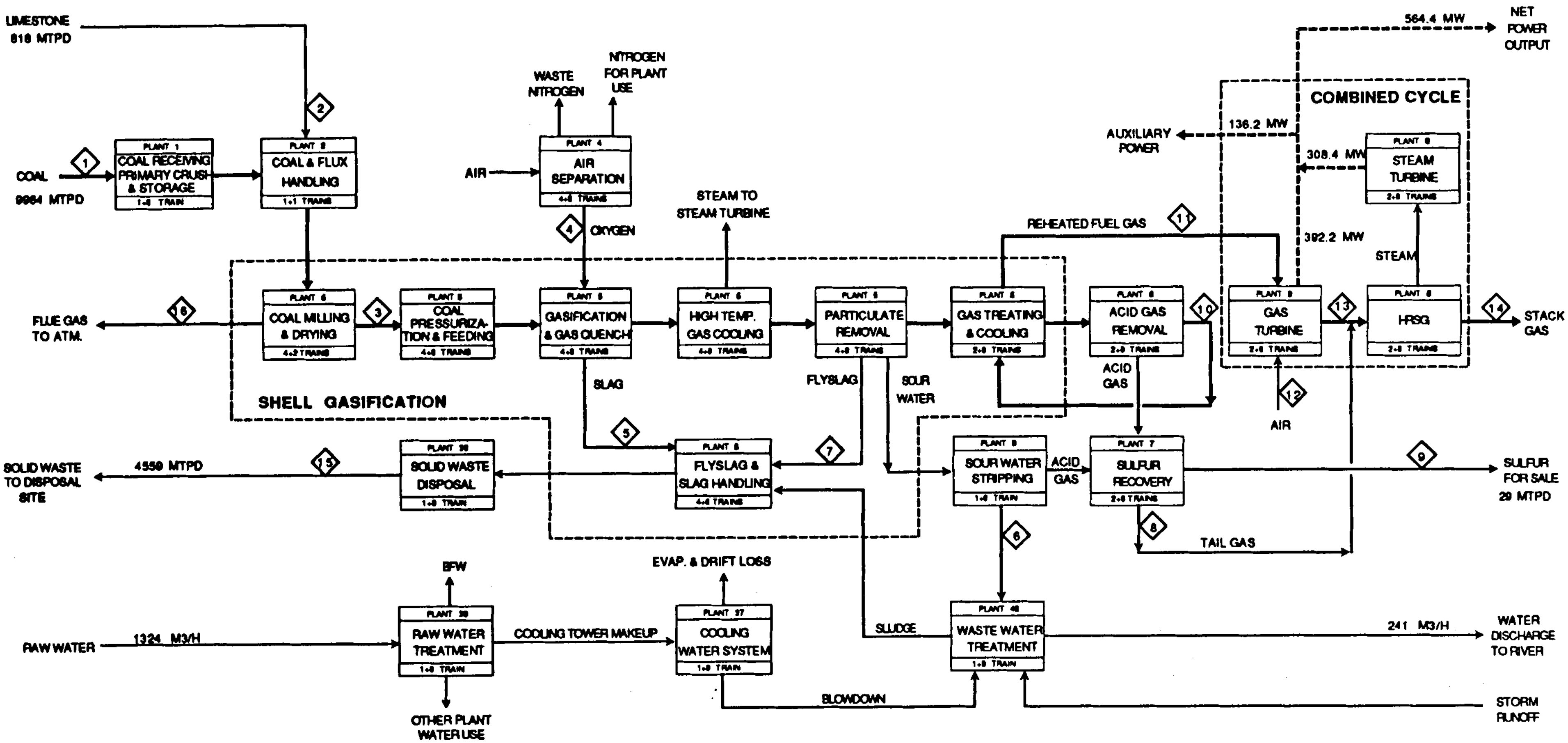

FIGURE 5-1

OVERALL BLOCK FLOW DIAGRAM
IGCC PLANT (SHELL CASE)
29.5 C AMBIENT TEMPERATURE

Table 5-1

MAJOR STREAMS OF IGCC PLANT
(SHELL CASE)

STREAM NUMBER	1	2	3	4	5	6	7	8
STREAM DESCRIPTION	COAL FEED	LIME-STONE	MILLED COAL FEED	OXYGEN TO GASIFIER	SLAG	STRIPPED WATER	FLYSLAG	TAIL GAS
GASES: kg-mol/hr								
H_2								6.5
CO								
CO_2								77.3
H_2S								0.1
COS								0.1
NH_3								
CH_4								
C_2H_6								
C_3H_8								
N_2				34.5				146.7
AR				102.2				0.1
H_2O								14.8
O_2				6705.2				
SO_2								
TOTAL: KG-MOL/HR	0.0	0.0	0.0	6841.9	0.0	0.0	0.0	245.6
LIQUIDS: kg/hr								
H_2O	74730		6990		25224	41081	4350	
SULPHUR								
SOLIDS: kg/hr								
COAL(MAF)	179352		181429					
FLUX		25740	25740					
ASH/SLAG	161085		161085		142930		17400	
BIO SLUDGE								
SULPHUR					4		1	
TOTAL: KG/HR	415167	25740	375244	219609	168157	41081	21752	7804
TEMPERATURE, C	29.4	29.4	90.0	140.0	60.0	40.6	65.6	38.3
PRESSURE, kg/cm2(g)	0.00	0.00	0.00	35.65	0.00	1.41	0.00	0.11

STREAM NUMBER	9	10	11	12	13	14	15	16
STREAM DESCRIPTION	SULPHUR By-PRODUCT	PRODUCT SYNGAS	REHEATED SYNGAS	AIR TO GAS TURBINES	GAS TURBINE EXHAUST	STACK GAS	SOLID WASTE	COAL DRYING FLUE GAS
GASES: kg-mol/hr								
H_2		4053.2	4053.2					
CO		11164.2	11164.2					
CO_2		1060.4	1060.4		12224.6	12302.0		427.4
H_2S		0.4	0.4					
COS								
NH_3								
CH_4								
C_2H_6								
C_3H_8								
N_2		1262.2	1262.2	96223.5	97485.7	97632.5		1447.6
AR		231.2	231.2	1148.9	1378.0	1378.2		24.8
H_2O		53.3	53.3	4158.4	13542.8	13564.2		4004.9
O_2				25814.6	18205.4	18201.9		109.7
SO_2					0.4	0.5		0.0
TOTAL: KG-MOL/HR	0.0	17824.8	17824.8	127343.4	142837.0	143079.3	0.0	6014.3
LIQUIDS: kg/hr								
H_2O							29574	
SULPHUR	1224							
SOLIDS: kg/hr								
COAL(MAF)								
FLUX								
ASH/SLAG							160330	
BIO SLUDGE							4	
SULPHUR							5	
TOTAL: KG/HR	1224	413125	413125	3642279	4150474	4158278	189913	136008
TEMPERATURE, C	132.2	40.0	157.2	29.4	601.7	120.0	29.4	107.8
PRESSURE, kg/cm2(g)	4.92	24.61	23.91	0.00	0.04	0.00	0.00	0.00

Table 5-2

UTILITY SUMMARY
(SHELL CASE)

Plant Number	Plant Name	Power kW	Steam kg/hr: 108 kg/cm2 542 C	Steam kg/hr: 25 kg/cm2 358 C	Steam kg/hr: 16 kg/cm2 satd	Steam kg/hr: 8 kg/cm2 satd	Steam kg/hr: 4 kg/cm2 satd	BFW kg/hr	Blowdown kg/hr	Condensate kg/hr	Cooling Water: Duty MMkcal/hr	Cooling Water: Flow mkg/hr	Make-Up Water: Raw kg/hr	Make-Up Water: Filtered kg/hr	Make-Up Water: Demin kg/hr
1	Coal Receiving & Storage	418													
2	Coal & Limestone Handling	130													
4	Air Separation	98,452									77.29	9,293			
5	Coal Gasification	20,428	(422,685)		44,375		(3,380)	431,311	(5,246)	(44,375)	70.01	6,298		10,771	
6	Acid Gas Removal	w/above				47,541				(47,541)	w/above	w/above			
7	Sulphur Recovery	w/above			(4,022)		290	5,206	(94)	(816)					
8	Sour Water Stripping	45				5,867									
9	Combined Cycle														
	Gas Turbine	(392,200)		95,073											
	Steam Turbine	(308,400)	871,173	7,230	(40,353)	(53,408)		(436,517)		(819,343)	447.67	54,401			126,958
	HRSG		(448,489)	(102,303)			(3,090)		(11,240)	912,076					
	BFW Pumps & Aux. Equipment	5,860													
37	Cooling Water System	7,525							16,580		(594.97)	(69,992)		1,134,996	
38	Raw Water Supply & Treatment	674											1,324,000	(1,157,126)	(126,958)
40	Waste Water Treatment	66													
	General Facilities	840												11,358	
	Transformer Losses	1,752													
	TOTAL	(564,410)	0	0	0	0	0	0	0	0	0	0	1,324,000	0	0

Notes: ( ) indicates production

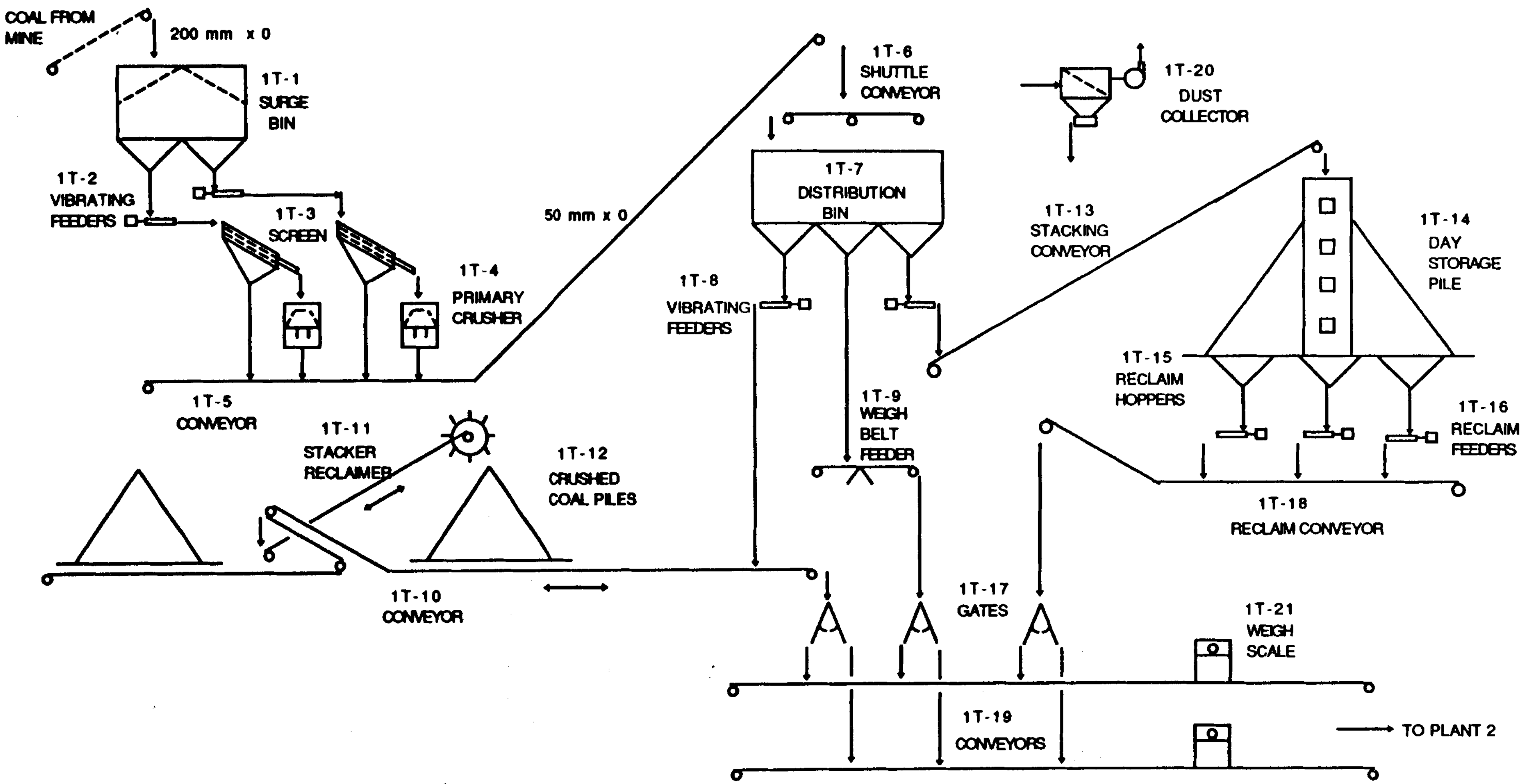

FIGURE 5-2

FLOW DIAGRAM
COAL RECEIVING, PRIMARY CRUSHING, & STORAGE (PLANT 1)
(SHELL CASE)

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The total coal storage (all live storage) is 15 days. Considering that the IGCC plant is located close to the mine and the live storage is most likely to be used only for rare and unforeseen long-term interruptions of coal supply, the live storage has been allotted to two separate and independent storage and reclaim systems. These consist of a single circular day pile (10000 tonnes live and 35000 tonnes total) for regular day-to-day use and a large coal storage yard (11 days storage) with two coal piles to provide the balance of the storage requirement. The two independent stacking and reclaim systems, combined with the capability to bypass the stockpiles, offer very high operating flexibility and reliability.

Day Storage Pile. The day pile is formed by a fixed stacking conveyor and consists of a circular pile 80 meters in diameter at the base. A concrete lowering tube with side openings is used to reduce wind blown dust during stacking.

For reclaiming, three hoppers and vibrating feeders are provided below the pile in a tunnel. The reclaimed coal is collected in a day stock reclaim conveyor which feeds the transport conveyor to down stream equipment. The transport conveyor operates all 3 shifts of the day and is provided with an installed standby.

Coal Storage Yard. When desired, crushed coal from the distribution bin may be sent to the storage yard using the storage yard belt conveyor.

A reversible stacker cum bucket wheel reclaimer with a 270° slewing capability is used to form two piles each up to 320 meters in length on either side of the yard conveyor. The piles are 14.5 meters high. The raising and lowering capability of the stacking boom prevents excessive dusting during stacking and also permits layering of the coal to facilitate blending of the coal supplies.

When operating as a reclaimer, the rotating bucket wheel picks up the coal from the pile and places it on the boom conveyor which now operates in the reverse direction. The yard conveyor which is also reversible receives the coal from the boom conveyor and deposits the coal over the transport conveyor mentioned previously.

Other Facilities. The distribution bin is provided with a dedicated outlet and a weigh feeder so that measured quantities of crushed coal may be fed to the transport conveyor and sent directly to Plant 2, thereby bypassing the storage systems. Only quantities received in excess of downstream demand are stored. The transport conveyor and storage pile reclaim systems are designed for a capacity of 500 tph.

All transfer points in the plant are provided with dust extraction facilities connected to bag houses and exhausters for the control of fugitive dust.

Coal and Limestone Handling (Plant 2)

This plant conveys crushed coal received from Plant 1 to the coal gasification plant (Plant 5). Also included are facilities to receive, store, and crush the limestone required as a fluxing agent for the gasifier. A flow diagram of this plant is shown in Figure 5-3.

The coal received from Plant 1 is delivered by the silo feed conveyor to the top of the day silos of the coal milling and drying unit in Plant 5. A tripper conveyor is used to distribute the coal among the silos.

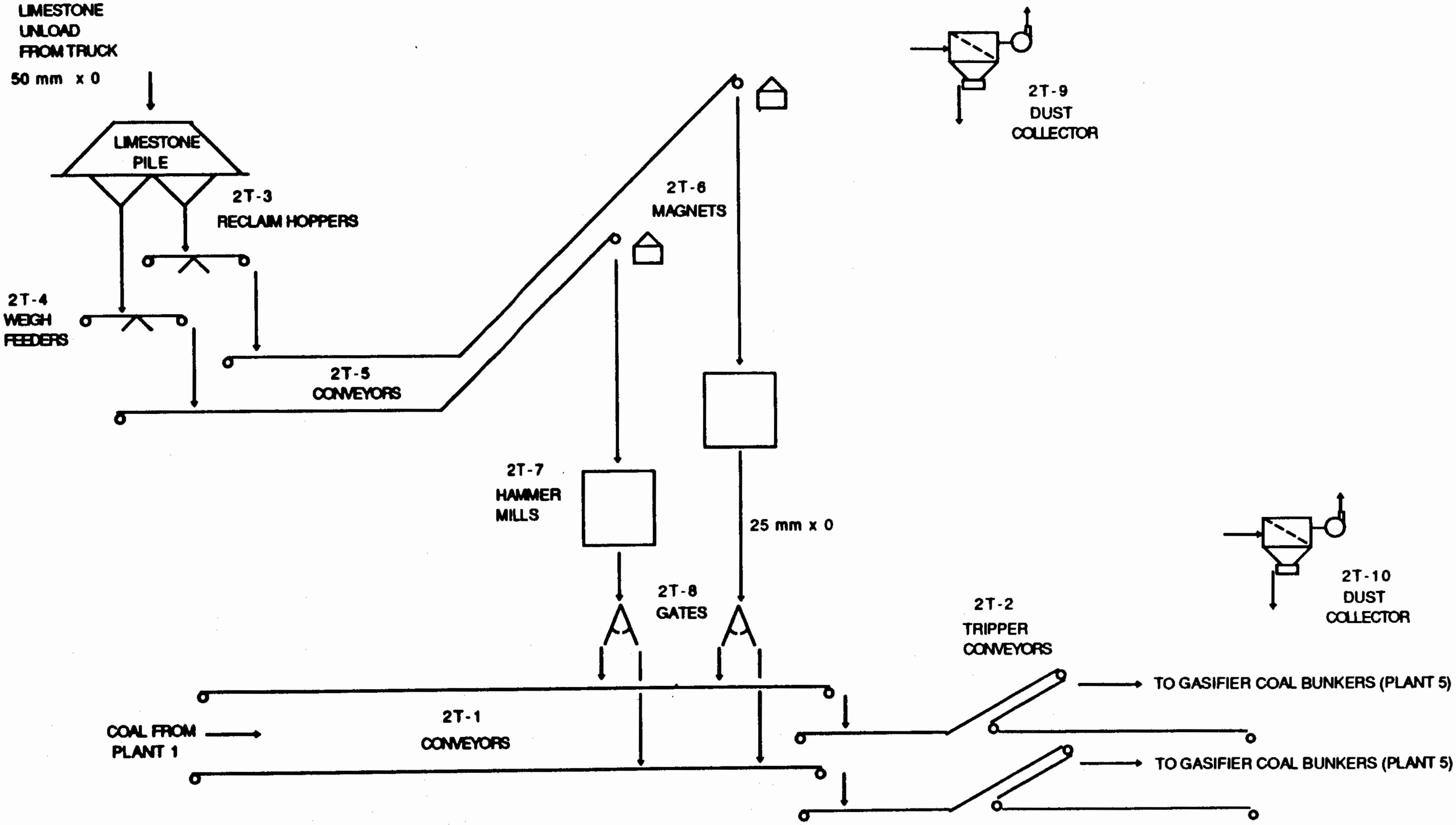

FIGURE 5-3

FLOW DIAGRAM
COAL AND LIMESTONE HANDLING (PLANT 2)
(SHELL CASE)

Limestone received in trucks is unloaded in the storage area and reclaimed using a weigh feeder. It is then crushed to a nominal size of 25 mm x 0 using a hammer mill type of crusher. The crushed flux is placed on the silo feed conveyor mentioned above.

All equipment items in this plant are provided with identical and installed spare units as the equipment are to be operated all 3 shifts of the day. The material transfer points are provided with dust extraction facilities for dust control.

Air Separation (Plant 4)

The air separation unit primarily provides the oxidant feed required for gasifying coal in the Shell gasification unit. In addition, the unit provides high-purity nitrogen which is also needed in Shell's unit.

Design Basis. Four parallel, 25% capacity trains are used, each designed to supply 1350 MTPD of contained oxygen at a purity of 98 percent (by volume).

Product oxygen is delivered from this plant at 36.7 kg/cm^2 abs pressure. Coproduct high-purity nitrogen streams of 375 and 240 MTPD (per train) are supplied at 63 kg/cm^2 abs and at 9 kg/cm^2 abs, respectively.

The design incorporates two backup systems for oxygen and pure nitrogen supply. The oxygen backup system includes liquid oxygen storage equivalent to a one-day, full-capacity production from one train and gaseous oxygen storage equivalent to a 25-minute production from one train. The nitrogen backup system provides both gaseous and liquid nitrogen storage capacities sufficient to run one train for 25 minutes and for one day, respectively.

Electric motors are used for compressors, expansion turbines, and all other drives in the air separation unit.

Description. Atmospheric air is drawn through an inlet air filter, compressed in a two-stage axial centrifugal compressor and then cooled in the aftercooler with direct contact with cooling water.

The compressed air is processed in a conventional cryogenic separation unit (air separation cold box), typically incorporating reversing heat exchangers and turboexpanders for refrigeration, and refluxed distillation columns for separation. Air is separated into a 98 percent oxygen stream, a highly pure nitrogen stream, and a less pure waste nitrogen stream.

The oxygen discharged from the cold box is compressed to its delivery pressure in a water-intercooled centrifugal compressor using four stages. It is then preheated to 250 C using 15.8 kg/cm^2 abs saturated steam before it is fed to the gasifier.

The high-purity nitrogen discharged from the cold box is first compressed to 11 kg/cm^2 abs in the first two stages of a four water-cooled stage centrifugal compressor. Part of this compressed stream is supplied as low pressure nitrogen to the gasification unit, while the remaining part is compressed further to 63 kg/cm^2 abs in the last two stages of the compressor to produce high pressure nitrogen for the gasification unit.

The waste nitrogen stream leaving the cold box is vented to the atmosphere.

Shell Coal Gasification (Plant 5)

The design of this plant unit is based on the process information furnished by Shell. The major process areas are described below.

Coal Milling and Drying. The coal and limestone stream received from Plant 2 is ground to 90 percent minus 88 microns with a maximum of 10 percent minus 5 microns in a ball mill prior to feeding to the gasifier. In the mill, the coal is simultaneously dried to 2% moisture. The coal milling and drying facility has four operating trains and one spare train for every two operating trains.

The design coal has a high ash content and is very abrasive due to its high silica content in the ash. To maintain a high plant availability under this environment, the choice of mill is very critical. As discussed in Section 4.1.2, ball mill is selected for this design.

Coal received from Plant 2 is stored in six coal feed bins, i.e., one per grinding mill. A tramp iron magnet is used to capture stray metal objects before the milling. Each feed bin is equipped with a dust collection system and one reciprocating feeder.

The reciprocating feeders transfer coal through air seal rotary feed valves and into the ball mills. Hot gas generated from combustion of a portion of the clean gasification product gas is used to dry, classify and transport the ground coal from the mill. Air required for the combustion is preheated by the low pressure steam from the combined cycle plant (Plant 9). The hot gas is attemperated to 538 C with the cold recycle gas from the mill exhaust prior to its use.

The milled coal is separated from the exhaust gas using cyclones and fabric filter bag houses. The exhaust gas is pressurized by a fan for venting and for recycling back to the mill. The venting is to prevent the moisture buildup in the gas recycle loop.

Ground solids from the cyclones and baghouses are collected in surge bins and fed by screw feeders to the transport pumps. The transport nitrogen gas recycled from the gasification unit is reused and compressed to about 50 kg/cm^2 abs by the transport gas compressor to pneumatically convey the ground coal to the coal pressurization and feeding unit.

Coal Pressurization and Feeding. Milled and dried coal is pressurized in this unit for transporting and feeding to the gasifier using high pressure nitrogen. Each of the four trains used basically consists of a receiving vessel, two lock hoppers and a feed hopper.

The incoming ground coal is separated from its transport nitrogen in the receiving vessel. The nitrogen is recycled to the coal milling and drying area through bag filters located inside the receiving vessel. The coal collected at the bottom of the receiving vessel is periodically transferred to one of the two accompanying lock hoppers.

The two lock hoppers are operated on a time cycle (programmable logic controlled) such that one is filled and pressurized while the other is emptied and depressurized. Once a lock hopper has been filled with coal from the receiving vessel, the lock hopper is pressurized with high-pressure nitrogen and its contents are subsequently discharged into the feed hopper. After emptying, the lock hopper is depressurized and readied for the next batch of coal from the receiving vessel. Nitrogen vented from the lock hopper during the depressurization step is filtered and discharged to the atmosphere. Pressurized coal is continuously withdrawn from the feed hopper and pneumatically conveyed with nitrogen to the gasifier's coal burners.

Gasification/Gas Quench and High Temperature Gas Cooling. Pressurized coal is metered to the gasifier through two opposed burners along with oxygen. The oxygen stream is preheated using 15.8 kg/cm^2 abs saturated steam prior to its feeding to the gasifier. Steam, if necessary, can be fed simultaneously to the gasifier. The gasifier is operated at 32 kg/cm^2 abs pressure in excess of 1540 C. It consists of an outer pressure vessel and an inner, water-cooled membrane wall. The overall gasification process is exothermic and the gasifier wall temperature is controlled by circulating boiler feed water through the membrane wall to generate saturated steam for subsequent superheating in the syngas cooler. The membrane wall encloses the gasification zone from which two outlets are provided: one, at the bottom for the removal of slag; the other, at the top for the removal of the hot raw gas.

The majority of ash contained in the feed coal leaves the gasification zone in the form of molten slag. The high gasification temperature ensures that the molten slag flows freely down the membrane wall into a water-filled compartment at the bottom of the gasifier. As the molten slag comes in contact with the water bath, the slag solidifies into dense, glassy granules which fall into a collecting vessel located beneath the slag bath.

The temperature of the slag bath is controlled by circulating the water through an external cooler. A portion of the circulating water is purged to the wet particulate removal unit to control the buildup of suspended solids.

The hot raw product gas leaving the gasification zone is quenched with a recycle gas stream to solidify the entrained molten slag to ash-like solid material (flyslag) prior to entering the syngas cooler. The quenched gas passes from the gasifier to the syngas cooler through a connecting duct which is also lined with a water-cooled membrane wall for steam generation.

The syngas cooler recovers high-level heat from the quenched raw gas by generating superheated high-pressure steam. Each syngas cooler consists of superheat, evaporative, and economizer sections. Four 25% trains are provided for the gasifier and syngas cooler. A steam drum and boiler feed water circulation pumps are provided for each gasifier/syngas cooler train.

Slag Handling. Slag from the water-filled collection vessel at the bottom of each gasifier is transferred to a pair of lock hoppers, operating on a timed cycle.

During filling, the slag is washed with clean makeup water to remove entrained gas and any surface impurities. The makeup water after wash flows from the lock hoppers to the slag bath system in the gasifier. After filling, a lock hopper is depressurized and the slag is fed to a dewatering vessel equipped with an inclined screw to lift the settled solids off the bottom and deposit them on a belt conveyor for delivery to a temporary storage bin in the solid waste disposal plant (Plant 30).

Four 25% trains are used in this plant section.

Particulate Removal. The cooled raw gas from the syngas cooler is directed to a cyclone to remove bulk of the entrained flyslag. The raw gas leaving the cyclone is sent for wet scrubbing to further reduce residual flyslag to a level of less than 1 ppm. Other minor contaminants such as soluble alkali salts are also removed to low levels.

To control the concentration of contaminants in the water after scrubbing, makeup water is continually added from the gas treating and cooling section to the wet scrubbing system, and a blowdown stream is withdrawn to the sour water stripping plant (Plant 8).

Four 25% trains are used in this plant section.

Gas Treating and Cooling. The washed raw gas from wet scrubbing is routed to a catalytic hydrolyzer to convert the minor nitrogen contaminant (hydrogen cyanide) to ammonia, and carbonyl sulfide to hydrogen sulfide. The gas is heated to the desired reaction temperature by medium pressure (15.8 kg/cm^2 abs) steam before entering the hydrolyzer. The hydrolyzer effluent is subsequently cooled to 37.8 C by consecutive heat exchange with fuel gas product, recycle process condensate, steam turbine condensate and cooling water. The product fuel gas is reheated to 157.2 C, 24 kg/cm^2 abs in this process before being delivered to the gas turbines.

Prior to the heat exchange with cooling water, a makeup water stream is mixed with the gas to remove ammonia. After cooling, the two-phase mixture is separated in a knockout drum from which condensate is sent to the wet scrubbing section as scrubber makeup water and the cooled scrubbed gas is directed to the acid gas removal plant (Plant 6) for sulfur cleanup.

Two 50% trains are used in this plant section.

Flyslag Handling and Storage. Flyslag from the cyclone is pneumatically conveyed to one of the two flyslag lock hoppers which operate on a programmed time cycle. After a lock hopper is filled, the flyslag is swept with high pressure nitrogen to purge entrained raw gas. After purging, the lock hopper is depressurized and the flyslag is pneumatically conveyed to a silo for intermediate storage. All vent gases from the flyslag lock hoppers and the storage silo are filtered of particulates and sent to the main flare to be incinerated before being released to the atmosphere.

The silo is sized for up to 96 hours flyslag production; sufficient to permit regularly scheduled silo unloading operations. During the unloading operation, the flyslag is discharged to a pug mill and mixed with a diluted sludge stream from the effluent water treating plant (plant 40). The wetted flyslag is discharged from the pug mill is conveyed to a temporary storage bin in the solid waste disposal plant (Plant 30). Wetting of the flyslag minimizes dusting as the material is transported.

Four 25% trains are used in this plant section.

Acid Gas Removal (Plant 6)

The acid gas removal system employs Shell's proprietary Sulfinol-M process to remove hydrogen sulfide from the raw gas. The H_2S absorbing solvent used in the Sulfinol-M process is a 25/50/25 solution of water/MDEA/Sulfolane. Two 50% trains are used. Shell provided the design information.

The raw gas enters the acid gas absorber where H_2S is absorbed by counter current contact with the solvent. The clean product fuel gas contains about 20 ppm(v) H_2S plus COS (carbonyl sulfide) and is delivered from the acid gas absorber to the product reheat exchanger in the gasification plant (Plant 5). This is equivalent to 99% sulfur removal and is substantially higher than the removal requirement specified for this study. Shell chose to do so because they felt that the Sulfinol-M process can easily achieve this level of removal with only a marginal cost increase.

Rich solvent from the acid gas absorber is regenerated in the stripper column by stripping vapors generated by the reboiler, which uses intermediate pressure (8 kg/cm^2 abs) steam as the heat source.

Lean regenerated solvent is withdrawn from the stripper column and heat exchanged with the rich solvent before it is recycled to the absorber. Stripper overhead, rich in H_2S, is cooled to condense water and sent for sulfur recovery (Plant 7).

Sulfur Recovery (Plant 7)

The sulfur recovery plant uses a two-stage Claus process where acid gases are combusted and reacted to produce elemental sulfur as a salable product. The sulfur recovery is 98.5%. This combined with the 99% removal in the acid gas removal unit provides an overall sulfur recovery of 98% for the IGCC plant. Two 50% trains are used. The design is based on the process information provided by Shell.

Feeds to the Claus unit include sour gas from the sour water stripper (Plant 8) and acid gas from the acid gas removal plant (Plant 6). Acid gas from the sour water stripper contains ammonia and is combusted in the first of the two chambers comprising a reaction furnace for complete oxidation of ammonia. This ensures the prevention of unwanted side reactions which would otherwise occur during the H_2S conversion step. In the second combustion chamber, the bulk of the H_2S rich acid gas from Plant 6 is combusted to consume approximately one-third of the total feed H_2S.

The combined combustion product from the two combustion chambers contains the desired 2:1 stoichiometric ratio of H_2S/SO_2 which react to form sulfur and water. Over one-half of the conversion to sulfur obtained in the Claus unit occurs in the reaction furnace. Reaction products at approximately 1371 C are cooled consecutively in a waste heat boiler and the first sulfur condenser. Condensed sulfur flows from the condenser to a covered underground heated sulfur pit.

Gases from the first sulfur condenser subsequently pass through two catalytic conversion stages to achieve the desired recovery of sulfur. Each stage consists of an auxiliary burner, catalytic converter, and condenser.

In each auxiliary burner a small portion of the acid gas from Plant 6 is combusted as fuel to maintain the reactor feed temperature above the sulfur dew point and prevent condensation in the catalyst bed. The same 2:1 H_2S/SO_2 ratio is maintained for the catalytic conversion to sulfur and water. Tail gas from the final condenser enters a coalescer vessel where any entrained liquid sulfur is separated. The tail gas then flows to mix with the gas turbine exhaust gas in the combined cycle plant (Plant 9) where all the residual sulfur compounds in the tail gas are incinerated to sulfur dioxide under the high temperature of the gas turbine exhaust.

Liquid sulfur is pumped from the sulfur pit to aluminum pans for cooling and solidification into blocks for sale.

Heat is recovered in the sulfur recovery unit by generation of steam at medium and low pressure levels. Medium pressure (15.8 kg/cm^2 abs) saturated steam is generated in the waste heat boiler and the first sulfur condenser. Low pressure (3.9 kg/cm^2 abs) saturated steam is generated in the second sulfur condenser.

Sour Water Stripping (Plant 8)

Process purge water from the wet particulate removal system in the gasification plant (Plant 5) is fed to a sour water stripper for removal of ammonia and hydrogen sulfide. A feed drum is provided with adequate holdup volume to avoid stripper column upsets that could occur due to variations in the feed rate and feed composition. One single train is used in this plant area.

Intermediate pressure steam (8 kg/cm^2 abs) provides the necessary heat and stripping medium in the column to reduce the ammonia level in the feed water to less than 50 ppm(w) and at the same time removes essentially all the hydrogen sulfide and dissolved raw gases. The acid gas (containing ammonia) from the stripper overhead accumulator is sent to a Claus unit (Plant 7) for sulfur recovery. The stripper bottom stream, which still contains a minor amount of suspended solids, is cooled by exchange with cooling water and sent to waste water treating (Plant 40).

Combined Cycle (Plant 9)

The combined cycle plant basically consists of two trains. Each train includes a GE MS9001F gas turbine, a steam turbine, a HRSG, and the necessary BFW and condensate systems. As discussed in Section 4.2.3, no bypass damper is placed between the gas turbine and HRSG in the present design.

The plant is designed to have a close integration with the process area. The combined cycle configuration and its integration with the process area are described below.

Gas Turbine. Based on the clean gas composition supplied by Shell, GE provided the following gas turbine performance (one 9F gas turbine) at both the normal and design ambient temperatures:

	29.4 C (Normal)	18.3 C (Design)
Fuel(LHV), Million Kcal/h	493	520
Fuel Gas Temperature, C	157.2	157.2
Relative Humidity	80	60
NO_x Steam, 1000 kg/h	47.5	54.9
Exhaust Flow, 1000 kg/h	2075.3	2179.0
Exhaust Temperature, C	601.7	590.6
Power Output, MW	196.1	214.1

The gas turbine includes the gas turbine engine, the electric generator, and auxiliaries such as the fuel system, lube oil system, and control system. The gas turbine engine is located inside the turbine building at the mezzanine level downstream of the inlet air ducts and upstream of the exhaust ducts. The inlet air filter equipment is located on the building roof.

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The gas turbine is constructed in a single shaft configuration in which the turbine, compressor and generator are in tandem on a single shaft. Air is the primary working fluid. The air is filtered before it enters the compressor where it is compressed to a pressure approximately 13.5 times atmospheric pressure. The air enters the combustors where NO_x emission control steam and fuel are mixed with the air and burned. The hot combustion gas then expands through the turbine which produces power to drive the compressor and the generator. The combustion gas exhausts from the turbine and is directed to the heat recovery steam generator (HRSG).

The gas turbine-generator system is designed and rated to operate continuously in base load generation service. The gas turbine can start and load quickly and automatically with minimum start-up fuel and manpower. It also can follow load readily. The single shaft gas turbine configuration has fast governor response and high inertia so it enhances the stability of electric utility systems.

The gas turbine output flange is located at the compressor end of the rotor assembly to provide "cold end" drive. This feature substantially improves alignment control and provides an axial exhaust to optimize the plant arrangement for combined-cycle applications. The gas turbine is connected to the generator through a solid coupling.

The gas turbine has an 18-stage axial flow compressor with modulated inlet guide vanes. Interstage extraction is used for turbine nozzle and wheelspace cooling and can be externally controlled. Because the blading material in the compressor has high corrosion resistance, a coating is not required.

A reverse flow combustion system with multiple combustion chambers and fuel nozzles is used. Retractable spark plugs and flame detectors are standard parts of the combustion system. Crossfire tubes connect each combustion chamber to adjacent chambers on both sides. Steam injection is provided for NO_x emissions control.

The gas turbine has three turbine stages. The first and second stage nozzles and buckets are air cooled. All turbine buckets are coated to provide corrosion resistance. The turbine section is coupled to an axial diffuser with optimum pressure recovery for higher thermal efficiency.

The rotor is a two-bearing single shaft design with high torque capability. It incorporates internal cooling and thermal response control in the turbine section. Both the compressor and turbine sections are constructed of individually rabbetted discs held with through bolts. For field changeout, the unit rotor is handled as one piece.

The turbine and compressor casings are horizontally split for ease of inspection and maintenance. For each combustion chamber, the liners and transition pieces can be individually changed out. Borescope holes are located in the compressor, combustion, and turbine sections to facilitate visual inspection. The journal and thrust bearings are readily accessible, and removal of turbine or compressor casing(s) is not required for bearing maintenance.

The electric generator for the gas turbine is a two-pole synchronous unit that operates at 3,000 rpm to produce 50 Hz, 240 MVA power at 16500 volts. The generator has static excitation. A starting motor is connected to the generator-collector end through a torque converter for starting purposes. The generator is hydrogen-cooled. The hydrogen is in turn cooled by the cooling

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water. The generator is also provided with a hydrogen feed system (from hydrogen stored at pressure in cylinders) and a carbon dioxide purge system for maintenance.

Auxiliaries that support operation of the gas turbine and electric generator include the lube oil system, the fuel system, the hydraulic system, the start system, the engine cleaning system, the fire protection system, and the control system.

A common lube oil system serves both the gas turbine engine and electric generator. The functions of the lube oil system are to supply pressurized lubricating oil to the journal bearings, pressurized oil for the turning gear hydraulic motor, and jacking oil for journal bearing breakaway, and to collect, cool, filter, and deaerate the lubricating oil.

The fuel system for the gas turbine includes a dual fuel nozzle, vortex generator-type combustion chambers, a fire valve to protect against leaks in the fuel system, double hydraulically actuated shutoff and vent valves for positive fuel shutoff, and a fuel gas strainer/fuel oil filter to protect the valves from particles in the fuel.

A number of the auxiliary system controls that support operation of the gas turbine have high-force hydraulic actuators. The function of the hydraulic system is to supply hydraulic servo oil at high pressure to the controls for the fuel stop valves, fuel and steam modulating valves, and compressor bleed control valves.

The Claus tail gas incineration using gas turbine exhaust has raised some concerns and requires special design care.

A shut-off valve needs to be installed at the tail gas mixing point with the gas turbine exhaust and needs also to be synchronized with the generator breaker. This would assure that the tail gas is mixed into the exhaust gas only when the gas turbine is running. A small flare has been provided as part of the Claus unit to handle the vent stream during startup, shutdown and any other unusual periods of operation. Closing of the tail gas shut-off valve to the gas turbine would cause automatic diversion of the tail gas to the flare.

There is concern whether the Claus tail gas, which is mixed into the turbine exhaust, can be completely incinerated. Shell has indicated based on their experience with Claus tail gas, H_2S and COS can be completely incinerated at 538 C. As GE's gas turbine meets this temperature requirement, the Claus tail gas incineration is expected to be complete.

Steam Generation and Consumption in the Process Area. A steam balance of the process area is shown in Figure 5-4. The major flows are shown in Table 5-3. Steam is generated and consumed in the process plant at four pressure and temperature levels.

The syngas coolers and gasifier cooling in the Shell gasification plant produce superheated high pressure steam at 110.6 kg/cm^2 abs and 542 C which is sent to the steam turbine in the combined cycle plant. The boiler feed water required for this steam production is supplied at 216 C.

Medium pressure saturated steam at 15.8 kg/cm^2 abs is produced in the sulfur condenser and waste heat boiler in the sulfur recovery plant. It is consumed for preheating oxygen from the air separation plant, for fuel gas reheating prior to COS hydrolysis in the gasification plant, and to provide a source of

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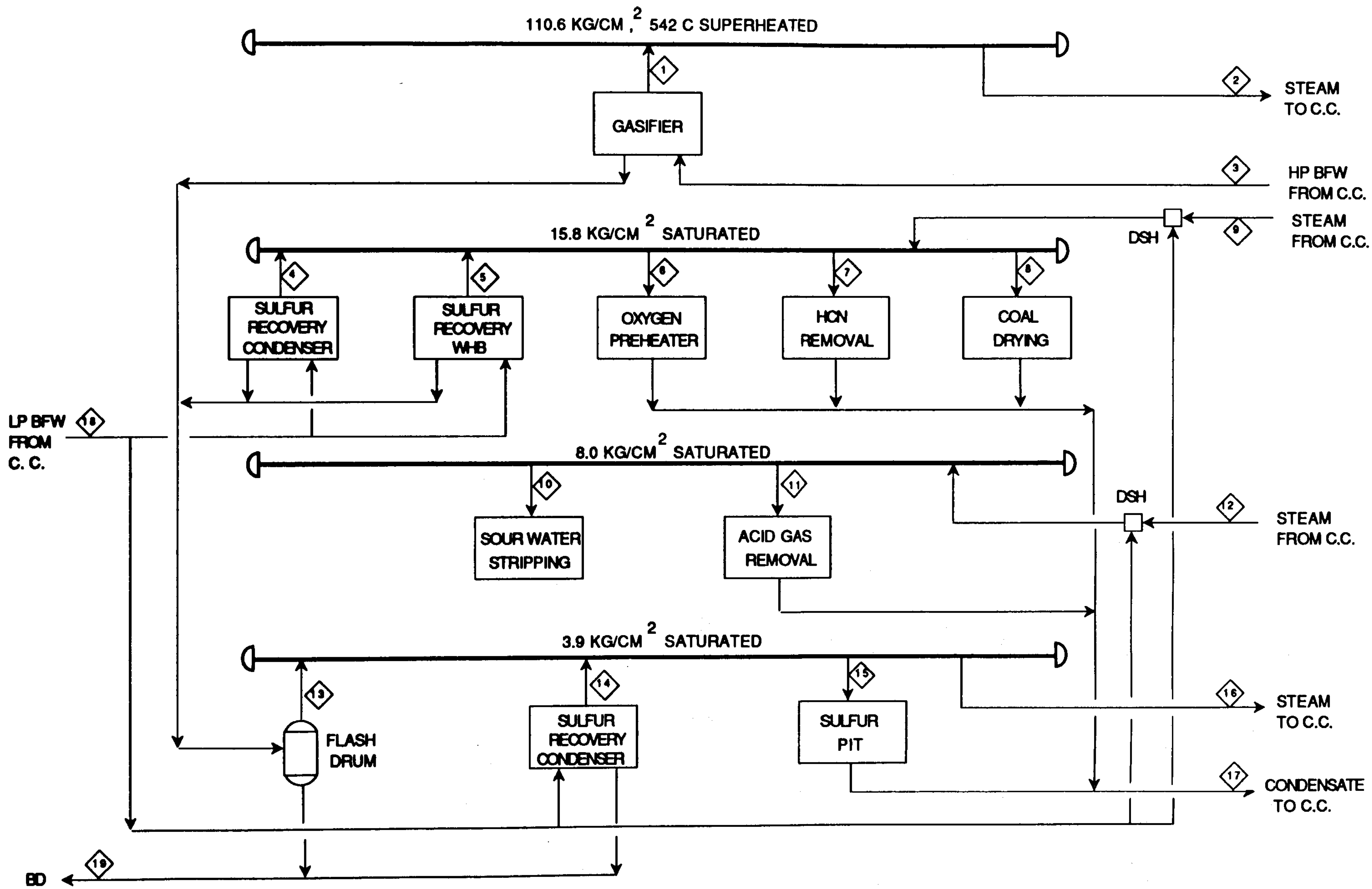

FIGURE 5-4 PROCESS STEAM BALANCE DIAGRAM (SHELL CASE)

Table 5-3

STREAM FLOW FOR PROCESS STEAM
(SHELL CASE)

Stream No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
STREAM DESCRIPTION	HP STEAM FROM GASIFIER	HP STEAM TO COMBINED CYCLE	HP BFW FROM COMBINED CYCLE	STEAM FROM SULPHUR COND.	STEAM FROM SULPHUR WHB	STEAM TO OXYGEN PREHEAT	STEAM TO HCN REMOVAL	STEAM TO COAL DRYING	STEAM FROM COMBINED CYCLE	STEAM TO SWS UNIT	STEAM TO AGR UNIT	STEAM FROM COMBINED CYCLE	FLASH STEAM	STEAM FROM SULPHUR COND.	STEAM TO SULPHUR PIT	STEAM TO COMBINED CYCLE	COND. TO COMBINED CYCLE	LP BFW FROM COMBINED CYCLE	BLOW-DOWN
Pressure, Kg/cm2 abs	110.55	110.55	114.77	0.15	15.82	15.82	15.82	15.82	17.58	8.09	8.09	9.14	3.87	3.87	3.87	3.67	15.82	17.58	3.87
Temperature, C	541.7	541.7	215.6	199.9	199.9	199.9	199.9	199.9	483.9	170.0	170.0	394.4	141.7	141.7	141.7	141.7	200.6	108.9	141.7
Flow, 1000 Kg/h	422.69	422.69	431.31	0.97	3.05	4.84	16.65	22.89	31.69	5.87	47.54	44.22	3.39	0.52	0.82	3.09	92.73	22.49	5.33
Enthalpy, Kcal/kg	813.31	813.31	204.94	651.51	651.51	651.51	651.51	651.51	804.79	645.73	645.73	761.73	637.70	637.70	637.70	637.70	171.43	93.44	126.86

1. Enthalpy values are based on 0 kcal/kg for liquid water at 15.6 C

heat for the coal drying unit. Overall, there is a net requirement for this level of process steam which is provided by desuperheating of an extraction steam from the steam turbine in the combined cycle plant.

Intermediate pressure saturated steam at 8 kg/cm^2 abs is required as stripping steam in the sour water stripping plant and for solvent regeneration in the acid gas removal plant. The sour water stripper uses live steam injection. Therefore, the steam is lost in the stripping process. The total requirement is provided by desuperheating of an extraction steam from the steam turbine in the combined cycle plant.

Low pressure saturated steam at 3.9 kg/cm^2 abs is produced from the sulfur condenser in the sulfur recovery plant and is consumed for sulfur pit and line heating in the sulfur recovery plant. In addition, the high pressure steam blowdown from the gasifier syngas coolers is flashed, which generates an additional amount of 3.9 kg/cm^2 abs saturated steam. Overall, there is a surplus of this pressure level steam which is used as part of the deaeration steam for the deaerator in the combined cycle plant.

All the steam production in the process plants assumes a 2 percent blowdown. The blowdown is collected and sent to the cooling tower basin for reuse.

Steam Cycle. The steam cycle for the combined cycle unit employs a dual pressure level HRSG and a reheat steam turbine-generator. The cycle configuration is shown in Figure 5-5 and the major stream flows at the 29.5 C annual average temperature are shown in Table 5-4.

The gas turbine exhausts to the heat recovery steam generator, where heat energy is transferred from the exhaust gas to feedwater to produce and reheat steam for the nominal 103 kg/cm^2 abs/538 C/ 538 C steam bottoming cycle of the combined-cycle power system. The gas turbine exhaust enters the HRSG at 602 C and exits the HRSG at 120 C.

The arrangement of HRSG heat recovery in the direction of gas flow is as follows:

- o HP superheater (final stage)
- o IP reheater
- o HP superheater (initial stage)
- o HP evaporator
- o IP superheater and HP economizer (final stage)
- o IP evaporator
- o HP economizer (initial stage) and IP economizer
- o Integral deaerator

In designing the heat recovery surface, all the evaporators assume an 11.1 C pinch point and all the economizers assume an 11.1 C temperature approach.

Condensate is pumped from the surface condenser hotwell by condensate pumps to the integral deaerator. Prior to entering the deaerator, the condensate is preheated in a condensate preheater located in the gas treating and cooling section of the gasification plant (Plant 5).

The integral deaerator directly extracts heat from the HRSG for deaeration at 1.41 kg/cm^2 abs pressure. A small amount of IP saturated steam is used when necessary as the pegging steam to maintain the deaeration pressure and stack

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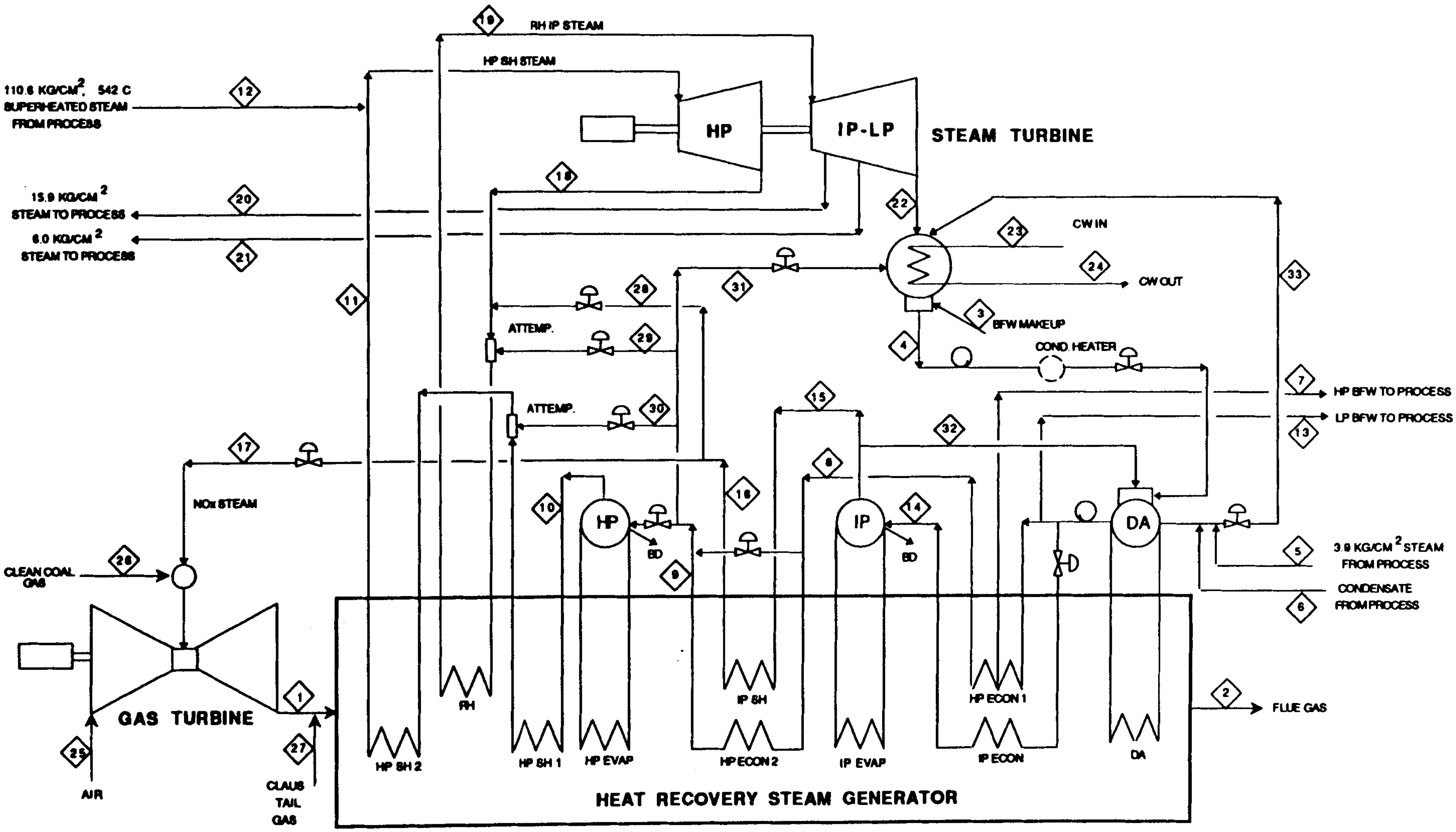

FIGURE 5-5 COMBINED CYCLE FLOW DIAGRAM (SHELL CASE) 29.5 C AMBIENT TEMPERATURE

Table 5-4

STREAM FLOW FOR COMBINED CYCLE
(SHELL CASE)

Stream No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
STREAM DESCRIPTION	GAS TURBINE EXHAUST	STACK GAS	BFW MAKE-UP	CONDEN-SATE	PROCESS STEAM TO DA	PROCESS COND. TO DA	HP BFW TO PROCESS	HP BFW FROM HP ECON 1	HP BFW FROM HP ECON 2	STEAM FROM HP BOILER	HP STEAM FROM HRSG	HP STEAM FROM PROCESS	LP BFW TO PROCESS	LP BFW FROM IP ECON	STEAM FROM IP BOILER	IP STEAM FROM HRSG	NOX INJECTION STEAM
Pressure, kg/cm2 abs	1.02	0.96	1.41	0.12	3.87	15.82	114.77	113.57	110.56	110.56	109.14	110.55	17.58	27.43	27.43	26.72	26.72
Temperature, C	601.7	120.0	29.4	48.9	141.7	200.6	215.6	216.7	305.6	317.2	541.7	541.7	108.9	216.7	227.8	358.3	358.3
Flow, 1000 kg/hr	4148.40	4156.03	126.95	946.29	3.06	92.73	431.31	457.64	457.64	448.49	448.49	422.69	22.49	104.39	102.30	102.30	95.07
Enthalpy, kcal/kg	191.54	60.73	13.86	33.36	637.70	171.43	204.94	206.23	313.03	632.24	813.31	813.31	93.44	206.23	653.57	735.52	735.52

Stream No.	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33
STREAM DESCRIPTION	EXHAUST FROM HP TURBINE	REHEATED IP STEAM	EXTRACT STEAM TO PROCESS	EXTRACT STEAM TO PROCESS	EXHAUST FROM LP TURBINE	COOLING WATER SUPPLY	COOLING WATER RETURN	AIR TO GAS TURBINE	SYNGAS TO GAS TURBINE	TAIL GAS TO GAS TURBINE	IP STEAM TO REHEAT	REHEAT ATTEMP WATER	SH ATTEMP WATER	HP BFW ECON 2 CIRC	DA PEGGING STEAM	DA STEAM DUMP
Pressure, kg/cm2 abs	26.72	25.32	17.58	9.14	0.12	3.52	2.46	0.98	24.96	1.14	47.61	110.55	110.55	110.55	27.43	1.41
Temperature, C	349.4	537.8	483.9	394.4	48.9	36.1	44.4	29.4	157.2	38.3	193.3	305.6	305.6	305.6	227.8	108.9
Flow, 1000 kg/hr	571.17	578.40	31.69	44.22	1073.26	54401.32	54401.32	3642.28	411.05	7.80	7.23	0.00	0.00	0.00	0.00	0.00
Enthalpy, kcal/kg	730.53	831.30	804.76	761.73	589.68	20.62	26.85	15.48	47.91	25.61	735.52	313.03	313.03	313.03	653.57	626.80

1. Enthalpy values are based on 0 kcal/kg
for liquid water at 0 C

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gas temperature. The stack gas temperature is controlled to be above the acid dew point of the fuel combusted in the combined cycle plant.

The deaerated condensate is pumped by a transfer pump as boiler feedwater for HP steam (nominal 103 kg/cm^2 abs) and IP steam (nominal 25 kg/cm^2 abs) production and to provide the low pressure BFW required in the process area. A portion of the BFW from HP economizer is withdrawn as the HP BFW required for the gasifier syngas cooler.

Multi-element control is provided to regulate the feedwater flow to the HP steam drum. The feedwater has the option to bypass the HP economizer and to circulate through the surface condenser. This is to keep the feedwater temperature at a minimum of 9.4 C below the evaporation temperature to avoid steaming in the HP economizer.

The IP saturated steam from the IP steam drum is superheated in the IP superheater to provide NO_x control steam for the gas turbine. The excess superheated IP steam joins the cold reheat steam from the steam turbine.

The HP saturated steam from the HP steam drum is further superheated in the HP superheater before feeding to the steam turbine. The steam turbine has a HP section and an IP-LP section. The HP superheated steam is expanded to the 25 kg/cm^2 abs pressure range in the HP turbine section. The cold reheat combines with the excess superheated IP steam as mentioned previously for reheating in the HRSG. The reheated steam is expanded in the IP and LP turbine sections before it is exhausted to the surface condenser.

Steam is extracted from the steam turbine IP-LP section at 15.8 kg/cm^2 abs and 8 kg/cm^2 abs pressure levels for use in the process area.

The steam temperature is usually not controlled except when the gas turbine exhaust temperature is increased due to part load operation or high ambient temperature operation. The high exhaust temperature may cause the HRSG superheater and reheater temperatures to increase. The HP superheated steam temperature is limited to 566 C by an attemperator at an intermediate point in the superheater. The IP reheated steam temperature is also limited to 566 C by an attemperator at an intermediate point in the cold reheat line. Water for these two attemperators is drawn from the discharge of HP economizer.

The surface condenser operates at 88 mm HgA vacuum using cooling water from the cooling tower. The surface condenser also receives excess steam dumped from the deaerator, steam returned from turbine seals and other miscellaneous uses, and makeup boiler feedwater from the raw water supply and treating plant.

The steam pressure is controlled by the steam turbine. The pressure slides over most of the operating range, varying with steam flow through the turbine. The minimum pressure of approximately 42 kg/cm^2 abs and the maximum operating pressure of approximately 106 kg/cm^2 abs are controlled by the steam turbine initial pressure governor.

Heat Recovery Steam Generator. The HRSG is constructed in accordance with Section I of the ASME Boiler Code and Indian Boiler Regulations (IBR). It is outfitted with the normal compliment of ASME code safety valves to minimize the potential for overpressure. In addition, the steam turbine bypass valves also function as pressure limiting valves. The steam is bypassed if the pressure increases more than 5% of the design value.

Heat transfer in the HRSG takes place in crosscounter flow in the superheater, reheater, and economizer sections. Tubes are supported from the top of the modules.

The evaporators consist of vertical tube bundles suspended from the steam drums. Fin tubes are welded to horizontal headers in removable racks of three rows. The steam drums are equipped with a nitrogen blanketing system and an internal steam purification system.

All tube welds are outside the gas flow path in gas-tight sections in which the headers are mounted.

The HRSG is internally insulated and is not insulated on the outside. Therefore, the shell is relatively cool and has low thermal stress. The internal surface of the insulation material (gas side) will be covered with stainless steel sheets supported by studs and shingled to permit free expansion.

The HRSG is started with hot exhaust from the gas turbine. If the HRSG is cold, the vents are opened to discharge the nitrogen and initial steam. The steam pressure rises at the rate controlled by the gas turbine exhaust gas temperature. The steam temperature is controlled during starting by the turbine exhaust gas temperature. The steam generated is discharged from the superheater discharge to the cold reheat line and from the hot reheat line to the condenser through the bypass system.

Once the steam pressure is increased to the bypass valve pressure setting, the steam turbine is warmed-up, rolled and synchronized with steam from the reheater. The steam flow is increased by further increasing load on the gas turbine. At approximately 30-40 percent of the steam turbine load, the main steam is admitted to the throttle and the main steam bypass to cold reheat is shut off. The HRSG is brought to full load by increasing gas turbine output to rated load.

During normal operation, the HRSG operates in a following mode, generating steam at a rate proportional to the energy received from the gas turbine. Shutdown is effected by reducing gas turbine load to reduce energy to the HRSG. As the gas turbine is unloaded, it is recommended that load be held at approximately 65 percent load on the gas turbine while the steam turbine is unloaded by diverting the steam to the bypass systems. This load is selected because the steam temperature is near rated so maximum heat will be retained to minimize starting time for a subsequent start. To complete the shutdown, the energy is reduced by modulating the gas turbine inlet guide vanes while maintaining the highest temperature. The HRSG isolation valves are closed to maintain pressure and maximum heat.

If satisfactory water chemistry is maintained, the HRSG has minimal maintenance requirements. The fuels used in the gas turbine are not ash forming so minimum or no external deposits would be expected.

The cloth-type expansion joints require replacement at approximately six year intervals, coinciding with the major inspection on the gas turbine.

Internal cleaning will be required with intervals depending on the water quality. The integral deaerator is designed to deliver feedwater with oxygen concentration of 7 ppb or less and provisions for chemical treatment and checking of water are included, so internal corrosion of the pressure parts will be minimal if the equipment is operated in accordance with specifications.

The internal inspection of the pressure parts will be required as mandated by local authorities.

Steam Turbine-Generator. The steam turbine is comprised of a HP section, an IP-LP section, and auxiliary systems. The auxiliary systems include the shaft sealing system, lubricating oil system and hydraulic system. The generator is comprised of the generator, exciter and auxiliary systems. The generator auxiliary systems include the shaft sealing system, hydrogen system and CO_2 purge systems. Other auxiliary systems include pumps, filters, blowers, pressure regulators, instruments and controls to form complete support systems for the main equipment.

Ratings of the major equipment in the steam turbine-generator system are:

- o Turbine - The turbine is rated for approximately 160 MW, 3000 rpm, single-flow straight condensing reheat steam turbine with 76 cm last stage buckets. This unit is designed for inlet throttle steam conditions of 103 kg/cm^2 abs, 538 C with 538 C reheat; and exhausting at 88 mm HgA. The turbine will also be capable of operating at the off-ambient, inlet throttle conditions up to 108 kg/cm^2 abs and 542 C. The turbine is assumed to have 85% efficiency in the HP section and 86% efficiency in the IP-LP section.
- o Generator - The generator is rated approximately for 180 MVA, 3000 rpm, 3-phase, 50 Hz, 16.5 kV, 0.85 pf, 0.55 short circuit ratio, hydrogen-cooled synchronous generator with four (4) corner-mounted coolers.
- o Exciter - The static excitation system will be rated 560 kW, 400 volts and 1500 DC amps.

The steam turbine expands steam received from the HRSG to drive the generator which converts shaft energy to electrical energy. Steam from the HRSG superheater passes through the main steam stop valve to the high pressure section. The steam expands through the high pressure section which exhausts to the reheater in the HRSG. Steam passes from the reheater through the reheat intercept valves to the intermediate pressure section. The steam further expands through the low pressure section and exhausts downward to the condenser.

The steam turbine-generator system is designed to operate as a coordinated major component of the combined-cycle system. It operates in a following mode generating power as a function of steam received from the HRSG.

Auxiliary Steam System. The auxiliary steam system receives, conditions, and distributes steam to secondary users during the various modes of plant operation. The system is designed to furnish steam during all steady-state and transient load conditions. The auxiliary steam during normal operation is provided from the main turbine cold reheat piping (HP exhaust). Secondary and tertiary auxiliary steam sources are the main steam connection and an auxiliary boiler, respectively.

The auxiliary steam system includes the auxiliary boiler, a common steam distribution header, with various branch lines for receiving and supplying steam. The auxiliary boiler, rated at 11 000 kg/hr, 18.6 kg/cm^2 abs saturated,

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provides steam for startup and the auxiliary steam system. The auxiliary boiler can be fired on No. 2 fuel oil.

Balance of Plant

Solid Waste Disposal (Plant 30). The bottom slag and fly slag discharged from the gasification plant (Plant 5) are stored separately in two storage bins, each sized for 3 days storage. From the storage bins, the slag and fly slag are transported to the disposal area in slurry form, through pipelines extending to about 8 km long. Pumps required for pumping water for slurry making (10% solid) and for pumping ash slurry are located in the ash water pump house and ash slurry pump house respectively. The pipelines run in an underground trench within the plant and are on over-ground RCC pedestals outside the plant area and in the ash disposal area.

An area of about 500 acres has been provided for ash disposal which would be adequate for 25 years of plant life. The ash slurry is discharged into lagoons formed by constructing dykes where the ash particles settle and water is collected at the top. This water and rain water collected within the pond is discharged through decent water towers and draw-off pipes to the clarification pond where the remaining ash particles, if any, are removed. The clear water is pumped back to the plant for re-use. During the rainy season, the excess water is discharged to the near-by river. Out of the total flow of recirculating water system, about 30% would be lost in ash pond area through evaporation, seepage, etc. The remainder is passed through rock filters and collected back in the ash water sump.

Relief and Blowdown Systems (Plant 31). The purpose of the relief and blowdown systems is:

- To burn any combustibles that may be vented from the plant during startup, shutdown, or under normal operating conditions
- To burn combustibles released from the plant during emergencies and plant upset conditions
- To protect the system equipment against damages from operating disturbances

The relief and blowdown systems basically consist of a main flare stack and the associated knockout drum. It has a single train and is designed to handle the maximum raw gas flow rate from the gasification plant.

The possible sources of combustibles to be disposed of in the flare stack are:

- Vent gas released from the slag lockhoppers in the gasification plant
- Gasifier startup gases from the gasification plant
- Any other gases flared during startup or upset conditions

These gases are routed from individual headers to the knockout drum before entering the main flare stack. A controlled liquid level is maintained in the knockout drum by means of the KO drum pump. The liquid which is mainly water condensate is pumped to the ash pond. The flare stack is equipped with a flare tip burner and appropriate burner control and ignition system.

During normal operation, vent gas from the slag lockhoppers in the gasification plant is continuously incinerated in the relief and blowdown systems. Because of the low heating value of these gases, LPG is required as supplemental fuel for flaring.

The Claus tail gas is sent to the gas turbines for incineration. Vent gas from the Claus unit during startup or upset conditions is incinerated in a small flare system within the Claus unit.

Interconnecting Piping (Plant 32). The purpose of this system is to provide all piping and pipeways required for transmitting the process, utility, and waste fluids between the various process, power and utility areas, except for the following piping systems which are included in their corresponding areas:

- Main flare system piping
- Potable water piping
- Fire water piping

The major items in the interconnecting piping system are:

- Fuel oil lines
- Pipe and pipeways for raw water supply and BFW makeup water supply
- Pipe and pipeways for treated waste water and steam blowdown
- Instrument and service air lines
- Oxygen and nitrogen supply from the air separation plant to the gasification plant
- Steam lines to the liquid oxygen and liquid nitrogen vaporizers
- Pipe and pipeways between process areas
- Distribution of cooling water and service water from the cooling tower
- Coal gas, steam, feed water, and condensate lines between the process and power areas
- Miscellaneous process and utility piping

Compressed Air System (Plant 33). This system furnishes compressed air for plant and instrument air uses.

The capacity of compressed air system is 8000 Nm^3/h. Half of the air is for plant air and the other half is for instrument air. The instrument air is dried to -40 C dew point before its use. This compressed air system has four operating trains.

Each compressed air train has one nonlubricated, centrifugal air compressor supplying 2000 Nm3/h clean compressed oil-free air. The pressure at the compressor outlets is 8 kg/cm^2 abs. Each train also has one twin-tower cycling type air dryer and one air receiver. Half of the compressed air from the air compressor is dried in the air dryer and used as instrument air. All necessary instruments, valves and piping are included, and maintenance stations are located throughout the plant.

Fuel Oil and LPG System (Plant 34). This system maintains and supplies sufficient quantities of No. 2 fuel oil and LPG for the following uses:

- Gasifier startup
- Gas turbine startup
- Auxiliary boiler
- Mobile equipment

No. 2 fuel oil is delivered by truck to a storage tank. Oil from the tank is pumped by a fuel oil pump to the gasifiers and the auxiliary boiler.

LPG is received by tank truck to a high pressure (14 kg/cm^2 abs) storage bullet. From the bullet, LPG is distributed to the flare system through a pressure regulator.

Electrical System (Plant 35). The purpose of the electrical system is to control and deliver generated power to the 220 KV distribution grids and to provide auxiliary power for in-plant loads.

The battery limits for the high voltage portion of the electrical design terminate at the 220 kV bus bars at the main substation. The main substation is outside the present scope of work. All interfacing high voltage equipment is part of this design.

The electrical system consists of step-up transformers for the gas turbine and steam turbine generators. It also includes a distribution transformer and a startup transformer for 6.6 kV auxiliary load service. A spare startup transformer of 100% capacity is provided.

Each of the gas and steam turbine generators is rated for 16.5 kV. An 18 kV non-segregated phase bus connects the generator output to a 16.5-220 kV power transformer for delivery to the main substation.

High voltage connections to the main substation are provided through a circuit breaker-and-a-half scheme. Three 220 kV circuit breakers and associated switches, current transformers and potential transformers are furnished in a switchyard.

The 18 kV bus for the gas turbine is tapped to feed a 16.5-6.6 KV distribution transformer which serves as the primary source of auxiliary power for the plant auxiliaries except the air separation plant and cooling system. A 6.6 kV double-ended load center is provided to distribute power to all medium voltage loads. A double-ended 400 V load center provides low voltage power for small motors and miscellaneous plant loads.

The air separation plant is a major power consumer in the IGCC plant. The power required is delivered from the 220 kV distribution grid. The power is stepped down to 16.5 kV and distributed to the various uses in the air separation plant through its own substations. The battery limits for the electrical system of the air separation plant are at the 16.5 kV switchgear feeder terminals in the air separation plant's main substation.

A dual breaker-and-a-half scheme is used to provide 220 kV power switching for the two short transmission lines to the air separation plant. Each transmission line terminates at an HV switch and 50/67 MVA power step down transformer located at the air separation plant's main substation. A double-ended 16.5 kV switchgear arrangement distributes this power through 18 kV feeder cables to the various substations in the air separation plant.

Instrumentation and Controls (Plant 36). The purpose of plant instrumentation and controls is to provide automatic control and sequencing of plant operations, with manual backup, and to provide condition monitoring and diagnostic capabilities.

A distributed digital control system (DDCS) provides a high level of control flexibility and reliability using highly redundant microprocessor-based controls. The microprocessor based controllers are field mounted in local control compartments in each major plant area. These microprocessor controllers are connected to a central control room by a dual fiber-optic data highway. They provide "stand-alone" control even if communication via the data highway has failed.

The central control room contains station control processors, control modules, CRT's and keyboards, printers, and alarm consoles. The CRT's display for operator control and monitoring. The control room has real time diagnostic and prognostic capabilities on operational status and health of major components and provides history file storage of selected critical parameters.

The control system uses redundant microprocessor controllers, power supplies, control sensors, and data highways. The control system also uses significant manual backup capability and a full critical process display with auto-manual station for operator intervention. On-line condition monitoring with diagnostic and prognostic capability is included.

Cooling Water System (Plant 37). All the cooling loads in the IGCC plant are provided by a mechanical draft cooling tower. The required water flow is shown in the overall water balance diagram (Figure 5-6) and the stream flow table (Table 5-5).

The cooling tower consists of 29 cells (2500 m^3/h per cell) and associated auxiliary equipment, including fans with motors and gear drives, a water distribution system, a deluge fire protection system, piping and instrumentation, and all structural components necessary for complete tower installation. The tower is designed based on a summer dry bulb temperature of 35 C with 5.6 C temperature approach, 8.3 C temperature range, and five cycles of concentration.

From the cooling tower, the cooling water is divided into a circulating water system and a service water systems. The circulating water system services the combined cycle power plant, and the service water system provides the cooling requirements in the gasification and air separation plants. Makeup water from the raw water supply and treatment system (Plant 38) is introduced to the cooling water system at the cooling tower basin.

Six 25 percent capacity circulating water pumps and two 50 percent capacity service water pumps of the vertical, wet-pit, mixed-flow type take suction from the cooling tower basin for the circulating and service water systems respectively. Electrohydraulically operated butterfly valves are provided in each pump discharge line. In the circulating water system, cooling water is sent to the surface condenser, condenser vacuum pump coolers, turbine lube oil coolers, generator H_2 coolers and an auxiliary cooling water closed-loop circuit.

The auxiliary cooling water circuit is a closed-loop system that uses demineralized water as the cooling medium. This circulating water passes the heat to the circulating water system through auxiliary cooling water heat exchangers. The cooling loads in this closed-loop circuit are characterized by small tubed exchanger requiring clean cooling water to avoid plugging such as the turbine control fluid coolers, BFW pump coolers, steam sample coolers.

The auxiliary cooling water circuit consists of three 50 percent capacity auxiliary cooling water pumps, two 100 percent capacity auxiliary cooling water heat exchangers, the system head tank to provide the makeup demineralized water, and a closed-loop piping system, which supplies cooling water to the various auxiliary loads. The auxiliary cooling water head tank is located above the highest circuit component. The tank is sized to accommodate thermal expansion and contraction of the coolant and any surge in the circuit.

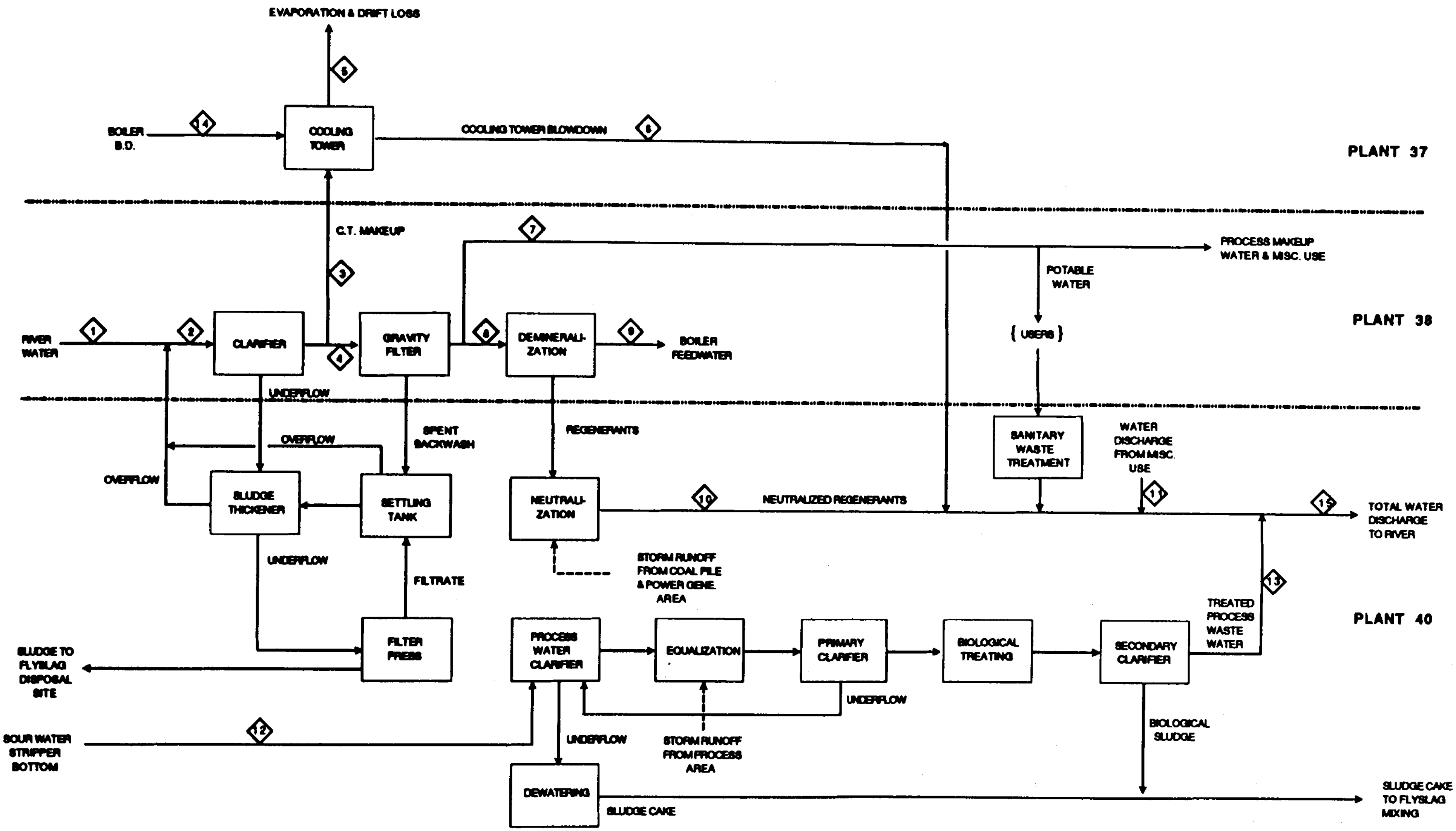

FIGURE 5-6

OVERALL WATER BALANCE DIAGRAM
IGCC PLANT (SHELL CASE)

Table 5-5

MAJOR STREAMS OF OVERALL WATER BALANCE
IGCC PLANT (SHELL CASE)

Stream Number	Stream Name	Flow, m3/h
1	Total River Water Intake	1324
2	Clarifier Feed Water	1361
3	Cooling Tower Makeup	1135
4	Gravity Filter Feed Water	178
5	Cooling Tower Evaporation & Drift Loss	992
6	Cooling Tower Blowdown	160
7	Process Makeup Water & Misc. Use	30
8	Demineralizer Feed	148
9	Boiler Feed Water	127
10	Neutralized Demineralizer Regenerants	21
11	Water Discharge from Misc. Use	11
12	Sour Water Stripper Bottom	41
13	Treated Process Waste Water	41
14	Boiler Blowdown	17
15	Total Water Discharge to River	241

Makeup of demineralized water with corrosion inhibitors is added to the system at this tank.

Raw Water Supply and Treatment (Plant 38). The purpose of this system is to provide process water, cooling tower makeup water, and boiler makeup water for the IGCC plant. The major processing blocks in this system are shown in the overall water balance diagram, Figure 5-6. The major stream flows are shown in Table 5-5.

Raw water is obtained from the Damodar River. Water to be used as boiler makeup water is pumped from the raw water intake to a clarifier. Potassium permanganate, sodium carbonate, and alum are added to the clarifier to remove iron and manganese from the water, and to coagulate suspended solids. The suspended solids settle to the bottom of the clarifier as sludge. The clarified water is pumped to two gravity filters for further suspended solids removal. Sodium hypochlorite is added to the filter influent to control bacterial growth in the filter beds. The filters are backwashed once per day.

A portion of the filtered water is used as process makeup water for the gasification plant and as plant potable water. The remaining filtered water is pumped to two parallel cation then anion resin exchanger trains. The effluent from the two anion exchanger vessels goes to two parallel mixed bed polishing units. The demineralized water produced is stored in a tank with 4 hours of boiler feed water storage capacity. The expected demineralized water quality is:

Total Hardness as $CaCO_3$	Max 10 ppbw
Iron as Fe	Max 2 ppbw
Silica as SiO_2	Max 5 ppbw
TDS	Max 100 ppbw

This water quality is suitable for high pressure boiler systems.

To sluice slag from the gasification plant to the ash pond, raw water is required to provide the high pressure, medium pressure, and low pressure sluice water. Two 100 percent capacity supply pumps are provided for each of these slag sluice water streams.

Under normal conditions, the makeup water to cooling tower needs only to be clarified prior to its use. However, during a heavy rain storm, the river water may become very turbid and further filtration in the gravity filters is required.

Fire Protection (Plant 39). The fire protection system includes the following:

- o Fire protection water yard mains, hydrants, and valves
- o Automatic wet pipe sprinkler systems
- o Deluge sprinkler systems
- o Pre-action sprinkler system
- o Water spray systems
- o Carbon dioxide systems
- o Halon systems
- o Standpipes and hose reels
- o Portable extinguishers
- o Fire and smoke monitors, detectors, and alarms
- o Fire barriers

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Fire protection water is provided by two supply water pumps to the fire loop at 18.3 kg/cm^2 abs. The fire protection system shall comply with the requirements of the Indian Tariff Advisory Committee.

Waste Water Treating (Plant 40). This system treats waste water generated from the gasification plant, combined cycle plant, and raw water supply and treatment system. The major process blocks in this system are shown in the overall water balance diagram, Figure 5-6. The major stream flows are shown in Table 5-5.

Waste water from the gasification plant is the sour water stripper bottom. Treating of this process waste water includes clarification and solids concentration followed by biotreatment for BOD reduction and nitrification. The sour water stripper bottom, which contains a minor amount of suspended solids, is fed to the process water clarifier. The clarifier provides sufficient residence time, with the aid of flocculant, for the bulk of the suspended solids to settle. Clarifier underflow is collected in a holdup tank and, during flyslag silo unloading periods, is further concentrated and dewatered by filtration. The concentrate is then mixed with the biosludge from biotreatment and diluted with treated water to form a slurry stream. The slurry is sent to the pug mill in the flyslag handling and storage system. The process water clarifier overflow is pumped to an equalization/surge tank where it is mixed with contaminated storm water runoff collected from concrete pads in the process area.

From the equalization tank, the combined effluent is then subjected to further clarification in a primary clarifier. The small quantity of underflow from the primary clarifier is recycled to the process water clarifier. The overflow is sent to a series of rotating biological contactors to ensure nitrification of the residual ammonia and any other nitrogen compounds present in the overflow stream. A small amount of nutrient phosphorus is added to the clarifier overflow, as well as sodium bicarbonate/sodium hydroxide to control alkalinity.

The effluent from the biotreaters contains a small amount of suspended biosludge. The biosludge is separated in a secondary clarifier and mixed with concentrated solids from process water clarification as described above. A portion of the treated water from the secondary clarifier is used for flyslag wetting and the remainder is pumped to disposal.

Backwash water from the gravity filters in the raw water supply and treatment system is pumped to a spent backwash water settling tank where suspended solids are allowed to settle. The top two-thirds of the tank contents is recycled to the clarifier, and the bottom third, which contains the settled solids, is pumped to a thickener. Underflow from the clarifier in the raw water treatment system is also pumped to this thickener. The thickener concentrates the sludge to approximately 6 percent solids. This sludge is then pumped to a filter press for final dewatering to 30% solids. The thickener overflow is recycled to the clarifier. The filtrate from the filter press is recycled to the settling tank. The filter cake is sent to the flyslag disposal site for final disposal.

The cation and anion exchangers in the raw water treatment system are regenerated once every day and the mixed bed units are regenerated every 10 days. The cation beds are first backwashed with filtered water, then regenerated with a 2 percent solution of sulfuric acid. Sixty-six degrees Baume sulfuric acid is diluted to 2 percent concentration in an inline static mixer. The anion beds are regenerated with a 5 percent solution of sodium

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hydroxide. Fifty percent sodium hydroxide is diluted to 5 percent solution in a mix tank. Regenerant brines flow into an agitated brine neutralization tank. The regenerated resin beds are rinsed with demineralized water pumped from the boiler feed water storage tank. The first couple of bed volumes of rinse water are sent to the neutralization tank. The combined brines are alkaline and additional sulfuric acid is added to the neutralization tank for pH control to produce a near neutral waste for discharge.

Sanitary waste from the plant is collected and routed to a package sanitary waste treatment unit. The treated waste water is discharged to river.

General Services and Mobile Equipment (Plant 41). The purpose of this unit is to provide mobile equipment for general plant services, and other equipment required for the laboratory, office, shop, and warehouse areas. This includes mobile equipment that is not specifically assigned to any single process or power generation area. Examples include: front-end loaders, forklifts, mobile cranes, etc. Furniture and fixtures for the warehouse, control, and administrative buildings are also included.

Site Preparation and Improvements (Plant 42). This area includes the site preparation and improvements necessary to accommodate the IGCC plant. No piling is required.

Buildings (Plant 43). This plant area includes only the buildings not specifically related to any process or power generation plants. These buildings are the control building, administrative building, warehouse, laboratory, firehouse, medical facility, machine shop and maintenance building.

A number of buildings are located within the IGCC plant, but are included in their respective area cost estimates:

- Turbine-generator building (in Plant 9)
- Auxiliary service building (in Plant 9)
- Raw water treatment building (in Plant 38)
- Waste water treatment building (in Plant 40)
- Air separation plant compressor buildings, cryogenic unit, and its own control building (Plant 4)

5.1.2 Texaco Case

An overall block flow diagram of the IGCC plant using Texaco gasifier is shown in Figure 5-7. The number of operating and spare trains used is indicated for each of the major process and power blocks in Figure 5-7. The major stream flows (at the 29.5 C annual average ambient temperature) are shown in Table 5-6. An overall utility summary based on the same ambient temperature is shown in Table 5-7. Equipment lists are shown in Appendix B. A description of the plant facilities is as follows.

Coal Transportation System

This system is the same as that described for the Shell case.

Coal Receiving, Primary Crushing, and Storage (Plant 1)

A flow diagram of this plant is shown in Figure 5-8.

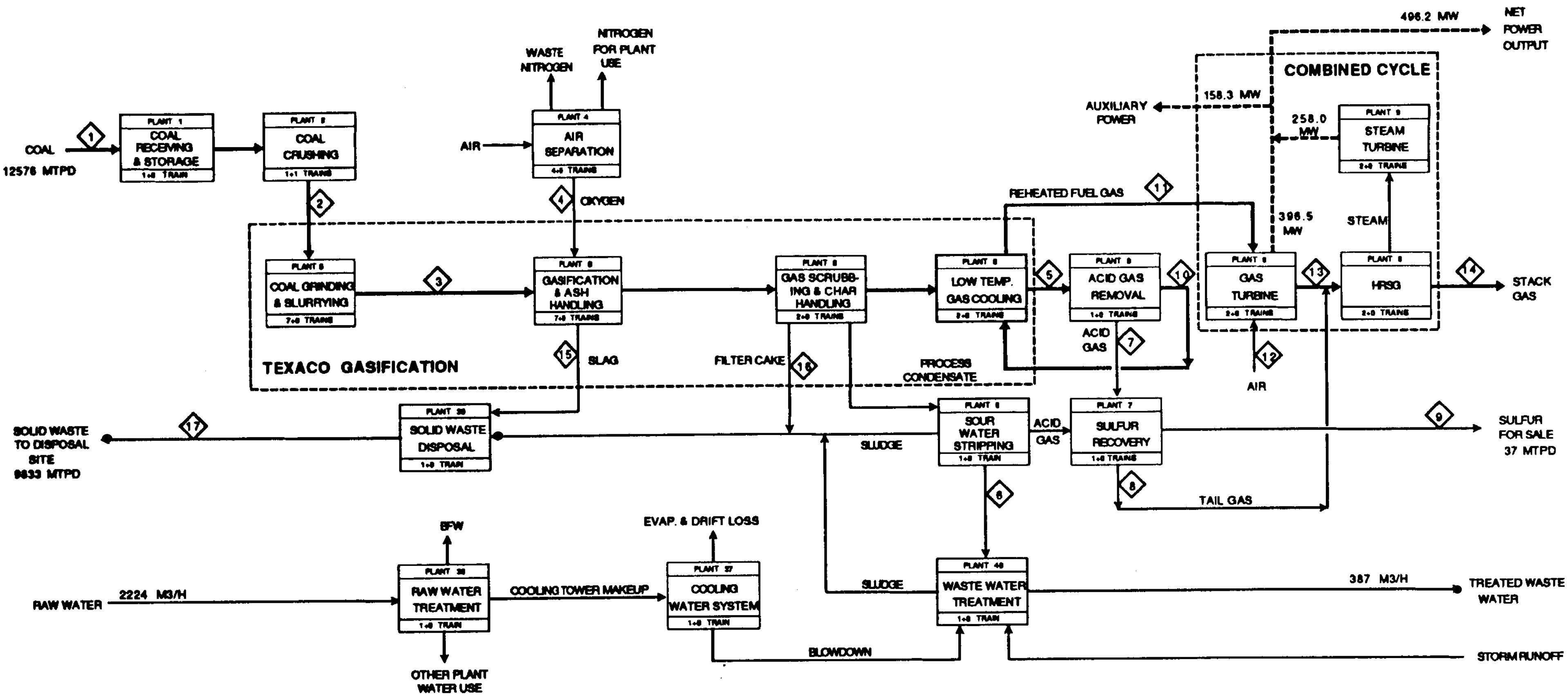

FIGURE 5-7

OVERALL BLOCK FLOW DIAGRAM IGCC PLANT (TEXACO CASE)

Table 5-6

MAJOR STREAMS OF IGCC PLANT
(TEXACO CASE)

STREAM NUMBER	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
STREAM DESCRIPTION	COAL FEED	CRUSHED COAL	COAL SLURRY FEED	OXYGEN TO GASIFIER	RAW SYNGAS TO AGR UNIT	STRIPPED WATER	ACID GAS TO SULPHUR RECOVERY	TAIL GAS	SULPHUR BY-PRODUCT	PRODUCT SYNGAS	REHEATED SYNGAS	AIR TO GAS TURBINE	GAS TURBINE EXHAUST	STACK GAS	GASIFIER SLAG	FILTER CAKE	SOLID WASTE
GASES: kg-mol/hr																	
H2					6850.7		1.9			6848.8	6848.8						
CO					8793.7		2.2			8791.5	8791.5						
CO2					6602.5		603.0	605.7		5999.5	5999.5		14836.8	15442.7			
H2S					52.27		52.11	2.84		0.16	0.16						
COS					1.34		0.40	0.16		0.94	0.94						
NH3																	
CH4					45.1		0.3			44.9	44.9						
C2H6																	
C3H8																	
N2				48.7	186.7			115.9		186.7	186.7	101152.6	101339.3	101455.1			
AR				144.1	144.1		0.0	1.5		144.0	144.0	1270.4	1414.5	1416.0			
H2O					66.0		38.4	93.0		95.7	95.7	4377.3	11411.6	11507.4			
O2				9467.0				0.9				27210.0	19298.5	19294.8			
SO2								1.18					1.09	5.27			
TOTAL: KG-MOL/HR	0.0	0.0	0.0	9659.7	22742.4	0.0	698.3	821.1	0.0	22112.3	22112.3	134010.2	148301.7	149121.3	0.0	0.0	0.0
LIQUIDS: kg/hr																	
H2O	94,330	94,330	202,223			82,388									174,125	30,729	204,854
SULPHUR									1,549								
SOLIDS: kg/hr																	
COAL(MAF)	226,391		226,391														
FLUX																	
ASH/SLAG	203,333		203,333												174,125	30,729	204,854
BIO SLUDGE																	
SULPHUR																	
TOTAL: KG/HR	524,054	524,054	631,948	310,053	565,470	82,388	29,102	31,847	1,549	537,597	537,597	3,833,886	4,371,474	4,403,321	348,251	61,458	409,709
TEMPERATURE, C	29.4	29.4	60.0	139.4	40.6	54.4	43.3	137.8	132.2	47.8	193.3	29.4	591.7	126.7	76.7	82.2	77.2
PRESSURE kg/cm2(g)	0.00	0.00	44.30	40.79	26.72	4.92	0.60	0.07	4.92	26.02	23.91	0.00	0.04	0.00	0.00	0.00	0.00

Table 5-7

UTILITY SUMMARY
(TEXACO CASE)

			Steam, kg/hr									Cooling Water		Make-Up Water		
Plant Number	Plant Name	Power kW	108 kg/cm2 542 C	43 kg/cm2 satd	25 kg/cm2 358 C	8.1 kg/cm2 satd	3.9 kg/cm2 satd	2.1 kg/cm2 satd	BFW kg/hr	Blowdown kg/hr	Condensate kg/hr	Duty MMkcal/hr	Flow mkg/hr	Raw kg/hr	Filtered kg/hr	Demin kg/hr
1	Coal Receiving & Storage	551														
2	Coal Handling	831														
4	Air Separation	125,027										102.14	12,281			
5	Coal Gasification	5,547					(359,097)		480,273	(7,182)		380.25	46,208		107,893	
6	Sulphur Removal	504					46,689				(46,689)	21.60	2,597			
7	Sulphur Recovery	190		2,763			(5,617)	(595)	6,851	(205)	(3,196)					
8	Sour Water Stripping	167				14,900					(14,900)	5.75	690			
9	Combined Cycle															
	Gas Turbine	(396,460)														
	Steam Turbine	(258,004)	505,611	(2,763)	97,813	(14,900)	318,025				(1,040,361)	497.27	60,428			133,692
	HRSG		(505,611)		(97,813)			595	(487,124)	(12,314)	1,105,146					
	BFW Pumps & Aux. Equipment	5,777														
37	Cooling Water System	16,018								19,701		(1,007.00)	(122,204)		1,930,412	
38	Raw Water Supply & Treatment	1,122												2,224,081	(2,049,664)	(133,692)
40	Waste Water Treatment	76														
	General Facilities	840													11,358	
	Transformer Losses	1,836														
	TOTAL	(496,178)	0	0	0	0	0	0	0	0	0	0	0	2,224,081	0	0

Notes: ( ) indicates production

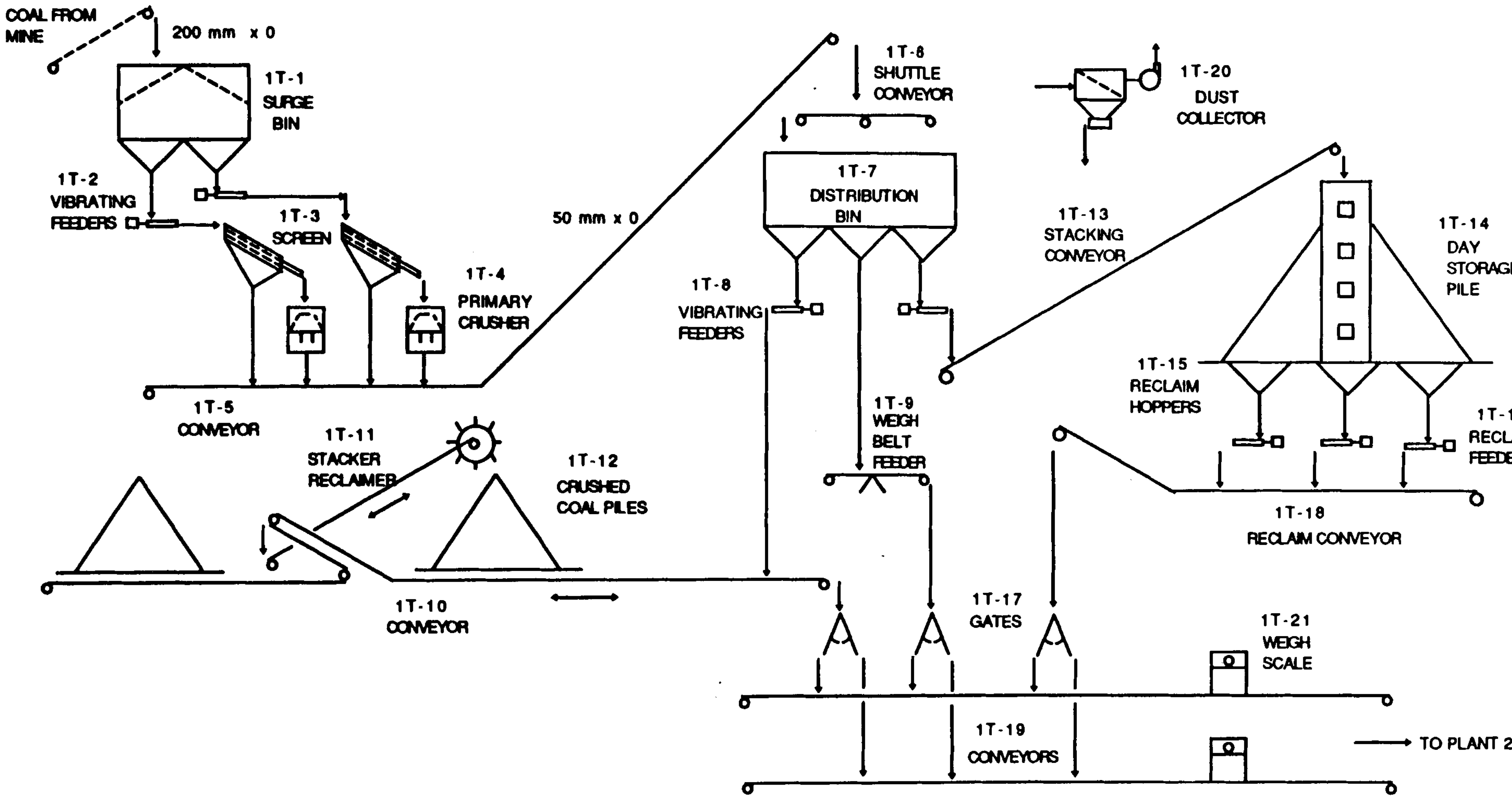

FIGURE 5-8

FLOW DIAGRAM
COAL RECEIVING, PRIMARY CRUSHING, & STORAGE (PLANT 1)
(TEXACO CASE)

The design and description of this plant is identical to that in the Shell case. The only exception is that the feeders, conveyors, and reclaimers are designed for a coal throughput of 600 instead of 500 tph because the Texaco gasifier has a higher coal requirement.

Coal Secondary Crushing (Plant 2)

A flow diagram of this plant is shown in Figure 5-9.

This plant crushes the 50 mm x 0 coal from Plant 1 to a 13 mm top size product. The crushed coal is then transported to the gasification plant (Plant 5). The Texaco gasifier does not require flux and therefore there are no limestone receiving and handling facilities.

Coal from Plant 1 is received by the crushing plant feed conveyor. A tramp iron magnet removes any tramp iron found in the feed. The conveyor delivers the coal to a 60-tonne surge bin. The surge bin serves two 300 tph capacity crushing trains. Each train includes a scalping screen and a short head cone crusher.

Crushed coal from the crushers is collected by the crusher discharge conveyors to feed to the day bin of the coal slurry preparation unit in Plant 5. A tripper conveyor distributes the coal along the length of the day bin.

The design rating of the crushing plant represents a 40 percent redundancy in capacity. The crushing plant feed conveyor, the day bin feed conveyor and the tripper conveyor are provided with identical spare units.

Air Separation (Plant 4)

The design and description of this plant are identical to that in the Shell case. The only differences are:

- The oxygen production rate is higher. Four parallel, 25% capacity trains are used, each designed to supply 1820 MTPD of contained oxygen at 42 kg/cm^2 abs. The Texaco gasifier uses slurry feed which requires more oxygen to combust and evaporate the slurry water in the gasifier.
- The slurry feed also eliminates the high purity nitrogen production which is required for the coal pressurizing and feeding to the gasifier in the Shell case.

Texaco Coal Gasification (Plant 5)

The Texaco gasifier can be operated with a waste heat boiler mode or a quench mode. As discussed in Section 4.1.3, the quench mode is selected for this study. The design is based on the process information provided by Texaco. Due to the reason given in Section 4.1.3, Texaco has elected to operate the gasifier without a fluxing agent.

The Texaco gasification can be broken down into several sections. They are described individually below.

Coal Grinding. The crushed coal from Plant 2 is stored in a storage bin. From the bin, coal flows by vibrating feeders and weight feeders to the coal mills for wet grinding into slurry. The mills are of ball mill type. Additives are

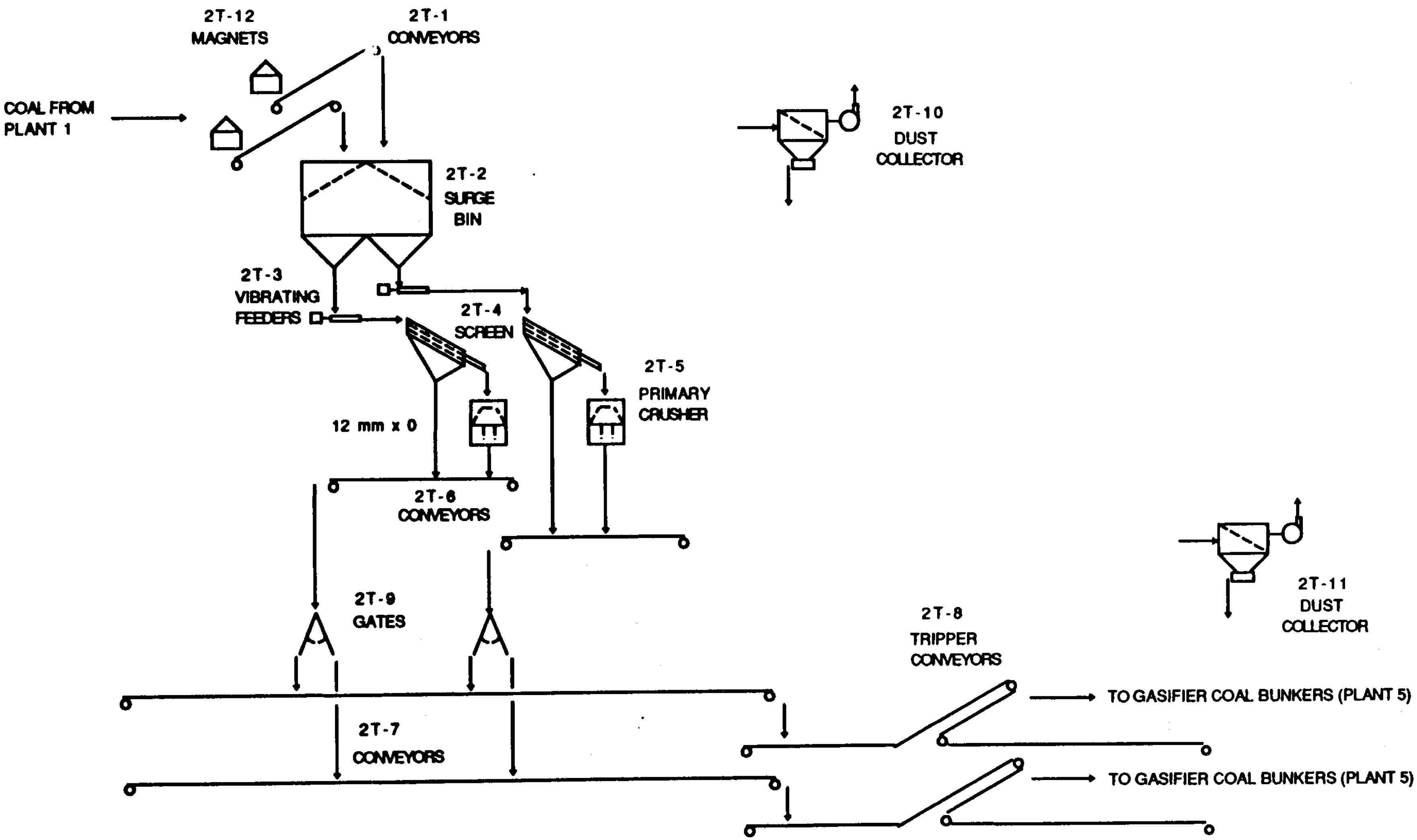

FIGURE 5-9

FLOW DIAGRAM
COAL SECONDARY CRUSHING AND HANDLING (PLANT 2)
(TEXACO CASE)

injected to increase the slurry concentration. Ammonia may also be injected to control the slurry pH value. The slurry product has a 68% solids concentration.

The slurry exits the coal mills through a trommel screen into the mill discharge tanks. The slurry is kept in suspension in the tanks by agitators. After passing through the slurry vibrating screen, the slurry is pumped to two slurry storage tanks.

Slurry Feeding, Gasification, and Gas Scrubbing. The coal slurry from the storage tanks is fed to the process burner of the gasifier by the slurry charge pumps. The slurry can be transferred if necessary from one storage tank to the other by the slurry transfer pumps. In the process burner, the slurry mixes with oxygen delivered from the air separation plant. The process burner is kept cool by a closed loop cooling water circuit.

The gasifier is a refractory-lined vessel in which the coal slurry and oxygen react under high temperature and pressure to form synthesis gas. Meanwhile, the coal ash is melted to form slag. The synthesis gas and molten slag are water quenched in the quench chamber of the gasifier. The quenched gas is scrubbed of particulates first in the nozzle scrubber and then in the syngas scrubber. Trays in the syngas scrubbers are irrigated by return process condensate from the low temperature cooling section of the gasification plant. Water from the bottom of the syngas scrubber is recycled to the nozzle scrubber and the quench ring of the quench chamber.

Slag Removal. The solidified slag formed in the quench chamber is sent to a lockhopper. A rotary slag crusher is located between the quench chamber and the lockhopper to break large slag particles. Normally water circulates between the quench chamber and lockhopper. Every 20-30 minutes, the lockhopper is isolated, depressurized, and emptied into a slag sump. The lockhopper flush drum provides the necessary flush water for emptying the lockhopper.

The slag is removed and dewatered to 50% moisture by a drag conveyor in the slag sump. The dewatered slag is sent for disposal. Water in the slag sump is water cooled and pumped to the lockhopper flush drum.

Char/Water Handling. A water blowdown stream (called black water) is drawn from the quench chamber, cooled by heat exchange with the makeup water to the syngas scrubber, and flashed in a flash drum. The flashed water is water cooled and then flows to a gravity settler. Flocculants may be added to the settler to enhance the settling of soots. Clear overhead from the settler (called gray water) flows to a storage drum. The soot slurry (20% solids concentration) drawn from the settler bottom is sent for dewatering to 50% solids cake in a vacuum filter unit. Water wash is used during the filtration to ensure moisture contained in the cake is clean and safe for transport. The filtrate is routed back to the gravity settler.

Overhead gas from the black water flash drum is water cooled to condense its water vapor before it is sent to the sulfur recovery plant (Plant 7).

Grey water from the storage drum is split into three streams. The first stream, combined with process condensate from the low temperature cooling and deaerated water from the combined cycle plant, becomes the makeup water for the syngas scrubber. The second stream is a purge stream sent to sour water stripping (Plant 8). This purge prevents buildup of chlorides, formates, and other nonvolatile matter in the water circulation loop in the gasification plant. The third stream is used as makeup water to the lockhopper flush drum.

Low temperature Cooling. The gas leaving the syngas scrubber is cooled sequentially by first preheating the clean fuel gas from the acid gas removal unit to 193 C, followed by generating 2.1 kg/cm^2 abs saturated steam, and then by cooling water. The final gas temperature is 48 C before the gas is fed to the acid gas removal plant.

Acid Gas Removal (Plant 6)

The acid gas removal employs Dow's GAS/SPEC process. Dow provided the basic design information for this plant.

This plant has the same process arrangement as described for the Sulfinol-M process in the Shell case but the solvent used is a highly selective MDEA solution (called Gas/SPEC SS-2 solvent). Texaco gas has a very high CO_2 content. A highly selective solvent is required to minimize the CO_2 removal so as to maximize the gas mass flow to the gas turbine.

The design sulfur removal is 98 %. The CO_2 removal is 9 %, i.e. 91 % slippage through the removal system. Only one train is used for this plant.

Sulfur Recovery (Plant 7)

The acid gas produced from the acid gas removal plant has a higher CO_2 content than that in the Shell case. This diluted feed can not sustain sulfur combustion in the Claus unit. As a result, the Selectox unit licensed by Parson is used for the sulfur recovery.

The Selectox process is very similar to the Claus unit except the sulfur combustion is carried out catalytically at low temperature. The lower combustion temperature reduces the sulfur concentration requirement in the feed gas.

The sulfur recovery is 92%. This recovery level was chosen because beyond this level there would be a substantial cost increase for the recovery. This recovery level combined with the 98% removal in the acid gas removal unit provides an overall sulfur recovery of 90% for the IGCC plant.

Sour Water Stripping (Plant 8)

In this plant, purge water from the Texaco gasification (Plant 5) is first subject to chemical precipitation and then sour water stripping. The chemical precipitation removes toxic metals, cyanide, and sulfate to enhance the effectiveness of subsequent biotreatment in the waste water treatment plant (Plant 40).

The chemical precipitation consists of two stages. In the first stage, ferrous sulfate is added to precipitate sulfide and cyanide. In the second stage, lime is added to precipitate iron and other metals. The sludge produced is filtered and sent for solid waste disposal.

The sour water stripping following the chemical precipitation is identical to that described for the Shell case.

Combined Cycle (Plant 9)

The design and description of this plant is very similar to that in the Shell case. Highlighted below are the major differences.

Gas Turbine. Based on the clean gas composition supplied by Texaco, GE provided the following gas turbine performance (one 9F gas turbine) at both the normal and design ambient temperatures:

	29.4 C (Normal)	18.3 C (Design)
Fuel(LHV), Million Kcal/h	499	524
Fuel Gas Temperature, C	193.3	193.3
Relative Humidity	80	60
NO_x Steam, 1000 kg/h	0	0
Exhaust Flow, 1000 kg/h	2185.7	2299.0
Exhaust Temperature, C	591.7	581.7
Power Output, MW	198.3	213.6

The Texaco gas has a very high CO_2 content. CO_2 acts as a diluent to suppress the flame temperature in the gas turbine combustor. As a result, no NO_x steam injection is required.

Steam Generation and Consumption in the Process Area. A steam balance of the process area is shown in Figure 5-10. The major flows are shown in Table 5-8. Steam is generated and consumed in the process plant at four pressure and temperature levels.

High pressure saturated steam at 43.2 kg/cm^2 abs is consumed for gas preheating in the sulfur recovery plant. This is provided by desuperheating of an extraction steam from the steam turbine in the combined cycle plant.

Medium pressure saturated steam at 8.1 kg/cm^2 abs is required as stripping steam in the sour water stripping plant. This steam requirement is provided by desuperheating of an extraction steam from the steam turbine in the combined cycle plant.

Intermediate pressure saturated steam at 3.9 kg/cm^2 abs is produced from the sulfur condenser in the sulfur recovery plant and low temperature heat recovery in the Texaco gasification plant. It is consumed for sulfur pit and line heating in the sulfur recovery plant and solvent regeneration in the acid gas removal plant. In addition, the high pressure condensate from the gas preheater in the sulfur recovery plant is flashed, which generates an additional amount of 3.9 kg/cm^2 abs saturated steam. Overall, there is a surplus of this pressure level steam which is fed to the steam turbine in the combined cycle plant.

Low pressure saturated steam at 2.1 kg/cm^2 abs is produced from the sulfur condenser in the sulfur recovery plant. This steam is routed to the deaerator in the combined cycle plant.

Steam Cycle. The steam cycle configuration is shown in Figure 5-11 and the major stream flows at the 29.5 C annual average temperature are shown in Table 5-9.

The cycle configuration is identical to that in the Shell case. The major differences are:

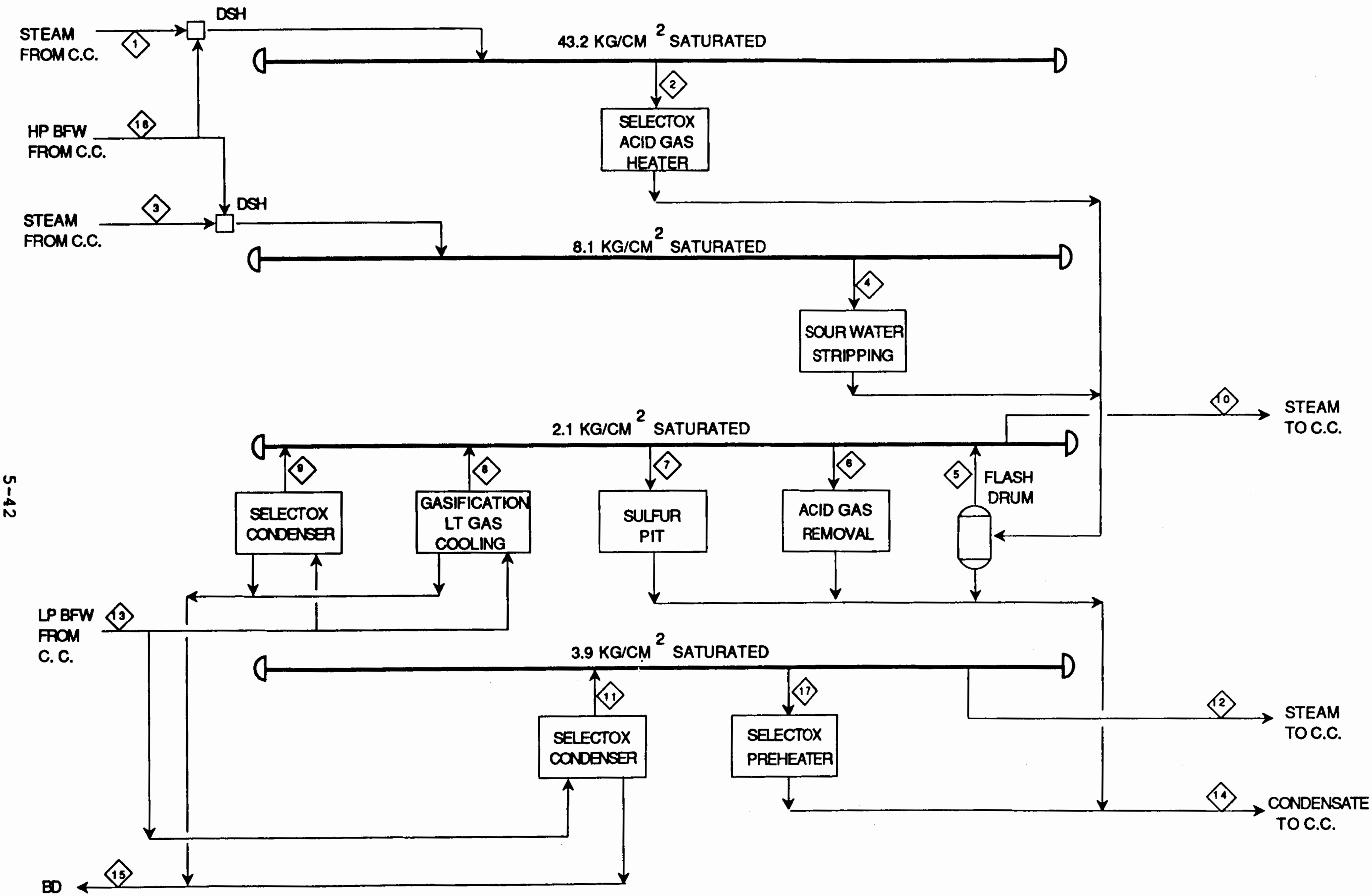

FIGURE 5-10 PROCESS STEAM BALANCE DIAGRAM (TEXACO CASE)

Table 5-8

STREAM FLOW FOR PROCESS STEAM
(TEXACO CASE)

Stream No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
STREAM DESCRIPTION	STEAM FROM HP TURBINE	STEAM TO ACID GAS HEATERS	STEAM FROM IP TURBINE	STEAM TO SWS UNIT	FLASH STEAM	STEAM TO AGR UNIT	STEAM TO SULPHUR PIT	STEAM FROM LT GAS COOLING	STEAM FROM SULPHUR COND.	STEAM TO LP TURBINE	STEAM FROM SULPHUR COND.	STEAM TO DA	LP BFW FROM COMBINED CYCLE	COND. TO COMBINED CYCLE	BLOW-DOWN	HP BFW FROM COMBINED CYCLE	STEAM TO SULFUR PREHEAT
Pressure, kg/cm2 abs	43.25	43.25	8.09	2.31	3.87	3.87	3.87	3.87	3.87	3.87	2.11	2.11	7.03	8.09	3.87	45.71	2.11
Temperature, C	410.8	253.3	380.8	170.0	141.7	141.7	141.7	141.7	141.7	141.7	121.1	121.1	115.6	148.3	141.7	115.6	121.1
Flow, 1000 kg/hr	2.33	2.76	12.42	14.90	0.70	46.69	0.29	359.10	5.21	318.02	0.60	0.60	373.13	64.79	7.39	2.91	0.84
Enthalpy, kcal/kg	757.27	653.29	735.52	645.73	637.90	637.90	637.90	637.90	637.90	637.90	631.23	631.23	100.24	133.29	126.86	100.24	631.23

1. Enthalpy values are based on 0 kcal/kg for liquid water at 0 C

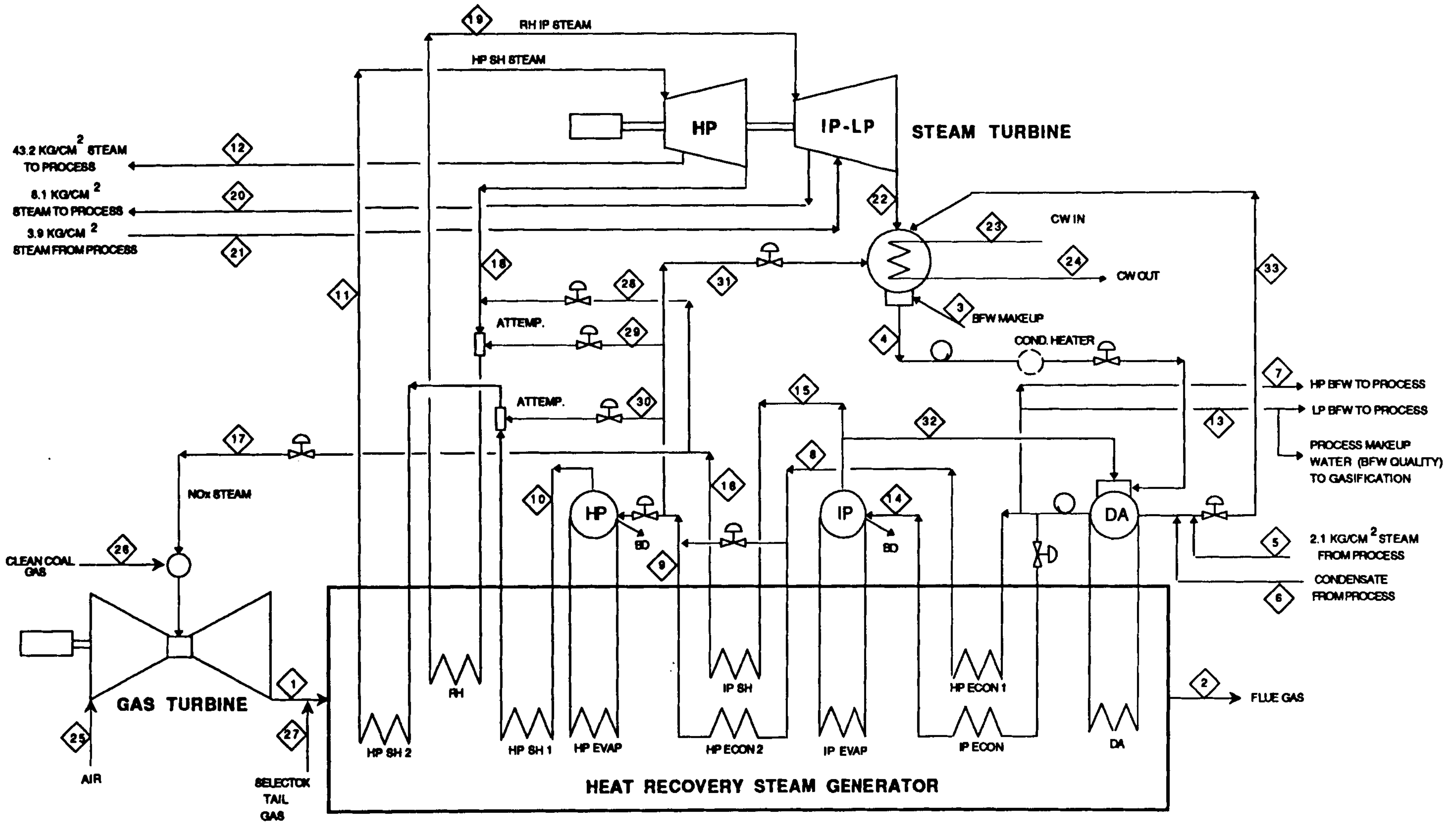

FIGURE 5-11 COMBINED CYCLE FLOW DIAGRAM (TEXACO CASE) 29.5 C AMBIENT TEMPERATURE

Table 5-9

STREAM FLOW FOR COMBINED CYCLE
(TEXACO CASE)

Stream No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
STREAM DESCRIPTION	GAS TURBINE EXHAUST	STACK GAS	BFW MAKE-UP	CONDEN-SATE	PROCESS STEAM TO DA	PROCESS COND. TO DA	HP BFW TO PROCESS	HP BFW FROM HP ECON 1	HP BFW FROM HP ECON 2	STEAM FROM HP BOILER	HP STEAM FROM HRSG	EXTRACT STEAM TO PROCESS	LP BFW TO PROCESS	LP BFW FROM IP ECON	STEAM FROM IP BOILER	IP STEAM FROM HRSG	NOX INJECTION STEAM
Pressure,kg/cm2 abs	1.02	0.98	1.41	0.12	2.11	8.09	45.71	113.57	110.55	110.55	109.14	43.25	7.03	27.43	27.43	26.72	26.72
Temperature,C	591.7	126.7	29.4	48.9	121.1	148.3	115.6	216.7	306.1	317.2	541.7	410.6	115.6	216.7	227.8	358.3	358.3
Flow, 1000 kg/hr	4371.47	4403.32	133.69	1040.39	0.60	64.79	116.91	515.93	515.93	505.61	505.61	2.33	373.13	99.81	97.81	97.81	0.00
Enthalpy, kcal/kg	180.19	55.33	13.86	33.36	631.18	133.29	100.24	206.23	313.01	632.24	813.31	757.27	100.24	206.23	653.57	735.52	735.52

Stream No.	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33
STREAM DESCRIPTION	EXHAUST FROM HP TURBINE	REHEATED IP STEAM	EXTRACT STEAM TO PROCESS	PROCESS STEAM TO LP TURBINE	EXHAUST FROM LP TURBINE	COOLING WATER SUPPLY	COOLING WATER RETURN	AIR TO GAS TURBINE	SYNGAS TO GAS TURBINE	TAIL GAS TO GAS TURBINE	IP STEAM TO REHEAT	REHEAT ATTEMP WATER	ATTEMP WATER FOR HP STEAM	HP BFW ECON 2 CIRC	DA PEGGING STEAM	DA STEAM DUMP
Pressure,kg/cm2 abs	26.72	25.32	8.09	3.87	0.12	3.52	2.46	0.98	24.96	1.05	26.72	110.55	110.55	110.55	27.43	1.41
Temperature,C	349.4	537.8	380.6	141.7	48.9	36.1	44.4	29.4	193.3	137.8	358.3	306.1	306.1	306.1	227.8	115.6
Flow, 1000 kg/hr	503.28	601.09	12.42	318.02	906.70	60427.83	60427.83	3833.89	537.60	31.85	97.81	0.00	0.00	0.00	0.00	0.00
Enthalpy, kcal/kg	730.53	831.29	735.52	637.90	584.62	20.62	26.65	15.48	62.71	59.34	735.52	313.01	313.01	313.01	653.57	629.18

1. Enthalpy values are based on 0.0 kcal/kg
for liquid water at 0 deg C

- o As the Texaco gasifier uses quench mode operation, there is no 110 kg/cm^2 abs steam produced from the gasification plant to feed to the steam turbine.
- o Steam is extracted from the steam turbine at 43.2 and 8.1 kg/cm^2 abs to satisfy steam need in the process area.
- o Excess 3.9 kg/cm^2 abs steam from the process area is fed to the IP-LP section of the steam turbine.
- o A portion of the 2.1 kg/cm^2 abs steam produced from the process area is fed to the deaerator and a portion is fed to the IP-LP section of the steam turbine.
- o The HP boiler feed water for process use is no longer necessary to be preheated to 216 C as required by Shell for their syngas cooler. Therefore, this feed water stream is delivered directly from the deaerator.

Heat Recovery Steam Generator. The HRSG mechanical details described in the Shell case also apply to the Texaco case.

Steam Turbine-Generator. The steam turbine has the same basic configuration as that in the Shell case except for the rating. The turbine is rated for approximately 130 MW. The generator is rated for approximately 150 MVA.

Auxiliary steam system. The design and description of this system is identical to that in the Shell case.

Balance of Plant

Solid Waste Disposal (Plant 30). The solid waste to be disposed of, in this case, consists of bottom slag and filter cake (dewatered soot) from the gasification plant and the sludge from the treatment of waste water plant and other plant. The solid waste contains 50% moisture which is made into slurry form (10% solid) by addition of raw water for transportation to the ash disposal area through pipelines. Further description of this plant is similar to that in the Shell Case.

Relief and Blowdown Systems (Plant 31). The description of this plant area is identical to that in the Shell case.

Interconnecting Piping (Plant 32). The description of this plant area is identical to that in the Shell case.

Compressed Air System (Plant 33). The description of this plant area is identical to that in the Shell case.

Fuel Oil and LPG System (Plant 34). The description of this plant area is identical to that in the Shell case.

Electrical System (Plant 35). The description of this plant area is identical to that in the Shell case.

Instrumentation and Controls (Plant 36). The description of this plant area is identical to that in the Shell case.

Cooling Water System (Plant 37). The description of this plant area is identical to that in the Shell case. But as more heat is rejected in the Texaco case, the cooling tower capacity is larger. The cooling tower has 48 cells in total at 2600 m^3/h circulation rate per cell.

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Raw Water Supply and Treatment (Plant 38). The major processing blocks in this system are shown in the overall water balance diagram, Figure 5-12. The major stream flows are shown in Table 5-10. The description of this system is identical to that in the Shell case.

Fire Protection (Plant 39). The description of this plant area is identical to that in the Shell case.

Waste Water Treating (Plant 40). The description of this plant area is identical to that in the Shell case except the treatment of sour water stripping bottom requires no primary clarification. Solids in the sour water have been removed during the chemical precipitation in the sour water stripping plant (Plant 8).

General Services and Mobile Equipment (Plant 41). The description of this plant area is identical to that in the Shell case.

Site Preparation and Improvements (Plant 42). The description of this plant area is identical to that in the Shell case.

Buildings (Plant 43). The description of this plant area is identical to that in the Shell case.

5.1.3 KRW Case

An overall block flow diagram of the IGCC plant using the KRW gasifier is shown in Figure 5-13. The number of operating and spare trains used is indicated for each of the major process and power blocks in Figure 5-13. The major stream flows (at the 29.5 C annual average ambient temperature) are shown in Table 5-11. An overall utility summary based on the same ambient temperature is shown in Table 5-12. Equipment lists are shown in Appendix C. A description of the plant facilities included is as follows.

Coal Transportation System

This system is the same as that described for the Shell case.

Coal Receiving, Primary Crushing, and Storage (Plant 1)

A flow diagram of this plant is shown in Figure 5-14.

The design and description of this plant are identical to that in the Shell case. The only exception is that the coal is crushed to 37 mm x 0 size instead of 50 mm x 0 and the crushed coal is delivered to Plant 3 for drying prior to the secondary crushing in Plant 2.

Coal and Limestone Handling (Plant 2)

A flow diagram of this plant is shown in Figure 5-15.

This plant crushes the dried coal from Plant 3 to a 6 mm top size product. The crushed coal is then transported to the gasification plant (Plant 5). Also included are facilities to receive, store, and crush the limestone required for in-situ sulfur removal in the gasifier. The plant is designed to operate all 3 shifts of the day.

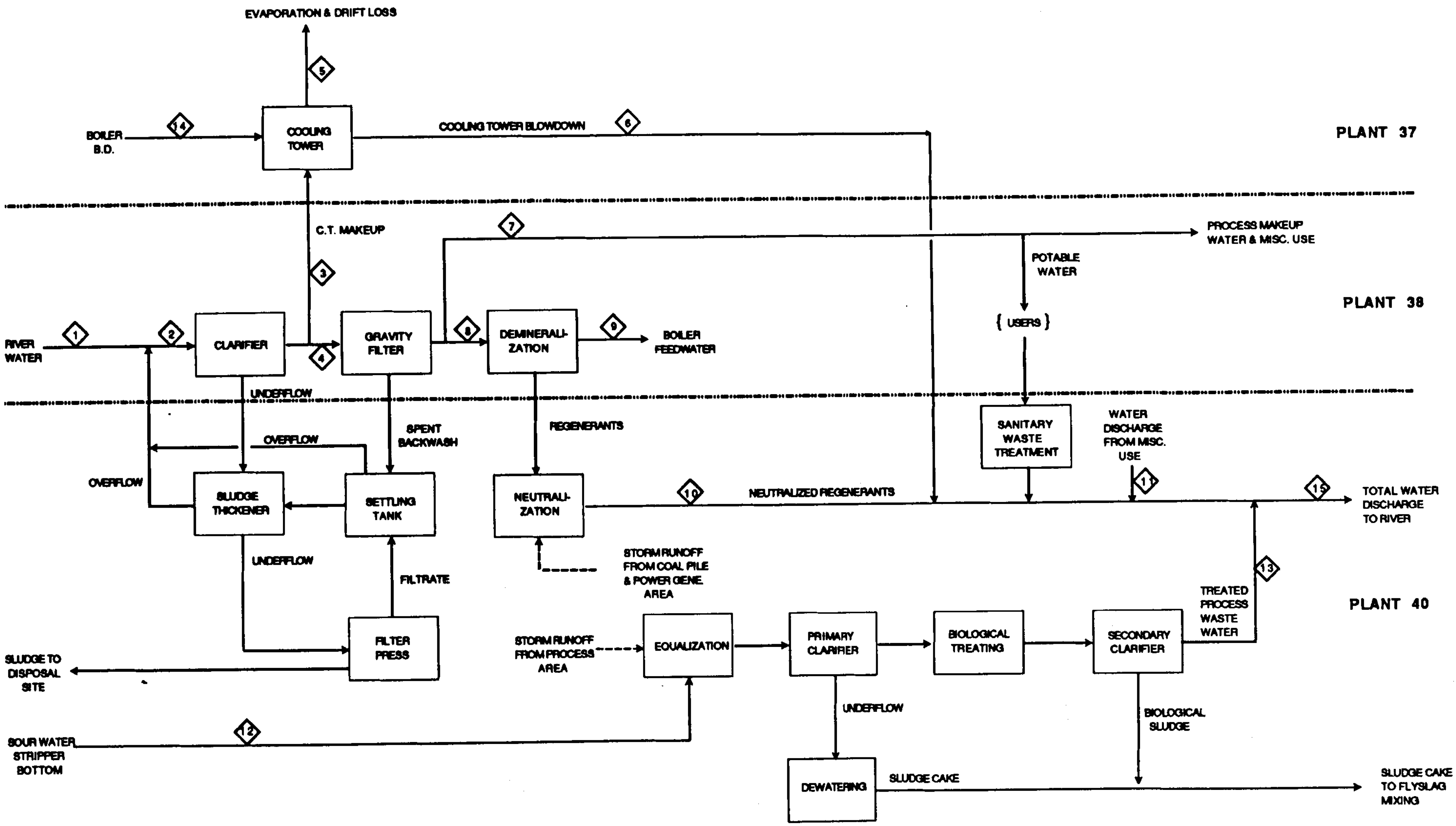

FIGURE 5-12

OVERALL WATER BALANCE DIAGRAM IGCC PLANT (TEXACO CASE)

Table 5-10

MAJOR STREAMS OF OVERALL WATER BALANCE
IGCC PLANT (TEXACO CASE)

Stream Number	Stream Name	Flow, m3/h
1	Total River Water Intake	2224
2	Clarifier Feed Water	2286
3	Cooling Tower Makeup	1930
4	Gravity Filter Feed Water	283
5	Cooling Tower Evaporation & Drift Loss	1686
6	Cooling Tower Blowdown	264
7	Process Makeup Water & Misc. Use	127
8	Demineralizer Feed	155
9	Boiler Feed Water	134
10	Neutralized Demineralizer Regenerants	22
11	Water Discharge from Misc. Use	11
12	Sour Water Stripper Bottom	82
13	Treated Process Waste Water	82
14	Boiler Blowdown	20
15	Total Water Discharge to River	387

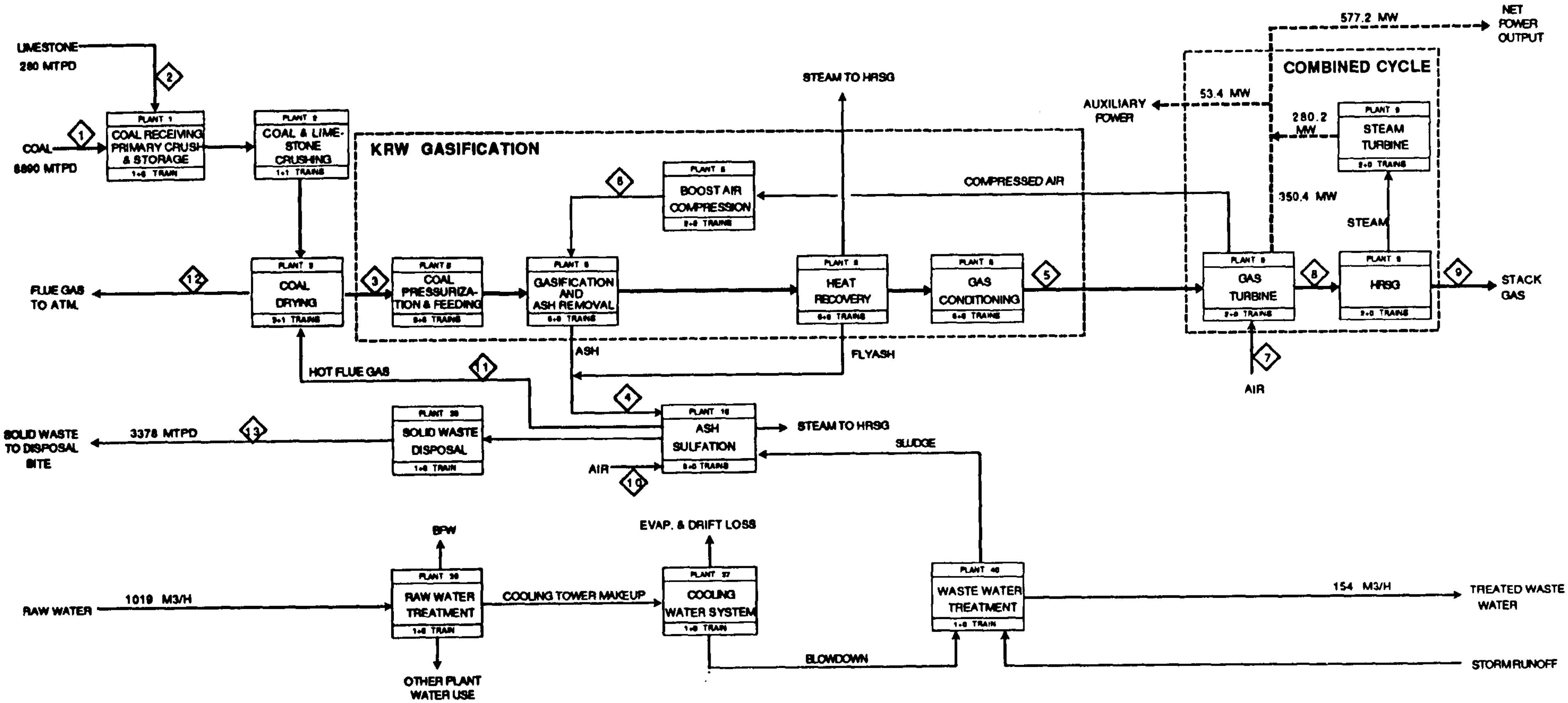

FIGURE 5-13

OVERALL BLOCK FLOW DIAGRAM
IGCC PLANT (KRW CASE)

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Table 5-11

MAJOR STREAMS OF IGCC PLANT
(KRW CASE)

STREAM NUMBER		1	2	3	4	5	6	7	8	9	10	11	12	13
STREAM DESCRIPTION		RAW COAL FEED	LIME-STONE	GASIFIER FEED	GASIFIER ASH	PRODUCT SYNGAS	AIR TO GASIFIER	AIR TO GAS TURBINE	GAS TURBINE EXHAUST	STACK GAS	COMB AIR TO ASH SULFA-TION	FLUE GAS TO COAL DRYING	FLUE GAS TO ATM.	SOLID WASTE
GASES: kg-mol/hr														
	H_2					4499.5								
	CO					7876.2								
	CO_2					1773.0			10096.0	10096.0		1077.7	1077.7	
	H_2S					6.2								
	COS					1.3								
	NH_3					8.0								
	CH_4					445.6								
	C_2H_6													
	C_3H_8													
	N_2					15769.4	15673.1	101416.6	101516.9	101516.9	5734.4	5734.4	5734.4	
	AR					196.8	196.8	1273.8	1273.8	1273.8	72.0	72.0	72.0	
	H_2O					2344.7	162.0	4388.6	11464.0	11464.0	248.1	248.1	3061.6	
	O_2						4216.1	27281.0	15962.6	15962.6	1542.6	415.4	415.4	
	SO_2								7.5	7.5				
TOTAL:	KG-MOL/HR	0.0	0.0	0.0	0.0	32920.7	20248.1	134360.0	140320.8	140320.8	7597.2	7547.6	10361.1	0.0
LIQUIDS:	H_2O													
kg/hr	SULPHUR													
SOLIDS:	H_2O	66,677		15,992										
kg/hr	COAL(MAF)	159,978		159,978										
	LIMESTONE		11,658	11,658										
	ASH	143,775		143,775	150,125									140,753
	BIO SLUDGE													
	SULPHUR													
TOTAL:	KG/HR	370,430	11,658	331,403	150,125	807,145	584,744	3,843,893	4,056,796	4,056,796	217,347	228,621	279,390	140,753
TEMPERATURE, C		29.4	29.4	29.4	315.6	537.8	343.3	29.4	601.7	143.3	29.4	871.1	71.1	29.4
PRESSURE, kg/cm2 ab		1.03	1.03	1.03	1.03	29.51	36.20	1.03	1.07	1.03	1.03	1.07	1.03	1.03

Table 5-12

UTILITY SUMMARY
(KRW CASE)

Plant No	Plant Name	Power kW	Steam kg/hr 108 kg/cm2 542 C	Steam kg/hr 111 kg/cm2 316 C	Steam kg/hr 27 kg/cm2 349 C	Steam kg/hr 25 kg/cm2 510 C	BFW kg/hr	Blowdown kg/hr	Condensate kg/hr	Cooling Water Duty MMkcal/hr	Cooling Water Flow mkg/hr	Make-Up Water Raw kg/hr	Make-Up Water Filtered kg/hr	Make-Up Water Demin kg/hr
1	Coal Receiving & Storage	373												
2	Coal & Limestone Handling	1,110												
3	Coal Drying	2,100												
5	Coal Gasification	35,108	41,011	(421,546)			427,869	(6,323)		20.11	2,418			
9	Combined Cycle													
	Gas Turbine	(350,400)	726,878											
	Steam Turbine	(280,210)			(726,878)	773,482			(829,127)	431.32	51,758			55,647
	HRSG		(767,889)	493,721	726,878	(773,482)	(501,488)	(6,868)	829,127					
	BFW Pumps & Aux. Equipment	5,849												
10	Ash Sulphation	710		(72,176)			73,619	(1,443)		35.00				
37	Cooling Water System	5,300						14,635		(486.43)	(54,176)		855,421	
38	Raw Water Supply & Treatment	450										950,034	(866,780)	(55,647)
40	Waste Water Treatment	40												
	General Facilities	840											11,358	
	Transformer Losses	1,577												
	TOTAL	(577,153)	0	0	0	0	0	0	0	0	0	950,034	0	0

Notes: ( ) indicates production

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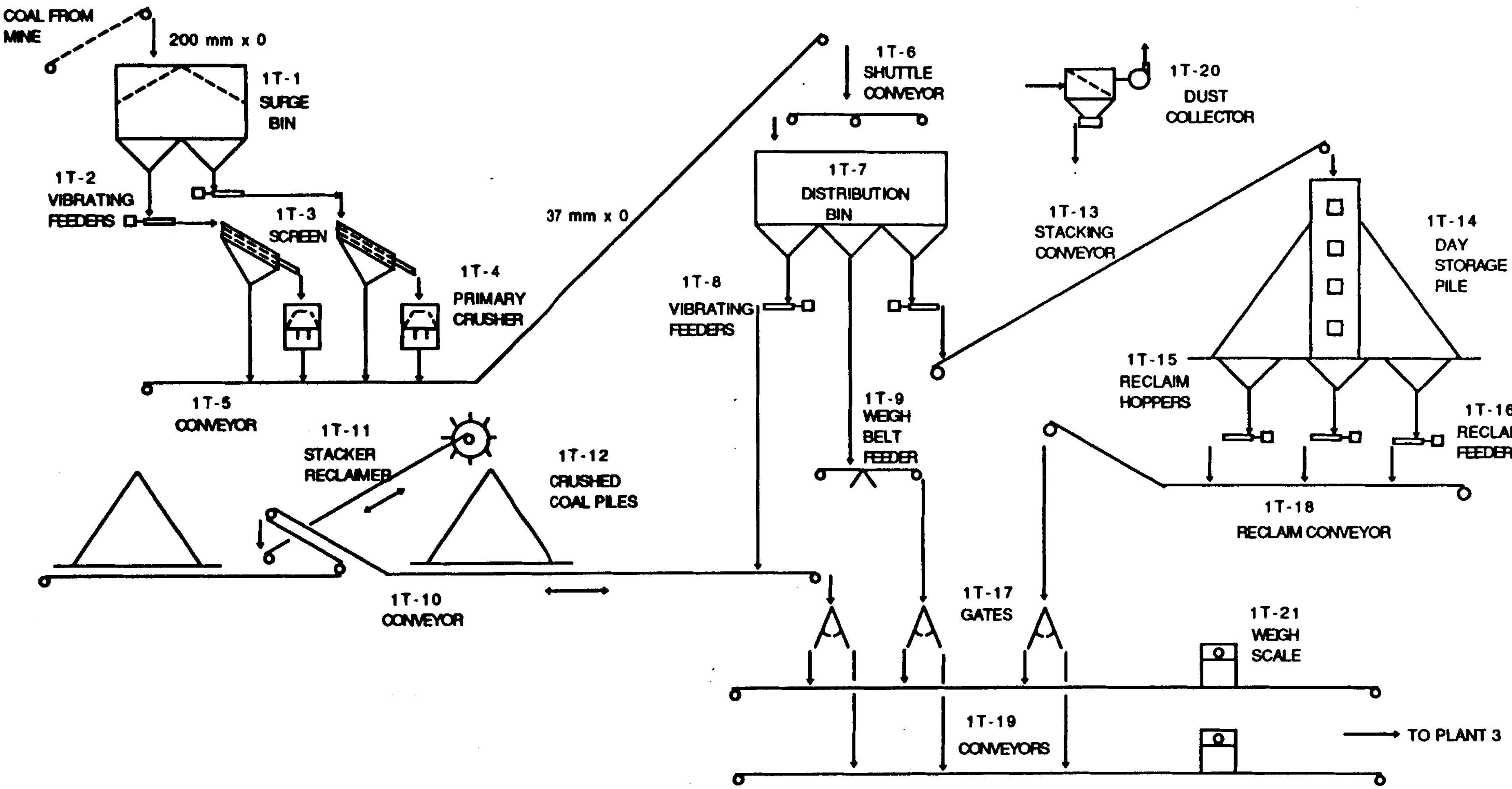

FIGURE 5-14

FLOW DIAGRAM
COAL RECEIVING, PRIMARY CRUSHING, & STORAGE (PLANT 1)
(KRW CASE)

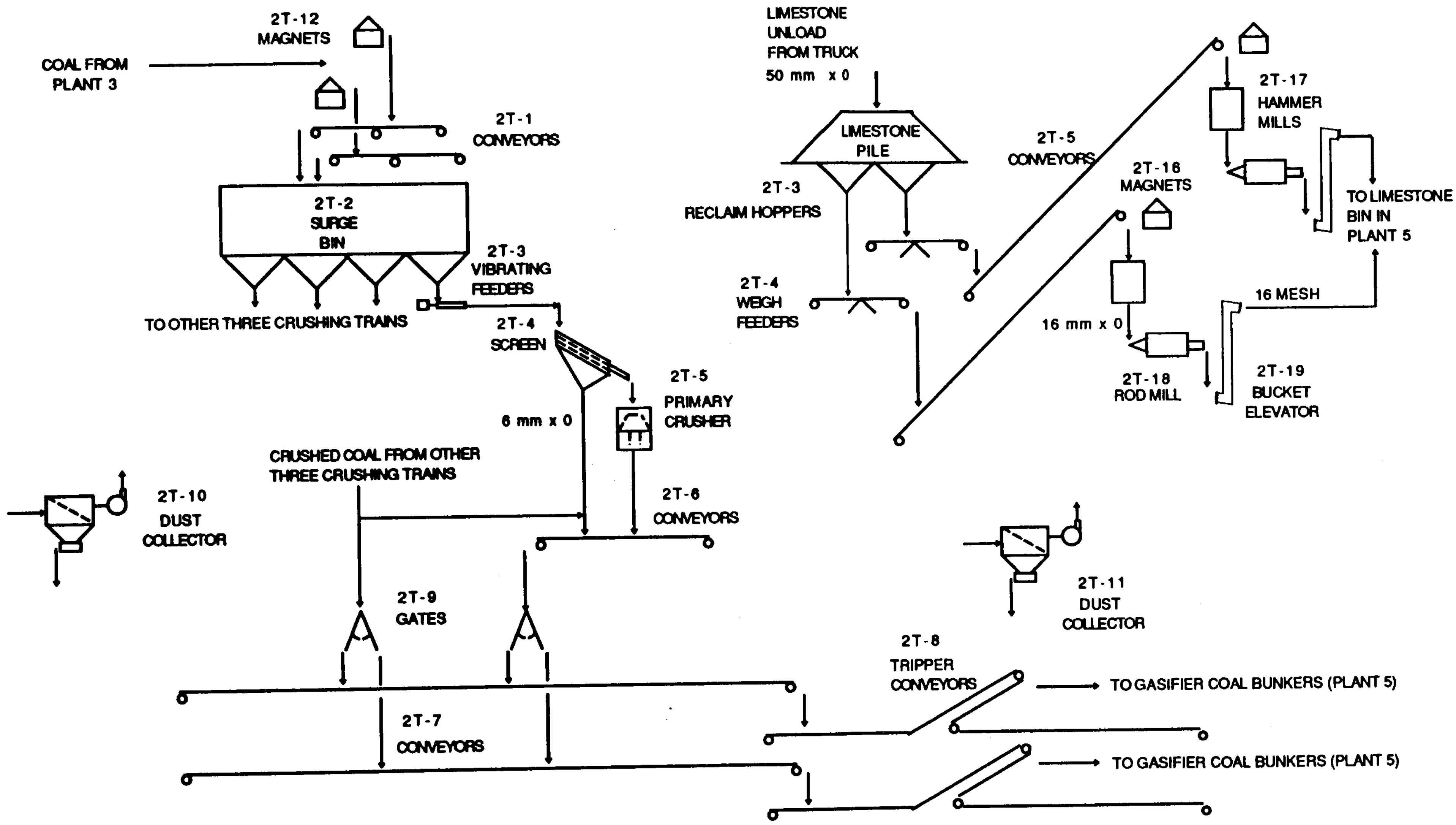

FIGURE 5-15

FLOW DIAGRAM
COAL AND LIMESTONE HANDLING (PLANT 2)
(KRW CASE)

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The dried coal of 37 mm top size from Plant 4 is received by a shuttle belt conveyor that feeds a surge bin. Tramp iron magnets separate out harmful iron lumps, if any, from the coal. From the surge bin, the coal is distributed to 4 crushing trains. One of the trains represents a spare.

Each crushing train consists of a scalping screen and a short head cone crusher. The coal is crushed to a 6 mm (nominal) top size and is collected by a crusher discharge conveyor which also receives the undersize from the scalping screen. The crushed coal from all the trains is collected by a day bin feed conveyor which in turn feeds a tripper conveyor. The tripper conveyor fills the day bins in the gasification plant. Installed spare units are included for the shuttle conveyor, day bin feed conveyor and the tripper conveyor.

Limestone of top size 50 mm is received in trucks and unloaded in the storage area. It is reclaimed by a weigh feeder at a controlled rate and fed to a hammer mill type crusher at a maximum rate of 15 tph. The flux is reduced to a top size of 6 mm, the required feed size for the next stage of size reduction in a rod mill. The rod mill which operates in a dry open-circuit mode is designed to grind 13.5 tph of flux to a nominal size of 16 mesh and below. The ground product is conveyed by a bucket elevator to the day bin for flux in the gasification plant. This limestone handling and preparation facility has a spare train.

Coal Drying (Plant 3)

A flow diagram of this plant is shown in Figure 5-16.

The major purpose of this plant is to dry the coal from Plant 1. It reduces the coal moisture from 18% to 5% as required for the KRW gasifier. This drying unit is placed ahead of the secondary coal crushing in Plant 2. Pre-drying of the coal facilitates the secondary crushing and screening. The drying plant is designed to operate all 3 shifts of the day.

The coal from Plant 1 is received by the feed conveyor which feeds a dryer feed bin. The bin serves two identical coal drying trains each designed for a feed rate of 220 tph. Weigh feeders are provide to control the feed rate to each dryer.

The dryers are conventional fluid bed dryers used extensively in the bituminous coal industry. Hot flue gas (870 C) from the combustion of gasifier ash (Plant 10) supplies the heat necessary to dry the coal. This gas stream is tempered to a temperature of 504 C using the recycle gas from the dryer exhaust.

The exhaust gas from the bed is passed through two cyclone dust collectors where most of the coarse dust in the gas is separated out. A part of the dedusted gas is recycled to the dryer. Use of recycled gas rather than air for tempering the hot gas for drying keeps the oxygen content below 8 percent to prevent fires and dust explosions. The net exhaust gas is vented to the atmosphere through bag houses.

The dried coal at around 82 C is collected on a dryer discharge conveyor to transport to Plant 2 for secondary crushing. Spare units are provided for the drying plant feed conveyor and discharge conveyor.

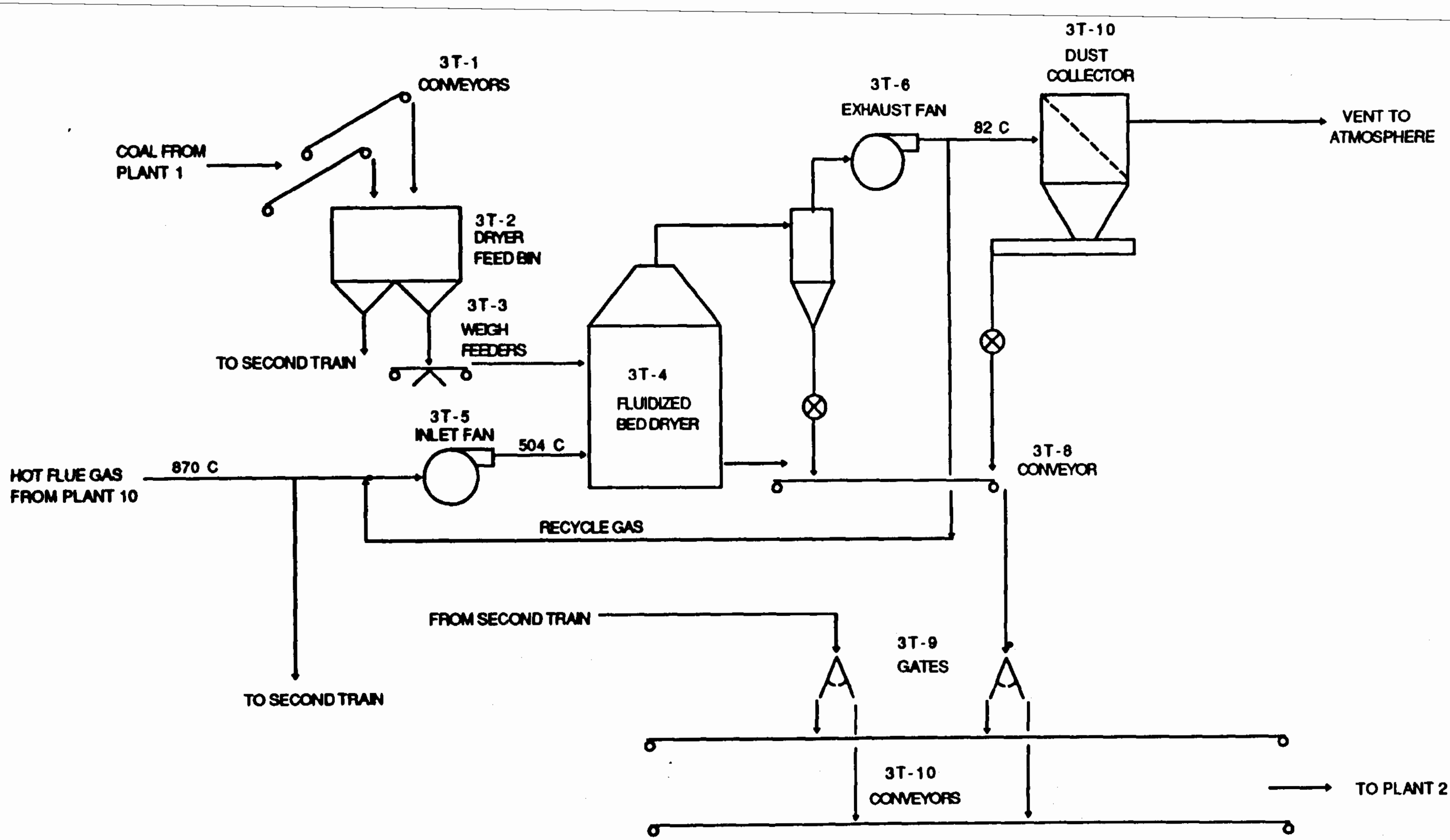


FIGURE 5-16

FLOW DIAGRAM
COAL DRYING (PLANT 3)
(KRW CASE)

Air Separation (Plant 4)

No air separation plant is required for the KRW case because the gasifier is air blown.

KRW Coal Gasification (Plant 5)

This plant uses air-blown KRW gasifier with in-bed sulfur removal by limestone. The gasification air required is extracted from the gas turbine compressor in the combined cycle plant. A process flow diagram of this plant is shown in Figure 5-17. Except boost air compression, six operating trains with no spares are used. KRW Energy System, Inc. provided the process information. The following describes a single gasification train.

Boost Air Compression. The boost air compression increases the air pressure extracted from the gas turbine compressor to the pressure required for the gasification. Two 50% trains are used for this subsystem.

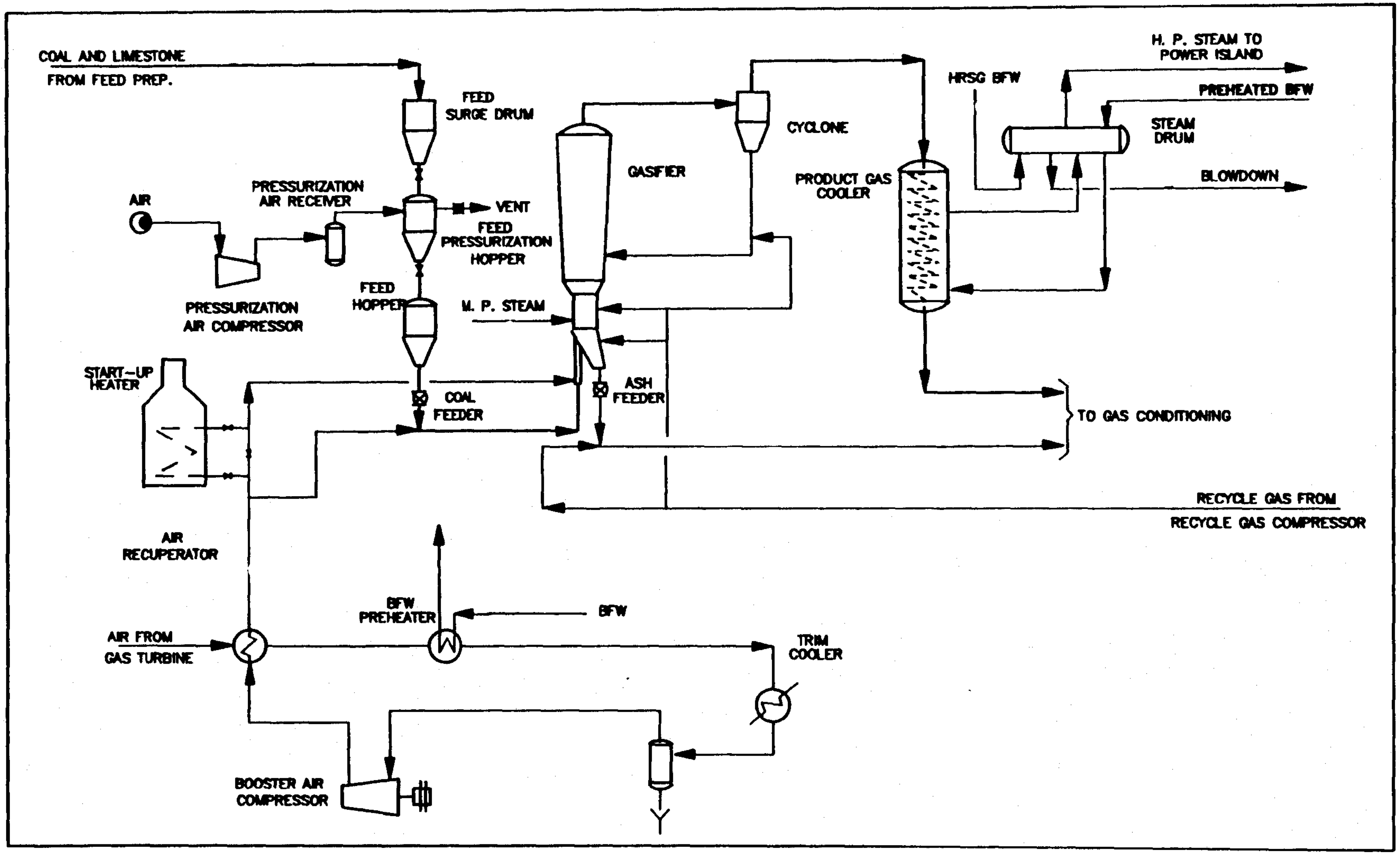
Air from the gas turbine compressor discharge has a relatively high-temperature and is first cooled in the air recuperator by heat exchange with the boost compressor discharge air. After the initial cooling, a second cooler, the BFW preheater, is employed to preheat boiler feed water from the deaerator while cooling the air to a lower temperature. The air is finally cooled by cooling water in the trim cooler prior to entering the booster air compressor via a knockout drum which collects water condensed in the trim cooler.

Coal Gasification. This area consists of five functional subsystems: lockhopper air compression, coal/sorbent pressurization, gasification and fines removal, ash removal, and heat recovery. The subsystems are described separately below:

Lockhopper Air Compression. A separate air compressor is provided for lockhopper pressurization. The compressor is sized for the average flow required by the lockhoppers. To accommodate the large periodic flows to the lockhoppers, a surge vessel is included. A common spare compressor is provided for every two gasification trains.

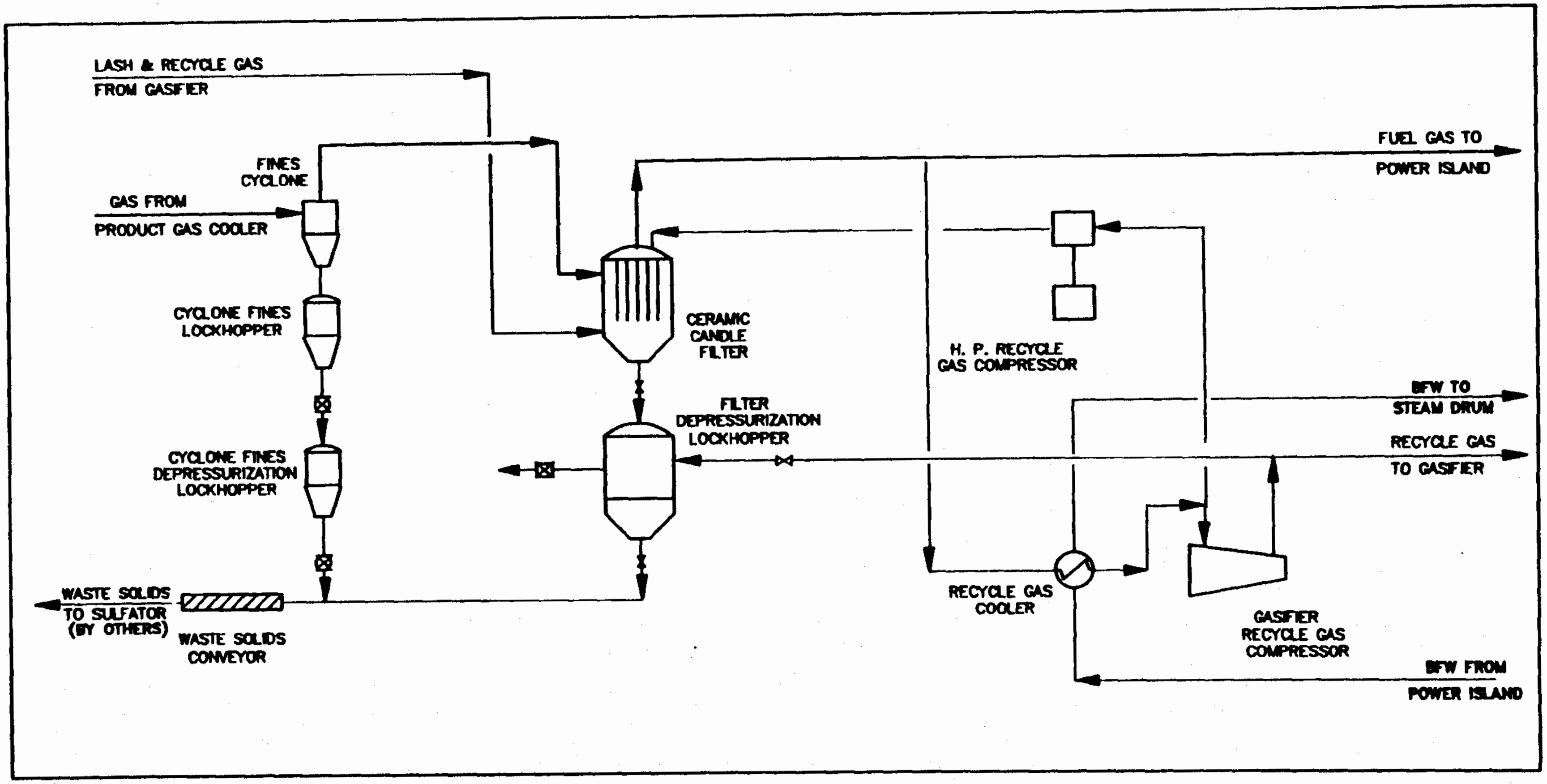
Coal/Sorbent Pressurization. A conventional lockhopper system is used to pressurize the coal and limestone feed. The two feedstocks are received separately from Plant 2 and are mixed in a single surge bin. This bin operates at atmospheric pressure and serves as a reserve of raw material for the pressurizing lockhoppers located beneath the bin.

The lockhopper periodically receives coal from the surge bin. Two valves are used between the lockhopper and the bin: the upper valve to initiate or stop solids flow and the lower to provide a gas tight seal. After a batch of coal is received, the lockhopper is pressurized with high-pressure air. When the pressure in the lockhopper is equalized with the feed hopper, a valve located beneath the lockhopper is opened to dump the material into the feed hopper. When the lockhopper is empty, the valve is closed and the lockhopper is vented to atmospheric pressure to repeat the cycle.



OXIDANT COMPRESSION AND GASIFICATION

Figure 5-17
Process Flow Diagram
KRW Gasification (Sheet 1)



GAS CONDITIONING & RECYCLE GAS COMPRESSION

Figure 5-17
Process Flow Diagram
KRW Gasification (Sheet 2)

A vent filter is installed on the pressurizing/venting line to essentially eliminate particulate emissions when the pressurization hopper is vented. The lockhopper is pressurized through this same filter to provide an automatic "backwashing" of the filter media.

The feed hopper is operated at a constant pressure sufficient to permit starwheel feed metering and pneumatic conveying of the coal/limestone mixture to the gasifier by an air stream. The relative proportions of coal and limestone sent to the feed surge bin will be established by set-point adjustments based on an analysis of the gasifier product gas obtained from an on-line sulfur analyzer.

Gasification and Fines Removal. The KRW gasifier is a pressurized fluidized-bed gasifier. The gasifier is a refractory-lined carbon steel pressure vessel, divided into a number of functional zones, where coal devolatilization, combustion, gasification, desulfurization, and ash and spent-sorbent cooling occur.

Coal and limestone are pneumatically fed to the gasifier through a central feed tube. Additional air is also fed through this same feed tube and the streams merge to form a central jet where the coal is quickly devolatilized. The char formed is further combusted in the jet to provide the heat necessary for endothermic devolatilization, gasification, calcination and desulfurization reactions.

Within the bed a number of competing reactions occur. The principal reactions of interest are the gasification reactions:

$$C + H_2O = CO + H_2$$
$$C + CO_2 = 2\ CO$$

Carbon monoxide and hydrogen are the major constituents of the product gas. Methane and other hydrocarbons are produced in lesser quantities, primarily from the devolatilization process. The operating temperature of the gasifier is sufficiently high to crack any tars or oils that might be produced.

The fluidized bed also presents a favorable environment for desulfurization of the gas. Hydrogen sulfide, produced from the sulfur in the coal, is removed from the gas phase by limestone according to the following reactions:

$$CaCO_3 = CaO + CO_2$$
$$CaO + H_2S = CaS + H_2O$$

The limestone calcination (the first reaction above) occurs very quickly due to the low CO_2 partial pressure in the gasifier. The design sulfur removal is 78%.

As the carbon in the char is consumed, the particles become enriched in ash. The ash particles then tend to adhere to each other and agglomerate and, along with the dense calcium sulfide/oxide particles, separate from the char bed because of their different fluidization characteristics.

This separation occurs primarily in a region that surrounds the central feed tube at the bottom of the gasifier vessel.

Gas leaves the gasifier from the top and enters a cyclone. The cyclone separates the majority of the fine particulates that escape the gasifier bed and returns them to the bed by a fluidized dip-leg.

A startup heater is included to provide hot air (538 C) necessary for the initial heatup and initiation of reaction in the gasifier. It is a standard gas-fired heater using LPG fuel. Only one startup heater is provided for all six gasification trains.

Ash Removal. Ash and spent sorbent are removed from the gasifier by the ash feeder. They are then conveyed from the gasifier area to the bottom of the gas filter by a slip stream of recycle gas. The ash/sorbent mixture is mixed with the fines collected by a filter.

Heat Recovery. Heat recovery from the product gas is accomplished in a fire-tube type product gas cooler. In the cooler, the gas is cooled to 538 C by generating high pressure saturated steam. The steam generated is sent to the HRSG in the combined cycle plant (Plant 9) for superheating.

Gas Conditioning. The cooled product gas from the product gas cooler is further cleaned of the remaining particulates through high efficiency cyclones and a ceramic candle gas filter prior to its delivery to the combined cycle plant. The elements in the gas filter are periodically blown back with high pressure recycle gas to clean the filter surface by dislodging the trapped solids which are collected and removed from the bottom of the filter vessel.

The gas conditioning system addresses the engineering aspects of cooling hot particulates from particulate removal devices in a cost effective manner. The recovered solids are mixed with the "LASH" (ash plus spent limestone sorbent from the fluid bed gasifier) recovered from the filter in order to cool the fines to a sufficiently low temperature to permit the use of low cost, high reliability lockhoppers, valving, and solids handling equipment, and also to help promote the flow of fine material (both small in size and low in density). The mixture temperature leaving this operation would be near the "LASH" temperature since the quantity of "LASH" is much greater than the quantity of fines.

The cooled solids are transferred to a depressurization lockhopper where the pressure is reduced to atmospheric, and from which the solids are sent to the ash sulfation plant (Plant 10) through an enclosed, water cooled conveyor. Lockhopper pressurization is accomplished with gas from the high pressure recycle gas compressor. When vented, this gas is routed through the lockhopper filter to the sulfator for ultimate disposal by combustion.

Recycle-Gas Compression. Two separate recycle gas compressors are employed.

The high pressure recycle gas compressor supplies high-pressure (49 kg/cm^2 abs) recycle gas to be used for filter blowback and lockhopper compression. A gas receiver is included to provide the surge capacity necessary to accommodate the periodic gas flows to the depressurization hopper and the filter. A common spare compressor is provided for every two gasification trains.

The gasifier recycle-gas compressor provides the recycle gas required for the gasifier use and for ash transport. A common spare compressor is provided for every two gasification trains.

Prior to compression in these compressors, the recycle gas is cooled by preheating the boiler feedwater from the combined cycle plant.

Acid Gas Removal (Plant 6)

No acid gas removal plant is required for the KRW case because of the in-situ sulfur removal in the gasifier.

Sulfur Recovery (Plant 7)

No sulfur recovery plant is required for the KRW case because there is no acid gas removal plant.

Sour Water Stripping (Plant 8)

As a result of the hot gas cleanup used, no process waste water is produced in the KRW case and no sour water stripping plant is required.

Combined Cycle (Plant 9)

The design and description of this plant is very similar to that in the Shell case. Highlighted below are the major differences.

Gas Turbine. Based on the clean gas composition supplied by KRW, GE provided the following gas turbine performance (one 9F gas turbine) at both the normal and design ambient temperatures:

	29.4 C (Normal)	18.3 C (Design)
Fuel(LHV), Million Kcal/h	438	460
Fuel Gas Temperature, C	537.8	537.8
Relative Humidity	80	60
NO_x Steam, 1000 kg/h	0	0
Exhaust Flow, 1000 kg/h	2028.4	2127.0
Exhaust Temperature, C	601.7	587.2
Power Output, MW	175.2	193.0
Air Extracted, 1000 kg/h	292.4	306.4
Extrac. Air Press., kg/cm^2 (a)	12.4	13.0
Extrac. Air Temp., C	384.4	372.8

The KRW gas is a low-Btu gas, containing a significant amount of nitrogen. Nitrogen acts as a diluent to suppress the flame temperature in the gas turbine combustor. As a result, no NO_x steam injection is required in this case. Air is extracted from the gas turbine compressor to provide gasification air. The flow and condition of this extracted air stream are also summarized above.

Steam Generation and Consumption in the Process Area. A steam balance of the process area is shown in Figure 5-18. The major flows are shown in Table 5-13. Steam is generated and consumed in the process plant at two pressure and temperature levels.

High pressure saturated steam at 110.6 kg/cm^2 abs is produced by waste heat recovery in the gasification plant and ash sulfation plant. This steam is sent for superheating in the HRSG.

Medium pressure superheated steam at 36.2 kg/cm^2 abs, 538 C is required as the gasification steam. This steam requirement is provided by pressure reduction of the high pressure superheated steam produced from the HRSG of the combined cycle plant.

Steam Cycle. The steam cycle configuration is shown in Figure 5-19. The major stream flows at the 29.4 C annual average temperature are shown in Table 5-14.

The cycle configuration is identical to that in the Shell case. The major differences are:

- o As the KRW gasifier and ash sulfation produce only saturated high pressure steam, this steam is superheated first in the HRSG before it is fed to the steam turbine.
- o No steam is extracted from the steam turbine to satisfy steam need in the process area.
- o A portion of the high pressure superheated steam produced from the HRSG is pressure letdown to 36.2 kg/cm^2 abs as the gasification steam.
- o A high temperature boiler feedwater and a low temperature boiler feedwater are drawn from two separate points of the HRSG economizer for process use.

Heat Recovery Steam Generator. The HRSG mechanical details described in the Shell case also apply for the KRW case. However, the KRW case has no sulfur recovery plant. Therefore, there is no sulfur recovery tail gas feeding together with the gas turbine exhaust to the HRSG.

Steam Turbine-Generator. The steam turbine has the same basic configuration as that in the Shell case, except forthe rating. The turbine is rated for approximately 140 MW. The generator is rated for approximately 165 MVA.

Auxiliary Steam System. The design and description of this system is identical to that in the Shell case.

Ash Sulfation (Plant 10)

The gasifier ash is rich in unconverted carbon (about 9%). It also contains CaS because of the in-situ sulfur removal in the KRW gasifier using limestone injection. The major purposes of ash sulfation plant are to recover energy from the unconverted carbon and to convert CaS into disposable $CaSO_4$.

The ash sulfation is basically an atmospheric fluidized bed combustor (AFBC) based on a bubbling bed design. In the combustor, carbon conversion is assumed to be 98% and CaS conversion is assumed to be 90%.

The hot flue gas from the combustor is used for coal drying. The amount of air to the combustor is determined by the gas flow and heat requirements for the coal drying. The excess air level under this condition is 23%.

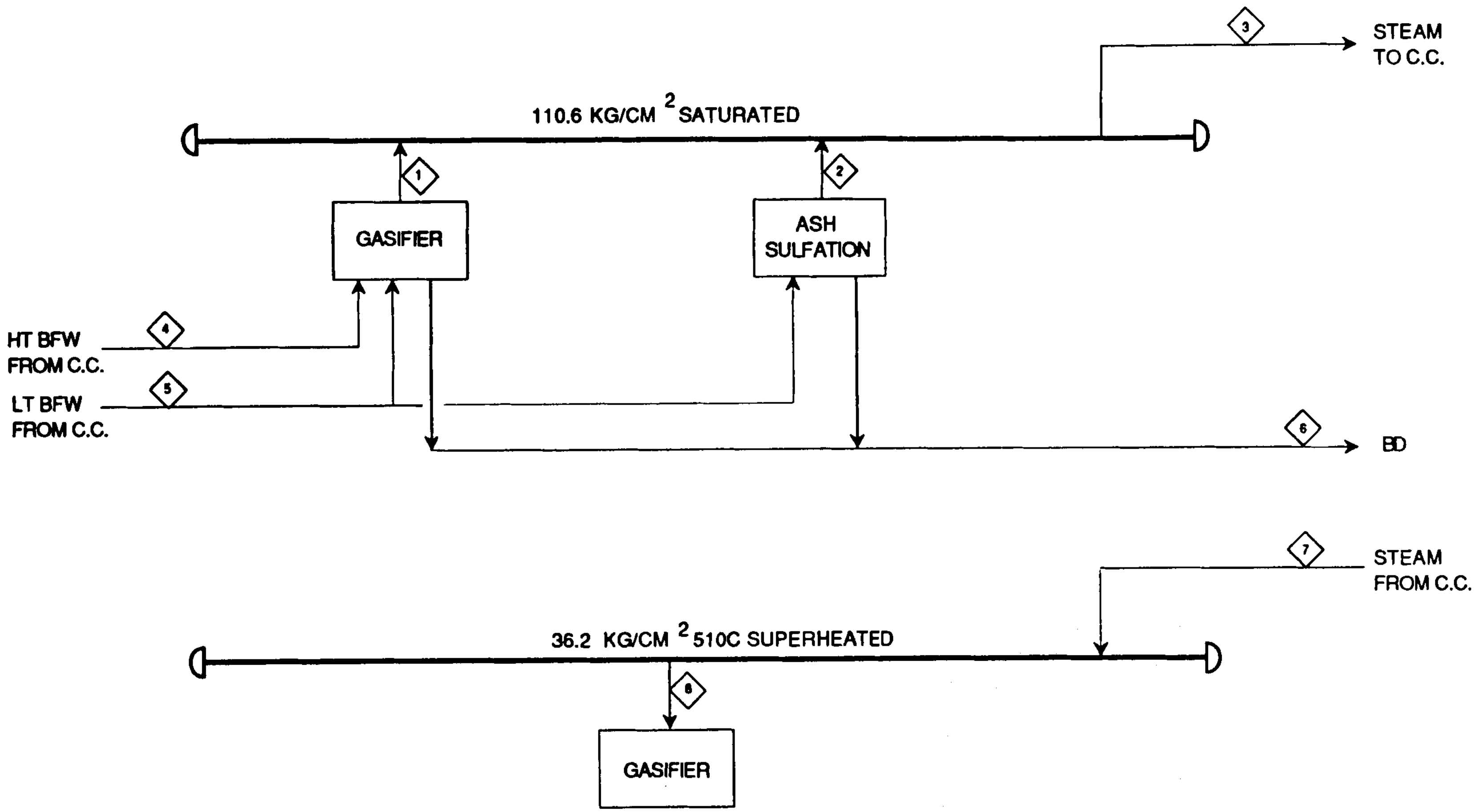


FIGURE 5-18 PROCESS STEAM BALANCE DIAGRAM (KRW CASE)

Table 5-13

STREAM FLOW FOR PROCESS STEAM
(KRW CASE)

Stream No.	1	2	3	4	5	6	7	8
STREAM DESCRIPTION	HP STEAM FROM GASIFIER	HP STEAM FROM ASH SULFATION	HP STEAM TO COMBINED CYCLE	HP BFW FROM COMBINED CYCLE	HP BFW FROM COMBINED CYCLE	BLOW-DOWN	STEAM FROM COMBINED CYCLE	STEAM TO GASIFIER
Pressure, kg/cm2 abs	112.52	112.52	110.55	55.09	114.63	110.55	36.22	36.22
Temperature, C	318.3	318.3	318.3	304.4	110.0	318.3	537.8	537.8
Flow, 1000 kg/hr	421.55	72.18	493.72	355.35	146.13	7.77	41.01	41.01
Enthalpy, kcal/kg	630.46	630.46	630.46	311.40	94.58	331.01	828.96	828.96

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1. Enthalpy values are based on 0 kcal/kg
for liquid water at 0 C

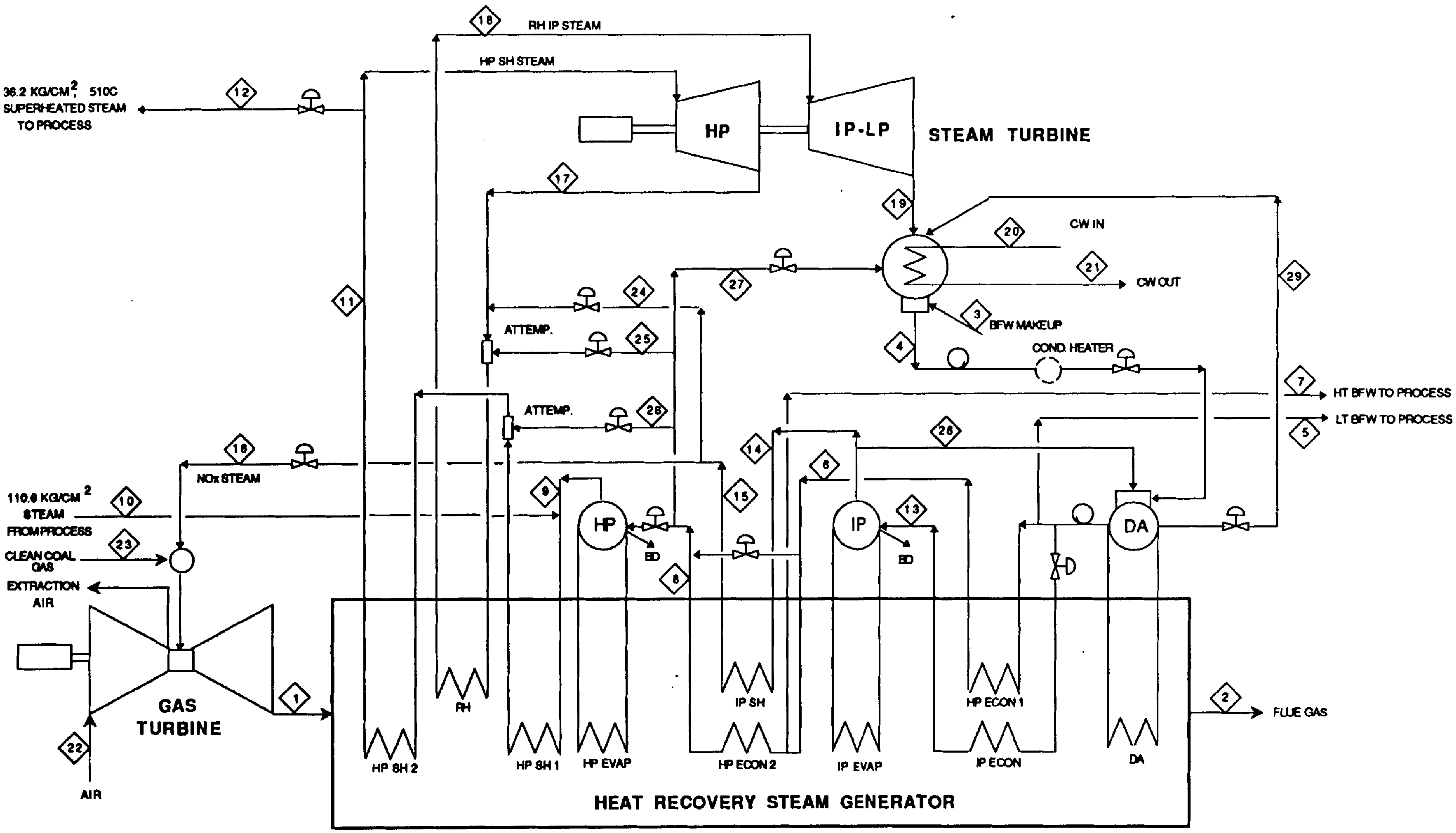

FIGURE 5-19 COMBINED CYCLE FLOW DIAGRAM (KRW CASE) 29.5 C AMBIENT TEMPERATURE

Table 5-14

STREAM FLOW FOR COMBINED CYCLE
(KRW CASE)

Stream No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
STREAM DESCRIPTION	GAS TURBINE EXHAUST	STACK GAS	BFW MAKE-UP	COND-SATE	BFW TO PROCESS	HP BFW FROM HP ECON 1	BFW TO PROCESS	HP BFW FROM HP ECON 2	STEAM FROM HP BOILER	HP STEAM FROM PROCESS	HP STEAM FROM HRSG	HP STEAM TO PROCESS	LP BFW FROM IP ECON	STEAM FROM IP BOILER	IP STEAM FROM HRSG
Pressure, kg/cm2 abs	1.02	0.98	1.48	0.12	114.63	116.03	114.63	110.55	110.55	110.55	109.14	109.14	27.43	27.43	26.72
Temperature, C	601.7	143.3	29.4	48.9	110.0	216.7	304.4	306.1	317.2	318.3	541.7	541.7	216.7	227.8	358.3
Flow, 1000 kg/hr	4056.79	4056.79	56.65	829.13	146.13	635.12	355.35	279.77	274.17	493.72	767.89	41.01	63.62	46.60	46.60
Enthalpy, kcal/kg	166.16	61.73	13.86	33.36	94.58	206.22	311.40	313.01	632.24	632.68	813.31	813.31	206.23	653.57	735.52

Stream No.	16	17	18	19	20	21	22	23	24	25	26	27	28	29
STREAM DESCRIPTION	NOX INJECTION STEAM	EXHAUST FROM HP TURBINE	REHEATED IP STEAM	EXHAUST FROM LP TURBINE	COOLING WATER SUPPLY	COOLING WATER RETURN	AIR TO GAS TURBINE	SYNGAS TO GAS TURBINE	IP STEAM TO REHEAT	REHEAT ATTEMP WATER	ATTEMP WATER FOR HP STEAM	HP BFW ECON 2 CIRC	DA PEGGING STEAM	DA STEAM DUMP
Pressure, kg/cm2 abs	26.72	26.72	25.32	0.12	3.52	2.48	0.98	23.91	26.72	110.55	110.55	110.55	27.43	1.48
Temperature, C	358.3	349.4	537.8	48.9	36.1	46.1	29.4	537.8	358.3	306.1	306.1	306.1	227.8	110.0
Flow, 1000 kg/hr	0.00	726.88	773.48	773.48	51757.58	51757.58	584.74	607.15	46.60	0.00	0.00	0.00	15.75	0.00
Enthalpy, kcal/kg	735.52	730.53	831.30	591.32	20.62	26.85	15.48	197.51	735.52	313.03	313.03	313.03	653.57	627.23

1. Enthalpy values are based on 0 kcal/kg for liquid water at 0 C

The combustion temperature is 871 C. The excess heat from the combustor is removed by generating 110.6 kg/cm^2 abs saturated steam.

The gasifier ash fed to the combustor is at 316 C and has a top particle size of 6 mm. It contains quite a bit of fines. Whether a circulating fluidized bed combustor is a better design choice will be subject to future study.

Spent ash leaving the combustor is cooled by a water cooled screw conveyor. The cooled ash is then discharged for disposal.

Balance of Plant

Solid Waste Disposal (Plant 30). The solid waste, in this case, mainly consists of disposal of the sulfated ash produced from the ash sulfation plant (Plant 10). The ash from the sulfation plant is taken to the slurry making tank where a 10% solid containing slurry is made with addition of raw water for transportation to the ash disposal area through a pipeline. Further description of this plant is same as that in the Shell case.

Relief and Blowdown Systems (Plant 31). The description of this plant area is identical to that in the Shell case.

Interconnecting Piping (Plant 32). The description of this plant area is identical to that in the Shell case.

Compressed Air System (Plant 33). The description of this plant area is identical to that in the Shell case.

Fuel Oil and LPG System (Plant 34). The description of this plant area is identical to that in the Shell case.

Electrical System (Plant 35). The description of this plant area is identical to that in the Shell case. The only difference is that there is no air separation plant and therefore there is no power to be distributed to this plant.

Instrumentation and Controls (Plant 36). The description of this plant area is identical to that in the Shell case.

Cooling Water System (Plant 37). The description of this plant area is identical to that in the Shell case. But as less heat is rejected in the KRW case, the cooling tower capacity is smaller. The cooling tower has 24 cells in total at 2500 m3/h circulation rate per cell.

Raw Water Supply and Treatment (Plant 38). The major processing blocks in this system are shown in the overall water balance diagram, Figure 5-20. The major stream flows are shown in Table 5-15. The description of this system is identical to that in the Shell case.

Fire Protection (Plant 39). The description of this plant area is identical to that in the Shell case.

Waste Water Treating (Plant 40). The description of this plant area is identical to that in the Shell case, except that there is no process waste water to be treated.

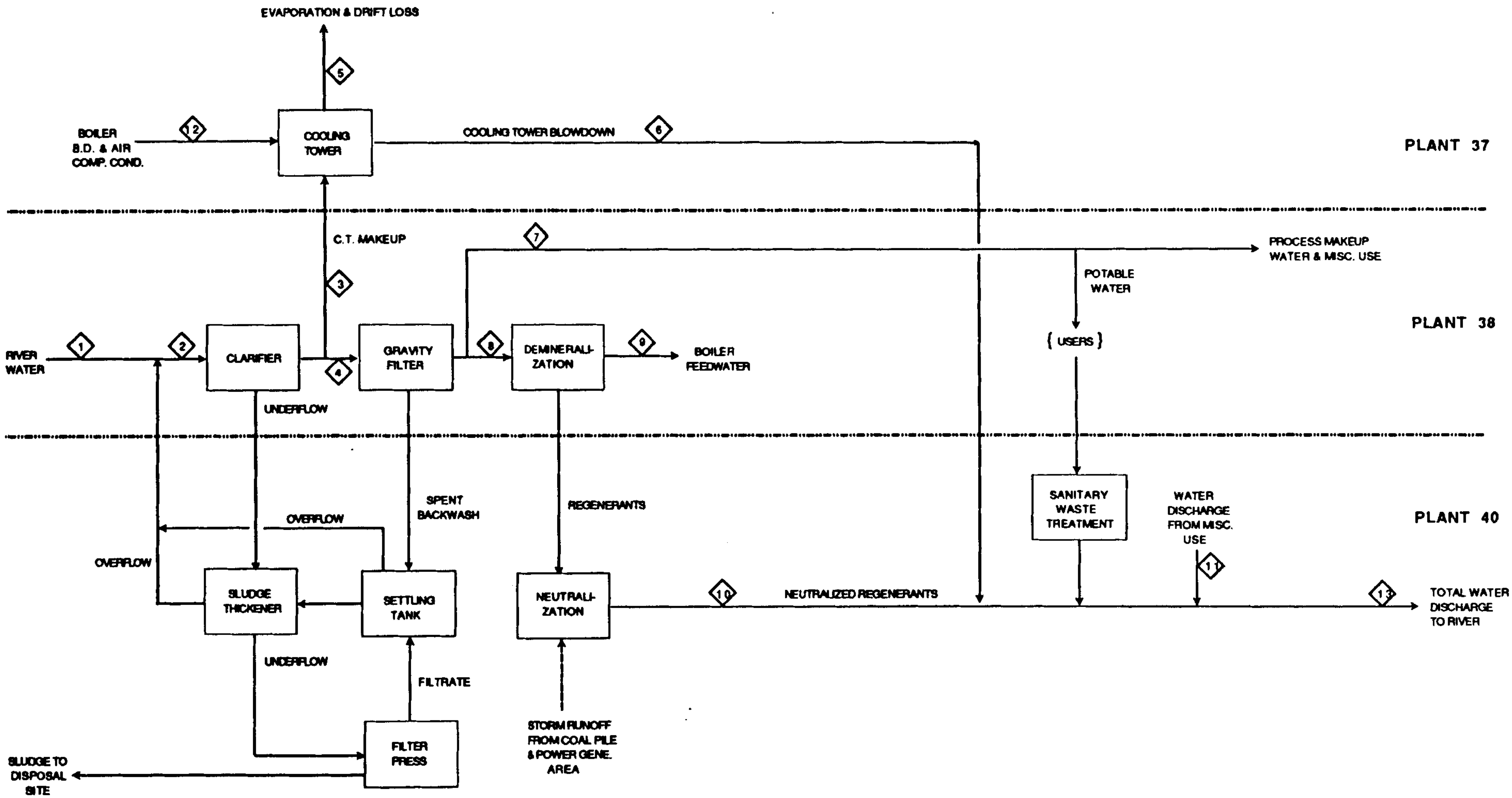

FIGURE 5-20

OVERALL WATER BALANCE DIAGRAM
IGCC PLANT (KRW CASE)

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Table 5-15

MAJOR STREAMS OF OVERALL WATER BALANCE
IGCC PLANT (KRW CASE)

Stream Number	Stream Name	Flow, m3/h
1	Total River Water Intake	1019
2	Clarifier Feed Water	1047
3	Cooling Tower Makeup	924
4	Gravity Filter Feed Water	84
5	Cooling Tower Evaporation & Drift Loss	822
6	Cooling Tower Blowdown	126
7	Process Makeup Water & Misc. Use	19
8	Demineralizer Feed	65
9	Boiler Feed Water	56
10	Neutralized Demineralizer Regenerants	9
11	Water Discharge from Misc. Use	11
12	Boiler BD & Air Comp. Condensate	24
13	Total Water Discharge to River	154

General Services and Mobile Equipment (Plant 41). The description of this plant area is identical to that in the Shell case.

Site Preparation and Improvements (Plant 42). The description of this plant area is identical to that in the Shell case.

Buildings (Plant 43). The description of this plant area is identical to that in the Shell case.

5.1.4 Moving Bed Case

An overall block diagram of the IGCC plant using the moving bed gasifier is shown in Figure 5-21. The number of operating and spare trains used are indicated for each of the major process and power blocks. The major stream flows (at the 29.5 C annual average ambient temperature) are shown in Table 5-16. An overall utility summary for the same ambient temperature is shown in Table 5-17. A description of the plant facilities follows.

Coal Transportation System

This system is the same as that described for the Shell case.

Coal Receiving and storage (Plant 1)

A flow diagram of this plant is shown in Figure 5-22.

The facilities included and the description of this plant are very similar to those of the Shell case. The major differences are:

- o Coal is delivered from the mine by a merry go round rail system instead of a direct belt conveying system. The coal received is conveyed from the coal storage bunker of the merry go round system to the distribution bin at a rate of about 900 tph..
- o Sized coal (+6-50 mm) as required for the moving bed gasifier is assumed to be available at a premium price. Therefore, the coal received does not require further crushing.
- o The coal reclaimed from the large storage pile is screened to remove any fines generated during the storage before it is conveyed to the gasification plant. The fines removed are sent for disposal.

Tar and Oil Fired Boiler (Plant 4)

In this plant, tar and oil produced in the gasification plant is fired to raise high pressure, superheated steam at 110 kg/cm^2 abs and 542 C to feed the steam turbine in Plant 9 for power generation. Two boilers, each of 150 t/h steam generation capacity, are installed.

Moving Bed Coal Gasification (Plant 5)

The major process areas in this plant are described below.

Coal Gasification. Graded coal of 6-50 mm size from Plant 1 is received at the overhead bunker located at the top of each gasifier. Fourteen gasifiers for operation at a pressure of 24 kg/cm^2 are provided. Coal from the bunker is fed to the gasifier through the lock hopper which is operated automatically through a hydraulic controller.

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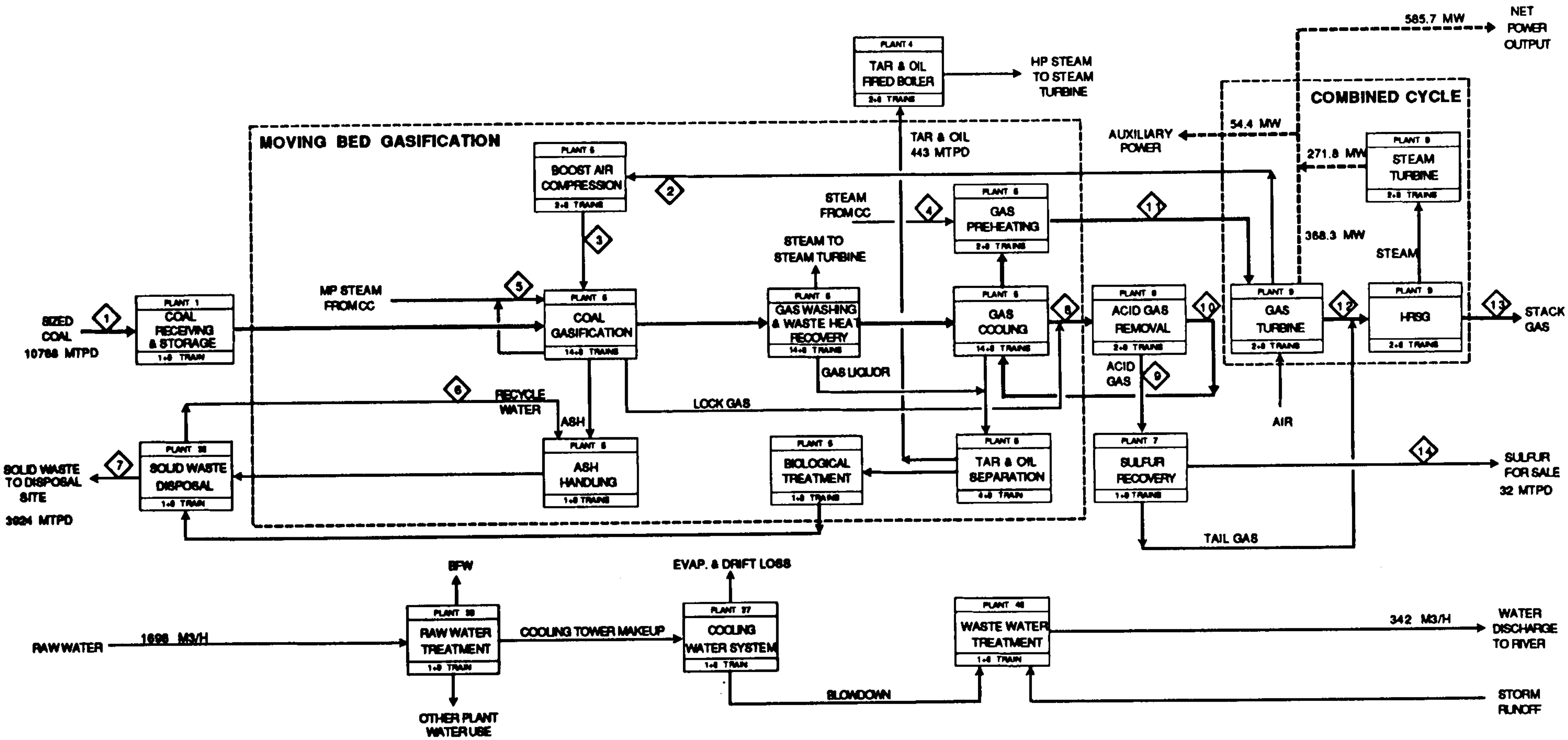

FIGURE 5-21

OVERALL BLOCK FLOW DIAGRAM IGCC PLANT (MOVING BED CASE) 29.5 C AMBIENT TEMPERATURE

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Table 5-16

MAJOR STREAMS FOR IGCC PLANT
(MOVING BED CASE)

Stream Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Stream Description	COAL TO GASIFIER	AIR FROM GT	AIR TO GASIF	STEAM FROM C.C.	STEAM TO GASIF.	RECYCLE WATER	ASH SETTLED	GAS TO AGR	ACID GAS	PROD GAS EXIT AGR	PROD GAS PREHEAT	GAS TO TO HRSG	STACK GAS	SULPHUR BY PRODUCT
Gases: kg-mol/h														
H2								7,135.8	1.9	7,133.9	7,133.9			
CO								4,745.8	1.2	4,744.6	4,744.6			
CO2								5,325.3	486.4	4,838.9	4,838.9	11,824.6	11,824.6	
CH4								1,196.7	5.3	1,191.4	1,191.4			
C2H4								68.6		68.6	68.6			
N2+AR		12,865.0	15,557.5					15,636.3		15,636.3	15,636.3	100,126.8	100,126.8	
O2		3,410.0	4,135.5					34.9		34.9	34.9	13,734.5	13,734.5	
H2S								44.6	44.4	0.1	0.1			
SO2												3.4	3.4	
H2O		1,122.0	134.8	361.1	9,571.1			102.9	53.3	160.6	160.6	14,056.5	14,056.5	
TOTAL: Kg-mol/hr		17,397.0	19,827.8	361.1	9,571.1			34,290.8	592.6	33,809.3	33,809.3	139,745.9	139,745.9	
Liquids: kg/hr														
H2O	80,757					1,342,000								
Sulphur														1,313
Solids: kg/hr														
Coal (MAF)	103,897													
Ash/Slag	174,077						163,500							
Sulphur														
Total: kg/hr	358,731	489,536	570,372	6,500	172,280	1,342,000	163,500	844,833	23,992	822,840	822,840	4,016,572	4,016,572	1,313
Temperature, C	29.4	331.7	145.0	253.5	292.5	40.0	40.0	42.0	43.3	48.0	157.2	607.4	121.0	132.2
Press, kg/cm2 g	0	11.27	31	43.2	32	5	0	23	1	22.8	22.6	0.04	0	4.9

Table 5-17

UTILITY SUMMARY
(MOVING BED CASE)

Plant No.	Plant Name	Power, kw	Steam, kg/hr 106 kg/cm2 542 C	43 kg/cm2 Sat.	33 kg/cm2 293 C	27.3 kg/cm2 Sat.	3.87 kg/cm2 Sat.	2.1 kg/cm Sat.	BFW, kg/hr	Blow-down, kg/hr	Conden-sate, kg/hr	DM Water, kg/hr	Cooling Water, m3/hr	Raw Water, m3/hr
1&2	Coal Receiving,	779												
	Storage & Handling													
3	Oil/Tar fired Boiler	1,284	216,400				(1,530)		220,700	(2,770)				
5	Gasification	35,875		6,500	172,280		19,640		223,420			123,770	15,620	
					(100,100)		(120,690)	(210)	(126,370)	(4,010)	(5,110)			
6&7	Acid Gas Removal &						38,190	720	6,350				3,512	
	Sulfur Recovery	1,252		2,400			(4,950)	(510)		(10)	(40,690)			
9	Combined Cycle													
	Gas Turbine	(368,300)												
	Steam Turbine	(271,800)	(686,400)	(7,600)	(72,180)	103,000	73,000		584,460		(782,600)		52,193	
	HRSG		470,000	(1,300)		(103,000)	(3,660)		(908,560)	(7,800)	828,400	86,140		
	BFW Pumps & Aux Equip	3,980												
37	Cooling Water System	7,206								14,590			(71,325)	
38	Raw Water Supply/Treat.													
40	Waste Water System	1,671										(209,910)		1,698
	Gener. Facility & Losses	2,353												
	TOTAL	(585,700)	0	0	0	0	0	0	0	0	0	0	0	1,698

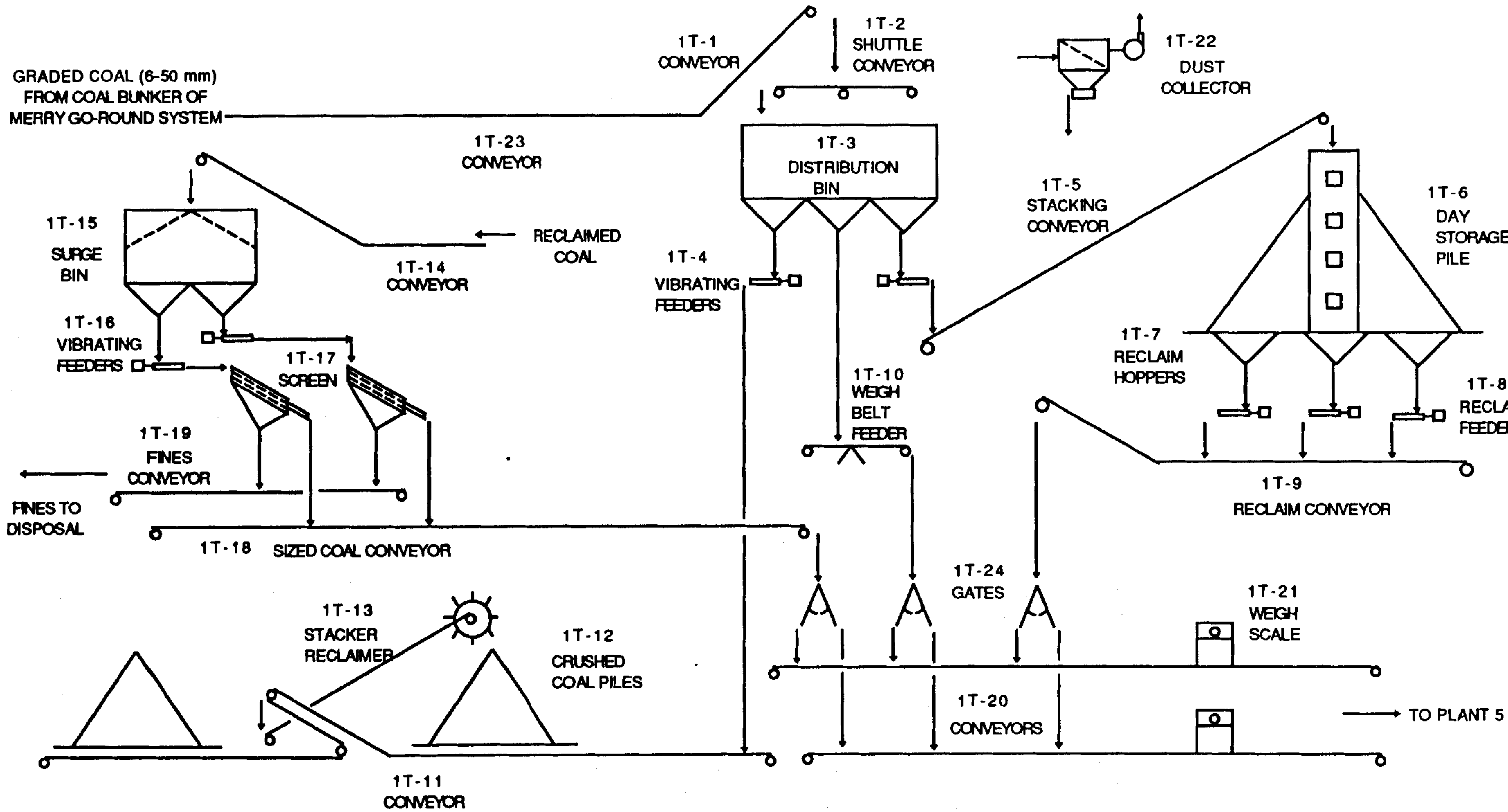

FIGURE 5-22

FLOW DIAGRAM
COAL RECEIVING, RECEIVING, & STORAGE (PLANT 1)
(MOVING BED CASE)

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The gasifier is a shaft type jacketed vessel and has an ash grate at the bottom and a coal distributor at the top. The distributor with raking arms helps to break up any agglomerated coal and to ensure a uniform flow of gas. This is essential while processing caking coals. For non-caking coal, a cylindrical skirt is adequate. The grate at the bottom rotating at very slow speed supports the fuel bed and helps to withdraw the ash from the gasifier. The gasifying media, air and steam, fed from the bottom through ports in the grate is evenly distributed over the cross section of the gasifier. The downward flow of coal counter current to the gasifying media and gaseous products results in banging temperature and concentration profile over the length of the reactor.

As coal moves down the gasifier, it is dried, preheated and devolatilised into char. Most of the char is gasified and the residual char is combusted with oxygen in the air to provide the endothermic heat for the gasification reactions. The maximum temperature that occurs in the combustion zone has to be less than the ash fusion point for facilitating dry ash removal and is controlled by the steam admitted along with the oxidant. Saturated steam is generated within the jacket of the reactor, thus keeping the outer wall temperature of the gasifier cool and no refractory lining is required.

The large fuel inventory in the reactor ensures safe and smooth operation. Any unavoidable fluctuation in coal properties is thus taken care. Because of this and its excellent dynamic response behaviour, the gasifier can be brought to full load very quickly from a hot standby condition. The availability factor is high.

The product gas, consisting of CO_2, CO, H_2 , CH_4, N_2, tar, oil, and undecomposed steam, leaves the gasifier at about 355 C. The ash residue with about 5% combustibles is discharged in dry condition through a lock hopper system operated in a time cycle.

A major portion of the required quantity of air for gasification is extracted from the air compressor of the gas turbine and the balance from an auxiliary compressor. Air from the gas turbine (471.2 t/h) at 12.3 kg/cm^2 and 381.7 C exchanges heat in a waste heat boiler to generate saturated steam at 3.87 kg/cm^2 and is further cooled in a trim cooler to about 42 C. The additional quantity of air required for gasification (96.7 t/h) is drawn through the auxiliary compressor at 12.3 kg/cm^2 and fed to the booster compressor along with the air drawn from gas turbine. The total quantity of air at 32 kg/cm^2 and 130 C is fed to the gasifiers.

Process steam drawn from the steam turbine at 33 kg/cm^2 and the saturated jacket steam from the gasifier provide the steam input to gasification.

<u>Gas Washing and Waste Heat Boiler</u>. The gas leaving the gasifier at 355 C is first scrubbed in a quench vessel with recirculated gas liquor and cooled to 165 C. It then passes to the waste heat boiler where low pressure steam at 3.8 kg/cm^2 is generated and the gas gets cooled to 155 C. The gas flows to a gas heater to preheat the cooled and purified fuel gas, then is further cooled in a pre-cooler followed by an after-cooler. In the pre-cooler, the gas is cooled to 1400 C while preheating boiler feed water. In the after-cooler, it is cooled to 42 C by exchange of heat with cooling water. The gas then goes to the acid gas removal section. The gas used for pressurising the coal lock chamber flows to a gas holder which is recompressed and mixed with the main stream of raw gas fed to the acid gas removal system. The number of quench vessels, waste heat boilers, gas

heaters, pre-coolers, and after-coolers are the same as the number of gasifiers.

The condensed liquids from the waste heat boiler, gas heater, pre-cooler and after-cooler are depressurised in two expansion vessels for oily and tarry gas liquor streams, respectively. Tar, oil, and gas liquor are separated in gravity separators. The tar fraction collected at an appropriate height in the primary secondary separators flow to tar storage tanks. The oil fraction drawn as overflow from the primary/secondary tar separators along with the oily gas-liquor streams are fed to oil-separator. The oil separated flows to oil storage tanks. The gas liquor separated in primary/secondary tar separators and in oil separators flows to the gas liquor storage tank. The excess gas liquor, after meeting the requirement of recycle to the quench vessel, is pumped to the waste water treatment section. Steam heating is provided in the primary and secondary separators and tar storage tanks.

This section has four operating trains.

Waste Water Treatment. The gas-liquor contains phenols, fixed and free ammonia, thiocyanates, other heterocyclic compounds, and suspended solids. It requires a combined physico-chemical and biological treatment before it can be reused. The treatment consists of primary treatment, biological treatment and polishing. The primary treatment comprises of: (1) equalisation to alternate the flow and characteristics of the gas liquor, (2) treatment with lime to adjust pH to 11.6 and to remove oil and grease, and (3) air stripping of ammonia. The stripped ammonia is absorbed in dilute sulphuric acid and the ammonium sulphate thus formed is recovered by subsequent evaporation and crystallisation. After neutralisation with sulphuric acid to a pH of 8, the gas liquor is subjected to biological oxidation with a special microbial culture in two trickling filters. The liquor is finally polished in actuated carbon filters and recycled to the ash handling plant.

Acid Gas Removal (Plant 6)

The design of this unit is the same as that adopted for the Texaco cases. Two operating trains without spare are required.

Sulfur Recovery (Plant 7)

The design of this unit is the same as that adopted for the Texaco cases. One train is required.

Combined Cycle (Plant 9)

The design and description of this plant is similar to that in the Shell case. Highlighted below are the major differences.

Gas Turbine. Based on the clean gas composition, GE provided the following gas turbine performance (one 9F gas turbine) at both the normal and design ambient temperatures:

	29.4 C (Normal)	18.3 C (Design)
Fuel(LHV), Million Kcal/h	491.5	514.6
Fuel Gas Temperature, C	157.2	157.2
Relative Humidity	80	60

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NO_x Steam, 1000 kg/h	0	0
Exhaust Flow, 1000 kg/h	2001.3	2098.3
Exhaust Temperature, C	610	594.4
Power Output, MW	184.2	201.1
Air Extraction, 1000 kg/h	235.6	246.7

The moving bed gasifier gas has very high CO_2 and N_2 contents. CO_2 and N_2 acts as diluents to suppress the flame temperature in the gas turbine combustor. As a result, no NO_x steam injection is required.

Steam Generation and Consumption in the Process Area. A steam balance of the process area is shown in Figure 5-23. The major flows are shown in Table 5-18. Steam is generated and consumed in the process plant at six pressure and temperature levels.

High pressure superheated steam at 108 kg/cm^2 abs is generated in the tar/oil fired boilers. It flows to the steam turbine for power generation. High pressure saturated steam at 43.2 Kg/cm^2 abs is consumed for clean fuel gas preheating and also in sulfur recovery plant. This is provided by desuperheating of an extraction steam from the steam turbine. Saturated steam is produced at 33 kg/cm^2 abs pressure in the gasifier water jacket. This is fed back into gasifier as part of the gasification steam. Balance of the gasification steam is provided by extraction of steam at 35 kg/cm^2 abs from the steam turbine.

Intermediate pressure 3.9 kg/cm^2 abs saturated steam is produced in the gasifier waste heat recovery, cooling of the gas turbine extraction air, the sulfur recovery unit, and also by flashing of various boiler blowdown and steam condensate streams. After meeting the requirement of deaerator and other miscellaneous uses, the balance quantity of this intermediate pressure steam flows to the steam turbine.

Low pressure saturated steam at 2.1 kg/cm^2 abs is produced from the sulfur condenser in the sulfur recovery plant. This steam is utilized in the Selectox preheater.

Steam Cycle. The steam cycle configuration is shown in Figure 5-24 and the major stream flows at 29.5 C annual average temperature are shown in Table 5-19. This cycle configuration is very similar to that in the Shell case. The major differences are:

- o HP superheated steam generated in the tar/oil fired boiler is fed to the steam turbine along with HP superheated steam generated from HRSG.
- o Steam is extracted from the steam turbine at 43.2 kg/cm^2 abs and 35.0 kg/cm^2 abs to meet the steam demand in process area.
- o Excess 3.9 kg/cm^2 abs steam from the process area is fed to the IP-LP section of the steam turbine.
- o HP BFW for process area is delivered from the deaerator.

Heat Recovery Steam Generator. The HRSG mechanical details described in the Shell case also apply for the moving bed case.

Steam Turbine Generator. The steam turbine has the same basic configuration as that in the Shell case, except for the rating. The turbine is rated for approximately 140 MW and generator is rated for 160 MVA.

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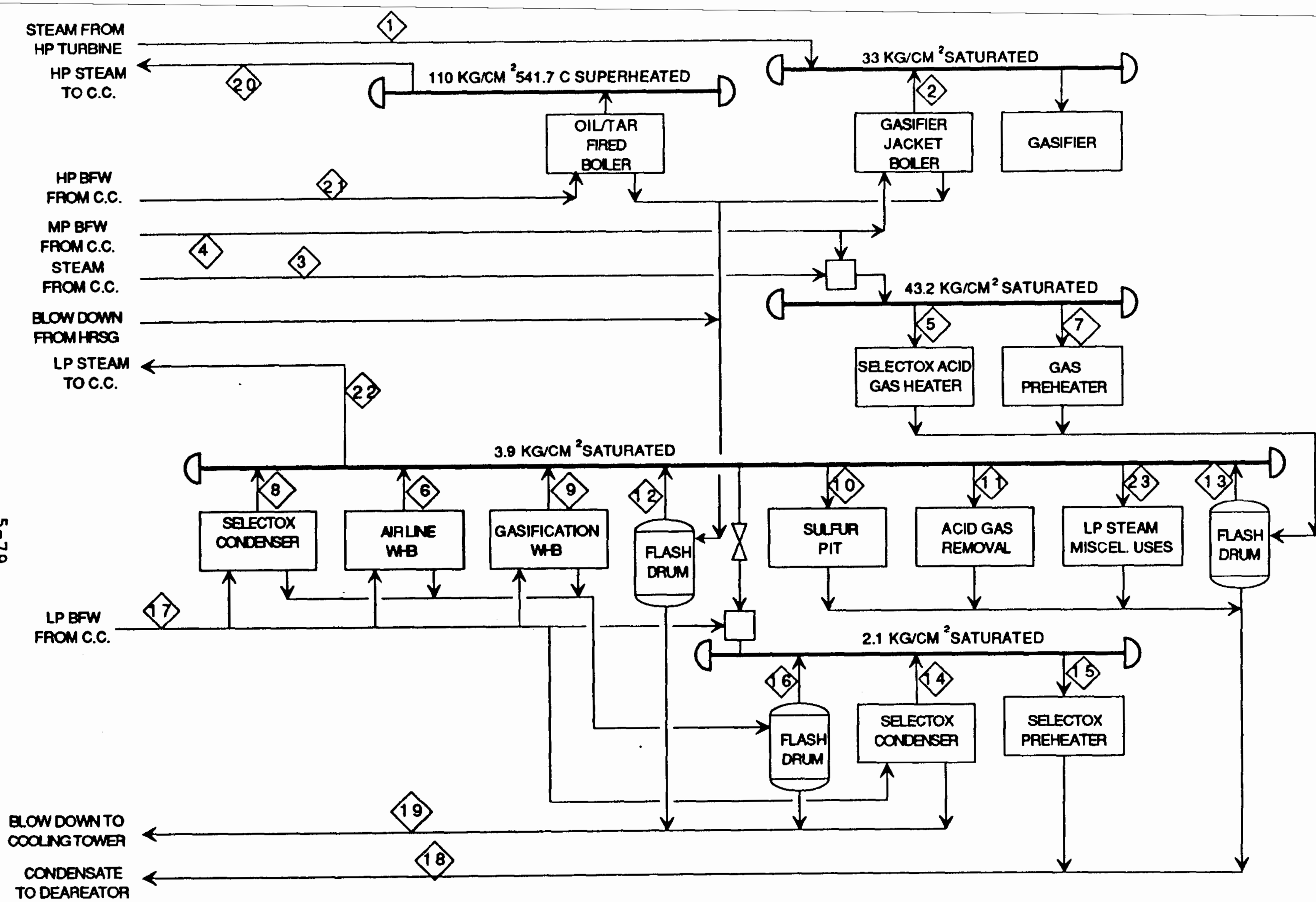

FIGURE 5-23 PROCESS STEAM BALANCE DIAGRAM (MOVING BED CASE)

Table 5-18

STREAM FLOW FOR PROCESS STEAM
(MOVING BED CASE)

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12
STREAM DESCRIPTION	STEAM FROM HP TURBINE	STEAM FROM JACKET BOILER	STEAM FROM HP TURBINE	MP BFW FROM C.C.	STEAM TO ACID GAS HEATER	STEAM FROM AIR LINE WHB	STEAM TO GAS PRE HEATER	STEAM FROM SULFUR COND	STEAM FROM GASIF. WHB	STEAM TO SULFUR PIT	STEAM TO AGR	STEAM FROM BLOW DOWN
Pressure, kg/cm2 abs	35.00	33.00	43.20	40.00	43.20	3.87	43.20	3.87	3.87	3.87	3.87	3.87
Temperature, C	383.8	238.1	410.6	115.6	253.8	141.8	253.8	141.8	141.8	141.8	141.8	141.8
Flow, 1000 kg/h	72.18	100.10	7.41	103.49	2.40	50.37	6.40	4.44	68.56	0.25	37.83	6.35
Enthalpy, kcal/kg	760.84	669.52	772.55	116.50	668.60	653.51	668.60	653.51	653.51	653.51	653.51	653.51

STREAM NO.	13	14	15	16	17	18	19	20	21	22	23
STREAM DESCRIPTION	STEAM FROM COND. FLASH	STEAM FROM SULFUR COND.	STEAM TO SULFUR PREHTR	STEAM FROM BD FLASH	LP BFW FROM C.C.	COND TO DEAREATOR	BLOW DOWN TO COOLING TOWER	HP STEAM TO C.C.	HP BFW FROM C.C.	LP STEAM TO C.C.	LP STEAM TO MISCEL. USES
Pressure, kg/cm2 abs	3.87	2.10	2.10	2.10	3.87	2.10	2.10	110.00	130.00	3.87	3.87
Temperature, C	141.8	121.2	121.2	121.2	116.2	121.2	121.2	541.7	115.6	141.8	141.8
Flow, 1000 kg/h	2.09	0.51	0.72	0.10	126.36	65.15	14.33	216.40	220.70	73.97	19.64
Enthalpy, kcal/kg	653.51	646.77	646.77	646.77	116.50	121.55	121.55	829.23	118.01	653.51	653.51

1. Enthalpy values are based on 0 kcal/kg for liquid water at 0 C

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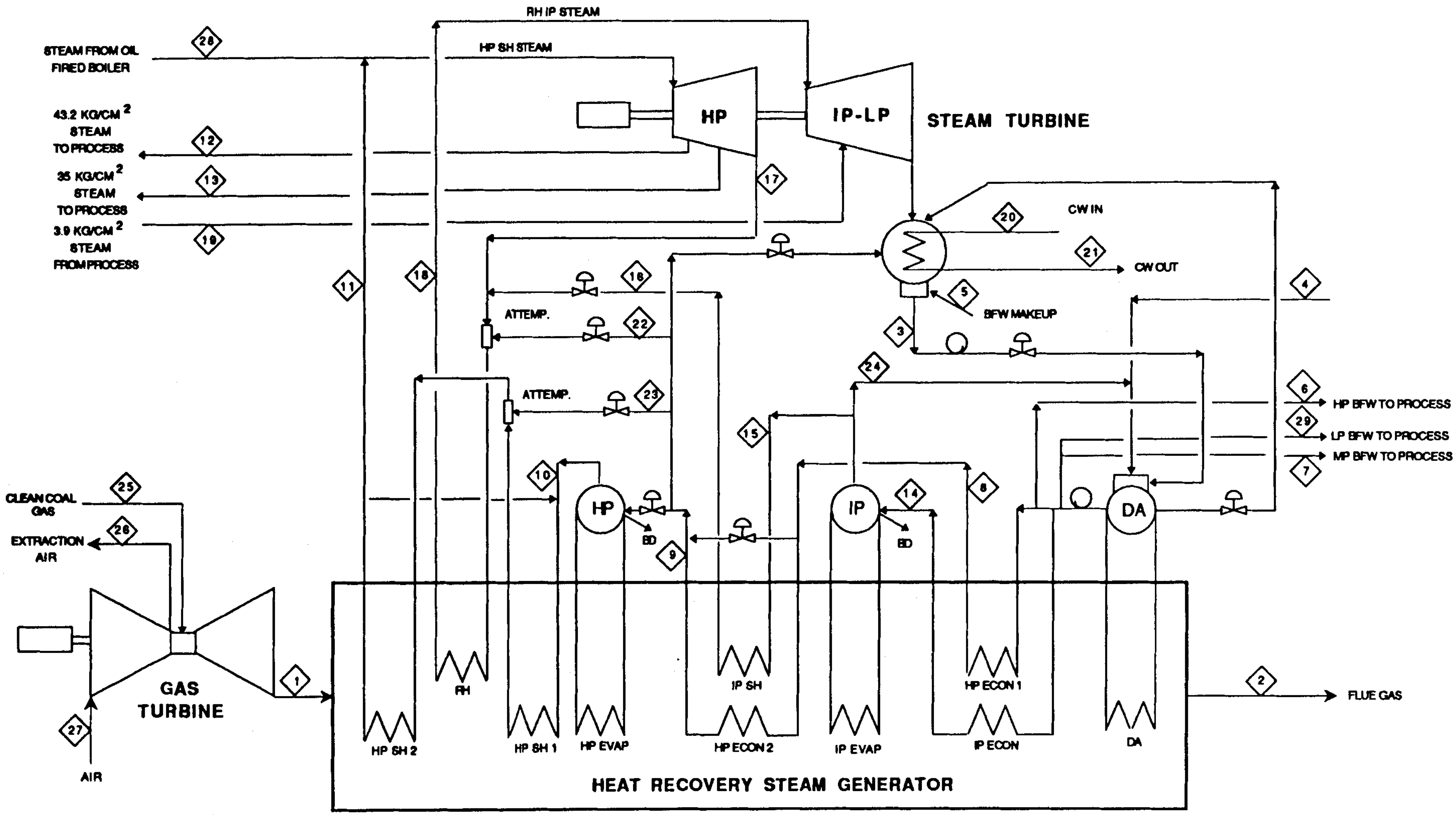

FIGURE 5-24 COMBINED CYCLE FLOW DIAGRAM (MOVING BED CASE) 29.5 C AMBIENT TEMPERATURE

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Table 5-19

STREAM FLOW FOR COMBINED CYCLE
(MOVING BED CASE)

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12
STREAM DESCRIPTION	EXHAUST TO HRSG	STACK GAS	TURBINE COND.	COND. FROM STEAM SYSTEM	DM WATER MAKE UP	HP BFW TO OIL-FIRED BOILER	IP BFW GASIF JACKET BOILER	BFW FROM HP ECON-1	BFW FROM HP ECON-2	STEAM FROM HP BOILER	HP STEAM FROM HRSG	EXTR. STEAM TO PROCESS
Pressure, kg/cm2 abs	1.02	0.98	0.12	2.10	4.00	130.00	40.00	130.00	130.00	130.00	109.00	43.20
Temperature, C	607.0	121.0	49.0	121.2	115.0	115.6	115.6	218.0	306.0	218.0	541.7	410.6
Flow, 1000 kg/h	4017	4017	782.60	45.51	207.23	220.70	103.49	479.40	479.40	479.40	470.00	7.41
Enthalpy, kcal/kg	163.24	30.74	49.05	121.55	115.25	118.01	116.50	223.74	328.74	647.10	828.80	772.55

STREAM NO.	13	14	15	16	17	18	19	20	21	22	23	24
STREAM DESCRIPTION	EXTR. STEAM TO PROCESS	BFW FROM IP ECON-1	STEAM FROM IP BOILER	IP STEAM FROM IP-SH	EXHAUST FROM HP TURBINE	PRE HEATED IP STEAM	PROCESS STEAM TO LP-TURB	COOLING WATER SUPPLY	COOLING WATER RETURN	REHEAT ATTEMP. WATER	HP STEAM ATTEMP. WATER	DEAR. PEGGING STEAM
Pressure, kg/cm2 abs	35.00	40.00	27.50	26.70	26.70	25.30	3.87	3.50	2.50	130.00	130.00	27.50
Temperature, C	383.8	218.0	228.0	358.0	349.4	537.8	141.7	36.1	44.4	306.0	306.0	228.0
Flow, 1000 kg/h	72.18	105.06	103.00	103.00	606.60	709.60	73.00	52093	52093	0	0	0
Enthalpy, kcal/kg	760.84	223.20	669.40	749.00	745.40	847.10	653.58	36.10	44.40	328.74	328.74	669.40

STREAM NO.	25	26	27	28	29
STREAM DESCRIPTION	CLEAN COAL GAS	EXTR. AIR	TAIL GAS TO EXHAUST	HP STEAM FROM OIL-BOILER	LP BFW TO PROCESS
Pressure, kg/cm2 abs	22.60	12.31	1.06	110.00	3.87
Temperature, C	157.2	381.7	137.8	541.7	116.2
Flow, 1000 kg/h	822840	471325	26.93	216.40	126.36
Enthalpy, kcal/kg	1242.60	93.75	43.17	829.23	116.50

1. Enthalpy values are based on 0 kcal/kg for liquid water at 0 C

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Auxiliary Steam System. The design and description of this system is identical to that in the Shell case.

Balance of Plant

Solid Waste disposal (plant 30). The ash from the ash lock of individual gasifier falls into the ash sluice way. The ash is carried to a grizzly separator to separate the over size material from the fines. The fines are returned to the sluice way and the over size material is crushed in a roll crusher and falls into the sluice way. The 10% solid containing ash slurry is transported to the ash disposal area through a pipeline. Necessary pumps for circulation of sluice water are provided. Makeup water for the sluice system is obtained from the waste water treatment plant. The sluice ways are totally enclosed and provided with suction fans and scrubbers. While about 164 t/h of ash is expected to be produced from all the fourteen gasifiers, the ash disposal plant is designed for a capacity of 180 t/h to take care of fluctuation in the quality of coal.

Relief and Blowdown Systems (Plant 31). The description of this plant area is identical to that in the Shell case. However, as the gasifiers are air blown, there is no oxygen piping system.

Compressed Air System (Plant 33). The description of this plant area is identical to that in the Shell case.

Fuel oil and LPG System (Plant 34). Fuel oil produced in the gasification plant is used for gas turbine startup and auxiliary boiler. Required storage is provided in different plant sections.

The description of the LPG system is identical to that in the Shell case.

Electrical system (Plant 35). The description of this plant area is identical to that in the Shell case.

Instrumentation and Control (Plant 36). The description of this plant area is identical to that in the Shell case.

Cooling Water System (Plant 37). All the plant cooling loads are provided by a mechanical draft cooling tower. The required water flow is shown in the overall water balance diagram (Figure 5-25) and the stream flow table (Table 5-20).

The cooling tower consists of 33 cells (2500 m3/h per cell). The description of this system is identical to that in the Shell Case.

Raw Water Supply and Treatment (Plant 38). The major processing blocks in this system are shown in the overall water balance diagram, Figure 5-25. The major stream flows are shown in Table 5-20. Description of this system is identical to that in the Shell case.

Fire Protection (Plant 39). The description of this plant area is identical to that in the Shell case.

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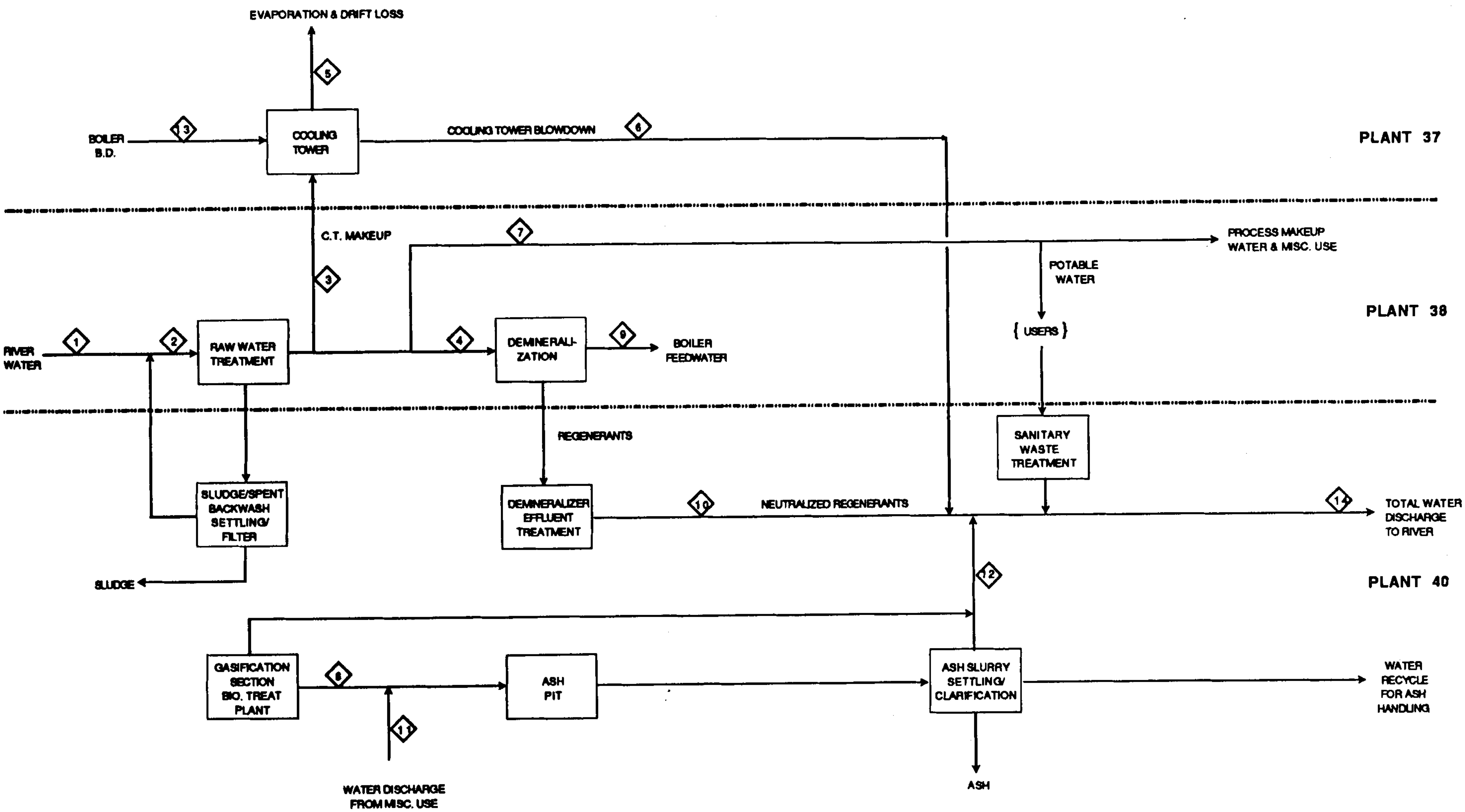

FIGURE 5-25

OVERALL WATER BALANCE DIAGRAM IGCC PLANT (MOVING BED CASE)

Table 5-20

MAJOR STREAMS OF OVERALL WATER BALANCE
IGCC PLANT (MOVING BED CASE)

Stream Number	Stream Name	Flow, m3/h
1	Total River Water Intake	1698
2	Water to Water Treatment Plant	1829
3	Cooling Tower Makeup	1374
4	Demineralization Plant Feed	244
5	Cooling Tower Evaporation & Drift Loss	1200
6	Cooling Tower Blowdown	189
7	Process Makeup Water & Misc. Use	20
8	Water Recovered from Bio-treatment	130
9	Boiler Feed Water	210
10	Neutralized Demineralizer Regenerants	33
11	Water Discharge from Misc. Use	0
12	Ash Slurry Settling/Clarification Disch.	112
13	Boiler Blowdown	15
14	Total Water Discharge to River	354

Waste Water Treating (Plant 40). The gasification plant waste water treatment has been described under Plant 5.

Other plant waste water treatments required are identical to those described for the Shell cases.

Site Preparation and Improvements (Plant 42). The description of this plant area is identical to that in the Shell case.

Buildings (Plant 43). The description of this plant area is identical to that in the Shell case.

5.2 PLANT PERFORMANCE SUMMARY

5.2.1 Plant Efficiency

Table 5-21 summarizes the plant resource requirements, power outputs, heat rates, and efficiencies for the four IGCC cases. A breakdown of the in-plant power consumption for all the four cases is shown in Table 5-22. The transformer losses shown in Table 5-22 are assumed to be 0.25% of the gross power generated.

In Table 5-21, the Texaco case is seen to consume substantially more coal and has a higher heat rate than the other three cases. This is because the slurry feed system of the Texaco gasifier suffers severe thermal penalty when a high ash coal is used. Another reason is that Texaco chose to use quench operating mode for the gasifier as discussed in Section 4.1.3. It is estimated that if the waste heat boiler mode is used, the heat rate can be improved by 20%.

In future studies, coal washing should be considered for the Texaco gasifier. The washing directly increases the gasifier thermal efficiency. It also removes the capacity bottleneck caused by the ash lockhopper valve and enables the gasifier to operate in the thermally more efficient waste heat boiler mode. Only with washed coal, Texaco can be competitive with other gasifiers.

The moving bed case has a better heat rate than the Texaco case. But this heat rate is considerably higher than the Shell and KRW cases. This is because the moving bed case requires a large quantity of steam injected to the gasifier to avoid ash clinkering.

The KRW case has the best heat rate among all cases. The major reasons are:

- The gasifier is operated at low temperature and thus has a relatively high cold gas efficiency
- The gasifier uses in-situ sulfur capture
- The gasifier uses hot gas cleanup
- There is air integration between the gasifier and gas turbine

The last three process features are not commercially proven. The technical uncertainties are discussed in Section 5.4.2.

5.2.2 Plant Heat Flow

Figures 5-26 to 29 show the overall plant heat flows of the four IGCC cases. All the heat flows are expressed as percentages of the total HHV content in the coal feed.

Table 5-21

IGCC PLANT PERFORMANCE

	Study Case			
	Shell	Texaco	KRW	Moving Bed
Plant Resources Requirements				
Coal (as received)				
MTPD	9,964	12,576	8,890	10,768
HHV, million Kcal/h (a)	1,383	1,746	1,234	1,472
LHV, million Kcal/h	1,315	1,660	1,173	1,421
Limestone, MTPD	618	0	280	0
Raw Water, m3/h	1,324	2,224	1,019	1,698
Plant Output, MW				
Gross Power Generated				
Gas Turbine	392.2	396.5	350.4	368.3
Steam Turbine	308.4	258.0	280.2	271.8
Total	700.6	654.5	630.6	640.1
In-Plant Power Consumption	136.2	158.3	53.4	54.4
Net Power to Grid	564.4	496.2	577.2	585.7
Heat Rate, Kcal/kwh				
HHV Basis	2,451	3,519	2,138	2,514
LHV Basis	2,330	3,345	2,033	2,427
Overall Thermal Efficiency, %				
HHV Basis	35.1	24.4	40.2	34.2
LHV Basis	36.9	25.7	42.3	35.4
Sulfur Byproduct, MTPD	29	37	0	32

(a) The coal HHV is 3332 kcal/kg in the first three cases. It is 3282 kcal/kg in the moving bed case.

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Table 5-22

IN-PLANT POWER CONSUMPTION
(KW)

Plant Number	Plant Name	Study Case: Shell	Texaco	KRW	Moving Bed
1	Coal Receiving & Storage	418	551	373	779
2	Coal and Limestone Handling	130	831	1110	w/above
3	Coal Drying/Oil Fired Boiler	-	-	2,100	1,284
4	Air Separation	98,452	125,027	-	-
5	Coal Gasification	20,428	5,547	35,108	35,875
6	Acid Gas Removal	w/above	504	-	1,252
7	Sulfur Recovery	w/above	190	-	w/above
8	Sour Water Stripping	45	167	-	-
9	Combined Cycle	5,860	5,777	5,849	3,980
10	Ash Sulfation	-	-	710	-
37	Cooling Water Systems	7,525	16,018	5,300	7,206
38	Raw Water Supply & Treating	674	1,122	450	w/below
40	Waste Water Treatment	66	76	40	1,671
	General Facilities	840	840	840	2,353
	Transformer Losses	1,752	1,636	1,577	w/above
	Total	136,190	158,286	53,457	54,400

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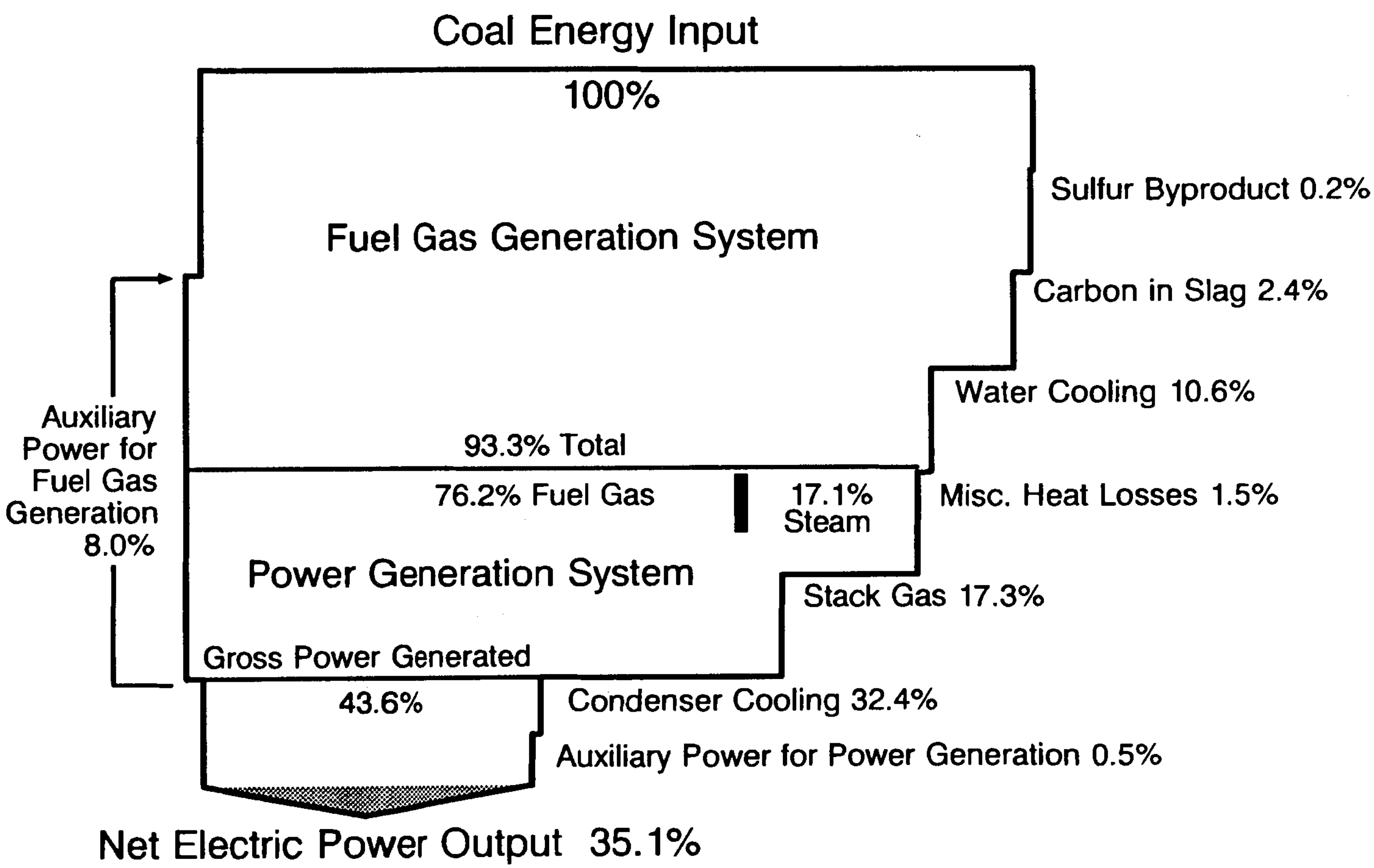

Figure 5-26 OVERALL PLANT HEAT FLOW (SHELL CASE)

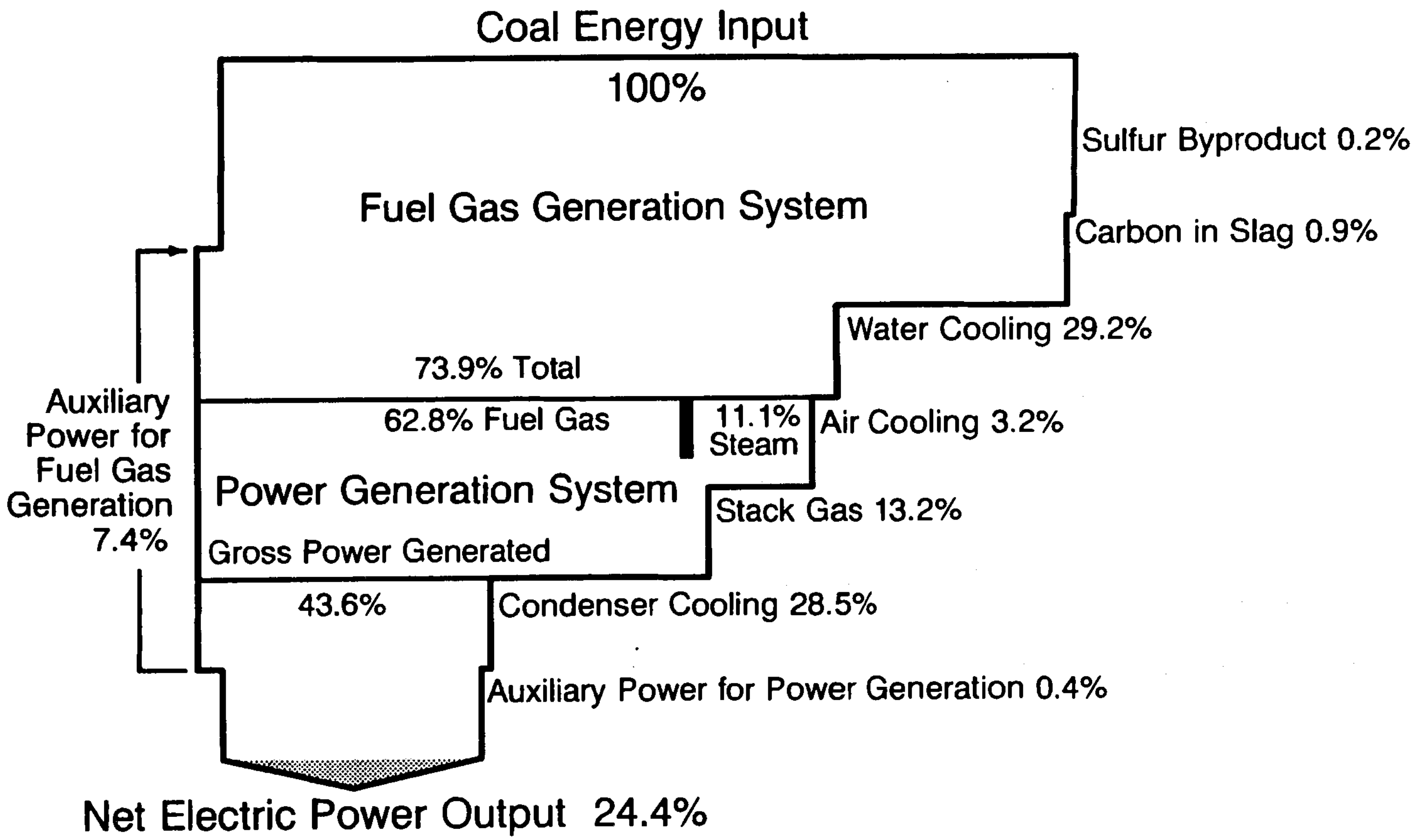

Figure 5-27 OVERALL PLANT HEAT FLOW (TEXACO CASE)

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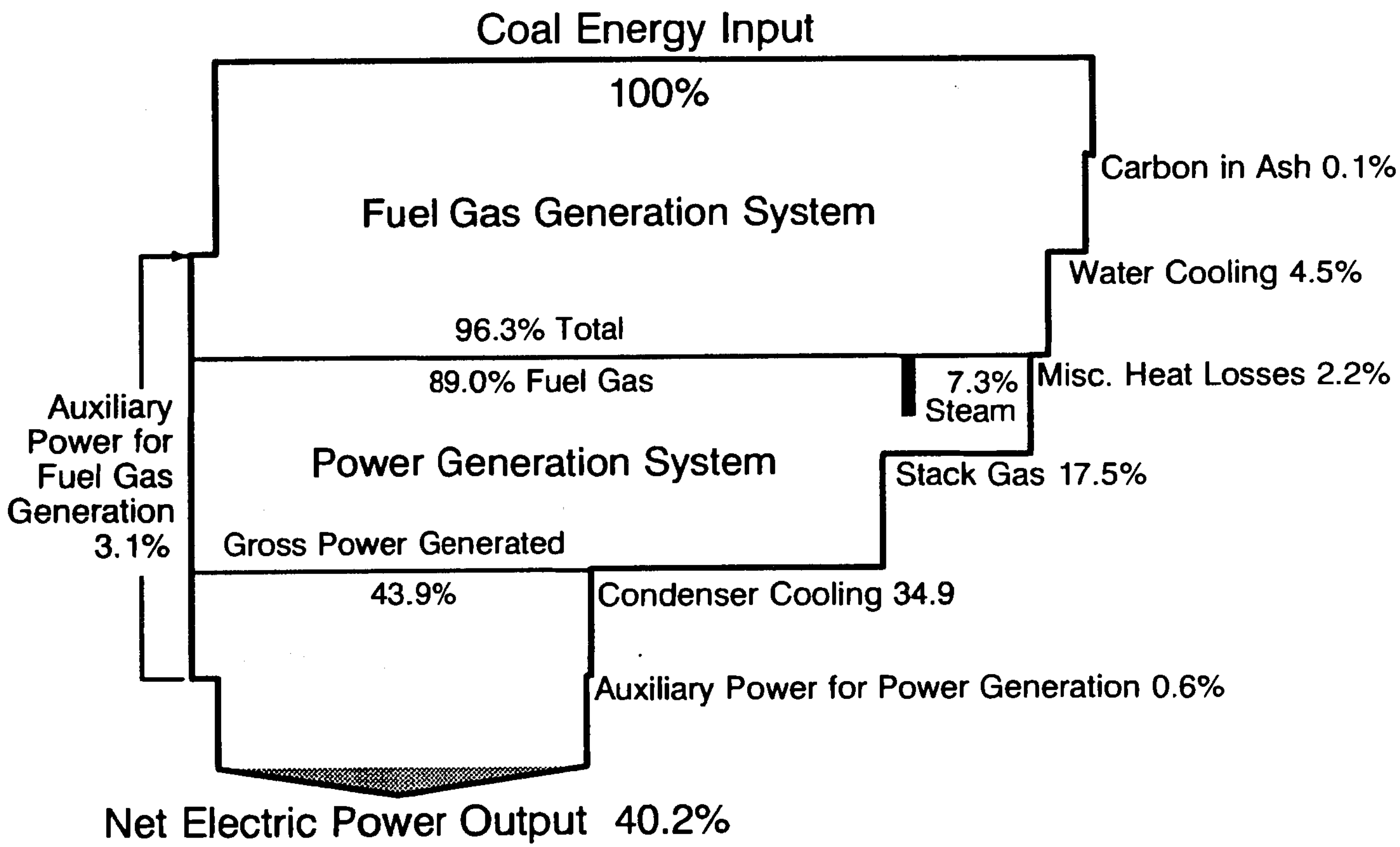

Figure 5-28 OVERALL PLANT HEAT FLOW (KRW CASE)

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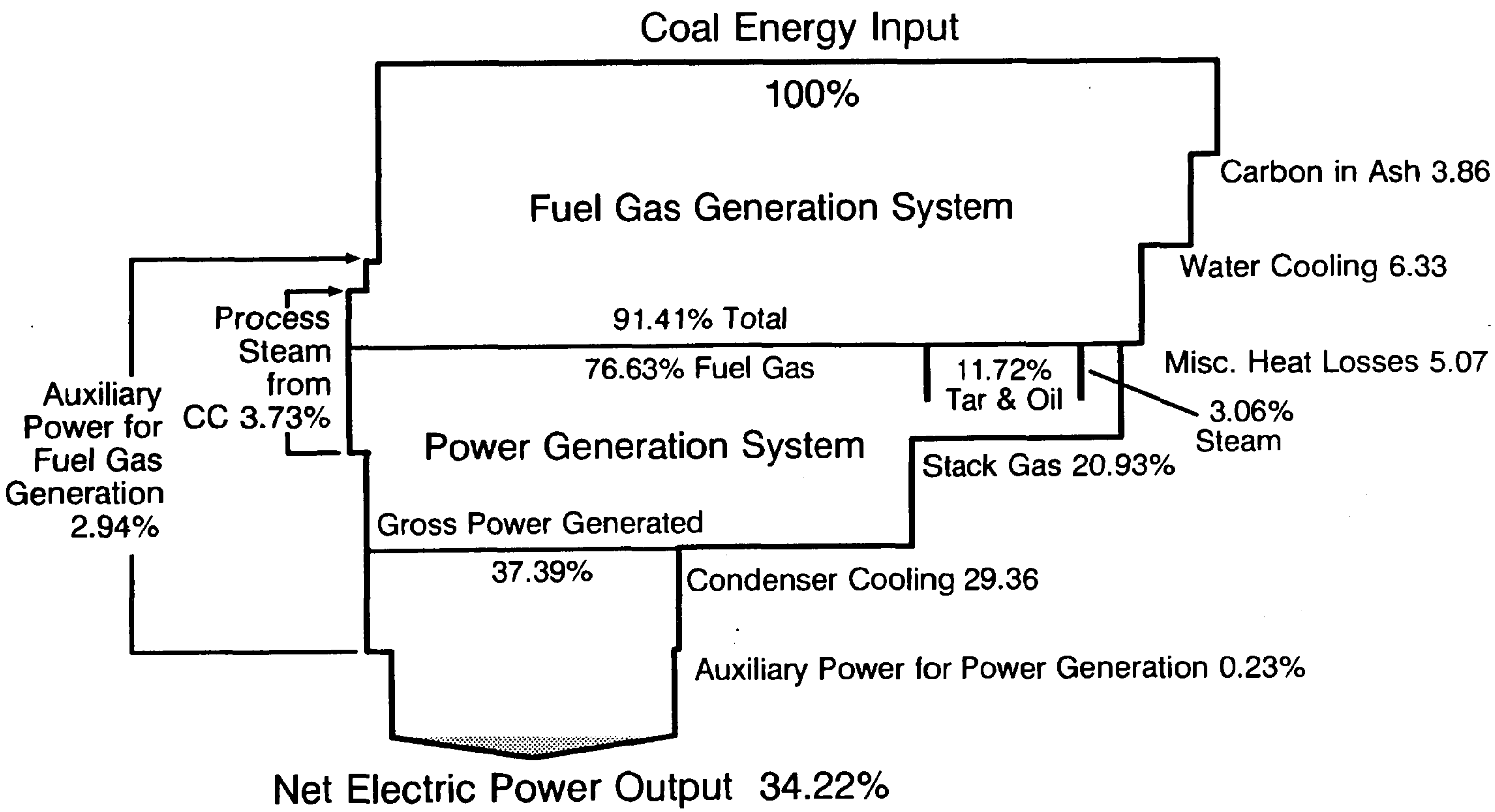

Figure 5-29 OVERALL PLANT HEAT FLOW (MOVING BED CASE)

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In each of the heat flow diagrams, the IGCC plant is broken down into a fuel gas generation block and a power generation block. On the right side of each diagram, various heat losses from these two major plant blocks are shown. The energy leaving the fuel gas block consists mainly of fuel gas and steam which are both sent to the power block for power generation. The gross power produced, after subtracting auxiliary power requirements for the fuel gas and power blocks, is the net power output of the IGCC plant.

The percentage of energy in coal retained as fuel gas, or the so-called cold gas efficiency, can account for most of the plant efficiency differences among the four IGCC cases. Typically, the plant efficiency is higher if the cold gas efficiency is higher. For example, the cold gas efficiency is the highest in the KRW case and so is the plant efficiency. This is because fuel gas energy is converted to power through combined cycle at a conversion efficiency in the 50% range while steam is converted to power through steam turbine at 30-35% efficiency only.

5.2.3 Emission Inventory

A summary of emissions from the IGCC plant is shown in Table 5-23. The emissions include NO_x, CO, SO_x, and particulates emissions to air, water discharge, and solid waste discharge.

The NO_x emission is based on 75 ppmv concentration in the HRSG exhaust gas.

The SO_x emission is based on 98, 90, 78, and 92% sulfur capture for the Shell, Texaco, KRW, and moving bed cases, respectively. In the Shell, Texaco, and moving bed cases, the sulfur recovery represents the maximum capture level achievable without significant cost increase of the acid gas removal and sulfur recovery plants. In the KRW case, the in-bed sulfur capture cost is lower at lower capture level. Therefore, the sulfur capture level is kept lower than the other three cases.

5.3 COST ESTIMATE

This subsection presents estimates of the capital requirements, project lead time, and cost of generation for the IGCC plants described above. The estimating approach, including the data sources and methodology, is also described.

All the estimates are based on the fourth quarter of 1989 as the pricing date.

For the Shell, Texaco, and KRW cases, Bechtel developed the capital costs based on U.S. conditions. The Indian team then translated them into India conditions. For the moving bed case, the Indian team developed the costs directly under India conditions.

The Indian team developed the costs of generation for all the four cases.

5.3.1 Estimate Approach in US costs

The estimating approach used by Bechtel for the U.S. costs included maximum use of actual cost experience on similar projects, with supplemental use of vendor data. Reports of similar type projects and historical data from constructed facilities were also used. Extensive use was made of engineering and cost information developed for earlier IGCC studies.

In the Shell case, the following plant areas are proprietary designs of Shell:

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Table 5-23

IGCC PLANT EMISSIONS

	Study Case			
	Shell	Texaco	KRW	Moving Bed
Air Emissions				
NOx, kg/h				
From Combined Cycle	418.87	434.89	411.49	409.80
From Main Flare (a)	0.17	0.00	0.00	0.00
Total	419.04	434.89	411.49	409.80
CO, kg/h				
From Combined Cycle	136.36	136.36	136.36	136.36
From Main Flare (a)	5.44	0.00	0.00	0.00
Total	141.80	136.36	136.36	136.36
SOx, kg/h				
From Combined Cycle	37.37	337.28	480.00	217.60
From Main Flare (a)	1.04	0.00	0.00	0.00
Coal Dring Flue Gas	1.22	-	0.00	0.00
Total	39.62	337.28	480.00	217.60
Particulates, kg/h				
From Combined Cycle	20.2	20.2	20.2	20.2
From Coal Rec. & Prep.	3.4	3.4	3.4	3.4
Total	23.6	23.6	23.6	23.6
Water Discharge, m3/h				
Treated Process Waste Water	41	82	-	-
Cooling Tower Blowdown	160	264	126	189
Neutralized Demin. Regenerants	21	22	9	33
Ash Settling/Biotreat Discharge	-	-	-	112
Discharge from Misc. Water Usage	11	11	11	-
Treated Sanitary Waste	8	8	8	8
Total	241	387	154	342
Solid Waste Discharge, MTPD				
Shell Slag (15% Moisture)	4,036	-	-	-
Shell Flyslag (20% moisture)	522	-	-	-
Texaco Slag (50% moisture)	-	8,358	-	-
Texaco Filter Cake (50% moisture)		1,475		
KRW Ash (0% moisture)	-	-	3,378	-
Moving Bed Ash (0% moisture)	-	-	-	3,924
Raw Water Treatment Sludge	1	1	1	1
Total	4,559	9,834	3,379	3,925

(a) From incineration of vent gas released during Shell flyslag removal

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- o Coal Gasification (Plant 5)
- o Acid Gas Removal (Plant 6)
- o Claus Sulfur Recovery (Plant 7)
- o Sour Water Stripping (Plant 8)
- o Process Waste Water Treatment (part of Plant 40)

For these areas, Shell furnished the equipment cost and installation manhours.

In the Texaco case, the following plant areas are proprietary designs of the specified process vendors:

- o Coal Gasification (Plant 5)-Texaco
- o Selectox Sulfur Recovery (Plant 7)-Parson
- o Process Waste Water Treatment (part of Plant 40)-Texaco

For these areas, the respective vendors furnished the necessary equipment costs and installation manhours.

In the KRW case, the following plant areas are proprietary design of KRW:

- o Coal Gasification (Plant 5)
- o Ash Sulfation (Plant 10)

For these areas, KRW furnished the necessary equipment costs and installation manhours.

General Electric provided equipment cost and installation manhours for the gas turbine.

For the air separation plant, a turnkey cost which includes materials and labor as a direct subcontract price was estimated based on Bechtel's previous project experiences.

The remaining costs were developed based on equipment lists contained in Appendices A-C.

5.3.2 Capital Cost Estimate Under US Conditions

Capital costs of the Shell, Texaco, and KRW cases under US conditions are shown respectively in Tables 5-24 to 26. A breakdown of the owner's cost is shown in Table 5-27.

The total capital requirement consists of plant facilities investment and owner's costs.

The plant facilities investment is the sum of the total plant cost, contingency, and initial catalyst and chemicals.

The total plant cost is the total constructed cost of all on-site processing facilities, power generating units, and general facilities and is the sum of the following:

- o Direct field material
- o Direct field labor (includes fringes and benefits)
- o Subcontracts
- o Indirect field costs and engineering

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Table 5-24

CAPITAL COST REQUIREMENTS UNDER US CONDITION
$1,000 , 4th Q-1989
(Shell Case)

Plant No.	Plant Name	Direct Field Material	Direct Field Labor	Direct Field Subcontract	Indirect Cost and Engineering	Total Cost
1	Coal Rec., Crushing, Storage	14,579	6,005	1,416	8,356	30,356
2	Coal and Limestone Handling	2,651	1,092	257	1,519	5,519
4	Air Separation	1,605	397	111,789	14,033	127,825
5	Shell Coal Gasification	195,920	73,775	0	102,598	372,293
6	Acid Gas Removal	3,356	1,321	0	1,819	6,496
7	Sulfur Recovery (Claus)	3,152	1,241	0	1,709	6,102
8	Sour Water Stripping	1,140	430	0	598	2,168
9	Combined Cycle					
	Gas Turbine	84,800	3,219	1,750	13,837	103,606
	HRSG & Stack	25,190	6,691	787	10,290	42,959
	Steam Turbines	30,335	3,836	0	7,752	41,923
	Cond/BFW Systems	9,737	4,961	2,965	6,842	24,504
30	Solid Waste Disposal	654	310	1,308	567	2,840
31	Relief & Blowdown	876	330	0	459	1,664
32	Interconnecting Piping	7,114	3,786	294	4,947	16,141
33	Compressed Air System	1,104	501	102	681	2,388
34	Fuel Oil and LPG System	927	61	1,553	363	2,904
35	Electrical System	18,366	7,552	0	10,299	36,217
36	Instrumentation and Controls	2,719	0	3,243	715	6,677
37	Cooling Water System	2,125	405	3,419	1,100	7,049
38	Raw Water Supply and Treatment	4,268	308	1,694	1,045	7,314
39	Fire Protection	1,322	666	1,100	1,005	4,093
40	Waste Water Treating					
	Process Waste Water Treating	5,906	2,342	0	3,220	11,468
	Other Waste Water Treating	4,428	309	250	893	5,880
41	General Ser. & Mobile Equipment	557	0	0	67	624
42	Site Preparation and Improvement	0	0	4,529	543	5,072
43	Buildings	619	403	2,740	836	4,598
	Total Plant Cost	423,450	119,941	139,197	196,094	878,682
	Contingency					105,442
	Initial Catalyst and Chemicals					3,000
	Plant Facilities Investment					987,124
	Owner's Cost					43,776
	Total Capital Requirements					1,030,900

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Table 5-25

CAPITAL COST REQUIREMENTS UNDER US CONDITION
$1,000 , 4th Q-1989
(Texaco Case)

Plant No.	Plant Name	Direct Field Material	Direct Field Labor	Direct Field Subcontract	Indirect Cost and Engineering	Total Cost
1	Coal Rec., Crushing, Storage	13,254	5,459	1,287	7,597	27,597
2	Coal Secondary Crushing	6,627	2,729	644	3,798	13,798
4	Air Separation	2,185	541	152,192	19,105	174,023
5	Texaco Coal Gasification	155,100	64,552	0	87,812	307,464
6	Acid Gas Removal	4,027	1,585	0	2,183	7,795
7	Sulfur Recovery (Selectox)	3,340	1,313	0	1,809	6,462
8	Sour Water Stripping	2,070	979	0	1,297	4,346
9	Combined Cycle					
	Gas Turbine	84,800	3,219	1,750	13,837	103,606
	HRSG & Stack	25,205	6,695	788	10,296	42,984
	Steam Turbines	26,300	3,326	0	6,721	36,347
	Cond/BFW Systems	8,749	4,457	2,664	6,147	22,017
30	Solid Waste Disposal	1,053	499	2,107	914	4,572
31	Relief & Blowdown	876	330	0	459	1,664
32	Interconnecting Piping	7,114	3,786	294	4,947	16,141
33	Compressed Air System	1,104	501	102	681	2,388
34	Fuel Oil and LPG System	927	61	1,553	363	2,904
35	Electrical System	18,366	7,552	0	10,299	36,217
36	Instrumentation and Controls	2,719	0	3,243	715	6,677
37	Cooling Water System	3,517	671	5,659	1,820	11,668
38	Raw Water Supply and Treatment	5,826	420	2,312	1,427	9,985
39	Fire Protection	1,322	666	1,100	1,005	4,093
40	Waste Water Treating					
	Process Waste Water Treating	7,830	2,987	0	4,142	14,959
	Other Waste Water Treating	6,044	422	342	1,219	8,027
41	General Ser. & Mobile Equipment	557	0	0	67	624
42	Site Preparation and Improvement	0	0	4,529	543	5,072
43	Buildings	619	403	2,740	836	4,598
	Total Plant Cost	389,532	113,152	183,305	190,040	876,029
	Contingency					105,124
	Initial Catalyst and Chemicals					2,200
	Plant Facilities Investment					983,353
	Owner's Cost					44,322
	Total Capital Requirements					1,027,675

Table 5-26

CAPITAL COST REQUIREMENTS UNDER US CONDITION
$1,000 , 4th Q-1989
(KRW Case)

Plant No.	Plant Name	Direct Field Material	Direct Field Labor	Direct Field Subcontract	Indirect Cost and Engineering	Total Cost
1	Coal Rec., Crushing, Storage	13,254	5,459	1,287	7,597	27,597
2	Coal and Limestone Handling	14,579	6,005	1,416	8,356	30,356
3	Coal Drying	7,322	2,678	0	3,749	13,749
5	KRW Coal Gasification	91,174	43,780	0	57,873	192,827
9	Combined Cycle					
	Gas Turbine	84,800	3,219	1,750	13,837	103,606
	HRSG & Stack	23,510	6,245	735	9,604	40,094
	Steam Turbines	28,079	3,551	0	7,176	38,805
	Cond/BFW Systems	9,189	4,681	2,798	6,457	23,125
10	Ash Sulfation	39,200	7,069	0	12,282	58,551
30	Solid Waste Disposal	555	263	1,110	481	2,409
31	Relief & Blowdown	876	330	0	459	1,664
32	Interconnecting Piping	7,114	3,786	294	4,947	16,141
33	Compressed Air System	1,104	501	102	681	2,388
34	Fuel Oil and LPG System	927	61	1,553	363	2,904
35	Electrical System	14,693	6,041	0	8,240	28,974
36	Instrumentation and Controls	2,719	0	3,243	715	6,677
37	Cooling Water System	1,759	336	2,829	910	5,834
38	Raw Water Supply and Treatment	3,648	263	1,447	893	6,251
39	Fire Protection	1,322	666	1,100	1,005	4,093
40	Waste Water Treating	3,784	264	214	763	5,025
41	General Ser. & Mobile Equipment	557	0	0	67	624
42	Site Preparation and Improvement	0	0	4,529	543	5,072
43	Buildings	619	403	2,740	836	4,598
	Total Plant Cost	350,784	95,599	27,148	147,834	621,364
	Contingency					74,564
	Initial Catalyst and Chemicals					500
	Plant Facilities Investment					696,428
	Owner's Cost					32,478
	Total Capital Requirements					728,906

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Table 5-27

BREAKDOWN OF OWNER'S COST UNDER US CONDITION
$1,000, 4th Q-1989

	Study Case		
	Shell	Texaco	KRW
License Fees/Royalities	Excluded	Excluded	Excluded
Spare Parts Inventory	3,395	3,385	2,401
Organization and Startup Costs			
1 month fixed O&M	2,344	2,387	1,735
1 month variable O&M	1,426	1,287	888
1 week fuel	985	1,243	879
2% of plant facilities investment	19,742	19,667	13,929
Working Capital			
14 days fuel	1,969	2,486	1,757
3 months labor	2,391	2,540	2,140
2 months other consumables	5,946	5,656	3,820
25% of above three items	2,577	2,670	1,929
AFDC	Excluded	Excluded	Excluded
Land Costs (100 acres @ $30,000/acre)	3,000	3,000	3,000
Total Owner's Costs	43,776	44,322	32,478

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The various cost items above are described as follows.

Direct Field Material Costs

The direct field material costs are for permanent physical plant facilities and include the following elements:

- o Equipment - Equipment includes all machinery used in the completed facility such as boilers, rotating machinery, heat exchangers, tanks, vessels, etc.

- o Bulk Materials - These are the physical materials used in constructing the completed plant, such as concrete, steel, building materials, pipe and fittings, valves, wire and conduit, instruments, insulation, paint, etc.

- o Sales Tax - Sales taxes included are 0.4 percent of the direct field material costs.

- o Freight - Freight included are 5 percent of the direct field material costs.

Direct Field Labor Costs

The components of direct field labor costs are labor manhours and composite labor wage rate.

The labor manhours are estimated based on experience for the construction of conventional process and combined cycle power plants.

The composite labor wage rate reflects a craft mix derived from similar type projects. The wage rate includes payroll additives and craft benefits. Payroll additives are costs such as workman's compensation. Craft benefits include health and welfare, vacation, pension fund, apprentice fund, and travel and subsistence expense. The resulting composite wage rate used in this study is $25.75 per hour for direct field labor.

Direct Subcontracts

The components of direct subcontracts are equipment and materials furnished by the subcontractors, including installation labor costs and indirect costs of the subcontractors.

Indirect Field and Home Office Engineering Costs

Indirect field costs are those costs which cannot be directly identified with any specific construction operation for the permanent plant facilities and are in support of the construction operation. The cost for indirect field cost, including both labor and materials, is 85 percent of the total direct field labor cost. It covers the following items:

- o Miscellaneous Construction Services (Labor):
  - General and Final Cleanup
  - Maintenance of Tools and Equipment
  - Material Testing
  - Welders' Testing
  - Watchmen and Guards

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Unallocated Services
Assembly/disassembly of Major Construction Equipment
Manual Survey
Performance and Operation Testing
Show-up and Voting Time

- o Temporary Construction
- o Materials:

Temporary Buildings
Construction and Haul Roads
Construction Utilities
Temporary Power
Miscellaneous Temporary Construction
Scaffolding
Material Handling
Maintenance of Tools and Equipment
Welders' Testing
Weather/Storm Related
Construction Equipment
Tools
Fuels
Consumables
Purchased Utilities

Home office engineering manhours and other home office services are accounted for through the addition of 12 percent of the direct and indirect field costs. These costs are intended to cover the expenses of the following items:

- o Labor for engineering design, procurement, technical services, administrative support and project management services.
- o Office expenses such as materials, telephone, reproduction and computer costs, travel, etc.
- o Office overhead costs and fee.

Contingency

Contingency is applied to an estimate to denote the level of confidence in the values ascribed to the finite elements of the particular estimate. The amount of contingency is the estimator's judgment of the cost applied to the complete estimate to yield the most probable total cost or the cost at some specified probability of underrun/overrun. The addition of the contingency value does not improve the overall accuracy of the estimate, but rather reduces the probability of overrun to the desired level.

Contingencies are assigned to each major plant area and an overall weighted average contingency was determined. The resulting overall contingency is 12 percent. This contingency is based on achieving approximately a 50 percent probability of underrun.

Initial Catalyst and Chemicals

The initial catalyst and chemical include the initial charge of catalyst and chemicals contained within the process equipment.

Owner's Costs

Owner's costs are defined as the following:

- o Spare parts inventory

- o Organization and startup costs
- o Owner's management costs
- o Working capital
- o Allowance for funds during construction (AFDC)
- o Land costs

Spare parts inventory is the cost of equipment spares to be maintained in stock at the plant. For this study, the cost of this inventory is estimated as three months of maintenance materials cost.

Organization and startup costs are to cover administrative costs and operator training, equipment checkout, changes in plant equipment, extra maintenance, and inefficient use of coal or other materials during plant startup. These costs are estimated as follows:

- o One month of fixed operating and maintenance costs, which consist of operating and maintenance labor, maintenance materials, and administrative and support labor; insurance and property taxes are not included (they are part of the fixed charges).
- o One month of variable operating costs, excluding fuel, at full (100 percent) capacity; these costs consist of catalysts, chemicals, and solid waste disposal.
- o One week fuel cost at full (100 percent) capacity; this charge covers inefficient operation that occurs during the startup period.
- o 2.0 percent of the plant facilities investment (including contingency); this charge covers expected changes and modifications to equipment that will be needed to bring the plant up to full capacity.

Owner's management costs are those costs necessary to manage the project's engineering, construction, licensing, legal, and financial contractors and consultants. These costs include expenses for owner's home office staff and expenses for permitting and licensing activities necessary to allow construction and operation of the plant.

Working capital is the value of the inventories of raw materials and other consumables. This value is capitalized and included in the working capital account, and is estimated as follows:

- o Fourteen days' supply of coal based on full capacity.
- o Three months of labor costs.
- o Two months' supply of other consumables (excluding fuel) based on full capacity operations.
- o A contingency of 25 percent of the total of the above three items.

Allowance for funds during construction (AFDC) is the cost due to interest charges which are accumulated between the time money is expended for construction and the time that the construction is completed.

Land costs include the costs of acquiring the land required for the plant and slag and flyslag disposal. An allowance of 100 acres at $30,000 per acre is assumed.

5.3.3 Capital Cost Estimate Under India Conditions

Capital costs of the four IGCC cases under India conditions are shown in Tables 5-28 to 31.

Table 5-28

CAPITAL COST REQUIREMENTS
4th Q-1989
(Shell Case, India Condition)

S1 No.	Plant Name	Rs. Lakhs Foreign Component	India Component	Total	Total in $ Million
1	Coal Transportation System	-	3,010	3,010	17.71
2	Coal and Limestone Handling System	-	3,853	3,853	22.66
3	Air Separation	14,821	1,520	16,341	96.12
4	Shell Coal Gasification	10,003	43,081	53,084	312.26
5	Acid Gas Removal	163	755	918	5.40
6	Sulfur Recovery	151	711	862	5.07
7	Sour Water Stripping	56	253	309	1.82
8	Combined Cycle	15,858	19,025	34,883	205.19
9	Solid Waste Disposal	-	4,410	4,410	25.94
10	Relief & Blowdown	49	190	239	1.41
11	Interconnecting Piping	359	1,776	2,135	12.56
12	Compressed Air System	-	240	240	1.41
13	Fuel Oil and LPG System	-	459	459	2.70
14	Electrical System	-	6,610	6,610	38.88
15	Instrumentation and Controls	653	360	1,013	5.96
16	Cooling Water System	-	3,139	3,139	18.46
17	Raw Water Supply and Treatment	-	1,712	1,712	10.07
18	Fire Protection	-	339	339	1.99
19	Waste Water Treating	269	2,419	2,688	15.81
20	General Ser. & Mobile Equipment	-	1,400	1,400	8.24
21	Site Prep., Improvement & Buildings	-	8,880	8,880	52.24
	Total Field Cost	42,382	104,142	146,524	861.91
22	Engineering Fee	2,200	5,126	7,326	43.09
	Total Plant Cost	44,582	109,268	153,850	905.00
	Contingency (5%)	2,229	5,463	7,692	45.25
	Initial Catalysts & Chemicals	561	28	589	3.46
	Plant Facilities Investment	47,372	114,759	162,131	953.71
	Owner's Cost	3,265	16,090	19,355	113.85
	Total Capital Requirements	50,637	130,849	181,486	1,067.56
	Duties & Taxes	-	24,055	24,055	141.50
	Total Capital w/Duties & Taxes	50,637	154,904	205,541	1,209.06

Table 5-29

CAPITAL COST REQUIREMENTS
4th Q-1989
(Texaco Case, India Condition)

Sl No.	Plant Name	Rs. Lakhs Foreign Component	India Component	Total	Total in $ Million
1	Coal Transportation System	-	3,080	3,080	18.12
2	Coal and Limestone Handling System	-	4,203	4,203	24.72
3	Air Separation	20,174	2,067	22,241	130.83
4	Texaco Coal Gasification	7,917	35,010	42,927	252.51
5	Acid Gas Removal	194	904	1,098	6.46
6	Sulfur Recovery	162	750	912	5.36
7	Sour Water Stripping	104	488	592	3.48
8	Combined Cycle	15,858	17,704	33,562	197.42
9	Solid Waste Disposal	-	5,600	5,600	32.94
10	Relief & Blowdown	49	190	239	1.41
11	Interconnecting Piping	359	1,776	2,135	12.56
12	Compressed Air System	-	240	240	1.41
13	Fuel Oil and LPG System	-	459	459	2.70
14	Electrical System	-	6,177	6,177	36.34
15	Instrumentation and Controls	653	360	1,013	5.96
16	Cooling Water System	-	5,404	5,404	31.79
17	Raw Water Supply and Treatment	-	2,716	2,716	15.98
18	Fire Protection	-	339	339	1.99
19	Waste Water Treating	355	3,225	3,580	21.06
20	General Ser. & Mobile Equipment	-	1,400	1,400	8.24
21	Site Prep., Improvement & Buildings	-	8,880	8,880	52.24
	Total Field Cost	45,825	100,972	146,797	863.51
22	Engineering Fee	2,200	5,140	7,340	43.18
	Total Plant Cost	48,025	106,112	154,137	906.69
	Contingency (5%)	2,401	5,306	7,707	45.33
	Initial Catalysts & Chemicals	411	21	432	2.54
	Plant Facilities Investment	50,837	111,439	162,276	954.56
	Owner's Cost	3,287	16,014	19,301	113.54
	Total Capital Requirements	54,124	127,453	181,577	1,068.10
	Duties & Taxes	-	24,345	24,345	143.21
	Total Capital w/Duties & Taxes	54,124	151,798	205,922	1,211.31

Table 5-30

CAPITAL COST REQUIREMENTS
4th Q-1989
(KRW Case, India Condition)

S1 No.	Plant Name	Rs. Lakhs Foreign Component	India Component	Total	Total in $ Million
1	Coal Transportation & Limestone	-	2,980	2,980	17.53
2	Coal Handling System and Drying	-	4,903	4,903	28.84
3	KRW Coal Gasification	4,656	21,442	26,098	153.52
4	Combined Cycle	14,561	17,833	32,394	190.55
5	Ash Sulfation	2,001	7,490	9,491	55.83
6	Solid Waste Disposal	-	3,960	3,960	23.29
7	Relief & Blowdown	49	190	239	1.41
8	Interconnecting Piping	359	1,776	2,135	12.56
9	Compressed Air System	-	240	240	1.41
10	Fuel Oil and LPG System	-	459	459	2.70
11	Electrical System	-	5,950	5,950	35.00
12	Instrumentation and Controls	653	360	1,013	5.96
13	Cooling Water System	-	2,598	2,598	15.28
14	Raw Water Supply and Treatment	-	1,364	1,364	8.02
15	Fire Protection	-	339	339	1.99
16	Waste Water Treating	172	716	888	5.22
17	General Ser. & Mobile Equipment	-	1,400	1,400	8.24
18	Site Prep., Improvement & Buildings	-	8,880	8,880	52.24
	Total Field Cost	22,451	82,880	105,331	619.59
19	Engineering Fee	1,580	3,687	5,267	30.98
	Total Plant Cost	24,031	86,567	110,598	650.58
	Contingency (5%)	1,202	4,328	5,530	32.53
	Initial Catalysts & Chemicals	94	5	99	0.58
	Plant Facilities Investment	25,327	90,900	116,227	683.69
	Owner's Cost	1,866	13,257	15,123	88.96
	Total Capital Requirements	27,193	104,157	131,350	772.65
	Duties & Taxes	-	14,635	14,635	86.09
	Total Capital with Duties & Taxes	27,193	118,792	145,985	858.73

Table 5-31

CAPITAL COST REQUIREMENTS
4th Q-1989
(Moving Bed Case, India Condition)

S1 No.	Plant Name	Rs. Lakhs Foreign Component	India Component	Total	Total in $ Million
1	Coal Transportation System	-	3,030	3,030	17.82
2	Coal Handling System	-	2,200	2,200	12.94
3	Gasification, Gas Cooling, & Gas Liquor Sep	6,977	25,214	32,191	189.36
4	Acid Gas Removal	388	1,808	2,196	12.92
5	Sulfur Recovery	145	685	830	4.88
6	Tar and Oil Fired Boiler	-	2,710	2,710	15.94
7	Combined Cycle	14,561	17,833	32,394	190.55
8	Solid Waste Disposal	-	4,800	4,800	28.24
9	Relief & Blowdown	49	190	239	1.41
10	Interconnecting Piping	359	1,776	2,135	12.56
11	Compressed Air System	-	150	150	0.88
12	Fuel Oil and LPG System	-	218	218	1.28
13	Electrical System	-	5,872	5,872	34.54
14	Instrumentation and Controls	653	360	1,013	5.96
15	Cooling Water System	-	3,572	3,572	21.01
16	Raw Water Supply and Treatment	-	1,690	1,690	9.94
17	Fire Protection	-	1,960	1,960	11.53
18	Waste Water Treating	-	339	339	1.99
19	General Ser. & Mobile Equipment	-	1,400	1,400	8.24
20	Site Prep., Improvement & Buildings	-	8,880	8,880	52.24
	Total Field Cost	23,132	84,687	107,819	634.23
21	Engineering Fee	1,617	3,774	5,391	31.71
	Total Plant Cost	24,749	88,461	113,210	665.94
22	Contingency (5%)	1,237	4,423	5,661	33.30
23	Initial Catalysts & Chemicals	600	209	809	4.76
	Plant Facilities Investment	26,586	93,093	119,680	704.00
	Owner's Cost	2,388	14,655	17,043	100.25
	Total Capital Requirements	28,974	107,748	136,723	804.25
	Duties & Taxes	-	16,161	16,161	95.06
	Total Capital with Duties & Taxes	28,974	123,909	152,884	899.31

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In the first three cases, costs for the coal gasification, acid gas removal, sulfur recovery, sour water stripping, combined cycle, relief and blowdown, interconnecting piping, fuel oil and LPG system, instrumentation and controls, and waste water treating units were derived from the U.S. costs presented in Tables 5-24 to 26 above. Costs of the remaining plant units and the entire moving bed case were directly estimated under the Indian conditions.

In all four cases, costs of the offsites and supporting facilities such as coal transportation system, raw water supply and treatment, solid waste disposal system, and electrical system were factored from the PC plant presented in Section 6. This is to establish a consistent basis for comparison between the IGCC plant and PC plant.

The bases used for converting U.S. costs into India costs and other cost estimate bases are as follows:

Exchange Rate. An exchange rate of Rs 17 per US dollar is assumed.

Direct Field Material. To convert from the U.S. direct field material cost to India, the bulk material for civil and structural is taken out first because it can be procured in India.

For all plant units except the air separation, combined cycle, and fuel oil and LPG units, it is assumed that 30% of the remaining direct field material will be imported and the other 70% will be procured in India.

For the combined cycle unit, it is assumed that only the gas turbine will be imported and the remaining equipment and material will be procured in India.

For the fuel oil and LPG unit, the entire unit will be procured in India.

For equipment and material to be procured in India, it is assumed the India costs will be 25% higher than the U.S. costs (10% for ocean freight and marine insurance and 15% for overall higher cost markup in India).

Direct Field Labor. To adjust the labor cost, the labor productivity in India is assumed to be 40% of that in US. The labor rate in India is assumed to be Rs 17/h.

Direct Field Subcontract. The major item under this category is the air separation plant. For this plant unit, it is assumed that 70% of its cost is equipment and 30% is labor. All the equipment is to be imported as a package unit and all the labor is to be indigenous supply.

The subcontract costs in other plant units are assumed to be all indigenous supply and also have a 70/30 split between equipment and labor. The labor adjustments are the same as those described above for the direct field labor.

Indirect Cost. This cost is broken down to 70% material and 30% labor, all assumed to be indigenous supply. The labor adjustments are the same as those described above for the direct field labor.

Engineering Services. It was assumed that the basic design package would be prepared by a foreign engineering company and the detailed engineering would be performed by an Indian engineering company but checked by the former. The total engineering cost is estimated to be 5% of the total field cost and the split between the foreign and Indian engineering companies is 30 and 70%. The license and know-how would be obtained from appropriate foreign process licensors. The total licensing fee is assumed to be $3.5 millions.

Working Capital. This cost was estimated based on the following provisions:

- o Coal: 15 days
- o Limestone: 60 days
- o Consumables: 60 days
- o Salary and wages: 60 days

Spare Parts. The cost to provide a three-year supply of both foreign and Indian spare parts is estimated to be 5% of the equipment cost.

Interest During Construction. An equity/debt ratio of 1:1 is used to calculate this cost. It is also assumed that the equity portion would be spent first before the loan portion is used. The total project duration is 4 years. The interest rate is assumed to be 15% per year.

Contingency. This is calculated at 5% of the capital cost.

Duties and Taxes. The duties and taxes rate assumed are as following:

- o Ocean freight and marine insurance: 10% of FOB cost
- o Custom duty: 30% of CIF cost (cost include ocean freight)
- o Sales tax: 4% of FOR cost (freight on rail)
- o Excise duty: 15.75% of FOR and sales tax
- o Inland transport: 4% of FOR
- o Insurance: 1.5% of FOR
- o Income tax on foreign license and engineering: 30%
- o R&D cess on foreign license and engineering: 7%

Land. The total land requirement is 1505 acres (see Section 5.5 for more details). The land is assumed to be available at no cost.

5.3.4 Project Lead Time

The total project lead time from project award to commercial operation is estimated to be 4 years. This includes permitting, engineering, procurement, plant construction, and startup. But it excludes plant licensing.

5.3.5 Cost of Generation

The costs of generation for the four IGCC cases are presented in Table 5-32. These costs are shown for 5500, 6000, 7000, and 7400 hours per year of plant operation. The bases used to derive these costs are described below.

Labor and Overheads. This cost is estimated based on a total plant staff of 1400 as shown in Table 5-33. The average salary and benefit is assumed to be Rs. 50,000 per year.

Maintenance Materials. Total annual maintenance materials estimated to be 2% of the total plant cost including contingency.

Depreciation. This cost is calculated based on 3.6% of the total capital excluding the working capital.

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Table 5-32

COST OF GENERATION OF IGCC PLANT

(Based On 10% Pre Tax Return On Equity, 4th Q-1989 Pricing)

	Study Case			
	Shell	Texaco	KRW	Moving Bed
Gross Power Produced, MW	700.6	654.5	630.6	640.1
Net Power Produced, MW	564.4	496.2	577.2	585.7
Aux. Power Consumption, % of Gross Power	19.4	24.2	8.5	8.5
Project Capital Requirement				
Total Capital, Rs lakhs	205,541	205,922	145,985	152,884
Rs/kw Gross Power Generated	29,338	31,462	23,150	23,884
Annual (5500h/y) Coal Consumption, kg/kW gross	3,259	4,403	3,231	3,855
Heat Rate (HHV basis), Kcal/kWh net power	2,451	3,519	2,138	2,611
Specific Coal Consumption, kg/kWh net power	0.736	1.056	0.642	0.766
Fixed Costs, Rs/y/kW gross power				
Labor and Overhead	99.91	106.95	111.01	109.36
Maintenance Material	531.50	570.27	415.04	424.43
Chemicals & Catalysts	188.70	222.46	84.36	289.49
Depreciation	1,050.39	1,126.66	828.79	853.25
Interest on Long Term Loan	2,200.34	2,359.69	1,736.26	1,791.32
Return on Equity	1,466.89	1,573.12	1,157.51	1,194.22
Interest on Working Capital Loan	81.75	84.86	65.43	93.22
Total Fixed Costs	5,619.49	6,044.01	4,398.39	4,755.29
Variable Costs (5500 h/y), Rs/y/kw gross power				
Coal	782.22	1,056.81	775.37	1,079.44
Limestone	75.60	-	38.06	-
Raw Water	13.36	22.69	11.83	14.59
Ammonium Sulfate Credit	-	-	-	(9.85)
Sulfur Credit	(23.81)	(25.49)	-	(26.06)
Total Variable Costs	847.37	1,054.01	825.26	1,058.12
Total Fixed and Variable Costs, Rs/y/kW	6,466.86	7,098.02	5,223.65	5,813.41
Electricity Cost, Paise/kWh net power				
@5500 hr/y operation	146.0	170.2	103.8	115.5
@6000 hr/y operation	135.4	158.1	96.5	107.6
@7000 hr/y operation	118.8	139.2	85.0	95.3
@7400 hr/y operation	113.4	133.0	81.3	91.3

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Table 5-33

IGCC PLANT STAFFING REQUIREMENT

	Number of People
Operation	
Coal Transportation	90
Coal Handling	124
Air Separation	80
Coal Gasification	230
Acid Gas Removal, Sulfur Rec., Sour Water Strip.	44
Combined Cycle	84
Solid Waste Disposal	32
Relief and Blowdown	4
Compressed Air	16
Fuel Oil and LPG	8
Electrical System	40
Raw Water and Cooling Water System	60
Fire Protection	16
Waste Water Treating	12
Total Operation	840
Maintenance Staff	300
Technical Services	50
Materials Management	50
Finance and Accounts	50
Administration	60
Personnel and Training Center	50
Grand Total	1,400

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Interest on Long Term Loan. This is assessed at 15% of 50% of the total capital.

Return on Equity. This is 10% on 50% of the total capital.

Interest on Working Capital Loan. This is assessed at 17% of 75% of the working capital.

Raw Material Costs and Byproducts Credit. These costs and credit are as follows:

Coal(Run of Mine)	Rs 240/tonne (Shell, Texaco, KRW cases)
Sized Coal	Rs 280/tonne (Moving Bed case)
Limestone	Rs 374/tonne
Fuel Oil	Rs 3,200/m^3
Water	Rs 1/m^3
Sulfur Credit	Rs 2,510/tonne
Ammoniun Sulfate Credit	Rs 500/tonne

5.4 ECONOMIC AND RISK COMPONENTS

5.4.1 Availability Analysis

The IGCC plant is designed to achieve a target equivalent availability of 85%. Realization of this goal is confirmed by a unit-by-unit availability analysis. The equivalent availability is derived from a probability model based on the component availability and planned outage rate of the IGCC plant.

The Shell case is chosen as the representative IGCC facility. The availability analysis is performed only for this case.

Component Availability

Table 5-34 summarizes the component availability for each of the major plant systems. The component availability is defined as the probability that a plant component is in operating condition at any given time, i.e. the available hours divided by period hours when not on planned outage.

The major plant systems (or components) and the source of the component availability are discussed below.

Coal Milling and Drying. The use of ball mill in the Shell gasification plant provides a high availability for the coal milling and drying unit. A ball mill has typically 95% availability as compared to 70-80% availability of a roller mill or a bowl mill. This component availability is derived from Bechtel in-house data.

Coal Gasification. The component availability of the gasification system, excluding the coal milling and drying unit, is provided by Shell.

Air Separation Plants. The two, nominal 50 percent parallel air separation trains each have a component availability of 98 percent. To ensure maximum oxygen availability, the plant is slightly oversized in order to provide both liquid and gaseous oxygen storage. The oxygen storage is equivalent to one spare train. The entire system has been modeled as three 50 percent trains. The estimate of component availability is based on vendor quotations.

Table 5-34

COMPONENT AVAILABILITY

	No. of Trains	Availability per Train
Coal Milling & Drying	4+2	0.9500
Coal Gasification (1)	4+0	0.9300
Air Separation (2)	4+1	0.9800
Combined Cycle	2+0	0.9500
Single Train System		
Coal Receiving & Crushing (3)	1+0	1.0000
Waste Water Treatment	1+0	0.9990
Other Balance of Plant	1+0	0.9980

(1) Include coal pressurization & feeding, gasification & gas quench, high temp. gas cooling, particulate removal, gas treating & cooling, acid gas removal, sulfur removal, and flyslag & slag handling

(2) The one day oxygen storage provided is equivalent to one spare train

(3) The 15 days coal storage provided after coal crushing increases the availability to essentially 1.0

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Combined Cycle Units. The two parallel combined cycle units are both designed for combined cycle operation only, without HRSG bypass stacks for simple cycle gas turbine operation. The component availability is provided by GE.

Single Train Systems. Several plant systems have been grouped together in the analysis to limit the number of low probability operating states and therefore clarify the overall presentation. Each of these systems has been modeled as a single train, 100 percent unit. Although they may contain redundant processing equipment and can operate at derated conditions, the systems as a whole have been considered to operate in the 100 percent or 0 percent mode. Each of these combined systems is described below:

Coal Receiving and Crushing. The 15 days coal storage provided after the coal crushing increases the component availability to be close to 1.

Waste Water Treating. The Shell waste water treating unit is provided with feed storage capacity, giving it a high overall reliability.

Other Balance of Plant. This category includes balance of plant systems not included in the other categories including the switchyard, cooling water systems, air and nitrogen supply, fire water protection, and other miscellaneous minor systems. Component availability data has been taken from NERC (North American Electric Reliability Council).

Planned Outage Rate

Table 5-35 contains a summary of the planned maintenance cycle for the major equipment including the gas turbines, steam turbine, and gasifiers. The average planned outage rate over the maintenance cycle is 4.28%.

Equivalent availability

Table 5-36 provides an equivalent availability analysis of the IGCC plant.

The analysis calculates the probability and the percentage of plant output level at various plant operating states as represented by the number of trains operating in the individual plant system. The equivalent availability is the product of probability and percentage of plant output level at the given operating state.

The overall plant equivalent availability, which is the sum of the equivalent availabilities at the various operating states, is 88.1% during the period when the plant is not on planned maintenance. By taking into account the planned outage rate, the overall equivalent availability of the IGCC plant is 84.53% which is very close to the 85% target value.

The analysis above indicates that a high plant availability can be achieved for the IGCC plant even with the high ash content and very abrasive Indian coal. It is achieved by providing sufficient spare capacities at the critical service points of the IGCC plant and by a proper selection of coal preparation equipment.

5.4.2 Other Risk Issues

As mentioned in Section 4.1.3, Texaco indicated the slag lockhopper valve capacity has limited their gasifier throughput to 1900 MTPD coal (on as received basis). Shell, on the other hand, has assumed that a higher capacity

Table 5-35

PLANNED MAINTENANCE CYCLE

Year	Planned Maintenance Duration, hrs					
	1	2	3	4	5	6
Gas Turbine Combustion Inspection	105	105		105	105	
Gas Turbine Hot Gas Path Inspection			240			
Gas Turbine Major Inspection						460
Steam Turbine Major Inspection						840
Gasifier Inspection/Maintenance		480		480		480
Longest Duration, hrs	105	480	240	480	105	840
Annual Average Days	15.6					
Planned Outage Rate, %	4.28					

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Table 5-36

ESTIMATE OF EQUIVALENT AVAILABILITY

Number of Trains Operating						
Coal Milling & Drying	Coal Gasification	Air Separation	Combined Cycle	Single Train Systems	Plant Output, %	Equivalent Availability, %
4	4	4	2	1	100	66.901153
4	4	4	1	1	50	3.521113
4	4	3	2	1	75	0.189629
4	4	3	1	1	50	0.013307
4	4	2	2	1	50	0.002580
4	4	2	1	1	50	0.000272
4	4	1	2	1	25	0.000013
4	4	1	1	1	25	0.000001
4	3	4	2	1	75	15.106712
4	3	4	1	1	50	1.060120
4	3	3	2	1	75	0.057093
4	3	3	1	1	50	0.004007
4	3	2	2	1	50	0.000777
4	3	2	1	1	50	0.000082
4	3	1	2	1	25	0.000004
4	3	1	1	1	25	0.000000
4	2	4	2	1	50	1.137064
4	2	4	1	1	50	0.119691
4	2	3	2	1	50	0.004297
4	2	3	1	1	50	0.000452
4	2	2	2	1	50	0.000088
4	2	2	1	1	50	0.000009
4	2	1	2	1	25	0.000000
4	2	1	1	1	25	0.000000
4	1	4	2	1	25	0.028528
4	1	4	1	1	25	0.003003
4	1	3	2	1	25	0.000108
4	1	3	1	1	25	0.000011
4	1	2	2	1	25	0.000002
4	1	2	1	1	25	0.000000
4	1	1	2	1	25	0.000000
4	1	1	1	1	25	0.000000
3	4	4	2	1	75	0.107789
3	4	4	1	1	50	0.007564
3	4	3	2	1	75	0.000407
3	4	3	1	1	50	0.000029
3	4	2	2	1	50	0.000006
3	4	2	1	1	50	0.000001
3	4	1	2	1	25	0.000000
3	4	1	1	1	25	0.000000
3	3	4	2	1	75	0.032453
3	3	4	1	1	50	0.002277
3	3	3	2	1	75	0.000123
3	3	3	1	1	50	0.000009
3	3	2	2	1	50	0.000002
3	3	2	1	1	50	0.000000
3	3	1	2	1	25	0.000000
3	3	1	1	1	25	0.000000
3	2	4	2	1	50	0.002443
3	2	4	1	1	50	0.000257
3	2	3	2	1	50	0.000009
3	2	3	1	1	50	0.000001
3	2	2	2	1	50	0.000000
3	2	2	1	1	50	0.000000
3	2	1	2	1	25	0.000000
3	2	1	1	1	25	0.000000
3	1	4	2	1	25	0.000061
3	1	4	1	1	25	0.000006
3	1	3	2	1	25	0.000000
3	1	3	1	1	25	0.000000
3	1	2	2	1	25	0.000000
3	1	2	1	1	25	0.000000
3	1	1	2	1	25	0.000000
3	1	1	1	1	25	0.000000

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Table 5-36

ESTIMATE OF EQUIVALENT AVAILABILITY

Number of Trains Operating						
Coal Milling & Drying	Coal Gasification	Air Separation	Combined Cycle	Single Train Systems	Plant Output, %	Equivalent Availability, %
2	4	4	2	1	50	0.002837
2	4	4	1	1	50	0.000299
2	4	3	2	1	50	0.000011
2	4	3	1	1	50	0.000001
2	4	2	2	1	50	0.000000
2	4	2	1	1	50	0.000000
2	4	1	2	1	25	0.000000
2	4	1	1	1	25	0.000000
2	3	4	2	1	50	0.000854
2	3	4	1	1	50	0.000090
2	3	3	2	1	50	0.000003
2	3	3	1	1	50	0.000000
2	3	2	2	1	50	0.000000
2	3	2	1	1	50	0.000000
2	3	1	2	1	25	0.000000
2	3	1	1	1	25	0.000000
2	2	4	2	1	50	0.000096
2	2	4	1	1	50	0.000010
2	2	3	2	1	50	0.000000
2	2	3	1	1	50	0.000000
2	2	2	2	1	50	0.000000
2	2	2	1	1	50	0.000000
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1	1	2	1	1	25	0.000000
1	1	1	2	1	25	0.000000
1	1	1	1	1	25	0.000000

Equivalent availability when not on planned outage, %	88.31
Planned outage rate, %	4.28
Overall equivalent availability, %	84.53

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slag lockhopper valve can be developed and become available in the future. The gasifier throughput assumed by Shell for this study is 2600 MTPD coal. For comparison, the KRW gasifier throughput assumed for this study is 1600 MTPD coal.

The Shell gasifier size above is substantially larger than that used in Shell's Deer Park demonstration plant. Similarly, the KRW gasifier size above is substantially larger than that tested in KRW's Waltz Mill pilot plant. There are scale-up risks in both cases.

Both the Shell and KRW gasifiers have not tested coals with an ash content comparable to that of Indian coal. Texaco, on the other hand, has tested coals for an ash content up to 30% in their Montebello pilot plant. The moving bed gasifier is commercially proven and has tested the high ash Indian coal with successful results. But it faces the problem of economically using the coal fines rejected and treatment of the water effluent.

There are additional technical risks in the KRW case. The gasifier air extraction from gas turbine has not been demonstrated. The in-bed sulfur capture and hot gas particulate removal using ceramic filter have been tested but only with very limited experience. The carbon conversion achievable is not certain. There is a possibility that the ash may not agglomerate because it has a very high fusion temperature.

In Indian coal, the mineral matter is intrinsically mixed with the carbonaceous matter. As a result, the ash produced during gasification is mostly fine particles (-40μ). If the KRW gasifier fails to agglomerate them into large particles to drop out from the gasifier, these ash particles will be elutriated and become difficult to be retrieved.

The largest technical uncertainty of the KRW gasifier, however, is the ash sulfation. During the sulfation process, the calcium sulfate ($CaSO_4$) product formed has a tendency to block the particle pore and hinder further reaction because it is a larger molecule than calcium sulfide (CaS). Typically only 30-40% CaS conversion can be achieved in this process. This conversion level can be increased to 90% if 1-2% alkali salt is added. However, only limited tests have been carried out.

Calcium sulfide is a reactive compound. It releases hydrogen sulfide to atmosphere once exposed to moisture during disposal. Incomplete conversion of this compound in the sulfation process presents an environmental problem.

There are no technological risks involved with the moving bed gasifier because it is the most commercially exploited process and its suitability for Indian high ash coals has been established.

5.5 SITE LAYOUTS

A preliminary plot plan of the IGCC plant is shown in Figure 5-30. The Shell case is used to represent the IGCC plant. The total plant area requirement is estimated as follows:

	Acre
Plant area	300
Township	200
Ash disposal	500
Railway siting for merry go round system	140
Makeup water corridor	140
Approach road, ash disposal corridor	225
Total	1505

A description of the layout arrangement follows.

Coal Yard

The merry go round coal delivery rail line enters the northwest corner of the plant battery limit. The coal unloading and storage facilities are located at the north-western/western side of the plant, leaving adequate space for temporary construction equipment. As the prevailing wing direction is from southeast to northwest, dust generation during the coal handling and storage would not normally affect the main plant area.

Gasification, Gas Cleaning, and Combined Cycle Facilities

The gasification and gas cleaning units are located in a block by the side of coal storage area to minimize the coal handling cost. Further to the east is the combined cycle block including the transformer yard.

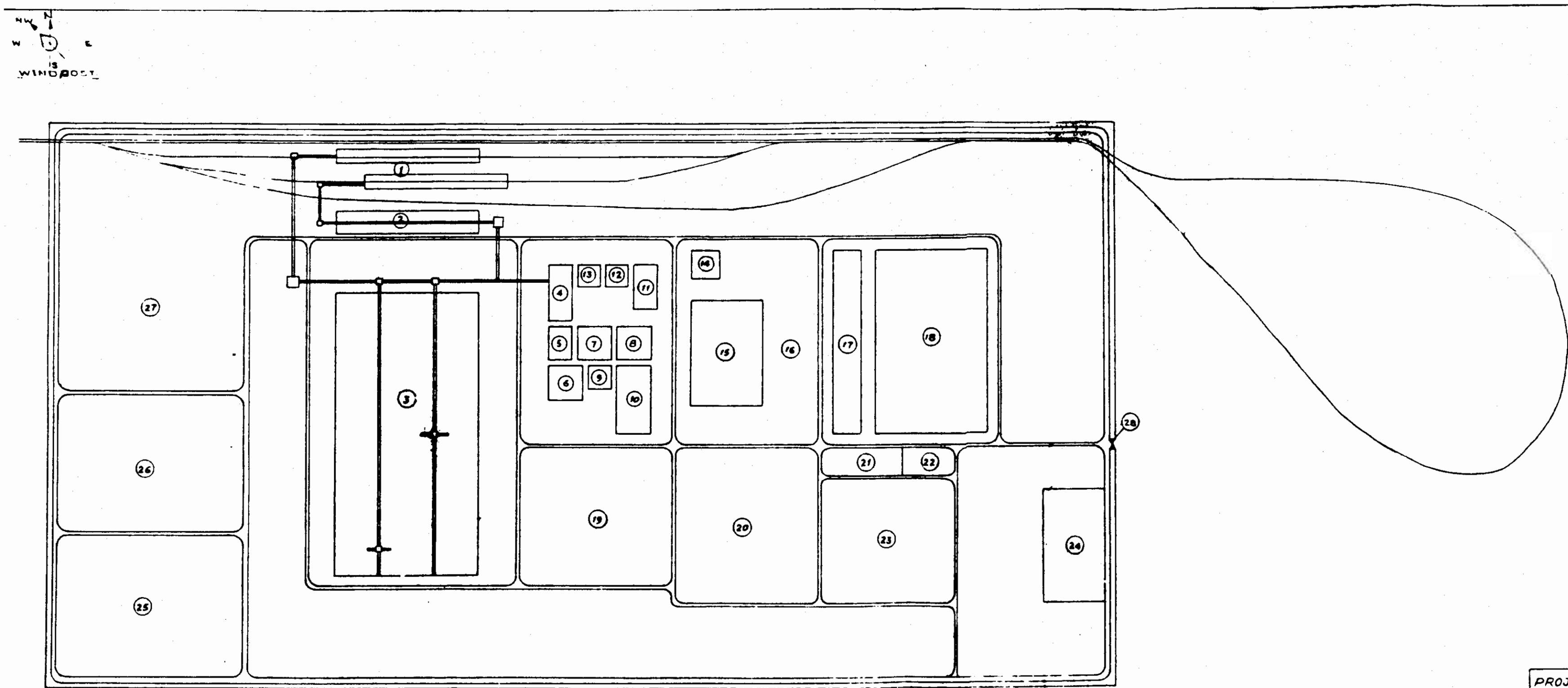
Water Treatment and Cooling Towers

These facilities are located in a separate block directly by the eastern side of the combined cycle block. As the major cooling water consumption is for the combined cycle plant, the closeness of these two blocks can result in saving of piping costs.

Switch Yard

The outgoing transmission lines go towards south and southeast. Therefore, the switch yard is located facing south in a block south of the combined cycle plant.

The plot plan includes other facilities such as workshop, warehouse, fire station, administrative building, etc. Adequate space is provided for contractors offices, stores, and fabrication facilities in the western side of the plant to avoid interference in the construction activities.



SL NO	PLANTS
28	MAIN GATE
27	FABRICATION & LAYOUT AREA
26	CONTRACTOR'S STORES
25	CONTRATOR'S OFFICES
24	ADMINISTRATIVE BUILDING
23	WAREHOUSE
22	FIRE STATION
21	CANTEEN
20	SWITCHYARD AREA
19	WORKSHOP
18	CLARIFLOCULATOR
17	COOLING TOWER
16	TRANSFORMER YARD
15	POWER PLANT
14	LUBE OIL STORAGE
13	FIRE PROTECTION
12	SERVICE WATER
11	ASU
10	SULFUR RECOVERY
9	SOUR WATER STRIPPING
8	ACID GAS REMOVAL
7	GAS TREATING & COOLING
6	FLYSLAG & SLAG HANDLING
5	PARTICULATE REMOVAL
4	COAL GASIFICATION
3	COAL STORAGE
2	LIMESTONE STORAGE
1	TRACK HOPPERS

PROJECTS & DEVELOPMENT INDIA LTD. SINDHI

TITLE : GENERAL PLOT PLAN

PROJECT : I G C C STUDY (SHELL CASE)

SCALE 1:4000

JOB NO. 2 · 2

DWG NO -

Figure 5-30 IGCC PLANT LAYOUT

Section 6

PC PLANT EVALUATION

This section presents the plant design, thermal efficiency, cost estimate, and emissions of the PC plant.

The PC plant uses one unit and has a design capacity of 600 MW so as to be consistent with that of the IGCC plant. The design and cost data were derived basically by capacity adjustment from the 2 x 500 MW PC plant feasibility study recently conducted by the National Thermal Power Corporation for the North Karanpura Super Thermal Power Project[2,3]. No site adjustments were necessary as the North Karanpura Project site is very close to the Piparwar site chosen for the present study. The coal used in the North Karanpura Project is the same as that in the IGCC plant design.

6.1 PLANT DESCRIPTION

6.1.1 Main Plant & Associated Auxiliaries

Steam Generator

The steam generator is of pulverized coal fired single reheat, single drum type and is designed for variable pressure operation.

The main parameters at 100% BMCR (boiler maximum continuous rating) are as follows:

Pressure at superheater outlet:	179 kg/cm2 a
Temperature at superheater outlet:	540 C
Steam pressure at reheater inlet:	47 kg/cm2 a
Steam temperature at reheater inlet:	346 C
Steam temperature at reheater outlet:	540 C
Feed water temperature at economiser inlet:	256 C

Furnace. The furnace of the steam generator is of radiant, dry bottom type with tangential firing and enclosed by water cooled and all welded membrane walls. A water impounded bottom ash hopper is installed at the furnace bottom. A spray type attemperator controls the superheater outlet temperature for varying loads. The superheater and reheater tubes are a combination of radiation and convection type. The economizer is non-steaming type.

Steam Generator Circulation System. This system employs either controlled or natural circulation. The natural circulation boiler employs ribbed tubing from water wall in all high heat zones to avoid onset of Departure from Nucleate Boiling (DNB). The controlled circulation boiler employs internally rifled boiler tubing for water wall in all high heat zones to maintain a minimum circulation at part load and limit DNB. Three 50% circulating pumps are used.

Air and Flue Gas System. A balanced draft system is provided. There are two axial FD fans and two radial ID fans and two pairs of regenerative rotary type air preheaters, one pair each for the primary air and secondary air. Steam coil air preheaters are provided for startup, low load operation, or abnormal conditions.

Fuel Oil Burning System. Heavy furnace oil is fired in this system for boiler startup, warmup and low load operation up to 30%. Necessary pumps, filters, and heaters are included.

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Coal Burning System. This system consists of coal mills. Coal from raw coal bunkers is fed into the mills by coal feeders. Primary air fans transport pulverized coal from the mills to burners.

Soot Blowing System. This system uses fully automatic, sequentially controlled, microprocessor based steam soot blowers. It has short retractable rotary wall blowers for the furnace and long retractable rotary blowers for the superheater and economiser.

Chemical Dosing System. To control the water quality in the steam generator, tri-sodium phosphate is dosed in the boiler drum. The dosing system required includes preparation and metering tanks, dosing pumps, connected piping, valves, and fittings.

Auxiliary Steam System. There are a high capacity pressure reduction station and a low capacity pressure reduction station taking their steam tapoffs from the main stream line and cold reheat line, respectively. The auxiliary steam level used is 16 kg/cm2 a and 210 C.

An auxiliary steam generator is included to provide steam during station blackout and for precommissioning activities.

Electrostatic Precipitator

A high efficiency electrostatic precipitator is provided to limit the flue gas particulates emission to 100 mg/Nm^3. The precipitator includes a microprocessor based programmable type rapper control system. The transformer rectifier sets use a high fire point oil as the cooling medium. The dust collection hoppers at all strategic locations have a minimum storage capacity of twelve hours and heating arrangements to prevent ash sticking to the sloping sides and down pipes.

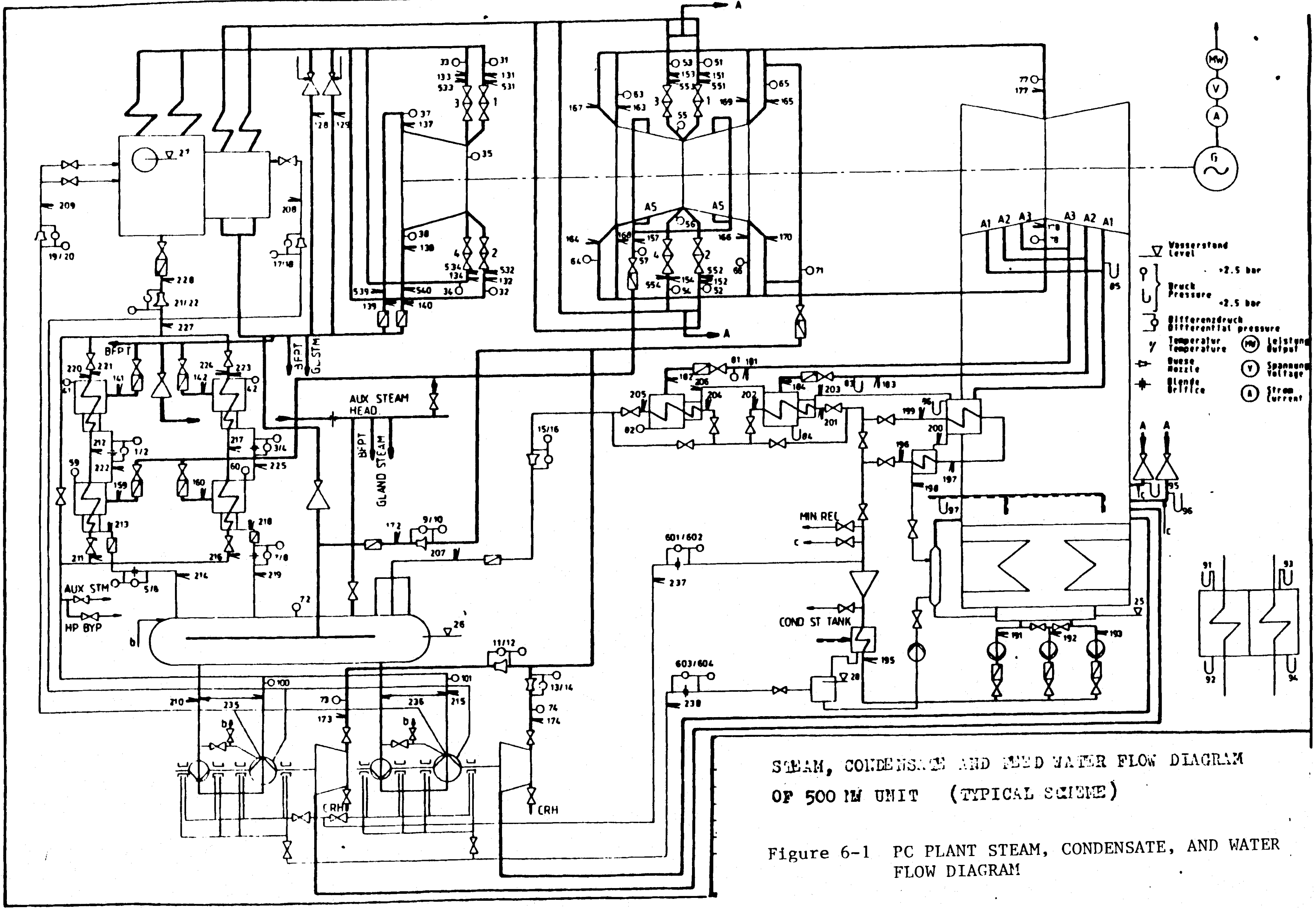
Turbine and Its Auxiliaries

This unit covers the turbine and its integral systems such as the control oil system, lube oil system, automatic turbine run-up system, HP/LP bypass system, condensers, condenser air evacuation system, complete regenerative feed heating system, condensate pumps with drives, boiler feed pumps with drives, LP chemical dosing system, auxiliary equipment cooling water system, instrumentation and control devices, turbine supervisory instruments, turbine protection and interlock system, automatic turbine testing system, and hydrogen generation plant.

A flow diagram of the steam, condensate, and feed water system and the associated heat balance based on a 500 MW unit are shown in Figure 6-1 and 2 respectively. As the design capacity for this study is 600 MW, all the flowrates shown in these diagrams shall be increased by a 6:5 ratio.

Steam Turbine. The steam turbine is of tandem compound, single reheat, regenerative, condensing, multi-cylinder design with separate HP and LP casings. The turbine throttle steam is at 170 kg/cm2 a and 537 C. The reheat steam temperature is 537 C. The maximum turbine exhaust pressure is 89 mm Hga. The turbine speed is 3000 rpm.

Condenser. The condenser uses stainless steel tubes with an integral air cooling section. The hotwell is designed for 5 minutes storage. The LP heater No.1 is mounted in the condenser neck.



STEAM, CONDENSATE AND FEED WATER FLOW DIAGRAM
OF 500 MW UNIT (TYPICAL SCHEME)

Figure 6-1 PC PLANT STEAM, CONDENSATE, AND WATER FLOW DIAGRAM

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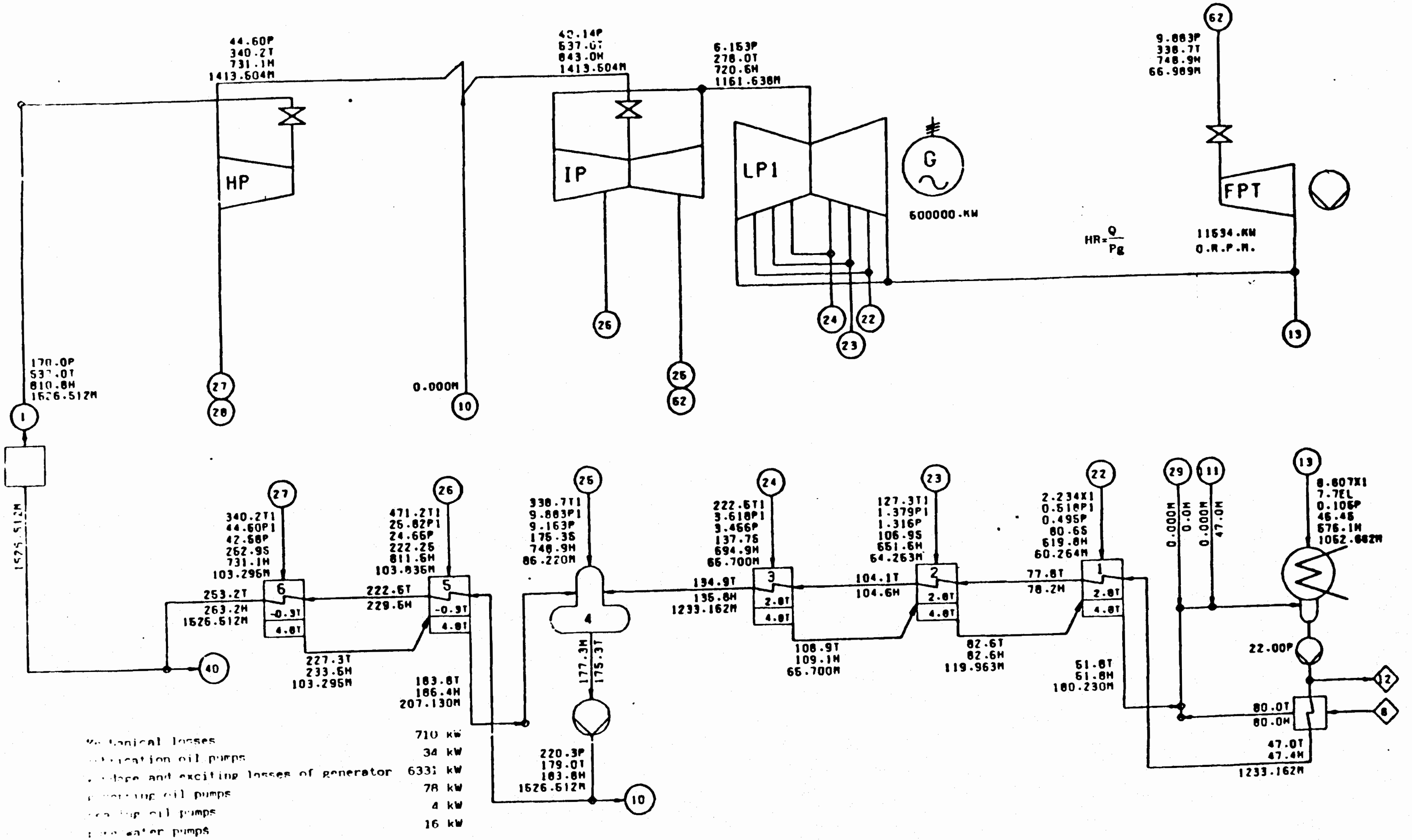

TYPICAL HEAT BALANCE DIAGRAM
OF 500 MW UNIT

Figure 6-2 PC PLANT HEAT BALANCE DIAGRAM

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Air Extraction System. Two 100% mechanical vacuum pumps are provided for condenser air evacuation.

Lube Oil System. This system provides lubrication for the bearings of the turbine generator and supplies oil to the hydraulic turbine gear during startup and shutdown. It also provides jacking requirements during turning gear operation and supplies oil to the generator seals under emergency condition.

The main oil pump is centrifugal type driven by the turbine. Two 100% AC driven auxiliary oil pumps provide the turbine oil requirement during startup and shut down. A DC driven emergency lube oil pump provides bearing lubrication requirements under low lube oil pressure.

Two 100% motor driven, out of which one DC motor driven, jacking oil pumps, are provided to lift the rotor at the bearing during the turning gear operation. These pumps take suction from main oil tank.

In case of providing hydraulically driven barring gear, two separate 100% capacity motor driven pumps, one of which is DC motor driven, are exclusively provided for barring gear.

The lubrication oil is cooled in two 100% oil coolers. The cooling medium is demineralized water.

Every hour, 20% of the total oil charge in the turbine system is routed for purification. The purification system consists of centrifuge, polishing filter, explosion proof motors, motor driven feed pumps, and heaters.

A main oil tank of sufficient capacity to allow eight oil changes per hour for liberating entrained air is included. In addition, there is a lube oil storage and purification system. This is for storing and purifying oil from unit oil tanks and also to supply new oil to the unit lube oil tanks. The central system is equipped with clean and dirty oil tanks, transfer pumps, and a complete self-contained purification unit which is identical in all respects to the unit purifiers.

Gland Steam Sealing System. The HP and IP turbine shaft glands are sealed to prevent escape of steam into the atmosphere. The LP turbine glands are sealed for preventing leakage of atmospheric air into the turbine. Steam is used for sealing these spring backed labyrinth glands.

Up to 40% load on the turbine, seal steam is provided by the auxiliary steam header or cold reheat line through a seal steam regulating valve. Above 40% load, the seal steam is cut off and the leak-off steam from the HP and IP shaft glands is used for sealing the LP turbine glands. The excess leak-off steam goes to the gland steam condenser. A desuperheating type bypass is provided to cater during outage of the gland steam condenser. Two full capacity vapour exhausters are provided to remove non-condensable gases from the gland steam condenser.

Governing/Regulatory System. The turbine has throttle or nozzle controlled type governing. The steam turbine generator unit is equipped with an electrohydraulic governing system backed up by a mechanical hydraulic control system. Alternatively a 100% backup electronic controller is provided. The system also includes pre-emergency governors, emergency governor, load limit or speed/load changer, tracking devices, and initial steam pressure regulator.

HP/LP Bypass. The HP/LP bypass stations provide the following requirement:

- o Quick startup of the steam generator from cold and warm conditions
- o Quick hot restart of the turbine
- o Parallel operation of the bypass with turbine in the event of large load throw off
- o House load operation followed by large load throw off
- o To keep the steam generator in operation so as to avoid a fire out in the steam generator following full load rejection.

The HP bypass system is sized for 1000 tph of main steam flow at rated main steam conditions. The LP bypass is sized for steam inlet conditions (pressure and temperature) in hot reheat line as those corresponding to 60% MCR (maximum continuous rating).

HP/LP Heaters. There are three LP heaters and two HP heaters. Boiler feed water is heated in these heaters by extraction steam from turbine and cold reheat steam. Condensed steam in the heaters (drain) is sent to next lower heater. Drain from the HP heaters finally ends up in deaerator. Drain from LP heaters finally ends in the condenser.

All these heaters have a manual/motorized bypass arrangement on the condensate feed line. The heaters are of U-tube with all seamless stainless steel construction, surface type, horizontal with integral condensing and drain cooling zones. The HP heaters have a desuperheating zone.

Deaerator. The deaerator is of horizontal, direct contact spray or spray cum tray type with a horizontal feed water storage tank. The storage tank is sized to hold sufficient feed water for about 10 minutes running at full load at a filling faction of 0.66. The maximum dissolved oxygen content is 0.005 ml/liter in the deaerated condensate.

Boiler Feed Pumps. Two 50% turbine driven pumps and two 30% electric motor driven pumps with booster pumps mounted on the common shaft are provided. They are of horizontal, centrifugal type with a stiff shaft design. The deaerated boiler feedwater from the deaerator is compressed to 220 kg/cm2 a in these pumps.

The pump outer casing is of barrel type with end rotor removal. The inner pump assembly composed of shaft, impellers, and stage casings can be removed and replaced as a unit without disturbing the feed piping. Each feed pump has a modulated recirculation control valve to protect the pump under low flow condition.

Condensate Pumps. These pumps consist of three 50% capacity motor driven units. They are of vertical canister type, multi-stage, centrifugal diffuser design. These pumps transfer the condensate from the condenser to the condensate polishing unit.

Auxiliary Cooling System. The gas cooler, oil coolers of the turbo-generator, boiler feed pumps, oil coolers etc. are supplied with cooling condensate in a closed cycle. The cycle consists of a water-to-water heat exchanger, pumps, an overhead tank arrangement for the initial filling and its makeup requirement.

LP Chemical Dosing System. The purpose of this dosing system is to maintain the pH of condensate and feed water and to effectively deal with residual dissolved oxygen in condensate and feed water. The dosing consists of injecting hydrazine and ammonia in the boiler feed pump suction line and in condensate line after the polishing unit. The dosing equipment consists of storage and preparation tanks, metering tanks, and dosing pumps.

Hydrogen Generation Plant. A hydrogen generation plant of 14 NM^3/h capacity is included to meet the hydrogen requirements. It includes a bottling facility of the hydrogen gas generated and the equipment to feed the makeup hydrogen to the generator.

Chimney

The height of the flue gas emission point is 275 m above the plant grade level. The chimney consists of reinforced concrete wind shield with two insulated steel liners (flues). The liners are made from mild steel but the portion of the liners projecting above the wind shield and a few meters below the roof are made from special alloy steel. Fabric (non-metallic) expansion compensators are provided to cater for thermal elongation of the liners.

The chimney roof slab is of reinforced concrete treated for water proofing and protected by a layer of acid resistant tiles. The grade level slab is of reinforced concrete with an ironite floor finish. An elevator (rack and pinion type) is provided along the chimney for the full height. The top few meters of the external surface of the windshield are painted for acid and heat protection.

6.1.2 Control and Instrumentation

Control Tower

The boiler, turbine, and generator, along with their associated auxiliaries are controlled and monitored from unit-wise centralized air conditioned control room on the operating floor of the unit control tower.

Display Strategy and Conventional Instruments

The control philosophy adopted is based on using display devices like CRTs, trend recorders, and printers of microprocessor-based Distributed Digital Control, Monitoring and Information System (DDCMIS). Adequate conventional display devices like indicators, recorders window annunciators, status indicators, and lamps are provided as back-up display devices. A separate hardwired annunciation system is provided for important alarms.

Distributed Digital Control, Monitoring and Information System (DDCMIS)

The modulating controls and open loop controls of the related and interactive groups are integrated into one set of hardware. However, independent monitoring and information system hardware is also used to carry out these monitoring and information functions such as historical data storage/retrieval, performance calculations, and logs which are not directly related to control tasks. All these sub-systems are connected together through redundant system bus.

Both single loop controller and multi-loop controller are used. For single loop controllers, no controller redundancy is provided except for very few critical cases. For multi-loop controllers all the functional controllers have 100% hot back-up.

Due to the dust conditions in a coal-fired power plant, the electronic hardware of the complete DDCMIS system is contained in a centralized air-conditioned room without physical distribution through the plant.

For single loop controllers, the signal conditioning, distribution and monitoring system is kept independent of the control and logic function modules/units. Thus, important process parameters can be available to the operator for manual control in the event of failure of the control and logic function modules/units, bus system, and control operation system. For multi-functions controllers, the signal conditioning and processing may be combined in the functional controllers because the redundant controllers are available. A separate, stand alone sequence of 'Event Monitoring Equipment' with its own printer is provided. However, the information of this equipment is also made available to information system of DDCMIS through suitable communication interface.

Though the auto/manual operation for all devices is provided through CATs/keyboards, the manual break up operation facility through dedicated push-button tiles (one for each drive) is also provided on the desk/panel for all fans and pumps associated with the boiler and turbine-generator auxiliaries and all the interlocked isolating valves and dampers. In addition, dedicated conventional hand/auto stations are provided for all the modulating control devices. All the non-interlocked isolating valves and dampers are operated from CATs only. Testing is carried out from the switch gear.

Steam and Water Analysis System (SWAS)

As the water chemistry is critical for power plant operation, a comprehensive steam and water analysis system is provided. This system includes sampling and on line analysis of parameters like conductivity, pH, dissolved oxygen, residual hydrazine, silica, phosphate, sodium etc. at all critical points in the condensate, feed water, and steam cycle.

Uninterruptible Power Supply System (UPS)

This system supplies uninterrupted power to critical control and instrument loads. It consists of one 100% capacity battery, two 100% capacity chargers and two 100% capacity inverters. During normal operation, the UPS loads are supplied by both the inverters, each working at 50% load. In case of failure of one inverter, a static switch will automatically transfer all the UPS loads to the healthy inverter. In case both inverters fail, a standby AC source will feed the UPS loads.

Major C&I System (Included Under Main Plant Packages)

A furnace safeguard supervisory system (FSSS) is provided for furnace purging, automatic oil firing, flame monitoring, sequential startup and shut down of mills etc.

An automatic turbine run-up system (ATRS) is provided to run the turbine automatically, up to block load level through cold, warm, and hot startup.

6.1.3 Water Systems

Raw Water Treatment

This system treats river raw water to meet the plant requirements of cooling water, makeup water, demineralized water, clarified and filtered water, and potable water.

The treatment uses separate clarifiers for the cooling water and demineralized water. Each consists of a stilling chamber, flash mixers, clariflocculators, a chlorination system, an alum, lime, and coagulant aid dosing system, and a

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sludge disposal system. An above-ground clarified water storage tank is provided to meet the requirements of A/C and ventilation plant make-up and ash handling plant seal water. To meet the potable water requirements, two filters are provided.

The clarified water is further treated in gravity filters before it is sent to the demineralizer.

Sludge from clarifloculators is collected in sludge pits and sent to ash disposal area. Other waste water from raw water treatment plant is sent to liquid effluent treatment plant for disposal.

The demineralization consists of activated carbon filter, cation exchangers, degasser system (composed of degasser tower, degasser water tank, degassed water pumps, blowers for degasser etc.), anion exchangers, and mixed bed exchanger. The cation resins are regenerated with hydrochloric acid and the anion resins with sodium hydroxide. The regeneration facilities consist of bulk acid/alkali storage tanks, solution preparation tanks, dosing pumps etc. Air blowers are provided for mixing of the resins in the mixed bed. Storage is provided for the demineralized water and condensate. Waste water from raw water treatment plant is sent to liquid effluent treatment plant for disposal.

A full flow deep mixed bed condensate polisher is employed. The resins used are of strongly acidic cation and strongly basic anion type. An external regeneration facility is provided for the exhausted resins. The exhausted resins from the polisher are hydraulically transferred to the resin separation/cation regeneration vessel. A spare charge of resin is kept in the mixed resin storage tank for immediate exchange of resins with the exhausted ones. Waste water from the acid/alkali/demineralized water storage is sent to liquid effluent treatment plant for disposal.

Cooling Water Supply

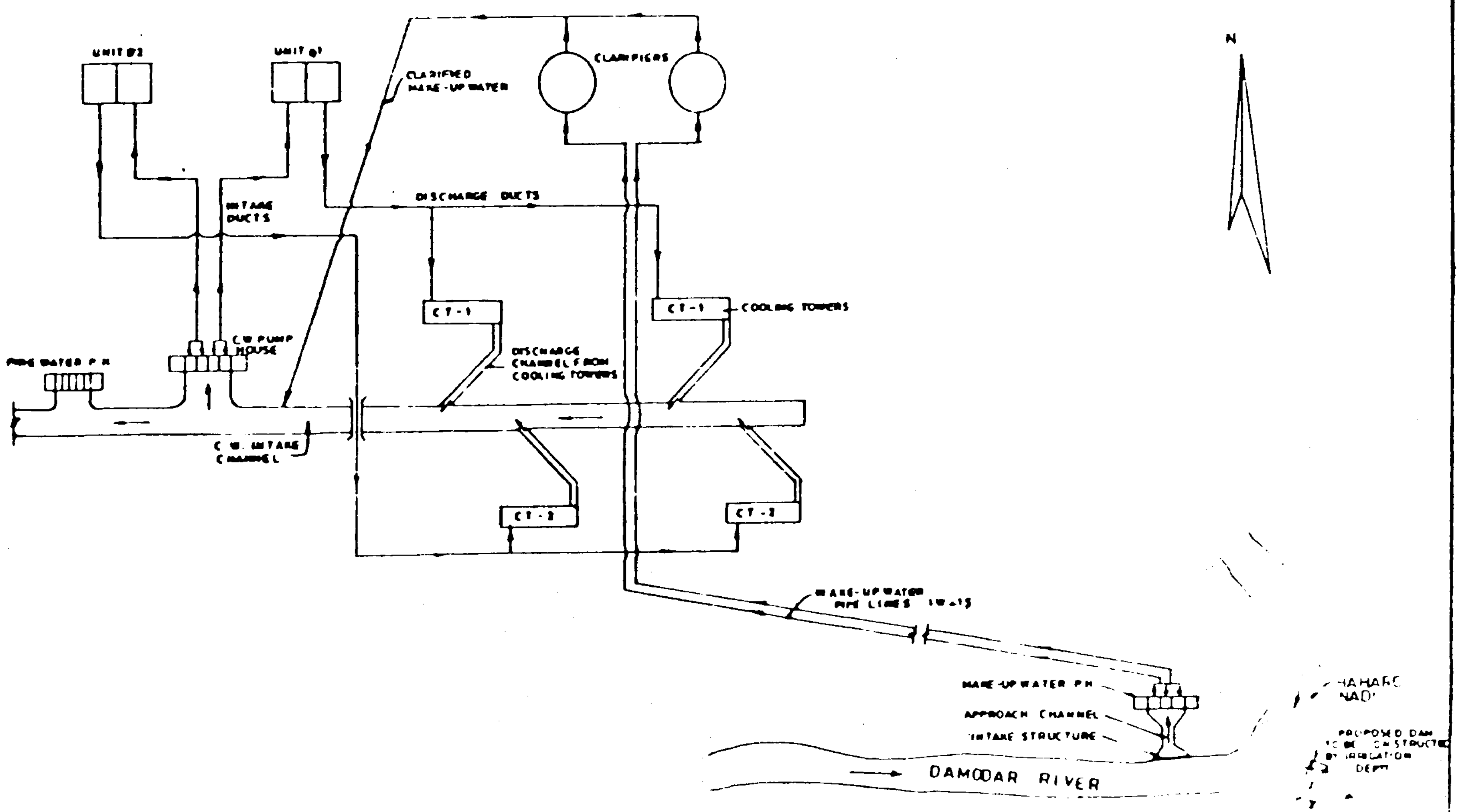
The plant cooling is provided by the use of induced draft or natural draft cooling towers as shown in Figure 6-3. This diagram is based on a 2 x 500 MW plant. For this study where only 1 x 600 MW unit is used, only one of the two cooling trains shown will be required.

Makeup water is pumped through two 100% capacity pipe lines to a plant water reservoir. The makeup water and fire water pump house has provisions for future units also. The reservoir has two portions, one in operation and other for maintenance. A separate storage pond is provided for return water from the ash pond and effluent treatment. The water from this pond is used for ash handling purpose only.

A pump house is located next to the reservoir. It houses makeup water pumps. The makeup water pumps send the raw makeup water for cooling towers to clarifiers. Clarified water is conveyed to the CW intake channel under gravity flow. A CW pump house pumps the CW water to the condenser ducts then back to the cooling tower. The fire water pump house is located on the intake channel.

All pump houses are provided with trash rack for filtering out debris and other floating matter. The makeup water pump house is additionally provided with travelling water screen. Stoplogs are provided for pump bays for isolation of any bay during maintenance period. The material handling equipment are provided in all the pump houses.

Blowdown from the cooling tower is sent to the ash handling system.



C.W. SYSTEM SCHEMATIC

Figure 6-3 PC PLANT CW SYSTEM SCHEMATIC

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The cooling tower has four cells. Closed circuit cooling water system is adopted for auxiliary cooling of the steam generator and turbine generator. Demineralized water is used in the closed circuit as the cooling medium which in turn is cooled in plate heat exchangers by water from the cooling tower. Chlorine is dosed in the cooling water system to prevent growth of algae and bacteria.

Liquid Effluent Treatment

Effluents From Bottom Ash Handling System. The bottom ash handling system effluent is collected in an underground collection tank. After being treated for dissolved solids removal, it is recycled back to the ash handling system.

Coal Pile Runoff Water. This runoff water is collected in open around the coal stockpile and flows into a settling pond from which the decanted water is sent to the liquid effluent treatment plant.

Boiler Blowdown. Boiler blowdown water is sent to the liquid effluent treatment plant for disposal.

Chemical Laboratory. Waste water from the chemical laboratory is sent to the liquid effluent treatment plant for disposal.

Sampling Rack. Waste water from the sampling rack is sent to the liquid effluent treatment plant for disposal.

Oil Storage Waste. Waste water from oil storage is first treated to remove oil and then sent to the liquid effluent treatment plant for disposal. Recovered oil is collected in an oil recovery tank.

Coal Handling Dust Extraction System. Effluents from all dust extraction points in the coal handling areas are collected into a common settling pond. The decanted water is conveyed to the liquid effluent treatment plant.

Station Drains. All the station drains are collected into a settling basin equipped with oil skimmers. The decanted water is conveyed to the liquid effluent treatment plant.

Liquid Effluent Treatment Plant. The treatment plant primarily consists of dissolved solids removal equipment, filter bed press, waste water pond, waste water neutralization equipment, etc.

Miscellaneous Pumps

Miscellaneous pumps are provided to supply water to various utility points.

CW Circulating Water Treatment Plant

To maintain the required cycles of concentration in the open recirculating type CW system, the station is provided with a side stream filtration and a scale/corrosion inhibitor chemical dosing system.

Ash Water Recirculation System

The system recovers water from ash disposal system and puts it back into the ash water sump.

Chemical Laboratory

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Chemical laboratory equipment, testing chemicals and reagents, glass ware items, and safety equipment are provided for analysis of coal, ash, and water.

6.1.4 Coal and Fuel Handling System

Coal Transportation and Handling System

Run-of-mine coal is transported to the power station by a merry-go-round rail system similar to that described for the moving bed IGCC plant.

The coal handling plant basically consists of two trains, one working and one standby. A schematic of this plant is shown in Figure 6-4.

Coal from the underground track hopper at the end of the merry-go-round system is retrieved by rotary paddle feeders and conveyed to a crusher house. Crushed coal (-20 mm) is conveyed to the boiler bunkers or stacked into a stockyard through stacker-cum-reclaimer (S/R) machines. The stockyard provides 14 days coal storage. Coal from the stockyard is reclaimed by the S/R machines. Travelling trippers are used to dump coal into the raw coal bunkers of the boilers.

Fuel Oil System

Fuel oil is delivered to the power station by rail wagon. From the rail wagon, it is transferred to storage tanks through a set of positive displacement pumps. From the storage tanks, the fuel oil flows by gravity to a pressurizing unit to feed to the boiler.

6.1.5 Ash Handling System

A schematic of the ash handling system is shown in Figure 6-5.

Bottom ash resulting from combustion of coal in the boiler falls into a w-type water impounded ash storage hopper provided under the furnace bottom. Every four hours, the bottom ash hopper outlet gates are opened and the stored ash is crushed with the help of clinker grinders and transported in slurry form by means of jet pumps to the bottom ash slurry sump in the ash slurry pump house.

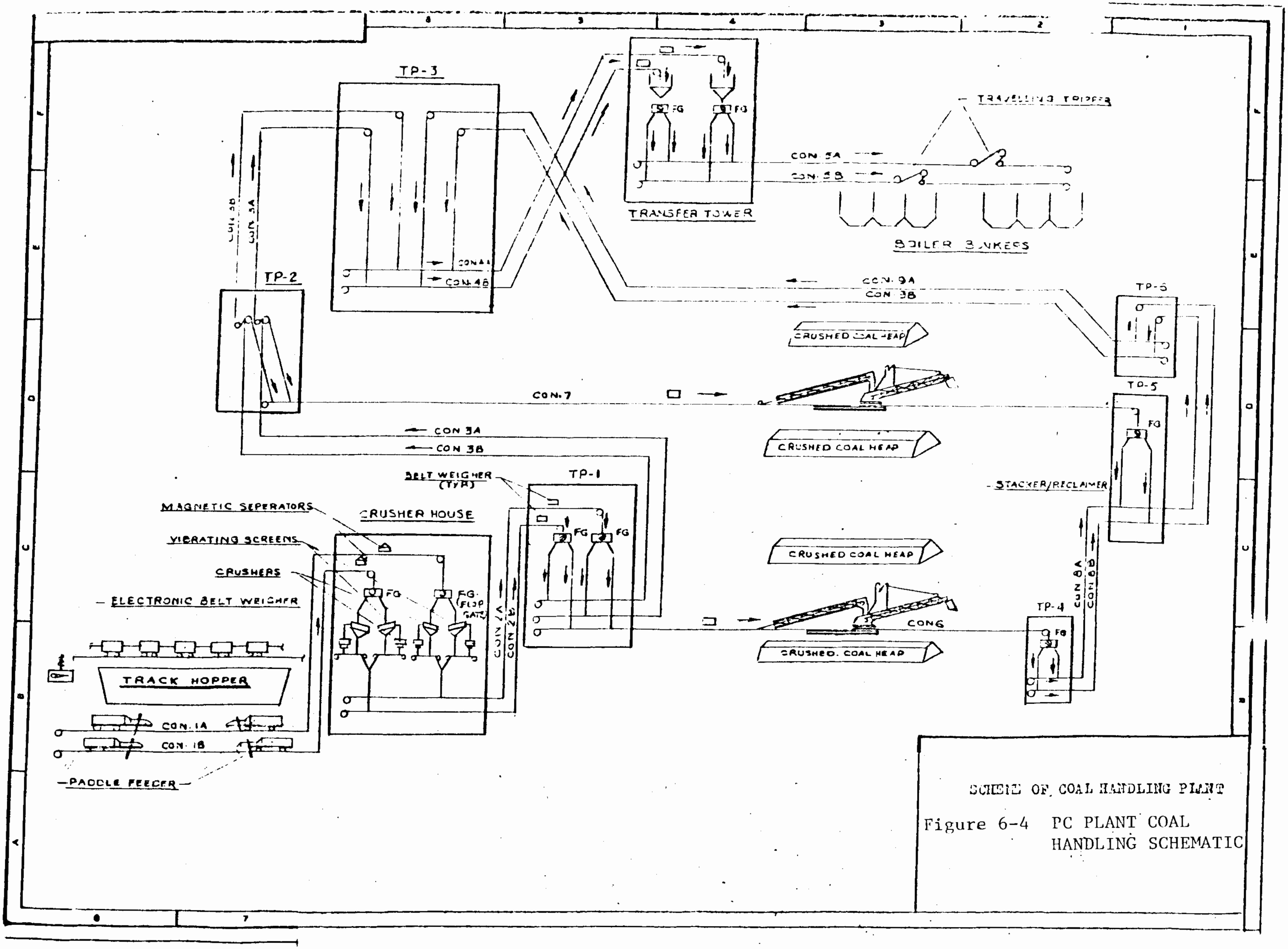
Fly ash extracted from the electrostatic precipitators and air preheater hoppers is pneumatically conveyed to buffer/surge hoppers and further to the fly ash storage silos.

Ash from these silos is mixed with water and the resultant ash slurry is pumped to an ash pond. Provision is made for dry discharge of ash from these silos for sale purpose.

The bottom ash and fly ash are led to separate sumps in the ash slurry pump house. From these sumps, the slurries are pumped to the respective ash ponds.

High pressure and low pressure ash water pumps are provided to supply water for extraction and conveying of the bottom and fly ash.

A dense phase pneumatic conveying system is employed for handling of the mill rejects. The rejects accumulate in a vessel provided at the outlet of the mill reject chute. High pressure air is made to enter the vessel to convey the rejects to a storage silo. From the silo, the rejects are carried away by trucks.



SCHEME OF COAL HANDLING PLANT

Figure 6-4 PC PLANT COAL HANDLING SCHEMATIC

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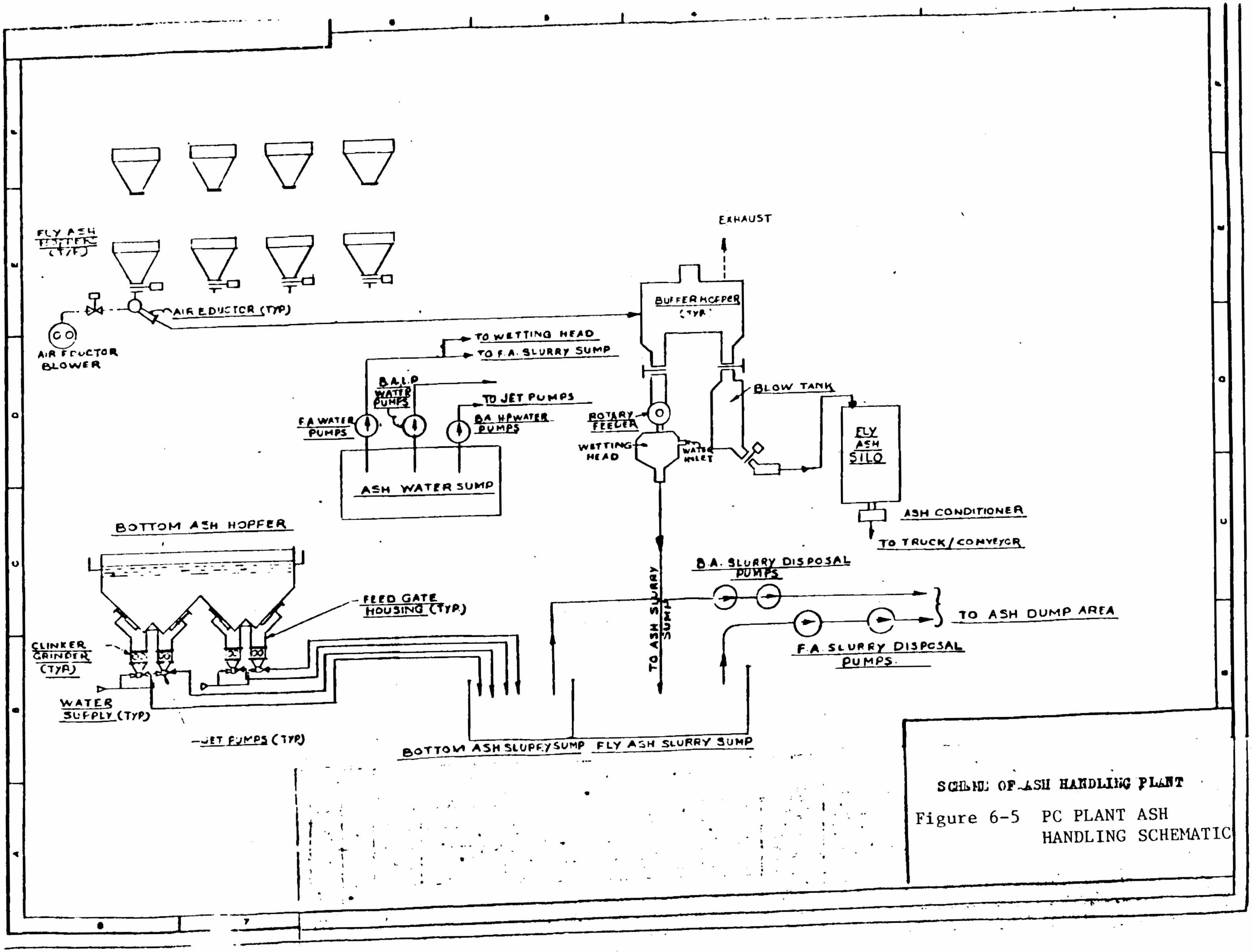

Figure 6-5 PC PLANT ASH HANDLING SCHEMATIC

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An area of about 500 acres has been identified for the ash disposal.

Dikes are provided around and inside the disposal pond. Ash slurry discharged into the ponds is allowed to stagnate so that ash particles settle to the bottom and water is collected at the top. This clear water and rain water collected in the ponds during normal rains is allowed to flow over the weirs in the decant water tower and passes through draw off galleries to the clarification ponds. At the clarification ponds, remaining ash particles are removed and the clear water is pumped back to the plant for reuse for the ash slurry making. During heavy rainfall, the excess discharge coming out of the draw off culverts is directly discharged into the river.

6.1.6 Other Common Facilities

Station and Instrument Air Compressors

Two air compressors at 8 kg/cm2 g pressure are provided to meet the station air requirements. These compressors are of reciprocating, nonlubricated type complete with intercooler, after cooler, moisture separators, air receivers and drive motors.

Three compressors of the same description above and three air drying units designed for -40 C dew point at atmospheric pressure are provided to deliver moisture and oil free air for plant controls and instrumentation.

Fire Protection System

The plant fire protection includes the following systems:

- A hydrant system complete with piping, valves, instrumentation, hoses, nozzles etc,
- An automatic/manual high velocity water spray system provided for all transformers in transformer yard, main and unit turbine oil tanks and purifier, turbine oil/lube oil piping, boiler burner fronts, lube oil system for turbine operated boiler feed pump etc,
- An medium velocity water spray system with foam injection capability for fuel oil/diesel oil storage tanks,
- A sprinkler protection system provided for coal conveyors, coal galleries, transfer points, crusher house, cable vaults and cable galleries,
- Halon-1301 protection for control room, control equipment room, DAS, and inverter room,
- A fire alarm system
- Portable and mobile extinguishers at strategic locations of the plant

For the above systems, a suitable number of electric motor and diesel engine driven pumps along with water storage sump tank are provided.

Elevators and Lifts

The arrangements consist of:

- Two passenger lifts in the service building
- Two E.O.T. cranes of 95/15 tonnes in T.G. Hall
- One E.O.T. crane of 30 tonnes capacity in CW pump house and monorails for lifting or placing trash racks
- A frame type hoisting device for maintenance of travelling water screen, etc.
- One elevator for stack maintenance.

Air Conditioning System

In this system, facilities are provided for filtering, cooling, heating, humidifying the air supply to maintain space conditions within specified limit and provid filtered fresh air to suit ventilation requirement. The area envisaged for air conditioning are control tower, 33 kV & 400 kV switchgear control rooms, service buildings, relay room, ESP control room, water treatment plant control room, coal handling plant control rooms, etc.

Ventilation System

A ventilation system is provided to maintain the inside condition of buildings within a stipulated maximum temperature. All evaporative cooling system is selected in such a way that the maximum temperature within the treated space does not exceed a temperature of 5 C below ambient during summer or five air changes rate per hour, whichever is higher. The areas to be covered under this system include the turbine hall and all auxiliary buildings. All mechanically ventilated areas are designed to a maximum temperature of 2 C above ambient or ten air changes rate, whichever is higher. A vacuum cleaning system is provided to clean the different dust-generating areas of the power station.

6.1.7 Electrical System

An electrical single line diagram and an auxiliary power supply arrangement diagram are shown in Figures 6-6 and 6-7, respectively. As these diagrams are based on a 2 x 500 MW plant, most of the equipment sizes shown need to be scaled down to the 1 x 600 MW capacity used in this study.

Turbo-Generator

The main design specifications of the generator are as follows:

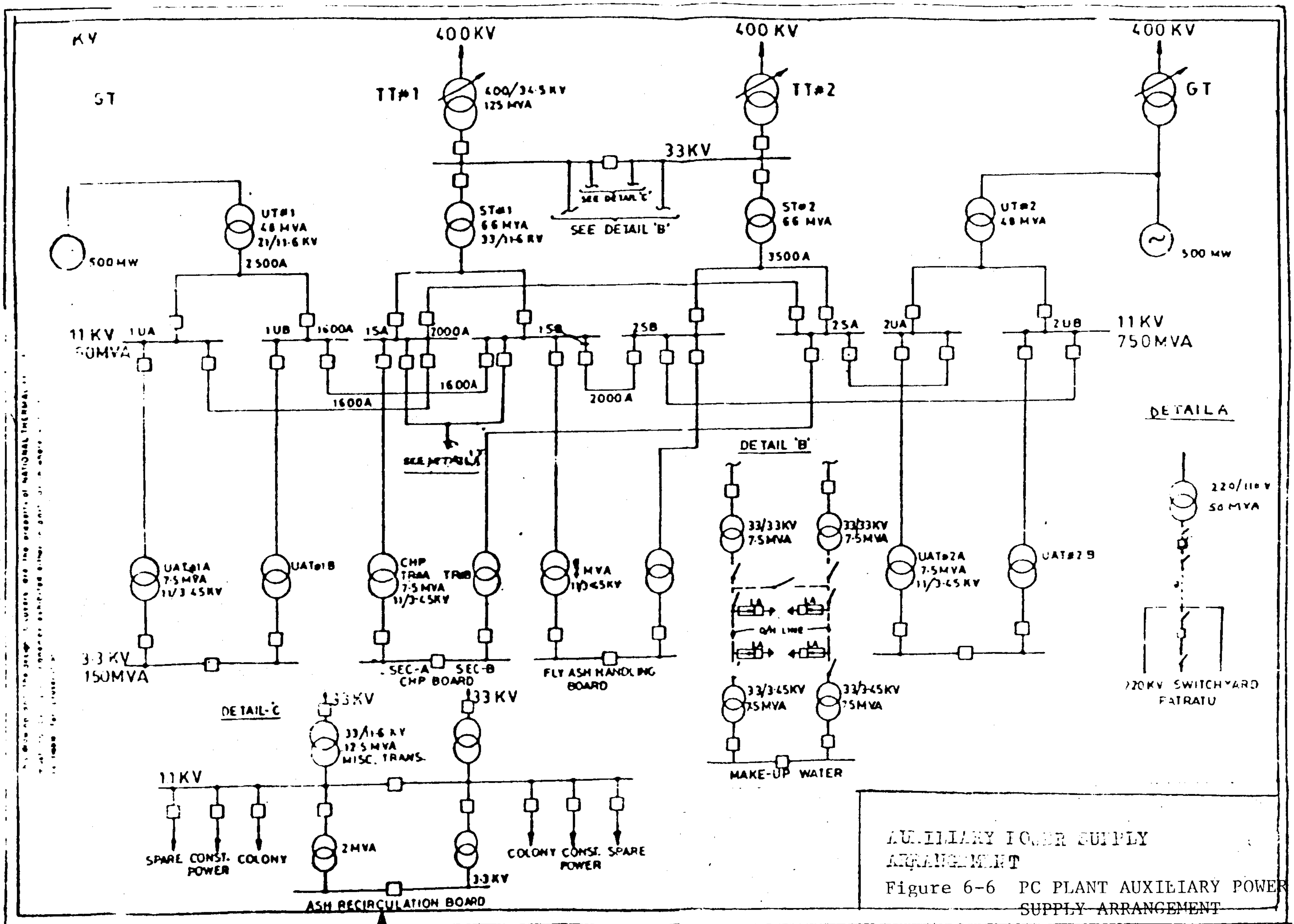
Nominal rating	600 MW
Rated output	706 MVA
Power factor	0.85 lag
Rated voltage	in range of 18 KV to 24 KV
Speed	3000 rpm
Frequency	50 Hz
Short circuit ratio	0.5

The stator winding of the generator is cooled by means of demineralised water, passing through the hollow stator conductors. The generator includes auxiliary systems such as the stator water system, seal oil system, and gas system complex with all accessories.

The generator is connected to the generator transformer through isolated phase bus ducts which are of continuous enclosure, self-cooled type and equipped with an air pressurization system. Necessary current and voltage transformers are included in the bus duct for generator excitation control, performance testing, metering, protection, and synchronizing. Surge protection equipment and a generator neutral grounding cubicle with distribution transformer and secondary resistor are also provided.

Power Transformers

Power generated from the generator is stepped up to 400 KV by a transformer for evacuation through transmission lines.



AUXILIARY POWER SUPPLY ARRANGEMENT

Figure 6-6 PC PLANT AUXILIARY POWER SUPPLY ARRANGEMENT

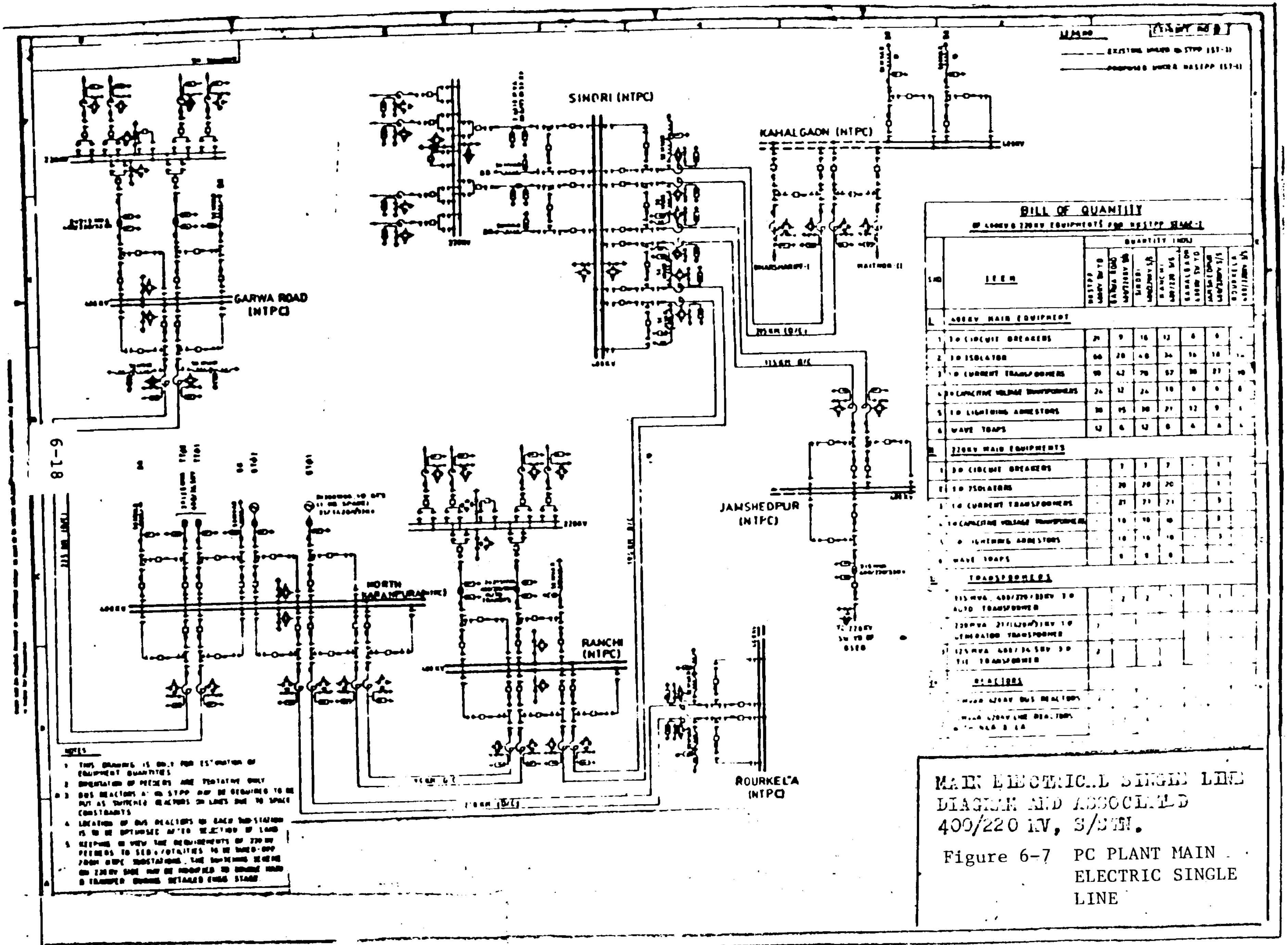


Figure 6-7 PC PLANT MAIN ELECTRIC SINGLE LINE

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BEST AVAILABLE

The generator has three single phase transformers. They are OFAF cooled with on-load tap changer.

Electrical Auxiliary System

The plant auxiliary power requirement derives from station supplies via two winding 33/11.6 kV 66 MVA station transformers and from unit supplies via 21/11.6 KV, 48 MVA unit transformers. These transformers feed to 11 kV station and unit boards which have a fault rating of 40 kA break & 110 HA make. Station and unit transformers are ONAN/ONAF/OFAF cooled effectively with off circuit tap changer.

Interconnection through busduct between unit and station buses between different station buses is provided to cater for unit or station transformer outage.

Two 7.5 MVA, 11/3.45 kV unit auxiliary transformers connected to respective bus section by cables are provided for each unit with interconnection between the two sections.

3.3 kV switchgears connected by cables to 11/3.45 kV sized for two 100% transformers are provided for coal handling plant, fly ash disposal system, makeup water system and ash water recirculation system.

The power for ash recirculation water system, colony, and construction is fed through two 33/11.6 kV 12.5 MVA isolating transformers. These isolating transformers are connected to 33 KV station board. 11/3.45, 11/0.433 or 3.3/0.433 kV transformers are provided to meet the local loads of power plant. These are located at respective load centers.

Neutral Grounding Arrangements

High resistance neutral grounding with distribution transformer and secondary resistor is used for neutral grounding the generator.

Both the 11 kV and 3.3 kV systems are low resistance, non-effectively earthed to limit the earth fault current to 300 Amps. The 415 V system has solidly earthed neutral.

33,11 and 3.3 kV Switchgears

The 33 kV switchgear is of indoor, metal clad, drawout type with vacuum/SF6 circuit breakers.

The 11 and 3.3 kV switchgears are of indoor, metal clad, drawout type with vacuum/SF6 circuit breakers. Contactors are used for 3.3 kV auxiliaries.

415 V switchgears

The 415 V switchgears distribute power to the various motor control centers. These switchboards are of indoor, drawout type, metal clad with air break circuit breakers.

DC System

This system consists of:

- Two 220 V batteries and float cum boost chargers to supply DC power to emergency pumps, emergency lighting, protection, annunciation control, indication etc
- Two +24 V and two -24 V batteries with chargers for turbine control and instrumentation
- Two 220 V batteries and chargers for the complete EHV switchyards
- Two 50 V batteries and chargers for complete PLCC
- Two 110 V batteries and charges for ash handling system
- Two 110 V batteries and charges for makeup water system
- One 48 V and two 48 V batteries and chargers for station even Siren and Telecommunication System (PAX) respectively
- Two 10 V batteries and chargers for ash handling system

Protective Relayings and Controls

The protective relaying system is provided for switchyards, lines, generators, transformers, meters, auxiliary system, etc. to minimize the damage to equipment in case of fault and abnormal conditions. Necessary control facilities (including synchronising where applicable) are provided in the each unit control board for all breakers, diesel generator, transformers, OLTC, etc. together with interlocks and protections.

Cables

All power and control cables required for 33 KV, 11 KV, 3.3 KV, and 415 V system, DC system are provided.

Emergency Power Supply System

One 750 KVA diesel generator is installed for providing emergency power during blackout for certain essential applications like battery chargers, emergency lighting, essential air conditioning/ventilation and all auxiliaries necessary for bearing operation of the main steam turbine and boiler feedwater pump turbines.

Station Grounding

Buried grounding mats employing suitable dia MS rods are provided for EHV switchyards, main plant area, pump houses etc. All the connections above the ground are of galvanized steel.

Lighting System

The lighting system includes the necessary transformers, distribution boards and panels, HPMV, sodium vapour fluorescent and incandescent lighting fixtures, lighting masts, etc. Normal lighting of the plant is operated with the station AC power. About 20% of these fixtures also has arrangement for being fed from diesel generators on failure of station AC supply. Emergency DC lighting is provided at all strategic locations.

Plant Communication System

The communication facilities include:

- A PABX telephone system
- A public address system with party and paging channel
- Radio paging system for key personnels and walkie-talkie sets

Start Up Power

One 220 KV single circuit line is provided to import plant starting power in case of station black out.

Clock System

A master clock panel is provided in the switchyard, control room together with a number of follower clocks located at key points throughout the power plant.

Electrical Laboratory

All necessary electrical laboratory testing equipment are provided.

6.2 PLANT PERFORMANCE SUMMARY

Table 6-1 summarizes the plant resource requirements, power outputs, heat rates, and overall efficiencies for the PC plant both with and without flue gas desulfurization (FGD). The FGD is assumed to have a 70% sulfur capture as that specified for the IGCC plant.

6.3 COST ESTIMATE

This subsection presents estimates of the capital requirements, project lead time, and cost of generation for the PC plant described above.

All the estimates are based on fourth quarter of 1989 as the pricing date. As mentioned previously, the cost data were mainly derived from a PC plant feasibility study for the North Karanpura Super Thermal Power Project[2,3].

6.3.1 Capital Cost Estimate

Capital costs of the PC plant with and without FGD are shown in Table 6-2. Inclusion of FGD is estimated to increase the PC plant capital requirements by 20%.

The estimate procedure and scope are the same as those used for the North Karanpura Super Thermal Power Project[2,3].

6.3.2 Project Lead Time

The total project lead time from placement of order to commissioning is estimated to be 5 years.

6.3.3 Cost of Generation

The costs of generation for the PC plant with and without FGD are shown in Table 6-3. These costs are shown for 5500, 6000, 7000, and 7400 hours per year of plant operation. The bases used to derive these costs are described below.

O & M Charges

These costs include labor and overheads and maintenance materials. Based on actual operating data from various PC plants in India, these costs are estimated to be 2% of the total project capital requirements.

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Table 6-1

PC PLANT PERFORMANCE SUMMARY

	No FGD	With FGD
Plant Resources Requirements		
Coal (as received)		
MTPD	10,886	10,886
HHV, million Kcal/h	1,511	1,511
LHV, million Kcal/h	1,437	1,437
Limestone, MTPD	0	280
Raw Water, m3/h	2,754	3,000
Plant Output, MW		
Gross Power Generated	600.0	600.0
In-Plant Power Consumption	42.0	51.0
Net Power to Grid	558.0	549.0
Heat Rate, Kcal/kwh		
HHV Basis	2,708	2,753
LHV Basis	2,575	2,617
Overall Thermal Efficiency, %		
HHV Basis	31.8	31.2
LHV Basis	33.4	32.9
Sulfur Byproduct, MTPD	0	0

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Table 6-2

CAPITAL COST REQUIREMENTS OF PC PLANT
4th Q-1989

S1 No.	Plant Name	Rs. Lakhs	$ Million
1	Coal Transportation System	3,020	17.76
2	Coal Handling System	3,658	21.52
3	Steam Generator, Turbo Generator & Aux.	50,930	299.59
4	Ash Handling System	4,700	27.65
5	Fuel Oil System	218	1.28
6	Compressed Air System	119	0.70
7	Raw Water Supply and Treatment	3,144	18.49
8	Cooling Water System	3,792	22.31
9	Fire Protection	323	1.90
10	Effluent Treating	421	2.48
11	Electrical Work	5,658	33.28
12	Instrumentation and Controls	1,653	9.72
13	General Ser. & Mobile Equipment	1,823	10.72
14	Site Prep., Improvement & Buildings	9724	57.20
15	Engineering & Establishment	5,873	34.55
	Total Plant Cost	95,056	559.15
	Contingency	4,753	27.96
	Owner's Cost	6,677	39.28
	Total PC Capital Requirements	106,486	626.39
	FGD Cost	21,297	125.28
	Total PC Capital Requirements with FGD	127,783	751.67

Table 6-3

COST OF GENERATION OF PC PLANT

(Based On 10% Pre Tax Return On Equity, 4th Q-1989 Pricing)

	PC	PC+FGD
Gross Power Produced, MW	600.0	600.0
Net Power Produced, MW	558.0	549.0
Aux. Power Consumption, % of Gross Power	7.0	8.5
Project Capital Requirement		
Total Capital, Rs lakhs	106,486	127,783
Rs/kw Gross Power Generated	17,748	21,297
Annual (5500h/y) Coal Consumption, kg/kw gross	4,158	4,158
Heat Rate (HHV basis), Kcal/kwh net power	2,708	2,753
Specific Coal Consumption, kg/kwh net power	0.813	0.826
Annual (5500h/y) Oil Consumption, kl/kw gross	0.044	0.044
Specific Oil Consumption, ml/kwh net power	8.60	8.74
Fixed Costs, Rs/y/kw gross power		
O&M Charges	354.95	425.94
Depreciation	634.55	762.33
Interest on Long Term Loan	1,331.08	1,597.29
Return on Equity	887.38	1,064.86
Interest on Working Capital Loan	61.79	84.79
Total Fixed Costs	3,269.75	3,935.22
Variable Costs (5500 h/y), Rs/y/kw gross power		
Coal	997.88	997.88
Limestone	-	40.00
Fuel Oil	140.80	140.80
Raw Water	25.25	27.50
Total Variable Costs	1,163.93	1,206.18
Total Fixed and Variable Costs, Rs/y/kw	4,433.68	5,141.40
Electricity Cost, Paise/kWh net power		
@5500 hr/y operation	86.7	102.2
@6000 hr/y operation	81.4	95.6
@7000 hr/y operation	73.0	85.4
@7400 hr/y operation	70.3	82.1

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Depreciation

This cost is calculated based on 3.6% of the total capital excluding the working capital.

Interest on Long Term Loan

This is assessed at 15% of 50% of the total capital.

Return on Equity

This is 10% on 50% of the total capital.

Interest on Working Capital Loan

This is assessed at 17% of 75% of the working capital.

Raw Material Costs

These costs are as following:

Coal	Rs 240/tonne
Limestone	Rs 374/tonne
Fuel Oil	Rs 3,200/m^3
Water	Rs 1/m^3

6.4 ENVIRONMENTAL ASPECTS

This subsection illustrates the regulatory requirements, the pollution control measures provided, and the gaseous emission, liquid discharges, and solid wastes generated from the PC plant.

6.4.1 Regulatory Requirements

Department of Environment, Government of India

A detailed environmental impact assessment has been conducted for the proposed project.

Bihar State Pollution Prevention and Control Board

Effluent standards formulated by the Board will be complied.

Emission and Ambient Quality Standards

The ambient air quality and emission of particulate matter will comply with the standards stipulated by CPCB vide their notification dated 16.12.1982 and Emission Regulations Part I (COINDS/17/1983-84) respectively.

6.4.2 Pollution Control Measures

Adequate measures are undertaken to mitigate environmental pollution due to solid, liquid, and gaseous discharges from proposed power generating station.

Solid Waste

Ash is the principal solid waste generated by the project. In addition, a small quantity of mill rejects is produced at the plant site. The fly ash is

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arrested in ESP and collected in dry. It is subsequently dumped pneumatically into a silo. Viability of commercial utilization is examined. The ash is conditioned with water, and sprinklers provided to control fugitive dust emissions during transportation and compaction. The unutilized portion of fly ash is disposed off in slurry from dump area. The disposal areas are landscaped and reclaimed in stages.

The bottom ash is sluiced to the ash disposal area. The proposed location of the ash disposal area is in southern bank of Saphi river. The ash pond is properly designed so that escape of ash into the water body is prevented. An earthern dyke is constructed to retain the ash and sedimentation principle is strictly followed. It is envisaged that the final effluent will have a suspended solid concentration of less than 100 mg/l.

Water Pollution

The proposed power station utilizes an open type recirculating condenser cooling system using induced natural draft cooling towers. It is anticipated that no thermal pollution will occur.

The liquid discharge as waste water from the plant is treated as necessary.

The demineralized wastes, boiler blowdown, and boiler cleaning wastes are neutralized. The neutralized effluent along with clarifier wastes, plant drains, coal handling area waste and coal storage area runoff are directed to a settling tank. After sedimentation, the effluent are discharged into the main plant waste stream. Tertiary treatment if found necessary shall be employed to minimize the pollutants.

The sanitary wastes in the plant and township is separately treated biologically before discharge.

Air Pollution

Electrostatic precipitators (ESP) with high efficiency is installed to control particulates emissions from the plant. Anticipated efficiency of ESP is more than 99.9% to limit the particulate emissions below 150 mg/Nm^3.

Fugitive dust from coal stacking dust handling area is controlled by sprinkling water. A planned arboriculture is developed around the ash disposal area to reduce the fugitive dust emission. A tall stack of 275 m height is constructed for dispersion of sulphur dioxide over a large area. Space is provided for flue gas desulphurization. NO_x is controlled through efficient design of boiler. Extensive plantation in and around the plant area and township will be undertaken which will act as sink for pollutants.

Noise

Adequate silencing equipments will be provided at appropriate locations to attenuate noise to acceptable levels.

6.4.3 Environmental Impact Assessment (EIA)

The salient data of the Environmental Impact Assessment of North Karanpura Super Thermal Power Plant (STPP) is furnished in Table 6-4. The emissions include NO_x, CO, SO_2, and particulate matter into ambient air, water discharges and solid waste discharges. The Piparwar site where IGCC is located is very near to the site of North Karanpura STPP. Hence the meteorological conditions are the same in both cases.

Table 6-4

PC PLANT EMISSIONS

Air Emissions	
NOx, kg/h	2,110
CO, kg/h	Negligible
SO2, kg/h	2,970
Particulates, kg/h	412
Water Discharge, m3/h	
Treated Process Waste Water	200
Cooling Tower Blowdown	(a)
Neutralized Demin. Regenerants	20
Discharge from Misc. Water Usage	200
Treated Sanitary Waste	10
Total	430
Solid Waste Discharge, t/d	
Fly Ash	3,440
Bottom Ash	860
Total	4,300

(a) Used in ash handling plant

6.5 **PLANT AREA REQUIREMENT**

The total plant area requirement for the PC plant is estimated as following:

	Acre
Plant area	300
Township	200
Ash disposal	500
Railway siting for merry go round system	140
Makeup water corridor	140
Approach road, ash disposal corridor	225
Total	1505

6.6 **GENERAL LAYOUT**

The general layout covers the civil and architectural works for structures/facilities coming in the main plant area composed of main building, control tower block, air washer building, boiler elevation shaft, bunker building, compressor house, service building, DG set building, coal handling structures in boiler area, ESP control room building, transformer yard, auxiliary startup boiler, boiler area paving, miscellaneous foundation in transformer yard, boiler areas, foundation for cable and pipe supporting trestles, and condenser polishing plant and regenerative building complex. As among the above-mentioned buildings, ESP control room building, service building, startup boiler control room and condenser polishing plant building are made of RCC frame structure. All other buildings have structural steel.

Section 7

COMPARISON OF IGCC AND PC PLANTS

In this section, the plant efficiencies and costs of the four IGCC technologies described in Section 5 are compared with those of the PC plant described in Section 6.

Based on this comparison and other considerations, an overall ranking among these IGCC technologies is presented to select the best technologies for future demonstration and commercialization in India.

7.1 PLANT EFFICIENCY COMPARISON

A comparison of the IGCC and PC plant efficiencies is shown in Table 7-1. The relative heat rates included in the table are calculated using the PC plant with FGD as the base.

Table 7-1 indicates that all the IGCC plants except the Texaco case have better heat rates than the PC plant. In the KRW case, the difference is very substantial. Reasons for the heat rate differences among the IGCC technologies have been discussed previously in Section 5.2.

Compared with other IGCC plants outside India, the heat rates shown in this study are all substantially higher. For example, the typical heat rate for a Shell-based IGCC plant in U.S. or Europe is 2050-2200 Kcal/kWh while it is 2451 Kcal/kWh in this study. The major reason is, of course, due to the high ash content of the India coal used. But there are several other reasons.

One reason is the plant site has a very high elevation and ambient temperature. At higher elevation and ambient temperature, the gas turbine produces less power and has lower efficiency.

Another reason is the high moisture content (18 wt%) assumed for the design coal. This is to take into account the high precipitation in the region, particularly in the monsoon season. The high moisture content means either more energy is required for coal drying or more water is to be evaporated in the gasifier. In both cases, the overall plant efficiency is penalized.

Another reason applicable only to the Shell and Texaco gasifiers is that the Indian coal used has a very high ash fusion temperature. These two gasifiers which operate in slagging mode are forced to have a very high operating temperature. As a result, the cold gas efficiency drops and the overall plant heat rate increases.

In the present design for the Shell case, no air integration between the gas turbine and air separation plant as currently being implemented in the 200 MW Shell demonstration project in Holland has been incorporated. Shell indicates that use of this integration scheme can improve the plant heat rate by about 50 Kcal/kWh. This is an additional reason for the higher than expected heat rate for the Shell case.

7.2 ECONOMIC COMPARISON

A comparison of the capital requirements and costs of generation of IGCC and PC plants is shown in Table 7-2. The relative unit capitals and relative costs of generation shown are calculated using the PC plant with FGD as the base.

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Table 7-1

PERFORMANCE COMPARISON BETWEEN IGCC AND PC PLANTS

	IGCC Plant				PC Plant	
	Shell	Texaco	KRW	Moving Bed	Without FGD	With FGD
Net Power Output, MW	564.4	496.2	577.2	585.7	558.0	549.0
Coal Consumption (as received), t/d	9,964	12,576	8,890	10,768	10,886	10,886
Specific Power, MWh/t of coal	1.36	0.95	1.56	1.31	1.23	1.21
Heat Rate (HHV basis), Kcal/kWh	2,451	3,519	2,138	2,514	2,708	2,753
Relative Heat Rate	0.89	1.28	0.78	0.91	0.98	Base

Table 7-2

COST COMPARISON BETWEEN IGCC AND PC PLANTS
(4th Q, 1989 Pricing)

	IGCC Plant				PC Plant	
	Shell	Texaco	KRW	Moving Bed	Without FGD	With FGD
Net Power Output, MW	564.4	496.2	577.2	585.7	558.0	549.0
Total Capital Required, Rs Crores	2,055	2,059	1,460	1,529	1,065	1,278
Unit Capital, Rs/kW net	36,418	41,500	25,292	26,103	19,084	23,276
Relative Unit Capital	1.56	1.78	1.09	1.12	0.82	Base
Cost of Generation, Paise/kWh						
@ 5500 h/y operation	146.0	170.2	103.8	115.5	86.7	102.2
@ 6000 h/y operation	135.4	158.1	96.5	107.6	81.4	95.6
@ 7000 h/y operation	118.8	139.2	85.0	95.3	73.0	85.4
@ 7400 h/y operation	113.4	133.0	81.3	91.3	70.3	82.1
Relative Cost of Generation (based on 5500 h/y operation)	1.43	1.67	1.02	1.13	0.85	Base

Table 7-2 indicates that all the IGCC cases are more capital intensive and have higher costs of generation than the PC plant without FGD. The KRW and moving bed cases are, however, cost competitive with the PC plant with FGD.

In Table 7-2, the costs of generation are compared at four levels of plant operation hours. As most of the IGCC cases are thermally more efficient than the PC plant, the differences in cost of generation between IGCC and PC reduce as plant operation hours increase.

As IGCC plant usually consists of multiple trains in both the process and power blocks, it is expected to have a higher plant availability than the PC plant. A preliminary availability analysis presented in Section 5.4.1 indicates the present IGCC plant design can achieve 85% availability or about 7400 h/y plant operation. At this operating level, the cost of generation in the KRW case is actually lower than that in the PC plant without FGD if the PC plant is operated less than 6000 h/y.

The Shell case has a very high capital requirement because it has a very high operating temperature and requires very large and expensive waste heat boilers. The Texaco case, even though it requires no waste heat boiler as a result of the quench operation, has about the same capital requirement as the Shell case because its lower plant efficiency requires substantially more coal to be processed.

The moving bed case has a lower capital requirement than the Shell and Texaco cases because (1) it is air blown without requirement of an expensive air separation plant and (2) the low product gas temperature from the gasifier, as a result of the counter-current flow reactor used, minimizes the waste heat recovery requirement. The KRW case has the lowest capital requirement because it operates at low temperature, uses in-bed sulfur capture and hot gas cleanup, and has no air separation plant.

7.3 **OVERALL RANKING OF IGCC TECHNOLOGIES**

In addition to the plant efficiency and economics discussed above, there are other considerations for selecting the proper IGCC technologies for demonstration and commercialization in India. An overall ranking of the four IGCC technologies is shown in Table 7-3. In this table, the IGCC technologies are rated according to fifteen criteria grouped under three major categories: process, performance, and cost.

7.3.1 Ranking Methodology

The rating is based on a score from 1 to 10 for each of the fifteen criteria. A higher number means a better rating. Each criterion is in turn assigned a weighing factor, also from 1 to 10. A higher number means it is a more significant criterion.

A weighted average of the score is derived for each major criteria category. Each category is also assigned a weighing factor from 1 to 10. Then a final score is derived based on the weighted average of the three categories. The weighted average is defined at the bottom of Table 7-3.

7.3.2 Rationale for the Rating

The rationale behind the scores given to each IGCC technology are described below for each of the fifteen selection criteria.

Table 7-3

OVERALL RANKING OF IGCC TECHNOLOGIES

Weight Factor		Shell	Texaco	KRW	Moving Bed
	Process				
10	1. Maturity	7	10	4	10
7	2. Scale-up Risk	10	10	5	10
5	3. Capacity per Gasifier	10	6	8	2
10	4. Suitability for High Ash Coal	5	1	10	8
7	5. Cope with High Ash Fusion Temp.	5	3	8	10
5	6. Cope with High Coal Moisture	6	10	8	10
7	7. Coal Size Requirement	10	10	10	2
5	8. Need for Special Equipment	6	7	3	6
10	9. Auxiliary Power Consumption	5	3	10	10
7	10. Load Following Capability	10	10	8	5
	Weighted Average	7.2	6.7	7.6	7.7
	Performance				
10	11. Heat Rate	7	2	10	5
5	12. Raw Water Consumption	7	2	10	7
5	13. Quantity of Solid Waste	8	7	4	3
	Weighted Average	7.3	3.3	8.5	5.0
	Cost				
10	14. Capital in $/kW	3	2	10	8
10	15. Cost of Generation	5	3	10	8
	Weighted Average	4.0	2.5	10.0	8.0
	Summary				
7	Process	7.2	6.7	7.6	7.7
10	Performance	7.3	3.3	8.5	5.0
7	Cost	4.0	2.5	10.0	8.0
	Weighted Average	6.3	4.0	8.7	6.7

$$\text{Weighted average} = \frac{\Sigma\ (\text{rating in i-th criterion})\ (\text{weighing factor for i-th criterion})}{\Sigma\ (\text{weighing factor for i-th criterion})}$$

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Maturity

The scores given reflect that the Texaco and moving bed gasifiers are commercially proven, the Shell gasifier is very close to commercialization, and the KRW gasifier has been demonstrated only on pilot plant scale.

Scale-Up Risk

This is rated according to the gasifier scale-up risks discussed in Section 5.4.2.

Capacity per Gasifier

The moving bed gasifier has the lowest throughput rate. The Shell and Texaco gasifiers which use entrained flow reactor have the highest throughput rate. The KRW gasifier which uses fluidized bed reactor has a throughput rate in between.

Suitability for High Ash Coal

As discussed in Section 5.2.1, the Texaco gasifier is severely penalized by the ash content due to the slurry feed system used. The large amount of energy required to melt a huge quantity of ash in this gasifier also makes it undesirable for high ash coal. As the Shell gasifier also operates under slagging condition, this gasifier is rated with a lower score than the KRW and moving bed cases.

The moving bed case is rated lower than the KRW case because high ash coal means more attemperating steam is required for this gasifier to maintain its dry bottom operation.

Cope with High Ash Fusion Temperature

The high ash fusion temperature penalizes most to the slagging gasifiers as in the Shell and Texaco cases. It penalizes the KRW case to less a degree because this gasifier is operated in an ash agglomeration mode. The high ash fusion temperature is actually favored by the moving bed gasifier due to its dry bottom operation.

The Texaco case has a lower score than the Shell case because the addition of a fluxing agent to reduce the ash fusion temperature will increase the mineral feed to the gasifier and further compound the problem of its slurry feed system with the high coal ash content.

Cope with High Coal Moisture

The scores given are a direct reflection of the coal drying requirement. Coal is dried to 2% and 5% in the Shell and KRW cases, respectively. No coal drying is required in the Texaco and moving bed cases.

Coal Size Requirement

The moving bed case has the lowest score because it can not use coal fines. Other three gasifiers can all accept coal fines.

Need for Special Equipment

In this evaluation, each IGCC case is judged on its requirements for special equipment which can not be manufactured in India and has to be imported such as grinding mill, gasifier refractory, waste heat boiler, ceramic filter, etc.

Auxiliary Power

This is rated according to the in-plant power consumption shown in Table 5-22.

Load Following Capability

The entrained flow reactors used in the Shell and Texaco gasifiers can turn down or up very quickly to respond to load changes. The fluidized bed reactor in the KRW case is slower in responding. The moving bed reactor is further slower.

Heat Rate

This is rated according to the plant efficiency shown in Table 5-21.

Raw Water Requirement

This is rated according to the total raw water requirement shown in Table 5-21.

Quantity of Solid Waste

This is rated according to the amount of solids to be disposed of from each IGCC plant as shown in Table 5-21.

Capital in $/kw

This is rated according to this cost shown in Table 7-2.

Cost of Generation

This is rated according to this cost shown in Table 7-2.

7.4 CONCLUSIONS

From the plant efficiency and economic comparison in Sections 7.1 and 7.2, it can be concluded that an IGCC plant can compete with a PC plant.

The relative ranking among the four IGCC technologies as presented in Section 7.3 indicates that the KRW gasifier or similar fluidized bed gasifiers such as U-Gas is most attractive to use.

The moving bed gasifier, even though is less efficient and more costly than the fluidized bed gasifier, is also attractive because it is a self-developed technology and has been proven for using high ash Indian coal.

The Shell technology has an attractive heat rate and is very close to commercialization. But it has a very high capital requirement. Thus, it probably does not warrant further consideration.

Due to the severe penalties imposed by its slurry feed system on both the heat rate and capital cost, the Texaco technology is not recommended.

As any emerging technology, the use of IGCC plant has, inevitably, technical uncertainties and economic risks. The possible uncertainties and risks have been discussed in detail in Section 5.4.2.

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Section 8

IGCC DEMONSTRATION PLANT

After evaluating the IGCC mode of power generation for a 600 MW commercial plant with various coal gasification technologies and their economic comparability with a pulverized coal based thermal power plant of the same capacity, it was decided to set up an IGCC demonstration unit of about 50-60 MW capacity based on fluidized bed gasification technology. The location of the demonstration plant was to be so chosen that it could offer maximum infrastructure facilities in order to minimize the capital investment for the demonstration plant. The availability of a gas turbine at the location could further reduce the capital expenditure of the demonstration unit.

Keeping these facts in view, several locations such as Dadari, Talcher, Maithon, Badarpur, and Indraprastha were examined. After considering the merits and the demerits of each of the locations, it was decided to establish the IGCC demonstration unit at the Delhi Electric Supply Undertaking's (DESU) power complex at Indraprastha, New Delhi. DESU is having a pulverized coal based thermal power plant of 277.5 MW in total (1 x 30 MW, 3 x 62.5 MW and 1 x 60 MW) at Indraprastha. By the side of the thermal power plant, DESU is also having six gas turbines (GE-MS6001B) of 30 MW capacity each, presently operating on simple cycle. Actions have already been initiated to convert them into combined cycle operation by installing six heat recovery steam generators (HRSG) and three steam turbo-generators of 34.2 MW capacity each. Natural gas is being used as main fuel and naphtha/HSD as a standby fuel. Initially, naphtha/HSD were used as main fuel but were changed over to natural gas after modification in the gas turbines.

The proposed demonstration plant envisages to replace natural gas by coal gas in one of the gas turbines by installing a fluidized bed coal gasification unit of matching capacity. The advantage of locating the demonstration unit at the Indraprastha power complex would be the availability of a gas turbine as well as other facilities, such as coal handling, storage, and primary crushing units, water supply, power supply, and startup steam. There are two study cases related to the use of KRW and U-Gas gasification processes for the demonstration plant respectively. This section presents the plant description and design, cost estimate, and construction schedule.

8.1 PLANT DESCRIPTION

8.1.1 KRW Case

An overall block flow diagram of the IGCC demonstration plant using KRW gasifier is shown in Figure 8-1. The number of operating and spare trains used is also indicated for each of the major process and power blocks in Figure 8-1. The major stream flows (at 29.5 C ambient temperature) are shown in Table 8-1. An overall utility summary based on the same ambient temperature is shown in Table 8-2. Equipment lists are shown in Appendix E.

In the evaluation for 600 MW commercial design presented in Section 5, the KRW case uses six gasifiers. For the demonstration plant, only one gasifier of 61.5% throughput rate is used. As the plant operating conditions are kept the same, all the process flows and utility requirement would be in direct proportion of (10.25%) to the 600 MW design. The gasification plant is sized for a normal and maximum fuel gas flow of 89.9 and 94.5 million Kcal/h (LHV)

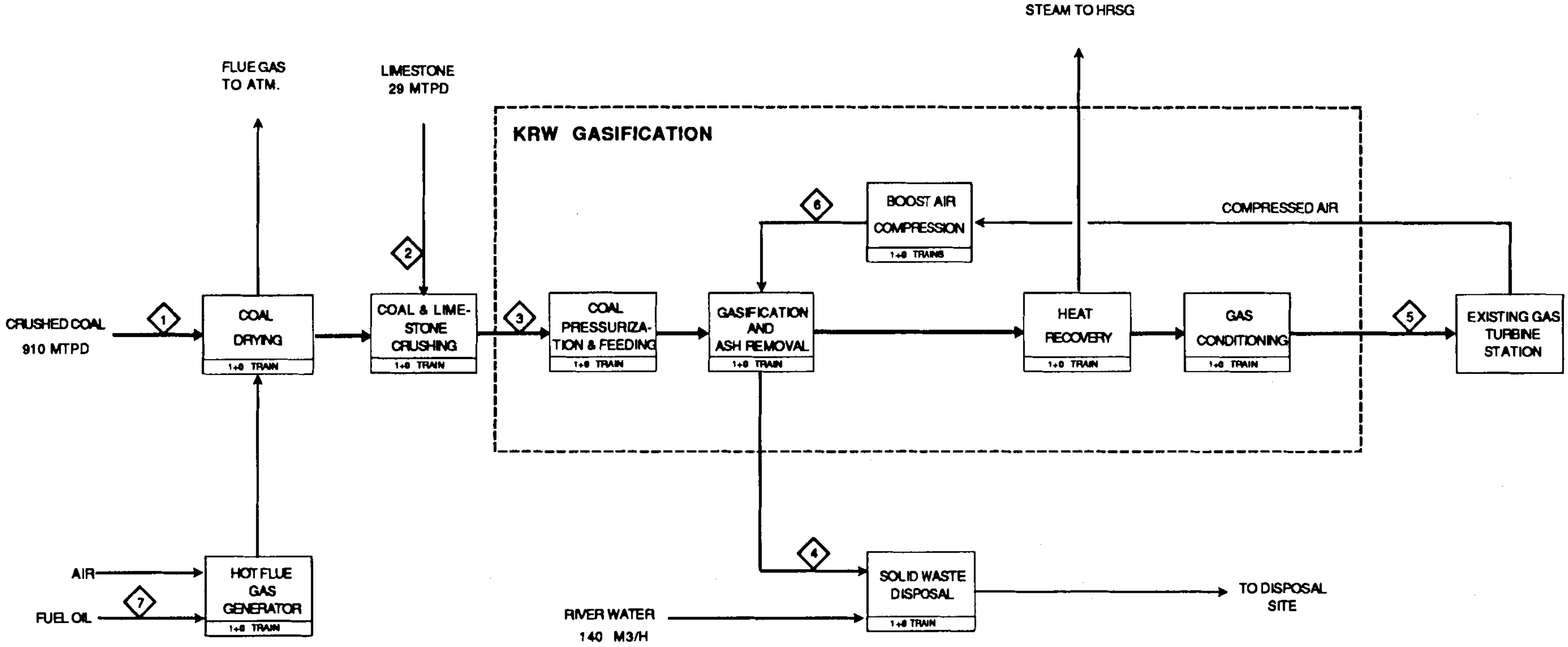

FIGURE 8-1

OVERALL BLOCK FLOW DIAGRAM IGCC DEMONSTRATION PLANT (KRW CASE)

Table 8-1

MAJOR STREAMS FOR IGCC DEMONSTRATION PLANT
(KRW CASE)

Stream Number	1	2	3	4	5	6	7
Stream Description	RAW COAL FEED	LIMESTONE	GASIFIER FEED	GASIFIER ASH	PRODUCT SYN GAS	AIR TO GASIFIER	FUEL OIL
Gases: kg-mol/h							
H2					461.0		
CO					807.0		
CO2					181.7		
CH4					45.7		
C2H4							
N2+AR					1,636.0	1,626.0	
O2						432.0	
H2S+COS					0.7		
NH3					0.8		
H2O					240.2	16.6	
TOTAL: Kg-mol/hr					3,373.1	2,074.6	
Liquids: kg/hr							
H2O	6,825		1,636				
Fuel Oil							530
Solids: kg/hr							
Coal (MAF)	16,375		16,375				
Ash/Slag	14,717		14,717	15,384			
Limestone		1,208	1,208				
Total: kg/hr	37,917	1,208	33,936	15,384	82,701	59,913	530
Temperature, C	29.4	29.4	29.4	315.6	537.8	343.3	
Press, kg/cm2 a	1.03	1.03	1.03	1.03	23.4	36.2	

Table 8-2

UTILITY SUMMARY OF IGCC DEMONSTRATION PLANT
(KRW CASE)

			Steam, kg/hr			Cooling Water	
Sl No.	Plant Name	Power, kw	101 kg/cm2 Sat. (1, 2)	36 kg/cm2 510 C	BFW, m3/h	Duty MMKcal/h	Flow, mKg/h
1	Coal & Limestone Handling	123					
2	Coal Drying	215					
3	Coal Gasification	3,598	(43,199)	4,202	5	2.1	210
4	Water System	64					
	Total	4,000	(43,199)	4,202	5	2.1	210

Note:

(1) Number in ( ) means production
(2) Based on the use of 304.4 C BFW

respectively. The normal flow corresponds to the amount of fuel gas specified by General Electrical (GE) to fully load the gas turbine. The maximum flow provides 5% excess capacity.

A description of the plant facilities included is as follows.

Coal Receiving, Primary Crushing and Storage

The DESU's Indraprastha PC thermal power plant receives coal by railway wagons. It is unloaded by wagon tipplers and sometimes manually also. The storage capacity at the site is about 70,000 to 80,000 tonnes. It has a primary crusher of 750 t/h capacity (at present derated to 450 t/h) which crushes ROM coal (250-300 mm size) to 18-25 mm size. A primary crusher of same capacity (750 t/h) is being installed presently after which the existing one would be used as a standby unit. The existing coal handling, storage and primary crushing facilities would be utilized for the supply of crushed coal to demonstration plant. Therefore, no separate provision for these facilities has been made for the demonstration plant.

Transportation of Crushed Coal to the Battery Limit and to Coal Drying Unit

Transportation of crushed coal from the existing PC plant of DESU to the battery limit of the demonstration plant would be made by railway wagons. The existing railway siding of the PC plant just passes outside of the northern boundary of the proposed demonstration plant site. At present, the siding crosses the ring road just beyond the boundary limit of the demonstration site, causing frequent disruption to road traffic. There is a plan to reroute the existing railway siding in order to avoid the ring road crossing in 2 to 3 years time. In that event, the existing rail yard up to the northern boundary of the demonstration plant (before the ring road crossing) would be utilized for crushed coal transportation from the PC plant to the demonstration site. For this purpose, one locomotive and an adequate number of wagons have been provided. Coal would be loaded by rotary disc loader at the PC plant area.

Coal Drying

The major purpose of this plant is to dry the primary crushed coal from 18% moisture to 5% as required for the KRW gasifier. This drying unit is placed ahead of the secondary coal crushing. Pre-drying of the coal facilitates the secondary crushing and screening. The drying plant is designed to operate all the three shifts.

The primary crushed coal received in railway wagons shall be unloaded manually by the side of track and stack by dozers. Dozers will also feed side by side to an underground reclaiming hopper from where coal will be fed to the drying unit by means of a vibrating feeder and tunnel conveyor.

The dryer is a conventional fluid bed dryer used extensively in the coal industry. Hot flue gas generated from a fuel oil fired furnace supplies the heat necessary to dry the coal as the ash sulfation plant has not been considered presently. The flue gas stream is tempered to a temperature of 504 C using the recycle gas from the dryer exhaust.

The exhaust gas from the bed is passed through two cyclone dust collectors, where most of the coarse dust in the gas is separated out. A part of the dedusted gas is recycled to the dryer. Use of recycled gas rather than air for tempering the hot gas for drying keeps the oxygen content below 8% to prevent

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fires and dust explosions. The net exhaust gas is vented to the atmosphere through bag houses.

Secondary Coal Crushing and Limestone Handling and Crushing

From the drying unit, coal will be fed to the coal crusher by a gravity chute for a secondary crushing to -6 mm. The secondary crusher house shall be provided with two coal crushers (one working plus one standby).

Limestone shall be received in trucks at site and shall be unloaded manually and stacked by a dozer. A pay loader shall feed limestone into an over-ground bunker. A belt feeder installed beneath the bunker will convey limestone to a bucket elevator. The bucket elevator will feed limestone to a hammer mill for primary crushing. The primary crushed limestone shall be fed to a rod mill through a gravity chute for secondary crushing.

Belt conveyor ET4, after taking feed from the secondary coal crusher house and from the limestone crusher house, shall feed to belt conveyor ET5. Bucket elevator ET6 shall take feed from belt conveyor ET5 through a fixed plough. Bucket Elevator ET6 shall feed coal and limestone to overhead belt conveyor ET7. Belt conveyor ET7 shall feed material into a set of over-ground storage bunkers by 5 nos. fixed plough. Storage bunkers in all shall have 1000 tonnes (one day storage) capacity. These storage bunkers shall be provided with vibrating feeders to feed material to belt conveyor ET5. Belt conveyor ET5 shall feed material into a bucket elevator ET8 which, in turn, will feed into the feed bunker of the gasification unit.

KRW Coal Gasification

The description of this is identical to that in Section 5.1.3. The entire facilities consist of one train.

Combined Cycle

For the demonstration plant, one of the six gas turbines at DESU would be suitably modified to use coal gas as fuel. The air required for gasification would be bled from the turbine at an intermediate pressure and after that it would be boosted by a booster compressor up to the gasification pressure.

Gas Turbine

Based on the clean gas composition of KRW process, GE provided the following gas turbine performance (one MS-6001B) at two fuel supply temperatures of 176.7 C (350 F) and 537.8 C (1000 F) and for a normal ambient temperature of 29.5 C. The 176.7 C fuel gas temperature is typical of the temperatures being considered for coal gasification applications with current control valve technology. The 537.8 C fuel gas temperature represents development levels of fuel temperature for control valves at this time.

Ambient temperature, C	29.5	29.5
Fuel temperature, C	176.7 (350 F)	537.8 (1000 F)
Output, kW	34,680	34,270
Heat rate, Kcal/kWh (LHV Basis)	2,887	2,623
Exhaust gas flow, 10^3 kg/hr	475.78	473.47

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Exhaust gas temperature, C	557	555.5
NO_x, ppm vol @ 15% O_2	<42	<42
Gas Turbine Exhaust Gas Analysis (Volume percent):		
Nitrogen	73.41	73.67
Argon	0.88	0.88
Oxygen	11.77	12.63
Carbon dioxide	7.04	6.35
Water	6.90	6.47
Compressed Air Bleed:		
Flow, Kg/h	66,580.5	59,764.2
Pressure, Kg/cm2 a	11.46	11.25
Temperature, C	360.5	360.0
Fuel:		
Flow, Kg/h	90,499	81,238
Pressure, Kg/cm2 a	21.1	21.1
Temperature, C	176.67	537.78
LHV, Kcal/Kg	1,106.4	1,106.4

The KRW gas is low calorific gas, containing a significant amount of nitrogen. Nitrogen acts as a diluent to suppress the flame temperature in the gas turbine combustor. As a result, no NO_x steam injection is required in this case. Air is extracted from the gas turbine compressor to provide gasification air. The flow and condition of this extracted air stream are also summarized above.

Ash Sulfation

At present, the demonstration plant does not include this section. However, this would be added later on and therefore provision in the plant layout has also been made for this section.

Steam Generation and Consumption in the Process Area

High pressure (101 kg/cm2 a) saturated steam is generated in the gasification plant. KRW currently does not have experience related to the superheated steam generation but they do not anticipate any technical difficulty associated with superheated steam production. The 36.2 kg/cm2 a, 510 C superheated steam required for the gasifier is provided by depressurizing the high pressure steam. The balance excess steam is exported to HRSG and steam turbine of the combined cycle for generation of power. The requirement of startup steam would be met from the HRSG section of the gas turbines.

Balance of Plant

Solid Waste Disposal. Solid waste consists of the ash produced from the gasification plant. The ash from the gasification plant is taken to the slurry making tank where a 10% solid containing slurry is made with addition of river water for transportation to the ash disposal area through a pipeline. This arrangement is similar to the existing ash disposal system of the Indraprastha PC power plant. The water for this purpose would be drawn from the nearby Yamina River. Necessary provisions for pumps and pipes have been made for this purpose.

Relief and Blowdown System. The purpose of the relief and blowdown system is:

- o To burn any combustibles that may be vented from the plant during startup, shutdown, or under normal operating conditions
- o To burn combustibles released from the plant during emergencies and plant upset conditions
- o To protect the system equipment against damages from operating disturbances

The relief and blowdown system basically consists of a main flare stack and the associated knockout drum. It has a single train and is designed to handle the maximum raw gas flow rate from the gasification plant.

Interconnecting Piping. The major items in the interconnecting piping system are:

- o Product fuel gas from the gasification plant to the gas turbine
- o Air from the gas turbine to the gasification plant
- o Export steam from the gasification plant to the HRSG/steam turbine of the combined cycle plant
- o Start up steam from the HRSG to the gasification plant
- o Fuel oil/HSD from the gas turbine to the gasification plant

Compressed Air System. This system provides compressed air for plant and instrument air use. The capacity of the compressed air system is 1200 Nm^3/hr. Half of the air is for plant air and the other half is for instrument air. The compressed air system has two operating trains. Each compressed air train supplies 600 Nm^3/hr of compressed air at a pressure of 8 kg/cm^2 a. The system is complete with air dryer and receiver for instrument air.

Water System. The requirement of cooling water circulation for the gasification plant is 210 m^3/hr which will be supplied from the facilities of gas turbine station. The requirements of BFW for steam generation of the gasification plant would be 44.3 m^3/hr. About 39 m^3/hr of condensate would be available after condensing the export steam in steam turbine of combined cycle. Therefore, BFW makeup would be 5 m^3/hr which will be supplied from the facilities of the gas turbine station. The requirement of 3 m^3/hr of portable water will be met from the existing facilities of the gas turbine station.

Auxiliary Power. The requirement of 4 MW of auxiliary power would be met from the existing facilities of the gas turbine station. The necessary voltage step-down facilities have been included in the gasification plant.

Fire Protection. The fire protection system includes the following:

- o Fire protection water yard mains, hydrants, and valves
- o Automatic wet pipe sprinkler system
- o Deluge sprinkler system
- o Water spray system
- o Carbon dioxide system
- o Halon system

- o Stand pipes and hose reels
- o Portable extinguishers
- o Fire and smoke monitors, detectors, and alarms
- o Fire barriers

Fire protection water is provided by two supply water pumps to the fire loop at 18.3 kg/cm^2 a.

Waste Water Treating. No waste water is generated from the gasification plant as the hot gas cleanup system has been adopted.

Buildings. This includes only buildings not specifically related to any process plants. The provision includes the administrative building and warehouse.

8.1.2 U-Gas Case

An overall block flow diagram of the IGCC demonstration plant using U-Gas gasifier is shown in Figure 8-2. The number of operating and spare trains used is indicated for each of the major process blocks in Figure 8-2. The major stream flows at 29.5 C ambient temperature are shown in Table 8-3. An overall utility summary based on the same ambient temperature is shown in Table 8-4.

A description of the facilities in the demonstration plant is as follows:

Coal Receiving, Primary Crushing, and Storage

The description of this plant is identical to that in the KRW case.

Transportation of Crushed Coal to the Battery Limit and to Coal Drying Unit

The description of this plant is identical to that in the KRW case.

Coal Drying

The description of this plant is identical to that in the KRW case, except that coal in this case would be dried to 2.5% moisture instead of 5.0% in the KRW case.

Secondary Coal Crushing and Limestone Handling

The description is identical to that in the KRW case.

U-Gas-Coal Gasification

The U-Gas process in the present application provides for gasification of crushed coal with air and steam in a fluidized bed, with addition of limestone to the fluid bed for bulk desulfurization.

The solids enter the reaction section of the gasifier. Here the fluidized solids react with steam and air at a temperature of 982 C and a pressure of 24.96 kg/cm^2 a to produce a raw low-Btu fuel gas. The limestone captures the bulk of the sulfur in the coal as calcium sulfide.

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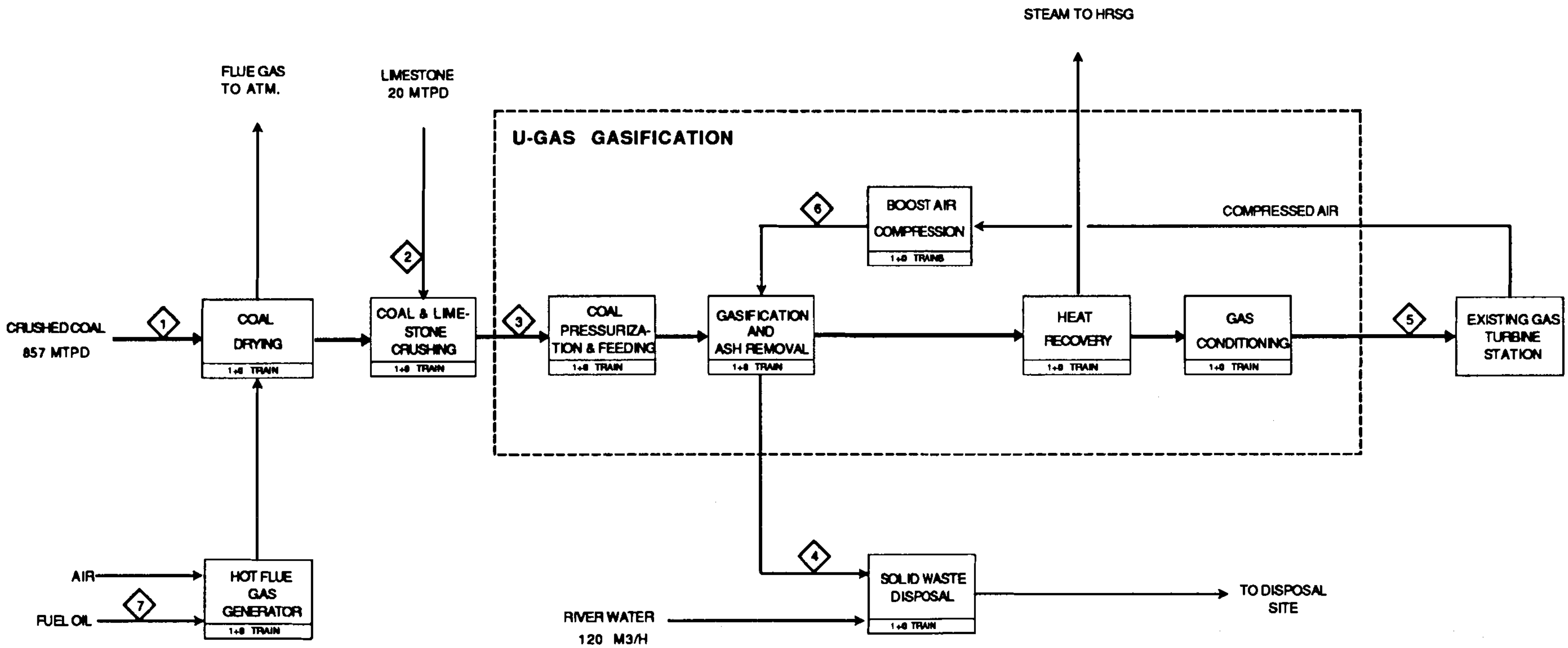

FIGURE 8-2

OVERALL BLOCK FLOW DIAGRAM IGCC DEMONSTRATION PLANT (U-GAS CASE)

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Table 8-3

MAJOR STREAMS FOR IGCC DEMONSTRATION PLANT
(U-Gas CASE)

Stream Number	1	2	3	4	5	6	7
Stream Description	RAW COAL FEED	LIMESTONE	GASIFIER FEED	GASIFIER ASH	PRODUCT SYN GAS	AIR TO GASIFIER	FUEL OIL
Gases: kg-mol/h							
H_2					321.2		
CO					680.8		
CO_2					252.7		
CH_4					129.9		
C_2H_4							
N_2+AR					1,618.6		
O_2							
H_2S+COS					0.8		
NH_3					5.5		
H_2O					205.1		
TOTAL: Kg-mol/hr					3,214.6	2,036.7	
Liquids: kg/hr							
H_2O	6,427		751				
Fuel Oil							560
Solids: kg/hr							
Coal (MAF)	15,421		15,421				
Ash/Slag	13,860		13,860	12,991			
Limestone		833	833				
Total: kg/hr	35,708	833	30,865	12,991		58,817	560
Temperature, C	29.4	29.4	29.4	816.0	537.8	343.3	
Press, kg/cm2 a	1.03	1.03	1.03	24.5	23.4	27.6	

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Table 8-4

UTILITY SUMMARY OF IGCC DEMONSTRATION PLANT
(U-Gas CASE)

Sl No.	Plant Name	Power, kw	Steam, kg/hr: 101 kg/cm2 Sat. (1, 2)	Steam, kg/hr: 31 kg/cm2 311.1 C	BFW, m3/h	Cooling Water: Duty MMKcal/h	Cooling Water: Flow, mKg/h
1	Coal & Limestone Handling	123					
2	Coal Drying	215					
3	Coal Gasification	2,667	(36,834)	5,704	6	2.6	260
4	Water System	64					
	Total	3,069	(36,834)	5,704	6	2.6	260

Note:

(1) Number in ( ) means production
(2) Based on the use of 304.4 C BFW

The gas leaves the gasifier and passes through two stages of cyclone in series to reduce the entrained solids to around 5,000 ppmw. The solids removed in the cyclone gravitate back to the gasification zone in the gasifier vessel.

Gasification steam is admitted to the bottom of the lower gasification zone through an inclined annular grid, while the gasification air enters through a centrally located venturi. As individual particles of coal in the fluid bed become depleted in carbon, the ash contained therein softens and agglomerates. These agglomerates increase in size until they are large enough to fall through the central venturi, counter-current to the incoming gasification air. In this way, the ash is separated in almost carbon-free form from the fluid bed in the U-GAS process.

In this application, however, the residue contains not only the ash agglomerates but also spent limestone carrying the sulfur in the incoming coal in the form of calcium sulfide. For this material to be dumped without restriction, it is necessary to convert the calcium sulfide to the sulfate form. This conversion is carried out in a subsidiary fluid bed beneath the venturi. Agglomerates falling through the venturi are fully oxidized at 816 C (1500 F) by fluidization with gasification air, giving a fully burned-out residue corresponding in composition to a fluid bed boiler ash.

The oxidized residue at 815 C, still under pressure, is cooled to 93 C in the water cooled cooling screw, using deaerated water as the coolant. The solids are then depressurized to atmospheric pressure via a lock hopper, and pneumatically conveyed to the discharge silo.

Heat Recovery

Raw gas from the gasification section is cooled to 538 C by generation of 103 kg/cm^2 a saturated steam in a waste heat boiler. A portion of this steam is used for the process. The balance is available for export to the steam turbine.

The process air is available from turbine compressor at 12.3 kg/cm^2 a and 382 C. This air is cooled and compressed to 28.13 kg/cm^2 a. Air is also employed for coal and limestone transport to the gasifier.

Particulate Removal

The particulates in the raw fuel gas are removed with ceramic filters operating at 538 C and 23.9 kg/cm^2 a. The filters reduce the entrained solids to 1 ppmw to protect the turbine.

The filters are cleaned on-line by back pulsing in sections using the pressurized fuel gas or steam as applicable.

The solids collected from the raw product gas filter are recycled to the gasifier for disposal with the ash.

Balance of Plant

The descriptions of the following plants are identical to that in the KRW case.

- o Gas turbine

- o Steam generation and consumption
- o Solid waste disposal
- o Relief and Blowdown system
- o Interconnecting pipings
- o Compressed air system
- o Water system
- o Auxiliary power
- o Fire Protection
- o Buildings

8.1.3 Site Layouts

A preliminary plot plan of the IGCC demonstration plant is shown in Figure 8-3. The site is in the southern side of the existing gas turbine station of DESU situated at a distance of about 350 m. The site belongs to PWD where a tar-stone chip mixing plant of temporary nature is located. The site will have to be acquired from the Delhi PWD. The area measures to be about 4 acres.

The existing railway siding to the Indraprastha PC plant just passes outside its northern boundary after crossing the inter ring-road. This siding would be re-routed in 2-3 years time after which the existing railway siding would be utilized for transporting the crushed coal from the PC plant.

The coal unloading and storage have been kept near the northern boundary to make use of the railway lines. Coal drying and secondary crushing units have been sited in the southern side of the plot to gain distance for achieving the conveyor height to the gasification plant which has been located in the northern side near the western boundary. Ash slurry pond is located near the eastern side from where the slurry pipe can be routed to the disposal area along the side of existing ash slurry pipes.

8.2 COST ESTIMATE

This subsection presents estimates of the capital requirements and annual operating cost for the demonstration plant. The estimating approach, including the data sources and methodology is also described.

All the estimates are based on the fourth quarter of 1990 as the pricing period.

As both the processes, KRW and U-Gas, have almost similar process features, particularly after the removal of the ash sulfation section from the KRW process for the present time, only one representative capital cost and annual operating cost for both the processes have been worked out.

The estimates for the coal drying and coal gasification units of the KRW case and the coal gasification unit of the U-Gas case were developed by Bechtel under U.S. conditions. KRW sent their estimates of the gasification plant under U.S. conditions. Similarly IGT sent equipment cost of their U-Gas gasification plant under U.S. conditions.

PDIL converted the U.S. cost of gasification and coal drying plants into Indian condition as well as estimated the cost of all other facilities directly under Indian conditions. PDIL also estimated the annual operating cost.

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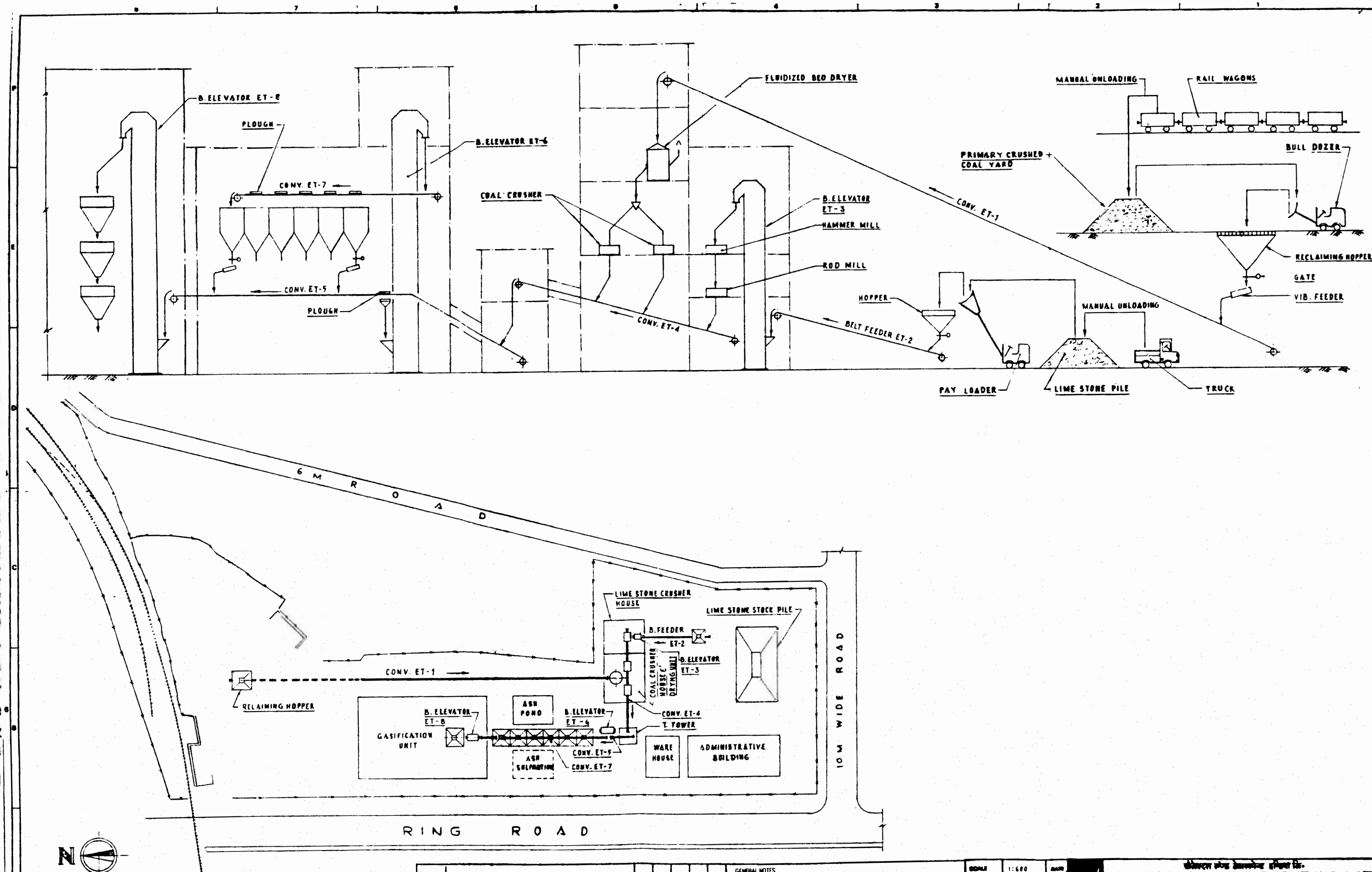

GENERAL NOTES

1. ALL DIMENSIONS ARE IN MM UNLESS OTHERWISE STATED.
2. ALL PROJECTIONS ARE THIRD ANGLE UNLESS OTHERWISE STATED.
3. DO NOT SCALE THE DRAWING.
4. WELDING SYMBOLS ARE TO IS : 813.
5. SURFACE FINISH SYMBOLS ARE TO IS : 696.

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TITLE: I.G.C.C DEMONSTRATION PLANT LAYOUT (FIG: 8-3)

8-15

CLIENT

PROJECT 2494 | DRG. NO. | SHEET ... OF ... | REV.

8.2.1 Estimate Approach to U.S. Costs

The description is identical to that as given in 5.3.1.

8.2.2 Cost Estimate under U.S. Conditions

The cost estimate as given by Bechtel based on inputs from KRW and IGT is presented in Table 8-5.

Other descriptions are identical to 5.3.2.

8.2.3 Capital Cost Estimate Under Indian Conditions

The one representative capital cost for both the processes under Indian conditions is shown in Table 8-6. The base capital cost does not include the provisions for duty and taxes, startup expenses and interest during construction as the demonstration plant has been considered as a research and developmental work. However, these costs are shown separately in Table 8-7. The costs of coal gasification and coal drying units were derived from the U.S. costs of the KRW case as given in Table 8-5. The cost of the remaining plant was directly estimated under Indian conditions.

Exchange Rate

An exchange rate of Rs. 18 per U.S. dollar is assumed.

Direct Field Material

For coal gasification, to convert from direct field material cost in U.S. to India, the bulk material for civil and structural has been taken out first because it could be procured in India.

After this, it has been assumed that 70% of the remaining direct field material will be imported and other 30% will be procured in India. The component of foreign supply has been kept higher in this case as this is the first plant and also a demonstration plant. Therefore the equipment are envisaged of proprietary design nature and to be procured from experienced foreign suppliers. For equipment and material to be procured in India, it is assumed that the India cost will be 25% higher than the U.S. costs (10% for ocean freight and marine insurance and 15% for overall higher cost markup in India).

Direct Field Labour

To adjust the labor cost, the labour productivity in India is assumed to be 40% of that in the United States. The labor rate in India is assumed to be Rs. 27/h.

The descriptions of the following items are identical to those given in Section 5.3.3.

- o Direct field subcontract
- o Indirect cost
- o Engineering services
- o Working capital
- o Spare parts
- o Interest during construction, except that project duration is 3 years.

Table 8-5

GASIFICATION PLANT COST SUMMARY
for IGCC DEMONSTRATION PROJECT
(US $1,000, 4th Q, 1990)

	KRW Case	U-Gas Case
Capital Cost Requirement (US $)		
Coal Drying (1 train)		
Direct Field Material	842	By Indian
Direct Field Labor	308	By Indian
Direct Field Subcontract	0	By Indian
Indirect Cost & Engineering	431	By Indian
Subtotal	1,581	By Indian
Coal Gasification (1 train)		
Direct Field Material	15,693	15,258
Direct Field Labor	8,353	10,482
Direct Field Subcontract	0	0
Indirect Cost & Engineering	10,837	13,068
Subtotal	34,883	38,808
Ash Sulfation (1 train)		
Direct Field Material	4,883	N/A
Direct Field Labor	880	N/A
Direct Field Subcontract	0	N/A
Indirect Cost & Engineering	1,530	N/A
Subtotal	7,293	N/A

Table 8-6

CAPITAL COST REQUIREMENTS
IGCC DEMONSTRATION PLANT
(4th Q - 1990)

S1 No.	Plant Name	Rs. Lakhs Foreign Component	India Component	Total	Total in $ Million
1	Coal Handling System	-	700	700	3.89
2	Coal Drying	-	350	350	1.94
3	Coal Gasification	1,982	2,925	4,907	27.26
4	Water System	-	30	30	0.17
5	Solid Waste Disposal	-	150	150	0.83
6	Relief & Blowdown	8	32	40	0.22
7	Interconnecting Piping	80	320	400	2.22
8	Compressed Air System	-	38	38	0.21
9	Fire Protection	-	30	30	0.17
10	Non-Plant Buildings	-	100	100	0.56
	Total Field Cost	2,070	4,675	6,745	37.47
11	Software Fee				
	Foreign (Basic Engineering)	486	-	486	2.70
	Indian	-	636	636	3.53
	Total Plant Cost	2,556	5,311	7,867	43.71
12	Contingency	127	266	393	2.19
13	Organisation Cost	-	20	20	0.11
14	Spares	104	126	230	1.28
15	Margin on Working Capital	-	32	32	0.18
	Total Capital Requirements	2,787	5,755	8,542	47.46
	Gas Turbine Modifications	360	40	400	2.22
	Total Capital with GT Modifications	3,147	5,795	8,942	49.68

1$ = 18 Rs.

Table 8-7

ESTIMATES FOR OTHER FACILITIES
IGCC DEMONSTRATION PLANT
(4th Q - 1990)

S1 No.	Plant Name	Rs. Lakhs Foreign Component	India Component	Total	Total in $ Million
1	Duties & Taxes				
	a. Sales Tax & Excise Duty	-	428	428	2.38
	b. Customs Duty	-	760	760	4.22
	c. Income Tax/R&D Cess on Foreign Basic Engineering	-	170	170	0.94
2	Startup Expenses	-	156	156	0.87
3	Interest During Construction	-	622	622	3.46
	Total	0	2,136	2,136	11.87

1$ = 18 Rs.

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- o Contingency
- o Duty and taxes

8.2.4 Annual Operating Cost

The annual operating cost is presented in Table 8-8. This cost is based on 6,000 hours per year of plant operation. This operating cost does not include provisions for depreciation, interest on long-term loan, return on equity and interest on working capital (short-term loan) as the demonstration plant has been considered as a research and development work. However, these are shown separately in Table 8-9.

Labor and Overhead

This cost is estimated based on a total additional plant employees of 60 as shown in Table 8-10. The average salary and benefit is assumed to be Rs. 60,000 per year.

Maintenance Materials

Total annual maintenance material is estimated to be 2% of the total plant cost.

Depreciation

This cost is calculated based on 3.6% of the total plant cost, excluding the margin on working capital.

Interest on Long Term Loan

This is assessed at 15% of 50% of the total capital.

Return on Equity

This is 10% of 50% of the total capital

Interest on Working Capital Load

This is assessed at 17% of 75% of the working capital.

Raw Materials and Byproduct Credit

Coal	Rs. 645/tonne
Limestone	Rs. 374/tonne
Fuel oil	Rs. 4000/KL
D. M. water	Rs. 10/m^3
Filtered water	Rs. 5/m^3
Raw water	Rs. 1/m^3
Electricity	Rs. 1000/MWh
High pressure steam	Rs. 250/tonne
Natural gas	Rs. 2456/1000 Nm^3

8.3 CONSTRUCTION SCHEDULE

The time schedule for the construction of the demonstration plant is given in Figure 8-4.

Table 8-8

ANNUAL OPERATING COST
IGCC DEMONSTRATION PLANT
(4th Q-1990 Pricing)

		Annual Consumption @6000 h/y	Unit Rate, Rs/Unit	Rs. Lakhs/yr
Fixed Costs				
Labor and Overheads				36
Maintenance Material				157
Chemicals & Catalysts				5
Total Fixed Costs				198
Variable Costs				
Coal	Tonnes	227,500	645	1,467
Limestone	Tonnes	5,000	374	19
Fuel Oil	KL	3,652	4,000	146
Power	MWh	24,000	1,000	240
Water	-	-	-	5
High Pressure Steam	Tonnes	(234,000)	250	(585)
Total Variable Costs				1,292
Total Annual Operating Costs				1,490
Saving in Natural Gas	1,000 Nm3	63,459	2,456	1,559
Net Saving				68

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Table 8-9

OTHER ANNUAL FIXED COST
IGCC DEMONSTRATION PLANT
(4th Q-1990 Pricing)

S1 No.	Item	Rs. Lakhs/yr
1	Depreciation	398
2	Interest on Long Term Loan	831
3	Interest on Short Term Loan	16
3	Return on Equity	554
	Total	1,799

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Table 8-10

IGCC DEMONSTRATION PLANT STAFFING REQUIREMENT

	Number of People
Operation	
Shift Engineer	4
Coal Handling & Transportation	18
Coal Drying, Secondary Crushing, Limestone Handling	8
Coal Gasification	8
Offsites	8
Total Operation	46
Maintenance	14
Grand Total	60

It has been assumed that services of overheads such as personnel, administration, and accounts would be provided by the existing staff of DESU for the IGCC demonstration plant.

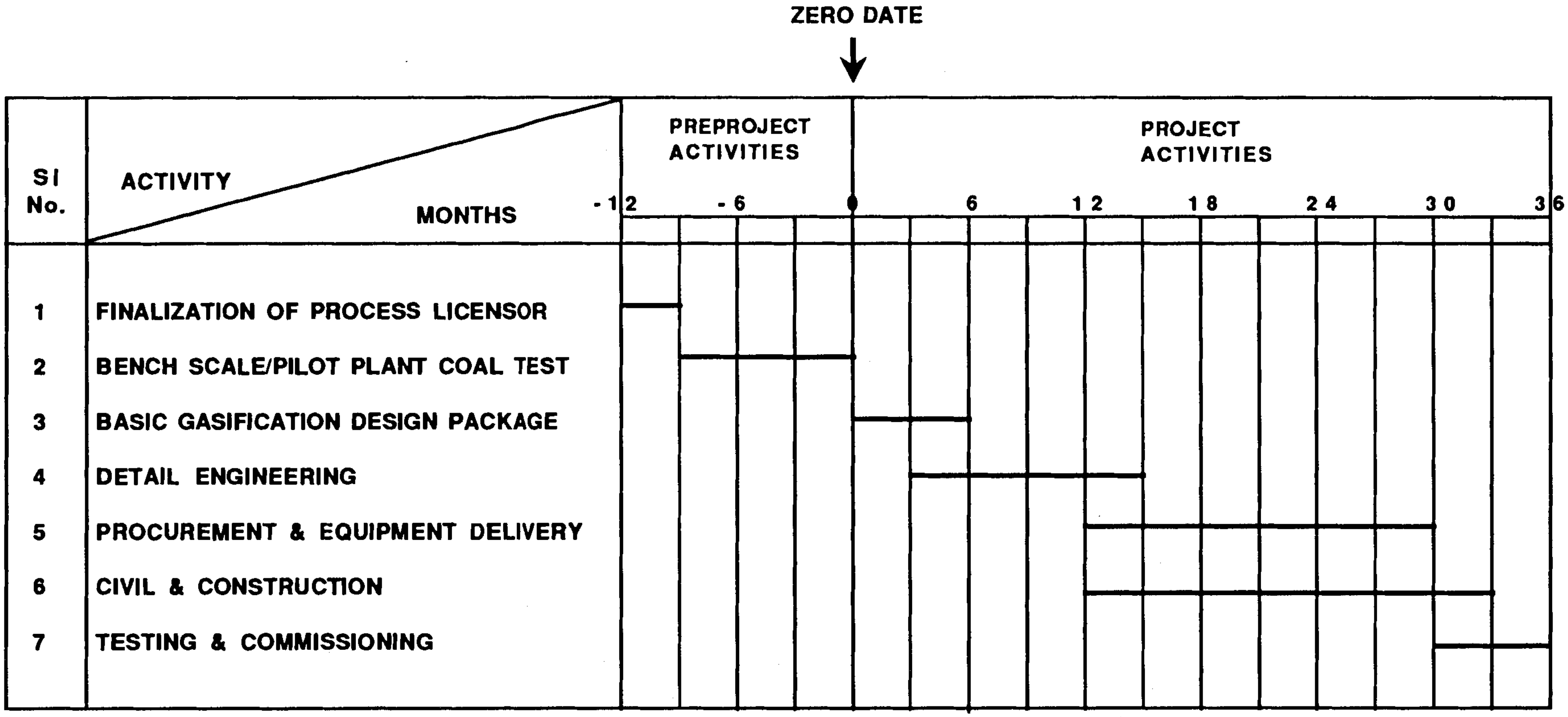

FIGURE 8-4 IMPLEMENTATION PLAN IGCC DEMONSTRATION PLANT

The construction of the plant includes several activities such as finalization of the process licensors, testing of the candidate coal in bench scale/pilot plant levels, preparation of the basic design package of gasification plant based on the test results, preparation of detailed engineering of gasification and other supporting and off-site facilities, and procurement, erection, testing, and commissioning of the plant.

While preparing the time schedule, it has been assumed that activities like finalization of the foreign licensor and testing of coal are pre-project activities before the start of the zero date. The project activities start with the preparation of the basic design package. The total time schedule has been estimated at 36 months from the zero date, out of which 33 months will be for mechanical completion and 3 months for commissioning for the plant.

Before zero-date, the following activities have been assumed to be completed:

- o Finalization of the process license and its approval by the Government
- o Approval of the project capital cost including foreign exchange
- o Bench scale/pilot plant testing of the candidate coal

It has been assumed that the basic design package of gasification plant will be prepared by the process licensor in participation with the Indian team, and detailed engineering, procurement, erection and commissioning will be done by a consortium of Indian organizations. However, the checking/supervision of process licensor has been also envisaged during detailed engineering and erection and commissioning of the plant.

Section 9

IGCC COMMERCIALIZATION STEPS IN INDIA

The first step in the commercialization plan of IGCC technology in India is to build a demonstration plant and fully demonstrate the technology by the year of 1995. The Department of Power of Government of India has a budget provision in the 8th Five Year Plan for the demonstration plant.

The potential users of IGCC technology in India are:

- o National Thermal Power Corporation
- o Various State Electricity Boards
- o Captive power plants
- o Small power generation units in the private sectors

The potential applications of IGCC are as:

- o Retrofit
- o Grass root

A substantial number of coal fired thermal power plants in the range of 20-100 MW capacity installed in the sixties and seventies are operating at efficiencies in the range of 18-26%. This is in comparison to the plants installed in the later part of seventies and eighties operating at efficiencies ranging from 30-37%. Some of these plants have been derated and operated at low plant load factor (PLF). In some plants, the boilers, auxiliaries, and control systems have outlived the safe operating life and became obsolete. However, some of the equipment like steam turbine, electric generator and transformers are in operating condition and could be utilized for many more years efficiently.

Overhauling and revamping of these plants would be necessary to maintain them in running condition but the efficiency may not increase by any appreciable value. The environmental laws are stringent now compared to the situation existing when the plants were installed. Large investments are required for the installation of pollution control equipment, namely flue gas desulfurization (FGD) units to make these plants environmentally compatible, which increase the rehabilitation cost and consequently the cost of power generation. The equipment of these old plants which still have sufficient residual life could be utilized in the following manner.

- o In power plants where the boiler and steam turbine are not in working condition and have outlived their life but electric generators are in good condition and have sufficient residual life, gas turbine can be installed to serve as simple cycle power plant.
- o In power plants where steam turbines and electric generators both are in working condition having efficient residual life, gas turbine and waste heat boiler can be installed to operate the plant on combined cycle mode.

In both cases, the existing facilities like coal handling, ash disposal and water available in the thermal power plant could be utilized and

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integrated with the coal gasification plant which reduces the capital investment.

With the environmental laws becoming more stringent, in the coal fired power plant located in the metropolitan cities, the installation of coal gasifiers together with gas turbines as topping cycle could minimise the pollution and increase the output of the plant.

The natural gas based power plants presently operating in the country have efficiencies ranging from 30-33% for simple cycle mode and 40-45% for combined cycle mode. In India, the resources of natural gas are limited whereas the country has abundant resources of high ash non-coking coals. The natural gas is needed for several products/uses (chemicals, fertilizers and in steel plants) besides power generation. Therefore the short term strategy could be to use natural gas for power generation through combined cycle to meet power demand and accelerate growth. The long term strategy could be to replace natural gas by coal gas from high ash coals.

Based on the performance of the demonstration plant to be set up during the 8th Plan period, commercial scale application of IGCC is proposed as follows:

- Retrofitting of gasifiers in the older power plants of capacities ranging from 20-100 MW during the 9th Plan period
- Replacement of natural gas by coal gas by installation of coal gasifiers in the combined cycle plants during the 9th Plan period
- Installation of new IGCC based power plants having module capacity of 300 MW during the 10th Plan period

REFERENCES

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REFERENCES

(1) Summary Report of the Test Program on the 1 tph Moving Bed Gasifier PDU at Hyderabad, by CSIR

(2) North Karanpura Super Thermal Power Project, Feasibility Report, Stage I (2 x 500 MW), by NTPC, June 1988

(3) North Karanpura Super Thermal Power Project, Addendum to Feasibility Report, Stage I (2 x 500 MW), by NTPC, October 1989

Appendix A

EQUIPMENT LISTS

IGCC PLANT

(SHELL CASE)

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Table A-0

EQUIPMENT LIST
(SHELL CASE)
COAL TRANSPORTATION (MERRY-GO ROUND) SYSTEM

Item No.	Title	Qty.	Description/Unit	Remarks
1	Rail Track		Length - 20 km	
2	Wagons	26	Bottom Discharge	
3	Locomotives	3	WDS - 6	
4	In Motion Weigh Bridge	2	90 tonnes	
5	Signalling & Telecommunication			
6	Coal Bunker for Receiving Raw Coal (0-200 mm) from Merry-Go-Round System	1	100 m3	

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Table A-1

EQUIPMENT LIST
PLANT 1 (SHELL CASE)
COAL RECEIVING, PRIMARY CRUSHING & STORAGE

Item No.	Title	Qty.	Description	Hp Each	Total HP	Remarks
1T-1	Surge Bin	1	Capacity- 120 tons Construction- Steel Plan Size- 5m x 10m Liners: Conical portion CS Outlets: 2	0	0	
1T-2	Surge Bin Feeder	2	Type: Vibrating Capacity- 0 to 500 tph Width- 1200mm	20	40	
1T-3	Scalping Screen	2	Type: Vibrating, Double deck Feed rate- 500 tph Size- 2.1m x 4.9m Top Deck- 75mm Bot Deck- 50mm	40	80	
1T-4	Primary Crusher	2	Type: Symons Std. Cone or equal Size- 2.1m(7 feet) Feed Size- 200mm Product Size: 50 mm, nominal	350	700	
1T-5	Crushed Coal Conveyor	1	Type: Belt Capacity- 1000 tph Width- 1050mm Length- 75m ft. Lift- 18m Speed- 2.75 mps	50	50	
1T-6	Crushed Coal Shuttle Conveyor	1	Type: Reversible Shuttle Belt Capacity- 1000 tph Width - 1050mm Length - 7m Lift- nil Speed- 2.75 mps	15+5	20	
1T-7	Distribution Bin	1	Capacity- 160 tons Construction- CS Plan- 12m x 4m Vetical side- 4m Conical side- 2.5m No of outlets- 3 Clearance from ground- 6m	0	0	
1T-8	Distribution Bin Vib. Feeder	2	Type: Vibrating Capacity- 0 to 1000 tph Width- 1200mm	30	60	

Table A-1

EQUIPMENT LIST
PLANT 1 (SHELL CASE)
COAL RECEIVING, PRIMARY CRUSHING & STORAGE

Item No.	Title	Qty.	Description	Hp Each	Total HP	Remarks
1T-9	Dist. Bin. Weigh Feeder	1	Type: Weigh Belt Capacity- 0 to 500 tph Width- 1200 mm	15	15	
1T-10	Storage Yard Belt Conveyor	1	Type: Reversible Belt Capacity- 1000 tph Width- 1050mm Length- 360m Lift- 8M Speed- 2.75 mps	125	125	
1T-11	Reversible Stacker Reclaimer	1	Stacking- 1000 tph Reclaiming- 0 to 500 tph Boom Length- 35 m Boom Conveyor- Reversible Width- 1050 mm	250	250	
1T-12	Crushed Coal Storage Pile	2	Type - Open Pile Capacity - 57,500 tons live-5.5 Days Pile Length- 320m Pile height- 14.5m		0	
1T-13	Day Store Stacking Conv.	1	Type: Belt Capacity- 1000 tph Width- 1050mm Length- 120m Lift- 23m Speed- 2.75 mps	125	125	
1T-14	Day Storage Pile	1	Diameter- 80m Height- 27.5m Capacity- 10,000 tons- live 35,000 tons- total Accesory- Lowering tube	0	0	
1T-15	Reclaim Hoppers	3	Capacity- 10 tons Construction- CS Location- Below ground-under day storage -in tunnel	0	0	
1T-16	Reclaim Feeders	1+2	Type: Vibrating Capacity- 0 to 500 tph Width- 900mm	20	60	
1T-17	Motorized gate	3	Type- Two way Flow- 500 tph	5	15	

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Table A-1

EQUIPMENT LIST
PLANT 1 (SHELL CASE)
COAL RECEIVING, PRIMARY CRUSHING & STORAGE

Item No.	Title	Qty.	Description	Hp Each	Total HP	Remarks
1T-18	Day stock Reclaim Conveyor	1+1	Type: Belt Capacity- 500 tph Width- 900 mm	50	100	
			Length- 150m Lift- 9M Speed- 2.25 mps	0	0	
1T-19	Transport Conveyor	1+1	Type: Belt Capacity- 500 tph Width- 900 mm Length- 50m Lift- 3m Speed- 2.25 mps	25	50	
1T-20	Dust Collectors	2	Type - Bag House Area - 350 Sq m Fan: Flow - 10 cubic mps	75+3	156	
1T-21	Belt Scale	2	Belt Width- 900 mm Capacity- 500 tph	0	0	

Table A-2

EQUIPMENT LIST
PLANT 2 (SHELL CASE)
COAL AND LIMESTONE HANDLING

Item No.	Title	Qty.	Description	HP Each	Total HP
2T-1	Silo Feed conveyor	1+1	Type: Belt Capacity- 520 tph Width- 900 mm Length- 125m Lift- 25m Speed- 2.25 mps	75	150
2T-2	Tripper Conveyor	1+1	Type: Belt Capacity- 520 tph Width- 900 mm Length- 35m Lift- 4m Speed- 2.25 mps Auxiliary- Motorized tripper	20+5	50
2T-3	Flux Reclaim Hopper	1+1	Capacity- 3 tons Volume- 2 cu m Construction- CS Plan- 1.2m x 1.2 m Side Slope- 50 deg	0	0
2T-4	Reclaim Weigh Feeders	1+1	Type:Weigh Belt Capacity- 30 tph Width- 400 mm Length- 3m Lift- nil	3	6
2T-5	Flux Crusher Feed Conveyor	1+1	Type: Belt Capacity- 30 tph Width- 450 mm Length- 9m Lift- 4m Speed- 2.25 mps	3	6
2T-6	Tramp Iron Magnet	1+1	B elt width- 450 mm	5	10
2T-7	Flux Crusher	1+1	Type: Hammer mill Capacity- 30 tph Feed- 50 mm Product- 25mm	30	60
2T-8	Motorized gate	1+1	Flow- 30 tph	2	4
2T-9	Dust Collector - Crushing	1	Type - Bag House Area - 90 Sq m Flow - 2.5 cubic mps	20+3	23
2T-10	Dust Collector - Bunker top	1	Type - Bag House Area - 180 Sq m Fan: Flow - 5 cubic mps	40+3	43

Table A-3

EQUIPMENT LIST
PLANT 4 (SHELL CASE)
AIR SEPARATION

Four trains, each has a design capacity of 1350 MTPD of contained oxygen at a purity of 98% by volume.

Oxygen delivery pressure is 36.7 kg/cm2 (a) and at 140 C.

Each trains also produces 375 MTPD high purity nitrogen at 63 kg/cm2 (a) pressure and 149 C.

Each trains further produces 240 MTPD high purity nitrogen at 9 kg/cm2 (a) pressure and 149 C.

This plant includes a liquid oxygen storage of 1350 tonnes, a gaseous oxygen storage of 25 tonnes.

This plant includes a liquid nitrogen storage of 615 tonnes, a gaseous nitrogen storage of 12 tonnes.

All the air, oxygen, and nitrogen compressors are electric motor driven.

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Table A-4

EQUIPMENT LIST
PLANTS 5, 6, 7, 8 (SHELL CASE)
COAL GASIFICATION, ACID GAS REMOVAL, SULFUR RECOVERY, SOUR WATER STRIPPING

These four plants are proprietary design of Shell. No equipment list is available. The design is described in Section 5.1.1. The specific design capacities are as following.

Plant No.	Plant Name	No. of Trains	Design Capacity/Train
5	Coal Gasification		
	Coal Milling & Drying	4+2	2615 MTPD coal feed, 163 MTPD limestone feed
	Coal Press. & Feeding	4	2324 MTPD of combined dried coal (2% moist) and limestone
	Gasification & Gas Quench	4	2324 MTPD of combined dried coal (2% moist) and limestone
	High Temp. Gas Cooling	4	64 million Kcal/h duty
	Particulate Removal	4	106 000 Nm3/h gas flow
	Gas Treating & Cooling	2	212 000 Nm3/h gas flow
	Flyslag & Slag Handling	4	1060 MTPD slag & 137 MTPD flyslag
6	Acid Gas Removal	2	212 000 Nm3/h gas flow
7	Sulfur Recovery	2	15.2 MTPD sulfur production
8	Sour Water Stripping	1	41 m3/h sour water feed

Table A-5

EQUIPMENT LIST
PLANT 9 (SHELL CASE)
COMBINED CYCLE

Item No.	Title	Qty.	Description/Unit	Remarks
9C-1	Blowdown Flash Drum	2	Vertical vessel, C.S. Design pressure: 4.2 Kg/cm2 (g) Design temperature: 190 C Diameter:91 cm T-T:260 cm	
9C-2	Condensate Storage Tank	1	Vertical vessel, C.S. with epoxy lining Design pressure: 3.5 Kg/cm2 (g) Design temperature: 51 C Diameter:8.3 m T-T:12 m	
9E-1	Heat Recovery Steam Generator	2	Duel pressure system, include the steam drums and deaerator, and a stack Heat transfer area (extended surface) is: HP superheater:11000 m2 Reheater:12900 m2 HP evaporator:37300 m2 IP superheater:2200 m2 HP economizer I:26300 m2 IP evaporator:24500 m2 HP economizer II:50300 m2 IP economizer:6500 m2 Integral deaerator:14600 m2 Steam condition is: HP:103 kg/cm2 abs, 538 C IP & RH:25 kg/cm2 abs, 538 C Stack: 32m high, 7.5m diameter	
9E-2	Surface Condenser	2	Shell & tube, single shell, 2 passes Shell: C.S., tube: S.S. Include vacuum pump package Duty :230 million Kcal/h Surface area:12000 m2	
9F-1	Startup Boiler	1	Rated at 11000 kg/h, 18.6 kg/cm2 abs saturated steam	
9G-1	Condensate Pump	2+2	Horizontal centrifugal Casing: cast iron, impeller: bronze Flow:526 m3/h Temp:49C Diff. pressure:2.11 kg/cm2 Power:66 BHP	

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Table A-5

EQUIPMENT LIST
PLANT 9 (SHELL CASE)
COMBINED CYCLE

Item No.	Title	Qty.	Description/Unit	Remarks
9G-2	LP Boiler Feedwater Pump	2+2	Horizontal centrifugal, 11-13% Cr Flow:65 m3/h Temp:109C Diff. pressure:26.8 kg/cm2 Power:80 BHP	
9G-3	HP Boiler Feedwater Pump	2+2	Horizontal centrifugal, 11-13% Cr Flow:514 m3/h Temp:109C Diff. pressure:119 kg/cm2 Power:2680 BHP	
9G-4	Condensate Transfer Pump	2+1	Horizontal centrifugal, 316 S.S. Flow:514 m3/h Temp:49C Diff. pressure:2 kg/cm2 Power: 66 BHP	
9K-1	Gas Turbine-Generator	2	General Electric MS9001F gas turbine, single shaft, with inlet filter and other auxiliary systems, rated 212 MW at ISO Generator: hydrogen cooled, 50 Hz, 3000 rpm, 16500 volts, 240 MVA	
9K-2	Steam Turbine-Generator	2	Triple extraction, double flow condensing 76 cm last stage bucket, steam flow: HP SH: 458000 kg/h RH: 461000 kg/h 17.6 kg/cm2 (a) extrac steam: 17000 kg/h 9 kg/cm2 (a) extrac steam: 23000 kg/h Generator: hydrogen cooled, 50 Hz, 3000 rpm, 16500 volts, 180 MVA	
9R-1	Gas Turbine Building	2	34m x 40m floor area, 16m high structure, lower part reinforced concret. upper part structure steel	
9R-2	Steam Turbine Building	1	34m x 45m floor area, 16m high structure, lower part reinforced concret. upper part structure steel	

Table A-6

EQUIPMENT LIST
PLANT 30 (SHELL CASE)
SOLID WASTE DISPOSAL

Item No.	Title	Qty.	Description/Unit	Remarks

Designed for 4559 MTPD slag flow.

Table A-7

EQUIPMENT LIST
PLANT 31 (SHELL CASE)
RELIEF & BLOWDOWN

Item No.	Title	Qty.	Description/Unit	Remarks
31D-1	Knock Out Drum	1	Horizontal Vessel, C.S. Design Temp: 66C Design Pressure: 1 kg/cm2 (g) Diameter: 3 m T-T: 11m	
31F-1	Main Flare	1	Design gas flow: 335 000 kg/h Design heat duty: 1000 million Kcal/h C.S. Diameter: 110 cm Height: 32 m	
31G-101	K.O. Drum Pump	1+1	Centrifugal, C.S. Liquid head: 20 m Flow: 34 m3/h BHP: 5 HP	

Table A-8

EQUIPMENT LIST
PLANT 32 (SHELL CASE)
INTERCONNECTING PIPING

Major items of this plant are:

Fuel oil lines
Pipe and pipeways for raw water supply and BFW makeup water supply
Pipe and pipeways for treated waste water and steam blowdown
Instrument and service air lines
Oxygen and nitrogen supply from the air separation plant to the gasification plant
Steam lines to the liquid oxygen and liquid nitrogen vaporizers
Pipe and pipeways between process areas
Distribution of cooling water and service water from the cooling tower
Coal gas, steam, feedwater, and condensate lines between the process and power areas
Miscellaneous process and utility piping

Table A-9

EQUIPMENT LIST
PLANT 33 (SHELL CASE)
COMPRESSED AIR SYSTEM

Item No.	Title	Qty.	Description/Unit	Remarks
33C-1	Compressed Air Receiver	4	Vertical vessel, C.S. Design pressure: 10 kg/cm2 (g) Design pressure: 65 C Diameter: 1.37 m T-T: 3.81m	
33K-1	Air Compressor	4	Design gas flow: 2 000 Nm3/h Pressure head: 6.9 kg/cm2 Cast iron casing, C.S. Impeller Centrifugal, motor drive 300 BHP	
33T-1	Desiccant Air Dryer	4	Twin tower, cycling type Design gas flow: 1000 Nm3/h Design pressure: 10 kg/cm2 (g) Design temperature: 65 C	

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Table A-10

EQUIPMENT LIST
PLANT 34 (SHELL CASE)
FUEL OIL AND LPG SYSTEM

Item No.	Title	Qty.	Description/Unit	Remarks
34C-1	Fuel Oil Tank	1	Vertical vessel, C.S. 15 000 barrels storage Diameter: 16 m Height: 12 m	
34C-2	LPG Storage Tank	1	Horizontal high pressure storage bullet Storage capacity: 240 barrels	
34G-1	Fuel Oil Pump	2+1	Centrifugal, C.S. Flow: 230 gpm or 52 m3/h Pressure head: 40 m liquid 15 BHP	

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Table A-11

EQUIPMENT LIST
PLANT 35 (SHELL CASE)
ELECTRICAL SYSTEMS

Item No.	Title	Qty.	Description/Unit	Remarks
35P-1	H.V. Circuit Breaker	21	235KV, 2000A, 63KA RMS system	
35P-2	H.V. Disconnect Switches	42	3-pole 235 KV, "v" type center break	
35P-3	H.V. Disconnect Switches with Earthing Blade	6	3-pole 235 KV, 2000A, vertical break with grounding blade	
35P-4	H.V. Lighting Arresters	11	184 KV	
35P-5	Step-up Transformer for Gas Turbines	2	180/240/300 MVA, OA/FA/FOA, 16.5-220 KV, Delta-Wye	
35P-6	Step-up Transformer for Steam Turbines	2	120/160/200 MVA, OA/FA/FOA, 16.5-220 KV, Delta-Wye	
35P-7	Step-down Transformer for Air Separation and Cooling Tower	4	50/67 MVA, OA/FA, 220-16.5 KV, Wye-Wye, core form type	
35P-8	Step-down Transformer for Startup	1	12 MVA, FOA, 220-6.6 KV, Wye-Wye, core form type	
35P-9	Step-down Transformer for Combined Cycle Auxiliary Power	2	4.2/5.25 MVA, OA/FA, 16.5-6.6 KV, Delta-Wye	
35P-10	Step-down Transformer for Process Plant Auxiliary Power	6	5/6.25 MVA, OA/FA, 16.5-6.6 KV, Delta-Wye	
35P-11	Step-down Transformer for Combined Cycle Auxiliary Power (L.V.)	4	2/2.3 MVA, OA/FA, 6.6 KV- 480 V, Delta-Wye	
35P-12	Step-down Transformer for Process Plant Auxiliary Power (L.V.)	6	1.5 MVA, OA 16.5 KV- 480 V, Delta-Wye	
35P-13	M.V. Switchgear	2	16.5 KV, 750MVA S.C., 3000A	
35P-14	M.V. Motor Control Center	8	6.6 KV, 250MVA S.C., 2000A	
35P-15	L.V. Load Center Buses	4	400 V, 42 KA S.C., 3000A	
35P-16	L.V. Motor Control Center	lot	400 V, 800A	

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Table A-12

EQUIPMENT LIST
PLANT 37 (SHELL CASE)
COOLING WATER SYSTEM

Item No.	Title	Qty.	Description/Unit	Remarks
37E-1	Cooling Tower	1	29 cells, 2500 m3/h water circulation per cell, 5 cycles of concentration	
37E-2	Auxiliary Cooling Water Heat Exchanger	4	Shell and tube, C.S., 50 m2 bare tube surface area	
37G-1	Circulating Water Pump	4+2	Centrifugal, case iron Design flow: 14300 m3/h Liquid head: 11m 720 BHP	
37G-2	Service Water Pump	2	Centrifugal, case iron Design flow: 8200 m3/h Liquid head: 37m 1400 BHP	
37G-3	Auxiliary Cooling Water Pump	2+1	Centrifugal, case iron Design flow: 200 m3/h Liquid head: 68m 65 BHP	
37D-1	Demineralized Water Head Tank	1	Vertical vessel, C.S. with epoxy lining Design pressure: 3.5 kg/cm2 (a) Design Temperature: 65 C Diameter: 1.2 m T-T: 2.6 m	
37V-1	Biocide Additive Package	1	Include one tank with 2x100% metering pumps, sizing based on 1200 m3/h CT makeup water rate	
37V-2	Scale Inhibitor Additive Package	1	Include one tank with 2x100% metering pumps, sizing based on 1200 m3/h CT makeup water rate	
37V-3	Corrosion Inhibitor Additive Package	1	Include one tank with 2x100% metering pumps, sizing based on 1200 m3/h CT makeup water rate	
37V-4	Chlorination Package	1	Sizing based on 1200 m3/h CT makeup water rate	

Table A-13

EQUIPMENT LIST
PLANT 38 (SHELL CASE)
RAW WATER SUPPLY AND TREATMENT

Item No.	Title	Qty.	Description/Unit	Remarks
38G-1	Clarifier Feed Pump	2+1	Centrifugal, Cast Iron Design Flow: 700 m3/h Liquid Head: 21 m 70 BHP	
38G-2	Alum Metering Pump	1+1	metering, Alloy 20 Design Flow: 0.1 m3/h Liquid Head: 70 m 0.5 BHP	
38G-3	Soda Ash Metering Pump	1+1	metering, vendor spec material Design Flow: 0.1 m3/h Liquid Head: 70 m 0.5 BHP	
38G-4	Potassium Permanganate Meteing Pump	1+1	metering, vendor spec material Design Flow: 0.1 m3/h Liquid Head: 70 m 0.5 BHP	
38G-5	Filtered Water Pump	2+1	Centrifugal, Cast Iron Design Flow: 90 m3/h Liquid Head: 15 m 7 BHP	
38G-6	Demineralizer Feed Pump	4+1	Centrifugal, Cast Iron Design Flow: 40 m3/h Liquid Head: 21 m 5 BHP	
38G-7	Sulfuric Acid Metering Pump	1+1	metering, C.S. Teflon lining Design Flow: 0.7 m3/h Liquid Head: 70 m 0.5 BHP	
38G-8	Water Pump for Acid Dilution	1+1	Centrifugal, Cast Iron Design Flow: 32 m3/h Liquid Head: 15 m 3 BHP	
38G-9	Sodium Hydroxide Transfer Pump	1+1	Centrifugal, C.S. Design Flow: 4.5 m3/h Liquid Head: 15 m 2 BHP	
38G-10	Sodium Hydroxide Feed Pump	1+1	Centrifugal, C.S. Design Flow: 17 m3/h Liquid Head: 15 m 2 BHP	

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Table A-13

EQUIPMENT LIST
PLANT 38 (SHELL CASE)
RAW WATER SUPPLY AND TREATMENT

Item No.	Title	Qty.	Description/Unit	Remarks
38G-11	Demineralizer Rinse Pump	1+1	Centrifugal, Cast Iron Design Flow: 23 m3/h Liquid Head: 15 m 3 BHP	
38G-12	Boiler Feed Water Makeup Pump	4+1	Centrifugal, Cast Iron Design Flow: 34 m3/h Liquid Head: 21 m 4 BHP	
38G-13	Filter Feed Water Pump	2+1	Centrifugal, Cast Iron Design Flow: 90 m3/h Liquid Head: 15 m 7 BHP	
38G-14	Cooling Tower Makeup Water Pump	2+1	Centrifugal, Cast Iron Design Flow: 600 m3/h Liquid Head: 70 m 195 BHP	
38G-15	Sodium Hypochlorite Metering Pump	1	Centrifugal, High Si Design Flow: 0.02 m3/h Liquid Head: 70 m 0.25 BHP	
38G-16	Raw Water Intake Pump	2+1	Centrifugal, Cast Iron Design Flow: 700 m3/h Liquid Head: 35 m 110 BHP	
38D-1	Alum Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-2	Soda Ash Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-3	Potassium Permanganate Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-1	Alum Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-2	Soda Ash Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	

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Table A-13

EQUIPMENT LIST
PLANT 38 (SHELL CASE)
RAW WATER SUPPLY AND TREATMENT

Item No.	Title	Qty.	Description/Unit	Remarks
38D-3	Potassium Permanganate Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-4	Sodium Hypochlorite Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-5	Filtered Water Tank	2	Vertical vessel, C.S., epoxy lining Diameter: 4.27 m Height: 4.27 m	
38D-6	Sulfuric Acid Storage Tank	1	Vertical vessel, C.S. Diameter: 4.27 m Height: 6.7 m	
38D-7	Sodium Hydroxide Storage Tank	1	Vertical, C.S., Neoprene-Latex coated Diameter: 5.49 m Height: 7.92 m	
38D-8	Sodium Hydroxide Feed Tank	1	Vertical, C.S., Neoprene-Latex coated Diameter: 1.52 m Height: 1.52 m	
38D-9	Boiler Feed Water Storage Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 8 m Height: 8 m	
38D-10	Filter Feed Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 4.87 m Height: 4.27 m	
38R-1	Water Treatment Building	1	Preengineered metal building, 18m x 55m with 7.3 m eave height	
38Z-1	Raw Water Clarifier	2	Vertical vessel, C.S., epoxy lining Diameter: 14.63 m Height: 6.71 m	
38Z-2	Gravity Filter	2+1	Vertical vessel, C.S., epoxy lining Diameter: 6.1 m Height: 4.57 m	
38Z-3	Demineralizer Package	2	Include cation, anion, and mixed bed exchangers, Capacity: 70 m3/h demineralized water	

Table A-14

EQUIPMENT LIST
PLANT 39 (SHELL CASE)
FIRE PROTECTION

Item No.	Title	Qty.	Description/Unit	Remarks
39D-1	LP Carbon Dioxide Storage Tank	1	8 tonnes	
39G-1	Fire Water Pump	2	Centrifugal, driven by diesel engine Design flow: 450 m3/h Liquid head: 180 m 400 BHP	
39 Y-1	Halon System	2	Installed in control rooms	
39Y-2	Carbon Dioxide System	2	Installed in turbine building	
39Y-3	Hose Cart	4	.2 m steel wheels, each with 80 m long 6.35 cm diameter hose	
39Y-4	Hose Reel	20	30 m long, 3.81 cm diameter	
39Y-5	Fire and Smoke Detector	16		
39Y-6	Fire Hydrants	60	Dry barrel type, 15 cm inlet with pump connection	
39Y-7	Deluge & Sprinkler System		Located over rotating components that handle flammable fluid plus transformers	
39Y-8	Portable Extinguisher	60		
39Y-9	Yard Fire Water Piping	1	8000 m	
39Y-10	Building Fire Water Piping	1	8000 m	

Table A-15

EQUIPMENT LIST
PLANT 40 (SHELL CASE)
WASTE WATER TREATING

Item No.	Title	Qty.	Description/Unit	Remarks
40G-1	Clarifier Sludge Pump	1+1	Centrifugal, Cast Iron with rubber lining, Design Flow: 2.3 m3/h Liquid Head: 15 m 0.5 BHP	
40G-2	Backwash Water Pump	1+1	Centrifugal, Cast Iron Design Flow: 13.8 m3/h Liquid Head: 15 m 2 BHP	
40G-3	Backwash Settled Water Pump	1+1	Centrifugal, Cast Iron Design Flow: 13.8 m3/h Liquid Head: 15 m 2 BHP	
40G-4	Thickener Underflow Pump	1+1	Mayno, 304 S.S. Design Flow: 1 m3/h Liquid Head: 21 m 0.5 BHP	
40G-5	Regenerant Discharge Pump	2+1	Centrifugal, Alloy 20 Design Flow: 34 m3/h Liquid Head: 30 m 6 BHP	
40G-6	Slop Oil Pump	1	Recip, Cast Iron Design Flow: 1.1 m3/h Liquid Head: 21 m 1 BHP	
40G-7	Storm Runoff Water Pump	1	Centrifugal, Cast Iron Design Flow: 300 m3/h Liquid Head: 23 m 35 BHP	
40G-8	Oily Water Pump	1	Centrifugal, Cast Iron Design Flow: 2.3 m3/h Liquid Head: 15 m 2 BHP	
40G-9	Thickener Overflow Pump	1+1	Centrifugal, Cast Iron Design Flow: 4 m3/h Liquid Head: 15 m 2 BHP	
40D-1	Neutralization Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 4.87 m Height: 5.49m	

Table A-15

EQUIPMENT LIST
PLANT 40 (SHELL CASE)
WASTE WATER TREATING

Item No.	Title	Qty.	Description/Unit	Remarks
40D-2	Spent Backwash Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 5.12 m Height: 5.12 m	
40D-3	Oily Water Sump	1	Rectangular vessel, concrete, 1.21 m x 1.21 m x 1.82 m	
40D-4	Thickener Overflow Sump	1	Rectangular vessel, concrete, 1.82 m x 1.82 m x 2.44 m	
40Y-1	Process Waste Water Treating Package	1	Proprietary design of Shell, include clarification, biotreament, and dewatering of sludge; 41 m3/h feed water	
40Z-1	Sludge Thickener	1	Vertical vessel, C.S., epoxy lining Diameter: 5.8 m Height: 6.7 m	
40Z-2	Filter Press	5	304 S.S., 120 m2 filter area	
40Z-3	Sanitary Waste Treatment Package	1	8 m3/h capacity	

Table A-16

EQUIPMENT LIST
PLANT 43 (SHELL CASE)
BUILDINGS

Item No.	Title	Qty.	Description/Unit	Remarks
43R-1	Control Building	1	Three story, steel frame, 23m x 38m	
43R-2	Administration Building Including Laboratory & Medical Facility	1	Two story, concrete, 30m x 44m	
43R-3	Warehouse	1	Pre-engineered metal building, 45m x 60m with 6.7m eave height and cast in place reinforced slab	
43R-4	Machine Shop and Maint. Building	1	Pre-engineered metal building, 12m x 30m with 6.7m eave height and cast in place reinforced slab	

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Table A-17

EQUIPMENT LIST
PLANT 36, 41, 42 (SHELL CASE)
INSTRUMENT AND CONTROL, GENERAL SERVICES AND MOBILE EQUIPMENT, SITE PREPARATION

These three plants have been defined and described in Section 5.1.1.

No equipment lists were developed for these plants.

Appendix B

EQUIPMENT LISTS

IGCC PLANT

(TEXACO CASE)

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Table B-0

EQUIPMENT LIST
(TEXACO CASE)
COAL TRANSPORTATION (MERRY-GO ROUND) SYSTEM

Item No.	Title	Qty.	Description/Unit	Remarks
1	Rail Track		Length - 20 km	
2	Wagons	26	Bottom Discharge	
3	Locomotives	3	WDS - 6	
4	In Motion Weigh Bridge	2	90 tonnes	
5	Signalling & Telecommunication			
6	Coal Bunker for Receiving Raw Coal (0-200 mm) from Merry-Go-Round System	1	100 m3	

Note: The facilities described above are identical to those of the Shell case.

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Table B-1

EQUIPMENT LIST
PLANT 1 (TEXACO CASE)
COAL RECEIVING, PRIMARY CRUSHING & STORAGE

Item No.	Title	Qty.	Description	Hp Each	Total HP	Remarks
1T-1	Surge Bin	1	Capacity- 120 tons Construction- Steel Plan Size- 5m x 10m Liners: Conical portion CS Outlets: 2	0	0	
1T-2	Surge Bin Feeder	2	Type: Vibrating Capacity- 0 to 500 tph Width- 1200mm	20	40	
1T-3	Scalping Screen	2	Type: Vibrating, Double deck Feed rate- 500 tph Size- 2.1m x 4.9m Top Deck- 75mm Bot Deck- 50mm	40	80	
1T-4	Primary Crusher	2	Type: Symons Std. Cone or equal Size- 2.1m(7 feet) Feed Size- 200mm Product Size: 50 mm, nominal	350	700	
1T-5	Crushed Coal Conveyor	1	Type: Belt Capacity- 1000 tph Width- 1050mm Length- 75m ft. Lift- 18m Speed- 2.75 mps	50	50	
1T-6	Crushed Coal Shuttle Conveyor	1	Type: Reversible Shuttle Belt Capacity- 1000 tph .Width - 1050mm Length - 7m Lift- nil Speed- 2.75 mps	15+5	20	
1T-7	Distribution Bin	1	Capacity- 160 tons Construction- CS Plan- 12m x 4m Vetical side- 4m Conical side- 2.5m No of outlets- 3 Clearance from ground- 6m	0	0	
1T-8	Distribution Bin Vib. Feeder	2	Type: Vibrating Capacity- 0 to 1000 tph Width- 1200mm	30	60	

Table B-1

EQUIPMENT LIST
PLANT 1 (TEXACO CASE)
COAL RECEIVING, PRIMARY CRUSHING & STORAGE

Item No.	Title	Qty.	Description	Hp Each	Total HP	Remarks
1T-9	Dist. Bin. Weigh Feeder	1	Type: Weigh Belt Capacity- 0 to 600 tph Width- 1200 mm	15	15	
1T-10	Storage Yard Belt Conveyor	1	Type: Reversible Belt Capacity- 1000 tph Width- 1050mm Length- 360m Lift- 8M Speed- 2.75 mps	125	125	
1T-11	Reversible Stacker Reclaimer	1	Stacking- 1000 tph Reclaiming- 0 to 600 tph Boom Length- 35 m Boom Conveyor- Reversible Width- 1050 mm	250	250	
1T-12	Crushed Coal Storage Pile	2	Type - Open Pile Capacity - 57,500 tons live-5.5 Days Pile Length- 320m Pile height- 14.5m		0	
1T-13	Day Store Stacking Conv.	1	Type: Belt Capacity- 1000 tph Width- 1050mm Length- 120m Lift- 23m Speed- 2.75 mps	125	125	
1T-14	Day Storage Pile	1	Diameter- 80m Height- 27.5m Capacity- 10,000 tons- live 35,000 tons- total Accesory- Lowering tube	0	0	
1T-15	Reclaim Hoppers	3	Capacity- 10 tons Construction- CS Location- Below ground-under day storage -in tunnel	0	0	
1T-16	Reclaim Feeders	1+2	Type: Vibrating Capacity- 0 to 600 tph Width- 900mm	20	60	
1T-17	Motorized gate	3	Type- Two way Flow- 600 tph	5	15	

Table B-1

EQUIPMENT LIST
PLANT 1 (TEXACO CASE)
COAL RECEIVING, PRIMARY CRUSHING & STORAGE

Item No.	Title	Qty.	Description	Hp Each	Total HP	Remarks
1T-18	Day stock Reclaim Conveyor	1+1	Type: Belt Capacity- 600 tph Width- 900 mm Length- 150m Lift- 9M Speed- 2.75 mps	50 0	100 0	
1T-19	Transport Conveyor	1+1	Type: Belt Capacity- 600 tph Width- 900 mm Length- 50m Lift- 3m Speed- 2.75 mps	25	50	
1T-20	Dust Collectors	2	Type - Bag House Area - 350 Sq m Fan: Flow - 10 cubic mps	75+3	156	
1T-21	Belt Scale	2	Belt Width- 900 mm Capacity- 600 tph	0	0	

Table B-2

EQUIPMENT LIST
PLANT 2 (TEXACO CASE)
SECONDARY COAL CRUSHING AND HANDLING

Item No.	Title	Qty.	Description	Hp Each	Total HP
2T-1	Crushing Plant Feed Conv.	1+1	Type: Belt Capacity- 600 tph Width- 900 mm Length- 50m Lift- 18m Speed- 2.75 mps	60	120
2T-2	Surge Bin	1	Capacity- 60 tons Construction- CS Plan- 3m x 6m Outlets-2	0	0
2T-3	Vibrating Feeder	2	Type:Vibrating Capacity- 300 tph	15	30
2T-4	Secondary Screens	2	Type: Vibrating, Double deck Feed rate- 300 tph Size- 2.4m x 6m Top Deck- 40mm Bot Deck- 13mm	40	80
2T-5	Secondary Crusher	2	Type: Symons Std. Cone or equal Size- 2.1m(7 feet) Feed Size- 50mm Product Size:13 mm, nominal	350	700
2T-6	Crusher Discharge Conveyor	2	Type: Belt Capacity- 200 tph Width- 900 mm Length- 12m Lift- 3m Speed- 2 mps	10	20
2T-7	Day Bin Feed conveyor	1+1	Type: Belt Capacity- 600 tph Width- 900 mm Length- 135m Lift- 25m Speed- 2.75 mps	100	200
2T-8	Tripper Conveyor	1+1	Type: Belt Capacity- 600 tph Width- 900 mm Length- 35m Lift- 4m Speed- 2.75 mps Auxiliary- Motorized tripper	25+5	60
2T-9	Motorized gate	2	Flow- 300 tph	2	4

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Table B-2

EQUIPMENT LIST
PLANT 2 (TEXACO CASE)
SECONDARY COAL CRUSHING AND HANDLING

Item No.	Title	Qty.	Description	Hp Each	Total HP
2T-10	Dust Collector - Crushing	2	Type - Bag House Area - 180 Sq m Fan: Flow - 5 cubic mps	40+3	86
2T-11	Dust Collector - Bunker top	1	Type - Bag House Area - 180 Sq m Fan: Flow - 5 cubic mps	40+3	43
2T-12	Tramp Iron Magnet	1+1	B elt width- 900 mm	5	10

Table B-3

EQUIPMENT LIST
PLANT 4 (TEXACO CASE)
AIR SEPARATION

Four trains, each has a design capacity of 1950 MTPD of contained oxygen at a purity of 98% by volume.

Oxygen delivery pressure is 42 kg/cm2 (a) and at 140 C.

This plant includes a liquid oxygen storage of 1950 tonnes, a gaseous oxygen storage of 35 tonnes.

All the air, oxygen, and nitrogen compressors are electric motor driven.

Table B-4

EQUIPMENT LIST
PLANTS 5 AND 8 (TEXACO CASE)
COAL GASIFICATION AND SOUR WATER STRIPPING

These two plants are proprietary design of Texaco. No equipment list is available. The design is described in Section 5.1.2. The specific design capacities are as following.

Plant No.	Plant Name	No. of Trains	Design Capacity/Train
5	Coal Gasification		
	Coal Grinding & Slurrying	7	2000 MTPD coal feed, 68% (bone dry coal basis) slurry
	Gasification & Ash Handling	7	2000 MTPD of coal
	Carbon Scrubbing	2	268 000 Nm3/h gas flow
	Low Temp. Gas Cooling	2	268 000 Nm3/h gas flow
8	Sour Water Stripping	1	82 m3/h sour water feed

Table B-5

EQUIPMENT LIST
PLANT 6 (TEXACO CASE)
ACID GAS REMOVAL

Item No.	Title	Qty.	Description/Unit	Remarks
6C-1	Absorber	1	Vertical vessel, C.S., include mist eliminator, 10 trays, 4 passes Design pressure: 30 Kg/cm2 (g) Design temperature: 150 C Diameter: 4.2 m T-T: 15 m	
6C-2	Stripper	1	Vertical vessel, C.S., include mist eliminator, 20 trays, 2 passes Design pressure: 10 Kg/cm2 (g) Design temperature: 150 C Diameter: 3 m T-T: 20 m	
6C-3	Stripper Reflux Drum	1	Horizontal cylindrical vessel, C.S. Design pressure: 10 Kg/cm2 (g) Design temperature: 150 C Diameter: 1.5 m T-T: 5 m	
6C-4	Solvent Surge Tank	1	Horizontal cylindrical vessel, C.S. Design pressure: 32 Kg/cm2 (g) Design temperature: 150 C Diameter: 3.5 m T-T: 10 m	
6D-1	Solvent Storage Tank	1	Cone roof, 316 SS Design pressure: Atmosphere Design temperature: 45 C Diameter: 6 m T-T: 8.5 m	
6E-1	Lean Solvent Trim Cooler	1	Shell & tube Duty: 13.6 million Kcal/h Surface area: 1352 m2 Shell material: C.S. Shell design pressure: 30 Kg/cm2 (g) Shell design temperature: 90 C Tube material: C.S. Tube design pressure: 20 Kg/cm2 (g) Tube design temperature: 150 C	

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Table B-5

EQUIPMENT LIST
PLANT 6 (TEXACO CASE)
ACID GAS REMOVAL

Item No.	Title	Qty.	Description/Unit	Remarks
6E-2	Lean-Rich Solvent Exchanger	1	Shell & tube Duty: 21.5 million Kcal/h Surface area: 2440 m2 Shell material: C.S. Shell design pressure: 11 Kg/cm2 (g) Shell design temperature: 150 C Tube material: C.S. Tube design pressure: 30 Kg/cm2 (g) Tube design temperature: 150 C	
6E-3	Stripper Reboiler	1	Vertical thermosyphon Duty: 23.42 million Kcal/h Surface area: 1430 m2 Shell material: C.S. Shell design pressure: 10 Kg/cm2 (g) Shell design temperature: 150 C Tube material: C.S. Tube design pressure: 10 Kg/cm2 (g) Tube design temperature: 150 C	
6E-4	Stripper Overhead Condenser	1	Shell & tube Duty: 7.6 million Kcal/h Surface area: 550 m2 Shell material: C.S. Shell design pressure: 10 Kg/cm2 (g) Shell design temperature: 150 C Tube material: C.S. Tube design pressure: 7 Kg/cm2 (g) Tube design temperature: 110 C	
6G-1	Solvent Feed Pump	1+1	Horizontal centrifugal Casing: C.S., impeller: ductile iron Flow:30 m3/h Temp:30 C Liquid head:35 m Power:6 BHP	
6G-2	Lean Solvent Recycle Pump	1+1	Horizontal centrifugal Casing: C.S., impeller: ductile iron Flow:550 m3/h Temp:123 C Liquid head:350 m Power:880 BHP	
6G-3	Stripper Reflux Pump	1+1	Horizontal centrifugal Casing: C.S., impeller: ductile iron Flow:45 m3/h Temp:44 C Liquid head:50 m Power:11 BHP	

Table B-5

EQUIPMENT LIST
PLANT 6 (TEXACO CASE)
ACID GAS REMOVAL

Item No.	Title	Qty.	Description/Unit	Remarks
6T-4	Solvent Carbon Filter	1+1	Vertical drum packed bed, C.S. Design pressure: 40 Kg/cm2 (g) Design temperature: 150 C Diameter: 2 m T-T: 6 m	

Table B-6

EQUIPMENT LIST
PLANT 7 (TEXACO CASE)
SULFUR RECOVERY

This Selectox process used for this plant is a proprietary design of Parson. No equipment list is available. The design id described in Section 5.1.2.

One train is used. The design gas feed is 16400 Nm3/h with 7.5% H_2S.

The sulfur recovery is 93%.

Total sulfur produced is 37 MTPD in solid block.

Table B-7

EQUIPMENT LIST
PLANT 9 (TEXACO CASE)
COMBINED CYCLE

Item No.	Title	Qty.	Description/Unit	Remarks
9C-1	Blowdown Flash Drum	2	Vertical vessel, C.S. Design pressure: 4.2 Kg/cm2 (g) Design temperature: 190 C Diameter:91 cm T-T:260 cm	
9C-2	Condensate Storage Tank	1	Vertical vessel, C.S. with epoxy lining Design pressure: 3.5 Kg/cm2 (g) Design temperature: 51 C Diameter:8.3 m T-T:12 m	
9E-1	Heat Recovery Steam Generator	2	Duel pressure system, include the steam drums and deaerator, and a stack Heat transfer area (extended surface) is: HP superheater:11650 m2 Reheater:8170 m2 HP evaporator:41100 m2 IP superheater:2100 m2 HP economizer I:30450 m2 IP evaporator:23950 m2 HP economizer II:18200 m2 IP economizer:3900 m2 Integral deaerator:27850 m2 Steam condition is: HP:103 kg/cm2 abs, 538 C IP & RH:25 kg/cm2 abs, 538 C Stack: 32m high, 7.5m diameter	
9E-2	Surface Condenser	2	Shell & tube, single shell, 2 passes Shell: C.S., tube: S.S. Include vacuum pump package Duty :255 million Kcal/h Surface area:13300 m2	
9F-1	Startup Boiler	1	Rated at 11000 kg/h, 18.6 kg/cm2 abs saturated steam	
9G-1	Condensate Pump	2+2	Horizontal centrifugal Casing: cast iron, impeller: bronze Flow:470 m3/h Temp:49C Diff. pressure:2.5 kg/cm2 Power:53 BHP	

Table B-7

EQUIPMENT LIST
PLANT 9 (TEXACO CASE)
COMBINED CYCLE

Item No.	Title	Qty.	Description/Unit	Remarks
9G-2	LP Boiler Feedwater Pump	2+2	Horizontal centrifugal, 11-13% Cr Flow:50 m3/h Temp:116C Diff. pressure:26.4 kg/cm2 Power:60 BHP	
9G-3	HP Boiler Feedwater Pump	2+2	Horizontal centrifugal, 11-13% Cr Flow:300 m3/h Temp:116C Diff. pressure:119 kg/cm2 Power:1185 BHP	
9G-4	Condensate Transfer Pump	2+1	Horizontal centrifugal, 316 S.S. Flow:470 m3/h Temp:49C Diff. pressure:2 kg/cm2 Power: 60 BHP	
9G-5	Process Makeup Water (BFW Quality) Transfer Pump	2+2	Horizontal centrifugal, 11-13% Cr Flow:175 m3/h Temp:116C Diff. pressure:5.3 kg/cm2 Power: 45 BHP	
9K-1	Gas Turbine-Generator	2	General Electric MS9001F gas turbine, single shaft, with inlet filter and other auxiliary systems, rated 212 MW at ISO Generator: hydrogen cooled, 50 Hz, 3000 rpm, 16500 volts, 240 MVA	
9K-2	Steam Turbine-Generator	2	Triple extraction, double flow condensing 76 cm last stage bucket, steam flow: HP SH: 265000 kg/h RH: 316000 kg/h 43.2 kg/cm2 (a) extrac steam: 1230 kg/h 8.1 kg/cm2 (a) extrac steam: 6500 kg/h 3.9 kg/cm2 (a) inlet steam: 167000 kg/h Total Exhaust: 476000 kg/h Generator: hydrogen cooled, 50 Hz, 3000 rpm, 16500 volts, 150 MVA	
9R-1	Gas Turbine Building	2	34m x 40m floor area, 16m high structure, lower part reinforced concret. upper part structure steel	
9R-2	Steam Turbine Building	1	34m x 45m floor area, 16m high structure, lower part reinforced concret. upper part structure steel	

Table B-8

EQUIPMENT LIST
PLANT 30 (TEXACO CASE)
SOLID WASTE DISPOSAL

Item No.	Title	Qty.	Description/Unit	Remarks

Designed for 9834 MTPD slag flow.

Table B-9

EQUIPMENT LIST
PLANT 31 (TEXACO CASE)
RELIEF & BLOWDOWN (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
31D-1	Knock Out Drum	1	Horizontal Vessel, C.S. Design Temp: 66C Design Pressure: 1 kg/cm2 (g) Diameter: 3 m T-T: 11m	
31F-1	Main Flare	1	Design gas flow: 335 000 kg/h Design heat duty: 1000 million Kcal/h C.S. Diameter: 110 cm Height: 32 m	
31G-101	K.O. Drum Pump	1+1	Centrifugal, C.S. Liquid head: 20 m Flow: 34 m3/h BHP: 5 HP	

Note 1: This plant is identical to that in the Shell case.

Table B-10

EQUIPMENT LIST
PLANT 32 (TEXACO CASE)
INTERCONNECTING PIPING

Major items of this plant are:

Fuel oil lines
Pipe and pipeways for raw water supply and BFW makeup water supply
Pipe and pipeways for treated waste water and steam blowdown
Instrument and service air lines
Oxygen and nitrogen supply from the air separation plant to the gasification plant
Steam lines to the liquid oxygen and liquid nitrogen vaporizers
Pipe and pipeways between process areas
Distribution of cooling water and service water from the cooling tower
Coal gas, steam, feedwater, and condensate lines between the process and power areas
Miscellaneous process and utility piping

Table B-11

EQUIPMENT LIST
PLANT 33 (TEXACO CASE)
COMPRESSED AIR SYSTEM (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
33C-1	Compressed Air Receiver	4	Vertical vessel, C.S. Design pressure: 10 kg/cm2 (g) Design pressure: 65 C Diameter: 1.37 m T-T: 3.81m	
33K-1	Air Compressor	4	Design gas flow: 2 000 Nm3/h Pressure head: 6.9 kg/cm2 Cast iron casing, C.S. Impeller Centrifugal, motor drive 300 BHP	
33T-1	Desiccant Air Dryer	4	Twin tower, cycling type Design gas flow: 1000 Nm3/h Design pressure: 10 kg/cm2 (g) Design temperature: 65 C	

Note 1: This plant is identical to that in the Shell case.

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Table B-12

EQUIPMENT LIST
PLANT 34 (TEXACO CASE)
FUEL OIL AND LPG SYSTEM (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
34C-1	Fuel Oil Tank	1	Vertical vessel, C.S. 15 000 barrels storage Diameter: 16 m Height: 12 m	
34C-2	LPG Storage Tank	1	Horizontal high pressure storage bullet Storage capacity: 240 barrels	
34G-1	Fuel Oil Pump	2+1	Centrifugal, C.S. Flow: 230 gpm or 52 m3/h Pressure head: 40 m liquid 15 BHP	

Note 1: This plant is identical to that in the Shell case.

Table B-13

EQUIPMENT LIST
PLANT 35 (TEXACO CASE)
ELECTRICAL SYSTEMS

Item No.	Title	Qty.	Description/Unit	Remarks
35P-1	H.V. Circuit Breaker	21	235KV, 2000A, 63KA RMS system	
35P-2	H.V. Disconnect Switches	42	3-pole 235 KV, "v" type center break	
35P-3	H.V. Disconnect Switches with Earthing Blade	6	3-pole 235 KV, 2000A, vertical break with grounding blade	
35P-4	H.V. Lighting Arresters	11	184 KV	
35P-5	Step-up Transformer for Gas Turbines	2	180/240/300 MVA, OA/FA/FOA, 16.5-220 KV, Delta-Wye	
35P-6	Step-up Transformer for Steam Turbines	2	100/130/160 MVA, OA/FA/FOA, 16.5-220 KV, Delta-Wye	
35P-7	Step-down Transformer for Air Separation and Cooling Tower	4	63/85 MVA, OA/FA, 220-16.5 KV, Wye-Wye, core form type	
35P-8	Step-down Transformer for Startup	1	12 MVA, FOA, 220-6.6 KV, Wye-Wye, core form type	
35P-9	Step-down Transformer for Combine Cycle Auxiliary Power	2	4.2/5.25 MVA, OA/FA, 16.5-6.6 KV, Delta-Wye	
35P-10	Step-down Transformer for Process Plant Auxiliary Power	6	5/6.25 MVA, OA/FA, 16.5-6.6 KV, Delta-Wye	
35P-11	Step-down Transformer for Combine Cycle Auxiliary Power (L.V.)	4	2/2.3 MVA, OA/FA, 6.6 KV- 480 V, Delta-Wye	
35P-12	Step-down Transformer for Process Plant Auxiliary Power (L.V.)	6	1.5 MVA, OA 16.5 KV- 480 V, Delta-Wye	
35P-13	M.V. Switchgear	2	16.5 KV, 750MVA S.C., 3000A	
35P-14	M.V. Motor Control Center	8	6.6 KV, 250MVA S.C., 2000A	
35P-15	L.V. Load Center Buses	4	400 V, 42 KA S.C., 3000A	
35P-16	L.V. Motor Control Center	lot	400 V, 800A	

Table B-14

EQUIPMENT LIST
PLANT 37 (TEXACO CASE)
COOLING WATER SYSTEM

Item No.	Title	Qty.	Description/Unit	Remarks
37E-1	Cooling Tower	1	48 cells, 2600 m3/h water circulation per cell, 5 cycles of concentration	
37E-2	Auxiliary Cooling Water Heat Exchanger	4	Shell and tube, C.S., 50 m2 bare tube surface area	
37G-1	Circulating Water Pump	4+2	Centrifugal, case iron Design flow: 15900 m3/h Liquid head: 11m 800 BHP	
37G-2	Service Water Pump	4	Centrifugal, case iron Design flow: 16000 m3/h Liquid head: 37m 2750 BHP	
37G-3	Auxiliary Cooling Water Pump	2+1	Centrifugal, case iron Design flow: 200 m3/h Liquid head: 68m 65 BHP	
37D-1	Demineralized Water Head Tank	1	Vertical vessel, C.S. with epoxy lining Design pressure: 3.5 kg/cm2 (a) Design Temperature: 65 C Diameter: 1.2 m T-T: 2.6 m	
37V-1	Biocide Additive Package	1	Include one tank with 2x100% metering pumps, sizing based on 1950 m3/h CT makeup water rate	
37V-2	Scale Inhibitor Additive Package	1	Include one tank with 2x100% metering pumps, sizing based on 1950 m3/h CT makeup water rate	
37V-3	Corrosion Inhibitor Additive Package	1	Include one tank with 2x100% metering pumps, sizing based on 1950 m3/h CT makeup water rate	
37V-4	Chlorination Package	1	Sizing based on 1950 m3/h CT makeup water rate	

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Table B-15

EQUIPMENT LIST
PLANT 38 (TEXACO CASE)
RAW WATER SUPPLY AND TREATMENT

Item No.	Title	Qty.	Description/Unit	Remarks
38G-1	Clarifier Feed Pump	2+1	Centrifugal, Cast Iron Design Flow: 1170 m3/h Liquid Head: 21 m 115 BHP	
38G-2	Alum Metering Pump	1+1	metering, Alloy 20 Design Flow: 0.1 m3/h Liquid Head: 70 m 0.5 BHP	
38G-3	Soda Ash Metering Pump	1+1	metering, vendor spec material Design Flow: 0.1 m3/h Liquid Head: 70 m 0.5 BHP	
38G-4	Potassium Permanganate Meteing Pump	1+1	metering, vendor spec material Design Flow: 0.1 m3/h Liquid Head: 70 m 0.5 BHP	
38G-5	Filtered Water Pump	2+1	Centrifugal, Cast Iron Design Flow: 145 m3/h Liquid Head: 15 m 11 BHP	
38G-6	Demineralizer Feed Pump	4+1	Centrifugal, Cast Iron Design Flow: 40 m3/h Liquid Head: 21 m 5 BHP	
38G-7	Sulfuric Acid Metering Pump	1+1	metering, C.S. Teflon lining Design Flow: 0.7 m3/h Liquid Head: 70 m 0.5 BHP	
38G-8	Water Pump for Acid Dilution	1+1	Centrifugal, Cast Iron Design Flow: 32 m3/h Liquid Head: 15 m 3 BHP	
38G-9	Sodium Hydroxide Transfer Pump	1+1	Centrifugal, C.S. Design Flow: 4.5 m3/h Liquid Head: 15 m 2 BHP	
38G-10	Sodium Hydroxide Feed Pump	1+1	Centrifugal, C.S. Design Flow: 17 m3/h Liquid Head: 15 m 2 BHP	

Table B-15

EQUIPMENT LIST
PLANT 38 (TEXACO CASE)
RAW WATER SUPPLY AND TREATMENT

Item No.	Title	Qty.	Description/Unit	Remarks
38G-11	Demineralizer Rinse Pump	1+1	Centrifugal, Cast Iron Design Flow: 23 m3/h Liquid Head: 15 m 3 BHP	
38G-12	Boiler Feed Water Makeup Pump	4+1	Centrifugal, Cast Iron Design Flow: 35 m3/h Liquid Head: 21 m 4 BHP	
38G-13	Filter Feed Water Pump	2+1	Centrifugal, Cast Iron Design Flow: 150 m3/h Liquid Head: 15 m 12 BHP	
38G-14	Cooling Tower Makeup Water Pump	2+1	Centrifugal, Cast Iron Design Flow: 1000 m3/h Liquid Head: 70 m 330 BHP	
38G-15	Sodium Hypochlorite Metering Pump	1	Centrifugal, High Si Design Flow: 0.02 m3/h Liquid Head: 70 m 0.25 BHP	
38G-16	Raw Water Intake Pump	2+1	Centrifugal, Cast Iron Design Flow: 1170 m3/h Liquid Head: 35 m 185 BHP	
38D-1	Alum Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-2	Soda Ash Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-3	Potassium Permanganate Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-1	Alum Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-2	Soda Ash Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	

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Table B-15

EQUIPMENT LIST
PLANT 38 (TEXACO CASE)
RAW WATER SUPPLY AND TREATMENT

Item No.	Title	Qty.	Description/Unit	Remarks
38D-3	Potassium Permanganate Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-4	Sodium Hypochlorite Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-5	Filtered Water Tank	2	Vertical vessel, C.S., epoxy lining Diameter: 5 m Height: 5 m	
38D-6	Sulfuric Acid Storage Tank	1	Vertical vessel, C.S. Diameter: 4.27 m Height: 6.7 m	
38D-7	Sodium Hydroxide Storage Tank	1	Vertical, C.S., Neoprene-Latex coated Diameter: 5.49 m Height: 7.92 m	
38D-8	Sodium Hydroxide Feed Tank	1	Vertical, C.S., Neoprene-Latex coated Diameter: 1.52 m Height: 1.52 m	
38D-9	Boiler Feed Water Storage Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 8 m Height: 8 m	
38D-10	Filter Feed Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 5.7 m Height: 5 m	
38R-1	Water Treatment Building	1	Preengineered metal building, 18m x 55m with 7.3 m eave height	
38Z-1	Raw Water Clarifier	2	Vertical vessel, C.S., epoxy lining Diameter: 17.65 m Height: 8.16 m	
38Z-2	Gravity Filter	2+1	Vertical vessel, C.S., epoxy lining Diameter: 7.1 m Height: 5.3 m	
38Z-3	Demineralizer Package	2	Include cation, anion, and mixed bed exchangers, Capacity: 80 m3/h demineralized water	

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Table B-16

EQUIPMENT LIST
PLANT 39 (TEXACO CASE)
FIRE PROTECTION (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
39D-1	LP Carbon Dioxide Storage Tank	1	8 tonnes	
39G-1	Fire Water Pump	2	Centrifugal, driven by diesel engine Design flow: 450 m3/h Liquid head: 180 m 400 BHP	
39 Y-1	Halon System	2	Installed in control rooms	
39Y-2	Carbon Dioxide System	2	Installed in turbine building	
39Y-3	Hose Cart	4	1.2 m steel wheels, each with 80 m long 6.35 cm diameter hose	
39Y-4	Hose Reel	20	30 m long, 3.81 cm diameter	
39Y-5	Fire and Smoke Detector	16		
39Y-6	Fire Hydrants	60	Dry barrel type, 15 cm inlet with pump connection	
39Y-7	Deluge & Sprinkler System		Located over rotating components that handle flammable fluid plus transformers	
39Y-8	Portable Extinguisher	60		
39Y-9	Yard Fire Water Piping	1	8000 m	
39Y-10	Building Fire Water Piping	1	8000 m	

Note 1: This plant is the same as that in the Shell case.

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Table B-17

EQUIPMENT LIST
PLANT 40 (TEXACO CASE)
WASTE WATER TREATING

Item No.	Title	Qty.	Description/Unit	Remarks
40G-1	Clarifier Sludge Pump	1+1	Centrifugal, Cast Iron with rubber lining, Design Flow: 2.8 m3/h Liquid Head: 15 m 0.5 BHP	
40G-2	Backwash Water Pump	1+1	Centrifugal, Cast Iron Design Flow: 16.8 m3/h Liquid Head: 15 m 2 BHP	
40G-3	Backwash Settled Water Pump	1+1	Centrifugal, Cast Iron Design Flow: 16.8 m3/h Liquid Head: 15 m 2 BHP	
40G-4	Thickener Underflow Pump	1+1	Mayno, 304 S.S. Design Flow: 1 m3/h Liquid Head: 21 m 0.5 BHP	
40G-5	Regenerant Discharge Pump	2+1	Centrifugal, Alloy 20 Design Flow: 36 m3/h Liquid Head: 30 m 6 BHP	
40G-6	Slop Oil Pump	1	Recip, Cast Iron Design Flow: 1.1 m3/h Liquid Head: 21 m 1 BHP	
40G-7	Storm Runoff Water Pump	1	Centrifugal, Cast Iron Design Flow: 300 m3/h Liquid Head: 23 m 35 BHP	
40G-8	Oily Water Pump	1	Centrifugal, Cast Iron Design Flow: 2.3 m3/h Liquid Head: 15 m 2 BHP	
40G-9	Thickener Overflow Pump	1+1	Centrifugal, Cast Iron Design Flow: 6 m3/h Liquid Head: 15 m 3 BHP	
40D-1	Neutralization Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 5 m Height: 5.6m	

Table B-17

EQUIPMENT LIST
PLANT 40 (TEXACO CASE)
WASTE WATER TREATING

Item No.	Title	Qty.	Description/Unit	Remarks
40D-2	Spent Backwash Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 5.2 m Height: 5.2 m	
40D-3	Oily Water Sump	1	Rectangular vessel, concrete, 1.21 m x 1.21 m x 1.82 m	
40D-4	Thickener Overflow Sump	1	Rectangular vessel, concrete, 1.94 m x 1.94 m x 2.60 m	
40Y-1	Process Waste Water Treating Package	1	Proprietary design of Texaco, include clarification, biotreament, and dewatering of sludge; 82 m3/h feed water	
40Z-1	Sludge Thickener	1	Vertical vessel, C.S., epoxy lining Diameter: 5.8 m Height: 6.7 m	
40Z-2	Filter Press	5	304 S.S., 120 m2 filter area	
40Z-3	Sanitary Waste Treatment Package	1	8 m3/h capacity	

Table B-18

EQUIPMENT LIST
PLANT 43 (TEXACO CASE)
BUILDINGS (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
43R-1	Control Building	1	Three story, steel frame, 23m x 38m	
43R-2	Administration Building Including Laboratory & Medical Facility	1	Two story, concrete, 30m x 44m	
43R-3	Warehouse	1	Pre-engineered metal building, 45m x 60m with 6.7m eave height and cast in place reinforced slab	
43R-4	Machine Shop and Maint. Building	1	Pre-engineered metal building, 12m x 30m with 6.7m eave height and cast in place reinforced slab	

Note 1: This plant is identical to that in the Shell case.

Table B-19

EQUIPMENT LIST
PLANT 36, 41, 42 (TEXACO CASE)
INSTRUMENT AND CONTROL, GENERAL SERVICES AND MOBILE EQUIPMENT, SITE PREPARATION

These three plants have been defined and described in Section 5.1.2.

No equipment lists were developed for these plants.

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Appendix C

EQUIPMENT LISTS

IGCC PLANT

(KRW CASE)

Table C-0

EQUIPMENT LIST
(KRW CASE)
COAL TRANSPORTATION (MERRY-GO ROUND) SYSTEM

Item No.	Title	Qty.	Description/Unit	Remarks
1	Rail Track		Length - 20 km	
2	Wagons	26	Bottom Discharge	
3	Locomotives	3	WDS - 6	
4	In Motion Weigh Bridge	2	90 tonnes	
5	Signalling & Telecommunication			
6	Coal Bunker for Receiving Raw Coal (0-200 mm) from Merry-Go-Round System	1	100 m3	

Note: The facilities described above are identical to those of the Shell case.

Table C-1

EQUIPMENT LIST
PLANT 1 (KRW CASE)
COAL RECEIVING, PRIMARY CRUSHING & STORAGE

Item No.	Title	Qty.	Description	Hp Each	Total HP	Remarks
1T-1	Surge Bin	1	Capacity- 120 tons Construction- Steel Plan Size- 5m x 10m Liners: Conical portion CS Outlets: 2	0	0	
1T-2	Surge Bin Feeder	2	Type: Vibrating Capacity- 0 to 500 tph Width- 1200mm	20	40	
1T-3	Scalping Screen	2	Type: Vibrating, Double deck Feed rate- 500 tph Size- 2.4m x 4.9m Top Deck- 75mm Bot Deck- 37mm	40	80	
1T-4	Primary Crusher	2	Type: Symons Std. Cone or equal Size- 2.1m(7 feet) Feed Size- 200mm Product Size: 37 mm, nominal	350	700	
1T-5	Crushed Coal Conveyor	1	Type: Belt Capacity- 1000 tph Width- 1050mm Length- 75m ft. Lift- 18m Speed- 2.75 mps	50	50	
1T-6	Crushed Coal Shuttle Conveyor	1	Type: Reversible Shuttle Belt Capacity- 1000 tph Width - 1050mm Length - 7m Lift- nil Speed- 2.75 mps	15+5	20	
1T-7	Distribution Bin	1	Capacity- 160 tons Construction- CS Plan- 12m x 4m Vetical side- 4m Conical side- 2.5m No of outlets- 3 Clearance from ground- 6m	0	0	
1T-8	Distribution Bin Vib. Feeder	2	Type: Vibrating Capacity- 0 to 1000 tph Width- 1200mm	30	60	

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Table C-1

EQUIPMENT LIST
PLANT 1 (KRW CASE)
COAL RECEIVING, PRIMARY CRUSHING & STORAGE

Item No.	Title	Qty.	Description	Hp Each	Total HP	Remarks
1T-9	Dist. Bin. Weigh Feeder	1	Type: Weigh Belt Capacity- 0 to 600 tph Width- 1200 mm	15	15	
1T-10	Storage Yard Belt Conveyor	1	Type: Reversible Belt Capacity- 1000 tph Width- 1050mm Length- 360m Lift- 8M Speed- 2.75 mps	125	125	
1T-11	Reversible Stacker Reclaimer	1	Stacking- 1000 tph Reclaiming- 0 to 600 tph Boom Length- 35 m Boom Conveyor- Reversible Width- 1050 mm	250	250	
1T-12	Crushed Coal Storage Pile	2	Type - Open Pile Capacity - 57,500 tons live-5.5 Days Pile Length- 320m Pile height- 14.5m		0	
1T-13	Day Store Stacking Conv.	1	Type: Belt Capacity- 1000 tph Width- 1050mm Length- 120m Lift- 23m Speed- 2.75 mps	125	125	
1T-14	Day Storage Pile	1	Diameter- 80m Height- 27.5m Capacity- 10,000 tons- live 35,000 tons- total Accesory- Lowering tube	0	0	
1T-15	Reclaim Hoppers	3	Capacity- 10 tons Construction- CS Location- Below ground-under day storage -in tunnel	0	0	
1T-16	Reclaim Feeders	1+2	Type: Vibrating Capacity- 0 to 600 tph Width- 900mm	20	60	
1T-17	Motorized gate	3	Type- Two way Flow- 600 tph	5	15	

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Table C-2

EQUIPMENT LIST
PLANT 2 (KRW CASE)
COAL AND LIMESTONE HANDLING

Item No.	Title	Qty.	Description	Hp Each	Total HP
2T-1	Shuttle Belt Conv.	1+1	Type: Reversible Shuttle Belt Capacity- 500 tph Width- 900 mm Length- 10m Lift- nil Speed- 2.25 mps	5+3	16
2T-2	Surge Bin	1	Capacity- 100 tons Construction- CS Plan- 3m x 16m Outlets-4	0	0
2T-3	Vibrating Feeder	3+1	Type:Vibrating Capacity- 125 tph	10	40
2T-4	Secondary Screens	3+1	Type: Vibrating, Double deck Feed rate- 300 tph Size- 2.4m x 6m Top Deck- 30mm Bot Deck- 6mm	40	160
2T-5	Secondary Crusher	3+1	Type: Symons Std. Cone or equal Size- 2.1m(7 feet) Feed Size- 37mm Product Size- 6 mm, nominal	350	1400
2T-6	Crusher Discharge Conveyor	3+1	Type: Belt Capacity- 125 tph Width- 900 mm Length- 12m Lift- 3m Speed- 2 mps	10	40
2T-7	Day Bin Feed conveyor	1+1	Type: Belt Capacity- 500 tph Width- 900 mm Length- 135m Lift- 25m Speed- 2.25 mps	75	150
2T-8	Tripper Conveyor	1+1	Type: Belt Capacity- 500 tph Width- 900 mm Length- 35m Lift- 4m Speed- 2.25 mps Auxiliary- Motorized tripper	25+3	56
2T-9	Motorized gate	4	Flow- 125 tph	2	4

Table C-2

EQUIPMENT LIST
PLANT 2 (KRW CASE)
COAL AND LIMESTONE HANDLING

Item No.	Title	Qty.	Description	Hp Each	Total HP
2T-10	Dust Collector - Crushing	4	Type - Bag House Area - 180 Sq m Fan: Flow - 5 cubic mps	40+3	172
2T-11	Dust Collector - Bunker top and flux Handling	2	Type - Bag House Area - 900 Sq m Fan: Flow - 5 cubic mps	40+3	86
2T-12	Tramp Iron Magnet	2	B elt width- 900 mm	5	10
2T-13	Flux Reclaim Hopper	1+1	Capacity- 3 tons Volume- 2 cu m Construction- CS Plan- 1.2m x 1.2 m Side Slope- 50 deg	0	0
2T-14	Reclaim Weigh Feeders	1+1	Type: Weigh Belt Capacity- 15 tph Width- 400 mm Length- 3m Lift- nil	3	6
2T-15	Crusher Feed Conveyor	1+1	Type: Belt Capacity- 15 tph Width- 450 mm Length- 9m Lift- 4m Speed- 0.5 mps	2	4
2T-16	Tramp Iron Magnet	1+1	B elt width- 450 mm	5	10
2T-17	Flux Crusher	1+1	Type: Hammer mill Capacity- 15 tph Feed- 50 mm Product- 6mm	30	60
2T-18	Rod Mill	1+1	Type- Dry Rod mill- Open circuit Feeed- 13.5 tph Feed Size- 6 mm Product Size- 16 mesh Size- 1.8 m dia. x 3m long	100	200
2T-19	Bucket Elevator	1+1	Type- Spaced Bucket- Chain Capacity- 18 tph (Design) Lift- 15 m	15	30

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Table C-3

EQUIPMENT LIST
PLANT 3 (KRW CASE)
COAL DRYING

Item No.	Title	Qty.	Description	Hp Each	Total HP
3T-1	Drying Plant Feed Conveyor	1+1	Type: Belt Capacity- 500 tph Width- 900 mm Length- 40m Lift- 10m Speed- 2.25 mps	40	80
3T-2	Dryer Feed Bin	1	Capacity- 100 tons Construction- CS Plan- 4.5m x 9m Outlets-2	0	0
3T-3	Weigh Feeder for Dryer	2	Type:Weigh Belt Capacity- 250 tph Width- 900 mm Length- 4m Lift- nil	10	20
3T-4	Fluid Bed Drying System	2	Bed Area-11 sq.m Wet Coal Feed Rate- 220 tph Feed Moisture- 18 % Product Moisture- 5 % Evaporation-30.1 tph Below Bed Hot Gas Temp- 504° C Product Temp.- 82° C Stack GasTemperature- 82° C Stack Gas Dew Point- 72°C Flue Gas For Drying: Flow- 3.616 ton-mole per hour@870° C Recycle Gases: Flow- 3.14 ton-mole per hour@72° C Auxiliaries: Cyclones	0	0
3T-5	Inlet Fan	2	Flow- 120 cubic mps SP- 525 mm Water Temp. 504° C	1000	2000
3T-6	Exhaust Fan	2	Flow- 68 cubic mps SP- 525 mm Water Temp. 82° C	600	1200
3T-7	Dust Collector	4	Type: Bag House Filtering Area- 860 sq.m Temperature- 90° C	0	0

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Table C-3

EQUIPMENT LIST
PLANT 3 (KRW CASE)
COAL DRYING

Item No.	Title	Qty.	Description	Hp Each	Total HP
3T-8	Dryer Discharge Conveyor	2	Type: Belt Capacity- 250 tph Width- 900 mm Length- 15m Lift- 3m Speed- 1.25 mps Material Temp- 80° C	7.5	15
3T-9	Motorized Gate	2	Type- Two way Flow- 250 tph	2	4
3T-10	Crushing Plant Feed Conv.	1+1	Type: Belt Capacity- 500 tph Width- 900 mm Length- 50m Lift- 17m Speed- 2.25 mps	40	80

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Table C-4

EQUIPMENT LIST
PLANTS 5 AND 10 (KRW CASE)
COAL GASIFICATION AND ASH SULFATION

These two plants are proprietary design of KRW. No equipment list is available. The design is described in Section 5.1.3. The specific design capacities are as following.

Plant No.	Plant Name	No. of Trains	Design Capacity/Train
5	Coal Gasification		
	Boost Air Compression	6	80 000 Nm3/h gas flow comp. from 12.4 to 36.2 kg/cm2 (a
	Gasification	6	1342 MTPD of coal (5% moisture) & 50 MTPD limestone
	Ash Removal	6	630 MTPD of ash
	Heat Recovery	6	Producing 74 000 kg/h saturated steam at 112.5 kg/cm2 (a
	Gas Conditioning	6	284 500 Nm3/h gas flow
	Recycle Gas Compression	6+3	For ash transport and for filter operation
10	Ash Sulfation	6	630 MTPD of ash feed, 18 million kcal/h firing duty

Table C-5

EQUIPMENT LIST
PLANT 9 (KRW CASE)
COMBINED CYCLE

Item No.	Title	Qty.	Description/Unit	Remarks
9C-1	Condensate Storage Tank	1	Vertical vessel, C.S. with epoxy lining Design pressure: 3.5 Kg/cm2 (g) Design temperature: 51 C Diameter:8.3 m T-T:12 m	
9E-1	Heat Recovery Steam Generator	2	Duel pressure system, include the steam drums and deaerator, and a stack Heat transfer area (extended surface) is: HP superheater:22000 m2 Reheater:12000 m2 HP evaporator:31000 m2 IP superheater:1050 m2 HP economizer I:40500 m2 IP evaporator:18100 m2 HP economizer II:26100 m2 IP economizer:2900 m2 Integral deaerator:7500 m2 Steam condition is: HP:109 kg/cm2 abs, 542 C IP & RH:25 kg/cm2 abs, 538 C Stack: 32m high, 7.5m diameter	
9E-2	Surface Condenser	2	Shell & tube, single shell, 2 passes Shell: C.S., tube: S.S. Include vacuum pump package Duty :216 million Kcal/h Surface area:11300 m2	
9F-1	Startup Boiler	1	Rated at 11000 kg/h, 18.6 kg/cm2 abs saturated steam	
9G-1	Condensate Pump	2+2	Horizontal centrifugal Casing: cast iron, impeller: bronze Flow:375 m3/h Temp:49C Diff. pressure:2.5 kg/cm2 Power:43 BHP	

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Table C-5

EQUIPMENT LIST
PLANT 9 (KRW CASE)
COMBINED CYCLE

Item No.	Title	Qty.	Description/Unit	Remarks
9G-2	LP Boiler Feedwater Pump	2+2	Horizontal centrifugal, 11-13% Cr Flow:30 m3/h Temp:110C Diff. pressure:26.8 kg/cm2 Power:36 BHP	
9G-3	HP Boiler Feedwater Pump	2+2	Horizontal centrifugal, 11-13% Cr Flow:365 m3/h Temp:110C Diff. pressure:119 kg/cm2 Power:1960 BHP	
9G-4	Condensate Transfer Pump	2+1	Horizontal centrifugal, 316 S.S. Flow:375 m3/h Temp:49C Diff. pressure:2.1 kg/cm2 Power: 45 BHP	
9K-1	Gas Turbine-Generator	2	General Electric MS9001F gas turbine, single shaft, with inlet filter and other auxiliary systems, rated 212 MW at ISO Generator: hydrogen cooled, 50 Hz, 3000 rpm, 16500 volts, 240 MVA	
9K-2	Steam Turbine-Generator	2	Double flow condensing 76 cm last stage bucket, steam flow: HP SH: 363400 kg/h RH: 406100 kg/h Generator: hydrogen cooled, 50 Hz, 3000 rpm, 16500 volts, 165 MVA	
9R-1	Gas Turbine Building	2	34m x 40m floor area, 16m high structure, lower part reinforced concret. upper part structure steel	
9R-2	Steam Turbine Building	1	34m x 45m floor area, 16m high structure, lower part reinforced concret. upper part structure steel	

Table C-6

EQUIPMENT LIST
PLANT 30 (KRW CASE)
SOLID WASTE DISPOSAL

Item No.	Title	Qty.	Description/Unit	Remarks

Designed based on 3925 MTPD ash flow.

Table C-7

EQUIPMENT LIST
PLANT 31 (KRW CASE)
RELIEF & BLOWDOWN (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
31D-1	Knock Out Drum	1	Horizontal Vessel, C.S. Design Temp: 66C Design Pressure: 1 kg/cm2 (g) Diameter: 3 m T-T: 11m	
31F-1	Main Flare	1	Design gas flow: 335 000 kg/h Design heat duty: 1000 million Kcal/h C.S. Diameter: 110 cm Height: 32 m	
31G-101	K.O. Drum Pump	1+1	Centrifugal, C.S. Liquid head: 20 m Flow: 34 m3/h BHP: 5 HP	

Note 1: This plant is identical to that in the Shell case.

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Table C-8

EQUIPMENT LIST
PLANT 32 (KRW CASE)
INTERCONNECTING PIPING

Major items of this plant are:

- Fuel oil lines
- Pipe and pipeways for raw water supply and BFW makeup water supply
- Pipe and pipeways for treated waste water and steam blowdown
- Instrument and service air lines
- Steam lines to the liquid oxygen and liquid nitrogen vaporizers
- Pipe and pipeways between process areas
- Distribution of cooling water and service water from the cooling tower
- Coal gas, steam, feedwater, and condensate lines between the process and power areas
- Miscellaneous process and utility piping

Table C-9

EQUIPMENT LIST
PLANT 33 (KRW CASE)
COMPRESSED AIR SYSTEM (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
33C-1	Compressed Air Receiver	4	Vertical vessel, C.S. Design pressure: 10 kg/cm2 (g) Design pressure: 65 C Diameter: 1.37 m T-T: 3.81m	
33K-1	Air Compressor	4	Design gas flow: 2 000 Nm3/h Pressure head: 6.9 kg/cm2 Cast iron casing, C.S. Impeller Centrifugal, motor drive 300 BHP	
33T-1	Desiccant Air Dryer	4	Twin tower, cycling type Design gas flow: 1000 Nm3/h Design pressure: 10 kg/cm2 (g) Design temperature: 65 C	

Note 1: This plant is identical to that in the Shell case.

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Table C-10

EQUIPMENT LIST
PLANT 34 (KRW CASE)
FUEL OIL AND LPG SYSTEM (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
34C-1	Fuel Oil Tank	1	Vertical vessel, C.S. 15 000 barrels storage Diameter: 16 m Height: 12 m	
34C-2	LPG Storage Tank	1	Horizontal high pressure storage bullet Storage capacity: 240 barrels	
34G-1	Fuel Oil Pump	2+1	Centrifugal, C.S. Flow: 230 gpm or 52 m3/h Pressure head: 40 m liquid 15 BHP	

Note 1: This plant is identical to that in the Shell case.

Table C-11

EQUIPMENT LIST
PLANT 35 (KRW CASE)
ELECTRICAL SYSTEMS

Item No.	Title	Qty.	Description/Unit	Remarks
35P-1	H.V. Circuit Breaker	21	235KV, 2000A, 63KA RMS system	
35P-2	H.V. Disconnect Switches	42	3-pole 235 KV, "v" type center break	
35P-3	H.V. Disconnect Switches with Earthing Blade	6	3-pole 235 KV, 2000A, vertical break with grounding blade	
35P-4	H.V. Lighting Arresters	11	184 KV	
35P-5	Step-up Transformer for Gas Turbines	2	180/240/300 MVA, OA/FA/FOA, 16.5-220 KV, Delta-Wye	
35P-6	Step-up Transformer for Steam Turbines	2	110/145/180 MVA, OA/FA/FOA, 16.5-220 KV, Delta-Wye	
35P-7	Step-down Transformer for Process Auxi. Power & Cooling Tower	6	5/6.25 MVA, OA/FA, 16.5-6.6 KV, Delta-Wye	
35P-8	Step-down Transformer for Startup	1	12 MVA, FOA, 220-6.6 KV, Wye-Wye, core form type	
35P-9	Step-down Transformer for Combined Cycle Auxiliary Power	2	4.2/5.25 MVA, OA/FA, 16.5-6.6 KV, Delta-Wye	
35P-11	Step-down Transformer for Combinec Cycle Auxiliary Power (L.V.)	4	2/2.3 MVA, OA/FA, 6.6 KV- 480 V, Delta-Wye	
35P-12	Step-down Transformer for Process Plant Auxiliary Power (L.V.)	6	1.5 MVA, OA 16.5 KV- 480 V, Delta-Wye	
35P-13	M.V. Switchgear	2	16.5 KV, 750MVA S.C., 3000A	
35P-14	M.V. Motor Control Center	8	6.6 KV, 250MVA S.C., 2000A	
35P-15	L.V. Load Center Buses	4	400 V, 42 KA S.C., 3000A	
35P-16	L.V. Motor Control Center	lot	400 V, 800A	

Table C-12

EQUIPMENT LIST
PLANT 37 (KRW CASE)
COOLING WATER SYSTEM

Item No.	Title	Qty.	Description/Unit	Remarks
37E-1	Cooling Tower	1	24 cells, 2500 m3/h water circulation per cell, 5 cycles of concentration	
37E-2	Auxiliary Cooling Water Heat Exchanger	4	Shell and tube, C.S., 50 m2 bare tube surface area	
37G-1	Circulating Water Pump	4+2	Centrifugal, case iron Design flow: 14000 m3/h Liquid head: 11m 700 BHP	
37G-2	Service Water Pump	2	Centrifugal, case iron Design flow: 3600 m3/h Liquid head: 37m 600 BHP	
37G-3	Auxiliary Cooling Water Pump	2+1	Centrifugal, case iron Design flow: 200 m3/h Liquid head: 68m 65 BHP	
37D-1	Demineralized Water Head Tank	1	Vertical vessel, C.S. with epoxy lining Design pressure: 3.5 kg/cm2 (a) Design Temperature: 65 C Diameter: 1.2 m T-T: 2.6 m	
37V-1	Biocide Additive Package	1	Include one tank with 2x100% metering pumps, sizing based on 1000 m3/h CT makeup water rate	
37V-2	Scale Inhibitor Additive Package	1	Include one tank with 2x100% metering pumps, sizing based on 1000 m3/h CT makeup water rate	
37V-3	Corrosion Inhibitor Additive Package	1	Include one tank with 2x100% metering pumps, sizing based on 1000 m3/h CT makeup water rate	
37V-4	Chlorination Package	1	Sizing based on 1000 m3/h CT makeup water rate	

Table C-13

EQUIPMENT LIST
PLANT 38 (KRW CASE)
RAW WATER SUPPLY AND TREATMENT

Item No.	Title	Qty.	Description/Unit	Remarks
38G-1	Clarifier Feed Pump	2+1	Centrifugal, Cast Iron Design Flow: 500 m3/h Liquid Head: 21 m 50 BHP	
38G-2	Alum Metering Pump	1+1	metering, Alloy 20 Design Flow: 0.1 m3/h Liquid Head: 70 m 0.5 BHP	
38G-3	Soda Ash Metering Pump	1+1	metering, vendor spec material Design Flow: 0.1 m3/h Liquid Head: 70 m 0.5 BHP	
38G-4	Potassium Permanganate Meteing Pump	1+1	metering, vendor spec material Design Flow: 0.1 m3/h Liquid Head: 70 m 0.5 BHP	
38G-5	Filtered Water Pump	2+1	Centrifugal, Cast Iron Design Flow: 45 m3/h Liquid Head: 15 m 4 BHP	
38G-6	Demineralizer Feed Pump	2+1	Centrifugal, Cast Iron Design Flow: 34 m3/h Liquid Head: 21 m 4 BHP	
38G-7	Sulfuric Acid Metering Pump	1+1	metering, C.S. Teflon lining Design Flow: 0.7 m3/h Liquid Head: 70 m 0.5 BHP	
38G-8	Water Pump for Acid Dilution	1+1	Centrifugal, Cast Iron Design Flow: 32 m3/h Liquid Head: 15 m 3 BHP	
38G-9	Sodium Hydroxide Transfer Pump	1+1	Centrifugal, C.S. Design Flow: 4.5 m3/h Liquid Head: 15 m 2 BHP	
38G-10	Sodium Hydroxide Feed Pump	1+1	Centrifugal, C.S. Design Flow: 17 m3/h Liquid Head: 15 m 2 BHP	

Table C-13

EQUIPMENT LIST
PLANT 38 (KRW CASE)
RAW WATER SUPPLY AND TREATMENT

Item No.	Title	Qty.	Description/Unit	Remarks
38G-11	Demineralizer Rinse Pump	1+1	Centrifugal, Cast Iron Design Flow: 10 m3/h Liquid Head: 15 m 2 BHP	
38G-12	Boiler Feed Water Makeup Pump	2+1	Centrifugal, Cast Iron Design Flow: 30 m3/h Liquid Head: 21 m 4 BHP	
38G-13	Filter Feed Water Pump	2+1	Centrifugal, Cast Iron Design Flow: 45 m3/h Liquid Head: 15 m 4 BHP	
38G-14	Cooling Tower Makeup Water Pump	2+1	Centrifugal, Cast Iron Design Flow: 455 m3/h Liquid Head: 70 m 150 BHP	
38G-15	Sodium Hypochlorite Metering Pump	1	Centrifugal, High Si Design Flow: 0.02 m3/h Liquid Head: 70 m 0.25 BHP	
38G-16	Raw Water Intake Pump	2+1	Centrifugal, Cast Iron Design Flow: 500 m3/h Liquid Head: 35 m 80 BHP	
38D-1	Alum Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-2	Soda Ash Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-3	Potassium Permanganate Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-1	Alum Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-2	Soda Ash Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	

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Table C-13

EQUIPMENT LIST
PLANT 38 (KRW CASE)
RAW WATER SUPPLY AND TREATMENT

Item No.	Title	Qty.	Description/Unit	Remarks
38D-3	Potassium Permanganate Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-4	Sodium Hypochlorite Mix Tank	1	Vertical vessel, FRP Diameter: 2.13 m Height: 2.28 m	
38D-5	Filtered Water Tank	2	Vertical vessel, C.S., epoxy lining Diameter: 3.5 m Height: 3.5 m	
38D-6	Sulfuric Acid Storage Tank	1	Vertical vessel, C.S. Diameter: 4.27 m Height: 6.7 m	
38D-7	Sodium Hydroxide Storage Tank	1	Vertical, C.S., Neoprene-Latex coated Diameter: 5.49 m Height: 7.92 m	
38D-8	Sodium Hydroxide Feed Tank	1	Vertical, C.S., Neoprene-Latex coated Diameter: 1.52 m Height: 1.52 m	
38D-9	Boiler Feed Water Storage Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 6.3 m Height: 6.3 m	
38D-10	Filter Feed Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 3.8 m Height: 3.5 m	
38R-1	Water Treatment Building	1	Preengineered metal building, 18m x 55m with 7.3 m eave height	
38Z-1	Raw Water Clarifier	2	Vertical vessel, C.S., epoxy lining Diameter: 13.3 m Height: 6.2 m	
38Z-2	Gravity Filter	2+1	Vertical vessel, C.S., epoxy lining Diameter: 4.7 m Height: 3.5 m	
38Z-3	Demineralizer Package	2	Include cation, anion, and mixed bed exchangers, Capacity: 30 m3/h demineralized water	

Table C-14

EQUIPMENT LIST
PLANT 39 (KRW CASE)
FIRE PROTECTION (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
39D-1	LP Carbon Dioxide Storage Tank	1	8 tonnes	
39G-1	Fire Water Pump	2	Centrifugal, driven by diesel engine Design flow: 450 m3/h Liquid head: 180 m 400 BHP	
39 Y-1	Halon System	2	Installed in control rooms	
39Y-2	Carbon Dioxide System	2	Installed in turbine building	
39Y-3	Hose Cart	4	1.2 m steel wheels, each with 80 m long 6.35 cm diameter hose	
39Y-4	Hose Reel	20	30 m long, 3.81 cm diameter	
39Y-5	Fire and Smoke Detector	16		
39Y-6	Fire Hydrants	60	Dry barrel type, 15 cm inlet with pump connection	
39Y-7	Deluge & Sprinkler System		Located over rotating components that handle flammable fluid plus transformers	
39Y-8	Portable Extinguisher	60		
39Y-9	Yard Fire Water Piping	1	8000 m	
39Y-10	Building Fire Water Piping	1	8000 m	

Note 1: This plant is the same as that in the Shell case.

Table C-15

EQUIPMENT LIST
PLANT 40 (KRW CASE)
WASTE WATER TREATING

Item No.	Title	Qty.	Description/Unit	Remarks
40G-1	Clarifier Sludge Pump	1+1	Centrifugal, Cast Iron with rubber lining, Design Flow: 1.7 m3/h Liquid Head: 15 m 0.5 BHP	
40G-2	Backwash Water Pump	1+1	Centrifugal, Cast Iron Design Flow: 5 m3/h Liquid Head: 15 m 1 BHP	
40G-3	Backwash Settled Water Pump	1+1	Centrifugal, Cast Iron Design Flow: 5 m3/h Liquid Head: 15 m 1 BHP	
40G-4	Thickener Underflow Pump	1+1	Mayno, 304 S.S. Design Flow: 0.5 m3/h Liquid Head: 21 m 0.5 BHP	
40G-5	Regenerant Discharge Pump	1+1	Centrifugal, Alloy 20 Design Flow: 10 m3/h Liquid Head: 30 m 3 BHP	
40G-6	Slop Oil Pump	1	Recip, Cast Iron Design Flow: 1.1 m3/h Liquid Head: 21 m 1 BHP	
40G-7	Storm Runoff Water Pump	1	Centrifugal, Cast Iron Design Flow: 300 m3/h Liquid Head: 23 m 35 BHP	
40G-8	Oily Water Pump	1	Centrifugal, Cast Iron Design Flow: 2.3 m3/h Liquid Head: 15 m 2 BHP	
40G-9	Thickener Overflow Pump	1+1	Centrifugal, Cast Iron Design Flow: 2 m3/h Liquid Head: 15 m 2 BHP	
40D-1	Neutralization Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 3.75 m Height: 4.2m	

Table C-15

EQUIPMENT LIST
PLANT 40 (KRW CASE)
WASTE WATER TREATING

Item No.	Title	Qty.	Description/Unit	Remarks
40D-2	Spent Backwash Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 3.5 m Height: 3.5 m	
40D-3	Oily Water Sump	1	Rectangular vessel, concrete, 1.21 m x 1.21 m x 1.82 m	
40D-4	Thickener Overflow Sump	1	Rectangular vessel, concrete, 1.3 m x 1.3 m x 1.75 m	
40Z-1	Sludge Thickener	1	Vertical vessel, C.S., epoxy lining Diameter: 3.9 m Height: 4.5 m	
40Z-2	Filter Press	5	304 S.S., 40 m2 filter area	
40Z-3	Sanitary Waste Treatment Package	1	8 m3/h capacity	

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Table C-16

EQUIPMENT LIST
PLANT 43 (KRW CASE)
BUILDINGS (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
43R-1	Control Building	1	Three story, steel frame, 23m x 38m	
43R-2	Administration Building Including Laboratory & Medical Facility	1	Two story, concrete, 30m x 44m	
43R-3	Warehouse	1	Pre-engineered metal building, 45m x 60m with 6.7m eave height and cast in place reinforced slab	
43R-4	Machine Shop and Maint. Building	1	Pre-engineered metal building, 12m x 30m with 6.7m eave height and cast in place reinforced slab	

Note 1: This plant is identical to that in the Shell case.

Table C-17

EQUIPMENT LIST
PLANT 36, 41, 42 (KRW CASE)
INSTRUMENT AND CONTROL, GENERAL SERVICES AND MOBILE EQUIPMENT, SITE PREPARATION

These three plants have been defined and described in Section 5.1.3.

No equipment lists were developed for these plants.

Appendix D

EQUIPMENT LISTS

IGCC PLANT

(MOVING BED CASE)

Table D-0

EQUIPMENT LIST (MOVING BED CASE)
COAL TRANSPORTATION (MERRY GO ROUND) SYSTEM

Sl.No.	Title	Qty.	Description
1.	Railway track	-	Length - 20 Km
2.	Wagons	28	Bottom discharge
3.	Locomotives	3	WDS - 6
4.	In motion weigh bridge	2	90 Te
5.	Signalling & telecommunication		
6.	Coal bunker for receiving sized coal (6-50 mm) from Merry-Go-Round System and feeding to IT-23 in Plant-2	1	100 M^3

Table D-1

EQUIPMENT LIST

Plant-1 (Moving Bed case)

COAL RECEIVING, STORAGE & HANDLING

Item No.	Title	Qty.	Description/Unit	Remarks
IT-1	Sized Coal conveyer	1	Type: Belt Capacity: 900 tph Width: 1050 mm Length: 75m	
IT-3	Distribution Bin	1	Capacity: 175 tons Material: CS Plan: 13m X 4m Vertical side: 4m Conical side: 2.5m No. of outlets: 3 Clearance from ground: 6m	
IT-2	Shuttle Conveyo r	1	Type: Reversible shuttle belt. Capacity: 900 tph Width: 1050 mm Length: 7m	
IT-4	Distribution Bin Vibrating Feeder	2	Type: Vibrating, Capacity: 0 to 900 tph Width: 1200 mm	
IT-5	Day Store Stacking conveyor	1	Type: Belt, Capacity: 900 tph Width: 1050 mm Length: 120m	
IT-6	Day storage pile	1	Diameter: 80m Height: 27.5m Capacity: 10000 tons -live 35000 tons - total Accessory: Lowering tube	

Table D-1

Item No.	Title	Qty.	Description/Unit	Remarks
IT-7	Reclaim Hoppers	3	Capacity: 10 tons. Construction: CS Location: Below ground under day storage in tunnel	
IT-8	Reclaim Feeders	1+2	Type: Vibrating, Capacity: 0-500 tph Width: 900mm	
IT-9	Day stock Reclaim conveyor	1	Type:Belot, Capacity: 500 tph Width: 900 mm Length: 150m	
IT-10	Dist. Bin Weigh belt feeder	1	Type: Weigh Belt Capacity: 0-500 tph Width: 1200 mm	
IT-11	Storage yard Belt conveyor	1	Type: Reversible Belt, Capacity: 900 tph Width: 1050 mm Length: 360m	
IT-12	Sized coal storage pile	2	Type: Open Pile, Capacity: 62,000 tons live- 5.5. days.	
IT-13	Reversible stacker reclaimer	1	Stocking: 900 tph Reclaiming: 0-500 tph Boom length: 35m Boom conveyoer:Reversible Width: 1050mm	
IT-14	Storage yard belt conveyor	1	Type: Belt Capacity: 900 tph Width: 1050 mm Length: 360m	
IT-15	Surge Bin	1	Capacity: 130 tons Construction: Steel Plan size : 5m X 11m Liners: Conical portion CS Outlets: 2	
IT-16	Vibrating Feeder	2	Type: Vibrating, Capacity: 0-500 tph Width: 1200mm	

Table D-1

Item No.	Title	Qty.	Description/Unit	Remarks
IT-17	Scalping screen	2	Type: Vibrating single deck. Feed rate: 500 tph Size: 2.1m X 4.9m Deck size - 6 mm	
IT-18	Conveyoer	1	Type: Belt Capacity: 500 tph Width: 900 mm Length: 360m	
IT-19	Conveyo-r to disposal	1	Type: Belt Capacity: 500 tph Width: 900 mm Length: 360m	
IT-20	Transport conveyor	1+1	Type: Belt Capacity: 500tph Width: 900mm Length: 50m	
IT-21	Weigh scale	2	Belt width 900mm Capacity: 500 tph	
IT-22	Dust Collectors	2	Type: Bag House, Area: 350 Sq.m. Fan Flow: 10 Cubic mps.	
IT-23	Sized coal conveyor.	1	Type: Belt. Capacity: 900 tph Width: 1050 mm Length: 75m	

Table D-2

EQUIPMENT LIST
PLANT 4 (MOVING BED CASE)
TAR AND OIL FIRED BOILER

Item No.	Title	Qty.	Description/Unit	Remarks
1	Tar & Oil fired boiler	2	Capacity : 150 Te/hr of steam Steam condition : Pressure : 112 Kg/cm2g Temp. : 542°C	

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TABLE D-3
EQUIPMENT LIST
PLANT-5 (MOVING BED CASE)
COAL GASIFICATION

Sl. No.	Plant Name	No. of trains	Design Capacity/Train
01.	Gasification	14	808 MTPD of coal (HHV-3282 Kcal/Kg)
02.	Gas washing & waste heat boiler	14	Gas washing 58000 Nm3/hr of raw gas laden with tar, oil & dust. Waste heat boiler. Heat load 2.725 X 10^6 Kcal/hr.
03.	Tar & oil separation	4	Tar separation - 417 Kg/hr(total) Oil separation- 4433 Kg/hr (total)
04.	Clean gas preheating & gas cooling	14	Heat loads of gas Heater-I 1.82 X10^6 $\frac{Kcal}{hr}$, Precooler: 1.18 X10^6 $\frac{Kcal}{hr}$, After cooler: 7.0 X 10^6 $\frac{Kcal}{hr}$
05.	Additional & boost air compressor	2	Additional air compressor capacity 41,000 Nm3/hr each from 0.98 to 12.3 kg/cm2 abs. Boost air compressor capacity 245000 Nm3/hr each from 12 to 32 kg/cm2 abs.
06.	Ash handling	1	4120 MTPD of ash (total)
07.	Gas preheating by steam	2	Shell & tube type heat exchanger, surface area-200m2 (each)

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Table D-4

Equipment List
Plant 6 (Moving Bed Case)
Acid Gas Removal

Item No.	Title	Qty.	Description/Unit	Remarks
6C-1	Absorber	2	Vertical Vessel, C.S. include mist eliminator, 10 trays, 4 passes Design pressure: 30 Kg/cm2(g) Design temp. : 150 C Diameter : 4.0 m T-T : 15 m	
6C-2	Stripper	2	Vertical vessel, C.S., include mist eliminator, 20 trays, 2 passes Design pressure: 10 Kg/cm2(g) Design temp. : 150 C Diameter : 2 m T-T : 20 m	
6C-3	Stripper Reflux Drum	2	Horizontal cylindrical vessel, C.S., Design pressure:10 Kg/cm2(g) Design temp. : 150 C Diameter :1.4m T-T : 5 m	
6C-4	Solvent Surge Tank	2	Horizontal cylindrical vessel, C.S., Design pressure: 32 Kg/cm2(g) Design temp. : 150 C Diameter : 3.5 m T-T : 8.75 m	
6D-1	Solvent Storage Tank	2	Cone roof, 316 SS Design pressure :Atmosphere Design temp. : 45 C Diameter : 5.75 m T-T : 8.2 m	
6E-1	Lean Solvent Trim Cooler	2	Shell & tube Duty : 11.9 million Kcal/h Surface area : 1183 m2 Shell material : C.S. Shell design pressure: 30 Kg/cm2(g) Shell design temp.: 90C Tube material : C.S. Tube design pressure : 20 Kg/cm2(g) Tube design temp. : 150C	

Table D-4

EQUIPMENT LIST
PLANT 6 (MOVING BED CASE)
ACID GAS REMOVAL

Item No.	Title	Qty.	Description/Unit	Remarks
6E-2	Lean -Rich Solvent Exchanger	2	Shell & tube Duty : 18.8 Million Kcal/h Surface area:2134 m2 Shell material : C.S. Shell design pressure: 11 Kg/cm^2 (g) Shell design temp.:150C Tube material : C.S. Tube design pressure : 30 Kg/cm^2 (g) Tube design temp.: 150C	
6E-3	Stripper Reboiler	2	Vertical thermosyphon Duty : 9.5 million Kcal/h Surface area: 580 m^2 Shell matêrial : C.S. Shell design pressure: 10 Kg/cm^2 (g) Shell design temp.: 150C Tube material : C.S. Tube design pressure : 10 Kg/cm^2 (g) Tube design temp.: 150C	
6E-4	Stripper Overhead Condenser	2	Shell & Tube Duty : 3.1 million Kcal/h Surface area : 225 m^2 Shell material : C.S. Shell design pressure : 10 Kg/cm^2 (g) Shell design temp.: 150C ~~Shell~~ Tube material: C.S. Tube design pressure : 7 Kg/cm^2 (g) Tube design temp.: 110C	
6G-1	Solvent Feed Pump	2+1	Horizontal centrifugal Casing: C.S.,impeller: ductile iron, Flow:26 m3/h Temp. : 30 C Liquid head : 35 m	

Table D-4

EQUIPMENT LIST
PLANT 6 (MOVING BED CASE)
ACID GAS REMOVAL

Item No.	Title	Qty.	Description/Unit	Remarks
6G-2	Lean Solvent Recycle Pump	2+1	Horizontal centrifugal Casing:C.S.,impeller: ductile iron Flow : 480 m^3/h Temp : 123 C Liquid Head : 350m	
6G-3	Stripper Reflux Pump	2+1	Horizontal centrifugal Casing;C.S.,impeller: ductile iron Flow : 20 m^3/h Temp : 44 C Liquid head : 50m	
6T-4	Solvent Carbon Filter	2+1	Vertical drum packed bed, C.S. Design pressure : 40 Kg/cm^2 (g) Design temperature:150C Diameter : 2 m	

Table D-5

EQUIPMENT LIST
PLANT 7 (MOVING BED CASE)
SULPHUR RECOVERY

This Selectox process used for this plant is a proprietary design of Parson. No equipment list is available.

One train is used. The normal gas feed is 13937 Nm^3/h with 7.5% H_2S.

Total sulfur produced is 33.3 MTPD in solid block.

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Table D-6

EQUIPMENT LIST
PLANT 9 (MOVING BED CASE)
COMBINED CYCLE

Item No.	Title	Qty.	Description/Unit	Remarks
9C-1	Blowdown Flash Drum	2	Vertical vessel, C.S. Design pressure:4.2kg/cm2(g) Design temperature:190C Diameter: 1725mm T-T 4100mm	
9C-2	Condensate Storage Tank	1	Vertical vessel, C.S. with epoxy lining Design pressure: 3.5 kg/cm2(g) Design temperature: 51°C Diameter: 7.4 m T-T 10.7m	
9C-3	Naptha tank (for start up and shut down of GT)	1	Capacity : 100 m^3	
9E-1	Heat Recovery Steam Generator	2	Duel pressure system, include the steam drums and deaerator, and a stack Heat transfer area (extended surface) is: HP superheater: 10860 m2 Reheater: 9210m2 HP evaporator: 44200 m2 IP superheater: 2100 m2 HP economizer 1: 33150 m2 IP evaporator: 23820m2 HP economizer II: 17515m2 IP economizer: 1650 m2 Integral deaerator: 25400m2 Steam condition is: HP: 109 kg/cm2 abs, 538 C IP & RH:25 kg/cm2 abs, 538 C Stack: 32m high, 7.3m diameter	
9E-2	Surface Condenser	2	Shell & tube, single shell, 2 passes Shell: C.S., tube: S.S. Include vacuum pump package Duty: 202 million Kcal/h Surface area: 10600 m2	
9F-1	Startup Boller	1	Rated at 11000 kg/h, 18.6 kg/cm2 abs saturated steam	
9G-1	Condensate Pump	2+2	Horizontal centrifugal Casing: Cast iron, impeller: bronze Flow: 390 m3/h Temp: 49C Diff. pressure 4.4 kg/cm2	

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Table D-6
EQUIPMENT LIST
PLANT 9 (MOVING BED CASE)
COMBINED CYCLE

Item No.	Title	Qty.	Description/Unit	Remarks
9G-2	LP Boiler Feedwater Pump	2+2	Horizontal centrifugal, 11-13% Cr Flow: 130 m3/h Temp: 116°C Diff : pressure: ~~XXXXX~~ 35 Kg/cm2	
9G-3	HP Boiler Feedwater Pump	2+2	Horizontal centrifugal, 11.13% Cr Flow: 440 m3/h, Temp: 116°C Diff. pressure: 148.3 kg/cm2	
9G-4	Condensate Transfer Pump	2+1	Horizontal centrifugal, 316 S.S. Flow: 390 m3/h Temp: 49C Diff. pressure 3.52 kg/cm2	
9G-5	Process make up water (BFW quality) Transfer pump	1+1	Horizontal centrifugal, 11-13%, Cr Flow: 100 m3/hr Temp: 49°C Diff. pressure: 3.52 Kg/cm2	
9G-6	Naptha pump (For start up and shut down of GT)	1+1	Capacity: 4m3/hr Suction/Discharge (Kg/cm2g) : 0/15	
9K-1	Gas turbine generator	2	General Electric MS9001F gas turbine, single shaft, with inlet filter and other auxiliary systems, rated 212 MW at ISO Generator: hydrogen cooled, 50 HZ, 3000 rpm, 16500 volts, 240 MVA	
9K-2	Steam Turbine Generator	2	Triple extraction double flow condensing 76 cm last stage bucket, steam flow: HP SH: 360360 kg/h RH: 372,540 kg/h 43.2 kg/cm2 (a) extrac steam: 3890 kg/h 35 kg/cm2 (a) extrac steam: 37900 kg/h 3.9 Kg/cm^2 (a) 38325 Kg/h inlet steam Generator: hydrogen cooled, 50 Hz, 3000 rpm, 16500 volts, 180 MVA	

Contd.....

Table D-6

Item No.	Title	Qty.	Description/Unit	Remarks
9R-1	Gas Turbine Building	2	34m X 40m floor area, 16m high structure, lower part reinforced concrete, upper part structure steel	
9R-2	Steam T-urbine Bu-ilding	1	34m X 45m floor area, 16m high structure, lower part reinforced concrete, upper part structure steel.	

Table D-7

EQUIPMENT LIST
PLANT 30 (MOVING BED CASE)
SOLID WASTE DISPOSAL

Sl. No.	Title	Qty.	Description
1.	Ash flow channels	2	Service: Flow of ash slurry of about 10% ash from gasification plant to ash pit Flow: 2000 Te/hr Length of Channel: 200m (approx. width of channel- 900mm) Channels will lead to an ash slurry pit with pumping facility and shall have adequate slope
2.	Ash slurry pump	2+1	Capacity: 1500 Te/h of ash slurry Disch, pressure: 7 Kg/cm2g Material: High chrome steel
3.	Ash settling pond	2	Ash slurry (10% ash) quantity: 2000 te/hr clean water from the pond should overflow to a clean water pond, from where it will be pumped back and reused in the system. While one of the settling pond will be in line, another will be under drying/ash removal operation.
4.	Clean water pump	1+1	Capacity : 1600 m3/hr Disch press: 5kg/cm2g

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Table D-8

EQUIPMENT LIST

PLANT 31 (MOVING BED CASE)

RELIEF & BLOWDOWN (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
31D-1	Knock Out Drum	1	Horizontal Vessel, C.S. Design Temp: 66C Design Pressure: 1kg/cm^2 (g) Diameter: 3m T-T: 11m	
31F-1	Main Flare	1	Design gas flow: 806500NM^3/h Design heat duty: 1146 million Kcal/h C.S. Diameter: 200 cm Height: 32m	
31G-101	K.O.Drum Pump	1+1	Centrifugal, C.S. Liquid head: 20m Flow: 34 m3/h	

Note 1 : This plant is identical to that in the Shell case.

Table D-9

EQUIPMENT LIST
PLANT 32 (MOVING BED CASE)
INTERCONNECTING PIPING

Major items of this plant are:

Fuel oil lines

Pipe and pipeways for raw water supply and BFW makeup water supply

Pipe and pipeways for treated waste water and steam blowdown

Instrument and service air lines

Steam lines to the liquid oxygen and liquid nitrogen vaporizers

Pipe and pipeways between process areas

Distribution of cooling water and service water from the cooling tower

Coal gas, steam, feedwater, and condensate lines between the process and power areas

Miscellaneous process and utility piping

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Table D-10
EQUIPMENT LIST
PLANT 33 (MOVING BED CASE)
COMPRESSED AIR SYSTEM

Item No.	Title	Qty.	Description/Unit	Remarks
33C-1	Compressed Air Receiver	3	Vertical vessel, C.S. Design pressure: 10kg/cm2(g) Design Temperature 65C Diameter: 1.37 m T-T: 3.81m	
33K-1	Air Compressor	3	Design gas flow: 2000 Nm3/h Pressure head: 6.9 kg/cm2 Cast iron casing, C.S. Impeller Centrifugal, motor drive	
33T-1	Desiccant Air Dryer	3	Twin tower, cycling type Design gas flow: 1000 Nm3/h Design pressure:10kg/cm2(g) Design pressure: 65C	

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Table D-11

EQUIPMENT LIST
PLANT 34 (MOVING BED CASE)
FUEL OIL HANDLING SYSTEM

Item No.	Title	Qty.	Description/Unit	Remarks
34C-1	Fuel Oil Tank	2	Capacity: $400m^3$	
34G-1	Fuel Oil Pump	2	Centrifugal, C.S. Capacity: 40m3/h	

Fuel oil unloading from railway tankers & handling facilities has been provided.

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Table D-12
EQUIPMENT LIST
PLANT 35 (MOVING BED CASE)
ELECTRICAL SYSTEMS

Item No.	Title	Qty.	Description/Unit	Remarks
35P-1	H.V.Circuit Breaker	21	235KV, 2000A, 63KA RMS system	
35P-2	H.V.Disconnect Switches	42	3-pole 235 KV,"V" type center break	
35P-3	H.V. Disconnect Switches with Earthing Blade	6	3-pole 235 KV, 2000A, vertical break with grounding blade.	
35P-4	H.V.Lighting Arresters	11	184 KV	
35P-5	Step-up Transformer for Gas Turbines	2	180/240/300 MVA, OA/FA/FOA, 16.5-220 KV, Delta-Wye	
35P-6	Step-up Transformer for Steam Turbines	2	110/145/180 MVA, OA/FA/FOA, 16.5-220 KV, Delta-Wye	
35P-7	Step-down Transformer for Process Auxi. Power & Cooling Tower	6	5/6.25 MVA, OA/FA, 16.5-6.6 KV, Delta-Wye	
35P-8	Step-down Transformer for Start up	1	12MVA, FOA, 220-6.6 KV, Wye-Wye, core form type	
35P-9	Step-down Transformer for combined Cycle Auxiliary power	2	4.2/5.25 MVA, OA/FA 16.5-6.6 KV, Delta-Wye	
35P-11	Step-down Transformer for combined cycle Ausiliary Power (L.V.)	4	2/2.3 MVA, OA/FA, 6.6 KV-480 V, Delta-Wye	
35P-12	Step-down Transformer for Process Plant Auxiliary Power (L.V.)	6	1.5 MVA, OA 16.5 KV, 480 V, Delta-Wye	
35P-13	M.V.Switchgear	2	16.5 KV, 750MVA S.C. 3000A	
35P-14	M.V.Motor Control Center	8	6.6 KV, 250MVA S.C., 2000A	
35P-15	L.V.Load Center Buses	4	400 V, 42 KA S.C. 3000A	
35P-16	L.V.Motor Control Center	lot	400 V, 800A	

Table D-13

EQUIPMENT LIST

PLANT 37 (MOVING BED CASE)

COOLING WATER SYSTEM

Sl.No.	Title	Qty.	Description
1.	Cooling Tower	1	33 cells, 2500 m^3/h water circulation per cell, 5 cycles of concentration
2.	Circulating water pumps	9+2	Centrifugal, cast iron, Design flow- 9200 m3/hr Discharge pressure : 5 Kg/cm^2g
3.	Chemical dosing unit		

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TABLE D-14

EQUIPMENT LIST

PLANT 38 (MOVING BED CASE)

RAW WATER SUPPLY AND TREATMENT

Sl. No.	Title	Qty.	Description
01.	Raw water transfer pump	1+1	Centrifugal, cast iron, Flow- 2100 m3/hr Discharge pressure - 12kg/cm2g
02.	Raw water storage pond	1	Capacity - 70,000 m3
03.	Raw water transfer pump from pond to water treatment plant	1+1	Centrifugal, cast iron, Flow- 2100 m3/hr Discharge pressure-5kg/cm2g
04.	Water Treatment Plant	1	Capacity - 2000 m3/hr
(i)	Sludge filter arrangement with recycle of recovered water		
(ii)	Process water pump	1+1	Capacity-2000 m3/hr Discharge pressure-5kg/cm2g
(iii)	Sanitary water pump		
05.	DM water Plant	1	Capacity - 260 m3/hr
(i)	DM water transfer pump	1+1	Capacity - 260m3/hr Discharge pressure-5kg/cm2g
(ii)	Condensate polishing Unit	1	Capacity - 900 m3/h of polished condensate.

Table D-15
EQUIPMENT LIST
PLANT 39 (MOVING BED CASE)
FIRE PROTECTION (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
39D-1	LP Carbon Dioxide Storage Tank	1	8 tonnes	
39G-1	Fire Water Pump	2	Centrifugal, driven by diesel engine Design flow: 450 m^3/h Liquid head: 180m	
39Y-1	Halon System	2	Installed in control rooms	
39Y-2	Carbon Dioxide System	2	Installed in turbine building	
39Y-3	Hose Cart	4	1.2m steel wheels, each with 80m long 6.35 cm diameter hose	
39Y-4	Hose Reel	20	30m long, 3.81 cm diameter	
39Y-5	Fire and Smoke De-tector	16		
39Y-6	Fire Hydrants	60	Dry barrel type, 15 cm inlet with pump connection	
39Y-7	Deluge & Sprin-kler System		Located over rotating components that handle flammable fluid plus transformers.	
39Y-8	Portable Extin-guisher	60		
39Y-9	Yard Fire Water Piping	1	8000m	
39Y-10	Building Fire Water Piping	1	8000m	

Note 1: This plant is the same as that in the Shell case.

Table D-16
EQUIPMENT LIST
PLANT 40 (MOVING BED CASE)
WASTE WATER TREATING

Item No.	Title	Qty.	Description/Unit	Remarks
40G-1	Clarifier Sludge Pump	1+1	Centrifugal, Cast Iron with rubber lining, Design Flow: 2.5 m3/h Liquid Head: 15m	
40G-2	Backwash Water Pump	1+1	Centrifugal, Cast Iron Design Flow: 15.3m3/h Liquid Head: 15m	
40G-3	Backwash Settled water pump	1+1	Centrifugal, Cast Iron Design Flow: 15.3m3/h Liquid Head : 15m, 2 BHP	
40G-4	Thickener Under-flow Pump	1+1	Mayno, 304 S.S. Deisgn Flow: 1 m3/h Liquid Head: 21m	
40G-5	Regenerant Disch-arge Pump	2+1	Centrifugal, Alloy 20 Design Flow: 35m3/h Liquid Head: 30m	
40G-6	Slop Oil Pump	1	Recip, Cast Iron Design Flow: 1.1 m3/h Liquid Head: 21m	
40G-7	Storm Runoff Water Pump	1	Centrifugal, Cast Iron Design Flow: 300 m3/h Liquid Head: 23m	
40G-8	Oily Water Pump	1	Centrifugal, Cast Iron Design Flow: 2.3 m3/h Liquid Head: 15m	
40G-9	Thickener Overflow pump	1+1	Centrifugal, Cast Iron Design Flow: 5 m3/h Liquid Head: 15m	
40D-10	Neutralization Tank	1	Vertical vessel, C.S., epoxy lining Diameter: 5m Height : 5.6 m	

Table D-16

EQUIPMENT LIST
PLANT 40 (MOVING BED CASE)
WASTE WATER TREATING

Item No.	Title	Qty.	Description/Unit	Remarks
40D-2	Spent Backwash Tank	1	Vertical vessel, CS epox y lining Diameter: 5.2m Height: 5.2m	
40D-3	Oily Water Sump	1	Rectangular vessel, concrete, 1.21m X 1.21 m X 1.82m	
40D-4	Thickener Over-flow Sump	1	Rectangular vessel, concrete, 1.94m X 1.94m X 2.60m	
40Y-1	Process waste water Treating Package	1	Proprietary design of NEERI, include equalisation, lime treatment, ammonia, stripping by air and its recovery, neutralisation and biological treatment of phenol and cynides; waste water flow rate 180 m3/hr .	
40Z-1	Sludge Thickener	1	Vertical vessel, C.S., epoxy lining Diameter: 5.8m Height: 6.7 m	
40Z-2	Filter Press	5	304 S.S., 120 m2 filter area	
40Z-3	Sanitary Waste Treatment Pack-age	1	8 m3/h capacity	

Table D-17

EQUIPMENT LIST
PLANT 43 (MOVING BED CASE)
BUILDINGS (NOTE 1)

Item No.	Title	Qty.	Description/Unit	Remarks
43R-1	Control Building	1	Three story, steel frame, 23m X 38m	
43R-2	Administration Building including Laboratory & Medical Facility.	1	Two story, concrete, 30m X 44m	
43R-3	Warehouse	1	Pre-engineered metal building, 45m X 60m with 6.7m eave height and cast in place reinforced slab	
43R-4	Machine Shop and Maint. Building	1	Pre-engineered metal building, 12m X 30m with 6.7m eave height and cast in place reinforced slab	

Note 1: This plant is identical to that in the Shell case.

Table D-18

EQUIPMENT LIST
PLANT 36, 41, 42 (MOVING BED CASE)
INSTRUMENT AND CONTROL, GENERAL SERVICES AND MOBILE EQUIPMENT, <u>SITE PREPARATION</u>

These three plants have been defined and described in Section 5.1.4

No equipment lists were developed for these plants.

Appendix E

EQUIPMENT LISTS

DEMONSTRATION PLANT

Table E-1

EQUIPMENT LIST

Crushed Coal Transportation from PC Plant to Demonstration Plant Battery Limit.

Sl. No.	T i t l e	Qty.	Description
1.	Rotary Disc Loader or Cam shell	1	Capacity : 200 Te/hr
2.	Railway Locomotive	1	
3.	Railway Wagons	10	8 wheelers, Capacity - 50 Te

Table E-2

EQUIPMENT LIST

COAL UNLOADING AND DRYING

Sl. No.	T i t l e	Qty.	Description
1.	Coal Reclaiming hopper	1	R.C.C., Capacity : 40 Te
2.	Vibratory feeder	1	Capacity : 100 Te/hr
3.	Reclaiming conveyor (BT 1)	1	Belt Width : 650 mm Capacity : 100 Te/hr
4.	Dozer	2	Capacity : 90 HP
5.	Payloader	1	
6.	Fluidbed drying system	1	Wet coal feed rate : 100 tph Feed moisture - 18% Product moisture - 5%/2.5% Evaporation - 13.7tph/16.3 tph Below bed hot gas temp. - 504°C Product temp. - 82°C Stack gas - 82°C Stack gas dew point - 72°C Auxiliaries - Cyclones
7.	Flue gas generator complete with air blower and auxiliaries	1	Fuel oil fired, fuel oil consumption - 530/560 kg/hr
8.	Inlet fan	1	Flow - 55 cubic mps SP - 525 mm water Temp. - 504°C
9.	Exhaust fan	1	Flow - 31 cubic mps SP - 525 mm water Temp. - 82°C
10.	Dust collector	2	Type - Bag house Filtering area - 390 Sq.m Temperature - 90°C

Table E-3

EQUIPMENT LIST

Secondary coal crusher, limestone handling & crushing

Sl. No.	T i t l e	Qty.	Description
1.	Limestone reclaiming hopper	1	Capacity : 5 Te MOC : C.S.
2.	Belt feeder (ET 2)	1	Capacity : 3.5 Te/hr Width : 400 mm
3.	Bucket elevator (ET 3)	1	Capacity : 3.5 Te/hr Type : Belt bucket elevator
4.	Coal crusher	2	Capacity : 100 Te/hr
5.	Belt conveyor (ET 4)	1	Capacity : 100 Te/hr Width : 650 mm
6.	Belt conveyor (ET 5)	1	Capacity : 100 Te/hr Width : 650 mm
7.	Bucket Elevator (ET 6)	1	Capacity : 100 Te/hr Type : Chain bucket elevator
8.	Belt conveyor (ET 7)	1	Capacity : 100 Te/hr width : 650 mm
9.	Storage Bunkers	1 set of 6 nos.	Capacity : 170 Te (each) MOC : RCC
10.	Vibratory feeders	6	Capacity : 25 Te/hr
11.	Bucket elevator (ET 8)	1	Capacity : 100 Te/hr Type : Chain Bucket elevator
12.	Hammer Mill	1	Capacity : 3.5 Te/hr Product size : (-) 6 mm
13.	Rod Mill	1	Capacity : 3.5 Te/hr Product size : 16 mesh

Table - E-4

EQUIPMENT LIST

Coal Gasification

Sl. No.	T i t l e	No. of trains	Design capacity per train
A.	Coal Gasification (KRW Case)		
1.	Boost Air Compressor	1	49200 Nm^3/hr gas flow compressed from 12.4 to 36.2 Kg/cm^2a
2.	Gasification	1	910 MTPD of Coal (5% moisture)
3.	Ash Removal	1	370 MTPD of Ash
4.	Heat Recovery	1	Producing 43,199 Kg/hr saturated steam at 101 kg/cm2a
5.	Gas Conditioning	1	174968 Nm^3/h gas flow
6.	Recycle gas Compression	1	For ash transport and for filter operation
B.	Coal Gasification (U-Gas)		
1.	Boost Air Compressor	1	48300 Nm^3/hr gas flow compressed from 12.4 to 27.6 Kg/cm^2a
2.	Gasification	1	857 MTPD of coal (2.5% moisture)
3.	Ash Removal	1	312 MTPD of Ash
4.	Heat Recovery	1	Producing 36834 kg/hr saturated steam at 101 kg/cm^2a
5.	Gas Conditioning	1	166747 Nm^3/h gas flow

Table - E-5

EQUIPMENT LIST

SOLID WASTE DISPOSAL

Sl. No.	Title	Qty.	Description
1.	Ash Slurry Pit	1	Capacity : 750 M^3
2.	Ash Slurry Pump	2+1	Capacity : 90 M^3/hr Discharge pressure : 9 kg/cm^2a
3.	Slurry Discharge Pipe	1	Length : 6 Km Dia : 200 mm
4.	River Water Pump	1+1	Capacity : 160 M^3/hr Discharge Pressure : 9 kg/cm^2a
5.	River Water Pipe	1	Length : 1 Km Dia : 200 mm

Table - E-6

EQUIPMENT LIST

INTER CONNECTING PIPING

Sl. No.	Items	Specification
	Major items of this plant are :	
1.	Product fuel gas from gasification plant to gas turbine	Pipe Length : 400 M Dia : 500 mm Material : Alloy Steel
2.	Air from gas turbine to gasification	Pipe Length : 400 M Dia : 300 mm Material : Alloy Steel
3.	Export steam from gasification plant to HRSU/Steam turbine	Pipe Length : 400 M Dia : 200 mm Material : CS
4.	Start up Steam from HRSU to gasification	Pipe Length : 400 M Dia : 150 mm Material : Alloy Steel
5.	Fuel oil from storage to coal drying	Pipe Length : 400 M Dia : 25 mm Material : CS

Table - E-7

EQUIPMENT LIST

COMPRESSED AIR SYSTEM

Sl. No.	Title	Qty.	Description
1.	Air compressor along with air receiver and air drying system	2	Capacity : 600 Nm3/hr Pressure : 7 kg/cm2 Cast iron casing, CS impeller, centrifugal

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