11-3-3 Establishment of Master Plan

Further studies have been carried out as follows to establish the Master Plan.

(1) Derivatives Plant

1) Conformity with Indonesian Policy

Both fuel methanol and urea production will conform with;

- Energy policy
- Industrialization policy
- Transmigration policy

2) Prospect for Demand

Although the demand for methanol as a raw material for other chemicals will not increase in a great degree as is stated in section 9-4, it would drastically increase if fuel methanol is accepted as fuel in Indonesia. In this sense it is advantageous to produce fuel methanol.

For export, however, the prospect for methanol demand depends on its production cost since the methanol from this project must compete in foreign markets with those being produced in the Middle East and Oceania from cheap natural gas.

There will be a gradually increasing demand for urea. The competitiveness of urea from coal will, however, depend on its production cost since Indonesia has abundant natural gas resources of small scale reserves for LNG but enough for Urea.

3) Distribution Network

Fuel methanol is intended for use at small stationary electric power generation facilities as well as by automobiles like buses on fixed service route. Since no distribution network for fuel methanol exists at the moment, an investigation will have to be made in full detail in order to establish a completely new system.

On the other hand, in principle, an existing distribution network can be used for urea, even though it may have to be enforced.

4) Transportation

Pipeline and shipping/loading facilities including tankages for fuel methanol must be constructed. Also methanol tanker fleet, tank trucks, etc. must be prepared for the transportation of fuel methanol. These will cause a big additional investment. Although an existing system could be used for transportation of urea further from Palembang, an improvement of existing railway or construction of a new railway between Banko and Palembang would be necessary.

5) Competitive Plant

Although the methanol plant in Bunyu Island started operation in 1986, it will not be a competitive plant considering its capacity of 330,000 tons/year and location. On the other hand, urea production facilities in Palembang with much better site condition than in Banko naturally cause disadvantage to urea from this project in terms of production cost.

6) Technology Development

Many plants in the world are producing methanol or urea from natural gas. There would be no difficulty in replacing natural gas with synthesis gas.

7) Construction

Equipment and construction materials will be unloaded at Palembang and hauled for 200 km to the plant site. This means that the construction work will not be so easy especially in constructing both methanol and urea plants at the same time due to a large amount of work and transportation.

8) Operation and Maintenance

Since both methanol and urea plants exist in Indonesia, no difficulties would be found either in operation or maintenance. Evidently, however, difficulties will increase significantly if both of methanol and urea plants are constructed and put into operation.

9) Employees

Bringing a significant increase of employment opportunities, Case 2 of methanol/urea co-production will comform with Indonesian policy although it will also give rise to a problem with employing numbers of well qualified workers for operation and maintenance.

10) Investment Cost

Construction of a high pressure facility such as urea plant in addition to methanol plant will naturally increase the investment cost, even if the capacity of methanol plant is reduced, causing the difficulty of fund raising.

11) Prospect for Viability

According to the preliminary economic evaluation, only Case 1 of methanol production seems to be advantageous.

(2) Electric Power Generation Plant

1) Prospect for Demand

There will be constantly growing demand for electricity in Indonesia as shown in the Interim Report III (1986), pp. 159-160.
In the proposed Master Plan, however, only the case of supplying electricity to the adjacent area to the plants is to be discussed as is previously stated.

2) Technologies

Fluidized bed combustion has been selected for the Master Plan as per ATTACHMENT 11-3 and further development of technology for coal firing power generation is to be reviewed and incorporated into the final Proposed Project in the 3rd stage.

(3) Evaluation

Evaluation on chemical production plants is summerized in Table 11-3-7 which suggests that Case 1, constructing only a methanol plant, is advantageous. In the 2nd stage, however, we are to hold Case 2 of methanol and urea production.

To summerize, the following two cases of Master Plan are proposed in the 2nd stage.

i) Base Case
   - Case 1-B (Fig. 11-3-2)
     5,000 T/D Methanol Plant and 98 MW Fluidized bed combustion boiler

ii) Alternative
   - Case 2-B (Fig. 11-3-3)
     4,060 T/D Methanol Plant, 1,750 T/D
     Urea Plant and 147 MW Fluidized bed combustion boiler

The Master Plan covers on-site facilities, off-site facilities and infrastructure as listed in Table 11-3-8.

On-site facilities and off-site facilities are to be discussed in more detail in part 12.

Table 11-3-7 Evaluation on Chemical Production Plant

	Fuel Methanol	Fuel Methanol and Urea	Remarks
1. Conformity with Indonesian Policy	o	o	
2. Prospect for Demand			
- Domestic	o	o and △	
- Export	△	△ and △	
3. Distribution Network	x	x and o	
4. Transportation	o	o and x	
5. Competitive Plant	o	o and x	
6. Technology Development	o	o and o	
7. Construction	△	x	
8. Operation and Maintenance	△	x	
9. Number of Employees	△	o	
10. Investment Cost	△	x	
11. Prospect for Viability	o - △	△ - x	
12. Total Evaluation	o - △	△ - x	

o : Good   △ : Average   x : Poor

Table 11-3-8 On-site Facilities, Off-site Facilities and Infrastructure (1/2)

(1) On-site Facilities

1) Coal Gasification

i) Steel Scrap Stock Yard
ii) Coal Gasification
iii) Gas Holders

2) Methanol Production

3) Ammonia/Urea Production

4) Product Storage and Shipping

5) Boiler and Power Generation Facility

6) Air Separation Facility

7) Utility Facilities

i) Cooling Water System
ii) Service Water System
iii) Boiler Feed Water System
iv) Industrial Water System
v) Fuel Gas System
vi) Fuel Oil System
vii) Nitrogen System
viii) Instrument Air System
ix) Plant Air System
x) Steam System
xi) Steam Condensate Recovery System
xii) Electricity Distribution System

8) Interconnection Pipelines

i) Raw Materials and Products
ii) Utilities
iii) Waste Water and Gas

9) Flare System

10) Fire Fighting System

i) Fire Fighting Facilities
ii) Fire Engine House

Table 11-3-8 On-site Facilities, Off-site Facilities and Infrastructure (2/2)

11) Auxiliary Facilities

- i) Offices
- ii) Laboratory
- iii) Workshop
- iv) Warehouse
- v) Training Center
- vi) Mess Hall
- vii) Guard House
- viii) Mosque
- ix) Telecommunication Facilities
- x) Road Lighting

(2) Office Facilities

1) Belt Conveyor System

2) Stock Piles

- i) Brown Coal Stock Yard
- ii) Limestone Stock Yard

3) Water Intake System

4) Waste Disposal Facilities

- i) Ash and Slag Disposal
- ii) Dust Disposal (Incinerator)
- iii) Waste Water Treatment Facility

(3) Infrastructure

1) Airport or Heliport

2) Housing Complex

3) Guest House

4) Club House

5) Hospital

6) School

7) Mosque and Church

8) Market

9) Recreation Facililties

10) Access Road

11) Parking Lot

12. PRELIMINARY CONCEPTUAL DESIGN OF PROPOSED MASTER PLANS

In order to provide the basis for economic viability studies, preliminary conceptual design has been carried out for the two cases of Master Plan proposed in section 11-3.

Preliminary conceptual design in this stage covers on-site facilities including utility facilities and auxiliary facilities, and off-site facilities.

12-1 CIRCUMSTANCE OF BANKO AND ITS SURROUNDINGS

This section introduces the circumstance of Banko and its surroundings such as location and traffic, population and facilities, climate, port and river which are the basis to determine the plant location and configuration as well as to carry out the overall conceptual design.

12-1-1 Location and Traffic

Banko area (at 104^{o} east longitude and $3^{o}41'$ south latitude) lies 10 - 15 km to the southeast of Tanjung Enim, stretching for 10 - 20 km in gentle unduration with a clump of bushes in South Sumatra Province. (See Fig. 12-1-1)

Tanjung Enim, a small town with a population of 5,000, is 190 km away or 4-hour-drive distant from Palembang, and 20 km south of Muara Enim.

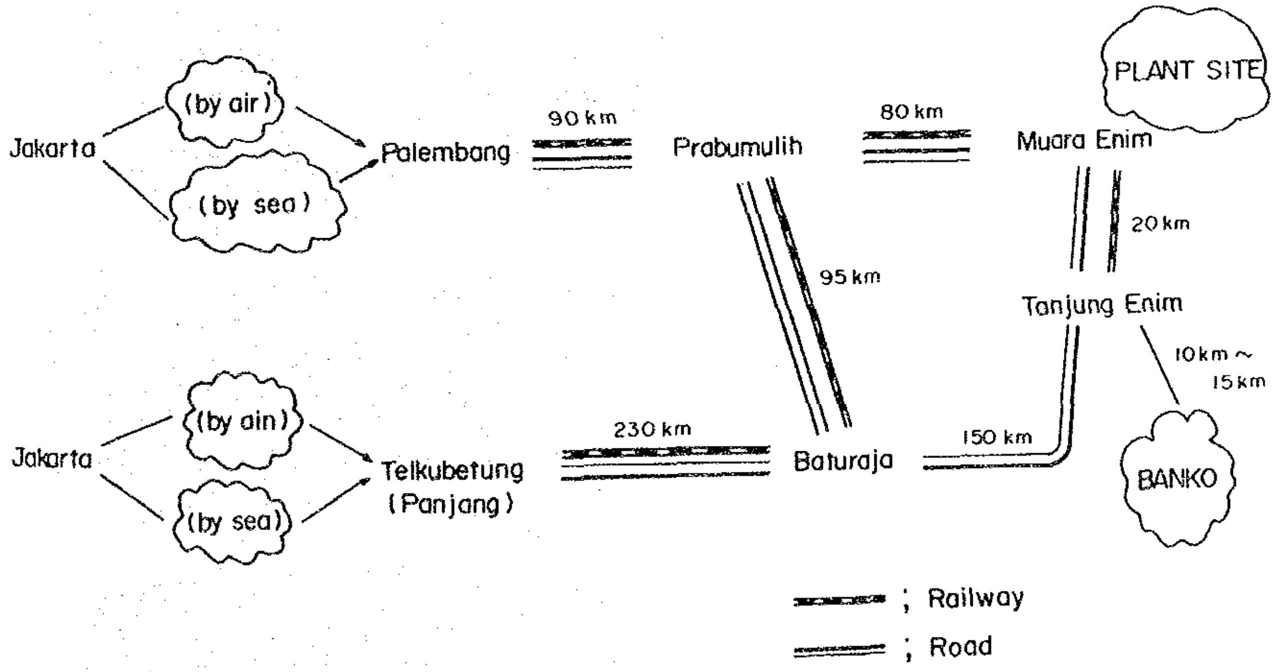


Fig. 12-1-1 Location of Banko

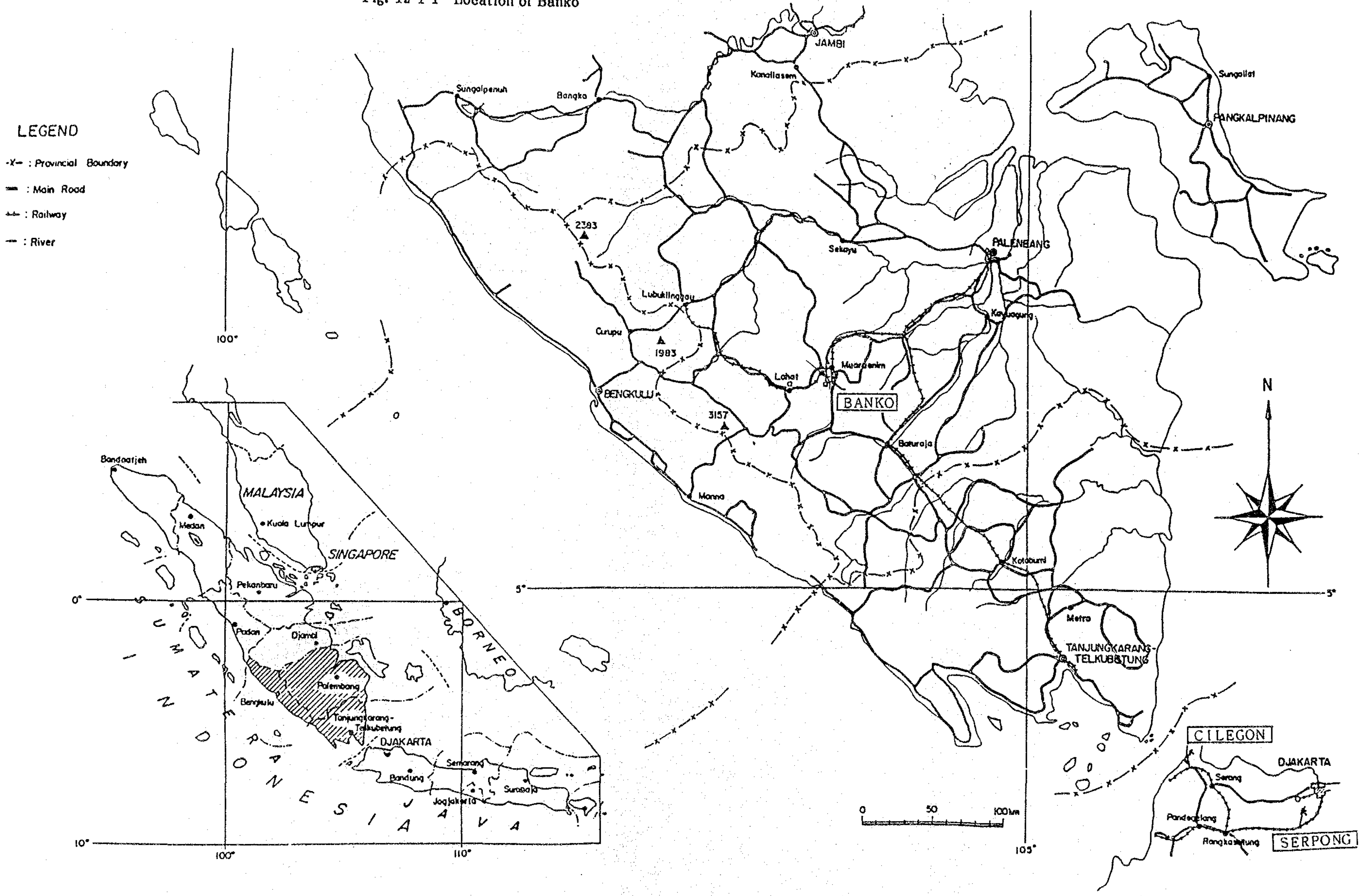
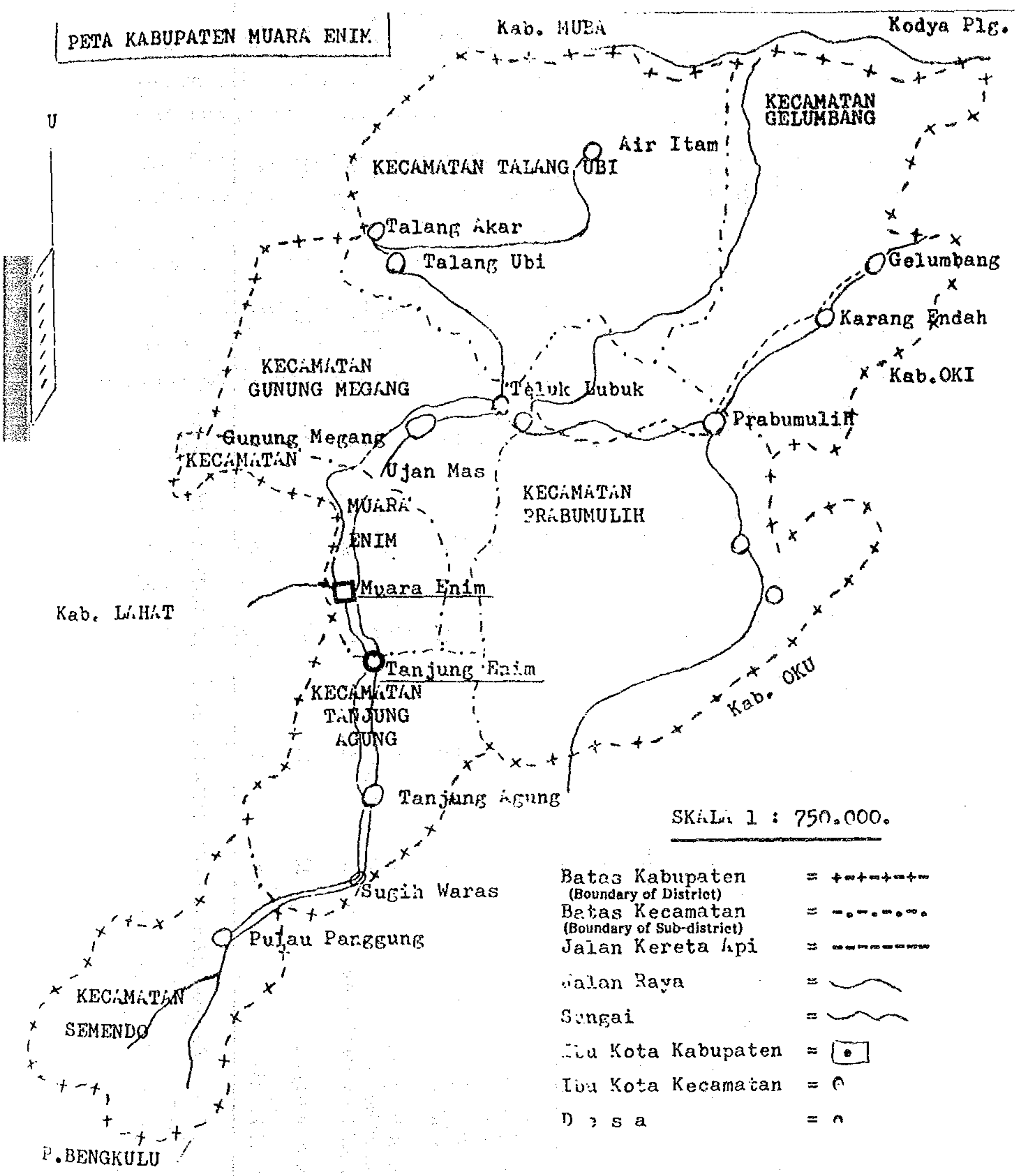


Fig. 12-1-2 Map of Muara Enim District



Source; KABUPATEN MUARA ENIM, DALAM ANGKA, 1982

Table 12-1-1 Population and Public Facilities of Muara Enim District

(1982)

Sub-district	Semendo	Tanjung Agung	Muara Enim	Genung Megang	Talang Ubi	Prabumulih	Gelumbang	Total
Area, km^2	900	850	475	1,900	1,850	2,150	1,450	9,575
Population, persons	29,932	57,857	34,337	43,346	90,207	115,854	79,637	451,170
Density, persons/km^2	33	68	72	23	49	54	55	47
No. of Villages	31	32	20	23	41	48	66	261
No. of Schools								
. Elementary	38	54	42	37	70	99	92	432
. Jr. High School	4	6	6	4	10	10	6	46
. High School	1	3	6	1	3	7	1	22
No. of Hospitals	-	1	1	-	1	2	-	5
(No. of Beds)	(-)	(unknown)	(28)	(-)	(20)	(115)	(-)	(163)
No. of Medical Clinics	3	5	4	5	5	11	9	42
No. of Mosques	93	98	45	48	111	217	98	710
No. of Hotels	0	2	4	0	2	7	0	15

Source; KABUPATEN MUARA ENIM, DALAM ANGKA, 1982

12-1-2 Population and Facilities

Muara Enim District, which Banko area belongs to, is divided into 7 sub-districts as depicted in Fig. 12-1-2. Table 12-1-1 shows the population, number of villages and the conditions of public facilities for each sub-district as of 1982.

On the opposite side of Tanjung Enim across the Enim River, the Bukit Asam Coal Mining Company (P.T.B.A) is producing about 1,500,000 tons per year of steam coal and anthracite, and its expansion project is underway, aiming at annual production of 3,000,000 ton-coal in the final stage.

In the vicinity of P.T.B.A., Bukit Asam Power Station (65,000 kW x 2) was constructed and started operation in 1987. With the completion of two projects in Bukit Asam, the population and the public facilities in this area will increase in number.

12-1-3 Climate

Lying close to the equator, this area is in a tropical climate having two seasons through a year; a dry season from May to October, and a rainy season from November to April.

Some climate data are shown in Table 12-1-2 and Table 12-1-3.

Table 12-1-2 Climate of Tanjung Enim

		March, '83	August, '84
Monthly average temperature	°C	27.7	27.4
Monthly max. temperature	°C	34.0	33.5
Monthly min. temperature	°C	21.5	20.0
Monthly average relative humidity	%	78.2	72.8
Monthly max. relative humidity	%	99.0	99.0
Monthly min. relative humidity	%	48.0	41.0
Average wind velocity	m/s	2.5	2.8
Max. wind velocity	m/s	8.0	8.0

Source; HYDROLOGY FIELD PROGRAM, BACOMDAT PROJECT

Table 12-1-3 Rainfalls at Muara Enim

(1980)

	Rainfall in mm	No. of Rainy Days
Jan.	726	19
Feb.	396	18
Mar.	419	22
Apr.	422	26
May	172	5
Jun.	106	8
Jul.	89	9
Aug.	175	11
Sep.	293	13
Oct.	193	13
Nov.	432	20
Dec.	344	18
Total	3,767	182

Source; HYDROLOGY FIELD PROGRAM,
BACOMDAT PROJECT

12-1-4 Port

At the Port of Palembang, the products of this project are to be loaded on to tankers or freighters for further delivery. Outline of the Port of Palembang is shown in Fig. 12-1-3.

According to the Head Office of the Port Authority of Palembang, this port is so congested that it may be impossible either to get adjacent place for methanol tank construction or to use one of the existing berths for methanol shipping exclusively. It was suggested, however, that methanol tanks could be built in the residential area surrounding the port by purchasing the land, and that the existing offshore berth could be extended for tanker anchoring.

In this case, methanol is to be transferred from the onshore tank to the offshore berth through pipeline.

The maximum tanker capacity accessible to Palembang port is 17,000 tons. Annual dredging keeps the depth of Musi river over 7 meters.

12-1-5 River

As transportation means and water resources for the plant, the river condition largely affects the economic aspect of the Project.

Fig. 12-1-4 shows the approximate location of the towns and rivers concerned with this study as well as the locations of the places where the relevant data and pictures were taken.

With regard to the transportation of heavy equipment through the river to the plant site, Table 12-1-4 and Fig. 12-1-5 show the hydrographic data for 4 points on the route taken in Nov., 1985.

Picture A and B show the existing jetties at the downstream of Muara Enim where the Lematang and the Enim river meet, and Picture C is the Ampera Bridge at Palembang which is the only bridge over the river between Palembang and Muara Enim.

For other information regarding the barge transportation;

- 150-ton-container was reportedly unloaded without trouble in dry season at the jetty shown in Picture A.
- River level fractuate for about four meters through the year.
- A small and low bridge lies over the Enim River between Muara Enim and Tanjung Enim and will be obstructive to transportation in case a barge needs to sail up the Enim River.

As far as the above is concerned, there seems to be no problem with transportation of heavy equipment to Muara Enim by barge.

In terms of water resource, the flow rate of the Lematang River seems to be sufficient enough even in dry season because the water requirement in the plant is less than 1 m^3/sec or 3,600 ton/hour.

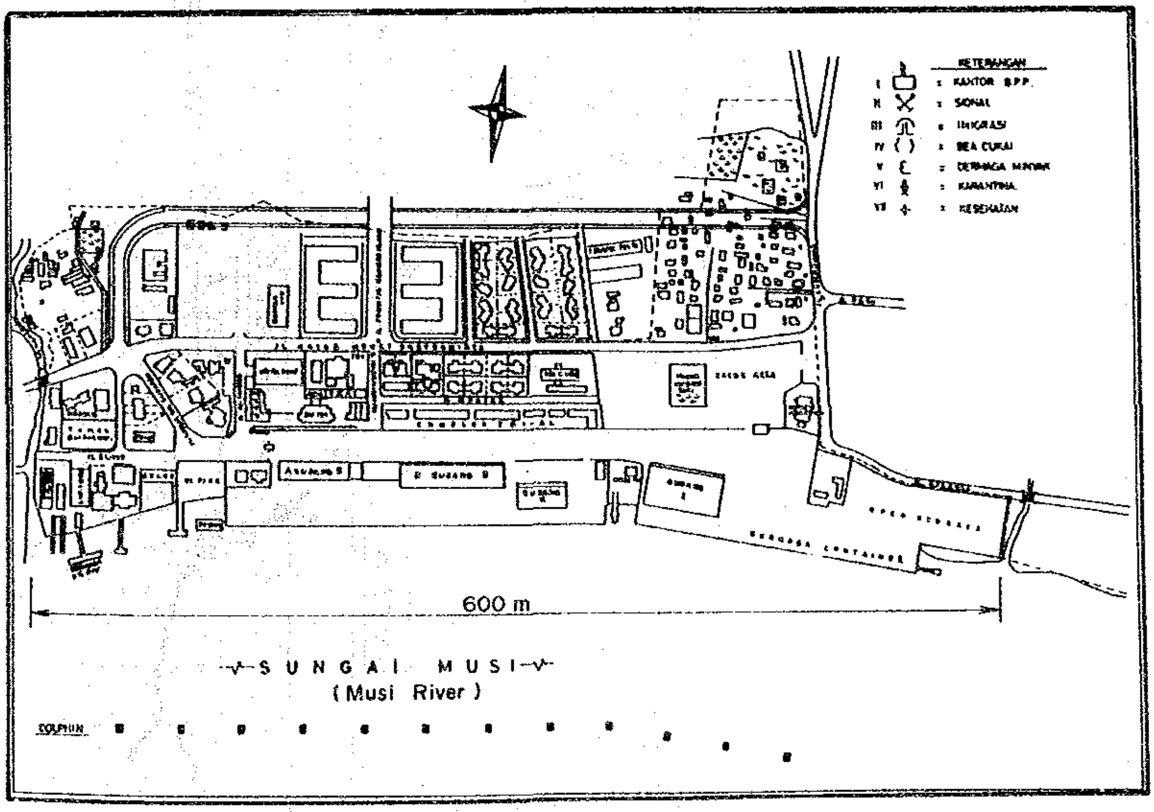
As for the quality of the river water, however, there are no data available so that the water quality should be examined and reflected in the plant design in the final stage of the Project.

Fig. 12-1-3 Port of Palembang

Location	;	2°58'S, 104°46'E
Whole Area	;	500 ha
Facilities Area	;	22.5 ha
River Depth	;	9 - 11 m Lws
River Width	;	350 m
Max. Tanker to anchor	;	17,000 DWT

Jetty

Owner	Length	Width	Capacity	Depth
Boom Baru	476 m	10.5 m	3 t/m^2	7 m Lws
Kontainer	180 "	19.5 "	3.2 "	9.3 "
PPL. S. Lais	185 "	15.0 "	1.5 "	2.5 "
Pusri	680 "			
Pertamina	301 "			
"	314 "			
"	80 "			
"	250 "			



Source: Catalog for the Port of Palembang

Fig. 12-1-4 Hydrographical Map

- through Palembang and Muara Enim -

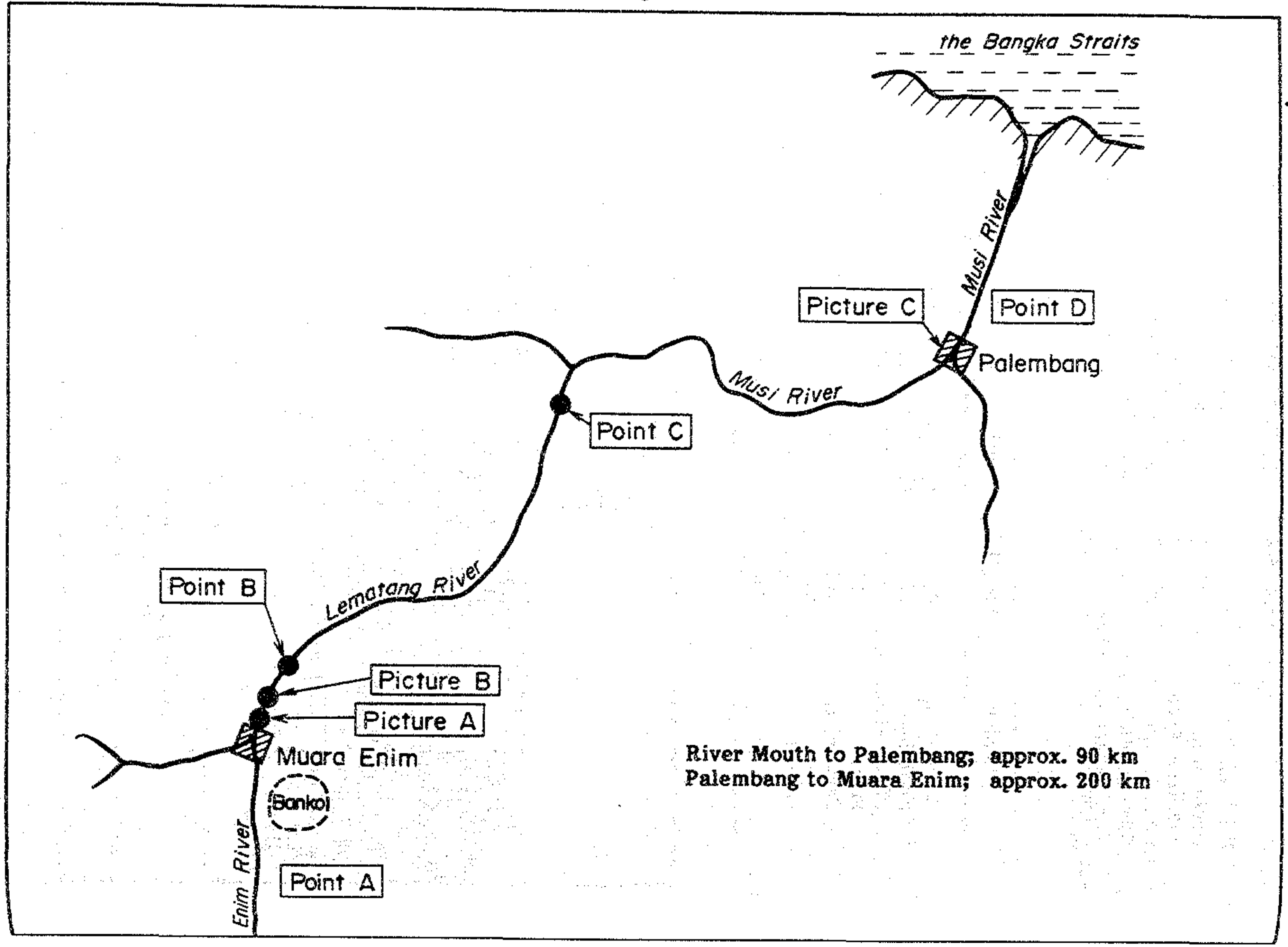


Table 12-1-4 Hydrographic Data of Rivers

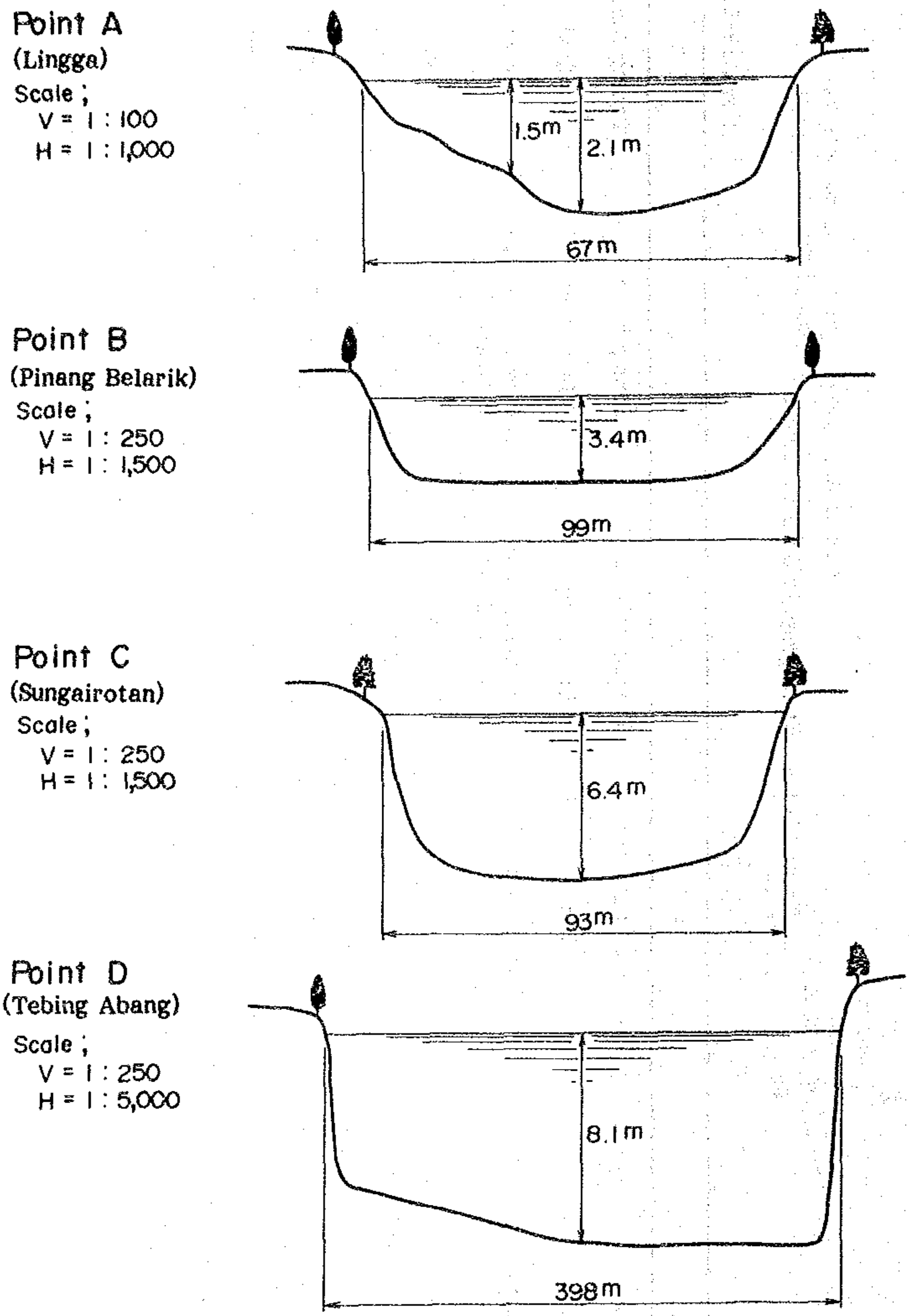
(Nov., 1985)

Point		A	B	C	D
Place		Lingga	Pinang Belarik	Sungairotan	Tebing Abang
River		Enim	Lematang	Lematang	Musi
Location		Unknown	10 km downstream of Muara Enim	100 km downsteam of Muara Enim	unknown
Width,	m	67	99	93	390
Depth (Max.)	m	2.1	3.6	6.4	8.1
Velocity,	m/sec	0.58	0.82	0.84	0.84
Flow Rate, (estimated)	m^3/sec	49	208	398	2,302

* See also Fig.   for reference.

Source; DIRECTORAT PENYELIDIKAN MASALAR AIR (DPMA)

Fig. 12-1-5 Cross Section of Rivers
(Nov., 1985)



Source; DIRECTRAT PENYELIDIKAN MASALAR AIR (DPMA)

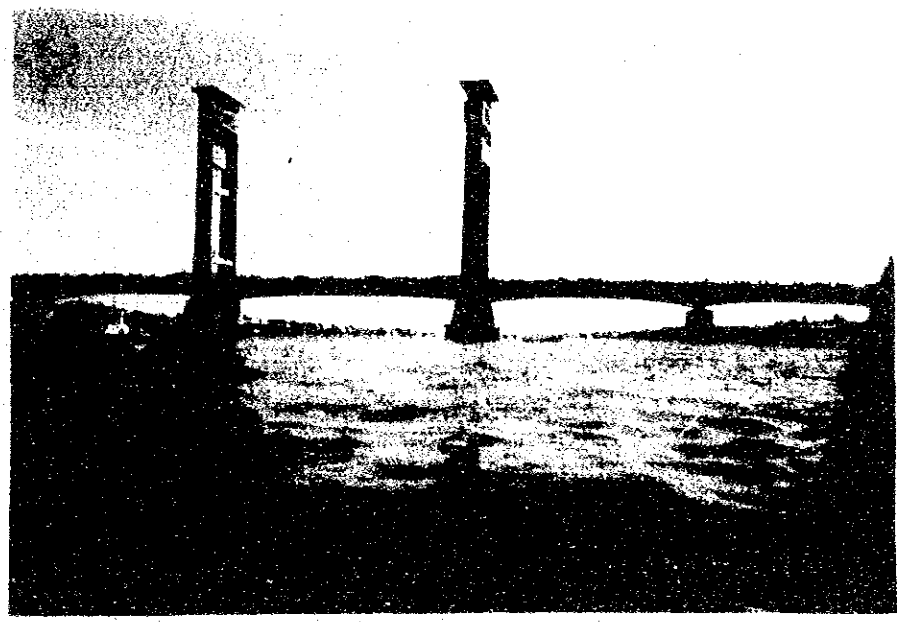
Fig. 12-1-6
Pictures Related to Rivers

Picture A

A Jetty at Desa Muara Enim where 150-ton-container was unloaded

Picture B

A Jetty in use by Pertamina



Picture C

Ampera Bridge at Palembang, the only bridge over this route

12-2 BASIS OF CONCEPTUAL DESIGN

12-2-1 Plant Location

The plant site isn't definitely specified in this study and a riverside area close to the mine is to be selected as the plant site after the mining area is chosen out of N.W. Banko, Central Banko and North Suban Jeriji in the 3rd stage, although three areas shown in Fig. 12-2-1 were proposed in the original Master Plan.

Geological conditions, water resource and other factors should be confirmed and incorporated into the site selection as well as proximity to the mining site.

12-2-2 Equipment Transportation

(1) Transportation Means

As discussed in subsection 6-2-3 of the Interim Report II (1986), transportation by way of water course is advantageous and to be selected, although the problem of the small and low bridge mentioned in 12-1-5 must be taken into account if N.W. Banko is chosen as the plant site.

(2) Transportation Plan

1) Shipment

Cargos are to be loaded on to freighters at Japanese ports such as Yokohama, Hiroshima or Hakata whichever closer to the manufacturing factories and to be shipped to the Port of Palembang (See Fig. 12-2-2).
Considering the water depth and transshipment at the Palembang Port to barges in rotation, a 10,000 DWT class freighter is suitable.

2) Transshipment

At the Port of Palembang, the cargos are to be transshipped to six barges (3,000 DWT/each) which are moored in the Port. (See ① and ② in Fig. 12-2-3). Unloading work will take about 3 days/voyage.

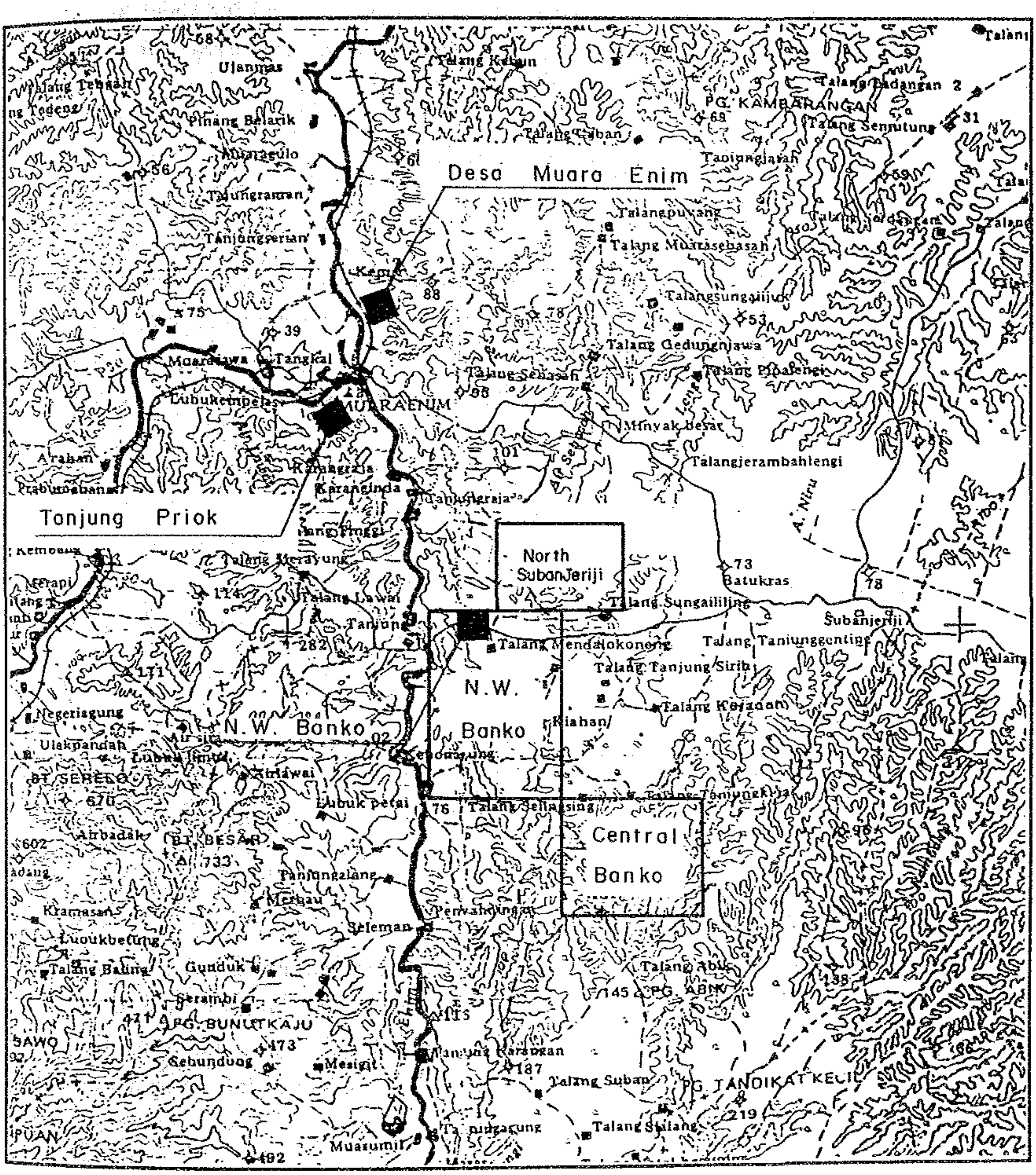


Fig. 12-2-1 Possible Plant Site Locations

3) Barge Towing

Each barge is to be towed by one tug boat (single towing) for about 250 km to the unloading site through the Musi and the Lematang River, or moreover through the Enim River (See 3 in Fig. 12-2-3)

Tug Boat ; 1,500 HP

barge ; 3,000 DWT (20 m x 60 m x 4.2 m)

4) Equipment Unloading

A slope jetty and a floating barge is to be provided at the unloading site to cope with the flucturation of water level between a dry and a rainy seasons.
A heavy cargo is to be rolled off by a dolly through a slope jetty while general cargos are to be unloaded to a trailer by a crawler crane installed on the floating barge. (See 4 in Fig. 12-2-3)

12-2-3 Feed Coal

(1) Coal Quality as mined:

C, %	:	27.4
V.M., %	:	32.8
Ash, %	:	4.8
Mo, %	:	35.0
Total, %	:	100.0
HV, Kcal/kg	:	4,430

(2) Coal Quality at Plant Gate

After received in a bunker hopper, mined coal is crushed into appropriate size and then carried to the plant site by a belt conveyor system. Since either the mining area or the plant site hasn't yet been selected, it is assumed that the belt conveyor extends to the same length of 13 km as studied in the Interim Report II (FY1986), pp. 192-197.
During above mentioned pretreating and transportation, some of moisture will vaporize naturally resulting coal quality at a plant gate as follows.

Annex 5. Transportation Route Map

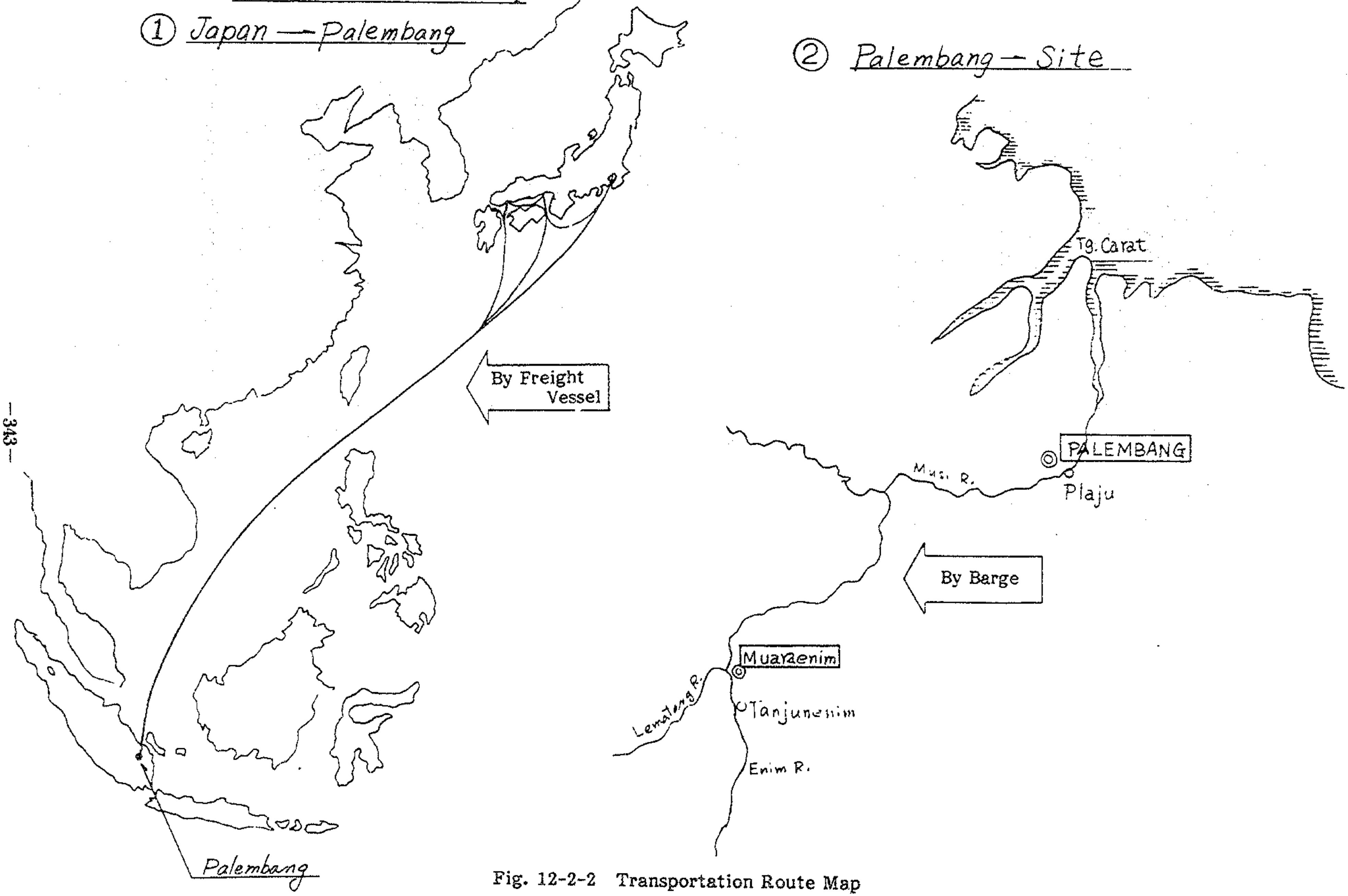


Fig. 12-2-2 Transportation Route Map

Table 12-2-1 Coal Quality at Plant Gate
(cited from Table 8-4-4)

(%)

	North West Banko	Central Banko	Suban Jeriji Banko
Mo (as mined)	(27.6)	(36.7)	(42.5)
Mo (Plant gate)	23.1	25.3	26.8
C	38.3	34.6	32.0
V.M.	35.6	34.4	36.6
Ash	3.0	5.7	4.6
Total	100.0	100.0	100.0

12-2-4 Utilities

(1) General

All the utilities except raw water and coal are to be generated inside the coal gasification complex at the following conditions.

HP St'm	:	480°C, 65 kg/cm^{2}G
MP St'm I	:	350°C, 40 kg/cm^{2}G
MP St'm II	:	250°C, 40 kg/cm^{2}G
LP St'm	:	155°C, 3.5 kg/cm^{2}G
BFW	:	110°C, 55 kg/cm^{2}G
C. Water	:	32°C (Supply)/42°C (Return)

Steady operation of utility facilities as wel as the process plants is required in order to keep the minimum supply of utilities necessary to achieve the safe shutdown of the process plants in case of emergency such as power failure, stoppage of industrial water receiving, etc.
Countermeasures for utilities stabilization and safety are to be considered as follows.

i) Preparing for the unexpected stoppage of industrial water from the off-site facilities, the industrial water system is to be provided with a required capacity of pit at a minimum.

ii) Important equipment should consist of two or more equivalent units which will run in parallel.

iii) Besides an electrical motor, a diesel engine is to be installed to drive an equipment required to maintain operation in case of power failure in order to keep the safety of the plants.
Also preparing for long period power failure, diesel generators are to be provided to supply electricity to important instrumentation facilities and equipments necessary for diesel engine operation.

(2) Boiler and Electric Power Generation

In order to minimize the coal consumption, efficient utilization of energy should be considered:

i) Facilities which don't need high level energy source are to utilize LP Steam in principle.

ii) Waste heat recovery should be incorporated at a maximum in the coal gasification plant and the methanol plant by heating BFW up to 250°C.
Saturated MP steam recovered in the process will be furthermore superheated in the power plant up to 350°C, 40 kg/cm^{2}G (MP Steam) or 480°C 65 kg/cm^{2}G (HP Steam)

iii) Residual fuel gas from the methanol plant is to be used for lime calcination and steam superheating.

iv) Large-sized compressors in the air separation, methanol and ammonia plants are to be driven by steam turbine instead of electrical motor.

(3) Cooling Water System

A centralized cooling tower is to be installed in the utilities center to supply cooling water to each plant.
In consideration of climate data, the supply and return temperature have been set at 32°C and 42°C respectively, instead of 30°C and 37°C which were applied in the original Master Plan. The following should be studied and reflected in the final conceptual design in the 3rd stage.

i) Selection of sterilizer agent which allows the blow down water to be discharged to the river.

ii) Separation of the cooling water system into two different ΔT arrangements; i.e. one is for process heat exchangers and the other is for turbine condensers.

12-2-5 Waste Disposal and Pollution Control

Because the coal gasification complex generates or handles toxic materials during operation, it's essential to incorporate the prevention of the environment pollution into the plant design. Studies on this matter, however, will be carried out in the 3rd stage in full detail.

(1) Water Disposal Treatment

Since Banko belongs to the upstream district of the Musi, Lematang and Emin River, the discharge of waste water containing toxic substance will inevitably cause wide area water pollution. Much attention must be paid to avoid such a serious problem.

1) Separate sewerage should be provided for clean and dirty water. The dirty or contaminated water is to be treated by ordinary methods such as API oil separator, biological contact oxidation method and coagulating sedimentation.

2) In order to prevent thermal pollution as well as contamination, a pit or a reservoir is to be provided to store and cool the clean waste water before disposal.

3) In addition to regularly discharged water, a large amount of waste water may be let out from the plants in case of emergency, and is to be tentatively sent to an appropriate size of pond and then treated for disposal.

(2) Solid Wastes Disposal

Solid wastes generated in the coal gasification complex are dust and slag from the coal gasification plant, and ash from the fluidized bed boiler. Since all of them are harmless, they are to be carried to and discarded at a predetermined dump yard.

(3) Air Pollution Control

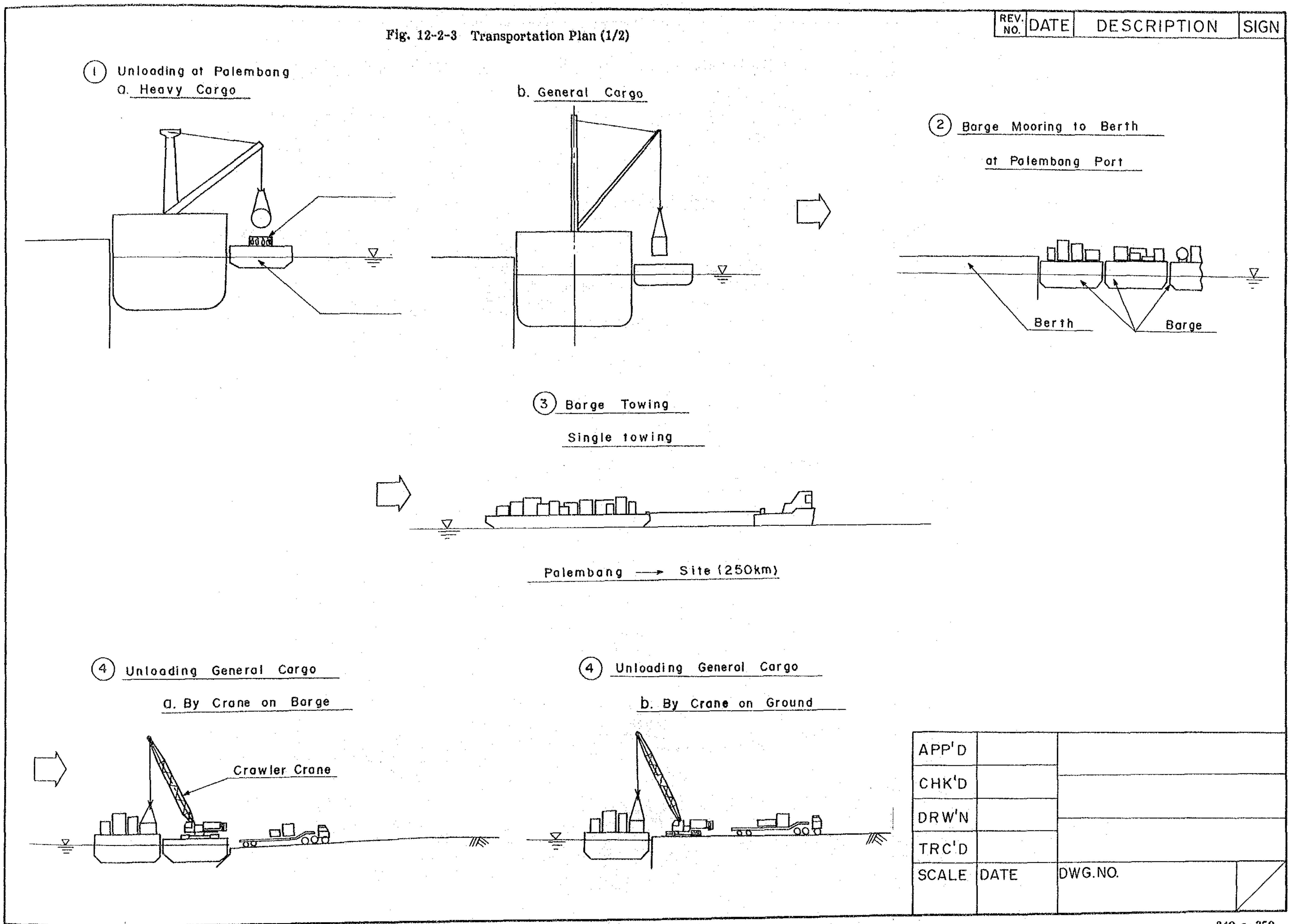
In general, major materials causing air pollution are sulfur oxide and nitrogen oxide contained in the flue waste gas. In this study, however, no special measures against air pollution such as de-SO_X or de-NO_X facilities are to be incorporated for the following reasons.

i) The content of the sulfur in Banko coal is small.

ii) Each combustion facility in the plants is provided with dedusting equipment.

iii) The flue gas from fluidized bed boiler contains small amount of SO_X and NO_X.

Fig. 12-2-3 Transportation Plan (1/2)

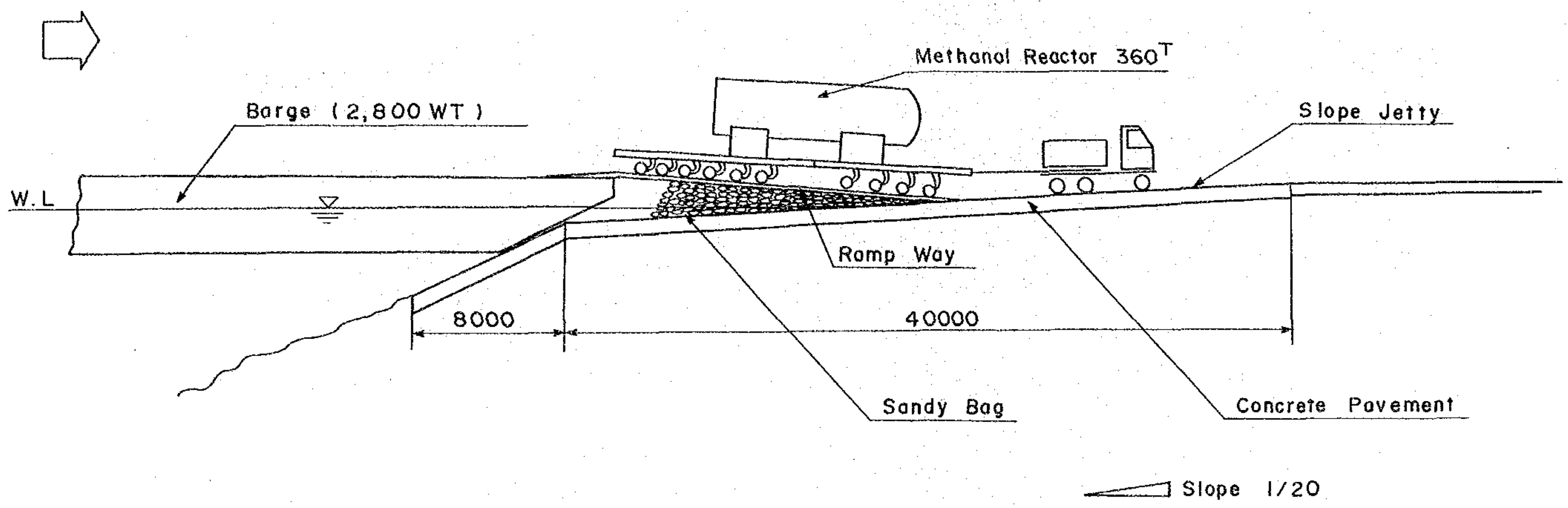


REV. NO.	DATE	DESCRIPTION	SIGN

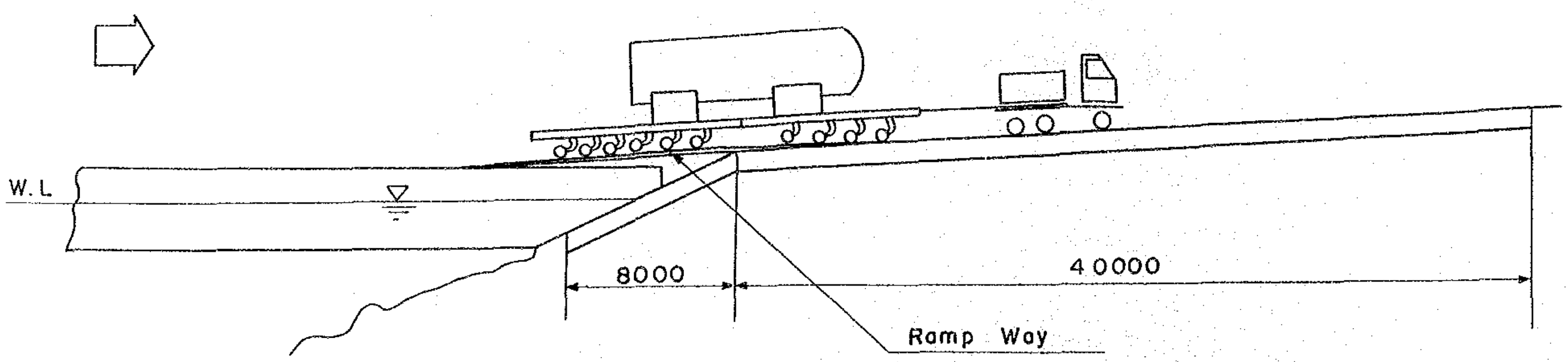
④ Unloading Heavy Cargo

Fig. 12-2-3 Transportation Plan (2/2)

a. Max. High Water Level



b. Low Water Level



APP'D		
CHK'D		
DRW'N		
TRC'D		
SCALE	DATE	DWG.NO.

12-3 PRELIMINARY CONCEPTUAL DESIGN OF MASTER PLAN

12-3-1 Master Plan Case 1

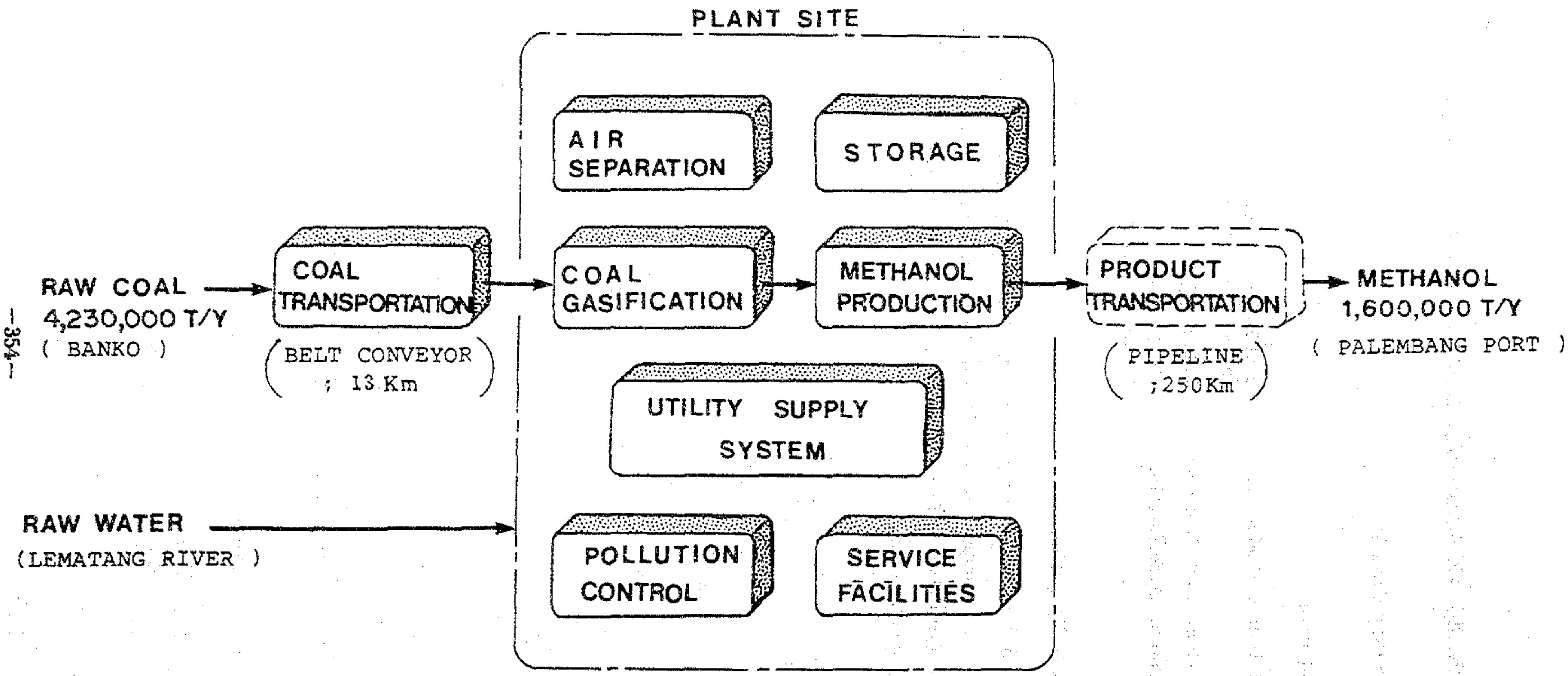
(1) Product Plan

1)	Methanol Production	:	1,600,000 tons/year (5,000 tons/day)
2)	Annual Operation Days	:	320 days/year
3)	Product Specification	:	Chemical Grade (99.9% CH_3OH)

(2) Plant Configuration

Fig. 12-3-1 shows the scope of the methanol production complex divided into eight blocks. The component facilities in each block are listed in Table 12-3-1. Major on-site facilities, off-site facilities and overall scheme are described in the following subsections.

Fig. 12-3-1 Overall Block Flow Diagram



* Component facilities consisting each block are listed in Table 12-3-1

Table 12-3-1 Plant Configuration

1) Belt Conveyor System

Primary Crusher/Feeder
Overland Coal Conveyor

2) Coal Gasification

Coal Storage and Handling
Coal Pretreatment
Coal Gasification
Gas Cooling/Dedusting
Calcination

3) Methanol Plant

Gas Compression
Gas Treating
Methanol Synthesis
Methanol Distillation

4) Air Separation Plant

Air Separation
Liquid Oxygen Tank
Liquid Nitrogen Tank

5) Utility System

Power Generation
Power Distribution
Steam Boiler
Water Cooling
Raw Water Intake/Pretreatment
Instrument/Plant Air Supply

6) Pollution Control/Safety System

Waste Water Treatment
Solid Waste Disposal
Flare/Blowdown
Fire Fighting

7) Storage

Product Tank
Chemicals Tank
LPG Tank
Fuel Oil Tank
Lubricating Oil Tank

8) Service Facilities

Administration Office
Laboratory
Warehouse
Accommodation
Canteen
Cafeteria
Leisure Center
Mosque
Communication System
Maintenance Shop
Service Water Supply

(3) On-site Facilities

1) Coal Gasification

i) Process Flow Diagram

See Fig. 12-3-2.

ii) Process Description

(For details, see the interim report (May 1985), page 234-237)

a) Coal Pretreating

The coal *, carried from the mine site by conveyor, is fed to the pulverizer through the primary crusher and dewatering drum. After dried and pulverized, the coal is then carried pneumatically to the coal feed system. The pulverized coal is at first stored in a feed tank, and then supplied continuously to the gasifier.

* Note ;	Moisture at Plant Gate	(%)
	N.W. Banko	23.1
	Central Banko	25.3
	Suban Jeriji Banko	26.8

b) Gasification

The gasifier is a simple furnace with firebrick lining. The furnace holds several hundred tons of molten iron at a temperature of 1,400-1,600°C. Coal, oxygen and steam are blown onto the surface of this molten iron at high speed through a specially designed non-submersion-type lances; this brings about an instantaneous gasification reaction in the iron bath.

The coal ashes, formed as molten slag, float on the iron bath surface by gravity and scrubbed from the gasifier.

c) Product gas treatment

The high temperature gas produced in the gasifier is cooled by a two stage gas cooler where the sensible energy of the gas is recovered by generating steam, and a small amount of dust in the gas is removed in a bag house.

iii) Major Equipment

Specifications and the number of units of major equipment are listed in Table 12-3-2.

Table 12-3-2 Major Equipment
(Coal Gasification)

Description	Q'ty	Capacity	Specification
1. Coal Handling Section			
1.1 Primary Crusher	4	120 T/H	Dimension: 3,560W x 2,690L x 1,890H Weight: 30 T/unit
1.2 Dewatering Drum	4	100 T/H	Dimension: 4,800 ø x 29,000L Weight: 540 T/unit
1.3 Coal Pulverizer	4	80 T/H	Dimension: 5,300 ø x 8,300H Weight: 280 T/unit
2. Gasification Process Section			
2.1 Gasifier	3+1	100 T/H coal	Shell dimension: 5,400ø x 17,700H Weight: 670 T/unit
2.2 Ladle	3	290 Tonnes	Dimension: 4,800ø x 6,700 H Weight: 65 T/unit
2.3 Ladle Crane	1	450 Tonnes	Span: 14,000 mm Weight: 670 T/unit
3. Gas Treatment Section			
3.1 Radiation Cooler	3+1	170 KNm3/H	Dimension: 4,100ø x 30,600H Weight: 450 T/unit
3.2 Convection Cooler	3+1	170 KNm3/H	Demension: 4,100ø x 17,300H Weight: 450 T/unit
3.3 Heat Exchanger	3+1	170 KNm3/H	Dimension: 4,100ø x 20,400H Weight: 540 T/unit

2) Methanol Production

i) Process Flow Diagram

See Fig. 12-3-3

ii) Process Description

(For details, see the interim report (May 1985), page 245-249)

a) Dust Removal and 1st Compression

The raw gas leaving the gasifier at 3 kg/cm^2G contains 10-50 mg/Nm^3 dust.

The dust in the raw gas is reduced to 5 mg/Nm^3 and this gas is compressed to 20 kg/cm^2G.

b) CO-Shift Conversion/COS Hydrolysis

In order to adjust hydrogen/carbon monoxide ratio as required for the methanol production, 55% of the raw gas goes to CO-shift convertor and 45% of raw gas to the COS hydrolizer.

Both gas streams are then mixed together after being cooled by generating steam, and introduced to the acid gas removal unit.

c) Acid Gas Removal

Acid gases such as H_2S and CO_2 are removed from the raw gas by hot potassium carbonate (HPC) solution.

The raw gas containing about 27% of CO_2 and 200 ppm of H_2S is reduced to 3.5% and a few ppm of CO_2 and H_2S, respectively.

d) Methanol Synthesis

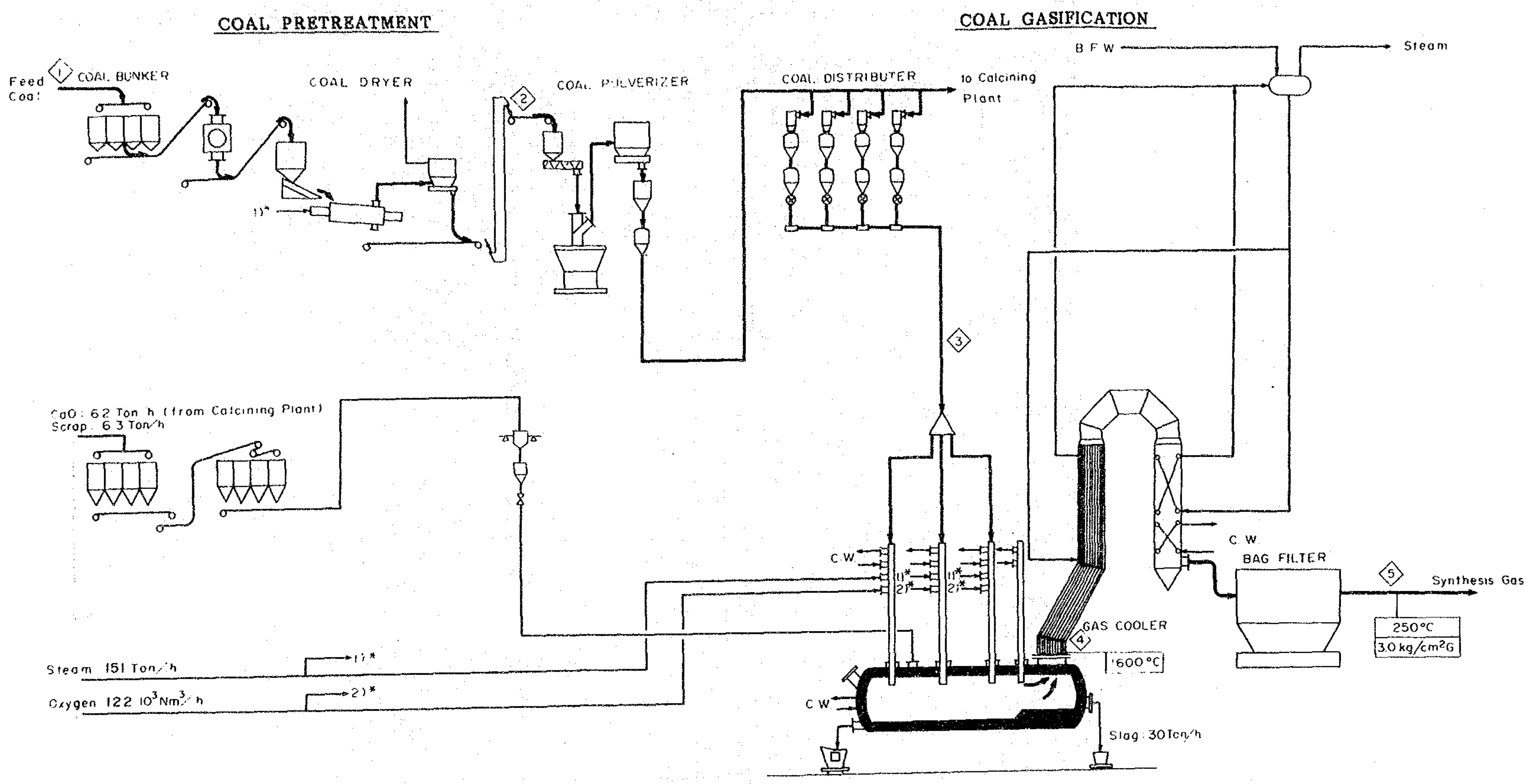
After compressed to 52 kg/cm^2G, the synthesis gas is fed to the catalytic reactor at 225°C after heat exchange with the reactor effluent. As the catalyst cannot tolerate the adiabatic temperature rise of this exothermic reaction, the heat is removed by generating 40 kg/cm^2G steam in the shell side of the reactor.

The produced methanol, after cooled, is separated from the unconverted gas in the separator and then sent to the distillation section via a depressuring valve. The raw methanol from synthesis unit is purified to 99.9% through three distillation columns before storage.

iii) Major Equipment

Specifications and the number of units of major equipment are listed in Table 12-3-3.

Fig. 12-3-2 Simplified Process Flow Diagram
- Coal Pretreatment Gasification -



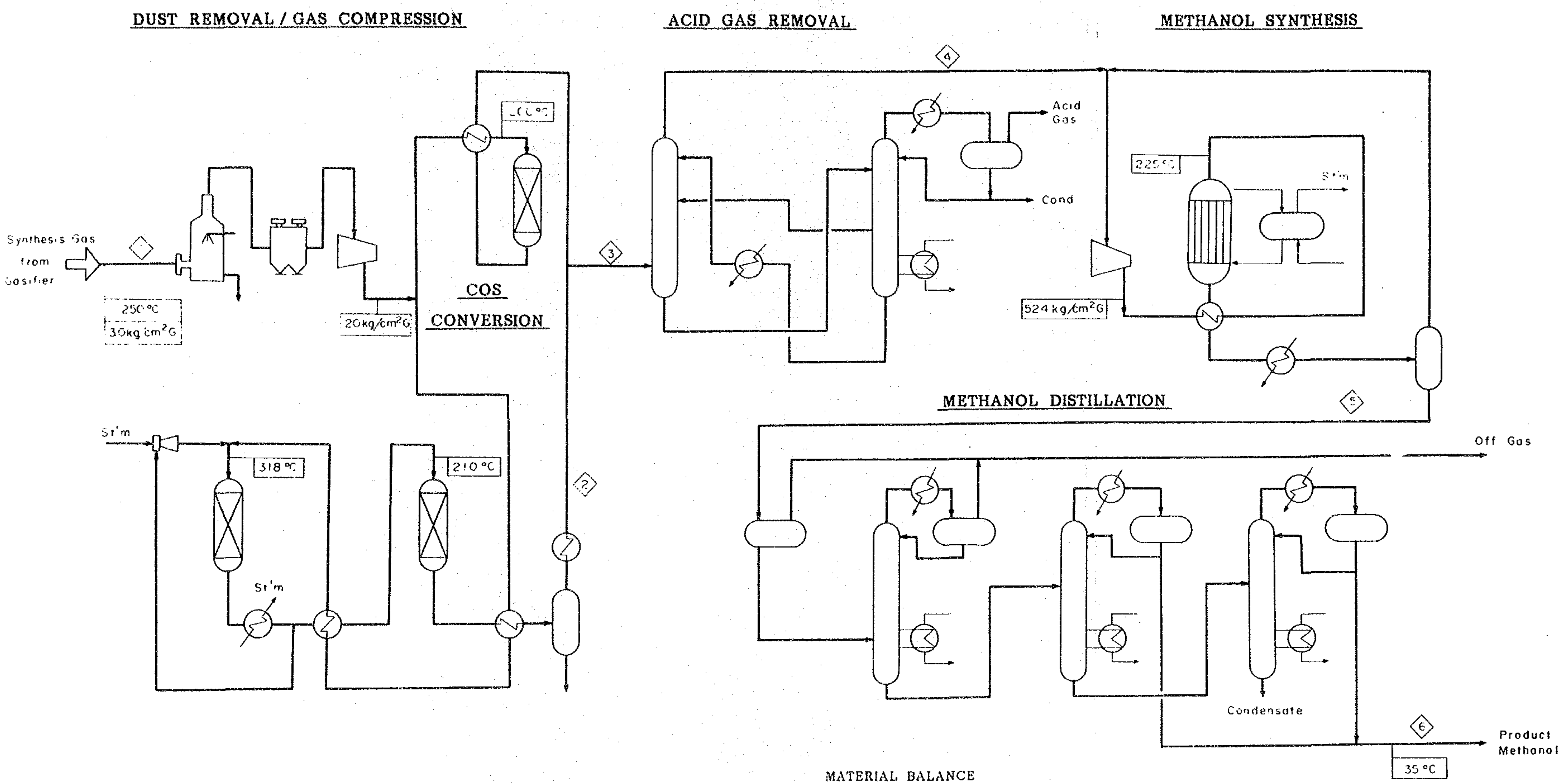
MATERIAL BALANCE

	1	2	3
Coal Rate, Ton/h	426	326	308
Moisture, %	35	15	10
Size, mm	< 40	< 3	-74 (>70%)

COAL GASIFIER

	4	5
Gas Rate, $10^3 Nm^3/h$	537.6	537.6
Comp. CO, vol%	57.0	57.0
H_2, vol%	33.2	33.2
CO_2, vol%	4.1	4.1
N_2, vol%	0.4	0.4
H_2O	5.3	5.3
H_2S/COS, ppm	65/22	65/22
T.S, ppm	87	87
Dust, g/Nm^3	25.0	0.01 - 0.05

Fig. 12-3-3 Simplified Process Flow Diagram
- Gas Pretreatment · Methanol Production -



MATERIAL BALANCE

	1	2	3	4
Flow Rate, $10^3 Nm^3/h$	537.6	435.0	664.2	504.8
Comp. CO, vol%	57.0	1.2	21.5	28.4
H_2, vol%	33.2	60.1	51.5	67.7
CO_2, vol%	4.1	38.4	26.7	3.5
N_2, vol%	0.4	0.3	0.3	0.4
H_2O, vol%	5.3	-	-	-
H_2S/COS, ppm	65/22	55/-	66/-	-
Dust, g/Nm^3	0.01	-	-	-

	5	6
Flow Rate, Ton/h	223.3	208.3
Comp. CH_3OH, wt%	94.2	$\geqq$ 99.9
Inerts, wt%	0.4	-
H_2O, wt%	5.4	$\leqq$ 0.1

Table 12-3-3 Major Equipment
(Methanol Production Section)

Description	Q'ty	Specification		
Dedusting (3 trains)		Capacity	;	170,000 Nm^3/h/train
o Dust Washer	3+1S	Dust, In/out	;	50/5 mg/Nm^3
CO Shift (2 trains)		Capacity	;	140,000 Nm^3/h/train
o High Temp. Converter	2	CO, In/Out	;	59.6/1.2 vol.%
o Low Temp. Converter	2	Type	;	Vertical, Cylindrical with catalyst
COS Hydrolysis (2 trains)		Capacity	;	116,000 Nm^3/h/train
COS Converter	2	COS, In/Out	;	50/0.1 ppm
Acid Gas Removal (2 trains)		Capacity	;	338,000 Nm^3/h/train
o Absorber	2	CO_2, In/Out	;	26.1/3.5 vol.%
o Regenerator	2	H_2S, In/Out	;	200/0.1 ppm
Methanol Synthesis (2 trains)		Capacity	;	253,000 Nm^3/h/train
o Methanol Reactor	2	Type	;	Vertical, Cylindrical with Catalyst
Methanol Distillation (2 trains)		Capacity	;	2,500 ton/h-Methanol/Train
o Pre-run Column	2	Type	;	Vertical, Cylindrical with Tray
o Pressure Column	2			
o Pressureless Column	2			

3) Air Separation

i) Process Flow Diagram

See Fig. 12-3-4.

ii) Process Description

a) Pretreatment

Feed air to be separated is taken from the top of an air filter where solid contamination is removed.

Clean air which is free from solid contamination is compressed to required pressure (about 5.4 kg/cm^2G) by a feed air compressor driven by a steam turbine and sent to a trickling cooler and cooled down to about 5^oC by direct contact with cooling water and chilled water.

Feed air is then sent to molecular sieves air dryers (adsorbers).

In molecular sieves air dryers, the remaining water and carbon dioxide is removed to permit the feed air to go into the cryogenic cold box system.

The waste nitrogen from the upper part of an upper rectifying column is used for the reactivation stream of molecular sieves.

b) Cooling Down

The most of air from a molecular sieves air dryer is introduced to the cold box and cooled to cryogenic temperature in an air heat exchanger against pure oxygen, pure nitrogen and waste nitrogen.

Some of air from a molecular sieves air dryer is compressed by an air blower connected to an expansion turbine and cooled down by an aftercooler and a turbine air precooler.

The boosted air is introduced to a cold box and cooled down in an air heat exchanger.

It is withdrawn from the middle part of an air heat exchanger, then expanded through an expansion turbine to provide refrigeration duty and fed to an upper rectifying column.

c) Air Separation into Oxygen and Nitrogen

Initial separation of the air into an oxygen-rich liquid fraction (liquid air) and a gaseous nitrogen fraction is accomplished in a lower rectifying column while final separation into pure oxygen and pure nitrogen is effected in an upper rectifying column.

After passing through a liquid air supercooler, liquid air is expanded and introduced as the feed into an upper rectifying column.

Liquid nitrogen is extracted from the middle part of an lower rectifying column, expanded and fed to an upper rectifying column as reflux.

In an upper rectifying column, the liquid air and reflux nitrogen are separated into product pure oxygen, pure nitrogen and waste nitrogen.

Product pure oxygen is withdrawn from the bottom of an upper rectifying column, warmed in an air heat exchanger to ambient temperature and sent to an oxygen compressor.

Product pure nitrogen is withdrawn from the top of an upper rectifying column, warmed in a liquid nitrogen supercooler and an air heat exchanger to ambient temperature and sent to a nitrogen compressor.

The waste nitrogen is withdrawn from the upper part of an upper rectifying column and warmed in a liquid air supercooler and an air heat exchanger before going out from the cold box.

Most of waste nitrogen is introduced to an evaporating cooler where the water from a trikling cooler is cooled against the waste nitrogen and discharged to atmosphere.

The rest of waste nitrogen is introduced to a reactivation preheater and a reactivation heater and used to reactivate the molecular sieves in molecular sieves air dryers.

d) Product Compression

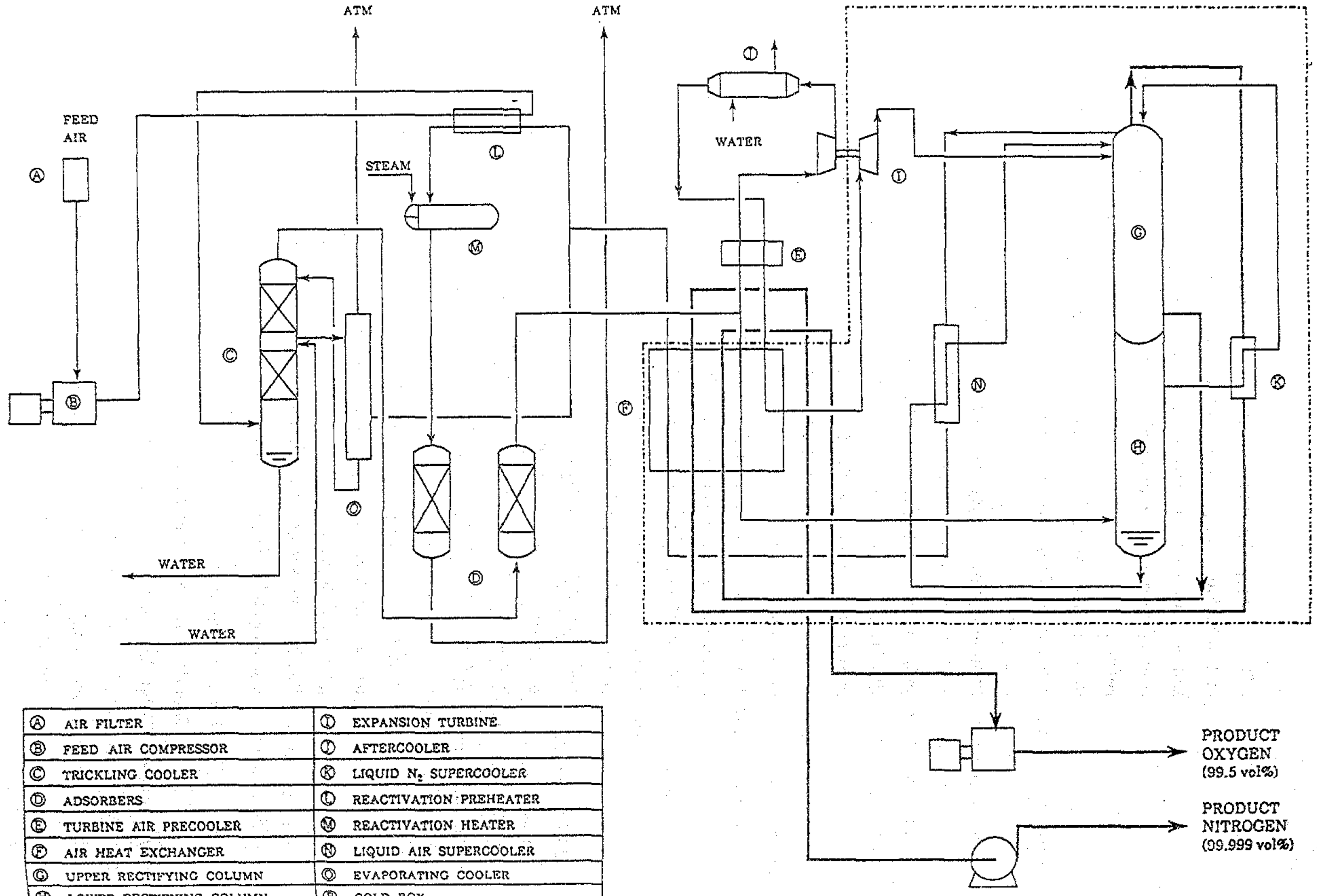
Product pure oxygen (99.5 vol%) is compressed to 15 kg/cm^{2}G by an oxygen compressor driven by a steam turbine and sent to the gasification plant.

Product pure nitrogen (99.999 vol%) is compressed to 0.3 kg/cm^{2}G by a nitrogen blower and sent to the ammonia and urea plant.

iii) Major Equipment

Specification and the number of unit of major equipment are listed in Table 12-3-4.

Fig. 12-3-4 Simplified Process Flow Diagram for Air Separation Plant



Ⓐ AIR FILTER	Ⓘ EXPANSION TURBINE
Ⓑ FEED AIR COMPRESSOR	Ⓙ AFTERCOOLER
Ⓒ TRICKLING COOLER	Ⓚ LIQUID N_2 SUPERCOOLER
Ⓓ ADSORBERS	Ⓛ REACTIVATION PREHEATER
Ⓔ TURBINE AIR PRECOOLER	Ⓜ REACTIVATION HEATER
Ⓕ AIR HEAT EXCHANGER	Ⓝ LIQUID AIR SUPERCOOLER
Ⓖ UPPER RECTIFYING COLUMN	Ⓞ EVAPORATING COOLER
Ⓗ LOWER RECTIFYING COLUMN	Ⓟ COLD BOX

Table 12-3-4 Major Equipment
(Air Separation)

Description	Q'ty	Specification
Trickling Cooler	2	Dimension: 3,500 ϕ x 18,000 H
Evaporating Cooler	2	Dimension: 3,000 ϕ x 8,000 H
Adsorber	4	Dimension: 5,000 ϕ x 12,500 H
Upper Rectifying Column	2	Dimension: 5,000 ϕ x 19,000 H
Lower Rectifying Column	2	Dimension: 5,000 ϕ x 10,000 H
Feed Air Compressor	2	Capacity: 300,000 Nm^3/h Discharge Pressure: 5.4 kg/cm^2G Weight: 240 ton
Product Oxygen Compressor	2	Capacity: 61,000 Nm^3/h Discharge Pressure: 15 kg/cm^2G Weight: 48 ton

4) Product Storage and Shipping

i) Methanol Storage

Two cone roof tanks with a storage capacity of 50,000 Kl each are to be installed in the tank yard. The storage capacity corresponds to 15-day plant operation.

ii) Methanol Shipping

Assuming pipeline transportation from the gasification complex to Palembang, methanol shipping system is to be equipped with four pumps with a capacity of 200 Kl/H each.

iii) In addition, other storage tanks are to be installed in the liquid, storage tank yard as per the following.

Fuel Oil	:	10,000 Kl x 2
Lubricant Oil	:	500 Kl x 1
LPG	:	10,000 Kl x 2
Chemicals	:	100 Kl x 5

5) Power Plant

i) Process Flow Diagram

See Fig. 12-3-5 and Fig. 12-3-6.

ii) Process Description

a) The plant consists of 2 units of 52 MW steam turbine generator set, and 4 units of fluidized bed boiler.

b) Fluidized bed boiler is especially suitable for burning difficult-burn coal such as Banko coal with high water content.

c) The feedwater mixed with LP Steam is heated by 2 units of deaerators and 2 units of HP feedwater heaters.

Saturated MP steam from the gasification plant and methanol plant is superheated and then partly sent to the methanol plant and, for the rest, input to the intermediate stage of the steam turbine.

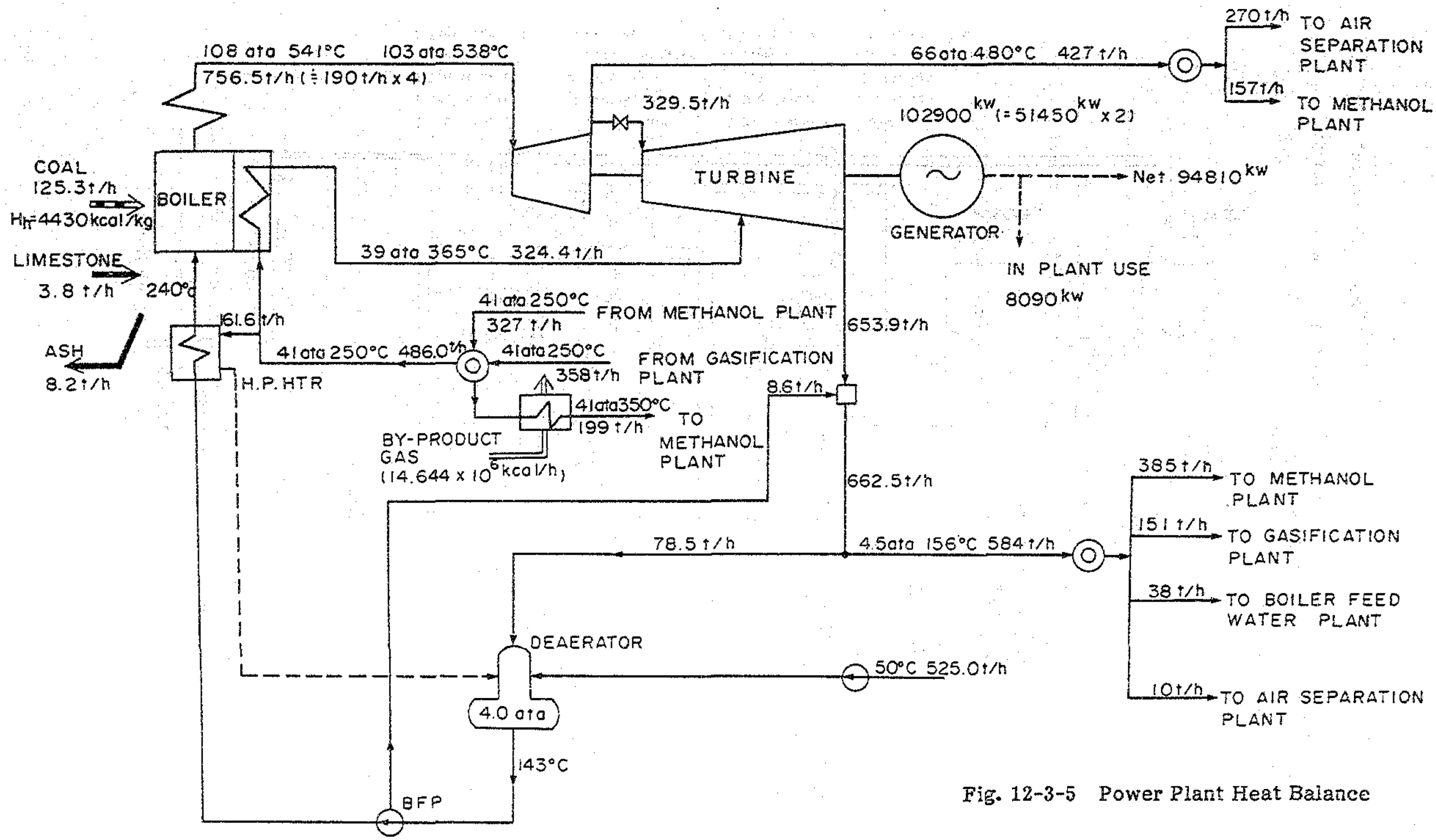
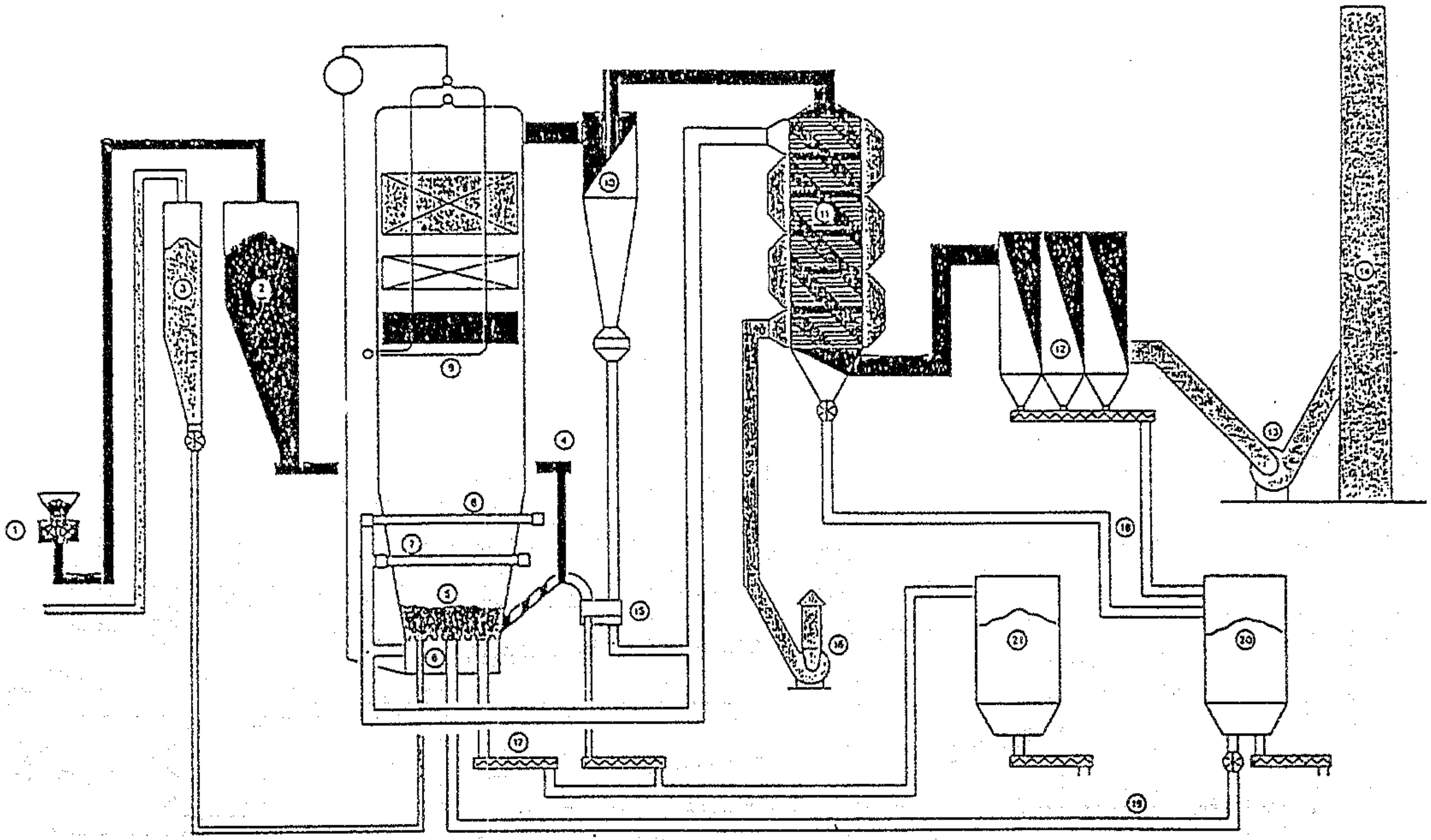


Fig. 12-3-5 Power Plant Heat Balance



1 Coal Crusher
2 Coal Bunker
3 Limestone Bunker
4 Coal Feed
5 Fluidized Bed
6 Primary Air
7 Secondary Air
8 Tertiary Air
9 Steam Generator
10 Cyclone
11 Air Preheater
12 Bag Filter
13 IDF
14 Stack
15 Ash Siphon
16 FDF
17 Bed Ash
18 Fly Ash
19 Fly Ash Recycle
20 Fly Ash Silo
21 Bed Ash Silo

Fig. 12-3-6 Scheme of Fluidized Bed Boiler

iii) Major Equipment

Specification and the number of major equipment are listed in Table 12-3-5.

Table 12-3-5 Major Equipment
(Power Plant)

Description	Q'ty	Specification
Fluidized Bed Boiler	4	190 t/h, 107 atg 541°C/240°C
Steam Turbine/Generator Unit	2	51,450 kW
Deaerator	2	383 t/h
HP Feedwater Heater	2	380 t/h
Boiler Feed Pump	4	445 t/h, 125 atg

6) Utility Facilities

i) Cooling Water System

Cooling Water System is shown in Fig. 12-3-7 and 12-3-8.

Cooling water is supplied from the Cooling Water Plant to each plant at 32°C and returned at 42°C after cooling the process gas and liquid, steam turbine condensate and compressed gas to required temperature.

In Cooling Water Plant, returned cooling water is cooled from 42°C to 32°C through ordinary cooling towers.

Normally, 2% of circulating cooling water is lost in the cooling towers as accompanied by air into atmosphere and 1% of circulating cooling water is blown down for controling the content of impurities in circulating water. Therefore, 3% of the cooling water is made up from Industrial Water Plant continuously.

In this stage, Cooling Water Plant is located at one area together, but it will be reviewed in the 3rd stage to install the cooling towers separately close to each plant from the economical point of view.

Fig. 12-3-7 Cooling Water System

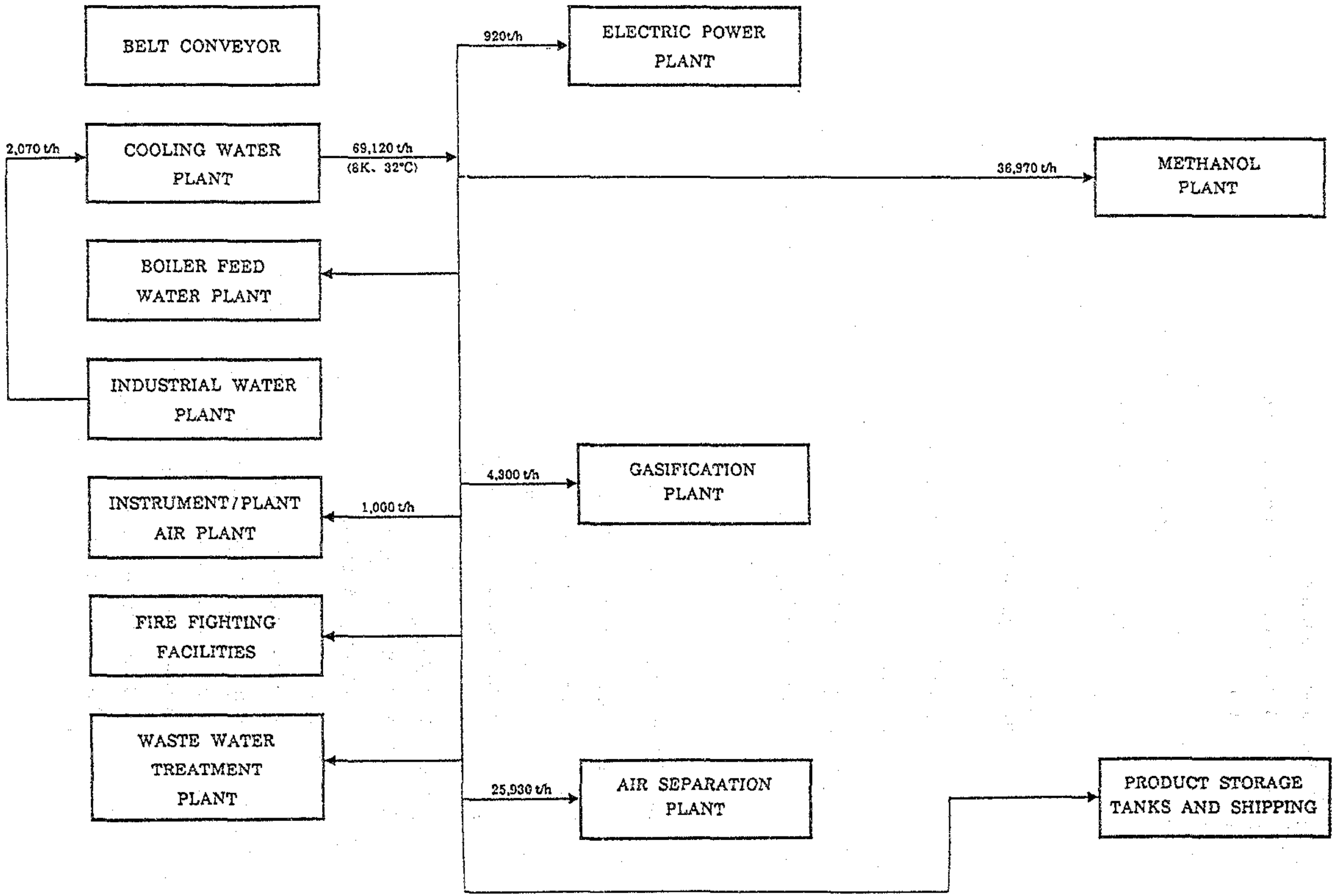
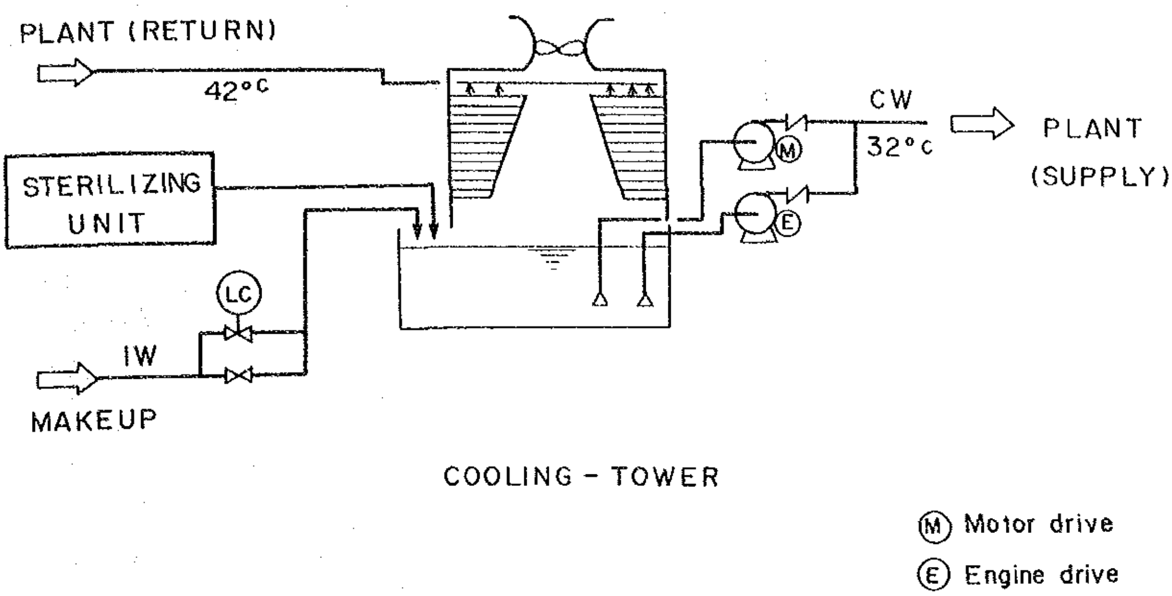


Fig. 12-3-8 Cooling Water Plant Flow



ii) Service Water System

There are two kinds of service water. One is drinking water and the other is used for washing hand and face or tableware.
Drinking water shall be prepared in bottles or cans from the outside of the factory and the other is supplied from Industrial Water Plant after being sterilized through piping.

iii) Boiler Feed Water System

Boiler Feed Water System is shown in Fig. 12-3-9 and 12-3-10.
Main source of boiler feed water is steam condensate recovered from each plant and industrial water is made up for the evaporated and blown down loss in the circulating boiler feed water.
There are two kinds of adsorber in this plant and cations such as Fe, Mg, Na-ion and anions such as Cl, SO_4-ion in the feed water are adsorbed and removed so that the treated water meets the boiler feed water specification. A small amount of carbon dioxide and oxygen dissolved in the water is also removed in a stripper and deaerator.

Fig. 12-3-9 Boiler Feed Water System

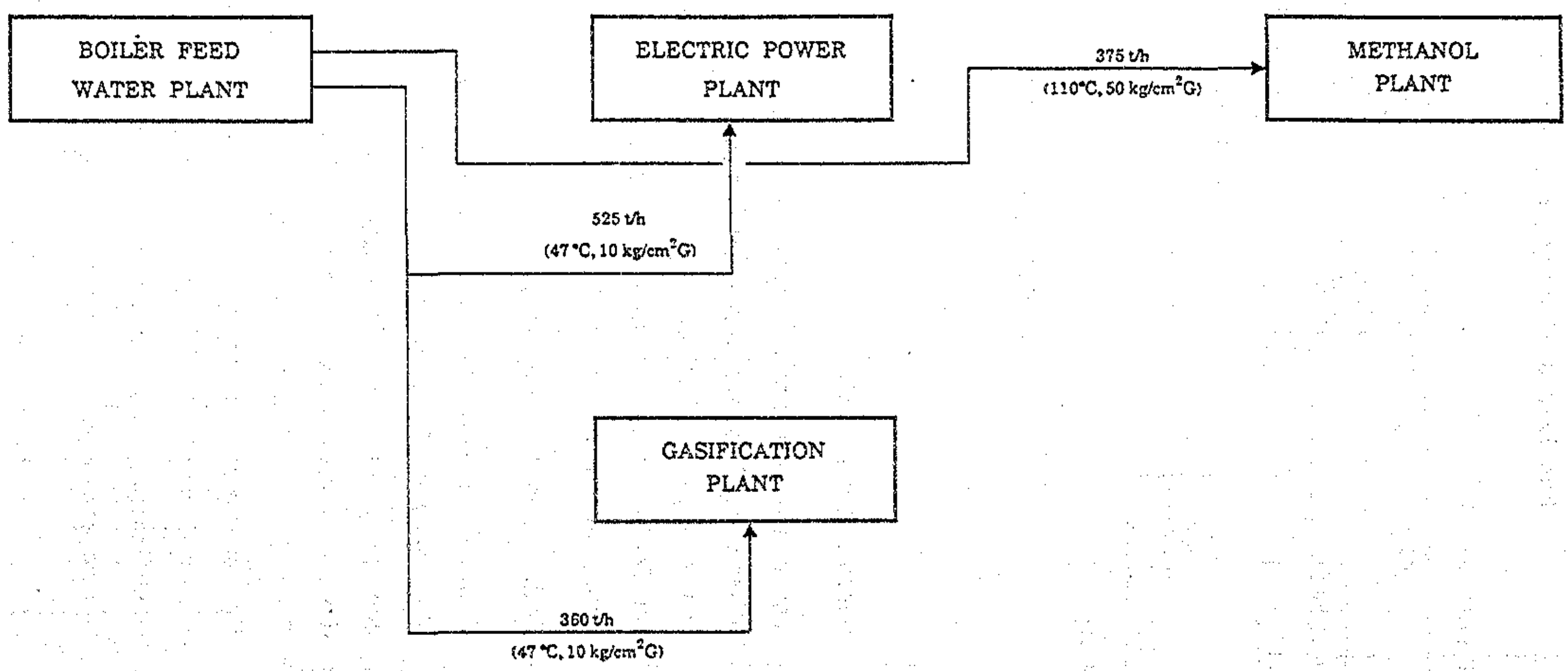
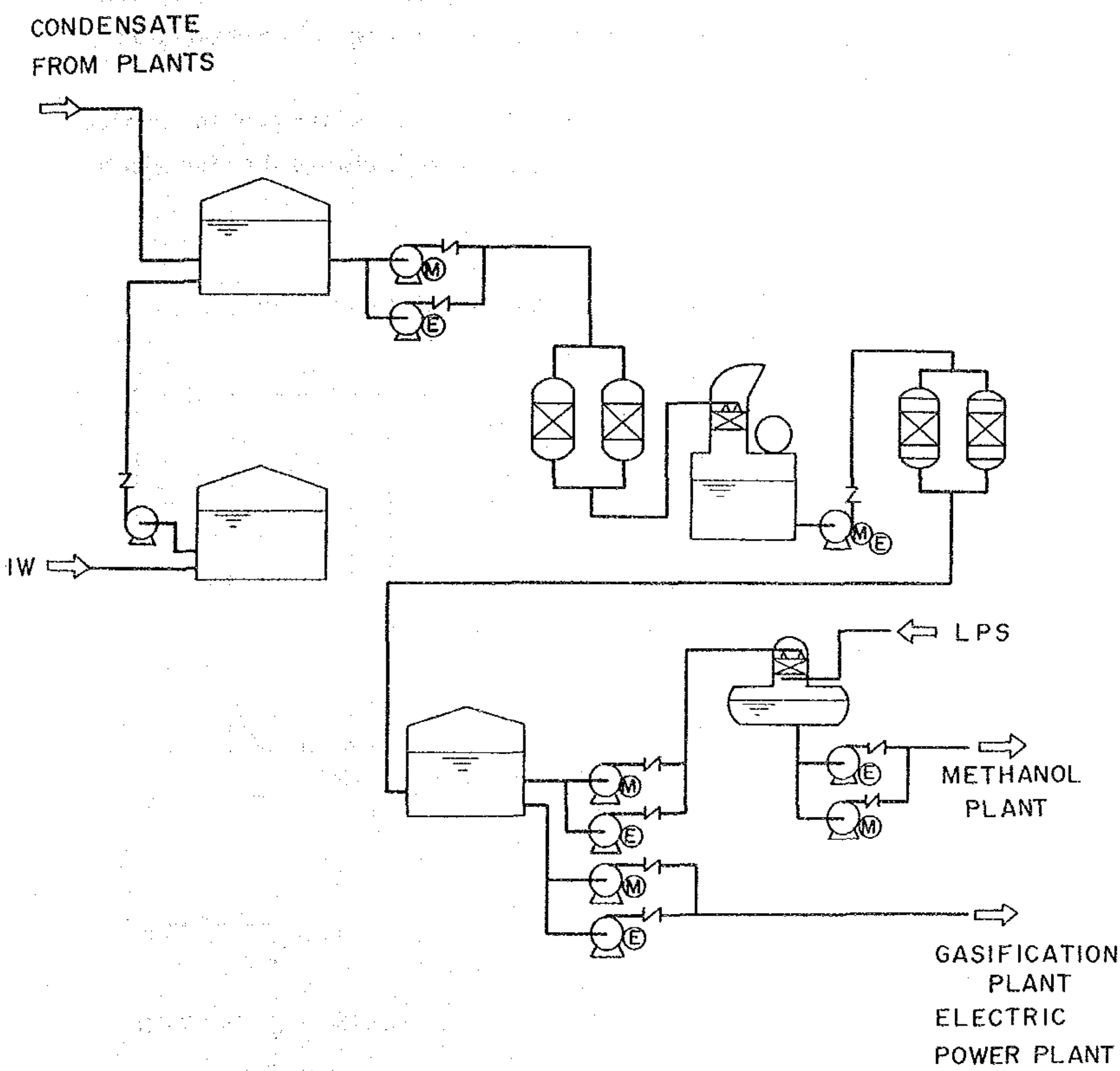


Fig. 12-3-10 Boiler Feed Water and Steam Condensate Flow



iv) Industrial Water System

Industrial Water System is shown in Fig. 12-3-11 and 12-3-12.

River Water is used as the source of industrial water after special treatment for removing the muddy materials at the off-site.

Another water pool is prepared there and the primary sterilizing treatment is carried out, and the cleared water is sent to the on-site.

At the on-site, a reasonable capacity of water pool is prepared so that continuous water supply can be kept in case of emergency at the off-site.

A small amount of water is sent from this water pool for service water as mentioned in section ii), and this pool is also used as the source of fire water.

Fig. 12-3-11 Industrial Water Plant Flow

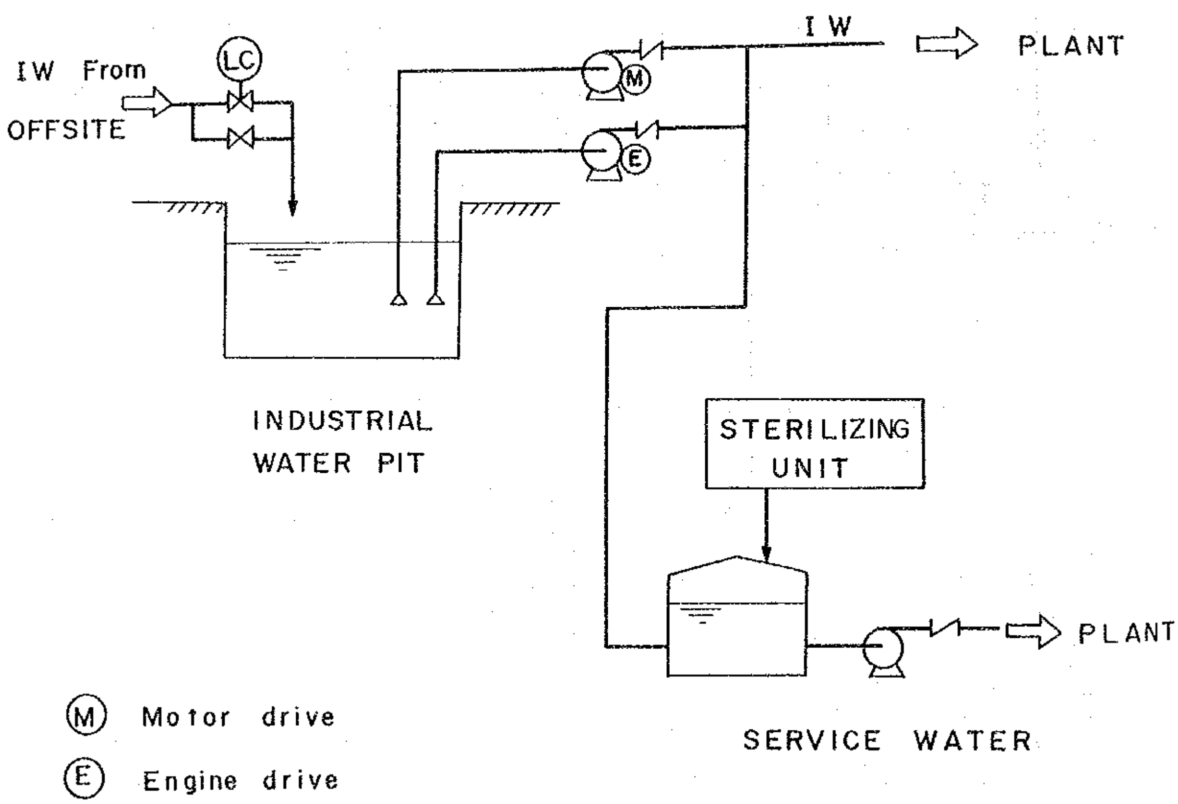
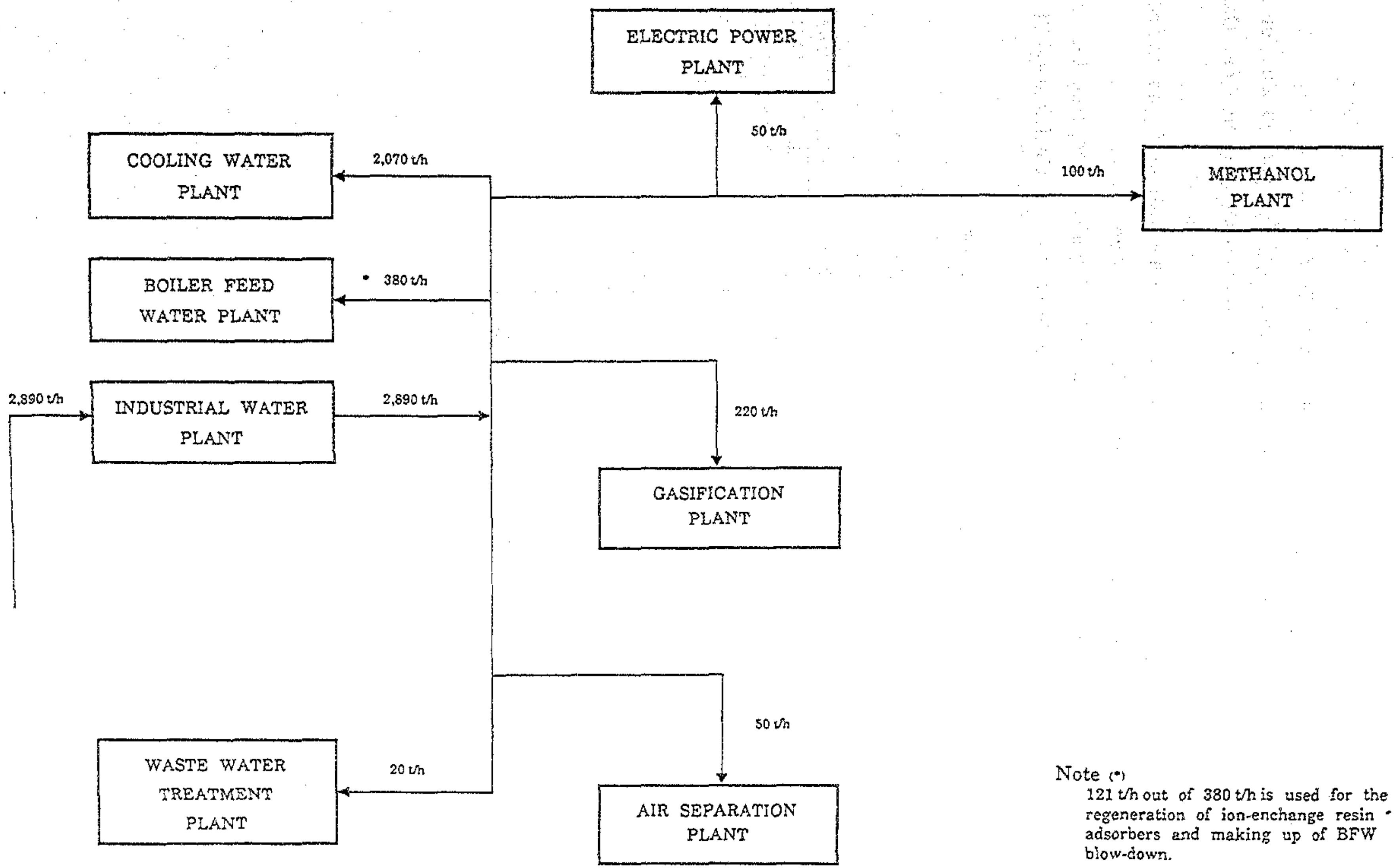


Fig. 12-13-12 Industrial Water System

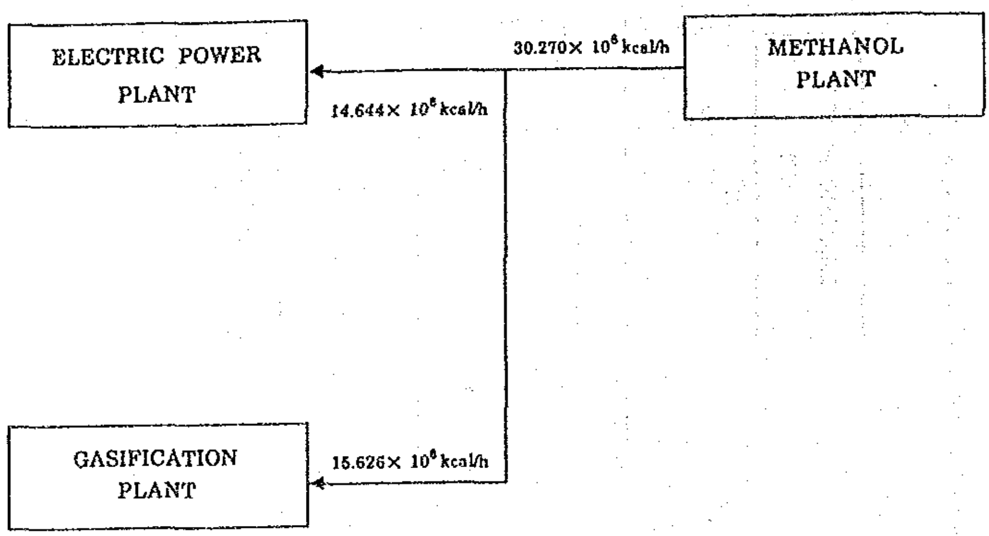


Note (*)
121 t/h out of 380 t/h is used for the regeneration of ion-enchange resin adsorbers and making up of BFW blow-down.

v) Fuel Gas System

Fuel Gas System is shown in Fig. 12-3-13.
The source of fuel gas is by-produced in Methanol Production Plant and it is sent preferentially to the calcination unit in Coal Gasification Plant.
The rest of it is sent to Boiler Plant which is consumed for the superheating of MP Steam and Flare System.
Another fuel gas such as LPG or LNG shall be prepared temporarily for the start-up of the gasifier and calciner in Coal Gasification Plant.

Fig. 12-3-13 Fuel Gas System



vi) Fuel Methanol System

Fuel methanol is prepared for diesel engines of a fire water pump, cooling water pump, boiler feed pump, industrial water pump and air compressors which are operated in case of emergency in Boiler and Electric Power Plant.

If it is impossible to receive electricity from the outside, engine driven generators shall be installed. Fuel methanol is stored in cone roof type tanks in Tank Yard.

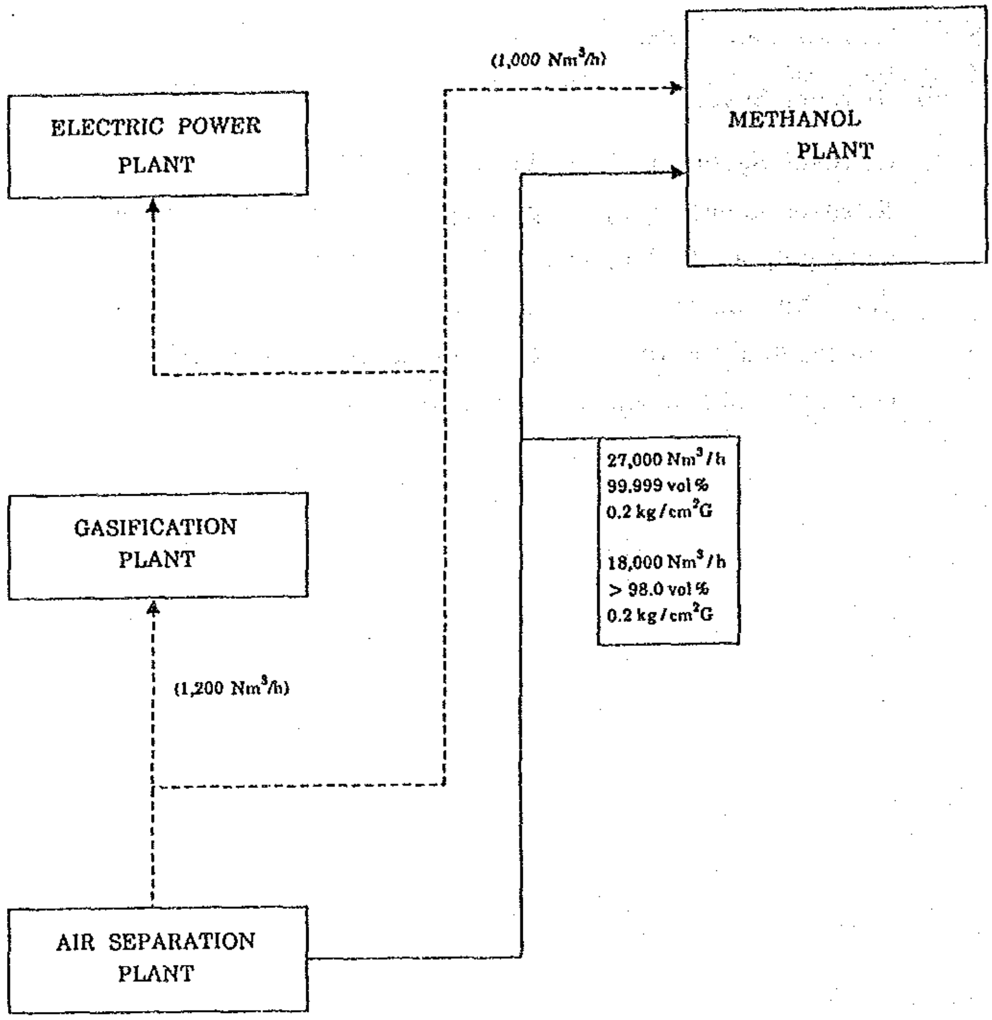
vii) Nitrogen System

Nitrogen System is shown in Fig. 12-3-14.

Nitrogen is necessary for purging the combustible materials in equipment and piping at start-up and shut-down stage.

For this purpose, nitrogen produced in Air Separation Plant is compressed by the use of a compressor (a spare compressor of air compressors) and sent to each plant at 6 kg/cm^2G.

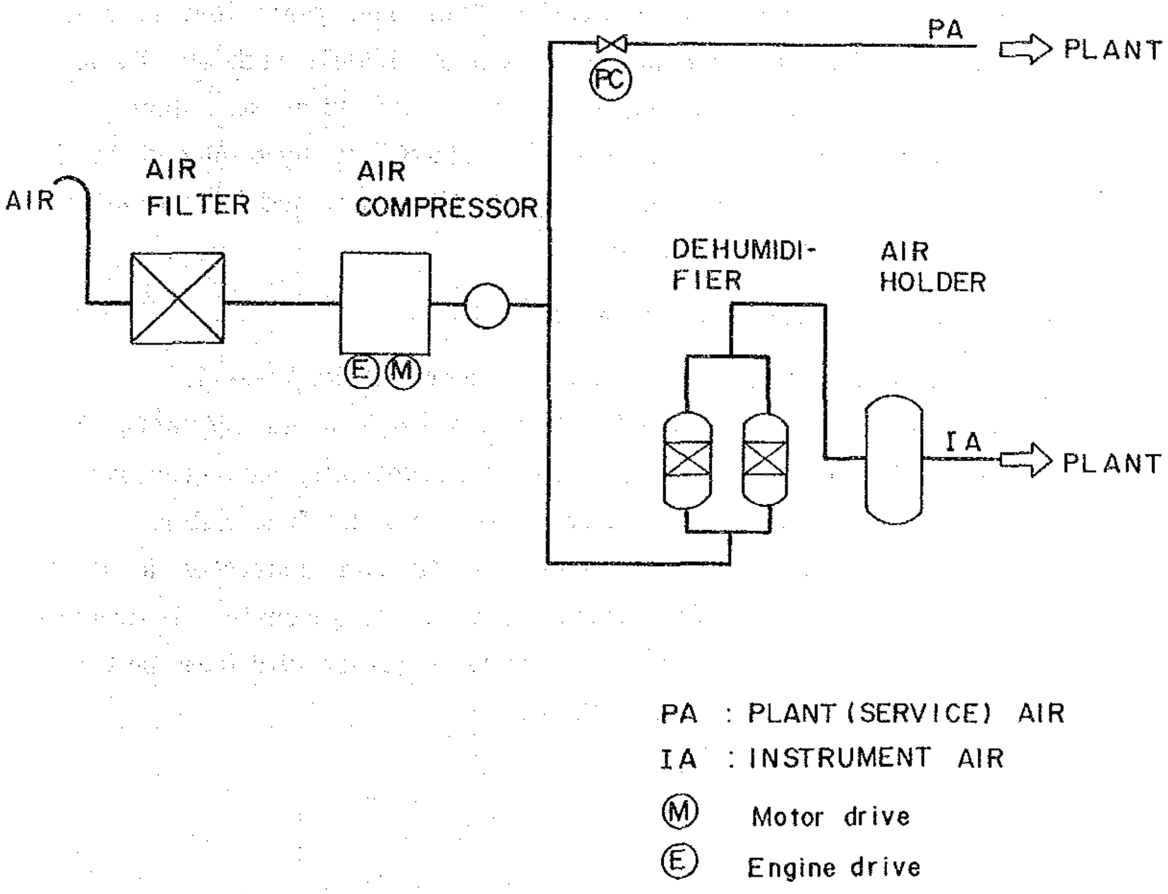
Fig. 12-3-14 Nitrogen System



viii) Instrument Air System

Instrument/Plant Air Plant Flow is shown in Fig. 12-3-15.
Instrument air is compressed together with plant air by air compressors. Normally, most of compressed air is sent to a dehumidifier where the saturated moisture is removed, and is supplied to each plant via an instrument air holder.

Fig. 12-3-15 Instrument/Plant Air Plant Flow



ix) Plant Air System

Plant Air Flow is shown in Fig. 12-3-15.
Plant air is used for maintenance works during the normal operation and periodical maintenance of each plant.
Normally, some amount of the compressed air from instrument air compressors is directly used as the plant air.

x) Steam System

Steam System is shown in Fig. 12-3-16.
HP Steam is consumed in steam turbines for air compressors and oxygen compressors in Air Separation Plant, a raw gas compressor and a CO_2 compressor in Methanol Production Plant and generators in Electric Power Plant. MP Steam (40 kg/cm^{2}G, 350^{o}C) and LP Steam are consumed mainly in process heaters and deaerators of each plant.
Saturated MP Steam (40 kg/cm^{2}G, 250^{o}C) is by-produced in Coal Gasification Plant and Methanol Production Plant and is superheated in Boiler Plant from 250^{o}C to 350^{o}C.

xi) Steam Condensate Recovery System

Steam Condensate Recovery System is shown in fig. 12-3-17.
All steam condensate from HP-Steam, MP-Steam (40 kg/cm^{2}G, 350^{o}C) and LP Steam mentioned in Section x), is practically recovered, gathered in Boiler Feed Water Plant and reused as the boiler feed water.
Boiler and Electric Power Plant has its own deaerator in it, and recovered condensate from steam turbines for genreators is deaerated there and reused as the boiler feed water together with fresh boiler feed water from Boiler Feed Water Plant.

Fig. 12-3-16 Steam System

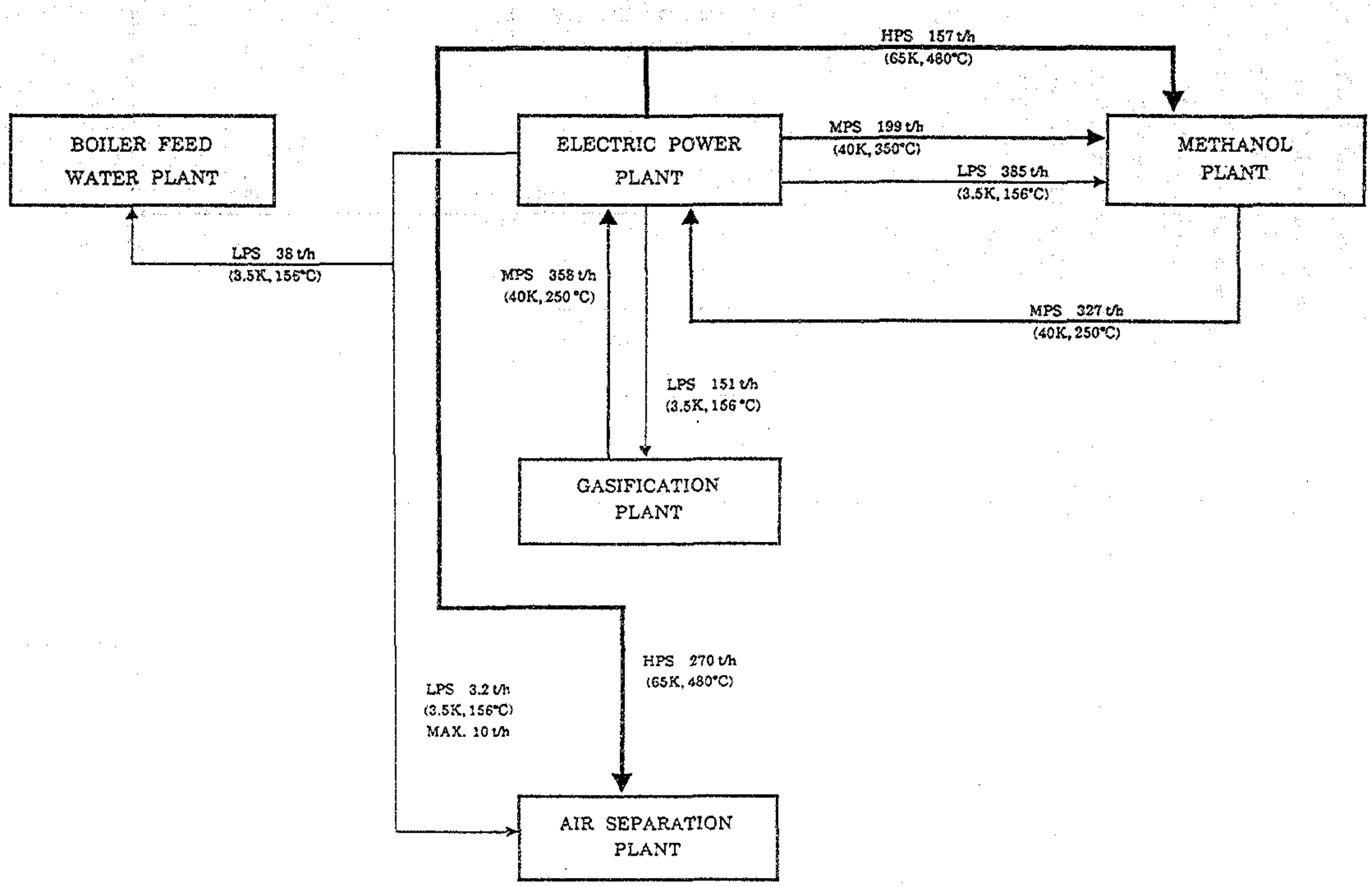
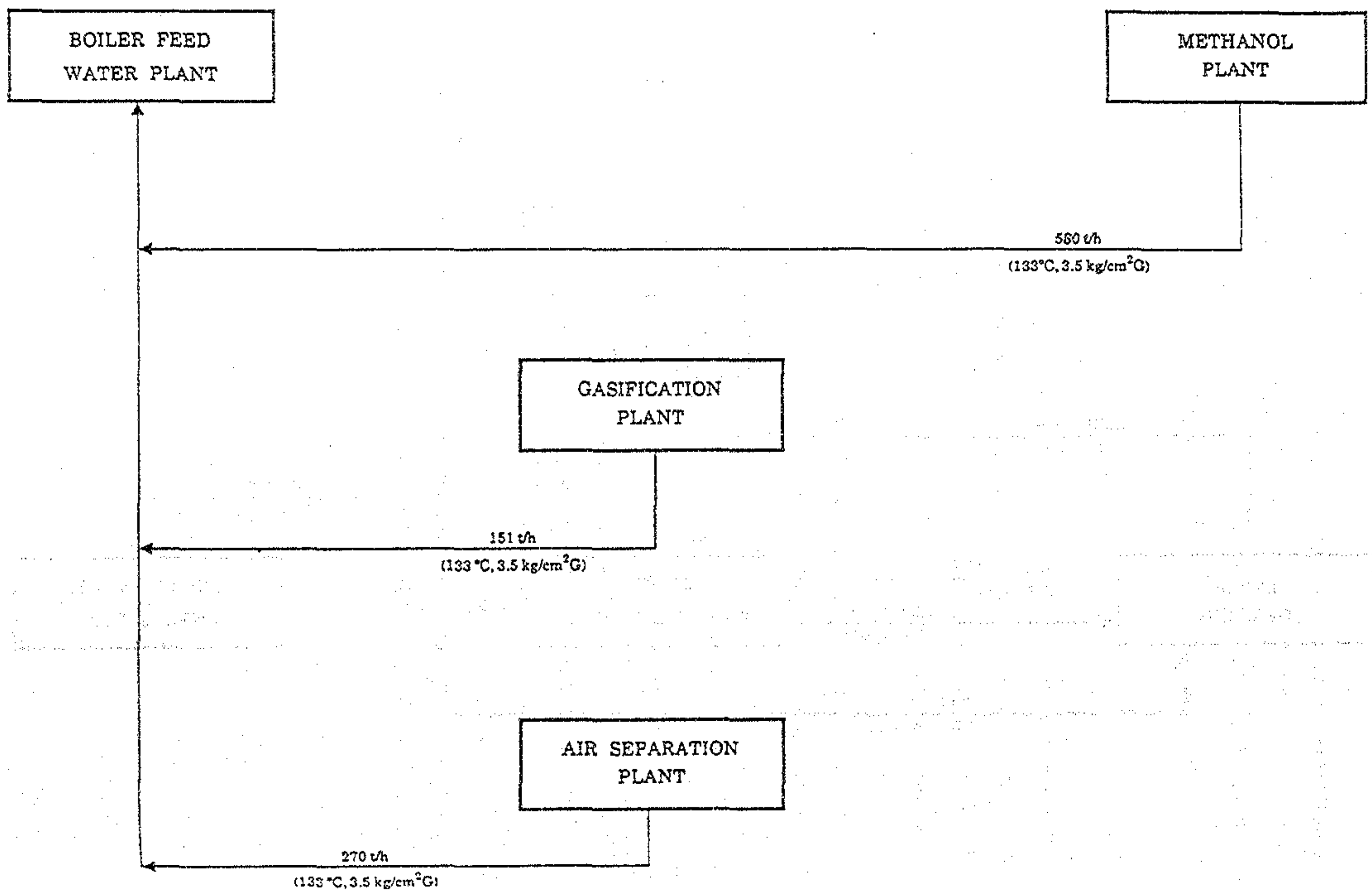


Fig. 12-3-17 Steam Condensate Recovery System



xii) Electricity Distribution System

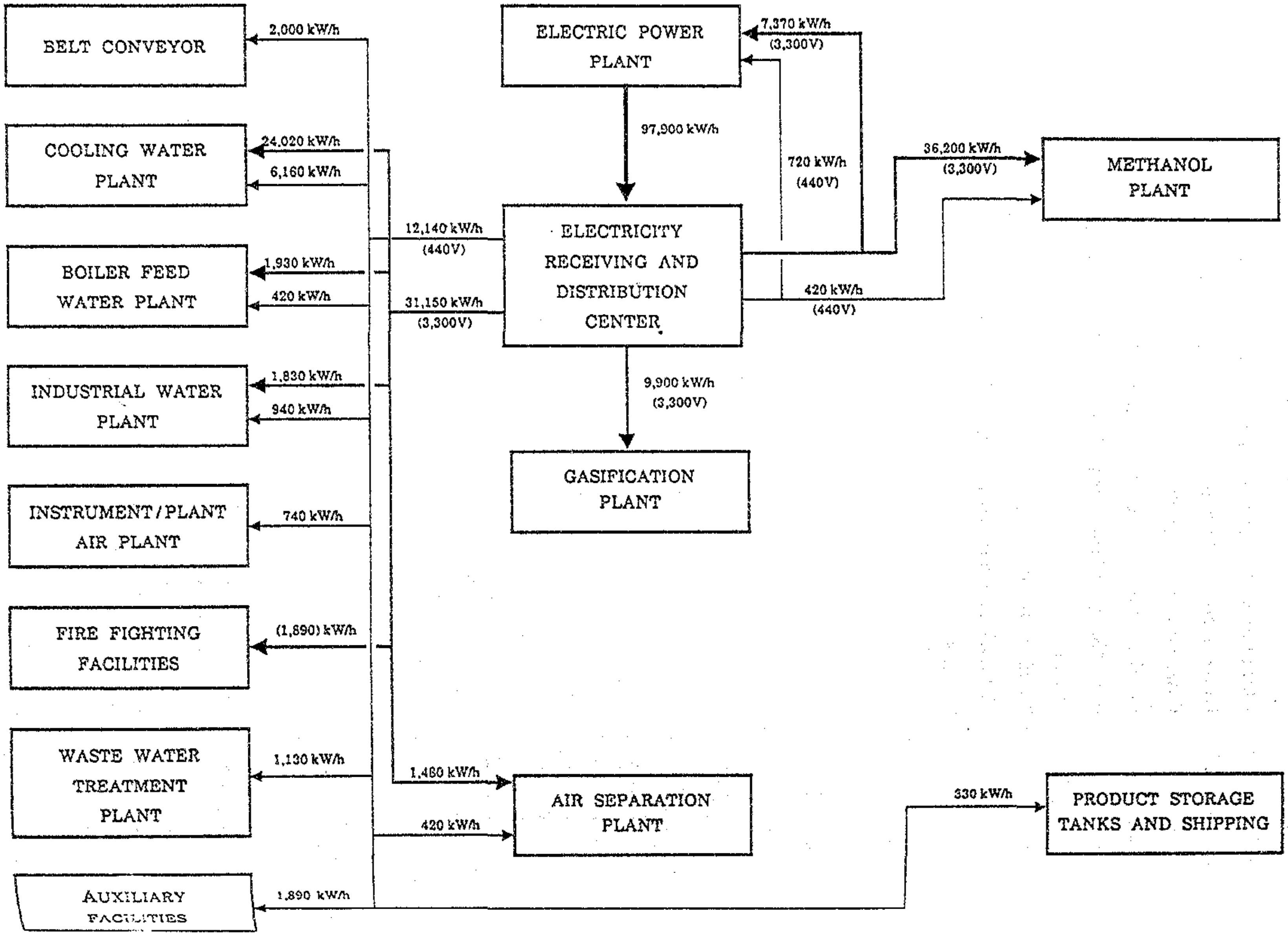
Electricity Distribution System is shown in Fig. 12-3-18.

Generated electricity is transmitted from Electric Power Plant through power cables at 11,000 volt.

In Electricity Receiving and Distribution Center, this high tension electricity is transformed into 3,300 volt and 440 volt and distributed to each plant.

3,300 volt electricity is used for bigger capacity motors (more than 200 kW) and 440 volt electricity is for smaller capacity ones (less than 200 kW).

Fig. 12-3-18 Electricity Receiving and Distribution System



7) Flare System

Flare System is shown in Fig. 12-3-19.

This facility is operated mainly at the start-up and shut-down stage of Coal Gasification and Methanol Production Plant to burn the systhesis gas from Coal Gasification Plant and the purge gas from Methanol Production Plant.

It is also operated automatically in the case of emergent shut-down of Coal Gasification and/or Methanol Production Plant.

8) Fire Fighting System

The fixed fire fighting system flow is shown in Fig. 12-3-20.

For general fire fighting such as a coal or building fire, fire water is used and alcofoam solution is used for a methanol fire. Therefore, necessary numbers of alcofoam solution hydrant are arranged around Methanol Production Plant and a alcofoam system is set up by the side of Tank Yard.

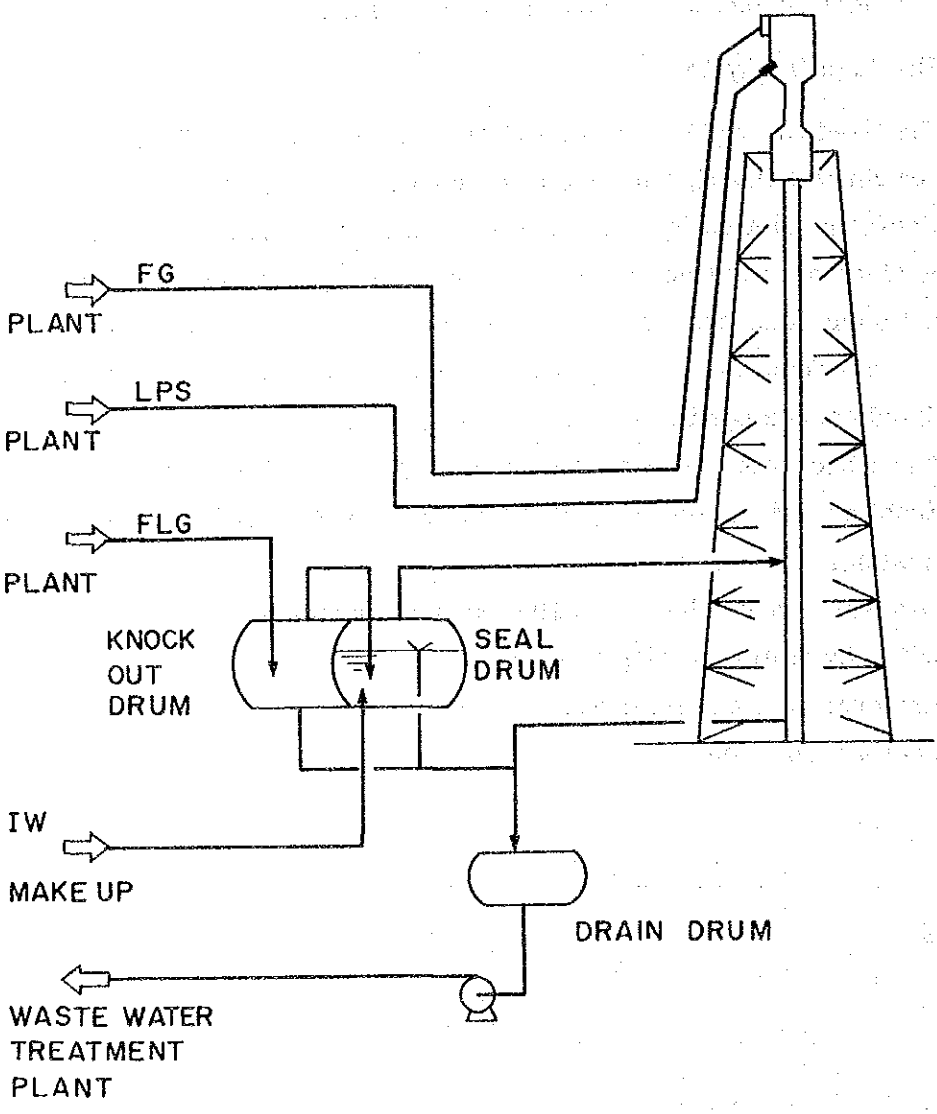
This alcofoam system supplies alcofoam solution to the hydrants and air foam chambers equipped to methanol storage tanks.

Water hydrants are arranged principally around Coal Gasification Plant, Coal Handling Area, Boiler and Electric Power Generation Plant and other buildings.

Fire water is supplied from the industrial water pool by fire pumps which are driven by motors or diesel engines.

Fire engines are prepared in the fire station and they can discharge water and alcofoam solution.

Fig. 12-3-19 Flare Gas Stack System Flow



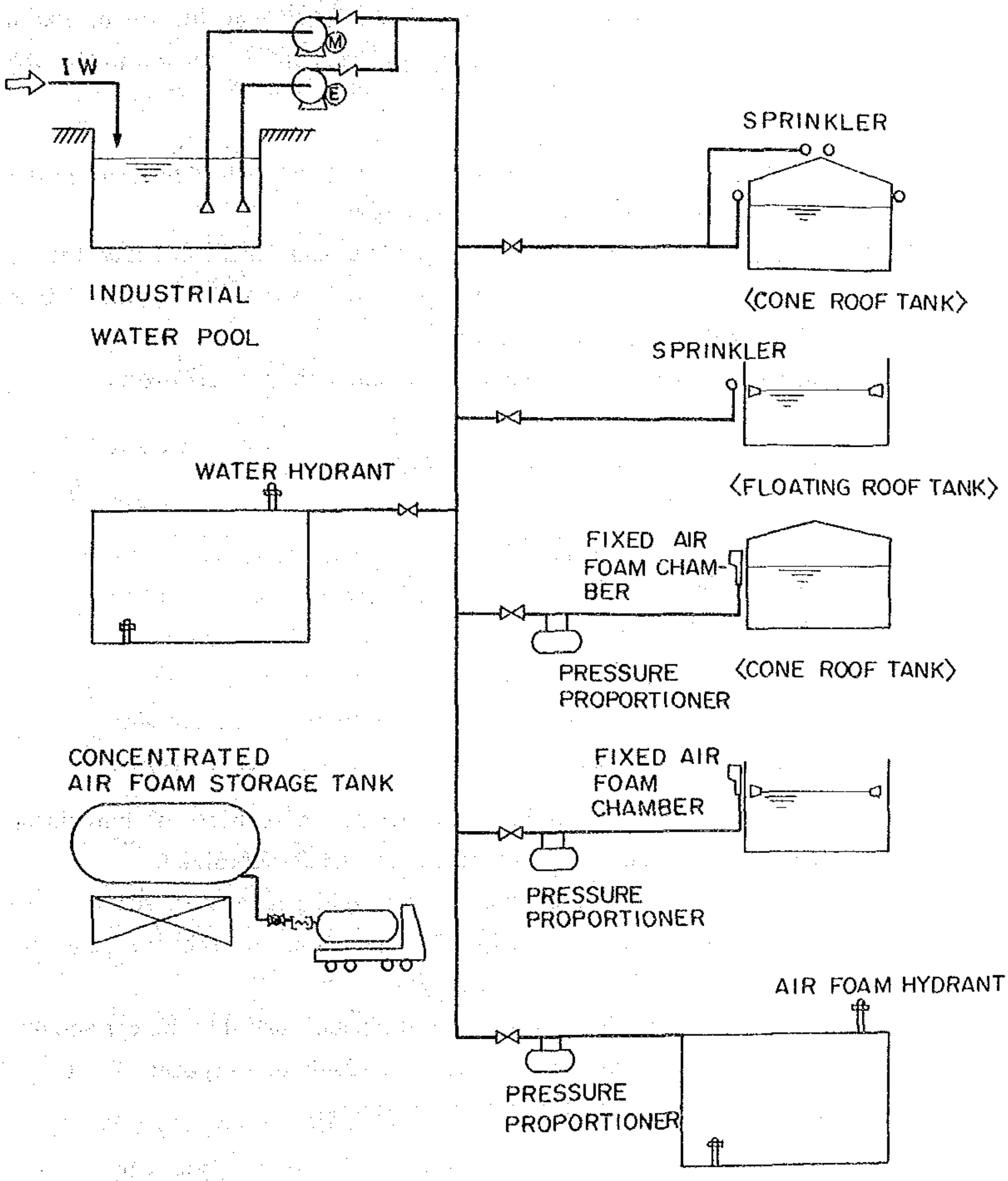
FG : Fuel gas (PILOT FUEL GAS)

LPS : LOW PRESSURE STEAM

FLG : FLARE GAS

IW : INDUSTRIAL WATER

Fig. 12-3-20 Fire Fighting System Flow



Ⓜ : Motor drive

Ⓔ : Engine drive

IW: Industrial water

9) Auxiliary Facilities

i) Office

The administration office shall consist of necessary office rooms for all staff members working in the factory except foremen and operators who are normally working in the central control room. A computer room, a telephone and telex room, a typing and copy machine room, and an air conditioning and hot water supply system shall be annexed to the office.

ii) Laboratory

On line analyzers are installed in plants for continuous and automatic analyses of flowing materials in process.

However, properties of raw materials and final products for plants, utilities and waste are analyzed and examined in the laboratory periodically or in case of necessity.

In the laboratory, the following equipment shall be arranged.

a) Gas chromatographs

b) Atomic absorption spectroscopy

c) Moisture meter

d) Potentiometric titrator

e) Conductivity meter

f) pH instrument

g) Slag analyzer

h) Others

iii) Workshop

In consideration of the local conditions, spare parts of machinery and equipment should be kept as simplified and standardized.

Furthermore, it is desirable to have one package spares or complete spares for special machinery and equipment in order to complete the field maintenance work efficiently.

In the workshop, the following maintenance work shall be carried out.

a) Assembly of one package spares and complete spares.

b) Cleaning and adjustment of instrument.

c) Thorough overhaul of machinery.

d) Prefabrication of simple pipe arrangement.

Main machine tools in the workshop shall be as follows:

a) Lethes

b) Drilling machines

c) Grinding machines

d) Welding machines

e) Measuring and inspection instrument

iv) Others

A guard house and a fire station shall be built near the entrance of the factory and a mosque shall be in the neighborhood of the administration office.

It is also necessary to build a warehouse and a training center close to the workshop.

(4) Off-site Facilities

1) Stock Piles

The stock piles consists of a brown coal stock yard, a limestone stock yard and a steel scrap stock yard.

The brown coal which is crushed into appropriate size at the mining site is carried to the brown coal stock yard by conveyor lines continuously and stocked there for at least several day's operation of Coal Gasification and Boiler Plant. Stocked brown coal is transferred to the coal handling unit by other short conveyor lines and fed to Coal Gasification and Boiler Plant.

On the other hand, the limestone and steel scrap are carried in by dump trucks and stocked in a limestone yard and a steel scrap yard respectively.

They are also transferred to Coal Gasification Plant by short conveyor lines.

The stock capacity of both stock yard shall be determined in consideration of the details for the transportation of limestone and steel scrap.

2) Water Intake System

A water pool is prepared close by the river at lower level than the surface of river water so that the water can flow into the pool spontaneously.

While the raw water is sent from the pool to a precipitator, coagulant is added to separate suspended mud as coagulated ~ sedimented floc.

Supernatant water is pumped up from the precipitator and is sent to the plant site as industrial water.

After settled, floc is discharged by a drainage pump to a pond to be located nearby, where residual water is naturally vaporized.

3) Waste Disposal Facilities

There are two kinds of waste. One is waste water and the other is solid waste.

Blow down water from Cooling Water and Boiler Feed Water Plant, and steam condensate from the adsorbers in Air Separation Plant and the reactors and columns in Methanol Production Plant become main waste water.

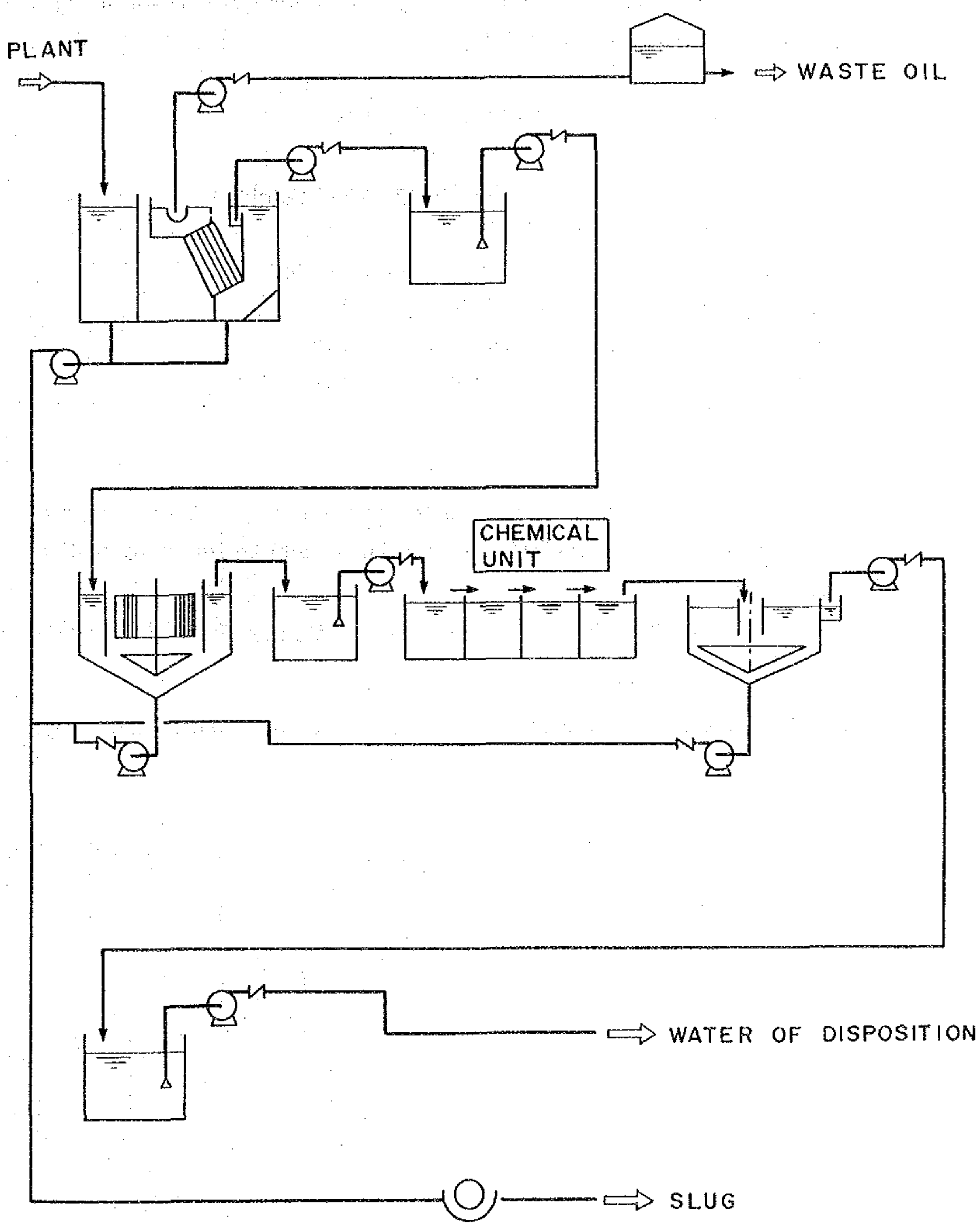
Waste water is gathered to waste water treatment unit in Water Treatment Plant and the detrimental materials to health are removed there. (See Fig. 3-12-21)

Treated water is returned to the river and the sludgy materials are disposed in the solid waste handling area.

Major solid waste are the slag from a gasifier in Coal Gasification Plant and ash from Boiler Plant.

They are also gathered in the solid waste handling area and transferred to the soil dump area in the mining site.

Fig. 12-3-21 Waste Water Treatment Flow



(5) Overall Scheme

1) Material Balance

The overall material balance and utility requirement are shown in Fig. 12-3-22, Fig. 12-3-23 and Table 12-3-6.

Table 12-3-6 Utility Requirement

Coal	125 T/h	(external supply)
Raw Water	2,890 T/h	(ditto)
Electricity	97,900 kW	(internal supply)
Cooling Water	69,120 T/h	(ditto)
BFW	1,260 T/h	(ditto)
HP Steam	757 T/h	(ditto)

2) Plant Layout

The exact layout cannot be determined in this stage, but the image of the layout as well as the required area will be of help to the study in the final step.

In this regards, the plant layout is roughly estimated as shown in fig. 12-3-24.

3) Construction Schedule

Roughly estimated construction schedule of the coal gasification complex is shown in Fig. 12-3-25.

Fig. 12-3-22 Overall Material Balance (Case 1)

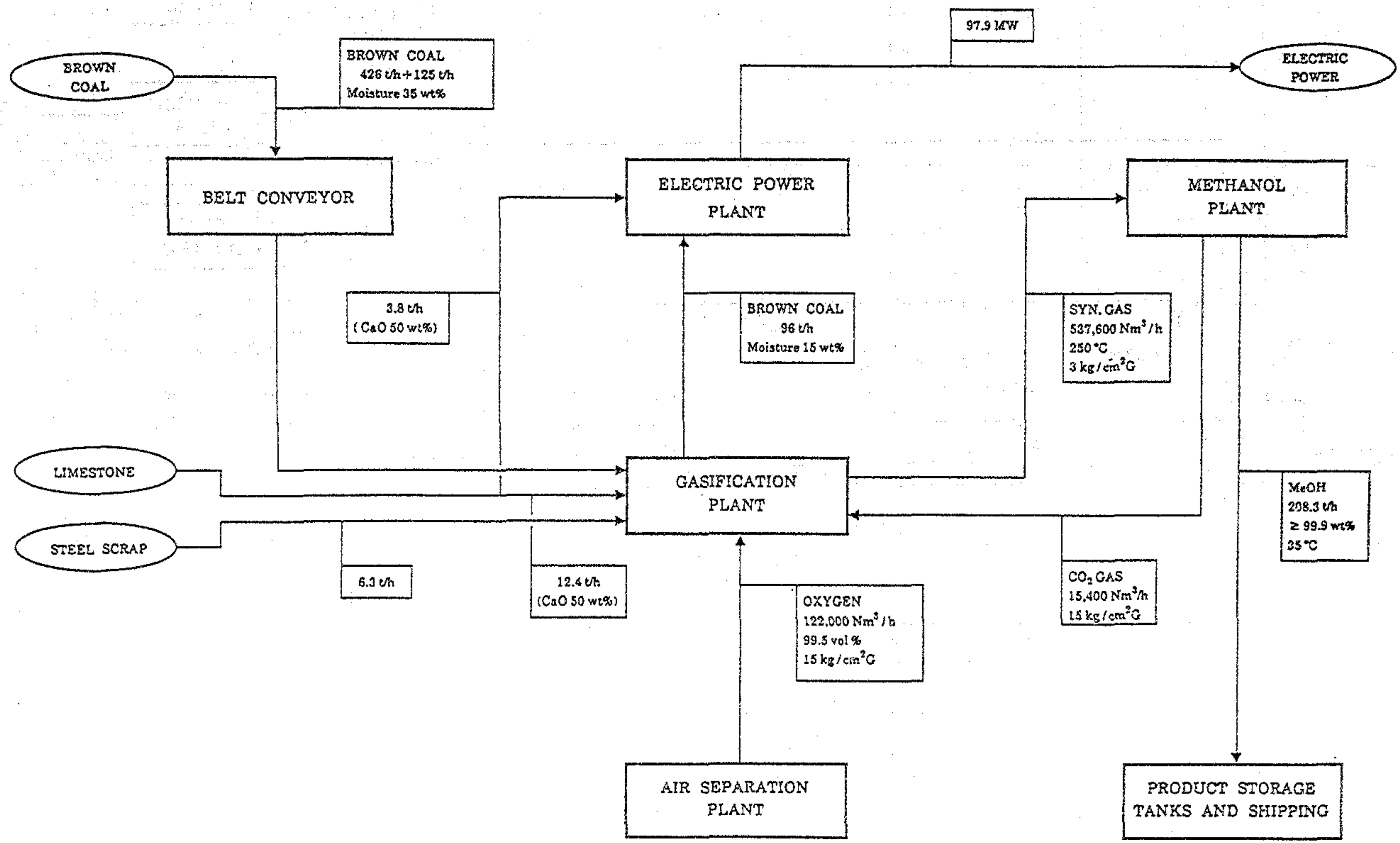
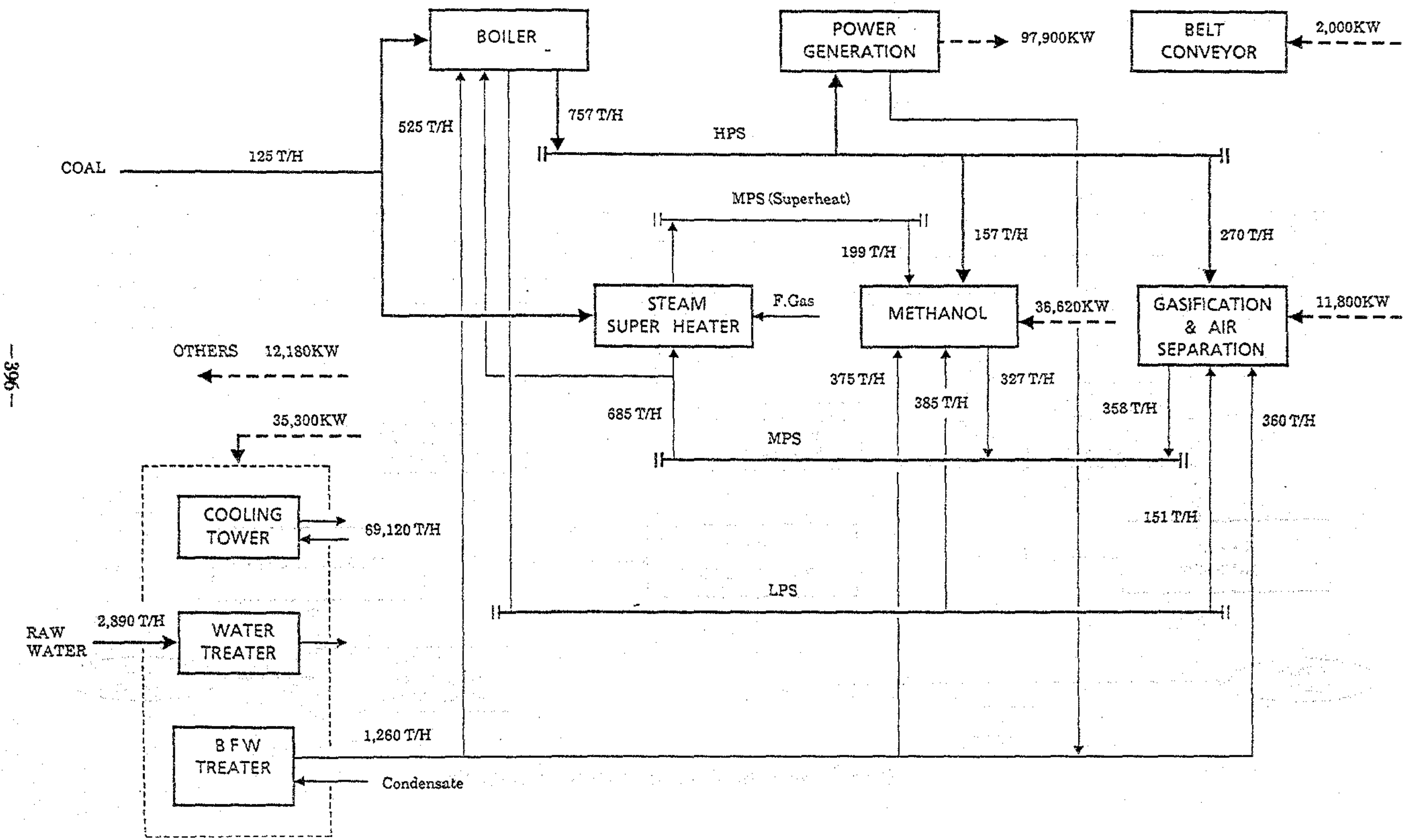


Fig. 12-3-23 Utility Summary (Case 1)



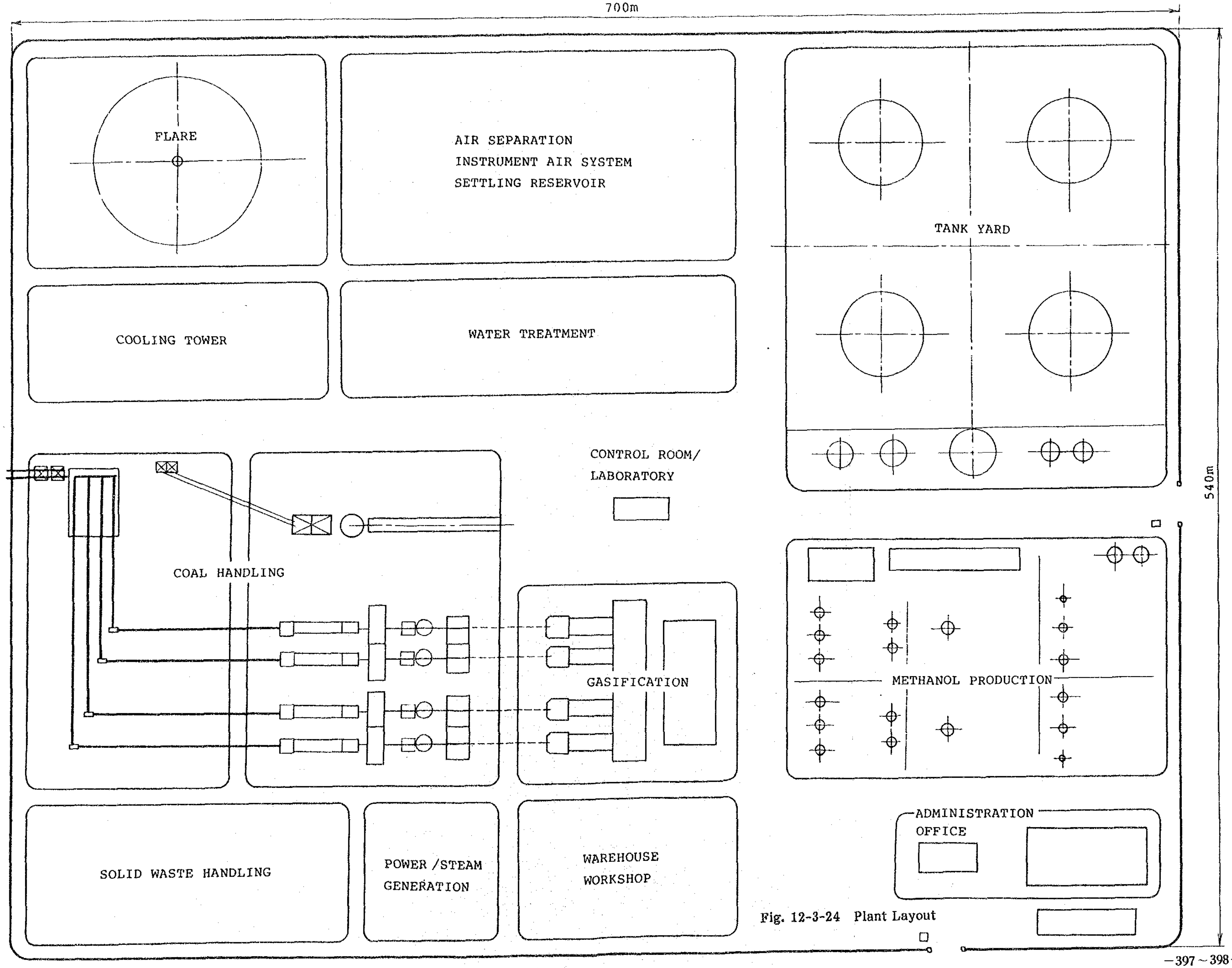
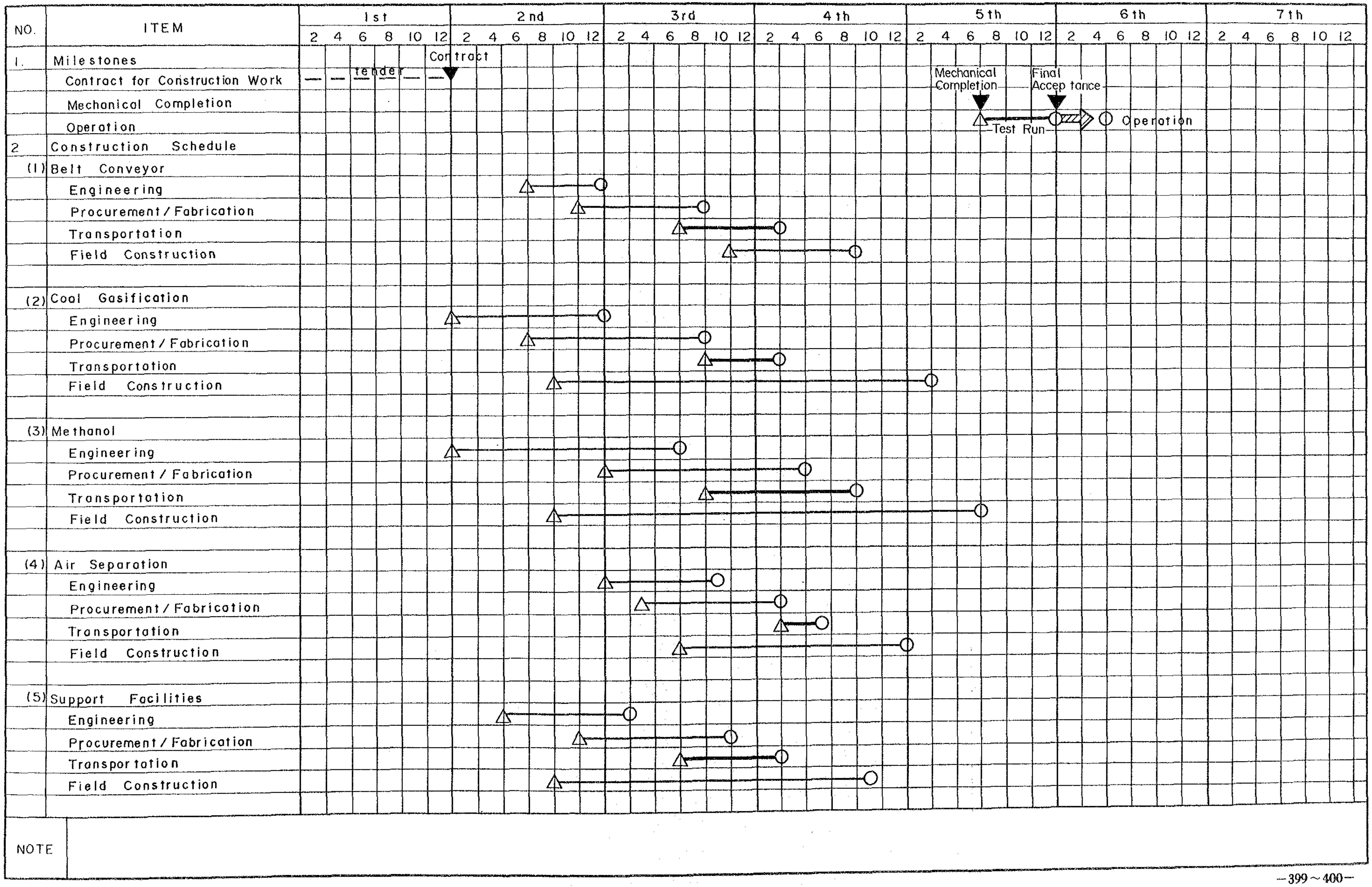


Fig. 12-3-24 Plant Layout

Fig. 12-3-25 Coal Gasification Complex Construction Schedule



12-3-2 Master Plan Case 2

(1) Product Plant

1) Production Rate

Methanol	:	1,300,000 ton/year (4,060 ton/day)
Urea	:	560,000 ton/year (1,750 ton/day)

2) Annual Operation Days : 320 days/year

3) Product Specification

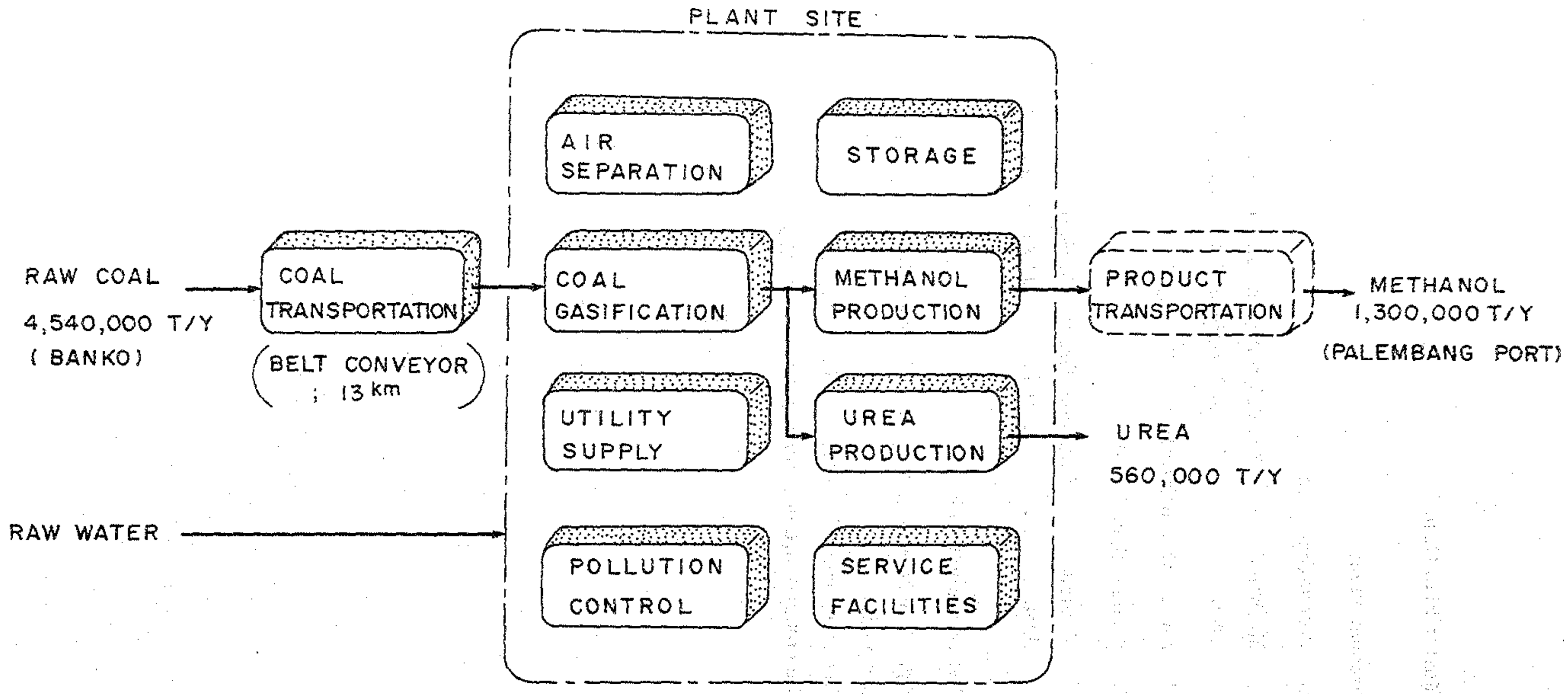
Methanol	:	Chemical Grade (99.9% pure)
Urea	:	ditto (99.8% pure)

(2) Plant Configuration

Fig. 12-3-26 shows the overall block flow diagram of methanol/urea production complex.

The component facilities are listed in Table 12-3-8. Main process and systems in the complex are described in the following pages.

Fig. 12-3-26 Overall Block Flow Diagram



* Component facilities consisting each block are listed in Table 12-3-8.

Table 12-3-8 Plant Configuration

1) Belt Conveyor System

Primary Crusher/Feeder
Overland Coal Conveyor

2) Coal Gasification

Coal Storage and Handling
Coal Pretreatment
Coal Gasification
Gas Cooling/Dedusting
Calcination

3) Methanol Plant

Gas Compression
Gas Treating
Methanol Synthesis
Methanol Distillation

4) Ammonia/Urea

Gas Compression
Gas Treating
Ammonia Synthesis
Urea Synthesis
Urea Prilling
Refrigeration System

5) Air Separation Plant

Air Separation
Liquid Oxygen Tank
Liquid Nitrogen Tank

6) Utility System

Power Generation
Power Distribution
Stream Boiler
Water Cooling
Raw Water Intake/Pretreatment
Instrument/Plant/Air Supply

7) Pollution Control/Safety System

Waste Water Treatment
Solid Waste Disposal
Flare/Blowdown
Fire Fighting

8) Storage

Product Tank
Chemicals Tank
LPG Tank
Fuel Oil Tank
Lubricating Oil Tank

9) Service Facilities

Administration Office
Laboratory
Warehouse
Accommodation
Canteen
Cafeteria
Leisure Center
Mosque
Communication System
Maintenance Shop
Service Water Supply

(3) On-site Facilities

1) Coal Gasification

See Subsection 12-3-1.

2) Methanol Production

i) Process Flow Diagram

See Fig. 12-3-27 and Fig. 12-3-28.

ii) Process Description

See Subsection 12-3-1.

iii) Major Equipment

See Table 12-3-9.

3) Ammonia/Urea Production

i) Process Flow Diagram

See Fig. 12-3-27, Fig. 12-3-29 and Fig. 12-3-30.

ii) Process Description

The ammonia/urea plant consists of the following process steps:

- o Dust Removal and 1st Compression
- o CO-Shift Conversion
- o Acid Gas Removal
- o Nitrogen Washing
- o Ammonia Synthesis
- o Urea Synthesis
- o Evaporation and Prilling

a) Dust Removal and 1st Compression

The raw gas leaving the gasifier at 3 kg/cm^{2}G contains 50 mg/Nm^3 dust.

The dust content in the raw gas is reduced to 5 mg/Nm^3 and this gas is compressed to 50 kg/cm^{2}G.

b) CO-Shift Conversion

In order to increase hydrogen content in the raw gas, carbon monoxide is hydrolized into carbon dioxide and hydrogen in the converter as expressed in the following formula:

$$CO + H_2O = CO_2 + H_2 + \Delta H$$

To keep the catalyst bed at a proper temperature, process steam or product gas is used to dissipate the reaction heat. Shift conversion hydrolyzes also COS to H_2S.

c) Acid Gas Removal

The Rectisol process using cold methanol as the solvent consists of an acid gas absorber, CO_2 stripper, H_2S stripper, and distillation tower.

The feed gas containing about 38% of CO_2 and a small amount of H_2S (55 ppm) is supplied to the acid gas absorber where CO_2 and H_2S are readily scrubbed by contacting with cold methanol resulting in 10 ppm of CO_2 in the treated gas. The treated gas from the absorber is sent to the nitrogen washing unit at a temperature of -50°C.

After CO_2 and H_2S gas dissolved in the fat solvent are recovered separately through CO_2 and H_2S strippers, the lean solvent is recycled to the absorber.

The recovered CO_2 gas (99% purity) is utilized as raw material for urea synthesis.

d) Nitrogen washing

The gas from the acid gas removal unit still contains 10 ppm of CO_2 and methanol mist. Since these impurities sometimes causes plugging in the process, it is to be adsorbed by molecular sieves.

The gas free from impurities is cooled and supplied to the N_2 washer where CO, methane, etc. are scrubbed by liquid nitrogen. The treated gas leaving the top of the N_2 washer is mixed with a certain amount of nitrogen to meet the suitable H_2/N_2 ratio for NH_3 synthesis.

e) NH_3 Synthesis

After compressed and heated to 210 kg/cm²G and 135°C, the feed gas is sent to the NH_3 converter. Ammonia is produced by the following reaction:

$$3H_2 + N_2 = 2HN_3 + \Delta H$$

The effluent leaving the reactor at a temperature of 330°C is cooled through steam generator, feed gas preheater and chillers.

The cold effluent is introduced to the gas-liquid separator where product ammonia is separated from the unconverted gas.

The product ammonia is pumped to storage at -33°C and the unconverted gas is recycled to the converter.

f) Urea Synthesis

Urea synthesis is expressed in the following equations.

$$CO_2 + 2NH_3 = NH_4CO_2NH_2 + \Delta H$$
$$NH_4CO_2NH_2 = NH_2CONH_2 + H_2O - \Delta H$$

CO_2 and liquid NH_3 produced in the upstream units are pressurized and introduced to reactor section. The reactor section consists of reactor, stripper, carbamate condenser and HP scrubber where urea synthesis takes place via carbamate formation.

The operating conditions of the reactor is at about 140 kg/cm^{2}G and 180 - 185°C.

Produced urea from the stripper is depressurized to 3 kg/cm^{2}G and sent to LP recirculation section in which unconverted mixtures associated with the product urea is recovered and recycled to HP scrubber in the form of carbamate.

g) Evaporation and prilling

The urea solution coming from the recirculation stage contains about 72 percent by weight of urea.

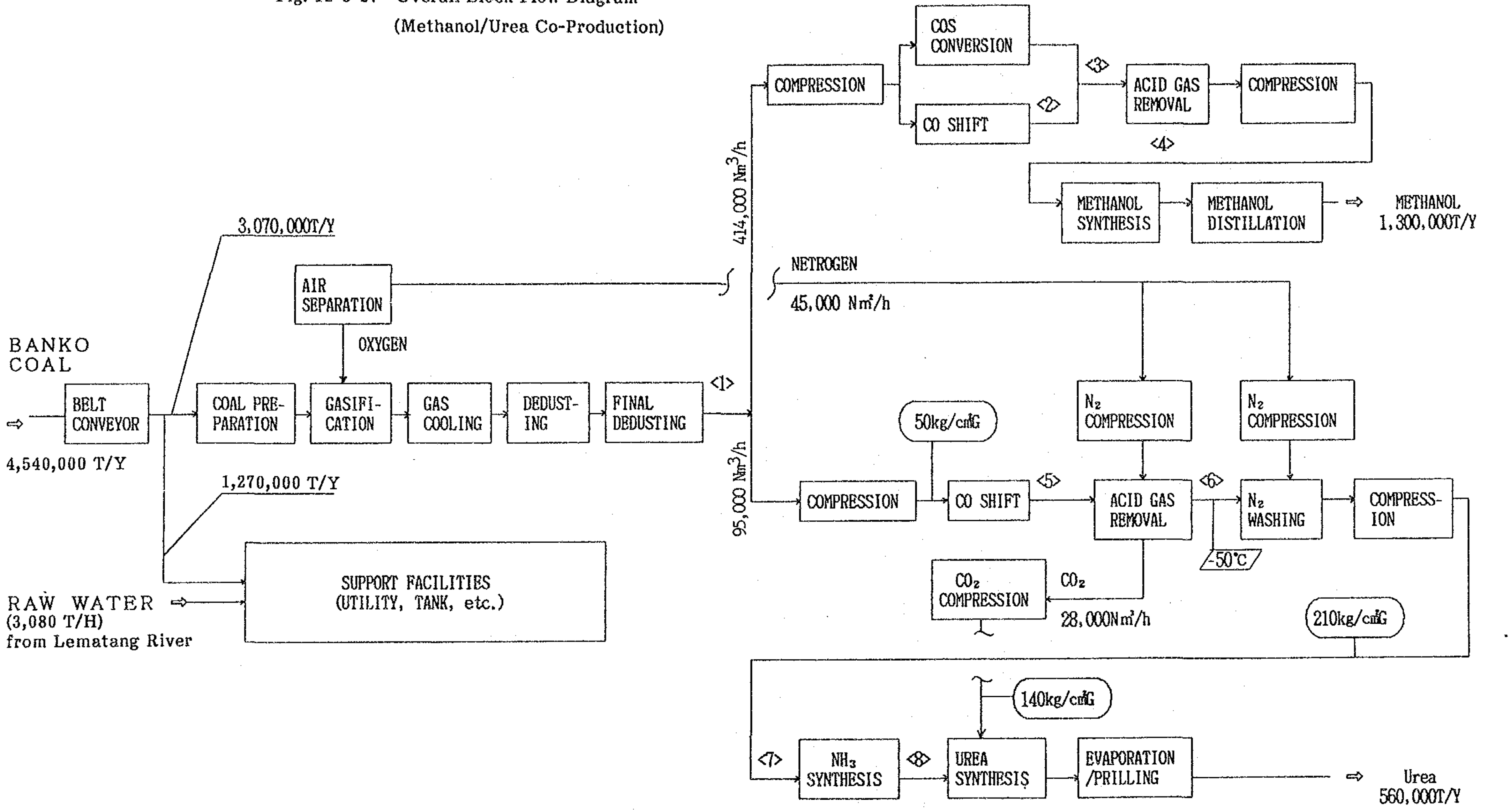
This solution is concentrated to 99.8 percent urea in two steps under vacuum.

The resultant molten stream is prilled with the aid of rotating prilling bucket.

iii) Major equipment

Specifications and the number of units of major equipment are listed in Table 12-3-10.

Fig. 12-3-27 Overall Block Flow Diagram
(Methanol/Urea Co-Production)

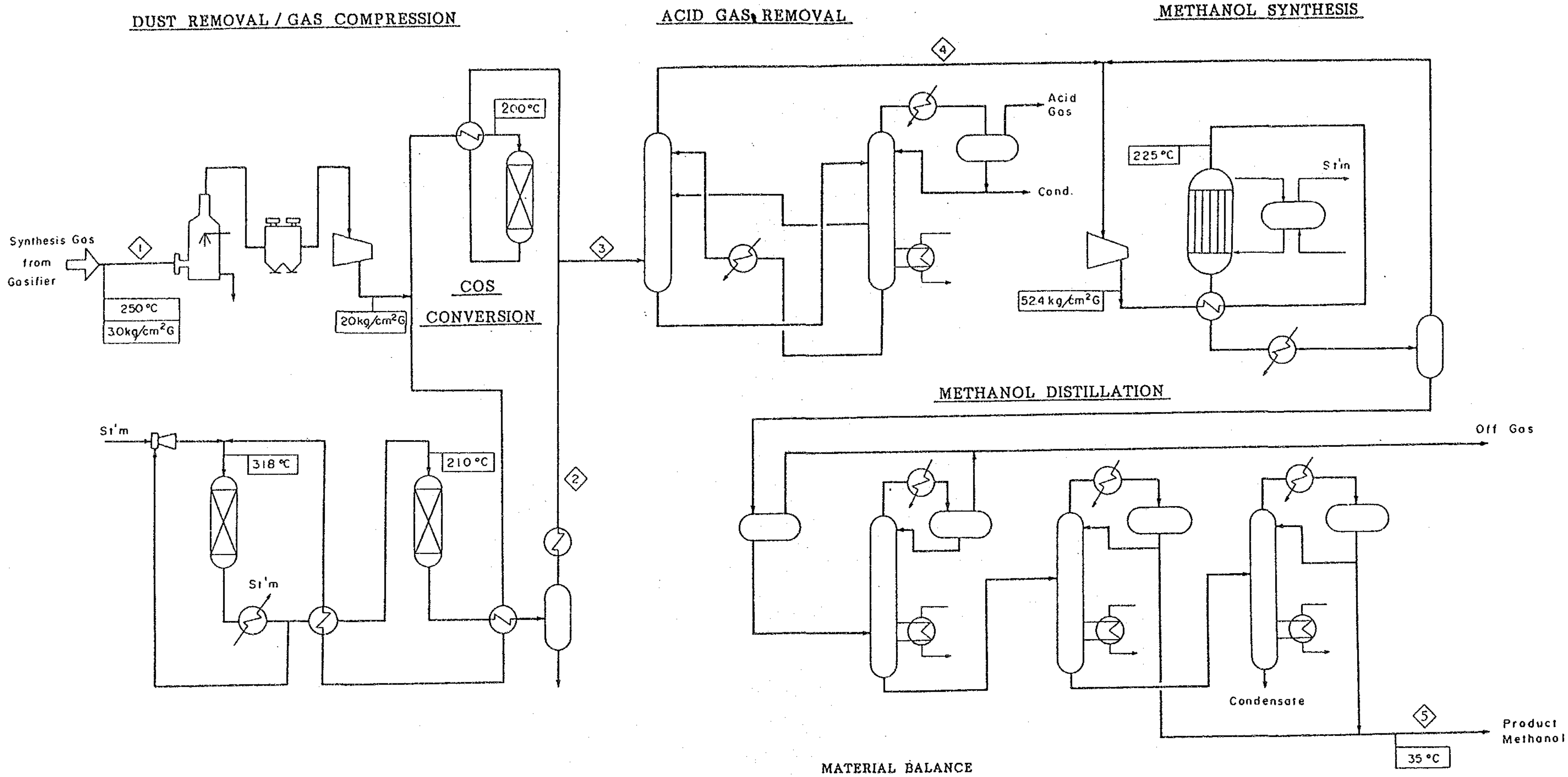


OVERALL MATERIAL BALANCE

Stream	<1>	<2>	<3>	<4>	<5>	<6>	<7>
Flow Rate $10^3 Nm^3/h$	509.2	353.8	540.3	410.6	147.8	89.2	110.3
Composition							
CO, vol.%	60.2	1.2	21.5	28.4	3.0	5.0	<1ppm
H_2, "	35.1	60.1	51.5	67.7	58.2	94.6	75.0
CO_2, "	4.3	38.4	26.7	3.5	38.5	<10ppm	-
N_2, "	0.4	0.3	0.3	0.4	0.3	0.4	25.0
H_2S/COS, vol.ppm	65/22	55/-	66/-	-/-	55/-	-/-	-/-

	<8>
Flow Rate, ton/h	41.7
Composition	
NH_3, wt.%	≧99.8
H_2O, "	≦ 0.2

Fig. 12-3-28 Simplified Process Flow Diagram
- Gas Pretreatment · Methanol Production -



MATERIAL BALANCE

	1	2	3	4
Flow Rate (Dry), $10^3 Nm^3/h$	437.3	353.3	540.3	410.6
Comp. CO, vol%	57.0	1.2	21.6	28.4
H_2, vol%	33.2	60.1	51.5	67.7
CO_2, vol%	4.1	38.4	26.7	3.5
N_2, vol%	0.4	0.3	0.3	0.4
H_2O, vol%	5.3	-	-	-
H_2S/COS, ppm	65/22	55/-	66/-	-
Dust, g/Nm^3	0.01	-	-	-

	5
Flow Rate, Ton/h	169.4
Comp. CH_3OH, wt%	99.9
Inerts, wt%	-
H_2O, wt%	0.1

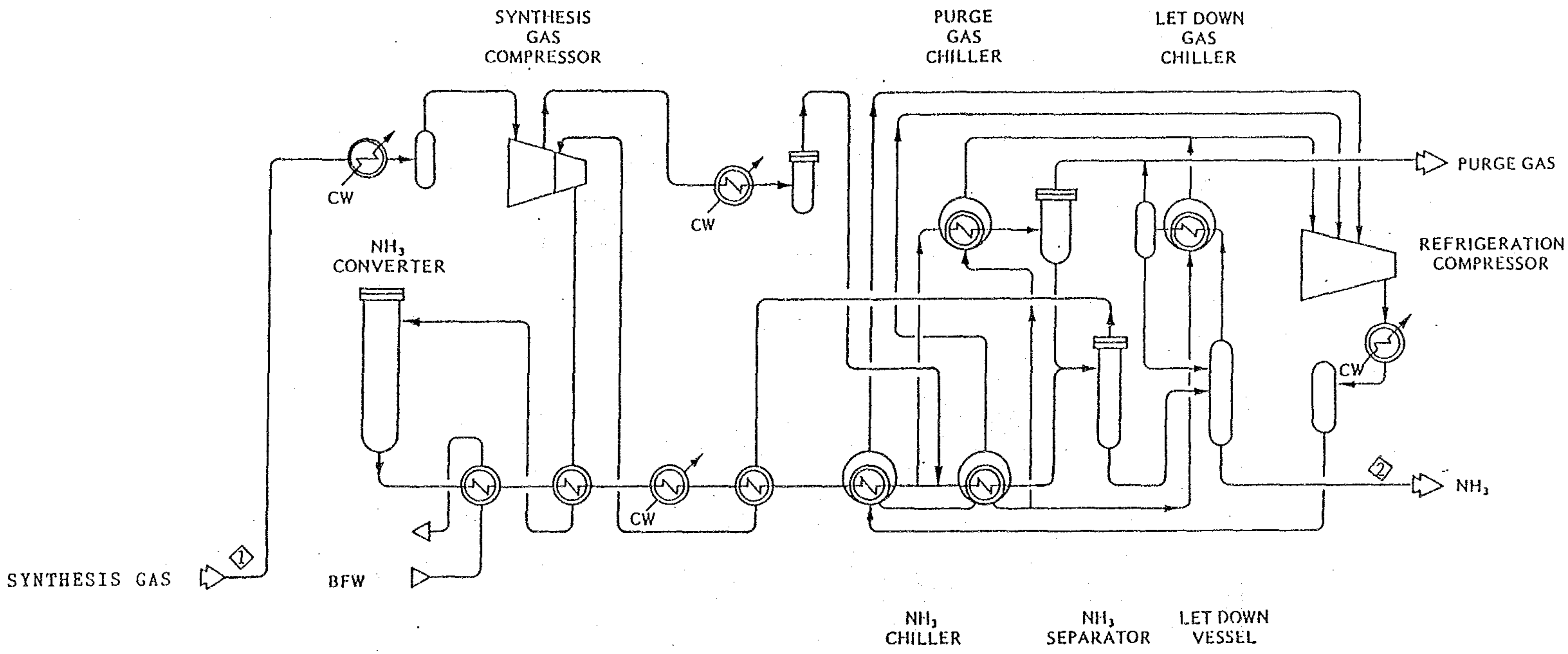
Table 12-3-9 Major Equipment
(Methanol Production Section)

Description	Q'ty	Specification	
Dedusting (3 trains)		Capacity ;	139,000 Nm^3/h/train
o Dust Washer	3+1S	Dust, In/out ;	50/5 mg/Nm^3
CO Shift (2 trains)		Capacity ;	114,000 Nm^3/h/train
o High Temp. Converter	2	CO, In/Out ;	59.6/1.2 vol.%
o Low Temp. Converter	2	Type ;	Vertical, Cylindrical with catalyst
COS Hydrolysis (2 trains)		Capacity ;	95,000 Nm^3/h/train
COS Converter	2	COS, In/Out ;	50/0.1 ppm
Acid Gas Removal (2 trains)		Capacity ;	275,000 Nm^3/h/train
o Absorber	2	CO_2, In/Out ;	26.1/3.5 vol.%
o Regenerator	2	H_2S, In/Out ;	200/0.1 ppm
Methanol Synthesis (2 trains)		Capacity ;	206,000 Nm^3/h/train
o Methanol Reactor	2	Type ;	Vertical, Cylindrical with Catalyst
Methanol Distillation (2 trains)		Capacity ;	2,100ton/h-Methanol/Train
o Pre-run Column	2	Type ;	Vertical, Cylindrical with Tray
o Pressure Column	2		
o Pressureless Column	2		

Fig. 12-3-29 Simplified Process Flow Diagram

- Ammonia Production -

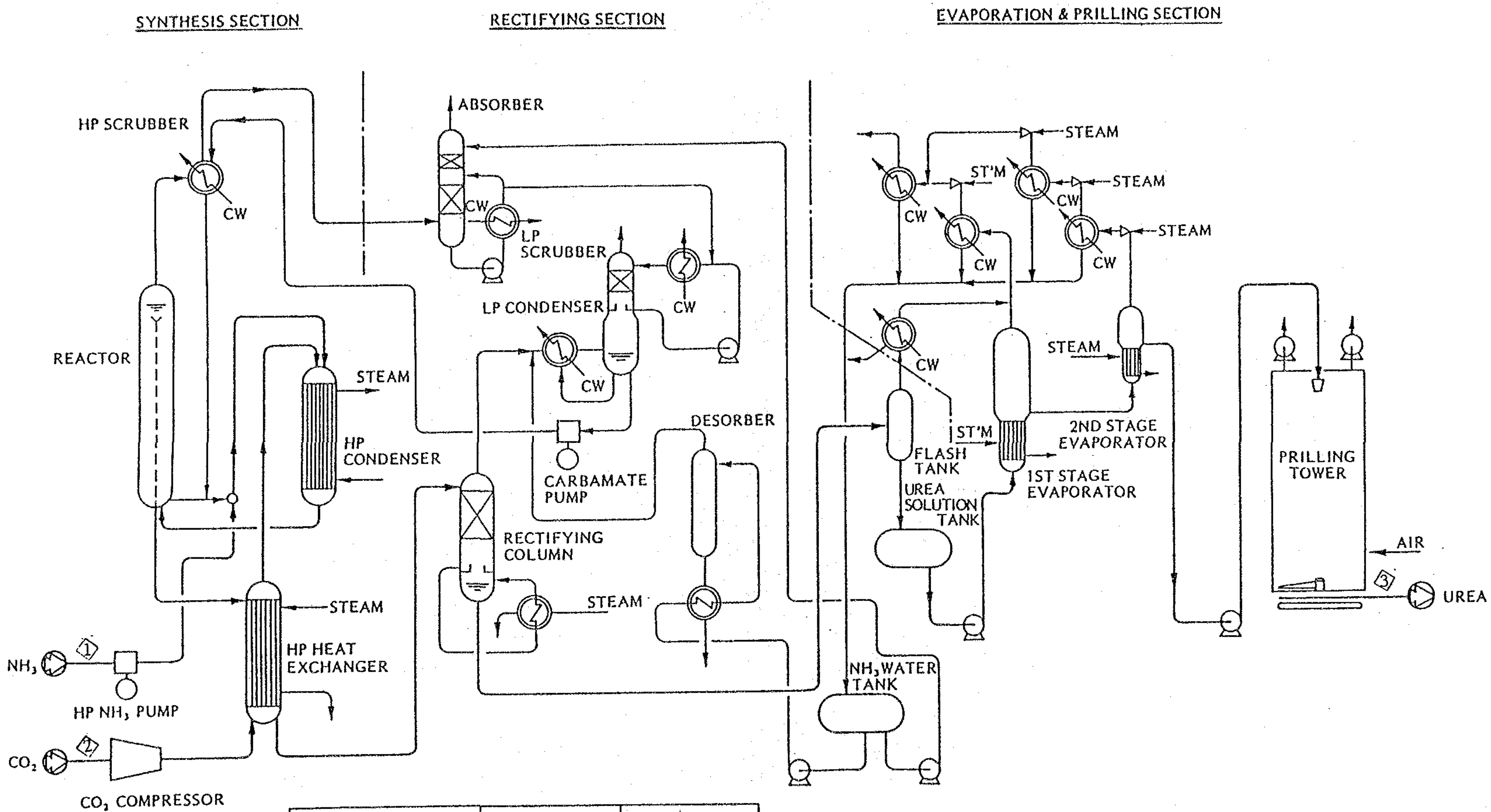
NH₃ SYNTHESIS SECTION



	①
Flow Rate, $10^3 Nm^3/H$	110.3
Composition	
CO, Vol %	< 1ppm
H_2, "	75.0
N_2, "	25.0

	②
Flow Rate, Ton/H	41.7
Composition	
NH_3, wt %	≧ 99.8
H_2O, "	≦ 0.2

Fig. 12-3-30 Simplified Process Flow Diagram
- Urea Production -



	①	②
Flow Rate, Ton/H	41.7	55.0
Composition		
NH_3, wt%	≧ 99.8	
CO_2, "		≧ 99.9
H_2O, "	≦ 0.2	≦ 0.1

	③
Flow Rate, Ton/H	72.9
Composition	
$(NH_2)_2CO$, wt%	≧ 99.7
H_2O , "	≦ 0.3

table 12-3-10 Major Equipment
(Ammonia/urea Production Section)

Description	Q'ty	Specification		
Dedusting		Capacity	;	95,000 Nm^3/h
o Dust Washer	1	Dust, In/Out	;	50/5 mg/Nm^3
CO Shift		Capacity	;	95,000 Nm^3/h
o High Temp Converter	1	CO, In/Out	;	60.2/3.0 vol.%
o Low Temp Converter	1	Type	;	Vertical, Cylindrical with Catalyst
Acid Gas Removal		Capacity	;	148,000 Nm^3/h
o Acid Gas Absorber	1	CO_2, In/Out	;	38.5 vol.%/<10 vol.ppm
o CO_2 Flash Column	1	H_2S, In/Out	;	55 vol. ppm/ -
o H_2S Flash Column	1			
o Methanol Rectifier	1			
Nitrogen Washing				
o Washing Column	1	Capacity	;	89,200 Nm^3/h
	1	CO, In/Out	;	5.0 vol.%/<1 vol. ppm
NH_3 Synthesis		Capacity	;	41.7 ton/h as Product NH_3
o NH_3 Converter	1	Type	;	Vertical, Radial Flow with Catalyst
Urea Synthesis		Capacity	;	72.9 ton/h as Product Urea
o Reactor	1	Type	;	Vertical, Cylindrical

4) Air Separation

See Subsection 12-3-1.

5) Product Storage and Shipping

See Subsection 12-3-1.
Urea storage and shipping facilities are included in the Ammonia/Urea Production Plant.

6) Power Plant

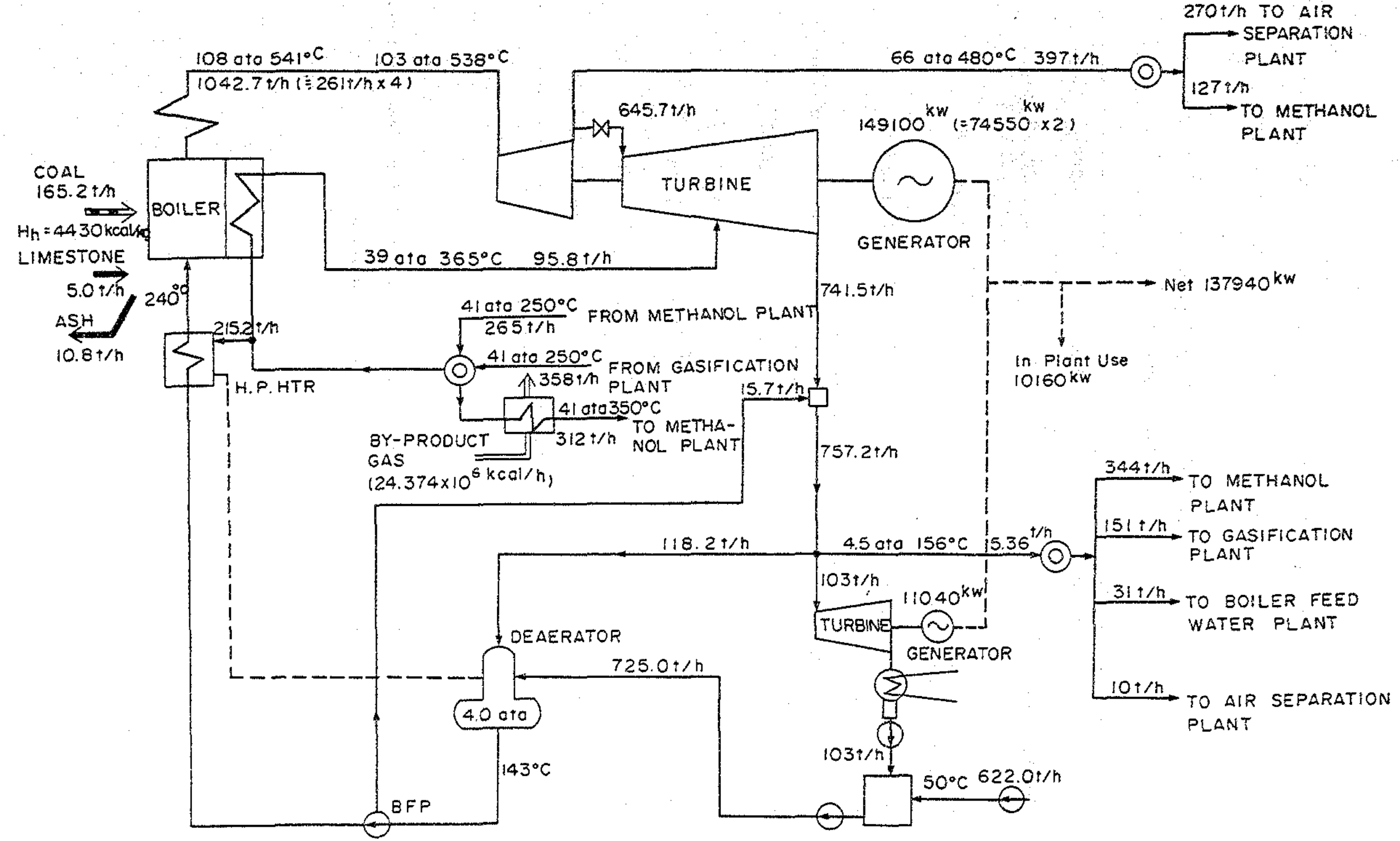
i) Process Flow Diagram

See Fig. 12-3-31 and Fig. 12-3-6.

ii) Process Description

The plant consists of two units of 75 MW back pressure extract turbine generator set, one 11 MW condensing turbine generator set, and 4 units of fluidized bed boiler.

Fig. 12-3-31 Power Plant Heat Balance



iii) Major Equipment

See Table 12-3-11.

Table 12-3-11 Major Equipment
(Power Plant)

Description	Q'ty	Specification
Fluidized Bed Boiler	4	261 t/h, 107 atg 541°C/240°C
Steam Turbine/Generator Unit (Back pressure extract)	2	74,550 kW
Steam Turbine/Generator Unit (Condensing)	1	11,040 kW
Steam Condenser	1	103 t/h, 686 mmHgV
Vacuum Pump	1	686 mmHgV
Condensate Pump	2	120 t/h, 120 m
Deaerator	2	530 t/h
HP Feedwater Heater	2	522 t/h
Boiler Feed Pump	4	615 t/h, 125 atg

7) Utility Facilities

Utility facilities are to be designed in the same way as Case 1 although each utility subsystem shows slightly different balance.
Refer to subsection 12-3-1.

8) Flare System

See subsection 12-3-1.

9) Fire Fighting System

See subsection 12-3-1.

10) Auxiliary Facilities

See Subsection 12-3-1.

(4) Off-site Facilities

See subsection 12-3-1.

(5) Overall Scheme

1) Material Balance

See Fig. 12-3-32, Fig. 12-3-33 and Table 12-3-12.

Table 12-3-12 Utility Requirement

Coal	165 T/h	(external supply)
Raw Water	3,080 T/h	(ditto)
Electricity	147,100 kW	(internal supply)
Cooling Water	70,580 T/h	(ditto)
BFW	1,292 T/h	(ditto)
HP Steam	1,043 T/h	(ditto)

2) Plant Layout

See Fig. 12-3-34.

3) Construction Schedule

No big modification to the project schedule shown in fig. 12-3-25 will be needed in Case 2.

Fig. 12-3-32 Overall Material Balance (Case 2)

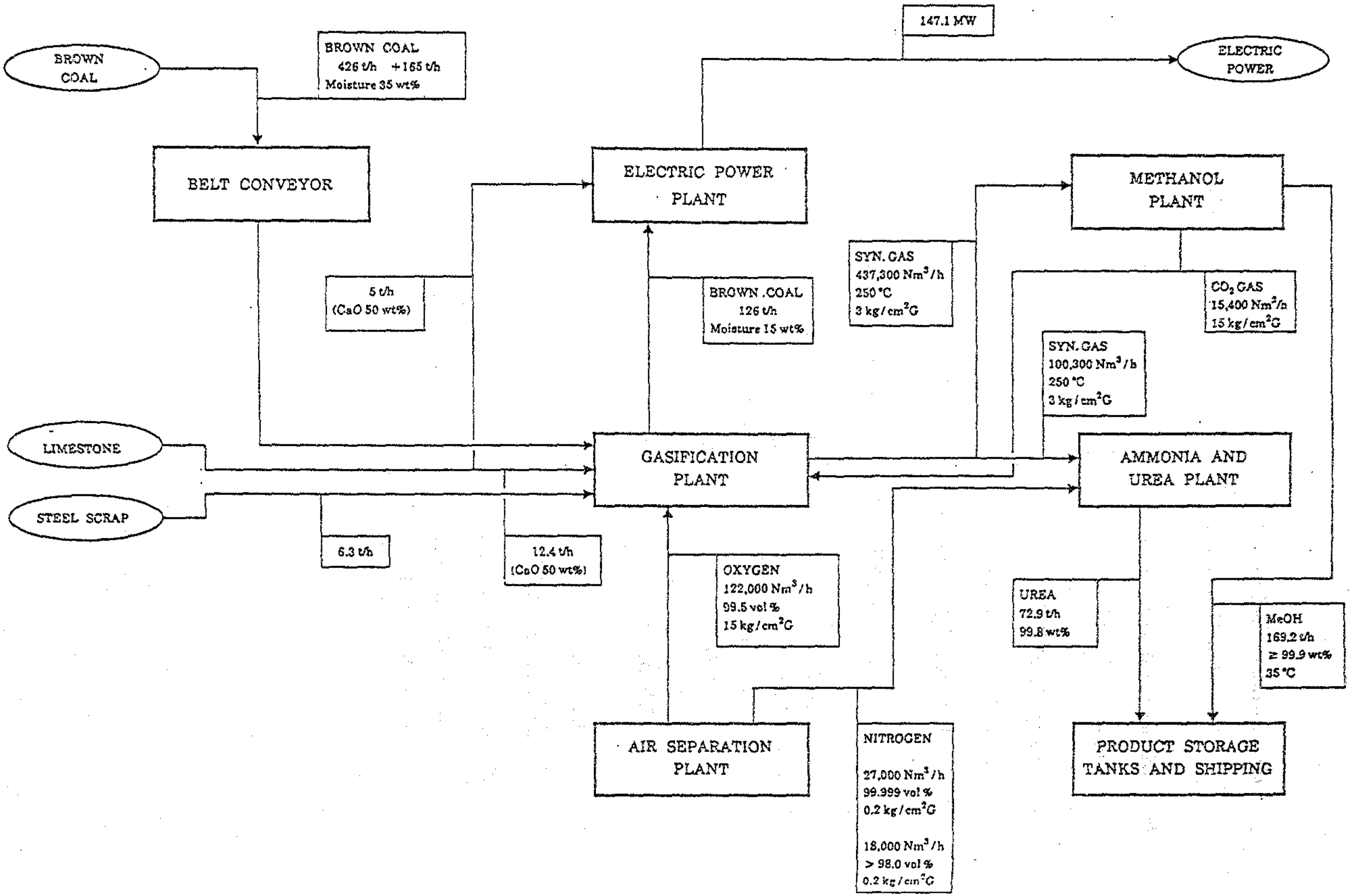


Fig. 12-3-33 Utility Summary (Case 2)

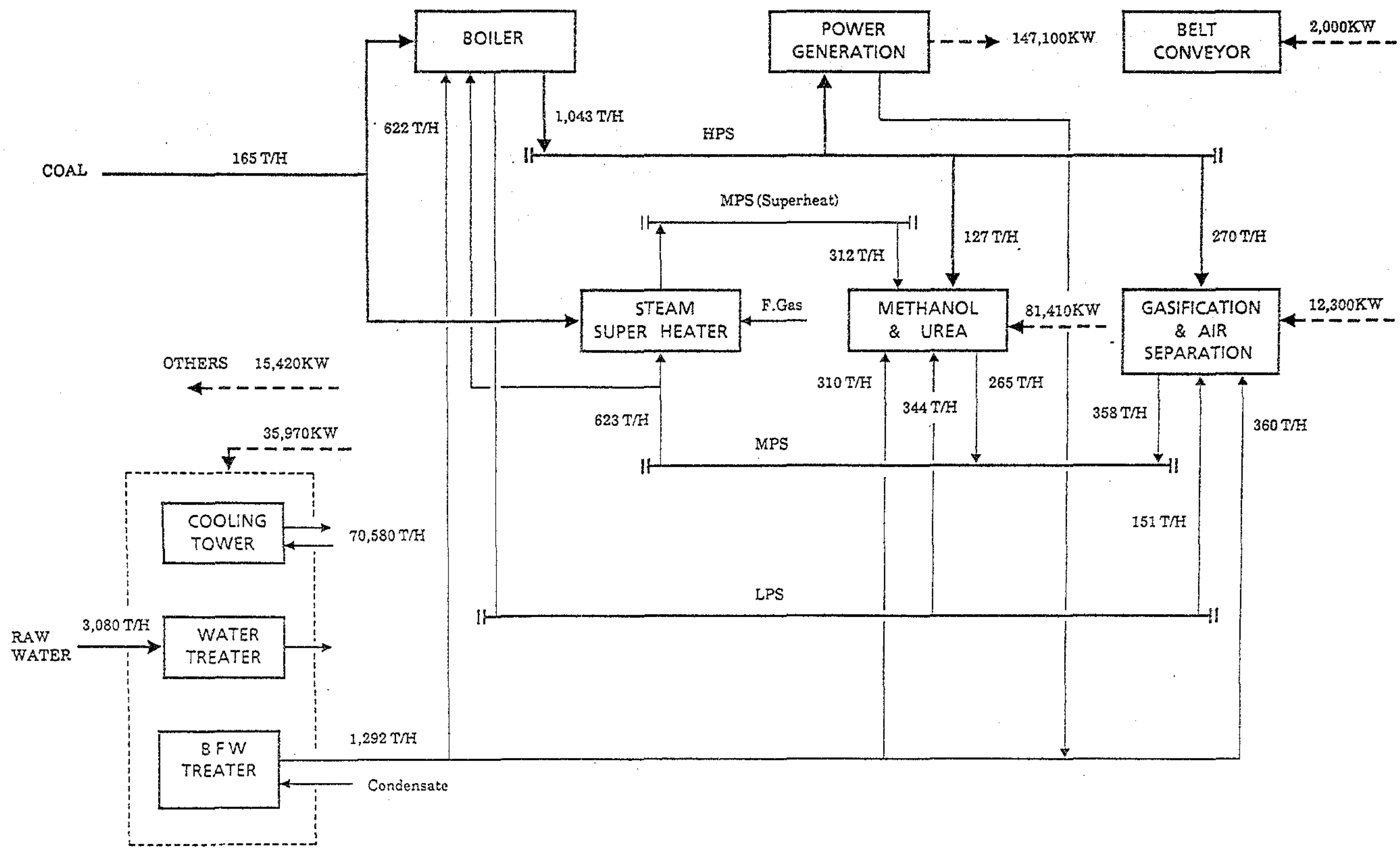
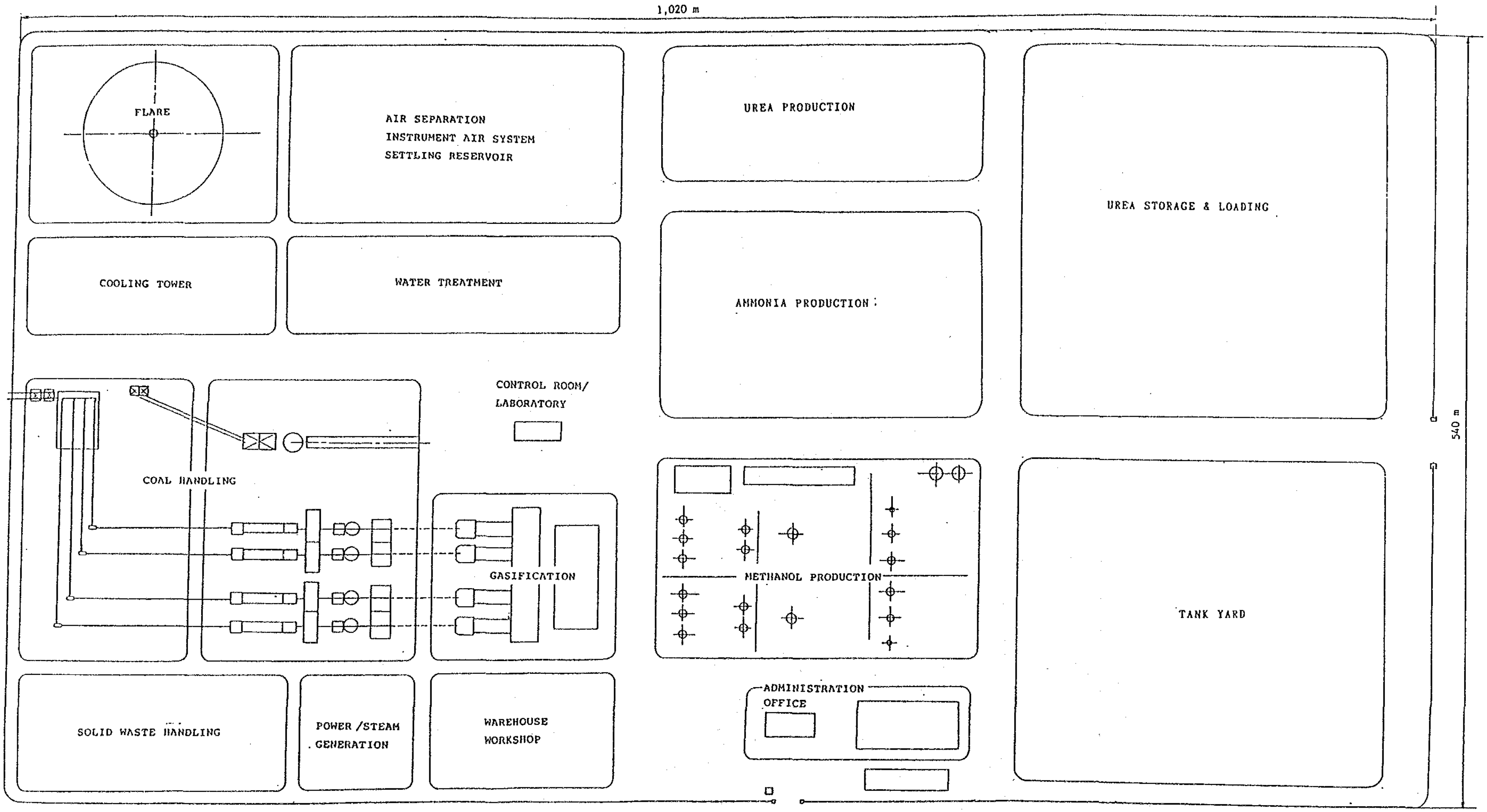


Fig. 12-3-34 Plant Layout



13. PRELIMINARY EVALUATION OF ECONOMIC VIABILITY

Financial viability and profitability of the project was evaluated by means of financial statement* and internal rate of return (hereafter referred to as IRR) on total project investment on the basis of master plan mentioned above.

* Projected Profit & Loss Statement
Projected Cash Flow Statement
Projected Balance Sheet

13-1 ASSUMPTIONS FOR FINANCIAL ANALYSIS

Assumptions of principal factors for financial analysis for Master Plan Case 1 and Case 2 are essentially same as those in the study on preliminary evaluation of economic feasibility carried out in FY1985 and FY1986. Such assumptions were assessed only for the purpose of preliminary financial analysis and not mean any concrete and desirable project plan because such a concrete and desirable project plan is not yet studied at present time.

It is scheduled that assessment and establishment of principal factors for financial analysis will be carried out at the 3rd Stage (Feasibility Study Stage).

13-1-1 Master Plan Case 1

(1) Production Schedule

1) Annual Production; 1,600,000 ton of chemical grade methanol

2) Plant Construction Period; 1990 - 1993 (4 years)
where 30% completion at the end of 1990
60% completion at the end of 1991
80% completion at the end of 1992
100% completion at the end of 1993

(Note); In this financial study, it is assumed that escalation factor is out of considerations. Therefore, time schedule such as 1990 - 1993 is assumed only for reference.

3) Project Life; 1994 - 2023 (30 years)
where 70% of full operation in 1994
85% of full operation in 1995
100% of full operation in 1996 and after

4) Annual Operation Days; 320 days

(2) Finance

1) Debt/Equity Ratio; 75/25

2) Currency

For Annual Revenue/Expenditure;	Rupiah
For Capital Investment;	Yen
Exchange Rate;	0.18 Yen/Rupiah

Accordingly, debt is repayed by exchanging Rupiah for yen at the above exchange rate.

3) Debt Repayment Schedule

Terms of 12 years after commitment, including 4 years of grace period with 8 years equal payments of principal.

4) Interest

i) Long-term Loan; 8% per annum

Assumed supplyer's credit (7.2% p.a.) plus bank loan and project risk premium.

ii) Short-term Loan; 8% per annum

A short term loan would be raised commensurate with annual cash deficiency and would be repayed after development loan.

iii) Interest during Construction Period

In accordance with a general rule in similar projects, interest paid or accrued during construction period is capitallized and amortized over a 10-year period from 1994.

(3) Escalation

No escalation is assumed.

(4) Price and Costs

1) Sales Price of Methanol at Plant Gate; 194 Rp/kg (35 ¥/kg)

2) Capital Investment Costs

i) Fixed-capital Investment;

	10^6 Rupiah	(10^6 Yen)
Coal Gasification	301,900	(54,500)
Coal Transportation	43,800	(7,900)
Methanol Synthesis	188,400	(34,000)
Air Separation	89,200	(16,100)
Power Generation	99,700	(18,000)
Support Facilities	159,600	(28,800)
Equipment Transportation	63,700	(11,500)
Contingency	47,600	(8,600)
Total	993,900	(179,400)

(Note); Construction cost of each plant was reviewed based on the revised master plan. As the result, total fixed-capital investment cost was slightly increased in comparison with that of previous estimation in the study of FY1985.

	10^6 Rp/Yr	(10^6¥/Yr)
ii) Working Capital;	50,216	(9,064)

(Note); Working capital is added as cash-flow at the end of the project.

iii) Start-up Expense;	6,882	(1,242)
iv) Operator Training Cost;	2,598	(469)

v) Investment Schedule; Shown in Table 13-1-1

Table 13-1-1 Investment Schedule

	1990	1991	1992	1993
Fixed Capital	30%	30%	20%	20%
Working Capital	-	-	-	100%
Start-up Expense	-	-	-	100%
Operator Training	-	-	-	100%

3) Annual Expense

i) Fixed Costs

a) Depreciation and Amortization

	Period	Amount	
	Years	10^6 Rp/Yr	(10^6 ¥/Yr)
- Boiler, Power Plant, Cooling Tower, Buildings	15	13,702	(2,473)
- Others	10	94,296	(17,020)
b) Maintenance		23,172	(4,182)
c) Insurance		9,269	(1,673)

(Note); Capital investment for the plant construction including expense and interests during construction period is depreciated and amortized based on straight line method.

	10^6 Rp/Yr	(10^6 ¥/Yr)
ii) Variable Costs		
a) Raw Materials 1)		
- Coal	67,895	(12,255)
- $CaCO_3$	665	(120)
b) Superviser and Operating Labor		
- Foreign Staff 2)		
- Local Labor	2,715	(490)
c) Catalysts and Chemicals	3,413	(616)

(Note); 1) In the study of preliminary evaluation of economic feasibility in FY1985 and FY1986, $14.85/ton-coal was assumed as raw material cost. In this study, coal cost was assumed to be $14.48/ton on the basis of the study on coal mining cost in FY1986 (for details, see the Interim Report III, page 71 -102). Cost of lime stone consumed in gasification plant and fluidized-bed boiler was estimated to be $4.83/ton assuming that it was one-thrid of coal cost.

2) Foreign staff decrease in number as the project proceeds.

Table 13-1-2 Costs for Foreign Staffs

Op. Year	1st	2nd	3rd	4th	5th	6th-30th
Year	1994	1995	1996	1997	1998	1999-2023
% on 1st year	100	70	50	30	10	0
Cost, 10^6 Rp/Yr	7,900	5,530	3,950	2,370	790	0
(Cost, 10^6 ¥/Yr)	(1,426)	(998)	(713)	(428)	(143)	(0)

	10^6 Rp/Yr	(10^6 ¥/Yr)
iii) Plant Overhead Costs	10,615	(1,916)
iv) Administration Expenses	5,307	(958)

(5) Evaluation Criteria

1) Financial Statement

i) Profit and Loss Statement
ii) Cash Flow Statement
iii) Balance Sheet

2) IRR on Total Project Cost before Tax

In accordance with the following equation, cash flow is discounted to the present value as of 1985.

$$\sum_{i=0}^{n} \frac{(C_{in,\,i} - C_{out,\,i})}{(1+r)^i} = 0 \text{ ---------------- eq. (1)}$$

where,

Cin, i; cash-inflow at ith year from 1985
Cout, i; cash-outflow at ith year from 1985
r ; discount rate (=IRR)
n ; project life (1990-2023)
i = 0 at 1985

Cash-inflow	Cash-outflow
• Sales Proceeds	• Investment excluding interest during construction period.
• Residual value of investment	• Total operating expenditure excluding depreciation and interest

13-1-2 Master Plan Case 2

(1) Production Schedule

1) Annual Production;

Methanol 1,300,000 ton (Chemical grade)
Urea 560,000 ton (Ditto)

2) Plant Construction Period; Same as with Case 1

3) Project Life; Same as with Case 1

4) Annual Operation Days; Same as with Case 1

(2) Finance

Same as with Case 1.

(3) Escalation

Same as with Case 1.

(4) Price and Costs

1) Sales Price of Products at Plant Gate;

Methanol 194 Rp/kg (35 ¥/kg)
Urea 166 Rp/kg (30 ¥/kg, 150 $/T)

(Note); Sales price of methanol is same as that in Case 1. Sales price of urea at plant gate was assumed referring to the preliminary evaluation study on urea production cost executed in FY1986 in which international FOB price and transportation cost of urea from plant to Palembang were estimated to be 170-180 $/ton and 25 $/ton respectively.

2) Capital Investment Costs

i) Fixed-capital Investment;

	10^6 Rupiah	(10^6 Yen)
Coal Gasification	301,900	(54,500)
Coal Transportation	45,400	(8,200)
Methanol Synthesis	162,900	(29,400)
Ammonia/Urea Synthesis	154,000	(27,800)
Air Separation	89,200	(16,100)
Power Generation	139,600	(25,200)
Support Facilities	164,600	(29,700)
Equipment Transportation	63,700	(11,500)
Contingency	56,600	(10,200)
Total	1,177,800	(212,600)

(Note); Construction cost of each plant was reviewed based on the recent information. As the result, total fixed-capital investment cost was almost same as that of estimation in FY1986.

ii) Working Capital; 57,839 (10,440)

(Note); Working capital is added as cash-flow at the end of the project.

iii) Start-up Expense; 7,490 (1,352)

iv) Operator Training Cost; 3,202 (578)

v) Investment Schedule; Same as with Case 1

3) Annual Expense

i) Fixed Costs

a) Depreciation and Amortization

	Period	Amount	
	Years	10^6 Rp/Yr	(10^6 ¥/Yr)
- Boiler, Power Plant, Cooling Tower, Buildings	15	16,952	(3,060)
- Others	10	110,614	(19,966)
b) Maintenance		27,770	(5,012)
c) Insurance		11,108	(2,005)

(Note); See the relevant note in 13-1-1.

	10^6 Rp/Yr	(10^6 ¥/Yr)
ii) Variable Costs		
a) Raw Materials[1)]		
- Coal	72,825	(13,145)
- $CaCO_3$	715	(129)
b) Superviser and Operating Labor		
- Foreign Staff[2)]		
- Local Labor	3,346	(604)
c) Catalysts and Chemicals	3,324	(600)

(Note); 1) See the relevant note in 13-1-1.

2) Foreign staff decrease in number as the project proceeds.

Table 13-1-3 Costs for Foreign Staffs

Op. Year	1st	2nd	3rd	4th	5th	6th-30th
Year	1994	1995	1996	1997	1998	1999-2023
% on 1st year	100	70	50	30	10	0
Cost, 10^6 Rp/Yr	9,651	6,756	4,825	2,895	965	0
(Cost, 10^6 ¥/Yr)	(1,742)	(1,219)	(871)	(523)	(174)	(0)

	10^6 Rp/Yr	(10^6 ¥/Yr)
iii) Plant Overhead Costs	12,997	(2,346)
iv) Administration Expenses	6,499	(1,173)

(5) Evaluation Criteria

1) Same as with Case 1

13-2 RESULTS AND EVALUATION

13-2-1 Results

Results are summerized in Table 13-2-1.

Profit and loss statement and cash flow statement are shown in Table 13-2-2 - 13-2-5.

Table 13-2-1 Results of Financial Analysis

Case	Case 1 (Methanol Production)	Case 2 (Methanol/Urea Co-production)
IRR on Total Investment	13.0%	12.2%
First Year to Have Profit before Tax (Year from Operation Starts)	3rd	3rd
Clear off of Accumulated Loss (Year from Operation Starts)	6th	7th
Pay off of All the Debts (Year from Loan Raised)	12th	12th
Minimum Sales Price (IRR=Interest Rate (8%))	Methanol 148 Rp/kg (26.7 ¥/kg)	Methanol 194 Rp/kg (35 ¥/kg) Urea 37 Rp/kg (6.7 ¥/kg) (33.4 $/T)

(Note); Minimum sales price of urea are calculated under fixed price of methanol.

Table 13-2-2 Profit and Loss Statement of Case 1

(Unit: 10^9 Rupiah)

Year	OP Year	Revenue	Expenditure					Profit			Retained Earning
			Variable Cost	Fixed Cost	General	Interest Paid	Total	Before Tax	(Tax)	Net Profit	
1994	1	217.2	61.0	140.4	15.9	70.4	287.8	-70.6	0	-70.6	-70.6
1995	2	263.7	69.4	140.4	15.9	65.7	291.5	-27.8	0	-27.8	-98.4
1996	3	310.2	78.6	140.4	15.9	57.5	292.5	17.8	0	17.8	-80.6
1997	4	310.2	77.1	140.4	15.9	46.9	280.4	29.9	0	29.9	-50.7
1998	5	310.2	75.5	140.4	15.9	35.4	267.2	43.0	0	43.0	-7.7
1999	6	310.2	74.7	140.4	15.9	23.7	254.7	55.5	22.0	33.5	25.8
2000	7	310.2	74.7	140.4	15.9	13.5	244.6	56.7	30.2	35.5	61.3
2001	8	310.2	74.7	140.4	15.9	4.5	235.5	74.7	34.4	40.3	101.6
2002	9	310.2	74.7	140.4	15.9	0	231.0	79.2	36.4	42.8	144.4
2003	10	310.2	74.7	140.4	15.9	0	231.0	79.2	36.4	42.8	187.2
2004	11	310.2	74.7	46.1	15.9	0	136.8	173.5	79.8	93.7	280.9
2005	12	310.2	74.7	46.1	15.9	0	136.8	173.5	79.8	93.7	374.5
2006	13	310.2	74.7	46.1	15.9	0	136.8	173.5	79.8	93.7	468.2
2007	14	310.2	74.7	46.1	15.9	0	136.8	173.5	79.8	93.7	561.9
2008	15	310.2	74.7	46.1	15.9	0	136.8	173.5	79.8	93.7	655.6
2009	16	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	756.7
2010	17	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	857.8
2011	18	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	958.9
2012	19	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	1,060.0
2013	20	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	1,161.1
2014	21	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	1,262.1
2015	22	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	1,363.2
2016	23	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	1,464.3
2017	24	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	1,565.4
2018	25	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	1,666.5
2019	26	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	1,767.6
2020	27	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	1,868.7
2021	28	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	1,969.8
2022	29	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	2,070.8
2023	30	310.2	74.7	32.4	15.9	0	123.1	187.2	86.1	101.1	2,171.9
	Total	9,167.9	2,228.8	2,121.7	477.7	317.6	5,145.8	4,022.1	1,850.2	2,171.9	

Table 13-2-3 Cash Flow Statement of Case 1

(Unit: 10^9 Rupiah)

(IRR: 13.027%)

Year	OP Year	Investment	Profit Before Tax	Depreciation/ Amortization	Interest Paid	Cash Flow	DCF (Base; 1985)
1990		-298.2	-	-	-	-298.2	-161.6
1991		-298.2	-	-	-	-298.2	-143.0
1992		-198.8	-	-	-	-198.8	-84.4
1993		-258.5	-	-	-	-258.5	-97.0
1994	1	-	-70.6	108.0	70.4	107.8	35.8
1995	2	-	-27.8	108.0	65.7	145.9	42.9
1996	3	-	17.8	108.0	57.5	183.2	47.6
1997	4	-	29.9	108.0	46.9	184.8	42.5
1998	5	-	43.0	108.0	35.4	186.4	37.9
1999	6	-	55.5	108.0	23.7	187.2	33.7
2000	7	-	56.7	108.0	13.5	187.2	29.8
2001	8	-	74.7	108.0	4.5	187.2	26.4
2002	9	-	79.2	108.0	0	187.2	23.3
2003	10	-	79.2	108.0	0	187.2	20.7
2004	11	-	173.5	13.7	0	187.2	18.3
2005	12	-	173.5	13.7	0	187.2	16.2
2006	13	-	173.5	13.7	0	187.2	14.3
2007	14	-	173.5	13.7	0	187.2	12.7
2008	15	-	173.5	13.7	0	187.2	11.2
2009	16	-	187.2	0	0	187.2	9.9
2010	17	-	187.2	0	0	187.2	8.8
2011	18	-	187.2	0	0	187.2	7.8
2012	19	-	187.2	0	0	187.2	6.9
2013	20	-	187.2	0	0	187.2	6.1
2014	21	-	187.2	0	0	187.2	5.3
2015	22	-	187.2	0	0	187.2	4.8
2016	23	-	187.2	0	0	187.2	4.2
2017	24	-	187.2	0	0	187.2	3.7
2018	25	-	187.2	0	0	187.2	3.3
2019	26	-	187.2	0	0	187.2	2.9
2020	27	-	187.2	0	0	187.2	2.6
2021	28	-	187.2	0	0	187.2	2.3
2022	29	-	187.2	0	0	187.2	2.0
2023	30	-	187.2	0	0	237.4	2.3
	Total	-1,053.7	4,022.1	1,148.5	317.6	4,484.8	0.0

Table 13-2-4 Profit and Loss Statement of Case 2

(Unit: 10^9 Rupiah)

Year	OP Year	Revenue	Expenditure					Profit			Retained Earning
			Variable Cost	Fixed Cost	General	Interest Paid	Total	Before Tax	(Tax)	Net Profit	
1994	1	241.6	66.8	166.4	19.5	83.8	336.5	-94.9	0	-94.9	-94.9
1995	2	293.4	75.4	166.4	19.5	79.3	340.6	-47.3	0	-47.3	-142.2
1996	3	345.2	85.0	166.4	19.5	70.8	341.8	3.4	0	3.4	-138.8
1997	4	345.2	83.1	166.4	19.5	59.8	328.9	16.3	0	16.3	-122.6
1998	5	345.2	81.2	166.4	19.5	47.8	314.9	30.3	0	30.3	-92.3
1999	6	345.2	80.2	166.4	19.5	34.6	300.7	44.4	0	44.4	-47.9
2000	7	345.2	80.2	166.4	19.5	20.5	286.6	58.5	5.2	53.4	5.5
2001	8	345.2	80.2	166.4	19.5	6.6	272.8	72.4	33.3	39.1	44.6
2002	9	345.2	80.2	166.4	19.5	0	266.2	79.0	36.3	42.7	87.2
2003	10	345.2	80.2	166.4	19.5	0	266.2	79.0	36.3	42.7	129.9
2004	11	345.2	80.2	55.8	19.5	0	155.5	189.6	87.2	102.4	232.3
2005	12	345.2	80.2	55.8	19.5	0	155.5	189.6	87.2	102.4	334.7
2006	13	345.2	80.2	55.8	19.5	0	155.5	189.6	87.2	102.4	437.1
2007	14	345.2	80.2	55.8	19.5	0	155.5	189.6	87.2	102.4	539.5
2008	15	345.2	80.2	55.8	19.5	0	155.5	189.6	87.2	102.4	641.9
2009	16	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	753.4
2010	17	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	865.0
2011	18	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	976.5
2012	19	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	1,088.0
2013	20	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	1,199.6
2014	21	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	1,311.1
2015	22	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	1,422.7
2016	23	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	1,534.2
2017	24	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	1,645.8
2018	25	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	1,757.3
2019	26	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	1,868.9
2020	27	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	1,980.4
2021	28	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	2,092.0
2022	29	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	2,203.5
2023	30	345.2	80.2	38.9	19.5	0	138.6	206.6	95.0	111.5	2,315.1
	Total	10,199.3	2,396.8	2,526.8	584.9	403.1	5,911.6	4,287.7	1,972.6	2,315.1	

Table 13-2-5 Cash Flow Statement of Case 2

(Unit: 10^9 Rupiah)

(IRR: 12.024%)

Year	OP Year	Investment	Profit Before Tax	Depreciation/ Amortization	Interest Paid	Cash Flow	DCF (Base; 1985)
1990		-353.4	-	-	-	-353.4	-198.4
1991		-353.4	-	-	-	-353.4	-176.7
1992		-235.5	-	-	-	-235.5	-105.0
1993		-304.1	-	-	-	-304.1	-120.7
1994	1	-	-94.9	127.6	83.8	116.4	41.2
1995	2	-	-47.3	127.6	79.3	159.6	50.3
1996	3	-	3.4	127.6	70.8	201.7	56.6
1997	4	-	16.3	127.6	59.8	203.7	51.0
1998	5	-	30.3	127.6	47.8	205.6	45.8
1999	6	-	44.4	127.6	34.6	206.6	41.0
2000	7	-	58.5	127.6	20.5	206.6	36.5
2001	8	-	72.4	127.6	6.6	206.6	32.6
2002	9	-	79.0	127.6	0	206.6	29.0
2003	10	-	79.0	127.6	0	206.6	25.8
2004	11	-	189.6	16.9	0	206.6	23.0
2005	12	-	189.6	16.9	0	206.6	20.5
2006	13	-	189.6	16.9	0	206.6	18.3
2007	14	-	189.6	16.9	0	206.6	16.3
2008	15	-	189.6	16.9	0	206.6	14.5
2009	16	-	206.6	0	0	206.6	12.9
2010	17	-	206.6	0	0	206.6	11.5
2011	18	-	206.6	0	0	206.6	10.3
2012	19	-	206.6	0	0	206.6	9.1
2013	20	-	206.6	0	0	206.6	8.1
2014	21	-	206.6	0	0	206.6	7.3
2015	22	-	206.6	0	0	206.6	6.5
2016	23	-	206.6	0	0	206.6	5.8
2017	24	-	206.6	0	0	206.6	5.1
2018	25	-	206.6	0	0	206.6	4.6
2019	26	-	206.6	0	0	206.6	4.1
2020	27	-	206.6	0	0	206.6	3.6
2021	28	-	206.6	0	0	206.6	3.2
2022	29	-	206.6	0	0	206.6	2.9
2023	30	-	206.6	0	0	264.4	3.3
	Total	-1,246.4	4,287.7	1,360.4	403.1	4,862.7	0.0

13-2-2 Evaluation

(1) Profit and Loss

From the viewpoint of profitability, both projects of Case 1 and Case 2 are financially viable. After the projects record deficit for the first two years, they record surplus from the third year onward.
The cumulative deficit of Case 1 is cleared off in the 6th year but that of Case 2 is in the 7th year.

(2) Internal Rate of Return before Tax

As far as IRR is concerned, the resulting 13.0% of IRR on Case 1 and 12.2% on Case 2 cannot be considered as a high rate in general standard due to large investment costs. However, if low cost funds such as the interest rate of 8% assumed in this study is arranged, both cases are considered to be viable.

(3) Debt Repayment

Debt repayment is accomplished in eight years from start of plant operation in both cases. This period is not so long term in consideration of thirty years of project life.

(4) Evaluation

Profitability of Case 1 is superior to that of Case 2 from the viewpoint of IRR.
Provided that the crude oil price rises higher than 30$/BBL which corresponds to 35¥/kg of methanol price at plant gate, the viability of the project Case 1 would be enhanced because the noncommerical Banko coal is not affected by oil.
It should be noted that the final judgment must be based on the recognition that a quantified profitability standard can serve only as a guide.
Because the basic aim of a profitability analysis is to give a measure of the attractiveness of the project for comparison to other possible projects, the results must be dealt with accordingly.

13-3 SENSITIVE ANALYSIS OF PROPOSED MASTER PLAN

13-3-1 Cases for Sensitivity Analysis

Since the assumptions for the financial analysis at this stage have uncertainties more or less, major cost-effective factors such as sales price, construction costs and material (coal and lime stone) costs are examined from the viewpoint of their sensitivity on the profitability of the project.

Table 13-3-1 shows the cases to be analysed.

Table 13-3-1 Cases for Sensitivity Analysis

Case 1 (Methanol Production Case)		
Base Case		
	Methanol Sales Price	194 Rp/kg (35 ¥/kg)
	Construction Costs	993,900 x 10^6 Rp (179,400 x 10^6 ¥)
	Material Costs	68,560 x 10^6 Rp/Yr (12,375 x 10^6 ¥/Yr)
I.	Variation of Methanol Sales Price	
	Case 1-I-1 ;	30% decrease
	Case 1-I-2 ;	30% increase
II.	Variation of Construction Costs	
	Case 1-II-1 ;	20% dcrease
	Case 1-II-2 ;	20% increase
III.	Variation of Material Costs	
	Case 1-III-1 ;	30% decrease
	Case 1-III-2 ;	30% increase
Case 2 (Methanol/Urea Co-production Case)		
Base Case		
	Urea Sales Price	166 Rp/kg (30 ¥/kg, 150 $/ton)
	(Methanol Sales Price - fixed at 194 Rp/kg (35 ¥/kg))	
	Construction Costs	1,177,800 x 10^6 Rp (212,600 x 10^6 ¥)
	Material Costs	73,540 x 10^6 Rp/Yr (13,274 x 10^6 ¥/Yr)
I.	Variation of Urea Sales Price	
	Case 2-I-1 ;	30% decrease
	Case 2-I-2 ;	30% increase
II.	Variation of Construction Costs	
	Case 2-II-1 ;	20% decrease
	Case 2-II-2 ;	20% increase
III.	Variation of Material Costs	
	Case 2-III-1 ;	30% decrease
	Case 2-III-2 ;	30% increase

13-3-2 Results and Evaluation

Results are summarized in Table 13-3-2 and Table 13-3-3, and the sensitivity of each cost-effective factor on IRR is graphically expressed in Fig. 13-3-1 and Fig. 13-3-2.

(1) Case 1

Sales price affects on the profitability of the project with the highest sensibility and construction cost follows the next. Material (coal) costs show less sensibility because the mining cost is enough low.

1) Sales Price

Sales price affects on the profitability of the project to a large extent.
Case 1-I-1 (30% decrease) shows that the project is obviously not feasible because the accumulated loss is not cleared off during project life, while Case 1-I-2 (30% increase) shows better financial results.
When IRR of Base Case is assumed to be equivalent to the interest rate which is 8% in this study, the sales price resulted from eq. (1) is 148 Rp/kg (26.7 ¥/kg) which can be regarded as the minimum sales price.
This minimum sales price corresponds to 24% decrease of the sales price assumed in Base Case. Therefore, as far as the sales price is concerned, the risk of the project is considered to be small, if oil price is higher than 30$/BBL.

2) Construction Costs

Construction costs are also crucial factor for the sensitivity of the project. In this study, construction costs increased for 20% (Case 1-II-2) are not attractive on the profitability. However, it is also true that construction costs may be decreased by detailed design proceeds and experienced constructor. Therefore, more detailed study on the construction costs will be required in the 3rd Stage.

3) Material Costs

Material costs affect not so much on IRR as sales price and construction costs, because material costs are enough low. Furthermore, the coal price would not be influenced by the price rise of other commercial energies, because Banko coal can not be commercially transacted owing to its low quality.

(2) Case 2

1) Sales Price

Urea sales price affects on the profitability of the project, but it does not so much comparing with Case 1 because production ratio of urea to methanol is low. Consequently, minimum sales price of urea under fixed price of methanol is so low that it is estimated to be below zero in Case 2-II-1 and Case 2-III-1.
However, the overall profitability of Case 2 is inferior to that of Case 1 as shown in Table 13-3-2.

2) Construction Costs

Construction costs are a crucial factor for the financial aspect of the project. Influence of them on IRR is almost same as that in Case 1.

3) Material Costs

Material costs affect not so much on IRR as construction costs. Influence of them on IRR is almost same as that in Case 1.

Table 13-3-2 Results of Sensitivity Analysis (Case 1)

		IRR on Total Investment before Tax	First Year to Have Profit before Tax (Year from Operation Starts)	Clear off of Accumulated Loss (Year from Operation Starts)	Pay off of All the Debts (Year from Loan Raised)	Minimum Sales Price (IRR = 8%)
Case 1 (Base)		13.0%	3rd	6th	12th	Methanol 148 Rp/kg (26.7 ¥/kg)
Case 1-I-1	Methanol Sales Price 30% down	6.4%	11th	____ 1)*	33rd	
1-I-2	Methanol Sales Price 30% up	18.1%	2nd	2nd	12th	
Case 1-II-1	Construction Costs 20% down	16.0%	2nd	3rd	12th	Methanol 130 Rp/kg (23.5 ¥/kg)
1-II-2	Construction Costs 20% up	10.8%	6th	12th	14th	Methanol 165 Rp/kg (29.8 ¥/kg)
Case 1-III-1	Material Costs 30% down	14.3%	3rd	4th	12th	Methanol 135 Rp/kg (24.3 ¥/kg)
1-III-2	Material Costs 30% up	11.7%	4th	10th	13th	Methanol 161 Rp/kg (29.1 ¥/kg)

(Note)* 1) Not cleared off during project life.

Table 13-3-3 Results of Sensitivity Analysis (Case 2)

	IRR on Total Investment before Tax	First Year to Have Profit before Tax (Year from Operation Starts)	Clear off of Accumulated Loss (Year from Operation Starts)	Pay off of All the Debts (Year from Loan Raised)	Minimum Sales Price (IRR = 8%)
Case 2 (Base)	12.2%	3rd	7th	12th	Urea 37 Rp/kg (6.7 ¥/kg)
Case 2-I-1 Urea Sales Price 30% down	10.7%	6th	12th	14th	
2-I-2 Urea Sales Price 30% up	13.7%	3rd	5th	12th	
Case 2-II-1 Construction Costs 20% down	15.2%	2nd	3rd	12th	Urea1)* < 0
2-II-1' ditto					Urea2)* 0 Methanol 184 Rp/kg (33.2 ¥/kg)
2-II-2 Construction Costs 20% up	10.0%	8th	14th	15th	Urea 97 Rp/kg (17.5 ¥/kg)
Case 2-III-1 Material Costs 30% down	13.4%	3rd	5th	12th	Urea1)* < 0
2-III-1' ditto					Urea3)* 0 Methanol 192 Rp/kg (34.7 ¥/kg)
2-III-2 Material Costs 30% up	11.0%	6th	12th	14th	Urea 78 Rp/kg (14.0 ¥/kg)

(Note)* 1) IRR is larger than 8% even if urea sales price is assumed to be zero under fixed price of methanol (194 Rp/kg, 35 ¥/kg).

2) When IRR is assumed to be 8%, methanol sales price results in 184 Rp/kg (33.2 ¥/kg) under zero of urea price.

3) When IRR is assumed to be 8%, methanol sales price results in 192 Rp/kg (34.7 ¥/kg) under zero of urea price.

Fig. 13-3-1 Sensitivity of Cost-effective Factors for Case 1

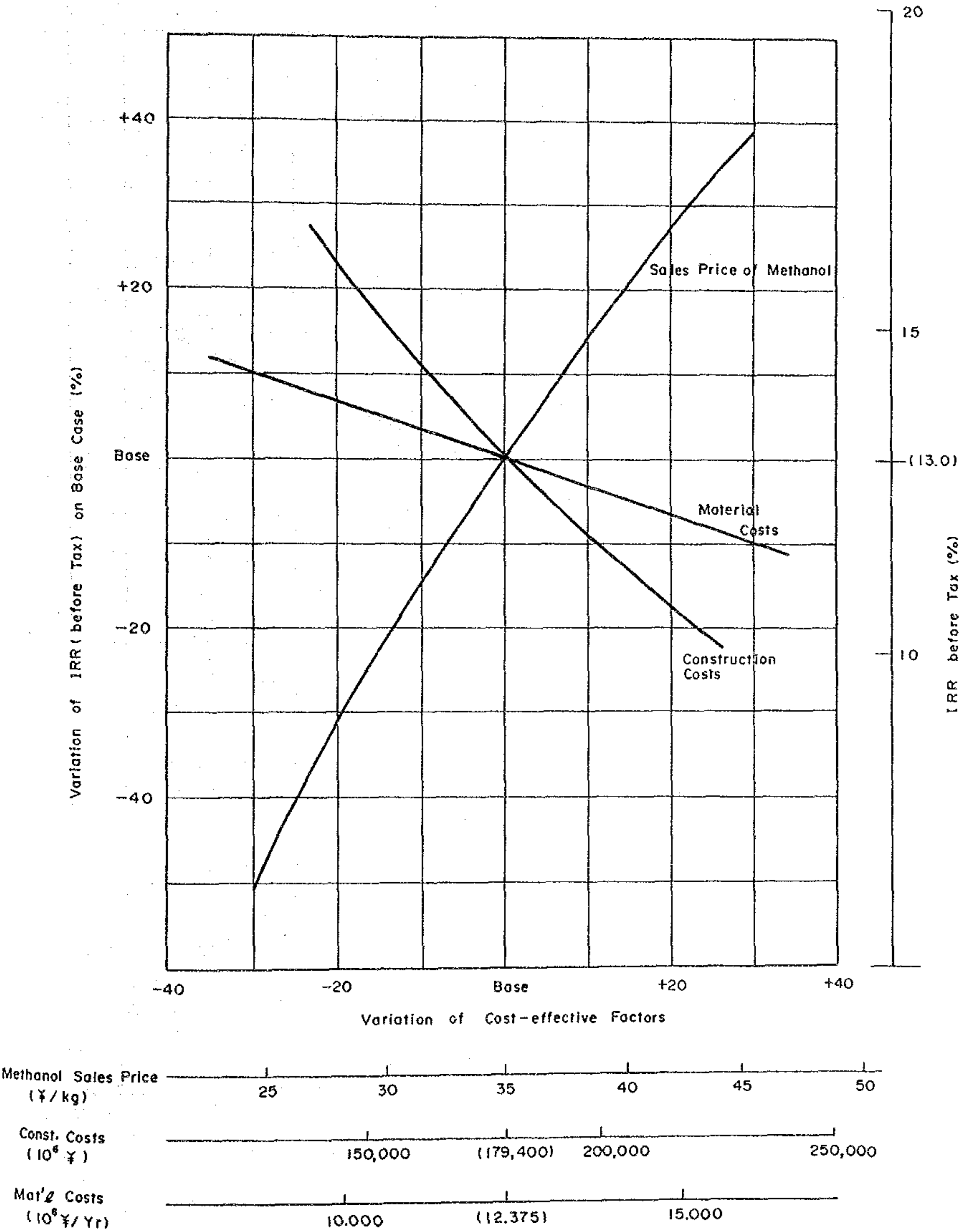
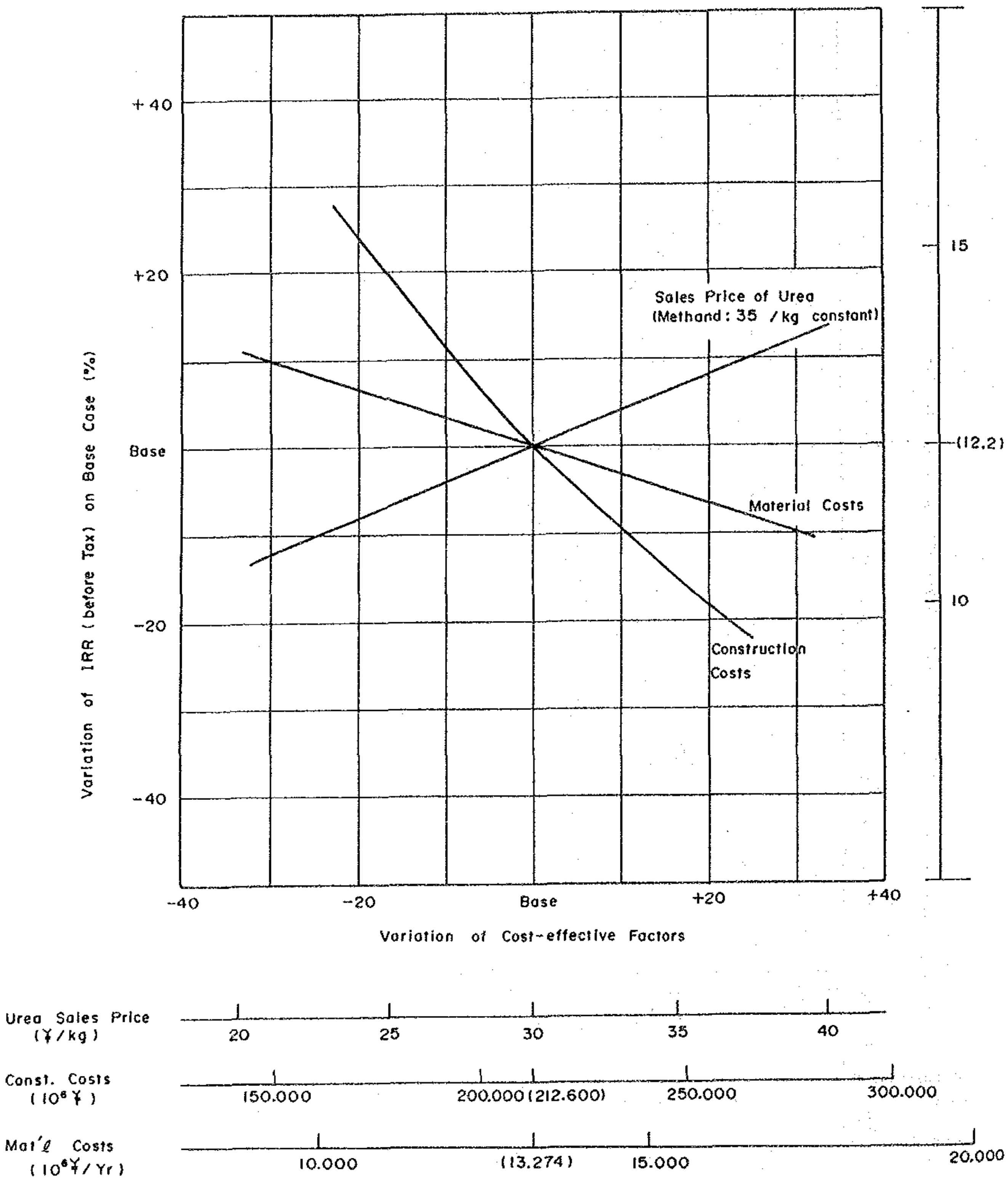


Fig. 13-3-2 Sensitivity of Cost-effective Factors for Case 2



13-4 ECONOMIC VIABILITY OF FUEL METHANOL

13-4-1 Profitability of Fuel Methanol Project

The project of fuel methanol production (1,600,000 ton/Yr) from Banko coal was evaluated preliminarily in terms of financial viability and profitability with the result showing 13.0% of IRR before tax and interest in Case 1 (Base Case) when the plant gate price of fuel methanol was assumed at 194 Rp/kg (35 ¥/kg) which was set during 2nd stage.

As a result of financial study, this project has the possibility to be appraised as viable in case of oil price hike (higher than 30 $/bbl), because methanol price which is linked with oil price was found to be dominant factor for the profitability of the project as described in Section 13-3.

Furthermore, the relationship between demand and price of crude oil and fuel methanol was gained through the study on introducing fuel methanol in Indonesia by using LP model in FY1986.

The results are as follows;

i) In case of crude oil price of less than 25 $/bbl, there is no demand for fuel methanol.

ii) In case of 30 $/bbl of crude oil price, there can be demand of 1.6 million tons for fuel methanol in 1995, if fuel methanol can be supplied at less than 111 $/kl (139 $/ton, 27.8 ¥/kg).

iii) When fuel methanol price is fixed at 139 $/kl (175 $/ton, 35 ¥/kg), croude oil price is 38 $/bbl for allowing the introduction of the total amount of fuel methanol production (1.6 million tons per year).

(For details, see the Interim Report III (FY1986), page 286-318)

In sptie of the above evaluation, the possibility of the viability for this fuel methanol project would be emphasized because the price of Banko coal is not affected by oil price and the plant construction cost may be decreased when crude oil is low in price.

13-4-2 Competitiveness of Fuel Methanol against Oil Products

The relative value and competitiveness of fuel methanol for transportation use were roughly estimated in terms of economic aspects compared with commercially used fuels such as gasoline and diesel oil supposing that produced fuel methanol in Banko area is imported to Japan.

By using the fuel efficiency (kcal/km) and the price (¥/l) of fuel methanol, gasoline and diesel oil, the fuel costs equivalent to 1 litre of fuel methanol were estimated on the assumption that the imported fuel methanol is delivered through the existing supply system in Japan and the price of oil products is set by retail in 1985.
The results are summerized in Table 13-4-1 and mean that economic viability of fuel methanol as transportation fuel is superior to that of gasoline but inferior to that of diesel oil.
(For details, see the Interim Report II (FY1985), page 232-237.)

Table 13-4-1 Economic Comparison of Transportation Fuels

	L.H.V kcal/l	Consumption Rate (kcal/km)	Retail Price (Yen/l)	Required Volumetric Ratio (Equiv. to 1 l of Methanol)	Fuel Cost (Yen/l-methanol equiv.)
Methanol	3,800	253	B.Tax 44[1]	1.0	44
Gasoline	7,950	335	B.Tax 96 (A.Tax 150)	0.63[2]	B.Tax 60 (A.Tax 95)
Diesel Oil	8,650	253	B.Tax 81 (A.Tax 105)	0.44[3]	B.Tax 36 (A.Tax 46)

(Note);

1) Plant gate price (35 ¥/kg) plus costs of transportation from Banko area and of delivery in Japan.

2) $$\text{Req.Vol.Ratio} = \frac{\text{Gasoline (l/km)}}{\text{Methanol (l/km)}} = \frac{335\ \text{(kcal/km)}}{7{,}950\ \text{(kcal/l)}} \Big/ \frac{253\ \text{(kcal/km)}}{3{,}800\ \text{(kcal/l)}}$$

$$= 0.63\ \text{l - gasoline / l - methanol}$$

3) $$\text{Req.Vol.Ratio} = \frac{\text{Diesel Oil (l/km)}}{\text{Methanol (l/km)}} = \frac{253\ \text{(kcal/km)}}{8{,}650\ \text{(kcal/l)}} \Big/ \frac{253\ \text{(kcal/km)}}{3{,}800\ \text{(kcal/l)}}$$

$$= 0.44\ \text{l - diesel oil / l - methanol}$$

In addition to the economic aspects, fuel methanol should be evaluated as clean energy for environmental problems. Environmental pollution caused mainly by exhaused gas emission from automobiles is one of the urban problems especially in Japan where the NOx emission standard (0.06 ppm) has not yet been cleared. Among all transportation fuels, diesel fuel is supposed to be the main source of NOx emission, and in order to establish an effective technology to clear the standard, methanol engine is under development to put it into practice in Japan.

Since the above analysis was carried out preliminarily, the evaluation study of export posibilities for fuel methanol from Banko coal including an advantageous aspect as a clean energy should be continued in the 3rd stage.

13-5 PROPOSED POLICY AND MEASURES FOR INTRODUCING FUEL METHANOL

13-5-1 Proposed Policy for Introducing Fuel Methanol

(1) Energy Policy

1) Intensification for Fuel Methanol

The energy policy in Indonesia is requesting to accelerate and intensify the survey and exploration of all energy resources.

Fuel methanol, which is derivative of Banko coal, would be very important alternative energy to petroleum in transportation and electricity power generation sectors.

As shown in Section 13-4, the economic viability of fuel methanol has been preliminarily proven, providing that the oil price needs higher than 30 $/bbl.

At present time, the oil price is around 18 $/bbl, which is lower than the value of economic feasibility of fuel methanol.

However, it is estimated that oil price will be around 30 $/bbl in 2000 years, according to the estimation by studies of IEA and IEE (Institute of Energy Economics, Japan) etc.

Export of oil is the most important role of providing both foreign exchange and government revenue to finance economic development.

To secure the supply of oil to export, and to guarantee the domestic energy supply, the development of alternative energy sources which are useful in transportation sector would be urgent program in Indonesia, if one considers that the commercial scale production of fuel methanol needs long period of around 10 years for preparation and construction of a plant. It is proposed that the survey of fuel methanol from Banko coal should be accelerated and intensified as one of energy policy for a better identification of fuel methanol's potential.

2) Diversification by Fuel Methanol

To reduce the dependence on oil and to apply the best and most efficient energy for each particular energy demand are also indicated by the energy policy of Indonesia. Notwithstanding efforts to move into alternative energy sources, however, 100% of energy in transportation sector and electricity generation sector (diesel generators) depend on oil.

Oil is the best and most efficient energy for transportation sector, and therefore oil will have the role of being the nation's prime source of transportation energy in long term.

However, fuel methanol is expected to be the most prospective alternative energy in transportation sector because of its excellent performance as fuel for internal combustion engines.

It is believed that the diversification of oil in transportation sector as well as electricity generation sector (diesel generators) can be achieved by fuel methanol in long term.

It is proposed that Indonesia Government put priority on fuel methanol as alternative energy for internal combustion engines in transportation and electricity generation sectors.

(2) Industrial Development Policy

1) Export of Fuel Methanol

Fuel methanol can be evaluated as clean energy for environmental problems especially in Japan where NOx emission is severely controlled by the standard. To export fuel methanol derived from non-exportable coal such as Banko coal would contribute to provide foreign exchange and to develop high technology industry in Indonesia.

It is proposed that the survey of fuel methanol from Banko coal should be evaluated and intensified as an effort for a better identification of potential exportable goods derived from non-exportable energy resources.

2) Pricing and Tax Policy

Industrial development program of fuel methanol must be toward improving overall national economic structure.

In order to do so, close relationship among Ministry of Mine and Energy, Ministry of Industry, Ministry of Transmigration and BPPT as well as BAPPENAS will be required.

Pricing and tax policy of petroleum for domestic consumption and tax policy for fuel methanol industry should be pursued in order to assist the development of fuel methanol industry especially during the penetration stage of fuel methanol in domestic and foreign market.

3) Industrial Development Program

To produce 5,000 ton per day of fuel methanol, (equivalent of 19,000 bbl per day of gasoline), it is preliminarily estimated that around 1,000 billion Rupiah of fixed-capital investment, 4 million tons per year of coal and 1,000 persons of technical staff and skilled labor for operation will be required.
For such a large scale project, national project type such as ASAHAN alminum project would be preferable system to develop.
Since the study for industrial development program is carried out in FY1988, the detailes will be discussed furthermore in the 3rd stage of this study.

(3) Transmigration Policy

1) Transmigration Pattern

The development of fuel methanol industry as well as coal mining will increase opportunity for employment and assist regional development.
To assist contribution by Indonesian people to such opportunity for employment, it is proposed that a concrete model study of transmigration pattern for industry and mining should be examined.

2) Infrastructure for Transmigration

Infrastructures required for fuel methanol industry will be prepared by the fuel methanol project.
However infrastructures required for immigrants will be prepared through transmigration program. The above mentioned transmigration pattern and the criteria of infrastructures between industrial program and transmigration program will be studied in the 3rd stage of this study.

13-5-2 Measures for Introducing Fuel Methanol

(1) Steering Committee for Introduing Fuel Methanol

The development of fuel methanol industry and application of fuel methanol in domestic market are completely new trial in Indonesia.
And therefore the assessment and application of fuel methanol must be pursued jointly among relavant organizations of Government and private sectors.
In order to do so, it is recommended to organize Steering Committee authorized by the Government.

Technical assessment for fuel methanol production and its utilization, financial and economic evaluation of the project, and related matters to energy policy, industrial policy and transmigration policy would be discussed in the Steering Committee.

The results of a study by the Steering Committee would be reported to BAKOREN through the Energy Resources Technical Committee who are charged with formulating the nation's energy plan and providing assessments on energy matters.

(2) Gasification Test by Large Scale Facilities

The technical availability of a molten iron bath gasification process to Banko coal has been already proven through the test operation of small scale gasification test facilities installed in PUSPIPTEK, Jakarta. The next activity necessary to commercialization of Banko coal gasification would be to install a large scale test plant to confirm durability of the process and to obtain operation and maintenance technique through test operation.

The large scale test plant will be installed in a yard of synthesis gas consumer and produced gas will be utilized effectively as feed stock by synthesis gas consumer.

It is recommended that the program and finance for the test will be studied by the Steering Committee.

(3) Fleet Test of Fuel Methanol Engines

New technology on fuel methanol engines has been developed in many countries such as West Germany, U.S.A. and Japan.

However, for application in Indonesia, fleet test of fuel methanol automobile would be required to confirm the durability of automobile in Indonesia, to demonstrate the operability to users and to establish fuel methanol supply system.

It is recommended that the program and finance for the test will be studied by the Steering Committee and include the following:

i) Gas turbine generators (Modification of an existing one)
ii) Fuel methanol-diesel engine generators
iii) High way/express buses
iv) City buses in Jakarta
v) Mining equipment such as dozer, dump truck and power shovel in Bukit Assam

14. CONCLUSION AND RECOMMENDATION

14-1 CONCLUSION

1) Export of oil is the most important role of providing both foreign exchange and government revenue to finance economic development.
To secure the supply of oil to export and to guarantee the domestic energy supply, particularly for transportation sector, the development of alternative energy which is useful for internal combustion engines would be urgent program among energy nation's policy.

2) Technical reliability of Banko coal gasification by a molten iron bath process has been proven by the coal gasification test facilities installed in PUSPIPTEK, JAKARTA.
20 kinds of Banko coal sampled from various areas and seams were successfully gasified.

3) It was confirmed through the coal sampling study that Banko coal is non-exportable coal with low calorific value, 3500 - 4500 kcal/kg as mined, but abundant in reserves and low in mining cost of around 14.5 $/ton as mined.

4) The preliminary economic feasibility study shows that the fuel methanol production from Banko coal is economically and technically feasible, if oil price is higher than around 30 $/bbl.

   Note: According to the reports by IEA and IEE etc. it is estimated that oil price will be increased to around 30 $/bbl in 2000 years.

5) Banko coal effective utilization project will need more than 10 years for finacing, organization of enterprise and construction work against start of production.
Therefore all of necessary preparatory works, including further detailed technical and economic feasibility study, would be proceeded as soon as possible.

14-2 RECOMMENDATION

1) The 3rd stage (feasibility study stage) will be carried out in FY1988 in accordance to the Scope of Work.

2) To formulate the nation's fuel methanol plan and to pursue assessments on fuel methanol matters, a Steering Committee authorized by the Government will be organized among relavant organizations in Indonesia.