10.4 POWER GENERATION COST

The power generation cost per kWh of the project is estimated as follows:

	At Panama II substation (Receiving point)	At power station (Sending-end)
- *If import tax is not included*	*5.01 Cent/kWh*	*4.77 Cent/kWh*
- If import tax is included	5.18 Cent/kWh	4.92 Cent/kWh

Tables 10.4(1) and 10.4(2) show detail of the above calculation. This estimate was made under the following conditions:

a) Power station is operated at the plant factor of 68.5%.

b) Station service loss factor (kWh loss) is 7.1%.

c) Transmission loss factor (annual average) is 0.66%.

d) Thermal efficiency (annual average) of power station is 35%.

e) Service life is estimated at 25 years for power station and 35 years for transmission line and substation.

f) Coal price (6,600 kcal/kg) is US$42/ton.

g) Loan conditions are 10% interest and 25 years repayment for foreign currency portion and 8% interest and 10 years repayment for local currency portion.

h) Cost ratio of operation and maintenance, and administration costs to the construction cost is 4.5% for power station and 2.3% for transmission line and substation.

Table 10.3 (1) Construction Cost

(Millions of Balboas)

Item	Foreign currency	Local currency	Total
Direct Cost	108.68	39.92	148.60
1. Power station	(100.83)	(34.27)	(135.10)
(1) Electrical and mechanical equipment	(81.77)	(14.43)	(96.20)
a) Boiler and its accessory	27.63	4.87	32.50
b) Turbine-generator and its accessory	39.70	7.00	46.70
c) Coal handling and ash handling equipment	9.01	1.59	10.60
d) Environment protection equipment	3.65	0.65	4.30
e) Miscellaneous equipment	1.78	0.32	2.10
(2) Civil works	(11.46)	(11.24)	(22.70)
a) Land reclamation	0.16	0.17	0.33
b) Jetty	3.96	2.03	5.99
c) Water intake and outlet	3.96	3.07	7.03
d) Foundation works	2.94	4.65	7.59
e) Miscellaneous works	0.44	1.32	1.76
(3) Architectural works	(7.60)	(8.60)	(16.20)
a) Powerhouse	5.40	4.22	9.62
b) Stack	0.75	1.62	2.37
c) Administration building and others	1.45	2.76	4.21
2. Transmission line and substation	(7.85)	(5.65)	(13.50)
a) Transmission line	5.64	5.25	10.89
b) Substation and others	2.21	0.40	2.61
Indirect Cost	9.21	4.19	13.40
1. Physical contingency	5.41	1.99	7.40
2. Administrative cost	0	2.20	2.20
3. Engineering fee	3.80	0	3.80
Escalation	12.02	7.97	19.99
Interest During Construction	21.00	6.80	27.80
Total	150.91	58.88	209.79
Import Tax	0	35.09	35.09
Grand Total	150.91	93.97	244.88

Table 10.3 (2) Annual Disbursement of Construction Cost (Import Tax is not included)

(Millions of Balboas)

	Total			1988			1989			1990			1991			1992		
	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total
(1) Power station																		
Total direct cost	100.83	34.27	135.10	0	0	0	0	0	0	24.70	10.83	35.53	56.05	16.01	72.06	20.08	7.43	27.51
Total indirect cost	8.37	3.81	12.18	0.69	0.40	1.09	0.69	0.40	1.09	2.10	0.99	3.09	3.25	1.25	4.50	1.64	0.77	2.41
Price escalation	11.25	6.91	18.16	0.09	0.02	0.11	0.04	0.04	0.08	2.21	1.74	3.95	6.17	3.24	9.41	2.74	1.87	4.61
Interest during construction	18.91	5.84	24.75	0.04	0.02	0.06	0.12	0.05	0.17	1.60	0.61	2.21	6.32	1.97	8.29	10.83	3.19	14.02
Total	139.36	50.83	190.19	0.82	0.44	1.26	0.85	0.49	1.34	30.61	14.17	44.78	71.79	22.47	94.26	35.29	13.26	48.55
(2) Transmission line and substation																		
Total direct cost	7.85	5.65	13.50	0	0	0	0	0	0	6.55	2.15	8.70	0.52	2.69	3.21	0.78	0.81	1.59
Total indirect cost	0.84	0.38	1.22	0.07	0.04	0.11	0.07	0.04	0.11	0.21	0.10	0.31	0.33	0.12	0.45	0.16	0.08	0.24
Price escalation	0.77	1.06	1.83	0	0	0	0	0	0	0.56	0.33	0.89	0.09	0.53	0.62	0.12	0.20	0.32
Interest during construction	2.09	0.96	3.05	0	0	0	0.01	0	0.01	0.39	0.10	0.49	0.80	0.34	1.14	0.89	0.52	1.41
Total	11.55	8.05	19.60	0.07	0.04	0.11	0.08	0.04	0.12	7.71	2.68	10.39	1.74	3.68	5.42	1.95	1.61	3.56
(3) Grand Total	150.91	58.88	209.79	0.89	0.48	1.37	0.93	0.53	1.46	38.32	16.85	55.17	73.53	26.15	99.68	37.24	14.87	52.11

Note: FC : Foreign currency portion
LC : Local currency portion

Table 10.3 (3) Annual Disbursement of Construction Cost (Import Tax is included)

(Millions of Balboas)

	Total			1988			1989			1990			1991			1992		
	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total
(1) Power station																		
Total direct cost	100.83	34.27	135.10	0	0	0	0	0	0	24.70	10.83	35.53	56.05	16.01	72.06	20.08	7.43	27.51
Total indirect cost	8.37	3.81	12.18	0.69	0.40	1.09	0.69	0.40	1.09	2.10	0.99	3.09	3.25	1.25	4.50	1.64	0.77	2.41
Price escalation	11.25	6.91	18.16	0.09	0.02	0.11	0.04	0.04	0.08	2.21	1.74	3.95	6.17	3.24	9.41	2.74	1.87	4.61
Interest during construction	18.91	5.84	24.75	0.04	0.02	0.06	0.12	0.05	0.17	1.60	0.61	2.21	6.32	1.97	8.29	10.83	3.19	14.02
Import tax	0	31.57	31.57	0	0	0	0	0	0	0	6.08	6.08	0	17.55	17.55	0	7.94	7.94
Total	139.36	82.40	221.76	0.82	0.44	1.26	0.85	0.49	1.34	30.61	20.25	50.86	71.79	40.02	111.81	35.29	21.20	56.49
(2) Transmission line and substation																		
Total direct cost	7.85	5.65	13.50	0	0	0	0	0	0	6.55	2.15	8.70	0.52	2.69	3.21	0.78	0.81	1.59
Total indirect cost	0.84	0.38	1.22	0.07	0.04	0.11	0.07	0.04	0.11	0.21	0.10	0.31	0.33	0.12	0.45	0.16	0.08	0.24
Price escalation	0.77	1.06	1.83	0	0	0	0	0	0	0.56	0.33	0.89	0.09	0.53	0.62	0.12	0.20	0.32
Interest during construction	2.09	0.96	3.05	0	0	0	0.01	0	0.01	0.39	0.10	0.49	0.80	0.34	1.14	0.89	0.52	1.41
Import tax	0	3.52	3.52	0	0	0	0	0	0	0	2.59	2.59	0	0.40	0.40	0	0.53	0.53
Total	11.55	11.57	23.12	0.07	0.04	0.11	0.08	0.04	0.12	7.71	5.27	12.98	1.74	4.08	5.82	1.95	2.14	4.09
(3) Grand Total	150.91	93.97	244.88	0.89	0.48	1.37	0.93	0.53	1.46	38.32	25.52	63.84	73.53	44.10	117.63	37.24	23.34	60.58

Table 10.3 (4) **Detail of Direct Cost and Indirect Cost**

(Millions of Balboas)

	Total			1988			1989			1990			1991			1992		
	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total
Direct Cost																		
A. Power station	100.83	34.27	135.10	0	0	0	0	0	0	24.70	10.83	35.53	56.05	16.01	72.06	20.08	7.43	27.51
1. Electrical and mechanical equipment	81.77	14.43	96.20	0	0	0	0	0	0	16.35	2.89	19.24	49.07	8.65	57.72	16.35	2.89	19.24
2. Civil works	11.46	11.24	22.70	0	0	0	0	0	0	6.25	5.51	11.76	3.91	4.06	7.97	1.30	1.67	2.97
3. Architectural works	7.60	8.60	16.20	0	0	0	0	0	0	2.10	2.43	4.53	3.07	3.30	6.37	2.43	2.87	5.30
B. Transmission line facilities	7.85	5.65	13.50	0	0	0	0	0	0	6.55	2.15	8.70	0.52	2.69	3.21	0.78	0.81	1.59
1. Transmission line	5.64	5.25	10.89	0	0	0	0	0	0	5.08	2.07	7.15	0	2.45	2.45	0.56	0.73	1.29
2. Substation	2.21	0.40	2.61	0	0	0	0	0	0	1.47	0.08	1.55	0.52	0.24	0.76	0.22	0.08	0.30
Sub-total of Direct Cost	108.68	39.92	148.60	0	0	0	0	0	0	31.25	12.98	44.23	56.57	18.70	75.27	20.86	8.24	29.10
Indirect Cost																		
1. Contingencies	5.41	1.99	7.40	0	0	0	0	0	0	1.55	0.65	2.20	2.82	0.93	3.75	1.04	0.41	1.45
2. Administrative cost	0	2.20	2.20	0	0.44	0.44	0	0.44	0.44	0	0.44	0.44	0	0.44	0.44	0	0.44	0.44
3. Engineering fee	3.80	0	3.80	0.76	0	0.76	0.76	0	0.76	0.76	0	0.76	0.76	0	0.76	0.76	0	0.76
Sub-total of Indirect Cost	9.21	4.19	13.40	0.76	0.44	1.20	0.76	0.44	1.20	2.31	1.09	3.40	3.58	1.37	4.95	1.80	0.85	2.65
Total	117.89	44.11	162.00	0.76	0.44	1.20	0.76	0.44	1.20	33.56	14.07	47.63	60.15	20.07	80.22	22.66	9.09	31.75

Table 10.4 (1) Power Generation Cost (Import Tax is not included)

	Unit	Panama II S.S. (Receiving point)	Power Station (Sending end)	Transmission line and Substation
1. Basis for Calculation				
Plant capacity	MW	150	150	
Annual plant load factor	%	68.5	68.5	68.5
Annual energy production	GWh	900	900	836.1
Annual enregy sent out	"	830.6	836.1	830.6
Station service and transmission loss factor	%	8.07	7.1	0.66
Annual plant efficiency	%	35.0	35.0	-
Service life of facilities	Years	-	25	35
Fuel cost (6,600 kcal/kg Base)	$/t	42	42	
2. Construction Cost	M$	209.79	190.19	19.60
(FC portion) (LC portion)	" "	(150.91) (58.88)	(139.36) (50.83)	(11.55) (8.05)
3. Annual Expenditure				
(1) Depreciation	$10^3$$	8,168	7,608	560
(2) Interest	"		10,776	692
(FC portion) (LC portion)	" "	11,468	(9,779) (997)	(579) (113)
(3) Operation and maintenance cost (including administration cost)	"	7,826	7,445	381
(4) Total	"	27,462	25,829	1,633
4. Unit Generation Cost				
(1) Fixed cost	C/kWh	3.31	3.09	-
(2) Fuel cost	"	1.70	1.68	-
(3) Total cost	"	5.01	4.77	-

Table 10.4 (2) Power Generation Cost (Import Tax is included)

	Unit	Panama II S.S. (Receiving point)	Power Station (Sending end)	Transmission line and Substation
1. Basis for Calculation				
Plant capacity	MW	150	150	
Annual plant load factor	%	68.5	68.5	68.5
Annual energy production	GWh	900	900	836.1
Annual enregy sent out	"	830.6	836.1	830.6
Station service and transmission loss factor	%	8.07	7.1	0.66
Annual plant efficiency	%	35.0	35.0	-
Service life of facilities	Years	-	25	35
Fuel cost (6,600 kcal/kg Base)	$/t	42	42	
2. Construction Cost	M$	244.88	221.76	23.12
(FC portion)	"	(150.91)	(139.36)	(11.55)
(LC portion)	"	(93.97)	(82.40)	(11.57)
3. Annual Expenditure				
(1) Depreciation	$10^3$$	9,531	8,870	661
(2) Interest	"	11,530	10,789	741
(FC portion)	"		(9,779)	(579)
(LC portion)	"		(1,010)	(162)
(3) Operation and maintenance cost (including administration cost)	"	7,826	7,445	381
(4) Total	"	28,887	27,104	1,783
4. Unit Generation Cost				
(1) Fixed cost	C/kWh	3.48	3.24	-
(2) Fuel cost	"	1.70	1.68	-
(3) Total cost	"	5.18	4.92	-

CHAPTER 11 ECONOMIC EVALUATION

CHAPTER 11 ECONOMIC EVALUATION

11.1 METHODOLOGY

The results of load forecast described in Chapter 3 shows that a new power station of around 150 MW should be commissioned in 1992/93. Further, the shape of load curve of the power system and the supply capability of the existing power stations will lead to consider that this new power station is to be operated at a high plant factor of around 68%.

In the IRHE's "Plan Maestro de Expansion" two projects are planned to enter service in the period from 1991 to 1995. The one is the proposed coal-fired power plant project and the other is the Esti-Barrigon hydro power project. But, the priority of commissioning of these two projects is not yet decided.

The Esti-Barrigon project (Alternative 2-B) is planned to have an installed capacity of 114 MW with an annual energy generation of 642 GWh, so it can be operated at a high plant factor of around 64%. But, this project has many other alternatives, so the final plan is not yet decided. Further, it is informed that there is a problem in finance due to its huge amount of investment. Therefore, it is not appropriate for the moment to compare the Esti-Barrigon project with the proposed coal-fired power plant project.

For the above reasons, the economic evaluation of the proposed coal-fired power station shall be made in the form of cost comparison with its alternative thermal power stations of the same supply capability as that of the proposed coal-fired power station. These alternatives are oil-fired power station, combined-cycle power station and gas turbine power station. For this cost comparison two methods shall be used, i.e. the "Screening curves method" and the "Internal rate of return method" (Equalizing discount rate method).

The analysis by the screening curves method will be made in the following manner:

a) The annual fixed cost (capital cost consisting of interest and depreciation, and operation and maintenance, and administration costs) per kW, and the fuel cost per kWh, both at sending-end, of each alternative are calculated.

b) By using the above fixed cost and fuel cost, "Time-cost curve" which varies with annual operation hour of each alternative is plotted on a graph.

c) The intersecting point of time-cost curves of two power stations represents a break-even point for economic operation of these two alternatives. If annual operation hour which corresponds to the break-even point of alternatives A and B is put as "X", "X" can be obtained from the following equation:

x (difference of fuel costs per kWh of A and B) = (difference of annual fixed costs per kW of A and B)

d) A marginal plant factor for economic operation of each alternative can be obtained from the above operation hour which corresponds to the break-even point. The plant factors thus obtained for these alternatives and the plant factor of around 68% expected for the new power station will lead to judge what type of power station is the optimum.

The above screening curves method is used to select the optimum solution among alternatives by comparing their respective annual cost which varies with annual operation hour. In this connection, it is to be noted that the capital cost is calculated at a given rate of interest.

As compared with the above, the internal rate of return method is used to judge the economy of the proposed project in comparing its total discounted cost with that of alternatives under a given annual operation hour or plant factor. For this purpose, this method calculates a discount rate which equalizes the total costs incurred during a given service life and converted to the present worth of the proposed project to those of its alternatives during the same service life. If the equalizing discount rate thus calculated exceeds the so-called social rate of discount which reflects the opportunity cost of capital (in general 10 to 12%), the proposed project is judged to be feasible.

11.2 CONDITIONS FOR EVALUATION

Conditions adopted in this economic evaluation are the following:

11.2.1 Prices

Consistent with the principles of economic evaluation, all items expected for fuel price are expressed in real terms of 1986, i.e. excluding any future inflation.

11.2.2 Rate of Interest

In the economic evaluation the question arises what value should be allocated to discount rate or interest rate which reflects the opportunity cost of capital. At present in most countries values ranging from 10% to 12% are used, and IRHE uses a discount rate of 12% to make ranking study of the projects in its "Plan Maestro de Expansion". Therefore, to calculate the capital cost of each type of power station in this economic evaluation an interest rate of 12% shall be used.

11.2.3 Price of Fuel

The price of crude oil reached peak in 1982 and then gradually declined until February 1986, but since March 1986 the price sharply fell down. With the slash in crude oil price, coal price has also declined but variation in price of the latter was not so large as that of oil price. The slash in fuel price during the period from 1982 up to the present is as shown below.

Year	Crude oil (US$/barrel)	Coal (US$/ton)
1982	34.07	54.07
1983	29.66	52.88
1984	29.14	48.43
1985/Jan. - 1986/Feb.	29.10 - 27.34	47.44 - 42.00
1986/Mar.	22.38	
1986/Apr.	16.41	
1986/May - 1986/Dec.	13.00 - 14.00	42.00

As shown above, during the period from May 1986 to the end of the year the price of crude oil remained almost constantly at US$13.0 to 14.0 per barrel. However, at the General Assembly held in December 1986 at Geneva the OPEC has decided to enforce a fixed selling price system of US$18.0 per barrel from January 1987.

In Panama, the price of crude oil (CIF) as of October 1986 was US$15.37 per barrel. But, taking into account the above OPEC decision, the import price of crude oil for January 1987 in Panama is expected to be US$18.5 per barrel.

The price ratios of Bunker C and diesel oil to crude oil are different by country. As of January 1987, the prices of Bunker C and diesel oil are respectively estimated at US$15.0 and US$19.0 per barrel against crude oil price of US$18.5 per barrel. Consequently, the price ratios of Bunker C and diesel oil to crude oil are 0.81 and 1.027, respectively.

Therefore, the above-mentioned expected prices of Bunker C and diesel oil as of January 1987 shall be used in the "Base study" of the economic evaluation. On the other hand, a "Sensitivity analysis" shall be conducted for fuel price rising up to the level experienced during 1984 and 1985, i.e. crude oil price of US$29.1 per barrel and coal price of US$48.4 per ton. The price of Bunker C and diesel oil in the "Sensitivity analysis" shall be estimated using the above-mentioned price ratios.

Thus, the price of fuel to be used in this economic evaluation will become as follows:

		Base study	Sensitivity analysis
Crude oil	(US$/barrel)	18.5 (1)	29.1 (2)
Bunker C	(US$/barrel)	15.0 (1)	23.6
Diesel oil	(US$/barrel)	19.0 (1)	29.9
Coal	(US$/ton)	42.0	48.4 (2)

Note: (1) Expected prices for January, 1987 in Panama
(2) Prices experienced in 1984-85

11.2.4 Station Service Loss Factors

Station service loss factors of power and energy consumed by auxiliary equipment and machines of the power station are estimated as follows:

	Power loss	Energy loss
Coal-fired	6.0%	7.1%
Oil-fired	4.5%	5.6%
Combined-cycle	1.25%	1.5%
Gas turbine	0.65%	0.8%

11.2.5 Non-availability Factor

Non-availability factor caused by scheduled maintenance and forced outage is estimated as follows:

Coal-fired and oil-fired power stations:

- Shutdown for scheduled maintenance		30.00 days
- Forced outage (365 - 30) x 3% =		10.05 days
	Total	40.05 days

Combined-cycle and gas turbine power stations:

- Shutdown for scheduled maintenance		40.00 days
- Forced outage (365 - 40) x 5% =		16.25 days
	Total	56.25 days

Therefore, the non-availability factor of combined-cycle and gas turbine power stations will be 4.44% higher than that of coal-fired and oil-fired power stations as indicated below:

$$\frac{56.25 - 40.05}{365} = 0.0444$$

11.2.6 Capacity Drop of Gas Turbine

The annual average temperature on the power plant site is about 28°C. At this temperature the ISO rating capacity of gas turbine will drop by about 16%.

11.2.7 Thermal Efficiency

The proposed power station is planned to be operated at full load for 4,200 hours and at half load for 3,600 hours annually as indicated in Fig. 7.3.1. Therefore, the thermal efficiencies at generator-terminal and at sending-end of each tyep of power station are estimated as follows:

	Generator-terminal	Sending-end
Coal-fired	35%	35% x (1-0.071) = 32.5% (2,645 kcal/kWh)
Oil-fired	36%	36% x (1-0.056) = 34.0% (2,530 kcal/kWh)
Combined-cycle	40.3%	40.3% x (1-0.015) = 39.7% (2,166 kcal/kWh)
Gas turbine	29.4%	29.4% x (1-0.008) = 29.2% (2,945 kcal/kWh)

11.2.8 Service Life

Service life of each type of power station is as estimated below:

Coal-fired	25 years
Oil-fired	25 years
Combined-cycle	20 years (Heavy duty)
Gas turbine	13 years

11.2.9 Operation and Maintenance, and Administration Costs

Statistically, the ratio of costs for operation and maintenance, and administration to the construction cost of power station is estimated as follows:

Coal-fired	4.5%
Oil-fired	4.5%
Combined-cycle	4.5%
Gas turbine	4.0%

The above cost ratios shall be used in this economic evaluation.

11.3 ECONOMIC EVALUATION MADE BY SCREENING CURVES METHOD

11.3.1 Annual Fixed Cost per KW at Sending-end

(1) Capital Cost

As described in Chapter 10, the construction cost of the proposed coal-fired power station is estimated at B/.147.30 million. Therefore, its unit construction cost per kW installed is B/.982. As compared with this, the unit construction costs of oil-fired, combined-cycle and gas turbine power stations are estimated as follows:

Coal-fired	B/.982/kW
Oil-fired	B/.750/kW
Combined-cycle	B/.550/kW
Gas turbine	B/.290/kW

The capital cost can be calculated by multiplying the construction cost by the following capital recovery factor:

$$\frac{r(1+r)^n}{(1+r)^n - 1}$$

Where; r : Rate of interest
n : Service life

At the interest rate of 12%, the capital recovery factor of each type of power station is calculated as follows:

Power station	Service life	Capital recovery factor
Coal-fired	25 years	0.12750
Oil-fired	25 years	0.12750
Combined-cycle	20 years	0.13388
Gas turbine	13 years	0.15568

The economic comparison of alternative power stations must be made based on the same supply capability at sending-end of power station. When taking account of station service loss factor and non-availability factor of each power station and capacity drop of gas turbine, their capital costs are calculated as follows:

Coal-fired $982 \times \frac{1}{(1 - 0.06)} \times 0.12750 = B/.\ 133.20/kW$

Oil-fired $750 \times \frac{1}{(1 - 0.045)} \times 0.12750 = B/.\ 100.13/kW$

Combined-cycle $550 \times \frac{1}{(1-0.0125)\ (1-0.16)} \times 1.0444 \times 0.13388$

$= B/.\ 92.71/kW$

Gas turbine $290 \times \frac{1}{(1-0.0065)\ (1-0.16)} \times 1.0444 \times 0.15568$

$= B/.\ 56.50/kW$

(2) Operation and Maintenance, and Administration Costs

The operation and maintenance, and administration costs at sending-end are estimated as follows:

Coal-fired $982 \times \frac{1}{(1 - 0.06)} \times 0.045 = B/.\ 47.01/kW$

Oil-fired $750 \times \frac{1}{(1 - 0.045)} \times 0.045 = B/.\ 35.34/kW$

Combined-cycle $550 \times \frac{1}{(1-0.0125)\ (1-0.16)} \times 1.0444 \times 0.045$

$= B/.\ 31.16/kW$

Gas turbine $290 \times \frac{1}{(1-0.0065)\ (1-0.16)} \times 1.0444 \times 0.04$

$= B/.\ 14.52/kW$

(3) Annual Fixed Costs

From costs estimated in paragraphs (1) and (2) above, the annual fixed costs of each type of power station will amount to:

Coal-fired	133.20 + 47.01 = B/. 180.21/kW
Oil-fired	100.31 + 35.34 = B/. 135.47/kW
Combined-cycle	92.71 + 31.16 = B/. 123.87/kW
Gas turbine	56.50 + 14.52 = B/. 71.02/kW

11.3.2 Fuel Cost per KWh at Sending-end

The thermal efficiency and the price of fuel, respectively shown in section 11.2.6 and in section 11.2.2 lead to calculate the fuel cost per kWh at sending-end as follows:

Item	Coal-fired	Oil-fired	Combined-cyle	Gas turbine
Fuel used	Coal	Bunker-C	Diesel oil	Diesel oil
Heat value of fuel	6,600 Kcal/kg	9,700 Kcal/lt	9,570 Kcal/lt	9,570 Kcal/lt
Thermal efficiency	2,645 Kcal/kWh	2,530 Kcal/kWh	2,030 Kcal/kWh	2,890 Kcal/kWh
Price of fuel:				
Base study	US$42.00/ton (B/.0.0420/kg)	US$15.00/b (B/.0.09434/lt)	US$19.00/b (B/.0.1195/lt)	US$19.00/b (B/.0.1195/lt)
Sensitivity analysis	US$48.40/ton (B/.0.0484/kg)	US$23.60/b (B/.0.01484/lt)	US$29.90/b (B/.0.1881/lt)	US$29.90/b (B/.0.1881/lt)
Fuel cost per kWh:				
Base study	B/.0.01683/kWh	B/.0.02461/kWh	B/.0.02705/kWh	B/.0.03677/kWh
Sensitivity analysis	B/.0.01940/kWh	B/.0.03871/kWh	B/.0.04257/kWh	B/.0.05788/kWh

11.3.3 Screening Curve(Time-Cost Curves)

Annual generation costs per kW for selected operation hours of each type of power station, which calculated from the above-mentioned annual fixed costs per kW and fuel cost per kWh, are given in Table 11.3.3.

Fig. 11.3.3 (1) and 11.3.3 (2) are obtained by plotting values given in the above table on the graphs. These figures show the screening curves (time-cost curves) of the proposed coal-fired power station and its alternatives. On these figures, annual operation hour which corresponds to the intersecting point of time-cost curves of two power stations represents a break-even point for economic operation of these two alternatives.

11.3.4 Plant Factor at Break-even Point

As described in section 11.1.(c), if annual operation hour which corresponds to the break-even point of alternatives A and B is put as "X", "X" can be obtained from the following equation:

x (difference of fuel costs per kWh of A and B)
= (difference of annual fixed costs per kW of A and B)

By using the above equation, annual operation hours (or plant factors) at break-even points between alternatives are calculated as follows:

(1) Base study

a) Coal-fired vs oil-fired

$x(0.02461 - 0.01683) = (180.21 - 135.47)$
$x = 5{,}750$ hours
Plant factor : 65.6%

b) Coal-fired vs combined-cycle

$x(0.02705 - 0.01683) = (180.21 - 123.87)$
$x = 5{,}513$ hours
Plant factor : 62.9%

c) Coal-fired vs gas turbine

$x(0.03677 - 0.01683) = (180.21 - 71.02)$
$x = 5{,}476$ hours
Plant factor : 62.5%

d) Oil-fired vs gas turbine

$x(0.03677 - 0.02461) = (135.47 - 71.02)$
$x = 5{,}300$ hours
Plant factor : 60.5%

From the above marginal plant factors for economic operation and the time-cost curves given in Fig. 11.3.3 (1), it is concluded that in the actual price conditions of US$18.50/barrel for crude oil and US$ 42.00/ton for steam coal:

- For operation at a plant factor of less than 60.5%, the gas turbine alternative will be the most economical.

- For operation at a plant factor from 60.5% to 65.6%, the most economical will be the oil-fired alternative.

- For operation at a plant factor of more than 65.6%, the proposed coal-fired power station will be the most economical.

(2) Sensitivity analysis

a) Coal-fired vs oil-fired

$x(0.03871 - 0.01940) = (180.21 - 135.47)$
$x = 2,317$ hours
Plant factor: 26.5%

b) Coal-fired vs combined-cycle

$x(0.04257 - 0.01940) = (180.21 - 123.87)$
$x = 2,432$ hours
Plant factor: 27.8%

c) Coal-fired vs gas turbine

$x(0.05788 - 0.01940) = (180.21 - 71.02)$
$x = 2,838$ hours
Plant factor: 32.4%

From the above plant factors and the time-cost curves given in Fig. 11.3.3 (2), it is concluded that in the anticipated price conditions of US$29.10/barrel for crude oil and US$48.40/ton for steam coal:

- As far as the new power station is planned to be operated at a plant factor of more than 32.4%, it will be appropriate to select coal-fired power station as the most economical solution.

Table 11.3.3 Annual Generation Cost Per KW at Sending-End

(B/.)

Items	Base study			Sensitivity analysis		
	2,000 hours	5,000 hours	7,000 hours	2,000 hours	5,000 hours	7,000 hours
Coal-fired						
Fuel cost	33.66	84.15	117.81	38.80	97.00	135.80
Fixed cost	180.21	180.21	180.21	180.21	180.21	180.21
Total	213.87	264.36	298.02	219.01	277.21	316.01
Oil-fired						
Fuel cost	49.22	123.05	172.27	77.42	193.55	270.97
Fixed cost	135.47	135.47	135.47	135.47	135.47	135.47
Total	184.69	258.52	307.74	212.89	329.02	406.44
Combined-cycle						
Fuel cost	54.10	135.25	189.35	85.14	212.85	297.99
Fixed cost	123.87	123.87	123.87	123.87	123.87	123.87
Total	177.97	259.12	313.22	209.01	336.72	421.86
Gas turbine						
Fuel cost	73.54	183.85	257.39	115.76	289.40	405.16
Fixed cost	71.02	71.02	71.02	71.02	71.02	71.02
Total	144.56	254.87	328.41	186.78	360.42	476.18

Fig. 11.3.3 (1) Time-cost curves and Break-Even Points for Economic Operation (Base Study)

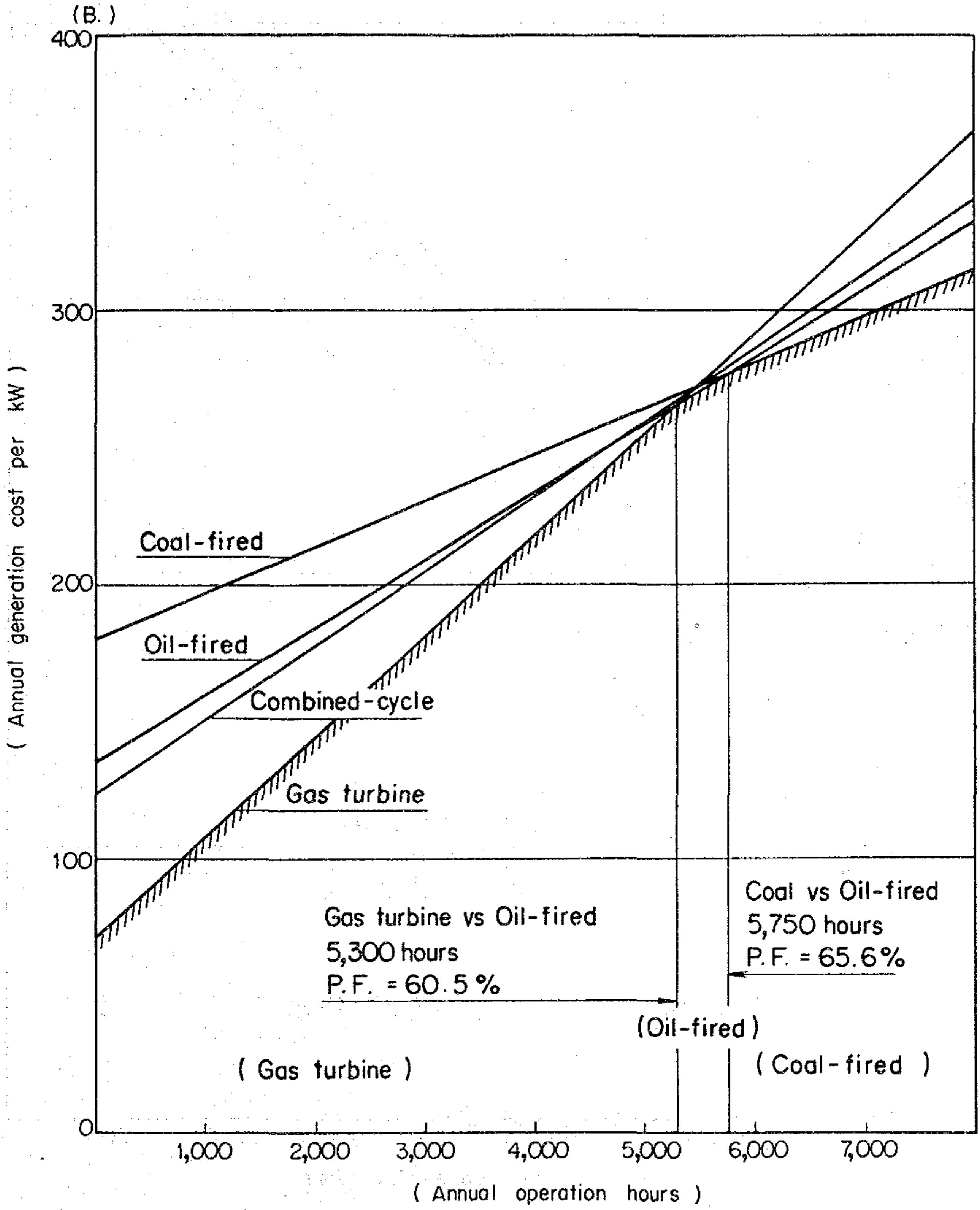
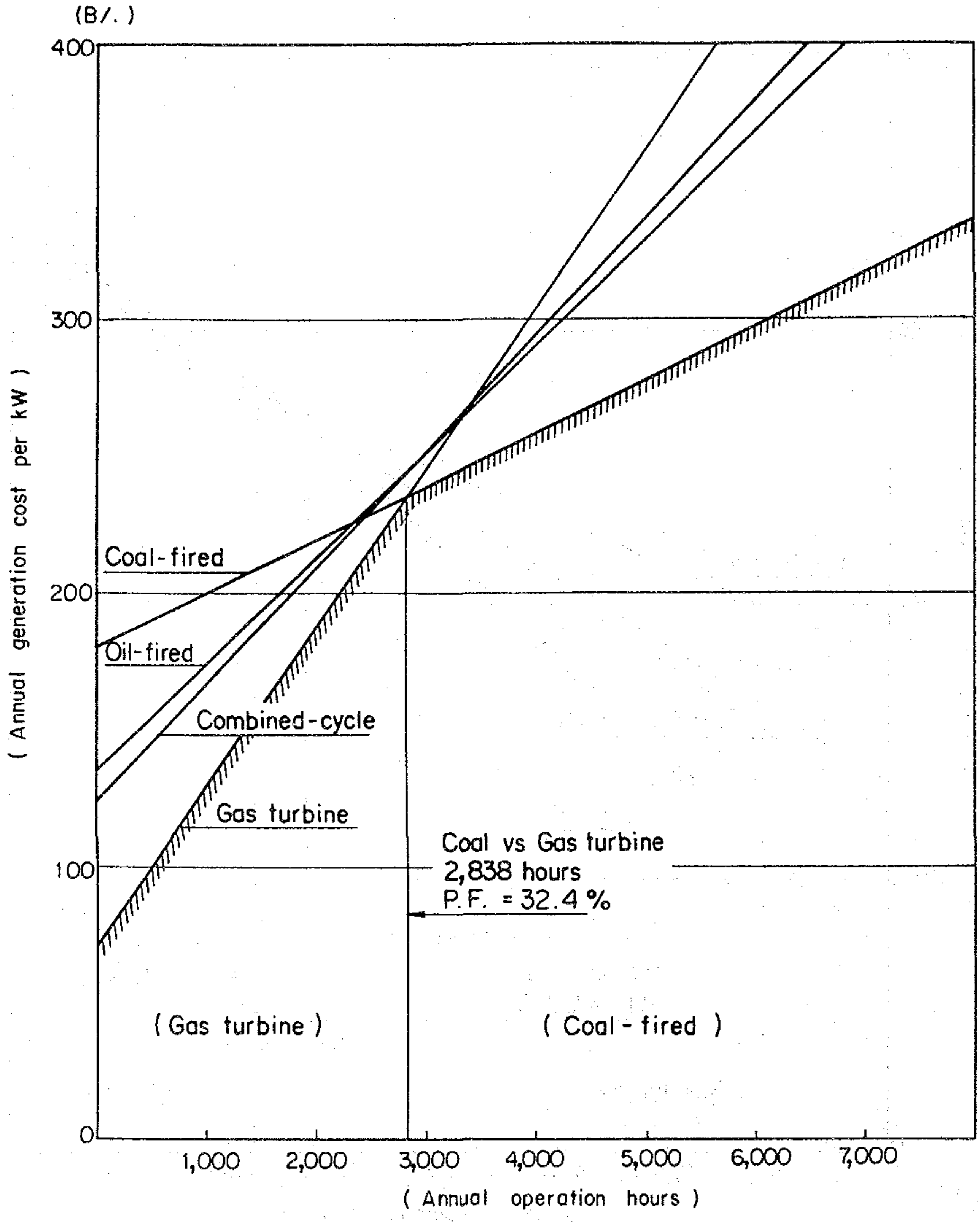


Fig. 11.3.3 (2) Time–Cost Curves and Break–Even Points for Economic Operation (Sensitivity Analysis)



11.4 ECONOMIC EVALUATION MADE BY INTERNAL RATE OF RETURN METHOD

In the economic evaluation made by screening curves method in section 11.3, the annual generation cost of each type of power station was calculated at the given interest rate of 12% in order to obtain its marginal plant factor for economic operation.

As compared with the above method, the internal rate of return method (equalizing discount rate method) has a purpose to calculate a discount rate which equalizes the total costs of the proposed project to those of its alternative, both converted to the present worth, to compare it with a discount rate reflecting the opportunity cost of capital of the country. In Panama such a social rate of discount is said to be 12%.

The service life is estimated to be 25 years for coal-fired and oil-fired power stations, 20 years for combined-cycle power station and 13 years for gas turbine power station. Therefore, the discount calculation shall be made on the costs incurred during the first 13 years operation for each type of power station, and the construction costs of coal-fired, oil-fired and combined-cycle power stations shall be converted to present worths corresponding to the first 13 years operation.

11.4.1 Construction Cost of the Power Station

The economic comparison of various types of power stations must be made based on the same supply capability at sending-end. the basic features of the proposed coal-fired power plant project are the following:

- Construction cost		B/. 147.30 million
- Installed capacity		150.0 MW
- Capacity at sending-end	150.0 x (1 - 0.06) =	141.0 MW
- Annual generation		900 GWh
- Sent-out energy	900 x (1 - 0.071) =	836.1 GWh

Therefore, the unit construction costs per kW of alternative power stations which take into account station service loss factor (section 11.2.4), non-availability factor (section 11.2.5) and capacity drop of gas turbine (section 11.2.6) are estimated as follows:

Oil-fired	$750 \times \frac{141\ MW}{(1 - 0.045)}$	= B/. 110.73 million
Combined-cycle	$550 \times \frac{141\ MW}{(1 - 0.0125)(1 - 0.16)}$	= B/. 97.63 million
Gas turbine	$290 \times \frac{141\ MW}{(1 - 0.0065)(1 - 0.16)}$	= B/. 51.19 million

11.4.2 Operation and Maintenance, and Administration Costs

The ratio of operation and maintenance, and administration costs to construction cost is estimated at 4.5% for coal-fired, oil-fired and combined-cycle power stations and 4.0% for gas turbine power station, so these costs of each type of power station are as estimated below:

Coal-fired	147.30 x 0.045 = B/. 6.63 million
Oil-fired	110.73 x 0.045 = B/. 4.98 million
Combined-cycle	97.63 x 0.045 = B/. 4.39 million
Gas turbine	51.19 x 0.040 = B/. 2.05 million

11.4.3 Fuel Cost

The annual sent-out energy required for each type of power station is 836.1 GWh, and the fuel cost per kWh at sending-end is described in section 11.3.2. These values lead to calculate the following annual fuel cost for each type of power station:

	Base study		Sensitivity analysis	
	Unit cost (B/./kWh)	Annual cost (B/. million)	Unit cost (B/./kWh)	Annual cost (B/. million)
Coal-fired	0.01683	14.07	0.01940	16.22
Oil-fired	0.02461	20.58	0.03871	32.37
Combined-cycle	0.02705	22.62	0.04257	35.59
Gas turbine	0.03677	30.74	0.05788	48.39

11.4.4 Total Annual Costs

The total annual costs including operation and maintenance, and administration costs and fuel cost will amount to the following:

	Base study (B/. million)	Sensitivity analysis (B/. million)
Coal-fired	20.70	22.85
Oil-fired	25.56	37.35
Combined-cycle	27.01	39.98
Gas turbine	32.79	50.44

11.4.5 Construction Cost Coverted to Present Worth Corresponding to the First 13 Years Operation

Since the service life of coal-fired power station is estimated at 25 years, its annual capital cost at an interest rate of "r" % is calculated by multiplying its construction cost by the following capital recovery factor:

$$\frac{r(1 + r)^{25}}{(1 + r)^{25} - 1} \quad \text{(Capital recovery factor)}$$

The construction cost corresponding to the first 13 years operation, converted to present worth at a discount rate of "r" %, is obtained by multiplying the above annual capital cost by the following cumulative present worth conversion factor:

$$\frac{(1 + r)^{13} - 1}{r(1 + r)^{13}} \quad \text{(Cumulative present worth conversion factor)}$$

Therefore, the construction cost corresponding to the first 13 years operation is calculated as follows:

- Coal-fired and oil-fired power stations:

$$\text{Construction cost} \times \frac{r(1 + r)^{25}}{(1 + r)^{25} - 1} \times \frac{(1 + r)^{13} - 1}{r(1 + r)^{13}}$$

- Combined-cycle power station:

$$\text{Construction cost} \times \frac{r(1 + r)^{20}}{r(1 + r)^{20} - 1} \times \frac{(1 + r)^{13} - 1}{r(1 + r)^{13}}$$

11.4.6 Operation and Maintenance, and Administration Cost and Fuel Cost Converted to Present Worth Corresponding to the First 13 Years Operation

The costs converted to present worth at a discount rate of "r" % of the captioned costs corresponding to the first 13 years operation are calculated by multiplying their total annual costs by the following cumulative present worth conversion factor:

$$\frac{(1 + r)^{13} - 1}{r(1 + r)^{13}}$$

11.4.7 Total Costs Converted to Present Worth of Each Type of Power Station

The total costs incurred during the first 13 years operation and converted to present worth of each type of power station are given in Tables 11.4.7(1) and 11.4.7(2). These costs are obtained by multiplying the construction costs in section 11.4.1 and total annual costs in section 11.4.4 by the above-mentioned capital recovery factor and cumulative present worth conversion factor at selected discount rates.

11.4.8 Economic Internal Rate of Return (Equalizing Discount Rate)

Tables 11.4.7(1) and 11.4.7(2) give also differences of costs of the proposed coal-fired power station and those of its alternatives.

Fig. 11.4.8(1) and 11.4.8(2) are obtained by plotting the above cost differences on the graphs. In these figures, a discount rate on which there is no cost difference represents an equalizing discount rate, or an economic internal rate of return (EIRR) of the proposed coal-fired power station.

EIRR of the proposed coal-fired power station as against alternative thermal power stations obtained from the above figures are as follows:

	Base study	Sensitivity analysis
Coal-fired vs oil-fired	12.60%	39.30%
Coal-fired vs combined-cycle	13.25%	34.30%
Coal-fired vs gas turbine	13.40%	29.10%

11.5 CONCLUSION

Among various types of thermal power stations, the unit construction cost of coal-fired power station is the largest but its fuel cost per kWh is the least. Due to rapid decline in oil price since March 1986 the economic advantage of coal-fired power station at present is not so large as before. However, even in the actual price of fuel, based on a crude oil price of US$18.5 per barrel, the proposed coal-fired power station will be the most economical among various types of thermal power stations if an operation at a plant factor of more than 66% is required (conclusion of the "Base study"). Further, in the anticipated price of fuel, based on a crude oil price of US$29.1 per barrel, the proposed coal-fired power station will be more advantageous, i.e. more economical than any other type of thermal power station if an operation at a plant factor of more than 33% is required (conclusion of the "Sensitivity analysis"). Thus, it is concluded that the proposed coal-fired power plant project will be economically feasible because an operation at a plant factor of around 68% is required for new power station to be commissioned in 1992/93.

The above conclusion is obtained from economic evaluation in which an interest rate of 12% is used for calculate the capital costs of the proposed power station and its alternatives. In addition to this, it is appropriate to show the result obtained from another economic evaluation as follows:

The alternative thermal power stations must supply the same capacity and the same quantity of annual energy at sending-end as those of the proposed coal-fired power station. In this case, the economic internal rate of return (EIRR) of the proposed power station, that is the discount rate which equalizes the total costs of the proposed power station to those of its alternatives is calculated to be 12.60 to 13.40% in the actual price of fuel, based on a crude oil price of US$18.5 per barrel (conclusion of the "Base study"), and 29.1 to 39.3% in the anticipated price of fuel, based on a crude oil price of US$29.1 per barrel (conclusion of the "Sensitivity analysis"). Therefore, when considering that in Panama a social rate of discount of 12% is used, it is concluded that the proposed coal-fired power plant project is economically feasible.

Tabe 11.4.1 (1) Costs Converted to Present Worth and Difference of Costs Between Coal-Fired and Alternatives (Base Study)

(B/.million)

Items	Coal-fired	Oil-fired	Combined-cycle	Gas turbine
Discount rate: 12%				
Construction cost	120.64	90.69	83.96	51.19
O & M and fuel costs	132.97	164.18	173.50	210.63
Total	253.61	254.87	257.46	261.82
Alternative - Coal-fired	-	+1.26	+3.85	+8.21
Discount rate: 13%				
Construction cost	122.99	92.46	85.11	51.19
O & M and fuel costs	126.72	156.47	165.35	200.73
Total	249.71	248.93	250.46	251.92
Alternative - Coal-fired	-	-0.78	+0.75	+2.21
Discount rate: 14%				
Construction cost	125.22	94.13	86.13	51.19
O & M and fuel costs	120.94	149.33	157.80	191.57
Total	246.16	243.46	243.93	242.76
Alternative - Coal-fired	-	-2.70	- 2.23	-3.40

Table 11.4.1 (2) Costs Converted To Present Worth and Difference of Costs Between Coal-Fired and Alternatives (Sensitivity Analysis)

(B/.million)

Items	Coal-fired	Oil-fired	Combined-cycle	Gas turbine
Discount rate: 28%				
Construction cost	141.65	106.49	94.36	51.19
O & M and fuel costs	78.31	128.01	137.02	172.87
Total	219.96	234.50	231.38	224.06
Alternative - Coal-fired	-	+14.54	+11.42	+4.10
Discount rate: 30%				
Construction cost	142.61	107.21	94.90	51.19
O & M and fuel costs	73.65	120.38	128.86	162.57
Total	216.26	227.59	223.76	213.76
Alternative - Coal-fired	-	+11.33	+7.50	-2.50
Discount rate: 32%				
Construction cost	143.45	107.83	95.34	51.19
O & M and fuel costs	69.47	113.56	121.56	153.36
Total	212.92	221.39	216.90	204.55
Alternative - Coal-fired	-	+8.47	+3.98	-8.37
Discount rate: 34%				
Construction cost	144.11	108.33	95.74	51.19
O & M and fuel costs	65.71	107.41	114.97	145.05
Total	209.82	215.74	210.71	196.24
Alternative - Coal-fired	-	+5.92	+0.89	-13.58
Discount rate: 40%				
Construction cost	145.48	109.36	96.52	51.19
O & M and fuel costs	56.41	92.20	98.69	124.51
Total	201.89	201.56	195.21	175.70
Alternative - Coal-fired	-	-0.33	-6.68	-26.19

Fig. 11.4.8 (1) Economic Internal Rate of Return
(Base Study)

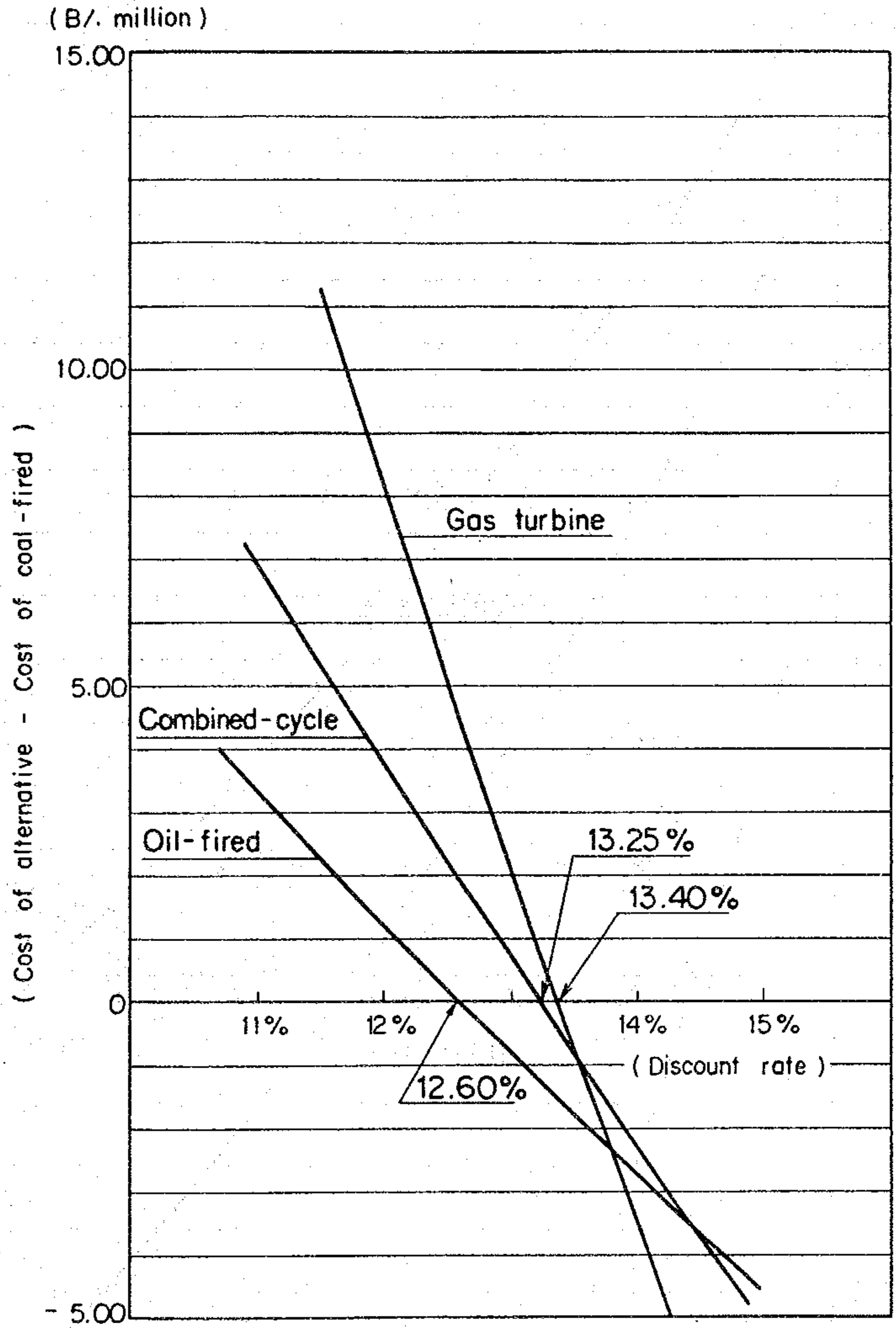
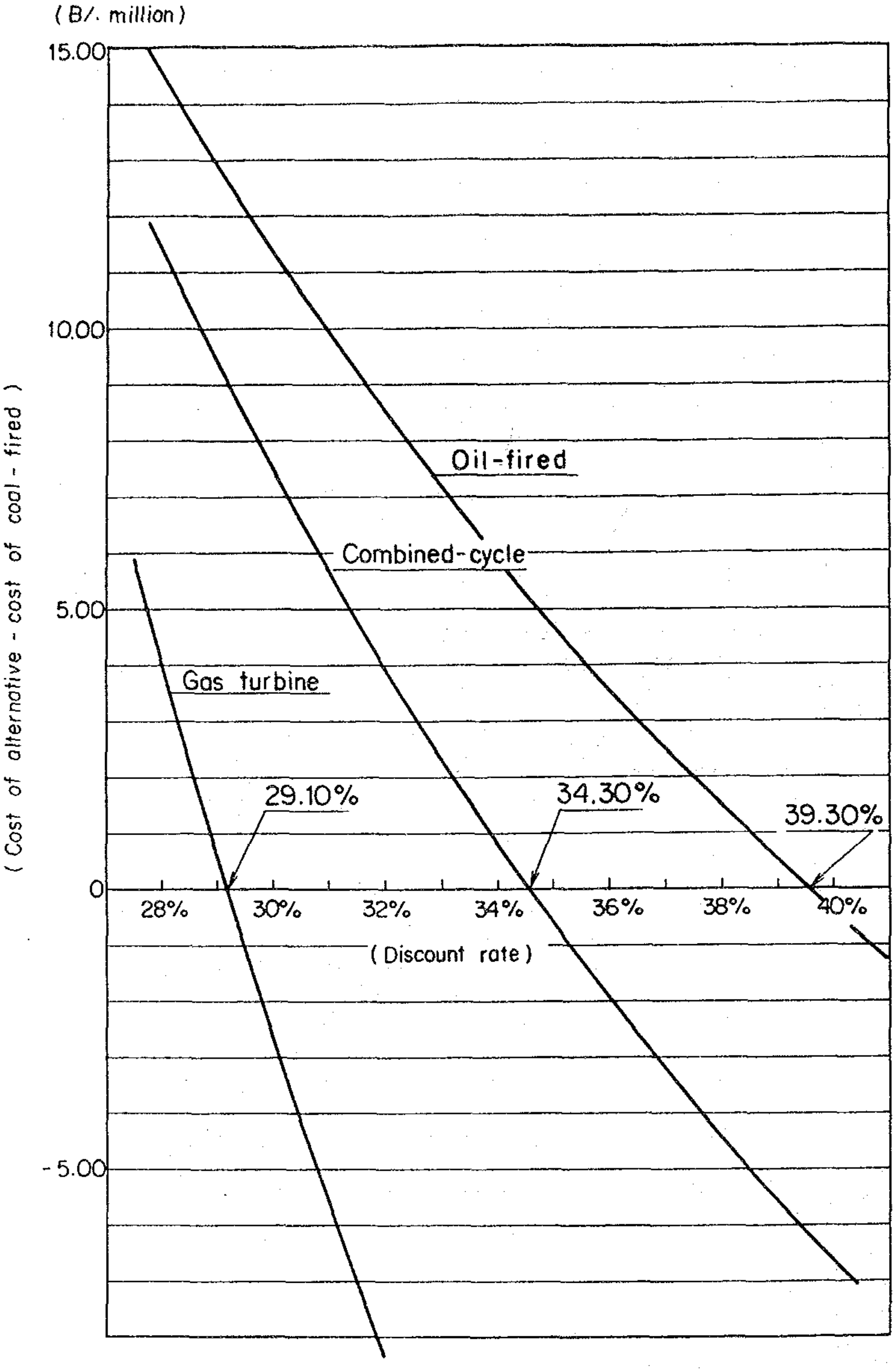


Fig. 11.4.8 (2) Economic Internal Rate of Return
(Sensitivity Analysis)



CHAPTER 12 FINANCIAL ANALYSIS

CHAPTER 12 FINANCIAL ANALYSIS

12.1 METHODOLOGY

The financial analysis of the project shall be made by using the following two methods:

a) Preparation of profit and loss statement, and calculation of rate of return. That is:

- Preparation of repayment schedule of the borrowings based on a loan condition deemed reasonable.

- Preparation of profit and loss statement, and calculation of rate of return (ratio of operating income to average net fixed assets in operation).

- Calculation of yearly cash balance.

b) Calculation of equalizing discount rate (so-called "Financial internal rate of return"), that is:

- Calculation of discount rate which equalizes the revenue obtained from sales of energy to the total expenses incurred during the whole service life of the project. This discount rate, as compared with the social rate of discount in Panama, will serve for evaluating the financial soundness of the project.

12.2 CONDITIONS FOR ANALYSIS

Conditions used for this financial analysis are the following:

12.2.1 Loan Conditions

Financial analysis made on a soft loan condition between governments is not appropriate for the stage of planning. To evaluate financial soundness of the project it is necessary to apply commercial loan conditions. For this purpose, the following loan conditions will serve as the reference:

- Inter-American Development Bank (IDB)

Interest rate	9.50% (1985)
Repayment period	15 - 25 years

- OECD Export Credit Guide Line

Interest rate	11.20% (1985/Jan. - 1986/Jan.)
(lowest limit)	10.15% (1986/Jan. - 1986/Jul.)
	8.75% (1986/Jul. -)
Repayment period	8.5 - 10 years

- Commercial banks (Loan in US$)

Interest rate	10 - 12% (1985)
	8.3% (1986)
Repayment period	10 years

In 1986 the interest rate declined generally, but it is anticipated that the rate will gradually rise in the future.

Taking the above situations into account, the financial analysis shall be made on the following loan conditions:

- For foreign currency portion:

Interest rate	10%
Repayment period	25 years (From commissioning year)

- For local currency portion:

Interest rate	8%
Repayment period	10 years (From commissioning year)

12.2.2 Construction Cost

Taking 1986 prices as the basis, the construction cost shall include a price escalation of 2.0% per annum for foreign currency portion and 3.5% per annum for local currency portion. The imported equipment and materials shall include uniformly 35% import tax.

12.2.3 Price of Other Items

a) Average rate per unit sold of electricity

To estimate the revenue from sales of energy supplied by the proposed project, an average rate per unit sold of B/. 0.1272/kWh shall be used, excluding price rise in the future. Of this unit rate, 65% shall be allocated to the project for its power generation and transmission.

b) Coal price

A coal price of US$42.00/ton at present shall be used for calculating fuel cost, excluding price rise in the future.

c) Operation and maintenance, and administration costs

The operation and maintenance, and administration costs of the power station shall be estimated at 4.5% of its construction cost. For transmission line and substation, the ratio of these costs to the construction cost shall be estimated at 2.3%. Price escalation of these costs in the future shall be excluded.

d) Depreciation cost

The depreciation cost shall be calculated by straight line method with no scrap value from total construction cost including interest during construction. The service life shall be estimated to be 25 years for power station and 35 years for transmission line and substation.

12.3 PROFIT AND LOSS CALCULATION AND RATE OF RETURN

12.3.1 Annual Disbursement of Construction Cost

The annual disbursement of the total construction cost including import tax and interest during construction is as shown below:

(Millions of Balboas)

Year	Base Cost			I.D.C.			Total		
	F.C.	L.C.	Total	F.C.	L.C.	Total	F.C.	L.C.	Total
1988	0.85	0.46	1.31	0.04	0.48	0.06	0.89	0.48	1.37
1989	0.80	0.48	1.28	0.13	0.05	0.18	0.93	0.53	1.46
1990	36.33	24.81	61.14	1.99	0.71	2.70	38.32	25.52	63.84
1991	66.41	41.79	108.20	7.12	2.31	9.42	73.53	44.10	117.63
1992	25.52	19.63	45.15	11.72	3.71	15.43	37.24	23.34	60.58
Total	129.91	87.17	217.08	21.00	6.80	27.80	150.91	93.97	244.88

Note: F.C. : Foreign currency portion
L.C. : Local currency portion
I.D.C.: Interest during construction

The total construction costs of power station and transmission line and substation are as follows:

Unit: (B/. million)

	Base cost	I.D.C.	Total
Power station	199.07	24.75	221.76
Transmission line and substation	20.07	3.05	23.12
Total	217.08	27.80	244.88

12.3.2 Operating Revenue (Revenue from Sales of Energy)

The average rate per unit sold of electricity in 1985 was B/. 0.1272/kWh, while shares of power generation, transmission, distribution and administration sectors in the operating expenses in 1984 and 1985 were averaged to:

Generation	59%
Transmission	6%
Distribution	23%
General administration	12%
Total	100%

The power generation and transmission sectors hold 65% of the total operating expenses. Therefore, 65% of the above average rate per unit sold can be allocated to the power generation and transmission sectors.

The transmission and distribution loss factor during 6 years from 1980 to 1985 was fairly high, namely from 18.4% to 15.8% as shown in Table 2.4.1, but it is anticipated to gradually decrease in the future. In this study a loss factor of 15% is used.

As described in Chapters 3 and 11, the proposed coal-fired power station is planned to supply 836.1 GWh annually at sending-end of the power station. Therefore, the revenue to be allocated to the proposed project is estimated at:

B/. 0.1272/kWh x 0.65 x 836.1 GWh x 0.85 = B/. 58.76 million

12.3.3 Operating Expenses

(1) Operation and Maintenance, and Administration Costs

Ratio of the above costs to the construction cost (not including interest during construction) is estimated to be 4.5% for power station and 2.3% for transmission line and substation. Therefore, these costs will be:

- Power station	197.01 x 0.045 = B/. 8.87 million
- Transmission line and substation	20.07 x 0.023 = B/. 0.46 million
Total	B/. 9.33 million

(2) Fuel Cost

As shown in section 11.3.2 in Chapter 11, the unit fuel cost of the proposed coal-fired power station is estimated to be B/. 0.01683/kWh at sending-end for coal price of US$42.00/ton. Therefore, the annual fuel cost will be:

B/. 0.01683/kWh x 836.1 GWh = B/. 14.07 million

(3) Depreciation Cost

The total depreciation costs including power station and transmission line and substation will amount to the following:

- Power station	221.76/25 =	B/. 8.87 million
- Transmission line and substation	23.12/35 =	B/. 0.66 million
	Total	B/. 9.53 million

12.3.4 Repayment Schedule of the Borrowings

Table 12.3.4 shows the repayment schedule of the borrowings financed in the conditions stated in section 12.2.1.

12.3.5 Profit and Loss Calculation

The above-mentioned operating revenue, operating expenses and financial expenses (interest) calculated in Sections 12.3.2 and 12.3.3 will lead to the profit and loss statement given in Table 12.3.5.

12.3.6 Rate of Return

From the profit and loss statement given in Table 12.3.5, the rate of return (ratio of operating income to average net fixed assets in operation) and the rate of net income (ratio of net income to average net fixed assets in operation) of the project for the first 10 years and for the whole service life of 25 years are calculated as follows:

a) For the first 10 years:

- Accumulated amount of average net fixed assets in operation			B/. 1,972.35 million
- Accumulated amount of operating income	25.83 x 10	=	B/. 258.30 million
- Accumulated amount of net income			B/. 65.70 million

- Rate of return	258.30/1,972.35	=	13.1%
- Rate of net income	65.70/1,972.35	=	3.3%

b) For the whole service life of 25 years:

- Accumulated amount of average net fixed assets in operation			B/. 3,144.00 million
- Accumulated amount of operating income			B/. 645.75 million
- Accumulated amount of net income			B/. 347.33 million
- Rate of return	645.75/3,144.00	=	20.5%
- Rate of net income	347.33/3,144.00	=	11.1%

12.3.7 Cash Flow and Yearly Cash Balance

Tables 12.3.4 and 12.3.5 lead to the cash flow from the starting year of the project to the end of its service life given in Table 12.3.7. From this table it is concluded that:

- The project will produce a surplus of B/. 8.06 million annually during the first 10 years of its operation, and a surplus of B/. 21.05 million annually during the last 15 years (B/. 21.00 million in the last year).

- Due to interest during construction (B/. 27.80 million), deficit in the accumulated cash balance will continue up to the 3rd year (1995) from the commissioning and turn to black in the 4th year (1996).

Table 12.3.4 Procurement of Fund and Repayment Schedule

(Millions of Balboas)

No.	Year	Fund procurement			Repayment schedule							
					Foreign currency				Local currency			
		Foreign currency	Local currency	Total	Interest	Principal	Total	Outstanding balance	Interest	Principal	Total	Outstanding balance
	1988	0.85	0.46	1.13	(0.04)			0.85	(0.02)			0.46
	1989	0.80	0.48	1.28	(0.13)			1.65	(0.05)			0.94
	1990	36.33	24.81	61.14	(1.99)			37.98	(0.71)			25.75
	1991	66.41	41.79	108.20	(7.12)			104.39	(2.31)			67.54
	1992	25.52	19.63	45.15	(11.72)			129.91	(3.71)			87.17
1	1993				12.99	1.32	14.31	128.59	6.97	6.02	12.99	81.15
2	1994				12.86	1.45	14.31	127.14	6.49	6.50	12.99	74.65
3	1995				12.71	1.60	14.31	125.54	5.97	7.02	12.99	67.63
4	1996				12.55	1.76	14.31	123.78	5.41	7.58	12.99	60.05
5	1997				12.38	1.93	14.31	121.85	4.80	8.19	12.99	51.86
6	1998				12.19	2.12	14.31	119.73	4.15	8.84	12.99	43.02
7	1999				11.97	2.34	14.31	117.39	3.44	9.55	12.99	33.47
8	2000				11.74	2.57	14.31	114.82	2.68	10.31	12.99	23.16
9	2001				11.48	2.83	14.31	111.99	1.85	11.14	12.99	12.02
10	2002				11.20	3.11	14.31	108.88	0.97	12.02	12.99	0
11	2003				10.89	3.42	14.31	105.46				
12	2004				10.55	3.76	14.31	101.70				
13	2005				10.17	4.14	14.31	97.56				
14	2006				9.76	4.55	14.31	93.01				
15	2007				9.30	5.01	14.31	88.00				
16	2008				8.80	5.51	14.31	82.49				
17	2009				8.25	6.06	14.31	76.43				
18	2010				7.64	6.67	14.31	69.76				
19	2011				6.98	7.33	14.31	62.43				
20	2012				6.24	8.07	14.31	54.36				
21	2013				5.44	8.87	14.31	45.49				
22	2014				4.55	9.76	14.31	35.73				
23	2015				3.57	10.74	14.31	24.99				
24	2016				2.50	11.81	14.31	13.18				
25	2017				1.18	13.18	14.36	0				
	Total	129.91	87.17	217.08	227.89	129.91	357.80		42.73	87.17	129.90	

Note: Figures in parenthesis show interest during construction.
Capital recovery factors: 0.110168 for foreign loan and 0.149029 for local loan.

Table 12.3.5 Profit and Loss Statement, and Fixed Assets in Operation

(Millions of Balboas)

No.	Year	Operating revenue	Operating expenses: O & M, administration	Operating expenses: Fuel cost	Operating expenses: Depreciation	Operating expenses: Total	Operating income	Interest	Net income: Yearly amount	Net income: Accumulated amount	Average net fixed assets in operation: Yearly	Average net fixed assets in operation: Accumulated
	1988							0.06	-0.06	-0.06		
	1989							0.18	-0.18	-0.24		
	1990							2.70	-2.70	-2.94		
	1991							9.43	-9.43	-12.37		
	1992							15.43	-15.43	-27.80		
1	1993	58.76	9.33	14.07	9.53	32.93	25.83	19.96	5.87	-21.93	210.12	240.12
2	1994	58.76	9.33	14.07	9.53	32.93	25.83	19.35	6.48	-15.45	230.59	470.71
3	1995	58.76	9.33	14.07	9.53	32.93	25.83	18.68	7.15	-8.30	221.06	691.77
4	1996	58.76	9.33	14.07	9.53	32.93	25.83	17.96	7.87	-0.43	211.53	903.30
5	1997	58.76	9.33	14.07	9.53	32.93	25.83	17.18	8.65	8.22	202.00	1,105.30
6	1998	58.76	9.33	14.07	9.53	32.93	25.83	16.34	9.49	17.71	192.47	1,297.77
7	1999	58.76	9.33	14.07	9.53	32.93	25.83	15.41	10.42	28.13	182.94	1,480.71
8	2000	58.76	9.33	14.07	9.53	32.93	25.83	14.42	11.41	38.54	173.41	1,654.12
9	2001	58.76	9.33	14.07	9.53	32.93	25.83	13.33	12.50	52.04	163.88	1,818.00
10	2002	58.76	9.33	14.07	9.53	32.93	25.83	12.17	13.66	65.70	154.35	1,972.35
11	2003	58.76	9.33	14.07	9.53	32.93	25.83	10.89	14.94	80.64	144.82	2.117.17
12	2004	58.76	9.33	14.07	9.53	32.93	25.83	10.55	15.28	95.92	135.29	2.252.46
13	2005	58.76	9.33	14.07	9.53	32.93	25.83	10.17	15.66	111.58	125.76	2.378.22
14	2006	58.76	9.33	14.07	9.53	32.93	25.83	9.76	16.07	127.65	116.23	2,494.45
15	2007	58.76	9.33	14.07	9.53	32.93	25.83	9.30	16.53	144.18	106.70	2,601.15
16	2008	58.76	9.33	14.07	9.53	32.93	25.83	8.80	17.03	161.21	97.17	2,698.32
17	2009	58.76	9.33	14.07	9.53	32.93	25.83	8.25	17.58	178.79	87.64	2,785.96
18	2010	58.76	9.33	14.07	9.53	32.93	25.83	7.64	18.19	196.98	78.11	2,864.07
19	2011	58.76	9.33	14.07	9.53	32.93	25.83	6.98	18.85	215.83	68.58	2,932.65
20	2012	58.76	9.33	14.07	9.53	32.93	25.83	6.24	19.59	235.42	59.05	2,991.70
21	2013	58.76	9.33	14.07	9.53	32.93	25.83	5.44	20.39	255.81	49.52	3,041.22
22	2014	58.76	9.33	14.07	9.53	32.93	25.83	4.55	21.28	277.09	39.99	3,081.21
23	2015	58.76	9.33	14.07	9.53	32.93	25.83	3.57	22.26	299.35	30.46	3,111.67
24	2016	58.76	9.53	14.07	9.53	32.93	25.83	2.50	23.33	322.68	20.93	3,132.60
25	2017	58.76	9.33	14.07	9.53	32.93	25.83	1.18	24.65	347.33	11.40	3,144.00
	Total	1,469.00	233.25	351.75	238.25	823.25	645.75	298.42	347.33			

Table 12.3.7 Cash flow

(Millions of Balboas)

No.	Year	Cash inflow				Cash outflow				Balance	
		Fund procurement	Net income	Depreciation	Total	Construction works	Repayment of principal: Foreign	Repayment of principal: Local	Total	Yearly	Accumulated
	1988	1.31	-0.06		1.25	1.31			1.31	-0.06	-0.06
	1989	1.28	-0.18		1.10	1.28			1.28	-0.18	-0.24
	1990	61.14	-2.70		58.44	61.14			61.14	-2.70	-2.94
	1991	108.20	-9.43		98.77	108.20			108.20	-9.43	-12.37
	1992	45.15	-15.43		29.72	45.15			45.15	-15.43	-27.80
1	1993		5.87	9.53	15.40		1.32	6.02	7.34	8.06	-19.74
2	1994		6.48	9.53	16.01		1.45	6.50	7.95	8.06	-11.68
3	1995		7.15	9.53	16.68		1.60	7.02	8.62	8.06	-3.62
4	1996		7.87	9.53	17.40		1.76	7.58	9.34	8.06	4.44
5	1997		8.65	9.53	18.18		1.93	8.19	10.12	8.06	12.50
6	1998		9.49	9.53	19.02		2,12	8.84	10.96	8.06	20.56
7	1999		10.42	9.53	19.95		2.34	9.55	11.89	8.06	28.62
8	2000		11.41	9.53	20.94		2.57	10.31	12.88	8.06	36.68
9	2001		12.50	9.53	22.03		2.83	11.14	13.97	8.06	44.74
10	2002		13.66	9.53	23.19		3.11	12.02	15.13	8.06	52.80
11	2003		14.94	9.53	24.47		3.42		3.42	21.05	73.85
12	2004		15.28	9.53	24.81		3.76		4.76	21.05	94.90
13	2005		15.66	9.53	25.19		4.14		4.14	21.05	115.95
14	2006		16.07	9.53	25.60		4.55		4.55	21.05	137.00
15	2007		16.53	9.53	26.06		5.01		5.01	21.05	158.05
16	2008		17.03	9.53	26.56		5.51		5.51	21.05	179.10
17	2009		17.58	9.53	27.11		6.06		6.06	21.05	200.15
18	2010		18.19	9.53	27.72		6.67		6.67	21.05	221.20
19	2011		18.85	9.53	28.38		7.33		7.33	21.05	242.25
20	2012		19.59	9.53	29.12		8.07		8.07	21.05	263.30
21	2013		20.39	9.53	29.92		8.87		8.87	21.05	284.35
22	2014		21.28	9.53	30.81		9.76		9.76	21.05	305.40
23	2015		22.26	9.53	31.79		10.74		10.74	21.05	326.45
24	2016		23.33	9.53	32.86		11.81		11.81	21.05	347.50
25	2017		24.65	9.53	34.18		13.18		13.18	21.00	368.50
	Total	217.08	347.33	238.25	802.66	217.08	129.91	87.17	434.16	368.50	

12.4 CALCULATION OF EQUALIZING DISCOUNT RATE (FINANCIAL INTERNAL RATE OF RETURN)

The so-called "financial internal rate of return (FIRR)" is the discount rate which equalizes the total revenue of the project to the total expenses incurred from the beginning of the project to the end of its service life. This equalizing discount rate is obtained by the following discount calculation:

12.4.1 Cash Flow

In the discount calculation, interest must be excluded from cash flow. The cash flow of the proposed project to be used for this purpose is the following:

(Millions of Balboas)

Year	Revenue	Expenses			
		Construction Cost	O & M and Administration	Fuel Cost	Total
1988	-	1.31	-	-	1.31
1989	-	1.28	-	-	1.28
1990	-	61.14	-	-	61.14
1991	-	108.20	-	-	108.20
1992	-	45.15	-	-	45.15
1993 - 2017 (25 years)	58.76	-	9.33	14.07	23.40

12.4.2 Present Worth Calculation

During the period of 25 years from the commissioning, the revenue (B/. 58.76 million annually) and the expenses (B/. 23.40 million annually) are constant every year. In this case, the present worths of the accumulated totals of these revenue and expenses can be obtained by multiplying annual revenue and expenses by the following cumulative present worth conversion factor:

$$\frac{(1 + r)^{25} - 1}{r(1 + r)^{25}} \times \frac{1}{(1 + r)^5}$$

Where: r : Discount rate

At the discount rate of 13%, 14% and 15%, the present worths of each accumulated totals of these revenue and expenses, and their differences are calculated as follows:

(Millions of Balboas)

Item	Discount rate		
	13%	14%	15%
Revenue (A)	233.79	209.76	188.85
Expenses (B)	228.51	214.45	201.84
Construction cost	(135.41)	(130.92)	(126.63)
O & M, fuel, etc.	(93.10)	(83.53)	(75.21)
Difference (A) - (B)	5.28	-4.69	-12.99

12.4.3 Equalizing Discount Rate

Fig. 12.4.1 was established to obtain the required equalizing discount rate, by plotting on the graph the differences of revenue and expenses given in the above table corresponding to their respective discount rates. The intersecting point of 13.5% on Fig. 12.4.3 shows the equalizing discount rate, i.e. financial internal rate of return (FIRR).

12.5 CONCLUSION

The proposed coal-fired power plant project is expected to show a very good financial performance as described below, even if its required fund for construction is financed in the relatively hard conditions, i.e. interest rate of 10% for foreign currency portion and 8% for local currency portion:

a) The rate of return (ratio of operating income to average net fixed assets in operation) will be very high, namely 13.1% in average for the first 10 years and 20.5% in average for the whole service life of 25 years.

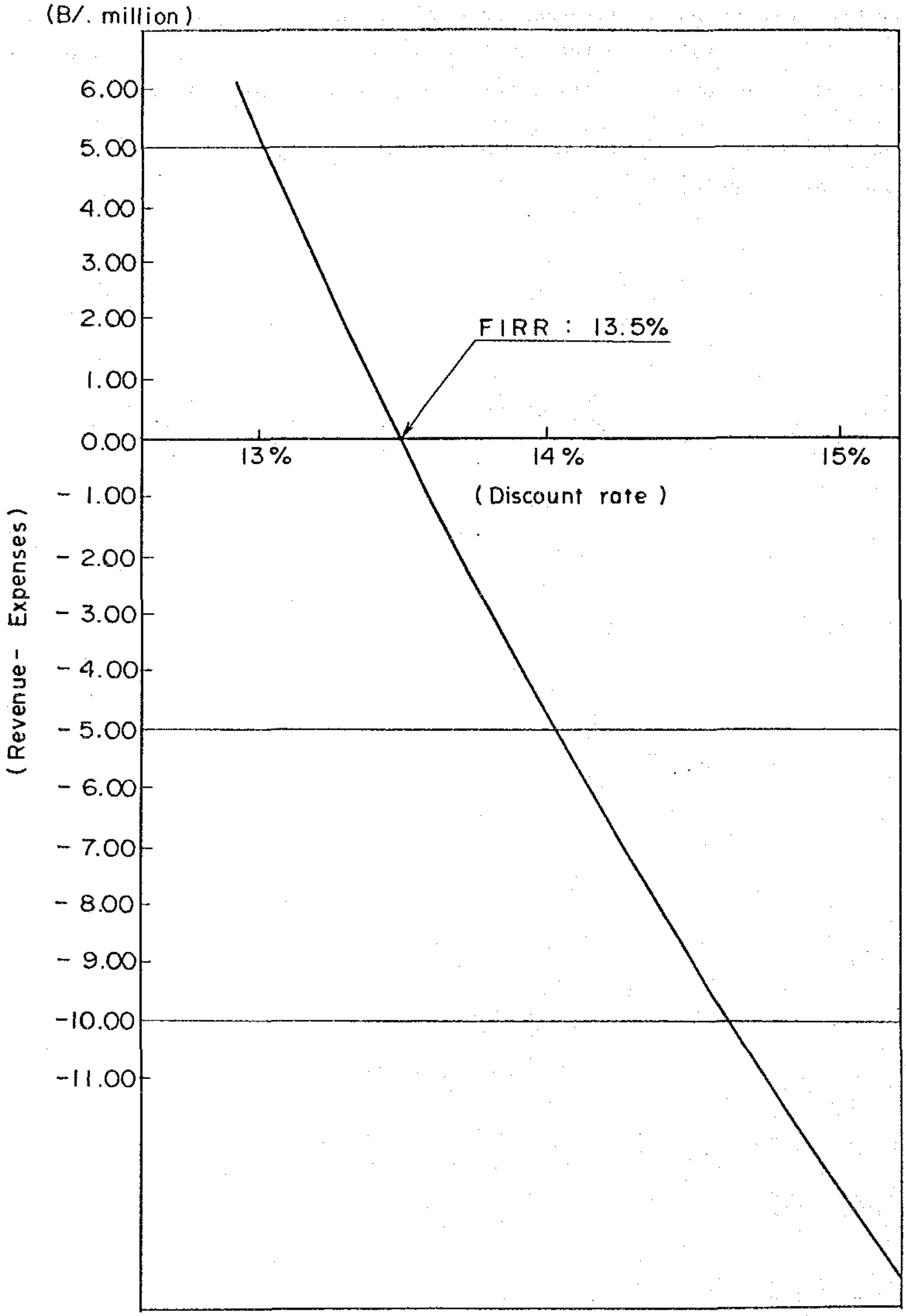
b) The rate of net income (ratio of net income to average net fixed assets in operation) will be also high, 3.3% in average for the first 10 years and 11.1% in average for the whole service life of 25 years.

c) The yearly cash balance will be black every year from the commissioning to the end of service life. Due to interest during construction, deficit in the accumulated cash balance will continue up to the 3rd year from the commissioning but turn to black in the 4th year.

Further, the financial internal rate of return which equalizes the total revenue of the project to the total expenses incurred from the beginning of the project to the end of its service life is calculated to be 13.5%.

From the above, it is concluded that the proposed project is feasible from financial viewpoint.

Fig. 12.4.3 Equalizing Discount Rate (Financial Internal Rate of Return (FIRR))



CHAPTER 13 ENVIRONMETAL PROTECTION COUNTERMEASURES AND ITS EVALUATION

CHAPTER 13 ENVIRONMENTAL PROTECTION COUNTERMEASURES AND ITS EVALUATION

13.1 OUTIINE OF ENVIRONMENTAL EVALUATION

13.1.1 Basic Conception of Environmental Countermeasures

Programming the Telfers island coal-fired power plant construction requires the consideration of following factors of prime importance:

(1) The coal-fired power plant should not affect the sea-going operation of the Panama Canal.

(2) The coal-fired power plant should not affect the surrounding environment.

JICA survey mission has carried out the investigation on following subjects by reference to the above-cited basic conception :

(1) Influence of coal carrying ship operation

(2) Influence of heated effluent

(3) Influence of air pollution

(4) Influence on the Panama Canal dredging

The investigation has revealed the inference as follows that the operation of the coal-fired power plant will not affect the Panama Canal ship operation or surrounding environment.

13.2 RESULT OF INVESTIGATION

13.2.1 Influence of Coal Carrying Ship Operation

The power plant operation will involve the 10,000-DWT coal ship operation at the averaged rate of once every 10 days, unloading the coal by being moored at the jetty for 4 - 5 days including the arrival and departure time. The coal ship is comparatively small in size (capacity of coal vessel) and comparatively unfrequent port entraces. On top of that the coal unloading and berth operation can be carried out within the turning basin, Fig. 4.3.1(3). The ship operation will therefore not affect the Panama Canal sea-going operation.

13.2.2 Influence of Heat Effluent

Condenser cooling water (8 m^3/s) used by the power plant is taken from the Cristobal Harbor and discharged into the French Canala. The cooling water flow amount is little and its temperature rise is controlled low (temperature: 7°C) and therefore it will not cause the water temperature to rise in the whole Cristobal Harbour, needless to say the Panama Canal. On the contrary, the effluent is expected to clean the French Canal where currently the water is always stagnant instead of flowing.

13.2.3 Influence of Air Pollution

It is scheduled that the power plant will be equipped with high-performance electrostatic precipitation, low No_x design boiler and high stacks which serve to reduce the landing ground level concentration of pollutant matters by enhancing atmospheric diffusion. It means the reduction of pollutants at the place of the max. ground level concentration much below the air quality standard of the world, particularly the USA Ambient Air Quality Standard. In addition, since the place of max. ground level concentration occurrence is 6.4 km. apart from the power plant and outside of the Cristobal Harbour anchorage area as well as Colon City, there will be no abad influence on the surrounding environment.

	Ambient air quality standard in USA	Max. ground level concentration from the power plant (each unit)
SOx	0.14 ppm (D)	0.009 ppm (D)
NOx	0.05 ppm (A)	0.004 ppm (D)
Dust	0.26 mg/Nm^3 (D)	0.004 mg/Nm^3 (D)

Note: (D) : Daily average value
(A) : Annual average value

As for the prevention measures against coal dust dispersion, the coal dust dispersion is inhibited by means of water sprays in the coal yard and unloaders, and the coal conveyor is provided with dust covers.

Dry ash from the combustion system is moistened by means of water sprays to prohibit ash dispersion. The coal ash disposal area is provided with sprinklers and ash is covered with soil as soon as disposed, so that the dusts are controlled from being dispersed.

13.2.4 Influence on the Panama Canal Dredging

The dredged materials from the dredging operation of the Panama Canal near the Cristobal Harbour are currently loaded and piled up temporarily in the Telfers island so that they may be used as the road base materials. Since this operation can be carried out in a site adjacent to the power plant site, there is no influence on the operation.

Fig. 13.2.3 (1) Max. Ground Level Concentration Line

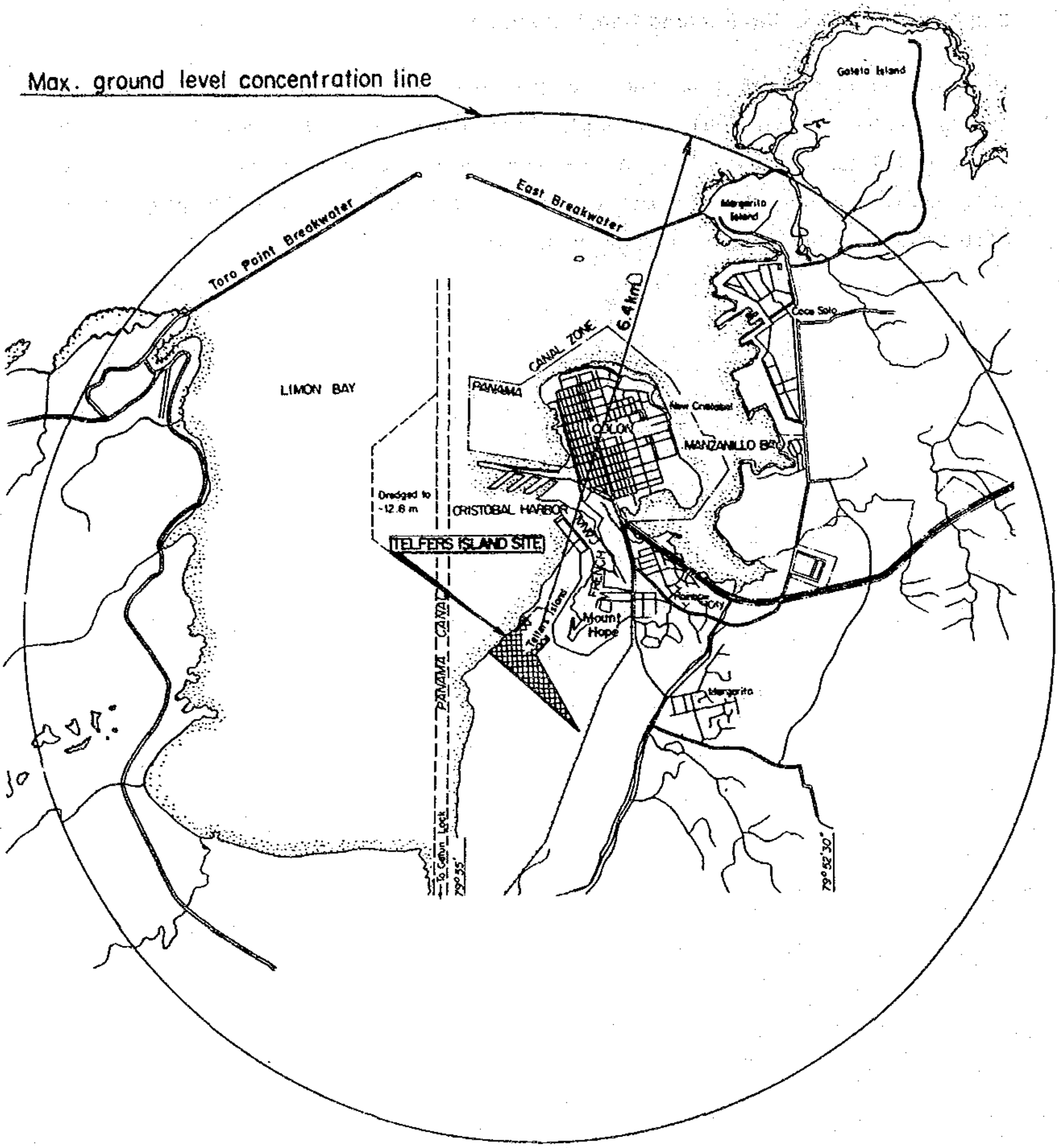
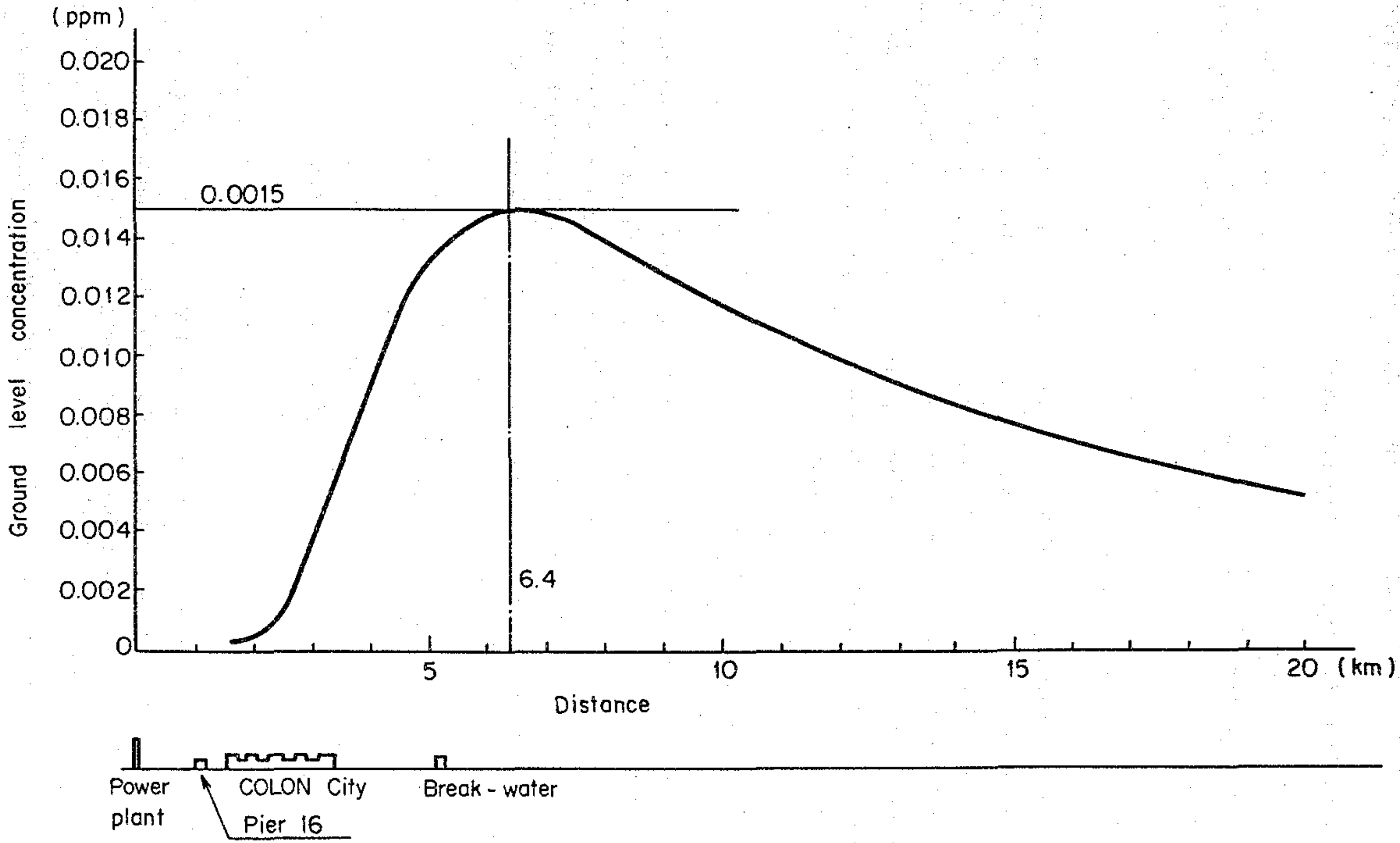


Fig. 13.2.3 (2) Ground Level Concentration Curve



13.3 DESIGN PARAMETERS OF ENVIRONMENTAL PROTECTION FACILITIES

13.3.1 World Air Pollution Emission Standard

The emission standard varies from country to country, as shown in Table 13.3.1, depending upon her criteria, and there is no international standard.

13.3.2 Conception of Design

As widely known, while high-performance environmental protection facilities may be desirable for the dwellers of a region but they are expensive in facility, operation and maintenance costs, and therefore responsible for the increase in power generating cost. JICA survey mission has programmed a system which meets the requirements in Panama as well as surrounding site regions with a good regard to the power generating cost in planning environmental protection facilities.

13.3.3 Panama Situation

JICA Survey Mission has investigated the proposed site surroundings situation as well as Panama situation, through the recent local survey. The investigation has revealed that the Panama situation resembles that in Okinawa, Japan; both Panama and Okinawa feature semi-tropical oceanic climate, and high temperature and humidity and are similar in the scale of power generation system.

Similarities between Panama and Okinawa:

Items	Panama	Okinawa
Climate	Semi-tropical Oceanic climate	Same
	N.L. 10° abt.	N.L. 26° abt.
Averaged temperature (month)	25 - 30°C	16 - 28°C
Averaged humidity (month)	75 - 90%	60 - 74%
Averaged sea water temperature (month)	27 - 29°C	18 - 33°C
Population density	240 persosns/km2	490 persons/km2

Number of existing power source	850 MW	800 MW

13.3.4 Environmental Protection Countermeasures Parameter

As cited above, situational similarities between Panama and Okinawa have led the JICA Survey Mission to select the Okinawa emission standard as the Project design parameters. Table 13.3.4 indicates the practial values. As for the noise and vibration level, since both project sites belong to an industrial area, the level to be applied to an industrial area have been adopted.

[Reference]
Japan has more population density than that of Panama and is an advanced industrial country. Consequently her emission standard features fairly stringent values on the international level. However, from the viewpoint of a long-term and future great development of Panama, the Japanese emission standard has been adopted.

Fig. 13.3.1 National Emission Standard

1. Air Pollution (in case of 75 MW x 2 u Coal Fired Power Plant)

	Japan	USA	West Germany	Sweden	Others
SOx	K-Value control method $q = K \times 10^{-3} \times He^2$ Nm^3/h K = 3.0 - 17.5	520 ng/J 433 ppm	400 mg/Nm^3 140 ppm	100 ng/J 100 ppm	Canada 245 ppm Holland 192 ppm
NOx	300 ppm	260 ng/J 301 ppm	800 mg/Nm^3 389 ppm	280 ng/J 325 ppm	Canada 299 ppm Australia 350 ppm Holland 313 ppm
Suspended Particulate Matter	100 mg/Nm^3	13 ng/J 31 ng/Nm^3	50 mg/Nm^3	36 mg/Nm^3	Canada 116 mg/Nm^3 Australia 250 mg/Nm^3 Belgium 150 mg/Nm^3

Note; q: The hourly volume of sulphur oxides emitted (Nm^3/h)
He: Effective stack height (m)

2. Waste Water in Japan (in Case of Sea)

PH : 5 - 9
COD : 160 mg/ℓ
BOD : Out of regulation
SS : 200 mg/ℓ
Normal-hexane extract : 5 mg/ℓ

3. Noise Level in Japan

Unit: dB (A)

Category	Day time	Morning & Evening	Night time
1st zone (limited zone)	45 - 50	40 - 45	40 - 45
2nd zone (residential zone)	50 - 60	45 - 50	40 - 45
3rd zone (residential and commercial zone)	60 - 65	55 - 65	50 - 55
4th zone (industrial zone)	65 - 70	60 - 70	55 - 60

4. Vibration Level in Japan

Unit: dB

Category	Day time	Mid night
1st zone (residential zone)	60 - 65	55 - 60
2nd zone (commercial and industrial zone)	65 - 70	60 - 65

Table 13.3.4 Design Valuse of Environment Protection

(1) Air Pollution Countermeasures

(a) SOx

Control method: Ground level concentration control
Maximum ground level concentration = 0.015 ppm
(It is called K-value control method in Japan.)

Therefore, the value corresponds to K = 9.0
($Cmax = K \times 1.72 \times 10^{-3}$)

(b) NOx

Control method: Emission concentration control (at top of stack)
Maximum concentration = 300 ppm

(c) Dust

Control method: Emission concentration control (at top of stack)
Maximum concentration = 0.1 g/Nm^3

(2) Water Pollution Countermeasures

Control method: Emission concentration control (at outlet)

(a) Maximum waste water concentration

SS (Suspended Solids)	= 200 mg/ℓt
COD (Chemical Oxygen Demand)	= 160 mg/ℓt
Normal Hexane Extract (oil)	= 5 mg/ℓt
PH (Hydrogen Ion concentration)	= 5 - 9

(b) Heated effluent for cooling water

Maximum temperature rise = 7°C

(3) Noise Countermeasures

Control method: Impact level control (at the boundary)

Maximum impact level:	Day time	= 65 dB (A)
	Night time	= 60 dB (A)

(4) Vibration Countermeasures

Control method: Impact level control (at the boundary)

Maximum impact level:	Day time	= 65 dB
	Night time	= 65 dB

13.4 EVALUATION OF ENVIRONMENTAL IMPACT

13.4.1 Prediction and Evaluation of Environmental Impact

Table 13.4.1(1) indicates the prediction and evaluation of environmental impact on the surrounding area in the case of environmental protection countermeasures being carried out using the design parameters cited above.

As indicated in Table 13.4.1(1), the power plant has impact on its environments to a lesser degree than the world environmental standard (see Table 13.4.1(2) Ambient Air Quality Standard) particularly below the USA and Japanese standard. Consequently it is expected that there will be no bad influence on surrounding environment.

Table 13.4.1(2) indicates the scope of temperature rise of more than 2°C in surface sea-water due to heated effluent and its area is approx 680 x $10^3 m^2$.

13.4.2 Environment Impact Prediction Procedures

The prediction of the above-cited environment impact has been prepared using the following procedures:

(1) Prediction Exhaust Gas Diffusion

The worldly known Bossanque Satton method is used to predict exhaust gas diffusion. As for the details, reference is made to Appendix I.

(2) Prediction Heated Effluent Diffusion

The predictive simulation was carried out by means of electronic computer using prediction method developed by Electric Power Research and Institute of Japan for predicting the dispersion of heated effluent. As for the details, reference is made to Appendix II.

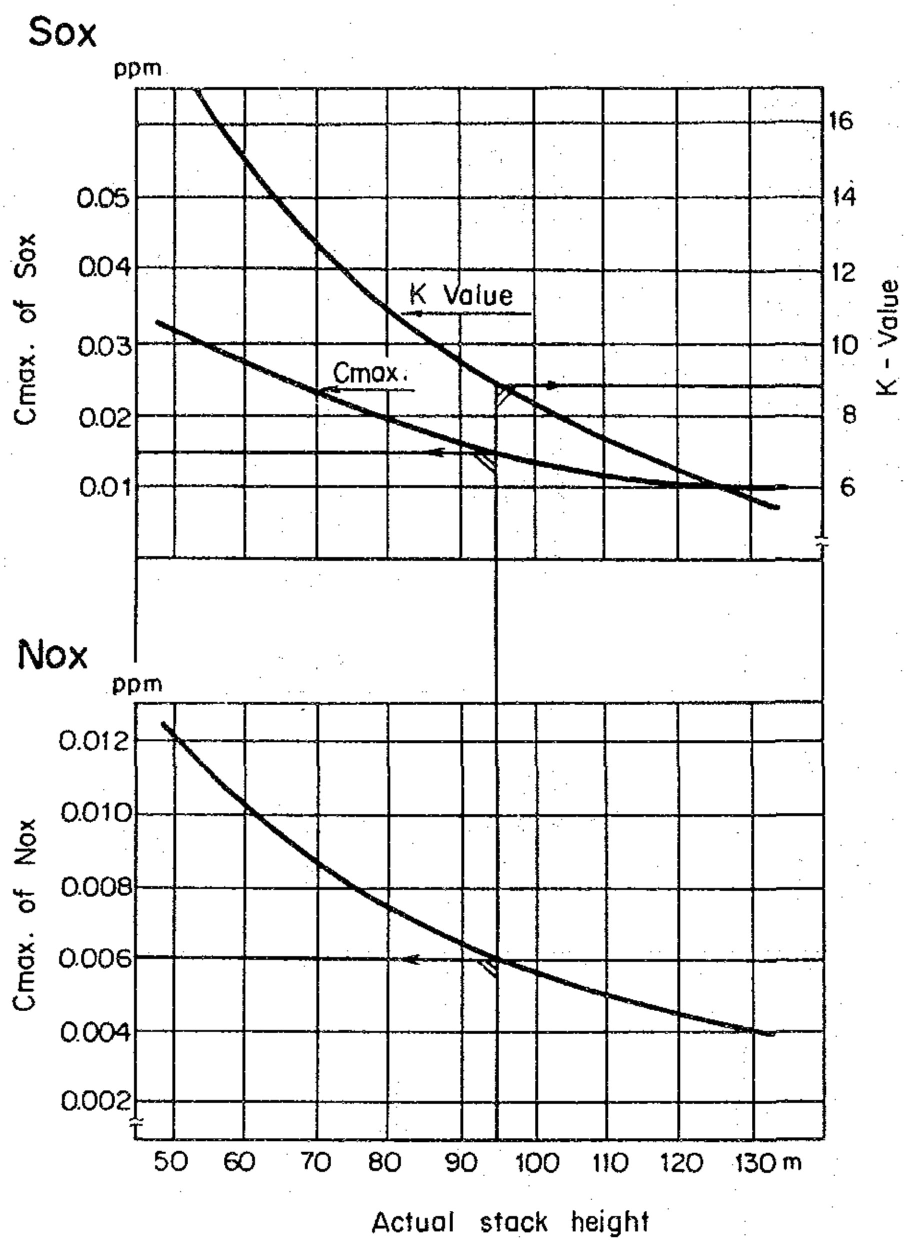
Table 13.4.1 (1) Prediction and Evaluation of Environment Impact

Item	Design	Description
1. General		
Name of power plant	Coal-fired P.S.	Basic design vlaue
Rated capacity	75.0 MW	
Power plant efficiency (100% load)	36.0 %	
Kind of fuel	Steam coal	
Fuel consumption (air dry)	28.5 t/h	
Gross calorific value	6,600 kcal/kg	
Sulfur content	1.0%	
Flue gas quantity (Dry)	266 x $10^3 Nm^3/h$	
Flue gas temperature	140°C	Boiler design value: 140°C
Actual stack height	95.0 m	Stack design height 95 m
Effective stack height	151.0 m	Actual height 95 m + momentum rise effective 23.7 m + buoyancy rise effective 32.3 m
Flue gas speed at top of stack	30.0 m/s	
2. Air pollution countermeasure		
(1) SOx		
SOx emission concentration	752 ppm	
SOx emission quantity	200 Nm^3/h	Depends on fuel sulfur content
Maximum ground level concentration * (H)	0.015 ppm	Ambient air quality in Japan : 0.1 ppm
ditto * (D)	0.009 ppm	" : 0.09 ppm In USA : 0.14 ppm
Corresponds to K-value	8.77	Standard in Japan: K = 3.0 - 17.5 At Okinawa: K = 9.0
Distance, maximum concentration occur	6.4 km	Outside of anchorage area of the Panama Canal and Colon City
(2) NOx		
NOx emission concentration	300 ppm	Boiler design value: 300 ppm
NOx emission quantity	80 Nm^3/h	
NOx ground level concentration * (H)	0.006 ppm	Ambient air quality in West Germany: 0.1 ppm
ditto * (D)	0.004 ppm	in Japan : 0.04 - 0.06 ppm
		in USA : 0.05 ppm (Annual Average)
Distance, maximum concentration occur	6.4 km	Same as SOx

Item	Design	Description
(3) Dust		
Dust emission concentration	0.1 g/Nm^3	Electro-static precipitator design value : 0.1 g/Nm^3
Dust emission quantity	26.6 kg/h	
Maximum ground level concentration (H)	0.002 mg/Nm^3	Ambient air quality in Sweden: 0.1 mg/m^3
ditto (D)	0.001 mg/Nm^3	" in Japan : 0.1 mg/m^3
		in USA : 0.26 mg/m^3
Distance, maximum concentration occur	6.4 km	Same as SOx
3. Water Pollution Countermeasure		
(1) Waste water		
SS (Suspended Solids)	200 mg/ℓt	Emission standard in Japan : 200 mg/ℓt
COD (Chemical Oxygen Demand)	160 mg/ℓt	" 160 mg/ℓt
Normal hexane extract (oil)	5 mg/ℓt	" 5 mg/ℓt
PH (Hydrogen-ion concentration)	5 - 9	" 5 - 9
(2) Heated effluent for cooling water		
Maximum temperature rise	7°C	General value in Japan: 7°C Out of regulation in Japan
Cooling water quantity	4.0 m^3/s	8.0 m^3/s in total for No.1 and No.2 units
		Cooling water is discharged into French Canal
4. Noise Countermeasure		
Maximum impact level		
Day time	65 dB (A)	Standard of Japan: 65 - 70 dB (A) at industrial zone impact
Night time	60 dB (A)	" : 55 - 60 dB (A) "
5. Vibration Impact Level		
Day time	65 dB	Standard of Japan: 65 - 70 dB at industrial zone impact
Night time	65 dB	" : 60 - 65 dB "

Note: *(H) : Hourly value
*(D) : Daily average value

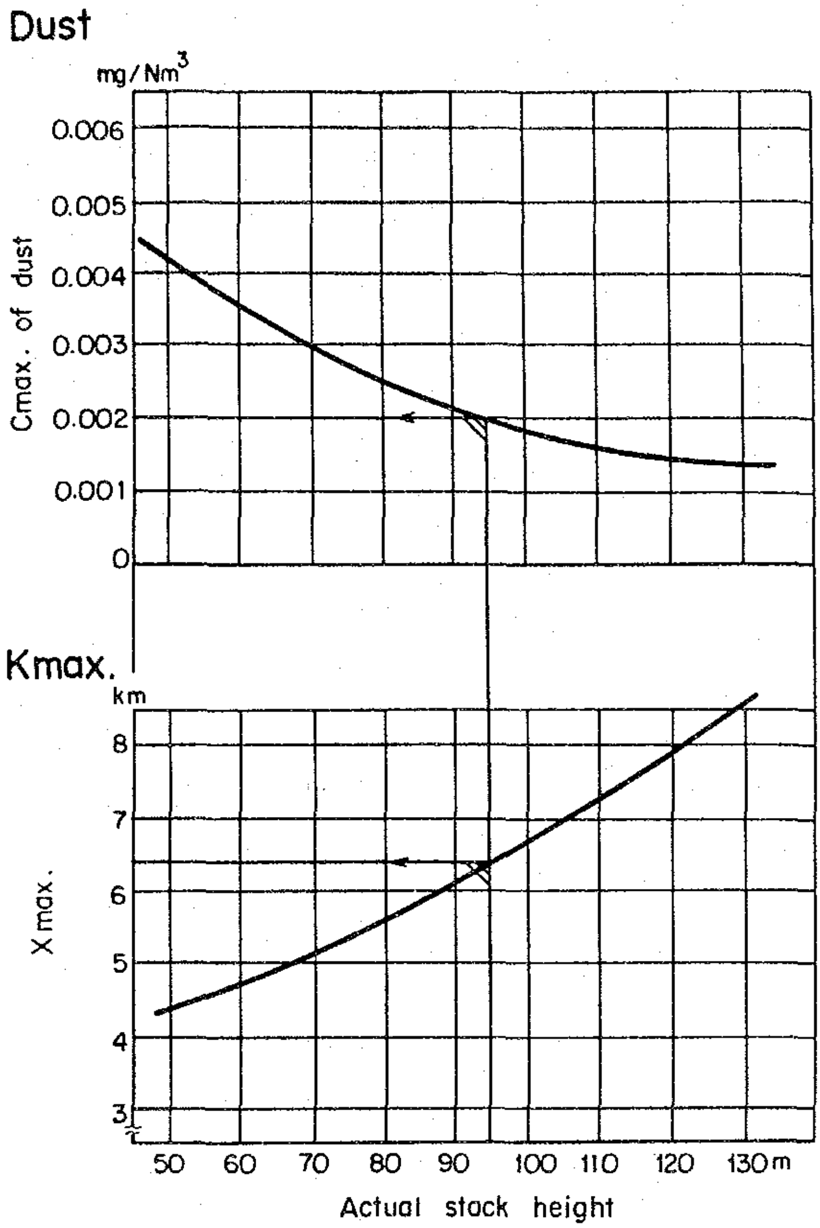
Fig. 13.4.1 (1) Relation Between Stack Height and Ground Level Concentration



Note: Cmax : Maximum ground level concentration (Hourly)

Cmax. (of Sox) = $k \times 1.72 \times 10^{-3}$ ppm

Fig. 13.4.1 (2) **Relation Between Stack Height and Ground Level Concentration**



Note: Xmax. Distance, maximum concentration occur

$Xmax. = He^{1.143} \times 20.8 \times 10^{-3}$

$He = H_o + 0.65\ H_m + 0.65\ H_t$

H_e : Effective stack height

H_m : Momentum rise effective height

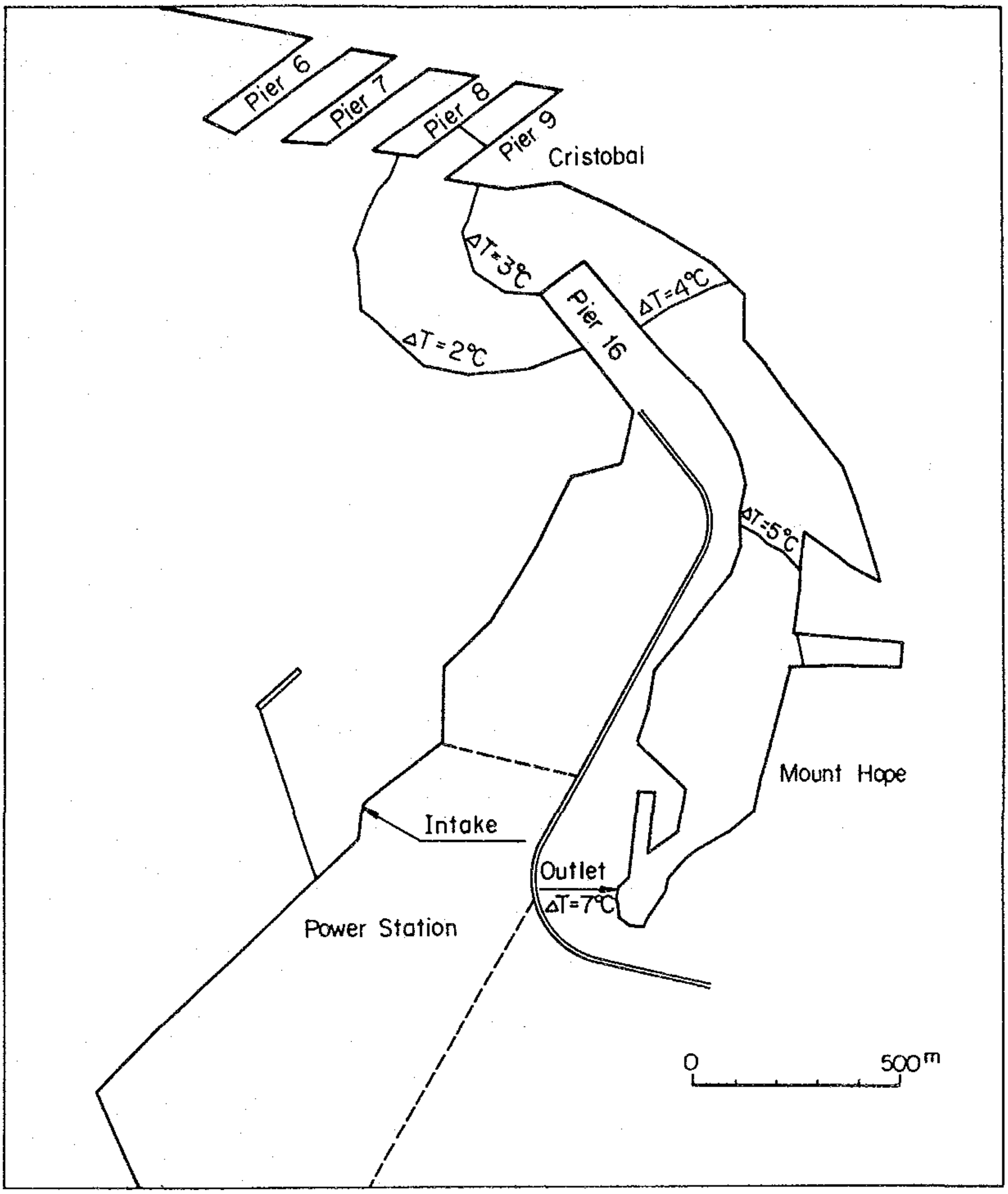
H_t : Buoyancy rise effective height

Table 13.4.1 (2) Ambient Air Quality Standard

Kind of Pollutant	Japan	U.S.A.	West Germany	France	Sweden
SOx	0.1 ppm (H) 0.04 ppm (D)	0.14 ppm (D) 0.003 ppm (A)	0.16 ppm	0.38 ppm (D)	0.1 ppm (D)
NOx	0.04 - 0.06 ppm (D)	0.05 ppm (A)	0.1 ppm	-	-
Suspended Particalate Matter	0.1 mg/m^3 (D)	0.26 mg/m^3 (D)	0.1 mg/m^3	0.35 mg/m^3 (D)	0.1 mg/m^3 (H)

Note; (H): Hourly (D): Daily Average (A): Annual Average

Fig. 13.4.2 (2) Prediction Result of the Discharged Warm Water Diffusion Range



13.5 MAIN FEATURES OF ENVIRONMENT COUNTERMEASURE EQUIPMENT

Main features of environment countermeasure equipment in this project is shown in Table 13.5.1.

Table 13.5.1 Main Features of Environment Countermeasure Equipment

(1) Air Pollution Countermeasure

(a) For SOx

- Coal blending system to average sulfur content
- High and fast gas speed stack: 95 m and 30 m/s to reduce ground level concentration

(b) For NOx

- Two stage combustion systems
- Flue gas mixing system
- Low NOx burner
  Boiler outlet NOx concentration: less than 300 ppm
- High and fast gas speed stack: same as SOx

(c) For Dust

- Electro-static precipitater (low temperature gas type 140°C)
  Outlet gas concentration : less than 0.1 g/Nm^3
  Dust collecting efficiency: more than 99.25%
- High and fast gas speed stack: Same as SOx

(2) Water Pollution Countermeasure

(a) For Waste Water

- SS : Sedimentation and filtration equipment
  Outlet SS concentration: less than 200 mg/lt
- Oil: Oil separater equipment
  Outlet oil concentration: less than 5 mg/lt
- PH : PH-Neutralization equipment
  Outlet PH value: 5 - 9

(b) For Heated Effluent for Cooling Water

- Large cooling area condenser
  Maximum temperature : 7°C
  Cooling water quantity: 4.0 m^3/s for each unit

- Outlet of cooling water will be located at French Canal to well diffuse.

(3) Noise Countermeasure

- Main equipment will be installed in powerhouse located far from boundary to reduce noise level.

- Low noise equipment will be used.
  Impact noise level at boundary will be:
  Day time (Coal unloader operation) : less than 65 db (A)
  Night time (Coal unloader stop) : less than 60 db (A)

(4) Vibration Countermeasure

- Main equipment will be installed far from boundary.
  Impact vibration level at boundary: less than 65 db (All time)

(5) Miscellaneous

- Water sprays will be equipped at coal storage yard and coal unloader to restrain dust emmision.

- Outdoor type belt conveyer will be covered.

- Dry ash will be wetted by water spray and disposed ash will be covered with soil to restrain dust emission.

13.6 MONITORING OF ENVIRONMENTAL IMPACT

Environmental impact assessment involved with power plant operation has been mentioned above.

However, for inhabitants, living around the site and related government offices, it should be necessary to justify the evaluation vlaue by measuring real value. From this point, in order to get understanding and confidence, IRHE should monitor ambient environment before and after plant operation and monitor a change of environmental impact. Table 13.6.1 shows preferable monitoring items, period and points. Monitoring should be started 18 months before No.1 unit commissioning (about one year before No.1 unit initial firing) in order to compare with measured vlaues, before and after plant operation, respectively. Air pollution measuring point is indicated at Fig. 13.6.1 with regard to estimated ground concentration, wind direction and population density.

It is economical that mobile monitoring station which installs all monitoring equipments in an air polution monitoring car moves around four points every week and measure all monitoring items.

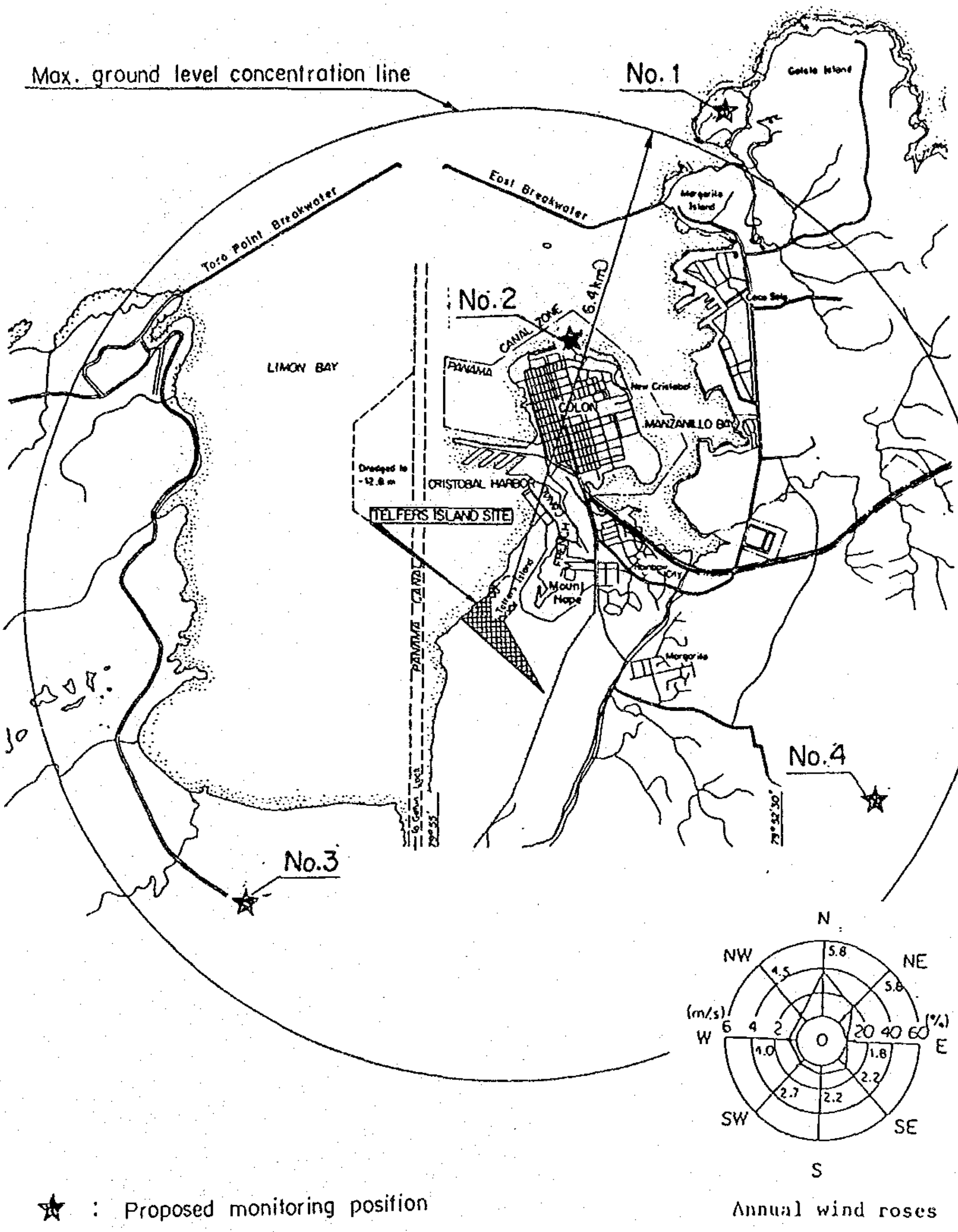
Furthermore, all monitoring points should be selected among the points where have no influence of exhaust gas of automobiles.

Moreover, these should be the same points in order to observe a change of measured values.

Table 13.6.1 Monitoring Items

	Item	Point	Period	Other
Air	SOx NOx Dust Wind direction Wind velocity Ambient temperature	4 points Indicated at Fig. 13.6.1	each point 1/month each point 1 week continuous record	by mobile measuring station
Water quality	P.H. S.S.(Suspended solid) Water temperature	Intake Outlet French canal (Center) Ash disposal area Waste water	1/month	manual
Noise	-	Property line of power plant area 10 points	1/month (day and night)	manual
Vibration	-	ditto	1/year	manual
Exhaust gas	SOx NOx Dust Gas temperature	Stack or flue gas duct	Continuous recordd	full fine monitoring at power station

Fig. 13.6.1 Monitoring Position for Air Pollution



APPENDIX I

Summary of Dust Emission Item

		Unit	Calculated value
Output		MW	75
Coal consumption (wet)		kg/h	30.1
Flue gas volume (wet)		Nm^3/h	282×10^3
" (dry)		"	266×10^3
Flue gas temperature		°C	140
Flue gas velocity		m/s	30
Stack height		m	95
Effective stack height		m	151
O_2 density		%	6
Dust Emission	SOx emission quantity	Nm^3/h	200
	SOx emission concentration	ppm	752
	SOx max emission ground level concentration	"	0.015
	The distance of max. ground level concentration	km	6.44
	Relative K value	-	8.77
	NOx emission quantity	Nm^3/h	80
	NOx emission concentration	ppm	300
	NOx emission ground level concentration	"	0.004
	Dust emission quantity	kg/h	26.6
	Dust emission concentration	g/Nm^3	0.1
	Dust max. emission ground level concentration	mg/Nm^3	0.001

Characteristic of Designed Coal

Item		Unit	Designed coal	Analysis condition
Calorific vlaue (higher)		kcal/kg	6,600	wet
Surface moisture		%	5.2	received
	Inherent moisture	%	4.0	wet
	Ash	%	13.0	wet
	Volatile matter	%	35	wet
	Fixed carbon	%	48	wet
Total sulfur		%	1.0	wet
Total nitrogen		%	1.5	wet
	C	%	69.8	dry
	H	%	4.2	dry
	N	%	1.56	dry
	O	%	9.7	dry
	S	%	10.4	dry
	Ash	%	13.7	dry

Calculation of Dust Emission

Item	
	° Output = 75 MW MCR/ECR = 1.05 ° Flue gas O_2 = 6% ° Plant efficiency (Calorific value base) = 36.0% ° Characteristic of coal Higher (Calorific value) = 6,600 kcal/kg Moisture W1 = 5.2% (as received) Ash = 13.0% (wet) Inherent moisture = 4.0% (wet) C' = 69.8% (dry) H' = 4.2% (dry) N' = 1.56% (dry) O' = 9.7% (dry) S' = 0.9% (dry) Ash = 13.7% (dry)
Coal consumption (F)	° Dry coal Fcd = $\frac{7.5 \times 10^3 \times 860}{6,600 \times 0.36} \times 1.05 \times 10^{-3}$ = 28.5 t/h ° Moisture coal Fcw = $28.5 \times \frac{1}{1 - 0.052} = 30.1$ t/h
Conversion of each ultimate (as received)	
° $W = W1 + \frac{W2\ (100-W1)}{100}$	$W = 5.2 + \frac{4.0 \times (100-5.2)}{100} = 9.0\%$
° $C = \frac{C'(100-W1)}{100}$	$C = \frac{69.8 \times (100-9.0)}{100} = 63.52\%$
° $H = \frac{H'(100-W)}{100}$	$H = \frac{4.2 \times (100-9.0)}{100} = 3.82\%$
° $N = \frac{N'(100-W)}{100}$	$N = \frac{1.56 \times (100-9.0)}{100} = 1.42\%$
° $S = \frac{S'(100-W)}{100}$	$S = \frac{1.04 \times (100-9.0)}{100} = 0.95\%$
° $O = \frac{O'(100-W)}{100}$	$O = \frac{9.7 \times (100-9.0)}{100} = 8.83\%$

Calculation of gas volume	
° Theoretical air volume (Ao)	
$Ao = 8.89.C + 26.7(H-\frac{O}{8}) + 3.33.S$	$Ao = 8.89 \times 0.6352 + 26.7 \times (0.0382 - \frac{0.0883}{8}) + 3.33 \times 0.0095 = 6.40\ Nm^3/kg$
° Theoretical gas volume (Go)	
$Go = 0.79.Ao + 1.867.C + 1.2.H + 0.8\ N + 0.7S + 1.244W$	$Go = 0.79 \times 6.4 + 1.867 \times 0.6352 + 11.2 \times 0.0382 + 0.8 \times 0.0142 + 0.7 \times 0.0095 + 1.244 \times 0.090 = 6.81\ Nm^3/kg$
° Percentage of excess air (m)	
$m = \frac{21}{21 - O2}$	$m = \frac{21}{21-6.0} = \underline{1.40}$
° Actual wet gas volume (Gw)	
$Gw = Go + (m-1)Ao$	$Gw = 6.81 + (1.40-1) \times 6.40 = \underline{9.37\ Nm^3/kg}$
° Actual dry gas volume	
$Gd = Gw - \frac{22.4}{18}(9H+W)$	$Gd = 9.37 - \frac{22.4}{18} \times (9 \times 0.0382+0.090) = \underline{8.83\ Nm^3/kg}$
° Boiler outlet wet gas volume (Qw)	
$Qw = Gw \times Fcw$	$Qw = 9.37 \times 30.1 \times 10^3 = \underline{282 \times 10^3\ Nm^3/h}$
° Boiler outlet dry gas volume	
$Qd = Gd \times Fcw$	$Qd = 8.83 \times 30.1 \times 10^3 = \underline{266 \times 10^3\ Nm^3/h}$
He calculation of effective stack height	
° 15°C gas volume (Q)	
$Q = \frac{Qw}{3600} \times \frac{273+t}{273}$	$Q = \frac{282 \times 10^3}{3,600} \times \frac{273 + 15}{273} = 82.6\ m^3/s$

° Flue gas velocity V	
$V = \frac{Q}{A}$	$V = \frac{82.6}{2.75} = 30$ m/s
° Flue gas temperature	
$T = 273 + tg$	$T = 273 + 140 = 413°K$
° Hm calculation	
$Hm = \frac{0.795\sqrt{Q.V}}{1 + \frac{2.58}{V}}$	$Hm = \frac{0.795 \times \sqrt{82.6 \times 30}}{1 + \frac{2.58}{30}} = \underline{36.4\ m}$
° J calculation	
$J = \frac{1}{\sqrt{Q.V}}(1{,}460-296 \times \frac{V}{T-288}) + 1$	$J = \frac{1}{\sqrt{82.6 \times 30}} \times (1{,}460-296 \times \frac{30}{413-288}) + 1 = \underline{28.9}$
° Ht calculation	
$Ht = 2.01 \times 10^{-3} \times Q \times (T-288) \times (2.3 \log_{10}J+\frac{1}{J}-1)$	$Ht = 2.01 \times 10^{-3} \times 82.6 \times (413-288) \times (2.3 \log_{10} 28.9 + \frac{1}{28.9} - 1) = \underline{49.7\ m}$
° He calculation	
$He = Ho + 0.65(Hm+Ht)$	$He = 95 + 0.65\ (36.4 + 49.73) = 151$ m
° SOx emission quality	
$Qs = 7 \times S \times Fod$	$Qs = 7 \times 1.0 \times 28.5 = 200\ Nm^3/h$
° SOx emission concentration	
$qs = \frac{Qs}{Qd} \times 10^6$	$qs = \frac{200}{266 \times 10^3} \times 10^6 = \underline{752\ ppm}$
° SOx max emission ground level (Cmax)	$Cmax = 1.72 \times \frac{200}{151^2} = 0.015$ ppm
$Cmax = 1.72 \times \frac{Qs}{He^2}$	
(1 hour value)	

$Cmax(24) = 0.59 \times Cmax$ (24 hour value)	$Cmax(24) = 0.59 \times 0.015 = 0.009$ ppm
° The distance of max ground level concentration	
$Xmax = 20.8 \times He^{1.143} \times 10^{-3}$	$Xmax = 20.8 \times 151^{1.143} \times 10^{-3} = 6.44$ km
° Relative K value	
$K = \frac{Qs}{10^{-3}.He^2}$	$K = \frac{200}{10^{-3} \times 151^2} = 8.77$
Calculation of nitrogen an oxide emission quantity	
° NOx emission concentration (qn)	
$qn = \frac{21 - O_2}{21 - 6} \times qNOx$	$qn = \frac{21 - 6}{21 - 6} \times 300 \text{ ppm} = \underline{300 \text{ ppm}}$
qNox : O_2 6% conversion value	
° NOx emission quantity (QNOx)	
$QNOx = qN \times Qd \times 10^{-6}$	$QNOx = 300 \times 266 \times 10^3 \times 10^{-6} = 80 \text{ Nm}^3/h$
° NOx max emission ground level concentration (Cmax)	
$Cmax = 1.72 \times \frac{QNOx}{He^2}$ (1 hour value)	$Cmax = 1.72 \times \frac{80}{151^2} = 0.006$ ppm
$Cmax(24) = 0.59 \times Cmax$ (24 hour value)	$Cmax(24) = 0.59 \times 0.006 = 0.004$ ppm

Calculation of dust emission quantity	
° Boiler outlet dust concentration	
$q'ds = \frac{Ash \times Fod \times 10^6}{Qd}$	$q'ds = \frac{0.13 \times 28.5}{266 \times 10^3} \times 10^6 = 13.9\ g/Nm^3$
° ESP outlet dust concentration	
$qds = q'dst\ (1-q_{EP})$	$qds = 13.9 \times (1-0.9925) = 0.1\ g/Nm^3$
q_{EP} : EP efficient 99.25%	
° Dust emission quantity	
$Qd = qds \times Qd \times 10^{-3}$	$Qd = 0.1 \times 266 \times 10^3 \times 10^{-3} = 26.6\ kg/h$
° Emission ground level concentration	
$Cmax = 1.72\ \frac{Qd}{He^2}$ (1 hour value)	$Cmax = 1.72 \times \frac{26.6}{151^2} = 0.002\ mg/m^3$
$Cmax(24) = 0.59 \times Cmax$ (24 hour value)	$Cmax(24) = 0.59 \times 0.001 = 0.001$

APPENDIX II

Appendix II Prediction of the Discharged Warm Cooling Water Diffusion

1. Discharged Warm Cooling Water Diffusion and Cooling Process

The temperature of cooling water discharged from the power plant outlet into the sea is about 7°C higher than that of the original sea water, (environmental water temperature), because the sea water is heated in the course of passage through the condenser, and the density is thereby lowered, causing the discharged water to diffuse over the sea surface. The process in which the discharged warm cooling water is diffused and cooled is a complex combination of three physical phenomena, i.e., heat transfer due to the flow of discharged warm cooling water released, mixing with ambient cold seawater and heat radiation into atmosphere.

Main mixing processes on which discharged warm cooling water diffusion depends are introduction of lower layer seawater, eddy diffusion and tide mixing, magnitude of which affording the information of diffusion and mixing in the sea.

Under the calm climatic conditions without a tidal influence, consideration of the discharged warm water cooling process in the semi-infinite expansion of the sea with its front open depicts first the flow of discharged warm water released will dominate the waters around the outlet, permitting the mix-cooling as the result of vibration effect and continuous introduction of cool water from lower layers. As the distance from the outlet increases, sea water eddy becomes increasingly dominant over the flow of water released, accelerating the mix dilution, and the water temperature becomes gradually lowered. Meanwhile the heat exchange between the sea surface and adjacent atmosphere causes the cooling.

Theoretical analysis and field survey have revealed as regards the vertical influence of water temperature increase that, because horizontal heat diffusion is by far greater than vertical heat diffusion due to the density flow characteristics of the discharged warm water, the heat is delivered horizontally in the depth of about 2 - 3 m under the sea surface.

The above-cited diffusion process leads to the formation of the scope of influence of seawater temperature due to the discharged warm water, there being variations of its size and configuration with various surfacial configurations of adjacent waters and longshore currents.

2. Analytical Procedures of Diffusion Prediction

Developed by Japan Electric Power Research Center, the procedures for predicting the scope of diffusion of warm water discharged into the sea are represented by the hydrological momentum equation dictating the discharged warm cooling water flow and longshore current, the continuity equation and the thermal diffusion equation having regard to the thermal balance between the sea surface and atmosphere, taking a number of factors related thereto, i.e., marine phenomenonal conditions including discharge amount, discharge water flow rate, discharged water temperature, marine phenomenal configurations, location of outlet, water temperature mechanism of nature aspect in the waters turbulence mechanism in waters, longshore currents including tide and ebb, etc. and such climatic conditions as wind, sunshine, atmospheric temperature, humidity, etc. into consideration of above-cited basic equations so that numerical computation may be operated by means of large-sized computers.

Operating the analysis in the above procedures cited above requires the information of sea streams and turbulence characteristics so that the analysis may be operated in accordance with the diffusion characteristics in the waters for analysis.

If the waters into which cooling water is discharged is located in a bay as in the case of this site, it is believed that periodical tide stream is dominant but that meanwhile the tide stream may be moderate because of tidal difference being as minimal as 0.3 m approx. Hence the analysis operated by discharging the cooling water into still water, assuming that the waters to be analyzed is a type of still water.

3. Computation Conditions and Results

Table II-1 indicates the computation conditions. Meteorological and marine phenomenal conditions have been derived from the data of rainy season in which heat exchange observation is handicapped. Diffusion coefficient have been represented by the measurements of a bay whose conditions are similar to those of this Project site, in the absence of data from this site.

Fig13.4.2(2)indicates the computation results, which denies, the possibility of recirculation since the location of intake is outside the scope of rising temperature.

Table II-1 Computatioo Computation

Item	Conditions	Remarks
Meteorological Conditions:		
Season	Rainy season	
Mean atmospheric temperature	27°C	
Relative humidity	85%	
Marine Phenomenonal Conditions:		
Environmental water temperature	28.4°C	
Diffusion coefficient	5×10^3 cm^2/sec	
Cooling Water:		
Flow amount	8 m^3/sec	
Difference between environmental water temperature and discharged water temperature	7°C	

CHAPTER 14 COAL ASH UTILIZATION

CHAPTER 14 COAL ASH UTILIZATION

14.1 CLASSIFICATION OF COAL ASH

In case the power plant with an installed capacity of two (2) units of 75 MW is operated at an annual capacity factor of 68.5%, the quantities of ash to be produced at the power plant are estimated about 40,000 tons per year.

The coal ash is classified into three (3) categories according to its grain size and place of accumulation:

Table 14.1 Classification of Coal Ash

Category	Place of accumulation	Build up ratio (%)	Grain size
Clinker	Boiler bottom	10	0.1 - 10 mm
Cinder ash	ECO hopper	10	Ranging from bottom ash to fly ash grain size
	GRF "		
	AH "		
Fly ash	EP hopper	80	0.005 - 0.05 mm

14.2 COAL ASH UTILIZATION

At present, the coal ash is utilized in Japan and in the other industrialized countries for the following purposes.

(1) Cement Admixture

Application of fly ash which is a fine particle offers following merits when mixed into cement at the rate of 5 - 30%.

1) Workability of concrete can be improved.

2) Hydrative reaction is accelerated and hydration heat is reduced.

3) Temperature rise is controlled and drying shrinkage is reduced.

4) Long-age strength of concrete can be increased.

5) Persistence of concrete against chemical erosion, particularly acid-proofness can be increased.

6) More smoothness on finished surface and better appearance.

7) Cement economization which lowers the material cost.

Meanwhile mixing fly ash into cement induces following demerits:

1) Prolongation of concrete curing time.

2) Concrete initial strength is lowered.

3) Fluidity is increased and more AE agent is required.

(2) Raw Materials for Cement Manufacture

Cement is produced with limestone as main material, and clay, silica, gypsum, iron slag, etc.

Since coal ash contains the principal constituents same as those of clay, viz. silicon dioxide (SiO_2) and aluminium oxides (AL_2O_3), it is used by many cement manufacturers as a substitute for clay.

Fly ash, clinker ash and cinder ash may be used as a substitute for clay and in practice the latter two are dominant the industrial use.

It is necessary to add silica to fly ash since this material contains silica less than clay.

(3) Asphalt Filler

Asphalt concrete consists of asphalt, crushed stone, sand, limestone powder (filler), etc.

The filler particulate diameter is upto 0.74 mm. Asphalt concrete contains the filler about 2 - 7 wt% for improving workability, stability and durability.

Coal ash is similar to limestone powder filler in properties but has such a merit that energy is saved in production. Clinker ash is used in this field.

(4) Pavement Materials

Cinder ash is used as a substitute for sand for base and subbase materials in road construction.

14.3 COAL ASH TREATMENT FACILITIES

Coal ash utilization depends upon the demand for coal ash. At present, it is understood that no enterprises including Cement Panama have an idea of coal ash utilization.

Under the circumstances, the ash handling facilities have been designed on the basis that all coal ash be disposed. It means that the following equipment should additionally be installed if in future coal ash utilization is required.

1) Classing facilities of coal ash
2) Increase of fly ash tank capacity
3) Modification of fly ash loading facilities