CHAPTER V

HYDROPOWER DEVELOPMENT PLAN

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5.1 Project Area

5.1.1 Topography and Geology

(1) Topography

Palawan Island in which the Study area is located is long and narrow in shape with a chain of mountains, the Mantalingajan range, extending through the central portion. The highest mountain on the island is Mt. Mantalingajan (2,086m).

Rivers in and around the Project area originate in the above range. Rivers on the east side of the divide flow in a southeasterly direction into the Sulu Sea while those on the west side flow in a westerly direction into the South China Sea. As the distance from the mountain to the sea is short, river extension is likewise short and lengths of the Candawaga and Culasian rivers which flow through the Project area, are only about 19km and 17km, respectively. Due to the steep gradient in the mountain area, no large tributaries exist and the catchment area of each river is therefore small.

Profiles of the Candawaga and Culasian rivers are presented in FIG. 5-1. Of the Candawaga's total length (29km), about 21km flow through mountain area. River gradient under elevation 100m is about 1/80 while that over elevation 100m is about 1/40; however, the slope of the upstream portion is extremely steep. About 10km of the Culasian River's total 17km length flows through the mountain area; however, river gradient is estimated to be gentler than that of the Candawaga with a gradient of about 1/120 at elevations near 60m. Vegetation mainly consists of tropical rain forest while on steep mountain slopes rock outcrops, sparse woods and grassland are found.

(2) Geology

Geological conditions in the Candawaga and Culasian river basins are outlined as follows:

a) Ultra-acidic intruded rocks underlaying the Mantalingajan range form steep terrain.

b) The Project area is widely overlaid by the Panas formation which consists of sandstone and shale.

c) Alluvium forms a flood plain along the coast.

A general map of the Project area is presented in FIG. 1-1.

The intake dam is proposed at a site where riverbed level is 255m, dam height is about 13.5m and dam length is 51m. Both abutments consist of fresh hard shale, while the riverbed consists of unconsolidated sand and gravel layers 4 to 5m in depth comprised of basalt and sandstone massive rock to sand. The hard shale on both abutments is considered to form a suitably stable bedrock for the proposed intake dam in terms of both hardness and permeability.

The bedrock of the open channel, tunnel and penstock is mostly hard sandstone and shale, while in the upstream area, Irahauan Metavoleanic basalt and tuffaceous breccia are distributed. These layers are hard and fresh in the lower portion of the slope from the riverbed; in the higher portion, however, they are weathered to latelite.

Weathered CL and CM[1/] class shale or talus deposits are distributed in the proposed power station site at the mountain skirt; however, these do not require relocation of the powerhouse site. A sand and gravel layer extends between the mountainous area and flat land along the river. Sand and gravel deposits are also distributed along valleys in the mountains. The quantity of these deposits, however, are insufficient for aggregate use and, in addition, they include boulders of 100mm diameter or more. Sand and gravels in the riverbed, on the other hand, are of sufficient strength and quantity for use as concrete aggregate in dam construction.

1/ CL, CM are those from classification of rock quality in dam foundation by U.S. Standards

5.1.2 Meteorology and Hydrology

(1) Meteorology

The climate in the Philippines is greatly affected by prevailing winds, with the Northeast Monsoon from December to January, the trade winds in April and the Southwest Monsoon from July to September. According to Coronas's climatic classification, the west coast of Palawan Island where the Project area is located belongs to climatic Type I, defined as having "two pronounced seasons: dry from November to April and wet during the rest of the year".

According to observations at the Rio Tuba Mine, monthly mean temperature is 27.4°C with little fluctuation from month to month. Maximum mean monthly temperature is 28.9°C in April, and minimum mean monthly temperature is 26.4°C in August. Average annual relative humidity is 75.3% with a maximum and minimum mean monthly humidity of 81.7% in July and of 67.1% in March, respectively. Dominating wind directions are north to northeast from November to May and southwest to southeast for the rest of the year.

(2) Rainfall

Rainfall observations are concentrated in the east coast of the island with very little data available for the west side where the Project area is located. Interviews at the site and the Provincial Profile of Palawan, however, reveal that rainfall on the west coast is higher in comparison with the east coast due to the influence of the Southwest Monsoon.

Annual average rainfall at major stations in the Project area vicinity are as listed in the following table.

ANNUAL AVERAGE RAINFALL

Station	Altitude (m)	Annual Ave. Rainfall (mm)	Annual Ave. Rainy Days	Period of Calculation
Brooke's Point	10	1,559	95	1 Jan, 1975 - 31 Dec. 1984
Pier Area, Rio Tuba	0	1,635	132	- do -
Guintalunan, Rio Tuba	63	1,737	147	- do -
S. Bulanjao, Rio Tuba	610	3,794	161	1 Jan, 1983 - 31 Dec. 1984

(3) Candawaga River Discharge Conditions

Water level observations for the Candawaga River have been made by the Rio Tuba Mine since June 1984 at a site with a riverbed elevation of 60m. As the observation period is very short, however, very few discharge data have been collected and consequently discharge simulation on the basis of the same would be unreliable.

Accordingly, in consideration of available discharge data on the Tamlang River which was analysed in 1984, discharge simulation was conducted by the Tank Model Method assuming the hydrological structures of the Candawaga basin to be the same as those of the Tamlang River.

Simulated discharge for the Candawaga River was checked against discharge data recorded in April 1985 during the field survey. The estimated annual average discharge curve for 1975-84 is presented in FIG. 5-3.

(4) River Use

Irrigated paddy area in the low flat land of the Candawaga River basin is roughly estimated at 200ha on the basis of interviews and a 1/50,000 topographical map. In addition, development of a 200ha Communal Irrigation Project (CIP) in the Candawaga basin is identified under the PIADP.

Potential irrigation development area within the Candawaga basin is therefore estimated at about 400ha. An analysis revealed that there is sufficient discharge for peak irrigation requirement in the basin downstream of the intake for power generation proposed under the present Project.

5.2 Optimum Development Plan

5.2.1 Basic Development Approach

As discussed in CHAPTER I, an economical energy source is essential for the proposed segregation plant plan of the Rio Tuba Mine. A combination of diesel generation and low cost hydropower obtained from the mountains in the Rio Tuba Mine vicinity is envisioned as the most practical supply plan.

River gradient of the Candawaga River ranges from 1/31 to 1/1,000 in the Project area and is particularly steep in the upstream portion at the proposed intake site with a gradient of 1/31 to 1/40 (FIG. 5-1). The storage capacity of a reservoir type dam would accordingly be small and therefore such a plan might be uneconomical. Accordingly, run-of-river type rather than reservoir type hydropower generation must be employed at this site.

The discharge of the Candawaga River and available head are insufficient to provide the constant output of 8,500kW required for the segregation plant. Combined use of the new deisel generators planned by the Rio Tuba Mine is therefore a necessary prerequisite of the Candawaga hydropower development plan. In this case accordingly, hydropower is not an alternative energy source to diesel generation but rather a means of reducing diesel fuel costs.

As the objective of the proposed hydropower development is reduction of diesel fuel costs, benefit is regarded as the kWh value of the proposed diesel generation for the segregation plant. This value, multiplied by annual generated energy from the proposed hydropower, is considered as benefit. Optimum development scale has been determined on the basis of the difference in annual benefit and cost (B-C).

5.2.2 Determination of kW and kWh Values for Diesel Generation

Only the kWh value, among the kW value obtained mainly from fixed cost (5,000kW x 3) and kWh value obtained from variable cost (fuel) for the diesel generation plan as discussed in section 5.2.1, is regarded as effective benefit in evaluation of optimum scale for the Candawaga hydropower development plan. Projected output of proposed hydropower during dry season is only about 13% of that in the rainy season and the remaining 87% must be supplemented by diesel generation. The kW value was not considered in evaluation as installed capacity of diesel generation can not be reduced.

Main features of the proposed Rio Tuba Mine diesel generators and KW and kWh costs as of March 1985 are outlined below. As calculations for kW and kWh values are presented in TABLE 5-1, obtained kWh value is ¥14.86/kWh.

a) Main Features of Diesel Generators

Capacity: 5,000kW x 3 units
V-type, 16 cylinder, 720rpm

Fuel Consumption: Bunker C, 9,660kcal/kg, 193g/kWh

Operation Conditions: 2 regular units, 1 stand-by unit
24-hour operation

Periodic Inspection: every 3,000 operation hours
(inspection period: 30 days)

b) Total Construction Cost: ¥1.2 billion

c) Depreciation: 17-year period, fixed installment method,
10% residual value

d) Interest: 8%

e) Unit Fuel Price: ¥71.01/ℓ (Bunker C ₱4.9076/ℓ,
₱1 = ¥13.573)

f) kW & kWh Unit Price: ¥10,940/kW, ¥14.86/kWh

5.2.3 Optimum Development Plan

(1) Selection of Intake Dam and Powerhouse Sites

Three alternative intake sites in the upstream Candawaga River were selected on the basis of catchment area, topography and geology as determined through field survey results. Respective elevations of the intake dam sites and corresponding intake water level are I_1-280m, I_2-260m and I3-235m. In consideration of river gradient and intake route, four alternative hydropower sites were identified. Two of these sites are on the Candawaga River with tailrace water levels of P_1-72m and P_2-101m. The remaining two are located on the Culasian River, assuming possible trans-diversion from the Candawaga River to obtain greater head, and their respective tailrace water levels are P_3-63m and P_4-79m. The locations of the above sites are presented in FIG. 5-4.

The economic feasibility of the above 3 alternative intake dam sites combined with the 4 alternative powerhouse sites were compared on the basis of maximum discharge designated at 3.85m^3/s. A maximum discharge of 3.85m^3/s is equivalent to a 90-day discharge taken from a 10-year average in the case of I_1 (intake level: 280m), a 95-day discharge in the case of I_2 (intake level: 260m) and a 110-day discharge in the case of I_3 (intake level: 235m). Minimum flow at each intake site ranges from 0.56-0.61m^3/s which is only about 15% of the maximum 3.85m^3/s discharge. Accordingly, to allow power generation even at minimum flow, two wide range efficiency turbines are proposed. Construction cost estimates are based on prices, labor wages, machinery costs, and equipment and materials cost as of March, 1985.

Results of comparative analysis are presented in TABLE 5-2. Alternative intake dam I_2 (intake level: 260m) and alternative hydropower site P_3 (tailrace water level: 63m) was selected as the most economical combination, with a maximum output of 6,000kW. If only alternative powerhouse sites on the Candawaga River are considered, a combination of I_1 (intake level: 280m) and P_2 (tailrace water level: 101m) is most economical; however, this combination is inferior when compared with diversion to the Culasian River as in combination I_2 and P_3.

(2) Determination of Maximum Discharge

Economic evaluation was undertaken for 5 variations of discharge - 3.5, 3.7, 3.85, 4.1 and 4.3m^3/s (5,450-6,710kW) for the selected optimum economical plan of 260m Candawaga River intake and

63m Culasian River tailrace. The same evaluation was also conducted for the 280m Candawaga River intake and 101m Candawaga River tailrace combination. The results of analysis are presented in TABLE 5-3 and FIG. 5-5 and 5-6.

As can be seen from the said figures, the kWh construction cost, B/C and B-C are all most economical when maximum discharge is $3.85m^3/s$.

(3) Main Features of the Optimum Plan

As a result of the above intake and powerhouse site optimization and power generation scale study, construction of an intake dam on the Candawaga River is proposed at an intake elevation of EL.260m, with diversion to the Culasian River via a 7.7km canal and with a tailrace water level of EL.63m. Maximum discharge is designated at $3.85m^3/s$, effective head at 185.1m, and maximum output at 6,000kW. Annual energy was estimated at 32.1GWh based on the average of daily energy over the 10-year period from 1975-84. Monthly generated energy for each year is tabulated in TABLE 5-4.

Construction cost required for the plan was calculated at ¥3.95 billion including interest during construction based on unit prices as of March 1985. Generated energy at the Rio Tuba Mine which will be substituted by the proposed hydropower is 29.0GWh/year in consideration of transmission loss, etc., and the corresponding fuel cost (¥14.86/kWh) at present is ¥430.9 million/year. Hydropower cost on the other hand, is ¥399.9 million/year and the difference in these two costs, ¥31.0 million/year, represents the savings obtained through use of hydropower. An outline of the development plan is presented hereunder.

Main Features of the Proposed Plan

Intake Site	Candawaga River
Power Station Site	Along the Culasian River
Location	Culasian River
Catchment Area	30.8km^2
Power Plant Scheme	
Generation Method	Run-of-River Type
Intake Water Level	280m
Tailrace Water Level	63m
Gross Head	197m
Maximum Output	6,000kW
Maximum Discharge	3.85m^3/s
Effective head	185.1m
Minimum Output	780kW
Annual Generated Energy	32.1GWh (10-year average) 29.0GWh at Rio-Tuba Mine
Outline of Facilities	
Intake Dam	
Type	Concrete gravity
Height x Crest Length	13.5m x 51m
Waterway Length	
Open Channel	7,400m
Tunnel	300m
Penstock Line	552m (ϕ1,650-620mm)
Powerhouse	3,000kW x 2 units; (Horizontal Shaft Francis Turbine)
Transmission Line	length: 38km; 69kV
Substation	2 units
Access Road	9,500m
Connection Road	2,800m
Cost and Benefit	
Construction Cost	¥3,950 million
Construction Cost per kWh	¥123.1/kWh
Benefit/Cost Ratio	¥1.078/kWh (Annual Cost Rate: 10.13%)
Benefit - Cost	¥31.1 million

With the alternative Candawaga River tailrace plan (intake level: 280m; tailrace water level: 101m) which took into consideration a possible irrigation plan in the downstream Candawaga River, an annual energy of 28.8GWh is obtained with a maximum discharge of 3.85m^3/s, an effective head of 168.8m and maximum output of 5,470kW. Construction cost for this plan is ¥4,051 billion and hydropower can replace 26.0GWh/year of energy presently provided by diesel at a cost of ¥387 million/year in diesel fuel. This represents a saving of ¥-23.4 million in fuel costs and original cost of energy with hydropower is ¥15.76/kWh. In comparison with the proposed plan, this latter plan is thus less favorable in terms of cost and fuel savings. Features of the plan are as presented in TABLE 5-5.

With diversion from the Candawaga to the Culasian River, as proposed in the selected plan, river flow in the Candawaga River lower stream will be reduced. As the resultant reduction in water level could adversely affect irrigation, diversion walls will be installed in the riverbed at irrigation intake sites to maintain intake level. Moreover, as the irrigated area in the Candawaga River plain, even with agricultural development, is only about 400ha, downstream flow beyond the hydropower intake point for diversion is judged to be sufficient for irrigation needs.

5.3 Transmission Line and Substation

(1) Transmission Plan

The transmission line from the proposed hydropower plant on the Culasian River to the Rio Tuba Mine was planned in consideration of the following.

a) Minimal transmission loss and economy in design of transmission line, poles, etc. and in selection of voltage.

b) Minimum possible length of transmission line.

c) Minimization of road and river crossings.

d) Ease of access for transport and maintenance of materials and equipment during the construction period.

In consideration of the above factors, voltage was designated at 69kV and the transmission line route was planned as shown in the GENERAL PLAN. The transmission line is 38km, about 3km of which follow along the Culasian River from the powerhouse. The line then runs southwards and the distance from the powerhouse to sandval is about 24km. The route passes through mixed forest and is predominantly level land except for a few undulations.

(2) Rio Tuba Mine Substation Plan

A conventional type outdoor substation will be set-up near the new diesel powerhouse to link the transmission line from the hydropower plant to the proposed Rio Tuba Mine electrical network.

At the substation transmission voltage of 69kV will be reduced to 4.16kV, the voltage of the diesel generator bus line. Accordingly, a 6,600kVA, 3-phase transformer will be installed. Vacuum breakers will be used for both 69kV and 4.16kV to reduce maintenance. An indoor metal clad type for the 4.16kV side will be installed in the proposed diesel powerhouse distribution switchboard room with the control panel. The energy source will be the same as that for the proposed diesel generators.

(3) PALECO Connection Plan

Under the proposed plan, 1,127kW is to be supplied to PALECO for domestic use in the first project year (1989), increasing gradually thereafter to 2,100kW after 5 years. For this purpose, construction of a substation is planned in Sandoval, Bataranza Municipality, where voltage will be reduced to 34.5kV and distributed to PALECO. As PALECO is responsible for construction of residential transmission lines, the same have been excluded from the Project.

(4) Power Distribution Plan for Vicinity Area of the Project Site

A 13.2kV distribution line will be constructed at Culasian and Candawaga (Marcos Municipality) to supply electricity for domestic use. The distribution line will follow along the Culasian river from the powerhouse to Culasian and then extend about 13km to

Candawaga. The wooden poles which are proposed for the 69kV transmission line will also be used for the 13.2kV distribution line for several kilometers from the powerhouse.

CHAPTER VI

CONSTRUCTION SCHEDULE AND COST ESTIMATES

CHAPTER VI

CONSTRUCTION SCHEDULE AND COST ESTIMATES

6.1 Main Structures and Facilities

Civil structures and electric facilities required for the Project are as outlined below. Preliminary design drawings for these structures and facilities are presented at the end of this report.

(1) Main Structure

1) Intake Dam

Intake Water Level: EL. 260m

Type & dimension: Concrete gravity
Height: 13.5m, Length: 51m

Overflow section: Design discharge: 610m^3/s
Overflow crest length: 40.0m
Overflow water depth: 3.5m

Intake: Max. intake discharge: 3.85m^3/s
Entrance width: 4.4m
Check gate width: 1.5m
height: 1.7m

Settling basin: Length: 22.5m
Effective width: 7.8m
Effective water depth: 1.65m

2) Head Race

Type & length: Open canal: 7,400m, Tunnel: 300m
Slope: 1/1,000

Open canal section: Concrete flume: 1.5m, Height: 1.95m

Tunnel section: Rectangular horseshoe type
Height: 2.5m, Width: 2.0m

O&M Road: Effective width: 4.0m

3) Head Tank

Dimension: Width: 5m, Effective water depth: 2m
Length: 231m

4) Penstock

Dimension: Diameter: ϕ1.65m - ϕ0.62m
Length: 552m (FRPM: 472m, Steel: 80m)

5) Powerhouse

Dimension: Width: 10m, Length: 22m, Height: 8m

(2) Main Electric Facilities

1) Turbine

Type & number:	Horizontal shaft Francis type; 2 units
Maximum output:	3,110kW
Maximum discharge:	1.925m^3/s each.
Rated speed:	1,200 rpm
Governor closing speed:	6 sec.

2) Generator

Type & number:	Horizontal shaft three-phase synchronous type; 2 units
Maximum output:	3,320 kVA
Voltage:	4,160V
Power factor:	90%
Frequency:	60Hz

3) Main Transformer

Type & number:	Outdoor type three-phase oil-immersed self-cooled type; 2 units
Rated capacity:	6,600kVA
Rated voltage:	4.16/69 $\pm$5% kV

4) PALECO Connection Transformer

Type & number:	Outdoor three-phase oil-immersed Self-cooled type; 1 unit
Rated capacity:	2,200kVA
Rated voltage:	69 $\pm$ 5%/34.5kV

5) Transmission Line

Transmission voltage: 69kVA

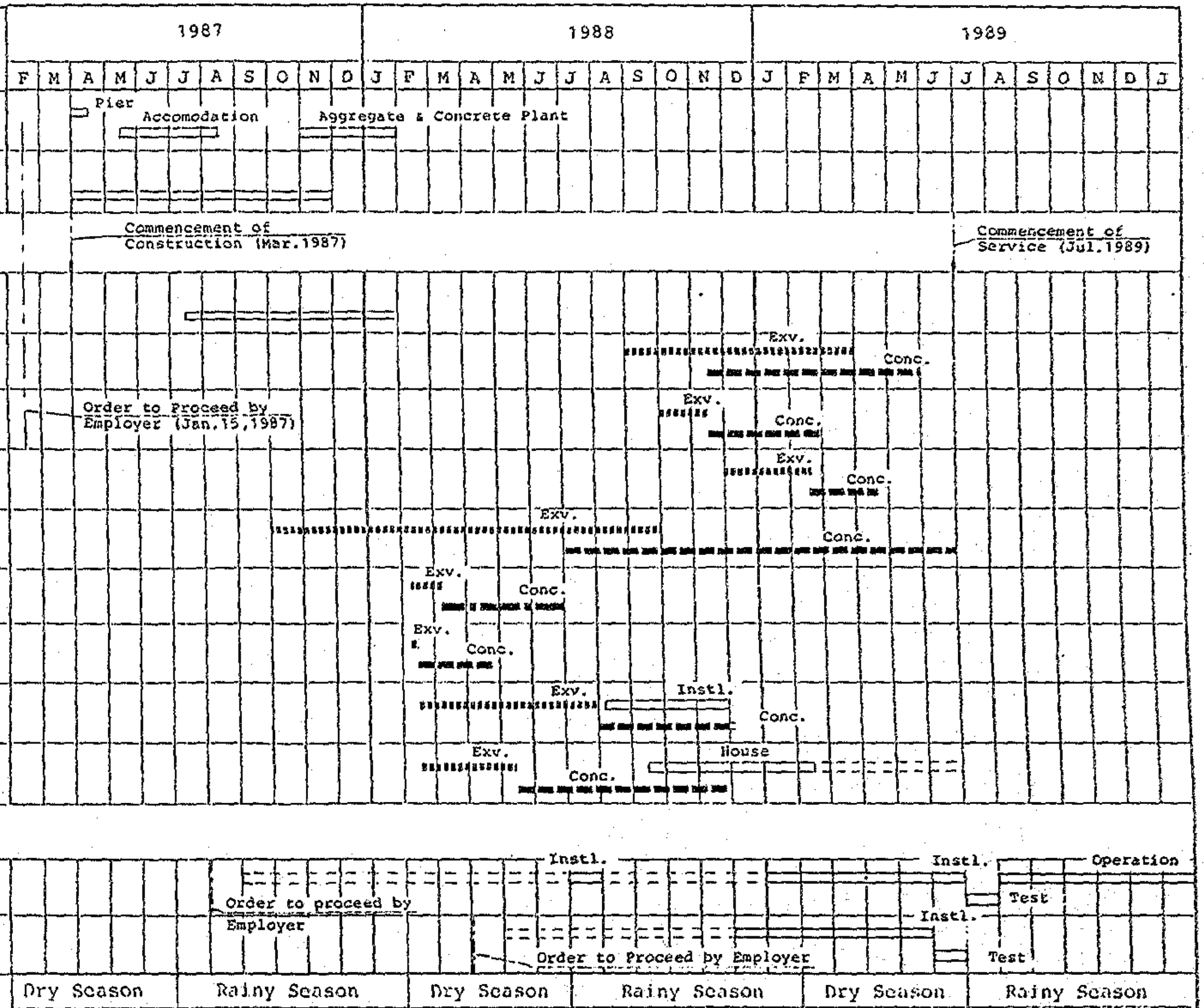
Length:	38km
Channel:	1
Electric wire:	Aluminum cable steel reinforced (ACSR) 110.8MCM (56.14mm^2)
Overhead grounding wire:	Zinc-coated steel cable AWG2 (33.62mm^2)
Insulator:	250mm chinning insultator 5 pieces
Support:	Wooden pole

6.2 Construction Schedule

The proposed construction schedule is shown on the next page.

CONSTRUCTION SCHEDULE

ITEM	QUANTITY
PREPARATORY WORKS & TEMPORARY FACILITIES	
ACCESS ROAD	9,500 m
CIVIL WORKS	
CONNECTION ROAD	3,300 m
INTAKE DAM	Exv. 11,900 m³ Conc. 5,000 m³
INTAKE	Exv. 2,000 m³ Conc. 900 m³
SETTLING BASIN	Exv. 3,000 m³ Conc. 640 m³
HEADRACE	7,680 m Exv. 125,000 m³ Conc. 12,800 m³
HEADTANK	Exv. 11,000 m³ Conc. 4,600 m³
SPILLWAY	Exv. 1,000 m³ Conc. 600 m³
PENSTOCK	Exv. 6,600 m³ Conc. 460 m³ Instl. 552 m
POWERHOUSE	Exv. 8,700 m³ Conc. 2,100 m³ House 3,300 m³
ELECTRO-MECHANICAL WORKS	
TURBINE & GENERATOR	3,000kW 2 units
TRANSMISSION LINE & SUBSTATION	69 kVx1 cct 38 km
REMARKS	



NOTE; Excavation
Concrete
Other Works

Exv. : Excavation
Conc. : Concrete works
Instl. : Installation

6.3 Construction Cost

(1) Basic Considerations

Construction Cost has been estimated based on the following basic considerations.

1) Cost estimation has been conducted considering such factors as construction schedule, natural conditions of the Project area, construction scale and technical level of construction.

2) Costs include the following items:

   - Direct cost for civil structures such as intake dam, headrace and powerhouse and electro-mechanical facilities including the transmission line and related substation facilities and miscellaneous works including temporary works
   - Land acquisition and compensation costs
   - Administration cost including engineering services
   - Physical contingency
   - Interest during construction

3) Volume of construction works was estimated based on preliminary design drawings.

4) Main civil and electro-mechanical equipment and main construction material will be imported while construction equipment will be that existent in the Philippines.

5) All equipment for power generation, transmission line and substation will be designed and manufactured overseas.

6) Unit cost for construction was based on unit costs as of 31 March 1985 in the Philippines and Japan. The exchange rate is ₱1 = ¥13.573.

7) Administration cost includes costs for detailed field surveys, detailed design, temporary works for administration and construction supervision.

8) Physical contingency cost has been calculated at 10% against direct cost plus land aquisition and compensation.

9) Interest during the construction period was calculated on the basis of construction and disbursement schedules.

(2) Construction Cost

Unit: ¥million

1. Civil Works	1,922.3
(1) Intake dam	179.0
(2) Intake	48.2
(3) Settling basin	37.0
(4) Headrace	828.6
(5) Head tank (incl. spillway)	255.3
(6) Penstock	137.3
(7) Powerhouse (house, basement)	192.6
(8) Miscellaneous works (incl. temporary works)	244.3
2. Electro-mechanical Facilities	811.3
(1) Power equipment (turbine, generator, transformer, etc.)	555.4
(2) Rio Tuba side substation	103.8
(3) Transmission line (incl. distribution line to Candawaga & Culasian)	152.1
3. Land Acquisition and Compensation	41.8
4. Administration (incl. engineering service fee)	589.2
5. Physical Contingency	325.4
6. Interest during Construction Period	260.0
Total	3,950.0

6.4 Disbursement Schedule

Disbursement schedule of construction cost is as tabulated below.

(million yen)

Item \ Year	1986	1987	1988	1989	Total
Civil Works	0	426.9	932.2	563.2	1,922.3
Electro-mechanical Facilities	0	52.7	442.4	316.2	811.3
Land Acquisition and Compensation	0	25.8	0	16.0	41.8
Administration	132.0	237.0	124.4	95.8	589.2
Physical Contingency	0	68.6	68.0	188.8	325.4
Interest during Construction	0	0	0	260.0	260.0
Total	132	811	1,567	1,440	3,950

Construction cost of the alternative Candawaga River power station scheme is shown in TABLE 6-1. As shown in the table, total construction cost has been estimated at ¥4,051 million.

CHAPTER VII

ENERGY COST

CHAPTER VII

ENERGY COST

7.1 Hydropower

Energy cost for the proposed hydropower plant under the Project was estimated as kWh cost at the Rio Tuba Mine supplying point in order to compare the proposed diesel generation for the segregation plant. The kWh cost was calculated from annual cost divided by annual supplied energy. Annual cost for hydropower is defined as the sum of the following annual costs: interest, depreciation, property tax, personnel expenses, maintenance cost, miscellaneous cost and management cost. Annual energy, on the other hand, is defined as the annual energy supplied at Rio Tuba Mine which is calculated from annual generated energy subtracting shutdown loss, transmission and transformer losses and auxiliary use.

Basic considerations for calculation of these items are presented below:

(1) Total construction cost for the Project is ¥3.95 billion.

(2) Interest is 5.9%. Of the total power plant output (6,000kW), the domestic supply portion (2,100kW) will be funded by JICA at an interest rate of 2%. The remainder is to be funded by other financing agencies at an interest rate of 8%.

(3) Depreciation is a fixed amount of 2% of construction cost. Although there is some variation in the depreciation period for each facility, depreciation is assumed at 45 years with residual value at 10%.

(4) Property tax is 2.5% for 55% of the book value in the Philippine tax system. Under the Philippine tax system, pioneer ventures in high priority investment fields are exempted from or allowed reductions on all taxes except for business tax. For this Project, a 10% reduction is considered for the 4-year period from 1989 to 1991 which is equivalent to the 13th to 15th year after mine operation commencement.

(5) Personnel expenses are ¥11.43 million and number of staff is the same as that required for maintenance of existing Rio Tuba Mine diesel generators.

(6) Maintenance is 0.4% of construction costs and includes cost of facility maintenance, materials and parts, and contract work.

(7) Miscellaneous costs are 0.1% of construction costs including miscellaneous costs for operation and maintenance such as wear and tear expenses, rent, and damage insurance.

(8) Management costs are equivalent to 8% of total personnel expenses, repair costs and other costs and are the burden share of management expenses for the Rio Tuba Mine and Rio Tuba Mining Corp.

(9) Electric energy is designated at 29,020MWh in consideration of transmission loss, electricity for auxiliary use, transformer loss and shutdown ratio.

Energy cost of each year of the 45-year project life is presented in TABLE 7-1 under the Fixed Unit Cost column and in FIG. 7-1. As shown in the table, energy cost reduces year by year with ¥13.61/kWh in the first year, ¥12.01/kWh in the tenth year, ¥10.03/kWh in the twentieth year and ¥5.07/kWh in the final year. Capital recovery cost which is presented in the table is the equalized energy cost for certain periods calculated by discounting the fixed unit cost to the present for each year by a 5.6% interest rate value, totalling the same and then multiplying by the capital recovery factor.

Capital recovery costs for the proposed hydropower plan are summarized below:

i) 1st year : ¥13.61/kWh

ii) 17-year equalized cost
(17-year life of diesel generator) : ¥12.43/kWh

iii) 45-year equalized cost
(45-year life of hydropower facilities): ¥11.14/kWh

Annual cost for a 45-year useful life is ¥11.14/kWh.

7.2 Diesel Generation

The power generation cost for the proposed diesel power plant (5,000kW x 3units) of the Rio Tuba Mine was calculated according to the conditions delineated below. Annual energy for this case was calculated at 72,600MWh on the basis of a 8,500kW flat generation throughout the year and subtracting auxiliary use (3%). Accordingly, fixed cost is against 3 units of 5,000kW and variable cost is the cost for year-round 8,500kW flat generation. In this case, hydropower generation is not considered.

(1) Total construction cost is ¥1.2 billion.

(2) Interest is 8%.

(3) Depreciation is a fixed rate of 5.3% of construction cost. The residual value of facilities after the 17-year life planned by the Rio Tuba mine is 10%.

(4) Property tax is 2.5% for 95% of book value. Property tax for the 11th to 12th years after the commencement of mine operation and for the 13th to 15th years are to be reduced 20% and 10%, respectively.

(5) Personnel expenses are ¥16 million. In consideration of the larger sized diesel facilities to be installed as compared with present facilities, the present number of O&M staff is increased 40%.

(6) Cost of repairs is 2.09% of construction costs.

(7) Other costs are 0.1% of construction costs.

(8) Management costs are considered to be 8% of total personnel expenses, repair costs and other costs.

(9) Electric energy is 72,600MWh and, in consideration of auxiliary use, etc., can be used for the segregation plant.

(10) Fuel cost in the first year, 1985, is ¥71.01/ℓ. This includes the price of Bunker C oil (₱4.9076/ℓ including ¥66.01/ℓ for transportation costs) presently used at the Rio Tuba Mine, plus

lubricating oil and diesel oil. Annual escalation rate at 1.3% for oil price was adopted.

(11) Variable cost (fuel cost) is calculated by multiplying Bunker C consumption of 0.204ℓ/kWh (193kg/kWh) by the above fuel cost.

(12) Facility replacement will take place every 17 years.

The power generation cost for each year of a 45-year period calculated in accordance with the above conditions, and annual equalized power generation cost are presented in TABLE 7-2 and FIG. 7-1. In order to compare diesel generation with generation costs for hydropower, generation costs were calculated for a 45-year period considering replacement costs for every 17-year period. A summary of the results is presented below.

	Generation Cost (¥/kWh)	Capital Recovery Cost (¥kWh)
i) 1st year	18.67	18.67
ii) 17th year	20.81	19.45
iii) 45th year	29.65	20.68

Residual value of diesel generators as of the 45th year is 41.7% of initial investment value.

7.3 Combination of Hydropower and Diesel Generation

Energy cost has been calculated for a case in which energy for both the segregation plant at the Rio Tuba Mine and domestic use under PALECO is supplied by a combination of hydropower and diesel generation. In this case, the cost is calculated at the Sandoval substation point for a 45-year period from August 1, 1989 when commencement of hydropower generation is planned. Energy demand is as presented in the following table.

Demand Source	Annual Demand (MWh)	Aug. to Dec., 1989 (MWh)
i) Rio Tuba	72,600	(29,027)
ii) Domestic Use	6,420 (after 1993)	(2,633)

Annual energy supply from 1989-93 increases year by year as domestic demand is not fully accrued against supply capacity. Annual supply for each year is as presented in the following table and details are shown in TABLE 4-10.

Year	Diesel Supply (MWh)	Hydropower Supply (MWh)	Total Supply (MWh)
1989	14,570	17,090	31,660
90	47,660	29,020	76,680
91	48,430	29,020	77,450
92	49,270	29,020	78,290
93	50,000	29,020	79,020
after 1994	- do -	- do -	- do -

Diesel generation cost was calculated after modification of certain items in 7.2 as follows:

(1) Depreciation Period of Diesel Generator

As the operation time per generator is about 32% shorter in comparison with diesel generation alone, a 19-year depreciation period was adopted against the 17-year diesel generator life. The residual value is 10% after a 19-year period.

(2) Facility Replacement

Replacement will take place every 19 years on the basis of the above item(1), and residual value for the diesel facilities in the 45th year is consequently 66.8% of the initial investment.

Diesel generation costs for a 45-year period calculated according to the above conditions are presented in TABLE 7-3. Power generation cost for the combination of hydropower and diesel generation was also calculated.

(3) Personnel, Repairs and Miscellaneous Expenses

These costs are determined at 85% of diesel generation alone in consideration of facility operating hours.

(4) Diesel Fuel Cost

A proportional increase due to load factor was considered in fuel costs for diesel generation.

Power generation costs for the combination of hydropower and diesel generation for a 45-year period calculated according to the above conditions and annual generation cost are presented in TABLE 7-4 and FIG. 7-1. The results are summarized in the table below.

	Generation Cost (¥/kWh)	Capital Recovery Cost (¥kWh)
i) 1st year	16.47	16.47
ii) 19th year	17.99	17.87
iii) 45th year	22.09	18.16

7.4 Unit Price of Electricity Sold to PALECO

As mentioned in Section 4.4, the Rio Tuba Mine intends to supply electricity to PALECO at an appropriate rate to supplement residential demand which cannot be fulfilled by hydropower alone. Long-term supply at a stable rate would also contribute to efficient PALECO management. Accordingly, the unit rate for electricity sold to PALECO is designated at ¥17.87/kWh, which is the annual cost for a 19-year period with combined hydropower and diesel generation as studied in Section 7.3.

Transmission lines must be constructed by PALECO for distribution of electricity supplied from the Sandoval substation (Bataranza Municipality) to Brooke's Point and the northern area. In addition substations are required in several other locations. Cost for these facilities is estimated at ¥215 million, while annual maintenance costs for a 19-year period were estimated at ¥6.40/kWh. Accordingly, total cost entailed in supply of electricity from the Rio Tuba Mine to PALECO is ¥24.27/kWh. As discussed in Section 2.2.2, PALECO power generation cost in 1984 was ¥35.95/kWh and therefore this rate will provide long-term benefits to PALECO management.

CHAPTER VIII

FINANCIAL ANALYSIS

CHAPTER VIII

FINANCIAL ANALYSIS

8.1 Basic Considerations

(1) Monetary Unit

Generally, the local currency (peso) or the US dollar (foreign currency) are used in cost estimates of project evaluation. However, in the case of both financial and economic analysis in this report, the Japanese yen has been adopted for several reasons. First the implementing agency is planning to carry out the Project as a prerequisite for a future Japanese loan. Second, as mentioned in CHAPTER II, the Philippines presently suffers from a high inflation rate and consequently substantial adjustments are required if the peso is used in cost estimates. The Japanese yen, on the other hand, will not be as greatly affected by inflation rates and was therefore adopted in estimates.

(2) Special Features of Cost and Benefit

As the objective of financial analysis is to study the internal rate of return of the project from the standpoint of the implementing agency, expenditures required for construction and operation and maintenance are regarded as project cost while income obtained after commencement of operation is regarded as project benefit.

Power projects are commonly implemented by the government or public corporations. Initial investment such as that for dams, power plant, transmission lines and substation facilities as well as operation and maintenance costs (hereinafter referred to as O&M costs) is usually regarded as expenditure, while revenues from sale of electricity are generally regarded as benefit. Under the present Project however, the majority of electricity generated will be consumed by the Rio Tuba Mining Corp., a private enterprise, while a limited portion will be supplied for domestic use. Although revenue is obtained from sale of electricity for domestic supply, income is not obtained from power supply to the nickel segregation plant; on the contrary, the latter is considered as one item of mine operation costs.

In comparison with alternative energy sources, hydropower generation generally requires a relatively larger construction cost but a very low O&M cost. As discussed in CHAPTER VII, hydropower generation under the Project was similarly superior as compared to the second best alternative, diesel generation, in terms of low O&M cost and in consideration of the unstable diesel fuel supply and the rising trend in diesel fuel prices. Accordingly, benefit for the Rio Tuba Mine with construction and operation of a hydropower plant to supplement diesel power is the consequent savings in O&M cost as compared with use of diesel power alone.

Cost on the other hand, would be the difference between added investment cost with combined use of hydropower and diesel generation, and that for diesel generation alone. If it is limited to the initial investment, the difference between the two cases is equivalent to the cost of hydropower facilities. Cost for replacement of facilities, when viewed from the perspective of cash flow, varies, in some years showing negative cost as the period for replacement of generators and other equipment varies with each alternative. Negative cost represents investment avoided as a result of hydropower plant construction and should therefore be regarded as one kind of benefit.

(3) Determination of Project Life

Project life for hydropower generation is usually about 50 years; however, as this Project will be implemented as one part of mine operation at the Rio Tuba Mine, project life was determined to be equivalent to the life of mine operation. If mine operation ceases in 10 years, the value of hydropower facilities to the implementing agency equals the savings in O&M cost, the revenue from the sale of electric supply over the 10-year period and the residual value of the facilities in their tenth year.

Development potential of Rio Tuba Mine nickel reserves in 1983, even if restricted solely to the high quality Guintalunan mining area is 23 million WMT and if the present annual production of 500,000 DMT is assumed to continue, potential mine operation is almost 45 years. Moreover, with installation of the proposed nickel segregation plant, local segregation of lower grade nickel is envisioned to expand the mine development area.

For the above reasons, and on the basis of the life of various equipment, project life was determined to be 45 years commencing from completion of construction.

8.2 Benefit Estimates

As stated above, revenue from sale of electricity is regarded as domestic supply benefit, while Rio Tuba Mine benefit is regarded as the difference between O&M cost for diesel generation alone and that for combined use of diesel and hydropower generation. Details of benefit for each item are discussed hereunder.

(1) Electricity Sales Revenue

Power generation and electric supply in most parts of the world are usually managed by public enterprises or government run electric companies. Excluding Japan and a few other countries such as China, such public power corporations generally determine electric rates according to Long-Run Marginal Costs (LRMC). The objective of this method is optimum allocation of resources from the perspective of the national economy.

In Japan on the other hand, electric rates are determined by the Accounting System, which focuses on recovery of invested capital, including that of past as well as present investments. In the past all nations employed this method; however, recently the LRMC method has become more widely used.

However, as a portion of privately generated electricity is to be supplied for domestic use under the Project, the accounting system, assuming that users would bear the cost of electricity, was adopted for electric rate determination. The adopted system rate of ¥17.87/kWh for sale of energy to PALECO which was determined as in 7.3 & 7.4 is relatively inexpensive compared to PALECO's present unit generation cost of ¥35.95/kWh even in consideration of costs for the transmission line and other items (¥6.40/kWh) required for supply from the Rio Tuba Mine. The Project is therefore expected to contribute to reduction of present PALECO deficits.

A business tax on Rio Tuba Mining Corp. income from sales of electricity may be imposed. Moreover, a corporate tax on overall revenues and profits from mining and segregation operations is envisioned. If such taxes are imposed on energy income, it will be necessary to make allowances for taxes on the above system rate. However, as the tax portion of the rate is regarded as future expenditure, it may be disregarded in cost estimates for financial evaluation. Accordingly, revenue from sales of electricity will be regarded as income after tax.

(2) Savings in O&M Costs

Savings in O&M costs mainly consist of the value of diesel fuel which will be saved through combination of hydropower and diesel generation. According to the World Bank (WB/IFC) long term forecast, the price of oil related energy in 1983 fixed prices will decline for a short period, rising again to the present level in 1990[1/]. From 1990 to 1995 annual average price increase is projected at 12.3%. The annual average energy related price increase for the ten year forecast period (1985-95) is 2.1% versus an annual average rate of only 0.8% for other general prices.

The annual rate of increase for energy related prices is thus 1.3% which is higher than that for other general prices. In financial analysis, when prices of certain goods or services are projected by a reliable source to increase noticeably in comparison with other prices, the designated prices (but only those prices) are generally escalated in cost estimates. The World Bank forecasts are often used as the most reliable source, and 1.3% annual escalation of oil related energy prices is adopted in this report.

The short-term price decline projected by the World Bank is now occurring and world supply and demand balance has deteriorated

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1/ Half-Yearly Revision of Commodity Price Forecasts and Quarterly Review of Commodity Markets for Dec. 1984, World Bank, January 1985, p2-26.

while the price of energy related items is tending to decline. In addition, worldwide energy conservation efforts are expected to continue and if oil producing countries which attempted to limit oil production by OPEC pacts, etc., begin to increase production for financial reasons, an increase in oil prices is not envisioned for a long-term period. Taking this possibility into consideration, the case in which the price of oil related items is assumed to increase at the same rate as others is evaluated in the section of sensitivity analysis (8.5).

The difference of O&M costs other than diesel fuel cost, which consists of repairs, tax (fixed property tax) and labor, are greater in the case of combined use than in that of diesel generation alone. Consequently, the difference shows negative value as opposed to savings in diesel fuel. This negative difference in price is therefore regarded as cost.

8.3 Cost Estimates

As mentioned previously, the difference in O&M cost between the two cases (combined use of hydropower and diesel generation and use of diesel generation alone) and income from sale of electricity were adopted as project benefits. Cost, therefore, is designated as the difference in construction and equipment replacement costs for the two cases. As the diesel facilities themselves are the same in initial investment price for both cases, a difference only occurs in the year of required replacement.

(1) Construction Costs

Construction costs were estimated using fixed prices as of March 1985 with reference to market prices at the time of the feasibility study. As these are fixed prices, inflation in both Japan and the Philippines is not accounted for and thus the results are different from actual costs at commencement or completion of construction.

Although about 20% of construction costs consist of equipment and materials imported from Japan, the Rio Tuba Mining Corp. is classified as an export oriented enterprise in the Philippines and in accordance with Presidential Decree No. 1789, equipment imported for the Project is exempted from customs duties. Such duties have therefore been excluded from estimates of imported equipment and materials.

(2) Replacement Costs

All hydropower facilities such as intake dam, canal, generator, and transmission line are assumed to be depreciated during the 45-year project life, and residual value in the last year of project implementation is designated at 10% of initial investment cost. Replacement of diesel facilities for combined generation is estimated to occur every 19 years and residual value in the nineteenth year is estimated as 10% of the original value. Thus replacement cost for facilities is assumed to total 90% of the original value on the cash flow chart. Similarly, replacement of diesel facilities for diesel generation alone is estimated to occur every 17 years and replacement cost is assumed to be the original value of the equipment minus the 10% residual value.

In either case, the fixed installment depreciation method was adopted for the last facilities installed and residual values were calculated for the final project year. However, although these residual values appear in the cost column under the cash flow, the values are negative costs and should clearly be considered as benefits as are negative costs arising from different replacement periods (Section 8.2).

8.4 Financial Internal Rate of Return (FIRR) and Sensitivity Analysis

Based on the above conditions, the FIRR was calculated at 10.55% (Case 1 as attached at the end of this Chapter). Moreover, FIRR for the combination of hydropower and diesel generation is 10.66% (Case 2 as attached) where total energy is assumed to be consumed by the Rio Tuba Mine for internal use and none is supplied for residential use.

Sensitivity analysis was conducted for the following cases, and cash flow statements are presented in TABLE 8-1 to 8-13.

(1) Fluctuation in Initial Investment Cost (but not including fluctuations in fixed property tax and residual value)

a) When total investment amount rises 5% due to certain primary factors excluding inflation, FIRR is 10.11%.

b) When total investment amount rises 15% with the same condition as above, FIRR equals 9.32%.

c) When total investment amount is 5% less than expected because contingencies are much less than estimates or due to other factors, FIRR equals 11.04%. (Cost for diesel, however, is not changed because the same is already minimum value.)

d) When total investment amount is 10% less than expected due to various factors, FIRR equals 11.58%.

(2) Change in Relative Rate of Diesel Fuel (Bunker C)

a) When escalation of the price of diesel fuel increases at an annual rate of 0.5% in relation to general prices, FIRR equals 9.46%

b) When the relative price of diesel fuel increases at the same rate as general prices, which means no relative price escalation, FIRR equals 9.02%.

(3) Sales of Electricity

a) When sales of electricity are 10% less than the forecasted power demand, FIRR equals 10.31%. (Consumption by Rio Tuba Mine is not assumed to change).

b) When sales of electricity are 20% less than the forecasted power demand, FIRR equals 10.08%.

(4) Combined Case

When above (1)C, (2)b and (3)a are combined, FIRR equals 8.29%.

The following cases, although they deviate slightly from the general prerequisites of financial evaluation, were also considered in sensitivity analysis.

a) When inflation during the project construction period (1st to 4th year) is 3.5%, Rate of Return equals 9.64%.

b) When interest during the construction period is 5.9%, Rate of Return equals 9.59%.

c) When interest during the construction period is 8.0%, Rate of Return equals 9.29%.

d) When above a) and b) are combined, Rate of Return equals 8.74%.

8.5 Results of Financial Evaluation

The results of the above financial analysis are as summarized below.

a) FIRR for the combination of hydropower and diesel generation plan is 10.52%. Moreover, results of sensitivity analysis show that FIRR is reduced to 9.02% when there is no increase in the relative price of oil related items.

b) FIRR decreases 0.13% when part of Rio Tuba Mine electricity is used for residential supply through PALECO in comparison with consumption of total electricity within the mine alone.

c) When facility investment is increased 10% for reasons other than inflation, FIRR decreases 1.23%, whereas when facility investment decreases 10%, FIRR increases 1.03%. Although these fluctuations are not so large, their effect on loan conditions is great.

d) As electricity is supplied at cost, fluctuations in income from domestic electric supply do not significantly affect FIRR.

e) If various prices increase 3.5% due to inflation during construction and benefit does not change (when there is no increase in diesel fuel price and selling price to PALECO remains constant), the rate of return will decrease about 1% becoming 9.64%.

f) If conditions are the same as in item e) with an interest rate of 5.9% during construction, the rate of return will decrease to 8.74%.

From the results of analysis, the following conclusions can be made. Project implementation will result in effective savings in fuel and production costs and is thus financially feasible. It is possible however that the price of oil related items may not increase or even decrease in which case the internal rate of return will decrease. In consideration of stagnation of the international nickel market price and of the uncertainty of socio-political conditions in the Philippines, the Project may not be feasible for implementation solely on a commercial base.

As the Project includes domestic supply of electricity through PALECO, the rate of return is slightly less than that for consumption by the Rio Tuba Mine alone. Furthermore, there is no guarantee that PALECO will be able to collect electric rates from all beneficiaries, and in this case, PALECO and Rio Tuba Mining Corp. income will both fall short of projections and rate of return will decrease. However, the awareness of local residents about the Project is very high and the contribution of the Project to the surrounding area through the corporation's investment will be well-received.

On the basis of the results of financial analysis, the Project is considered appropriate for a long-term, low interest public loan.

FINANCIAL INTERNAL RATE OF RETURN (CASE 1)

FIRR= 0.105513   NPV=-0.014413

Million Yen

Project Year	Year	Generation by Hydro and Diesel Power Plants: Investment		Operation and Maintenance: Hydropower Plant		Operation and Maintenance: Diesel Power Plant			Diesel Power Generation (w/o Hydro): Investment	Operation & Maintenance			Cost	Benefit					Benefit - Cost
		Hydro	Diesel	Tax	Repair /Others	Fuel	Tax	Repair /Others		Fuel	Tax	Repair /Others		Fuel Saving	Tax Saving	Repair /Others Saving	Turn-over from EnergySold	Total	
1	1986	132.00											132.00					0.00	-132.00
2	1987	810.00											810.00					0.00	-810.00
3	1988	1567.00	1200.00						1200.00				1567.00					0.00	-1567.00
4	1989	1181.00		49.15	33.67	911.86	25.65	38.94		1124.48	25.65	45.66	1181.00	212.62	-49.15	-26.95	25.19	161.71	-1019.29
5	1990			48.16	33.67	773.52	24.43	38.94		1139.10	24.29	45.66	0.00	365.58	-48.30	-26.95	72.89	363.22	363.22
6	1991			47.18	33.67	810.00	23.22	38.94		1153.91	22.93	45.66	0.00	343.91	-47.47	-26.95	86.65	356.14	356.14
7	1992			51.33	33.67	832.50	24.45	38.94		1168.91	23.97	45.66	0.00	336.41	-51.81	-26.95	101.66	359.31	359.31
8	1993			50.24	33.67	843.32	23.10	38.94		1184.10	22.46	45.66	0.00	340.78	-50.88	-26.95	114.70	377.65	377.65
9	1994			49.15	33.67	854.29	21.75	38.94		1199.50	20.95	45.66	0.00	345.21	-49.95	-26.95	114.70	383.01	383.01
10	1995			48.06	33.67	865.39	20.39	38.94		1215.09	19.44	45.66	0.00	349.70	-49.01	-26.95	114.70	388.44	388.44
11	1996			46.96	33.67	876.64	19.04	38.94		1230.89	17.93	45.66	0.00	354.24	-48.07	-26.95	114.70	393.92	393.92
12	1997			45.87	33.67	888.04	17.69	38.94		1246.89	16.42	45.66	0.00	358.85	-47.14	-26.95	114.70	399.46	399.46
13	1998			44.78	33.67	899.58	16.34	38.94		1263.10	14.91	45.66	0.00	363.51	-46.21	-26.95	114.70	405.05	405.05
14	1999			43.69	33.67	911.28	14.99	38.94		1279.52	13.40	45.66	0.00	368.24	-45.28	-26.95	114.70	410.71	410.71
15	2000			42.59	33.67	923.12	13.64	38.94		1296.15	11.88	45.66	0.00	373.03	-44.35	-26.95	114.70	416.43	416.43
16	2001			41.50	33.67	935.12	12.29	38.94		1313.00	10.37	45.66	0.00	377.88	-43.42	-26.95	114.70	422.21	422.21
17	2002			40.41	33.67	947.28	10.94	38.94		1330.07	8.86	45.66	0.00	382.79	-42.49	-26.95	114.70	428.05	428.05
18	2003			39.32	33.67	959.60	9.59	38.94		1347.36	7.35	45.66	0.00	387.77	-41.56	-26.95	114.70	433.96	433.96
19	2004			38.23	33.67	972.07	8.24	38.94		1364.88	5.84	45.66	0.00	392.81	-40.63	-26.95	114.70	439.93	439.93
20	2005			37.13	33.67	984.71	6.89	38.94	1080.00	1382.62	4.33	45.66	-1080.00	397.91	-39.69	-26.95	114.70	445.97	1525.97
21	2006			36.04	33.67	997.51	5.53	38.94		1400.59	28.50	45.66	0.00	403.09	-13.07	-26.95	114.70	477.77	477.77
22	2007		1080.00	34.95	33.67	1010.48	4.18	38.94		1418.80	26.99	45.66	1080.00	408.33	-12.14	-26.95	114.70	483.94	-596.06
23	2008			33.86	33.67	1023.61	28.50	38.94		1437.25	25.48	45.66	0.00	413.63	-36.88	-26.95	114.70	464.50	464.50
24	2009			32.77	33.67	1036.92	27.15	38.94		1455.93	23.97	45.66	0.00	419.01	-35.95	-26.95	114.70	470.81	470.81
25	2010			31.67	33.67	1050.40	25.80	38.94		1474.86	22.46	45.66	0.00	424.46	-35.01	-26.95	114.70	477.20	477.20
26	2011			30.58	33.67	1064.05	24.45	38.94		1494.03	20.95	45.66	0.00	429.98	-34.08	-26.95	114.70	483.65	483.65
27	2012			29.49	33.67	1077.89	23.10	38.94		1513.45	19.44	45.66	0.00	435.57	-33.15	-26.95	114.70	490.17	490.17
28	2013			28.40	33.67	1091.90	21.75	38.94		1533.13	17.93	45.66	0.00	441.23	-32.22	-26.95	114.70	496.76	496.76
29	2014			27.30	33.67	1106.09	20.39	38.94		1553.06	16.42	45.66	0.00	446.96	-31.27	-26.95	114.70	503.44	503.44
30	2015			26.21	33.67	1120.47	19.04	38.94		1573.25	14.91	45.66	0.00	452.78	-30.34	-26.95	114.70	510.19	510.19
31	2016			25.12	33.67	1135.04	17.69	38.94		1593.70	13.40	45.66	0.00	458.66	-29.41	-26.95	114.70	517.00	517.00
32	2017			24.03	33.67	1149.79	16.34	38.94		1614.42	11.88	45.66	0.00	464.62	-28.49	-26.95	114.70	523.88	523.88
33	2018			22.94	33.67	1164.74	14.99	38.94		1635.41	10.37	45.66	0.00	470.66	-27.56	-26.95	114.70	530.85	530.85
34	2019			21.84	33.67	1179.88	13.64	38.94		1656.67	8.86	45.66	0.00	476.78	-26.62	-26.95	114.70	537.91	537.91
35	2020			20.75	33.67	1195.22	12.29	38.94		1678.20	7.35	45.66	0.00	482.98	-25.69	-26.95	114.70	545.04	545.04
36	2021			19.66	33.67	1210.76	10.94	38.94		1700.02	5.84	45.66	0.00	489.26	-24.76	-26.95	114.70	552.25	552.25
37	2022			18.57	33.67	1226.50	9.59	38.94	1080.00	1722.12	4.33	45.66	-1080.00	495.62	-23.83	-26.95	114.70	559.54	1639.54
38	2023			17.47	33.67	1242.44	8.24	38.94		1744.51	28.50	45.66	0.00	502.06	2.79	-26.95	114.70	592.60	592.60
39	2024			16.38	33.67	1258.60	6.89	38.94		1767.19	26.99	45.66	0.00	508.59	3.72	-26.95	114.70	600.06	600.06
40	2025			15.29	33.67	1274.96	5.53	38.94		1790.16	25.48	45.66	0.00	515.20	4.66	-26.95	114.70	607.61	607.61
41	2026		1080.00	14.20	33.67	1291.53	4.18	38.94		1813.43	23.97	45.66	1080.00	521.90	5.59	-26.95	114.70	615.24	-464.76
42	2027			13.11	33.67	1308.32	28.50	38.94		1837.01	22.46	45.66	0.00	528.68	-19.15	-26.95	114.70	597.28	597.28
43	2028			12.01	33.67	1325.33	27.15	38.94		1860.89	20.95	45.66	0.00	535.56	-18.21	-26.95	114.70	605.10	605.10
44	2029			10.92	33.67	1342.56	25.80	38.94		1885.08	19.44	45.66	0.00	542.52	-17.28	-26.95	114.70	612.99	612.99
45	2030			9.83	33.67	1360.01	24.45	38.94		1909.59	17.93	45.66	0.00	549.57	-16.35	-26.95	114.70	620.97	620.97
46	2031			8.74	33.67	1377.69	23.10	38.94		1934.41	16.42	45.66	0.00	556.72	-15.42	-26.95	114.70	629.05	629.05
47	2032			7.65	33.67	1395.60	21.75	38.94		1959.50	14.91	45.66	0.00	563.95	-14.49	-26.95	114.70	637.21	637.21
48	2033	-369.00	-682.12	6.55	33.67	1413.75	20.39	38.94	-381.18	1985.03	13.40	45.66	-669.94	571.28	-13.54	-26.95	114.70	645.49	1315.43

FINANCIAL INTERNAL RATE OF RETURN (CASE 2)

FIRR= 0.106639 NPV=0.005219

Million Yen

Project Year	Year	Generation by Hydro and Diesel Power Plants: Investment							Diesel Power Generation(w/o Hydro)				Cost	Benefit					Benefit - Cost
		Investment		Operation and Maintenance: Hydropower Plant		Operation and Maintenance: Diesel Power Plant			Invest-ment	Operation & Maintenance								Total	
		Hydro	Diesel	Tax	Repair /Others	Fuel	Tax	Repair /Others		Fuel	Tax	Repair /Others		Fuel Saving	Tax Saving	Repair /Others Saving	Turn-over from EnergySold		
1	1986	132.00											132.00					0.00	-132.00
2	1987	810.00											810.00					0.00	-810.00
3	1988	1567.00	1200.00						1200.00				1567.00					0.00	-1567.00
4	1989	1181.00		49.15	33.67	889.11	25.65	38.94		1124.48	25.65	45.66	1181.00	235.37	-49.15	-26.95	0.00	159.27	-1021.73
5	1990			48.16	33.67	707.30	24.43	38.94		1139.10	24.29	45.66	0.00	431.80	-48.30	-26.95	0.00	356.55	356.55
6	1991			47.18	33.67	716.49	23.22	38.94		1153.91	22.93	45.66	0.00	437.42	-47.47	-26.95	0.00	363.00	363.00
7	1992			51.33	33.67	725.81	24.45	38.94		1168.91	23.97	45.66	0.00	443.10	-51.81	-26.95	0.00	364.34	364.34
8	1993			50.24	33.67	735.25	23.10	38.94		1184.10	22.46	45.66	0.00	448.86	-50.88	-26.95	0.00	371.03	371.03
9	1994			49.15	33.67	744.80	21.75	38.94		1199.50	20.95	45.66	0.00	454.69	-49.95	-26.95	0.00	377.79	377.79
10	1995			48.06	33.67	754.49	20.39	38.94		1215.09	19.44	45.66	0.00	460.60	-49.01	-26.95	0.00	384.64	384.64
11	1996			46.96	33.67	764.29	19.04	38.94		1230.89	17.93	45.66	0.00	466.59	-48.07	-26.95	0.00	391.57	391.57
12	1997			45.87	33.67	774.23	17.69	38.94		1246.89	16.42	45.66	0.00	472.66	-47.14	-26.95	0.00	398.57	398.57
13	1998			44.78	33.67	784.30	16.34	38.94		1263.10	14.91	45.66	0.00	478.80	-46.21	-26.95	0.00	405.64	405.64
14	1999			43.69	33.67	794.49	14.99	38.94		1279.52	13.40	45.66	0.00	485.03	-45.28	-26.95	0.00	412.80	412.80
15	2000			42.59	33.67	804.82	13.64	38.94		1296.15	11.88	45.66	0.00	491.33	-44.35	-26.95	0.00	420.03	420.03
16	2001			41.50	33.67	815.28	12.29	38.94		1313.00	10.37	45.66	0.00	497.72	-43.42	-26.95	0.00	427.35	427.35
17	2002			40.41	33.67	825.88	10.94	38.94		1330.07	8.86	45.66	0.00	504.19	-42.49	-26.95	0.00	434.75	434.75
18	2003			39.32	33.67	836.62	9.59	38.94		1347.36	7.35	45.66	0.00	510.74	-41.56	-26.95	0.00	442.23	442.23
19	2004			38.23	33.67	847.49	8.24	38.94		1364.88	5.84	45.66	0.00	517.38	-40.63	-26.95	0.00	449.80	449.80
20	2005			37.13	33.67	858.51	6.89	38.94	1080.00	1382.62	4.33	45.66	-1080.00	524.11	-39.69	-26.95	0.00	457.47	1537.47
21	2006			36.04	33.67	869.67	5.53	38.94		1400.59	28.50	45.66	0.00	530.92	-13.07	-26.95	0.00	490.90	490.90
22	2007		1080.00	34.95	33.67	880.98	4.18	38.94		1418.80	26.99	45.66	1080.00	537.82	-12.14	-26.95	0.00	498.73	-581.27
23	2008			33.86	33.67	892.43	28.50	38.94		1437.25	25.48	45.66	0.00	544.82	-36.88	-26.95	0.00	480.99	480.99
24	2009			32.77	33.67	904.03	27.15	38.94		1455.93	23.97	45.66	0.00	551.90	-35.95	-26.95	0.00	489.00	489.00
25	2010			31.67	33.67	915.78	25.80	38.94		1474.86	22.46	45.66	0.00	559.07	-35.01	-26.95	0.00	497.11	497.11
26	2011			30.58	33.67	927.69	24.45	38.94		1494.03	20.95	45.66	0.00	566.34	-34.08	-26.95	0.00	505.31	505.31
27	2012			29.49	33.67	939.75	23.10	38.94		1513.45	19.44	45.66	0.00	573.70	-33.15	-26.95	0.00	513.60	513.60
28	2013			28.40	33.67	951.97	21.75	38.94		1533.13	17.93	45.66	0.00	581.16	-32.22	-26.95	0.00	521.99	521.99
29	2014			27.30	33.67	964.34	20.39	38.94		1553.06	16.42	45.66	0.00	588.72	-31.27	-26.95	0.00	530.50	530.50
30	2015			26.21	33.67	976.88	19.04	38.94		1573.25	14.91	45.66	0.00	596.37	-30.34	-26.95	0.00	539.08	539.08
31	2016			25.12	33.67	989.58	17.69	38.94		1593.70	13.40	45.66	0.00	604.12	-29.41	-26.95	0.00	547.76	547.76
32	2017			24.03	33.67	1002.44	16.34	38.94		1614.42	11.88	45.66	0.00	611.98	-28.49	-26.95	0.00	556.54	556.54
33	2018			22.94	33.67	1015.47	14.99	38.94		1635.41	10.37,	45.66	0.00	619.93	-27.56	-26.95	0.00	565.42	565.42
34	2019			21.84	33.67	1028.67	13.64	38.94		1656.67	8.86	45.66	0.00	627.99	-26.62	-26.95	0.00	574.42	574.42
35	2020			20.75	33.67	1042.05	12.29	38.94		1678.20	7.35	45.66	0.00	636.16	-25.69	-26.95	0.00	583.52	583.52
36	2021			19.66	33.67	1055.59	10.94	38.94		1700.02	5.84	45.66	0.00	644.43	-24.76	-26.95	0.00	592.72	592.72
37	2022			18.57	33.67	1069.32	9.59	38.94	1080.00	1722.12	4.33	45.66	-1080.00	652.80	-23.83	-26.95	0.00	602.02	1682.02
38	2023			17.47	33.67	1083.22	8.24	38.94		1744.51	28.50	45.66	0.00	661.29	2.79	-26.95	0.00	637.13	637.13
39	2024			16.38	33.67	1097.30	6.89	38.94		1767.19	26.99	45.66	0.00	669.89	3.72	-26.95	0.00	646.66	646.66
40	2025			15.29	33.67	1111.56	5.53	38.94		1790.16	25.48	45.66	0.00	678.60	4.66	-26.95	0.00	656.31	656.31
41	2026		1080.00	14.20	33.67	1126.01	4.18	38.94		1813.43	23.97	45.66	1080.00	687.42	5.59	-26.95	0.00	666.06	-413.94
42	2027			13.11	33.67	1140.65	28.50	38.94		1837.01	22.46	45.66	0.00	696.35	-19.15	-26.95	0.00	650.25	650.25
43	2028			12.01	33.67	1155.48	27.15	38.94		1860.89	20.95	45.66	0.00	705.41	-18.21	-26.95	0.00	660.25	660.25
44	2029			10.92	33.67	1170.50	25.80	38.94		1885.08	19.44	45.66	0.00	714.58	-17.28	-26.95	0.00	670.35	670.35
45	2030			9.83	33.67	1185.72	24.45	38.94		1909.59	17.93	45.66	0.00	723.87	-16.35	-26.95	0.00	680.57	680.57
46	2031			8.74	33.67	1201.13	23.10	38.94		1934.41	16.42	45.66	0.00	733.28	-15.42	-26.95	0.00	690.91	690.91
47	2032			7.65	33.67	1216.75	21.75	38.94		1959.56	14.91	45.66	0.00	742.81	-14.49	-26.95	0.00	701.37	701.37
48	2033	-369.00	-682.12	6.55	33.67	1232.57	20.39	38.94	-381.18	1985.03	13.40	45.66	-669.94	752.47	-13.54	-26.95	0.00	711.98	1381.92

CHAPTER IX

ECONOMIC ANALYSIS

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ECONOMIC ANALYSIS

9.1 Approach

The objective of economic analysis is to assess benefit to the national economy which will arise from project implementation, versus financial analysis which assesses benefit to the project implementating agency. Benefit in terms of the national economy is equivalent to optimum allocation of resources such as capital, materials, equipment, and labor. In economic analysis, as in financial analysis, benefit and cost are quantified; however, in economic analysis these are expressed in terms of shadow price, whereas in financial analysis they are expressed in terms of market price.

Market prices, particularly in developing countries, are usually very different from the prices of a free competitive market due to the existence of monopolies and oligopolies, imposition of high tariffs, abitrary foreign exchange rates, high interest and subsidies. Such distorted market prices deviate from the original invested value, the scarcity value, etc. and benefit and cost expressed in market prices do not reflect the exact value in terms of the national economy.

Conversion from market price to shadow price consists of two procedures. The first is elimination of tax, interest, subsidies, etc. Such transfer payments merely represent the movement of resources within the nation as a whole, rather than resources used in the actual project. From the perspective of the national economy, benefit and cost offset each other. The second step in conversion is adjustment of distortion in the market price which is compared to prices in a free competitive system. Shadow price in the form of opportunity cost for goods and services is used for this purpose.

In the case of imported or traded goods, for example, the CIF price (cost, insurance and freight) at the country's representative port, plus domestic transportation costs, is used in estimates rather than the country's market price. The resultant price is assumed to reflect a more competitive market price. This is also true in the case of wages for unskilled labor, land price etc. which are usually determined according to policies such as application of land evaluation standards and minimum wage laws. These prices do not represent opportunity cost or economic loss from investment of goods and service in a project.

Opportunity cost is calculated according to the marginal productivity of service or goods invested in the project. Although the majority of people in the proposed Project area in Marcos Municipality, Palawan Province are engaged in agriculture, the marginal productivity of agriculture is low, due to the fact that water use is limited because the area was only recently opened, and a large, youthful labor force remains in the area. If laborers are employed, they are paid the minimum wage; however, marginal productivity of agriculture which is opportunity cost is much less than the minimum wage. From the viewpoint of the national econopmy, marginal productity itself which is lost due to investment in the Project is considered as cost. When each item of market price calculation used in financial evaluation is multiplied by a ratio to determine the shadow price for economic evalution, the ratio is referred to as a shadow rate and expressed in terms of opportunity cost/market price.

9.2 Prerequisites of Economic Evaluation

Energy projects generally fall within the category of public utility related projects. Public implies the existence of a market, while utility denotes output. Accordingly, a different approach is required in economic evaluation of energy projects as opposed to projects which deal with simple production of commodities.

Utilities such as electricity do not have a value as is; rather their value is realized only after they are used. If the utility is invested in an economic activity, the marginal value which arises from that activity is regarded as benefit. If the utility is used in the home, the value of convenience obtained from lighting or mechanical power is regarded as benefit. In the former where electricity is used for economic activity, benefit can be estimated by adding the supplemental production value (marginal productivity) which accrues from the additional investment for electric power, to each economic unit and taking the total.

This procedure however, requires a long period of time. Moreover, quantification of convenience benefit for residential consumption of electricity is not possible. To cope with this problem, the so-called "alternative facility method", in which the cost of the second best alternative is regarded as project benefit, is widely used in Japan. This method involves inadequate interpretation of opportunity cost of capital. With implementation of a certain project, investment for a second best alternative is considered to have been avoided and the cost of the alternative is considered to be saved.

In actual fact however, the entire cost has not been avoided. Rather, as the project is implemented, instead of investing capital, the difference between the project's cost and the alternative's cost is avoided. If the difference in cost is negative, it is regarded as cost, rather than as benefit. With the alternative facility method, even if the alternative facilities are second best (ie. lowest cost), it is possible to justify almost all projects as economically feasible.

In this connection, the alternative facilities method has not been applied in the present Project. Instead, project benefits were divided into two categories as in financial analysis; the value of savings obtained in electricity consumption by the Rio Tuba Mine expressed in economic value, and income obtained by PALECO through the sale of electricity regarded as benefit. The reasons for this approach are discussed hereunder.

As aforementioned, quantification of convenience benefit from use of electric power is not possible. One commonly used method to measure the same is willingness to pay (WTP) of the consumer. To determine WTP, an interview survey must be conducted in which the potential benefits of electricity are first explained and then the rate which the potential consumer is willing to pay for those benefits is obtained. Such a survey however, requires many interviews with good interpreters and a long period of time.

Instead it is possible to estimate WTP by ascertaining the present degree of electricity used by local residents, and the number of oil lamps and batteries which are used. In the present PALECO distribution area, the majority of households use electricity, including those households which must bear the costs of long and expensive in-coming lines and low income households which cannot afford the average cost (₱500-600) required for household wiring. In the urban areas of Puerto Princesa, Brooke's Point, etc., the electrification rate is almost 100%. In Brooke's Point area where few problems arise in payment of rates, over 90% of ordinary consumers pay their rates by a fixed date. From this fact it may be estimated that the present rate is close to or even less than the WTP of the ordinary consumer.

In unelectrified areas, excluding a few native communities in the mountains, all households own small lamps and/or large petromax lamps. Furthermore, 60% of households own transister radios which require frequent purchase of batteries. (Although less common, some higher income households own kerosene refrigerators, musical instruments, etc.). The consumer buys the kerosene for his lamp and the batteries for his radio at kiosks in each sitio or at the weekly market. Although the price varies with each site, kerosene costs an average of ₱4.25 (about ¥58) per bottle which is equivalent to 0.375ℓ, while batteries cost an average of ₱4.75 (about ¥64) each. Average consumption of kerosene even in low income households is 5.5ℓ/month and of batteries is 4 batteries/month while average monthly expenditure is about ₱64 (¥865) for kerosene, and about ₱19 (¥258) for batteries. These figures are for the lowest income bracket and consumption will naturally be greater the higher the income level. On the average, kerosene consumption is 10ℓ/month and battery consumption is 10 batteries/month.

The lowest basic PALECO rate (12kWh), on the other hand, is ₱50 (about ¥678) as of March 1985, and few households use more than this rate. Accordingly, conversion of presently used kerosene and batteries to electricity will result in savings. From this perspective also, the present electric rate may be assumed to be close to or less than WTP. If electric power is available, time and effort expended on procuring kerosene will also be eliminated resulting in unquantifiable benefits which should be considered in evaluation.

For the above reasons, the economic benefit of residential supply is regarded as WTP or total value of utility effect in the present report. This total value represents income of PALECO by sale of electricity.

9.3 Benefit

As discussed above, power production benefits for the Project are of two types; private consumption for nickel segregation and power supply to local residents.

(1) Mine Consumption

Benefit from mine consumption is savings in O&M cost expressed in economic value. The majority of O&M cost consists of diesel fuel (Bunker C) and the economic value is expressed in terms of border price. Oil refining capacity in the Philippines is substantial and oil is produced for domestic consumption as well as on consignment for PRETAMINA of Indonesia. Accordingly, border price of Bunker C oil in the Philippines can be designated as the international price (Singapore price), without adding transportation costs. FOB price of Bunker C oil in Singapore as of March 1985 is US$169/t[1/] (if the specific weight[2/] is 1, US$0.169/ℓ= ¥43/ℓ).

On the other hand, the purchase price of Bunker C at the Rio Tuba Mine as of March, 1985 is the Batan price plus transportation costs, or ₱4.6376/ℓ + ₱0.27/ℓ = ₱4.9076/ℓ ≒ ¥67/ℓ. If the same transportation cost is added to the above border price, the economic value of Bunker C at the Rio Tuba Mine is about ¥46/ℓ. In economic evaluation, the Bunker C price used in financial evaluation is therefore multiplied by the coefficient 0.69 (¥46/¥67). Although a fuel price of ¥71/ℓ was used in estimates in CHAPTER 7, this price includes lubricating and other types of oils. It is assumed here that the price of other oils may be adjusted to economic value by using the same coefficient as that for Bunker C oil.

Although there are other costs such as maintenance which make up savings, the proportion of these is insignificant when compared with costs of diesel fuel and accordingly, they are disregarded.

1/ Platt's Oilgram Price Report, April 1, 1985, Page 6-A.

2/ Specific weight of Bunker C is 0.921 - 1.021.

On the other hand, some additonal O&M costs occur for the combined hydropower with diesel generation plan in comparison to diesel generation alone. These are negative savings and they should be subdivided and adjusted to economic value for trade goods and labor wages, and transfer payment should be eliminated.

As can be seen from the cash flow chart in TABLE 8-1, property tax and remaining maintenance costs comprise the majority of O&M costs for hydropower while other costs are relatively minimal and may be disregarded. Conversion of additional costs arising from combined hydropower and diesel generation to economic value consists of removal of the transferrable item in the form of property taxes.

(2) Residential Supply

Benefit for residential supply is the income gained by PALECO from sale of electricity supplied from the Rio Tuba Mining Corp. and this income is based on PALECO's present rate which reflects WTP of the average household. Commercial and industrial enterprises in the Project area are very few in number and predominantly small-scale. Consequently, it can be assumed that residential supply includes commercial, industrial and public supply. Electricity will be sold to PALECO from the Rio Tuba Mining Corp. at a rate of ¥17.87/kWh and the PALECO rate will be ¥56.60/kWh.

PALECO has adopted the basic rate system; however, few households pay more than the basic rate. PALECO income from electric rates is proportionally greater than Rio Tuba Mining Corp. income from sale of electricity to PALECO. However, as data on the percentage of households consuming within the basic rate was unavailable and as electricity supplied by the Rio Tuba Mining Corp. is consumed through PALECO by ordinary households, the ratio of Rio Tuba Mining Corp. income from electricity sales is assumed to be the same as that for PALECO income from electric rates. The coefficient for the above is determined as PALECO rate/kWh ÷ Rio Tuba Mining Corp. selling price/kWh or ¥56.60/kWh ÷ ¥17.87/kWh = 3.17.

9.4 Cost Estimations

Economic costs in the present Project are the difference in construction costs for the combined hydropower and diesel generation plan and diesel generation alone expressed in terms of economic value. Construction costs are divided into those paid in foreign currency and those paid in domestic currency. As the Japanese yen is used for the foreign currency portion due to the nature of the Project, imported items are assumed to reflect economic price of a free competitive market. For the domestic portion, on the other hand, distortion of market price is presumed and market prices are converted to economic prices as discussed hereunder.

(1) Tax

In economic analysis, taxes are regarded merely as transfer of resources within the country itself and are therefore deducted from cost as a transfer payment. As discussed in section 8.4, the Project is exempted from customs duties and accordingly such duties are not included in estimates even in financial analysis. It is therefore necessary only to eliminate property taxes imposed on facilities.

(2) Exchange Rate

A shadow exchange rate, rather than a fixed rate is used to convert domestic currency to foreign currency in economic analysis. In 1984, however, the Philippine Government adopted the floating exchange rate system and consequently, the exchange rate fluctuates daily in accordance with international economic conditions as well as economic conditions in the Philippines. The exchange rate of 31 March, 1985 was therefore adopted instead of an exchange rate based on the standard conversion factor.

(3) Labor Wage

Shadow wages, which represent opportunity cost for employment of unskilled labor, were used for unskilled labor wage. The minimum wage law is applied in the Philippines and accordingly unskilled laborers recieve the minimum wage which consists of a basic wage of ₱37/day plus ₱37/day plus ₱16.5/day in allowances for a total of ₱53.5/day (¥726/day) as of March 1985. This wage represents a very large sum for opportunity cost of labor. According to an interview survey conducted in the Project area, daily wage during paddy, and coconut harvest when labor demand is highest is only about ₱20 and usually does not exceed ₱10. Even for as low a wage as ₱10/day, the majority of residents desire temporary work, indicating high underemployment and low marginal productivity of labor in the Project area.

Annual income of ordinary farm households ranges from ₱3,000 to ₱15,000; however, the average is about ₱6,000. Income of natives in the mountains is even less. Even with 3 laborers in one household, average annual productivity is less than ₱2,000. Marginal productivity is less than this figure, estimated at under ₱1,500/year. Small-scale farmers, however, work as temporary labor for an average of 20 days/year. Estimated income from this is about ₱300/year. Moreover, non-cash economic activities such as fishing for supplementary food supply are also common. Accordingly, ₱1,800/year is adopted as the opportunity cost for unskilled labor in this report. Thus shadow wage for unskilled labor is ₱6/day with 300 working days and the shadow wage rate for the Project area is therefore ₱6/₱53.5 = 0.11.

NEDA has used a coefficient of 0.8 multiplied by the minimum wage to obtain the shadow wage for unskilled labor. This coefficient however, is the average of the entire Philippines (temporary labor wage in Quezon which has more employment opportunities was ₱40/day) and is therefore considered inapplicable to the Project area where the underemployment ratio is high.

(4) Land Acquisition and Compensation Costs

According to cost estimates in this report, costs required for expropriation of land are estimated at only ¥1.1 million. The proposed dam site is located on public land with virtually no residences in the reservoir area. Economic value was determined by opportunity cost of land or marginal productivity of land. As the reservoir area is presently unused land covered by jungle, the economic value of land used for ponding or temporary facilities may be disregarded. Moreover, such temporary facilities as roads may also be used by local residents and thus should be regarded as benefit rather than as loss. Economic losses were therefore considered minimal in the present report and, at the same time were offset by benefits, with land acquisition costs amounting to zero.

For similar reasons, costs related to land compensation totalled only about ¥40 million. These costs include about ¥20 million for lumbering compensation and ¥15 million for water rights while the remainder is public compensation. Of this, 90% of lumbering compensation is comprised of compensation for timber cutting which, even if paid, would not be paid in economic value. In consideration of these factors, this compensation was estimated at ¥5 million. Moreover, water rights and public compensation mainly consist of compensation to 50 member households of the agricultural cooperative which built and maintains 200ha of irrigation facilities in Sicud area. As provision of a certain amount of Candagawa River irrigation water was planned in diversion to the Culasian River, the cost is considered appropriate, reflecting the economic value, and this value is also used in economic analysis.

(5) Fuel

Total fuel cost for construction works is ¥115 million and mainly consists of diesel oil for construction equipment and lighting. Although the price of Bataan refinery diesel oil at Rio Tuba was ₱6.41/ℓ(¥87.03/ℓ) at the end of March, 1985, the international market price at the same time according to Platt's Report was US$0.1835/ℓ (¥45.99/ℓ). With the addition of ¥3.66/ℓfor domestic transportation costs, the coefficient for total economic value at Rio Tuba was ¥49.65/¥87.03 = 0.57. The economic value of fuel cost was therefore calculated as ¥115 million x 0.57 = ¥65.55 million.

(6) Diesel Generators

The costs discussed above are all related to hydropower costs, while costs related to diesel generation have been ignored due to the fact that the difference between initial diesel facility investment costs for either case is zero. However, facility replacement costs vary with each case and require conversion to economic value along with residual value. The domestic currency portion of facility replacement costs is only 13%, of which 4.3% is wages, and 8.7% is materials and equipment, including buildings. Based on conversion of wages, traded goods, etc. to economic value, the conversion coefficient for adjustment of total cost and residual value to economic value is 0.95.

(7) Costs Covered by PALECO and Consumers

Economic benefits for the Project consist of savings in energy for the Rio Tuba Mine expressed in economic value and income for PALECO from supply of electricity to rural residents. In evaluation of the latter benefit, PALECO income, costs incurred for use should also be considered. These consist of PALECO expenditures to obtain electricity from the Rio Tuba Mining Corp. (eg. construction of distribution lines, installation of transformers and meters) and costs to the consumer who must pay for electric supply from PALECO (eg. purchase of bulbs, lamps and wiring). As the majority of these items are traded commodities, the cost converted to economic value is regarded as a cost item in cash flow for economic analysis.

9.5 EIRR and Results of Economic Evaluation

On the basis of the above discussion, EIRR was obtained at 12.60%, which is higher than FIRR. Indirect benefits are not included in this figure. In conversion of costs to economic value, civil works should have been subdivided more precisely, transfer payments such as taxes for heavy construction equipment, etc., were excluded, and procedures such as conversion of traded goods to border prices were not closely implemented. If these factors are considered in evaluation, economic cost would decrease and the EIRR would correspondingly increase.

In consideration of the above economic analysis, the proposed Project is feasible from the viewpoint of the national economy, and benefit for local residents is substantial.

Million Yen

EIRR= 0.126001 NPV=0.000590

Project Year	Year	Generation by Hydro and Diesel Power Plants: Investment: Rio Tuba: Hydro	Investment: Rio Tuba: Diesel	Investment: PALECO & Consumers: PALECO	Investment: PALECO & Consumers: Consumers	Operation and Maintenance: Hydro Power P: Repair /Others	Operation and Maintenance: Diesel Power Plant: Fuel	Operation and Maintenance: Diesel Power Plant: Repair /Others	Operation and Maintenance: PALECO & Consumers: Repair /Others	Diesel Power Generation (w/o Hydropower Plant): Invest-ment	Diesel Power Generation (w/o Hydropower Plant): Operation & Maintenance: Fuel	Diesel Power Generation (w/o Hydropower Plant): Operation & Maintenance: Repair /Others	Total Cost	Benefit: Fuel Saving	Benefit: Repair /Others Saving	Benefit: Turn-over from EnergySold	Benefit: Total Benefit	Benefit - Cos
1	1986	125.00											125.00				0.00	-125.00
2	1987	766.00		76.48									842.48				0.00	-842.48
3	1988	1515.00	1140.00	149.63						1140.00			1664.63				0.00	-1664.63
4	1989	1134.00		142.03	37.36	33.67	629.18	38.94	9.05		775.89	45.66	1313.39	146.71	-36.00	79.85	190.56	-1122.83
5	1990			32.78	21.66	33.67	533.73	38.94	9.05		785.98	45.66	54.44	252.25	-36.00	231.06	447.31	392.87
6	1991			32.78	21.66	33.67	558.90	38.94	9.05		796.20	45.66	54.44	237.30	-36.00	274.68	475.98	421.54
7	1992			32.78	21.66	33.67	574.43	38.94	9.05		806.55	45.66	54.44	232.12	-36.00	322.26	518.38	463.94
8	1993			32.78	21.66	33.67	581.89	38.94	9.05		817.03	45.66	54.44	235.14	-36.00	363.60	562.74	508.30
9	1994					33.67	589.46	38.94	9.05		827.65	45.66	0.00	238.20	-36.00	363.60	565.79	565.79
10	1995					33.67	597.12	38.94	9.05		838.41	45.66	0.00	241.29	-36.00	363.60	568.89	568.89
11	1996					33.67	604.88	38.94	9.05		849.31	45.66	0.00	244.43	-36.00	363.60	572.03	572.03
12	1997					33.67	612.75	38.94	9.05		860.35	45.66	0.00	247.61	-36.00	363.60	575.21	575.21
13	1998					33.67	620.71	38.94	9.05		871.54	45.66	0.00	250.83	-36.00	363.60	578.42	578.42
14	1999					33.67	628.78	38.94	9.05		882.87	45.66	0.00	254.09	-36.00	363.60	581.68	581.68
15	2000					33.67	636.96	38.94	9.05		894.34	45.66	0.00	257.39	-36.00	363.60	584.99	584.99
16	2001					33.67	645.24	38.94	9.05		905.97	45.66	0.00	260.74	-36.00	363.60	588.33	588.33
17	2002					33.67	653.62	38.94	9.05		917.75	45.66	0.00	264.12	-36.00	363.60	591.72	591.72
18	2003					33.67	662.12	38.94	9.05		929.68	45.66	0.00	267.56	-36.00	363.60	595.16	595.16
19	2004					33.67	670.73	38.94	9.05		941.76	45.66	0.00	271.04	-36.00	363.60	598.64	598.64
20	2005					33.67	679.45	38.94	9.05	1026.00	954.01	45.66	-1026.00	274.56	-36.00	363.60	602.16	1628.16
21	2006					33.67	688.28	38.94	9.05		966.41	45.66	0.00	278.13	-36.00	363.60	605.73	605.73
22	2007		1026.00			33.67	697.23	38.94	9.05		978.97	45.66	1026.00	281.74	-36.00	363.60	609.34	-416.66
23	2008					33.67	706.29	38.94	9.05		991.70	45.66	0.00	285.41	-36.00	363.60	613.01	613.01
24	2009			183.83		33.67	715.47	38.94	9.05		1004.59	45.66	183.83	289.12	-36.00	363.60	616.72	432.89
25	2010					33.67	724.78	38.94	9.05		1017.65	45.66	0.00	292.88	-36.00	363.60	620.48	620.48
26	2011					33.67	734.20	38.94	9.05		1030.88	45.66	0.00	296.68	-36.00	363.60	624.28	624.28
27	2012					33.87	743.74	38.94	9.05		1044.28	45.66	0.00	300.54	-36.00	363.60	628.14	628.14
28	2013					33.67	753.41	38.94	9.05		1057.86	45.66	0.00	304.45	-36.00	363.60	632.05	632.05
29	2014					33.67	763.20	38.94	9.05		1071.61	45.66	0.00	308.41	-36.00	363.60	636.00	636.00
30	2015					33.67	773.13	38.94	9.05		1085.54	45.66	0.00	312.41	-36.00	363.60	640.01	640.01
31	2016					33.67	783.18	38.94	9.05		1099.65	45.66	0.00	316.48	-36.00	363.60	644.08	644.08
32	2017					33.67	793.36	38.94	9.05		1113.95	45.66	0.00	320.59	-36.00	363.60	648.19	648.19
33	2018					33.67	803.67	38.94	9.05		1128.43	45.66	0.00	324.76	-36.00	363.60	652.36	652.36
34	2019					33.67	814.12	38.94	9.05		1143.10	45.66	0.00	328.98	-36.00	363.60	656.58	656.58
35	2020					33.67	824.70	38.94	9.05		1157.96	45.66	0.00	333.26	-36.00	363.60	660.86	660.86
36	2021					33.67	835.42	38.94	9.05		1173.01	45.66	0.00	337.59	-36.00	363.60	665.19	665.19
37	2022					33.67	846.29	38.94	9.05	1026.00	1188.26	45.66	-1026.00	341.98	-36.00	363.60	669.58	1695.53
38	2023					33.67	857.29	38.94	9.05		1203.71	45.66	0.00	346.42	-36.00	363.60	674.02	674.02
39	2024					33.67	868.43	38.94	9.05		1219.36	45.66	0.00	350.93	-36.00	363.60	678.53	678.53
40	2025					33.67	879.72	38.94	9.05		1235.21	45.66	0.00	355.49	-36.00	363.60	683.09	683.09
41	2026		1026.00			33.67	891.16	38.94	9.05		1251.27	45.66	1026.00	360.11	-36.00	363.60	687.71	-338.29
42	2027					33.67	902.74	38.94	9.05		1267.53	45.66	0.00	364.79	-36.00	363.60	692.39	692.39
43	2028					33.67	914.48	38.94	9.05		1284.01	45.66	0.00	369.53	-36.00	363.60	697.13	697.13
44	2029			183.83		33.67	926.37	38.94	9.05		1300.70	45.66	183.83	374.34	-36.00	363.60	701.94	518.11
45	2030					33.67	938.41	38.94	9.05		1317.61	45.66	0.00	379.20	-36.00	363.60	706.80	706.80
46	2031					33.67	950.61	38.94	9.05		1334.74	45.66	0.00	384.13	-36.00	363.60	711.73	711.73
47	2032					33.67	962.97	38.94	9.05		1352.09	45.66	0.00	389.13	-36.00	363.60	716.73	716.73
48	2033	-354.00	-648.01	-147.06		33.67	975.48	38.94	9.05	-362.12	1369.67	45.66	-786.95	394.19	-36.00	363.60	721.79	1508.74

CHAPTER X

INDIRECT PROJECT EFFECTS

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10.1 General

One of the major differences between developed countries and developing countries is the extensive use of electricity, not only in the urban areas, but also in rural areas, resulting from well-developed electrical networks. Electrification and rural development are highly interdependent. In view of the present economic situation in the Philippines and its high dependence on oil imports, reduction of rural electrification cost is a major difficulty. Development of other energy sources such as hydropower or thermal oil will thus contribute to promotion of rural electrification.

10.2 Indirect Effects

(1) Contribution to the National Economy

Annual energy (29.0GWh) obtained with the Candawaga River hydropower plan is equivalent to an annual 5,600t (about 37,000 barrels) of Bunker C oil. Thus, the hydropower plan will make a significant contribution to the Philippine economy.

(2) Improvement of Rural Living Conditions

With the envisioned supply of 2,100kW to PALECO, approximately 15,000 residences and 3,700 commercial enterprises which are presently unelectrified will be supplied with electricity by the tenth year (1998) after project implementation, thereby greatly improving rural living conditions

(3) Stimulation of Rural Development

The west coast of Palawan Island where the Project is located, remains undeveloped. With no roads in the area, the sole means of transport is by small boat.

Under the Project, a temporary pier at the coast and a 9km access road from the coast to the powerhouse site will be constructed in order to facilitate powerhouse construction works. Construction works will increase employment opportunities for local residents thereby increasing their income for a limited period of time. Moreover, temporary works for Project construction are expected to contribute greatly to rural development after Project completion. A transmission line is also planned to serve the village (approximately 600 households) at the mouth of the Candawaga and Culasian rivers.

Opportunities for rural development arising from electrification include integrated agricultural development of the lower Candawaga basin and surrounding area. For example, if integrated development of coconut which has a high potential in the said area, was promoted, including planting, harvesting, collection, processing and copra manufacturing, both farmers' income and employment opportunities in the rural area would increase.

TABLES

INFRASTRUCTURE PROGRAM INVESTMENT REQUIREMENT, 1983, 1984-87

Unit : million pesos at 1984 price

	Actual 1983	1984	Requirements 1985	1986	1987	1984-87 TOTAL	%
POWER AND ELECTRIFICAITON	11,938	7,962	8,193	6,121	8,114	30,390	40
Power	11,029	7,046	7,547	5,059	6,522	26,174	
Electrification	909	916	646	1,062	1,592	4,216	
TRANSPORT	5,924	5,920	4,612	4,269	4,727	19,527	26
Highways	3,644	3,542	2,894	3,159	3,439	12,943	
Railways	1,737	1,192	610	245	284	2,330	
Ports	462	961	956	760	896	3,573	
Airports,Airnavs	81	315	151	105	108	680	
WATER RESOURCES	3,957	3,775	4,995	4,503	5,837	19,110	25
Irrigation	1,777	1,704	2,629	2,611	2,259	9,203	
Water Supply	1,706	1,798	2,133	1,656	3,330	8,917	
Flood Control, Drainage and Shore-Protection	474	273	233	236	248	976	
SOCIAL/RELATED INFRASTRUCTURE	1,216	1,514	1,029	1,186	1,319	5,048	7
School buildings	760	1,206	715	808	918	3,647	
Public health facilities	266	180	184	209	225	797	
City infrastructure	101	116	125	154	158	553	
Official building	89	12	5	15	18	50	
COMMUNICATION	420	251	203	284	485	1,223	2
Communicaiton	386	230	187	259	460	1,135	
Mail	34	21	16	25	25	86	
Others	16	30	21	49	47	147	*
TOTAL	23,471	19,452	19,052	16,412	20,529	75,445	100

Source : Updated Philippine Development Plan, 1984-87

ENERGY CONSUMPTION IN THE PHILIPPINES

Unit : Million Barrels of Fuel oil Equivalent

	Actual				1984		1983-84 Growth Rate(%)	1987 Target
	1980	1981	1982	1983	Plan Target	Actual		
INDIGENOUS	N.A. (N.A.)	N.A. (N.A.)	N.A. (N.A.)	34.0 (34.5%)	38.3 (40.1%)	39.5 (42.0%)	16.0	72.2 (55.9%)
Conventional	N.A. (N.A.)	N.A. (N.A.)	N.A. (N.A.)	19.4 (19.7%)	24.1 (25.2%)	24.5 (26.1%)	26.6	60.8 (47.1%)
Oil	3.8 (4.3%)	1.4 (1.7%)	2.3 (2.8%)	4.7 (4.7%)	2.7 (2.8%)	3.5 (3.7%)	(24.5)	6.3 (4.9%)
Coal	N.A. (N.A.)	N.A. (N.A.)	N.A. (N.A.)	2.6 (2.7%)	4.7 (5.0%)	4.1 (4.4%)	57.0	22.5* (17.4%)
Hydro	6.2 (7.0%)	6.4 (7.9%)	6.6 (7.9%)	5.1 (5.2%)	9.3 (9.7%)	9.1 (9.7%)	78.3	15.5 (12.0%)
Geothermal	3.9 (4.4%)	4.8 (5.9%)	6.2 (7.4%)	7.0 (7.1%)	7.4 (7.7%)	7.8 (8.3%)	11.2	16.5 (12.8%)
NONCONVENTIONAL	-	0.6 (0.7%)	0.6 (0.7%)	14.6 (14.9%)	14.2 (14.9%)	15.0 (15.9%)	2.0	11.4 (8.8%)
Bagasse	-	-	-	5.5 (5.6%)	5.4 (5.7%)	6.6 (7.0%)	20.1	
Coconut Husk/shell	-	-	-	3.5 (3.6%)	-	3.2 (3.4%)	(10.0)	
Wood and Woodwaste	-	-	-	4.4 (4.5%)	8.7 (9.1%)	4.0 (4.3%)	(9.9)	5.3 (4.1%)
Rice Husk	-	-	-	0.7 (0.7%)	-	0.7 (0.7%)	1.4	
Others	-	0.6 (0.7%)	0.6 (0.7%)	0.5 (0.5%)	0.1 (0.1%)	0.5 (0.5%)	(6.1)	6.1 (4.7%)
IMPORTED	N.A. (N.A.)	N.A. (N.A.)	N.A. (N.A.)	64.4 (65.5%)	57.2 (59.6)	54.5 (58.0%)	(15.5)	56.9 (44.1%)
Oil	73.7 (83.3%)	67.1 (82.6%)	66.5 (79.7%)	63.5 (64.5%)	55.6 (58.2%)	53.1 (56.5%)	(16.4)	56.9 (44.1%)
Coal	N.A. (N.A.)	N.A. (N.A.)	N.A. (N.A.)	0.9 (1.0%)	1.6 (1.7%)	1.4 (1.5%)	49.5	-
Total	88.5 (100%)	81.2 (100%)	83.4 (100%)	98.4 (100%)	95.5 (100%)	94.0 (100%)	(4.6)	129.1 (100%)
Oil Dependence (%)	87.6	84.4	82.5	69.3	61.0	60.2	(1.3)	49.0
Oil Import Dependence (%)	83.3	82.6	79.7	64.5	58.2	56.5	(2.9)	44.1

Source : Philippine Development Plan, 1983-1987 1984 Philippine Development Report, Statistical Yearbook, 1984

Note : 1) N.A. is by reason that the rate of Indigenous and Imported amount is unclear

2) Target for 1987 is from Five-year Development Plan and is changed in Updated Philippine Development Plan

INSTALLED GENERATING CAPACITY IN THE PHILIPPINES

Unit : MW

	1983	1984	Growth Rate (Percent)
Plant Type			
Hydro	1,585.0(27.6%)	1,666.1(28.2%)	5.1
Geothermal	784.0(13.7%)	894.0(15.1%)	14.0
Coal	119.7(2.1%)	479.7(8.1%)	300.8
Oil/Diesel	3,079.7(53.7%)	2,689.3(45.6%)	(-12.7)
Nonconventional*	167.1(2.9%)	179.8(3.0%)	7.6
Nuclear	-	-	-
TOTAL	5,735.5(100%)	5,908.9(100%)	3.0
Utility Source			
NPC	5,001.0(87.2%)	5,196.0(87.9%)	3.9
NEA	117.3(2.0%)	135.0(2.3%)	15.1
Private Utilities and Self-generating industries	617.2(10.8%)	577.9(9.8%)	(-6.4)
TOTAL	5,735.5(100%)	5,908.9(100%)	3.0

*Includes dendrothermal, solar and others.
Sources: Ministry of Energy, National Power Corporation, National Electrificaiton Administration, and Board of Energy.

ELECTRICITY GENERATION IN THE PHILIPPINES

Unit : GWh

	1983	1984	Grouwth Rate (Percent)
Power Source			
Hydro	2,994(14.0%)	5,256(24.9%)	75.6
Geothermal	4,093(19.1%)	4,536(21.5%)	10.8
Coal	1,155(5.4%)	1,186(5.6%)	2.7
Oil/Diesel	12,353(57.5%)	9,310(41.0%)	(-24.6)
Nonconventional*	847(4.0%)	827(5.5%)	(-2.4)
Nuclear	-	-	-
TOTAL	21,442(100%)	21,115(100%)	(-1.5)
Utility Source			
NPC	18,682(87.1%)	18,693(88.5%)	0.1
NEA	98(0.5%)	32(0.2%)	(-67.3)
Private Utilities and Self-generating industries	2,662(12.4%)	2,390(11.3%)	(-10.2)
TOTAL	21,442(100%)	21,115(100%)	(-1.5)

*Includes dendrothermal, solar and others.
Sources: Ministry of Energy, National Power Corporation, National Electrification Administration, and Board of Energy.

TOTAL ELECTRICITY CONSUMPTION BY SECTOR IN THE PHILIPPINES*

Unit : GWh

	1983	1984	Growth Rate (Percent)
Residential	4,116(19.2%)	4,118(19.5%)	-
Commercial	3,451(16.1%)	3,167(15.0%)	(-8.2)
Industrial	8,966(41.8%)	8,656(41.0%)	(-3.5)
Utilities' own use and losses	3,901(18.2%)	4,012(19.0%)	2.8
Others**	1,008(4.7%)	1,162(5.5%)	15.3
TOTAL	21,442(100%)	21,115(100%)	(-1.5)

*Also equal to NPC, NEA and other power plants' generation.
**Includes consumption by government offices, streetlights, irrigation/water supply.
Sources: Ministry of Energy

STATUS OF HOUSEHOLD ELECTRIFICATION AS OF 1984 IN THE PHILIPPINES

Item	Potential Connections ('000)	Actual Household Connections ('000)	Percent Coverage
Cooperatives	5,722	2,500	43.7
Private*	3,178	1,700	53.5
TOTAL	8,900	4,200	47.2

*Estimates.
Sources: Ministry of Energy and National Electrificaiton Administration.

STATUS OF ELECTRIC COOPERATIVE IN THE PHILIPPINES

	1982	1983	1984
Cooperative	112	118	120
Municipalities Electrified	1,149	1,195	1,220
Barangay Electrified	15,779	17,140	18,250
Household Connections	2,031,040	2,284,000	2,485,000
Peak Load (kW)	595,732	604,250	598,000
Load Factor(%)	35.05	38.18	40.37
MWh Purchased/Generated	2,326,624	2,599,126	2,727,000
MWh Sold	1,829,339	2,020,778	2,115,000
Coop Consumption(MWh)	12,730	13,526	
Systems Loss(%)	21.4	22.3	22.4
Average Systems Rate(P)	0.73	0.92	
Average Power Cost/kWh(P)	0.41	0.54	

Source: National Electrification Administration

STATUS OF ELECTRIFICATION BY PALECO

	1982	1983	1984
1. Municipalities			
-Coverage	4	4	6
-Electrified	4	4	6
2. Barangays			
-Coverage	124	124	152
-Electrified	59	66	90
3. No. of Consummer			
-Coverage	14,358	18,070	24,524
-Electrified	9,807	11,674	13,728
Residential	7,840	9,262	10,724
Commercial	1,626	1,985	2,471
Industrial	4	6	4
Public Buildings	337	421	529
Street Lights	(625)	(648)	(737)
4. Generation Capacity(kW)	6,350	6,700	6,830
5. Energy Generation (kWh)	8,504,609	9,156,110	8,949,392
6. Energy sold (kWh)	7,102,787	7,499,223	7,280,120
Residential	2,037,011	2,183,154	2,256,952
Commercial	2,720,141	2,609,506	1,849,017
Industrial	414,252	698,413	1,353,959
Public Buildings	1,789,507	1,861,575	1,660,557
Street Lights	141,876	146,575	159,635
7. Coop. Consumption (kWh)	165,773	221,763	144,663
8. System Loss (kWh)	1,236,049	1,435,124	1,524,609
" (%)	15	16	17
9. Peak Load (kW)	2,430	2,780	2,835

kWh UNIT COST OF PALECO

		1982	1983	1984
1. Energy Sold(kWh)	A	7,102,787	7,499,223	7,280,120
2. Operating Revenues (₱)	B	13,246,211	15,553,586	25,123,793
3. Expenses (₱)	C	14,691,212	17,028,925	26,750,716
-Operating Expenses	D	11,378,766	13,161,178	22,123,078
-Power Generation Expenses	E	9,026,689	10,570,139	18,358,494
-Interest	F	1,771,546	2,316,899	2,867,249
-Depreciaiton	G	1,540,900	1,550,848	1,762,389
4. Power Generation Unit Cost(₱/kWh)	D/A	1.2709	1.4095	2.5217
5. Unit Cost(₱/kWh)	C/A	2.0684	2.2708	3.6745
6. Average Selling Rate(₱/kWh)	B/A	1.8649	2.0740	3.4510

STATUS OF ELECTRIFICATION BY PALECO (NARRA)

	1982	1983	1984
1. Municipalities			
-Coverage	2	2	2
-Electrified	2	2	2
2. Barangays			
-Coverage	37	37	37
-Electrified	21	23	28
3. No. of Consummer			
-Coverage	4,978	5,660	7,156
-Electrified	2,574	3,078	3,495
Residential	1,982	2,334	2,617
Commercial	502	619	722
Industrial	-	-	-
Public Buildings	90	125	156
Street Lights	(63)	(94)	(105)
4. Generation Capacity(kW)	700	800	800
5. Energy Generation (kWh)	806,721	1,104,274	980,776
6. Energy Sold (kWh)	623,444	802,654	785,725
Residential	288,548	336,163	337,088
Commercial	240,447	330,739	281,879
Public Buildings	53,656	88,750	119,189
Street Lights	40,793	47,002	47,569
7. Coop. Consumption (kWh)	52,611	111,225	23,596
8. System Loss (kWh)	130,666	190,395	171,455
" (%)	16%	17%	17%
9. Peak Load (kW)	300	350	350

STATUS OF ELECTRIFICATION BY PALECO (BROOKE'S POINT)

	1982	1983	1984
1. Municipalities			
-Coverage	1	1	1
-Electrified	1	1	1
2. Barangays			
-Coverage	27	27	27
-Electrified	5	10	12
3. No. of Consummer			
-Coverage	2,354	5,063	5,275
-Electrified	854	1,417	1,692
Residential	681	1,087	1,260
Commercial	149	287	375
Industrial	-	-	-
Public Buildings	24	43	57
Street Lights	(12)	(10)	(23)
4. Generation Capacity(kW)	150	400	400
5. Energy Generation (kWh)	137,306	319,534	491,033
6. Energy sold (kWh)	106,226	245,823	406,816
Residential	63,906	136,021	210,984
Commercial	34,285	87,523	162,509
Industrial	-	-	-
Public Buildings	6,954	20,586	30,348
Street Lights	1,081	1,693	2,975
7. Coop. Consumption (kWh)	4,511	5,609	12,286
8. System Loss (kWh)	26,569	68,102	71,931
" (%)	19%	21%	15%
9. Peak Load (kW)	130	230	210

ENERGY STATUS OF RIO TUBA MINE

	Running Hours	Total Energy Generated (kWh)	Total Fuel Consumption (Liters)	
1977	24,545	5,144,440	1,673,203	
1978	25,091	6,952,606	2,137,186	
1979	22,043	6,202,932	1,888,378	
1980	18,343	5,276,176	1,623,004	
1981	14,762	4,349,070	1,328,074	
1982	16,230	3,793,762	1,190,960	A-971,253 C-219,437
1983	11,735	2,130,264	712,563	A- 53,682 C-658,881
1984	13,593	2,136,404	696,265	A- 33,656 C-662,609

Note: A:Diesel Oil
C:Bunker C

	Energy Consumption (kWh)					
	Drying & Crushing	Plant-site	Town-site	Mine-site	Power Plant	Pier-site
1977	4,211,156	200,024	95,424	2,332	256,515	64,568
1978	5,427,568	286,462	589,462	8,671	317,012	90,757
1979	4,737,673	261,566	521,944	42,944	306,227	100,464
1980	3,792,900	297,636	595,512	30,742	243,752	84,622
1981	2,633,444	400,429	708,488	87,231	235,639	50,921
1982	1,935,366	406,170	698,480	143,730	308,659	97,412
1983	193,624	418,872	707,496	128,556	394,930	74,864
1984	223,297	388,891	740,976	118,640	389,617	66,274

kWh UNIT COST OF DIESEL GENERATION AT RIO TUBA MINE

Item	1981	1982	1983	1984
Total Cost (₱ x 1000) 1/	5,028.5	4,640.6	2,479.1	2,800.7
Distributed Energy (MWh) 2/	4,113.5	3,485.1	1,735.4	1,746.8
kWh Unit Cost (₱/kWh)	1.22	1.33	1.43	1.60
" ($/kWh)	0.1557	0.1572	0.1285	0.0958

Note 1/ Except interest and depreciation

2/ Except auxiliary use

ESTIMATED POPULATION GROWTH RATE

Year	ABORLAN	NARRA	BROOKE's POINT	QUEZON	BATARAZA	MARCOS
1975-1980	2.45 1/	3.57 1/	4.61 1/	4.52 1/	2.99 1/	-
1980-1985	2.2	3.2	4.0	4.5	3.5	3.5
1985-1990	2.0	2.8	3.5	4.5	3.5	4.0
1990-1995	1.8	2.4	3.0	4.0	3.5	3.5
1995-2000	1.6	2.0	2.6	3.5	3.0	3.0
2000-2005	1.4	1.7	2.2	3.0	2.6	2.6
2005-	1.2	1.4	1.8	2.6	2.2	2.2

Note: 1/ Actual

1) The population growth rate for Aborlan has decreased in recent years and this trend is envisioned to continue hereafter. However, PIADP is planning the construciton of numerous feeder roads into the area, and accordingly the population decrease is expected to be less than that originally projected by the Provincial Government Office.

2) The Provincial Government Office projected that the population growth rates in Narra and Brooke's Point would decrease suddenly. Although some decrease may occur due to promotion of family planning, migration to the area is also forecasted in view of its large area. Accordingly, a sudden, drastic decrease in the population growth rate is not envisioned.

3) Quezon and Marcos have large tracts of fertile cultivative lands. Main and feeder roads are now being built and, if electrificaiton also progresses, a large populaiton increase is forecasted. Even at present, the population is growing rapidly due to both migration and the high birth rate.

ESTIMATED PEAK AND ENERGY DEMANDS UNDER PALECO FOR PROJECT (OVERALL)

	Year	ABORLAN Peak Demand (kW)	ABORLAN Energy Demand (MWh)	NARRA Peak Demand (kW)	NARRA Energy Demand (MWh)	BROOKE'S POINT Peak Demand (kW)	BROOKE'S POINT Energy Demand (MWh)	QUEZON Peak Demand (kW)	QUEZON Energy Demand (MWh)	BATARAZA Peak Demand (kW)	BATARAZA Energy Demand (MWh)	MARCOS Peak Demand (kW)	MARCOS Energy Demand (MWh)	TOTAL Peak Demand (kW)	TOTAL Energy Demand (MWh)
1	1989	138	185	398	608	413	555	82	105	67	80	28	31	1,127	1,564
2	1990	159	515	466	1,711	509	1,643	105	319	85	241	34	89	1,357	4,517
3	1991	183	593	538	1,984	614	1,988	130	396	104	298	39	104	1,609	5,362
4	1992	209	679	615	2,273	732	2,376	158	483	126	382	46	121	1,886	6,294
5	1993	222	722	653	2,419	864	2,811	190	583	151	434	49	130	2,129	7,100
6	1994	235	767	693	2,575	1,011	3,298	226	696	179	515	53	141	2,397	7,993
7	1995	249	816	735	2,741	1,175	3,844	267	825	211	607	57	152	2,694	8,984
8	1996	264	866	781	2,923	1,256	4,119	288	891	226	652	61	163	2,876	9,613
9	1997	279	919	831	3,117	1,342	4,414	311	962	242	701	65	175	3,070	10,288
10	1998	296	975	883	3,324	1,435	4,730	335	1,040	260	753	70	188	3,278	11,010
11	1999	313	1,148	939	3,857	1,533	5,626	361	1,259	278	918	75	232	3,500	13,041
12	2000	331	1,218	999	4,112	1,639	6,027	389	1,380	298	986	81	249	3,736	13,952
13	2001	350	1,289	1,059	4,371	1,745	6,431	417	1,462	319	1,055	86	267	3,975	14,874
14	2002	369	1,365	1,122	4,646	1,857	6,862	447	1,571	341	1,129	92	285	4,229	15,859
15	2003	390	1,445	1,190	4,938	1,977	7,322	480	1,689	364	1,208	98	305	4,499	16,908
16	2004	412	1,530	1,262	5,250	2,105	7,814	515	1,816	389	1,293	105	326	4,787	18,028
17	2005	436	1,620	1,338	5,580	2,241	8,339	552	1,952	415	1,384	112	348	5,094	19,223
18	2006	459	1,712	1,414	5,915	2,377	8,864	590	2,090	442	1,475	119	371	5,401	20,427
19	2007	484	1,809	1,495	6,269	2,521	9,422	631	2,238	470	1,572	126	395	5,727	21,707
20	2008	510	1,912	1,580	6,645	2,674	10,016	674	2,397	500	1,676	135	421	6,073	23,067

ESTIMATED PEAK AND ENERGY DEMANDS UNDER PALECO (ABORLAN)

	Coverage			Residential				Commercial				Total	
	Year	Population	Household	Household Electrified	Average Demand (W)	Peak Demand (kW)	Energy Demand (MWh)	Number	Average Demand (W)	Peak Demand (kW)	Energy Demand (MWh)	Peak Demand (kW)	Energy Demand (MWh)
	1980	11,799	2,185										
1	1989	14,240	2,637	1,450	80	116	106	363	170	62	79	138	185
2	1990	14,524	2,690	1,614	83	134	294	403	179	72	221	159	515
3	1991	14,786	2,738	1,780	87	154	337	445	187	83	256	183	593
4	1992	15,052	2,787	1,951	90	176	385	488	197	96	294	209	679
5	1993	15,323	2,838	1,986	94	186	407	497	207	103	315	222	722
6	1994	15,599	2,889	2,022	97	197	431	506	217	110	336	235	767
7	1995	15,880	2,941	2,058	101	208	456	515	228	117	359	249	816
8	1996	16,134	2,988	2,091	105	220	482	523	239	125	383	264	866
9	1997	16,392	3,036	2,125	109	233	509	531	251	133	409	279	919
10	1998	16,854	3,084	2,159	114	246	538	540	264	142	436	296	975
11	1999	16,921	3,133	2,193	118	260	683	548	277	152	466	313	1,148
12	2000	17,191	3,184	2,228	123	274	721	557	291	162	497	331	1,218
13	2001	17,432	3,228	2,260	128	289	761	565	305	172	529	350	1,289
14	2002	17,678	3,273	2,291	133	305	802	573	321	184	563	369	1,365
15	2003	17,923	3,319	2,323	139	322	846	581	337	196	599	390	1,445
16	2004	18,174	3,366	2,356	144	339	892	589	353	208	638	412	1,530
17	2005	18,429	3,413	2,389	150	358	941	597	371	222	680	436	1,620
18	2006	18,650	3,454	2,418	156	377	990	604	390	235	722	459	1,712
19	2007	18,874	3,495	2,447	162	397	1,042	612	409	250	767	484	1,809
20	2008	19,100	3,537	2,476	169	417	1,097	619	430	266	815	510	1,912

ESTIMATED PEAK AND ENERGY DEMANDS UNDER PALECO (NARRA)

	Coverage			Residential				Commercial				Total	
	Year	Population	Household	Household Electrified	Average Demand (W)	Peak Demand (kW)	Energy Demand (MWh)	Number	Average Demand (W)	Peak Demand (kW)	Energy Demand (MWh)	Peak Demand (kW)	Energy Demand (MWh)
	1980	30,099	5,375										
1	1989	39,348	7,026	3,865	80	309	282	1,159	220	255	326	398	608
2	1990	40,450	7,223	4,334	83	361	790	1,300	231	300	921	466	1,711
3	1991	41,421	7,397	4,808	87	416	911	1,442	243	350	1,073	538	1,984
4	1992	42,166	7,530	5,271	90	474	1,039	1,581	255	403	1,235	615	2,273
5	1993	42,925	7,665	5,366	94	502	1,100	1,610	267	430	1,320	653	2,419
6	1994	43,898	7,803	5,462	97	532	1,164	1,639	281	460	1,411	693	2,575
7	1995	44,484	7,944	5,561	101	563	1,233	1,668	295	492	1,508	735	2,741
8	1996	45,374	8,103	5,672	105	597	1,308	1,702	310	527	1,615	781	2,923
9	1997	46,282	8,265	5,785	109	633	1,387	1,736	325	564	1,730	831	3,117
10	1998	47,207	8,430	5,901	114	672	1,471	1,770	341	604	1,852	883	3,324
11	1999	48,151	8,598	6,019	118	713	1,873	1,806	358	647	1,984	939	3,857
12	2000	49,114	8,770	6,139	123	756	1,987	1,842	376	693	2,125	999	4,112
13	2001	49,949	8,920	6,244	128	800	2,102	1,873	395	740	2,269	1,059	4,371
14	2002	50,798	9,071	6,350	133	846	2,223	1,905	415	790	2,423	1,122	4,646
15	2003	51,662	9,225	6,458	139	895	2,351	1,937	436	844	2,587	1,190	4,938
16	2004	52,540	9,382	6,568	144	946	2,487	1,970	457	901	2,763	1,262	5,250
17	2005	53,433	9,542	6,679	150	1,001	2,630	2,004	480	962	2,950	1,338	5,580
18	2006	54,181	9,675	6,773	156	1,055	2,774	2,032	504	1,025	3,141	1,414	5,915
19	2007	54,940	9,811	6,868	162	1,113	2,925	2,060	529	1,091	3,344	1,495	6,269
20	2008	55,709	9,948	6,964	169	1,174	3,085	2,089	556	1,161	3,561	1,580	6,645

ESTIMATED PEAK AND ENERGY DEMANDS UNDER PALECO (BROOKE'S POINT)

	Coverage			Residential				Commercial				Total	
	Year	Population	Household	Household Electrified	Average Demand (W)	Peak Demand (kW)	Energy Demand (MWh)	Number	Average Demand (W)	Peak Demand (kW)	Energy Demand (MWh)	Peak Demand (kW)	Energy Demand (MWh)
	1980	46.320	8.908										
1	1989	64.669	12.436	4.353	80	348	318	1,088	170	185	237	413	555
2	1990	66.932	12.872	5.149	83	428	938	1.287	179	230	704	509	1.643
3	1991	68.940	13.258	5.966	87	516	1.131	1.492	187	280	857	614	1.988
4	1992	71.009	13.656	6.828	90	614	1.346	1.707	197	336	1.030	732	2.376
5	1993	73.139	14.065	7.736	94	724	1.586	1.934	207	400	1.225	864	2.811
6	1994	75.333	14.487	8.692	97	846	1.853	2.173	217	471	1.446	1.011	3.298
7	1995	77.593	14.922	9.699	101	982	2.150	2.425	228	552	1.694	1.175	3.844
8	1996	79.611	15.310	9.951	105	1.048	2.294	2.488	239	595	1.825	1.256	4.119
9	1997	81.680	15.708	10.210	109	1.118	2.448	2.553	251	641	1.968	1.342	4.414
10	1998	83.804	16.116	10.476	114	1.193	2.612	2.619	264	691	2.118	1.435	4.730
11	1999	85.983	16.535	10.748	118	1.273	3.345	2.687	277	744	2.281	1.533	5.626
12	2000	88.219	16.965	11.027	123	1.358	3.569	2.757	291	802	2.458	1.639	6.027
13	2001	90.159	17.338	11.270	128	1.443	3.793	2.817	305	860	2.637	1.745	6.431
14	2002	92.143	17.720	11.518	133	1.534	4.032	2.879	321	923	2.830	1.857	6.862
15	2003	94.170	18.110	11.771	139	1.631	4.286	2.943	337	991	3.037	1.977	7.322
16	2004	96.242	18.508	12.030	144	1.733	4.555	3.008	353	1.063	3.259	2.105	7.814
17	2005	98.359	18.915	12.295	150	1.842	4.841	3.074	371	1.141	3.497	2.241	8.339
18	2006	100.130	19.256	12.516	156	1.950	5.126	3.129	390	1.219	3.738	2.377	8.864
19	2007	101.932	19.602	12.741	162	2.065	5.427	3.185	409	1.303	3.998	2.521	9.422
20	2008	103,767	19.955	12.971	169	2.186	5.745	3.243	430	1,393	4.271	2.674	10,016

ESTIMATED PEAK AND ENERGY DEMANDS UNDER PALECO (QUEZON)

	Coverage			Residential				Commercial				Total	
	Year	Population	Household	Household Electrified	Average Demand (W)	Peak Demand (kW)	Energy Demand (MWh)	Number	Average Demand (W)	Peak Demand (kW)	Energy Demand (MWh)	Peak Demand (kW)	Energy Demand (MWh)
	1980	10.063	1.864										
1	1989	14.955	2.991	897	80	72	66	179	170	31	39	82	105
2	1990	15.628	3.126	1.094	83	91	199	219	179	39	120	105	319
3	1991	16.253	3.251	1.300	87	113	246	260	187	49	149	130	396
4	1992	16.903	3.381	1.521	90	137	300	304	197	60	184	158	483
5	1993	17.579	3.516	1.758	94	165	360	352	207	73	223	190	583
6	1994	18.282	3.656	2.011	97	196	429	402	217	87	268	226	696
7	1995	19.013	3.803	2.282	101	231	506	456	228	104	319	267	825
8	1996	19.679	3.936	2.361	105	249	544	472	239	113	346	288	891
9	1997	20.368	4.074	2.444	109	268	586	489	251	123	376	311	962
10	1998	21.080	4.216	2.530	114	288	631	506	264	133	409	335	1.040
11	1999	21.818	4.364	2.618	118	310	815	524	277	145	445	361	1.259
12	2000	22.582	4.516	2.710	123	334	877	542	291	158	483	389	1.360
13	2001	23.259	4.652	2.791	128	357	939	558	305	170	523	417	1.462
14	2002	23.957	4.791	2.875	133	383	1.006	575	321	184	565	447	1.571
15	2003	24.676	4.935	2.961	139	410	1.078	592	337	199	611	480	1.689
16	2004	25.416	5.083	3.050	144	439	1.155	610	353	216	661	515	1.816
17	2005	26.179	5.236	3.141	150	471	1.237	628	371	233	715	552	1.952
18	2006	26.859	5.372	3.223	156	502	1.320	645	390	251	770	590	2.090
19	2007	27.557	5.511	3.307	162	536	1.408	661	409	271	830	631	2.238
20	2008	28.274	5.655	3.393	169	572	1.503	679	430	292	894	674	2.397

ESTIMATED PEAK AND ENERGY DEMANDS UNDER PALECO (ABTARAZA)

	Coverage			Residential				Commercial				Total	
	Year	Population	Household	Household Electrified	Average Demand (W)	Peak Demand (kW)	Energy Demand (MWh)	Number	Average Demand (W)	Peak Demand (kW)	Energy Demand (MWh)	Peak Demand (kW)	Energy Demand (MWh)
	1980	8,696	1,850										
1	1989	11,852	2,522	756	80	61	55	113	170	19	25	67	80
2	1990	12,267	2,610	913	83	76	166	137	179	24	75	85	241
3	1991	12,696	2,701	1,081	87	93	205	162	187	30	93	104	298
4	1992	13,140	2,796	1,258	90	113	248	189	197	37	114	126	362
5	1993	13,600	2,894	1,447	94	135	297	217	207	45	137	151	434
6	1994	14,076	2,995	1,647	97	160	351	247	217	54	164	179	515
7	1995	14,569	3,100	1,860	101	188	412	279	228	64	195	211	607
8	1996	15,006	3,193	1,916	105	202	442	287	239	69	211	226	652
9	1997	15,456	3,289	1,973	109	216	473	296	251	74	228	242	701
10	1998	15,920	3,387	2,032	114	231	507	305	264	80	246	260	753
11	1999	16,397	3,489	2,093	118	248	651	314	277	87	267	278	918
12	2000	16,889	3,593	2,156	123	266	698	323	291	94	288	298	986
13	2001	17,328	3,687	2,212	128	283	745	332	305	101	311	319	1,055
14	2002	17,779	3,783	2,270	133	302	795	340	321	109	335	341	1,129
15	2003	18,241	3,881	2,329	139	323	848	349	337	118	360	364	1,208
16	2004	18,715	3,982	2,389	144	344	905	358	353	127	388	389	1,293
17	2005	19,202	4,086	2,451	150	367	965	368	371	136	418	415	1,384
18	2006	19,625	4,175	2,505	156	390	1,026	376	390	146	449	442	1,475
19	2007	20,056	4,267	2,560	162	415	1,090	384	409	157	482	470	1,572
20	2008	20,497	4,361	2,617	169	441	1,159	393	430	169	517	500	1,676

ESTIMATED PEAK AND ENERGY DEMANDS UNDER PALECO (MARCOS)

	Coverage			Residential				Commercial				Total	
	Year	Population	Household	Household Electrified	Average Demand (W)	Peak Demand (kW)	Energy Demand (MWh)	Number	Average Demand (W)	Peak Demand (kW)	Energy Demand (MWh)	Peak Demand (kW)	Energy Demand (MWh)
	1980	2,168	401										
1	1989	3,012	602	331	80	27	24	33	170	6	7	28	31
2	1990	3,133	627	376	83	31	68	38	179	7	21	34	89
3	1991	3,242	648	422	87	36	80	42	187	8	24	39	104
4	1992	3,356	671	470	90	42	93	47	197	9	28	46	121
5	1993	3,473	695	486	94	46	100	49	207	10	31	49	130
6	1994	3,595	719	503	97	49	107	50	217	11	33	53	141
7	1995	3,721	744	521	101	53	115	52	228	12	36	57	152
8	1996	3,832	766	537	105	56	124	54	239	13	39	61	163
9	1997	3,947	789	553	109	61	133	55	251	14	43	65	175
10	1998	4,066	813	569	114	65	142	57	264	15	46	70	188
11	1999	4,188	838	586	118	69	182	59	277	16	50	75	232
12	2000	4,313	863	604	123	74	195	60	291	18	54	81	249
13	2001	4,426	885	620	128	79	209	62	305	19	58	86	267
14	2002	4,541	908	636	133	85	223	64	321	20	62	92	285
15	2003	4,659	932	652	139	90	237	65	337	22	67	98	305
16	2004	4,780	956	669	144	96	253	67	353	24	73	105	326
17	2005	4,904	981	687	150	103	270	69	371	25	78	112	348
18	2006	5,012	1,002	702	156	109	287	70	390	27	84	119	371
19	2007	5,122	1,024	717	162	116	305	72	409	29	90	126	395
20	2008	5,235	1,047	733	169	124	325	73	430	31	97	135	421

SUMMARY OF DEMAND FORECAST FOR PROJECT

	Year	Rio Tuba Mine		under PALECO		TOTAL	
		Peak Demand (kW)	Energy Demand (MWh)	Peak Demand (kW)	Energy Demand (MWh)	Peak Demand (kW)	Energy Demand (MWh)
1	1989	8,500	74,460	1,127	1,564 1/	9,627	76,024
2	1990	8,500	74,460	1,357	4,517	9,857	78,977
3	1991	8,500	74,460	1,609	5,362	10,109	79,822
4	1992	8,500	74,460	1,886	6,294	10,386	80,754
5	1993	8,500	74,460	2,129	7,100	10,629	81,560
6	1994	8,500	74,460	2,397	7,993	10,897	82,453
7	1995	8,500	74,460	2,694	8,984	11,194	83,444
8	1996	8,500	74,460	2,876	9,613	11,376	84,073
9	1997	8,500	74,460	3,070	10,288	11,570	84,748
10	1998	8,500	74,460	3,278	11,010	11,778	85,470
11	1999	8,500	74,460	3,500	13,041	12,000	87,501
12	2000	8,500	74,460	3,736	13,952	12,236	88,412
13	2001	8,500	74,460	3,975	14,874	12,475	89,334
14	2002	8,500	74,460	4,229	15,859	12,729	90,319
15	2003	8,500	74,460	4,499	16,908	12,999	91,368
16	2004	8,500	74,460	4,787	18,028	13,287	93,488
17	2005	8,500	74,460	5,094	19,223	13,594	93,683
18	2006	8,500	74,460	5,401	20,427	13,901	94,887
19	2007	8,500	74,460	5,727	21,707	14,227	96,167
20	2008	8,500	74,460	6,073	23,067	14,573	97,527

1/ Between August and December 1989.

BALANCE BETWEEN ENERGY DEMAND AND SUPPLY WITH PROJECT

	Year	Energy Demand Rio Tuba (MWh)	Hydropower Energy 1/ Total Supply (MWh)	PALECO Use (MWh)	Available for Rio Tuba (MWh)	Required Diesel Supply (MWh)
1	1989	72,600	17,090 2/	1,410 2/	15,680 2/	56,920
2	1990	72,600	29,020	4,080	24,940	47,660
3	1991	72,600	29,020	4,850	24,170	48,430
4	1992	72,600	29,020	5,690	23,330	49,270
5	1993	72,600	29,020	6,420	22,600	50,000
6	1994	72,600	29,020	6,420	22,600	50,000
7	1995	72,600	29,020	6,420	22,600	50,000
8	1996	72,600	29,020	6,420	22,600	50,000
9	1997	72,600	29,020	6,420	22,600	50,000
10	1998	72,600	29,020	6,420	22,600	50,000
11	1999	72,600	29,020	6,420	22,600	50,000
12	2000	72,600	29,020	6,420	22,600	50,000
13	2001	72,600	29,020	6,420	22,600	50,000
14	2002	72,600	29,020	6,420	22,600	50,000
15	2003	72,600	29,020	6,420	22,600	50,000
16	2004	72,600	29,020	6,420	22,600	50,000
17	2005	72,600	29,020	6,420	22,600	50,000
18	2006	72,600	29,020	6,420	22,600	50,000
19	2007	72,600	29,020	6,420	22,600	50,000
20	2008	72,600	29,020	6,420	22,600	50,000

Note: 1/ Considering energy loss; stop factor, auxiliary use loss of transmission line and transformers.
2/ Between August and December, 1979.

TABLE 5-1

POWER VALUE CALCULATION

Discription	Unit	Remarks
I. Alternative Diesel Plant		
Installed Capacity	5,000kWx3Unit	
Annual Operation Hours	8,760hr	Plant Factor 85%
Service Life	17 years	
Generator Terminal Energy	10,000x8,760x0.85 = 74,460MWh	
Auxiliary Power Use	2.5%	
Annual Generated Energy	74,460x(1-0.025) = 72,599MWh	
Construction Cost	$1,200\times10^{6}$yen	
II. Power Value		
kW Value		$CRF = \frac{0.08(1+0.08)^{17}}{(1+0.08)^{17}-1} = 0.11$
1) Capital Recovery Cost	$1,200\times10^{6}\times0.11 = 132\times10^{6}$yen	Interest 8%
2) O&M and Administrative Cost	$1,200\times10^{6}\times0.031 = 37.2\times10^{6}$yen	Ratio 3.1%
3) Total Fixed Cost	169.2×10^{16}yen	1)+2)
4) Unit Fixed Cost per kW	11,280yen/kW	
5) kW value	11,280x0.97 = 10,940yen/kW	Adjustment Factor for kW Value α = 0.97
kWh Value		
1) Fuel Cost	71.01yen/ℓ	4.9076₱/ℓx1.066x13.573¥/₱ = 71.01yen/ℓ
2) Fuel Consumption per kWh	0.204ℓ/kWh	
3) Fuel Cost per kWh	71.01x0.204 = 14.49yen/kWh	Adjustment Factor for kWh Value β = 1.00
4) kWh Value	14.49÷(1-0.025)x1.00 = 14.86yen/kWh	

Loss	(kW) Hydro	(kW) Diesel	(kWh) Hydro	(kWh) Diesel	
Transmission Loss	4.8%	0.5%	4.1%	2.0%	$= \frac{(1-0.048)(1-0.005)(1-0.01)(1-0.02)}{(1-0.005)(1-0.02)(1-0.025)} = 0.97$
Forced Dutage	0.5	2.0	-	-	
Auxiliary Power Use	1.0	2.5	0.5	2.5	
Overhaul	2.0	(8.2)	(5.0)	-	$= \frac{(1-0.041)(1-0.005)}{(1-0.02)(1-0.025)} = 1.00$

OPTIMIZATION STUDY FOR INTAKE-OUTLET SITE

Item	Intake I.W.L.	Candawaga R. 280m	Candawage R. 260m				Candawaga R. 235m		
	Outlet	Candawaga R.	Culasian R.		Candawaga R.		Culasian R.		Candawaga R.
	T.W.L.	101m	63m	79m	72m	101m	63m	79m	101m
	Case No.	1	2	3	4	5	6	7	8
Catchment Area	km^2	30.0	30.8	30.8	30.8	30.8	32.9	32.9	32.9
Water Way									
Channel	m	1.5x7,200	1.5x7,700	1.5x7,000	1.5x9,700	1.5x6,400	1.5x7,100	1.5x5,750	1.5x6,700
Penstock	m	370	552	600	490	310	380	510	250
Access Road	m	12,200	9,500	10,900	9,400	12,200	9,500	10,900	12,200
Connection Road	m	2,200	2,800	3,300	2,600	2,200	4,100	4,400	1,900
Power Plant Scheme		Run-of River Type							
Intake Water Level	EL.m	280	260	260	260	260	235	235	235
Head Tank Water Level	EL.m	272.8	252.3	253.0	250.3	253.6	227.9	229.2	228.3
Tailrace Water Level	EL.m	101	63	79	72	101	63	79	101
Effective Head	m	168.8	185.1	170.1	174.5	149.4	161.5	146.8	124.2
Maximum Discharge	m^3/s	3.85	3.85	3.85	3.85	3.85	3.85	3.85	3.85
Maximum Output	kW	5,470	6,000	5,520	5,660	4,840	5,240	4,760	4,030
Annual Generated Energy	GWh	28.8	32.1	29.5	30.3	25.9	29.1	26.4	22.2
Construction Cost	10^6¥	4,051	3,950	3,964	4,307	3,827	3,833	3,770	3,729
Construction Cost per kWh	¥/kWh	140.8	123.1	134.4	142.1	147.8	131.7	142.8	168.0
Benefit/Cost Ratio	B/C	0.943	1.078	0.987	0.933	0.897	1.007	0.929	0.790
Benefit - Cost	10^6¥	-23.4	31.1	-5.3	-29.3	-39.8	2.6	-27.3	-79.5

TABLE 5-3

OPTIMIZATION STUDY FOR MAXIMUM DISCHARGE

Item	Case	Proposed Culasian P/S Scheme					Alternative Candawaga P/S Scheme				
		Qmax = 3.5m³/s	3.7	3.85	4.1	4.3	Qmax = 3.5m³/s	3.7	3.85	4.1	4.7
Catchment Area	Km²			30.8					30.0		
Intake Water Level	EL.m			260.0					280.0		
Head tank Water Level	EL.m			252.3					272.8		
Tailrace Water Level	EL.m			63.0					101.0		
Effective Head	m	184.9	185.0	185.1	185.2	185.3	168.6	168.7	168.8	168.9	169.0
Maximum Discharge	m³/s	3.5	3.7	3.85	4.1	4.3	3.5	3.7	3.85	4.1	4.3
Maximum Output	kW	5,450	5,770	6,000	6,400	6,710	4,960	5,250	5,470	5,830	6,120
Annual Generated Energy	GWh	30.6	31.5	32.1	32.7	33.1	27.6	28.3	28.8	29.4	29.8
Number of Generator	unit	2	2	2	2	2	2	2	2	2	2
Construction Cost	10⁶¥	3,813	3,887	3,950	4,057	4,141	3,939	4,005	4,051	4,136	4,200
Construction Cost per kWh	¥/kWh	124.2	123.4	123.1	124.1	125.1	142.8	141.5	140.7	140.7	140.9
Benefit/Cost Retio		1.068	1.075	1.078	1.069	1.060	0.929	0.937	0.943	0.943	0.941
Benefit - Cost	10⁶¥	26.1	29.4	31.1	28.3	25.1	-28.2	-25.6	-23.4	-24.0	-25.2

Note: Fuel Cost per kWh : 14.86¥/kWh
Annual Cost for Hydropower Plant is 10.13% of Construction Cost.

MONTHLY OUTPUT AND GENERATED ENERGY

Hydropower Generation for 1975-1984Candawaga-Culasian Scheme Intake:EL.260.00 m C.A.:30.8 sq.km Q:3.65 CMS

Year	Item	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave./T
1975	Q (CMS)	3.849	3.237	2.228	1.588	1.246	2.989	3.026	3.787	3.849	3.849	3.849	3.838	3.104
	EffHead(m)	185.020	186.372	188.017	188.775	189.089	186.685	186.736	185.371	185.020	185.020	185.020	185.054	186.348
	Output (kW)	5999.9	5123.5	3469.1	2541.3	1963.2	4710.7	4780.7	5806.1	5999.9	5999.9	5999.9	5984.6	4863.4
	G.Engy.(MWh)	4463.99	3443.03	2581.05	1829.79	1460.63	3391.77	3556.85	4319.77	4319.99	4463.99	4319.99	4452.55	42603.40
1976	Q (CMS)	3.646	2.253	1.310	0.853	0.589	1.522	2.519	2.396	3.554	2.815	3.861	3.361	2.324
	EffHead(m)	185.490	187.972	189.035	189.379	189.527	131.495	187.433	187.662	185.667	187.104	186.620	186.085	182.865
	Output (kW)	5715.3	3537.3	2080.6	1273.8	813.1	2364.0	3968.0	3769.7	5571.6	4442.0	4812.0	5291.7	3638.5
	G.Engy.(MWh)	4252.20	2461.99	1547.97	916.60	605.02	1702.10	2952.24	2804.66	4011.59	3304.89	3464.67	3937.08	31961.00
1977	Q (CMS)	2.303	1.535	0.996	0.522	0.318	1.150	3.538	3.619	3.849	3.840	3.262	2.408	2.285
	EffHead(m)	187.909	188.836	189.280	170.579	110.058	93.734	185.727	185.558	185.020	185.048	186.312	187.722	171.307
	Output (kW)	3596.5	2462.2	1528.3	717.3	432.0	1797.2	5561.0	5678.4	5999.9	5988.2	5156.8	3778.6	3568.6
	G.Engy.(MWh)	2675.80	1654.64	1137.09	516.46	321.42	1294.03	4137.40	4224.77	4319.99	4455.23	3712.90	2811.28	31261.00
1978	Q (CMS)	1.508	0.935	0.626	0.066	0.433	0.637	0.326	1.740	3.082	3.803	3.746	3.085	1.669
	EffHead(m)	188.858	189.325	189.508	25.276	67.032	189.502	85.546	169.950	186.454	185.135	185.276	186.626	153.832
	Output (kW)	2413.0	1418.7	877.4	87.0	665.3	895.3	469.4	2701.8	4830.6	5937.3	5859.7	4875.2	2591.8
	G.Engy.(MWh)	1795.28	953.39	652.79	62.67	495.03	644.62	349.25	2010.20	3478.05	4417.39	4218.99	3627.16	22704.80
1979	Q (CMS)	1.751	1.004	0.651	0.833	0.812	1.639	3.775	3.706	2.866	3.849	3.842	3.290	2.346
	EffHead(m)	188.595	189.277	189.495	170.285	189.398	188.470	185.212	185.360	187.010	185.020	185.044	186.233	185.788
	Output (kW)	2762.8	1543.1	919.8	1237.3	1203.7	2539.1	5900.1	5802.0	4522.0	5999.9	5990.1	5189.0	3651.9
	G.Engy.(MWh)	2055.58	1036.99	684.34	890.87	895.62	1828.16	4389.69	4316.70	3255.87	4463.99	4312.89	3860.66	31991.40
1980	Q (CMS)	1.987	1.514	0.917	0.773	1.071	2.415	3.845	3.712	3.464	3.417	2.647	2.483	2.359
	EffHead(m)	188.323	188.809	189.335	189.361	189.031	187.426	185.033	185.360	185.885	185.995	187.390	187.594	187.454
	Output (kW)	3126.5	2409.0	1387.8	1122.4	1617.1	3770.1	5994.4	5811.4	5451.5	5388.9	4168.1	3886.8	3684.8
	G.Engy.(MWh)	2326.12	1676.69	1032.56	808.17	1203.15	2714.53	4459.90	4323.75	3925.14	4009.40	3001.04	2887.35	32367.80
1981	Q (CMS)	3.164	2.040	1.113	0.664	0.381	1.750	2.725	3.600	3.261	3.107	3.060	3.772	2.391
	EffHead(m)	186.422	188.257	189.192	189.489	128.398	162.921	187.183	185.599	186.208	186.594	186.680	185.216	180.101
	Output (kW)	4972.2	3202.0	1735.0	941.8	521.0	2728.3	4265.4	5651.3	5113.5	4911.4	4842.0	5895.7	3739.6
	G.Engy.(MWh)	3699.35	2151.75	1290.85	678.14	387.66	1964.43	3173.47	4204.62	3681.78	3654.13	3486.29	4386.42	32758.90
1982	Q (CMS)	2.399	1.370	0.842	0.688	0.827	1.972	2.905	2.424	1.990	2.340	1.970	1.299	1.756
	EffHead(m)	187.749	188.987	189.384	189.468	91.135	187.950	186.921	187.601	188.317	187.720	188.350	189.044	180.056
	Output (kW)	3775.3	2185.8	1255.4	985.5	1291.9	3090.6	4577.8	3808.3	3125.3	3675.5	3092.3	2061.0	2750.1
	G.Engy.(MWh)	2808.87	1468.37	934.05	709.59	961.17	2225.23	3405.91	2833.38	2250.24	2734.58	2226.52	1533.45	24091.30
1983	Q (CMS)	0.869	0.360	0.000	0.000	0.000	1.109	3.353	3.759	3.757	3.849	3.849	3.849	2.076
	EffHead(m)	189.362	121.848	0.000	0.000	0.000	74.675	186.078	185.224	185.275	185.020	185.020	185.020	124.966
	Output (kW)	1300.6	490.9	0.0	0.0	0.0	1724.9	5274.4	5871.0	5877.3	5999.9	5999.9	5999.9	3231.8
	G.Engy.(MWh)	967.64	329.90	0.00	0.00	0.00	1241.94	3924.17	4368.05	4231.70	4463.99	4319.99	4463.99	28311.40
1984	Q (CMS)	3.706	3.072	1.762	1.696	2.405	3.209	3.153	3.580	3.306	3.829	3.849	3.849	3.113
	EffHead(m)	185.387	186.644	188.587	188.569	187.579	186.292	186.467	185.825	186.186	185.076	185.020	185.020	186.385
	Output (kW)	5807.2	4850.4	2786.8	2686.1	3761.3	5027.1	4967.7	5512.6	5211.6	5972.9	5999.9	5999.9	4883.8
	G.Engy.(MWh)	4320.58	3375.89	2073.44	1933.99	2798.45	3619.57	3695.97	4101.38	3752.41	4443.90	4319.99	4463.99	42899.50
Ave/T	Q (CMS)	2.518	1.693	1.045	0.768	0.808	1.839	2.916	3.216	3.298	3.470	3.314	3.124	2.338
	EffHead(m)	187.311	176.987	170.183	150.118	134.125	158.915	176.234	184.351	186.104	185.773	186.073	186.361	173.561
	Output (kW)	3946.9	2660.8	1604.0	1159.2	1226.9	2864.7	4575.9	5041.3	5170.3	5431.6	5192.1	4895.6	3653.4
	G.Engy.(MWh)	2936.54	1851.92	1193.41	834.63	912.81	2062.64	3404.48	3750.73	3722.67	4041.15	3738.32	3642.39	32091.70

MAIN FEATURES OF ALTERNATIVE CANDAWAGA P/S SCHEME

Item		Discription	Remarks
River for Intake		Candawaga River	
Power Station Location		along Candawaga River	
River for Outlet		Candawaga River	
Catchment Area	km^2	30.8	
Outline of Development Scheme			
Generation Method		Run-of-River Type	
Intake Water Level	EL.m	280	
Tailrace Water Level	EL.m	101	
Gross Head	m	179	
Maximam Output	kW	5,470	
Maximam Discharge	m^3/s	3.85	
Effective Head	m	168.8	
Minimum Output	kW	700	
Annual Generated Energy	GWh	28.8	10 years average
Outline of Facilities			
Intake Dam			
Type		Concrete Gravity	
HeightxCrest Length	m	14 x 50	
Water Way Length (total)	m	7,520	
Open Channel	m	7,200	
Tunnel	m	-	
Penstock Line	m	320	ϕ1,650-620mm
Powerhouse		each 2,870kW x 2 unit	Horizontal Shaft Francis Turbine
Transmission Line	km	39.5	69kV x 1cct
Substation	unit	2	
Access Road	m	12,200	
Connection Road	m	2,600	
Construciton Cost	10^6¥	4,051	
Construction Cost per kWh	¥/kWh	140.7	
Benefit/Cost Ratio	B/C	0.943	Annual Cost 10.13%
Benefit - Cost	10^6¥	-23.4	at Consumer End

CONSTRUCTION COST FOR ALTERNATIVE CANDAWAGA P/S SCHEME

Unit : million yen

1. Civil Works	2,013.5
(1) Intake dam	187.7
(2) Intake	48.2
(3) Setlling basin	39.0
(4) Headrace	809.0
(5) Head tank (incl. over-flow seciton)	116.2
(6) Penstock	89.2
(7) Powerhouse (house, basement)	182.9
(8) Miscellaneous works (incl. temporary works)	541.3
2. Electrio-mechanical Facility	803.9
(1) Power equipments (turbine, generator, transformer etc.)	543.3
(2) Rio Tuba Side Substation	103.8
(3) Transmission line (incl. distribution line to Candawaga & Culasian)	156.8
3. Land Acquisition and Compensaiton	31.5
4. Administraiton	598.2
5. Physical Contingency	333.9
6. Interest during construciton period	270.0
TOTAL	4,051

45-YEAR kWh COST FOR PROPOSED HYDROPOWER

Discount Rate 5.0%

unit Million Yen

	Year	Book Value	Interest	Deprecia- tion	Real Property Tax	Personnel Expense	Repair Expense	Others Expense	Administ- ration Expense	Total Fixed Expense	Fixed Cost (¥/kWh	Discount Factor	Discount Value (¥/kWh)	Accumu- lated Value (¥/kWh)	Capital Recovery Factor	Capital Recovery Cost (¥/kWh)
1	1989	3,950.00	233.05	79.00	49.15	11.43	15.80	3.95	2.49	394.87	13.61	0.944287	12.85	12.85	1.059000	13.61
2	1990	3,871.00	228.39	79.00	48.16	11.43	15.80	3.95	2.49	389.23	13.41	0.891678	11.96	24.81	0.544673	13.51
3	1991	3,792.00	223.73	79.00	47.18	11.43	15.80	3.95	2.49	383.58	13.22	0.842000	11.13	35.94	0.373418	13.42
4	1992	3,713.00	219.07	79.00	51.33	11.43	15.80	3.95	2.49	383.07	13.20	0.795090	10.50	46.43	0.287931	13.37
5	1993	3,634.00	214.41	79.00	50.24	11.43	15.80	3.95	2.49	377.32	13.00	0.750793	9.76	56.20	0.236751	13.30
6	1994	3,555.00	209.75	79.00	49.15	11.43	15.80	3.95	2.49	371.57	12.80	0.708964	9.08	65.27	0.202724	13.23
7	1995	3,476.00	205.08	79.00	48.06	11.43	15.80	3.95	2.49	365.81	12.61	0.669466	8.44	73.71	0.178499	13.16
8	1996	3,397.00	200.42	79.00	46.96	11.43	15.80	3.95	2.49	360.06	12.41	0.632168	7.84	81.56	0.160399	13.08
9	1997	3,318.00	195.76	79.00	45.87	11.43	15.80	3.95	2.49	354.31	12.21	0.596948	7.29	88.84	0.146383	13.01
10	1998	3,239.00	191.10	79.00	44.78	11.43	15.80	3.95	2.49	348.55	12.01	0.563690	6.77	95.61	0.135225	12.93
11	1999	3,160.00	186.44	79.00	43.69	11.43	15.80	3.95	2.49	342.80	11.81	0.532285	6.29	101.90	0.128145	12.85
12	2000	3,081.00	181.78	79.00	42.59	11.43	15.80	3.95	2.49	337.05	11.61	0.502630	5.84	107.74	0.118624	12.78
13	2001	3,002.00	177.12	79.00	41.50	11.43	15.80	3.95	2.49	331.30	11.42	0.474627	5.42	113.16	0.112301	12.71
14	2002	2,923.00	172.46	79.00	40.41	11.43	15.80	3.95	2.49	325.54	11.22	0.448184	5.03	118.19	0.106920	12.64
15	2003	2,844.00	167.80	79.00	39.32	11.43	15.80	3.95	2.49	319.79	11.02	0.423215	4.66	122.85	0.102291	12.57
16	2004	2,765.00	163.14	79.00	38.23	11.43	15.80	3.95	2.49	314.04	10.82	0.399636	4.32	127.17	0.098274	12.50
17	2005	2,686.00	158.47	79.00	37.13	11.43	15.80	3.95	2.49	308.28	10.62	0.377371	4.01	131.18	0.094760	12.43
18	2006	2,607.00	153.81	79.00	36.04	11.43	15.80	3.95	2.49	302.53	10.42	0.356347	3.71	134.90	0.091664	12.37
19	2007	2,528.00	149.15	79.00	34.95	11.43	15.80	3.95	2.49	296.78	10.23	0.336494	3.44	138.34	0.088922	12.30
20	2008	2,449.00	144.49	79.00	33.86	11.43	15.80	3.95	2.49	291.02	10.03	0.317747	3.19	141.52	0.086478	12.24
21	2009	2,370.00	139.83	79.00	32.77	11.43	15.80	3.95	2.49	285.27	9.83	0.300044	2.95	144.47	0.084291	12.18
22	2010	2,291.00	135.17	79.00	31.67	11.43	15.80	3.95	2.49	279.52	9.63	0.283328	2.73	147.20	0.082325	12.12
23	2011	2,212.00	130.51	79.00	30.58	11.43	15.80	3.95	2.49	273.76	9.43	0.267543	2.52	149.73	0.080551	12.06
24	2012	2,133.00	125.85	79.00	29.49	11.43	15.80	3.95	2.49	268.01	9.24	0.252637	2.33	152.06	0.078944	12.00
25	2013	2,054.00	121.19	79.00	28.40	11.43	15.80	3.95	2.49	262.26	9.04	0.238562	2.16	154.22	0.077485	11.95
26	2014	1,975.00	116.53	79.00	27.30	11.43	15.80	3.95	2.49	256.50	8.84	0.225271	1.99	156.21	0.076156	11.90
27	2015	1,896.00	111.86	79.00	26.21	11.43	15.80	3.95	2.49	250.75	8.64	0.212720	1.84	158.05	0.074942	11.84
28	2016	1,817.00	107.20	79.00	25.12	11.43	15.80	3.95	2.49	245.00	8.44	0.200869	1.70	159.74	0.073830	11.79
29	2017	1,738.00	102.54	79.00	24.03	11.43	15.80	3.95	2.49	239.24	8.24	0.189678	1.56	161.30	0.072811	11.74
30	2018	1,659.00	97.88	79.00	22.94	11.43	15.80	3.95	2.49	233.49	8.05	0.179111	1.44	162.75	0.071873	11.70
31	2019	1,580.00	93.22	79.00	21.84	11.43	15.80	3.95	2.49	227.74	7.85	0.169132	1.33	164.07	0.071010	11.65
32	2020	1,501.00	88.56	79.00	20.75	11.43	15.80	3.95	2.49	221.98	7.65	0.159709	1.22	165.30	0.070214	11.61
33	2021	1,422.00	83.90	79.00	19.66	11.43	15.80	3.95	2.49	216.23	7.45	0.150811	1.12	166.42	0.069478	11.56
34	2022	1,343.00	79.24	79.00	18.57	11.43	15.80	3.95	2.49	210.48	7.25	0.142409	1.03	167.45	0.068797	11.52
35	2023	1,264.00	74.58	79.00	17.47	11.43	15.80	3.95	2.49	204.73	7.05	0.134475	0.95	168.40	0.068167	11.48
36	2024	1,185.00	69.92	79.00	16.38	11.43	15.80	3.95	2.49	198.97	6.86	0.126983	0.87	169.27	0.067582	11.44
37	2025	1,106.00	65.25	79.00	15.29	11.43	15.80	3.95	2.49	193.22	6.66	0.119908	0.80	170.07	0.067038	11.40
38	2026	1,027.00	60.59	79.00	14.20	11.43	15.80	3.95	2.49	187.47	6.46	0.113228	0.73	170.80	0.066533	11.36
39	2027	948.00	55.93	79.00	13.11	11.43	15.80	3.95	2.49	181.71	6.26	0.106920	0.67	171.47	0.066063	11.33
40	2028	869.00	51.27	79.00	12.01	11.43	15.80	3.95	2.49	175.96	6.06	0.100963	0.61	172.08	0.065626	11.29
41	2029	790.00	46.61	79.00	10.92	11.43	15.80	3.95	2.49	170.21	5.87	0.095338	0.56	172.64	0.065218	11.26
42	2030	711.00	41.95	79.00	9.83	11.43	15.80	3.95	2.49	164.45	5.67	0.090026	0.51	173.15	0.064837	11.23
43	2031	632.00	37.29	79.00	8.74	11.43	15.80	3.95	2.49	158.70	5.47	0.085011	0.46	173.62	0.064482	11.20
44	2032	553.00	32.63	79.00	7.65	11.43	15.80	3.95	2.49	152.95	5.27	0.080275	0.42	174.04	0.064150	11.16
45	2033	474.00	27.97	79.00	6.55	11.43	15.80	3.95	2.49	147.19	5.07	0.075802	0.38	174.42	0.063839	11.14

45-YEAR kWh COST FOR DIESEL (5,000kW x 3)

Discount Rate 8% unit Million Yen

	Year	Book Value	Interest	Deprecia-tion	Real Property Tax	Personnel Expense	Repair Expense	Others Expense	Administ-ration Expense	Total Fixed Expense	Fixed Cost (Y/kWh)	Fuel Cost (Y/l)	Variable Cost (Y/kWh)	kWh Unit Cost (Y/kWh)	Discount Factor	Discount Value (Y/kWh)	Accumu-lated Value (Y/kWh)	Capital Recovery Factor	Capital Recovery Cost (Yen/kWh)
1	1989	1,200.00	96.00	63.60	25.65	16.00	25.08	1.20	3.38	230.91	3.18	74.78	15.49	18.67	0.925926	17.28	17.28	1.080000	18.67
2	1990	1,136.40	90.91	63.60	24.29	16.00	25.08	1.20	3.38	224.46	3.09	75.75	15.69	18.78	0.857339	16.10	33.38	0.560769	18.72
3	1991	1,072.80	85.82	63.60	22.93	16.00	25.08	1.20	3.38	218.02	3.00	76.73	15.89	18.89	0.793832	15.00	48.38	0.388034	18.77
4	1992	1,009.20	80.74	63.60	23.97	16.00	25.08	1.20	3.38	213.97	2.95	77.73	16.10	19.04	0.735030	14.00	62.38	0.301921	18.83
5	1993	945.60	75.65	63.60	22.46	16.00	25.08	1.20	3.38	207.37	2.86	78.74	16.31	19.16	0.680583	13.04	75.42	0.250456	18.89
6	1994	882.00	70.56	63.60	20.95	16.00	25.08	1.20	3.38	200.77	2.77	79.76	16.52	19.28	0.630170	12.15	87.58	0.216315	18.94
7	1995	818.40	65.47	63.60	19.44	16.00	25.08	1.20	3.38	194.17	2.67	80.80	16.73	19.41	0.583490	11.32	98.90	0.192072	19.00
8	1996	754.80	60.38	63.60	17.93	16.00	25.08	1.20	3.38	187.57	2.58	81.85	16.95	19.53	0.540269	10.55	109.45	0.174015	19.05
9	1997	691.20	55.30	63.60	16.42	16.00	25.08	1.20	3.38	180.97	2.49	82.91	17.17	19.66	0.500249	9.84	119.29	0.160080	19.10
10	1998	627.60	50.21	63.60	14.91	16.00	25.08	1.20	3.38	174.38	2.40	83.99	17.39	19.80	0.463193	9.17	128.46	0.149029	19.14
11	1999	564.00	45.12	63.60	13.40	16.00	25.08	1.20	3.38	167.78	2.31	85.08	17.62	19.93	0.428883	8.55	137.01	0.140076	19.19
12	2000	500.40	40.03	63.60	11.88	16.00	25.08	1.20	3.38	161.18	2.22	86.19	17.85	20.07	0.397114	7.97	144.98	0.132695	19.24
13	2001	436.80	34.94	63.60	10.37	16.00	25.08	1.20	3.38	154.58	2.13	87.31	18.08	20.21	0.367698	7.43	152.41	0.126522	19.28
14	2002	373.20	29.86	63.60	8.86	16.00	25.08	1.20	3.38	147.98	2.04	88.45	18.32	20.36	0.340461	6.93	159.34	0.121297	19.33
15	2003	309.60	24.77	63.60	7.35	16.00	25.08	1.20	3.38	141.38	1.95	89.60	18.56	20.50	0.315242	6.46	165.81	0.116830	19.37
16	2004	246.00	19.68	63.60	5.84	16.00	25.08	1.20	3.38	134.78	1.86	90.76	18.80	20.65	0.291890	6.03	171.83	0.112977	19.41
17	2005	182.40	14.59	63.60	4.33	16.00	25.08	1.20	3.38	128.19	1.77	91.94	19.04	20.81	0.270269	5.62	177.46	0.109629	19.45
18	2006	1,200.00	96.00	63.60	28.50	16.00	25.08	1.20	3.38	233.76	3.22	93.14	19.29	22.51	0.250249	5.63	183.09	0.106702	19.54
19	2007	1,136.40	90.91	63.60	26.99	16.00	25.08	1.20	3.38	227.16	3.13	94.35	19.54	22.67	0.231712	5.25	188.34	0.104128	19.61
20	2008	1,072.80	85.82	63.60	25.48	16.00	25.08	1.20	3.38	220.57	3.04	95.57	19.79	22.83	0.214548	4.90	193.24	0.101852	19.68
21	2009	1,009.20	80.74	63.60	23.97	16.00	25.08	1.20	3.38	213.97	2.95	96.82	20.05	23.00	0.198656	4.57	197.81	0.099832	19.75
22	2010	945.60	75.65	63.60	22.46	16.00	25.08	1.20	3.38	207.37	2.86	98.07	20.31	23.17	0.183941	4.26	202.07	0.098032	19.81
23	2011	882.00	70.56	63.60	20.95	16.00	25.08	1.20	3.38	200.77	2.77	99.35	20.58	23.34	0.170315	3.98	206.05	0.096422	19.87
24	2012	818.40	65.47	63.60	19.44	16.00	25.08	1.20	3.38	194.17	2.67	100.64	20.84	23.52	0.157699	3.71	209.78	0.094978	19.92
25	2013	754.80	60.38	63.60	17.93	16.00	25.08	1.20	3.38	187.57	2.58	101.95	21.11	23.70	0.146018	3.46	213.22	0.093679	19.97
26	2014	691.20	55.30	63.60	16.42	16.00	25.08	1.20	3.38	180.97	2.49	103.27	21.39	23.88	0.135202	3.23	216.44	0.092507	20.02
27	2015	627.60	50.21	63.60	14.91	16.00	25.08	1.20	3.38	174.38	2.40	104.62	21.67	24.07	0.125187	3.01	219.46	0.091448	20.07
28	2016	564.00	45.12	63.60	13.40	16.00	25.08	1.20	3.38	167.78	2.31	105.98	21.95	24.26	0.115914	2.81	222.27	0.090489	20.11
29	2017	500.40	40.03	63.60	11.88	16.00	25.08	1.20	3.38	161.18	2.22	107.35	22.23	24.45	0.107328	2.62	224.89	0.089619	20.15
30	2018	436.80	34.94	63.60	10.37	16.00	25.08	1.20	3.38	154.58	2.13	108.75	22.52	24.65	0.099377	2.45	227.34	0.088827	20.19
31	2019	373.20	29.86	63.60	8.86	16.00	25.08	1.20	3.38	147.98	2.04	110.16	22.82	24.85	0.092016	2.29	229.63	0.088107	20.23
32	2020	309.60	24.77	63.60	7.35	16.00	25.08	1.20	3.38	141.38	1.95	111.60	23.11	25.06	0.085200	2.14	231.77	0.087451	20.27
33	2021	246.00	19.68	63.60	5.84	16.00	25.08	1.20	3.38	134.78	1.86	113.05	23.41	25.27	0.078889	1.99	233.76	0.086852	20.30
34	2022	182.40	14.59	63.60	4.33	16.00	25.08	1.20	3.38	128.19	1.77	114.52	23.72	25.48	0.073045	1.86	235.62	0.086304	20.33
35	2023	1,200.00	96.00	63.60	28.50	16.00	25.08	1.20	3.38	233.76	3.22	116.01	24.02	27.24	0.067635	1.84	237.46	0.085803	20.38
36	2024	1,136.40	90.91	63.60	26.99	16.00	25.08	1.20	3.38	227.16	3.13	117.51	24.34	27.47	0.062625	1.72	239.18	0.085345	20.41
37	2025	1,072.80	85.82	63.60	25.48	16.00	25.08	1.20	3.38	220.57	3.04	119.04	24.65	27.69	0.057986	1.61	240.79	0.084924	20.45
38	2026	1,009.20	80.74	63.60	23.97	16.00	25.08	1.20	3.38	213.97	2.95	120.59	24.97	27.92	0.053690	1.50	242.29	0.084539	20.48
39	2027	945.60	75.65	63.60	22.46	16.00	25.08	1.20	3.38	207.37	2.86	122.16	25.30	28.15	0.049713	1.40	243.69	0.084185	20.51
40	2028	882.00	70.56	63.60	20.95	16.00	25.08	1.20	3.38	200.77	2.77	123.74	25.63	28.39	0.046031	1.31	244.99	0.083860	20.55
41	2029	818.40	65.47	63.60	19.44	16.00	25.08	1.20	3.38	194.17	2.67	125.35	25.96	28.64	0.042621	1.22	246.21	0.083561	20.57
42	2030	754.80	60.38	63.60	17.93	16.00	25.08	1.20	3.38	187.57	2.58	126.98	26.30	28.88	0.039464	1.14	247.35	0.083287	20.60
43	2031	691.20	55.30	63.60	16.42	16.00	25.08	1.20	3.38	180.97	2.49	128.63	26.64	29.13	0.036541	1.06	248.42	0.083034	20.63
44	2032	627.60	50.21	63.60	14.91	16.00	25.08	1.20	3.38	174.38	2.40	130.31	26.99	29.39	0.033834	0.99	249.41	0.082802	20.65
45	2033	564.00	45.12	63.60	13.40	16.00	25.08	1.20	3.38	167.78	2.31	132.00	27.34	29.65	0.031328	0.93	250.34	0.082587	20.68

45-YEAR kWh COST FOR DIESEL (5,000kW x 3) WITH HYDROPOWER

Interest Rate 8%　　　　　　　　unit　Million Yen

	Year	Book Value	Interest	Deprecia-tion	Real Property Tax	Personnel Expense	Repair Expense	Others Expense	Administ-ration Expense	Total Fixed Expense	Fixed Cost (¥/kWh)	Fuel Cost (¥/l)	Variable Cost (¥/kWh)	kWh Unit Cost (¥/kWh)	Discount Factor	Discount Value (¥/kWh)	Accumu-lated Value (¥/kWh)	Capital Recovery Factor	Capital Recovery Cost (Yen/kWh)
1	1989	1,200.00	96.00	56.88	25.65	13.72	21.32	1.02	2.88	217.47	3.82	74.78	16.02	19.84	0.925926	18.37	18.37	1.080000	19.84
2	1990	1,143.12	91.45	56.88	24.43	13.72	21.32	1.02	2.88	211.71	4.44	75.75	16.23	20.67	0.857339	17.72	36.09	0.560769	20.24
3	1991	1,086.24	86.90	56.88	23.22	13.72	21.32	1.02	2.88	205.94	4.25	76.73	16.44	20.69	0.793832	16.42	52.51	0.388034	20.38
4	1992	1,029.36	82.35	56.88	24.45	13.72	21.32	1.02	2.88	202.62	4.11	77.73	16.65	20.76	0.735030	15.26	67.77	0.301921	20.46
5	1993	972.48	77.80	56.88	23.10	13.72	21.32	1.02	2.88	196.72	3.93	78.74	16.87	20.80	0.680583	14.16	81.93	0.250456	20.52
6	1994	915.60	73.25	56.88	21.75	13.72	21.32	1.02	2.88	190.82	3.82	79.76	17.09	20.90	0.630170	13.17	95.10	0.216315	20.57
7	1995	858.72	68.70	56.88	20.39	13.72	21.32	1.02	2.88	184.91	3.70	80.80	17.31	21.01	0.583490	12.26	107.36	0.192072	20.62
8	1996	801.84	64.15	56.88	19.04	13.72	21.32	1.02	2.88	179.01	3.58	81.85	17.53	21.11	0.540269	11.41	118.76	0.174015	20.67
9	1997	744.96	59.60	56.88	17.69	13.72	21.32	1.02	2.88	173.11	3.46	82.91	17.76	21.22	0.500249	10.62	129.38	0.160080	20.71
10	1998	688.08	55.05	56.88	16.34	13.72	21.32	1.02	2.88	167.21	3.34	83.99	17.99	21.34	0.463193	9.88	139.26	0.149029	20.75
11	1999	631.20	50.50	56.88	14.99	13.72	21.32	1.02	2.88	161.31	3.23	85.08	18.23	21.45	0.428883	9.20	148.46	0.140076	20.80
12	2000	574.32	45.95	56.88	13.64	13.72	21.32	1.02	2.88	155.41	3.11	86.19	18.46	21.57	0.397114	8.57	157.03	0.132695	20.84
13	2001	517.44	41.40	56.88	12.29	13.72	21.32	1.02	2.88	149.51	2.99	87.31	18.70	21.69	0.367698	7.98	165.00	0.126522	20.88
14	2002	460.56	36.84	56.88	10.94	13.72	21.32	1.02	2.88	143.61	2.87	88.45	18.95	21.82	0.340461	7.43	172.43	0.121297	20.92
15	2003	403.68	32.29	56.88	9.59	13.72	21.32	1.02	2.88	137.70	2.75	89.60	19.19	21.95	0.315242	6.92	179.35	0.116830	20.95
16	2004	346.80	27.74	56.88	8.24	13.72	21.32	1.02	2.88	131.80	2.64	90.76	19.44	22.08	0.291890	6.44	185.79	0.112977	20.98
17	2005	289.92	23.19	56.88	6.89	13.72	21.32	1.02	2.88	125.90	2.52	91.94	19.69	22.21	0.270269	6.00	191.80	0.109629	21.03
18	2006	233.04	18.64	56.88	5.53	13.72	21.32	1.02	2.88	120.00	2.40	93.14	19.95	22.35	0.250249	5.59	197.39	0.106702	21.06
19	2007	176.16	14.09	56.88	4.18	13.72	21.32	1.02	2.88	114.10	2.28	94.35	20.21	22.49	0.231712	5.21	202.60	0.104128	21.10
20	2008	1,200.00	96.00	56.88	28.50	13.72	21.32	1.02	2.88	220.32	4.41	95.57	20.47	24.88	0.214548	5.34	207.94	0.101852	21.18
21	2009	1,143.12	91.45	56.88	27.15	13.72	21.32	1.02	2.88	214.42	4.29	96.82	20.74	25.03	0.198656	4.97	212.91	0.099832	21.26
22	2010	1,086.24	86.90	56.88	25.80	13.72	21.32	1.02	2.88	208.52	4.17	98.07	21.01	25.18	0.183941	4.63	217.54	0.098032	21.33
23	2011	1,029.36	82.35	56.88	24.45	13.72	21.32	1.02	2.88	202.62	4.05	99.35	21.28	25.33	0.170315	4.31	221.86	0.096422	21.39
24	2012	972.48	77.80	56.88	23.10	13.72	21.32	1.02	2.88	196.72	3.93	100.64	21.56	25.49	0.157699	4.02	225.88	0.094978	21.45
25	2013	915.60	73.25	56.88	21.75	13.72	21.32	1.02	2.88	190.82	3.82	101.95	21.84	25.65	0.146018	3.75	229.62	0.093679	21.51
26	2014	858.72	68.70	56.88	20.39	13.72	21.32	1.02	2.88	184.91	3.70	103.27	22.12	25.82	0.135202	3.49	233.11	0.092507	21.56
27	2015	801.84	64.15	56.88	19.04	13.72	21.32	1.02	2.88	179.01	3.58	104.62	22.41	25.99	0.125187	3.25	236.37	0.091448	21.62
28	2016	744.96	59.60	56.88	17.69	13.72	21.32	1.02	2.88	173.11	3.46	105.98	22.70	26.16	0.115914	3.03	239.40	0.090489	21.66
29	2017	688.08	55.05	56.88	16.34	13.72	21.32	1.02	2.88	167.21	3.34	107.35	23.00	26.34	0.107328	2.83	242.23	0.089619	21.71
30	2018	631.20	50.50	56.88	14.99	13.72	21.32	1.02	2.88	161.31	3.23	108.75	23.29	26.52	0.099377	2.64	244.86	0.088827	21.75
31	2019	574.32	45.95	56.88	13.64	13.72	21.32	1.02	2.88	155.41	3.11	110.16	23.60	26.71	0.092016	2.46	247.32	0.088107	21.79
32	2020	517.44	41.40	56.88	12.29	13.72	21.32	1.02	2.88	149.51	2.99	111.60	23.90	26.89	0.085200	2.29	249.61	0.087451	21.83
33	2021	460.56	36.84	56.88	10.94	13.72	21.32	1.02	2.88	143.61	2.87	113.05	24.21	27.09	0.078889	2.14	251.75	0.086852	21.86
34	2022	403.68	32.29	56.88	9.59	13.72	21.32	1.02	2.88	137.70	2.75	114.52	24.53	27.28	0.073045	1.99	253.74	0.086304	21.90
35	2023	346.80	27.74	56.88	8.24	13.72	21.32	1.02	2.88	131.80	2.64	116.01	24.85	27.48	0.067635	1.86	255.60	0.085803	21.93
36	2024	289.92	23.19	56.88	6.89	13.72	21.32	1.02	2.88	125.90	2.52	117.51	25.17	27.69	0.062625	1.73	257.33	0.085345	21.96
37	2025	233.04	18.64	56.88	5.53	13.72	21.32	1.02	2.88	120.00	2.40	119.04	25.50	27.90	0.057986	1.62	258.95	0.084924	21.99
38	2026	176.16	14.09	56.88	4.18	13.72	21.32	1.02	2.88	114.10	2.28	120.59	25.83	28.11	0.053690	1.51	260.46	0.084539	22.02
39	2027	1,200.00	96.00	56.88	28.50	13.72	21.32	1.02	2.88	220.32	4.41	122.16	26.17	30.57	0.049713	1.52	261.98	0.084185	22.05
40	2028	1,143.12	91.45	56.88	27.15	13.72	21.32	1.02	2.88	214.42	4.29	123.74	26.51	30.79	0.046031	1.42	263.40	0.083860	22.09
41	2029	1,086.24	86.90	56.88	25.80	13.72	21.32	1.02	2.88	208.52	4.17	125.35	26.85	31.02	0.042621	1.32	264.72	0.083561	22.12
42	2030	1,029.36	82.35	56.88	24.45	13.72	21.32	1.02	2.88	202.62	4.05	126.98	27.20	31.25	0.039464	1.23	265.95	0.083287	22.15
43	2031	972.48	77.80	56.88	23.10	13.72	21.32	1.02	2.88	196.72	3.93	128.63	27.55	31.49	0.036541	1.15	267.10	0.083034	22.18
44	2032	915.60	73.25	56.88	21.75	13.72	21.32	1.02	2.88	190.82	3.82	130.31	27.91	31.73	0.033834	1.07	268.18	0.082802	22.21
45	2033	858.72	68.70	56.88	20.39	13.72	21.32	1.02	2.88	184.91	3.70	132.00	28.27	31.97	0.031328	1.00	269.18	0.082587	22.23

45-YEAR kWh COST FOR DIESEL AND HYDROPOWER COMBINAITON

		Available Energy			Diesel Power Plant		Hydro-power Plant		Combined with Diesel & Hydro	
	Year	Diesel Energy (MWh)	Hydro Energy (MWh)	Total Energy (MWh)	Unit Cost (¥/kWh)	Capital Recovery Cost (¥/kWh)	Unit Cost (¥/kWh)	Capital Recovery Cost (¥/kWh)	Unit Cost (¥/kWh)	Capital Recovery Cost (¥/kWh)
1	1989	14,570	17,090	31,660	19.34	19.84	13.61	13.61	16.47	16.47
2	1990	47,660	29,020	76,680	20.67	20.24	13.41	13.51	17.92	17.69
3	1991	48,430	29,020	77,450	20.69	20.38	13.22	13.42	17.89	17.77
4	1992	49,270	29,020	78,290	20.76	20.46	13.20	13.37	17.96	17.83
5	1993	50,000	29,020	79,020	20.80	20.52	13.00	13.30	17.94	17.87
6	1994	50,000	29,020	79,020	20.90	20.57	12.80	13.23	17.93	17.88
7	1995	50,000	29,020	79,020	21.01	20.62	12.61	13.16	17.92	17.88
8	1996	50,000	29,020	79,020	21.11	20.67	12.41	13.08	17.92	17.88
9	1997	50,000	29,020	79,020	21.22	20.71	12.21	13.01	17.91	17.88
10	1998	50,000	29,020	79,020	21.34	20.75	12.01	12.93	17.91	17.88
11	1999	50,000	29,020	79,020	21.45	20.80	11.81	12.85	17.91	17.88
12	2000	50,000	29,020	79,020	21.57	20.84	11.61	12.78	17.91	17.83
13	2001	50,000	29,020	79,020	21.69	20.88	11.42	12.71	17.92	17.88
14	2002	50,000	29,020	79,020	21.82	20.92	11.22	12.64	17.92	17.87
15	2003	50,000	29,020	79,020	21.95	20.95	11.02	12.57	17.93	17.87
16	2004	50,000	29,020	79,020	22.08	20.99	10.82	12.50	17.94	17.87
17	2005	50,000	29,020	79,020	22.21	21.03	10.62	12.43	17.96	17.87
18	2006	50,000	29,020	79,020	22.35	21.06	10.42	12.37	17.97	17.87
19	2007	50,000	29,020	79,020	22.49	21.10	10.23	12.30	17.99	17.87
20	2008	50,000	29,020	79,020	24.88	21.18	10.03	12.24	19.42	17.90
21	2009	50,000	29,020	79,020	25.03	21.26	9.83	12.18	19.45	17.92
22	2010	50,000	29,020	79,020	25.18	21.33	9.63	12.12	19.47	17.94
23	2011	50,000	29,020	79,020	25.33	21.39	9.43	12.06	19.49	17.96
24	2012	50,000	29,020	79,020	25.49	21.45	9.24	12.00	19.52	17.98
25	2013	50,000	29,020	79,020	25.65	21.51	9.04	11.95	19.55	18.00
26	2014	50,000	29,020	79,020	25.82	21.56	8.84	11.90	19.58	18.01
27	2015	50,000	29,020	79,020	25.99	21.62	8.64	11.84	19.62	18.03
28	2016	50,000	29,020	79,020	26.16	21.66	8.44	11.79	19.65	18.04
29	2017	50,000	29,020	79,020	26.34	21.71	8.24	11.74	19.69	18.05
30	2018	50,000	29,020	79,020	26.52	21.75	8.05	11.70	19.74	18.06
31	2019	50,000	29,020	79,020	26.71	21.79	7.85	11.65	19.78	18.07
32	2020	50,000	29,020	79,020	26.89	21.83	7.65	11.61	19.83	18.07
33	2021	50,000	29,020	79,020	27.09	21.86	7.45	11.56	19.88	18.08
34	2022	50,000	29,020	79,020	27.28	21.90	7.25	11.52	19.93	18.09
35	2023	50,000	29,020	79,020	27.48	21.93	7.05	11.48	19.98	18.09
36	2024	50,000	29,020	79,020	27.69	21.96	6.86	11.44	20.04	18.10
37	2025	50,000	29,020	79,020	27.90	21.99	6.66	11.40	20.10	18.10
38	2026	50,000	29,020	79,020	28.11	22.02	6.46	11.36	20.16	18.11
39	2027	50,000	29,020	79,020	30.57	22.05	6.26	11.33	21.64	18.12
40	2028	50,000	29,020	79,020	30.79	22.09	6.06	11.29	21.71	18.12
41	2029	50,000	29,020	79,020	31.02	22.12	5.87	11.26	21.78	18.13
42	2030	50,000	29,020	79,020	31.25	22.15	5.67	11.23	21.86	18.14
43	2031	50,000	29,020	79,020	31.49	22.18	5.47	11.20	21.93	18.14
44	2032	50,000	29,020	79,020	31.73	22.21	5.27	11.16	22.01	18.15
45	2033	50,000	29,020	79,020	31.97	22.23	5.07	11.14	22.09	18.16

SENSITIVITY ANALYSIS (CASE 1)

Million Yen

FIRR= 0.101087   NPV=-0.013818

Project Year	Year	Generation by Hydro and Diesel Power Plants: Investment: Hydro	Investment: Diesel	Operation and Maintenance: Hydropower Plant: Tax	Hydropower Plant: Repair /Others	Diesel Power Plant: Fuel	Diesel Power Plant: Tax	Diesel Power Plant: Repair /Others	Diesel Power Generation (w/o Hydro): Invest-ment	Operation & Maintenance: Fuel	Operation & Maintenance: Tax	Operation & Maintenance: Repair /Others	Cost	Benefit: Fuel Saving	Tax Saving	Repair /Others Saving	Turn-over from EnergySold	Total	Benefit - Co
1	1986	138.60											138.60					0.00	-138.60
2	1987	850.50											850.50					0.00	-850.50
3	1988	1645.35	1260.00						1260.00				1645.35					0.00	-1645.35
4	1989	1240.05		49.15	33.67	911.86	25.65	38.94		1124.48	25.65	45.66	1240.05	212.62	-49.15	-26.95	25.19	161.71	-1078.34
5	1990			48.16	33.67	773.52	24.43	38.94		1139.10	24.29	45.66	0.00	365.58	-48.30	-26.95	72.89	363.22	363.22
6	1991			47.18	33.67	810.00	23.22	38.94		1153.91	22.93	45.66	0.00	343.91	-47.47	-26.95	86.65	356.14	356.14
7	1992			51.33	33.67	832.50	24.45	38.94		1168.91	23.97	45.66	0.00	336.41	-51.81	-26.95	101.66	359.31	359.31
8	1993			50.24	33.67	843.32	23.10	38.94		1184.10	22.46	45.66	0.00	340.78	-50.88	-26.95	114.70	377.65	377.65
9	1994			49.15	33.67	854.29	21.75	38.94		1199.50	20.95	45.66	0.00	345.21	-49.95	-26.95	114.70	383.01	383.01
10	1995			48.06	33.67	865.39	20.39	38.94		1215.09	19.44	45.66	0.00	349.70	-49.01	-26.95	114.70	388.44	388.44
11	1996			46.96	33.67	876.64	19.04	38.94		1230.89	17.93	45.66	0.00	354.24	-48.07	-26.95	114.70	393.92	393.92
12	1997			45.87	33.67	888.04	17.69	38.94		1246.89	16.42	45.66	0.00	358.85	-47.14	-26.95	114.70	399.46	399.46
13	1998			44.78	33.67	899.58	16.34	38.94		1263.10	14.91	45.66	0.00	363.51	-46.21	-26.95	114.70	405.05	405.05
14	1999			43.69	33.67	911.28	14.99	38.94		1279.52	13.40	45.66	0.00	368.24	-45.28	-26.95	114.70	410.71	410.71
15	2000			42.59	33.67	923.12	13.64	38.94		1296.15	11.88	45.66	0.00	373.03	-44.35	-26.95	114.70	416.43	416.43
16	2001			41.50	33.67	935.12	12.29	38.94		1313.00	10.37	45.66	0.00	377.88	-43.42	-26.95	114.70	422.21	422.21
17	2002			40.41	33.67	947.28	10.94	38.94		1330.07	8.86	45.66	0.00	382.79	-42.49	-26.95	114.70	428.05	428.05
18	2003			39.32	33.67	959.60	9.59	38.94		1347.36	7.35	45.66	0.00	387.77	-41.56	-26.95	114.70	433.96	433.96
19	2004			38.23	33.67	972.07	8.24	38.94		1364.88	5.84	45.66	0.00	392.81	-40.63	-26.95	114.70	439.93	439.93
20	2005			37.13	33.67	984.71	6.89	38.94	1134.00	1382.62	4.33	45.66	-1134.00	397.91	-39.69	-26.95	114.70	445.97	1579.97
21	2006			36.04	33.67	997.51	5.53	38.94		1400.59	28.50	45.66	0.00	403.09	-13.07	-26.95	114.70	477.77	477.77
22	2007		1134.00	34.95	33.67	1010.48	4.18	38.94		1418.80	26.99	45.66	1134.00	408.33	-12.14	-26.95	114.70	483.94	-650.06
23	2008			33.86	33.67	1023.61	28.50	38.94		1437.25	25.48	45.66	0.00	413.63	-36.88	-26.95	114.70	464.50	464.50
24	2009			32.77	33.67	1036.92	27.15	38.94		1455.93	23.97	45.66	0.00	419.01	-35.95	-26.95	114.70	470.81	470.81
25	2010			31.67	33.67	1050.40	25.80	38.94		1474.86	22.46	45.66	0.00	424.46	-35.01	-26.95	114.70	477.20	477.20
26	2011			30.58	33.67	1064.05	24.45	38.94		1494.03	20.95	45.66	0.00	429.98	-34.08	-26.95	114.70	483.65	483.65
27	2012			29.49	33.67	1077.89	23.10	38.94		1513.45	19.44	45.66	0.00	435.57	-33.15	-26.95	114.70	490.17	490.17
28	2013			28.40	33.67	1091.90	21.75	38.94		1533.13	17.93	45.66	0.00	441.23	-32.22	-26.95	114.70	496.76	496.76
29	2014			27.30	33.67	1106.09	20.39	38.94		1553.06	16.42	45.66	0.00	446.96	-31.27	-26.95	114.70	503.44	503.44
30	2015			26.21	33.67	1120.47	19.04	38.94		1573.25	14.91	45.66	0.00	452.78	-30.34	-26.95	114.70	510.19	510.19
31	2016			25.12	33.67	1135.04	17.69	38.94		1593.70	13.40	45.66	0.00	458.66	-29.41	-26.95	114.70	517.00	517.00
32	2017			24.03	33.67	1149.79	16.34	38.94		1614.42	11.88	45.66	0.00	464.62	-28.49	-26.95	114.70	523.88	523.88
33	2018			22.94	33.67	1164.74	14.99	38.94		1635.41	10.37	45.66	0.00	470.66	-27.56	-26.95	114.70	530.85	530.85
34	2019			21.84	33.67	1179.88	13.64	38.94		1656.67	8.86	45.66	0.00	476.78	-26.62	-26.95	114.70	537.91	537.91
35	2020			20.75	33.67	1195.22	12.29	38.94		1678.20	7.35	45.66	0.00	482.98	-25.69	-26.95	114.70	545.04	545.04
36	2021			19.66	33.67	1210.76	10.94	38.94		1700.02	5.84	45.66	0.00	489.26	-24.76	-26.95	114.70	552.25	552.25
37	2022			18.57	33.67	1226.50	9.59	38.94	1134.00	1722.12	4.33	45.66	-1134.00	495.62	-23.83	-26.95	114.70	559.54	1693.54
38	2023			17.47	33.67	1242.44	8.24	38.94		1744.51	28.50	45.66	0.00	502.06	2.79	-26.95	114.70	592.60	592.60
39	2024			16.38	33.67	1258.60	6.89	38.94		1767.19	26.99	45.66	0.00	508.59	3.72	-26.95	114.70	600.06	600.06
40	2025			15.29	33.67	1274.96	5.53	38.94		1790.16	25.48	45.66	0.00	515.20	4.66	-26.95	114.70	607.61	607.61
41	2026		1134.00	14.20	33.67	1291.53	4.18	38.94		1813.43	23.97	45.66	1134.00	521.90	5.59	-26.95	114.70	615.24	-518.76
42	2027			13.11	33.67	1308.32	28.50	38.94		1837.01	22.46	45.66	0.00	528.68	-19.15	-26.95	114.70	597.28	597.28
43	2028			12.01	33.67	1325.33	27.15	38.94		1860.89	20.95	45.66	0.00	535.56	-18.21	-26.95	114.70	605.10	605.10
44	2029			10.92	33.67	1342.56	25.80	38.94		1885.08	19.44	45.66	0.00	542.52	-17.28	-26.95	114.70	612.99	612.99
45	2030			9.83	33.67	1360.01	24.45	38.94		1909.59	17.93	45.66	0.00	549.57	-16.35	-26.95	114.70	620.97	620.97
46	2031			8.74	33.67	1377.69	23.10	38.94		1934.41	16.42	45.66	0.00	556.72	-15.42	-26.95	114.70	629.05	629.05
47	2032			7.65	33.67	1395.60	21.75	38.94		1959.56	14.91	45.66	0.00	563.95	-14.49	-26.95	114.70	637.21	637.21
48	2033	-387.45	-716.23	6.55	33.67	1413.75	20.39	38.94	-400.24	1985.03	13.40	45.66	-703.44	571.28	-13.54	-26.95	114.70	645.49	1348.93