7. POWER SYSTEM ANALYSIS AND TRANSMISSION SYSTEM PLANNING

7. POWER SYSTEM ANALYSIS AND TRANSMISSION SYSTEM PLANNING

7.1 Power System Analysis

The various analytical studies were carried out for the new transmission system which is required for the construction of Kerawalapitiya Power Station. The new transmission system comprises two circuits operated with 220kV, having a length of about 18km from Kerawalapitiya Power Station to the existing Kotugoda Substation. In these studies, another 150MW combined cycle power plant to be implemented under BOO/BOT scheme on the same time schedule as this c/c project was also taken into consideration.

The analytical studies on the power system in 2001 when Kerawalapitiya plant is expected to be commissioned and also in 2005, four years thereafter, were performed in cooperation with CEB using PSS/E, which is a sort of computer soft-ware for the power system analysis.

As the input data for PSS/E didn't include the data for the stability analysis on generators to be put into service in the system after 1998, they were additionally prepared by the Study Team for computation on the system stability analysis. After checking the data for PSS/E's computation, the Study Team submitted them to CEB during the 2nd On-Site Study and requested CEB to analyze the power system stability.

As a result of the evaluation of the analytical study, the Study Team has reached the conclusion that the power systems in the years of 2001 and 2005 are not questionable at all in the respects of power flow, fault current and stability.

Conditions and criteria in this study are based on the description in the existing report "Master Plan Study for Development of the Transmission System of the Ceylon Electricity Board, January 1997 (hereinafter referred to as the Existing Report)".

7.2 Transmission System Planning

It is necessary to construct new transmission lines in order to send the power generated at Kerawalapitiya Power Station into the existing power system. Existing Kelanitissa Power Station is the nearest electrical facility located in a distance of about 8km from Kerawalapitiya Power Station. But it is not an economical plan because the route of transmission lines must pass through high-density population areas.

Therefore, the second nearest Kotugoda Substation of which route has less obstacles was selected as a first connection point with the existing power system. The route of transmission lines between Kotugoda and Kelawalapitiya was investigated and studied.

The study was made on the construction of newly planned 220kV transmission system of which length is about 18km from Kerawalapitiya to the existing Kotugoda Substation.

Besides, the Study Team also considered the remodeling of electric facilities in Kotugoda Substation which is attributed to the interconnection of planned transmission lines.

The transmission lines is interconnected with Kotugoda Substation by overhead lines connection. "Double Bus Bar One Bus Tie System" which is popular is applied for the 220kV bus system. For the equipment of switchgears, a conventional open type is adopted because of the economical reason.

8. PROJECT COST AND ECONOMIC/ FINANCIAL ANALYSES

8. PROJECT COST AND ECONOMIC/FINANCIAL ANALYSES

8.1 Project Cost

The project cost consists of equipment costs, spare parts cost, engineering fee, contingency, relevant tax fees, interest under construction and out-of-pocket expenses on the owner side. The total power plant cost and its breakdown without relevant tax fees and interest under construction are as shown in the table 8-1.

Table 8-1 The Project Cost and its Breakdown

Unit : US Dollar

Project Cost	Unit Cost	Unit Cost modified
Foreign consultant	5,000,000	5,000,000
Power plant	85,700,000	82,500,000
Civil	46,000,000	20,400,000
Erection	8,800,000	8,800,000
Access road development	960,000	192,000
Transmission line and substation	5,000,000	2,000,000
Compensation	800,000	160,000
Guarantee engineer	278,000	278,000
Contingency	7,200,000	5,700,000
CEB's administration charge	500,000	400,000
Total	160,238,000	125,520,000

Breakdown of power plant cost	Unit Cost	Unit Cost modified
Gas Turbine	42,500,000	42,500,000
Steam Turbine and accessories	17,300,000	17,300,000
HRSG and accessories	16,300,000	16,300,000
Emission monitoring	500,000	500,000
Building	5,000,000	1,800,000
Spare parts for a 5-year operation	4,100,000	4,100,000
Total	85,700,000	82,500,000

Notes :

1. Unit cost means the consolidated cost covering all facilities to be constructed/installed to operate no. 1unit.
2. Unit cost modified means the consolidated cost where cost for common facilities is divided by no. of unit they can cover.

8.2 Economic Evaluation

8.2.1 Economic Costs

A Project cost including net construction cost, a cost for preparatory works for approach road and so forth, a cost for compensation, and a cost for engineering services for supervision is estimated as mentioned in the main report. The Project cost consists of foreign currency portion and local currency portion. Based on this project cost, an economic cost is estimated for evaluation of the Project. In this case, the cost for compensation means a cost for removal of buildings and houses including a cost for land for people living in and around the Project area along planned pipe-line for fuel transportation and so forth and along the transmission line from the power plant to the nearest sub-station, so it might be called as the cost for countermeasure for living environment.

In estimation of the economic costs, following assumptions are set as general conditions based on the result of discussion with CEB;

(1) Price escalation rate of the costs:
- For foreign currency portion: 1 % per annum.
- For local currency portion : 10 % per annum.

(2) Exchange rate:
- US$ 1.00 = Rs. 63.80
- Japanese ¥100 = Rs.47.80

Each in terms of mid-rate as of May 15, 1998.

(3) Equipment and materials to be brought into Sri Lanka from abroad should be exempted from taxation, so that their CIF prices represent a border price.

<u>**Foreign currency portion**</u>

The foreign currency portion of the costs is estimated in either Cost Insurance Freight (CIF) price as a border price as mentioned above. Therefore, these international prices are assumed to reflect economic cost directly.

<u>**Local currency portion**</u>

Because it is presumed that local markets in developing countries are distorted by price controls and other regulations, prices in the domestic markets do not reflect economic scarcity of goods and services. This means that the prices can not be used to evaluate economic costs of local procurement and have to be converted into economic prices.

In economic analysis of a project, conversion factors are used to convert the costs in domestic markets into economic costs of a project.

Using export and import statistics, a standard conversion factor (SCF) was estimated at a rate of 0.9485. This SCF converts the domestic commodity prices into the economic prices that can be assumed to reflect the economic scarcity of the local goods and services in domestic markets.

However, the SCF is applied to only tradable goods. The economic cost of non-tradable goods and services have to be separately evaluated. Conversion factors of land, skilled and non-skilled labors, and local works are respectively estimated. They were estimated at 1.000 for land, 0.700 for unskilled labour considering the similar projects in developing countries, and 0.875 for local construction works including transportation considering the Goods and Services Tax (GST). Then, the weighted average of the conversion factors was calculated at 0.853 based on the work value, apply it to the financial cost to convert into the economic cost.

Calculation process is mentioned in the main report in detail, and summarized below together with the financial cost. In this case, the proposed power plant is for 150 MW with one (1) unit but the plant should be developed up to 750 MW with 5 units along with the CEB's long term program. Therefore, the Project cost is estimated in two (2) cases as (1) the cost for one unit only as Case-1, and (2) the total cost for plural units considering the said future development as Case-2. Price escalation should be excluded because that the evaluation of the Project is made by comparison of present values of cost and benefit in economic analysis.

Summary of Financial and Economic Costs of the Project

(Unit:US$1,000)

Year	2000	2001	2002	2003	2004	Total
Case-1						
Financial cost	1,576	40,731	77,919	9,455	332	130,012
Economic cost	1,537	37,213	74,690	8,484	332	122,257
Case-2						
Financial cost	1,576	65,225	89,408	13,319	342	169,871
Economic cost	1,537	56,760	84,687	11,540	342	154,866

8.2.2. Economic Benefit

In the case of without-Project, CEB should pay additional capacity cost (power cost) and energy cost for construction of facilities as an alternative power plant to cover electricity demand so that customers may be supplied necessary electricity without any trouble. If the Project is executed, these additional costs will be saved. These saved costs are given as economic benefit in the case of this kind of project.

In this Project, an oil fired conventional boiler-turbine power generation system is set as the said alternative plant. For estimation of the power benefit and energy benefit, the power value (KW-value) and energy value (kWh-value) for the alternative plant should be estimated. In this case, because technical characteristics of the oil fired conventional boiler-turbine power generation system and proposed combined cycle power plant are different, adjustment factors consisting of KW-value adjustment factor and kWh-value adjustment factor are to be estimated. Then, these adjustment factors are incorporated in the analysis, so that the benefits of the proposed combined cycle power plant derived from saved costs of the alternative oil fired conventional boiler-turbine power generation system should be identical. In this case, applied rates on power own use and force outage are based on the data keeping in JICA Study Team, and periodical overhaul and inspection will made during one month a year.

The annualized power value and the energy value of the alternative oil fired conventional boiler-turbine power generation system are resulted at US$141.66 per kW and at US$28.18 per MWh respectively as mentioned in the main report. In this case, the construction cost per kW as a base of kW value is based on the total Project cost. And, the applied fixed O/M cost and variable O/M cost is based on the data keeping in JICA Study Team. The plant life is assumed at 20 years for both the proposed plant and the alternative plant, and the fuel prices are average ones during these 3 years for both the auto diesel oil for proposed plant and heavy oil for alternative plant. The high heating value is the proposed one for proposed plant, and based on the data keeping in JICA Study Team for alternative plant.

In this Project, the external cost burdened by the people living in and around the Project area caused by air pollution due to emission of NO_x and SO_x should also be considered. If the emitted volume of NO_x and SO_x will be lower in the case of the proposed combined cycle power plant than in the alternative oil fired conventional boiler-turbine power generation system, the Project will get an additional economic benefit from an environmental viewpoint as an external cost saving. In the contrary case, a negative benefit will be derived from the same viewpoint.

In this case, the emission volume of NO_x for the proposed plant is the planned one. But for the alternative plant, a reasonable volume to be reached without any denitrification facilities. The emission volume of SO_x from the alternative plant is assumed at the same one from the proposed plant in order to equalize the impact to the air quality with the case of proposed plant. Therefore, the desulfurization efficiency of alternative plant will be 80 %.

Unit damage costs of NO_x and SO_x are given as US$446.6 per ton and US$180.4 per ton respectively in terms of 1990-price level in "Incorporating Environmental Concerns into Power Sector Decision-making -A Case Study of Sri Lanka-" issued by the World Bank as a World Bank environment paper No.6. Those unit damage costs of NO_x and SO_x are, for estimating the additional economic benefit as the external cost saving, estimated at US$1,158/ton and US$468/ton as of 1998 based on consumer price index of General Item in Colombo.

The economic benefits are resulted at US$21,986 x 10^3 in the annual power benefit, at US$26,819 x 10^3 in annual energy benefit and US$110 x 10^3 in external cost saving as studied in the main report. As a result, the proposed combined cycle power plant will emit lower volume of NO_x and SO_x as a whole than the alternative power generation system. So that an additional benefit will be derived due to completion of the Project.

8.2.3. Result of Economic Evaluation of Project

The economic evaluation of the Project is made by using cash flows of the said economic costs and economic benefits. The results are summarized below. In this case, B/C ratios are comparison of benefit and cost in present value of them, and B-C means net cash flow between benefits and costs also expressed by their present value. For calculation of present value, a discount rate of 10 % is applied according to a result of discussion with CEB used in similar projects in Sri Lanka.

Result of Economic Evaluation

Case	EIRR (%)	B/C ratio	B-C(US$1,000)
Case-1	11.50	1.05	11,383
Case-2	8.99	0.97	-9,323

As mentioned in previous clause, the proposed power plant is for 150 MW with one (1) generation unit but the plant should be developed up to 750 MW with 5 generation units along with the CEB's long term program. In these kind of cases, some of the facilities should be prepared previously at the first stage of the construction works of the plant. Therefore, the economic costs in Case-2 might be the nearest economic cost to the actual one. On the other hand, economic benefit can be estimated for one (1) generation unit only because that the proposed power plant for one (1) generation unit. To compare the economic benefits for one generation unit with the costs for plural generation units may be unfair from the general viewpoint.

From the viewpoint of above mentioned reason, the economic evaluation is made in 2 cases, i.e. Case-1 is for comparing the economic benefits for one generation unit with the economic costs for one generation unit and, Case-2 is for comparing the economic benefits for one generation unit with economic costs for plural generation units.

As indicating in the above Table, EIRR in Case-1 is resulted at 11.50 % meaning that the Project is economically feasible. On the other hand, EIRR in Case-2 is resulted at 8.99 % meaning that the Project is not sound economically reflecting a burden of economic costs for plural generation units on economic benefit for one generation unit.

8.2.4. Sensitivity Analysis in Economic Aspect

There are constant fluctuation in prices of construction materials for these kind of projects as a reflection of economy in the state.

It also gives an impact to the economic benefit because that the said benefit is estimated based on construction cost and fuel cost for the oil fired conventional boiler-turbine power generation system as an alternative plant for generation of electricity to cover the electricity demand as mentioned in previous clause.

Considering those situation, a sensitivity analysis is made for 8 combined cases in addition to base case for Case-1 under the conditions that the benefit will be decreased as -5 % and -10 %, and the cost will be increased as +5 % and +10 %. The result of this sensitivity analysis is summarized below:

Result of Sensitivity Test for EIRR

(%)

Cost	Benefit		
	Base case	-5%	-10%
Base case	11.50	9.77	7.90
+5%	9.85	8.09	6.16
+10%	8.26	6.43	4.39

As shown in the above Table, the EIRR under both the benefit and the cost in the base case is resulted at 11.50 % as already mentioned that is economically sound indicating enough higher rate than the discount rate of 10 %. On the other hand, (1) under the condition of -5 % of benefit and base case of cost and (2) under the condition of base of benefit and +5 % of cost, the EIRR became slightly lower than 10 % of discount rate as 9.77 % and 9.85 % respectively. It means that the Project is quite sensible against the said price fluctuation, but is economically feasible when the price fluctuation ranges within 5 % both in benefit and cost.

8.3 Financial Evaluation

8.3.1 Financial Benefit

If the Project is executed, the revenue of CEB might be increased by collection of electricity charge. This increasing revenue is a financial benefit in this kind of project.

For estimation of the financial benefit, it is presumed that the electricity newly supplied is for domestic customers because that detail selling structure for industrial and commercial customers, hotels, local authority and street lightening is not cleared.

An envisaged electricity price in 2003 is assumed at Rs.3.90 per kWh calculated on the basis of actual electricity price of Rs.2.27 as of 1995 and an envisaged annual price increase of electricity of 7.00 % per annum.

Because of performance-down and deterioration of generation facilities, the sending end capacity will become 157.0 MW during 5 years from the first year of commercial operation, 155.8 MW during 5 years from 6th years, 155.4 MW during 5 years from 11th years, and 155.2 MW during 5 years from 16th years from a technical viewpoint.

Resulted annual revenue as the financial benefit is shown below:

Annual Revenue of CEB due to Electricity to be Newly Supplied

Financial benefit	Unit	(2004-2008)	(2009-2013)	(2014-2018)	(2019-2023)
Annual revenue	US$1,000	56,500	56,068	55,924	55,852

8.3.2 Result of Financial Evaluation of Project

The financial evaluation of the Project is made by using cash flows of the aforementioned financial costs and financial benefits mentioned above. The results are summarized below. In this case, B/C ratios are comparison of benefit and cost in present value of them, and B-C means net cash flow between benefits and costs also expressed by their present value. For calculation of present value, a discount rate of 10 % is applied according to a result of discussion with CEB used in similar projects in Sri Lanka.

Result of Financial Evaluation

Case	FIRR (%)	B/C ratio	B-C(US$1,000)
Case-1	14.95	1.17	42,567
Case-2	11.54	1.06	16,518

By the same reason in economic evaluation mentioned in previous clause, the financial evaluation is made in 2 cases too, i.e. Case-1 is for comparing the financial benefits for one generation unit with the financial costs for one generation unit and, Case-2 is for comparing the financial benefits for one generation unit with financial costs for plural generation units as indicated in the above Table.

As indicating in the above Table, FIRR in Case-1 is resulted at 14.95 % meaning that the Project is financially feasible. And, FIRR in Case-2 is resulted at 11.54 % meaning that the Project has no any problems financially.

8.3.3 Sensitivity Analysis in Financial Aspect

There are constant fluctuation in prices of construction materials for these kind of projects as a reflection of economy in the state.

It also gives an impact to the financial benefit because that the said benefit is usually consisting of capacity charge from kW-value and energy charge from kWh-value.

Considering these situation, a sensitivity analysis is made for 8 combined cases in addition to base case for Case-1 under the conditions that the benefit will be decreased as -5 % and -10 %, and the cost will be increased as +5 % and +10 %. The result of this sensitivity analysis is summarized below:

Result of Sensitivity Test for FIRR

(%)

Cost	Benefit		
	Base case	-5%	-10%
Base case	14.95	13.30	11.56
+5%	13.38	11.73	9.98
+10%	11.89	10.23	8.45

As shown in the above Table, the FIRR under both the benefit and the cost in the base case is resulted at 14.95 % as already mentioned that is financially sound indicating enough higher rate than the discount rate of 10 %. Also, (1) under the condition of -10 % of benefit and +5 % of cost and (2) under the condition of -5 % of benefit and +10 % of cost, the FIRR became almost the same rate of discount of 10 % as 9.98 % and 10.23 % respectively that are still financially sound too. It means that the Project is enough financially feasible as a whole.

8.3.4 Repayability Analysis

For repayability analysis, the repayable amount of loan should be the whole required amount for construction of plural generation units for the reason as mentioned in previous clause including price contingency and excluding local costs as taxes, compensation cost and administration fees. The total construction cost including price contingency is a sum of US$200,192 x 10^3 as a result. From this figure, the said repayable amount of loan can be calculated.

The repaybility analysis is made in 3 cases, i.e. (1) the case of using the OECF loan, (2) the case of using the IDA (World Bank) loan and (3) the case of using the ADB loan, in the condition that the repayment should be made as the annual equal payment consisting of principal and its interest. In this case, their loan conditions are summarized below:

Summary of Loan Conditions of International Financing Institutions

		OECF	IDA	ADB
Interest rate	(%/annum)	1.80	0.75	1.00
Repayment period	Year	30	30	30
Grace period	Year	10	10	10

The local cost is assumed to use the domestic loan with 16 % of interest rate and repayment period is of 8 years with 2 years of grace period.

Repayability analysis is made by using the cash flow of necessary outflows and available inflows.

In results of the analysis, the Government of Sri Lanka may repay its principal of loan with necessary interest in all of 3 cases with some cash surplus. Because of short of grace period for local loan, there might be some deficits in 2002 and 2003 in all cases, but these deficits will be paid back from the surplus after completion of the construction works.

The surplus cashes of those 3 cases are around US$13.2 million in OECF loan, around US$15.9 million in IDA loan and around US$15.7 million in ADB loan during their repayment period.

8.4 Availability to Use Private Capital

The analysis of availability to use private capital is made in 2 cases as (1) the case of full cost borne by IPP and (2) the case of combined loan by OECF with IPP as base cases.

8.4.1 The Case of Full Cost Borne by IPP

Return on Equity (ROE) and Return on Investment (ROI)

For analyzing a probable profitability of IPP for the Project, a probable cash flow model should be formulated. In this case, an amount of inflow and outflow should be evaluated considering several project risks.

As mentioned in previous sub-clause, the electricity price to be sold by IPP to CEB should be based on capacity charge and energy charge. In this case, the power value should be estimated by the whole construction cost including probable price escalation so that avoiding economical risks. The envisaged power value and energy value is resulted at US$150.70 per kW and at US$36.93 per MWh.

Here, an interest rate of Japanese banking group is assumed at 8.50 % with repayment period of 14 years including the grace period of 4 years. The parameters for financial analysis in a case using an IPP are based on the said assumptions. For formulating the cash flow model, an equity ratio of IPP and taxable amount of capacity charge are assumed at 20 % and 18 % respectively and, period of selling agreement of electricity between IPP and CEB is assumed to be 20 years after completion of the construction works.

In the cash flow model of the base case, there will be deficit during the repayment period, and the IPP's return on equity (ROE) is resulted at 14.22 % and the return on investment (ROI) is resulted at 8.55 %.

<u>**Loan Life Debt Service Coverage Ratio (LLCR)**</u>

The probable LLCR of the Project is calculated by using calculation table based on the said assumed cash flow model at 0.8603 as the base case.

From the viewpoint of banking group, they may require at least a same rate of return from the Project with the IPP. However, in the case of equity ratio of 20 % mentioned above, ROE has resulted at 14.22 % and ROI has resulted at 8.55, and the loan amount from the banking group may not be recovered by the IPP's profit during the repayment period. If the ROE and ROI will be same rate, namely 10,86 % as the most suitable case, the LLCR will become 1.0579, and it can cover the said loan amount. But, the equity ratio should be at 34.94 %.

If the banking group would like to keep more than 1.4 of LLCR in order to keep stable repayment of their loan amount from the IPP, the equity ratio of the IPP should be more than 50 % as a result. As a conclusion, this Project is not adaptable for using IPP as a base case of full cost borne by IPP because that IPP can not prepare the amount of Project cost in case the cash balance shows deficits during the repayment period of loan from banking group.

8.4.2 The Case of Combined Loan by OECF with IPP

For making the analysis for the case of combined loan by OECF with IPP, the Project cost should be divided into 2 categories as the cost for common infrastructure to be filled by the amount of loan by OECF and the cost to be invested by IPP for main facilities.

<u>**Return on Equity (ROE) and Return on Investment (ROI)**</u>

The electricity price to be sold by IPP to CEB should be based on capacity charge and energy charge as already mentioned. In this case, the power value should be estimated by the whole construction cost to be invested by IPP including probable price escalation so that avoiding economical risks. The envisaged power value and energy value is resulted at US$105.04 per kW and at US$36.93 per MWh.

In the cash flow model for this case, there will still be deficit during the repayment period, but the said IPP's return on equity (ROE) is resulted at 17.69 % and the return on investment (ROI) is resulted at 10.38 %.

<u>Loan Life Debt Service Coverage Ratio (LLCR)</u>

The probable LLCR of the Project in this case is calculated by using calculation table based on the assumed cash flow model as mentioned above at 0.8616 in this base case.

In the case of equity ratio of 20 %, ROE has resulted at 17.69 % and ROI has resulted at 10.38 as mentioned above, and the loan amount from the banking group may not be recovered too by the IPP's profit during the repayment period. If the ROE and ROI will be the same rate, namely 12.76 % as the most suitable case, the LLCR will become 1.0666, and it can cover the said loan amount. But, the equity ratio should be at 35.37 %.

If the banking group would like to keep more than 1.4 of LLCR in order to keep stable repayment of their loan amount from the IPP, the equity ratio of the IPP should also be more than 50 % but this is not practicable. As a conclusion, this Project is not adaptable for using IPP as a base case of combined loan by OECF with IPP because that IPP can not prepare the amount of Project cost in case the cash balance shows deficits during the repayment period of loan from banking group.

8.5 Case Studies to Search Capabilities for Using Private Capital for the Project

8.5.1 Conditions of Case Studies

In the base cases studied in Clause 8.4, the unit selling price of electricity from IPP to CEB as its revenue was based only on the capacity charge and energy charge without any margin as an overhead and/or financial charges. So, the cash balance of IPP would be deficit during the repayment period of loan from the banking group.

For solving this problem, some margin should be considered in addition to the said selling price of electricity from IPP to CEB. In this study, this margin is set at 10 % to the total selling price of electricity based on capacity charge and energy charge, and is called as "financial charge".

Case studies are made as following 2 cases consisting of further 2 sub-cases with the same conditions of loan condition of banking group as interest rate, repayment period with grace period, period of selling agreement between IPP and CEB, and the equity ratio of IPP:

(1) Probable case of full cost borne by IPP, and
(2) Probable case of combined loan by OECF with IPP.

The Project cost estimated in the study is based on the unit prices of goods and materials dominated the existing market, so the cost may be said as ceiling amount of the Project cost. On the other hand, investors who want to become IPP would generally like to offer the lower prices than this cost because of competition. This is the reason why the projects can be completed by lower amount of costs by private capital than by public finance.

Considering the above situation, the said 2 probable cases can be divided in sub-cases as:

(1-1) Probable case-1 of full cost borne by IPP contracting with ceiling amount,
(1-2) Probable case-2 of full cost borne by IPP contracting with an amount of 80 % to the ceiling amount,
(2-1) Probable case-1 of combined loan by OECF with IPP contracting with ceiling amount, and
(2-2) Probable case-2 of combined loan by OECF with IPP contracting with an amount of 80 % to the ceiling amount.

Conditions of the said case studies are:

(1) Equity ratio of IPP:	20 %
(2) Period of selling agreement between IPP and CEB:	20 years after commencement of commercial operation.
(3) Financial charge:	10 % of capacity charge and energy charge

(4) Conditions of loan by banking group to IPP:

- Interest rate: 8.50 % per annum
- Repayment period: 14 years
- Grace period: 4 years included in the repayment period (meaning that the repayment will start after commencement of commercial operation)

Check points of the studies are:

(a) Ability of CEB to pay selling price set of electricity to IPP,
(b) Unit Sales Price of Electricity of IPP to CEB,
(c) Specific cost (levellized cost) of electricity during the project life,
(d) Capability of IPP to prepare necessary amount of Project to be executed (ROE, ROI and LLCR), and
(e) Sensitivity of LLCR corresponding to the equity ratio to search a negotiable equity ratio of IPP with banking group.

8.5.2 Result of Case Studies

For making clear the ability of CEB to pay selling price set to IPP, the revenue of CEB should be estimated based on the overall average of tariff as of 1995 even if detail mechanisms of sold energy can not be clarified because of security of marketability to conform to the electricity selling agreement between CEB and IPP. According to the financial statistic data of CEB, the overall average of tariff as of 1995 was Rs.3.70 per kWh. Therefore, the envisaged unit electricity price to end-customers will be Rs.6.36 (equivalent to US cents 9.97) per kWh in 2004 in the case of annual increasing ratio of electricity of 7.00 %.

When the contract for construction works will be signed with lower contract price than the ceiling amount between CEB and IPP, the power value to be a part of selling price as capacity charge from IPP to CEB should be based on this lower contract price because that the capacity charge is mainly based on the cost for construction works. The power values in Probable Case-2 of Full Cost Borne by IPP and in Probable Case-2 of Combined Loan by OECF with IPP are estimated at US$121.44 and US$85.20 per kW respectively.

(1) Ability of CEB to Pay Selling Price Set to IPP

In all 4 sub-cases, CEB has an ability to pay selling price set to IPP according to resulted cash flow model a result of the studies. Therefore, there will be no any problems in all cases to CEB.

(2) Unit Sales Price of Electricity of IPP to CEB

Unit sales prices of electricity to be sold by IPP to CEB have resulted as shown in the following Table together with those in base cases.

Unit Sales Price of Electricity of IPP to CEB

Cases	Rs./kWh	US cents/kWh
Base Case of Full Cost Borne by IPP	3.92	6.14
Base Case of Combined Loan by OECF with IPP	3.45	5.41
Probable Case-1 of Full Cost Borne by IPP	4.32	6.77
Probable Case-2 of Full Cost Borne by IPP	3.98	6.24
Probable Case-1 of Combined Loan by OECF with IPP	3.79	5.94
Probable Case-2 of Combined Loan by OECF with IPP	3.57	5.60

From the viewpoint of these results only, the Base Case of Combined Loan by OECF with IPP shows the best advantage to CEB. However, the cash balance of IPP will become deficit during the repayment period of loan by banking group, so this case can not adaptable to realize to use private capital because that IPP can not prepare the amount of cost for construction works as already studied.

Therefore, the second best in the Probable Case-2 of Combined Loan by OECF with IPP is the actual best for CEB if this case can be realized from the viewpoint of selling price of electricity of IPP to CEB.

(3) Specific Cost of Electricity During the Project Life

Specific costs of electricity during the Project life have resulted as shown in the following Table together with those in base cases:

Specific Cost of Electricity During the Project Life

Cases	Rs./kWh	US cents/kWh
Base Case of Full Cost Borne by IPP	3.92	6.14
Base Case of Combined Loan by OECF with IPP	3.63	5.69
Probable Case-1 of Full Cost Borne by IPP	4.32	6.77
Probable Case-2 of Full Cost Borne by IPP	3.98	6.24
Probable Case-1 of Combined Loan by OECF with IPP	3.97	6.22
Probable Case-2 of Combined Loan by OECF with IPP	3.74	5.86

From the viewpoint of these results only, the Base Case of Combined Loan by OECF with IPP shows the best advantage to CEB. However, this case can not adaptable to realize to use private capital because of the same reason mentioned above.

Therefore, the second best in the Probable Case-2 of Combined Loan by OECF with IPP is the actual best for CEB too if this case can be realized from the viewpoint of specific cost of electricity.

(4) Capability of IPP to Prepare Necessary Amount for Execution of Project

For making clear the capability of IPP to prepare necessary amount for execution of the Project, ROE, ROI and LLCR should be clarified. Especially, LLCR is the most important factor for realizing the Project execution.

ROE, ROI and LLCR have resulted as shown in the Table in next page together with those in base cases.

According to the said Table, levels of LLCR slightly clears the level of LLCR to be recovered the loan amount from banking group in both base cases in equity ratio of 35 %, but if IPP would like to negotiate with banking group, IPP should invest 50 % of the Project cost or more. So these cases are not practicable as already studied.

Generally speaking, most suitable level of equity ratio is ranging from 25 % to 30 %. From this viewpoint, the best case is the Probable Case-2 of Combined Loan by OECF with IPP showing the negotiable equity level of 30.5 % if this case can be realized that IPP can sign the contract with 80 % to the ceiling amount for Project cost estimated in the study.

Summary of Relationship Between Equity Ratio and ROE, ROI and LLCR

Case Studies	Equity (%)	ROE(%)	ROI(%)	LLCR
Base Case of Full Cost Borne by IPP				
Model case	20.00	14.22	8.55	0.8603
Most suitable case in ROE and ROI	34.94	10.86	10.86	1.0579
Negotiable case in LLCR	50.84	9.45	13.32	1.4000
Base Case of Combined Loan by OECF with IPP				
Model case	20.00	17.69	10.38	0.8616
Most suitable case in ROE and ROI	35.37	12.76	12.76	1.0666
Negotiable case in LLCR	50.76	10.82	15.13	1.4000
Probable Case-1 of Full Cost Borne by IPP				
Model case	20.00	26.49	15.06	1.1045
Most suitable case in ROE and ROI	36.00	17.53	17.53	1.3814
Negotiable case in LLCR	36.89	17.27	17.66	1.4000
Probable Case-2 of Full Cost Borne by IPP				
Model case	20.00	30.14	17.00	1.1254
Most suitable case in ROE and ROI	36.20	19.49	19.49	1.4112
Negotiable case in LLCR	35.69	19.68	19.42	1.4000
Probable Case-1 of Combined Loan by OECF with IPP				
Model case	20.00	33.39	18.71	1.1744
Most suitable case in ROE and ROI	36.34	21.23	21.23	1.4758
Negotiable case in LLCR	32.89	22.38	20.70	1.4000
Probable Case-2 of Combined Loan by OECF with IPP				
Model case	20.00	38.90	21.64	1.2158
Most suitable case in ROE and ROI	36.52	24.18	24.18	1.5321
Negotiable case in LLCR	30.52	27.68	23.26	1.3999

(5) Sensitivity of LLCR Corresponding to Equity

A sensitivity test is made by type of case study by equity ratio ranging from 10 % to 50 %.

In actual project market, there are several offering cases for executing the projects with LLCR of 1.3 level according to an interview survey by the Study Team in Japan.. From this viewpoint, 3 sub-cases as (1) the Probable Case-2 of Full Cost Borne by IPP, (2) the Probable Case-1 of Combined Loan by OECF with IPP and (3) the Probable Case-2 of Combined Loan by OECF with IPP can be realized showing LLCRs of 1.30 with equity ratio of 31 %, 1.30 with 28 % and 1.30 with 25 % respectively. Among these 3 cases, the Probable Case-2 of Combined Loan by OECF with IPP will be the best for IPP because of equity level, and there may be a capability to use private capital for Project execution.

8.5.3 Conclusion of Case Studies

A ranking test is made by points by items as repayability of IPP to banking group, unit sales price of electricity of IPP to CEB, specific cost of electricity during the Project life, cash balance of IPP during the period of repayment of loan by banking group, and negotiability of IPP with banking group.

As a result of the said ranking test, the Probable Case-2 of Combined Loan by OECF with IPP has gotten the highest points among the all case studies reflecting a situation mentioned above. Therefore, if the Government of Sri Lanka would like to use a private capital for executing the Project, a way of the Probable Case-2 of Combined Loan by OECF with IPP is the most adaptable one when IPP would like to become investor as an IPP even if the contract amount is lower than the ceiling amount up to 80 % to its estimated one in the study. In this case, ROE and ROI will become 32.39 % and 22.41 % respectively.

9. CONCLUSION AND RECOMMENDATION

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9.1 Conclusion

The purpose of this study is to conduct F/S including environmental impact assessment (EIA), for Kerawalapitiya C/C plant(150MW) project and also to transfer the related technology to CEB's personnel involved.

As a result of study and evaluation made from technical, economical/financial and environmental aspects, it has been concluded that the proposed project is feasible. The contents of the conclusion are as follows.

9.1.1 Electric power demand of Sri Lanka in 1995 was in the scale that the electric energy generated was 4,800 GWh and peak power demand was 980MW, and their growth rates exceeded 10% p.a. in average during 10 years from the late 1970s to the early 1980s, corresponding to the economic growth.

The growth rate of electric power generated during last two decades was 7.6% p.a. in average.

The peak demand was also growing during this period except 1996, similarly to electric power generated and its growth rate was 7.1% p.a. in average.

The electricity consumption per capita has been increasing so far and is anticipated to continue increasing because it is smaller than those in Asian countries having the same GDP per capita as Sri Lanka.

The electricity consumption of household has been increasing because of promotion of electrification from 46.8% in 1996 up to 80% in 2005.

As mentioned above, the electric power demand of Sri Lanka is steadily increasing.

The present power generating constitution of Sri Lanka is of a typical "hydropower as main and thermal power as subordinate" system. In rainfall-rich years, almost all electric power demand was catered by hydropower.

In drought years coming cyclically, the thermal power has been used supplimentarily, but recently it is revealed that thermal power can't make up for deficiency.

Therefore, it is strongly desired that thermal power insusceptible to rainfall should be expanded without delay.

9.1.2 Power generation development plan was made, utilizing WASP (Wien Automatic System Planning Package), a computer software developed by IAEA(International Atomic

Energy Agency).

According to the results obtained by WASP, it is concluded that by 2012, the hydropower and thermal power facilities to be expanded by 70MW and 2,588.5MW respectively while 116MW of the existing thermal power facilities to be demolished.

In this plan, this project is expected to be completed by 2001, for amelioration of the present constitution being of "hydropower as main and thermal as subordinate", in view of delay in implementation of coal-fired thermal power plants.

9.1.3 In accordance with the governmental regulation, the import, refinery and supply of fuel are monopolized by CPC(Ceylon Petroleum Corporation) in Sri Lanka.

Therefore, fuel oil to be used in CEB's power plants is supplied by CEB. The fuel amount which CPC can supply is limited and the fuel required on this project must be imported.

There are many kinds of fuel to be applied to this project; LNG(Liquefied Natural Gas), LPG(Liquefied Petroleum Gas), Naphtha, heavy diesel oil and auto diesel oil.

For the reasons mentioned below, the auto diesel oil to be imported is the most recommendable.

On this project(No.1 unit), the most popular auto diesel oil having sulfur contents of 0.5% is applied but when more units are constructed in the future, sulphur contents of auto diesel oil should be reduced to satisfy environmental restriction.

(1) In order to procure LNG, possible purchasers have to take part in a LNG project planning at the early stage and to settle a contract with a LNG supplier who requires very rigid trading conditions.

The LNG amount required on this project is very small, compared with the capacity of LNG plant.

(2) LNG supply in the global market is under control of only one company. Therefore, reliability in procurement and stability in cost is much concerned.

(3) Quite limited companies can supply a naphtha-fired gas turbine and further a naphtha-fired gas turbine must be provided with other fuel supply for start up purpose.

Cost of naphtha and naphtha application is rather expensive.

(4) Heavy diesel oil is applicable to a gas turbine as fuel but not so popular in the global market. CPC has stopped supplying heavy diesel oil since 1996.

(5) Auto diesel oil is preferably applicable to a gas turbine as fuel. It is available widely in the global market and accordingly easy to procure.

Further, in order to procure fuel oil efficiently, it is considered that in stead of CPC, CEB himself or other organization to be newly established will undertake fuel oil trading. CEB does not seem to be willing to do it and is suggested to discuss this matter with the authorities concerned.

9.1.4 For fuel oil unloading, at first three ways were studied; ①modification or ②expansion of the existing oil unloading berth in the Colombo Harbour and ③stallation of new oil unloading berth in the same harbour. None of them have been, however, found feasible.

It was decided to install an unloading buoy offshore 4.6km away from the seashore nearest to the site.

The size of fuel oil tank is expected of 30,000ton class and a single point mooring buoy is adopted.

Fuel oil in the tanker is to be transferred by a pump equipped in the tanker to fuel oil storage tanks in the power station through a buoy hose and pipeline laid down underground in the sea.

Similar unloading method is going to be installed for LPG plant owned by Shell Gas Lanka Limited and it was confirmed through discussion between the same company and the Study Team that the position of buoy, tanker maneuvering area and route of pipeline do not disturb with each other.

The sea in this area is rough during the monsoon season(May to September) but the mooring of tanker is confirmed possible.

9.1.5 There are considered three(3) kinds of cooling water system for steam condenser; a sea water once-through flow direct cooling method, a mechanical draft wet indirect cooling method and an air cooled indirect cooling method.

A sea water once-through flow direct cooling method is adopted because of advantages in cost and performance.

The sea water is taken in from the sea bottom off shore 460m away from the seashore through the pipeline laid down underground in the sea and through the culvert in the land to the condenser, taking into consideration the shallow sea and minimum environmental impact.

Cooling water from the condenser is discharged to the sea at the seashore through the culvert.

9.1.6 Main parameters and technical conditions for planning and design of power plant are as follows.

(1) Rating and no. of unit : 150MW class combined cycle power plant × one(1) unit

(2) Gas turbine inlet gas temperature : 1,200℃ class

(3) Steam conditions:

	High pressure	Low pressure
Steam-pressure	5～7Ma	0.5～0.7Ma
Steam temperature	480～500℃	150～200℃
Steam flow	95～120t/h	50～60t/h

(4) Plant availability : 70%

(5) Minimum load : 10% of rating as combined cycle power plant

(6) Capacity of fuel storage : for 45 days at rated load

(7) Ambient air conditions : Humidity 30℃(Dry globe), 26.7℃(Wet globe)
Relative humidity 78%
Ambient pressure 1.033bar

(8) Cooling sea water temperature : 27.5 ℃

(9) Condenser cooling method : Sea water once-through flow, direct cooling

(10) Applicable code and standard : Internationally recognized code and standard

(11) NO_x control : Steam injection on combined cycle mode operation
Water injection on open cycle mode operation to reduce NO_x concentration at gas turbine outlet to not more than 70ppm (O_2 15%).

(12) Altitude at the site : Almost Sea level

(13) Emission standard :

SO_2	340mg/MJ
NOx	130mg/MJ
Suspended particulate	40mg/MJ
Smoke opacity (Lingermann)	20%

(14) Effluent standard :

TSS	150mg/l	
TSS grain size	Suspended matter	:Not more than 3mm
	Precipitate	:Not more than 850 μm
pH	6.0～8.5	
BOD	100mg/l	
Oil & grease	20mg/l	
Temperature	45℃	
COD	250mg/l	
Chlorine residue	1.0mg/l	

(15) Noise level(SPL) : 85dB(A) 1 m distant from equipment

(16) Maximum temperature rise of cooling water : 10℃

(17) Operation mode : Combined Cycle operation
Open cycle operation (A bypass stack is installed between gas turbine and HRSG)

(18) Stack height : 80m(Both on a main stack and a bypass stack)

(19) Power station premises : 550m×500m

(20) Capacity of common infrastructure

a. Fuel oil unloading : 30,000t to be unloaded for 12hours.
(Capable to supply fuel oil for five(5) units.)

b. Condenser cooling water intake/discharge facility : 300MW(150MW×two(2)units)

c. Fuel oil storage tank : 150MW×one(1)unit

d. Sea water desalination plant : 150MW×one (1) unit

e. Transmission line : 300MW(150MW×two(2)units)

9.1.7 The optimum plant configuration must be scrutinized from many viewpoints such as the operability, maintainability and performance of the plant, influence on the grid system in the event of unit trip, plant construction cost and further power expansion capability of Kerawalapitiya power station. The following are main points.

(1) The number of gas turbine shall be one(1) or two(2), not to impair competition in the market.

(2) A HRSG(Heat Recovery Steam Generator) shall be provided for each gas turbine.

(3) The number of steam turbine shall be one (1) regardless of the number of gas turbine.

(4) To enhance plant operability, a gas turbine shaft(s) shall be independent of a steam turbine shaft.

(5) Plant thermal efficiency is expected to be 44~46% with steam injection for NOx abatement when fuel oil is fired.

(6) In case of a one-gas turbine configuration(100MW×one(1) unit), it is anticipated that the trip of this plant at off-peak load may cause frequency drop to the vicinity of 47.5Hz(limitation:48.5Hz) and eventually around 100MW of the system load must be shut down selectively.

(7) In case of a two-gas turbine configuration(50MW × two(1) units), the plant construction cost is raised but the trip of a gas turbine does not cause any impact on the grid system and the blackout in the power station also can be avoided unless two gas turbine trip simultaneously.

9.1.8 The particulars of main equipment in the power station are decided based upon the main parameters and technical conditions, as follows.

(1) Gas turbine

a. Type	Simple open cycle single shaft
b. Unit rating	50MW or 100MW on ISO conditions (To be decided by suppliers.)
c. No.of unit	One(1) or two(2) units (Depend upon plant configuration)
d. Elegible experience	Not less than 3 units each having a not less than 2,000-hour (cumulative) operation experience

(2) HRSG

a. Type	Dual pressure, non-reheat type
b. Direction of gas flow	Vertical
c. No.of unit	One(1) or two(2) units (Depend upon plant configuration)

(3) Steam turbine

a. Type	Mixed pressure, single flow, exhaust steam condenser type
b. No.of unit	One(1) unit
c. Rating	Around 50MW
d. Speed	3,000rpm
e. Vacuum	Approx.8kPa
f. Direction of exhaust	Preferably axial exhaust

(4) Generator

	For gas turbine	For steam turbine
a. Type	Enclosed, air cooled, cylindrical, rotating field, synchronous and alternating	
b. No. of unit	One(1) or two(2) units	One(1) unit
c. Superficial output	118MVA	59MVA
d. Real output	100MW	50MW
e. Voltage	11kV	11kV
f. Frequency	50Hz	50Hz
g. Power factor	0.85	0.85
h. Speed	3,000rpm	3,000rpm
i. No. of pole	2	2
j. Short circuit ratio	0.58～0.64	0.58～0.64
k. Insulation	Type F(Temperature rise: Equivalent to type B)	
l. Excitation system	Thyrister excitation	

(5) Sea water desalination plant

a. No. of plant One(1)

b. Type Multiple-effect distillation system

c. Capacity 1,500t/day

(6) Fuel oil storage tank(untreated oil)

a. Type Fixed roof, cylindrical

b. No. of unit Two (2)

c. Capacity 15,000kl each

(7) Fuel oil treatment facility

a. Type Centrifugal, self-cleaning

b. No. of unit Three (3)

c. Capacity 15t/h each

(8) Fuel oil storage tank (treated oil)

a. Type Fixed roof, cylindrical

b. No. of unit Two (2)

c. Capacity 8,000kl each

(9) Instrumentation and control system

a. Control system consists of the following systems, to meet need of combined cycle power plant.

(a) Unified hierarchical management, supervision and control system

(b) Centralized compact control and operation panel system

(c) Plant load/unit number management operation system

(d) Service life management system

b. Operation and monitoring can be made from CRT operation device incorporated in the integrated control panel, fully automatically from start up to shut down.

9.1.9 Transmission line and substation

To transmit electric power generated in this power plant to the grid system, the transmission line is installed from here to the existing Kotogoda substation, for which a route considered to be the most economical and of the least impact on the environment is selected.

(1) Transmission line

Type : Overhead, tower type, 200kV×2lines

Total length : 18km

(2) Substation

Type of cable introduction to substation: Overhead, tower typer

Type of 220kV bus : Double main bus, single bus coupler type

Type of 220kV switch gear : Conventional, open type

9.1.10 As a result of various analytical studies on the new transmission system between Kerawalapitiya Power Station and the existing Kotogoda Substation on the below mentioned conditions, it has been concluded that the power systems are not questionable at all in the respects of power flow, fault current and stability.

(1) Power plant facility : A 150MW of this C/C project and another 150MW to be constructed under BOO/BOT scheme at the same time as the former

(2) Years to be analyzed : 2001 when Kerawalapitiya Power Station is expected to be operated, and 2005

(3) Tool to be used for power system analysis : PSS/E

(4) Conditions for analysis and evaluation criteria : As per the existing report "Master Plan Study for Development of the Transmission System of the Ceylon Electricity Board, January 1997"

9.1.11 As a result of study on environmental impacts to be caused by the project , the following conclusions were obtained.

(1) Emission of SO_2, NO_2 and SPM will clear the permissible level for ambient air quality of the Sri Lanka Standards.

(2) Noise level by construction machinery and plant facility operation will clear the proposed standards at the boundary of the site.

(3) Quality of effluent from the site will clear the Sri Lanka Standards.

(4) The water temperature rise by cooling water to be discharged to the coastal sea is not more than 10°C higher than the ambient water temperature. The area susceptible to temperature rise will be minimized by rapid mixing with the large volume of ambient water body. Therefore, no significant impacts will be seen.

(5) Transmission line will be constructed along the boundary of conservation zone. Careful survey of local living fauna and flora will be carried out before construction, to minimize the impacts due to transmission tower construction work.

(6) Monitoring on ambient air quality and effluent to the environmental water body will be carried out and reported to the authorities concerned.

(7) Reasonable compensation will be made to people related to land acquirement, removal of housing or modification of housing or associated fixed assets.

9.1.12 Power plant layout was prepared both for a one-gas turbine configuration and a two-gas turbine configuration on the below mentioned conditions.

(1) Five(5) units of C/C power plant to be laid out.
(Five(5) is maximum number of unit which can be accommodated within the present power plant premises.)

(2) Fuel oil and condenser cooling water are supplied to the power station from a north-west direction.

(3) Switch gear station is located at the south-east area, taking account of the route of transmission line.

(4) A gas turbine(s), a steam turbine and generators shall be located indoors.

9.1.13 The following are recommended for operation and maintenance of C/C power plants, paying special attention to a gas turbine(s), because those main equipment except a gas turbine are considered to be well known to CEB's personnel.

(1) Spare parts required for a 5-year operation are included in scope of supply.

(2) A maintenance and repair shop equipped with equipment and instruments for inspection and repair is installed.

(3) Personnel in charge of operation and maintenance are trained at the site and manufactures' work shops.

(4) Two (2) guarantee engineers (one for mechanical items and the other for electrical and I/C items) are to station at the site for a year.

(5) Information management system having functions of operation record and diagnosis of operational performance is to be introduced.

9.1.14 The construction schedule is expected as follows.

(1)	L/A(Loan Agreement) to decision of consultant	5months
(2)	Additional survey to completion of tender documents	6months
(3)	Tendering to sign of contract with plant supplier	7months
(4)	Commencement of construction works to commercial operation	31months
	Total	49months

However, special attention shall be paid to the following.

(1) All works in the sea shall be avoided during the monsoon season from May to October.

(2) It takes eight (8) months for construction of the access road to the site.

(3) It takes twenty four(24) months for construction of the culvert (2.5km) for

intake/discharge water.

(4) Additional survey works(around 30 days) in the sea shall be made during the off-monsoon season at Engineering Service Stage I.

9.1.15 The project cost consists of equipment costs, spare parts cost, engineering fee, contingency, relevant tax fees, interest under construction and out-of-pocket expenses on the owner side.

The total power plant cost and its breakdown except relevant taxation and interest during construction are as shown in the below table.

Unit : US Dollar

Project Cost	Unit Cost	Unit Cost modified
Foreign consultant	5,000,000	5,000,000
Power plant	85,700,000	82,500,000
Civil	46,000,000	20,400,000
Erection	8,800,000	8,800,000
Access road development	960,000	192,000
Transmission line and substation	8,000,000	3,200,000
Compensation	800,000	160,000
Guarantee engineer	278,000	278,000
Contingency	7,200,000	5,700,000
CEB's administration charge	500,000	400,000
Total	163,238,000	126,720,000

Breakdown of power plant cost	Unit Cost	Unit Cost modified
Gas Turbine and accessories	42,500,000	42,500,000
Steam Turbine and accessories	17,300,000	17,300,000
HRSG and accessories	16,300,000	16,300,000
Emission monitoring	500,000	500,000
Building	5,000,000	1,800,000
Spare parts for a 5-year operation	4,100,000	4,100,000
Total	85,700,000	82,500,000

Notes :

1. Unit cost means the consolidated cost covering all facilities to be constructed/installed to operate no. 1unit.
2. Unit cost modified means the consolidated cost where total cost for common facilities is shared by units which they can cover

9.1.16. Economic and financial evaluation, and study on possibility of private capital utilization

(1) Economic and financial evaluation of project

The proposed power plant is a generation unit of 150MW but this power station is expected to be extended up to 750 MW with 5 generation units according to the CEB's long term program. In this kind of project, some infrastructures (common facilities) should be prepared in advance of the construction works of the plant.

On the other hand, economic benefit for this project must be estimated for only one generation unit because the project is intended to construct one generation unit. Generally, it can be regarded unfair to evaluate the benefits for one generation unit with the cost including cost of common infrastructure for plural generation units.

For the reason mentioned above, the economic and financial evaluation is made for 2 cases, i.e. Case-1 is to compare the benefit for one generation unit with the cost for one generation unit and, Case-2 is to compare the benefits for one generation unit with cost including cost of common infra-structure for plunal generation units.

As a result of economic and financial analyses, the project is evaluated as follows:

Result of Project Evaluation

Case	IRR (%)	B/C ratio	B-C(US$1,000)
Economic evaluation			
Case-1	11.50	1.05	11,383
Case-2	8.99	0.97	-9,323
Financial evaluation			
Case-1	14.95	1.17	42,567
Case-2	11.54	1.06	16,518

Where IRR means internal rate of return.

Considering the price fluctuation, the sensitivity analysis is made for economical and financial analyses of Case-1, for 8 combinations of change of conditions; the benefit is decreased by -5 % or -10 %, and the cost is increased by +5 % and +10 %.

The result of this sensitivity analysis is summarized below:

Result of Sensitivity Test for EIRR

(%)

Cost	Benefit		
	Base case	-5%	-10%
Base case	11.50	9.77	7.90
+5%	9.85	8.09	6.16
+10%	8.26	6.43	4.39

Result of Sensitivity Test for FIRR

(%)

Cost	Benefit		
	Base case	-5%	-10%
Base case	14.95	13.30	11.56
+5%	13.38	11.73	9.98
+10%	11.89	10.23	8.45

As shown in the above Tables, the EIRR in the base case is resulted in 11.50 % and the figure means that the project is economically sound because of higher rate than the discount rate of 10 %. In both cases of -5 % of benefit with base cost and base benefit with +5 % of cost, the EIRR becomes slightly lower than 10 % of discount rate as 9.77 % and 9.85 %, respectively. It means that the Project is quite sensible against the price fluctuation, but is economically feasible when the price fluctuation ranges within 5 % both in benefit and cost.

On the other hand, the FIRR in the base case is resulted in 14.95 % the figure means that the project is financially sound, too because of higher rate than the discount rate of 10 %. In both cases of -10 % of benefit with +5 % of cost, and of -5 % of benefit with +10 % of cost, the FIRR becomes 9.98 % and 10.23 %, respectively; almost the same rate of discount of 10 %. These are considered still financially sound. It means that as a whole the Project is enough financially feasible, too.

(2) Analysis of possibility of private capital utilization

The factors for making clear the possibility of private capital utilization are the Return on Equity (ROE), Return on Investment (ROI), and Loan Life Debt Service Coverage Ratio (LLCR) corresponding to the Equity ratio of IPP.

The below table shows results of the analysis.

Summary of Relationship Among Equity Ratio and ROE, ROI and LLCR

Case Studies	Equity (%)	ROE(%)	ROI(%)	LLCR
Base Case of Full Cost Borne by IPP with minimum selling price(1) and full ceiling amount(2) in contract				
Model case	20.00	14.22	8.38	0.8603
Loan recoverable case	31.18	11.40	7.30	1.0000
Negotiable case in LLCR	50.84	9.45	13.32	1.4000
Base Case of Combined Loan(4) with minimum selling price(1) and full ceiling amount(2) in contract				
Model case	20.00	17.69	10.29	0.8616
Loan recoverable case	31.06	13.65	8.67	1.0000
Negotiable case in LLCR	50.76	10.82	15.13	1.4000
Probable Case-1 of Full Cost Borne by IPP with selling price including financial charge(3) and full ceiling amount(2) in contract				
Model case	20.00	26.49	15.17	1.1045
Loan recoverable case	11.64	40.95	19.88	1.0000
Negotiable case in LLCR	36.89	17.27	11.19	1.4000
Probable Case-2 of Full Cost Borne by IPP with selling price including financial charge(3) and 80 % of the ceiling amount(2) in contract				
Model case	20.00	30.14	17.20	1.1254
Loan recoverable case	(Out of calculation. Equity ratio:less than 10%)			
Negotiable case in LLCR	35.69	19.63	12.66	1.4000
Probable Case-1 of Combined Loan(4) with selling price including financial charge(3) and full ceiling amount(2) in contract				
Model case	20.00	33.39	18.98	1.1744
Loan recoverable case	(Out of calculation. Equity ratio:less than 10%)			
Negotiable case in LLCR	32.89	23.79	14.43	1.4000
Probable Case-2 of Combined Loan(4) with selling price including financial charge(3) and 80 % of the ceiling amount(2) in contract				
Model case	20.00	38.90	22.03	1.2158
Loan recoverable case	(Out of calculation. Equity ratio:less than 10%)			
Negotiable case in LLCR	30.52	27.68	17.42	1.3999

(Notes)
(1) Minimum selling price of electricity consists of the capacity charge and energy charge only from IPP to CEB.
(2) Ceiling amount means the Project cost estimated in the Study excluding the administration.
(3) Financial charge is assumed at 10 % to the total of capacity and energy charges as margins.
(4) Combined loan scheme means that the common infrastructure is implemented with OECF loan by the Government of Sri Lanka while the power plant by IPP.

According to the above Table in both base cases having equity ratio of 31%, the level of LLCR slightly clears the level of LLCR(1.0) which indicates the capability of recovering loan amount from banking group, but for securing the conditions for IPP to negotiate with a banking group, that is, for acquiring 1.4 of the LLCR , IPP should invest 50 % of the Project cost or more. So these cases are not practicable.

Generally speaking, most suitable level of equity ratio ranges from 25 % to 30 %. From this viewpoint, the best case is the Probable Case-2 of Combined Loan where the negotiable equity level is 30.5 % and the contract amount with IPP should be 80 % of the ceiling amount for Project cost estimated in the study.

A sensitivity test is made by type of case study and by equity ratio in the range of 10 % to 50 %.

According to an interview survey by the Study Team in Japan, in actual project market, there are several offers where the project is to be executed with LLCR of 1.3 level. Referring to this, 3 sub-cases as (1) the Probable Case-2 of Full Cost Borne by IPP, (2) the Probable Case-1 of Combined Loan and (3) the Probable Case-2 of Combined Loan can be considered to be quite feasibility in view of LLCRs of 1.30 with equity ratio of 31 %, 1.30 with 28 % and 1.30 with 25 % respectively.

Among these 3 cases, the Probable Case-2 of Combined Loan is considered to be the best for IPP because of equity level, and there may be a capability to use private capital for Project execution. In this case, ROE and ROI will become 32.39 % and 19.36 %, respectively, and the selling price of electricity from IPP to CEB is Rs.3.57 (equivalent to US cents 5.60) per kWh while the specific cost (levellized cost) of electricity to CEB during the project life is Rs.3.74 (equivalent to US cents 5.86) per kWh.

In case the Government of Sri Lanka prefers a private capital utilization for executing the Project, the Probable Case-2 of Combined Loan is the most adaptable provided that IPP is prepared to invest in the project even if the contract amount is reduced down to 80 % of the ceiling amount.

9.1.17 Socio-economic impacts to be brought up by implementation of this project are as follows.

(1) The present power generation constitution being of typical "hydropower as main and thermal power as subordinate" will be ameliorated to some extent.

The forced limitation of power supply encountered in a droughty year may be evaded.

(2) The stable power supply will be given to the general citizens and industries whose power demands have been increasing.

(3) Activation and expansion will be expected in the business field of construction, iron and steel, transportation, communication ,and so forth related to power generation industry.

Particularly, expansion of local employment will be expected because of labour required for construction of power station.

(4) Since access road is constructed and further electric power supply and others become available in the reclaimed land where this power plant is constructed, the investment to the industrial estate within the land is expected to be accelerated.

9.2 Recommendation

This project is feasible from technical, economical/financial and environmental points of view. Therefore, this project should be implemented as soon as possible for contributing to CEB's basic policy that the present power generation facilities, e.g. typical "hydropower as main and thermal power as subordinate" system should be ameliorated and also for securing stable power supply to demand to be seen in 2001.

For earlier implementation of this project, the following items should be reviewed and proper action on them should be taken urgently.

9.2.1 It is of vital importance to secure financing, and the Sri Lanka Government is expected to seek for cooperation by international financing institutions on a governmental basis.

9.2.2 There are two methods considered for execution of this project.

(1) Method 1

Nominating the whole project as a project owned by CEB, CEB will plan out effective execution and Sri Lanka Government will take positive action on international financing institutions so that soft loan may be applied to the majority of project cost.

(2) Method 2

Nominating common infra-structure of the whole project as a national project, Sri Lanka Government trys to apply soft loan to it. Because cost of this common infra-structure is comparatively too big to be regarded as a part of cost required for No.1 unit of power plant facility, and can not be covered by benefit to be obtained by No.1 unit only.

On the other hand, power plant facility is to be installed under the BOO/BOT scheme by a IPP(Independent Power Producer).

There is a possibility in this method to enjoy advantages to be brought up both by a national project scheme and by a IPP project one.

Particularly, a case having the below conditions can be considered to be the most preferable for utilization of private capital;

a. Actual power generation cost is allowed to put a profit of 10% on power generation cost calculated based upon power cost and energy cost.
b. The power plant cost, that is, contract amount between CEB and IPP is 80% of the power plant cost estimated by the Study Team.

9.2.3 A variety of environmental clearances must be obtained for implementation of this project. Therefore, appropriate actions shall be taken well in advance, keeping close communication with the authorities/organizations concerned and making sufficient interfacing among them.

Particularly, it is desirable to fix up urgently and bona fide the compensations related to resettlement of inhabitants and removal/modification of their housing and etc.

9.2.4 Since the land where fuel oil pipelines and culverts for cooling water intake/discharge are to be laid down is not procured by CEB yet, the necessary action shall be taken urgently.

9.2.5 Reportedly, it will take 8 months for access road improvement. To avoid impediment to transportation of plant equipment and material, the improvement works should be executed, keeping close communication with the authorities and organization concerned.

9.2.6 In order to dilute financial burden caused by comparatively huge cost of common infrastructure of this project, once this project is decided to be implemented, the next expansion power plant should be planned to be constructed in succession at the reasonable intervals.

9.2.7 A foreign consultant had better be selected without delay, to impel effective and efficient execution of the project.

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