Fort William Thermal Power Project
Feasibility Study

The Ministry of Public Utilities
Of the Government of Mauritius

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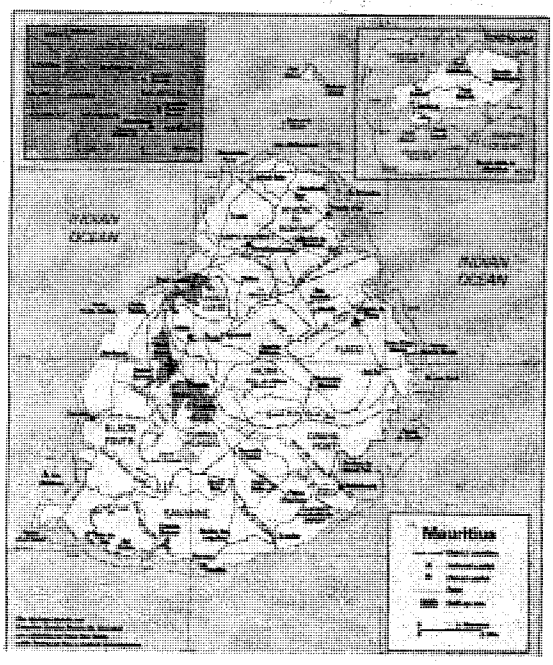

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by

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I. Introduction

The United States Trade and Development Agency (TDA) provided a grant to the Government of Mauritius (GOM), represented by the Ministry of Public Utilities (MPU), for the purpose of conducting a feasibility study for a new thermal power plant in Mauritius. K&M Engineering and Consulting Corporation ("K&M"), in association with The Kuljian Corporation (technical subcontractor) and Servansingh Jadav and Associates, (local environmental subcontractor) collectively known as "the K&M Team" was selected to conduct the feasibility study. This Final Report is a comprehensive presentation of the study work performed by the K&M Team.

This Final Report provides our findings. It is organized to follow the Terms of Reference for conducting the feasibility study. The Executive Summary reviews the most significant issues under consideration for planning a new independent power project (IPP) in Mauritius followed by the major Conclusions and Recommendations. The Final Report provides a discussion of the various Tasks performed and includes a series of appendices containing work products delivered and approved during the course of the study. These work products consist of the following items:

- Site Letter Report;
- Fuel Selection Letter Report;
- Technology Selection Letter Report;
- Electrical Study;
- Preliminary Environmental Impact Assessment;
- Estimated Project Cost & Project Schedule Report;
- Plant Description; and
- Power Sales Agreement and Concession Agreement term sheets

Also produced under the TDA Grant separate from this Final Report is a Request for Proposals (RFP) to select an IPP developer for the project.

II. Scope of Work

The scope of work (SOW) was prepared to study the feasibility of developing an international competitively bid IPP in Mauritius. Specifically, the SOW addresses the technical, economic, environmental and financial issues involved in structuring a project that provides a cost-effective source of electricity for the GOM, while also meeting the requirements of private sector investors and lenders.

The SOW was divided into thirteen tasks as follows:

Task 1 --- Review Existing Information
Task 2 --- Evaluate Siting and Land Use Issues
Task 3 --- Evaluate Fuel Procurement, Supply and Pricing

Task 4A – Evaluate Power Plant Technology
Task 4B - Evaluate Transmission Facilities Requirements
Task 5 – --Evaluate Environmental Impacts
Task 6 –-- Project Permit Requirements
Task 7 –-- Estimate Project Capital Costs
Task 8 –- Estimate Project Operations and Maintenance Costs
Task 9 -- Power Sales Agreement
Task 10 – Project Financing Options
Task 11 – Project Construction Schedule
Task 12 – Final Report
Task 13 – Preparation of Request for Proposal (RFP) for IPP Developer

The K&M Team conducted this assignment in three phases.

During the first phase of the study the Team traveled to Mauritius to accomplish Tasks 1 and 2 by the following steps:

- brief the client and reach agreement on the work plan and schedule for completing the study
- gather background data
- establish contacts with various GOM ministries and agencies
- meet with local financial institutions
- visit potential power plant sites
- brief US Embassy

K&M debriefed the Client prior to departing Mauritius and provided the Client with the Letter Report on Siting (Task 2).

During the second phase of the study the Team prepared the Letter Report on Fuel Procurement Supply and Pricing (Task 3); the Letter Report on Technology Selection (Task 4A) and the first draft of the Transmission Facilities Requirements Report (Task 4B). The Team also conducted meetings and phone interviews with members of the World Bank, the International Finance Corporation, the Export Import Bank of the United States (US Eximbank) and the Overseas Private Investment Corporation (OPIC) to discuss potential financing structures for the IPP.

The K&M Team and the Client consulted during Phase II and determined the study should cover three technical configurations at two sites. A representative from the K&M Team traveled to Mauritius to obtain the Client's input on these issues. From this point forward the scope was adjusted with the concurrence of TDA to cover these project options and the RFP was prepared to allow bidders to submit bids for these project configurations.

During the third and final phase of the study the Team completed the remaining study tasks. As part of this work, the Team prepared a financial model to evaluate the project. The model includes a proforma income statement and cash flow. The Team also prepared sensitivity analyses to quantify the impact of changes in various project assumptions.

Finally, the K&M Team prepared a draft Request for Proposal (RFP) document for an IPP that includes term sheets for a Power Purchase Agreement (PPA) and a Concession Agreement (CA) developed in Task 9. These documents were prepared to support the GOM's conduct of an international competitive bid for the IPP.

III. Executive Summary

Two sites were selected as feasible. Ft. William is the preferred site. Its potential for approval and use for a power plant is further advanced than other potential sites. It would be a difficult site for coal use, however. The Montagne Jacquots site was found feasible for a power plant and is considered more favorable as a site for the coal alternative.

A study was undertaken of the potential fuels for the project. Natural gas was eliminated due to costs associated with the significant infrastructure required for liquefied natural gas. Coal and residual fuel oil were selected as the best candidate fuels. Supply security was determined not to be a significant concern. Oil prices are expected to have (and have had) greater price volatility than coal. Current oil prices have been used in the economic analysis.

Three technologies were selected for development of design characteristics: combined cycle with residual fuel oil; diesel engines with residual fuel oil and a coal fired Rankine steam cycle plant. It was assumed for each technology that the plant will have a capacity of 300 MW and will be built in three 100 MW phases. This report concentrates on the first 100 MW phase. The combined cycle and diesel plants would be located at Fort William site, while the coal plant would be located at Montagne Jacquot site. For each technology, conceptual layout plans with fuel storage and handling areas are included. The IPP Developers will be allowed to propose the plant technology and site that they believe will provide the most competitive power for Mauritius. Final selection of the technology will be made during the IPP selection process.

A plant located at either site will connect to the grid via one double circuit 132 kV transmission line between the plant switchyard and St. Louis Substation sized to evacuate final planned site net power output capacity of 300 MW. The K&M Team studied transmission and interconnection issues taking into consideration the Central Electricity Board generation expansion plans.

A Preliminary Environmental Impact Assessment (EIA) was performed. The technologies and sites considered in the Feasibility Study are capable with appropriate mitigating measures of meeting the World Bank Guidelines and local requirements. The diesel alternative has an apparent problem with local NO_x emission requirements but not World Bank Guidelines. Similar diesel plants have been permitted in the Ft. William area, however. Further consideration of this matter is appropriate by MPU.

The project is planned to be developed and implemented as a project financed IPP. Therefore, the project structuring and the economic analysis have been conducted under those assumptions. Plant capital costs have been estimated from the conceptual designs developed. Developer costs,

including financing, have also been estimated as well as operations and maintenance costs. An investigation of financing source options and expected terms was conducted. It was found that several alternative sources of financing are expected to be available including multilateral banks, export credit agencies, and international and local commercial banks. Expected financing structure and terms have been developed and a financial model prepared to determine the economics of the project. A proforma has been provided for each technology. Financing actually utilized will be determined by the bidders. Sensitivity runs have been made to test the assumptions. Busbar electricity prices based on our assumptions for a 100 MW plant are estimated in the range of approximately $0.08/kWh to $0.10/kWh.

Summary Data

Plant Technology	Combined cycle	Diesel	Steam
Configuration	1, 100 MW 2 GT and 1 ST	2, 50 MW	2, 50 MW
Fuel	Residual oil	Residual oil	Coal
Site	Ft. William	Ft. William	Mont. Jacquot
EPC Cost	US$93 million	US$133 million	US$135 million
Project Cost	US$128 million	US$176 million	US$184 million
Schedule	16-24 months	21-24months	29-30 months
Price of Electricity	US$ 0.82 kWh	US$ 0.96 kWh	US$ 0.89 kWh

Term sheets were developed for the Power Purchase Agreement and Concession Agreement needed to structure the project as an IPP. International experience as well as the experience in Mauritius with the Bellevue project was used in preparing these term sheets. A review of the Mauritius requirements and institutional issues were taken into account in preparing the term sheets. Issues include: Concession Project Act, fuel supply, duties and importation; site ownership, government guarantees, currency convertibility and tariff structure.

IV. Conclusions and Recommendations

The price of electricity is influenced by the relatively small size of the plant (100 MW) and the need to import all the fuels.

The developer should be responsible to bring fuel for the project. In order to provide the lowest tariff and not distort the costs, duties should be waived. This recommendation has been used in the economic analysis in this report.

The estimated price of electricity varies 17% among the studied alternative technologies with combined cycle being the lowest.

Environmental requirements can be met with reasonable mitigating measures that have been included in the estimated and conceptual designs, except local NOx requirements for the diesel plant . This situation should be further considered by MPU.

A final EIA is required by the selected Developer on the specific technology, fuel, site and detail design parameters.

The project can be reasonably incorporated into the CEB grid.

Mauritius has had a successful experience with IPP project development and financing. Mauritius has well defined institutional provisions for IPP development.

The project should attract experienced international developers and lenders.

International IPP bidding is recommended for this project. The developer should be given the choice of two sites, three technologies and the appropriate fuel for the most competitive project as measured by cost per kWh.

Project financing options at reasonable terms should be available from various sources in including; multilateral banks, export credit agencies, and international and local commercial banks

Participation of the State Investment Corporation (SIC) as an investor in the project should be considered.

V. Analysis and Discussion

In the following sections are the details of the various tasks performed under the SOW and the recommendations which were made as a result of this work. Certain tasks, or groups of tasks, were the subjects of separate earlier reports that are included in the Appendices.

1.0 Evaluate Site and Land Issues - Task 2

For Task 2 of the Feasibility Study, the K&M team evaluated potential sites for the IPP project.

Considerations for site selection included:

- Sufficiency and suitability of the land
- Access
- Arrangements for fuel supply
- Proximity to interconnected grid
- Availability of cooling water
- Plant emissions
- Availability of infrastructure for plant operation and maintenance

Potential sites considered for the IPP project were:

- Fort William, near Port Louis
- Vieux Grand Port (SE, near Bois des Amourettes)
- Montagne Jacquot (West)

The Fort William site was identified as most appropriate for the project for the following reasons:

- It is of sufficient size for a 400 MW oil-fired plant although only a 300 MW plant has been considered.
- The area is well connected to approach roads and close to the country's sole commercial port.
- The underlying rock is sufficiently solid to support heavy foundations.
- Cooling water is available.
- Predominant winds will be directing noise and air emissions toward the sea (80% of the time).
- The site is protected from cyclones by mountains surrounding Port Louis.
- The interconnected grid to which the plant would be connected is nearby.
- The proximity of the city makes utilities such as water, telephones and electricity for the construction of the plant easily available.
-

The report on the work performed under this task can be found in Appendix A. Subsequent to the preparation of the report under Task 2, and having determined to present bidders with a broader selection, both in terms of plant technologies and site locations, it was decided that although the Fort William site remains the better location for a power project, the Montagne Jacquot site could also be considered for a coal fired project.

2.0 Evaluate Fuel Supply, Procurement and Pricing - Task 3

Under Task 3 the K&M Team reviewed and evaluated fuel supply, procurement and pricing for the project.

The fuel report issued as a result of the work under this Task considers gas, coal and petroleum fuels and their respective availability and pricing. Price information was then utilized in the Technology Selection report to develop a comparative cost of electricity generation.

The conclusions of the study performed under this Task are as follows:

- Practical fuels to be considered for the project are either petroleum fuels or coal.
- Security of supply is not considered to be a serious concern
- Coal prices are expected to remain more stable over the long run
- Use of LNG would require infrastructure costs for shipping, handling, storage and regasification which are too high for a project of the size considered
- The choice of the fuel will be closely related to the choice of the technology
- Custom duties and taxes applied in Mauritius could have an influence on the fuel and technology selected

- Fuel should be supplied by the project developer
- Environmental impacts linked to fuel selection can be managed satisfactorily.

The detailed report for this Task can be found in Appendix B. It must be noted that there has been a substantial increase in oil prices since our original report was prepared. For this Final Report's economic analysis we have used the current higher oil prices.

3.0 Evaluate Power Plant Technology - Task 4A

3.1 Analysis

As part of this study, the K&M Team performed a technology evaluation and prepared a Letter Report on Technology Selection (see Appendix C). We considered a combined cycle plant, a diesel power plant, and a coal fired power plant as alternative technologies for the new IPP project in Mauritius. Light distillate, gas oil, and heavy fuel oil were considered as fuel for the combined cycle option, and heavy fuel oil was considered for the diesel option. It was assumed for each technology that the plant will have a capacity of 300 MW and will be built in three 100 MW phases. The combined cycle and diesel plants would be located at Fort William site, while the coal plant would be located at Montagne Jacquot site.

The K&M Team evaluated the technologies above taking into consideration technical, economic, financial, and environmental issues. As a result of this evaluation, it was determined that all of these technologies are technically sound and proven. Combined cycle and diesel technologies have certain technical advantages over the coal plant. These include better heat rate, shorter construction schedules, and lower real estate requirements (therefore, combined cycle and diesel plants are able to fit in the more developed Fort William site).

Combined cycle and diesel plants have also environmental advantages over coal. A coal plant produces significant amounts of ash that has to be disposed of at a landfill that would require additional land. Cooling water requirements for coal plants are higher than for combined cycle or diesel plants. Additionally, CO_2 emissions for the coal plant would be double the CO_2 emissions for either the combined cycle or the diesel plants.

A preliminary economic evaluation in the Technology Selection Letter Report determined that, based on the fuel prices in effect at the time of the Letter Report preparation and depending on the assumptions regarding the import duties and taxes for fuel and generation level, either the combined cycle using heavy fuel oil or the coal plant would be the most economical options.

It should be noted that reliance of combined cycle and diesel technologies on fuel oil could have its disadvantages. Prices of fuel oil depend on crude oil prices and are extremely volatile (for the last 2 years, crude oil prices increased from approximately $10/bbl to approximately $30/bbl). Therefore, the fuel component of the cost of

electricity produced by combined cycle or diesel plant may fluctuate dramatically causing significant impact on electricity tariffs in Mauritius. Historically, coal prices have been much more stable and use of coal technology would provide better stability of electricity tariffs.

3.2 Plant Description

For each of the technologies considered above, the K&M team developed a conceptual design of the plant that is presented in Appendix D- Plant Description. Included are conceptual layout plans with fuel storage and handling areas and a single line diagram.

For a combined cycle power plant each 100 MW phase would have a 2 x 1 configuration with 2 combustion turbines, 2 HRSG's, and 1 steam turbine installed with each phase. Heavy fuel oil would be used as main fuel, and gas oil for startup. An auxiliary steam boiler would be provided for startup operations. The plant would have a once-through sea water condenser cooling system and would be provided with the necessary auxiliary systems and equipment. The plant would have heavy fuel oil storage sized for at least 30 days of base load operation. Combustion turbines, steam turbines, and HRSG's would be located outdoors and provided with weather enclosures. Buildings such as control room, switchyard building, mechanical shop, and the administrative building would be provided.

Each 100 MW phase of the diesel power plant would consist of two 50 MW diesel-generator units and the necessary auxiliary systems and equipment including the auxiliary steam boiler and HRSG's. Heavy fuel oil would be used as main fuel. Heavy fuel oil storage would be sized for at least 30 days of base load operation of the plant. The plant would be provided with a once-though cooling water system using sea water. The diesel-generators would be provided with weather enclosures. Buildings such as control room, switchyard building, mechanical shop, and administrative building would be provided.

Each 100 MW phase of coal plant would consist of two 50 MW trains, each composed of one steam boiler and one steam turbine as well as necessary auxiliary systems and equipment. Coal would be used as the main fuel and gas-oil used as the backup and startup fuel. Coal storage would be sized for at least 30 days of the base load operation of the plant. The plant would be provided with a once-though condenser cooling water system using sea water. Buildings such as power house, control room, switchyard building, mechanical shop, and administrative building would be provided.

4.0 Construction Schedule - Task 11

The K&M team developed construction schedules for the first 100 MW phase for the three technology options. It is estimated that the combined cycle plant and the diesel plant construction would be completed in 24 months, while the coal plant construction would take 30 months. The details of the schedules are in the Estimated Project Costs & Project Schedule Report in Appendix G.

5.0 Evaluate Transmission Facilities Requirements - Task 4B

The plant would be connected to the grid via one double circuit 132 kV transmission line between the plant switchyard and St. Louis Substation sized to evacuate plant net power output of 300 MW. The K&M Team studied transmission and interconnection issues taking into consideration the Central Electricity Board generation expansion plans and prepared the Report on Short Circuit, Load Flow and Transient Stability Studies (Appendix E). The studies were performed for the years 2005 and 2010, and for both the crop and inter-crop seasons, and determined the short circuit levels at the 132 kV, 66 kV and 22 kV buses, checked the load flow, voltage profiles, loading of the transformers and transmission lines, requirements for reactive power compensation of the 66 kV and 132 kV network, and transient behavior of the generators at the new IPP power plant.

The Short Circuit Study determined that the fault levels would increase due to addition of new generation. MPU should verify that the existing 66 kV, 22 kV, and 11 kV buses are adequately rated for the increased fault levels. Fault limiting reactors may be added at those buses if they are not adequately rated for the increased fault levels.

The Load Flow Study results confirmed that in order to improve the voltage and power factor profile, reactive power compensation would be required as identified in the Table 5.0-1 below:

TABLE 5.0-1: CAPACITOR BANK FOR REACTIVE POWER COMPENSATION

Station Reference (Bus ID)	Capacitor Bank to be Connected in MVAR							
	Year 2005 crop		Year 2005 Inter-crop		Year 2010 crop		Year 2010 Inter-crop	
	Case-I	Case-II	Case-I	Case II	Case-I	Case-II	Case-I	Case-II
Nicolay 2 (08)	10	10	5	5	20	15	20	15
Belle Vue (09)	18	12	15	8	15	12	18	10
Combo (33)	15	15	15	15	15	15	15	15
Rose Hill (18)	-	-	-	-	15	10	15	15
L'Avenir (46)	-	-	-	-	25	15	30	18
Ferney (25)	10	-	-	-	-	-	-	-
Union Valle (35)	-	-	3	-	-	-	-	-
TOTAL	53	37	38	28	90	67	98	73

NOTE: Case I: Case study with transformer/line outage.
Case II: Case study without transformer/line outage

The Load Flow Study also demonstrated that for network operation without any transformer or line outage, there will be no overloading of any transformer or line and the voltage drop at the buses will also be within the acceptable limit of ±10%. For network operation with

transformer/line outage, the overloading of a 45 MVA transformer at Belle Vue and of a 20 MVA transformer at Ft. Victoria will occur.

The Transient Stability Study demonstrated that if the 132 kV/66 kV transmission line fault is cleared within 300 ms, the new generators at the IPP power plant will remain in synchronism with the grid. Additionally, in case of a load rejection of 43.25 MW in the year 2005 and 57.3 MW in the year 2010, the voltage and frequency rise will be within the acceptable limit of ± 10% and ± 3%, respectively.

6.0 Preliminary Environmental Impact Assessment and Project Permits Requirements - Task 5 &6

The K&M Team prepared a Preliminary Environmental Impact Assessment (PEIA). For each technology, air emissions, effluent waste water quality, and noise from the proposed plant were evaluated against the more stringent of the World Bank or local environmental requirements.

It was determined that for the oil fired combined cycle and diesel plants emissions of particulate matter would be below the limits specified in the World Bank and local guidelines, and no installation of particulate removal equipment would be required. For the coal plant, electrostatic precipitators or baghouses would have to be installed to remove fly ash from the flue gas stream before discharging it to the atmosphere through the stack. Coal handling and ash handling and disposal systems would be designed and operated in a manner that would minimize dust emissions.

Sulfur dioxide (SO_2) emission levels would depend on the fuel sulfur content and may exceed the specified requirements in case that high sulfur fuel is used. For a coal fired power plant, the SO_2 emission requirements could be met by using low sulfur coal, by utilizing circulating fluidize bed (CFB) boilers, or by installing a flue gas desulfurization (FGD) system. For combined cycle and diesel technologies, selection of fuel oil with a sulfur content such that the SO_2 emissions would meet the regulations is an appropriate solution.

The technologies considered in the Feasibility Study are capable of meeting the World Bank and local NO_x emission requirements by using appropriate techniques. For the coal plant it could be use of low NO_x burners, for the combined cycle – water or steam injection, and for the diesel plant – water emulsification of the fuel oil. More consideration of the Mauritius diesel emissions requirements is warranted.

For each technology, the plant would be designed with waste water treatment equipment to meet effluent water requirements. Noise limitations would be met by provision of adequate sound insulation for equipment and buildings. Environmental impacts during construction would be mitigated by appropriate construction measures.

A Final EIA is required to be performed by the selected Developer based on the specific technology, fuel, site and detail design parameters.

The Preliminary EIA also includes a description of the project permitting process and the required permits. See Appendix F for the Preliminary EIA.

7.0 Economic Analysis - Tasks 7, 8, and 10

In order to evaluate the economic merits of each of the three different technologies being envisaged for the IPP in Mauritius, cost estimates were made, schedules developed and financing options, structure and costs explored. Based on assumptions provided in the detailed descriptions of the work, the K&M Team developed estimates of project costs and associated tariffs for each of the three technologies using a project financial model. Sensitivities have been calculated for major parameters.

Tasks 7, 8 and 10 of the K&M Team's Scope of Work relate to specific issues that are part of the overall economic analysis of the proposed IPP project. The following economic analysis first presents the costs associated with development and construction of the project (Task 7); then discusses how the potential financing structure was assessed (Task 10). The operational costs (Task 8) are then discussed followed by the assumptions used, the construction of the various tariff components and the tariffs which are estimated to be charged by the IPP to the utility (CEB) for sale of its capacity and energy.

7.1 Estimate of Project Capital Costs

The K&M Team studied the costs associated with the construction of an IPP power project using three different technologies: oil-fired combined cycle plant, diesel plant or coal-fired steam plant. A report, entitled "Estimated Project Costs and Project Schedule", summarizing the costs and construction schedules for all three technologies was prepared and can be found in Appendix G.

In performing these estimates we assumed a first phase of 100 MW with an ultimate size of the IPP project expected to be 300 MW. Costs of certain elements of the infrastructure for the full 300 MW plant that are to be constructed during the first phase have been included in these estimates.

A comparative table of capital costs for the three technologies reveals that the least capital intensive project would be a combined cycle plant, whose total cost of US$ 128 million is 31% less than the coal plant (US$ 184 million) and 28% less than the diesel plant (UD$ 176 million). The differences in costs for these plants (assuming identical financing terms) are mainly due to:

- Equipment cost differences: the EPC costs for a diesel or a coal plant are 40% to 42% higher than for a combined cycle plant;
- varying construction schedules (the coal plant requires a 2 1/2 year construction schedule, or 6 to 10 months more than the diesel or combined cycle plant), which result in higher financing costs such as interest during construction.

7.2 Project Financing Options and Structure

The K&M Team identified project financing options among various financing institutions for the IPP project. By contacting a variety of financing institutions, we were able to assess their willingness to lend to the project, and as a result of our discussions, we were able to determine a financing structure that would be acceptable to the lending community and to the Ministry, to allow implementation of the project. The institutions that were contacted include multilateral banks, export credit agencies and commercial banks (both foreign and Mauritian), a number of which have been involved in the financing of the island's first IPP project at Belle Vue:

- US Eximbank
- Overseas Private Investment Corporation (OPIC)
- World Bank
- International Finance Corporation (IFC)
- Mauritius Commercial Bank
- State Bank of Mauritius
- Hong Kong Shanghai Bank (HSBC, Port Louis & New York)
- Banque Nationale de Paris Intercontinentale (BNPI – Mauritius)
- Barclays Bank (Port Louis & Paris)
- Sumitomo Bank (London)

From discussions with the various agencies and banks it appears that they all represent options for the financing of the project. Also it appears from these discussions that the financing structure of this IPP project would likely follow the one that was used for the Belle Vue project (which was a non-recourse financing, with a foreign currency denominated loan provided by export credit agencies and commercial banks, and a local currency loan).

For the financing of the new IPP project, it is probable that multilateral and/or export credit agencies would play a key role in mobilizing offshore commercial bank debt. Local banks could provide remaining debt provided there is sufficient liquidity in the Rupee market. Because Mauritius is an investment grade country (Moody's rating Baa2), political risk coverage by way of a partial risk guarantee from the World Bank might not be required by the offshore lenders. However, if such coverage is determined to be beneficial, the World Bank would require a counter-guarantee from the GOM. In general, the role of multilateral lenders and export credit agencies will strengthen the perception of the project, ensure the provision of political risk coverage, allow for longer loan terms at more competitive rates, and allow additional financing to be mobilized from commercial banks.

In light of the above, and in order to model project revenues and expenses, the K&M Team has assumed a project financing structure for the IPP project. The main elements of the structure are as follows:

- Debt/equity ratio of 70/30.
- 20% of total project costs will be in Rupees sourced from local Mauritian banks, this amounts to approximately 30% of the debt
- 100% of the equity and the remaining 70% of the debt has been assumed to be in foreign currency (for ease of presentation all foreign currency denominated items are in USD).
- We have assumed that average loan terms will be of approximately 10 years (including the construction period), with grace periods ranging between 2 to 3 years (Mauritian commercial banks may offer longer grace periods than foreign lending agencies).
- Interest rates applied by foreign lenders are currently at LIBOR +3.75%, or approximately 9.75%. Mauritian commercial banks may apply higher base rates (9%-10%), the spread being slightly lower than foreign bank rates, for a total interest rate of 13.5%.

The K&M Team's assumptions for the project's financing terms as well as corresponding annualized debt service payments for the three technologies base cases and the sensitivity runs are displayed in Tables 7.1 –7.36, Summary Project Data.

Table 7.1 Mauritius - Combined [illegible]e Plant - Summary Project Data
Bas[illegible]ase

Project Cap. Costs (US$000)	
Total Hard Costs	93.834
Total Soft Costs	23.163
Int. During Construction	10.516
Total Project Costs	**127,514**

Debt/Equity Ratio (US$000)		
Debt	70%	89.259
Equity	30%	38.254
Total		**127,514**

Financing Terms	Sources	Debt share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
	For. Bk A	35.71%	31,878	10	9.75%	6
	For. Bk B	35.71%	31,878	10	9.75%	6
	Maur. Bks	28.57%	25,503	10	13.50%	12

Project Returns	
IRR	20.02%
Min. DSCR	1.25

Project Schedule	
Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions				
Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7850			
Heat Rate Degradation Between Major Overhauls (%)	2%			
Fuel Cost ($/Mbtu):	**3.65**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-22	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.50%	3.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,850	7,968	8,086	7,850

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	52,779	9,618	8,943	7,906	6,869	5,832	4,796	3,759	2,722	1,685	648										
Principal Payments	89,259	3,356	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545										
Total Debt Service	**142,038**	**12,974**	**18,488**	**17,451**	**16,414**	**15,377**	**14,340**	**13,304**	**12,267**	**11,230**	**10,193**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	920	920	920	920	920	920	920	920	920	920	776.9748	776.97479	776.9748	776.9748	776.975	776.9748	776.975	776.9748	776.9748	776.975
Total O&M Costs	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124
Fixed O&M Charge	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252
Variable O&M Charge	920	920	920	920	920	920	920	920	920	920	777	777	777	777	777	777	777	777	777	777
Fuel Charge	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977
Total Tariff	**48,901**	**49,076**	**48,901**	**49,076**	**48,901**	**49,076**	**48,901**	**49,076**	**48,901**	**49,076**	**45,982**	**46,129**	**45,982**	**46,129**	**45,982**	**46,129**	**45,982**	**46,129**	**45,982**	**46,129**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048
Fixed O&M Component	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
Total Tariff	**0.082**	**0.082**	**0.082**	**0.082**	**0.082**	**0.082**	**0.082**	**0.082**	**0.082**	**0.082**	**0.092**	**0.092**	**0.092**	**0.092**	**0.092**	**0.092**	**0.092**	**0.092**	**0.092**	**0.092**

Table 7.2 Mauritius - Combined [illegible]e Plant - Summary Project Data

SENSITIVITY ANALYSIS: CAPITAL COSTS (BEFORE IDC) DECREASED BY 10%

Project Cap. Costs (US$000)

Total Hard Costs	84,751
Total Soft Costs	21,292
Int. During Construction	9,522
Total Project Costs	**115,565**

Debt/Equity Ratio (US$000)

Debt	70%	80,896
Equity	30%	34,670
Total		**115,565**

Financing Terms

Sources	Debt share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	28,891	10	9.75%	6
For. Bk B	35.71%	28,891	10	9.75%	6
Maur. Bks	28.57%	23,113	10	13.50%	12

Project Returns

IRR	20.27%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7850			
Heat Rate Degradation Between Major Overhauls (%)	2%			
Fuel Cost ($/Mbtu):	**3.65**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-22	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.50%	3.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,850	7,968	8,086	7,850

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	47,833	8,717	8,105	7,165	6,226	5,286	4,346	3,407	2,467	1,527	587										
Principal Payments	80,896	3,041	8,651	8,651	8,651	8,651	8,651	8,651	8,651	8,651	8,651										
Total Debt Service	**128,729**	**11,758**	**16,756**	**15,816**	**14,876**	**13,936**	**12,997**	**12,057**	**11,117**	**10,178**	**9,238**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	920	920	920	920	920	920	920	920	920	920	776.9748	776.97479	776.9748	776.9748	776.975	776.9748	776.975	776.9748	776.9748	776.975
Total O&M Costs	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635	1,635
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	45	45	45	45	45	45	45	45	45	45	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,080**	**4,080**	**4,080**	**4,080**	**4,080**	**4,080**	**4,080**	**4,080**	**4,080**	**4,080**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**	**4,035**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999	21,999
Fixed O&M Charge	6,115	6,115	6,115	6,115	6,115	6,115	6,115	6,115	6,115	6,115	6,070	6,070	6,070	6,070	6,070	6,070	6,070	6,070	6,070	6,070
Variable O&M Charge	920	920	920	920	920	920	920	920	920	920	777	777	777	777	777	777	777	777	777	777
Fuel Charge	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977
Total Tariff	**46,590**	**46,765**	**46,590**	**46,765**	**46,590**	**46,765**	**46,590**	**46,765**	**46,590**	**46,765**	**43,675**	**43,823**	**43,675**	**43,823**	**43,675**	**43,823**	**43,675**	**43,823**	**43,675**	**43,823**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044
Fixed O&M Component	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
Total Tariff	**0.078**	**0.079**	**0.078**	**0.079**	**0.078**	**0.079**	**0.078**	**0.079**	**0.078**	**0.079**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**

Table 7.3 Mauritius - Combined [illegible]e Plant - Summary Project Data

SENSITIVITY ANALYSIS: CAPITAL COSTS (BEFORE IDC) INCREASED BY 10%

Project Cap. Costs (US$000)

Total Hard Costs	102.918
Total Soft Costs	25.034
Int. During Construction	11.509
Total Project Costs	**139,462**

Debt/Equity Ratio (US$000)

Debt	70%	97.623
Equity	30%	41.839
Total		**139,462**

Financing Terms

Sources	Debt share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	34,865	10	9.75%	6
For. Bk B	35.71%	34,865	10	9.75%	6
Maur. Bks	28.57%	27,892	10	13.50%	12

Project Returns

IRR	**19.81%**
Min. DSCR	**1.25**

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7850			
Heat Rate Degradation Between Major Overhauls(%)	2%			
Fuel Cost ($/Mbtu):	**3.65**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-22	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.50%	3.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,850	7,968	8,086	7,850

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	57,724	10,519	9,781	8,647	7,513	6,379	5,245	4,111	2,977	1,843	709										
Principal Payments	97,623	3,670	10,439	10,439	10,439	10,439	10,439	10,439	10,439	10,439	10,439										
Total Debt Service	**155,347**	**14,190**	**20,220**	**19,086**	**17,952**	**16,818**	**15,684**	**14,550**	**13,416**	**12,282**	**11,148**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	920	920	920	920	920	920	920	920	920	920	776.9748	776.97479	776.9748	776.9748	776.975	776.9748	776.975	776.9748	776.9748	776.975
Total O&M Costs	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998	1,998
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	55	55	55	55	55	55	55	55	55	55	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,453**	**4,453**	**4,453**	**4,453**	**4,453**	**4,453**	**4,453**	**4,453**	**4,453**	**4,453**	**4,398**	**4,398**	**4,398**	**4,398**	**4,398**	**4,398**	**4,398**	**4,398**	**4,398**	**4,398**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248	26,248
Fixed O&M Charge	6,488	6,488	6,488	6,488	6,488	6,488	6,488	6,488	6,488	6,488	6,433	6,433	6,433	6,433	6,433	6,433	6,433	6,433	6,433	6,433
Variable O&M Charge	920	920	920	920	920	920	920	920	920	920	777	777	777	777	777	777	777	777	777	777
Fuel Charge	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977
Total Tariff	**51,213**	**51,387**	**51,213**	**51,387**	**51,213**	**51,387**	**51,213**	**51,387**	**51,213**	**51,387**	**48,288**	**48,435**	**48,288**	**48,435**	**48,288**	**48,435**	**48,288**	**48,435**	**48,288**	**48,435**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052	0.052
Fixed O&M Component	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
Total Tariff	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**

Table 7.4 Mauritius - Combined [illegible]e Plant - Summary Project Data

SENSITIVITY ANALYSIS: FUEL OIL COSTS DECREASED BY 5 US$/BBL

Project Cap. Costs (US$000)

Total Hard Costs	93,834
Total Soft Costs	23,163
Int. During Construction	10,516
Total Project Costs	**127,514**

Debt/Equity Ratio (US$000)

Debt	70%	89,259
Equity	30%	38,254
Total		**127,514**

Financing Terms

Sources	Debt share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	31,878	10	9.75%	6
For. Bk B	35.71%	31,878	10	9.75%	6
Maur. Bks	28.57%	25,503	10	13.50%	12

Project Returns

IRR	**20.08%**
Min. DSCR	**1.25**

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7850			
Heat Rate Degradation Between Major Overhauls (%)	2%			
Fuel Cost ($/Mbtu):	**3.00**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-22	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.50%	3.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,850	7,968	8,086	7,850

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	52,779	9,618	8,943	7,906	6,869	5,832	4,796	3,759	2,722	1,685	648										
Principal Payments	89,259	3,356	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545										
Total Debt Service	**142,038**	**12,974**	**18,488**	**17,451**	**16,414**	**15,377**	**14,340**	**13,304**	**12,267**	**11,230**	**10,193**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	920	920	920	920	920	920	920	920	920	920	776.9748	776.97479	776.9748	776.9748	776.975	776.9748	776.975	776.9748	776.9748	776.975
Total O&M Costs	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124
Fixed O&M Charge	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252
Variable O&M Charge	920	920	920	920	920	920	920	920	920	920	777	777	777	777	777	777	777	777	777	777
Fuel Charge	14,421	14,564	14,421	14,564	14,421	14,564	14,421	14,564	14,421	14,564	12,181	12,302	12,181	12,302	12,181	12,302	12,181	12,302	12,181	12,302
Total Tariff	**45,766**	**45,910**	**45,766**	**45,910**	**45,766**	**45,910**	**45,766**	**45,910**	**45,766**	**45,910**	**43,334**	**43,455**	**43,334**	**43,455**	**43,334**	**43,455**	**43,334**	**43,455**	**43,334**	**43,455**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048
Fixed O&M Component	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Total Tariff	**0.077**	**0.077**	**0.077**	**0.077**	**0.077**	**0.077**	**0.077**	**0.077**	**0.077**	**0.077**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**

Table 7.5 Mauritius - Combined [illegible]e Plant - Summary Project Data

SENSITIVITY ANALYSIS: FUEL OIL COSTS INCREASED BY 5 US$/BBL

Project Cap. Costs (US$000)

Total Hard Costs	93.834
Total Soft Costs	23,163
Int. During Construction	10.516
Total Project Costs	**127,514**

Debt/Equity Ratio (US$000)

Debt	70%	89,259
Equity	30%	38.254
Total		127,514

Financing Terms

Sources	Debt share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	31,878	10	9.75%	6
For. Bk B	35.71%	31.878	10	9.75%	6
Maur. Bks	28.57%	25,503	10	13.50%	12

Project Returns

IRR	19.95%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7850			
Heat Rate Degradation Between Major Overhauls (%)	2%			
Fuel Cost ($/Mbtu):	**4.31**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-22	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.50%	3.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,850	7,968	8,086	7,850

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	52.779	9,618	8,943	7,906	6,869	5,832	4,796	3,759	2,722	1,685	648										
Principal Payments	89,259	3,356	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545										
Total Debt Service	**142,038**	**12,974**	**18,488**	**17,451**	**16,414**	**15,377**	**14,340**	**13,304**	**12,267**	**11,230**	**10,193**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	920	920	920	920	920	920	920	920	920	920	776.9748	776.97479	776.9748	776.9748	776.975	776.9748	776.975	776.9748	776.9748	776.975
Total O&M Costs	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124
Fixed O&M Charge	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252
Variable O&M Charge	920	920	920	920	920	920	920	920	920	920	777	777	777	777	777	777	777	777	777	777
Fuel Charge	20,691	20,897	20,691	20,897	20,691	20,897	20,691	20,897	20,691	20,897	17,477	17,651	17,477	17,651	17,477	17,651	17,477	17,651	17,477	17,651
Total Tariff	**52,036**	**52,242**	**52,036**	**52,242**	**52,036**	**52,242**	**52,036**	**52,242**	**52,036**	**52,242**	**48,630**	**48,804**	**48,630**	**48,804**	**48,630**	**48,804**	**48,630**	**48,804**	**48,630**	**48,804**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048
Fixed O&M Component	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035	0.035
Total Tariff	**0.087**	**0.088**	**0.087**	**0.088**	**0.087**	**0.088**	**0.087**	**0.088**	**0.087**	**0.088**	**0.097**	**0.097**	**0.097**	**0.097**	**0.097**	**0.097**	**0.097**	**0.097**	**0.097**	**0.097**

Table 7.6 Mauritius - Combined [illegible]e Plant - Summary Project Data

SENSITIVITY ANALYSIS: MINIMUM DSCR @ 1.30

Project Cap. Costs (US$000)

Total Hard Costs	93,834
Total Soft Costs	23,163
Int. During Construction	10,516
Total Project Costs	**127,514**

Debt/Equity Ratio (US$000)

Debt	70%	89,259
Equity	30%	38,254
Total		**127,514**

Financing Terms

Sources	Debt share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	31,878	10	9.75%	6
For. Bk B	35.71%	31,878	10	9.75%	6
Maur. Bks	28.57%	25,503	10	13.50%	12

Project Returns

IRR	21.21%
Min. DSCR	1.30

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7850			
Heat Rate Degradation Between Major Overhauls (%)	2%			
Fuel Cost ($/Mbtu):	**3.65**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-22	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.50%	3.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,850	7,968	8,086	7,850

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	52,779	9,618	8,943	7,906	6,869	5,832	4,796	3,759	2,722	1,685	648										
Principal Payments	89,259	3,356	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545										
Total Debt Service	**142,038**	**12,974**	**18,488**	**17,451**	**16,414**	**15,377**	**14,340**	**13,304**	**12,267**	**11,230**	**10,193**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	920	920	920	920	920	920	920	920	920	920	776.9748	776.97479	776.9748	776.9748	776.975	776.9748	776.975	776.9748	776.9748	776.975
Total O&M Costs	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048	25,048
Fixed O&M Charge	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252
Variable O&M Charge	920	920	920	920	920	920	920	920	920	920	777	777	777	777	777	777	777	777	777	777
Fuel Charge	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977
Total Tariff	**49,826**	**50,000**	**49,826**	**50,000**	**49,826**	**50,000**	**49,826**	**50,000**	**49,826**	**50,000**	**46,906**	**47,054**	**46,906**	**47,054**	**46,906**	**47,054**	**46,906**	**47,054**	**46,906**	**47,054**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Fixed O&M Component	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
Total Tariff	**0.084**	**0.084**	**0.084**	**0.084**	**0.084**	**0.084**	**0.084**	**0.084**	**0.084**	**0.084**	**0.093**	**0.094**	**0.093**	**0.094**	**0.093**	**0.094**	**0.093**	**0.094**	**0.093**	**0.094**

Table 7.7 Mauritius - Combined [illegible]e Plant - Summary Project Data

SENSITIVITY ANALYSIS: INTEREST RATES DECREASED BY 2%

Project Cap. Costs (US$000)

Total Hard Costs	93.834
Total Soft Costs	23.040
Int. During Construction	8.468
Total Project Costs	**125,342**

Debt/Equity Ratio (US$000)

Debt	70%	87.740
Equity	30%	37.603
Total		**125,342**

Financing Terms

Sources	Debt share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	31,336	10	7.75%	6
For. Bk B	35.71%	31,336	10	7.75%	6
Maur. Bks	28.57%	25,068	10	11.50%	12

Project Returns

IRR	**18.90%**
Min DSCR	**1.25**

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7850			
Heat Rate Degradation Between Major Overhauls (%)	2%			
Fuel Cost ($/Mbtu):	**3.65**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-22	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.50%	3.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,850	7,968	8,086	7,850

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	42,323	7,708	7,172	6,341	5,509	4,678	3,846	3,014	2,183	1,351	520										
Principal Payments	87,740	3,298	9,382	9,382	9,382	9,382	9,382	9,382	9,382	9,382	9,382										
Total Debt Service	**130,062**	**11,006**	**16,555**	**15,723**	**14,892**	**14,060**	**13,228**	**12,397**	**11,565**	**10,734**	**9,902**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	920	920	920	920	920	920	920	920	920	920	776.9748	776.97479	776.9748	776.9748	776.975	776.9748	776.975	776.9748	776.9748	776.975
Total O&M Costs	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750	21,750
Fixed O&M Charge	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252
Variable O&M Charge	920	920	920	920	920	920	920	920	920	920	777	777	777	777	777	777	777	777	777	777
Fuel Charge	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977
Total Tariff	**46,528**	**46,703**	**46,528**	**46,703**	**46,528**	**46,703**	**46,528**	**46,703**	**46,528**	**46,703**	**43,608**	**43,756**	**43,608**	**43,756**	**43,608**	**43,756**	**43,608**	**43,756**	**43,608**	**43,756**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.043	0.043	0.043	0.043	0.043	0.043	0.043	0.043	0.043	0.043
Fixed O&M Component	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
Total Tariff	**0.078**	**0.078**	**0.078**	**0.078**	**0.078**	**0.078**	**0.078**	**0.078**	**0.078**	**0.078**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**

Table 7.8 Mauritius - Combined [illegible]e Plant - Summary Project Data

SENSITIVITY ANALYSIS: INTEREST RATES INCREASED BY 2%

Project Cap. Costs (US$000)

Total Hard Costs	93,834
Total Soft Costs	23,290
Int. During Construction	12,614
Total Project Costs	**129,738**

Debt/Equity Ratio (US$000)

Debt	70%	90,817
Equity	30%	38,922
Total		**129,738**

Financing Terms

Sources	Debt share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	32,435	10	11.75%	6
For. Bk B	35.71%	32,435	10	11.75%	6
Maur. Bks	28.57%	25,948	10	15.50%	12

Project Returns

IRR	21.07%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7850			
Heat Rate Degradation Between Major Overhauls (%)	2%			
Fuel Cost ($/Mbtu):	**3.65**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-22	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.50%	3.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,850	7,968	8,086	7,850

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	63,592	11,594	10,774	9,525	8,276	7,027	5,778	4,528	3,279	2,030	781										
Principal Payments	90,817	3,414	9,711	9,711	9,711	9,711	9,711	9,711	9,711	9,711	9,711										
Total Debt Service	**154,409**	**15,008**	**20,486**	**19,237**	**17,987**	**16,738**	**15,489**	**14,240**	**12,991**	**11,741**	**10,492**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	920	920	920	920	920	920	920	920	920	920	776.9748	776.97479	776.9748	776.9748	776.975	776.9748	776.975	776.9748	776.9748	776.975
Total O&M Costs	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576	26,576
Fixed O&M Charge	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252
Variable O&M Charge	920	920	920	920	920	920	920	920	920	920	777	777	777	777	777	777	777	777	777	777
Fuel Charge	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977
Total Tariff	**51,354**	**51,529**	**51,354**	**51,529**	**51,354**	**51,529**	**51,354**	**51,529**	**51,354**	**51,529**	**48,434**	**48,582**	**48,434**	**48,582**	**48,434**	**48,582**	**48,434**	**48,582**	**48,434**	**48,582**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.045	0.045	0.045	0.045	0.045	0.045	0.045	0.045	0.045	0.045	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053
Fixed O&M Component	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
Total Tariff	**0.086**	**0.087**	**0.086**	**0.087**	**0.086**	**0.087**	**0.086**	**0.087**	**0.086**	**0.087**	**0.096**	**0.097**	**0.096**	**0.097**	**0.096**	**0.097**	**0.096**	**0.097**	**0.096**	**0.097**

Table 7.9 Mauritius - Combined [illegible]le Plant - Summary Project Data

SENSITIVITY ANALYSIS: LOAN TERMS INCREASED BY 2 YEARS

Project Cap. Costs (US$000)

Total Hard Costs	93.834
Total Soft Costs	23.163
Int. During Construction	10.516
Total Project Costs	**127,514**

Debt/Equity Ratio (US$000)

Debt	70%	89.259
Equity	30%	38.254
Total		**127,514**

Financing Terms

Sources	Debt share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	31.878	12	9.75%	6
For. Bk B	35.71%	31.878	12	9.75%	6
Maur. Bks	28.57%	25.503	12	13.50%	12

Project Returns

IRR	**18.16%**
Min. DSCR	**1.25**

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7850			
Heat Rate Degradation Between Major Overhauls (%)	2%			
Fuel Cost ($/Mbtu):	**3.65**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-22	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.50%	3.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,850	7,968	8,086	7,850

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	62,438	9,625	9,069	8,215	7,362	6,508	5,655	4,801	3,948	3,094	2,241	1,387	533								
Principal Payments	89,259	2,772	7,862	7,862	7,862	7,862	7,862	7,862	7,862	7,862	7,862	7,862	7,862								
Total Debt Service	**151,697**	**12,397**	**16,931**	**16,078**	**15,224**	**14,371**	**13,517**	**12,664**	**11,810**	**10,957**	**10,103**	**9,249**	**8,396**								

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	920	920	920	920	920	920	920	920	920	920	776.9748	776.97479	776.9748	776.9748	776.975	776.9748	776.975	776.9748	776.9748	776.975
Total O&M Costs	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212	22,212
Fixed O&M Charge	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252
Variable O&M Charge	920	920	920	920	920	920	920	920	920	920	777	777	777	777	777	777	777	777	777	777
Fuel Charge	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977
Total Tariff	**46,990**	**47,164**	**46,990**	**47,164**	**46,990**	**47,164**	**46,990**	**47,164**	**46,990**	**47,164**	**44,120**	**44,268**	**44,070**	**44,218**	**44,070**	**44,218**	**44,070**	**44,218**	**44,070**	**44,218**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044	0.044
Fixed O&M Component	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.013	0.013	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
Total Tariff	**0.079**	**0.079**	**0.079**	**0.079**	**0.079**	**0.079**	**0.079**	**0.079**	**0.079**	**0.079**	**0.088**	**0.088**	**0.088**	**0.088**	**0.088**	**0.088**	**0.088**	**0.088**	**0.088**	**0.088**

Table 7.10 Mauritius - Combine[illegible]cle Plant - Summary Project Data

SENSITIVITY ANALYSIS: MINIMUM DSCR @ 1.20

Project Cap. Costs (US$000)

Total Hard Costs	93.834
Total Soft Costs	23.163
Int. During Construction	10.516
Total Project Costs	**127,514**

Debt/Equity Ratio (US$000)

Debt	70%	89,259
Equity	30%	38,254
Total		**127,514**

Financing Terms

Sources	Debt share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	31,878	10	9.75%	6
For. Bk B	35.71%	31,878	10	9.75%	6
Maur. Bks	28.57%	25,503	10	13.50%	12

Project Returns

IRR	18.83%
Min. DSCR	1.20

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7850			
Heat Rate Degradation Between Major Overhauls (%)	2%			
Fuel Cost ($/Mbtu):	**3.65**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-22	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.50%	3.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,850	7,968	8,086	7,850

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	52,779	9,618	8,943	7,906	6,869	5,832	4,796	3,759	2,722	1,685	648										
Principal Payments	89,259	3,356	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545										
Total Debt Service	**142,038**	**12,974**	**18,488**	**17,451**	**16,414**	**15,377**	**14,340**	**13,304**	**12,267**	**11,230**	**10,193**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	920	920	920	920	920	920	920	920	920	920	776.9748	776.97479	776.9748	776.9748	776.975	776.9748	776.975	776.9748	776.9748	776.975
Total O&M Costs	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,955**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**	**2,812**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,267**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**	**4,217**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199	23,199
Fixed O&M Charge	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252	6,252
Variable O&M Charge	920	920	920	920	920	920	920	920	920	920	777	777	777	777	777	777	777	777	777	777
Fuel Charge	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977
Total Tariff	**47,977**	**48,152**	**47,977**	**48,152**	**47,977**	**48,152**	**47,977**	**48,152**	**47,977**	**48,152**	**45,057**	**45,205**	**45,057**	**45,205**	**45,057**	**45,205**	**45,057**	**45,205**	**45,057**	**45,205**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.039	0.039	0.039	0.039	0.039	0.039	0.039	0.039	0.039	0.039	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046
Fixed O&M Component	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
Total Tariff	**0.081**	**0.081**	**0.081**	**0.081**	**0.081**	**0.081**	**0.081**	**0.081**	**0.081**	**0.081**	**0.090**	**0.090**	**0.090**	**0.090**	**0.090**	**0.090**	**0.090**	**0.090**	**0.090**	**0.090**

Table 7.11 Mauritius - Combined Cycle Plant - Summary Project Data

SENSITIVITY ANALYSIS: NON FUEL OPERATING COSTS DECREASED BY 10%

Project Cap. Costs (US$000)

Total Hard Costs	93,834
Total Soft Costs	23,163
Int. During Construction	10,516
Total Project Costs	**127,514**

Debt/Equity Ratio (US$000)

Debt	70%	89,259
Equity	30%	38,254
Total		**127,514**

Financing Terms

Sources	Debt share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	31,878	10	9.75%	6
For. Bk B	35.71%	31,878	10	9.75%	6
Maur. Bks	28.57%	25,503	10	13.50%	12

Project Returns

IRR	19.84%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7850			
Heat Rate Degradation Between Major Overhauls (%)	2%			
Fuel Cost ($/Mbtu):	**3.65**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-22	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.50%	3.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,850	7,968	8,086	7,850

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	52,779	9,618	8,943	7,906	6,869	5,832	4,796	3,759	2,722	1,685	648										
Principal Payments	89,259	3,356	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545										
Total Debt Service	**142,038**	**12,974**	**18,488**	**17,451**	**16,414**	**15,377**	**14,340**	**13,304**	**12,267**	**11,230**	**10,193**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832
Variable O&M Costs	828	828	828	828	828	828	828	828	828	828	699.2773	699.27731	699.2773	699.2773	699.277	699.2773	699.277	699.2773	699.2773	699.277
Total O&M Costs	**2,660**	**2,660**	**2,660**	**2,660**	**2,660**	**2,660**	**2,660**	**2,660**	**2,660**	**2,660**	**2,531**	**2,531**	**2,531**	**2,531**	**2,531**	**2,531**	**2,531**	**2,531**	**2,531**	**2,531**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
Insurance during Operation	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817
BOP & Major Maintenance	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,027**	**4,027**	**4,027**	**4,027**	**4,027**	**4,027**	**4,027**	**4,027**	**4,027**	**4,027**	**3,977**	**3,977**	**3,977**	**3,977**	**3,977**	**3,977**	**3,977**	**3,977**	**3,977**	**3,977**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979	23,979
Fixed O&M Charge	5,858	5,858	5,858	5,858	5,858	5,858	5,858	5,858	5,858	5,858	5,808	5,808	5,808	5,808	5,808	5,808	5,808	5,808	5,808	5,808
Variable O&M Charge	828	828	828	828	828	828	828	828	828	828	699	699	699	699	699	699	699	699	699	699
Fuel Charge	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977
Total Tariff	**48,221**	**48,396**	**48,221**	**48,396**	**48,221**	**48,396**	**48,221**	**48,396**	**48,221**	**48,396**	**45,315**	**45,463**	**45,315**	**45,463**	**45,315**	**45,463**	**45,315**	**45,463**	**45,315**	**45,463**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048
Fixed O&M Component	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
Total Tariff	**0.081**	**0.081**	**0.081**	**0.081**	**0.081**	**0.081**	**0.081**	**0.081**	**0.081**	**0.081**	**0.090**	**0.090**	**0.090**	**0.090**	**0.090**	**0.090**	**0.090**	**0.090**	**0.090**	**0.090**

Table 7.12 Mauritius - Combine[illegible]cle Plant - Summary Project Data

SENSITIVITY ANALYSIS: NON FUEL OPERATING COSTS INCREASED BY 10%

Project Cap. Costs (US$000)

Total Hard Costs	93,834
Total Soft Costs	23,163
Int. During Construction	10,516
Total Project Costs	**127,514**

Debt/Equity Ratio (US$000)

Debt	70%	89,259
Equity	30%	38,254
Total		**127,514**

Financing Terms

Sources	Debt share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	31,878	10	9.75%	6
For. Bk B	35.71%	31,878	10	9.75%	6
Maur. Bks	28.57%	25,503	10	13.50%	12

Project Returns

IRR	20.20%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7850			
Heat Rate Degradation Between Major Overhauls (%)	2%			
Fuel Cost ($/Mbtu):	**3.65**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-22	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.50%	3.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,850	7,968	8,086	7,850

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	52,779	9,618	8,943	7,906	6,869	5,832	4,796	3,759	2,722	1,685	648										
Principal Payments	89,259	3,356	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545	9,545										
Total Debt Service	**142,038**	**12,974**	**18,488**	**17,451**	**16,414**	**15,377**	**14,340**	**13,304**	**12,267**	**11,230**	**10,193**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239
Variable O&M Costs	1012	1012	1012	1012	1012	1012	1012	1012	1012	1012	854.6723	854.67227	854.6723	854.6723	854.672	854.6723	854.672	854.6723	854.6723	854.672
Total O&M Costs	**3,251**	**3,251**	**3,251**	**3,251**	**3,251**	**3,251**	**3,251**	**3,251**	**3,251**	**3,251**	**3,093**	**3,093**	**3,093**	**3,093**	**3,093**	**3,093**	**3,093**	**3,093**	**3,093**	**3,093**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550
Insurance during Operation	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817	1,817
BOP & Major Maintenance	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,507**	**4,507**	**4,507**	**4,507**	**4,507**	**4,507**	**4,507**	**4,507**	**4,507**	**4,507**	**4,457**	**4,457**	**4,457**	**4,457**	**4,457**	**4,457**	**4,457**	**4,457**	**4,457**	**4,457**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269	24,269
Fixed O&M Charge	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,745	6,695	6,695	6,695	6,695	6,695	6,695	6,695	6,695	6,695	6,695
Variable O&M Charge	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	855	855	855	855	855	855	855	855	855	855
Fuel Charge	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977	14,829	14,977
Total Tariff	**49,582**	**49,757**	**49,582**	**49,757**	**49,582**	**49,757**	**49,582**	**49,757**	**49,582**	**49,757**	**46,648**	**46,795**	**46,648**	**46,795**	**46,648**	**46,795**	**46,648**	**46,795**	**46,648**	**46,795**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.041	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048	0.048
Fixed O&M Component	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030	0.030
Total Tariff	**0.083**	**0.084**	**0.083**	**0.084**	**0.083**	**0.084**	**0.083**	**0.084**	**0.083**	**0.084**	**0.093**	**0.093**	**0.093**	**0.093**	**0.093**	**0.093**	**0.093**	**0.093**	**0.093**	**0.093**

Table 7.13 Mauritius - Coa[illegible]nt - Summary Project Data

BASE CASE

Project Cap. Costs (US$000)	
Total Hard Costs	134.789
Total Soft Costs	32.638
Int. During Construction	18.881
Total Project Costs	**186,308**

Debt/Equity Ratio (US$000)		
Debt	70%	130.416
Equity	30%	55.892
Total		186,308

Financing Terms	Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
	For. Bk A	35.71%	46,577	10	9.75%	6
	For. Bk B	35.71%	46,577	10	9.75%	6
	Maur. Bks	28.57%	37,262	10	13.50%	12

Project Returns	
IRR	**19.32%**
Min. DSCR	**1.25**

Project Schedule	
Construction Start Date	1-Jan-02
Planned Construction Duration (months)	30
Commercial Operation Date (mm/dd/yy)	1-Jul-04
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions				
Type of Fuel	Coal			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	11795			
Heat Rate Degradation Between Major Overhauls (%)	0%			
Fuel Cost ($/Mton)	**34.59**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.00%	2.00%	0.00%
Heat Rate @ given load (BTU/kWh)	11,795	11,913	12,031	11,795

Estimated Plant Output (MWh)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Interest Expenses	77,114	7,056	13,719	12,309	10,794	9,279	7,764	6,249	4,734	3,219	1,704	284									
Principal Payments	130,416	0	11,876	13,946	13,946	13,946	13,946	13,946	13,946	13,946	13,946	6,973									
Total Debt Service	**207,530**	**7,056**	**25,595**	**26,255**	**24,740**	**23,225**	**21,710**	**20,195**	**18,680**	**17,165**	**15,650**	**7,257**									

Operation and Maintenance Payments (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed O&M Costs	1,153	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
Variable O&M Costs	500	1000	1000	1000	1000	1000	1000	1000	1000	1000	844.5378	844.53782	844.5378	844.5378	844.538	844.5378	844.538	844.5378	844.5378	844.538
Total O&M Costs	**1,653**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**

Other Costs of Operation (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
G&A	250	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,294	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588
BOP & Major Maintenance	1,860	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160
Agency Fees	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**3,454**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**

Tariff Components in US$000 per Year

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capacity Charge	17,370	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740
Fixed O&M Charge	3,801	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553
Variable O&M Charge	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	845	845	845	845	845	845	845	845	845	845
Fuel Charge	4,858	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207
Total Tariff	**26,529**	**53,059**	**53,059**	**53,059**	**53,059**	**53,059**	**53,059**	**53,059**	**53,059**	**53,059**	**51,394**	**51,344**	**51,344**	**51,344**	**51,344**	**51,344**	**51,344**	**51,344**	**51,344**	**51,344**

Tariff Components in US$ per kWh

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capital Cost Component	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069
Fixed O&M Component	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Total Tariff	**0.089**	**0.089**	**0.089**	**0.089**	**0.089**	**0.089**	**0.089**	**0.089**	**0.089**	**0.089**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**

Table 7.14 Mauritius - Co[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: CAPITAL COSTS (BEFORE IDC) DECREASED BY 10%

Project Cap. Costs (US$000)

Total Hard Costs	121,849
Total Soft Costs	30,053
Int. During Construction	17,124
Total Project Costs	**169,026**

Debt/Equity Ratio (US$000)

Debt	70%	118,318
Equity	30%	50,708
Total		**169,026**

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	42,256	10	9.75%	6
For. Bk B	35.71%	42,256	10	9.75%	6
Maur. Bks	28.57%	33,805	10	13.50%	12

Project Returns

IRR	**19.94%**
Min. DSCR	**1.25**

Project Schedule

Construction Start Date	1-Jan-02
Planned Construction Duration (months)	30
Commercial Operation Date (mm/dd/yy)	1-Jul-04
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Coal			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	11795			
Heat Rate Degradation Between Major Overhauls(%)	0%			
Fuel Cost ($/Mton)	**34.59**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.00%	2.00%	0.00%
Heat Rate @ given load (BTU/kWh)	11,795	11,913	12,031	11,795

Estimated Plant Output (MWh)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Interest Expenses	69,961	6,402	12,447	11,167	9,793	8,418	7,044	5,670	4,295	2,921	1,546	258									
Principal Payments	118,318	0	10,774	12,652	12,652	12,652	12,652	12,652	12,652	12,652	12,652	6,326									
Total Debt Service	**188,279**	**6,402**	**23,221**	**23,820**	**22,445**	**21,071**	**19,696**	**18,322**	**16,947**	**15,573**	**14,198**	**6,584**									

Operation and Maintenance Payments (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed O&M Costs	1,153	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
Variable O&M Costs	500	1000	1000	1000	1000	1000	1000	1000	1000	1000	844.5378	844.53782	844.5378	844.5378	844.538	844.5378	844.538	844.5378	844.5378	844.538
Total O&M Costs	**1,653**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**

Other Costs of Operation (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
G&A	250	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,165	2,329	2,329	2,329	2,329	2,329	2,329	2,329	2,329	2,329	2,329	2,329	2,329	2,329	2,329	2,329	2,329	2,329	2,329	2,329
BOP & Major Maintenance	1,860	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160
Agency Fees	45	45	45	45	45	45	45	45	45	45	45	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**3,320**	**5,034**	**5,034**	**5,034**	**5,034**	**5,034**	**5,034**	**5,034**	**5,034**	**5,034**	**5,034**	**4,989**	**4,989**	**4,989**	**4,989**	**4,989**	**4,989**	**4,989**	**4,989**	**4,989**

Tariff Components in US$000 per Year

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capacity Charge	16,043	32,086	32,086	32,086	32,086	32,086	32,086	32,086	32,086	32,086	32,086	32,086	32,086	32,086	32,086	32,086	32,086	32,086	32,086	32,086
Fixed O&M Charge	3,670	7,339	7,339	7,339	7,339	7,339	7,339	7,339	7,339	7,339	7,339	7,294	7,294	7,294	7,294	7,294	7,294	7,294	7,294	7,294
Variable O&M Charge	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	845	845	845	845	845	845	845	845	845	845
Fuel Charge	4,858	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207
Total Tariff	**25,071**	**50,141**	**50,141**	**50,141**	**50,141**	**50,141**	**50,141**	**50,141**	**50,141**	**50,141**	**48,476**	**48,431**	**48,431**	**48,431**	**48,431**	**48,431**	**48,431**	**48,431**	**48,431**	**48,431**

Tariff Components in US$ per kWh

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capital Cost Component	0.054	0.054	0.054	0.054	0.054	0.054	0.054	0.054	0.054	0.054	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064
Fixed O&M Component	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Total Tariff	**0.084**	**0.084**	**0.084**	**0.084**	**0.084**	**0.084**	**0.084**	**0.084**	**0.084**	**0.084**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**

Table 7.15 Mauritius - Coa[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: CAPITAL COSTS (BEFORE IDC) INCREASED BY 10%

Project Cap. Costs (US$000)

Total Hard Costs	147,728
Total Soft Costs	35,758
Int. During Construction	20,649
Total Project Costs	**204,134**

Debt/Equity Ratio (US$000)

Debt	70%	142,894
Equity	30%	61,240
Total		**204,134**

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	51,034	10	9.75%	6
For. Bk B	35.71%	51,034	10	9.75%	6
Maur. Bks	28.57%	40,827	10	13.50%	12

Project Returns

IRR	18.80%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-02
Planned Construction Duration (months)	30
Commercial Operation Date (mm/dd/yy)	1-Jul-04
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Coal			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	11795			
Heat Rate Degradation Between Major Overhauls (%)	0%			
Fuel Cost ($/Mton)	**34.59**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.00%	2.00%	0.00%
Heat Rate @ given load (BTU/kWh)	11,795	11,913	12,031	11,795

Estimated Plant Output (MWh)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annuallzed Debt Service Payments (US$000)

Year	*Totals*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Interest Expenses	84,493	7,732	15,032	13,487	11,827	10,167	8,507	6,847	5,187	3,527	1,867	311									
Principal Payments	142,894	0	13,012	15,280	15,280	15,280	15,280	15,280	15,280	15,280	15,280	7,640									
Total Debt Service	**227,387**	**7,732**	**28,044**	**28,767**	**27,107**	**25,447**	**23,787**	**22,127**	**20,468**	**18,808**	**17,148**	7,951									

Operation and Maintenance Payments (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed O&M Costs	1,153	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
Variable O&M Costs	500	1000	1000	1000	1000	1000	1000	1000	1000	1000	844.5378	844.53782	844.5378	844.5378	844.538	844.5378	844.538	844.5378	844.5378	844.538
Total O&M Costs	**1,653**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**

Other Costs of Operation (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
G&A	250	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,423	2,847	2,847	2,847	2,847	2,847	2,847	2,847	2,847	2,847	2,847	2,847	2,847	2,847	2,847	2,847	2,847	2,847	2,847	2,847
BOP & Major Maintenance	1,860	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160
Agency Fees	55	55	55	55	55	55	55	55	55	55	55	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**3,588**	**5,562**	**5,562**	**5,562**	**5,562**	**5,562**	**5,562**	**5,562**	**5,562**	**5,562**	**5,562**	**5,507**	**5,507**	**5,507**	**5,507**	**5,507**	**5,507**	**5,507**	**5,507**	**5,507**

Tariff Components in US$000 per Year

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capacity Charge	18,686	37,371	37,371	37,371	37,371	37,371	37,371	37,371	37,371	37,371	37,371	37,371	37,371	37,371	37,371	37,371	37,371	37,371	37,371	37,371
Fixed O&M Charge	3,933	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,812	7,812	7,812	7,812	7,812	7,812	7,812	7,812	7,812
Variable O&M Charge	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	845	845	845	845	845	845	845	845	845	845
Fuel Charge	4,858	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207
Total Tariff	**27,977**	**55,954**	**55,954**	**55,954**	**55,954**	**55,954**	**55,954**	**55,954**	**55,954**	**55,954**	**54,289**	**54,234**	**54,234**	**54,234**	**54,234**	**54,234**	**54,234**	**54,234**	**54,234**	**54,234**

Tariff Components in US$ per kWh

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capital Cost Component	0.063	0.063	0.063	0.063	0.063	0.063	0.063	0.063	0.063	0.063	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074
Fixed O&M Component	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Total Tariff	**0.094**	**0.094**	**0.094**	**0.094**	**0.094**	**0.094**	**0.094**	**0.094**	**0.094**	**0.094**	**0.108**	**0.108**	**0.108**	**0.108**	**0.108**	**0.108**	**0.108**	**0.108**	**0.108**	**0.108**

Table 7.16 Mauritius - Coa[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: FUEL COSTS DECREASED BY 10%

Project Cap. Costs (US$000)

Total Hard Costs	134.789
Total Soft Costs	32.638
Int. During Construction	18.881
Total Project Costs	**186,308**

Debt/Equity Ratio (US$000)

Debt	70%	130.416
Equity	30%	55.892
Total		186,308

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	46.577	10	9.75%	6
For. Bk B	35.71%	46.577	10	9.75%	6
Maur. Bks	28.57%	37.262	10	13.50%	12

Project Returns

IRR	19.32%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-02
Planned Construction Duration (months)	30
Commercial Operation Date (mm/dd/yy)	1-Jul-04
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Coal			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	11795			
Heat Rate Degradation Between Major Overhauls (%)	0%			
Fuel Cost ($/Mton)	**31.13**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.00%	2.00%	0.00%
Heat Rate @ given load (BTU/kWh)	11,795	11,913	12,031	11,795

Estimated Plant Output (MWh)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Interest Expenses	77,114	7,056	13,719	12,309	10,794	9,279	7,764	6,249	4,734	3,219	1,704	284									
Principal Payments	130,416	0	11,876	13,946	13,946	13,946	13,946	13,946	13,946	13,946	13,946	6,973									
Total Debt Service	**207,530**	**7,056**	**25,595**	**26,255**	**24,740**	**23,225**	**21,710**	**20,195**	**18,680**	**17,165**	**15,650**	**7,257**									

Operation and Maintenance Payments (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed O&M Costs	1,153	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
Variable O&M Costs	500	1000	1000	1000	1000	1000	1000	1000	1000	1000	844.5378	844.53782	844.5378	844.5378	844.538	844.5378	844.538	844.5378	844.5378	844.538
Total O&M Costs	**1,653**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**

Other Costs of Operation (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
G&A	250	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,294	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588
BOP & Major Maintenance	1,860	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160
Agency Fees	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**3,454**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**

Tariff Components in US$000 per Year

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capacity Charge	17,364	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729
Fixed O&M Charge	3,801	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553
Variable O&M Charge	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	845	845	845	845	845	845	845	845	845	845
Fuel Charge	4,372	8,745	8,745	8,745	8,745	8,745	8,745	8,745	8,745	8,745	7,386	7,386	7,386	7,386	7,386	7,386	7,386	7,386	7,386	7,386
Total Tariff	**26,038**	**52,076**	**52,076**	**52,076**	**52,076**	**52,076**	**52,076**	**52,076**	**52,076**	**52,076**	**50,562**	**50,512**	**50,512**	**50,512**	**50,512**	**50,512**	**50,512**	**50,512**	**50,512**	**50,512**

Tariff Components in US$ per kWh

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capital Cost Component	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069
Fixed O&M Component	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Total Tariff	**0.088**	**0.088**	**0.088**	**0.088**	**0.088**	**0.088**	**0.088**	**0.088**	**0.088**	**0.088**	**0.101**	**0.101**	**0.101**	**0.101**	**0.101**	**0.101**	**0.101**	**0.101**	**0.101**	**0.101**

Table 7.17 Mauritius - Coa[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: FUEL COSTS INCREASED BY 10%

Project Cap. Costs (US$000)

Total Hard Costs	134,789
Total Soft Costs	32,638
Int. During Construction	18,881
Total Project Costs	**186,308**

Debt/Equity Ratio (US$000)

Debt	70%	130,416
Equity	30%	55,892
Total		186,308

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	46,577	10	9.75%	6
For. Bk B	35.71%	46,577	10	9.75%	6
Maur. Bks	28.57%	37,262	10	13.50%	12

Project Returns

IRR	19.30%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-02
Planned Construction Duration (months)	30
Commercial Operation Date (mm/dd/yy)	1-Jul-04
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Coal			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	11795			
Heat Rate Degradation Between Major Overhauls (%)	0%			
Fuel Cost ($/Mton)	**38.05**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.00%	2.00%	0.00%
Heat Rate @ given load (BTU/kWh)	11,795	11,913	12,031	11,795

Estimated Plant Output (MWh)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Interest Expenses	77,114	7,056	13,719	12,309	10,794	9,279	7,764	6,249	4,734	3,219	1,704	284									
Principal Payments	130,416	0	11,876	13,946	13,946	13,946	13,946	13,946	13,946	13,946	13,946	6,973									
Total Debt Service	**207,530**	**7,056**	**25,595**	**26,255**	**24,740**	**23,225**	**21,710**	**20,195**	**18,680**	**17,165**	**15,650**	**7,257**									

Operation and Maintenance Payments (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed O&M Costs	1,153	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
Variable O&M Costs	500	1000	1000	1000	1000	1000	1000	1000	1000	1000	844.5378	844.53782	844.5378	844.5378	844.538	844.5378	844.538	844.5378	844.5378	844.538
Total O&M Costs	**1,653**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**

Other Costs of Operation (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
G&A	250	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,294	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588
BOP & Major Maintenance	1,860	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160
Agency Fees	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**3,454**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**

Tariff Components in US$000 per Year

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capacity Charge	17,364	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729	34,729
Fixed O&M Charge	3,801	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553
Variable O&M Charge	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	845	845	845	845	845	845	845	845	845	845
Fuel Charge	5,344	10,688	10,688	10,688	10,688	10,688	10,688	10,688	10,688	10,688	9,027	9,027	9,027	9,027	9,027	9,027	9,027	9,027	9,027	9,027
Total Tariff	**27,010**	**54,019**	**54,019**	**54,019**	**54,019**	**54,019**	**54,019**	**54,019**	**54,019**	**54,019**	**52,204**	**52,154**	**52,154**	**52,154**	**52,154**	**52,154**	**52,154**	**52,154**	**52,154**	**52,154**

Tariff Components in US$ per kWh

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capital Cost Component	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069	0.069
Fixed O&M Component	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018
Total Tariff	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.104**	**0.104**	**0.104**	**0.104**	**0.104**	**0.104**	**0.104**	**0.104**	**0.104**	**0.104**

Table 7.18 Mauritius - Coa[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: MINIMUM DSCR @ 1.30

Project Cap. Costs (US$000)

Total Hard Costs	134,789
Total Soft Costs	32,638
Int. During Construction	18,881
Total Project Costs	**186,308**

Debt/Equity Ratio (US$000)

Debt	70%	130,416
Equity	30%	55,892
Total		186,308

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	46,577	10	9.75%	6
For. Bk B	35.71%	46,577	10	9.75%	6
Maur. Bks	28.57%	37,262	10	13.50%	12

Project Returns

IRR	20.29%
Min. DSCR	1.30

Project Schedule

Construction Start Date	1-Jan-02
Planned Construction Duration (months)	30
Commercial Operation Date (mm/dd/yy)	1-Jul-04
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Coal			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	11795			
Heat Rate Degradation Between Major Overhauls (%)	0%			
Fuel Cost ($/Mton)	**34.59**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.00%	2.00%	0.00%
Heat Rate @ given load (BTU/kWh)	11,795	11,913	12,031	11,795

Estimated Plant Output (MWh)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Interest Expenses	77,114	7,056	13,719	12,309	10,794	9,279	7,764	6,249	4,734	3,219	1,704	284									
Principal Payments	130,416	0	11,876	13,946	13,946	13,946	13,946	13,946	13,946	13,946	13,946	6,973									
Total Debt Service	**207,530**	**7,056**	**25,595**	**26,255**	**24,740**	**23,225**	**21,710**	**20,195**	**18,680**	**17,165**	**15,650**	**7,257**									

Operation and Maintenance Payments (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed O&M Costs	1,153	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
Variable O&M Costs	500	1000	1000	1000	1000	1000	1000	1000	1000	1000	844.5378	844.53782	844.5378	844.5378	844.538	844.5378	844.538	844.5378	844.5378	844.538
Total O&M Costs	**1,653**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**

Other Costs of Operation (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
G&A	250	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,294	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588
BOP & Major Maintenance	1,860	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160
Agency Fees	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**3,454**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**

Trariff Components in US$000 per Year

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capacity Charge	17,940	35,880	35,880	35,880	35,880	35,880	35,880	35,880	35,880	35,880	35,880	35,880	35,880	35,880	35,880	35,880	35,880	35,880	35,880	35,880
Fixed O&M Charge	3,801	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553
Variable O&M Charge	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	845	845	845	845	845	845	845	845	845	845
Fuel Charge	4,858	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207
Total Tariff	**27,100**	**54,199**	**54,199**	**54,199**	**54,199**	**54,199**	**54,199**	**54,199**	**54,199**	**54,199**	**52,534**	**52,484**	**52,484**	**52,484**	**52,484**	**52,484**	**52,484**	**52,484**	**52,484**	**52,484**

Tariff Components in US$ per kWh

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capital Cost Component	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.071	0.071	0.071	0.071	0.071	0.071	0.071	0.071	0.071	0.071
Fixed O&M Component	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Total Tariff	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.105**	**0.104**	**0.104**	**0.104**	**0.104**	**0.104**	**0.104**	**0.104**	**0.104**	**0.104**

Table 7.19 Mauritius - Coa[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: INTEREST RATES DECREASED BY 2%

Project Cap. Costs (US$000)

Total Hard Costs	134,789
Total Soft Costs	32,400
Int. During Construction	15,153
Total Project Costs	**182,341**

Debt/Equity Ratio (US$000)

Debt	70%	127,639
Equity	30%	54,702
Total		**182,341**

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	45,585	10	7.75%	6
For. Bk B	35.71%	45,585	10	7.75%	6
Maur. Bks	28.57%	36,468	10	11.50%	12

Project Returns

IRR	19.06%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-02
Planned Construction Duration (months)	30
Commercial Operation Date (mm/dd/yy)	1-Jul-04
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Coal			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	11795			
Heat Rate Degradation Between Major Overhauls (%)	0%			
Fuel Cost ($/Mton)	**34.59**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.00%	2.00%	0.00%
Heat Rate @ given load (BTU/kWh)	11,795	11,913	12,031	11,795

Estimated Plant Output (MWh)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Interest Expenses	61,569	5,630	10,952	9,829	8,619	7,410	6,200	4,990	3,780	2,571	1,361	227									
Principal Payments	127,639	0	11,623	13,649	13,649	13,649	13,649	13,649	13,649	13,649	13,649	6,824									
Total Debt Service	**189,207**	**5,630**	**22,574**	**23,478**	**22,268**	**21,059**	**19,849**	**18,639**	**17,429**	**16,220**	**15,010**	7,051									

Operation and Maintenance Payments (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed O&M Costs	1,153	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
Variable O&M Costs	500	1000	1000	1000	1000	1000	1000	1000	1000	1000	844.5378	844.53782	844.5378	844.5378	844.538	844.5378	844.538	844.5378	844.5378	844.538
Total O&M Costs	**1,653**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**

Other Costs of Operation (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
G&A	250	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,294	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588
BOP & Major Maintenance	1,860	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160
Agency Fees	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**3,454**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**

Tariff Components in US$000 per Year

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capacity Charge	16,034	32,067	32,067	32,067	32,067	32,067	32,067	32,067	32,067	32,067	32,067	32,067	32,067	32,067	32,067	32,067	32,067	32,067	32,067	32,067
Fixed O&M Charge	3,801	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553
Variable O&M Charge	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	845	845	845	845	845	845	845	845	845	845
Fuel Charge	4,858	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207
Total Tariff	**25,193**	**50,386**	**50,386**	**50,386**	**50,386**	**50,386**	**50,386**	**50,386**	**50,386**	**50,386**	**48,721**	**48,671**	**48,671**	**48,671**	**48,671**	**48,671**	**48,671**	**48,671**	**48,671**	**48,671**

Tariff Components in US$ per kWh

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capital Cost Component	0.054	0.054	0.054	0.054	0.054	0.054	0.054	0.054	0.054	0.054	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064
Fixed O&M Component	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Total Tariff	**0.085**	**0.085**	**0.085**	**0.085**	**0.085**	**0.085**	**0.085**	**0.085**	**0.085**	**0.085**	**0.097**	**0.097**	**0.097**	**0.097**	**0.097**	**0.097**	**0.097**	**0.097**	**0.097**	**0.097**

Table 7.20 Mauritius - Coal [illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: INTEREST RATES INCREASED BY 2%

Project Cap. Costs (US$000)

Total Hard Costs	134,789
Total Soft Costs	35,024
Int. During Construction	22,772
Total Project Costs	**192,585**

Debt/Equity Ratio (US$000)

Debt	70%	134,809
Equity	30%	57,775
Total		**192,585**

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	48,146	10	11.75%	6
For. Bk B	35.71%	48,146	10	11.75%	6
Maur. Bks	28.57%	38,517	10	15.50%	12

Project Returns

IRR	19.84%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-02
Planned Construction Duration (months)	30
Commercial Operation Date (mm/dd/yy)	1-Jul-04
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Coal			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	11795			
Heat Rate Degradation Between Major Overhauls (%)	0%			
Fuel Cost ($/Mton)	**34.59**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.00%	2.00%	0.00%
Heat Rate @ given load (BTU/kWh)	11,795	11,913	12,031	11,795

Estimated Plant Output (MWh)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Interest Expenses	94,397	8,642	16,796	15,066	13,212	11,358	9,503	7,649	5,795	3,940	2,086	348									
Principal Payments	134,809	0	12,276	14,416	14,416	14,416	14,416	14,416	14,416	14,416	14,416	7,208									
Total Debt Service	**229,206**	**8,642**	**29,072**	**29,482**	**27,628**	**25,774**	**23,919**	**22,065**	**20,211**	**18,356**	**16,502**	7,556									

Operation and Maintenance Payments (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed O&M Costs	1,153	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
Variable O&M Costs	500	1000	1000	1000	1000	1000	1000	1000	1000	1000	844.5378	844.53782	844.5378	844.5378	844.538	844.5378	844.538	844.5378	844.5378	844.538
Total O&M Costs	**1,653**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**

Other Costs of Operation (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
G&A	250	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,294	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588
BOP & Major Maintenance	1,860	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160
Agency Fees	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**3,454**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**

Trariff Components in US$000 per Year

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capacity Charge	18,929	37,859	37,859	37,859	37,859	37,859	37,859	37,859	37,859	37,859	37,859	37,859	37,859	37,859	37,859	37,859	37,859	37,859	37,859	37,859
Fixed O&M Charge	3,801	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553
Variable O&M Charge	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	845	845	845	845	845	845	845	845	845	845
Fuel Charge	4,858	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207
Total Tariff	**28,089**	**56,178**	**56,178**	**56,178**	**56,178**	**56,178**	**56,178**	**56,178**	**56,178**	**56,178**	**54,513**	**54,463**	**54,463**	**54,463**	**54,463**	**54,463**	**54,463**	**54,463**	**54,463**	**54,463**

Tariff Components in US$ per kWh

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capital Cost Component	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.064	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Fixed O&M Component	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Total Tariff	**0.094**	**0.094**	**0.094**	**0.094**	**0.094**	**0.094**	**0.094**	**0.094**	**0.094**	**0.094**	**0.108**	**0.108**	**0.108**	**0.108**	**0.108**	**0.108**	**0.108**	**0.108**	**0.108**	**0.108**

Table 7.21 Mauritius - Coa[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: LOAN TERMS INCREASED BY 2 YEARS

Project Cap. Costs (US$000)

Total Hard Costs	134.789
Total Soft Costs	32.638
Int. During Construction	18.881
Total Project Costs	**186,308**

Debt/Equity Ratio (US$000)

Debt	70%	130.416
Equity	30%	55,892
Total		186,308

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	46.577	12	9.75%	6
For. Bk B	35.71%	46.577	12	9.75%	6
Maur. Bks	28.57%	37.262	12	13.50%	12

Project Returns

IRR	18.22%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-02
Planned Construction Duration (months)	30
Commercial Operation Date (mm/dd/yy)	1-Jul-04
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Coal			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	11795			
Heat Rate Degradation Between Major Overhauls (%)	0%			
Fuel Cost ($/Mton)	**34.59**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.00%	2.00%	0.00%
Heat Rate @ given load (BTU/kWh)	11,795	11,913	12,031	11,795

Estimated Plant Output (MWh)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Interest Expenses	91,227	7,056	13,788	12,627	11,380	10,133	8,885	7,638	6,391	5,144	3,897	2,650	1,403	234							
Principal Payments	130,416	0	9,794	11,488	11,488	11,488	11,488	11,488	11,488	11,488	11,488	11,488	11,488	5,744							
Total Debt Service	**221,642**	**7,056**	**23,582**	**24,115**	**22,867**	**21,620**	**20,373**	**19,126**	**17,879**	**16,632**	**15,385**	14,138	12,891	5,978							

Operation and Maintenance Payments (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed O&M Costs	1,153	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
Variable O&M Costs	500	1000	1000	1000	1000	1000	1000	1000	1000	1000	844.5378	844.53782	844.5378	844.5378	844.538	844.5378	844.538	844.5378	844.5378	844.538
Total O&M Costs	**1,653**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**

Other Costs of Operation (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
G&A	250	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,294	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588
BOP & Major Maintenance	1,860	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160
Agency Fees	50	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-
Total Other Costs of Op.	**3,454**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**

Tariff Components in US$000 per Year

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capacity Charge	16,378	32,756	32,756	32,756	32,756	32,756	32,756	32,756	32,756	32,756	32,756	32,756	32,756	32,756	32,756	32,756	32,756	32,756	32,756	32,756
Fixed O&M Charge	3,801	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,553	7,553	7,553	7,553	7,553	7,553	7,553
Variable O&M Charge	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	845	845	845	845	845	845	845	845	845	845
Fuel Charge	4,858	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207
Total Tariff	**25,538**	**51,075**	**51,075**	**51,075**	**51,075**	**51,075**	**51,075**	**51,075**	**51,075**	**51,075**	**49,410**	**49,410**	**49,410**	**49,360**	**49,360**	**49,360**	**49,360**	**49,360**	**49,360**	**49,360**

Tariff Components in US$ per kWh

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capital Cost Component	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Fixed O&M Component	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Total Tariff	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.086**	**0.098**	**0.098**	**0.098**	**0.098**	**0.098**	**0.098**	**0.098**	**0.098**	**0.098**	**0.098**

Table 7.22 Mauritius - Coa[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: MINIMUM DSCR @ 1.20

Project Cap. Costs (US$000)

Total Hard Costs	134,789
Total Soft Costs	33,173
Int. During Construction	18,891
Total Project Costs	**186,852**

Debt/Equity Ratio (US$000)

Debt	70%	130,797
Equity	30%	56,056
Total		**186,852**

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	46,713	10	9.75%	6
For. Bk B	35.71%	46,713	10	9.75%	6
Maur. Bks	28.57%	37,370	10	13.50%	12

Project Returns

IRR	**18.34%**
Min. DSCR	**1.20**

Project Schedule

Construction Start Date	1-Jan-02
Planned Construction Duration (months)	30
Commercial Operation Date (mm/dd/yy)	1-Jul-04
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Coal			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	11795			
Heat Rate Degradation Between Major Overhauls (%)	0%			
Fuel Cost ($/Mton)	**34.59**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.00%	2.00%	0.00%
Heat Rate @ given load (BTU/kWh)	11,795	11,913	12,031	11,795

Estimated Plant Output (MWh)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Interest Expenses	77,339	7,077	13,759	12,345	10,826	9,306	7,787	6,268	4,748	3,229	1,709	285									
Principal Payments	130,797	0	11,910	13,987	13,987	13,987	13,987	13,987	13,987	13,987	13,987	6,993									
Total Debt Service	**208,136**	**7,077**	**25,670**	**26,332**	**24,812**	**23,293**	**21,774**	**20,254**	**18,735**	**17,215**	**15,696**	7,278									

Operation and Maintenance Payments (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed O&M Costs	1,153	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
Variable O&M Costs	500	1000	1000	1000	1000	1000	1000	1000	1000	1000	844.5378	844.53782	844.5378	844.5378	844.538	844.5378	844.538	844.5378	844.5378	844.538
Total O&M Costs	**1,653**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,305**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**	**3,150**

Other Costs of Operation (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
G&A	250	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	1,294	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588
BOP & Major Maintenance	1,860	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160	2,160
Agency Fees	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**3,454**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,298**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**	**5,248**

Trariff Components in US$000 per Year

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capacity Charge	16,784	33,567	33,567	33,567	33,567	33,567	33,567	33,567	33,567	33,567	33,567	33,567	33,567	33,567	33,567	33,567	33,567	33,567	33,567	33,567
Fixed O&M Charge	3,801	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553	7,553
Variable O&M Charge	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	845	845	845	845	845	845	845	845	845	845
Fuel Charge	4,858	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207
Total Tariff	**25,943**	**51,887**	**51,887**	**51,887**	**51,887**	**51,887**	**51,887**	**51,887**	**51,887**	**51,887**	**50,222**	**50,172**	**50,172**	**50,172**	**50,172**	**50,172**	**50,172**	**50,172**	**50,172**	**50,172**

Tariff Components in US$ per kWh

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capital Cost Component	0.056	0.056	0.056	0.056	0.056	0.056	0.056	0.056	0.056	0.056	0.067	0.067	0.067	0.067	0.067	0.067	0.067	0.067	0.067	0.067
Fixed O&M Component	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Total Tariff	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.100**	**0.100**	**0.100**	**0.100**	**0.100**	**0.100**	**0.100**	**0.100**	**0.100**	**0.100**

Table 7.23 Mauritius - Coa[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: NON FUEL OPERATING COSTS DECREASED BY 10%

Project Cap. Costs (US$000)

Total Hard Costs	134,789
Total Soft Costs	32,638
Int. During Construction	18,881
Total Project Costs	**186,308**

Debt/Equity Ratio (US$000)

Debt	70%	130,416
Equity	30%	55,892
Total		186,308

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	46,577	10	9.75%	6
For. Bk B	35.71%	46,577	10	9.75%	6
Maur. Bks	28.57%	37,262	10	13.50%	12

Project Returns

IRR	18.80%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-02
Planned Construction Duration (months)	30
Commercial Operation Date (mm/dd/yy)	1-Jul-04
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Coal			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	11795			
Heat Rate Degradation Between Major Overhauls (%)	0%			
Fuel Cost ($/Mton)	**34.59**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.00%	2.00%	0.00%
Heat Rate @ given load (BTU/kWh)	11,795	11,913	12,031	11,795

Estimated Plant Output (MWh)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Interest Expenses	77,114	7,056	13,719	12,309	10,794	9,279	7,764	6,249	4,734	3,219	1,704	284									
Principal Payments	130,416	0	11,876	13,946	13,946	13,946	13,946	13,946	13,946	13,946	13,946	6,973									
Total Debt Service	**207,530**	**7,056**	**25,595**	**26,255**	**24,740**	**23,225**	**21,710**	**20,195**	**18,680**	**17,165**	**15,650**	**7,257**									

Operation and Maintenance Payments (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed O&M Costs	1,037	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075
Variable O&M Costs	450	900	900	900	900	900	900	900	900	900	760.084	760.08403	760.084	760.084	760.084	760.084	760.084	760.084	760.084	760.084
Total O&M Costs	**1,487**	**2,975**	**2,975**	**2,975**	**2,975**	**2,975**	**2,975**	**2,975**	**2,975**	**2,975**	**2,835**	**2,835**	**2,835**	**2,835**	**2,835**	**2,835**	**2,835**	**2,835**	**2,835**	**2,835**

Other Costs of Operation (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
G&A	225	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
Insurance during Operation	1,294	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588
BOP & Major Maintenance	1,674	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944
Agency Fees	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**3,243**	**5,032**	**5,032**	**5,032**	**5,032**	**5,032**	**5,032**	**5,032**	**5,032**	**5,032**	**5,032**	**4,982**	**4,982**	**4,982**	**4,982**	**4,982**	**4,982**	**4,982**	**4,982**	**4,982**

Tariff Components in US$000 per Year

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capacity Charge	17,052	34,105	34,105	34,105	34,105	34,105	34,105	34,105	34,105	34,105	34,105	34,105	34,105	34,105	34,105	34,105	34,105	34,105	34,105	34,105
Fixed O&M Charge	3,553	7,106	7,106	7,106	7,106	7,106	7,106	7,106	7,106	7,106	7,106	7,056	7,056	7,056	7,056	7,056	7,056	7,056	7,056	7,056
Variable O&M Charge	450	900	900	900	900	900	900	900	900	900	760	760	760	760	760	760	760	760	760	760
Fuel Charge	4,858	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207
Total Tariff	**25,914**	**51,827**	**51,827**	**51,827**	**51,827**	**51,827**	**51,827**	**51,827**	**51,827**	**51,827**	**50,178**	**50,128**	**50,128**	**50,128**	**50,128**	**50,128**	**50,128**	**50,128**	**50,128**	**50,128**

Tariff Components in US$ per kWh

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capital Cost Component	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Fixed O&M Component	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Total Tariff	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.087**	**0.100**	**0.100**	**0.100**	**0.100**	**0.100**	**0.100**	**0.100**	**0.100**	**0.100**	**0.100**

Table 7.24 Mauritius - Coa[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: NON FUEL OPERATING COSTS INCREASED BY 10%

Project Cap. Costs (US$000)

Total Hard Costs	134,789
Total Soft Costs	32,638
Int. During Construction	18,881
Total Project Costs	**186,308**

Debt/Equity Ratio (US$000)

Debt	70%	130,416
Equity	30%	55,892
Total		186,308

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	46,577	10	9.75%	6
For. Bk B	35.71%	46,577	10	9.75%	6
Maur. Bks	28.57%	37,262	10	13.50%	12

Project Returns

IRR	19.83%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-02
Planned Construction Duration (months)	30
Commercial Operation Date (mm/dd/yy)	1-Jul-04
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Coal			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	11795			
Heat Rate Degradation Between Major Overhauls (%)	0%			
Fuel Cost ($/Mton)	**34.59**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	1.00%	2.00%	0.00%
Heat Rate @ given load (BTU/kWh)	11,795	11,913	12,031	11,795

Estimated Plant Output (MWh)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Interest Expenses	77,114	7,056	13,719	12,309	10,794	9,279	7,764	6,249	4,734	3,219	1,704	284									
Principal Payments	130,416	0	11,876	13,946	13,946	13,946	13,946	13,946	13,946	13,946	13,946	6,973									
Total Debt Service	**207,530**	**7,056**	**25,595**	**26,255**	**24,740**	**23,225**	**21,710**	**20,195**	**18,680**	**17,165**	**15,650**	7,257									

Operation and Maintenance Payments (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed O&M Costs	1,268	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536	2,536
Variable O&M Costs	550	1100	1100	1100	1100	1100	1100	1100	1100	1100	928.9916	928.9916	928.9916	928.9916	928.992	928.9916	928.992	928.9916	928.9916	928.992
Total O&M Costs	**1,818**	**3,636**	**3,636**	**3,636**	**3,636**	**3,636**	**3,636**	**3,636**	**3,636**	**3,636**	**3,464**	**3,464**	**3,464**	**3,464**	**3,464**	**3,464**	**3,464**	**3,464**	**3,464**	**3,464**

Other Costs of Operation (US$000)

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
G&A	275	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550
Insurance during Operation	1,294	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588	2,588
BOP & Major Maintenance	2,046	2,376	2,376	2,376	2,376	2,376	2,376	2,376	2,376	2,376	2,376	2,376	2,376	2,376	2,376	2,376	2,376	2,376	2,376	2,376
Agency Fees	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**3,665**	**5,564**	**5,564**	**5,564**	**5,564**	**5,564**	**5,564**	**5,564**	**5,564**	**5,564**	**5,564**	**5,514**	**5,514**	**5,514**	**5,514**	**5,514**	**5,514**	**5,514**	**5,514**	**5,514**

Tariff Components in US$000 per Year

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capacity Charge	17,676	35,353	35,353	35,353	35,353	35,353	35,353	35,353	35,353	35,353	35,353	35,353	35,353	35,353	35,353	35,353	35,353	35,353	35,353	35,353
Fixed O&M Charge	4,050	8,099	8,099	8,099	8,099	8,099	8,099	8,099	8,099	8,099	8,099	8,049	8,049	8,049	8,049	8,049	8,049	8,049	8,049	8,049
Variable O&M Charge	550	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	929	929	929	929	929	929	929	929	929	929
Fuel Charge	4,858	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207
Total Tariff	**27,134**	**54,268**	**54,268**	**54,268**	**54,268**	**54,268**	**54,268**	**54,268**	**54,268**	**54,268**	**52,588**	**52,538**	**52,538**	**52,538**	**52,538**	**52,538**	**52,538**	**52,538**	**52,538**	**52,538**

Tariff Components in US$ per kWh

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed Capital Cost Component	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070
Fixed O&M Component	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Variable O&M Component	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Fuel Component	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016
Total Tariff	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.105**	**0.105**	**0.105**	**0.105**	**0.105**	**0.105**	**0.105**	**0.105**	**0.105**	**0.105**

Table 7.25 Mauritius - Dies[illegible]nt - Summary Project Data

BASE CASE

Project Cap. Costs (US$000)	
Total Hard Costs	133,086
Total Soft Costs	28,513
Int. During Construction	14,525
Total Project Costs	**176,124**

Debt/Equity Ratio (US$000)		
Debt	70%	123,287
Equity	30%	52,837
Total		176,124

Financing Terms	Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
	For. Bk A	35.71%	44,031	10	9.75%	6
	For. Bk B	35.71%	44,031	10	9.75%	6
	Maur. Bks	28.57%	35,225	10	13.50%	12

Project Returns	
IRR	19.35%
Min. DSCR	1.25

Project Schedule	
Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions				
Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7550			
Heat Rate Degradation Between Major Overhauls (%)	3%			
Fuel Cost ($/Mbtu)	**3.653862**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	0.00%	0.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,550	7,550	7,550	7,550

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	72,899	13,285	12,352	10,920	9,488	8,056	6,624	5,192	3,759	2,327	895										
Principal Payments	123,287	4,635	13,184	13,184	13,184	13,184	13,184	13,184	13,184	13,184	13,184										
Total Debt Service	**196,186**	**17,920**	**25,536**	**24,104**	**22,672**	**21,240**	**19,807**	**18,375**	**16,943**	**15,511**	**14,079**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	770	770	770	770	770	770	770	770	770	770	650.2941	650.29412	650.2941	650.2941	650.294	650.2941	650.294	650.2941	650.2941	650.294
Total O&M Costs	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767
Fixed O&M Charge	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012
Variable O&M Charge	770	770	770	770	770	770	770	770	770	770	650	650	650	650	650	650	650	650	650	650
Fuel Charge	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174
Total Tariff	**57,137**	**57,383**	**57,137**	**57,383**	**57,137**	**57,383**	**57,137**	**57,383**	**57,137**	**57,383**	**54,396**	**54,604**	**54,396**	**54,604**	**54,396**	**54,604**	**54,396**	**54,604**	**54,396**	**54,604**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Fixed O&M Component	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
Total Tariff	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.096**	**0.108**	**0.109**	**0.108**	**0.109**	**0.108**	**0.109**	**0.108**	**0.109**	**0.108**	**0.109**

Table 7.26 Mauritius - Dies[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: CAPITAL COSTS (BEFORE IDC) DECREASED BY 10%

Project Cap. Costs (US$000)

Total Hard Costs	120.201
Total Soft Costs	26.115
Int. During Construction	13.152
Total Project Costs	**159,468**

Debt/Equity Ratio (US$000)

Debt	70%	111.627
Equity	30%	47,840
Total		**159,468**

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	39,867	10	9.75%	6
For. Bk B	35.71%	39,867	10	9.75%	6
Maur. Bks	28.57%	31,894	10	13.50%	12

Project Returns

IRR	19.54%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7550			
Heat Rate Degradation between Major Overhauls (%)	3%			
Fuel Cost ($/Mbtu)	**3.653862**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	0.00%	0.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,550	7,550	7,550	7,550

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	66,005	12,029	11,184	9,888	8,591	7,294	5,997	4,701	3,404	2,107	810										
Principal Payments	111,627	4,197	11,937	11,937	11,937	11,937	11,937	11,937	11,937	11,937	11,937										
Total Debt Service	**177,632**	**16,225**	**23,121**	**21,824**	**20,528**	**19,231**	**17,934**	**16,637**	**15,341**	**14,044**	**12,747**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	770	770	770	770	770	770	770	770	770	770	650.2941	650.29412	650.2941	650.2941	650.294	650.2941	650.294	650.2941	650.2941	650.294
Total O&M Costs	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319	2,319
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	45	45	45	45	45	45	45	45	45	45	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,764**	**4,764**	**4,764**	**4,764**	**4,764**	**4,764**	**4,764**	**4,764**	**4,764**	**4,764**	**4,719**	**4,719**	**4,719**	**4,719**	**4,719**	**4,719**	**4,719**	**4,719**	**4,719**	**4,719**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806	29,806
Fixed O&M Charge	6,799	6,799	6,799	6,799	6,799	6,799	6,799	6,799	6,799	6,799	6,754	6,754	6,754	6,754	6,754	6,754	6,754	6,754	6,754	6,754
Variable O&M Charge	770	770	770	770	770	770	770	770	770	770	650	650	650	650	650	650	650	650	650	650
Fuel Charge	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174
Total Tariff	**53,912**	**54,158**	**53,912**	**54,158**	**53,912**	**54,158**	**53,912**	**54,158**	**53,912**	**54,158**	**51,177**	**51,384**	**51,177**	**51,384**	**51,177**	**51,384**	**51,177**	**51,384**	**51,177**	**51,384**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059
Fixed O&M Component	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
Total Tariff	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**

Table 7.27 Mauritius - Dies[illegible]ant - Summary Project Data

SENSITIVITY ANALYSIS: CAPITAL COSTS (BEFORE IDC) INCREASED BY 10%

Project Cap. Costs (US$000)	
Total Hard Costs	145.971
Total Soft Costs	30.912
Int. During Construction	15.899
Total Project Costs	**192,781**

Debt/Equity Ratio (US$000)		
Debt	70%	134.947
Equity	30%	57.834
Total		192,781

Financing Terms	Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
	For. Bk A	35.71%	48.195	10	9.75%	6
	For. Bk B	35.71%	48.195	10	9.75%	6
	Maur. Bks	28.57%	38.556	10	13.50%	12

Project Returns	
IRR	19.20%
Min. DSCR	1.25

Project Schedule	
Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years. from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions				
Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7550			
Heat Rate Degradation Between Major Overhauls (%)	3%			
Fuel Cost ($/Mbtu)	**3.653862**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	0.00%	0.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,550	7,550	7,550	7,550

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	79,793	14,541	13,521	11,953	10,385	8,818	7,250	5,683	4,115	2,547	980										
Principal Payments	134,947	5,073	14,430	14,430	14,430	14,430	14,430	14,430	14,430	14,430	14,430										
Total Debt Service	**214,740**	**19,615**	**27,951**	**26,383**	**24,816**	**23,248**	**21,681**	**20,113**	**18,545**	**16,978**	**15,410**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	770	770	770	770	770	770	770	770	770	770	650.2941	650.29412	650.2941	650.2941	650.294	650.2941	650.294	650.2941	650.2941	650.294
Total O&M Costs	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835	2,835
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	55	55	55	55	55	55	55	55	55	55	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**5,290**	**5,290**	**5,290**	**5,290**	**5,290**	**5,290**	**5,290**	**5,290**	**5,290**	**5,290**	**5,235**	**5,235**	**5,235**	**5,235**	**5,235**	**5,235**	**5,235**	**5,235**	**5,235**	**5,235**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729	35,729
Fixed O&M Charge	7,325	7,325	7,325	7,325	7,325	7,325	7,325	7,325	7,325	7,325	7,270	7,270	7,270	7,270	7,270	7,270	7,270	7,270	7,270	7,270
Variable O&M Charge	770	770	770	770	770	770	770	770	770	770	650	650	650	650	650	650	650	650	650	650
Fuel Charge	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174
Total Tariff	**60,361**	**60,607**	**60,361**	**60,607**	**60,361**	**60,607**	**60,361**	**60,607**	**60,361**	**60,607**	**57,616**	**57,823**	**57,616**	**57,823**	**57,616**	**57,823**	**57,616**	**57,823**	**57,616**	**57,823**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.071	0.071	0.071	0.071	0.071	0.071	0.071	0.071	0.071	0.071
Fixed O&M Component	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
Total Tariff	**0.101**	**0.102**	**0.101**	**0.102**	**0.101**	**0.102**	**0.101**	**0.102**	**0.101**	**0.102**	**0.115**	**0.115**	**0.115**	**0.115**	**0.115**	**0.115**	**0.115**	**0.115**	**0.115**	**0.115**

Table 7.28 Mauritius - Dies[illegible]ant - Summary Project Data

SENSITIVITY ANALYSIS: FUEL COSTS DECREASED BY 5 US$/BBL

Project Cap. Costs (US$000)

Total Hard Costs	133,086
Total Soft Costs	28,513
Int. During Construction	14,525
Total Project Costs	**176,124**

Debt/Equity Ratio (US$000)

Debt	70%	123,287
Equity	30%	52,837
Total		**176,124**

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	44,031	10	9.75%	6
For. Bk B	35.71%	44,031	10	9.75%	6
Maur. Bks	28.57%	35,225	10	13.50%	12

Project Returns

IRR	19.40%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7550			
Heat Rate Degradation Between Major Overhauls (%)	3%			
Fuel Cost ($/Mbtu)	**3.001387**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	0.00%	0.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,550	7,550	7,550	7,550

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	72,899	13,285	12,352	10,920	9,488	8,056	6,624	5,192	3,759	2,327	895										
Principal Payments	123,287	4,635	13,184	13,184	13,184	13,184	13,184	13,184	13,184	13,184	13,184										
Total Debt Service	**196,186**	**17,920**	**25,536**	**24,104**	**22,672**	**21,240**	**19,807**	**18,375**	**16,943**	**15,511**	**14,079**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	770	770	770	770	770	770	770	770	770	770	650.2941	650.29412	650.2941	650.2941	650.294	650.2941	650.294	650.2941	650.2941	650.294
Total O&M Costs	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767
Fixed O&M Charge	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012
Variable O&M Charge	770	770	770	770	770	770	770	770	770	770	650	650	650	650	650	650	650	650	650	650
Fuel Charge	13,584	13,786	13,584	13,786	13,584	13,786	13,584	13,786	13,584	13,786	11,472	11,643	11,472	11,643	11,472	11,643	11,472	11,643	11,472	11,643
Total Tariff	**54,184**	**54,386**	**54,184**	**54,386**	**54,184**	**54,386**	**54,184**	**54,386**	**54,184**	**54,386**	**51,902**	**52,073**	**51,902**	**52,073**	**51,902**	**52,073**	**51,902**	**52,073**	**51,902**	**52,073**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Fixed O&M Component	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023	0.023
Total Tariff	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.103**	**0.104**	**0.103**	**0.104**	**0.103**	**0.104**	**0.103**	**0.104**	**0.103**	**0.104**

Table 7.29 Mauritius - Dies[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: FUEL COSTS INCREASED BY 5 US$/BBL

Project Cap. Costs (US$000)

Total Hard Costs	133,086
Total Soft Costs	28,513
Int. During Construction	14,525
Total Project Costs	**176,124**

Debt/Equity Ratio (US$000)

Debt	70%	123,287
Equity	30%	52,837
Total		**176,124**

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	44,031	10	9.75%	6
For. Bk B	35.71%	44,031	10	9.75%	6
Maur. Bks	28.57%	35,225	10	13.50%	12

Project Returns

IRR	19.31%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7550			
Heat Rate Degradation Between Major Overhauls (%)	3%			
Fuel Cost ($/Mbtu)	4.306337			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	0.00%	0.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,550	7,550	7,550	7,550

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	72,899	13,285	12,352	10,920	9,488	8,056	6,624	5,192	3,759	2,327	895										
Principal Payments	123,287	4,635	13,184	13,184	13,184	13,184	13,184	13,184	13,184	13,184	13,184										
Total Debt Service	**196,186**	**17,920**	**25,536**	**24,104**	**22,672**	**21,240**	**19,807**	**18,375**	**16,943**	**15,511**	**14,079**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	770	770	770	770	770	770	770	770	770	770	650.2941	650.29412	650.2941	650.2941	650.294	650.2941	650.294	650.2941	650.2941	650.294
Total O&M Costs	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767
Fixed O&M Charge	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012
Variable O&M Charge	770	770	770	770	770	770	770	770	770	770	650	650	650	650	650	650	650	650	650	650
Fuel Charge	19,490	19,780	19,490	19,780	19,490	19,780	19,490	19,780	19,490	19,780	16,460	16,705	16,460	16,705	16,460	16,705	16,460	16,705	16,460	16,705
Total Tariff	**60,090**	**60,380**	**60,090**	**60,380**	**60,090**	**60,380**	**60,090**	**60,380**	**60,090**	**60,380**	**56,890**	**57,135**	**56,890**	**57,135**	**56,890**	**57,135**	**56,890**	**57,135**	**56,890**	**57,135**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Fixed O&M Component	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033	0.033
Total Tariff	**0.101**	**0.101**	**0.101**	**0.101**	**0.101**	**0.101**	**0.101**	**0.101**	**0.101**	**0.101**	**0.113**	**0.114**	**0.113**	**0.114**	**0.113**	**0.114**	**0.113**	**0.114**	**0.113**	**0.114**

Table 7.30 Mauritius - Dies[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: MINIMUM DSCR @ 1.30

Project Cap. Costs (US$000)

Total Hard Costs	133,086
Total Soft Costs	28,513
Int. During Construction	14,525
Total Project Costs	**176,124**

Debt/Equity Ratio (US$000)

Debt	70%	123,287
Equity	30%	52,837
Total		176,124

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	44,031	10	9.75%	6
For. Bk B	35.71%	44,031	10	9.75%	6
Maur. Bks	28.57%	35,225	10	13.50%	12

Project Returns

IRR	20.54%
Min. DSCR	1.30

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7550			
Heat Rate Degradation Between Major Overhauls(%)	3%			
Fuel Cost ($/Mbtu)	**3.653862**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	0.00%	0.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,550	7,550	7,550	7,550

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	72,899	13,285	12,352	10,920	9,488	8,056	6,624	5,192	3,759	2,327	895										
Principal Payments	123,287	4,635	13,184	13,184	13,184	13,184	13,184	13,184	13,184	13,184	13,184										
Total Debt Service	**196,186**	**17,920**	**25,536**	**24,104**	**22,672**	**21,240**	**19,807**	**18,375**	**16,943**	**15,511**	**14,079**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	770	770	770	770	770	770	770	770	770	770	650.2941	650.29412	650.2941	650.2941	650.294	650.2941	650.294	650.2941	650.2941	650.294
Total O&M Costs	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044	34,044
Fixed O&M Charge	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012
Variable O&M Charge	770	770	770	770	770	770	770	770	770	770	650	650	650	650	650	650	650	650	650	650
Fuel Charge	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174
Total Tariff	**58,413**	**58,660**	**58,413**	**58,660**	**58,413**	**58,660**	**58,413**	**58,660**	**58,413**	**58,660**	**55,673**	**55,881**	**55,673**	**55,881**	**55,673**	**55,881**	**55,673**	**55,881**	**55,673**	**55,881**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Fixed O&M Component	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
Total Tariff	**0.098**	**0.099**	**0.098**	**0.099**	**0.098**	**0.099**	**0.098**	**0.099**	**0.098**	**0.099**	**0.111**	**0.111**	**0.111**	**0.111**	**0.111**	**0.111**	**0.111**	**0.111**	**0.111**	**0.111**

Table 7.31 Mauritius - Dies[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: INTEREST RATES DECREASED BY 2%

Project Cap. Costs (US$000)

Total Hard Costs	133,086
Total Soft Costs	28,342
Int. During Construction	11,698
Total Project Costs	**173,126**

Debt/Equity Ratio (US$000)

Debt	70%	121,188
Equity	30%	51,938
Total		173,126

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	43,281	10	7.75%	6
For. Bk B	35.71%	43,281	10	7.75%	6
Maur. Bks	28.57%	34,625	10	11.50%	12

Project Returns

IRR	18.20%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7550			
Heat Rate Degradation Between Major Overhauls (%)	3%			
Fuel Cost ($/Mbtu)	**3.653862**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	0.00%	0.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,550	7,550	7,550	7,550

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	58,457	10,646	9,907	8,758	7,609	6,461	5,312	4,164	3,015	1,866	718										
Principal Payments	121,188	4,556	12,959	12,959	12,959	12,959	12,959	12,959	12,959	12,959	12,959										
Total Debt Service	**179,645**	**15,202**	**22,866**	**21,717**	**20,569**	**19,420**	**18,271**	**17,123**	**15,974**	**14,826**	**13,677**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	770	770	770	770	770	770	770	770	770	770	650.2941	650.29412	650.2941	650.2941	650.294	650.2941	650.294	650.2941	650.2941	650.294
Total O&M Costs	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489	29,489
Fixed O&M Charge	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012
Variable O&M Charge	770	770	770	770	770	770	770	770	770	770	650	650	650	650	650	650	650	650	650	650
Fuel Charge	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174
Total Tariff	**53,859**	**54,105**	**53,859**	**54,105**	**53,859**	**54,105**	**53,859**	**54,105**	**53,859**	**54,105**	**51,118**	**51,326**	**51,118**	**51,326**	**51,118**	**51,326**	**51,118**	**51,326**	**51,118**	**51,326**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059	0.059
Fixed O&M Component	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
Total Tariff	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.091**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**

Table 7.32 Mauritius - Dies[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: INTEREST RATES INCREASED BY 2%

Project Cap. Costs (US$000)

Total Hard Costs	133.086
Total Soft Costs	29.741
Int. During Construction	17.231
Total Project Costs	**180,058**

Debt/Equity Ratio (US$000)

Debt	70%	126.041
Equity	30%	54.018
Total		**180,058**

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	45.015	10	11.75%	6
For. Bk B	35.71%	45,015	10	11.75%	6
Maur. Bks	28.57%	36,012	10	15.00%	12

Project Returns

IRR	**20.52%**
Min. DSCR	**1.25**

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7550			
Heat Rate Degradation Between Major Overhauls(%)	3%			
Fuel Cost ($/Mbtu)	**3.653862**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	0.00%	0.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,550	7,550	7,550	7,550

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	87,244	15,911	14,781	13,067	11,353	9,640	7,926	6,212	4,498	2,785	1,071										
Principal Payments	126,041	4,738	13,478	13,478	13,478	13,478	13,478	13,478	13,478	13,478	13,478										
Total Debt Service	**213,285**	**20,649**	**28,259**	**26,545**	**24,831**	**23,118**	**21,404**	**19,690**	**17,977**	**16,263**	**14,549**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	770	770	770	770	770	770	770	770	770	770	650.2941	650.29412	650.2941	650.2941	650.294	650.2941	650.294	650.2941	650.2941	650.294
Total O&M Costs	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110	36,110
Fixed O&M Charge	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012
Variable O&M Charge	770	770	770	770	770	770	770	770	770	770	650	650	650	650	650	650	650	650	650	650
Fuel Charge	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174
Total Tariff	**60,479**	**60,725**	**60,479**	**60,725**	**60,479**	**60,725**	**60,479**	**60,725**	**60,479**	**60,725**	**57,738**	**57,946**	**57,738**	**57,946**	**57,738**	**57,946**	**57,738**	**57,946**	**57,738**	**57,946**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.061	0.061	0.061	0.061	0.061	0.061	0.061	0.061	0.061	0.061	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072
Fixed O&M Component	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
Total Tariff	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.102**	**0.115**	**0.115**	**0.115**	**0.115**	**0.115**	**0.115**	**0.115**	**0.115**	**0.115**	**0.115**

Table 7.33 Mauritius - Dies[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: LOAN TERMS INCREASED BY 2 YEARS

Project Cap. Costs (US$000)	
Total Hard Costs	133,086
Total Soft Costs	28,513
Int. During Construction	14,525
Total Project Costs	**176,124**

Debt/Equity Ratio (US$000)		
Debt	70%	123,287
Equity	30%	52,837
Total		**176,124**

Financing Terms	Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
	For. Bk A	35.71%	44,031	12	9.75%	6
	For. Bk B	35.71%	44,031	12	9.75%	6
	Maur. Bks	28.57%	35,225	12	13.50%	12

Project Returns	
IRR	17.46%
Min. DSCR	1.25

Project Schedule	
Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions				
Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7550			
Heat Rate Degradation between Major Overhauls (%)	3%			
Fuel Cost ($/Mbtu)	**3.653862**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	0.00%	0.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,550	7,550	7,550	7,550

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	86,240	13,295	12,526	11,347	10,168	8,989	7,810	6,631	5,453	4,274	3,095	1,916	737								
Principal Payments	123,287	3,829	10,860	10,860	10,860	10,860	10,860	10,860	10,860	10,860	10,860	10,860	10,860								
Total Debt Service	**209,528**	**17,124**	**23,386**	**22,207**	**21,028**	**19,849**	**18,670**	**17,491**	**16,312**	**15,133**	**13,955**	12,776	11,597								

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	770	770	770	770	770	770	770	770	770	770	650.2941	650.29412	650.2941	650.2941	650.294	650.2941	650.294	650.2941	650.2941	650.294
Total O&M Costs	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127	30,127
Fixed O&M Charge	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012
Variable O&M Charge	770	770	770	770	770	770	770	770	770	770	650	650	650	650	650	650	650	650	650	650
Fuel Charge	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174
Total Tariff	**54,496**	**54,743**	**54,496**	**54,743**	**54,496**	**54,743**	**54,496**	**54,743**	**54,496**	**54,743**	**51,806**	**52,014**	**51,756**	**51,964**	**51,756**	**51,964**	**51,756**	**51,964**	**51,756**	**51,964**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.051	0.051	0.051	0.051	0.051	0.051	0.051	0.051	0.051	0.051	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Fixed O&M Component	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
Total Tariff	**0.092**	**0.092**	**0.092**	**0.092**	**0.092**	**0.092**	**0.092**	**0.092**	**0.092**	**0.092**	**0.103**	**0.104**	**0.103**	**0.103**	**0.103**	**0.103**	**0.103**	**0.103**	**0.103**	**0.103**

Table 7.34 Mauritius - Dies[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: MINIMUM DSCR @ 1.20

Project Cap. Costs (US$000)	
Total Hard Costs	133,086
Total Soft Costs	29,579
Int. During Construction	14,541
Total Project Costs	**177,205**

Debt/Equity Ratio (US$000)		
Debt	70%	124,044
Equity	30%	53,162
Total		177,205

Financing Terms	Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
	For. Bk A	35.71%	44,301	10	9.75%	6
	For. Bk B	35.71%	44,301	10	9.75%	6
	Maur. Bks	28.57%	35,441	10	13.50%	12

Project Returns	
IRR	18.34%
Min. DSCR	1.20

Project Schedule	
Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions				
Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7550			
Heat Rate Degradation Between Major Overhauls (%)	3%			
Fuel Cost ($/Mbtu)	**3.653862**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	0.00%	0.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,550	7,550	7,550	7,550

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	73,346	13,366	12,428	10,987	9,546	8,105	6,664	5,223	3,783	2,342	901										
Principal Payments	124,044	4,663	13,264	13,264	13,264	13,264	13,264	13,264	13,264	13,264	13,264										
Total Debt Service	**197,390**	**18,030**	**25,693**	**24,252**	**22,811**	**21,370**	**19,929**	**18,488**	**17,047**	**15,606**	**14,165**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
Variable O&M Costs	770	770	770	770	770	770	770	770	770	770	650.2941	650.29412	650.2941	650.2941	650.294	650.2941	650.294	650.2941	650.2941	650.294
Total O&M Costs	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,805**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**	**2,685**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Insurance during Operation	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577
BOP & Major Maintenance	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**5,027**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**	**4,977**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675	31,675
Fixed O&M Charge	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012	7,012
Variable O&M Charge	770	770	770	770	770	770	770	770	770	770	650	650	650	650	650	650	650	650	650	650
Fuel Charge	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174
Total Tariff	**56,044**	**56,290**	**56,044**	**56,290**	**56,044**	**56,290**	**56,044**	**56,290**	**56,044**	**56,290**	**53,304**	**53,512**	**53,304**	**53,512**	**53,304**	**53,512**	**53,304**	**53,512**	**53,304**	**53,512**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.053	0.063	0.063	0.063	0.063	0.063	0.063	0.063	0.063	0.063	0.063
Fixed O&M Component	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014	0.014
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
Total Tariff	**0.094**	**0.095**	**0.094**	**0.095**	**0.094**	**0.095**	**0.094**	**0.095**	**0.094**	**0.095**	**0.106**	**0.106**	**0.106**	**0.106**	**0.106**	**0.106**	**0.106**	**0.106**	**0.106**	**0.106**

Table 7.35 Mauritius - Dies[illegible]ant - Summary Project Data

SENSITIVITY ANALYSIS: NON FUEL OPERATING COSTS DECREASED BY 10%

Project Cap. Costs (US$000)

Total Hard Costs	133,086
Total Soft Costs	28,513
Int. During Construction	14,525
Total Project Costs	**176,124**

Debt/Equity Ratio (US$000)

Debt	70%	123,287
Equity	30%	52,837
Total		**176,124**

Financing Terms

Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
For. Bk A	35.71%	44,031	10	9.75%	6
For. Bk B	35.71%	44,031	10	9.75%	6
Maur. Bks	28.57%	35,225	10	13.50%	12

Project Returns

IRR	19.23%
Min. DSCR	1.25

Project Schedule

Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions

Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7550			
Heat Rate Degradation Between Major Overhauls (%)	3%			
Fuel Cost ($/Mbtu)	**3.653862**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	0.00%	0.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,550	7,550	7,550	7,550

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	72,899	13,285	12,352	10,920	9,488	8,056	6,624	5,192	3,759	2,327	895										
Principal Payments	123,287	4,635	13,184	13,184	13,184	13,184	13,184	13,184	13,184	13,184	13,184										
Total Debt Service	**196,186**	**17,920**	**25,536**	**24,104**	**22,672**	**21,240**	**19,807**	**18,375**	**16,943**	**15,511**	**14,079**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832	1,832
Variable O&M Costs	693	693	693	693	693	693	693	693	693	693	585.2647	585.26471	585.2647	585.2647	585.265	585.2647	585.265	585.2647	585.2647	585.265
Total O&M Costs	**2,525**	**2,525**	**2,525**	**2,525**	**2,525**	**2,525**	**2,525**	**2,525**	**2,525**	**2,525**	**2,417**	**2,417**	**2,417**	**2,417**	**2,417**	**2,417**	**2,417**	**2,417**	**2,417**	**2,417**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
Insurance during Operation	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577
BOP & Major Maintenance	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710	1,710
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**4,787**	**4,787**	**4,787**	**4,787**	**4,787**	**4,787**	**4,787**	**4,787**	**4,787**	**4,787**	**4,737**	**4,737**	**4,737**	**4,737**	**4,737**	**4,737**	**4,737**	**4,737**	**4,737**	**4,737**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622	32,622
Fixed O&M Charge	6,619	6,619	6,619	6,619	6,619	6,619	6,619	6,619	6,619	6,619	6,569	6,569	6,569	6,569	6,569	6,569	6,569	6,569	6,569	6,569
Variable O&M Charge	693	693	693	693	693	693	693	693	693	693	585	585	585	585	585	585	585	585	585	585
Fuel Charge	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174
Total Tariff	**56,471**	**56,717**	**56,471**	**56,717**	**56,471**	**56,717**	**56,471**	**56,717**	**56,471**	**56,717**	**53,743**	**53,950**	**53,743**	**53,950**	**53,743**	**53,950**	**53,743**	**53,950**	**53,743**	**53,950**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Fixed O&M Component	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
Total Tariff	**0.095**	**0.095**	**0.095**	**0.095**	**0.095**	**0.095**	**0.095**	**0.095**	**0.095**	**0.095**	**0.107**	**0.107**	**0.107**	**0.107**	**0.107**	**0.107**	**0.107**	**0.107**	**0.107**	**0.107**

Table 7.36 Mauritius - Dies[illegible]nt - Summary Project Data

SENSITIVITY ANALYSIS: NON FUEL OPERATING COSTS INCREASED BY 10%

Project Cap. Costs (US$000)	
Total Hard Costs	133,086
Total Soft Costs	28,513
Int. During Construction	14,525
Total Project Costs	**176,124**

Debt/Equity Ratio (US$000)		
Debt	70%	123,287
Equity	30%	52,837
Total		**176,124**

Financing Terms	Sources	share	Amount (US$000)	Amort. Term (yr)	Interest Rate	Months of Grace
	For. Bk A	35.71%	44,031	10	9.75%	6
	For. Bk B	35.71%	44,031	10	9.75%	6
	Maur. Bks	28.57%	35,225	10	13.50%	12

Project Returns	
IRR	19.48%
Min. DSCR	1.25

Project Schedule	
Construction Start Date	1-Jan-03
Planned Construction Duration (months)	24
Commercial Operation Date (mm/dd/yy)	1-Jan-05
Term of Project (years, from COD)	20
Current Exchange Rate (Rupee to US$)	26.3
Estimated Annual Currency Devaluation	0.00%

Fuel Assumptions				
Type of Fuel	Fuel Oil			
New & Clean Guaranteed Heat Rate (MBtu/kWh)	7550			
Heat Rate Degradation Between Major Overhauls (%)	3%			
Fuel Cost ($/Mbtu)	**3.653862**			
Load Factor	**100%**	**95%**	**90%**	**50%**
Plant Operation @ given load in hrs/yr for yrs 1-10	-	1,000	5,000	1,000
Plant Operation @ given load in hrs/yr for yrs 11-20	-	500	4,500	1,000
Percent Heat Rate Variations @ given load	0.00%	0.00%	0.00%	0.00%
Heat Rate @ given load (BTU/kWh)	7,550	7,550	7,550	7,550

Estimated Plant Output (MWh)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Plant Size (MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Plant Utilization (%)	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	67.92%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%	57.36%
Plant Output (MWh)	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**595,000**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**	**502,500**

Annualized Debt Service Payments (US$000)

Year	*Totals*	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Interest Expenses	72,899	13,285	12,352	10,920	9,488	8,056	6,624	5,192	3,759	2,327	895										
Principal Payments	123,287	4,635	13,184	13,184	13,184	13,184	13,184	13,184	13,184	13,184	13,184										
Total Debt Service	**196,186**	**17,920**	**25,536**	**24,104**	**22,672**	**21,240**	**19,807**	**18,375**	**16,943**	**15,511**	**14,079**										

Operation and Maintenance Payments (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239	2,239
Variable O&M Costs	847	847	847	847	847	847	847	847	847	847	715.3235	715.32353	715.3235	715.3235	715.324	715.3235	715.324	715.3235	715.3235	715.324
Total O&M Costs	**3,086**	**3,086**	**3,086**	**3,086**	**3,086**	**3,086**	**3,086**	**3,086**	**3,086**	**3,086**	**2,954**	**2,954**	**2,954**	**2,954**	**2,954**	**2,954**	**2,954**	**2,954**	**2,954**	**2,954**

Other Costs of Operation (US$000)

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
G&A	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550
Insurance during Operation	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577	2,577
BOP & Major Maintenance	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090
Agency Fees	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-
Total Other Costs of Op.	**5,267**	**5,267**	**5,267**	**5,267**	**5,267**	**5,267**	**5,267**	**5,267**	**5,267**	**5,267**	**5,217**	**5,217**	**5,217**	**5,217**	**5,217**	**5,217**	**5,217**	**5,217**	**5,217**	**5,217**

Tariff Components in US$000 per Year

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capacity Charge	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912	32,912
Fixed O&M Charge	7,506	7,506	7,506	7,506	7,506	7,506	7,506	7,506	7,506	7,506	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456	7,456
Variable O&M Charge	847	847	847	847	847	847	847	847	847	847	715	715	715	715	715	715	715	715	715	715
Fuel Charge	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174	13,966	14,174
Total Tariff	**57,802**	**58,048**	**57,802**	**58,048**	**57,802**	**58,048**	**57,802**	**58,048**	**57,802**	**58,048**	**55,050**	**55,258**	**55,050**	**55,258**	**55,050**	**55,258**	**55,050**	**55,258**	**55,050**	**55,258**

Tariff Components in US$ per kWh

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Fixed Capital Cost Component	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.055	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Fixed O&M Component	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Variable O&M Component	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Fuel Component	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028	0.028
Total Tariff	**0.097**	**0.098**	**0.097**	**0.098**	**0.097**	**0.098**	**0.097**	**0.098**	**0.097**	**0.098**	**0.110**	**0.110**	**0.110**	**0.110**	**0.110**	**0.110**	**0.110**	**0.110**	**0.110**	**0.110**

7.3 Project Operation and Maintenance (O&M) Costs - Task 8

O&M costs will depend significantly on the selected technology, the type of fuel, the site, the specific design details of the plant, and the approach of each individual developer to such issues as staffing, organization of plant maintenance, spare part inventory, etc. O&M cost estimates in this report were based on K&M's in-house data, information collected from operating companies with experience in operating similar facilities, and assumptions as listed below:

- Plant staffing as provided in Tables 7.3-1 and 7.3-2 below.
- Plant labor costs assume two expatriates: Plant Manager and Operations Supervisor.
- Chemical costs assume chemicals for fuel treatment and cycle makeup water treatment and once through condenser cooling systems.
- Cost of initial inventory of spare parts is included in the EPC cost.
- Plant accumulates 6,000 – 7000 operating hours per year for all technologies and sites.
- Major overhaul is every 30,000 hours for the coal plant and every 12,000 hours for the combustion turbine burning heavy fuel oil and for diesel engines, based on manufacturers' recommendations.
- Lube oil costs for diesel engines are estimated assuming an oil consumption of 0.001 kg/kWh and a lube oil price of USD 2,400 per ton.
- Ash disposal costs for the coal fired plant option is included in the fuel price.

Table 7.3-1: Coal Plant Staffing Estimate

		Category	Total Personnel
Coal Handling			
	4	2 teams - 10-hour days	8
Operations			
	1	Control room operator	
	1	Ash/ auxiliary operator	
	1	Boiler operator	
	1	Turbine operator	
	1	Shift supervisor	
	5	x 4 shifts	20
Maintenance		**(Preventive & minor corrective repair)**[1]	
	1	Instrumentation	
	1	Electrical	
	1	Welders	
	1	Mechanical	
	4	x 4 shifts	16
Management			
		(Standard work week)	
	1	Plant manager	
	1	Operations supervisor	
	1	Chemist	
	1	Accountants	
	1	Secretarial / clerical	
	5		5
		Total:	49

[1] Major maintenance and overhauls performed by subcontractors

Table 7.3-2: Combined Cycle And Diesel Plant Staffing Estimate

Category			Total Personnel
Operations			
	1	Control room operator	
	1	Turbine operator/Diesel Operator	
	1	Auxiliary operator	
	1	Shift supervisor	
	4	x 4 shifts	16
Maintenance	**(Preventive & minor corrective repair)**[1]		
	1	Instrumentation	
	1	Electrical	
	1	Mechanical	
	1	Welders	
	4	x 4 shifts	16
Management			
	1	Plant manager	
	1	Operations supervisor	
	1	Chemist	
	1	Accountant	
	1	Secretarial / clerical	
	5		5
		Total:	37

[1] Major maintenance and overhauls performed by subcontractors

O&M costs are estimated on an annual basis and are separated into fixed costs and variable costs. Major categories of fixed O&M costs include plant labor, administration expenses, training, hiring, relocation and living costs, plant vehicles, equipment rental, utilities, and management fee. Variable O&M costs include maintenance equipment and tools, consumables such as greases and oils, chemicals, plant spares, regular maintenance and repair. Table 7.3-3 below provides the K&M Team's estimate of O&M costs for the three technologies. These figures were used in the financial models to calculate project costs.

Table 7.3-3: Estimated Annual O&M Costs (USD) for a 100 MW Power Project in Mauritius

	CC	Diesel	Coal
Fixed O&M Costs			
Plant labor	1,400,000	1,400,000	1,600,000
Hiring, relocation and living costs	110,000	110,000	120,000
Office and administration expenses	130,000	130,000	130,000
Training, travel, and general expenses	25,000	25,000	25,000
Plant vehicles	30,000	30,000	30,000
Equipment rental	50,000	50,000	50,000
Buildings and grounds	20,000	20,000	30,000
Utilities (telephone, domestic water)	70,000	70,000	70,000
Management fee	200,000	200,000	250,000
Total Fixed O&M Costs	**2,035,000**	**2,035,000**	**2,305,000**
Variable O&M Costs			
Maintenance equipment and tools	60,000	60,000	40,000
Consumables	90,000	90,000	90,000
Outside services	90,000	100,000	70,000
Chemicals	330,000	220,000	400,000
Plant spares	350,000	300,000	400,000
Annual maintenance and repair,	450,000	350,000	600,000
Lube oil cost		1,440,000	
Total Variable O&M Costs[1]	**1,370,000**	**2,560,000**	**1,600,000**
Fixed and Variable O&M Costs	**3,405,000**	**4,595,000**	**3,905,000**
Major overhauls			
Frequency, operating hrs	12,000	12,000	30,000
Major Overhaul Cost,	2,900,000	3,500,000	7,800,000

Fixed and Variable O&M Costs are incurred in both foreign currency (USD) and in local currency (Rupee).

[1] These Variable costs are assumed to apply for the plant utilization profile defined for the first 10 years of the project (7000 hours running time per year, see below for details in "Plant Output in MWh").

Additional Costs of Operation

In addition to the O&M costs described above, the projects will incur several additional operational costs which will be ultimately passed through into the fixed O&M component of the unit cost of power. These operational costs include:

- General and Administrative costs
- Insurance during operation
- Costs for annual maintenance (Balance of Plant – BOP) and Major maintenance
- Agency fees (expense related to the maintenance of accounts during the debt servicing period).

7.4 Additional Assumptions Required for Unit Cost of Power Calculation

In order to develop the unit cost of power, and based on previous work as part of this Feasibility Study, the K&M Team made the following additional assumptions:

Fuel Cost Assumptions:

Fuel cost assumptions are based on the information outlined in the Letter Report on Fuel (Task 3).

- Crude oil: for conservative measures, the K&M Team has applied what is believed to be the higher target price of crude oil: $28/Bbl, which converts into a unit price for heavy fuel oil of $3.65/MBtu.
- Coal: We have assumed that the project would purchase South African coal, which is projected to cost $34.59/ton, and has a calorific value of 25,376 Btu/kg or 11,535 Btu/lb.
- Fuel costs were not escalated. It was assumed that the price of crude will remain between US$22/BBL and US$28/BBL. This assumed potential variability was addressed by sensitivity runs.
- Similarly, it has been assumed that coal prices will remain flat over the life of the project. Potential variability was addressed by sensitivity runs.
- No duties or taxes are included.

Plant Output in MWh:

Plant output has been calculated based on the following assumptions as provided by MPU/CEB:

For the first 10 years of the project, the annual running time is 7000 hours (out of a total 8760 hours) with:

- 1000 hours running at 95% load
- 5000 hours running at 90% load
- 1000 hours running at 50% load

For the next 10 years of the project, the annual running time is 6000 hours with:

- 500 hours running at 95% load
- 4500 hours running at 90% load

- 1000 hours running at 50% load.

Heat Rate

For each technology, we have made the following assumptions:

	Combined Cycle	Diesel	Coal
New and clean HR (BTU/kWh)	7850	7550	11795
HR degradation between major overhauls.	2%	3%	none
HR variation with load:			
95%	1.5%	0%	1%
90%	3.0%	0%	2%
50%	0.0%	0%	0%

Debt service coverage ratio, taxes, depreciation, initial working capital

The following additional considerations were applied:

- Lenders are likely to require for a project of this nature that the debt service coverage ratio – DSCR – (ratio of operating income to principal and interest payments) remain at a minimum of 1.2 to 1.3. For the purpose of the base model, we have assumed a minimum DSCR of 1.25;
- Mauritius does not have tax holidays, but the project is considered pioneer technology, and the tax rate applied was 15% over the term of the project;
- The project is depreciated using the straight line methodology, whereby facility and transmission equipment depreciate over 20 years; loan expenses are amortized over 10 years and organizational and startup costs are amortized over 5 years;
- In order to avoid negative cash flows in the initial years of operation we have funded working capital requirements as estimated.

7.5 Project Unit Cost of Power

Using project capital cost estimates, financing terms assumptions described above, O&M and other operation cost assumptions, fuel cost estimates, load profiles and heat rates, the K&M Team calculated a unit cost of power in $/kWh. This tariff should be representative of that which will be charged to the utility for the sale of electricity. Tables 7.1 for the Combined cycle, Table 7.13 for the Coal plant and Table 7.25 for Diesel plant summarize the base case values of the different items described herein for all three technologies and provide the resulting tariffs in $/kWh. The tariff is divided into four components, two of which are part of the Capacity Purchase Price while the other two are part of the Energy Purchase Price.

It should be noted that the tariff expressed in $/kWh increases in year 2015 due to the assumed reduction in the plant load factor.

Capacity Purchase Price:

Fixed Capacity Charge (FCC) payable in $/kW/month:

The FCC covers, without limitation, all costs of debt service, distribution of dividends and return of capital. This component of the tariff can vary over the life of the project as will be described by the project bidders in their proposals. In the model, we have assumed a flat FCC over the life of the project.

Fixed O&M Charge (FOMC) payable in $/kW/month

FOMC includes fixed costs related to operation and maintenance of the plant. Such costs include, but are not limited to:

- Costs of salaries and labor
- Office supplies and any equipment, etc;
- Costs of O&M Contract and/or costs of salaries of personnel to operate and maintain the Facility, parts, tools, etc;

Energy Purchase Price:

Variable O&M Charge (VOMC)

The VOMC reflects the varying costs of operating the plant, net of fuel. Such expenditures include chemicals, consumables, maintenance, etc.

Fuel Charge (FC)

Calculated based on a given heat rate (accounts for changes in ambient temperature and plant loads and plant degradation), fuel consumption and fuel price.

Unit costs of power at commercial operation date, calculated for each of the three technologies are as follow:

Tariff Component in $/kWh)	Combined Cycle	Diesel	Coal
FCC	0.041	0.055	0.058
FOMC	0.011	0.012	0.013
VOMC	0.002	0.001	0.002
FC	0.030	0.028	0.016
Total	**0.082**	**0.096**	**0.089**

These tariffs illustrate the different cost requirements of each of the three technologies considered. The FCC component is a direct indication of the capital costs required for the project. Fixed and Variable O&M costs are fairly uniform across all three technologies. Fuel charges reflect higher costs of fuel oil versus coal. Fuel costs for the diesel plant will be slightly reduced due to a better heat rate than the one attainable in the combined cycle technology running on fuel oil.

Proformas were developed for the three technology base cases and are presented as Tables 7.5-1, 7.5-2 and 7.5-3.

Table 7.5-1
PROFORMA

POST CONSTRUCTION INCOME STATEMENTS

Calendar Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Calendar Year #	1	2	3	4	5	6	7	8	9	10	11	12	13
Power Sales (in US$000)													
Fixed Capacity Charge	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124	24,124
Fixed O&M Charge	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,302	6,252	6,252	6,252
Fuel Charge	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	17,556	17,731	14,829	14,977	14,829
Variable O&M	920	920	920	920	920	920	920	920	920	920	777	777	777
Supplemental Charge	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenues from Power Sales	**48,901**	**49,076**	**48,901**	**49,076**	**48,901**	**49,076**	**48,901**	**49,076**	**48,901**	**49,076**	**45,982**	**46,129**	**45,982**
Interest Income (in US$000)	535	436	483	384	431	333	379	281	327	0	72	0	72
Total Project Revenues (in US$000)	**49,436**	**49,512**	**49,384**	**49,460**	**49,332**	**49,409**	**49,281**	**49,357**	**49,229**	**49,076**	**46,054**	**46,129**	**46,054**
Operating Costs (in US$000)													
Fixed O&M Costs	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)
Variable O&M Costs	(920)	(920)	(920)	(920)	(920)	(920)	(920)	(920)	(920)	(920)	(777)	(777)	(777)
Fuel	(17,556)	(17,731)	(17,556)	(17,731)	(17,556)	(17,731)	(17,556)	(17,731)	(17,556)	(17,731)	(14,829)	(14,977)	(14,829)
General & Administrative Costs	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)
Insurance	(1,817)	(1,817)	(1,817)	(1,817)	(1,817)	(1,817)	(1,817)	(1,817)	(1,817)	(1,817)	(1,817)	(1,817)	(1,817)
Agency Fees	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	0	0	0
Balance of Plant	(450)	(450)	(450)	(450)	(450)	(450)	(450)	(450)	(450)	(450)	(450)	(450)	(450)
Major Overhauls	0	(2,900)	0	(2,900)	0	(2,900)	0	(2,900)	0	(2,900)	0	(2,900)	0
Total Operating Expenses	**(23,328)**	**(26,402)**	**(23,328)**	**(26,402)**	**(23,328)**	**(26,402)**	**(23,328)**	**(26,402)**	**(23,328)**	**(26,402)**	**(20,408)**	**(23,455)**	**(20,408)**
Operating Income (EBITD)	26,108	23,110	26,057	23,058	26,005	23,006	25,953	22,954	25,901	22,674	25,646	22,674	25,646
Adjusted EBITD *	24,658	24,560	24,607	24,508	24,555	24,456	24,503	24,404	24,451	24,124	24,196	24,124	24,196
Interest Expense	(9,618)	(8,943)	(7,906)	(6,869)	(5,832)	(4,796)	(3,759)	(2,722)	(1,685)	(648)	0	0	0
Operating Income (in US$000)	**16,490**	**14,167**	**18,150**	**16,189**	**20,172**	**18,211**	**22,194**	**20,233**	**24,216**	**22,026**	**25,646**	**22,674**	**25,646**
Depreciation and Amortization (in US$000)													
Depreciation Facility	(5,600)	(5,600)	(5,600)	(5,600)	(5,600)	(5,600)	(5,600)	(5,600)	(5,600)	(5,600)	(5,600)	(5,600)	(5,600)
Depreciation Trans Equip	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)
Depreciation Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0
Organizational Costs	(1,180)	(1,180)	(1,180)	(1,180)	(1,180)	0	0	0	0	0	0	0	0
Amortization of Loan Costs	(461)	(461)	(461)	(461)	(461)	(461)	(461)	(461)	(461)	(461)	0	0	0
Total Depreciation	(7,291)	(7,291)	(7,291)	(7,291)	(7,291)	(6,111)	(6,111)	(6,111)	(6,111)	(6,111)	(5,650)	(5,650)	(5,650)
Pretax Income (in US$000)	9,199	6,875	10,859	8,897	12,881	12,099	16,083	14,121	18,105	15,914	19,996	17,024	19,996
Taxes	(1,380)	(1,031)	(1,629)	(1,335)	(1,932)	(1,815)	(2,412)	(2,118)	(2,716)	(2,387)	(2,999)	(2,554)	(2,999)
Net Income (in US$000)	**7,819**	**5,844**	**9,230**	**7,563**	**10,949**	**10,284**	**13,670**	**12,003**	**15,389**	**13,527**	**16,997**	**14,470**	**16,997**

K&M Engineering and Consulting Corporation
Mauritius - Combined Cycle Project

Table 7.5-1
PROFORMA

POST CONSTRUCTION INCOME STATEMENTS

Calendar Year	2018	2019	2020	2021	2022	2023	2024
Calendar Year #	14	15	16	17	18	19	20
Power Sales (in US$000)							
Fixed Capacity Charge	24,124	24,124	24,124	24,124	24,124	24,124	24,124
Fixed O&M Charge	6,252	6,252	6,252	6,252	6,252	6,252	6,252
Fuel Charge	14,977	14,829	14,977	14,829	14,977	14,829	14,977
Variable O&M	777	777	777	777	777	777	777
Supplemental Charge	0	0	0	0	0	0	0
Total Revenues from Power Sales	**46,129**	**45,982**	**46,129**	**45,982**	**46,129**	**45,982**	**46,129**
Interest Income (in US$000)	0	72	0	72	0	72	0
Total Project Revenues (in US$000)	**46,129**	**46,054**	**46,129**	**46,054**	**46,129**	**46,054**	**46,129**
Operating Costs (in US$000)							
Fixed O&M Costs	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)
Variable O&M Costs	(777)	(777)	(777)	(777)	(777)	(777)	(777)
Fuel	(14,977)	(14,829)	(14,977)	(14,829)	(14,977)	(14,829)	(14,977)
General & Administrative Costs	(500)	(500)	(500)	(500)	(500)	(500)	(500)
Insurance	(1,817)	(1,817)	(1,817)	(1,817)	(1,817)	(1,817)	(1,817)
Agency Fees	0	0	0	0	0	0	0
Balance of Plant	(450)	(450)	(450)	(450)	(450)	(450)	(450)
Major Overhauls	(2,900)	0	(2,900)	0	(2,900)	0	(2,900)
Total Operating Expenses	**(23,455)**	**(20,408)**	**(23,455)**	**(20,408)**	**(23,455)**	**(20,408)**	**(23,455)**
Operating Income (EBITD)	22,674	25,646	22,674	25,646	22,674	25,646	22,674
Adjusted EBITD *	24,124	24,196	24,124	24,196	24,124	24,196	24,124
Interest Expense	0	0	0	0	0	0	0
Operating Income (in US$000)	**22,674**	**25,646**	**22,674**	**25,646**	**22,674**	**25,646**	**22,674**
Depreciation and Amortization (in US$000)							
Depreciation Facility	(5,600)	(5,600)	(5,600)	(5,600)	(5,600)	(5,600)	(5,600)
Depreciation Trans Equip	(50)	(50)	(50)	(50)	(50)	(50)	(50)
Depreciation Boiler	0	0	0	0	0	0	0
Organizational Costs	0	0	0	0	0	0	0
Amortization of Loan Costs	0	0	0	0	0	0	0
Total Depreciation	(5,650)	(5,650)	(5,650)	(5,650)	(5,650)	(5,650)	(5,650)
Pretax Income (in US$000)	17,024	19,996	17,024	19,996	17,024	19,996	17,024
Taxes	(2,554)	(2,999)	(2,554)	(2,999)	(2,554)	(2,999)	(2,554)
Net Income (in US$000)	**14,470**	**16,997**	**14,470**	**16,997**	**14,470**	**16,997**	**14,470**

CASH FLOWS & FINANCIAL RATIOS (in US$000)

PROFORMA

Calendar Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Previous Year Retained Cash Flow	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Income	**7,819**	**5,844**	**9,230**	**7,563**	**10,949**	**10,284**	**13,670**	**12,003**	**15,389**	**13,527**	**16,997**	**14,470**	**16,997**
Add:													
Depreciation Building	5,600	5,600	5,600	5,600	5,600	5,600	5,600	5,600	5,600	5,600	5,600	5,600	5,600
Depreciation Trans Equip	50	50	50	50	50	50	50	50	50	50	50	50	50
Organizational Costs	1,180	1,180	1,180	1,180	1,180	0	0	0	0	0	0	0	0
Amortization of Loan Costs	461	461	461	461	461	461	461	461	461	461	0	0	0
Cash Flow	15,110	13,136	16,522	14,854	18,240	16,396	19,782	18,114	21,500	19,639	22,647	20,120	22,647
Working Capital Investment	(19)	(14)	14	(14)	14	(14)	14	(14)	14	(14)	254	(12)	12
Cash Available for Debt Amortization	15,091	13,121	16,536	14,840	18,255	16,381	19,796	18,100	21,515	19,624	22,901	20,108	22,659
Debt Amortization	(3,356)	(9,545)	(9,545)	(9,545)	(9,545)	(9,545)	(9,545)	(9,545)	(9,545)	(9,545)	0	0	0
Free Cash Flow	**11,735**	**3,576**	**6,991**	**5,295**	**8,710**	**6,837**	**10,251**	**8,555**	**11,970**	**10,079**	**22,901**	**20,108**	**22,659**
Non-Operating Cash Flow													
Maintenance Res. Contribution	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)
Add:													
Maint. Res. Draw BOP	450	450	450	450	450	450	450	450	450	450	450	450	450
Maint. Res. Draw Major Maint.	0	2,900	0	2,900	0	2,900	0	2,900	0	2,900	0	2,900	0
Cash From (Funding)/Releasing Debt Reserve													
Funded Debt Service after Construction	0												
Required Debt Reserve (6 mos):	9,244	8,726	8,207	7,689	7,170	6,652	6,133	5,615	5,096	0	0	0	0
Cash from (Funding)/Releasing Debt Reserve	(9,244)	518	518	518	518	518	518	518	518	5,096	0	0	0
Year End Cash Flow	**1,041**	**5,545**	**6,059**	**7,263**	**7,778**	**8,805**	**9,320**	**10,524**	**11,038**	**16,626**	**21,451**	**21,558**	**21,209**

FINANCIAL RATIOS:	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Interest Coverage (EBITD/Interest)	2.71	2.58	3.30	3.36	4.46	4.80	6.90	8.43	15.37	34.99			
Adj. Interest Coverage (Adj. EBITD/Interest) *	2.56	2.75	3.11	3.57	4.21	5.10	6.52	8.97	14.51	37.22			
Debt Service Coverage (EBITD/Prin & Int)	2.01	1.25	1.49	1.40	1.69	1.60	1.95	1.87	2.31	2.22			
Adj. Debt Serv. Cov. (Adj. EBITD/Prin & Int) *	1.90	1.33	1.41	1.49	1.60	1.71	1.84	1.99	2.18	2.37			

* Note: Adjusted ratios replace BOP and Major Maintenance expense with actual annual fundings of the Maintenance Reserve

CASH FLOWS & FINANCIAL RATIOS (in US$000)

PROFORMA

Calendar Year	2018	2019	2020	2021	2022	2023	2024
Previous Year Retained Cash Flow	0	0	0	0	0	0	0
Net Income	**14,470**	**16,997**	**14,470**	**16,997**	**14,470**	**16,997**	**14,470**
Add:							
Depreciation Building	5,600	5,600	5,600	5,600	5,600	5,600	5,600
Depreciation Trans Equip	50	50	50	50	50	50	50
Organizational Costs	0	0	0	0	0	0	0
Amortization of Loan Costs	0	0	0	0	0	0	0
Cash Flow	20,120	22,647	20,120	22,647	20,120	22,647	20,120
Working Capital Investment	(12)	12	(12)	12	(12)	12	3,779
Cash Available for Debt Amortization	20,108	22,659	20,108	22,659	20,108	22,659	23,899
Debt Amortization	0	0	0	0	0	0	0
Free Cash Flow	**20,108**	**22,659**	**20,108**	**22,659**	**20,108**	**22,659**	**23,899**
Non-Operating Cash Flow							
Maintenance Res. Contribution	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)
Add:							
Maint. Res. Draw BOP	450	450	450	450	450	450	450
Maint. Res. Draw Major Maint.	2,900	0	2,900	0	2,900	0	2,900
Cash From (Funding)/Releasing Debt Reserve							
Funded Debt Service after Construction							
Required Debt Reserve (6 mos):	0	0	0	0	0	0	0
Cash from (Funding)/Releasing Debt Reserve	0	0	0	0	0	0	0
Year End Cash Flow	**21,558**	**21,209**	**21,558**	**21,209**	**21,558**	**21,209**	**25,349**

	2018	2019	2020	2021	2022	2023	2024
FINANCIAL RATIOS:							
Interest Coverage (EBITD/Interest)							
Adj. Interest Coverage (Adj. EBITD/Interest) *							
Debt Service Coverage (EBITD/Prin & Int)							
Adj. Debt Serv. Cov. (Adj. EBITD/Prin & Int) *							

* Note: Adjusted ratios replace BOP and Major Maintenance exp

K&M Engineering and Consulting Corporation
Mauritius - Coal Project

Table 7.5-2
PROFORMA

POST CONSTRUCTION INCOME STATEMENTS

Calendar Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Calendar Year #	1	2	3	4	5	6	7	8	9	10	11	12	13
Power Sales (in US$000)													
Fixed Capacity Charge	17,370	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740	34,740
Fixed O&M Charge	3,801	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,603	7,553	7,553
Fuel Charge	4,858	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	9,716	8,207	8,207	8,207
Variable O&M	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	845	845	845
Supplemental Charge	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenues from Power Sales	**26,529**	**53,059**	**53,059**	**53,059**	**53,059**	**53,059**	**53,059**	**53,059**	**53,059**	**53,059**	**51,394**	**51,344**	**51,344**
Interest Income (in US$000)	718	812	853	893	543	583	623	663	703	181	78	156	234
Total Project Revenues (in US$000)	**27,247**	**53,871**	**53,911**	**53,952**	**53,602**	**53,642**	**53,682**	**53,722**	**53,762**	**53,240**	**51,472**	**51,500**	**51,578**
Operating Costs (in US$000)													
Fixed O&M Costs	(1,153)	(2,305)	(2,305)	(2,305)	(2,305)	(2,305)	(2,305)	(2,305)	(2,305)	(2,305)	(2,305)	(2,305)	(2,305)
Variable O&M Costs	(500)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(845)	(845)	(845)
Fuel	(4,858)	(9,716)	(9,716)	(9,716)	(9,716)	(9,716)	(9,716)	(9,716)	(9,716)	(9,716)	(8,207)	(8,207)	(8,207)
General & Administrative Costs	(250)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)
Insurance	(1,294)	(2,588)	(2,588)	(2,588)	(2,588)	(2,588)	(2,588)	(2,588)	(2,588)	(2,588)	(2,588)	(2,588)	(2,588)
Agency Fees	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	0	0
Balance of Plant	(300)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)
Major Overhauls	0	0	0	0	(7,800)	0	0	0	0	(7,800)	0	0	0
Total Operating Expenses	**(8,405)**	**(16,759)**	**(16,759)**	**(16,759)**	**(24,559)**	**(16,759)**	**(16,759)**	**(16,759)**	**(16,759)**	**(24,559)**	**(15,094)**	**(15,044)**	**(15,044)**
Operating Income (EBITD)	18,843	37,112	37,152	37,192	29,042	36,883	36,923	36,963	37,003	28,681	36,378	36,456	36,534
Adjusted EBITD *	17,283	35,552	35,592	35,632	35,282	35,323	35,363	35,403	35,443	34,921	34,818	34,896	34,974
Interest Expense	(7,056)	(13,719)	(12,309)	(10,794)	(9,279)	(7,764)	(6,249)	(4,734)	(3,219)	(1,704)	(284)	0	0
Operating Income (in US$000)	**11,786**	**23,393**	**24,843**	**26,398**	**19,763**	**29,118**	**30,673**	**32,228**	**33,784**	**26,977**	**36,094**	**36,456**	**36,534**
Depreciation and Amortization (in US$000)													
Depreciation Facility	(4,084)	(8,167)	(8,167)	(8,167)	(8,167)	(8,167)	(8,167)	(8,167)	(8,167)	(8,167)	(8,167)	(8,167)	(8,167)
Depreciation Trans Equip	(40)	(80)	(80)	(80)	(80)	(80)	(80)	(80)	(80)	(80)	(80)	(80)	(80)
Depreciation Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0
Organizational Costs	(708)	(1,415)	(1,415)	(1,415)	(1,415)	(708)	0	0	0	0	0	0	0
Amortization of Loan Costs	(329)	(658)	(658)	(658)	(658)	(658)	(658)	(658)	(658)	(658)	(329)	0	0
Total Depreciation	(5,161)	(10,321)	(10,321)	(10,321)	(10,321)	(9,613)	(8,906)	(8,906)	(8,906)	(8,906)	(8,577)	(8,247)	(8,247)
Pretax Income (in US$000)	6,626	13,072	14,522	16,077	9,442	19,505	21,768	23,323	24,878	18,071	27,517	28,208	28,286
Taxes	(994)	(1,961)	(2,178)	(2,412)	(1,416)	(2,926)	(3,265)	(3,498)	(3,732)	(2,711)	(4,128)	(4,231)	(4,243)
Net Income (in US$000)	**5,632**	**11,111**	**12,344**	**13,665**	**8,026**	**16,579**	**18,502**	**19,824**	**21,146**	**15,360**	**23,389**	**23,977**	**24,043**

Table 7.5-2
PROFORMA

POST CONSTRUCTION INCOME STATEMENTS

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024
Calendar Year #	14	15	16	17	18	19	20	21
Power Sales (in US$000)								
Fixed Capacity Charge	34,740	34,740	34,740	34,740	34,740	34,740	34,740	17,370
Fixed O&M Charge	7,553	7,553	7,553	7,553	7,553	7,553	7,553	3,129
Fuel Charge	8,207	8,207	8,207	8,207	8,207	8,207	8,207	4,103
Variable O&M	845	845	845	845	845	845	845	422
Supplemental Charge	0	0	0	0	0	0	0	0
Total Revenues from Power Sales	**51,344**	**51,344**	**51,344**	**51,344**	**51,344**	**51,344**	**51,344**	**25,025**
Interest Income (in US$000)	312	0	78	156	234	312	0	0
Total Project Revenues (in US$000)	**51,656**	**51,344**	**51,422**	**51,500**	**51,578**	**51,656**	**51,344**	**25,025**
Operating Costs (in US$000)								
Fixed O&M Costs	(2,305)	(2,305)	(2,305)	(2,305)	(2,305)	(2,305)	(2,305)	(1,153)
Variable O&M Costs	(845)	(845)	(845)	(845)	(845)	(845)	(845)	(422)
Fuel	(8,207)	(8,207)	(8,207)	(8,207)	(8,207)	(8,207)	(8,207)	(4,103)
General & Administrative Costs	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(250)
Insurance	(2,588)	(2,588)	(2,588)	(2,588)	(2,588)	(2,588)	(2,588)	(1,294)
Agency Fees	0	0	0	0	0	0	0	0
Balance of Plant	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(300)
Major Overhauls	0	(7,800)	0	0	0	0	(7,800)	0
Total Operating Expenses	**(15,044)**	**(22,844)**	**(15,044)**	**(15,044)**	**(15,044)**	**(15,044)**	**(22,844)**	**(7,522)**
Operating Income (EBITD)	36,612	28,500	36,378	36,456	36,534	36,612	28,500	17,503
Adjusted EBITD *	35,052	34,740	34,818	34,896	34,974	35,052	34,740	17,503
Interest Expense	0	0	0	0	0	0	0	0
Operating Income (in US$000)	**36,612**	**28,500**	**36,378**	**36,456**	**36,534**	**36,612**	**28,500**	**17,503**
Depreciation and Amortization (in US$000)								
Depreciation Facility	(8,167)	(8,167)	(8,167)	(8,167)	(8,167)	(8,167)	(8,167)	(4,084)
Depreciation Trans Equip	(80)	(80)	(80)	(80)	(80)	(80)	(80)	(40)
Depreciation Boiler	0	0	0	0	0	0	0	0
Organizational Costs	0	0	0	0	0	0	0	0
Amortization of Loan Costs	0	0	0	0	0	0	0	0
Total Depreciation	(8,247)	(8,247)	(8,247)	(8,247)	(8,247)	(8,247)	(8,247)	(4,124)
Pretax Income (in US$000)	28,364	20,252	28,130	28,208	28,286	28,364	20,252	13,379
Taxes	(4,255)	(3,038)	(4,220)	(4,231)	(4,243)	(4,255)	(3,038)	(2,007)
Net Income (in US$000)	**24,110**	**17,214**	**23,911**	**23,977**	**24,043**	**24,110**	**17,214**	**11,372**

CASH FLOWS & FINANCIAL RATIOS (in US$000)

PROFORMA

Calendar Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Previous Year Retained Cash Flow	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Income	**5,632**	**11,111**	**12,344**	**13,665**	**8,026**	**16,579**	**18,502**	**19,824**	**21,146**	**15,360**	**23,389**	**23,977**	**24,043**
Add:													
Depreciation Building	4,084	8,167	8,167	8,167	8,167	8,167	8,167	8,167	8,167	8,167	8,167	8,167	8,167
Depreciation Trans Equip	40	80	80	80	80	80	80	80	80	80	80	80	80
Organizational Costs	708	1,415	1,415	1,415	1,415	708	0	0	0	0	0	0	0
Amortization of Loan Costs	329	658	658	658	658	658	658	658	658	658	329	0	0
Cash Flow	10,792	21,432	22,665	23,987	18,347	26,193	27,408	28,730	30,052	24,266	31,966	32,224	32,291
Working Capital Investment	3,819	(2,181)	0	0	0	0	0	0	0	0	137	4	0
Cash Available for Debt Amortization	14,612	19,251	22,665	23,987	18,347	26,193	27,408	28,730	30,052	24,266	32,103	32,229	32,291
Debt Amortization	0	(11,876)	(13,946)	(13,946)	(13,946)	(13,946)	(13,946)	(13,946)	(13,946)	(13,946)	(6,973)	0	0
Free Cash Flow	**14,612**	**7,376**	**8,719**	**10,041**	**4,401**	**12,247**	**13,462**	**14,784**	**16,106**	**10,320**	**25,130**	**32,229**	**32,291**
Non-Operating Cash Flow													
Maintenance Res. Contribution	(1,860)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)
Add:													
Maint. Res. Draw BOP	300	600	600	600	600	600	600	600	600	600	600	600	600
Maint. Res. Draw Major Maint.	0	0	0	0	7,800	0	0	0	0	7,800	0	0	0
Cash From (Funding)/Releasing Debt Reserve													
Funded Debt Service after Construction	0												
Required Debt Reserve (6 mos):	12,798	13,128	12,370	11,613	10,855	10,098	9,340	8,583	7,825	3,628	0	0	0
Cash from (Funding)/Releasing Debt Reserve	(12,798)	(330)	757	757	757	757	757	757	757	4,197	3,628	0	0
Year End Cash Flow	**254**	**5,486**	**7,916**	**9,238**	**11,398**	**11,444**	**12,660**	**13,982**	**15,304**	**20,757**	**27,198**	**30,669**	**30,731**

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
FINANCIAL RATIOS:													
Interest Coverage (EBITD/Interest)	2.67	2.71	3.02	3.45	3.13	4.75	5.91	7.81	11.49	16.83	128.06		
Adj. Interest Coverage (Adj. EBITD/Interest) *	2.45	2.59	2.89	3.30	3.80	4.55	5.66	7.48	11.01	20.49	122.57		
Debt Service Coverage (EBITD/Prin & Int)	2.67	1.45	1.42	1.50	1.25	1.70	1.83	1.98	2.16	1.83	5.01		
Adj. Debt Serv. Cov. (Adj. EBITD/Prin & Int) *	2.45	1.39	1.36	1.44	1.52	1.63	1.75	1.90	2.06	2.23	4.80		

* Note: Adjusted ratios replace BOP and Major Maintenance expense with actual annual fundings of the Maintenance Reserve

CASH FLOWS & FINANCIAL RATIOS (in US$000)

PROFORMA

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024
Previous Year Retained Cash Flow	0	0	0	0	0	0	0	0
Net Income	24,110	17,214	23,911	23,977	24,043	24,110	17,214	11,372
Add:								
Depreciation Building	8,167	8,167	8,167	8,167	8,167	8,167	8,167	4,084
Depreciation Trans Equip	80	80	80	80	80	80	80	40
Organizational Costs	0	0	0	0	0	0	0	0
Amortization of Loan Costs	0	0	0	0	0	0	0	0
Cash Flow	32,357	25,462	32,158	32,224	32,291	32,357	25,462	15,496
Working Capital Investment	0	0	0	0	0	0	0	4,220
Cash Available for Debt Amortization	32,357	25,462	32,158	32,224	32,291	32,357	25,462	19,716
Debt Amortization	0	0	0	0	0	0	0	0
Free Cash Flow	32,357	25,462	32,158	32,224	32,291	32,357	25,462	19,716
Non-Operating Cash Flow								
Maintenance Res. Contribution	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(300)
Add:								
Maint. Res. Draw BOP	600	600	600	600	600	600	600	300
Maint. Res. Draw Major Maint.	0	7,800	0	0	0	0	7,800	0
Cash From (Funding)/Releasing Debt Reserve								
Funded Debt Service after Construction								
Required Debt Reserve (6 mos):	0	0	0	0	0	0	0	0
Cash from (Funding)/Releasing Debt Reserve	0	0	0	0	0	0	0	0
Year End Cash Flow	30,797	31,702	30,598	30,664	30,731	30,797	31,702	19,716

	2017	2018	2019	2020	2021	2022	2023	2024
FINANCIAL RATIOS:								
Interest Coverage (EBITD/Interest)								
Adj. Interest Coverage (Adj. EBITD/Interest) *								
Debt Service Coverage (EBITD/Prin & Int)								
Adj. Debt Serv. Cov. (Adj. EBITD/Prin & Int) *								

* Note: Adjusted ratios replace BOP and Major Maintenance exp

Table 7.5-3
PROFORMA

POST CONSTRUCTION INCOME STATEMENTS

Calendar Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Calendar Year #	1	2	3	4	5	6	7	8	9	10	11	12	13
Power Sales (in US$000)													
Fixed Capacity Charge	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767	32,767
Fixed O&M Charge	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,062	7,012	7,012	7,012
Fuel Charge	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	16,537	16,783	13,966	14,174	13,966
Variable O&M	770	770	770	770	770	770	770	770	770	770	650	650	650
Supplemental Charge	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenues from Power Sales	**57,137**	**57,383**	**57,137**	**57,383**	**57,137**	**57,383**	**57,137**	**57,383**	**57,137**	**57,383**	**54,396**	**54,604**	**54,396**
Interest Income (in US$000)	711	603	639	531	568	459	496	388	424	0	72	0	72
Total Project Revenues (in US$000)	**57,848**	**57,985**	**57,776**	**57,914**	**57,704**	**57,842**	**57,633**	**57,771**	**57,561**	**57,383**	**54,469**	**54,604**	**54,469**
Operating Costs (in US$000)													
Fixed O&M Costs	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)
Variable O&M Costs	(770)	(770)	(770)	(770)	(770)	(770)	(770)	(770)	(770)	(770)	(650)	(650)	(650)
Fuel	(16,537)	(16,783)	(16,537)	(16,783)	(16,537)	(16,783)	(16,537)	(16,783)	(16,537)	(16,783)	(13,966)	(14,174)	(13,966)
General & Administrative Costs	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)
Insurance	(2,577)	(2,577)	(2,577)	(2,577)	(2,577)	(2,577)	(2,577)	(2,577)	(2,577)	(2,577)	(2,577)	(2,577)	(2,577)
Agency Fees	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	0	0	0
Balance of Plant	(450)	(450)	(450)	(450)	(450)	(450)	(450)	(450)	(450)	(450)	(450)	(450)	(450)
Major Overhauls	0	(2,900)	0	(2,900)	0	(2,900)	0	(2,900)	0	(2,900)	0	(2,900)	0
Total Operating Expenses	**(22,919)**	**(26,065)**	**(22,919)**	**(26,065)**	**(22,919)**	**(26,065)**	**(22,919)**	**(26,065)**	**(22,919)**	**(26,065)**	**(20,179)**	**(23,287)**	**(20,179)**
Operating Income (EBITD)	34,928	31,920	34,857	31,848	34,785	31,777	34,714	31,705	34,642	31,317	34,290	31,317	34,290
Adjusted EBITD *	33,478	33,370	33,407	33,298	33,335	33,227	33,264	33,155	33,192	32,767	32,840	32,767	32,840
Interest Expense	(13,285)	(12,352)	(10,920)	(9,488)	(8,056)	(6,624)	(5,192)	(3,759)	(2,327)	(895)	0	0	0
Operating Income (in US$000)	**21,643**	**19,568**	**23,936**	**22,360**	**26,729**	**25,153**	**29,522**	**27,946**	**32,315**	**30,422**	**34,290**	**31,317**	**34,290**
Depreciation and Amortization (in US$000)													
Depreciation Facility	(7,911)	(7,911)	(7,911)	(7,911)	(7,911)	(7,911)	(7,911)	(7,911)	(7,911)	(7,911)	(7,911)	(7,911)	(7,911)
Depreciation Trans Equip	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)
Depreciation Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0
Organizational Costs	(1,374)	(1,374)	(1,374)	(1,374)	(1,374)	0	0	0	0	0	0	0	0
Amortization of Loan Costs	(604)	(604)	(604)	(604)	(604)	(604)	(604)	(604)	(604)	(604)	0	0	0
Total Depreciation	(9,939)	(9,939)	(9,939)	(9,939)	(9,939)	(8,565)	(8,565)	(8,565)	(8,565)	(8,565)	(7,961)	(7,961)	(7,961)
Pretax Income (in US$000)	11,704	9,629	13,997	12,421	16,790	16,588	20,957	19,381	23,750	21,858	26,329	23,357	26,329
Taxes	(1,756)	(1,444)	(2,100)	(1,863)	(2,519)	(2,488)	(3,144)	(2,907)	(3,563)	(3,279)	(3,949)	(3,504)	(3,949)
Net Income (in US$000)	**9,949**	**8,184**	**11,898**	**10,558**	**14,272**	**14,100**	**17,814**	**16,474**	**20,188**	**18,579**	**22,380**	**19,853**	**22,380**

Table 7.5-3
PROFORMA

POST CONSTRUCTION INCOME STATEMENTS

Calendar Year	2018	2019	2020	2021	2022	2023	2024
Calendar Year #	14	15	16	17	18	19	20
Power Sales (in US$000)							
Fixed Capacity Charge	32,767	32,767	32,767	32,767	32,767	32,767	32,767
Fixed O&M Charge	7,012	7,012	7,012	7,012	7,012	7,012	7,012
Fuel Charge	14,174	13,966	14,174	13,966	14,174	13,966	14,174
Variable O&M	650	650	650	650	650	650	650
Supplemental Charge	0	0	0	0	0	0	0
Total Revenues from Power Sales	**54,604**	**54,396**	**54,604**	**54,396**	**54,604**	**54,396**	**54,604**
Interest Income (in US$000)	0	72	0	72	0	72	0
Total Project Revenues (in US$000)	**54,604**	**54,469**	**54,604**	**54,469**	**54,604**	**54,469**	**54,604**
Operating Costs (in US$000)							
Fixed O&M Costs	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)	(2,035)
Variable O&M Costs	(650)	(650)	(650)	(650)	(650)	(650)	(650)
Fuel	(14,174)	(13,966)	(14,174)	(13,966)	(14,174)	(13,966)	(14,174)
General & Administrative Costs	(500)	(500)	(500)	(500)	(500)	(500)	(500)
Insurance	(2,577)	(2,577)	(2,577)	(2,577)	(2,577)	(2,577)	(2,577)
Agency Fees	0	0	0	0	0	0	0
Balance of Plant	(450)	(450)	(450)	(450)	(450)	(450)	(450)
Major Overhauls	(2,900)	0	(2,900)	0	(2,900)	0	(2,900)
Total Operating Expenses	**(23,287)**	**(20,179)**	**(23,287)**	**(20,179)**	**(23,287)**	**(20,179)**	**(23,287)**
Operating Income (EBITD)	31,317	34,290	31,317	34,290	31,317	34,290	31,317
Adjusted EBITD *	32,767	32,840	32,767	32,840	32,767	32,840	32,767
Interest Expense	0	0	0	0	0	0	0
Operating Income (in US$000)	**31,317**	**34,290**	**31,317**	**34,290**	**31,317**	**34,290**	**31,317**
Depreciation and Amortization (in US$000)							
Depreciation Facility	(7,911)	(7,911)	(7,911)	(7,911)	(7,911)	(7,911)	(7,911)
Depreciation Trans Equip	(50)	(50)	(50)	(50)	(50)	(50)	(50)
Depreciation Boiler	0	0	0	0	0	0	0
Organizational Costs	0	0	0	0	0	0	0
Amortization of Loan Costs	0	0	0	0	0	0	0
Total Depreciation	(7,961)	(7,961)	(7,961)	(7,961)	(7,961)	(7,961)	(7,961)
Pretax Income (in US$000)	23,357	26,329	23,357	26,329	23,357	26,329	23,357
Taxes	(3,504)	(3,949)	(3,504)	(3,949)	(3,504)	(3,949)	(3,504)
Net Income (in US$000)	**19,853**	**22,380**	**19,853**	**22,380**	**19,853**	**22,380**	**19,853**

CASH FLOWS & FINANCIAL RATIOS (in US$000)

PROFORMA

Calendar Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Previous Year Retained Cash Flow	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Income	**9,949**	**8,184**	**11,898**	**10,558**	**14,272**	**14,100**	**17,814**	**16,474**	**20,188**	**18,579**	**22,380**	**19,853**	**22,380**
Add:													
Depreciation Building	7,911	7,911	7,911	7,911	7,911	7,911	7,911	7,911	7,911	7,911	7,911	7,911	7,911
Depreciation Trans Equip	50	50	50	50	50	50	50	50	50	50	50	50	50
Organizational Costs	1,374	1,374	1,374	1,374	1,374	0	0	0	0	0	0	0	0
Amortization of Loan Costs	604	604	604	604	604	604	604	604	604	604	0	0	0
Cash Flow	19,888	18,123	21,837	20,497	24,211	22,665	26,378	25,039	28,752	27,144	30,341	27,814	30,341
Working Capital Investment	(696)	(20)	20	(20)	20	(20)	20	(20)	20	(20)	245	(17)	17
Cash Available for Debt Amortization	19,192	18,103	21,857	20,477	24,231	22,645	26,399	25,018	28,772	27,123	30,586	27,797	30,358
Debt Amortization	(4,635)	(13,184)	(13,184)	(13,184)	(13,184)	(13,184)	(13,184)	(13,184)	(13,184)	(13,184)	0	0	0
Free Cash Flow	**14,557**	**4,919**	**8,674**	**7,293**	**11,047**	**9,461**	**13,215**	**11,835**	**15,589**	**13,940**	**30,586**	**27,797**	**30,358**
Non-Operating Cash Flow													
Maintenance Res. Contribution	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)
Add:													
Maint. Res. Draw BOP	450	450	450	450	450	450	450	450	450	450	450	450	450
Maint. Res. Draw Major Maint.	0	2,900	0	2,900	0	2,900	0	2,900	0	2,900	0	2,900	0
Cash From (Funding)/Releasing Debt Reserve													
Funded Debt Service after Construction	0												
Required Debt Reserve (6 mos):	12,768	12,052	11,336	10,620	9,904	9,188	8,472	7,755	7,039	0	0	0	0
Cash from (Funding)/Releasing Debt Reserve	(12,768)	716	716	716	716	716	716	716	716	7,039	0	0	0
Year End Cash Flow	**339**	**7,086**	**7,940**	**9,459**	**10,313**	**11,627**	**12,481**	**14,001**	**14,855**	**22,429**	**29,136**	**29,247**	**28,908**

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
FINANCIAL RATIOS:													
Interest Coverage (EBITD/Interest)	2.63	2.58	3.19	3.36	4.32	4.80	6.69	8.43	14.89	34.99			
Adj. Interest Coverage (Adj. EBITD/Interest) *	2.52	2.70	3.06	3.51	4.14	5.02	6.41	8.82	14.26	36.61			
Debt Service Coverage (EBITD/Prin & Int)	1.95	1.25	1.45	1.40	1.64	1.60	1.89	1.87	2.23	2.22			
Adj. Debt Serv. Cov. (Adj. EBITD/Prin & Int) *	1.87	1.31	1.39	1.47	1.57	1.68	1.81	1.96	2.14	2.33			

* Note: Adjusted ratios replace BOP and Major Maintenance expense with actual annual fundings of the Maintenance Reserve

CASH FLOWS & FINANCIAL RATIOS (in US$000)

PROFORMA

Calendar Year	2018	2019	2020	2021	2022	2023	2024
Previous Year Retained Cash Flow	0	0	0	0	0	0	0
Net Income	**19,853**	**22,380**	**19,853**	**22,380**	**19,853**	**22,380**	**19,853**
Add:							
Depreciation Building	7,911	7,911	7,911	7,911	7,911	7,911	7,911
Depreciation Trans Equip	50	50	50	50	50	50	50
Organizational Costs	0	0	0	0	0	0	0
Amortization of Loan Costs	0	0	0	0	0	0	0
Cash Flow	27,814	30,341	27,814	30,341	27,814	30,341	27,814
Working Capital Investment	(17)	17	(17)	17	(17)	17	4,471
Cash Available for Debt Amortization	27,797	30,358	27,797	30,358	27,797	30,358	32,285
Debt Amortization	0	0	0	0	0	0	0
Free Cash Flow	**27,797**	**30,358**	**27,797**	**30,358**	**27,797**	**30,358**	**32,285**
Non-Operating Cash Flow							
Maintenance Res. Contribution	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)	(1,900)
Add:							
Maint. Res. Draw BOP	450	450	450	450	450	450	450
Maint. Res. Draw Major Maint.	2,900	0	2,900	0	2,900	0	2,900
Cash From (Funding)/Releasing Debt Reserve							
Funded Debt Service after Construction							
Required Debt Reserve (6 mos):	0	0	0	0	0	0	0
Cash from (Funding)/Releasing Debt Reserve	0	0	0	0	0	0	0
Year End Cash Flow	**29,247**	**28,908**	**29,247**	**28,908**	**29,247**	**28,908**	**33,735**

	2018	2019	2020	2021	2022	2023	2024
FINANCIAL RATIOS:							
Interest Coverage (EBITD/Interest)							
Adj. Interest Coverage (Adj. EBITD/Interest) *							
Debt Service Coverage (EBITD/Prin & Int)							
Adj. Debt Serv. Cov. (Adj. EBITD/Prin & Int) *							

* Note: Adjusted ratios replace BOP and Major Maintenance exp

7.6 Sensitivity Runs

In order to determine how cost variations will impact project tariffs, we have run several sensitivities for each of the three technologies for comparison against the base case:

- Variation of capital costs by +/- 10%
- Variation of non fuel operating costs by +/- 10%
- Variation of fuel costs:
  - +/- 5 US$/BBL for fuel oil
  - +/- 10% for coal
- Variation of interest rates by +/- 2%
- Variation of minimum debt service coverage ratio (DSCR) by +/- 0.05
- Increase of loan terms by 2 years

The base case tariffs as indicated above were determined on the basis of a minimum DSCR of 1.25. This is the reference ratio that drives the value of the tariff by way of FCC fluctuations. When the minimum DSCR falls below 1.25, the FCC must be adjusted upward, thereby increasing the tariff; similarly, a minimum DSCR higher than 1.25 results in a reduction of the FCC and a lowering of the tariff. In all our sensitivity runs we have used the minimum DSCR of 1.25 as our reference point and have thus adjusted tariffs accordingly. Tables 7.2 –7.12 provide summary data for each of the Combined cycle sensitivity runs. Tables 7.14 –7.24 provide summary data for each of the Coal plant sensitivity runs. Tables 7.26 –7.36 provide summary data for each of the Diesel plant sensitivity runs.

Capital Cost variations

Variations in capital costs result in a readjustment of the FCC component of the tariff to compensate for higher or lower costs. The tariff variation resulting from capital cost increases or decreases are uniform for all three technologies.

	+10%	Base	-10%	% variation
Combined Cycle	0.086	0.082	0.078	+/- 5%
Diesel	0.101	0.096	0.091	+/- 5%
Coal	0.094	0.089	0.084	+/- 5%

Non Fuel Operating Cost Variations

Non fuel operating cost fluctuations, which will affect fixed and variable O&M tariff components, have relatively little effect.

	+10%	Base	-10%	% tariff variation
Combined Cycle	0.083	0.082	0.081	+/- 1%
Diesel	0.097	0.096	0.095	+/- 1%
Coal	0.091	0.089	0.087	+/- 2%

Fuel Cost Variations

Fuel cost variations have a similar impact to that of capital cost fluctuation. A change in either of those elements in a project can significantly impact resulting tariffs.

	+5 US$/BBL	Base	-5 US$/BBL	% tariff variation
Combined Cycle	0.087	0.082	0.077	+/- 6-7%
Diesel	0.101	0.096	0.091	+/- 5%
	+10% coal $		**-10% coal $**	
Coal	0.091	0.089	0.088	+/- 1-2%

Interest Rate Variations

	+200 basis points	Base	-200 basis points	% tariff variation
Combined Cycle	0.086	0.082	0.078	+/- 5%
Diesel	0.102	0.096	0.091	+/- 6%
Coal	0.094	0.089	0.085	+7% -5%

Increase in Loan Terms

Better loan tenor will positively impact the tariff in a significant manner. We have not looked at lower than 10 years as it is unlikely that such tenors would be required for the project.

	+2 years	Base	N/A	% tariff variation
Combined Cycle	0.079	0.082		- 4%
Diesel	0.092	0.096		- 4%
Coal	0.086	0.089		- 4%

Minimum DSCR Variations

Finally, we studied how a required minimum DSCR can impact the tariff.

	1.3	1.25	1.2	% tariff variation
Combined Cycle	0.084	0.082	0.081	+/- 2%
Diesel	0.98	0.096	0.094	+/- 2%
Coal	0.091	0.089	0.087	+/- 2%

These sensitivity runs also demonstrate the impact on the Developers' internal rate of return (IRR). This return is strongly influenced by the lenders required minimum DSCR. Changes in the DSCR minimum shows changes in the IRR under the assumptions we have used, a flat Fixed Component tariff. The IRR varies from 18.8% to 21.2%.

8.0 Power Purchase Agreement and Concession Agreement Term Sheets - Task 9

Terms sheets were prepared for the Power Purchase Agreement and Concession Agreement in this task. The successfully project financed Bellevue project in Mauritius was used as the model for these agreements. K&M adjusted the agreements based on international practice, the current requirements of the Concession Project Act, the Electricity Act and project specific parameters. The term sheets addressed issues including:

- entering into agreements with CEB/Mauritius
- Terms and conditions of the Build Own Operate (BOO) agreement
- Interconnection security and supply of power

The level of public - private partnership with CEB is limited to scope covered by the laws of Mauritius encouraging private power development. Training of CEB personnel is not applicable because this is a BOO project not a project that will be transferred at the end of the Term to CEB.

These term sheets were approved as part of the Request for Proposal submitted in Task 13. The terms sheets are included in Appendix H.

9.0 US Source Potential.

The Project specifications and characteristics have been aimed at developing the optimum requirements for the project. The project characteristics have been selected based on the needs of the power system of Mauritius. Three different designs have been developed. The specifications are, given the nature of the procurement envisioned, general performance based specifications. International codes and standards have been listed. World Bank Guidelines and Mauritius environmental requirements have been specified.

In accordance with the study Contract US TDA clause D - US Sources, we are identifying the availability of U.S. sources of supply so as to maximize their use in implementation.

The design responsibility for the project belongs to the selected Developer and will likely in turn be delegated to their EPC contractor within the general requirements and performance specifications provided.

Overall, the availability of U.S. supply and possible participation is very good. Four levels of possible participation have been identified.

First, as the project developer and investor. The immediate product of this study, the RFP, will be sent to international developers. The US has strong international developers that can compete for this project, including amongst others:

- Duke Energy (already active in Mauritius),
- AES Corporation,
- InterGen,
- Southern Co. International,
- Edison Mission Energy,
- CMS Generation, and
- Enron Corporation

The second level of participation possible is as EPC Contractor for a contract in the order of $ 85 million to $135 million. There are many strong US international EPC competitors available including:

- Washington Group,
- Bechtel Group,
- Black & Veatch,
- Burns & Roe,
- General Electric,
- Siemens Westinghouse,
- Foster Wheeler,
- Duke Engineering and
- Parsons Corp.

The third level of possible participation would be as major equipment supplier for power station equipment such as:

- Combustion turbine suppliers including; Siemens Westinghouse and GE Power Systems.

- Steam turbines suppliers including; GE Power Systems, Siemens Westinghouse and ABB Alstom Power Inc.

- Heat exchange equipment suppliers including; Yuba Heat Transfer, Foster Wheeler Energy Corp, and ABB Alstom Power Inc.

- Pump suppliers including; Fairbanks Morse Pump, Aurora Pump, Sterling Peerless Pump, Ingersoll-Rand Pumps, Goulds Pumps and Byron Jackson Pumps.

- Coal handling equipment including; United Conveyor Corporation.

- HRSG suppliers including; Foster Wheeler Energy Corp, Deltak LLC, Nooter/Eriksen Inc and Vogt-NEM.

- Steam generators suppliers including; Foster Wheeler Energy Corp and Babcock & Wilcox.

- Transformer suppliers including; Virginia Transformer Corp, GE-Prolec, Ferranti-Packard Transformers Ltd. and Waukesha Electric Systems.

- Control systems suppliers including; ABB Automation Inc, Rockwell International Corporation and Westinghouse Process Controls.

- Electrical switchgear and motors suppliers including; General Electric North American Switchgear Inc., Square D and Powel Electrical.

- Large diesel engines are not available from the US and would have to be sourced from elsewhere.

The fourth level of potential participation is as a fuel supplier. Coal is likely to be provided from South Africa. Fuel oil suppliers, however, may potentially include subsidiaries of U.S. based international oil companies such as Caltex and Mobil-Exxon which have been involved in supplying petroleum products to the Mauritius State Trading Corporation.

Appendix A

Letter Report of Site Selection – Task 2

21 April, 1999

Feasibility Study: IPP Base Load Power Station
Ministry of Public Utilities, Mauritius

SITE REVIEW FOR THE NEW IPP BASE LOAD POWER STATION

The proposed new power generating capacity for the island of Mauritius will be of thermal type, utilizing fossil fuels. Enough space is not available at the existing power stations of the island to accommodate the equipment and infrastructure for this additional generation capacity. Moreover, this location will also have to provide necessary space for future expansions. Therefore, this power plant has to be located on a new site. This report summarizes the investigations and recommendation regarding the selection of a site for this new power station.

MAJOR CONSIDERATIONS

The new units are required to generate electricity at a low cost so that they can be used for base load applications and therefore must have high generating efficiencies. The unit sizes should be relatively large in order to benefit from the economy of scale. The ultimate capacity of this power station should not be less than 300 MW, and preferably be 500 MW or more. Also, it should be possible to commission the first phase of this plant within a short time, preferably by the year 2003.

Some of the major considerations for siting of such a new thermal power station are:

- Availability of adequate land suitable for heavy construction
- Convenient access to the site for movement of equipment & materials
- Arrangement for supply of fuel to the site
- Connection with the existing electric transmission and distribution system for evacuation of power
- Availability of adequate cooling water for dissipation of waste heat
- Effect of emissions from the plant
- Availability of the utilities and infrastructure for operation and maintenance of the power plant

Availability of an adequate supply of cooling water for rejection of waste heat from efficient power generation processes which are suitable for base load applications, is an important consideration. Though this has been avoided in the Fort George power station by using radiators for cooling by atmospheric air with very good results, this solution will be too costly for a much larger power station such as this, and there will also be a significant loss in efficiency. Once-through type cooling systems for a large power station require supply of large quantities of water, which may be provided effectively only from the sea or a major river stream. Since there are no suitable large rivers on the island, the

latter is not an acceptable option for the proposed plant. The other alternative may be to adopt a closed-loop cooling system using atmospheric cooling towers, so that the power plant can be located in any suitable location, including inland. But such a plant will consume large quantities of fresh water as make-up, whereas almost all the fresh water available on the island is already being utilized for drinking and other domestic purposes, as well as for irrigation, and there is actually a shortage of this valuable resource now. It seems obvious that it will not be possible to divert large quantities of this scarce fresh water for the power plant. In effect this means that only suitable coastal locations, with easy access to a plentiful supply of sea water should be considered for the proposed power plant.

Another important consideration is a safe and low cost arrangement for supplying the large
quantities of fuel that will be consumed by the power plant, which, depending on the type of the fuel, may ultimately approach one million metric tons per year. All fuel has to be imported to the island by ships and therefore proximity to a harbor facility will have a great advantage. Movement of this amount of fuel materials over road will be a major burden to the traffic. Transportation of fuel oil by pipelines, laid out with proper safety considerations, will be comparatively easier to manage, but it will still add a significant cost element. A location near a facility suitable for unloading the large ships, which deliver the fuels from abroad, will have a major advantage in this regard.

POTENTIAL SITES

A survey was undertaken to identify possible sites on the island for the proposed new power station which best satisfy the above requirements, and the following three were found to merit further consideration:

- Fort William area near the city of Port Louis
- Vieux Grand Port area (near Bois Des Amourettes) on the south-eastern side of island
- Near Montagne Jaquots, on the western coast

A fourth area near Grand Riviere Sud-Est also seemed to have some potential, but very little relevant information could be obtained on it. Even if found to be a reasonable site, the entire process of its identification, acquisition and development is likely to take a much longer time, pushing it beyond the present schedule requirement.

Fort William

This is an 8.5-hectare plot immediately to the south of the limit of the port area for Port Louis, and is demarcated from it by the alignment of an abandoned sewer line. CEB has already initiated necessary actions for acquiring this vacant land from the Ministry of Housing, which is its present owner. It is understood that there will not be any significant land acquisition cost for the Ministry of Public Utilities.

On the sea front, it is surrounded by a corral reef, which extends from the channel for entering the port almost up to the mouth of the Grand River. This area seems to be underlain 12 to 15 meters below the surface by rock strata of sufficient strength to support heavy foundations on piles, as can be seen from the soil investigations done earlier at some of the adjacent locations, including a bulk sugar terminal. This will however have to be confirmed by borings. The area is generally marshy, and will have to be back-filled by 1.5 to 2 meters for construction of the power plant. Its seaward side will also have to be protected by suitable embankments.

It is well connected by approach roads, and very close to the only commercial port of Mauritius, so that movement of materials and equipment to it should not be a problem.

The available land will be adequate for an oil-fired plant of at least 400 MW using combined cycle units or large diesel generators. More space may be required for a coal-fired steam power plant considering the large coal storage area that will be needed. But this can be reclaimed from the sea if needed (water depth within the lagoon formed by the reef being generally less than 2 meters), as has already been done on the north side of the entrance channel for the port.

The near-by quay for the bulk sugar terminal is already being used for unloading of fuel oil for the power plant at Fort Victoria, and the on-shore storage tanks for this are actually located in the immediate vicinity of this site. It may therefore be possible to unload the fuel for this plant with the same facility. However, such use of the sugar terminal for oil unloading is already causing some safety concerns. If this is found to be a problem, it will be possible to construct a separate quay for it on the seaward side, again in the same manner as has already been done for the new quay for the relocated oil tank farm of the port. This should be suitable for unloading of coal also, if needed.

An adequate supply of cooling water is readily available from the sea. But the water near the shore is very polluted due to an active sewer discharge line south of the site, and therefore may support heavy growth of weeds, algae, etc. to block the flow, as has already been experienced at the nearby Fort Victoria power station. Also, cyclones are known to bring in large quantities of floating debris near the shore, which can choke the flow in a very short time. To overcome these problems, submerged intake heads for sea water may be located in the deeper water beyond the corral reefs, and the water drawn into the pump house located on shore by pipelines buried in the seabed. Most of the corral in this area is already dead due to the pollution caused by the discharge of sewage near it and so operation of the power plant is not expected to cause any additional damage.

Two particular issues for this location of a power station are the requirement to control the noise and air emissions, as there are many houses near the southern end of the site and the proximity of the bulk sugar terminal facility. Since the predominant wind direction is from the southeast (about 80% of the time), most of the air emissions and noise caused by the power plant will normally be directed towards the sea, causing only minimal impact

on the local population. The plant design needs to adhere to the environmental standards of Mauritius or The World Bank guidelines, whichever is more stringent, and an appropriate stack height will minimize impacts when the wind direction changes. Regarding noise, it should be considered that the new plant would replace the generation at the nearby old power stations at Fort Victoria and Saint Louis, and special mitigation measures can be included in the plant design if required to limit its noise to within applicable lmits.

This site will be near the major load centers. This section of the Mauritius coast is protected from the main thrust of the cyclones by the mountains surrounding the city of Port Louis. Work is being initiated now by CEB to upgrade and strengthen their existing system by adding additional grid ties at 132 kV. The existing 66 kV transmission line from Wooten to Rose Hill will be upgraded to 132 kV as part of the program. Evacuation of power from the new power station will be at 132 kV, and will be routed underground to the St. Louis power station because of area congestion and required security. The new 132 kV transmission lines may have to be routed along the canyon of the Grand River Northwest from the St. Louis power station up to the municipal dike and then can parallel the existing 66 kV line to Rose Hill.

This location also enjoys the advantage of benefiting from the extensive infrastructure of the largest city on the island so utilities, telephones, water and construction power will be readily available.

Vieux Grand Port

The only other natural harbor on the island potentially suitable for large ships is located on its southeastern side at the Grand Port area, and was actually the site of an old port. Breaks in the reef walls allow the ships to come in close to the shore, and this port was active during the Second World War. There is an old quay for unloading of fuel oil and 5 old oil tanks of 4,500 cubic meter capacity each still stand there, on a land owned by the Government. The quay was last repaired about 15 years ago at considerable cost. But this facility has never been used after its construction, and was finally abandoned due to some major defects. Since the entire shipping traffic of the island now depends on its only port on the north-east coast, there have been some proposals to re-open it as the second port, serving the southern end of the island including its international airport, which is located in this area. When this takes place, the site of the old oil tanks, etc. can be developed as a power station.

This may take some more time to become a reality, as a few serious problems need to be resolved first:

a) Considerable dredging will be needed to make the shipping channel suitable for navigation of large ships, and this will require significant expenditure.

b) This side of the island is exposed to the prevailing southeastern wind from the ocean, and may not protect the ships adequately during cyclones. Resulting swelling inside the harbor basin requires more than normal bottom clearance for the ships, so that ships of greater drafts may experience difficulties.
c) The surrounding coastal area is environmentally very sensitive, and harbors several rare species of flora and fauna, which are not found elsewhere. This area is therefore considered a national asset, and some portions of it are protected as a marine park (Blue Bay National Marine Reserve). It is also a major recreational center and a nucleus for Eco-tourism, as well as source of livelihood for many local fishermen. Opening of the new port and its associated industrial infrastructure, including a power station may upset the delicate balance of this region, and this aspect will require very careful considerations.

Due to these difficulties, it does not seem likely that this port will be opened before the year 2010 and so may not be a suitable choice for this power station. Siting of a power station here will face several other difficulties as well:

a) Existing load centers are further to the north, so that relatively long transmission lines will be necessary for evacuation of power and to connect it to the 132 kV section of the grid.
b) All pollutants released by the plant will be carried into the island during most of the year, and any accidental oil spills at the harbor will be driven to the shore by the wind, unlike the Fort William site. So such adverse effects may be more widespread.
c) Being surrounded by mountainous regions, the availability of suitable flat ground is rather restricted so that only a relatively small plant can be accommodated there after allowing for the facilities for the harbor itself.

In addition, utilities, telephone, water, etc. will have to be run for longer distances.

Montagne Jaquots

The shore to the south of the old prison at Pointe Aux Sables, up to the lighthouse at Pointe Aux Caves, is presently uninhabited, and may be considered for locating a power station. This area is a platform of basalt, generally rising vertically from the sea to a height of about 20 meters. More than adequate vacant land is available along the coast. All of this is, however, privately owned and the land acquisition may be a costly and lengthy process.

Numerous boulders cover top 1 meter of the land, but strong rocks suitable for heavy foundations generally underlie them.

Most of this area is too far above the sea level to be able to use sea water for once-through

cooling at a reasonable cost. At a few spots however the land comes down to only 2-3 meters above the sea level and may make such an arrangement possible, though cost of excavation and construction of the water intakes on the rocky coast will still be comparatively high. On the other hand, use of cooling towers could also be considered as a possible alternative. However, supply of fresh water, which can be used for make-up to the cooling towers, is also very limited in this region. A large sewage treatment plant has been proposed to be constructed at Montagne Jaquots, using loans from the World Bank. If a portion of its treated effluent, presently earmarked for irrigating the cane cultivation of the area, can be diverted for the power plant, it may be possible to resolve this problem.

Corral reefs do not protect the coasts in this area. There are also no nearby mountains in the hinterland to protect this area from strong winds. There are many colonies of living corrals in the waters off the coast, which are very sensitive to shipping activities. As a result all fuel and materials for the power plant has to be either unloaded at Port Louis and transported from there, or a berthing facility has to be constructed off the coast for unloading of ships, both of which pose some safety concerns. It may be possible to transport fuel oil from the port by buried pipelines (approx. 8 KM), but transportation of coal in such large quantities may be very difficult.

A major advantage of this site is that that there are no nearby inhabitants, and so noise from the plant is unlikely to be a problem. However, we understand that an EIA license has recently been issued to a new hotel to be located in the area, but its construction schedule is unknown.

Length of transmission lines required will be somewhat longer than for the Fort William site discussed earlier. Likewise, utilities, telephone, electricity and water will have to be run for longer distances. We understand water is in particularly short supply in this area.

RECOMMENDATION

Since there are many different considerations involved in selecting an optimum site for the proposed power station, the candidate sites have been compared first regarding each of these aspects separately, and then a composite score has been developed for them using appropriate weight factors. Such a comparison of the relative merits and demerits among the three sites discussed above indicates that the Fort William site will be the best choice for the proposed new power station (see Comparison Matrix for the three alternative sites). Acquisition of this site is now in an advanced stage, which could be consistent with the required time schedule.

It is therefore recommended that the Feasibility Study for a power plant to be located at the Fort William site.

Feasibility Study IPP Base Load Power Station Mauritius Ministry of Public Utilities
Comparison Matrix of Three Alternative Sites

April 22, 1999

Parameter	**Ft William (Ft. W)**	Ft. W points	**Vieux Grand Port (VGP)**	VGP points	**Montagne Jaquots (MJ)**	M J points
Site Availability						
Land availability and topography Max points 8	8 hectares available for use. Requires backfill to raise elevation.	5	Useable land scarce due to sea, port development areas and adjacent mountains.	3	Land readily available. Topography generally flat.	7
Geology and Foundations Max points 5	Requires piles based on nearby experience and data.	3	Little data available. Existing site excavated from mountain. Assume good rock. No piles expected.	4	Nearby borings available. Excavation and foundations expected to be reasonable. Piles are not expected.	4
Generating capacity, Oil Max points 10	Approximately 400 - 500MW	8	Approximately 300MW	4	Approximately 500 MW could be limited by availability of cooling tower make up water from treatment plant.	8
Generating capacity, Coal Max points 5	Approximately 300 MW limited by storage area, could be expanded by reclamation to reef	3	Approximately 150 MW. Seriously limited by fuel storage area.	2	Very difficult due to lack of access to port.	0
Land acquisition cost Max points 5	Currently State land, little cost if any	5	Currently State land, little cost if any	5	Currently private land; significant cost.	2

Parameter	Ft William (Ft. W)	Ft. W points	Vieux Grand Port (VGP)	VGP points	Montagne Jaquots (MJ)	M J points
Environment						
Air Emissions and meteorology Max points 10	Favorable, trade winds blows emissions out to sea	8	Unfavorable, trade winds blow emissions inland	3	Favorable, trade winds blow emissions out to sea	10
Land use/ Population density Max points 10	Dense residential areas adjacent to site. Bulk Sugar Facility nearby. Potential conflict with fuel use and air emissions	3	Individual houses in the vicinity	6	Near proposed sewerage treatment plant and prison. Also planned hotel project near lighthouse.	9
Terrestrial and aquatic Ecology Max points 10	Industrial area. Nearby sewer plant and sand fill area. Little impact on land or sea life.	10	Very sensitive area. Near National Marine Park (Blue Bay)	2	Dry land with scrub. Little impact. Valuable coral in the sea.	6
Noise Max points 10	Moderated by wind direction. Nearby neighbors may require special measures.	7	Exacerbated by wind direction. Few nearby neighbors but may require special measures.	7	Essentially no nearby neighbors.	10
Infrastructure						
Roads Max points 5	Short road improvement required. Delivery during construction easier due to location of Port Louis	5	Lengthy road improvement required. Delivery during construction very difficult. May require early completion of quay at the site for equipment delivery.	2	Some road improvement required depending on the schedule of the treatment plant. Delivery during construction from Port Louis difficult	3
Fuel access Max points 10	Nearest the port. Perhaps use existing quay at Sugar Bulk Facility. Potential conflict with Bulk Sugar Facility interests. Could build separate quay if	8	Require extensive port development to receive fuel ships. May be part of larger program to develop port. Schedule uncertain and perhaps very lengthy.	2	Need fuel oil pipeline from Port Louis, approx. 8km Alternative, moor ships off the site. Concerns are valuable coral in the area and an unsheltered ship mooring.	2

Parameter	Ft William (Ft. W)	Ft. W points	Vieux Grand Port (VGP)	VGP points	Montagne Jaquots (MJ)	M J points
	necessary					
Electrical transmission interface Max points 8	Congested area for evacuation of power. Use proven underground technology. Interconnection length 2.5 to 3 km to St. Louis, and another 8 km to Rose Hill	6	Interconnection length 25 km to Wooton. No high voltage transmission in the area. Mountains will make access difficult.	2	Interconnection length 15 km to Rose Hill.	5
Cooling water access Max points 8	Straightforward. Extend intake beyond nearby reef	7	Use large bay inside the reef or long piping outside reef 5 km away	5	Sea access difficult at most locations. Lower elevation possible. Otherwise very expensive pumping cost. Also possible use of wastewater (from sewage treatment plant) for cooling tower make up.	4
Schedule						
Schedule Max points 8	Most advance in planing and development. CEB has applied for the land and it has been earmarked by Ministry of Housing for a power plant.	8	Probably requires extensive development of the new port. Highly uncertain schedule, perhaps 2010 if at all.	0	Area is being developed with the construction of a sewage treatment facility. Schedule not clear. Feasibility may be dependent on treatment plant. Also some delays may be experienced in acquiring the land from private owners.	6
Total points = 112		**86**		**47**		**76**

Feasibility Study: IPP Base Load Power Station
Ministry of Public Utilities, Mauritius

Site Development Differential Cost Comparison

(Order of Magnitude Cost Estimates)

Cost Element	Fort William	Vieux Grand Port	Montagne Jaquots
Land Acqusition	State Land Small	State Land Small	Private Land Rs. 35,000,000
Site Preparation	Back Fill Rs. 60,000,000	Base	Base
Foundation	Piling Rs. 25,000,000	Base	Base
Utilities	Small	Rs. 2,000,000	Rs. 10,000,000
Sea Water Intake	Rs. 20,000,000	Rs 80,000,000	Rs. 40,000,000
Fuel Supply	Base	Base (New Port Needed)	Rs. 80,000,000 Oil Pipe Line
Electric Transmission	Rs 180,000,000 Cables near P/S	Rs. 200,000,000	Rs. 120,000,000
Access Road	Base	Base	Rs. 4,000,000
NET	Rs. 285,000,000	Rs. 282,000,000	Rs. 289,000,000

Appendix B

Letter Report of Fuel – Task 3

June 30, 1999

Feasibility Study: IPP Base Load Power Station
Ministry of Public Utilities, Mauritius

Task 3 Evaluate Fuel Procurement, Supply and Pricing

Introduction

This report covers fuel procurement, supply and pricing. The price information will be utilized in the letter report on Technology Evaluation in order to develop a comparative cost of electricity generation. Those costs, along with other fuel and technology factors will be utilized make a recommendation and selection on the combination of fuel and technology for the subject plant.

In this report we have considered gas, coal and petroleum fuels.

Conclusions

The practical fuels to consider for use on the project are:

- Petroleum
  - HFO
  - Diesel
  - Condensate,
  - Kerosene (considered due to the current tax / duty exemption)
- Coal

Security of supply should not be a serious concern with either petroleum or coal fuel.

Petroleum product prices are forecast to increase more than coal.

In addition, coal prices are expected to be more stable over the long run than those of petroleum products.

Natural gas (i.e. LNG) does not appear feasible due to the modest size of the project and the very high infrastructure cost required for LNG shipping, handling, storage and regasification.

The choice of fuel is intimately connected to the choice of technology.

Mauritius customs duty and taxes can affect the choice of fuel and technology

The current differential duties for different import regions strongly influence the choice of location of fuel supply.

Fuel should be supplied directly by the Developer of the plant.

Environmental impacts can be satisfactorily managed with the various fuel types considered.

A more detail environmental impact assessment will be covered in other parts of the feasibility study.

Fuel Prices and Supply

Fuel Markets of the Pacific Basin

While there is an international oil, gas and coal market, shipping costs have created some regionalization of world market. Oil markets are frequently described as the Atlantic Basin market and the Pacific Basin market, also sometimes referred as "East of Suez".

The supply sources for Mauritius are part of this Pacific market, which includes the major crude oil supply areas of the Persian Gulf (PG) and smaller crude oil production supplies in Indonesia and Malaysia. South Africa and the COMESA countries are not significant oil exporters. They are not considered a viable source of supply for the long term, although currently a significant portion of the CEB's oil is supplied from Madagascar.

The center for oil product trading is the large export-refining center of Singapore. The Singapore spot market price quotes are the basis for pricing in the Pacific Basin markets. While the export refineries of the countries in the PG region are the logical source for Mauritius, it is the Singapore market that determines the FOB export product prices from the PG. This pricing relationship is due to the fact that the major markets for PG oil products are the same as those supplied from Singapore, so PG prices are calculated from the Singapore prices.

In the Pacific Basin there is a large volume of refined product movement from the export refineries in the Middle East and Singapore. The total refined products shipped from Saudi Arabia, Kuwait, and UAE is almost 2 million barrels per day, which is about seventy percent of the output of the refineries in those countries. Singapore refineries produce about 1.2 million barrels per day of refined products and export almost all of it. Thus Pacific Basin markets have large product availability for all refined products from multiple locations.

Security of supply for refined products is not an issue in the region. However, while obtaining supply volumes of refined products may pose few worries; there are no guaranties on oil prices over the long term. Contracts will be tied to the changes in international crude oil and product spot market indices.

Coal supplies are also readily available in the Pacific Basin. Two of the world's three largest coal exporters are found in the Pacific Basin market region. Australia is the world leading coal exporter, shipping over 7 million metric tons of steam coal per month. South Africa is the third largest coal exporter with about 4.7 million metric tons per month and much of it shipping from the Indian Ocean port of Richard's Bay. As with oil there is large supply availability. While there are fewer coal suppliers than in the case of oil, there are sufficient suppliers for a competitive marketplace. Coal can be purchased on a long term contract basis and there is much less price volatility than in oil markets

Gas Fuels

Gas production occurs in the same areas as the crude oil producing areas. In fact, oil and gas are frequently coproduced from the same well. Gas production in these areas, which are separated

from major consuming areas by long ocean voyages, must be liquefied to be shipped to markets. The methane (CH4) in the gas is liquefied at very low temperatures and high pressures and shipped in special tankers. This liquefied natural gas (LNG) has its largest markets in Japan and Korea.

Gas market fuels for Pacific Basin markets include (LNG) and natural gas liquids produced in gas processing, such as propane. In the past LNG prices have primarily been sold on a long-term contract basis with the price tied to crude oil prices. Because of the environmental attractiveness of LNG, there is generally a modest quality premium for LNG relative to crude oil. The reference point for LNG pricing is Japan because it consumes about 60% of the world total. The average prices for LNG delivered to Japan is shown below for the last few years:

	1995	1996	1997	1998
LNG Delvrd to Japan, $/mmBTU:	3.41	3.59	3.90	3.06

Recently, the price has fallen as a consequence of a fall in crude oil prices. Currently there is surplus availability of LNG, and producers are searching for new buyers. Most LNG power projects have been very large-scale projects. The smallest reported power project is about 500MW, and most are 1000MW or more. The reason is that large is scale needed to cover the costs of the large special tankers required to deliver LNG; port facilities, storage for the low temperature LNG and regasification facilities. The economics for a 100 MW scale power facility for Mauritius using LNG is very unlikely to have favorable economics.

Natural gas liquid, propane, is widely used in the Pacific Basin markets with much of it produced in the Persian Gulf. Propane (also sometimes referred to as LPG) is used in the residential markets around the world as a heating and cooking fuel. Prices for propane are shown in Figure 1 FOB the Persian Gulf and delivered to Japan. The price difference is about 20$/mt which represents an average freight rate. The figure also shows a quite dramatic seasonal pattern, with prices rising in the autumn months and dropping to a low point in summer months.

Figure 1

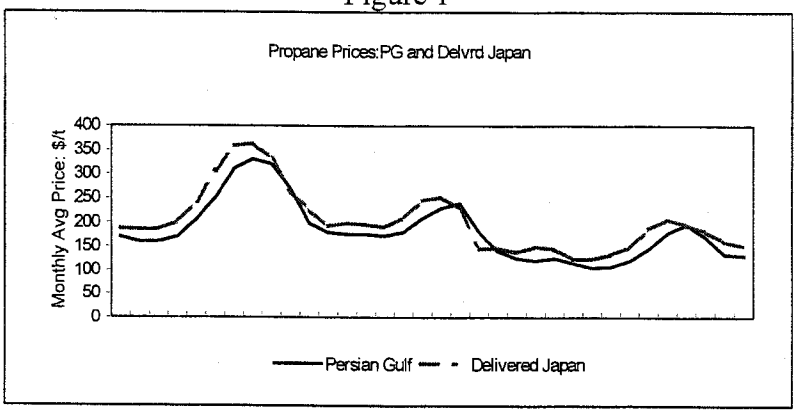
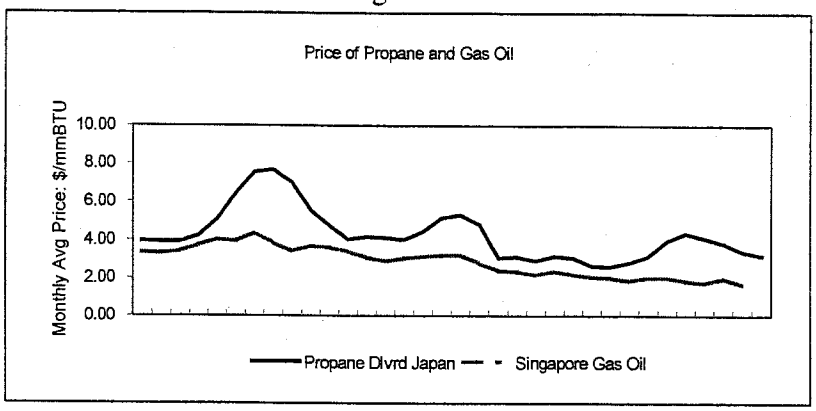


Figure 2 shows propane plotted with gas oil(diesel fuel). Propane in Asian markets is higher priced than distillate, especially when the seasonal up swings are included. Thus propane can be excluded from consideration because it costs more per barrel than diesel and the heat content is only 57% of diesel fuel.

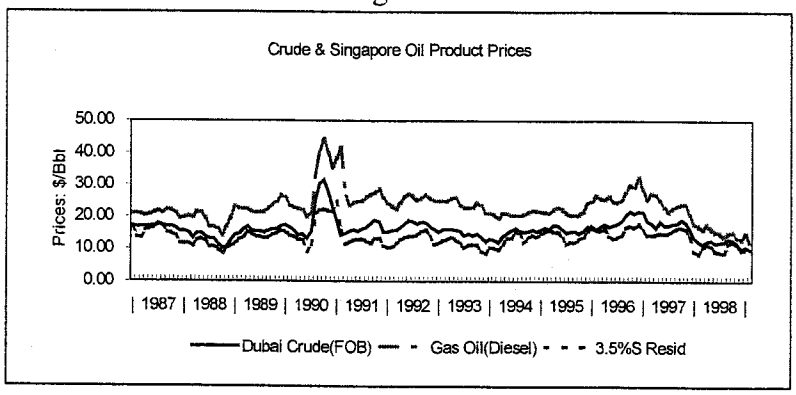
Figure 2



Crude Oil Derived Fuels

Fuels from crude oil can be divided into two groups, the light prime fuels, which includes naphtha (from which gasoline is produced), kerosene (used as jet fuel after hydrotreating), and gas oil (which is used as diesel or furnace oil for home heating). All of these fuels can be used as combustion turbine fuels and diesel can be used as both a diesel engine fuel and turbine fuel. These prime fuel are all higher priced than crude oil because crude oil also contains higher boiling, heavy, higher molecular weight material, which has lower value because it cannot be used in the "premium applications" – road vehicle fuel, aircraft fuel and residential heating and cooking fuel. The heavy component of crude oil is referred to as residual fuel and is used as a boiler fuel for ocean vessels (also referred to as bunker fuel) and power generation. Much of the residual fuel is converted to light prime fuel products in expensive refinery upgrading processes. Thus residual fuel is priced below the price of crude oil. Figure 3 shows the price of gas oil and residual product for the Pacific Basin market reference location, Singapore plotted along with Dubai crude oil.

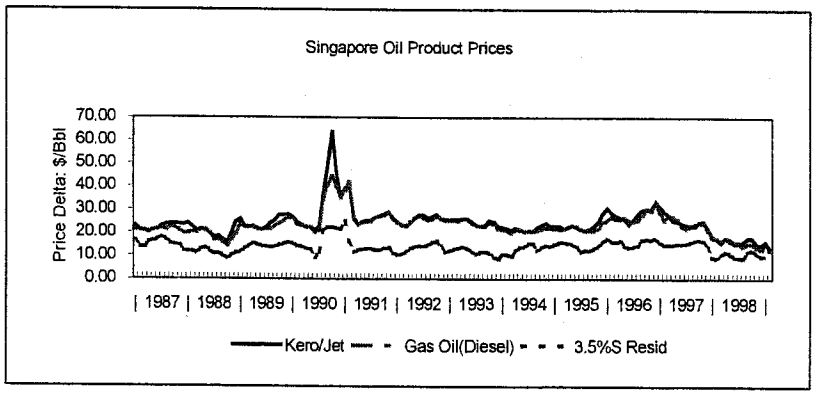
Figure 3



There are several grades of residual fuel based on the sulfur content and the viscosity. Higher sulfur content and higher viscosity means a less useful and lower priced product. The price differences between a high Sulfur resid (3.5wt%) and lower Sulfur resids (0.3 & 0.7wt%) has increased over the past two decades as environmental limits on SO2 emissions have tightened. The two viscosity grades, 180CST and 380 CST are related because the heavier 380 material can be converted to lighter 180 product by adding a lighter(higher valued) material such as diesel fuel.

Diesel is perhaps the most attractive turbine fuel as it is slightly lower in price than kerosene/jet and has a higher heat content per barrel (Figure 4).

Figure 4



Another interesting possibility is condensate, a byproduct of oil and natural gas production. This is a light naphtha boiling range material (liquid) that could be used as a combustion turbine fuel, a petrochemical feedstock(ethylene cracking) or a refinery feedstock. What makes it interesting is that production has increased rather rapidly in the Persian Gulf and price opportunities may exist because of the robust supply situation.

Naphtha is a raw distillation cut from crude oil that boils somewhere between 100 deg. F and 400 deg. F. It can be a light naphtha or full range naphtha (covering a broad boiling range). Naphtha is sold as a feedstock and is used as a petrochemical raw material for ethylene cracking and other uses. Naphtha is also often listed in sets of petroleum price data. This public price data, however, reflects an average price for naphtha that can have a variety of gravities and heat contents at varying prices and needs to be used with caution. The Singapore price data for naphtha shows it to be lower priced than gas oil (diesel), but the Asian naphtha show a higher specific gravity. When the gravity differences between naphtha and diesel are taken into account, the price per BTU is about the same. Since diesel is a final product with defined specifications, it would be the preferred choice over naphtha.

Coal Fuels

Coal is readily available from Australia and South Africa. A price history for coal from these sources is given Table 1 and shown in Figures 5 and 6. While coal and oil products compete in some markets the price of these energy products are driven by very different factors. Coal prices are strongly influenced by the opposing factors of improving production technology, which increases productivity and pushes prices down and increasing wage cost which exerts upward price pressure. There is good technology transfer and coal production costs in the U.S., Australia, and South Africa have exhibited similar trends. Coal prices have declined since 1985 on a current dollar(U.S.) basis but have risen at about 2% on a constant dollar basis.

Figure 5

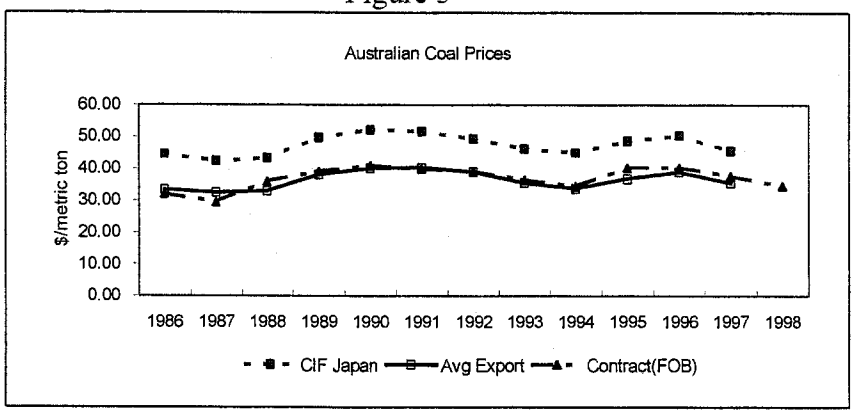


Figure 6

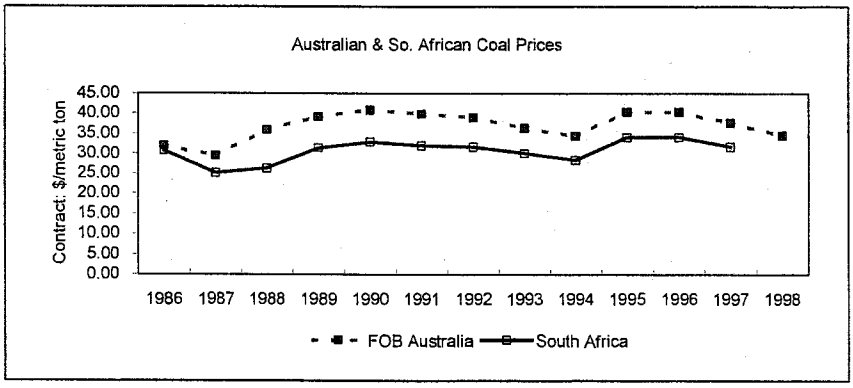


Table 1
Australian Steam Coal Prices

	Japan Avg. Import $/t(CIF)	Australia Avg. Export $/t(FOB)	Australia Contract(1) $/t(FOB)	S. Africa Contract(2) $/t(FOB)
1980	55.41	36.18		
1981	65.61	44.90		
1982	64.86	49.30		
1983	55.92	42.64		
1984	51.11	39.65		
1985	44.40	33.09		32.45
1986	44.44	33.25	31.98	30.73
1987	42.27	32.34	29.40	25.05
1988	43.34	32.90	35.87	26.27
1989	49.78	37.98	39.15	31.33
1990	52.23	40.03	40.85	32.85
1991	51.68	40.32	39.85	31.94
1992	49.29	38.87	38.90	31.67
1993	46.31	35.49	36.35	30.00
1994	44.92	33.71	34.35	28.35
1995	48.87	36.85	40.30	34.05
1996	50.24	38.89	40.30	34.05
1997	45.59	35.42	37.65	31.80
1998			34.50	

Sources: "Coal Information(1998 Edition)" – International Energy Agency
Notes
(1) Contract price is for Benchmark Reference adjusted to 6700 kcal/kg & .5wt% S
(2) Contract price is for Witbankcoal, 6400 kcal/kg & 1.0wt% S
(3) 6700 kcal/kg = 12061 BTU/LB & 6400 kcal/kg = 11521 BTU/LB

Fuel Price Forecast for Mauritius

As has been shown, oil product price trends are primarily related to crude oil price changes. Since 1985 the price trend for crude oil and oil product prices has stayed almost level on a current dollar basis. They have, of course, swung rather dramatically above and below that level price trend line. Most recently we have experienced a downswing in 1998 and into this year. These swings are the result of a cyclical swing from tight supply in 1996 to surplus availability in 1998. The low cost producers with large reserves are mostly members of OPEC, a cartel that is often ineffective in controlling production, especially when demand shifts. Thus OPEC production control, demand changes and new oil finds and production in non-OPEC countries all interact to determine oil market prices.

The methodology used to develop forecasts of fuel prices for Mauritius was to use forecasts of future crude oil and coal prices developed by major forecasting organizations and then estimate

individual oil products based on historic relationships to crude oil. In the final step delivered prices to Mauritius are developed based on K&M's estimate of changes in oil and coal international freight costs.

The price assumptions for K&M's forecasts largely follow the crude oil and coal price forecast projections of the U.S. DOE's "Annual Energy Outlook 1999". The DOE's oil price forecast falls within the range of forecast produced by DRI (DRI/McGraw-Hill), GRI (Gas Research Inst.), WEFA, the International Energy Agency (IEA), Petroleum Economics Ltd. (PEL), Petroleum Industry Research Associates, Inc. (PIRA), and Natural Resources Canada (NRCan). The most recent projections from these organizations that concentrate on petroleum, natural gas, and international oil markets are compared with the DOE projections in Table 2.

As can be seen in the forecast comparison of Table 2 all the forecasts with the exception of PEL show flat or slightly rising oil price forecast. The greatest variation in the forecast can be attributed to the uncertainty of forecasters about the amount of time required for crude oil prices to recover from the depressed market of 1998 when most their forecast were developed. There is no doubt that uncertainty exist in oil price forecasting and perhaps the set of forecasts of Table 2 may understate the potential for oil price rises, since they were developed during a depressed market period when optimism about price growth was very scarce.

Table 2
Forecasts of World Oil Prices (2000-2020)

	1997 dollars per barrel				
Forecast	**2000**	**2005**	**2010**	**2015**	**2020**
DOE reference	13.97	19.25	21.30	21.91	22.73
DRI	15.55	16.94	19.06	21.44	24.13
IEA1	18.49	27.19	27.19	NA	NA
IEA2	18.49	18.49	18.49	NA	NA
PEL	15.57	14.21	13.37	12.93	NA
PIRA	20.00	19.00	19.60	NA	NA
WEFA	18.27	19.04	19.75	20.52	21.32
GRI	17.16	16.86	16.81	17.02	NA
NRCan	20.76	20.76	20.76	20.76	20.76

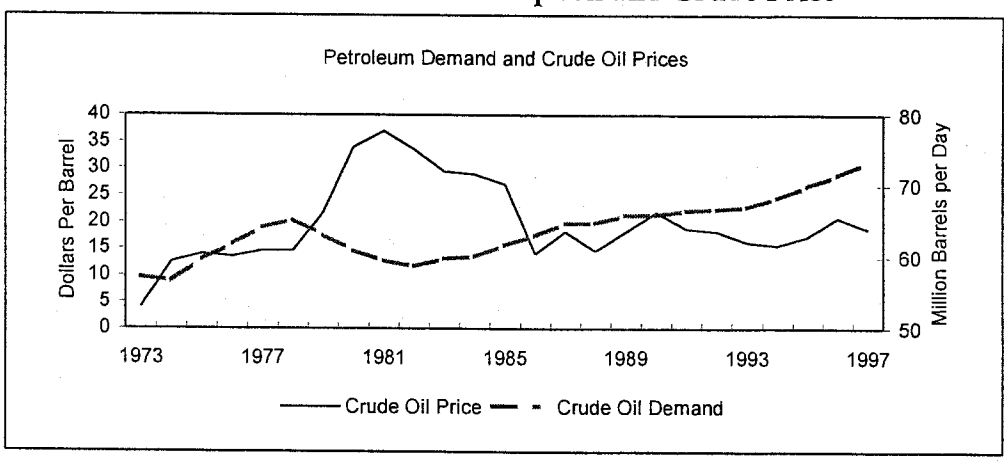
NA = not available.

The forecast of future prices for coal and oil products available as potential power fuels for Mauritius are shown in Table 3. As shown in Table 3 the past patterns for coal and crude oil price growth are forecast to change with oil price growth exceeding coal price growth over the forecast period. On a constant dollar basis coal prices are projected to decline (an average decline of about 1-% per year). The price growth rates for crude oil and coal prices are shown in the upper left corner of Table 3. On a current dollar basis coal prices are projected to rise. Oil prices are forecast to rise on both a constant and current dollar basis. The reason for the oil price trend is that oil demand will rise faster than non-OPEC production and OPEC's surplus production capacity will diminish and there will be greater upward price pressure in the market.

The oil price forecast is for very modest price growth, however, there is a significant probability that higher oil prices could occur. There is much greater price uncertainty with the oil price forecast than with the coal price forecast.

Understanding the basis for the contrast in price forecasts for coal and oil requires a review of historical price behavior and the underlying factors in that price history. For at least the past three decades coal price trends have been the result of combining rising wages and increasing productivity (tons per man day) and the forecast simply extents the historical trends. Crude oil pricing for the past decades is shown in Figure 7. From 1974 to 1979 crude prices rose from 4$/Bbl to 40$/Bbl. The consequence was a major decline in oil demand in the early 1980's and a collapse in crude oil prices. From 1979 to 1985 production and sales volumes for the OPEC oil producers were cut in half. From 1985 until today crude oil prices have fluctuated in the 15-20$/Bbl range. While prices have shown no growth in the 1985-1999 period, important changes have occurred. The large surplus production capacity that existed within OPEC has been substantially diminished. On the other hand improved technology has reduced the cost of finding and producing crude oil in non-OPEC areas. Thus the future forecast are based on the rationale that demand growth will further reduce OPEC's surplus production capacity allowing positive price growth, but improving technology and new production in non-OPEC areas will temper OPEC attempts to increase prices and the result will be a modest price growth. And as the forecast shows price growth in oil is expected to exceed price growth for coal.

Figure 7
Petroleum Consumption and Crude Price



The top section of Table 3 contains the factors used to develop refined product prices from future crude oil prices. First, Singapore prices are estimated based on analysis of our extended price series for crude oil and Singapore refined products(1986-1998). Then PG product prices are estimated from the Singapore prices. Finally delivered prices to Mauritius are estimated by adding freight to PG export prices. The price forecast is restated on a current dollar basis in Table 4.

Table 3 – Fuels Price Forecast For Mauritius Power Project (1997 Dollars)

Forecast Assumptions

	Growth Rates:% Dubai Crude	Growth Rates:% Aust & S Afr Coal	Sngpr Product Prices Relative to Dubai Crude		PG Product Prices Relative to Sngpr Product Prices		Coal Shipping Cost(1997,50dwt):	$/mt
							So. Africa -Mauritius(1500mi)	4.00
							Australia - Mauritius(4000mi)	7.00
			Multiply by		Subtract		Oil Shipping Cost(1997, 30dwt)	$/Bbl
97-00	-1	-2	Singapore K/J	1.43	P. Gulf K/J	1.36	P.G. - Mauritius: Gas Oil	1.47
00-05	1	-2	Singapore Gas Oil	1.31	P. Gulf Gas Oil	1.36	P.G. - Mauritius: K/J	1.39
05-10	1	-1	Sngpr 380 3.5S Resid	0.87	P. Gulf 380 Resid	1.16	P.G. - Mauritius: Resid	0.95
10-15	1.4	-1	For 180 Resid add:$/B		Sing Nap as Frac			
15-20	1.9	-0.5	Sngpr 180-380 Resid	1.11	of Sing Gas Oil	0.787		

Energy Price Forecast: 1997$

	Dubai Crude	Australian Coal	So. African Coal	Sngpr Naphtha	Sngpr Kero/Jet	Sngpr Gas Oil	Sngpr 3.5S FO 180cst	Sngpr 3.5S FO 380cst	Sngpr 3.5S FO 380cst	P. Gulf Propane	P. Gulf Kero/Jet	P. Gulf Gas Oil	P. Gulf 3.5S FO 180cst	P. Gulf 3.5S FO 380cst
	$/B	$/mt	$/mt	$/B	$/B	$/B	$/B	$/B	$/mt	$/mt	$/B	$/B	$/B	$/B
1997	18.00	37.00	32.50	20.26	25.74	23.51	16.80	15.69	100.40	209.6	24.38	22.15	15.64	14.53
2000	17.47	34.82	30.59	19.66	24.98	22.81	16.33	15.22	97.42	203.4	23.62	21.45	15.17	14.06
2005	18.36	31.48	27.65	20.66	26.25	23.97	17.11	16.00	102.39	213.7	24.89	22.61	15.95	14.84
2010	19.29	29.94	26.29	21.71	27.59	25.19	17.92	16.81	107.61	224.6	26.23	23.83	16.76	15.65
2015	20.68	28.47	25.01	23.27	29.57	27.01	19.13	18.02	115.36	240.8	28.21	25.65	17.97	16.86
2020	22.72	27.76	24.39	25.57	32.49	29.67	20.91	19.80	126.74	264.6	31.13	28.31	19.75	18.64

Prices Delivered to Mauritius

1997		44.00	36.50								25.77	23.62	16.59	15.48
2000		41.82	34.59								25.01	22.92	16.12	15.01
2005		38.48	31.65								26.28	24.08	16.90	15.79
2010		36.94	30.29								27.62	25.30	17.71	16.60
2015		35.47	29.01								29.60	27.12	18.92	17.81
2020		34.76	28.39								32.52	29.78	20.70	19.59

Conversion Factors:
Dubai Crude: 7.232 Bbl/MT
LPG(Propane): 21513 BTU/LB(GROSS), 4.223 LB/gal
380cst, 3.5S Resid: 6.4 Bbl/mt, 6.287 million BTU/BBL
180cst, 3.5S Resid: 6.5 Bbl/mt
Naphtha: 9.0 Bbl/mt, 4.63 million BTU/Bbl
Gas Oil: 7.45 Bbl/mt, 5.825 million BTU/BBL
K/J: 7.9 Bbl/mt, 5.67 Million BTU/BBL
Australian Coal: .5wtS, 12601 BTU/LB
South African Coal: 1.0wtS, 11521 BTU/LB

Table 4 – Fuels Price Forecast For Mauritius Power Project (Current Dollars)

Forecast Assumptions

	Growth Rates:% Dubai Crude	Growth Rates:% Aust & S Afr Coal	Sngpr Product Prices Relative to Dubai Crude		PG Product Prices Relative to Sngpr Product Prices		Coal Shipping Cost(1997,50dwt): So. Africa -Mauritius(1500mi) Australia -Mauritius(4000mi)
			Multiply by		Subtract		Oil Shipping Cost(1997, 30dwt)
97-00	-1	-2	Singapore K/J	0.00	P. Gulf K/J	1.36	P.G. - Mauritius: Gas Oil
00-05	1	-2	Singapore Gas Oil	0.00	P. Gulf Gas Oil	1.36	P.G. – Mauritius: K/J
05-10	1	-1	Sngpr 380 3.5S Resid	0.00	P. Gulf 380 Resid	1.16	P.G. – Mauritius: Resid
10-15	1.4	-1	For 180 Resid add:$/B		Sing Nap as Frac		
15-20	1.9	-0.5	Sngpr 180-380 Resid	1.11	of Sing Gas Oil	0.787	

Energy Price Forecast

	Dubai Crude	Australian Coal	So. African Coal	Sngpr Naphtha	Sngpr Kero/Jet	Sngpr Gas Oil	Sngpr 3.5S FO 180cst	Sngpr 3.5S FO 380cst	Sngpr 3.5S FO 380cst	P. Gulf Propane	P. Gulf Kero/Jet	P. Gulf Gas Oil	P. Gulf 3.5S FO 180cst	P. Gulf 3.5S FO 380cst
	$/B	$/mt	$/mt	$/B	$/B	$/B	$/B	$/B	$/mt	$/mt	$/B	$/B	$/B	$/B
1997	18.00	37.00	32.50	20.26	25.74	23.51	16.80	15.69	100.40	209.58	24.38	22.15	15.64	14.53
2000	18.34	36.57	32.12	20.64	26.23	23.95	17.15	15.99	102.31	213.56	24.80	22.52	15.93	14.77
2005	21.55	36.95	32.46	24.25	30.81	28.14	20.08	18.78	120.19	250.89	29.22	26.54	18.72	17.42
2010	25.71	39.89	35.04	28.93	36.76	33.57	23.88	22.40	143.38	299.31	34.95	31.76	22.34	20.86
2015	32.28	44.44	39.03	36.33	46.16	42.16	29.87	28.14	180.06	375.88	44.04	40.03	28.06	26.32
2020	43.29	52.89	46.46	48.71	61.90	56.53	39.84	37.73	241.44	504.01	59.31	53.94	37.63	35.52

Prices Delivered to Mauritius

1997		44.00	36.50								25.77	23.62	16.59	15.48
2000		43.92	36.32								26.26	24.07	16.93	15.76
2005		45.17	37.15								30.85	28.27	19.84	18.53
2010		49.21	40.37								36.80	33.72	23.60	22.12
2015		55.36	45.28								46.21	42.33	29.54	27.81
2020		66.23	54.08								61.96	56.74	39.44	37.33

Inflation Assumptions:

GDP Chain-Type Price Index(1992=100)

1997	1.116
2000	1.172
2005	1.310
2010	1.487
2015	1.742
2020	2.126

Fuel Duties and Taxes and Institutional Issues

Our understanding of the current Mauritius tax and duty on fuels under consideration for power generation is as follows:

Taxes (Sales/VAT)
10% on every fuel, except kerosene and LPG which also have no duty

Duty

Oil, varies with source location	
COMESA countries	18%
Other African countries	55%
Other counties	75%
Coal, varies with source location	
So Africa	15%
Other countries	35%

We understand that the STC transfer price includes the import levy duty. The 1.00 Rs/liter duty shown on CEB fuel price data sheets for fuel oil is an additional (per unit) duty. The 10% Sales/VAT is paid on the price after duty. We also understand that for some Bagasse plants, coal has been exempted from duties.

For an IPP project the Developer and his financiers will require a pass through on fuel costs for the project. Also, clearly any taxes and duties will be added to the tariff for electricity and pass through to the CEB and presumably the ultimate customer.

To measure the impact of taxes and duties on the selection of fuel and technology we will analyze the following two cases in the Technology Selection report.

Case one, the lowest cost alternative, assumes no taxes and no duties on fuel. This case is to achieve the desire to keep electric rates low and select fuel on its own economic merits.

Case two, utilizes reasonably likely supply locations with the current taxes and duties for these supply locations. This case shows some substantial relative differences in duties between fuel and source location and includes the 10% tax.

Oil 75%, likely supply location, Persian Gulf
Coal 15%, likely supply location, South Africa

Taxes and duties are an important source of government revenue and a major policy decision is required concerning this issue.

Supply of Fuel

Current Fuel Supply

Currently most fuel is imported into Mauritius through the State Trading Corporation (STC). STC is part of the Ministry of Industry and Commerce and. Its purpose is to provide Mauritius with a good product at a favorable price. STC buys rice, cement, flour and petroleum products;

gasoline, gas oil (diesel) and kerosene. They arrange for the CST 380 oil for Ft. George procurement and then turn the contract over to CEB for direct procurement.

For oil, STC imports, then sells to four local oil distribution companies who store, blend and distribute to the customers including the CEB. Price ceiling is set by Government considering the CIF, duties, taxes, oil company margin and STC cost. Oil companies can provide discount and manage their own margin.

Before 1983 private companies imported petroleum directly . The Government was concerned about the fairness of prices. Now STC uses annual international tendering process.

The STC buys four petroleum products through this annual tender. Total amount is about 800,000 tonnes:

1. 180 CTS oil for CEB diesel engine generators (70%), ship bunkering and a small amount for factories. Unloading is near Sugar Bulk storage facility. The CEB fuel is used for Ft Victoria and St. Louis stations.
2. Gas oil (for diesel trucks),
3. Gasoline, (for automobiles)
4. Kerosene, for aviation use and CEB's combustion turbines at Nicolay Station.

Fuel unloading and storage is in the general port area, including kerosene. Most fuels are then trucked out of the port area. This is an important constraint. There is a plan to re locate the storage area further from the city at the reclaimed port area. Setting up new company Mauritius Oil Storage Company (MOSCO).

STC have used Kuwait Oil, Mobil, Shell, Elf, Total, Caltex and some smaller companies. They have had good service. They have at least two suppliers each year for diversity. The 380 CST heavy oil supply is special case, one supplier, an older Madagascar refinery supplies the oil, at a very good price. The refinery does not have capacity to supply the Ft. William IPP.

STC reports they could enter into a long-term contract for fuel supply for an IPP, eliminating the local oil distributors as they do with CEB. The contract could be a fixed, renewable annually or indexed type.

CEB buys 380 CTS oil (heavy fuel oil, 3-% S) directly from Mozambique refinery. CEB uses common quay (with coal and fertilizer, "dirty cargoes" on far side of the port). Has its own pipeline (900m) heated and lagged and storage 6 tanks (30,000mt) at Ft. George Station.

Coal and LPG are privately imported. LPG is purchased privately by others; it is not used for electric sector. Coal has been used for 15 years with Bagasse. Coal is from So Africa. Belle Vue and the sugar estates buy their own coal. They recently set up a special company for this purpose.

Fuel Supply for IPP

We have considered two structures for the supply of fuel for the new IPP project.

1. Supply by the developer directly

2. Supply by the STC either directly to the developer similar to CEB or through the local distribution companies

We recommend that the developer be responsible for the fuel supply. The fuel cost is likely to be a pass through in the PPA based on plant efficiency requirements. It is also likely to be indexed to some agreed upon cost index. Competitive pressure through the RFP should provide an acceptable initial price and suitable index.

This supply strategy is in keeping with the conclusion of the World Bank's Energy Sector Review of 1994 and is consistent with current Mauritian policies to introduce additional privatization in the power generation sector through the use of IPP's. The developer could also consider the STC as one of its alternatives for fuel supply.

Given the expected size of the plant and its location, much if not all of the fuel handling facilities will be part of the project, leaving little if any opportunity to utilize existing facilities. Also, if the STC is involved, it should be expected that the Government will need to support their obligations under any fuel supply agreement increasing the Government's obligations and contingent liabilities related to the project.

Relative to the optimum generation mix from a strategic procurement stand point, there are several points to be made. We are not aware of a Government position or strategy on this issue. Earlier more comprehensive reports (JICA, Kennedy & Donkin and the World Bank) have differing emphasis on fuel use and generation expansion. JICA envisions coal plants around the year 2025. K&D don't identify coal. The World Bank has diesel engines as the backbone of the system. The fuels identified here and the technologies selected for further study are generally consistent with and cover the range of these other broader reports. When we complete additional work we will make a recommendation for this particular IPP project that will be based on the particular conditions of this study.

Handling and Storage Requirements for Fuels

Handling and storage requirements are dictated by the size of cargo vessel that must be unloaded. The high quality light products(naphtha, gasoline, jet, and diesel) are shipped in "clean" vessels which are smaller in size that most crude tankers(referred to as "dirty" cargoes and also includes residual fuels). The product tankers are most commonly in the 30-50 thousand DWT size range and may carry more than one cargo in segregated compartments. The maximum size of vessel that can be accommodated in the Mauritius port area for Ft William was reported to be 35,000-40,000dwt and 11-meter draft Data for oil product tankers is given below:

Ship Size	Typical Full Cargoes		Laden Draught	
DWT	tons	000bbls	Ft	meters
20,000	18700	140	30	9.2
30,000	28300	210	35	10.7
50,000	47000	350	39	12.8
70,000	67100	500	42	14.3
90,000	86600	650	47	16.2

Storage tank facilities at the receiving location must be able to receive a full cargo. Since they are not empty at the time of arrival the tank capacity would roughly need to be 1.5-2 times the cargo size to accommodate early or late arrivals.

For coal storage similar considerations exist. Sufficient storage is required to provide a continuity of supply to the plant if there are upsets to the delivery system. Plants often hold a number of days of supply, depending on reliability of the delivery between 30 and about 90.

The IEA requirement for petroleum storage is 90 days for OECD member countries. We understand that CEB is considering meeting this standard for its plants. However, Fort George Station, for one, does not have sufficient land area. We are not aware of any supply problem they have had due to this current storage level. This 90-day requirement appears excessive, expensive and not completely applicable to Mauritius unless some Government agreement has been made. We believe that 45 to 60 days should be sufficient and will use it for the study.

Environmental Issues

Earlier we referred to high quality oil products and lower quality products. The higher quality products have both have better combustion properties and contain much smaller quantities of non-hydrocarbon pollutants that can enter the atmosphere when combusted. From an environmental standpoint methane(primary component of natural gas) is the most attractive environmental fuel. For oil products environmental attractiveness is much poorer with the bottom of the barrel products, such as residual fuel. When crude oil is separated in a refinery by distillation most of the pollutants are concentrated in the heavy high boiling products. More of the sulfur, metals and other non-hydrocarbons are components of the complex higher boiling molecules. Moreover in refinery processing many refineries hydrotreat the kerosene and diesel materials to remove sulfur and improve their quality. Burning residual fuel in power generation has been sharply diminished in many world areas unless the facility is equipped with sophisticated stack gas treatment facilities. The environmental problems of combusting residual fuel are SO2(acid rain and sulfate particulate formation) and soot particulate which can contain poly-aromatic compounds(carcinogenic) and toxic metal contaminants.

Spills in transporting and unloading and storing products is a problem with all products requiring prevention and cleanup procedures to be in place. There are differences in the cleanup problem between oil products that are lighter than water(e.g. diesel and those that are heavier than water(e.g. residual fuel).

Coal storage will have particular considerations for Mauritius including ash disposal, protection from cyclones and heavy rain runoff.

The fuels under consideration should satisfy local and international environmental standards.

Summary

Coal and petroleum fuels are the most feasible choices of fuel for the project. In the Pacific Basin there is a large volume of refined product movements from the export refineries in the Middle East and Singapore. The Pacific Basin markets have large product availability for all refined products from multiple locations.

The economics for a 100 MW scale power facility using LNG is very unlikely to have favorable economics. The reason is that large is scale needed to cover cost of the large special tankers required to deliver LNG, port facilities, storage for the low temperature LNG and regasification facilities.

Security of supply for refined products is not an issue in the region. While obtaining supply volumes of refined products may pose few worries; there are no guaranties on oil prices over the long term. Contracts will be tied to the changes in international crude oil and product spot market indices.

Coal volumes are also readily available in the Pacific Basin. Two of the world's three largest coal exporters are found in the Pacific Basin market region. Australia is the world leading coal exporter, shipping over 7 million metric tons of steam coal per month. South Africa is the third largest coal exporter with about 4.7 million metric tons per day and much of it shipping from the Indian Ocean port of Richard's Bay. As with oil there is large supply volume availability and while fewer suppliers than in the case of oil, there are sufficient suppliers for a competitive marketplace. Coal can be purchased on a long term contract basis and there is much less price volatility than in oil markets.

On a constant dollar basis coal prices are projected to decline (an average decline of about 1% per year). On a current dollar basis coal prices will rise. Oil prices are forecast to rise on both a constant and current dollar basis. The reason for the oil price trend is that oil demand will rise faster than non-OPEC production and OPEC's surplus production capacity will diminish and there will be greater upward price pressure in the market. The oil price forecast is for very modest price growth, however, there is a significant probability that higher oil prices could occur. There is much greater price uncertainty with oil price forecast than with coal price forecast.

For an IPP project the Developer and his financiers will require a pass through on fuel costs for the project. Also, clearly any taxes and duties will be added to the tariff for electricity and pass through to the CEB and presumably the ultimate customer. Taxes and duties are an important source of government revenue and a major policy decision is required concerning this issue.

We recommend that the developer be allowed to supply the fuel directly without being required to use the STC. This supply strategy is in keeping with the conclusion of the World Bank's Energy Sector Review of 1994 and is consistent with current Mauritian policies to introduce

additional privatization in the power generation sector through the use of IPP's. The developer if they so chose could consider the STC as one of his alternatives for fuel supply.

The fuel price forecast will be utilized in the technology selection task to develop the cost of electricity. Two price structures will be utilized, one with duties and taxes and one without. From those costs and other fuel and technology factors an integrated recommendation will be made for fuel and technology selection for the IPP protect.

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Appendix C

Letter Report on Technology Selection – Task 4A

FEASIBILITY STUDY: IPP BASE LOAD POWER STATION

MINISTRY OF PUBLIC UTILITIES, MAURITIUS

POWER PLANT TECHNOLOGY SELECTION

1.0 ALTERNATIVE TECHNOLOGIES

Some of the technologies for power generation that can be considered for the proposed plant are:

(a) Steam power plant

(b) Diesel power plant

(c) Gas turbine power plant, operating on simple cycle

(d) Combined cycle power plant, incorporating gas and steam turbines.

1.1 Steam Power Plant

1.1.1 The main components are a steam generating unit and a steam turbine generator unit, along with their auxiliaries. Almost all types of fossil fuels, including solids such as coal and liquids such as fuel oil, can be burned in the steam generator to produce steam at high pressure and temperature. This steam is then expanded in the steam turbine to do mechanical work, which in turn is converted to electricity in the electric generator. The exhaust steam is condensed under vacuum in a surface-type condenser by cooling water, and the condensate is pumped back to the boiler to complete the cycle. The feed water to the boiler is preheated regeneratively by steam extracted from various intermediate stages of the turbine in heat exchangers (feed water heaters) to improve cycle efficiency. Typical parameters for a unit of the required size range may be as follows:

Steam pressure	:	87 bar (g)
Steam temperature	:	510°C
Condenser pressure	:	50 millibar
No. of extractions	:	5

1.1.2 A steam power plant will be able to utilize coal, which is the cheapest fuel available. Specific design of the steam generating unit will have to be matched with the type of coal expected to be used. A poor quality coal with high content of inert materials (ash), sulfur, etc., may cost less if it is to be transported over short distances from its mine, and a circulating or bubbling type, fluidized bed boiler, may be particularly suitable for using such coal. Most of the sulfur in the coal may be captured in the fuel bed itself by using an adsorbent such as limestone granules as the bed material, and so emissions of both SO_x and NO_x to the atmosphere can be kept to a relatively low level, even when using such a poor quality fuel.

1.1.3 Coal imported to Mauritius is unlikely to be of poor quality, as the additional cost of transportation of its ash content over long distances will add significantly to its cost. Typical sulfur content of coal imported to Mauritius is likely to be 1% or less. A conventional grate or stoker fired boiler will be more appropriate for using such fair to good quality coal in this size range as both its cost and auxiliary power consumption will be less. Pulverized coal firing, in which coal is first ground to a fine powder and then burnt as a suspension in air, can provide slightly better combustion but may not be suitable for the relatively small unit sizes being considered here.

1.1.4 All types of coal-fired boilers will require efficient dust collection equipment at the back end to limit emission of particulates with the flue gases to an acceptably low level. Both bag filters (bag houses) and electrostatic precipitators can be used in this application. Electrostatic precipitators usually provide better particulate removal while requiring very little maintenance for most types of coal. For some special coals with high resistivity ash (usually for coal with very low sulfur) and for smaller units, bag houses may be a more appropriate option.

1.1.5 Appropriate details of the boiler, such as those mentioned above, will have to be finalized only after considering the specific characteristics of the coal to be used. But these details should not have a significant impact on the overall economics of the plant for purposes of comparison with other technologies. A traveling grate type boiler with spreader stoker, along with electro-static precipitator has been considered for the present comparison.

1.2 Diesel Power Plant

1.2.1 These plants use a diesel engine as the prime mover for driving the electric generator. They normally use liquid fuels, though smaller engines can use gaseous fuel also. For the size range required here, the appropriate design would be a slow-speed diesel engine, which provides stable operation at a very high efficiency. These slow-speed diesel engines have the further advantage that they can use the cheaper heavy fuel oils and so can generate electricity at a low cost.

1.2.2 Similar diesel units of up to 30 MW size are already operating satisfactorily in Mauritius at the Fort George Power Plant. A number of 50 MW units are already operating successfully elsewhere, and a 70 MW unit is now becoming available. Such diesel plants may be an attractive option for the present power plant, and has, therefore, been included in this comparison.

1.3 Simple Cycle Gas Turbine Power Plant

Gas turbines are another suitable option for the prime mover to drive the electric generators. In contrast to diesel engines, which produce power only during a part of their operating cycle, gas turbines produce power as a continuous process. As a result, equipment dimensions and space requirements are significantly less for the gas turbines. Both gas and light distillates, such as aviation kerosene (Jet A1) and gas oil, can be used in gas turbines without significant problems. Larger industrial turbines can also burn heavy

fuel oil after suitable pretreatment with slightly reduced rating and more frequent maintenance overhauls. Gas turbine power plants require lowest capital investment and shortest lead time for installation due to their relatively simple plant arrangement. They are also suitable for quick start-ups and rapid load variations. These characteristics make them suitable for peaking applications. But they have the poorest thermal efficiency among the various technology options being considered. For this reason, simple cycle gas turbines are not attractive for base load power plants, and has not been considered as a suitable choice for the present study.

1.4 Combined Cycle Power Plant

1.4.1 Exhaust from a gas turbine carries large amounts of heat energy, which is wasted to atmosphere in a simple cycle plant and this is the reason for relatively poor efficiency of such plants. The exhaust gases are at a sufficiently high temperature to allow its use to generate steam in a waste heat recovery boiler. This steam can then be expanded in a steam turbine to generate more electricity, with no additional fuel consumed. Such combination of gas and steam turbines as an integrated power generation module makes the combined cycle plants one of the most efficient power generation technologies.

1.4.2 Steam turbine portion increases the plant output by approximately 50% of that of the gas turbine alone. A combined cycle module with 2 gas turbines and 1 steam turbine makes all electric generators of approximately same size. Such an arrangement has been considered for the present comparison.

1.4.3 Gas turbine units are available in two basic types: aeroderivatives and industrial types. Aeroderivative types usually have higher thermal efficiencies as they use very high compression ratios and firing temperatures. But these characteristics also require that only gaseous or light distillate fuels can be used in them. Industrial types are of more rugged design and may use lower cycle parameters so that they may be slightly less efficient. But they may be able to utilize the cheaper heavy fuels after suitable treatments (see below). The present comparison has considered such industrial type gas turbines for all the combined cycle options due to its fuel flexibility. But if light distillates are ultimately chosen as the fuel for the proposed power plant, the further advantages of aeroderivative types will need to be looked into.

1.5 Fuel Characteristics

Various types of fuels, which may be used in the proposed power plant, have been discussed in Reference 1. Existing fuel supply infrastructure of Mauritius may not be able to cater for the relatively large fuel requirement of the proposed power station, and a separate arrangement for importing them may be required. Salient characteristics of the fuels considered for the techno-economic comparison of the alternative technologies are summarized below:

	Coal	Jet A1	Fuel Oil	Gas Oil
Type	S. African	Kerosene	380 CST	No. 2 Oil
MMBTU/MT	25.4	44.8	40.96	43.4
Sulfur %	1	0.3	3.5	1
Kilojoules/MT	26.8×10^6	47.2×10^6	43.2×10^6	45.8×10^6

The fuel oil characteristics considered here are similar to the heavy fuel oil now being used in the diesel units at Fort George Power Plant, supplied by a refinery in Madagascar. High levels of various contaminants (Vanadium, Sodium, Ash materials, Sulfur, etc.) present in it will impact the plant cost, maintenance costs and availability of the combined cycle power plants using this fuel, and this has been duly considered in the economic comparisons. However, heavy fuel oil for the proposed power plant will probably have to be sourced from another supplier and therefore may have some differences in its detailed characteristics.

On-site storage capacities of fuel at the plant have been considered to be equal to 60 days of consumption at the base generation level.

1.6 Fuel & Technology Options

Suitability of the above power generation technologies for units of the size being considered with the different fuels is shown in the following table:

	Coal	Fuel Oil	Jet A1	Gas Oil
Steam Plant	Preferred	Yes	Yes	Yes
Diesel Plant	No	Preferred	Yes	Yes
Combined Cycle	No	Yes	Yes	Yes

The following five (5) possible alternatives have, therefore, been taken up for comparison:

1. Coal-fired Steam Power Plant - COAL
2. Heavy fuel oil fired Diesel Plant - DIES
3. Jet A1 fired Combined Cycle Plant - CCJT
4. Heavy fuel oil fired Combined Cycle Plant - CCFO
5. Gas oil fired Combined Cycle Plant - CCGO

2.0 GENERAL COMPARISON

2.1 A gross comparison of the different technologies regarding their energy balances can be summarized in a tabular form. If we assign a value of 100 for the net electric energy output for each of them, these will be as follows:

	Fuel Energy Input	Heat Energy In Cooling Water	Heat Energy In Exhaust Gases
Steam Plant (COAL)	407	200	107
Diesel Plant (DIES)	233	50	83
CCGT (CCJT, CCFO, CCGO)	255	70	85

2.2 Some of the obvious conclusions from this are:

(a) Steam plant will consume most fuel. Other two technologies will require 35% to 40% less fuel inputs. Emission of the combustion products will be proportional to these.

(b) Highest requirement of cooling water will be for the steam plant, which will require almost three times that required for diesel or CCGT plants.

2.3 Another broad comparison that can be made is regarding the requirement of real estate for a plant of the same size. Arranged from the least to highest, these are:

1. Diesel Plant
2. CCGT
3. Steam Plant

Maximum size of the power plant that can be accommodated within a given site area will be in the reverse order as above.

3.0 UNIT SIZE

3.1 In general, economics of power generation improves with the increase of the unit size (so called economy of scale). Maximum generating capacity that can be installed at a given site also increases correspondingly. But the size of the electric system to which the unit is connected limits the maximum unit size permissible.

(a) Sudden tripping of an operating unit must be compensated very quickly by increasing the generation of the other units of the system and load flows are to be redistributed in a smooth manner to avoid unacceptable system upsets which can

jeopardize its stability.

(b) Larger units require correspondingly larger spinning reserves to be maintained during system operation, so that the other units have to be run at part loads at reduced efficiencies. The following of the daily load patterns with efficient sequencing of the units also becomes more difficult.

3.2 While these aspects will actually depend on the specific characteristics of the electric system, this typically puts the upper limit on the unit size at about 10% to 15% of the peak demand on the system. The first units of the proposed plant are scheduled to start operating in 2003/2004 (see 6.0 below). The peak demand on the electric system at that time has been forecasted to be 270-370 MW by CEB (see Tables 5.1 and 5.2). Therefore, maximum desirable size of these units may be considered to be 30 to 50 MW. In a combined cycle plant, tripping of the gas turbine also removes another 50% generation through its steam turbine. So, the maximum size of gas turbines in a CCGT has to be limited to 30 - 35 MW site rating, corresponding to 50 MW block size.

3.3 Based on these considerations, the size of the alternative units have been considered to be as follows:

(a)	Steam and diesel plants (COAL & DIES)	:	50 MW
(b)	CCGT (CCJT, CCFO, & CCGO)	:	50 MW block size, or about 35 MW gas turbines (2 gas turbines and 1 steam turbine for a 100 MW plant)

4.0 ECONOMIC AND FINANCIAL EVALUATION

4.1 Typical Performances & Costs

These are summarized for the different options in Table: 1. The following are explanation of some of the items shown there:

(a) The coal plant has been considered with its least cost option of outdoor coal storage. In order to avoid excessive coal dust emissions during storms, it may be necessary to store the coal under a cover, such as in silos or storage sheds, which will increase its cost. But since this may not be essential for a relatively remote site such as Montagne Jacquots, this cost increase has not been considered in the present comparisons.

(b) To fire heavy fuel oil in internal combustion engines (Option 3 - Diesel Engine, Option 5 - Gas Turbine), it has to be washed with hot water and centrifuged to remove impurities. It also has to be heated to bring down the viscosity to the range needed for firing. To fire in gas turbines, heavy fuel oil needs to be treated in a similar but much more extensive manner. In addition to incombustible suspended matter (ash, tar), it will usually contain significant quantities of sodium, vanadium

etc., which produces deposits on gas turbine internals. Such fouling not only results in rapid loss of efficiency, but also can lead to hot corrosion causing premature failures. Sodium is first removed by washing with hot water along with centrifuging or electrostatic filtration. Result of centrifuging is usually less dependent on the raw fuel quality which can change from batch to batch and may be considered as the base option. Two stages of such washing/centrifuging are expected to be needed to reduce the sodium content to the level suitable for firing in the gas turbines. Suitable inhibitors (magnesium compounds) are then to be injected into it at the required dose to minimize fouling by vanadium compounds, in addition to a reduction of the turbine inlet temperature which will result in a slight derating. Impact of these on costs and performance of the gas turbine units has been included here.

A list of some of the installations where heavy fuel oil is being fired in gas turbines is presented in Appendix 1 for reference.

(c) Even though the plant is intended for base load duty, it is expected to run for significant periods at less than full load, so that its average efficiency will be lower than that a full load. The average load of an operating unit has been assumed to be about 70% and corresponding loss of efficiencies have been estimated to be as follows:

Option	1	2	3	4	5
Percent Reduction	15	5	10	10	10

(d) Capital costs include interest during construction. The expenditures have been considered to be distributed over the construction period as follows:

	Year 1	Year 2	Year 3
Coal (COAL)	20%	40%	40%
Diesel (DIES)	60%	40%	---
CCGT (CCJT, CCFO & CCGO)	40%	60%	---

(e) The annual fixed costs include operation and maintenance labor, general administration, land lease and other miscellaneous expenses.

(f) The consumables cost include costs of water, chemicals, lubricating oil, etc.

(g) First year fuel costs have been taken from Reference 1 and interpolated for the year 2003.

4.2 Generation Level

An important parameter for the proposed plant, which will have a significant impact on the

unit generation cost for the different technologies, is the generation level (KWH/KW) of its units. This is the amount of electrical energy (KWH) to be generated per year for each KW of the installed capacity. This however may change from year to year depending on the electrical demands, available capacity and marginal generation costs of the other units in the system, constraints of the power purchase agreements with the private generators, etc. Techno-economic comparison of alternative technologies for the proposed base-load plant requires an estimate of the generation levels required from it over the period under consideration (22 years). These may be based on an analysis of annual energy contributions from all the units in the system, and estimate for the first few years (up to the year 2010) has been presented in Reference 2 (Annexures I (c) and II (b)). Combining this with the installation sizes for these years gives the corresponding generation levels. For example, for CCFO technology, first phase of installation, for 100 MW net generation capacity, has been proposed in 2004 (see clause 6.0 and Table 5.3 below). The estimated energy generation needed from it in that year is 400 GWH, which translates to a generation level of 4,000 KWH/KW. Next year this increases to 6,000 KWH/KW. When the final module is brought into operation in 2010, the corresponding generation level becomes 4500 KWH/KW for the plant. Therefore a rough estimate for the generation level of the new units for at least the first few years of their operation will be in the range of 4000 to 6000 KWH/KW, and should increase slightly thereafter with the increase of system load. This also matches with the load duration profile for 2001, which shows annual average load factor for the system to be about 63%. An estimate of the energy contributions for the year 2010 on this basis, considering medium growth, may be as follows:

Total Consumption:	3,000	GWH
T&D Losses:	400	GWH
Total Generation Needed	3,400	GWH
Total Private Generation	1,250	GWH
Hydro	90	GWH
Nicolay Peaking	30	GWH
Fort George	680	GWH
Proposed Plant	1,350	GWH

It is possible to carry out such analysis of the expected energy contributions from the various generators of the system on the basis of their marginal generation costs to obtain a detailed estimate of the required generation levels for the years for which reliable data are available. For the life cycle cost analysis, this will have to be done year-by-year for a period of 20 to 30 years. Unfortunately, the long term projections which are to be used become less and less reliable regarding such details, and more over many assumptions will also have to be made regarding both the technical and economic characteristics of the future power plants which will follow this one. As a result, using a single average generation level obtained from these considerations may not provide a good basis for making the required decision.

To avoid such difficulties, comparative economics of the alternative generation technologies have been studied in this report over a wide range of probable average generation levels, and the recommendation has been based on its results. Most probable average generation

level has been considered to be 6,000 KWH/KW, but the range from 4,000 KWH/KW to 7,000 KWH/KW has been studied.

Operation of the new power plant will also be constrained by relatively low night loads of CEB's system. This may become particularly critical during the crop seasons (e.g. May to October) during the lowest demand hours (1 A.M. to 5 A.M. in the morning). A large portion of generation needed to meet these night loads will have to be kept aside for the Sugar Industry due to the contractual obligations with them, leaving only a small amount of power to be generated by CEB's own plants at that time:

	1999		2004		2006		2010	
	I/C	C	I/C	C	I/C	C	I/C	C
Min. Night Load:	102	92	120	108	127	114	143	129
Sugar Industry:								
Present Commitment	24	54.5	54	74.5	54	74.5	54	74.5
Add. Commitment:			8	16	8	16	8	16
Total:	24	54.5	62	90.5	62	90.5	62	90.5
Balance For CEB:	78	37.5	58	17.5	65	23.5	81	38.5

Such minimum generation of CEB may be only about 20 MW in 2004, gradually increasing to slightly above 40 MW in 2010 during these periods. One or two units of either Fort George or the new plant may provide this. For the proposed 50 MW unit/blocks of the new plant, this would require operation at loads as low as 40% of rated capacity. All the alternative technologies being considered for the new plant should be able to operate satisfactorily up to this level of turndown. But the existing diesel units at Fort George are likely to provide more economic generation at such low loads. They should therefore be the preferred choice for this duty, so that the units of the new plant will not be required to be run during such lowest demand periods, at least for the first few years. They may have to be started up and shutdown daily for some periods of the year initially and will have to be suitable for such cyclic duty. All the alternative technologies being considered can accommodate such operational requirement with proper designs. So this consideration may not have a significant impact on the choice among them.

4.3 Basis of Evaluation

Various aspects of the power plant economics are ultimately reflected in the generation cost of electricity. The unit generation cost becomes the single criteria by which alternative power plant options can be compared with each other directly regarding their relative economic advantages. However, the generation cost will change from year to year due to price escalations, even if the plant has been operating in the same manner. These varying generation costs can be represented by a Levelized Generation Cost. Here, the term "levelized" means a constant cost incurred over the time period under consideration, which will have the same Present Value at the time of plant start-up as that of these varying costs. Such levelized generation costs have been estimated for the proposed technology options under different scenarios for the project, as described below.

4.3.1 Time Frame for Evaluation

The plant has been assumed to start-up in the year 2003 for the purpose of this comparison only. Actual requirement for phasing of the units has been discussed in clause 6.0 below. Economics calculations have considered a time period of 22 years after that to match with the terms of typical Power Purchase Agreements.

4.3.2 Financing of Project

The project has been assumed to be financed by 30% equity and 70% debt. The indicative internal rate of return on the equity capital (before taxes) has been taken as 24%. The loan has been assumed to be obtained at 10% annual interest rate with a 10-year term.

4.3.3 Taxes and Duties on Fuel

These (3) alternatives have been considered:

(a) No taxes and duties on the fuels

(b) Tax 1: No taxes or duties on Kerosene (Jet A1). 15% import duty on coal, 75% import duty on gas oil and fuel oil. 10% VAT on coal, gas oil and fuel oil.

(c) Tax 2: Same as Tax 1 above, except that there is no import duty on gas oil and fuel oil.

4.3.4 Discount Rate

Calculations have been made for the following three (3) discount rates for the future cash flows:

(a) 8% per year

(b) 11% per year

(c) 14% per year

4.3.5 Generation Rates

Four (4) alternative annual generation rates have been considered:

(a) 4,000 KWH/KW

(b) 5,000 KWH/KW

(c) 6,000 KWH/KW

(d) 7,000 KWH/KW

The base generation rate mentioned in 4.2 earlier corresponds to (c) above.

4.3.6 Escalations & Fuel Prices

The fuel prices have been taken from Reference 1. South African coal and 380 CST grade fuel oil has been considered for the specific data for coal and fuel oil respectively.

The variable fuel prices as well as the general inflation data for the 22 years of the project period given in Reference 1 have been converted to levelized escalation rates for the three discount rates, and these are presented in Table 2. The first year fuel prices in $/MMBTU (year 2003) including the taxes and duties are also shown in this table.

4.4 Generation Cost Comparisons

Combinations of the above project alternatives give a total of nine (9) economic scenarios for five (5) alternative technologies and four (4) different generation levels, or 180 separate cases. An example of the detailed calculations for one of these cases is presented in Appendix-2, along with an explanation of its calculation steps. In order to perform these calculations such a large number of times and then to present them in a compact form suitable for convenient comparisons, an abbreviated but equivalent procedure has actually been used, which is explained in Appendix-3. Levelized generation costs for the five (5) technology alternatives have been calculated for these scenarios, and the results are presented in Tables 3.1 to 3.3 (total 9 sheets). All plant costs have been shown on per KW of installed capacity basis, considering 300 MW ultimate plant size at this site.

Breakdowns of the generation costs are shown for the base generation rate of 6,000 KWH/KW, in addition to the generation cost summaries for all the four generation rates. These generation costs are also shown as charts in Figures 1.1 to 3.3 (9 sheets) for easy comparison.

The levelized generation costs are least for CCFO for all scenarios with no tax on fuel, which represents the "economic" point of view. The results are similar with the "Tax 2" scenarios also. However for "Tax 1" scenarios, COAL will have the least generation costs for high generation levels and CCJT will have the least generation costs at low generation levels.

The crossover point between the two options moves to higher generation levels with increase of the discount rate (about 4,700 KWH/KW at 8%, increasing to 5,600 KWH/KW at 14%).

Summary of the rankings of the different technology options for all the scenarios according to these levelized generation costs are presented in Table 4. Fuel oil fired combined cycle plant (CCFO) is seen to be the best technology option for the proposed plant, followed by coal-fired steam plant (COAL).

The characteristics of the fuel oil considered for these comparisons are similar to that being used now in the diesel engines of the Fort George power plant. With suitable treatments, this fuel will give an acceptable performance in gas turbines, but there will be penalties on maintenance costs and availability, which have been considered in this analysis. [Note, the base price for heavy fuel oil used in this analysis is based upon the general market forecast included in K&M's Letter Report on Fuel (June 30, 1999), Reference 1]. Lower contaminant levels than these may be more suitable for burning in the gas turbines of the CCFO option, lowering its installation cost slightly. More importantly, it should increase the availability and reduce maintenance costs.

It is preferable that fuel oil for gas turbines should not have Vanadium content of more than 60 PPM, and preferably with lower amounts of Sodium, and Sulfur content of less than 0.5%. Impact on the generation cost of using such a cleaner, but costlier, fuel oil for the proposed combined cycle plant (referred to as CCFO1) and its comparison with CCFO and COAL can be seen in Figure 4.1 and 4.2 for the following typical scenarios:

11% Discount Rate, 30% Equity, No Tax on fuel
5000 KWH/KW Annual Generation : Figure 4.1
6000 KWH/KW Annual Generation : Figure 4.2

Therefore it may be desirable to use such a cleaner fuel for CCFO plant, even at a higher price than the base price of heavy fuel oil considered here. It can be seen that even if such cleaner fuel oil costs up to 40% to 50% more than the base price considered earlier, oil-fired combined cycle plant may still be the most economic choice. A further benefit is that cleaner fuel oil will also have higher availability and lower maintenance cost.

5.0 ENVIRONMENTAL CONSIDERATIONS:

5.1 Technology

A comparison of the options regarding this is summarized in the following table:

	COAL	DIES	CCJT	CCFO	CCGO
Fuel Consumption by WT.	257	91.2	90.9	100	93.8
CO_2 Emission	202	91.2	90	100	93.3
SO_2 Emission	73.3	91.2	7.8	100	27
Cooling water required	285	70	99	100	99

It may be seen that almost two and half times to three times weight of fuel will have to be supplied to the coal-fired plant (COAL) than CCGT/Fuel Oil (CCFO) and the ratio of cooling water requirements for them will also be similar. CO_2 emission of COAL will also be more than double. However, CCFO will emit the highest amount of SO_2. A further comparison of SO_2 emissions for COAL and CCFO are as follows:

	World Bank Guidelines	COAL	CCFO
T/day at 300 MW output	100 max.	73	100
gm/NM^3 in stack gases	5 max.	2.5	2.0

Both of these options will, therefore, meet the World Bank Guidelines for maximum allowable emission of SO_2. A significant difference among the options will be with respect to dust emissions. For all types of power generation technologies, some fine particles of ash, soot, etc., will be present in the gases coming out of the stacks. This will usually be the least with Kerosene & gas oil (CCJT & CCGO), somewhat more with fuel oil (DIES & CCFO), and highest for coal (COAL). But with proper control measures, such as high efficiency dust collector or electro-static precipitator for coal plants, this can be kept to low levels so that this should have little impact on the environment.

Fugitive dust emissions from outdoor storage of coal, coal handling plants, etc., may be a more significant problem. This can be reduced by storing coal indoors (in a hall or silo), but this adds to the plant cost, particularly because they have to withstand heavy storms, which visit Mauritius occasionally. For this reason, it will be preferable to locate coal-burning plants away from dense population areas.

Both solid and liquid fuels will generate some waste products, which will have to be disposed in a safe manner. Burning of coal will produce about 10% by weight of ash. A 300 MW coal-fired plant may produce up to 2 million MT of ash over the project period of

22 years. Coal ash can be utilized as a valuable aggregate material in the construction industry. Balance of ash, which cannot be utilized in this manner or for filling up of low-lying areas, will have to be hauled away to a suitable disposal area by trucks or barges. Since coal ash may contain traces of heavy metals, arsenic and other toxic materials, the ash deposit should be contained by an impervious layer to prevent any leachate to find its way into nearby aquifers. Oil fuels will on the other hand generate waste oils and sludge which may be incinerated at the plant site. Necessary costs for the special installations as well as operations for disposal of these wastes have been included suitably in the economic evaluations.

5.2 Site

When alternative sites for the proposed power plant were compared without reference to any specific technology, Fort William (FW) was judged to be the best choice with that near Montagne Jaquots (MJ) as the next choice. Some of the important aspects of this comparison were:

(a) Definition, survey road access and acquisition of FW are in an advanced stage, while this has not been started yet with MJ. So latter will need more development time and cost.

(b) Construction of heavy foundations will be cheaper but that of sea water intake and discharged for plant cooling will be costlier at MJ compared to FW.

(c) The FW site is near a densely populated neighborhood and is near the National Sugar Terminal, so that air and noise emissions from the power plant will be of more concern there, compared at MJ. Pristine nature of the coast at MJ, however, makes it more sensitive to ecological disruptions from shipping activities and water discharges from the power plant.

(d) Since FW is near a major existing port facility, supplying imported fuel to it will be relatively easy. MJ on the other hand will require either an oil pipeline or a new ship berthing and unloading facility on the coast (particularly for coal), both of which can have significant environmental problems.

(e) Arrangement for power evacuation and connections to the grid will be similar for both sites, and will put similar limits on the maximum size of the power plant at both of them.

(f) Land now available at FW will be inadequate for a 300 MW plant there, which will, therefore, need reclamation of more land from the sea. There are no such restrictions at MJ.

If we combine these considerations with the environmental impact of different types of fuel, discussed above, we can draw the following conclusions:

(a) Fort William will be the best site for an oil-fired power plant, i.e. for all technologies

other than COAL.

(b) Montagne Jaquots will be the best site for a coal-fired power plant provided environmental problems of a ship berthing and coal unloading facility on its coast can be resolved at a reasonable cost. This recommendation has assumed that there will not be unusual construction problems for the marine facilities at this site to increase the plant cost significantly.

6.0 PHASING OF UNITS

6.1 Planning Criteria

In order to meet the demand for electricity of the CEB system in a reliable manner, total dependable installed capacity of their power generating units need to exceed the peak demand with an adequate margin to allow for necessary flexibility of operation.

Margin 1
This is the percent by which the total generating capacity of the system need to exceed the peak demand, with the largest unit (or power block in case of combined cycle plants) out of service. This margin should not normally be less than 20%, but must be at least 5%.

Margin 2
This is similar to above, but considering two of the largest units (or blocks) out of operation at the same time. This should not be less than about 5% to provide the minimum required spinning reserve with one unit on scheduled shutdown for maintenance, and another one on unscheduled shutdown for any fault. This margin should not be negative if supply of electricity has to be maintained with high reliability.

6.2 Required Installations

6.2.1 The latest forecasts for electric demands developed by CEB for their system (Reference 3) predict the expected peak demands considering a "low growth" and a "high growth" scenario. The average of these two predictions (i.e. a "medium growth" scenario) may be considered to be the most probable case. Installations for the proposed plant may be planned to meet this medium growth scenario, while checking for the situation that may arise for the two extreme scenarios.

The installation plan developed as per these considerations for the medium and high growth scenarios are shown in Tables 5.1 and 5.2. However since both of the scenarios may be possible, the recommended installation plan needs to provide comfortable margins for medium growth, while still being able to cope with the high growth scenario without excessive shortfalls. Such recommended installation plan for CCFO is shown in Table 5.3 and in Table 5.4 for COAL. It will be seen that both of them have a 100 MW installation as the first phase in 2004 and a plant size of 300 MW by the year 2010.

6.2.2 The analysis presented in Annexure I (c) of Reference 2 indicates that no significant energy contribution should be necessary from the new plant till the end of the year 2003, at least

for the more likely medium growth scenario. However the margins in the generating capacity will not remain adequate till that time. These margins appear to be quite satisfactory till the end of 2002 for the medium growth projection and acceptable for the high growth scenario. But in the following year, Margin 2 becomes negative even for the medium growth case, indicating that maintenance of the large units may become difficult during the peak demand periods then. To avoid this problem, some additional generating capacity will be needed at that time on a standby basis to allow for possible maintenance outages.

The recommended installation program for the combined cycle plant (CCFO) presented in Table 5.3 provides this standby capacity in that year (2003). The specific combined cycle module configuration considered here will consist of three separate generating units: 2 gas turbines of about 35 MW net capacity each and 1 steam turbine of similar capacity, providing a combined generation about 100 MW net. All 3 of them working together in an integrated manner will be required for operation of the efficient combined cycle module, first one of which has been proposed to be completed in 2004 for being put into base load operation. But the gas turbines will get commissioned in the previous year to provide additional standby capacity to the system. The steam cycle portion of the module will still be under construction, and the new plant should not be operated as a base load plant at that time. But the gas turbine units will be available as standbys to allow maintenance of other units in the system if necessary. Charges for them should be almost entirely for their capacities and not for their energy generations. These capacity charges will be for the capital and fixed O&M costs of the simple cycle gas turbines, which is lowest among all the alternative technologies considered. They should therefore be an economic option for providing the required capacity margin at that time. But the economic analysis presented in this report has completely discounted any capital recovery during this period, which has been included in the construction time of the base load installation.

6.2.3 These conclusions are based on the information currently available regarding dependable capacities and retirement plans of the existing units, and expected additions of other new units in Mauritius during this period. This situation should therefore be reviewed from time to time, and timing of the future phases may have to be updated accordingly at that time.

7.0 CONCLUSIONS

Choice of the optimum technology for the proposed power plant will depend upon several factors, including the capital and operating costs of the plant; the availability, cost and quality of the fuel used to power the plant; and site and environmental considerations. . We have taken these considerations into account in analyzing the optimum technology for this independent power project

The site at Fort Williams will be the best choice for an oil-fired power plant. For a coal-fired power plant, Montagne Jaquots will be a better site, though an oil-fired plant can be located there also if needed.

If a reliable supply of fuel oil with relatively low levels of contaminants (see Section 4.4), not costing more than about 40% higher than the projected price of 380 CST heavy oil can be

arranged, **CCFO** will be the suitable technology. The site already identified by the Ministry of Public Utilities and the CEB at Fort Williams will be suitable for installation of such a power plant.

COAL, i.e. a coal-fired steam power plant, may be a good alternative to the above. A site near Montagne Jaquots will be suitable for such a power plant.

As a third alternative, **DIES**, i.e. a heavy oil fired diesel power plant may also be considered. This is the only fuel and technology combination, among those being considered here, which is already being used successfully on Mauritius in the required unit size range, and is therefore already proven in the context of Mauritius. The Fort Williams site will be appropriate for such an installation.

These choices regarding technologies and sites may be summarized as follows:

Fuel	Technology	Description	Site
Fuel Oil	CCFO	Oil Fired Combined Cycle	Fort Williams
Coal	COAL	Coal Fired Steam Plant	Mt. Jaquots
Fuel Oil	DIES	Diesel Power Plant	Fort Williams

We conclude that all three of the aforementioned technology choices are suitable for an IPP in Mauritius. Our analysis is based on an evaluation of the capital and operating costs for each of these technology options and includes a sensitivity analysis for a higher cost of cleaner fuel oil for the CCFO option. However, we recognize that Mauritius has important choices and considerations regarding the optimal technology, and the availability, cost and quality of fuel. Therefore, the Ministry of Public Utilities and CEB can allow IPP bidders to make proposals on any of the above technology options and allow bidders to make fuel supply arrangements for the IPP. By allowing proposals on any of the above technology options, the MPU and CEB can select the proposal that meets its technical and commercial requirements and offers the least cost tariff.

8.0 REFERENCES

1. Letter Report on Fuel, Fort William Feasibility Study - Milestone 3 (June, 1999)

2. A review of the Power Sector and the Bagasse Energy Development Programme - Report of Technical Committee, Ministry of Public Utilities (January, 1999).

3. Power Market Study, Mauritius Distribution System Study - Tractebel (Draft, January, 1999).

TABLE: 1
OPTIONS FOR POWER GENERATION TECHNOLOGY

ITEM	Unit	COAL	DIES	CCJT	CCFO	CCGO
Technology		Steam Plant	Diesel Engine	Combined Cycle	Combined Cycle	Combined Cycle
Fuel		Coal	Fuel Oil	Kerosine	Fuel Oil	Gas Oil
Auxiliary Power Use	%	8	3	3	4	3
Net Heatrate at rating	BTU/KWH	11795	7550	7810	7850	7810
Average Heatrate	BTU/KWH	13875	7950	8670	8720	8670
Cost Data:						
Initial Capital Cost	$/KW	1450	1550	680	700	685
Annual Fixed Cost ('03)	% of cap. cost	3.4	4	3.2	3.4	3.3
Consumables cost('99)	$/MWH	4	10	3	5	3.5
Fuel Price (2003):						
Without Taxes	$/MMBTU	1.4494	2.7137	5.1014	2.7137	4.5508
Tax 1	$/MMBTU	1.8336	6.3169	5.1014	5.2239	8.7603
Tax 2	$/MMBTU	1.8336	2.9851	5.1014	2.9851	5.0059

Project Period	Year	22
Installation Year		2003
Average Unit Load	%	70
Base Annual Generation	KWH/KW	6000

TABLE: 2

LEVELIZED INFLATION & ESCALATION RATES, %/YEAR

Base Year = 2003

Period = 2003 - 2025

Discount Rate	General	Coal		Fuel Oil			Gas Oil			Jet A1	
		No Tax	Tax 1 & 2	No Tax	Tax 1	Tax 2	No Tax	Tax 1	Tax 2	No Tax	Tax 1 & 2
8%	2.93	1.91	1.91	4.28	4.28	4.28	4.26	4.26	4.26	4.26	4.26
11%	2.87	1.82	1.82	4.20	4.20	4.20	4.18	4.18	4.18	4.18	4.18
14%	2.82	1.74	1.74	4.12	4.12	4.12	4.10	4.10	4.10	4.10	4.10
Base Cost $/MMBTU		1.4494	1.8336	2.7137	5.2239	2.9851	4.5508	8.7603	5.0059	5.1014	5.1014

TABLE: 3.1
LEVELIZED UNIT COST OF GENERATION

SCENARIO 1.1

30% EQUITY FINANCING
Without Taxes
On Fuel

Discount Rate, %/YEAR		8
Interest Rate	%/Year	10
Discount Rate	%/Year	8
General Escalation	%/Year	2.93
Eq. Disc. Rate	Per Year	0.049257

		COAL	DIES	CCJT	CCFO	CCGO
First year fuel prices	$/MMBTU	1.4494	2.7137	5.1014	2.7137	4.5508
Escalation Rate	%/Year	1.91	4.28	4.26	4.28	4.26
Eq. Disc. Rate	Per Year	0.059759	0.035673	0.035872	0.035673	0.035872
COST PER INSTALLED KW						
Annual Debt Service	$/YEAR	165.19	176.58	77.47	79.75	78.04
PW of Debt Costs	$	1108.42	1184.86	519.81	535.10	523.63
Annual Return on Equity	$/YEAR	105.33	112.59	49.39	50.85	49.76
PW of Return on Equity	$	1074.42	1148.52	503.86	518.68	507.57
PW of Capital Costs	$	2182.83	2333.37	1023.67	1053.78	1031.20
First year fuel cost	$/YEAR	120.66	129.44	265.37	141.98	236.73
PW of Fuel Costs	$	1428.73	1870.36	3827.78	2051.52	3414.65
First year consumables	$/YEAR	26.94	67.35	20.20	33.67	23.57
Fixed Costs	$/YEAR	49.3	62	21.76	23.8	22.605
Total O&M	$/YEAR	76.24	129.35	41.96	57.47	46.18
PW Of O&M Costs	$	981.61	1665.40	540.31	740.00	594.54
PW of Total Costs	$	4593.17	5869.13	5391.76	3845.30	5040.39
PW of Generation	KWH	61204.46	61204.46	61204.46	61204.46	61204.46
Unit Cost	C/KWH	7.50	9.59	8.81	6.28	8.24

UNIT COSTS, C/KWH:						
Generation KWH/KW		COAL	DIES	CCJT	CCFO	CCGO
	4000	9.81	12.15	9.87	7.39	9.32
	5000	8.43	10.61	9.24	6.73	8.67
	6000	7.50	9.59	8.81	6.28	8.24
	7000	6.85	8.86	8.51	5.97	7.93

TABLE: 3.1
LEVELIZED UNIT COST OF GENERATION **SCENARIO 1.2**

30% EQUITY FINANCING
Without Taxes
On Fuel

Discount Rate, %/YEAR **11**

Interest Rate	%/Year	10
Discount Rate	%/Year	11
General Escalation	%/Year	2.87
Eq. Disc. Rate	Per Year	0.079032

		COAL	DIES	CCJT	CCFO	CCGO
First year fuel prices	$/MMBTU	1.4494	2.7137	5.1014	2.7137	4.5508
Escalation Rate	%/Year	1.82	4.2	4.18	4.2	4.18
Eq. Disc. Rate	Per Year	0.090159	0.065259	0.065464	0.065259	0.065464
COST PER INSTALLED KW						
Annual Debt Service	$/YEAR	165.19	176.58	77.47	79.75	78.04
PW of Debt Costs	$	972.82	1039.91	456.22	469.64	459.57
Annual Return on Equity	$/YEAR	105.33	112.59	49.39	50.85	49.76
PW of Return on Equity	$	861.13	920.52	403.84	415.72	406.81
PW of Capital Costs	$	1833.95	1960.43	860.06	885.36	866.38
First year fuel cost	$/YEAR	120.66	129.44	265.37	141.98	236.73
PW of Fuel Costs	$	1117.64	1429.82	2926.80	1568.31	2610.90
First year consumables	$/YEAR	26.88	67.19	20.16	33.60	23.52
Fixed Costs	$/YEAR	49.3	62	21.76	23.8	22.605
Total O&M	$/YEAR	76.18	129.19	41.92	57.40	46.12
PW Of O&M Costs	$	761.19	1290.94	418.86	573.52	460.87
PW of Total Costs	$	3712.78	4681.19	4205.71	3027.19	3938.16
PW of Generation	KWH	49054.43	49054.43	49054.43	49054.43	49054.43
Unit Cost	C/KWH	7.57	9.54	8.57	6.17	8.03

UNIT COSTS, C/KWH:

Generation KWH/KW		COAL	DIES	CCJT	CCFO	CCGO
	4000	9.94	12.17	9.67	7.32	9.14
	5000	8.52	10.59	9.01	6.63	8.47
	6000	7.57	9.54	8.57	6.17	8.03
	7000	6.89	8.79	8.26	5.84	7.71

TABLE: 3.1
LEVELIZED UNIT COST OF GENERATION

SCENARIO 1.3

30% EQUITY FINANCING
Without Taxes
On Fuel

Discount Rate, %/YEAR		**14**
Interest Rate	%/Year	10
Discount Rate	%/Year	14
General Escalation	%/Year	2.82
Eq. Disc. Rate	Per Year	0.108734

		COAL	DIES	CCJT	CCFO	CCGO
First year fuel prices	$/MMBTU	1.4494	2.7137	5.1014	2.7137	4.5508
Escalation Rate	%/Year	1.74	4.12	4.1	4.12	4.1
Eq. Disc. Rate	Per Year	0.120503	0.094891	0.095101	0.094891	0.095101
COST PER INSTALLED KW						
Annual Debt Service	$/YEAR	165.19	176.58	77.47	79.75	78.04
PW of Debt Costs	$	861.63	921.06	404.08	415.96	407.05
Annual Return on Equity	$/YEAR	105.33	112.59	49.39	50.85	49.76
PW of Return on Equity	$	710.22	759.20	333.07	342.86	335.52
PW of Capital Costs	$	1571.85	1680.25	737.14	758.82	742.56
First year fuel cost	$/YEAR	120.66	129.44	265.37	141.98	236.73
PW of Fuel Costs	$	903.66	1131.85	2317.28	1241.48	2067.17
First year consumables	$/YEAR	26.82	67.06	20.12	33.53	23.47
Fixed Costs	$/YEAR	49.3	62	21.76	23.8	22.605
Total O&M	$/YEAR	76.12	129.06	41.88	57.33	46.08
PW Of O&M Costs	$	610.61	1035.22	335.91	459.85	369.58
PW of Total Costs	$	3086.12	3847.32	3390.33	2460.15	3179.32
PW of Generation	KWH	40457.67	40457.67	40457.67	40457.67	40457.67
Unit Cost	C/KWH	7.63	9.51	8.38	6.08	7.86

UNIT COSTS, C/KWH:

Generation KWH/KW		COAL	DIES	CCJT	CCFO	CCGO
	4000	10.06	12.20	9.51	7.25	9.00
	5000	8.60	10.59	8.83	6.55	8.32
	6000	7.63	9.51	8.38	6.08	7.86
	7000	6.93	8.74	8.06	5.75	7.53

TABLE: 3.2
LEVELIZED UNIT COST OF GENERATION

SCENARIO 2.1

30% EQUITY FINANCING
With Taxes (TAX 1)
On Fuel

Discount Rate, %/YEAR		8
Interest Rate	%/Year	10
Discount Rate	%/Year	8
General Escalation	%/Year	2.93
Eq. Disc. Rate	Per Year	0.049257

		COAL	DIES	CCJT	CCFO	CCGO
First year fuel prices	$/MMBTU	1.8336	6.3169	5.1014	5.2239	8.7603
Escalation Rate	%/Year	1.91	3.68	4.26	4.28	4.26
Eq. Disc. Rate	Per Year	0.059759	0.041667	0.035872	0.035673	0.035872
COST PER INSTALLED KW						
Annual Debt Service	$/YEAR	165.19	176.58	77.47	79.75	78.04
PW of Debt Costs	$	1108.42	1184.86	519.81	535.10	523.63
Annual Return on Equity	$/YEAR	105.33	112.59	49.39	50.85	49.76
PW of Return on Equity	$	1074.42	1148.52	503.86	518.68	507.57
PW of Capital Costs	$	2182.83	2333.37	1023.67	1053.78	1031.20
First year fuel cost	$/YEAR	152.65	301.32	265.37	273.31	455.71
PW of Fuel Costs	$	1807.46	4133.68	3827.78	3949.19	6573.20
First year consumables	$/YEAR	26.94	67.35	20.20	33.67	23.57
Fixed Costs	$/YEAR	49.3	62	21.76	23.8	22.605
Total O&M	$/YEAR	76.24	129.35	41.96	57.47	46.18
PW Of O&M Costs	$	981.61	1665.40	540.31	740.00	594.54
PW of Total Costs	$	4971.89	8132.45	5391.76	5742.97	8198.95
PW of Generation	KWH	61204.46	61204.46	61204.46	61204.46	61204.46
Unit Cost	C/KWH	8.12	13.29	8.81	9.38	13.40

UNIT COSTS, C/KWH:

Generation KWH/KW		COAL	DIES	CCJT	CCFO	CCGO
	4000	10.43	15.85	9.87	10.49	14.48
	5000	9.04	14.31	9.24	9.83	13.83
	6000	8.12	13.29	8.81	9.38	13.40
	7000	7.47	12.56	8.51	9.07	13.09

TABLE: 3.2
LEVELIZED UNIT COST OF GENERATION

SCENARIO 2.2

30% EQUITY FINANCING
With Taxes (TAX 1)
On Fuel

Discount Rate, %/YEAR		11
Interest Rate	%/Year	10
Discount Rate	%/Year	11
General Escalation	%/Year	2.87
Eq. Disc. Rate	Per Year	0.079032

		COAL	DIES	CCJT	CCFO	CCGO
First year fuel prices	$/MMBTU	1.8336	6.3169	5.1014	5.2239	8.7603
Escalation Rate	%/Year	1.82	3.6	4.18	4.2	4.18
Eq. Disc. Rate	Per Year	0.090159	0.071429	0.065464	0.065259	0.065464
COST PER INSTALLED KW						
Annual Debt Service	$/YEAR	165.19	176.58	77.47	79.75	78.04
PW of Debt Costs	$	972.82	1039.91	456.22	469.64	459.57
Annual Return on Equity	$/YEAR	105.33	112.59	49.39	50.85	49.76
PW of Return on Equity	$	861.13	920.52	403.84	415.72	406.81
PW of Capital Costs	$	1833.95	1960.43	860.06	885.36	866.38
First year fuel cost	$/YEAR	152.65	301.32	265.37	273.31	455.71
PW of Fuel Costs	$	1413.90	3179.36	2926.80	3019.01	5026.00
First year consumables	$/YEAR	26.88	67.19	20.16	33.60	23.52
Fixed Costs	$/YEAR	49.3	62	21.76	23.8	22.605
Total O&M	$/YEAR	76.18	129.19	41.92	57.40	46.12
PW Of O&M Costs	$	761.19	1290.94	418.86	573.52	460.87
PW of Total Costs	$	4009.04	6430.73	4205.71	4477.89	6353.25
PW of Generation	KWH	49054.43	49054.43	49054.43	49054.43	49054.43
Unit Cost	C/KWH	8.17	13.11	8.57	9.13	12.95

UNIT COSTS, C/KWH:

Generation KWH/KW		COAL	DIES	CCJT	CCFO	CCGO
	4000	10.54	15.74	9.67	10.27	14.06
	5000	9.12	14.16	9.01	9.59	13.40
	6000	8.17	13.11	8.57	9.13	12.95
	7000	7.50	12.36	8.26	8.80	12.63

TABLE: 3.2
LEVELIZED UNIT COST OF GENERATION

SCENARIO 2.3

30% EQUITY FINANCING
With Taxes (TAX 1)
On Fuel

Discount Rate, %/YEAR		14
Interest Rate	%/Year	10
Discount Rate	%/Year	14
General Escalation	%/Year	2.82
Eq. Disc. Rate	Per Year	0.108734

		COAL	DIES	CCJT	CCFO	CCGO
First year fuel prices	$/MMBTU	1.8336	6.3169	5.1014	5.2239	8.7603
Escalation Rate	%/Year	1.74	3.52	4.1	4.12	4.1
Eq. Disc. Rate	Per Year	0.120503	0.101236	0.095101	0.094891	0.095101
COST PER INSTALLED KW						
Annual Debt Service	$/YEAR	165.19	176.58	77.47	79.75	78.04
PW of Debt Costs	$	861.63	921.06	404.08	415.96	407.05
Annual Return on Equity	$/YEAR	105.33	112.59	49.39	50.85	49.76
PW of Return on Equity	$	710.22	759.20	333.07	342.86	335.52
PW of Capital Costs	$	1571.85	1680.25	737.14	758.82	742.56
First year fuel cost	$/YEAR	152.65	301.32	265.37	273.31	455.71
PW of Fuel Costs	$	1143.20	2530.58	2317.28	2389.85	3979.31
First year consumables	$/YEAR	26.82	67.06	20.12	33.53	23.47
Fixed Costs	$/YEAR	49.3	62	21.76	23.8	22.605
Total O&M	$/YEAR	76.12	129.06	41.88	57.33	46.08
PW Of O&M Costs	$	610.61	1035.22	335.91	459.85	369.58
PW of Total Costs	$	3325.65	5246.04	3390.33	3608.53	5091.46
PW of Generation	KWH	40457.67	40457.67	40457.67	40457.67	40457.67
Unit Cost	C/KWH	8.22	12.97	8.38	8.92	12.58

UNIT COSTS, C/KWH:

Generation KWH/KW		COAL	DIES	CCJT	CCFO	CCGO
	4000	10.65	15.66	9.51	10.09	13.73
	5000	9.19	14.04	8.83	9.39	13.04
	6000	8.22	12.97	8.38	8.92	12.58
	7000	7.53	12.20	8.06	8.58	12.26

TABLE: 3.3
LEVELIZED UNIT COST OF GENERATION

SCENARIO 3.1

30% EQUITY FINANCING
With Taxes (TAX 2)
On Fuel

Discount Rate, %/YEAR		8
Interest Rate	%/Year	10
Discount Rate	%/Year	8
General Escalation	%/Year	2.93
Eq. Disc. Rate	Per Year	0.049257

		COAL	DIES	CCJT	CCFO	CCGO
First year fuel prices	$/MMBTU	1.8336	2.9851	5.1014	2.9851	5.0059
Escalation Rate	%/Year	1.91	4.28	4.26	4.28	4.26
Eq. Disc. Rate	Per Year	0.059759	0.035673	0.035872	0.035673	0.035872
COST PER INSTALLED KW						
Annual Debt Service	$/YEAR	165.19	176.58	77.47	79.75	78.04
PW of Debt Costs	$	1108.42	1184.86	519.81	535.10	523.63
Annual Return on Equity	$/YEAR	105.33	112.59	49.39	50.85	49.76
PW of Return on Equity	$	1074.42	1148.52	503.86	518.68	507.57
PW of Capital Costs	$	2182.83	2333.37	1023.67	1053.78	1031.20
First year fuel cost	$/YEAR	152.65	142.39	265.37	156.18	260.41
PW of Fuel Costs	$	1807.46	2057.42	3827.78	2256.69	3756.13
First year consumables	$/YEAR	26.94	67.35	20.20	33.67	23.57
Fixed Costs	$/YEAR	49.3	62	21.76	23.8	22.605
Total O&M	$/YEAR	76.24	129.35	41.96	57.47	46.18
PW Of O&M Costs	$	981.61	1665.40	540.31	740.00	594.54
PW of Total Costs	$	4971.89	6056.19	5391.76	4050.47	5381.87
PW of Generation	KWH	61204.46	61204.46	61204.46	61204.46	61204.46
Unit Cost	C/KWH	8.12	9.90	8.81	6.62	8.79

UNIT COSTS, C/KWH:

Generation KWH/KW		COAL	DIES	CCJT	CCFO	CCGO
	4000	10.43	12.45	9.87	7.73	9.87
	5000	9.04	10.92	9.24	7.06	9.23
	6000	8.12	9.90	8.81	6.62	8.79
	7000	7.47	9.16	8.51	6.30	8.48

TABLE: 3.3
LEVELIZED UNIT COST OF GENERATION

SCENARIO 3.2

30% EQUITY FINANCING
With Taxes (TAX 2)
On Fuel

Discount Rate, %/YEAR		11
Interest Rate	%/Year	10
Discount Rate	%/Year	11
General Escalation	%/Year	2.87
Eq. Disc. Rate	Per Year	0.079032

		COAL	DIES	CCJT	CCFO	CCGO
First year fuel prices	$/MMBTU	1.8336	2.9851	5.1014	2.9851	5.0059
Escalation Rate	%/Year	1.82	4.2	4.18	4.2	4.18
Eq. Disc. Rate	Per Year	0.090159	0.065259	0.065464	0.065259	0.065464
COST PER INSTALLED KW						
Annual Debt Service	$/YEAR	165.19	176.58	77.47	79.75	78.04
PW of Debt Costs	$	972.82	1039.91	456.22	469.64	459.57
Annual Return on Equity	$/YEAR	105.33	112.59	49.39	50.85	49.76
PW of Return on Equity	$	861.13	920.52	403.84	415.72	406.81
PW of Capital Costs	$	1833.95	1960.43	860.06	885.36	866.38
First year fuel cost	$/YEAR	152.65	142.39	265.37	156.18	260.41
PW of Fuel Costs	$	1413.90	1572.82	2926.80	1725.16	2872.01
First year consumables	$/YEAR	26.88	67.19	20.16	33.60	23.52
Fixed Costs	$/YEAR	49.3	62	21.76	23.8	22.605
Total O&M	$/YEAR	76.18	129.19	41.92	57.40	46.12
PW Of O&M Costs	$	761.19	1290.94	418.86	573.52	460.87
PW of Total Costs	$	4009.04	4824.19	4205.71	3184.04	4199.26
PW of Generation	KWH	49054.43	49054.43	49054.43	49054.43	49054.43
Unit Cost	C/KWH	8.17	9.83	8.57	6.49	8.56

UNIT COSTS, C/KWH:

Generation KWH/KW		COAL	DIES	CCJT	CCFO	CCGO
	4000	10.54	12.46	9.67	7.64	9.67
	5000	9.12	10.89	9.01	6.95	9.01
	6000	8.17	9.83	8.57	6.49	8.56
	7000	7.50	9.08	8.26	6.16	8.24

TABLE: 3.3
LEVELIZED UNIT COST OF GENERATION

SCENARIO 3.3

30% EQUITY FINANCING
With Taxes (TAX 2)
On Fuel

Discount Rate, %/YEAR		**14**
Interest Rate	%/Year	10
Discount Rate	%/Year	14
General Escalation	%/Year	2.82
Eq. Disc. Rate	Per Year	0.108734

		COAL	DIES	CCJT	CCFO	CCGO
First year fuel prices	$/MMBTU	1.8336	2.9851	5.1014	2.9851	5.0059
Escalation Rate	%/Year	1.74	4.12	4.1	4.12	4.1
Eq. Disc. Rate	Per Year	0.120503	0.094891	0.095101	0.094891	0.095101
COST PER INSTALLED KW						
Annual Debt Service	$/YEAR	165.19	176.58	77.47	79.75	78.04
PW of Debt Costs	$	861.63	921.06	404.08	415.96	407.05
Annual Return on Equity	$/YEAR	105.33	112.59	49.39	50.85	49.76
PW of Return on Equity	$	710.22	759.20	333.07	342.86	335.52
PW of Capital Costs	$	1571.85	1680.25	737.14	758.82	742.56
First year fuel cost	$/YEAR	152.65	142.39	265.37	156.18	260.41
PW of Fuel Costs	$	1143.20	1245.05	2317.28	1365.64	2273.90
First year consumables	$/YEAR	26.82	67.06	20.12	33.53	23.47
Fixed Costs	$/YEAR	49.3	62	21.76	23.8	22.605
Total O&M	$/YEAR	76.12	129.06	41.88	57.33	46.08
PW Of O&M Costs	$	610.61	1035.22	335.91	459.85	369.58
PW of Total Costs	$	3325.65	3960.51	3390.33	2584.32	3386.05
PW of Generation	KWH	40457.67	40457.67	40457.67	40457.67	40457.67
Unit Cost	C/KWH	8.22	9.79	8.38	6.39	8.37

UNIT COSTS, C/KWH:

Generation KWH/KW		COAL	DIES	CCJT	CCFO	CCGO
	4000	10.65	12.48	9.51	7.56	9.51
	5000	9.19	10.87	8.83	6.86	8.83
	6000	8.22	9.79	8.38	6.39	8.37
	7000	7.53	9.02	8.06	6.05	8.04

TABLE: 4

ECONOMIC RANKING OF TECHNOLOGY OPTIONS FOR DIFFERENT PROJECT SCENARIOS

PROJECT SCENARIOS			TECHNOLOGY OPTIONS				
Fuel Tax	Discount	KWH/KW	COAL	DIES	CCJT	CCFO	CCGO
No Tax	8%	4000	3	4	3	1	2
"	"	5000	2	5	4	1	3
"	"	6000	2	5	4	1	3
"	"	7000	2	5	4	1	3
"	11%	4000	4	5	3	1	2
"	"	5000	3	5	4	1	2
"	"	6000	2	5	4	1	3
"	"	7000	2	5	4	1	3
"	14%	4000	4	5	3	1	2
"	"	5000	3	5	4	1	2
"	"	6000	2	5	4	1	3
"	"	7000	2	5	4	1	3
Tax 1	8%	4000	2	5	1	3	4
"	"	5000	1	5	2	3	4
"	"	6000	1	4	2	3	5
"	"	7000	1	4	2	3	5
"	11%	4000	3	5	1	2	4
"	"	5000	1	5	2	3	4
"	"	6000	1	5	2	3	4
"	"	7000	1	4	2	3	5
"	14%	4000	3	5	1	2	4
"	"	5000	2	5	1	3	4
"	"	6000	1	5	2	3	4
"	"	7000	1	4	2	3	5
Tax 2	8%	4000	4	5	2	1	3
"	"	5000	2	5	4	1	3
"	"	6000	2	5	4	1	3
"	"	7000	2	5	4	1	3
"	11%	4000	4	5	2	1	3
"	"	5000	4	5	3	1	2
"	"	6000	2	5	4	1	3
"	"	7000	2	5	4	1	3
"	14%	4000	4	5	2	1	3
"	"	5000	4	5	3	1	2
"	"	6000	2	5	4	1	3
"	"	7000	2	5	4	1	3
RANKING SUMMARY:							
Total Of Ranks			83	175	105	58	117
Number Of Times Ranked 1			8	0	4	24	0

TABLE: 5.1
INSTALLATIONS REQUIRED AT THE NEW PLANT FOR COMBINED CYCLE UNITS: MEDIUM GROWTH SCENARIO

	2001		2002		2003		2004		2005		2006		2007		2008		2009		2010	
	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C
CAPACITY, MW																				
New Plant	0	0	0	0	0	35	70	100	100	100	100	100	100	135	170	200	200	200	200	235
Others																				
CEB																				
St. Louis	40	40	40	40	20	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0
Ft. Victoria I	9	9	9	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ft. Victoria II	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Ft. George	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Nicolay	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Hydro	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15
Total	297	282	297	277	272	253	268	253	268	253	268	253	268	233	248	233	248	233	248	233
Private																				
F.U.E.L.	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20
Beau Champ	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14
Belle-Vue	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46
Continuous	0	39	0	39	0	39	0	39	0	30	0	30	0	18	0	18	0	18	0	18
Bagasse/Coal #2	0	0	0	0	0	0	0	0	0	27	36	27	36	27	36	27	36	27	36	27
Bagasse/Coal #3	0	0	0	0	0	0	0	0	0	0	0	0	0	46	62	46	62	46	62	46
SIC/SIDEC (Coal)	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Total	111	119	111	149	141	149	141	149	141	167	177	167	177	201	239	201	239	201	239	201
Grand Total	408	401	408	426	413	402	409	402	409	420	445	420	445	434	487	434	487	434	487	434
Total System (1)	408	401	408	426	413	437	479	502	509	520	545	520	545	569	657	634	687	634	687	669
Largest Unit/Block (b)	34	34	34	34	34	35	35	50	50	50	50	50	50	50	50	50	50	50	50	50
Next Largest ©	30	30	30	30	30	34	35	50	50	50	50	50	50	50	50	50	50	50	50	50
Firm Cap (d)(1-b)	374	367	374	392	379	402	444	452	459	470	495	470	495	519	607	584	637	584	637	619
Cap for Maint (e)(d-c)	344	337	344	362	349	368	409	402	409	420	445	420	445	469	557	534	587	534	587	569
Non Oil Capacity, %	34.6	33.4	34.6	38.5	41.4	37.5	35.7	32.7	33.6	35	38	35	38	38	40.9	34.1	39.2	34.1	39.2	32.3
Peak Demand (a)	290	300	305	315	321	331	340	350	362	372	389	399	419	429	452	462	489	499	529	539
Largest as % of (a)	11.7	11.3	11.2	10.8	10.6	10.6	10.3	14.3	13.8	13.4	12.9	12.5	11.9	11.7	11.1	10.8	10.2	10.0	9.5	9.3
Margin 1 (d/a-1)%	29.0	22.3	22.8	24.6	18.1	21.5	30.8	29.3	26.8	26.3	27.4	17.9	18.1	21.0	34.3	26.4	30.4	17.2	20.5	14.9
Margin 2 (e/a-1)%	18.6	12.3	13.0	15.1	8.7	11.2	20.5	15.0	13.0	12.9	14.5	5.4	6.2	9.3	23.2	15.6	20.2	7.1	11.1	5.7

TABLE: 5.2

INSTALLATIONS REQUIRED AT THE NEW PLANT FOR COMBINED CYCLE UNITS: HIGH GROWTH SCENARIO

	2001		2002		2003		2004		2005		2006		2007		2008		2009		2010	
	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C
CAPACITY, MW																				
New Plant	0	35	70	100	100	100	135	170	200	200	200	200	200	200	200	235	270	300	300	300
Others																				
CEB																				
St. Louis	40	40	40	40	20	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0
Ft. Victoria I	9	9	9	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ft. Victoria II	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Ft. George	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Nicolay	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Hydro	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15
Total	297	282	297	277	272	253	268	253	268	253	268	253	268	233	248	233	248	233	248	233
Private																				
F.U.E.L.	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20
Beau Champ	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14
Belle-Vue	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46
Continuous	0	39	0	39	0	39	0	39	0	30	0	30	0	18	0	18	0	18	0	18
Bagasse/Coal #2	0	0	0	0	0	0	0	0	0	27	36	27	36	27	36	27	36	27	36	27
Bagasse/Coal #3	0	0	0	0	0	0	0	0	0	0	0	0	0	46	62	46	62	46	62	46
SIC/SIDEC (Coal)	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Total	111	119	111	149	141	149	141	149	141	167	177	167	177	201	239	201	239	201	239	201
Grand Total	408	401	408	426	413	402	409	402	409	420	445	420	445	434	487	434	487	434	487	434
Total System (1)	408	436	478	526	513	502	544	572	609	620	645	620	645	634	687	669	757	734	787	734
Largest Unit/Block (b)	34	35	35	50	35	35	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Next Largest ©	30	34	35	50	34	35	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Firm Cap (d)(1-b)	374	401	443	476	478	467	494	522	559	570	595	570	595	584	637	619	707	684	737	684
Cap for Maint (e)(d-c)	344	367	408	426	444	432	444	472	509	520	545	520	545	534	587	569	657	634	687	634
Non Oil Capacity, %	34.6	30.7	29.5	31.2	33.3	32.7	31.4	28.7	28.1	29.4	32.1	29.4	32.1	34.1	39.2	32.3	35.5	29.4	34.2	29.4
Peak Demand (a)	334	344	352	362	373	383	396	406	424	434	457	467	495	505	536	546	582	592	632	642
Largest as % of (a)	10.2	10.2	9.9	13.8	9.4	9.1	12.6	12.3	11.8	11.5	10.9	10.7	10.1	9.9	9.3	9.2	8.6	8.4	7.9	7.8
Margin 1 (d/a-1)%	12.0	16.6	25.9	31.5	28.2	21.9	24.7	28.6	31.8	31.3	30.2	22.1	20.2	15.6	18.8	13.4	21.5	15.5	16.6	6.5
Margin 2 (e/a-1)%	3.0	6.7	15.9	17.7	19.0	12.8	12.1	16.3	20.0	19.8	19.3	11.3	10.1	5.7	9.5	4.2	12.9	7.1	8.7	-1.2

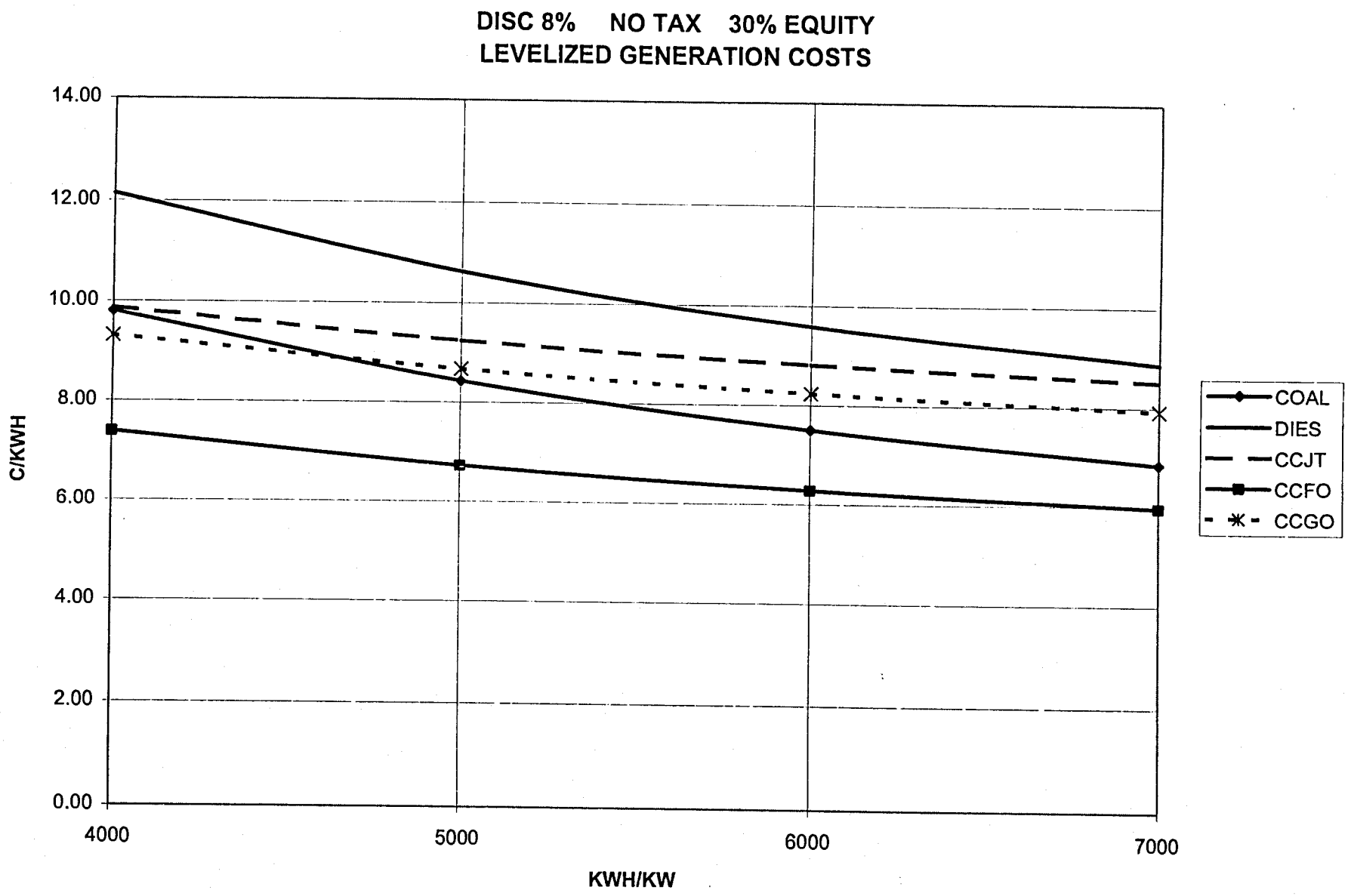
TABLE: 5.3
RECOMMENDED INSTALLATIONS AT THE NEW PLANT FOR COMBINED CYCLE UNITS

	2001		2002		2003		2004		2005		2006		2007		2008		2009		2010		
	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	
CAPACITY, MW																					
New Plant	0	0	0	0	35	70	100	100	100	100	100	135	170	200	200	200	200	235	270	300	
Others																					
CEB																					
St. Louis	40	40	40	40	20	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0	
Ft. Victoria I	9	9	9	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Ft. Victoria II	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	
Ft. George	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	
Nicolay	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	
Hydro	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	
Total	297	282	297	277	272	253	268	253	268	253	268	253	268	233	248	233	248	233	248	233	
Private																					
F.U.E.L.	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	
Beau Champ	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	
Belle-Vue	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	
Continuous	0	39	0	39	0	39	0	39	0	30	0	30	0	18	0	18	0	18	0	18	
Bagasse/Coal #2	0	0	0	0	0	0	0	0	0	27	36	27	36	27	36	27	36	27	36	27	
Bagasse/Coal #3	0	0	0	0	0	0	0	0	0	0	0	0	0	46	62	46	62	46	62	46	
SIC/SIDEC (Coal)	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
Total	111	119	111	149	141	149	141	149	141	167	177	167	177	201	239	201	239	201	239	201	
Grand Total	408	401	408	426	413	402	409	402	409	420	445	420	445	434	487	434	487	434	487	434	
Total System (1)	408	401	408	426	448	472	509	502	509	520	545	555	615	634	687	634	687	669	757	734	
Largest Unit/Block (b)	34	34	34	34	35	35	50	50	50	50	50	50	50	50	50	50	50	50	50	50	
Next Largest ©	30	30	30	30	34	35	50	50	50	50	50	50	50	50	50	50	50	50	50	50	
Firm Cap (d)(1-b)	374	367	374	392	413	437	459	452	459	470	495	505	565	584	637	584	637	619	707	684	
Cap for Maint (e)(d-c)	344	337	344	362	379	402	409	402	409	420	445	455	515	534	587	534	587	569	657	634	
Non Oil Capacity, %	34.6	33.4	34.6	38.5	38.2	34.7	33.6	32.7	33.6	35	38	32.8	33.7	34.1	39.2	34.1	39.2	32.3	35.5	29.4	
Peak Demand (a)	290	300	305	315	321	331	340	350	362	372	389	399	419	429	452	462	489	499	529	539	MEDIUM
Largest as % of (a)	11.7	11.3	11.2	10.8	10.9	10.6	14.7	14.3	13.8	13.4	12.9	12.5	11.9	11.7	11.1	10.8	10.2	10.0	9.5	9.3	GROWTH
Margin 1 (d/a-1)%	29.0	22.3	22.8	24.6	28.7	32.0	35.2	29.3	26.8	26.3	27.4	26.7	34.8	36.1	40.9	26.4	30.4	24.2	33.8	27.0	
Margin 2 (e/a-1)%	18.6	12.3	13.0	15.1	18.1	21.5	20.5	15.0	13.0	12.9	14.5	14.2	22.9	24.5	29.9	15.6	20.2	14.1	24.3	17.7	
Peak Demand (a)	246	256	257	267	269	279	283	293	300	310	320	330	343	353	368	378	395	405	425	435	LOW
Largest as % of (a)	13.8	13.3	13.2	12.7	13	12.5	17.7	17.1	16.7	16.1	15.6	15.2	14.6	14.2	13.6	13.2	12.7	12.3	11.8	11.5	GROWTH
Margin 1 (d/a-1)%	52	43.4	45.5	46.8	53.5	56.6	62.2	54.3	53	51.6	54.7	53	64.7	65.4	73.1	54.5	61.3	52.8	66.4	57.2	
Margin 2 (e/a-1)%	39.8	31.6	33.9	35.6	40.9	44.1	44.5	37.2	36.3	35.5	39.1	37.9	50.1	51.3	59.5	41.3	48.6	40.5	54.6	45.7	
Peak Demand (a)	334	344	352	362	373	383	396	406	424	434	457	467	495	505	536	546	582	592	632	642	HIGH
Largest as % of (a)	10.2	9.9	9.7	9.4	9.4	9.1	12.6	12.3	11.8	11.5	10.9	10.7	10.1	9.9	9.3	9.2	8.6	8.4	7.9	7.8	GROWTH
Margin 1 (d/a-1)%	12.0	6.7	6.3	8.3	10.7	14.1	15.9	11.3	8.3	8.3	8.3	8.1	14.1	15.6	18.8	7.0	9.5	4.6	11.9	6.5	
Margin 2 (e/a-1)%	3.0	-2.0	-2.3	0.0	1.6	5.0	3.3	-1.0	-3.5	-3.2	-2.6	-2.6	4.0	5.7	9.5	-2.2	0.9	-3.9	4.0	-1.2	

TABLE: 5.4
RECOMMENDED INSTALLATIONS AT THE NEW PLANT FOR STEAM OR DIESEL UNITS

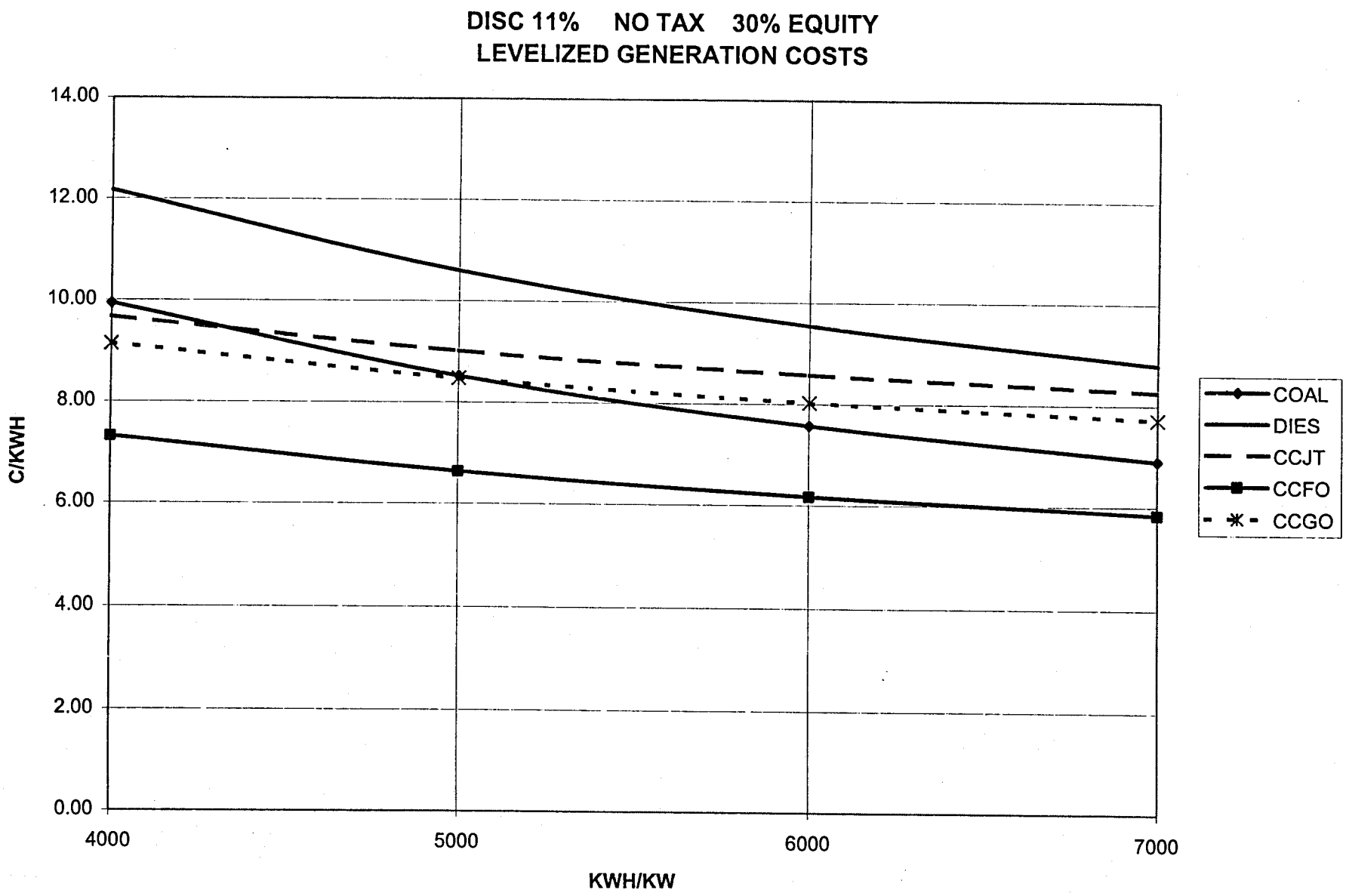
	2001		2002		2003		2004		2005		2006		2007		2008		2009		2010		
	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	
CAPACITY, MW																					
New Plant	0	0	0	0	50	50	100	100	100	100	100	150	150	150	150	200	200	250	250	300	
Others																					
CEB																					
St. Louis	40	40	40	40	20	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0	
Ft. Victoria I	9	9	9	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Ft. Victoria II	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	
Ft. George	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	
Nicolay	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	
Hydro	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	
Total	297	282	297	277	272	253	268	253	268	253	268	253	268	233	248	233	248	233	248	233	
Private																					
F.U.E.L.	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	
Beau Champ	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	
Belle-Vue	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	
Continuous	0	39	0	39	0	39	0	39	0	30	0	30	0	18	0	18	0	18	0	18	
Bagasse/Coal #2	0	0	0	0	0	0	0	0	0	27	36	27	36	27	36	27	36	27	36	27	
Bagasse/Coal #3	0	0	0	0	0	0	0	0	0	0	0	0	0	46	62	46	62	46	62	46	
SIC/SIDEC (Coal)	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
Total	111	119	111	149	141	149	141	149	141	167	177	167	177	201	239	201	239	201	239	201	
Grand Total	408	401	408	426	413	402	409	402	409	420	445	420	445	434	487	434	487	434	487	434	
Total System (1)	408	401	408	426	463	452	509	502	509	520	545	570	595	584	637	634	687	684	737	734	
Largest Unit/Block (b)	34	34	34	34	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	
Next Largest ©	30	30	30	30	35	35	50	50	50	50	50	50	50	50	50	50	50	50	50	50	
Firm Cap (d)(1-b)	374	367	374	392	413	402	459	452	459	470	495	520	545	534	587	584	637	634	687	684	
Cap for Maint (e)(d-c)	344	337	344	362	378	367	409	402	409	420	445	470	495	484	537	534	587	584	637	634	
Non Oil Capacity, %	34.6	33.4	34.6	38.5	36.9	36.3	33.6	32.7	33.6	35	38	31.9	34.8	37	42.2	34.1	39.2	31.6	36.5	29.4	
Peak Demand (a)	290	300	305	315	321	331	340	350	362	372	389	399	419	429	452	462	489	499	529	539	MEDIUM
Largest as % of (a)	11.7	11.3	11.2	10.8	15.6	15.1	14.7	14.3	13.8	13.4	12.9	12.5	11.9	11.7	11.1	10.8	10.2	10.0	9.5	9.3	GROWTH
Margin 1 (d/a-1)%	29.0	22.3	22.8	24.6	28.7	21.5	35.2	29.3	26.8	26.3	27.4	30.5	30.1	24.5	29.9	26.4	30.4	27.2	30.0	27.0	
Margin 2 (e/a-1)%	18.6	12.3	13.0	15.1	17.8	10.9	20.5	15.0	13.0	12.9	14.5	17.9	18.1	12.8	18.8	15.6	20.2	17.2	20.5	17.7	
Peak Demand (a)	246	256	257	267	269	279	283	293	300	310	320	330	343	353	368	378	395	405	425	435	LOW
Largest as % of (a)	13.8	13.3	13.2	12.7	18.6	17.9	17.7	17.1	16.7	16.1	15.6	15.2	14.6	14.2	13.6	13.2	12.7	12.3	11.8	11.5	GROWTH
Margin 1 (d/a-1)%	52.0	43.4	45.5	46.8	53.5	44.1	62.2	54.3	53.0	51.6	54.7	57.6	58.9	51.3	59.5	54.5	61.3	56.5	61.6	57.2	
Margin 2 (e/a-1)%	39.8	31.6	33.9	35.6	40.5	31.5	44.5	37.2	36.3	35.5	39.1	42.4	44.3	37.1	45.9	41.3	48.6	44.2	49.9	45.7	
Peak Demand (a)	334	344	352	362	373	383	396	406	424	434	457	467	495	505	536	546	582	592	632	642	HIGH
Largest as % of (a)	10.2	9.9	9.7	9.4	13.4	13.1	12.6	12.3	11.8	11.5	10.9	10.7	10.1	9.9	9.3	9.2	8.6	8.4	7.9	7.8	GROWTH
Margin 1 (d/a-1)%	12.0	6.7	6.3	8.3	10.7	5.0	15.9	11.3	8.3	8.3	8.3	11.3	10.1	5.7	9.5	7.0	9.5	7.1	8.7	6.5	
Margin 2 (e/a-1)%	3.0	-2.0	-2.3	0.0	1.3	-4.2	3.3	-1.0	-3.5	-3.2	-2.6	0.6	0.0	-4.2	0.2	-2.2	0.9	-1.4	0.8	-1.2	

FIGURE 1.1



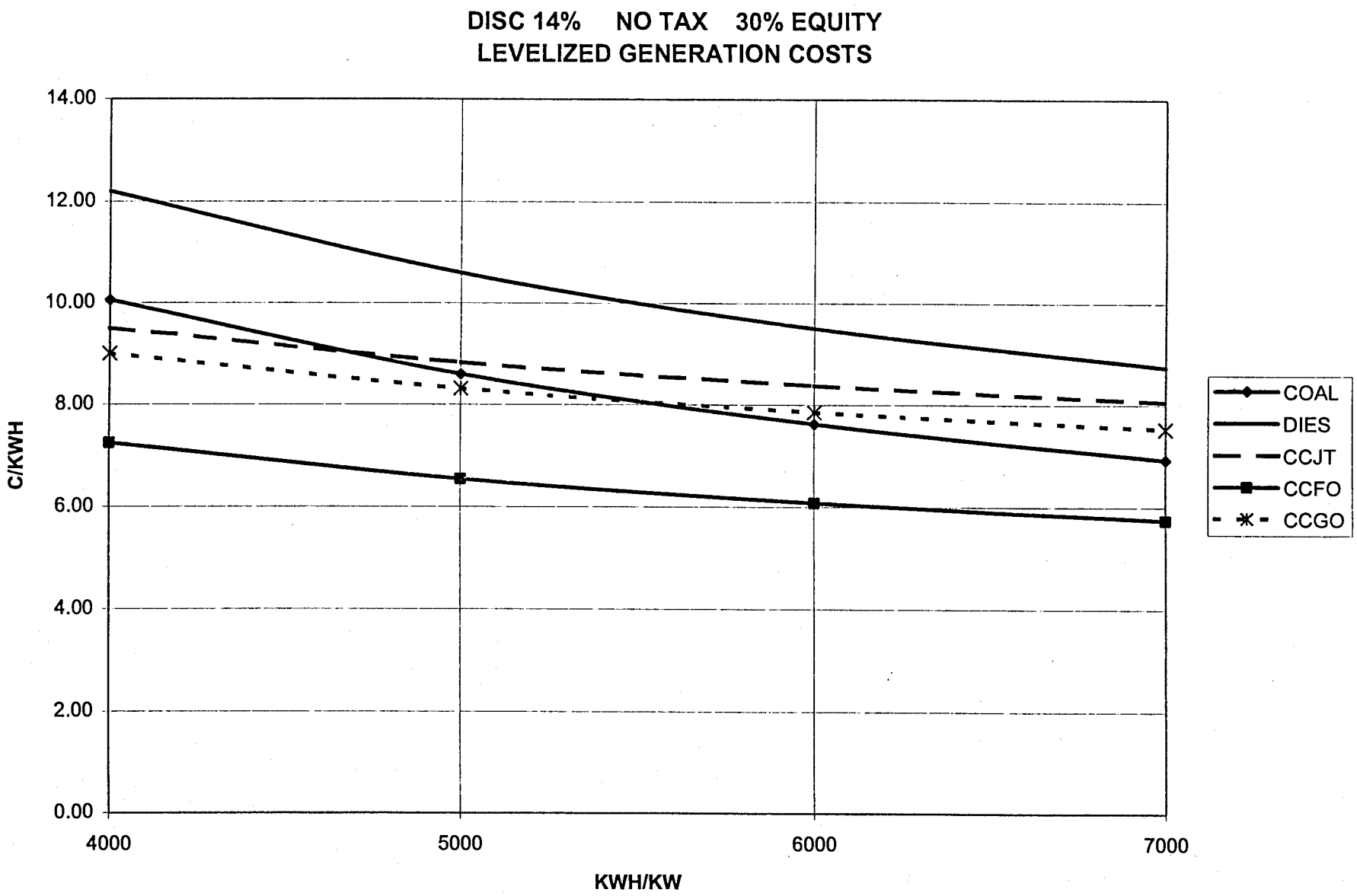
MTECH12 rev 2.xls

FIGURE 1.2



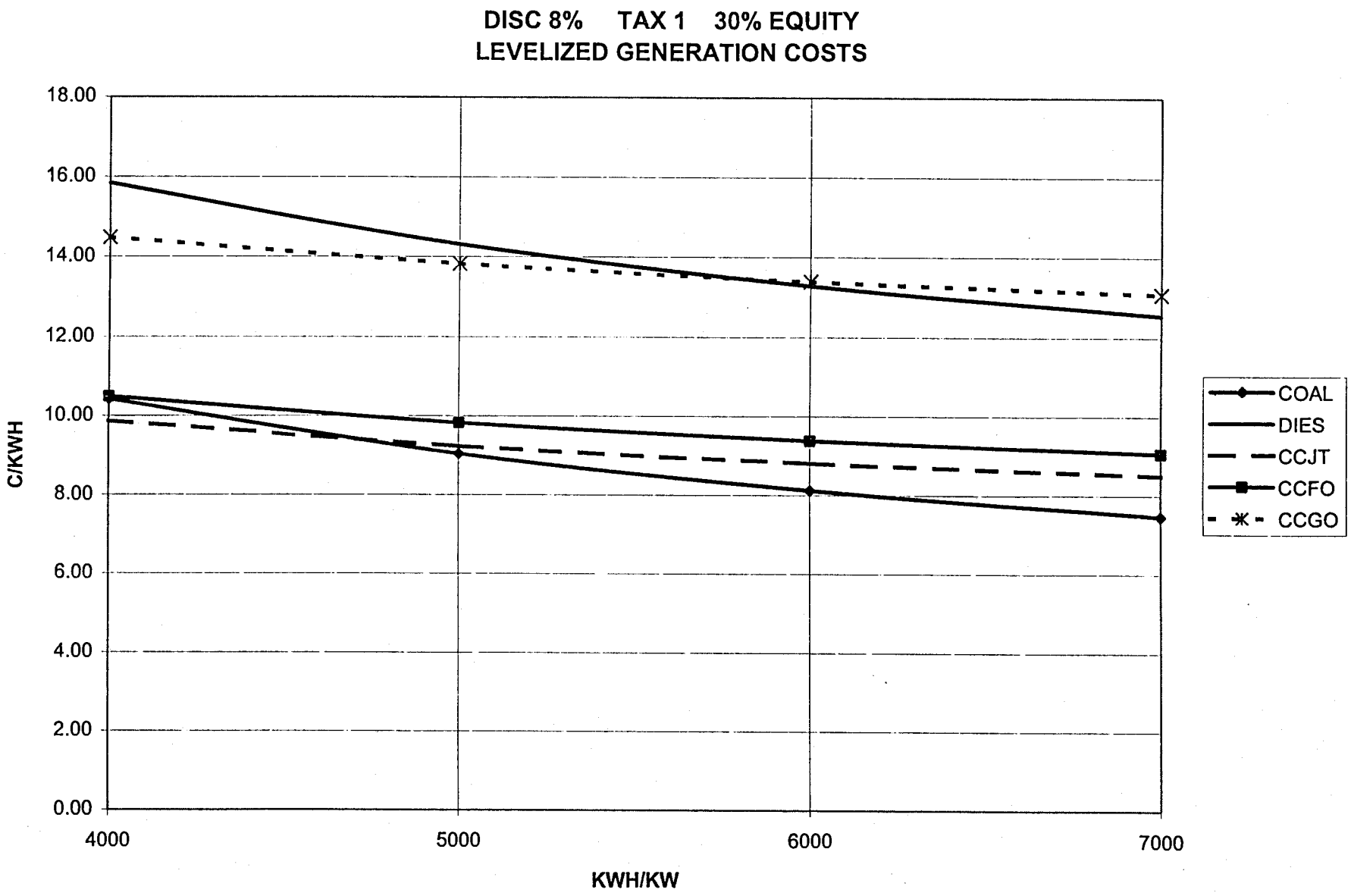
MTECH12 rev 2.xls

FIGURE 1.3



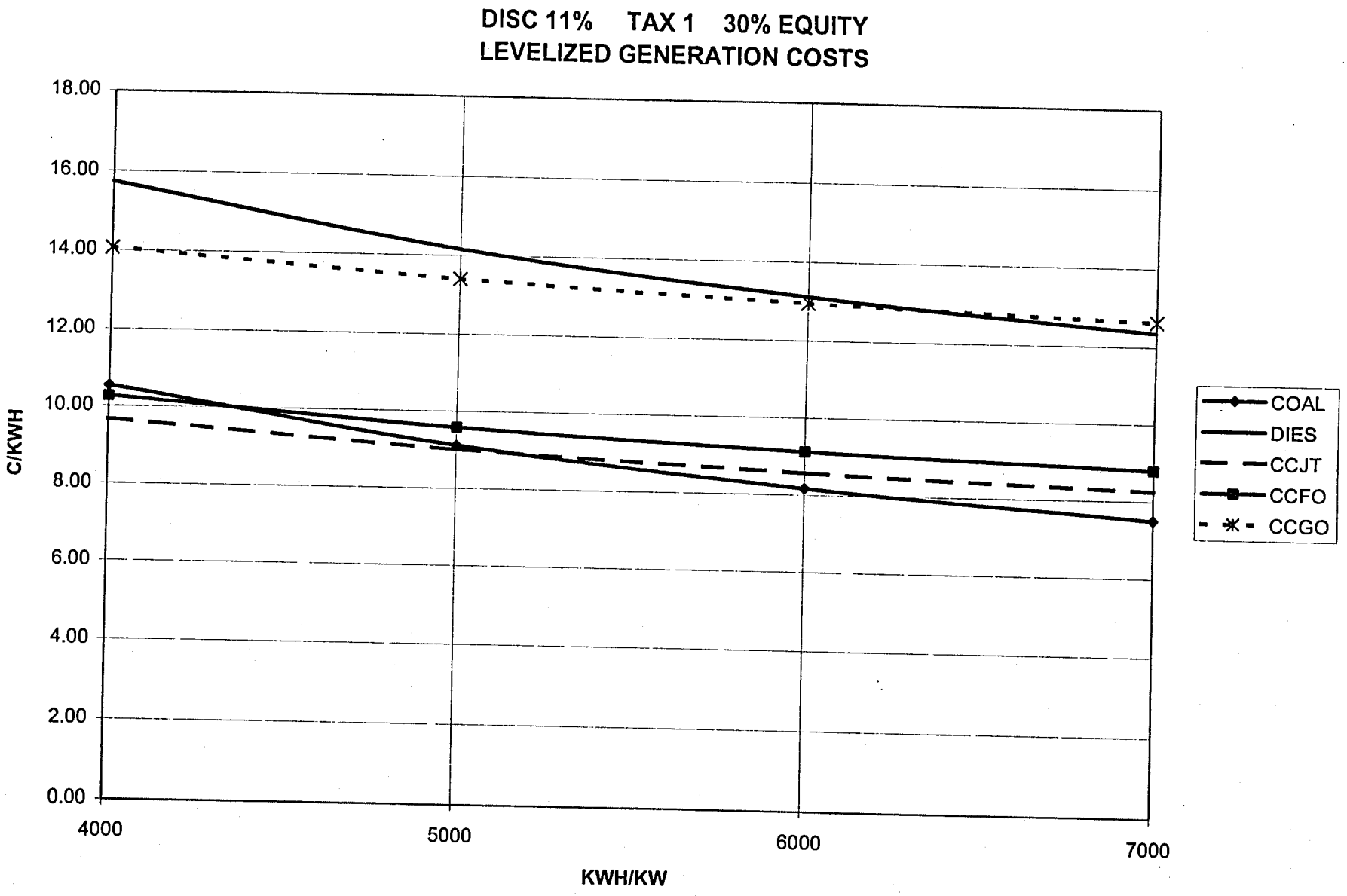
MTECH12 rev 2.xls

FIGURE 2.1



MTECH12 rev 2.xls

FIGURE 2.2



MTECH12 rev 2.xls

FIGURE 2.3

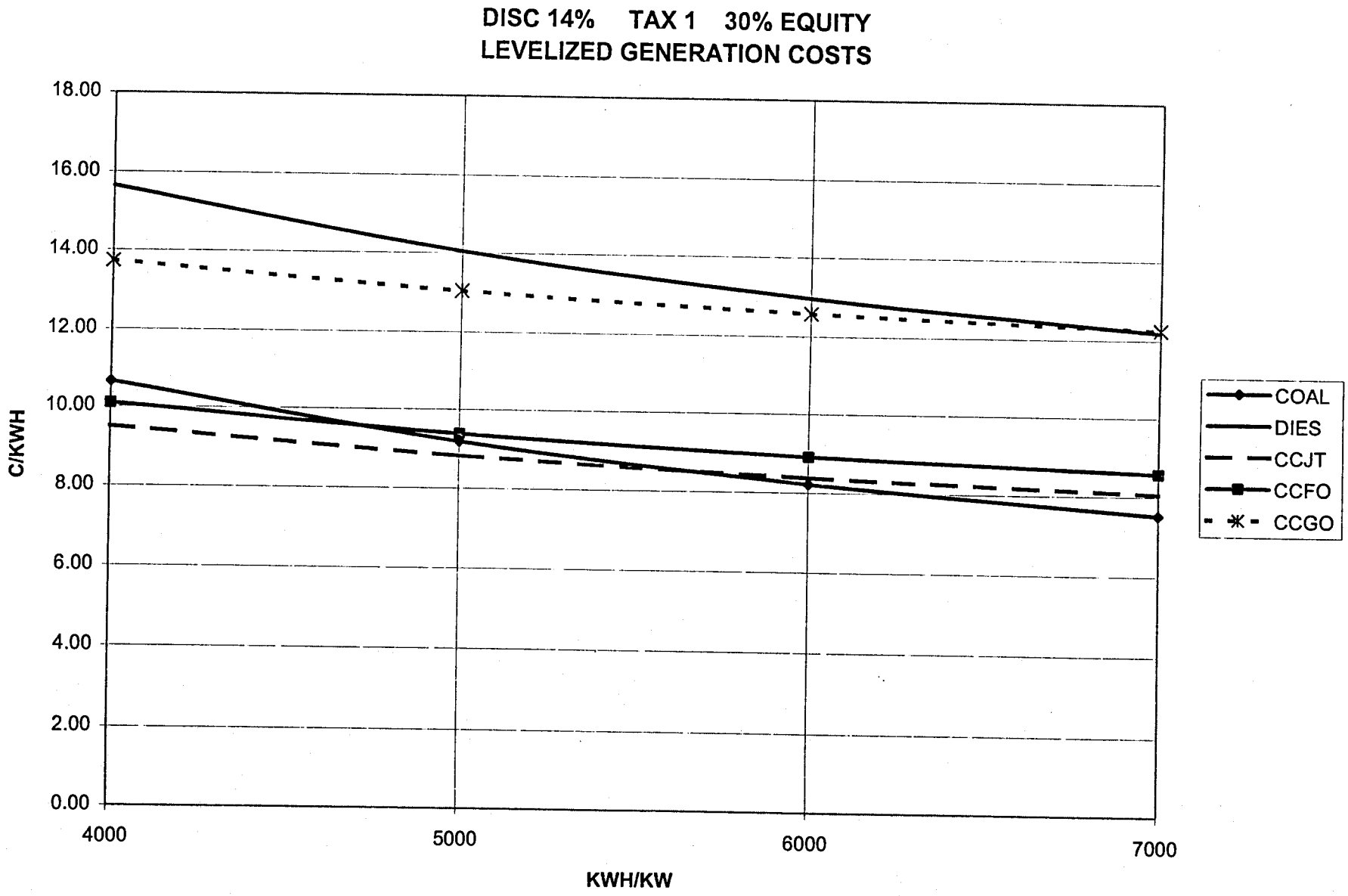


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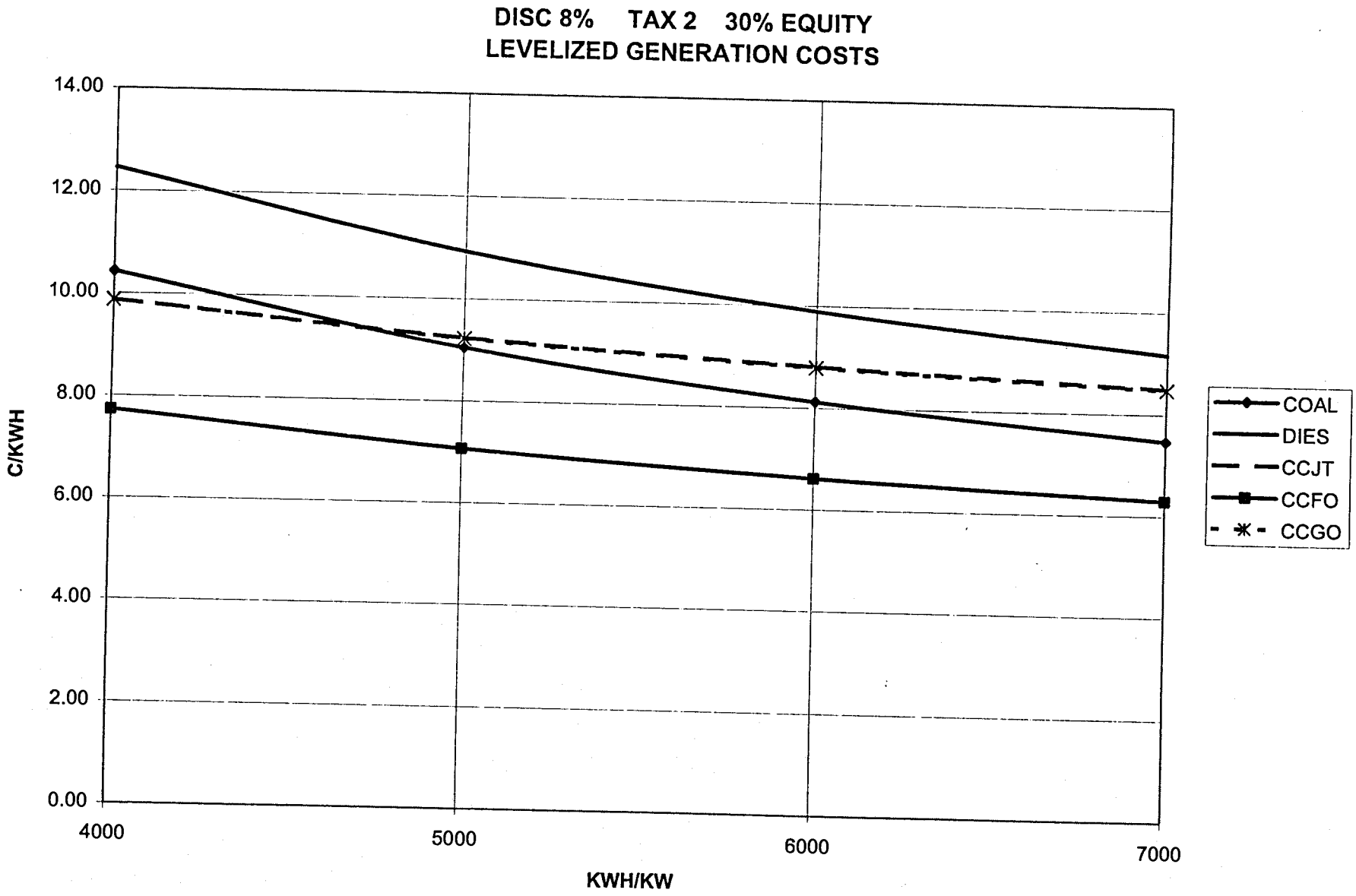
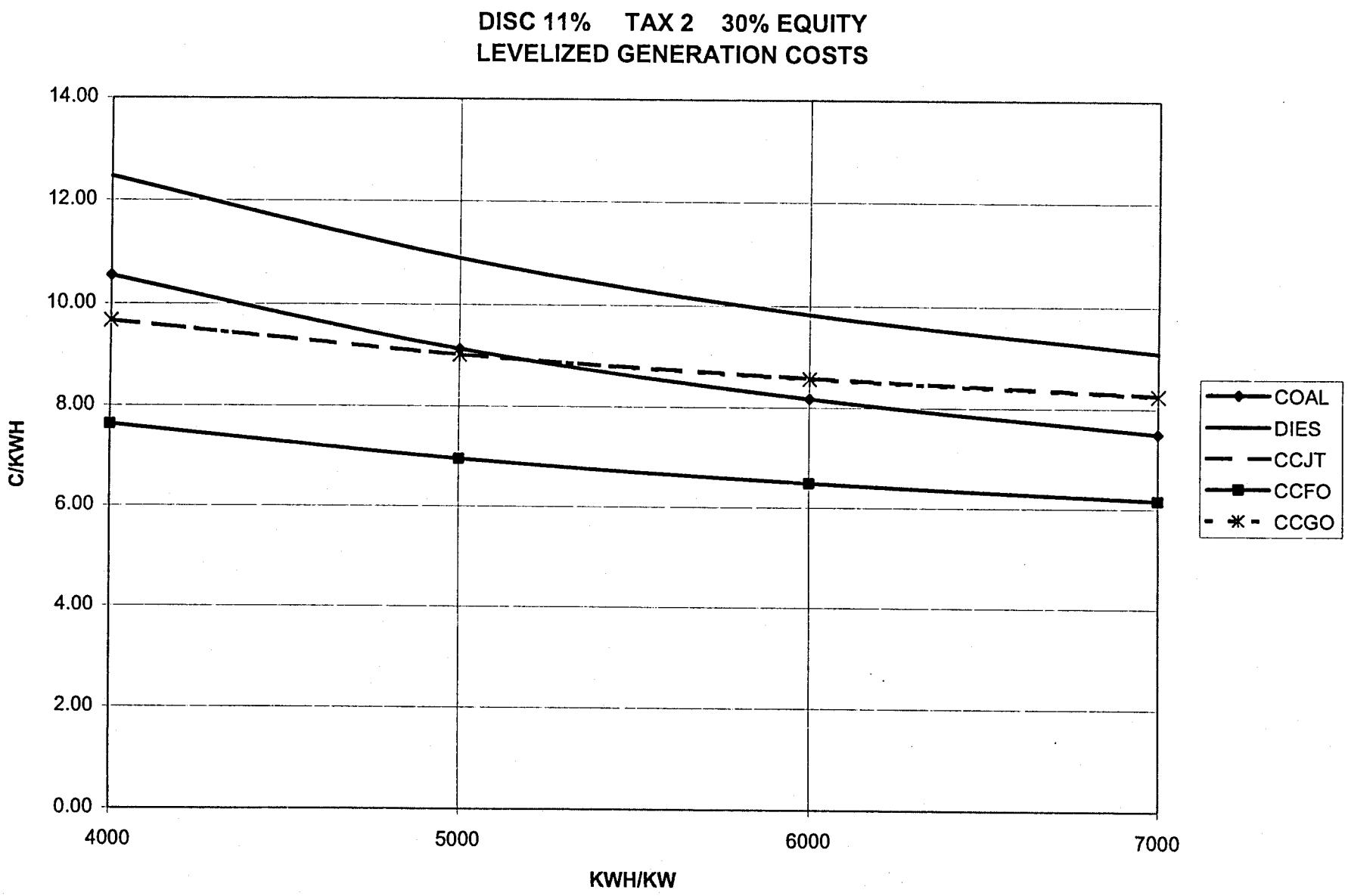
FIGURE 3.1



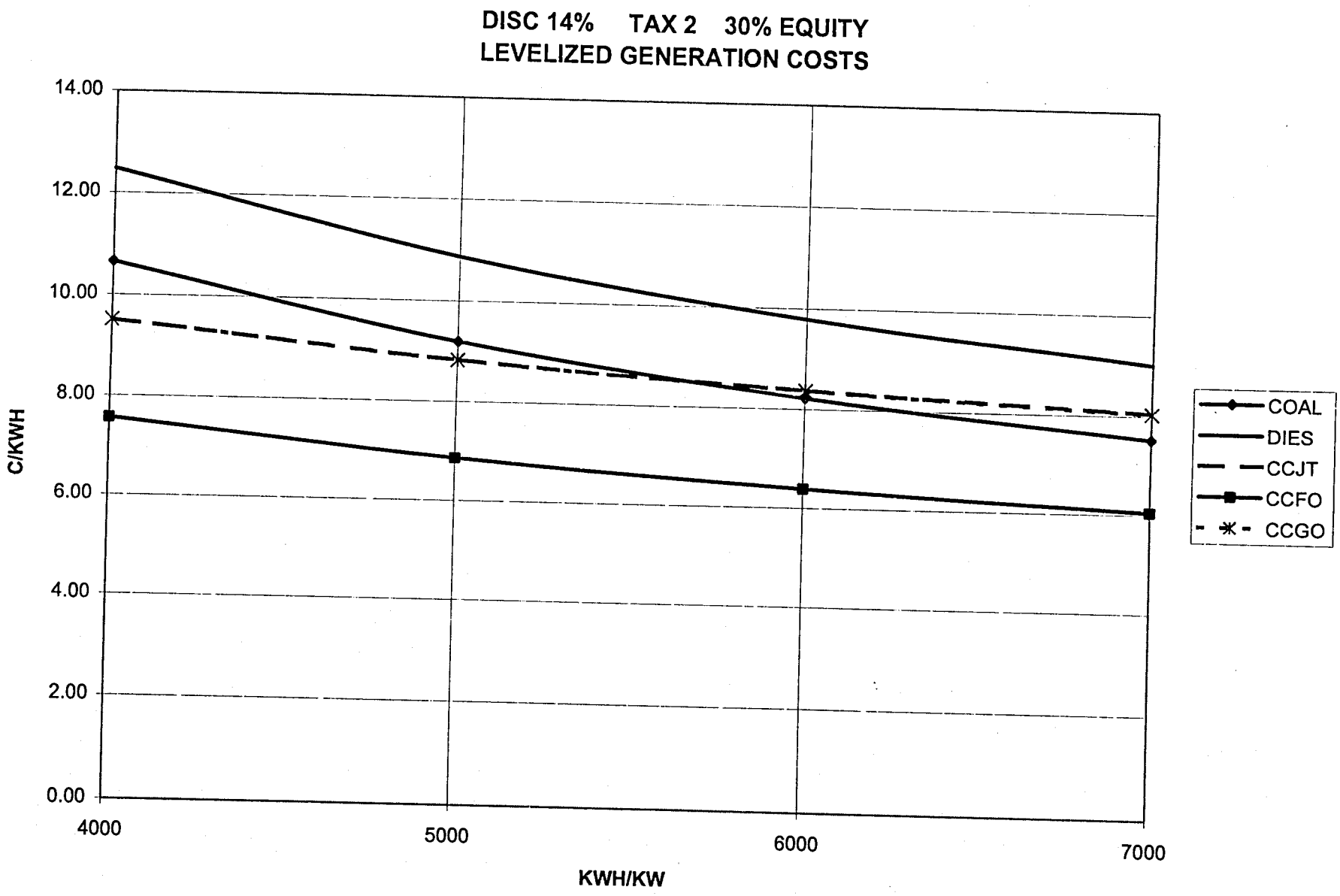
MTECH12 rev 2.xls

FIGURE 3.2



MTECH12 rev 2.xls

FIGURE 3.3



MTECH12 rev 2.xls

FIGURE 4.1

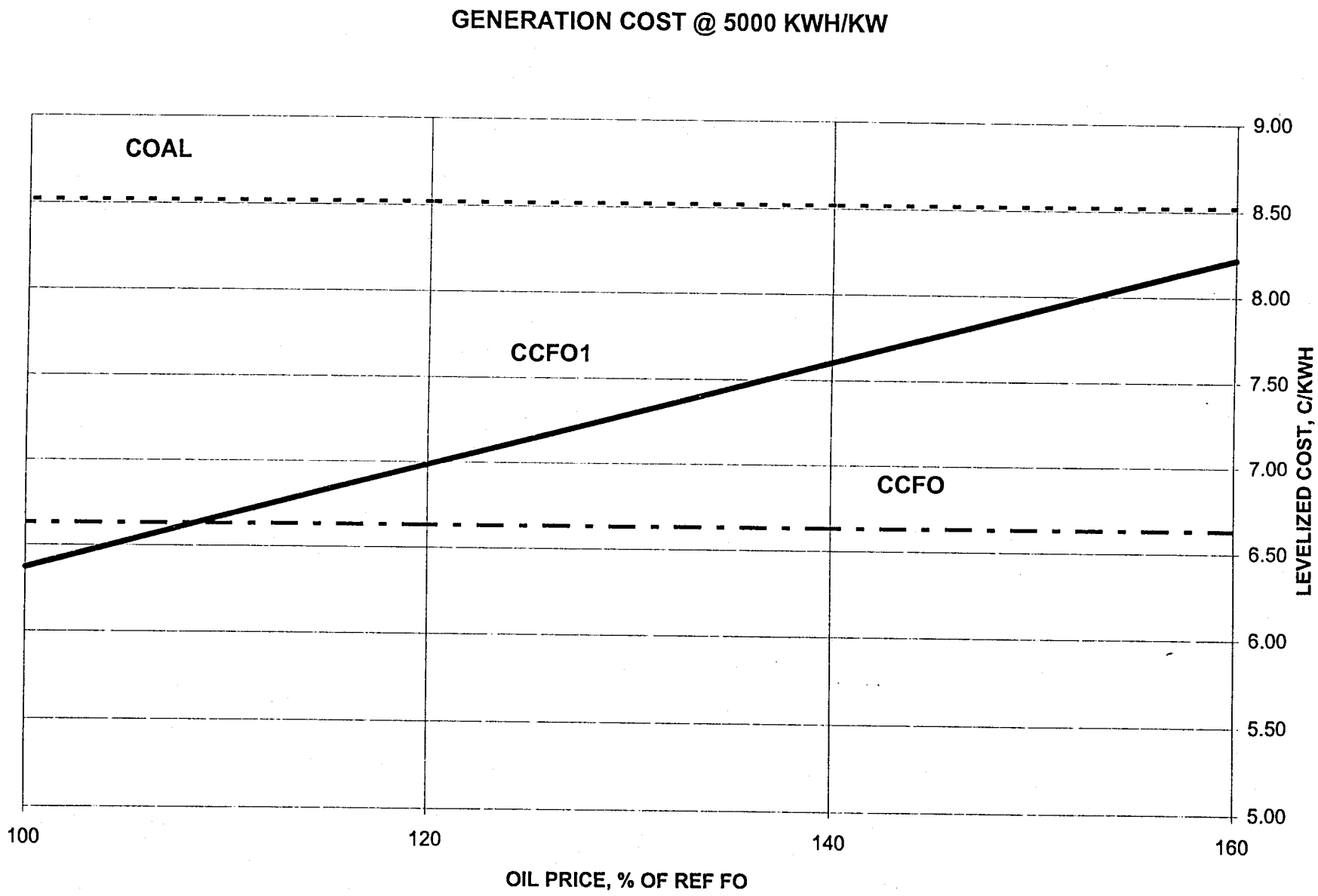
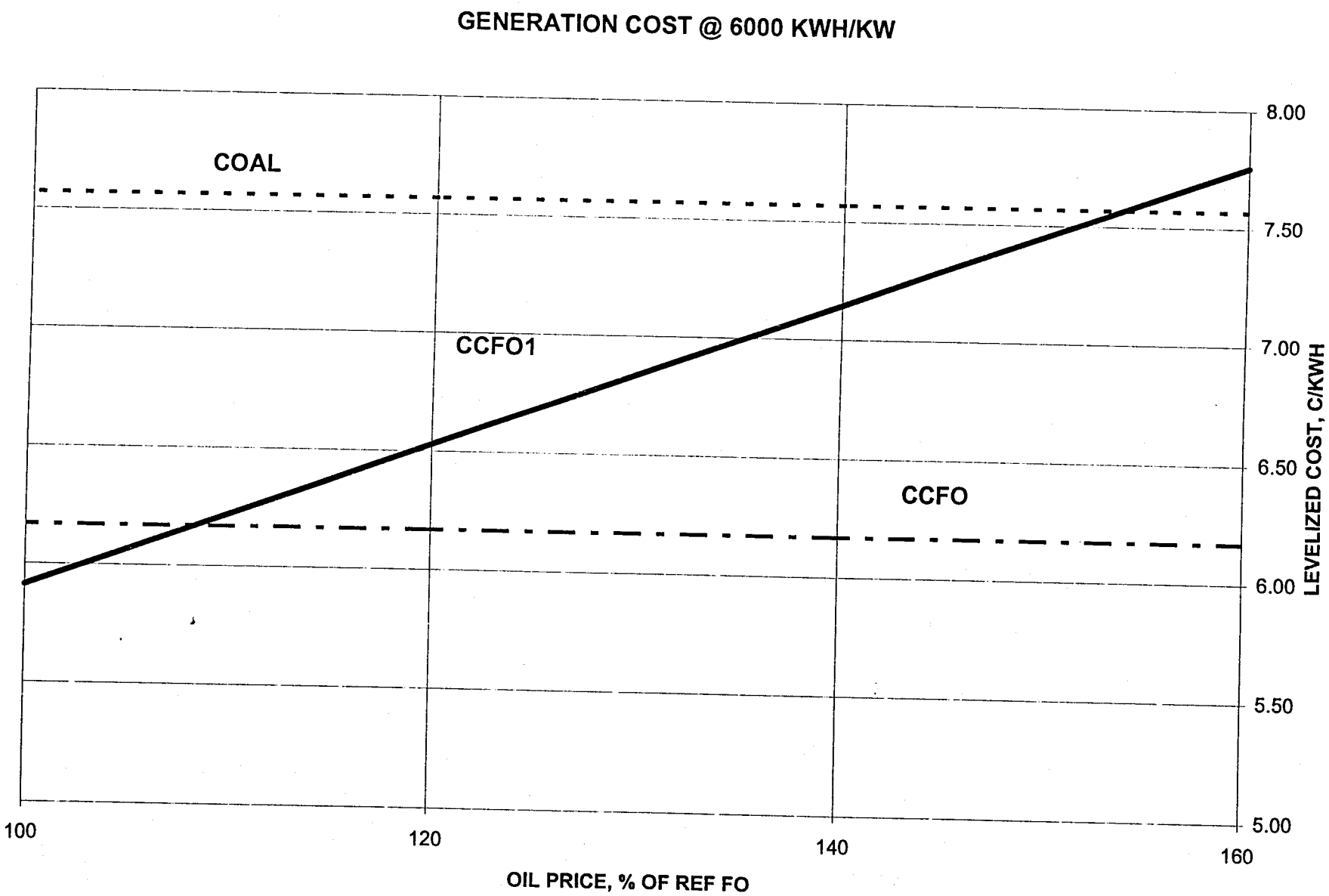

GENERATION COST @ 5000 KWH/KW
COAL
CCFO1
CCFO
9.00
8.50
8.00
7.50
7.00
6.50
6.00
5.50
5.00
LEVELIZED COST, C/KWH
100
120
140
160
OIL PRICE, % OF REF FO

FIGURE 4.2


GENERATION COST @ 6000 KWH/KW
COAL
CCFO1
CCFO
8.00
7.50
7.00
6.50
6.00
5.50
5.00
LEVELIZED COST, C/KWH
100
120
140
160
OIL PRICE, % OF REF FO

Power Systems

Gas Turbine Models with Heavy Fuels

Fuel Type: Crude And/Or Dist. (

Gas Turbine 051M

			Shipped	Comm'l
COMMISSION FED ELEC	ACAPULCO, LAS CRUCES	Simple Cycle	15-Sep-7	01-Feb-73

Gas Turbine 051P

			Shipped	Comm'l
EMPRESSA ELEC DE GUA	LAGUNA, GUATEMALA	SIMPLE CYCLE	15-Apr-77	31-Mar-78
SCECO-EAST	QAISUMAH, SAUDI ARAB	SIMPLE CYCLE	01-Apr-77	12-Dec-7
EMPRESSA ELEC DE GUA	LAGUNA, GUATEMALA	SIMPLE CYCLE	15-Apr-77	02-Jun-78
SCECO-EAST	QAISUMAH, SAUDI ARAB	SIMPLE CYCLE	25-Mar-82	09-Jan-83
SCECO-CENTRAL	LAYLA, SAUDI ARABIA	Simple Cycle	01-Nov-8	15-Jan-85
SCECO-CENTRAL	LAYLA, SAUDI ARABIA	Simple Cycle	01-Nov-8	15-Feb-85
SCECO-CENTRAL	LAYLA, SAUDI ARABIA		01-Nov-8	15-Mar-85
SCECO-CENTRAL	LAYLA, SAUDI ARABIA	Simple Cycle	01-Nov-8	15-Apr-85
SCECO-CENTRAL	LAYLA, SAUDI ARABIA		01-Dec-8	15-Jun-85
SCECO-CENTRAL	LAYLA, SAUDI ARABIA		01-Dec-8	15-Jul-85

Gas Turbine 061B

			Shipped	Comm'l
COMMISSION FED ELEC	CABORCA	Simple Cycle	15-May-8	01-Jan-82
TABOUK ELECTRIC CO	TABOUK II, SAUDI ARA	SIMPLE CYCLE	27-Sep-8	15-May-8
SCECO-EAST	QAISUMAH, SAUDI ARAB	SIMPLE CYCLE	26-Jun-84	20-Apr-85
SCECO-SOUTH	QUNFUDAH, SAUDIA ARA	SIMPLE CYCLE	29-Mar-83	01-Jun-86
SCECO-SOUTH	GIZAN, SAUDI ARABIA	SIMPLE CYCLE	14-Dec-8	23-Dec-8
SCECO-SOUTH	GIZAN, SAUDI ARABIA	SIMPLE CYCLE	19-Mar-82	05-Jan-83
SCECO-SOUTH	GIZAN, SAUDI ARABIA	SIMPLE CYCLE	28-Apr-82	29-May-8
TABOUK ELECTRIC CO	TABOUK II, SAUDI ARA	SIMPLE CYCLE	27-Sep-8	01-May-8
SCECO-SOUTH	QUNFUDAH, SAUDIA ARA	SIMPLE CYCLE	29-Mar-83	19-May-8
SCECO-EAST	QAISUMAH, SAUDI ARAB	SIMPLE CYCLE	28-Sep-8	19-May-8

Gas Turbine 071B

			Shipped	Comm'l
SCECO-WEST	JEDDAH	SIMPLE CYCLE	31-Aug-7	17-Jun-78
SCECO-WEST	JEDDAH	SIMPLE CYCLE	15-Dec-7	18-Aug-7
SCECO-WEST	JEDDAH	SIMPLE CYCLE	15-Feb-76	23-Sep-7
SCECO-WEST	JEDDAH	SIMPLE CYCLE	15-Mar-76	18-Nov-7
SCECO-WEST	JEDDAH	SIMPLE CYCLE	23-Mar-78	30-Dec-7
SCECO-WEST	JEDDAH	SIMPLE CYCLE	15-Dec-7	22-Feb-77
SCECO-WEST	JEDDAH	SIMPLE CYCLE	14-Nov-7	11-Sep-7
SCECO-WEST	JEDDAH	SIMPLE CYCLE	20-Oct-77	01-Nov-7
SCECO-WEST	JEDDAH	SIMPLE CYCLE	18-Nov-7	15-Aug-7
SCECO-WEST	JEDDAH	SIMPLE CYCLE	15-Feb-78	22-Oct-78
SCECO-WEST	JEDDAH	SIMPLE CYCLE	13-Jan-78	01-Oct-78

Gas Turbine 071E

			Shipped	Comm'l
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	25-Apr-80	07-Nov-8
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	21-Oct-80	07-Nov-8
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	15-Oct-80	22-Jul-81
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	17-Sep-8	19-Jul-81
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	18-Nov-8	23-Nov-8

Power Systems

Gas Turbine Models with Heavy Fuels

SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	29-Aug-8	05-May-8
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	29-Jul-80	05-May-8
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	24-Jul-80	05-Apr-81
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	23-Jun-80	11-Feb-81
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	06-Jun-80	03-Dec-8
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	28-Feb-80	28-Sep-8
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	22-Mar-80	02-Nov-8
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	06-Mar-80	24-Dec-8
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	01-Nov-7	29-Jul-80
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	20-Jun-80	04-Dec-8
SCECO-SOUTH	ABHA, SAUDI ARABIA	SIMPLE CYCLE	17-Feb-84	29-Oct-85
SCECO-SOUTH	GIZAN, SAUDI ARABIA	SIMPLE CYCLE	01-Nov-8	14-Feb-89
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	28-Sep-7	10-Jul-80
SCECO-SOUTH	GIZAN, SAUDI ARABIA	SIMPLE CYCLE	01-Nov-8	14-Feb-89
SCECO-SOUTH	QUNFUDAH, SAUDIA ARA	SIMPLE CYCLE	13-Jun-83	20-Jun-86
SCECO-SOUTH	ABHA, SAUDI ARABIA	SIMPLE CYCLE	15-Mar-84	18-Jan-86
SCECO-SOUTH	ABHA, SAUDI ARABIA	SIMPLE CYCLE	19-Jan-84	27-Oct-85
SCECO-SOUTH	QUNFUDAH, SAUDIA ARA	SIMPLE CYCLE	29-Jun-83	04-Aug-8

Gas Turbine **071EA**

			Shipped	Comm'l
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	31-Dec-9	01-Jan-19
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	31-Jan-93	01-Jan-19
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	21-Oct-93	31-Dec-9
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	30-Nov-9	01-Jan-19
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	21-Oct-93	31-Dec-9
SCECO-CENTRAL	RIYADH PP7, SAUDI AR	SIMPLE CYCLE	31-Dec-9	01-Jan-19

Fuel Type: CRUDE AND/OR GAS-(DU

Gas Turbine **051LA**

			Shipped	Comm'l
GENERAL PETROLEUM CO	SYRIA	SIMPLE CYCLE	15-Apr-72	19-Jul-73
GENERAL PETROLEUM CO	SYRIA	SIMPLE CYCLE	15-Apr-72	25-Jan-74

Gas Turbine **091B**

			Shipped	Comm'l
MEW/KUWAIT	DOHA SOUTH	SIMPLE CYCLE	15-Jul-82	27-Nov-8
MEW/KUWAIT	SULIYAH #1	SIMPLE CYCLE	15-Jan-82	04-May-8
MEW/KUWAIT	SULIYAH #1	SIMPLE CYCLE	15-Mar-82	17-Jun-83
MEW/KUWAIT	AL WAJBAH	SIMPLE CYCLE	15-May-8	11-Jan-84

Power Systems

Gas Turbine Models with Heavy Fuels

Fuel Type: CRUDE OIL (START UP

Gas Turbine 032A

			Shipped	Comm'l
SAUDI ARABIAN OIL CO	TURAIF	SIMPLE CYCLE	15-May-5	15-Jan-57

Gas Turbine 032B

			Shipped	Comm'l
SOPEG-ALGERIA	DIJAMA	NON REGENERATIVE CYC	15-Nov-6	15-Sep-6
SAUDI ARABIAN OIL CO	TURAIF	SIMPLE CYCLE	01-Jan-57	01-Dec-5
SOPEG-ALGERIA	DIJAMA	NON REGENERATIVE CYC	15-Nov-6	15-Sep-6
SAUDI ARABIAN OIL CO	SHUBAH	SIMPLE CYCLE	15-Feb-57	15-Dec-5
SAUDI ARABIAN OIL CO	WARIYA	SIMPLE CYCLE	15-Feb-57	15-Dec-5
SAUDI ARABIAN OIL CO	TURAIF	SIMPLE CYCLE	15-Mar-57	15-Dec-5
SAUDI ARABIAN OIL CO	QARYATAIN	SIMPLE CYCLE	15-Mar-57	15-Dec-5
SAUDI ARABIAN OIL CO	UWAIQILAH	SIMPLE CYCLE	15-Jan-57	15-Nov-5
SAUDI ARABIAN OIL CO	TURAIF	Simple Cycle	15-Feb-57	15-Nov-5
SAUDI ARABIAN OIL CO	JALAMID	SIMPLE CYCLE	15-Feb-57	15-Nov-5
SAUDI ARABIAN OIL CO	TURAIF	SIMPLE CYCLE	15-Sep-5	15-Dec-5

Gas Turbine 032J

			Shipped	Comm'l
SONATRACH	SKIKDA PIPELINE SC-3	SIMPLE CYCLE	15-Dec-7	01-Jan-75
SONATRACH	SKIKDA PIPELINE SC-3	SIMPLE CYCLE	15-Dec-7	01-Jan-75
PHILLIPS PETROLEUM	TEESSIDE, UK	SIMPLE CYCLE	15-Mar-75	12-Apr-78
SONATRACH	SKIKDA PIPELINE SC-3	SIMPLE CYCLE	15-Dec-7	01-Jan-75
PHILLIPS PETROLEUM	TEESSIDE, UK	SIMPLE CYCLE	15-Dec-7	12-Apr-78
PHILLIPS PETROLEUM	TEESSIDE, UK	SIMPLE CYCLE	15-Mar-75	12-Apr-78
PHILLIPS PETROLEUM	STATION 37-4A	SIMPLE CYCLE	15-Apr-75	12-Apr-78
PHILLIPS PETROLEUM	TEESSIDE, UK	SIMPLE CYCLE	15-Dec-7	12-Apr-78
PHILLIPS PETROLEUM	TEESSIDE, UK	SIMPLE CYCLE	15-Apr-75	12-Apr-78

Gas Turbine 051L

			Shipped	Comm'l
SCECO-WEST	JEDDAH PP2, SAUDI AR	SIMPLE CYCLE	15-Feb-66	15-Jun-66

Gas Turbine 051LA

			Shipped	Comm'l
ABU DHABI WATER & EL	MUBARRAS ISLAND, UAE	SIMPLE CYCLE	15-Oct-72	19-Mar-73
ABU DHABI WATER & EL	MUBARRAS ISLAND, UAE	SIMPLE CYCLE	15-Sep-7	09-Mar-73
PT CALTEX	DURI, INDONESIA	SIMPLE CYCLE	15-Jun-70	15-Dec-7
ABU DHABI WATER & EL	ABU DHABI, UAE	SIMPLE CYCLE	15-Dec-6	15-Mar-70
ABU DHABI WATER & EL	ABU DHABI, UAE	SIMPLE CYCLE	15-Jan-70	15-Apr-70
ABU DHABI WATER & EL	ABU DHABI, UAE	SIMPLE CYCLE	15-Mar-70	15-Jul-70

Gas Turbine 051N

			Shipped	Comm'l
GENERAL PETROLEUM CO	HOMS-1, SYRIA	SIMPLE CYCLE	15-Aug-7	25-Jul-75
GENERAL PETROLEUM CO	HOMS-1, SYRIA	SIMPLE CYCLE	15-Aug-7	04-Mar-75
SCECO-CENTRAL	RIYADH PP4, SAUDI AR	SIMPLE CYCLE	15-Oct-76	30-Apr-77
SCECO-CENTRAL	RIYADH PP4, SAUDI AR	SIMPLE CYCLE	15-Oct-76	09-May-7
SYRIA MINISTRY ELEC	SYRIA	SIMPLE CYCLE	15-Dec-7	12-Apr-75
GENERAL PETROLEUM CO	ASRIEH, SYRIA	SIMPLE CYCLE	15-Oct-73	18-Dec-7
SYRIA MINISTRY ELEC	STATION 1	SIMPLE CYCLE	15-Jan-73	24-Apr-74
SYRIA MINISTRY ELEC	SYRIA	SIMPLE CYCLE	15-Dec-7	03-Dec-7
GENERAL PETROLEUM CO	SOUEDIEH, SYRIA	SIMPLE CYCLE	15-Nov-7	15-May-7

Power Systems

Gas Turbine Models with Heavy Fuels

			Shipped	Comm'l
Gas Turbine 051P				
HAIKOU MACUN P.P.	HAIKOU MACUN P.P.	SIMPLE CYCLE	01-Sep-8	10-Mar-88
Gas Turbine 061B			**Shipped**	**Comm'l**
SHANTOU MUNICIPALITY	SHANTOU	CONDENSING-FITCHBURG	01-Jan-89	31-Dec-8
HUANENG INT'L PWR.	HUANENG		01-Jan-19	01-Jan-19
SCECO-CENTRAL	AL JUBA, SAUDI ARABI	SIMPLE CYCLE	15-Mar-86	15-Jul-86
OFFICE NATIONAL	TAN TAN, MOROCCO	SIMPLE CYCLE	21-Jan-90	10-Feb-92
OFFICE NATIONAL	TAN TAN, MOROCCO	SIMPLE CYCLE	21-Jan-90	15-Aug-9
OFFICE NATIONAL	TAN TAN, MOROCCO	SIMPLE CYCLE	21-Jan-90	23-Jun-92
SCECO-CENTRAL	AL JUBA, SAUDI ARABI	SIMPLE CYCLE	15-Jan-86	15-Jul-86
SCECO-CENTRAL	AL JUBA, SAUDI ARABI	SIMPLE CYCLE	15-Jan-86	15-Jul-86
SCECO-CENTRAL	AL JUBA, SAUDI ARABI	SIMPLE CYCLE	15-Jun-86	15-Jul-86
SCECO-CENTRAL	AL JUBA, SAUDI ARABI	SIMPLE CYCLE	15-Feb-86	15-Jul-86
HUANENG INT'L PWR.	HUANENG		01-Jan-19	01-Jan-19
SCECO-CENTRAL	AL JUBA, SAUDI ARABI	SIMPLE CYCLE	15-Apr-86	15-Jul-86
SCECO-CENTRAL	AL JUBA, SAUDI ARABI	SIMPLE CYCLE	15-May-8	15-Jul-86
Gas Turbine 071B			**Shipped**	**Comm'l**
FLORIDA POWER CORP	BARTOW	SIMPLE CYCLE	15-Feb-72	14-Jun-72
FLORIDA POWER CORP	BARTOW	SIMPLE CYCLE	15-Feb-72	14-Jun-72
FLORIDA POWER CORP	BARTOW	SIMPLE CYCLE	15-Feb-72	14-Jun-72
SCECO-CENTRAL	RIYADH PP4, SAUDI AR	SIMPLE CYCLE	01-Sep-7	18-May-7
SCECO-CENTRAL	RIYADH PP4, SAUDI AR	SIMPLE CYCLE	01-Jul-77	01-Oct-77
SCECO-CENTRAL	RIYADH PP4, SAUDI AR	SIMPLE CYCLE	15-Apr-77	01-Jul-77
SCECO-CENTRAL	RIYADH PP4, SAUDI AR	SIMPLE CYCLE	15-Mar-77	20-Aug-7
SCECO-CENTRAL	RIYADH PP4, SAUDI AR	SIMPLE CYCLE	15-Feb-77	18-Sep-7
FLORIDA POWER CORP	BARTOW	SIMPLE CYCLE	15-Feb-72	14-Jun-72
Gas Turbine 071C			**Shipped**	**Comm'l**
ARIZONA PUBLIC SERV	WEST PHOENIX	COMBINED CYCLE	15-Dec-7	22-Jun-76
ARIZONA PUBLIC SERV	WEST PHOENIX	COMBINED CYCLE	15-Dec-7	22-Jun-76
ARIZONA PUBLIC SERV	WEST PHOENIX	COMBINED CYCLE	15-Dec-7	22-Jun-76

Power Systems

Gas Turbine Models with Heavy Fuels

Fuel Type: MULTI-GAS-DIST-RESID

				Shipped	Comm'l
Gas Turbine 032F					
SONATRACH	BISKRA	NON REGENERATIVE CYC		15-Sep-7	15-Jan-72
SONATRACH	HAOUD	NON REGENERATIVE CYC		15-Oct-71	15-Apr-72
SONATRACH	HAOUD	NON REGENERATIVE CYC		15-Sep-7	15-Mar-72
SONATRACH	BISKRA	NON REGENERATIVE CYC		15-Nov-7	15-May-7
Gas Turbine 051LA				**Shipped**	**Comm'l**
PT CALTEX	MINAS, INDONESIA	SIMPLE CYCLE		15-Jun-75	15-Nov-7
CHEMIE-BOTLEK-RDD	ZOUTCLTEMIE STATION	SIMPLE CYCLE		15-Jul-70	16-Sep-7
Gas Turbine 051M				**Shipped**	**Comm'l**
HESS OIL	ST. CROIX, V.I.	HEAT RECOVERY		15-Apr-74	11-Sep-7
HESS OIL	ST. CROIX, V.I.	HEAT RECOVERY		15-Mar-74	21-Aug-7
S. ARAMCO-RIYADH REF	RIYADH	SIMPLE CYCLE		15-Jul-73	21-Aug-7
CENTRAL TERMICA NEA	BARRANGUERA, ARGENTI	SIMPLE CYCLE		15-Oct-75	15-Jan-80
S. ARAMCO-RIYADH REF	RIYADH	SIMPLE CYCLE		15-May-7	21-Aug-7
SAUDI ARAMCO	JEDDAH REFINERY	SIMPLE CYCLE		15-Jul-73	15-Sep-7
Gas Turbine 051N				**Shipped**	**Comm'l**
QATAR	RAS ABU ABOUD PWR ST	SIMPLE CYCLE		15-Dec-7	15-Jun-73
QATAR	RAS ABU ABOUD PWR ST	SIMPLE CYCLE		15-Feb-75	15-Sep-7
SHENZHEN JINGANG P.P	SHENZHEN JINGANG P.P	SIMPLE CYCLE		15-Mar-73	15-Sep-7
SHENGLI OIL	DONGYI, CHINA	SIMPLE CYCLE		15-Mar-73	15-Aug-7
QATAR	STATION #4	SIMPLE CYCLE		15-Mar-76	15-Jun-76
PEOPLES REPUBLIC	PEKING	SIMPLE CYCLE		15-Mar-73	15-Sep-7
ABU DHABI WATER & EL	ABU DHABI, UAE	SIMPLE CYCLE		15-Feb-75	08-Jul-75
ABU DHABI WATER & EL	ABU DHABI, UAE	SIMPLE CYCLE		15-Feb-75	08-Jul-75
Gas Turbine 051P				**Shipped**	**Comm'l**
ABU DHABI WATER & EL	ALAIN, UAE	SIMPLE CYCLE		15-May-7	18-May-7
HESS OIL	ST. CROIX, V.I.	HEAT RECOVERY		15-Jul-74	02-Aug-7
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE		15-Apr-81	15-Jan-82
DUBAI SMELTTER	UNITED ARAB EMIRATES	SIMPLE CYCLE		01-May-7	20-Oct-79
DUBAI SMELTTER	UNITED ARAB EMIRATES	SIMPLE CYCLE		01-Aug-7	15-Aug-7
HESS OIL	ST. CROIX, V.I.	HEAT RECOVERY		15-Aug-7	26-Aug-7
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE		15-Apr-81	15-Apr-82
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE		15-May-8	15-Jan-82
ARABIAN GULF OIL CO	MESSLA OIL FIELD	SIMPLE CYCLE		01-Mar-80	15-Mar-81
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE		15-Apr-81	15-Jan-82
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE		15-Apr-81	15-Jan-82
SLOUGH ESTATES LTD	SLOUGH EST.INDUS.PK.			15-Sep-8	15-Sep-8
ARABIAN GULF OIL CO	MESSLA OIL FIELD	SIMPLE CYCLE		01-Mar-80	15-Mar-81
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE		15-Jul-81	15-Jan-82
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE		15-Sep-8	15-Apr-82
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE		15-Sep-8	15-Apr-82
DUBAI SMELTTER	UNITED ARAB EMIRATES	SIMPLE CYCLE		01-Jul-78	28-Oct-79
E.P.C. BURMA	ELEC PWR CORP BURMA8	SIMPLE CYCLE		15-Aug-8	01-Jan-83
PT CALTEX	SUMATRA, INDONESIA	SIMPLE CYCLE		01-Dec-8	11-Jun-88

Power Systems

Gas Turbine Models with Heavy Fuels

PT CALTEX	DURI, INDONESIA	SIMPLE CYCLE	01-Jan-91	15-Aug-9
E.P.C. BURMA	THAKETA PWR STATION	SIMPLE CYCLE	01-Apr-88	01-Apr-90
ARAR PWR CO	ARAR, SAUDI ARABIA		01-Jan-19	01-Jan-19
ARAR PWR CO	ARAR, SAUDI ARABIA		01-Jan-19	01-Jan-19
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE	15-Oct-81	15-Apr-82
ARAR PWR CO	ARAR, SAUDI ARABIA		01-Jan-19	01-Jan-19
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE	01-Jan-19	15-Apr-82
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE	15-Jul-81	15-Apr-82
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE	15-Jul-81	15-Apr-82
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE	15-Jul-81	15-Apr-82
SCECO-EAST	QAISUMAH, SAUDI ARAB	SIMPLE CYCLE	03-Aug-7	04-Aug-8
SCECO-EAST	QAISUMAH, SAUDI ARAB	SIMPLE CYCLE	30-Jul-79	02-Jun-80
DUBAI SMELTTER	UNITED ARAB EMIRATES	SIMPLE CYCLE	01-Jun-78	17-May-8
ARAR PWR CO	ARAR, SAUDI ARABIA		01-Jan-19	01-Jan-19
PT CALTEX	DURI, INDONESIA	SIMPLE CYCLE	15-Apr-77	23-May-7
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE	15-Apr-81	15-Jan-82
STATE ORG OF ELEC IQ	MULLA ABDULLA P.S.	SIMPLE CYCLE	01-Jan-19	15-Jan-82
ABU DHABI WATER & EL	ALAIN, UAE	SIMPLE CYCLE	15-Dec-7	01-Jun-75

Gas Turbine 052N

			Shipped	Comm'l
QATAR	STATION #4	SIMPLE CYCLE	01-Dec-7	15-Sep-7
QATAR	STATION #4	SIMPLE CYCLE	01-Dec-7	15-Sep-7

Gas Turbine 061B

			Shipped	Comm'l
TURBO	UNKNOWN		01-Jan-19	01-Jan-19
INDIAN PETRO CHEMCAL	BARODA, INDIA	COMBINED CYCLE	22-Sep-8	01-Mar-87
INDIAN PETRO CHEMCAL	BARODA, INDIA	COMBINED CYCLE	22-Sep-8	01-Apr-88
BOUGAINVILLE COPPER	PAPUA, NEW GUINEA	SIMPLE CYCLE	15-Jan-82	15-Oct-82

Gas Turbine 071B

			Shipped	Comm'l
JERSEY CENTRAL P&L	GILBERT	COMBINED CYCLE	15-Jan-72	22-Apr-74
PORTLAND G.E.	BEAVER, OR	COMBINED CYCLE	15-Nov-7	30-Jun-74
PORTLAND G.E.	BEAVER, OR	COMBINED CYCLE	15-Nov-7	30-Jun-74
PORTLAND G.E.	BEAVER, OR	COMBINED CYCLE	15-Nov-7	30-Jun-74
PORTLAND G.E.	BEAVER, OR	Combined Cycle	15-Nov-7	30-Jun-74
PORTLAND G.E.	BEAVER, OR	COMBINED CYCLE	15-Nov-7	30-Jun-74
PORTLAND G.E.	BEAVER, OR	COMBINED CYCLE	15-Nov-7	30-Jun-74
PECO ENERGY COMPANY	CROYDON, PA	REGENERATIVE CYCLE	15-Oct-73	18-Jun-74
CENTRAL POWER & LIGH	LA PALMA	SIMPLE CYCLE	15-Dec-7	14-Nov-7
PECO ENERGY COMPANY	CROYDON, PA	REGENERATIVE CYCLE	15-Oct-73	18-Jun-74
PECO ENERGY COMPANY	CROYDON, PA	REGENERATIVE CYCLE	15-Oct-73	24-Jul-74
PECO ENERGY COMPANY	CROYDON, PA	REGENERATIVE CYCLE	15-Oct-73	18-Jun-74
PECO ENERGY COMPANY	CROYDON, PA	REGENERATIVE CYCLE	15-Oct-73	18-Jun-74
JERSEY CENTRAL P&L	GILBERT	COMBINED CYCLE	15-Jan-72	08-Jan-74
JERSEY CENTRAL P&L	GILBERT	REGENERATIVE CYCLE	15-Jan-72	22-Apr-74
PECO ENERGY COMPANY	CROYDON, PA	REGENERATIVE CYCLE	15-Oct-73	07-Aug-7
PECO ENERGY COMPANY	CROYDON, PA	REGENERATIVE CYCLE	15-Oct-73	05-Aug-7
PECO ENERGY COMPANY	CROYDON, PA	REGENERATIVE CYCLE	15-Oct-73	24-Jul-74
JERSEY CENTRAL P&L	GILBERT	REGENERATIVE CYCLE	15-Jan-72	23-May-7

Power Systems

Gas Turbine Models with Heavy Fuels

			Shipped	Comm'l
Gas Turbine 071C				
HOUSTON LIGHT & POWE	T.H. WHARTON	SIMPLE CYCLE	01-Nov-7	01-Dec-7
HOUSTON LIGHT & POWE	T.H. WHARTON	SIMPLE CYCLE	15-Sep-7	01-Dec-7
HOUSTON LIGHT & POWE	T.H. WHARTON	SIMPLE CYCLE	15-Oct-74	01-Dec-7
HOUSTON LIGHT & POWE	T.H. WHARTON	SIMPLE CYCLE	15-Nov-7	01-Dec-7
HOUSTON LIGHT & POWE	T.H. WHARTON	SIMPLE CYCLE	15-Nov-7	01-Dec-7
HOUSTON LIGHT & POWE	T.H. WHARTON	SIMPLE CYCLE	01-Nov-7	01-Dec-7
Gas Turbine 071E			**Shipped**	**Comm'l**
PUGET SOUND P&L	FREDERICKSON #1	SIMPLE CYCLE	01-Jan-19	27-Nov-8
PUGET SOUND P&L	FREDERICKSON #1	SIMPLE CYCLE	22-Apr-81	27-Nov-8
Gas Turbine 091A			**Shipped**	**Comm'l**
ELECTRICITE DE FRANC	BDF, FRANCE	SIMPLE CYCLE	15-Apr-75	15-Nov-7
Gas Turbine 091E			**Shipped**	**Comm'l**
ELECTRICITY SUPPLY	NORTH WALL	COMBINED CYCLE	15-Aug-8	01-Aug-8
ELECTRICITY SUPPLY	NORTH WALL	COMBINED CYCLE	15-Aug-8	15-Jan-82

Total of 223 GE Gas Turbines Burning Heavy Fuels

TABLE 1

HEAVY DUTY GAS TURBINES
BURNING ASH BEARING FUELS

INSTALLATION PERIOD
1950-1960

INSTALLATION LIST AND EXPERIENCE

Customer	Turbine Model	Appl. Code	No. of Units	Date Installed	Total Fired Hours	Fired Hours On ASH Bearing Fuels: Last Month*	Fired Hours On ASH Bearing Fuels: Total	Firing Temp. For Heavy Fuels	Metal Contamination Raw Fuel: Sodium(PPM)	Metal Contamination Raw Fuel: Vanadium(PPM)	Fuel Treatment Used
CRUDE OIL (1950-1960)											
MS-3000											
Arabian American Oil Co.	3002	M	2	1956	142,200		55,000	1450	2	12	V Inhibitor
Trans Arabian Pipeline	3002	M	7	1957	663,931		663,931	1450	2	12	V Inhibitor
		TOTAL UNITS	9	TOTAL HOURS	806,131		718,931				
RESIDUAL OIL (1950-1960)											
MS-3000											
Bangor Hydro-electric	3002	EU	2	1950-51	54,000		8,500	1500	20-100	50-360	2 STG Centrifuge V Inhibitor
Central Vermont	3002	EU	3	1952	131,000		50,000	1500	20-100	50-360	2 STG Centrifuge V Inhibitor
Union Pacific	3002 5001	L L	26 31	1951-54 1958-61	1,900,000		1,900,000	1450	0-10	1-55	2 STG Desalting and V Inhibitor
GTS John Sargent	3002	SP	1	1956	9,700		7,700	1450	15	58	2 STG Centrifuge V Inhibitor
Brazil	3001	EU	2	1958-60	427,000	6/72	10,000	1450			2 STG Centrifuge V Inhibitor
MS-8001											
British Columbia	8001	EU	4	1957-58	66,600		32,000	1450			2 STG Centrifuge V Inhibitor
		TOTAL UNITS	69	TOTAL HOURS	2,588,300		2,008,200				

N.I. - No Information

APPLICATION CODE
EI - Industrial Power Generation
EU - Utility Power Generation
L - Railroad Locomotive
M - Industrial Mechanical Drive
SP - Ship Propulsion

TABLE 2.1

HEAVY DUTY GAS TURBINES
BURNING ASH BEARING FUELS

INSTALLATION PERIOD
1961 - Present

INSTALLATION LIST AND EXPERIENCE

Customer	Turbine Model	Appl. Code	No. of Units	Date Installed	Total Fired Hours	Fired Hours On ASH Bearing Fuels: Last Month*	Fired Hours On ASH Bearing Fuels: Total	Firing Temp. For Heavy Fuels	Metal Contamination Raw Fuel: Sodium(PPM)	Metal Contamination Raw Fuel: Vanadium(PPM)	Fuel Treatment Used
CRUDE OIL											
MS-3000											
SOPEG	3002	M	2	1961	146,000	6/72	120,000	1500			
Phillips	3002	M	6	1976				1730	5.8	.6	1-STG Centrifuge
Sonatrach	3002	M	3	1977	---		---	1650	5.0	1.5	1-STG Centrifuge
MS-5000											
Oasis Oil Co.	5001	EI	1	1964	78,000	6/72	5,000	1450			
Saudi Arabia	5001	EU	1	1966	39,000		NI	1450			
Abu Dahbi	5001	EU	5	1968-70	35,000	6/72	1,000	1550			1-STG Centrifuge
Caltex	5001	EI	5	1970-75	213,800	4/77	185,000	1650	10	.6	1-STG Centrifuge
Abu Dhabi	5001	EU	4	1974	5,300	5/76	0	1650	25	.15	1-STG Centrifuge
Caltex	5001	EI	1	1977	---			1650			1-STG Centrifuge
MS-7000											
Florida Power Corp.	7001(B)	EU	4	1972	22,000	5/76	12,000	1840	10	3	2-STG ESD
Jersey Central	7001(B)	EU	4	1973	19,600	---	0	1750	-	-	None Installed
Portland GE	7001(B)	EU	6	1974	650	---	0	1840	-	-	2-STG ESD
Philadelphia Electric	7001(B)	EU	8	1975	32,500	---	0	1840			None Installed
Arizona Public Service	7001(B)	EU	1	1975	900	5/76	200	1800	14	.1	2-STG ESD
Arizone Public Service	7001(C)	EU	3	1976	3,000	---	0	1840	14	.1	2-STG ESD
Jeddah-Saudi Arabia	7001	EU	4	1977		4/77	1,500	1840			Centrifuge
		TOTAL HOURS	58	TOTAL HOURS	595,750		324,700				

N.I. - No Information

TABLE 2.2

HEAVY DUTY GAS TURBINES
BURNING ASH BEARING FUELS

INSTALLATION PERIOD
1961-Present

INSTALLATION LIST AND EXPERIENCE

Customer	Turbine Model	Appl. Code	No. of Units	Date Installed	Total Fired Hours	Fired Hours On ASH Bearing Fuels: Last Month*	Fired Hours On ASH Bearing Fuels: Total	Firing Temp. For Heavy Fuels	Fuel Viscosity @110°F	Fuel Viscosity S. G.	Metal Contamination Raw Fuel: Sodium (PPM)	Metal Contamination Raw Fuel: Vanadium (PPM)	Fuel Treatment Used
RESIDUAL OIL													
Broken Hills Prop.	3002	SP	2	1977	0		0	1650					
MS-5000													Centrigufe V Inhibitor
Central Vermont	5001	EU	1	1961	10,550		700	1450					
Ferrara	5001	EI	2	1963	112,400	3/70	51,700	1400		.94-.99	9-90	20-118	2-STG Centrifuge V Inhibitor
Green Mt. Power Co.	5001	EI	1	1965	8,200		600	1500					V Inhibitor
GE Lynn	5001	EI	1	1970	15,000	11/76	14,000	1650			100 max.	100 max.	2-STG Centrifuge or 2-STG ESD V Inhibitor
Broken Hills Prop.	5002	SP	2	1973-74	20,000	4/77	18,600	1650			40	2	1-STG Centrifuge
O.N.E. Morocco	5001	EU	3	1973-75	9,600	4/77	3,900	1650			34	71	2-STG ESD V-Inhibitor
Reksten	5002	SP	1	1974	10,000	4/77	9,000				100 max.	50-280	2-STG Centrifuge V Inhibitor
MS-7000													
Houston Lighting & Power**	7001(C)	EU	6	1974	4,200	---	0	1950					None Installed
Ohio Edison**	7001(B)	EU	2	1974	15,000	---	0	1750					None Installed
Salt River Projects	7001(B)	EU	1	1975	5,100		0	1840					None Installed
Alcoa Surinam	7001(B)	EU	1	1976	1,950	2/77	1,300	1750	N.I.	N.I.	60-150	80	2-STG Centrifuge V Inhibitor
Florida Power Corp	7001R(B)	EU	6	1976	6,720	2/77	2,030	1840	N.I.	N.I.	22-33	28-45	2-STG ESD Inhibitor
Central Power & Light**	7001(B)	EU	1	1976	140	---	0	1840					None Installed
Puerto Rico WRA	7001(B)	EU	8	1977	11,500	---	0	1840					3-STG ESD V Inhibitor
PLN Indonesia	7001(B)	EU	4	1977	0	---	0	1840					2-STG Centrifuge V Inhibitor
	TOTAL UNITS		41	TOTAL HOURS	230,350		101,830						

*If zero fired hours in previous month, month and year of last operation on heavy fuel is given.

**These units are not currently being fired on residual oil, but the gas turbines were originally provided with capability to burn residual oil. These units are included in this tabulation for completeness in the event the owner converts to residual oil.

Table 5-4

BBC - GAS TURBINES, HEAVY FUEL OIL

Plant, Country	Type	Year of order	Output (kW) site conditions
Lima I, Sta Rosa	12/8	1945	10,000
Chimbote, Peru	10	1945	4,000
Beznau I, Switzerland	12/8	1946	13,000
Beznau II, Switzerland	12/12	1946	27,000
Jeddah I, Saudiarabien*	10	1951	5,000
Sta Cruz, Tenerife	10	1949	4,400
Jeddah II, Saudiarabien*	10	1953	5,750
Jeddah III, Saudiarabien*	10	1953	22,500
St. Dizier, France	8	1953	5,900
Livorno I & II, Italy	12/8	1954	45,000
Fiumicino, Italy	12/8	1955	22,500
Otterbacken, Sweden	12/8	1955	27,500
Santa Cruz I & II, Algeria	12	1955	24;000
Multan, Pakistan	10	1956	5,700
Hyderabad, Pakistan	10	1956	5,700
Mayaquez I & II, Puerto Rico	12/8	1956	40,000
Oxelosund, Sweden	12/8	1957	27,500
Bremen, Vahr I & II, Germany	12/8	1957	50,000
Berlin, Steglitz I & II, Germany	12/8	1957	48,000
Brest, France	12	1959	17,200
Erfurt, Germany	12/8	1959	25,000
Corumba, Brazil	7	1962	2,700
Montevideo, Uruguay	12/8	1963	21,600
Nagoya Works, Japan	10	1966	6,300
Bermuda I, Bermudas	11L	1968	14,600
Bahamas, Blue Hill	11L	1969	13,650
Bermuda II, Bermudas	11LA	1970	15,650
Timelkam, Austria	13	1972	70,600
Kabul I & II, Afghanistan	9	1976	43,600
Salvador I-V, Brazil	11	1976	291,250
San Luis I & II, Brazil	11	1976	116,500
Lomé (2 units), Togo	9	1978	50,000
Tungshiao I, II, & III, Taiwan	11	1979	182,700

* Heavy fuel oil replaced by crude

Table 3

GE'S EXPERIENCE WITH HEAVY FUEL TREATMENT SYSTEMS
FEBRUARY 1994

C = Crude
R = Residual
B = Blend

CDS-P = Centrifuge Purification
CDS-W = Centrifuge Washing
EDS-W = Electrostatic Washing

Fuel	Treatment System Type	Customer	Frame Size	Number	Gas Turbine Fired Hours
C	EDS-W	APS, Arizona	7	4	3,600
C	CDS-W	ARAMCO, Saudi Arabia	3	9	
C	CDS-W	Caltex, Sumatra	5	9	200,000
C	CDS-W	Caltex, Indonesia	5	1	16,000
C	CDS-W	China National, China	5	1	
C	CDS-W	Electrico, Saudia Arabia	5	6	39,000
C	CDS/EDS-W	Empressa, Guatemala	5	2	22,000
C	EDS-W	FPC, Bartow, Florida	7	4	12,000
C	CDS-W	MEW (Dona, Al Wajbah) Quatar	9	4	150,000
C	CDS-W	Phillips, North Sea	3	6	45,000
C	CDS-P	SCECO-C Al Juba Saudi Arabia	6	7	104,000
C	CDS-P	SCECO-C Leyla Saudia Arabia	5	6	81,000
C	EDS-W	SCECO-C Riyadh Saudi Arbia	5	2	48,000
C	EDS-W	SCECO-C Riyadh Saudi Arabia	7	14	919,000
C	CDS-P	SCECO-E Al Quisumah Saudi Arabia	5	4	60,000
C	CDS-P	SCECO-E Al Quisumah Saudi Arabia	6	2	90,000
C	CDS-P	SCECO-S Al Duba Saudi Arabia	5	2	20,000
C	CDS-P	SCECO-S Gizan Saudi Arabia	6	2	10,000
C	CDS-P	SCECO-S Gizan Saudi Arabia	7	1	
C	CDS-P	SCECO-S Asir Saudi Arabia	7	4	
C	CDS-P	SCECO-S Tihama Saudi Arabia	7	5	53,000
C	EDS/CDS-P	SCECO-W Jeddah Saudi Arabia	7	7	693,000
C	CDS-W	SEDC Shantou China	6	6	8,100
C	CDS-W	SMPPC Shenzmeh China	6	2	40,000
C	CDS-W	SOE Mosul Iraq	5	10	
C	CDS-P	Sonatrach Djamha Algeria	3	2	250,000
C	CDS-P	Sonatrach Elnamra & Dishra Algeria	3	2	12,000
C	CDS-P	Sonatrach Elnamra II Argeria	3	1	180,000
C	CDS-P	SOPEG Algeria	3	2	120,000
C	CDS-W	WED Al Ain VAE	5	2	10,000
C	CDS-W	ZDC Zhuhhai China	6	2	6,400

NOTE: The "Gas Turbine Fired Hours" reported in this table are not current in all cases.

Table 3 (Continued)
GE'S EXPERIENCE WITH HEAVY FUEL TREATMENT SYSTEMS
FEBRUARY 1994

C = Crude
R = Residual
B = Blend

CDS-P = Centrifuge Purification
CDS-W = Centrifuge Washing
EDS-W = Electrostatic Washing

Fuel	Treatment System Type	Customer	Frame Size	Number of Units	Gas Turbine Fired Hours
R	CDS-W	Alcoa, Suriname	7	1	26,000
R	CDS-W	Alto Ferrara Italy	5	2	54,000
R	CDS-W	Central Vermont Power, Vermont	5	1	700
R	CDS-W	EDF, France	9	5	13,000
R	CDS-W	EECI, Ivory Coast	5	4	70,000
R	CDS-W	EMSA, Argentina	5	2	60,000
R	CDS-W	ENDESA, Chile	5	2	50,000
R	CDS-W	ENDESA, Chile	6	1	9,000
B	EDS-W	EPC, Burma	5	1	
R	CDS/EDS-W	FPC, Debary, Florida	7	6	45,000
B	CDS-W	GE Lynn	5	2	50,000
B	EDS-W	General Petro, Syria	5	6	101,000
R	CDS-W	Golden Valley, Alaska	7	2	47,500
R	CDS-W	Green Mountain Power, Vermont	5	1	600
R	CDS-W	Hess, St. Croix	5	1	
R	CDS-W	IPCL, India	5	3	200
R	EDS-W	IPCL, India	6	2	120,000
R	CDS-W	O.N.E. Morocco	5	6	192,000
R	CDS-W	O.N.E. Mohammedia Morocco	6	3	19,000
R	CDS-W	O.N.E. (Tan-Tan), Morocco	6	3	15,400
B	CDS-W	Pee, Syria	5	3	15,000
B	CDS-W	PLN, Indonesia	5	2	40,000
R	CDS-W	PLN, Indonesia	7	4	30,000
R	EDS-W	Progil, France	5	8	1,080,000
R	CDS-W	Puerto Rico	7	8	
R	CDS-W	Reksten, Norway	5	1	9,100
R	CDS-W	SEDC Nanshan, China	5	3	400
B	CDS-W	SENELEC Dakar Senegal	5	1	24,000
R	CDS-W	Shell, Curacao	5	1	17,000
R	CDS-W	Slough Estates, England	5	1	2,000
R	CDS-W	Taunton, Mass	5	1	10,000
R	EDS/CDS-W	TPC Tunghsaio, China	7	6	117,000
		WAPDA Kot Addu, Pakistan	9	4	63,000

NOTE: The "Gas Turbine Fired Hours" reported in this table are not current in all cases.

APPENDIX - 2

EXAMPLE OF DETAILED CALCULATIONS FOR LEVELIZED UNIT GENERATION COST

OPTION : CCFO TAX ON FUEL: NO TAX DISCOUNT RATE: 8%

All Values Are Per KW Of Installation. (SCENARIO 1.1)

LINE	YEAR		1	2	3	4	5	6	7	8	9	10	11	12
	Capital Charges													
1	Annual Debt Service	$	79.75	79.75	79.75	79.75	79.75	79.75	79.75	79.75	79.75	79.75		
2	Annual Return On Equity	$	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85
3	Total Capital Chages	$	130.59	130.59	130.59	130.59	130.59	130.59	130.59	130.59	130.59	130.59	50.85	50.85
4	Net Present Value	$1,054												
	Fuel Costs													
5	Net Annual Generation	KWH	6000	6000	6000	6000	6000	6000	6000	6000	6000	6000	6000	6000
6	Average Net Heat Rate	BTU/KWH	8720	8720	8720	8720	8720	8720	8720	8720	8720	8720	8720	8720
7	Annual Fuel Consumption	MMBTU	52.32	52.32	52.32	52.32	52.32	52.32	52.32	52.32	52.32	52.32	52.32	52.32
8	Fuel Oil Price	$/BBL	17.37	17.94	18.53	19.20	19.89	20.61	21.35	22.12	23.16	24.24	25.38	26.57
9		$/MMBTU	2.714	2.803	2.895	3.000	3.108	3.220	3.336	3.456	3.618	3.788	3.965	4.151
10	Annual Fuel Costs	$	141.98	146.66	151.48	156.94	162.60	168.46	174.54	180.83	189.30	198.17	207.45	217.17
11	Net Present Value	$2,043												
	O&M Costs													
12	Inflation Index		1.253	1.281	1.310	1.344	1.378	1.413	1.450	1.487	1.535	1.584	1.635	1.688
13	Annual Cost Of Consumables	$	33.67	34.43	35.20	36.11	37.03	37.98	38.96	39.96	41.24	42.57	43.94	45.35
14	Annual Fixed Costs	$	23.80	24.34	24.88	25.52	26.18	26.85	27.54	28.25	29.15	30.09	31.06	32.06
15	Total Annual O&M Costs	$	57.47	58.76	60.09	61.63	63.21	64.83	66.50	68.21	70.40	72.66	75.00	77.41
16	Net Present Value	$738												
17	**Total Generation Costs**	$	330.05	336.01	342.16	349.17	356.41	363.89	371.63	379.63	390.29	401.43	333.30	345.43
18	Net Present Value	$3,834												
19	Unit Generation Costs	C/KWH	5.50	5.60	5.70	5.82	5.94	6.06	6.19	6.33	6.50	6.69	5.56	5.76
	Levelized Unit Cost													
20	Levelized Unit Cost	C/KWH	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28
21	Net Annual Generation	KWH	6000	6000	6000	6000	6000	6000	6000	6000	6000	6000	6000	6000
22	Annual Generation Costs	$	376.80	376.80	376.80	376.80	376.80	376.80	376.80	376.80	376.80	376.80	376.80	376.80
23	Net Present Value	$3,844												

LINE	13	14	15	16	17	18	19	20	21	22
1										
2	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85
3	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85	50.85
4										
5	6000	6000	6000	6000	6000	6000	6000	6000	6000	6000
6	8720	8720	8720	8720	8720	8720	8720	8720	8720	8720
7	52.32	52.32	52.32	52.32	52.32	52.32	52.32	52.32	52.32	52.32
8	27.81	29.50	31.29	33.18	35.20	37.33	39.59	42.00	44.54	47.24
9	4.345	4.609	4.888	5.185	5.499	5.833	6.187	6.562	6.960	7.382
10	227.35	241.13	255.76	271.27	287.72	305.17	323.68	343.31	364.13	386.22
11										
12	1.742	1.813	1.886	1.963	2.043	2.126	2.212	2.302	2.396	2.493
13	46.81	48.71	50.69	52.76	54.90	57.13	59.45	61.87	64.38	67.00
14	33.09	34.43	35.83	37.29	38.81	40.38	42.03	43.73	45.51	47.36
15	79.90	83.15	86.53	90.05	93.71	97.51	101.48	105.60	109.90	114.36
16										
17	358.10	375.13	393.13	412.16	432.28	453.53	476.01	499.76	524.87	551.43
18										
19	5.97	6.25	6.55	6.87	7.20	7.56	7.93	8.33	8.75	9.19
20	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28
21	6000	6000	6000	6000	6000	6000	6000	6000	6000	6000
22	376.80	376.80	376.80	376.80	376.80	376.80	376.80	376.80	376.80	376.80
23										

CALCULATION NOTES

1. Capital Cost = $ 700
   Debt Capital = 70% = $490
   Interest Rate = 10% Term: 10 years
   Annual Debt Service = $79.75
   $= P \times i / (1-(1+i)^{-N})$
   P = Principal = $ 490
   i = Interest Rate = 0.1
   N = No. of years = 10

2. Equity Capital = 30% = $ 210
   Annual Return on Equity = 24%
   Repayment Period = 22 years
   Annual Repayment Installment = 50.85
   Same equation as (1) above, except:
   P = $ 210
   i = Rate of Return = 0.24
   N = 22 years

3. Sum of (1) & (2) = 130.59

4. Net Present Value = $ 1,054
   Cash Flow for 22 years
   Discount Rate = 8%

7. Product of (5) & (6) - Input Data
   MMBTU = Million BTU

8. Fuel price from Reference 1.

9. Based on calorific value of 6.4 MMBTU/Barrel

10. Product of (7) & (9)

11. NPV at 8% discount rate

12. Inflation index from reference 1

13. Cost inflated to 2003 for first year
    5×6 MWH $\times (1.0293)^4$ then escalated per general escalation rate

14. 3.4% of capital cost for first year then escalated per general escalation rate

15. Sum of (13) & (14)

19. Ratio of generation cost to generation for each year.

20-23. The Levelized Unit cost of 6.28 c/KWH has been checked. This value can be calculated by Trial-and-Error or in an explicit form from the equation for NPV (see Appendix –3).

APPENDIX - 3

NPV CALCULATIONS OF CONSTANT & ESCALATING CASH FLOWS

Annual cash flows are totals at the ends of the years. {CF}

Cash Flow for the 1st Year	=	C	
Project Period, YEARS	=	N	
Discount Rate, as fraction	=	d	= as % PER YEAR x 100

CASE I: *CASH FLOWS SAME FOR EACH YEAR*

Cash Flow for 1st Year	=	C_1	=	C
Present Value, p_1	=	$C/(1+d)^1$		
Cash Flow for 'n'th Year	=	Cn	=	C
Present Value, p_n	=	$C/(1+d)^n$		
Cash Flow for 'N'th Year	=	C_N	=	C
Present Value, p_N	=	$C/(1+d)^N$		

NPV(d){CF} = Net Present Value of {CF} at the discount rate of 'd'

= Sum of present values of cash flows from Year 1 to Year N

= $p_1 + \ldots\ldots + p_n + \ldots\ldots + p_N$

= $C/(1+d)^1 + \ldots + C/(1+d)^n + \ldots + C/(1+d)^N$

= $C \times (1-(1+d)^{-N})/d$ **(sum of GP series)**

CASE II: *CASH FLOWS ESCALATING AT A CONSTANT RATE FOR EACH YEAR*

Escalation Rate, as fraction	=	e	= as % PER YEAR x 100	
Cash Flow for 1st Year	=	C_1	=	C
Present Value, p_1	=	$C/(1+d)^1$		
	=	$C \times ((1+e)/(1+d))^1/(1+e)$		
Cash Flow for 'n'th Year	=	C_n	=	$C \times (1+e)^{n-1}$
Present Value, p_n	=	$C_n/(1+d)^n$		
	=	$C \times ((1+e)/(1+d))^n/(1+e)$		
Cash Flow for 'N'th Year	=	C_N	=	$C \times (1+e)^{N-1}$
Present Value, p_N	=	$C_N/(1+d)^N$		
	=	$C \times ((1+e)/(1+d))^N/(1+e)$		

Let, $(1+d)/(1+e)$ = $(1 + D)$

Then, D = $(d-e)/(1+e)$

NPV(d){CF}	=	Sum of present values of cash flows from Year 1 to Year N
	=	$p_1 + \ldots\ldots + p_n + \ldots\ldots + p_N$
	=	$(C/(1+D)^1)/(1+e) + \ldots + (C/(1+D)^n)/(1+e) + \ldots + (C/(1+D)^N)/(1+e)$
	=	$C \times (1-(1+D)^{-N})/(D \times (1+e))$
	=	NPV(D){CF}/(1+e)
NPV(D){CF}	=	Net Present Value of {CF} at the discount rate of 'D'
D	=	Equivalent Discount Rate
	=	(d-e)/(1+e)

CASE III : *CASH FLOWS ESCALATING AT VARIABLE RATES*

The variable cost escalations (as calclated from the inflation indexes for each year) can be converted to a "levelized" escalation rate, e, which will give the same NPV of the annual cash flows as the actual ones. This e has to be determined by trials.

The procedure for CASE II above can then be followed using e as the constant escalation rate.

CALCULATION OF LEVELIZED UNIT GENERATION COST

Let G_1, G_2, etc. be the annual generations {G}, A_1, A_2, etc. be the annual generation costs {A} & U1, U2, etc. be the unit generation costs, for year 1, year 2 etc.
Levelized unit generation cost is the equivalent constant unit generation cost, if used to replace the actual unit costs, U1, U2, etc., will result in new annual generation costs which will have the same NPV as the actual ones (A1, A2, etc.).

Levelized unit generation cost = U

Then, by definitions:

$$A_1 = U_1 \times G_1$$
$$A_2 = U_2 \times G_2$$
$$\text{----------}$$
$$A_n = U_n \times G_n$$
$$\text{----------}$$
$$A_N = U_N \times G_N$$

And,

$$\begin{aligned}
NPV\{A\} &= NPV\{A_1, A_2, \ldots, A_n, \ldots, A_N\} \\
&= NPV\{U_1 \times G_1, U_2 \times G_2, \ldots, U_n \times G_n, \ldots, U_N \times G_N\} \\
&= NPV\{U \times G_1, U \times G_2, \ldots, U \times G_n, \ldots, U \times G_N\} \\
&= (G_1/(1+d)^1 + \ldots + G_n/(1+d)^n + \ldots + G_N/(1+d)^N) \times U \\
&= NPV\{G_1, G_2, \ldots, G_n, \ldots, G_N\} \times U \\
&= NPV\{G\} \times U
\end{aligned}$$

Therefore, $U = NPV\{A\}/NPV\{G\}$

NOTE: $NPV\{G\} = (G_1/(1+d)^1 + \ldots + G_n/(1+d)^n + \ldots + G_N/(1+d)^N)$
This function is not being applied on a stream of cash flows, but has equation of same form as actual NPVs.

Appendix E

Report on Short Circuit, Load Flow and Transient Stability Studies – Task 4B

CENTRAL ELECTRICITY BOARD
MAURITIUS

REPORT ON SHORT CIRCUIT, LOAD FLOW & TRANSIENT STABILITY STUDIES FOR CEB, MAURITIUS, DISTRIBUTION SYSTEM

TKC JOB NO: K-3818
APRIL 2001

THE KULJIAN CORPORATION
3700 SCIENCE CENTER
PHILADELPHIA, PA 19104

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ATTACHMENT	DESCRIPTION
ATTACHMENT-1	TABLES, INSTALLATION REQUIRED AT NEW PLANT

REPORT ON SHORT CIRCUIT, LOAD FLOW & TRANSIENT STABILITY STUDIES

1.0 INTRODUCTION:

A study of the projected load growth & generation capacity of The Central Electricity Board, Mauritius, reveals that, in order to meet future load requirements with a reliable distribution network, additional generation is required in the St. Louis area and a 132 kV transmission network should be introduced. The purpose of these studies is to determine: the short circuit requirement of the buses by means of a Short Circuit Study; the voltage, power factor profile, transmission line and transformer loading conditions by means of a Load Flow Study; and the transient behavior of the proposed machines under line fault conditions by means of a Transient Stability Study.

2.0 OBJECTIVES OF THE STUDIES:

The objectives of the studies are as follows:

a.) To determine the short circuit level at the 132 kV, 66 kV & 22 kV buses due to the addition of generation during the years 2005 to 2010.

b.) To check the load flow of the 66 kV & 132 kV network, it's voltage profiles, loading of the transformers and transmission lines, and to determine if reactive power compensation will be required.

c.) To check the transient behavior of the proposed generators in the St. Louis area under the following conditions:

- Faults on 132 kV & 66 kV transmission lines
- Load rejection

3.0 DISTRIBUTION NETWORK:

3.1 The existing transmission & distribution network of The Central Electricity Board, Mauritius, consists of 66 kV & 22 kV substation facilities with 66 kV & 22 kV transmission lines. The study of the existing system network reveals that the system suffers from high line losses and low power factor profile. In order to improve the power factor and reduce the transmission line losses, a 132 kV transmission network system has been proposed to be integrated with the existing 66 kV transmission lines as follows:

a.) Proposed 132 kV/66 kV & 66kV/22kV Substations:

The following new substations are envisaged for the interconnection of the existing 66 kV network and the proposed 132 kV network:

- St. Louis – Two (2 x 100% capacity) 125 MVA transformers (2005)
- Rose Hill - Two 90 MVA transformers (2010)
- Amaury - Two 90 MVA transformers (2010)
- Wooton - Two 90 MVA transformers (2010)
- Nicolay 2 – 66 kV – no transformers (2005)
- Nicolay 2 - Two 90 MVA transformers (2010)
- L'Avenir – switch station only (no transformers) (2010)

66/22kV Substation:

- Sottise – Two 30 MVA transformers (2005)

b.) Proposed 132 kV & 66 kV transmission lines:

i) 132 kV single circuit transmission lines (installed on double circuit structures) between the following substations through the L'Avenir area:

- Nicolay 2 to Amaury
- Wooton to Amaury
- Wooton to Nicolay 2

The above transmission lines are envisaged to be installed by the year 2005. These lines will be designed for 132 kV but will operate initially at 66kV. By the year 2010 a switching station will be constructed at L'Avenir and the above lines will be converted to double circuit lines as follows:

- L'Avenir to Nicolay 2
- L'Avenir to Amaury
- L'Avenir to Wooton

ii) 132 kV double circuit lines between following substations:

- Fort William to Saint Louis (by year 2005)

iii) 132 kV double circuit lines (upgrade of existing 66 kV) by year 2010:

- Wooton to Rose Hill
- Rose Hill to St. Louis
- St. Louis to Nicolay 2 (use existing St. Louis to Nicolay)

iv) 66 kV transmission lines by year 2005 between following substations:

• Medine to La Chaumiere	-	Single circuit
• Union St. Aubin to Combo	-	Single circuit
• Nicolay 1 to Nicolay 2	-	Double circuit (use existing)
• SIC/SIDEC to Chaumiere	-	Single circuit
• Champagne to Combo	-	Single circuit
• Bell Vue – Sottise	-	Single circuit
• Amaury – Sottise	-	Single circuit

v) 66 kV lines/cables by year 2010 between following substations:

• Savannah to Combo	-	Single circuit
• Henrietta to Wooton	-	Double circuit, 8.8 Km overhead line & 10 Km underground cable.

c.) <u>66 kV transmission lines considered to be de-energized/deleted by year 2010:</u>

Double circuit transmission lines between the following substations:

- Wooton to Rose Hill
- St. Louis to Rose Hill
- Saint Louis to Nicolay 2 (formerly St. Louis to Nicolay)

3.2 New Generation is envisaged to be connected into the network as follows:

- <u>Proposed 100 MW generation near St. Louis in the year 2005:</u>

  The initial generation block will be comprised of two (2) 40 MW gas turbine generators and one 20 MW steam turbine generator. The generation will be at 11 kV and will be connected to the 132 kV network through 11/138 kV step-up transformers of the following ratings:

  For GTGs - (2) 60 MVA

  For STG - 30 MVA

- Additional new generation considered for the year 2005.

  30 MW generation at SIC/SIDEC connected to the 66 kV substation at La Chaumiere through a 11/69 kV 45 MVA step-up transformer.

  30 MW generation at Medine (Bagasse Coal #2) connected to the 66 kV substation at La Chaumiere through a 11/69 kV 45 MVA step-up transformer.

- New generation for the year 2010.

  Two additional identical Combined Cycle Generation blocks (see above for St. Louis area) are envisaged for the year 2010 and are to be connected to the 132 kV network through their respective similar step-up transformers.

  34 MW generation each at Union St. Aubin and Savannah SE and connected to the 66 kV substation at Combo through two (2) 11/69 kV, 45 MVA step-up transformers.

4.0 GENERATION AND LOAD SCHEDULE:

This study has been focused on the scenario of the years 2005 and 2010. The summary of generation as well as the load schedule considered for the study are as follows:

YEAR	GENERATION SCHEDULE	LOAD SCHEDULE
2005 Crop Season	420 MW	385.82 MW
2005 Inter-Crop Season	394 MW	375.82 MW
2010 Crop Season	634 MW	570.55 MW
2010 Inter-Crop Season	672 MW	560.70 MW

Adequate generation outage has been considered to establish load flow scenarios. The network drawing of the respective scenarios depicts the loads and the generation schedule.

5.0 SOFTWARE:

The latest version of a proven load flow program under the software package EDSA has been utilized to study power flow and voltage situations at the receiving and distribution substations.

The program recognizes the interconnected power system with cable, transformers, and generators for the analysis of the voltage profile and determination of active and reactive power flow, and is capable of determining bus voltage with power angle, bus power factor, flow of current through branches, line losses in kW and in KVAR, and transformer losses and percentage loading. The load flow study has been performed based on the Newton-Raphson method.

The software package provides the facility for short circuit studies with 3-phase symmetrical short circuits, and with single phase-to-ground faults, and determines the fault levels at the different network buses.

The software package also provides facility for transient stability studies. The software is capable of simulating the dynamic behavior of the power system due to a fault or load impact.

6.0 ASSUMPTIONS FOR THE STUDY:

6.1 For fault current calculations, the following ratios have been considered:

Transmission Lines: R (0)/R (+) = 3
X (0)/X (+) = 3

Transformers: R (0)/R (+) = 1
X (0)/X (+) = 1

Where: R (0), X (0): Zero sequence resistance and reactance.
R (+), X (+): Positive sequence resistance and reactance.

6.2. The short circuit study has been performed based on 3-phase bolted faults.

6.3 The peak demand has been considered from **Table-5.1-Installations required at the new plant for Combined Cycle Units (extract of CEB, Mauritius, Distribution System Study Report)** enclosed as Attachment-1. The load flow study, as well as the short circuit study, have been carried out with the consideration that all loads are lumped on 66 kV/22kV buses. Details are shown on the respective network drawings, enclosed.
The losses in the downstream distribution network are included in the peak demand considered.

6.4 The studies have been carried out for the year 2005 and 2010 crop and inter-crop seasons.

7.0 INPUT DATA:

7.1 Resistance & reactance values for generators, transmission lines and transformers considered for the study are given in the following tables:

Table-1: Transformer Data

Transformer MVA	% Impedance	X/R
125	12.0	40
90	12.5	38
65	12.5	31
60	12.0	30
50	12.5	30
48	12	30
45	12.5	28
38	12	28
30.6	12	25
30	11.53	25
29.4	12.3	25
25	12.5	25
20	9.58	21
17	10.74	19
15.3	11	18
15	11	18
15	9.8	18
12.5	12.5	17
10	9.6	16
7.5	6.86	14

NOTES:

1.) X/R Ratio of Transformers is based on ANSI/IEEE C37.010-1979.

2.) Impedances of existing Transformers are as per CEB, Mauritius, Drawing No. 1824-98.

Table - 2 : Input Data For Generators

Generator KVA Ratings	29260 29280		27260 28375 28387	23529 27280	30000		30800		15000		15000		12500	
Subtransient quantities														
$\%X''_d$ X/R"(+)	20.5	45	20.1	45	19.9	45	19	45	28	39	16.4	39	22.7	35
$\%X''_d$ X/R"(0)	10.25	22.50	10.05	22.50	9.95	22.50	9.50	22.50	14.00	19.50	8.20	19.50	11.35	17.50
$\%X''_d$ X/R"(-)	19.48	42.75	19.10	42.75	18.91	42.75	18.05	42.75	26.60	37.05	15.58	37.05	21.57	33.25
Transient quantities														
$\%X'_d$ X/R' (+)	28	61	28	61	28	61	28	61	39.2	54	39.2	54	31.78	49
$\%X'_d$ X/R' (0)	14.00	30.50	14.00	30.50	14.00	30.50	14.00	30.50	19.60	27.00	19.60	27.00	15.89	24.50
$\%X'_d$ X/R' (-)	26.60	57.95	26.60	57.95	26.60	57.95	26.60	57.95	37.24	51.30	37.24	51.30	30.19	46.55
Synchronous quantities														
$\%X_d$ X/R(+)	204.8	450	204.8	450	200	450	190	450	280	390	280	390	227	350
$\%X_d$ X/R(0)	102.40	225.00	102.40	225.00	100.00	225.00	95.00	225.00	140.00	195.00	140.00	195.00	113.50	175.00
$\%X_d$ X/R(-)	194.56	427.50	194.56	427.50	190.00	427.50	180.50	427.50	266.00	370.50	266.00	370.50	215.65	332.50

Table - 2 : Input Data For Generators (Cont'd)

Generator KVA Ratings	7425		8262		6855		18000		15000 17000		19500 19000		37270 35200	35294 37286
Subtransient quantities														
$\%X''_d$ X/R"(+)	21	30	23	32	38	45	15	40	19.67	40	16.8	41	22.8	45
$\%X''_d$ X/R"(0)	10.50	15.00	11.50	16.00	19.00	22.50	7.50	20.00	9.84	20.00	8.40	20.50	11.40	22.50
$\%X''_d$ X/R"(-)	19.95	28.50	21.85	30.40	36.10	42.75	14.25	38.00	18.69	38.00	15.96	38.95	21.66	42.75
Transient quantities														
$\%X'_d$ X/R' (+)	29.4	42	32.2	44.8	53.2	63	21	56	27.538	56	23.52	57.4	31.92	63
$\%X'_d$ X/R' (0)	14.70	21.00	16.10	22.40	26.60	31.50	10.50	28.00	13.77	28.00	11.76	28.70	15.96	31.50
$\%X'_d$ X/R' (-)	27.93	39.90	30.59	42.56	50.54	59.85	19.95	53.20	26.16	53.20	22.34	54.53	30.32	59.85
Synchronous quantities														
$\%X_d$ X/R(+)	210	300	230	320	380	450	150	400	196.7	400	168	410	228	450
$\%X_d$ X/R(0)	105.00	150.00	115.00	160.00	190.00	225.00	75.00	200.00	98.35	200.00	84.00	205.00	114.00	225.00
$\%X_d$ X/R(-)	199.50	285.00	218.50	304.00	361.00	427.50	142.50	380.00	186.87	380.00	159.60	389.50	216.60	427.50

Table - 2 : Input Data For Generators (Cont'd)

Generator KVA Ratings	37400 35000		47059		45000		27000		6250		47100	
Subtransient quantities												
%X"d X/R" (+)	20.1	45	20	45	11.3	45	19	45	21	30	15.0	45.0
%X"d X/R" (0)	10.05	22.50	10.05	45.00	5.65	22.50	9.50	22.50	10.50	15.00	7.5	22.5
%X"d X/R" (-)	19.10	42.75	19.1	45.00	10.74	42.75	18.05	42.75	19.95	28.50	14.5	42.75
Transient quantities												
%X'd X/R' (+)	28.14	63	28	61	15.82	63	26.6	63	29.4	42	21.0	63.0
%X'd X/R' (0)	14.07	31.50	14.50	30.50	7.91	31.50	13.30	31.50	14.70	21.00	10.5	31.5
%X'd X/R' (-)	26.73	59.85	26.6	57.95	15.03	59.85	25.27	59.85	27.93	39.90	19.93	59.85
Synchronous quantities												
%Xd X/R(+)	201	450	204.8	450.0	113	450	190	450	210	300	150.0	430.0
%Xd X/R(0)	100.50	225.00	102.4	225.0	56.50	225.00	95.00	225.00	105.00	150.00	75.0	225
%Xd X/R(-)	190.95	427.50	194.5	427.5	107.35	427.50	180.50	427.50	199.50	285.00	142.5	427.5

NOTES:

1.) X/R ratios of generators are based on ANSI/IEEE C37-010-1979.

2.) X"d, X'd, Xd of existing generators is as per the CEB, Mauritius, one line diagram dwg. no. 1824-98.

3.) (+) : Positive sequence

4.) (-) : Negative sequence

5.) (0) : Zero sequence.

Table – 3 : Input Data For Transmission Lines

Branch Reference	Transmission Line	Total Length (Meters)	No. of Ckts.	No. of Conductors per Phase	Conductor Size (mm sq)	Impedance per Circuit in Ohms R(+)	X(+)	R(-)	X(-)	R(0)	X(0)	Ampacity per Ckt. (Amps)	Conductor Maximum Temperature (Deg C)
66 kv lines													
27 – 23	Champagne – Wooton	16870	1	2	100	2.74	5.33	2.74	5.33	8.22	15.99	806	75
08,08B - 16 $	Nicolay 2 - St. Louis	6800	2	1	366	0.61	2.72	0.61	2.72	1.83	8.16	810	75
08B,C – 09 # 08D,C – 09 $	Nicolay 2 - Belle Vue	12611	2	1	150	2.7	5.15	2.7	5.15	8.1	15.45	523	75
16,16D – 31	St. Louis - La Chaumiere	8247	2	2	150	0.93	2.32	0.93	2.32	2.79	6.96	1046	75
31,31A – 32	La Chaumiere – Henrietta	12579	2	2	150	1.40	3.56	1.40	3.56	4.2	10.68	1046	75
27 – 29	Champagne - F.U.E.L.	16476	1	1	228	2.40	7.05	2.40	7.05	7.20	21.15	603	75
04,04A – 08	Ft. George – Nicolay 2	3303	2	1	570	0.263	1.29	0.263	1.29	0.79	3.87	1061	75
32 – 33	Henrietta – Combo	24000	1	1	150	4.80	8.40	4.80	8.40	14.4	25.2	523	75
29 –26	F.U.E.L. - Beau Champ	16491	1	1	150	3.02	5.83	3.02	5.83	9.06	17.49	523	75
06 – 06A,06B	Nicolay 1 – Nicolay 2	1000	2	1	150	0.21	0.41	0.21	0.41	0.63	1.23	523	75
09,09A –12	Belle Vue – Amaury	9866	2	1	150	1.97	3.45	1.97	3.45	5.92	10.35	523	75
12,12A – 29	Amaury - F.U.E.L.	9866	2	1	150	1.97	3.45	1.97	3.45	5.92	10.35	523	75
16C,E,I,J – 16	Ft. Victoria - St. Louis (Cable)	3000	4	1	240	0.34	0.17	0.34	0.17	1.02	0.51	290	85
29A-29	F.U.E.L. Power Stn – F.U.E.L. S/S	500	1	1	150	0.11	0.20	0.11	0.20	0.33	0.60	523	75
33-27	Combo – Champagne	3400	1	1	366	0.31	1.36	0.31	1.36	0.93	4.08	810	75
10C,D-09	Belle VueSE - Belle Vue	1180	2	1	366	0.11	0.437	0.11	0.437	0.33	1.311	810	75
41-31	Medine - La Chaumiere	8000	1	1	150	1.46	2.82	1.46	2.82	4.38	8.46	523	75
33A-33 $ 47 - 33 #	Union St. Aubin – Combo	1200	1	1	150	0.22	0.424	0.22	0.424	0.66	1.272	523	75
48 - 33 #	Savannah – Combo	1600	1	1	150	2.92	5.6	2.92	5.6	8.76	16.8	523	75
31C-31 $ 31C-49 #	SIC/SIDEC - La Chaumiere	9000	1	1	150	1.65	3.18	1.65	3.18	4.95	9.54	523	75
32,32A – 23 #	Henrietta – Wooton	18800	2	2	150	1.7	2.87	1.70	2.87	5.10	8.61	1046	75
16,16H -19 $	St. Louis - Rose Hill	7106	2	1	366	0.64	2.84	0.64	2.84	1.92	8.52	810	75
19,19B-23 $	Rose Hill – Wooton	9525	2	1	366	0.86	3.81	0.86	3.81	2.58	11.43	810	75
41 - 31 #	Medine - La Chaumiere	8000	1	1	150	1.46	2.82	1.46	2.82	4.38	8.46	523	75

Table – 3 : Input Data For Transmission Lines

Branch Reference	Transmission Line	Total Length (Meters)	No. of Ckts.	No. of Conductors per Phase	Conductor Size (mm sq)	Impedance per Circuit in Ohms R(+)	X(+)	R(-)	X(-)	R(0)	X(0)	Ampacity per Ckt. (Amps)	Conductor Maximum Temperature (Deg C)
66 kv lines contd.													
09-50	Bell Vue – Sottise	8500	1	1	150	1.54	3.0	1.54	3.0	4.62	9.0	523	75
12-50	Amaury – Sottise	25000	1	1	150	5.0	8.82	5.0	8.82	15.0	26.46	523	75
132 KV Lines													
02,02A - 17	Ft. William - St. Louis	3000	2	2	400	0.12	0.17	0.12	0.17	0.36	0.51	1702	75
17,17A -18 #	St. Louis - Rose Hill	7106	2	1	366	0.64	2.84	0.64	2.84	1.92	8.53	810	75
12-23*	Amaury – Wooton	27600	1	1	366	2.48	11.04	2.48	11.04	7.44	33.12	810	75
08-23*	Nicolay 2 – Wooton	22000	1	1	366	1.98	8.8	1.98	8.8	5.94	26.4	810	75
08-12*	Nicolay 2 – Amaury	25750	1	1	366	2.32	10.3	2.32	10.3	6.96	30.9	810	75
	Above three lines marked with (*) will operate at 66KV during year 2005.During year 2010 these lines will operate at 132 KV & the line data will be as follows												
46,46B -11 #	L'Avenir – Amaury	16700	2	1	366	1.5	6.68	1.50	6.68	4.50	20.04	810	75
46,46A - 22 #	L'Avenir – Wooton	10900	2	1	366	0.98	4.36	0.98	4.36	2.94	13.08	810	75
46 - 07,07C #	L'Avenir - Nicolay 2	8500	2	1	366	0.77	3.4	0.77	3.4	2.31	10.2	810	75
18,18A - 22 #	Rose Hill – Wooton	9525	2	1	366	0.86	3.81	0.86	3.81	2.58	11.45	810	75
07,07b – 17 #	Nicolay2 – St Louis	6800	2	1	366	0.61	2.72	0.61	2.72	1.83	8.16	810	75
22 kv lines													
24,24A - 25	Champagne – Ferney	4500	2	1	150	0.83	1.49	0.83	1.49	2.49	4.47	523	75
34 – 35	Combo - Union Vale	15900	1	1	150	2.92	5.20	2.92	5.2	8.76	15.6	523	75
25 – 35	Union Vale – Ferney	12700	1	1	100	3.54	4.38	3.54	4.38	10.62	13.14	403	75
Note													

1. Branch reference marked with ' # ' is applicable for the year 2010 only.
2. Branch reference marked with ' $ ' is applicable for year 2005 only.

8.0 SHORT CIRCUIT STUDY:

The short circuit study has been carried out for load scenarios for the years 2005 and 2010 crop seasons. The study has been performed for a 3-phase bolted fault. It is to be noted that the inter-crop season for the years 2005 and 2010 each have less generation and load than those of the respective crop seasons. Therefore, the short circuit studies for the crop seasons will provide more conservative results. Further, for the purpose of the short-circuit studies, parallel transformers as well as transmission lines have been considered so as to obtain the highest possible short circuit levels.

The study results are enclosed as Attachments - 2 and 3.

9.0 LOAD FLOW STUDY:

The load flow study has been performed based on the load scenarios for the crop as well as the inter-crop seasons for the years 2005 and 2010. Further, the case studies have been performed considering both transformer and line outages.

9.1 Network Configuration:

The network configurations used for the load flow studies are shown on the following drawings enclosed with this Report:

Case	Description	Drawing No.
1.	Single-line Diagram – Systems Study	E-001, Sheets 1 & 2
2.	Load Flow Study - for year 2005 crop season	E-002, Sheets 1 & 2
3.	Load Flow Study - for year 2005 inter-crop season	E-003, Sheets 1 & 2
4.	Load Flow Study - for year 2010 crop season.	E-004, Sheets 1 & 2
5.	Load Flow Study – for year 2010 inter-crop season	E-005, Sheets 1 & 2

The results of the load flow studies are enclosed as Attachments - 4 through 11.

10.0 TRANSIENT STABILITY STUDY:

10.1 The transient stability study has been carried out based on the load scenarios for the years 2005 and 2010 crop seasons. The study has been carried out to determine the minimum fault clearing time at the 132 kV/66 kV bus and the behavior of the proposed generation block (2 GTG and 1 STG) at Ft. William, under the following conditions:

1.) **Fault on the 132 kV Transmission Line:**

A three-phase to ground fault has been considered on the 132 kV transmission line between Ft. William and St. Louis.

2.) **Fault on the 66 kV Transmission Line**

A three-phase to ground fault has been considered on the 66 kV transmission line between Wooton and Nicolay 2.

3.) **Load rejection at the 66 kV Bus:**

The study has been performed based on a load rejection of 43.25 MW for the year 2005 and 57.3 MW for the year 2010.

10.2 **Governor and Exciter Models:**

10.2.1 Models for 40 MW GTG:

Simplified single-shaft GE Gas Turbine simulation model (Drg. E-005) for the Governor and IEEE-AC1 simulation model (Drg. E-006) for the Exciter have been considered for the study.

Machine Data:

Capacity of Machine	: 47059 kVA
Power Factor	: 0.85
Inertia Constant	: 16.3 sec.
Damping coefficient	: 0.7 PU
D-axis Transient Reactance	: 0.28 PU
D-axis Synchronous Reactance	: 2.048 PU
Q-axis Transient Reactance	: 0.55 PU
Q-axis Synchronous Reactance	: 1.87 PU
D-axis Open Circuit Transient Time Constant	: 5.0 sec.
Q-axis Open Circuit Transient Time Constant	: 0.5 sec.

Input Data for GE Gas Turbine Governor Model:

K	= 25 PU	T_1	= 0.05 sec.	T_2	= 0.830 sec.
T_3	= 0.5 sec.	$FL_{Max.}$	= 2.0 PU	$Fl_{min.}$	= 0.0 PU
T_4	= 0.2 sec	T_5	= 15.0 sec.	T_6	= 2.5 sec.
T_7	= 3.3 sec.	T_8	= 450.0°F	a	= 1.0

Exhaust Temperature = 1022°F. Ambient Temperature = 104°F

Input Data for Exciter Model (IEEE-AC1):

K_a	= 25.0 PU	T_A	= 0.02sec.	$Vr_{Max.}$	= 50.0 PU
$Vr_{Min.}$	= 0.00 PU	T_B	= 1.0 sec.	T_C	= 0.001 sec.
T_E	= 1.4 sec.	K_E	= 1.0 PU	SE(1)	= 0.86 PU
SE(0.75)	= 0.5 PU	K_F	= 0.001	T_F	= 1.0 sec.
K_C	= 0.04 PU	K_D	= 0.36 PU		

10.2.2 Model for 20 MW Steam Turbine:

IEEE Steam Turbine Governor simulation model (Drg. E007) and IEEE-STI model (Drg. E008) have been considered for the Steam Turbine Governor and Exciter, respectively.

Machine Data:

Capacity	: 23529 kVA
Power Factor	: 0.85
Inertia Constant	: 16.0 sec./4.0 sec.*
Damping Coefficient	: 3.0 PU
D-axis Transient Reactance	: 0.28 PU
D-axis Synchronous Reactance	: 2.04 PU
Q-axis Transient Reactance	: 0.7 PU
Q-axis Synchronous Reactance	: 1.372 PU
D-axis Open Circuit Transient Time Constant	: 5.5 sec.
Q-axis Open Circuit Transient Time Constant	: 1.5 sec.

Input Data for IEEE Steam Turbine Governor Model:

K	= 10.0 PU	T_1	= 0.2 sec.	T_2	= 0.0 sec.
T_3	= 1.0 sec.	$P_{Max.}$	= 1.5 PU	$P_{min.}$	= 0.0 PU

dP_{up}/dt = 0.1 PU dP_{dn}/dt = -0.01 PU Tch = 0.5 sec.

* Data applicable for machines added in 2010.

Input Data for Exciter Model (IEEE-ST1):

K_a	= 40.0 PU	T_A	= 0.05/0.1 sec.*	$Vr_{Max.}$	= 14.00 PU
$Vr_{Min.}$	= 0.0 PU	T_B	= 0.001/0.022 sec.*	T_C	= 0.001 sec.
K_F	= 0.03 PU	T_F	= 1.0 sec.	K_C	= 0.05 PU
$Vi_{Max.}$	= 1.4/1.0 PU*	$Vi_{Min.}$	= 0.0 PU		

* Data applicable for machines added in 2010

11.0 ANALYSIS OF THE RESULTS:

11.1 Short Circuit Study:

The results of the Short Circuit Study are summarized in Table-4, below:

TABLE-4

Bus Ref.	Maximum Symmetrical Phase-Fault Current for 3-Ph. Bolted Fault (kA)		Maximum Asymmetrical Short Circuit Current corresponding to 3-Cycle time for 3-Ph. Bolted Fault (kA)	
	CASE-I	**CASE-II**	**CASE-I**	**CASE-II**
132 kV BUS	1.4	2.1	6.1	11.4
66 kV BUS	3.2	4.2	15.7	18.8
22 kV BUS	6.4	7.6	15.3	16.0
11 kV BUS	13.7	17.4	39.1	74.9

NOTE: Case-I: For the year 2005 Crop Season
Case-II: For the year 2010 Crop Season

The fault levels at different buses will increase gradually due to the addition of generating units in different years, and will correspond to the symmetrical phase-fault current. However, the asymmetrical interrupting capacity of the breakers will correspond to a 3-cycle fault current as indicated in Table-4.

Fault levels at Fort William and Montagne Jacquot:

The 132 kV bus fault levels at Fort William (Bus ID:02) will be as follows:

i) 3-pole symmetrical fault : 2.1 K amp

ii) Asymmetrical Short Circuit Current Corresponding to 3-cycle time : 11.4 K amp

A.C. Component corresponding to 3-cycle : 10.4 K amp

D.C. Component corresponding to 3-cycle : 4.8 K amp

The location of Montagne Jacquot is about 6 Km from Fort William and hence the 132 kV bus fault level there will be virtually the same as that of Fort William.

11.2 Load Flow Study:

a.) The results of the load flow study are highlighted below in Tables-5 & 6:

TABLE-5: LOAD FLOW STUDY RESULT HIGHLIGHTS: (CASE STUDY-CONSIDERING TRANSFORMER/LINE OUTAGE)

Description	Load flow results for the year			
	2005 crop	2005 Inter-crop	2010 crop	2010 Inter-crop
Generation: MW	393.96	383.52	583.20	572.26
MVAR	267.74	265.84	383.64	371.78
Load: MW	385.82	375.82	570.55	560.70
MVAR	239.69	233.72	354.58	348.85
Capacitor in MVAR	53.00	38.00	93.00	98.00
Max. voltage drop in				
132 kv bus	0%	0%	4.9%	7.0%
66 kv bus	7.5%	0.4%	7.3%	7.2%
22 kv bus	6.6%	6.8%	6.7%	5.5%
11 kv bus	3.3%	2.0%	1.6%	4.3%
Power factor in				
Generator bus	80 – 86%	80 – 85%	80 – 85%	80 – 86%
load bus	85%	85%	85%	85%

TABLE 6: LOAD FLOW STUDY RESULT HIGHLIGHTS: (CASE STUDY-WITHOUT TRANSFORMER/LINE OUTAGE)

Description	Load Flow Results for the year			
	2005 Crop	2005 Inter-crop	2010 Crop	2010 Inter-crop
Generation: MW	392.12	382.30	578.28	569.06
MVAR	266.95	263.47	374.47	366.03
Load: MW	385.82	375.82	570.55	560.70
MVAR	239.69	233.66	354.58	348.85
Capacitor in MVAR	37.00	28.00	67.00	73.00
Max voltage drop in				
132 kV bus	0	0	0	0
66 kV bus	6.6%	0	2.2%	1.0%
22 kV bus	3.2%	6.3%	1.9%	1.0%
11 kV bus	2.2%	1.6%	0.1%	0.7%
Power factor in				
Generator bus	80 – 87%	80 – 87%	80 – 85%	80 – 87%
Load bus	85%	85%	85%	85%

TABLE 7: LOAD FLOW STUDY RESULT HIGHLIGHTS: (CASE STUDY-OUTAGE OF NICOLAY 2-WOOTN LINE FOR YEAR 2005)

Description	Load Flow Results for the year			
	2005 Crop with trans./ line outage	2005 Crop without trans./ line outage	2005 Inter-crop with trans./line outage	2005 Inter-crop without trans./line outage
Generation: MW	394.76	392.42	384.30	382.62
MVAR	268.89	268.38	265.91	264.65
Load: MW	385.82	385.82	375.82	375.82
MVAR	239.69	239.69	233.66	233.66
Capacitor in MVAR	55.00	37.00	38.00	28.00
Max voltage drop in				
132 kV bus	0	0	0	0
66 kV bus	8.7%	7.3%	0	0
22 kV bus	8.2%	4.0%	6.64%	6.8%
11 kV bus	4.0%	2.6%	1.0%	1.6%
Power factor in				
Generator bus	80 – 85%	80 – 86%	80 – 87%	80 – 85%
Load bus	85%	85%	85%	85%

11.3 Transient Stability Study:

The set of curves in Attachments-12 through 15 represents the transient behavior of the 40 MW GTG's and 20 MW STG's proposed for the years 2005 and 2010 under the following transmission line fault and load rejection conditions:

a.) Transmission Line Fault:

A 3-phase to ground fault simulated in the 132 kV and 66 kV transmission lines and cleared within 150 milliseconds (ms). The relative power angle, terminal voltage, relative speed and electric power response plots with respect to time show that the 40 MW GTGs, and the 20 MW STG are in stable condition after the removal of the fault. The study extended further, increasing the fault clearing time to 250/300 ms., and the followings are observed:

i) For the year 2005 a 132kv line fault to be cleared within 250 ms. However, a66kv line fault could be possible to clear within a wider window of 300ms, to ensure stability.

ii) For year 2010 both 132kv as well as 66kv line faults could be possible to clear within 300ms, to ensure stability.

It is to be noted that the maximum fault clearing time for a long transmission line could be up to 250ms. Therefore, system reliability with 250/300 ms fault clearing time will ensure system reliability.

b.) Load Rejection:

From the load pattern depicted in the network representation of the respective year, the maximum load block for the year 2005 crop season is about 43.25 MW and that for the year 2010 is 57.3 MW. Therefore, the study has been carried out with a rejection of 100% of the largest load block for the respective years under study.

The plots of relative power angle, relative speed, and terminal voltage response with time shows that the voltage and speed after the load rejection are well within the acceptable limits of ± 10% and ±3%, respectively, for all generators under consideration.

12.0 CONCLUSION:

The Short Circuit Study reveals that, due to the addition of new generation at Ft. William, Medine, SIC/SIDEC, and Union St. Aubin, the fault levels will increase, and if the existing buses (66, 22, and 11 kV) do not comply with the corresponding steady state fault current in the study result, introduction of reactors to limit the fault current will be necessary.

The Load Flow Study results confirm that, in order to improve the voltage and power factor profile, reactive power compensation will be required as indicated below:

TABLE- 8: CAPACITOR BANK FOR REACTIVE POWER COMPENSATION

Station Reference (Bus ID)	Capacitor Bank to be Connected in MVAR							
	Year 2005 crop		Year 2005 Inter-crop		Year 2010 crop		Year 2010 Inter-crop	
	Case-I	Case-II	Case-I	Case II	Case-I	Case-II	Case-I	Case-II
Nicolay 2 (08)	10	10	5	5	20	15	20	15
Belle Vue (09)	18	12	15	8	15	12	18	10
Combo (33)	15	15	15	15	15	15	15	15
Rose Hill (18)	-	-	-	-	15	10	15	15
L'Avenir (46)	-	-	-	-	25	15	30	18
Ferney (25)	10	-	-	-	-	-	-	-
Union Valle (35)	-	-	3	-	-	-	-	-
TOTAL	53	37	38	28	90	67	98	73

NOTE: Case I: Case study with transformer/line outage (without Nicolat2-Wooton feeder outage).

Case II: Case study without transformer/line outage

The load flow study results reveal the following:

For network operation without any transformer or line outage, there will be no overloading of any transformer or line. The voltage drop at the buses are also within the acceptable limit of ±10%.

For network operation with transformer/line outage, the overloading of the following transformers will occur:

Sl. No.	Year	Transformer Description	Transformer Loading	Remarks
1.	2010 crop with Trafo/line outage	a) 90 MVA transformer at Wooton	102%	
		b) 45 MVA transformer at Belle Vue substation	101%	
		c) 30 MVA transformer at sottise substation	114%	Transformer capacity to be increased to have (N-1) security factor.
3.	2010 inter-crop with Trafo/line outage	a) 45 MVA transformer at Bell Vue	120%	The overloading of the transformer is due to the fact that there is no generation at Mon Losir S.E., during inter-crop season.
		b) 30 MVA transformer at Sottise sub-station.	114%	Ref. remarks under 1(c).

The transient stability study results show that the new generators at Ft. William will remain in synchronism with the grid if the 132 kV/66 kV transmission line fault is cleared within 300 ms. Further, due to a load rejection of 43.25 MW in the year 2005 and 57.3 MW in the year 2010, the voltage and frequency rise will be within the acceptable limit of ± 10% and ± 3%, respectively.

Per MPU request the load flow study for year 2005 has been extended to include the option for outage of 66kV line between Nicolay2 – Wooton. The result highlights are indicated in Table–7. It appears that the bus voltage drop and the power factors are within acceptable limits.

It is observed that there is no overloading of the transformers or transmission lines under this scenario. It is to be noted that in order to keep the voltage drop and power factor within acceptable limits, the peaking power generation (mode 05A) at Nicolay1 has been considered to generate 5MW, during Inter-crop season, with transformer/line outage condition. For all other scenarios this generation considered as reserve power source.

ATTACHMENT-1

EXTRACT OF CEB, MAURITIUS

DISTRIBUTION SYSTEM STUDY REPORT

(1 SHEET)

ATTACHMENT-1: EXTRACT OF CEB, MAURITIUS
DISTRIBUTION SYSTEM STUDY REPORT

TABLE: 5.1
INSTALLATIONS REQUIRED AT THE NEW PLANT FOR COMBINED CYCLE UNITS

	2001		2002		2003		2004		2005		2006		2007		2008		2009		2010		
	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	
CAPACITY, MW																					
New Plant	0	0	0	0	35	70	100	100	100	100	135	170	200	200	200	200	235	270	300	300	
Others																					
CEB																					
St. Louis	40	40	40	40	20	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0	
Ft. Victoria I	9	9	9	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Ft. Victoria II	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	
Ft. George	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	
Nicolay	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	
Hydro	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	
Total	282	282	282	277	257	253	253	253	253	253	253	253	253	233	233	233	233	233	233	233	
Private																					
F.U.E.L.	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	
Beau Champ	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	
Belle-Vue	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	
Continuous	0	39	0	39	0	39	0	39	0	30	0	30	0	18	0	18	0	18	0	18	
Bagasse/Coal #2	0	0	0	0	0	0	0	0	0	27	36	27	36	27	36	27	36	27	36	27	
Bagasse/Coal #3	0	0	0	0	0	0	0	0	0	0	0	0	0	46	62	46	62	46	62	46	
SIC/SIDEC (Coal)	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
Total	111	149	141	149	141	149	141	149	141	167	177	167	177	201	239	201	239	201	239	201	
Grand Total	393	431	423	426	398	402	394	402	394	420	430	420	430	434	472	434	472	434	472	434	
Total System (1)	393	431	423	426	433	472	494	502	494	520	565	590	630	634	672	634	707	704	772	734	
Largest Unit/Block (b)	34	34	34	34	35	35	50	50	50	50	50	50	50	50	50	50	50	50	50	50	
Next Largest ©	30	30	30	30	35	35	50	50	50	50	50	50	50	50	50	50	50	50	50	50	
Firm Cap (d)(1-b)	359	397	389	392	398	437	444	452	444	470	515	540	580	584	622	584	657	654	722	684	
Cap for Maint (e)(d-c)	329	367	359	362	363	402	394	402	394	420	465	490	530	534	572	534	607	604	672	634	
Non Oil Capacity, %	32.1	38.1	36.9	38.5	36	34.7	31.6	32.7	31.6	35	34	30.8	30.5	34.1	37.8	34.1	35.9	30.7	32.9	29.4	
Peak Demand (a)	290	300	305	315	321	331	340	350	362	372	389	399	419	429	452	462	489	499	529	539	**MEDIUM**
Largest as % of (a)	11.7	11.3	11.2	10.8	10.9	10.6	14.7	14.3	13.8	13.4	12.9	12.5	11.9	11.7	11.1	10.8	10.2	10.0	9.5	9.3	**GROWTH**
Margin 1 (d/a-1)%	23.8	32.3	27.8	24.6	24.0	32.0	30.8	29.3	22.7	26.3	32.6	35.5	38.4	36.1	37.6	26.4	34.5	31.2	36.6	27.0	
Margin 2 (e/a-1)%	13.4	22.3	17.9	15.1	13.1	21.5	16.1	15.0	8.8	12.9	19.7	23.0	26.5	24.5	26.5	15.6	24.3	21.2	27.2	17.7	
Peak Demand (a)	246	256	257	267	269	279	283	293	300	310	320	330	343	353	368	378	395	405	425	435	**LOW**
Largest as % of (a)	13.8	13.3	13.2	12.7	13	12.5	17.7	17.1	16.7	16.1	15.6	15.2	14.6	14.2	13.6	13.2	12.7	12.3	11.8	11.5	**GROWTH**
Margin 1 (d/a-1)%	45.9	55.1	51.4	46.8	48	56.6	56.9	54.3	48	51.6	60.9	63.6	69.1	65.4	69	54.5	66.3	61.5	69.9	57.2	
Margin 2 (e/a-1)%	33.7	43.4	39.7	35.6	34.9	44.1	39.2	37.2	31.3	35.5	45.3	48.5	54.5	51.3	55.4	41.3	53.7	49.1	58.1	45.7	
Peak Demand (a)	334	344	352	362	373	383	396	406	424	434	457	467	495	505	536	546	582	592	632	642	**HIGH**
Largest as % of (a)	10.2	9.9	9.7	9.4	9.4	9.1	12.6	12.3	11.8	11.5	10.9	10.7	10.1	9.9	9.3	9.2	8.6	8.4	7.9	7.8	**GROWTH**
Margin 1 (d/a-1)%	7.5	15.4	10.5	8.3	6.7	14.1	12.1	11.3	4.7	8.3	12.7	15.6	17.2	15.6	16.0	7.0	12.9	10.5	14.2	6.5	
Margin 2 (e/a-1)%	-1.5	6.7	2.0	0.0	-2.7	5.0	-0.5	-1.0	-7.1	-3.2	1.8	4.9	7.1	5.7	6.7	-2.2	4.3	2.0	6.3	-1.2	

Appendix F

Preliminary Environmental Impact Assessment – Task 5

MINISTRY OF PUBLIC UTILITIES

Feasibility Study for Fort William Power Station

PRELIMINARY ENVIRONMENTAL IMPACT ASSESSMENT

July 2000

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FEASIBILITY STUDY FOR FORT WILLIAM POWER STATION
PRELIMINARY ENVIRONMENTAL IMPACT ASSESSMENT

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EXECUTIVE SUMMARY

1. INTRODUCTION

This Preliminary Environmental Impact Assessment (EIA) Report forms part of the feasibility study for the development of an independent thermal power generation facility which will be required to meet the future electricity demands in Mauritius.

The project will be implemented by private funds under Concession Project Act (1997).

Three alternative projects were considered on two sites as shown below.

Site	Alternative
Fort William	1. Combined Cycle Plant 2. Diesel plant
Montagne Jacquot	1. Coal Fired Plant

The proposed site at Fort William is located adjacent to the Robert Edward Hart Garden and the new Sand Plant and is of an area of 8.5 Ha. No specific site at Montagne Jacquot has been identified by the Ministry of Housing and Lands at the time of this report although a request was made to the Ministry. For the purpose of this Preliminary EIA Report, a 18 Ha site adjacent to the Montagne Jacquot Sewerage Treatment Plant has been assumed.

The project developer will be required to conduct a full EIA with specific design details and produce a report in order to obtain the EIA licence under the Environment Protection Act of 1991.

2. ENVIRONMENTAL IMPACTS AND MITIGATION

2.1 Air Quality

Emissions of pollutants such as Sulphur Dioxide (SO_2), Nitrous Oxides (NO_x), smoke and Carbon Monoxide (CO) will occur for all three alternatives. The SO_2 concentration will depend on the percentage sulphur content in the fuel used. Obviously lower percentage will lead to lesser SO_2 emission. Higher emissions of particulate matter (Total Suspended Solids and PM10) are expected in the coal plant alternative at Montagne Jacquot. The coal storage and handling required under this alternative will also produce dust emissions. These emissions will be limited by locating the storage areas downwind and by other measures such as covering of

conveyors etc. The predominant easterly winds will carry the stack emissions out to sea for most of the time. However, summer onshore winds can disperse the pollutants inland. The ground concentrations of the air pollutants can be limited by selection of appropriate stack height. More in depth study of the impacts to the three sensitive receptors at Fort William which are the Residential Areas, Bulk Sugar Terminal and Robert Edward Hart Garden will have to be carried out by developer during the full EIA.

Mitigative measures such as Electro-Static Precipitators will be used at Montagne Jacquot. Steam injection for NO_x emission control will be made in the gas turbines for the combined cycle alternative.

An air monitoring programme will be set up to check that the emissions and ambient air quality are complying with the standards.

Air quality impacts during the construction phase will be minimised by efficient site management practices.

2.2 NOISE

Various components of each alternative plant will produce noise to levels high enough to require mitigation measures. The most sensitive receptor will be the Residential Areas at Fort William.

The noise levels will be reduced to comply with the legal standards by the provision of noise barriers and the provision acoustic panels to the inside faces of machine halls. Large pumps, generating units and other equipment like coal crushers will be housed inside buildings.

2.3 WATER

The water requirement during the operational phase of each alternative will be as tabulated below:

Plant	Seawater	Fresh Water
Combined Cycle	25,000 m^3/hr	35 m^3/hr
Diesel Plant	17,000 m^3/hr	20 m^3/hr
Coal Fired	70,000 m^3/hr	60 m^3/hr

Seawater will be required mainly for cooling purposes. Fresh water will be used for cycle make-up, domestic and washing purposes. All the wastewater produced will be treated to meet the proposed national standards prior to discharge into the ocean. A regular monitoring programme will be implemented to ensure that the effluent discharge are in compliance with the relevant standards.

The stormwater runoff from the coal pile will be intercepted and diverted to sedimentation basins prior to discharge. The coal storage areas will be provided with an impermeable liner to prevent ingress of rainwater into the ground.

2.4 Solid Waste

Combustible solid waste and oily sludge will be incinerated. Other major waste such as coal ash will be disposed of by:

(i) Recycling by incorporation in concrete production.
(ii) Land disposal e.g. to an engineered landfill.

2.5 Fuel Storage and Handling

Oil spill protection will be provided around all the fuel tanks through the construction of retention dykes with an impermeable base. Fire protection will fully comply with the recommendations of the National Fire Protection Association (NFPA) of the USA.

Fire protection to coal storage will be by spraying of water and the use of sprinklers. Temperature alarms in coal bunkers will be provided. Protection against the possibility of explosions caused by coal dusts will be achieved, by proper ventilation and good housekeeping.

2.6 Health and Safety

Design and operation of the power plant will comply with applicable US and International Codes and Standards.

2.7 Transmission Line Impacts

The transmission lines from the power plant will be overhead 132 KV. The most significant impacts will be aesthetical and taking up of land.

2.8 Social and Cultural Impacts

The setting up of a new Power Plant on either site will not require the relocation of population. One beneficial impact at Fort William is that the uncontrolled dumping presently occurring on the site will cease. Both sites do not have any conservation or historical value. Nevertheless, public protests can be expected at Fort William and against the construction of a jetty for coal unloading at Montagne Jacquot.

The project will create new training and employment opportunities.

2.9 Traffic

Traffic impacts will occur mainly during the construction phase. No significant impact is expected during the operational phase.

3. CONCLUSION

The various environmental impacts likely to occur as a result of the setting up and operation of the new power plant will be mitigated through the use of appropriate mitigation measures to ensure compliance with the applicable environmental requirements.

1.0 INTRODUCTION

1.1. This report forms part of the feasibility study for the development of an independent thermal power generation facility. The study is being conducted for the Ministry of Public Utilities and is financed by the United States Trade and Development Agency (USTDA). Tasks 5 and 12 of the Terms of Reference require that Environmental Impacts, and Mitigative Measures be evaluated and reported.

1.1 PROJECT BACKGROUND

At present the total installed capacity of the Central Electricity Board (CEB) in terms of power generation amounts to approximately 410 MW, of which about 65% is diesel fired, 21% gas-oil fired and 14% hydroelectric. There are also a few small scale Independent Power Producers (IPP's) namely sugar mills which generate power through coal and bagasse fired co-generation. The latest of these plants to come into operation is the 60 MW capacity Belle Vue Power Plant.

Rust Kennedy & Donkin (1996) identified the total capacity to be generated by the CEB to 920 MW by the year 2015. As such in a least cost generation and transmission plan developed, it was proposed that a new site at Fort William be developed in phases up to a total capacity of 300 MW so as to meet the future power requirements. Also with the progressive decommissioning of the CEB Saint Louis and Fort Victoria Power Plants, another new and modern Power Generating Plant is deemed necessary to meet the forecast demand of the Island. The decommissioning of the existing Fort Victoria Plant is expected when the new power plant will start operation.

1.2 FEASIBILITY STUDY PURPOSE

In July 1997, the Government of Mauritius adopted the Concession Project Act that allows infrastructure projects to be set up and run by private investors. The law is designed to attract local and foreign private investment in projects that have so far been financed by public funds only. Projects can be implemented under four general categories, namely:

(i) Build, Operate and Transfer (BOT),

(ii) Build, Own and Operate (BOO),

(iii) Build, Own, Operate and Transfer (BOOT), and

(iv) Design, Build, Finance and Operate (DBFO)

This project has been identified to be implemented under the Concession Project Act (1997). The feasibility study is being conducted to allow the Government of Mauritius to manage the development of an independent thermal power generation facility in Mauritius.

The tasks to be covered within the study are summarised below.

(i) Review Existing Information,

(ii) Siting and Land Use Issues,

(iii) Fuel Procurement, Supply & Pricing,

(iv) Power Plant Technology & Transmission Facilities Requirements,

(v) Environmental Impacts and Project Permit Requirements,

(vi) Project Capital Costs,

(vii) Project Operations & Maintenance Costs,

(viii) Power Sales Agreement,

(ix) Project Financing Options,

(x) Project Construction Schedule, and

(xi) Final Report.

1.3 OVERVIEW OF THE PROPOSED PROJECT AND POTENTIAL SITES

The proposed new power generating station will be of thermal type, utilising fossil fuels. Some of the major considerations for siting of such a new power plant are:

- Availability of adequate land suitable for heavy construction.
- Convenient access to the site for movement of equipment & materials.
- Arrangement for supply of fuel to the site.
- Connection with the existing electric transmission and distribution system for evacuation of power.
- Availability of adequate cooling water or dissipation of waste heat.
- Effects of emissions from the plant.
- Availability of the utilities and infrastructure for operation and maintenance of the power plant.

A survey was undertaken to identify possible sites on the island which best satisfy the above requirements, and the following three were considered further:

- Fort William
- Montagne Jacquot
- Vieux Grand Port

Refer to Figure 1.1 for the location of the sites.

The Vieux Grand Port site was eventually eliminated because of the unfavourable site conditions.

1.4 ENVIRONMENTAL POLICY AND REGULATIONS

1.4.1 Government of Mauritius

The Department of Environment (DoE) within the Ministry of Environment and Urban & Rural Development is the administrative agency responsible for coordinating the government's environmental policy with activities involving:

1. Formulating government goals and strategies for environmental protection and natural resource management,

2. Coordinating and monitoring the implementation of the National Environment Action Plan (NEAP),

3. Providing advice and assistance to the other ministries in modifying and developing policies,

4. Providing support in promulgating legislation, and

5. Reviewing and formulating the development of environmental standards for National Environment Commission (NEC).

The Environmental Protection Act (EPA) of 1991 (refer to Appendix A) provides the legislative mandate for implementing governmental policies. The EPA, which consists of 11 parts, provides authority for enforcement, environmental impact assessments, spill and environmental emergencies, national environmental standards, coastal and maritime management, and a national environment fund.

The regulations for environmental impact assessments (EIA) in the EPA specify requirements for the submission of an application, the specific contents of an EIA, a period for public comment and hearing, EIA review, and EIA approval.

This environmental assessment addresses those aspects of the EPA dealing with the contents of the EIA (Part IV, Section 14) and compares emissions and waste discharges with recognized guidelines of the World Bank, as well as the DoE standards.

1.4.2 World Bank Guidelines

The World Bank has established environmental guidelines for use in evaluating the effectiveness of pollution control measures applied to projects that receive financial assistance. These guidelines provide minimum standards for common industrial processes and pollutants. However, the application of the guidelines must be

adjusted to each specific project depending on the environmental impacts and pollution control costs.

Table 1.1 summarises the World Bank Guidelines which apply for new thermal power plants.

1.4.3 General Environmental Design Criteria

Based on the World Bank guidelines and Mauritius Environment Standards, and the potential for environmental impacts from power plants, a list of general environmental design criteria have been developed (refer Table 1.2). These design criteria assist in minimizing environmental impacts and may be used as a guide by the IPP developer for evaluating environmental impacts from the project.

1.5 ENVIRONMENTAL IMPACT ASSESSMENT

This assessment represents preliminary Environmental Impact Study as part of the overall feasibility study. The objective of the assessment is to address the Scope of Work and existing guidelines for performing environmental assessments in sufficient depth to support competitive international tendering for similar types of projects internationally.

The full environmental impact report will be prepared by the successful IPP developer, based upon the actual site location, plant design and technology.

1.6 PROJECT PERMIT REQUIREMENTS

Figures 1.2 and 1.3 summarise the different steps for project permitting. The project will require a bidding process prior to the signature of a concession agreement according to the Concession Project Act (1997), which is included in Appendix C.

Table 1.1
World Bank Guidelines for New Thermal Power Plants

Environmental Resource	Criteria
Air	<u>Emissions Standards</u> 1. Particulate Matter (PM) PM < 50 mg/Nm^3 2. Sulphur Dioxide (SO_2) Less than 0.2 MT/day per MW for the first 500 MW + 0.1 MT/day for each additional MW of capacity > 500 MW $SO_2 \leq 2000$ mg/Nm^3 with a maximum level of 500 MT/day 3. Nitrogen Oxides (NO_x) 750 mg/Nm^3 for a coal fired plant 460 mg/Nm^3 for an oil fired plant 320 mg/Nm^3 for a gas fired power plant 300 mg/Nm^3 for fuel oil fired Combined Cycle dry at 15% oxygen 2000 mg/Nm^3 for diesel driven plant dry at 15% oxygen <u>Ambient Quality</u> 1. Particulate Matter Total Suspended Particulate - 80 µg/m^3 - annual average - 230 µg/m^3 - 24 hour average 2. $PM_{10} \leq 50$ µg/m^3 - annual average ≤ 150 µg/m^3 - 24 hour average 3. SO_2: 80 µg/m^3 - annual average 150 µg/m^3 - 24 hour average 4. NO_x: 100 µg/m^3 - annual average 150 µg/m^3 - 24 hour average

Environmental Resource	Criteria		
Water	**Parameter**		**Maximum Value (mg/l)**
Liquid Effluents	pH		6-9
	Total Suspended Solids		50
	Oil and Grease		10
	Total residual chlorine		0.2
	Chromium (Total)		0.5
	Copper		0.5
	Iron		1.0
	Zinc		1.0
	Temperature increase at the edge of the mixing zone		≤ 3° C
Solid Wastes	Landfill or other disposal sites provided they do not impact nearby water bodies		
Ambient Noise	**Maximum Allowable, Leq (hourly), in dB(A)**		
	Receptor	Daytime 07:00-22:00	Night time 22:00-07:00
	Residential Institutional Educational	55	45
	Industrial Commercial	70	70

Source: World Bank Pollution Prevention and Abatement Handbook, 1998

Table 1.2
General Environmental Design Criteria

Environmental Category	Criteria
Air Emissions[1]	1. Sulphur Dioxide (SO_2) a. 2000 mg/Nm^3 (World Bank) 2. Particulate matter (dust) a. 50 mg/Nm^3 concentration in stack gas (World Bank) b. Smoke : Ringlemann No. 2 or equivalent opacity (not to exceed more than 5 minutes in any period of one hour) 3. Nitrogen Oxides (NO_x): a. 1000 mg/m^3 for diesel plant b. 750 mg/Nm^3 for coal plant (World Bank) c. 300 mg/Nm^3 for fuel oil fired combined cycle (World Bank) 4. Carbon monoxide (CO) a. 1000 mg/m^3 concentration in stack gas 5. Fluorine compounds (F) a. 100 mg/m^3 concentration in stack gas 6. Hydrogen chloride (HCl) a. 200 mg/m^3 concentration
Ambient Air Quality[1]	1. SO_2 a. Annual average: 50 μg/m^3, maximum b. 24-hour average: 150 μg/m^3, maximum c. 1-hour average: 350 μg/m^3, maximum 2. Particulate Matter (TSP) a. Annual average: 50 μg/m^3, maximum b. 24-hour average: 150 μg/m^3, maximum 3. Particulate Matter (PM10) a. 24-hour average: 100 μg/m^3, maximum 4. NO_2 a. 24-hour average: 200 μg/m^3, maximum 5. NO_X a. 24-hour average: 150 μg/m^3 (World Bank) b. Annual average : 100 μg/m^3 (World Bank) 6. CO a. 8-hour average: 10,000 μg/m^3, maximum

Environmental Category	Criteria
	b. 1-hour average: 25,000 $\mu g/m^3$, maximum
Stack Height (SH)	Minimum stack height in order to avoid building downwash: SH > H + 2.5 L where: H = Building height (m) L = Lesser dimension of either the height or width (m) of the largest nearby building (e.g., boiler for a coal plant)
Water Discharge	1. The pH of all discharges should be between 6 and 9 2. There should be no discharge of wastestreams containing concentrations of metals (i.e., chromium and selenium) that are toxic to aquatic organisms 3. Total suspended solids: 50 mg/l max 4. Oil and Grease - 10 mg/l mx 5. Water used to transport bottom or fly ash should not be discharged to surface water 6. Thermal a. 40°C maximum b. No more than 3° C above intake water beyond a reasonable mixing zone 7. Chemical Oxygen Demand (COD): 750 mg/l max. 8. Biochemical Oxygen Demand (BOD_5): 250 mg/l max. 9. Maintenance and metal cleaning wastewater should not be discharged to surface waters 10. Floatables : 6 mm maximum size
Water Intake Structure	1. Intake velocity should be no greater than 0.3 m/s 2. As practicable, intakes should be located away from the littoral (shore or beach) zone of the water body 3. Intake should be located as to not affect fish breeding areas 4. Intake screens should be installed to minimise entrapment of native fish or other aquatic organisms
Water Discharge	1. Multi-port diffusers should be used as practicable for dispersal of

Environmental Category	Criteria
Structure	heated water from once-through cooling systems. 2. Location of discharges should consider the potential for dispersion offered by a particular water body and ecological sensitivity of the receiving water body.
Land/Solid Wastes	1. Ash disposal should occur within cells landfill, with topsoil covering a completed cell. Fugitive dust should be controlled through water spraying or other equivalent control technique. Runoff should be diverted to a sedimentation tank. 2. Land disposal of oily wastes (i.e., oil, solvents, transformer fluids etc.) should not be performed. Oily sludge will be incinerated.
Fuel Storage	A containment wall should be constructed around all fuel storage tanks and handling facilities. The embankment should be designed to retain the full/potential volume of the tank or the handled fuel.
Ecology	No significant impacts to endangered, rare, and vulnerable species as listed by the Committee on International Trade of endangered species.
Noise	1. Workers: No greater than 85 dBA average for an 8-hour shift; hearing protection can be used in lieu of this limit 2. At property boundary: 70 dBA average 3. In residential areas: 60 dBA daytime and 55 dBA night time average
Social and Cultural	1. Secondary growth effects (e.g.,spontaneous settleback) to the natural and cultural resources should be considered in the project development. A regional plan should be developed for significant secondary growth 2. Fair compensation and/or redesign of physical infrastructure for involuntary resettlement 3. Protection and/or preservation of significant archaeological and historical resources should be required

Note: 1. Figures derived from World Bank Guidelines are indicated in brackets. Other figures are taken from local standards (refer Appendix B)

2.0 PROJECT DESCRIPTION

Three alternatives have been considered during the course of this study, two of which apply for the Fort William Site and the third one to the Montagne Jacquot Site.

The project description given below are for typical plants utilising the proposed technologies. The IPP developer may change certain aspects of the design based on various technical and commercial considerations of his own.

2.1 PROPOSED POWER PLANTS ALTERNATIVES AT FORT WILLIAM

Two alternative designs of power plants have been proposed for this site: Combined Cycle (CCFO1) and Diesel (DIES). Main fuel for both of them will be low cost heavy fuel oil. Gas oil will be the back up fuel, to be used mainly during start-ups and shutdowns.

The combined cycle power plant will consist of 100 MW (net) blocks, each with two 37.5 MW gas turbine generators and one 31.5 MW steam turbine generator. Recommended installation program for them is shown in Table 2.1. Net total capacity of the power plant, after completion of its development in steps, will be 300 MW: to be provided by 3 combined cycle blocks. The diesel power plant will consist of 50 MW units. Its recommended installation program is shown in Table 2.2. Final total capacity will again be 300 MW, to be provided by 6 units.

2.1.1 Plant Arrangement

The 8.5 Ha site (refer to Figures 2.1 and 2.2) identified by Central Electricity Board (CEB) and Ministry of Housing & Lands for the power plant at Fort William. Additional area required for waterfront facilities, such as sea water intake and discharge and ship unloading jetty will be reclaimed from the sea. The site levels will be raised so that the general elevation of the main plant areas will be at approximately 2.7 m above mean sea level and protected by a seawall on the North/North West sides. Heavy foundations for equipment will be constructed on piles.

The seawater pump house will be located on the Northern side near the seashore. Cooling water will be drawn from the sea by Fibre Glass Reinforced Plastic (FRP) pipelines laid under the seabed to the fore bay of the pump house. These pipelines will receive water through screened intake heads, located at bed depths of about 10 m, and buoys with warning beacons will mark their locations.

The main seawater pumps will be of vertical type located in individual pump bays sized as per recommendations of Hydraulic Institute of USA. Each pump bay will be provided with a trash rack and a travelling water screen. A cleaning rake, travelling on rails, will serve all the trash racks. The travelling screens will be cleaned periodically by washing with water sprays. The wash water booster pumps will be of horizontal centrifugal type drawing water from the discharge header of the main seawater pumps. A separate set of smaller vertical pumps will supply seawater for cooling of the plant auxiliaries. These pumps will also supply water for fire protection, when

TABLE 2.1

RECOMMENDED INSTALLATIONS AT THE NEW PLANT FOR COMBINED CYCLE UNITS

	2001		2002		2003		2004		2005		2006		2007		2008		2009		2010		
	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	
CAPACITY, MW																					
New Plant	0	0	0	0	35	70	100	100	100	100	100	135	170	200	200	200	200	235	270	300	
Others																					
CEB																					
St. Louis	40	40	40	40	20	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0	
Ft. Victoria I	9	9	9	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Ft. Victoria II	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	
Ft. George	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	
Nicolay	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	
Hydro	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	
Total	297	282	297	277	272	253	268	253	268	253	268	253	268	233	248	233	248	233	248	233	
Private																					
F.U.E.L.	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	
Beau Champ	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	
Belle-Vue	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	
Continuous	0	39	0	39	0	39	0	39	0	30	0	30	0	18	0	18	0	18	0	18	
Bagasse/Coal #2	0	0	0	0	0	0	0	0	0	27	36	27	36	27	36	27	36	27	36	27	
Bagasse/Coal #3	0	0	0	0	0	0	0	0	0	0	0	0	0	46	62	46	62	46	62	46	
SIC/SIDEC (Coal)	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
Total	111	119	111	149	141	149	141	149	141	167	177	167	177	201	239	201	239	201	239	201	
Grand Total	408	401	408	426	413	402	409	402	409	420	445	420	445	434	487	434	487	434	487	434	
Total System (1)	408	401	408	426	448	472	509	502	509	520	545	555	615	634	687	634	687	669	757	734	
Largest Unit/Block (b)	34	34	34	34	35	35	50	50	50	50	50	50	50	50	50	50	50	50	50	50	
Next Largest ©	30	30	30	30	34	35	50	50	50	50	50	50	50	50	50	50	50	50	50	50	
Firm Cap (d)(1-b)	374	367	374	392	413	437	459	452	459	470	495	505	565	584	637	584	637	619	707	684	
Cap for Maint (e)(d-c)	344	337	344	362	379	402	409	402	409	420	445	455	515	534	587	534	587	569	657	634	
Non Oil Capacity, %	34.6	33.4	34.6	38.5	38.2	34.7	33.6	32.7	33.6	35	38	32.8	33.7	34.1	39.2	34.1	39.2	32.3	35.5	29.4	
Peak Demand (a)	290	300	305	315	321	331	340	350	362	372	389	399	419	429	452	462	489	499	529	539	**MEDIUM**
Largest as % of (a)	11.7	11.3	11.2	10.8	10.9	10.6	14.7	14.3	13.8	13.4	12.9	12.5	11.9	11.7	11.1	10.8	10.2	10.0	9.5	9.3	**GROWTH**
Margin 1 (d/a-1)%	29.0	22.3	22.8	24.6	28.7	32.0	35.2	29.3	26.8	26.3	27.4	26.7	34.8	36.1	40.9	26.4	30.4	24.2	33.8	27.0	
Margin 2 (e/a-1)%	18.6	12.3	13.0	15.1	18.1	21.5	20.5	15.0	13.0	12.9	14.5	14.2	22.9	24.5	29.9	15.6	20.2	14.1	24.3	17.7	
Peak Demand (a)	246	256	257	267	269	279	283	293	300	310	320	330	343	353	368	378	395	405	425	435	**LOW**
Largest as % of (a)	13.8	13.3	13.2	12.7	13	12.5	17.7	17.1	16.7	16.1	15.6	15.2	14.6	14.2	13.6	13.2	12.7	12.3	11.8	11.5	**GROWTH**
Margin 1 (d/a-1)%	52	43.4	45.5	46.8	53.5	56.6	62.2	54.3	53	51.6	54.7	53	64.7	65.4	73.1	54.5	61.3	52.8	66.4	57.2	
Margin 2 (e/a-1)%	39.8	31.6	33.9	35.6	40.9	44.1	44.5	37.2	36.3	35.5	39.1	37.9	50.1	51.3	59.5	41.3	48.6	40.5	54.6	45.7	
Peak Demand (a)	334	344	352	362	373	383	396	406	424	434	457	467	495	505	536	546	582	592	632	642	**HIGH**
Largest as % of (a)	10.2	9.9	9.7	9.4	9.4	9.1	12.6	12.3	11.8	11.5	10.9	10.7	10.1	9.9	9.3	9.2	8.6	8.4	7.9	7.8	**GROWTH**
Margin 1 (d/a-1)%	12.0	6.7	6.3	8.3	10.7	14.1	15.9	11.3	8.3	8.3	8.3	8.1	14.1	15.6	18.8	7.0	9.5	4.6	11.9	6.5	
Margin 2 (e/a-1)%	3.0	-2.0	-2.3	0.0	1.6	5.0	3.3	-1.0	-3.5	-3.2	-2.6	-2.6	4.0	5.7	9.5	-2.2	0.9	-3.9	4.0	-1.2	

TABLE 2

RECOMMENDED INSTALLATIONS AT THE NEW PLANT FOR STEAM OR DIESEL UNITS

	2001		2002		2003		2004		2005		2006		2007		2008		2009		2010		
	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	I/C	C	
CAPACITY, MW																					
New Plant	0	0	0	0	50	50	100	100	100	100	100	150	150	150	150	200	200	250	250	300	
Others																					
CEB																					
St. Louis	40	40	40	40	20	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0	
Ft. Victoria I	9	9	9	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Ft. Victoria II	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	
Ft. George	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	
Nicolay	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	
Hydro	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	30	15	
Total	297	282	297	277	272	253	268	253	268	253	268	253	268	233	248	233	248	233	248	233	
Private																					
F.U.E.L.	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	27	20	
Beau Champ	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	22	14	
Belle-Vue	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	62	46	
Continuous	0	39	0	39	0	39	0	39	0	30	0	30	0	18	0	18	0	18	0	18	
Bagasse/Coal #2	0	0	0	0	0	0	0	0	0	27	36	27	36	27	36	27	36	27	36	27	
Bagasse/Coal #3	0	0	0	0	0	0	0	0	0	0	0	0	0	46	62	46	62	46	62	46	
SIC/SIDEC (Coal)	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	
Total	111	119	111	149	141	149	141	149	141	167	177	167	177	201	239	201	239	201	239	201	
Grand Total	408	401	408	426	413	402	409	402	409	420	445	420	445	434	487	434	487	434	487	434	
Total System (1)	408	401	408	426	463	452	509	502	509	520	545	570	595	584	637	634	687	684	737	734	
Largest Unit/Block (b)	34	34	34	34	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	
Next Largest ©	30	30	30	30	35	35	50	50	50	50	50	50	50	50	50	50	50	50	50	50	
Firm Cap (d)(1-b)	374	367	374	392	413	402	459	452	459	470	495	520	545	534	587	584	637	634	687	684	
Cap for Maint (e)(d-c)	344	337	344	362	378	367	409	402	409	420	445	470	495	484	537	534	587	584	637	634	
Non Oil Capacity, %	34.6	33.4	34.6	38.5	36.9	36.3	33.6	32.7	33.6	35	38	31.9	34.8	37	42.2	34.1	39.2	31.6	36.5	29.4	
Peak Demand (a)	290	300	305	315	321	331	340	350	362	372	389	399	419	429	452	462	489	499	529	539	**MEDIUM**
Largest as % of (a)	11.7	11.3	11.2	10.8	15.6	15.1	14.7	14.3	13.8	13.4	12.9	12.5	11.9	11.7	11.1	10.8	10.2	10.0	9.5	9.3	**GROWTH**
Margin 1 (d/a-1)%	29.0	22.3	22.8	24.6	28.7	21.5	35.2	29.3	26.8	26.3	27.4	30.5	30.1	24.5	29.9	26.4	30.4	27.2	30.0	27.0	
Margin 2 (e/a-1)%	18.6	12.3	13.0	15.1	17.8	10.9	20.5	15.0	13.0	12.9	14.5	17.9	18.1	12.8	18.8	15.6	20.2	17.2	20.5	17.7	
Peak Demand (a)	246	256	257	267	269	279	283	293	300	310	320	330	343	353	368	378	395	405	425	435	**LOW**
Largest as % of (a)	13.8	13.3	13.2	12.7	18.6	17.9	17.7	17.1	16.7	16.1	15.6	15.2	14.6	14.2	13.6	13.2	12.7	12.3	11.8	11.5	**GROWTH**
Margin 1 (d/a-1)%	52.0	43.4	45.5	46.8	53.5	44.1	62.2	54.3	53.0	51.6	54.7	57.6	58.9	51.3	59.5	54.5	61.3	56.5	61.6	57.2	
Margin 2 (e/a-1)%	39.8	31.6	33.9	35.6	40.5	31.5	44.5	37.2	36.3	35.5	39.1	42.4	44.3	37.1	45.9	41.3	48.6	44.2	49.9	45.7	
Peak Demand (a)	334	344	352	362	373	383	396	406	424	434	457	467	495	505	536	546	582	592	632	642	**HIGH**
Largest as % of (a)	10.2	9.9	9.7	9.4	13.4	13.1	12.6	12.3	11.8	11.5	10.9	10.7	10.1	9.9	9.3	9.2	8.6	8.4	7.9	7.8	**GROWTH**
Margin 1 (d/a-1)%	12.0	6.7	6.3	8.3	10.7	5.0	15.9	11.3	8.3	8.3	8.3	11.3	10.1	5.7	9.5	7.0	9.5	7.1	8.7	6.5	
Margin 2 (e/a-1)%	3.0	-2.0	-2.3	0.0	1.3	-4.2	3.3	-1.0	-3.5	-3.2	-2.6	0.6	0.0	-4.2	0.2	-2.2	0.9	-1.4	0.8	-1.2	

required. All pumps will be located indoors inside a pump hall, which will have an Electric Overhead Travelling (EOT) crane and an unloading bay for their maintenance.

Seawater will be conveyed from the pump house to the power plant by buried pipes of FRP. An Electro-chlorination plant will be located next to the pump house. It will generate chlorine on site by electrolysis of seawater, which will be used for dosing to combat bio fouling of surfaces immersed in seawater.

Fuel oil will be supplied to the power plant by ships. It will be unloaded at a jetty and then pumped through a pipeline to the bulk storage tanks located along the Southern boundary of the site. These bulk oil tanks will be of about 16,000 Cu. M. capacity each (40 m dia. x 14 m high), and a total of 6 such tanks will be provided for the completed plant (2 initially). A fuel oil pump house and a fuel treatment plant will be located next to these tanks. Treated fuel oil will be stored in tanks of about 3,000 Cu. M. each, from which they will be supplied to the power plant. Two tanks of similar capacity will be provided for storing of gas oil, which will be used for back up and for an auxiliary boiler to supply steam for plant start-ups. Gas oil will be supplied to the plant by road tankers. All oil tanks will be located within containment walls for protection against accidental spills. Oily wastewater streams will be collected separately from other plant drains and then conveyed to an API type oil/water separator. Treated effluent from the separator will not contain more than 20 ppm of oil. Depending on the type of fuel oil that will be used for the plant, the separated oily matter may be in the form of a sludge, which will be disposed off by burning in an incinerator. A separate reboiler steam system will be used for heating of fuel oil. The reboilers will be supplied with steam from the auxiliary boiler initially, but from the plant auxiliary steam header during normal operation.

Plant auxiliaries will be cooled by inhibited de-mineralized water in a closed loop. Heat will be removed from these systems by auxiliary seawater in plate-type heat exchangers. Central Water Authority (CWA) water supply will be used for potable and service water systems of the plant, and for providing make-ups to the plant systems after necessary treatments. Corrosive effluents from the water treatment plant will be neutralized to bring its pH to 6 - 9 range before disposal. After cooling of the power plant equipment and their auxiliaries, the seawater drawn from the sea will be discharged back to it through an out-fall structure near the shoreline. Wastewater effluents from the plant will also be mixed with this seawater discharge, after removal of its harmful contents, for disposal into the sea.

The substation for evacuation of power from the plant will be located in the western side of the site. The high voltage switchgears will be of gas-insulated type and will be located indoors. The generator step-up transformers, unit transformers, etc. will be located outdoors. They will be connected to the substation by direct-buried high voltage armored cables. Other outdoor cables between plant facilities will be run through underground duct banks. Indoor cables will be run on cable trays and metal conduits.

The entire plant will be protected from fire as per recommendations of National Fire Protection Association (NFPA) of USA. This will include outdoor and indoor hydrants, sprinkler and deluge systems using water for fire fighting, carbon dioxide flooding systems, portable fire extinguishers, fire and smoke detectors, fire monitoring and

alarm systems etc. as appropriate for different areas of the plant. The fire alarm system will also notify the fire department in the event of a fire:

2.1.2 Combined Cycle Plant Alternative

The gas turbines will be of industrial type, and the steam turbines will be of axial discharge type to reduce their foundation heights. An unfired Heat Recovery Steam Generator (HRSG) will serve each gas turbine. Each steam turbine will be supplied with steam from two HRSGs. The gas turbine generators and the steam turbine generators with their auxiliaries will be located indoors inside a common turbine hall with EOT cranes for their maintenance. Air intake of the gas turbines will be through self-cleaning filter with silencers. Exhausts from the gas turbines will be ducted to their dedicated HRSGs for generation of steam for the steam turbines. The HRSGs will be located outdoors South of the turbine hall. They will generate steam at two pressure levels, and will also include an integral deaerating heater and a feed water preheater. Flue gases exiting the HRSGs will be discharged to the atmosphere through self-standing steel stacks of about 70 m heights. Exhaust steam from the steam turbines will be condensed in surface-type condenser by heat-exchange with cooling seawater. Condensate pumps located in the turbine hall will pump the condensates to the deaerators of the HRSGs through their feed water pre-heater sections. Boiler feed pumps located near the HRSGs will take suction from the storage tanks of the deaerators to feed the low and high-pressure steam generating sections (economizers, evaporators with drums, and super-heaters) of the HRSGs. High pressure and low-pressure steam from the HRSGs will be piped to the respective admissions of the turbines. Bypass systems will also be provided for sending the high pressure and low-pressure steam from the HRSGs directly to the condenser during start-ups and rapid load reductions. Steam extracted from an intermediate stage of the turbines will be injected into the gas turbines to control their NO_x emissions.

2.1.3 Diesel Plant Alternative

The diesel generator sets will be of low speed design and will be located indoors inside a power plant building. Heat will be recovered from the exhausts of the diesel engines to generate steam for various plant services, including fuel oil heating and treatment. The exhausts will discharge through steel stacks with silencers (exhaust mufflers). The arrangement will be similar to that of the newer units of the existing Fort George power plant.

2.1.4 Plant Buildings for Both Alternatives

Plant buildings will be provided with adequate ventilation. The power plant building will be provided with forced ventilation by supply fans and roof exhausters to remove heat dissipated by the machinery and hot surfaces, flue ducts, steam pipes, etc. for maintaining comfortable working conditions inside. Control room, control equipment room and the office areas of the power plant will be air-conditioned. Inside walls of the machine hall will be fitted with acoustic panels on the south and west sides to reduce propagation of airborne noise in these directions.

2.2 PROPOSED POWER PLANT AT MONTAGNE JACQUOT

This alternative will be a coal-fired plant with unit sizes of 50 MW each. Installation for the first phase will be for two such units (plant capacity 100 MW), and the ultimate plant capacity will be 300 MW, provided by 6 such units.

2.2.1 Plant Arrangement

Approximately 18 hectares of rectangular plot of land along the coast will be required for this plant. There will be a coal-unloading jetty towards one side. The seawater intake and pump house will be located towards the other end of the coastline. Description of the sea water system, auxiliaries cooling system and fire protection system will be similar to that of the Fort William plant.

Coal removed from the ships/barges will be brought to land by belt conveyors and fed to the crusher house, where they will be reduced to about 20 mm size. The crushed coal will then be stacked on grade in windrows of up to about 15 m heights by tripper-type stacker conveyors with telescoping chutes. The coal storage yard will be adequate for storing enough coal for two months of plant operation. A fleet of dumpers and bulldozers will be used to shape and to compact the coal storage piles with sloping sides (for rain water run-off), and push the coal on to the reclaim hoppers on the grade. Plough feeders under the reclaim hoppers will load the reclaimed coal on to the belt conveyors for supplying to the powerhouse. The belt conveyors will be of enclosed type with exhaust fans to minimize fugitive dust emissions and provided with dust collectors for the ventilation air at the discharge points. Water spraying will be used at the coal feeding points, coal stacking discharge chutes, and on the slopes of the coal piles during the dry season, to suppress coal dust. The conveyors feeding the powerhouse will raise the reclaimed coal to the top of the coalbunkers with an inclination not exceeding about 17 degrees and deliver it to the bunkers by moving trippers. The coalbunkers will be of fabricated steel construction to hold enough coal for 24 hours of boiler operation. The reclaim/bunker fill conveyors will be sized to fill all bunkers of the plant within one shift with simultaneous operation of both belts, and within two shifts with only one belt. Tripper discharge chutes to fill the bunkers will be closed by zipper arrangement and the bunkers will be ventilated through a dust collector to minimize escape of coal dust during bunker filling operations. Coal will be fed to the boilers (or coal mills feeding to the boilers in case of pulverized coal firing) by gravity through coal feeders and weigh scales.

<u>Steam Plant</u>

The main components are a steam generating unit and a steam turbine generator unit, along with their auxiliaries.

Typical parameters for a steam turbine generator unit of the required size range may be as follows:

Steam pressure:	87 bar (a)
Steam temperature:	510°C
Condenser pressure:	50 millibar

No. of extractions: 5

Type of boiler will depend on the specific details of the coal to be used, but for good quality South African coal, the choice will be either Spreader Stoker or Pulverized Coal firing, natural circulation, balanced-draft, drum-type, with economizer, air-heater and super-heater sections. Electro-static precipitators will be provided for each boiler to remove dust particles from flue gases leaving the boilers at better than 99% efficiency. The cleaned flue gases will then be discharged to the atmosphere through stacks of about 100 m heights (H + 2.5 L).

Fine ash particles (Fly Ash) collected in the air heater and precipitator hoppers will be pneumatically conveyed to an overhead fly ash silo. Boiler bottoms will be provided with water-impounded hoppers. Coarse ash particles (Bottom Ash) collected there will be conveyed to a separate overhead silo. Over-size lumps of bottom ash will be broken down to smaller sizes by clinker grinders before conveying. Ash from the ash silos will be periodically discharged to trucks for hauling to the ash dumping area off-site, e.g. to an engineered landfill.

3.0 ENVIRONMENTAL BASELINE

This section describes the Baseline Environment with respect to the Fort William and Montagne Jacquot sites and the surrounding areas. The information is based on the following:

- Site visits
- Existing sources of data

3.1 FORT WILLIAM

3.1.1 Site and Project Area

The Fort William Project Area has been assumed to be land within 1 km of the site. The project area is shown in Figure 3.1 and includes the following main features:

- Bulk Sugar Terminal, located to the North East of the proposed development of a minimum distance of approximately 300 m;
- Robert Edward Hart Garden most commonly known as Les Salines Garden, located to the East of the site at a minimum distance of approximately 250m;
- Petroleum Products Storage facilities located at a minimum distance of 210 m North East of the site.
- National Coast Guard Headquarters, located to the North of the site at approximately 400m.
- Les Salines and Western Cemeteries and crematorium adjacent to the East boundary of the site;
- Bain Des Dames, Cassis and Les Salines Residential Areas to the South and South West of the proposed development.
- Fort Victoria Power Station located to the South West of the site at a minimum distance of approximately 550m.
- Fort Victoria Sewerage Treatment Plant and Outfall located to the South West of the site at a distance of approximately 450m.
- Mauritius Telecom facilities located at approximately 900 m to the South South West of the site.
- Royal College and Cassis Government School located at approximately 900 m to the South Boundary of the site.

The site occupies approximately 8.5 Ha and is bounded as follows: -

- To the North by the Temporary Sand Plant. A disused sewage outfall and drainage trench form the boundary between the two sites.
- To the East and South by the Bain Des Dames Residential Area. Les Salines Cremation Ground and the Bain des Dames Fish Landing Station form part of this area to the East and South respectively.
- To the West by the Indian Ocean.

There is presently no development on the site except for a drainage channel and a buried fuel pipe belonging to the Central Electricity Board. The pipe conveys fuel oil from the storage facilities mentioned above to the Fort Victoria Power Station.

3.1.2 Climatic Conditions

Data for the meteorological station at Fort William, run by the Mauritius Meteorological Service, have been used as the basis for determining climatic conditions at the development site.

Temperature

Monthly means of maximum temperature, minimum temperature and the day's average taken as the mean of the maximum and minimum, for the Fort William station for period 1958 – 1975, are given in Table 3.1 below.

Table 3.1
Monthly Mean, Maximum and Minimum Temperatures recorded at Fort William (Period 1958 – 1975)

Month	Mean Maximum Temperature ^{0}C	Mean Minimum Temperature ^{0}C	Mean Average Temperature ^{0}C
January	30.9	23.8	27.3
February	31.3	24.1	27.7
March	30.9	23.8	27.3
April	30.0	23.0	26.5
May	28.4	21.0	24.7
June	26.7	19.5	23.1
July	25.7	19.1	22.4
August	25.5	18.7	22.1
September	26.9	19.2	23.1
October	28.1	20.1	24.1
November	29.7	21.4	25.5
December	30.5	23.0	26.7

Source : The Climate of Mauritius by B M Padya, 1984

From Table 3.1 above, it can be observed that the monthly mean average temperature varies form 22.1^{0}C in the winter months to 27.7^{0}C in the summer months. Mean maximum temperatures vary from a low of 25.5^{0}C in August to 31.3^{0}C in February. Mean minimum temperatures vary from 18.7^{0}C in August to 24.1^{0}C in February.

Rainfall

Precipitation is entirely comprised of rainfall. Figures for monthly mean rainfall for the Fort William station for the period 1951-1980 are shown in Table 3.2.

Table 3.2
Mean monthly rainfall for Fort William (Period 1951 – 1980)

Month	Rainfall (mm)
January	145
February	127
March	126
April	83
May	40
June	26
July	27
August	22
September	19
October	19
November	32
December	116
ANNUAL MEAN	**782**

Source : The Climate of Mauritius by B M Padya, 1984

Most of the rainfall occurs between the months of December and April, corresponding to the summer months, during which the mean monthly precipitation varies between 83 mm and 145 mm. The period from May to November is relatively dry with a precipitation level of 40 mm in May dropping to 19 mm in October. These months correspond to the winter season.

Wind Regime

Figure 3.2 shows a wind rose diagram for the Fort William station showing the percentage frequencies of wind direction and speed (monthly averages over the period 1987-90).

The prevailing winds for Mauritius are the South-Easterly trade winds. At Fort William the wind climate is modified by the mountain range on the eastern side of Port Louis. Prevailing winds at Fort William are easterlies (40% average over the year). Moderately frequent winds are experienced from the SE (23%) and less frequent winds from the North-East (13%). Winds on average blow from these sectors for 9

months of the year. Winds from all other sectors are relatively infrequent (1 - 3%) over the year. Calm days occur on average for 15% of the year.

The wind climate shows seasonal characteristics. The East and South-East winds continue to remain dominant over the year but a significant increase occurs in the frequency of winds from the North and North-West sectors. For example, the monthly frequency of North-West winds increase during the summer months of December (6%) January (5%) and February (7%), and are also of higher strength.

Wind Speed

The mean monthly wind speed distribution for Fort William over the period 1971 –1980 is given in Table 3.3.

Table 3.3
Mean Monthly Wind Speeds Measured at Fort William (1971-1980)

	Frequency (%)			
Wind speed (m/s)	Calm	0.5 – 3.0	3.5 – 8.0	8.5 – 13.0
Monthly mean	15.0	26.6	51.6	6.8
Monthly range	11-19	19-35	42-59	3-14

The figures show that likely wind speeds at the project site for the year as a whole are generally moderate, occurring most often in the range 3.5 - 8.0 m/s. Strong winds (8.5 – 13 m/s) occur on average for 2 days each month. Calm days (< 0.5 m/s) occur on average for 4 - 5 days per month.

The windiest months are January, February and March with high winds especially prevalent in February (14% of the month). These are mainly easterlies but can occur from most sectors.

Cyclones

Mauritius is subject to occasional tropical cyclones characterised by low pressure, high wind systems which typically occur in the summer months of December to March. Over the period 1860-1970, 39% of cyclones have been classified as 'weak' (gust speeds < 48 km/hr), 42% as 'moderate' (gust speeds between 48-80 km/hr) and 19% as 'strong' with gust speeds >80 km/hr). Tropical cyclone 'Connie' affected Mauritius over the period 27-29 January 2000 with gusts exceeding 110 km/hr.

Originating as small depressions in the Inter-Tropical Convergence Zone (ITCZ) a few degree South of the equator, tropical cyclones are a natural phenomenon which has considerable significance for Mauritius.

3.1.3 Air Quality

The development site is situated South West of the Port Louis Harbour. Existing air quality in the Port Area is expected to reflect the industrial nature of operations and is strongly influenced by the prevailing easterly wind regime. There is a tendency for

the air pollution to be out to sea for the majority of the year. Nevertheless, onshore winds may cause the city areas to be affected by the emissions.

Existing Air Pollution Sources in the Port Louis Area

Current activities around the site and the Port area as a whole are not significant generators of atmospheric pollution. The four exceptions are:

(i) Traffic related pollution
(ii) The Fort George Power Station
(iii) The Fort Victoria Power Station
(iv) The MCFI plant
(v) Odours

Traffic Related Pollution

The increasing number of vehicles in the Port Louis region, generate nitrogen oxides (NO_x), carbon monoxide (CO), particulates and other pollutants. However, it is a major source of local air pollution during extended peak hour traffic.

Fort George and Fort Victoria Power Stations

There are NO_x, SO_x and other particulate emissions which are the main causes of air pollution in and downwind of the Port Louis area.

MCFI Plant

The MCFI generates Nitrous Oxides (NO_x) and possibly nitric acid vapours as reported by ERM (1995). The stack emissions at the factory are supposed to comply with an emission limit of 1200 ppm of NO_x, however ERM reported that actual emissions have often exceeded this limit.

Odours

The main source of odour in the vicinity of the site is due to the nearby Bain des Dames Sewage Treatment Plant and sea outfall. Sewage from the Southern region of Port Louis undergoes only primary treatment before discharge through a 1000 m long outfall by pumping. Occasionally during periods of high flow, raw sewage is discharged directly on the shoreline when it undergoes decomposition with unpleasant odours emanating from the deposits.

This odour problem has been subjected to several complaints from the local inhabitants.

Dust

The main dust related problems is occurring at the open coal storage near the Fort George Power Station. Considerable amount of dust is blown during the handling and periods of high wind from the coal piles.

3.1.4 Topography & Geology

Topography

The Island of Mauritius has a dramatic landscape as a result of previous volcanic activity and the differential rates of erosion. The topography of the island is characterised by undulating central uplands surrounded by mountain ranges and coastal plains.

The landform of the project area, which forms part of the low-lying land adjacent to the Port Louis Harbour area, is relatively flat and is at an approximate level of +1.5 m amsl.

Geology

Mauritius has a geology dominated by the volcanic deposits which resulted in the formation of the Island through a series of basaltic lava flows some 0.2 millions to 9 millions years ago. Post-volcanic periods of erosion and deposition has affected the Port Louis area.

Borehole data from the site investigation done for the Port Louis Harbour. Development in 1972 revealed the following of Fort William:

0 - 1.5 m	-	Fine to coarse sand with coral and shell fragments
1.5 - 4.5 m	-	Medium dense coral fragments with fine to coarse sand
4.5 - 11 m	-	Moderately jointed mainly coralline reef limestone
Beyond 11 m	-	Moderately highly weathered fine grained vesicular Basalt – (Rock)

3.1.5 Aquatic Environment and Water Quality

Freshwater Environment

There exists a fresh water stream to the east of the site. The same is discharged in a larger trench along the site boundary adjacent to the sand plant. This trench appears to have been dug when the sand plant came into operation.

The water flow in the channel is very turbid and the almost standing water in the larger channel is subject to considerable algal growth, a sign of total eutrophication. The water is devoid of fish life and is polluted with solid wastes which might originate from local dumping.

Marine Environment

The quality of the coastal waters in the Port Louis region has been greatly affected by sewage outfalls, the effects of coastal and marine activities in particular in the port and other industrial areas, discharges from rivers and other influents.

The principal sources of actual and potential pollution within the project area are:

(i) The Fort Victoria sewage outfall

(ii) Storm drains
(iii) Ships wastes
(iv) Washing activities from the adjacent sand plant
(v) Effluents from the Fort Victoria Power Station

The Fort Victoria Sewage outfall discharging raw sewage mixed with Industrial effluents is the main cause of pollution. A description of the operation of the outfall was given under Section 3.1.3 of this report.

Following diving surveys, ERM (1995) described the waters near Fort William as follows:

"This zone extended from Bulk Sugar Terminals and comprised the harbor and an area South/Westward up to Fort Victoria.

Visibility was very low. Dead corals and thick sediment deposits were the only elements of the coastal ecosystem that could be seen, with no fish life. Midway in the vicinity of the shipwreck, the smell was unbearable due to the presence of raw sewage, human fecal matter and toilet paper etc. were found floating in this area" (see Plates 3.1 and 3.2).

3.1.6 Noise

No detailed noise survey was carried out to determine a baseline for noise levels within the project area. Previous surveys carried out in the Port area (Gibb, 2000) revealed that the main noise sources were road traffic, noise from the various industrial units, construction activities, barking dogs and marine traffic in the port.

However, the following sources can be identified to be related with the project at Fort William:

(i) The Fort Victoria Power Station
(ii) Activities within the Sand Plant and traffic generated as a result.

In the past, it was reported in the press that complaints were formulated by the local inhabitants against the noise generated at the Fort Victoria Power Station.

3.1.7 Terrestrial Ecology

The site is covered with tall grass, bushes and various species of trees. There are few marshy areas on the site.

No rare or endemic plant species were identified on site. The same also does not constitute a local habitat for endangered wild-life. Actually the site is being used for dumping purposes at several locations. This problem is more acute along the South and Eastern Boundaries of the site. The site does not have any conservation value for both the flora and fauna (see Plates 3.3 and 3.4).

3.1.8 Cultural, Historical and Recreational Sites

The Robert Edward Hart Garden

This green space is situated between the site and the Bulk Sugar Terminal and is carefully maintained. The place is used for recreational purposes and during the weekend many people visit the garden (see Plate 3.5).

The Western Cemetery

This old cemetery which is next to the above garden has been classified as a national monument.

La Grotte Etoile de la Mer

This is a newly constructed religious structure along to the site separated by the boundary access road.

Shiv Sagar Mandir

This Hindu Temple lies to the immediate South West boundary of the site.

3.1.9 Traffic and Infrastructure

Traffic

The flow of traffic in Port Louis is a major issue for Mauritius. Heavy congestion occurs mainly in the morning and evening peaks.

The site can be accessed from the M1 Motorway at a junction in Cassis near the overhead pedestrian crossing. Access to the South of the site can be from the Bain des Dames Coast Road. Another access to the North East of the site can be from the Robert Edward Hart Garden and using the road to the sand plant. (See Figure 3.3)

Water Supply

Water supply is the responsibility of the CWA. The supply system forms part of the Port Louis Water System. Port Louis receives the largest part of its water requirements from Grand River North West (GRNW) whose flow are diverted at the Municipal Dyke across the river to *Pailles* Filter Works. Other sources are:

- The *Moka* and *Profonde* Rivers, which are higher tributaries of GRNW via the *Monte Bello* Relief Pipeline; and
- *Pierrefonds* tunnel via *either* the *Pierrefonds* Relief Pipeline which brings water from *Pierrefonds* to *Pailles*, or the *Petite Rivière* Service Reservoir which supplies the residential areas of *Cité Vallijee, Cassis and Les Salines* among others.

The *Cassis-Valijee* sub-network is connected to the *Pierrefonds* Tunnel/*Petite Rivière* Reservoir by means of a 12" main.

Electricity Supply

The supply of electricity is the responsibility of the Central Electricity Board (CEB). Electricity supply is satisfactory on a national level.

Base load electricity is provided by the Diesel Power Stations at *St Louis*, Fort Victoria and Fort George; peak loads are met by the two gas turbines at Nicolay Station.

Telecommunications

Telephone and other telecommunications services are the responsibility of Mauritius Telecom. During the recent years, Mauritius Telecom has embarked on an upgrading and extension of the telecommunication network throughout the island. The Port Louis area has seven telephone exchanges with the main exchanges located at *Plaine Verte* and Port Louis centre.

The telecommunication network in the Port Louis areas is a combination of buried and overhead networks.

Sewer Networks

Port Louis has two main sewerage systems; the Port Louis South and the Port Louis North sewer networks.

The southern sewer network caters for the southern zone of Port Louis and includes *Cassis, Bell Village* and the *Plaine Lauzun* Industrial Zone. The lower lying areas such as *Tranquebar, Le Pouce* etc., are connected via the *Pouce Valley* trunk sewer which discharges at Fort Victoria.

Eventually the Fort Victoria outfall will be put out of use with the coming into operation of the new Montagne Jacquot Treatment Plant. The facilities at Fort Victoria will be converted into a pumping station.

Storm water Drains

The main storm water drainage system in the vicinity of Site is via an existing drainage channel which runs between the Bain des Dames Fish Land Station and the Shiv Sagar Mandir Temple. The walls of the drain has been recently reinforced by gabions.

3.1.10 Residential Areas

The communities within the project area are the Bain des Dames, Cassis and Les Salines residential areas. The population within these areas are mainly classified as low/middle income groups as is often the case in the Port Louis suburban communities.

There is a strong awareness among the inhabitants of the above communities as to the nature and extent of the pollution problem caused by sewage and industrial discharges. The fishermen within these communities are particularly aware of the problem and have been active in voicing their opinion to the authority in the past few years, which has also often been reported in the local Press. During the course of this study plastic bottles and solid wastes were found lying on the beach adjacent to the sand plant (See Plates 3.6 and 3.7).

3.2 MONTAGNE JACQUOT

3.2.1 Site and Project Area

We have assumed a site as described in Section 2 and have based our study on this assumption. The site assumed is to the west of the land meant for the future Montagne Jacquot Sewerage Treatment Plant. (Refer to Figure 3.4).

The virtual site facing the sea occupies 18 Ha and is actually undeveloped, unoccupied and is not used for any beneficial purpose although there have been proposals in the past for the setting up of a hotel. An EIA report has already been to the authorities to this effect.

The Project area of 1 km radius excludes any settlement/residential areas with the exception of the Petit Verger Prison which may eventually be given consideration once a site is identified by the IPP developer.

3.2.2 Climatic Conditions

The area falls into the North West climatic zone which is the same as Fort William. The rainfall, temperature and wind regime parameters can reasonably be assumed to be the same as described for the Fort William site.

3.2.3 Air Quality

There are no air pollution sources within the project area, as the region is still not developed. There was in the past a pig rearing facility adjacent to the Sewerage Treatment Plant land which was causing an odor problem. The facility has been abandoned now and the odor problem does not exist anymore.

3.2.4 Topography & Geology

Topography

Montagne Jacquot is situated on the western part of the island which descends gradually from an altitude of about 230 m to the coasts. The site is at 20 to 30 m above mean sea level.

Geology

The western part of Mauritius including Montagne Jacquot is comprised of intermediate lavas flows (2 - 3.5 millions years ago). These consists of grey granular-textured alkali basalts (i.e. doleritic basalts). The agglomerates are composed of pebbles of olivine basalt set in a matrix of scoria and ash. There is a small portion of sandy coast at Pointe aux Sables, which is localised and does not extend to the Montagne Jacquot area. Here, the coast is predominantly basalt boulders with Pebble area between but with a few small sandy patches.

The soil overlying the site has a depth varying from 60 - 100 cm and are classified as low Hamic Latosols which is a typical occurrence in the submid and lower rainfall zones which is the case for Montagne Jacquot.

3.2.5 Aquatic Environment and Water Quality

3.2.5.1 Freshwater Environment

There exists in the study area small streams and canals which are used mainly for irrigation purposes within the adjacent sugar cane fields.

3.2.5.2 Marine Environment

The main pollution source nearest to the project area is the Pointe aux Sables sewage outfall. This out-fall is approximately 5 km away from the site. The impact of the raw sewage effluent there can also be observed on the shoreline where extensive beds of algae are exposed at low tide up to 1 km from the entry of the outfall into the sea. The accumulated putrefying algae at the high water level add to the general unsightly and degraded appearance of the Pointe aux Sables Beach.

However, diving surveys carried out at Montagne Jacquot in 1997 during the study carried out for the Sewerage Treatment Plant project revealed the presence of live coral and fish life and was summarised as follows:

"In summary, the marine environment off the coast at Montagne Jacquot is characterised by ubiquitous and common species of coral, limited diversity characteristic of already impacted environments" (Black & Veatch, 1997).

3.2.6 Noise

As the site is still not developed yet, no permanent artificial noise exists. With the coming into operation of the Sewerage Treatment Plant, some noise impacts are expected.

3.2.7 Terrestrial Ecology

The site is covered by Savannah grassland with a few isolated trees, this area of land has no conservation value with respect to both the flora and fauna.

3.2.8 Cultural, Historical and Recreational Sites

The Montagne Jacquot is quite popular amongst recreational fishermen who are often seen fishing on the cocks along the coastline. Occasionally, people are seen to use the site and its surrounding for picnics.

3.2.9 Traffic and Infrastructure

Presently the site can only be accessed by an earth road branching off from the Pointe aux Sables coastal road and going along the prison wall to the site.

As the site is not developed, no services such as water, electricity, telecom and sewerage facilities are available yet and all the services will have to be provided with the advent of the project. However the services are available up to the prison area, from where it need to be extended.

3.2.10 Residential Areas

The nearest residential area to the study area is the Pointe aux Sables community, the nearest house being approximately 1.2 km away from the site. The Petit Verger Prison is approximately 1 km away from the site. Most of the residents in the area fall within the skilled and semi-skilled categories. However, with the advent of a few morcellement near the La Pointe Beach, a few higher income category people have moved to Pointe aux Sables.

4.0 PROJECT IMPACTS

4.1 AIR EMISSIONS

Air emissions from the power plant will be mainly from its stacks. Stack heights will be typically 2.5 times the height of nearest tallest structure (HRSG for combined cycle, powerhouse for diesel plant, boilers for the coal plant), or about 70 m for the first two and about 100 m for the last one.

All alternative plants will have 6 such stacks when completed. Exhaust velocities from the top of the stacks will be 15 to 20 m/sec.

4.1.1 Fort William

Combined Cycle Alternative

Discharge mass flow from each stack will be about 500 T/hr. Discharge temperature will be about 180° C at full load.

Gross composition by volume:

N2 + Argon	:	73.71%
O2	:	13.41%
$CO_2 + SO_2$	:	4.53%
Moisture	:	8.35%

Trace contaminants:

NO_x	:	60mg/Nm^3, corrected to 15% Oxygen content (steam inj.)
SO_2	:	600 mg/Nm^3 per % sulphur content of fuel oil. (0.5%S : 300 mg/Nm^3 1.0%S : 600 mg/Nm^3 3.5%S : 2100 mg/Nm^3)
CO_2	:	0.5T of CO_2/MW

Particulate Matter:

TSP	:	10 mg/ Nm^3
PM10	:	3 mg/Nm^3

Diesel Plant Alternative

Discharge mass flow from each stack will be about 187 T/hr. Discharge temperature will be about 340° C at full load, without exhaust heat recovery.

NO_x	:	1670 mg/Nm^3, corrected to 15% Oxygen
SO_2	:	1250 mg/Nm^3 per % sulphur content of fuel oil (0.5%S : 630 mg/Nm^3

		1.0%S : 1250 mg/Nm^3
		3.5%S : 4400 mg/Nm^3)
CO_2	:	0.4T of CO_2/MW

Particulate Matter:

TSP	:	10 mg/ Nm^3
PM10	:	3 mg/Nm^3

4.1.2 Montagne Jacquot

Coal Plant

Discharge mass flow from each stack will be about 270 T/hr. Discharge temperature will be about 160° C at full load.

NO_x	:	470 mg/Nm^3, corrected to 15% Oxygen
SO_2	:	2250 mg/Nm^3 per % sulphur content of coal
		(0.5%S : 1120 mg/Nm^3
		1.0%S : 2250 mg/Nm^3)
CO_2	:	1.0T of CO_2/MW

Particulate Matter:

TSP	:	100 mg/Nm^3
PM10	:	30 mg/Nm^3

4.1.3 Impacts

Considering all three alternatives, it can be observed that the Combined Cycle Alternative at Fort William will be the less polluting in terms of air emissions. The Diesel Plant alternative has a relative higher Nitrogen Oxides (NO_x) stack concentration. In general the stack Sulphur Dioxide (SO_2) concentration is directly related to the percentage content of sulphur in the fuel used. The Higher Sulphur contents in the fuel will obviously generate higher SO_2 concentration in the stacks.

Nevertheless, it is predicted that the predominant offshore winds on both sites will generally direct the emissions to the ocean. However, the less dominant on shore winds will turn the stack emissions inland and might affect the most sensitive receptors which are residential areas, Bulk Sugar Terminal (BST) and REH which are at Fort William. These impacts should be given further consideration through the use of an appropriate Air Quality/Dispersion model.

During talks held with officials of the BST in February 1999, it was pointed out that the BST is of national strategic importance for the Mauritian Economy. The terminal is equipped with several air intakes to keep the sugar stored at a pre-determined moisture content. Fouling of these intakes with dust particles or other pollutants might cause the stored sugar inappropriate for export. It is strongly recommended that BST officials be involved in the preparation of the full EIA report.

Also, impacts of the pollutants on the endemic plants within the nearby Robert Edward Garden at Fort William will have to be investigated further and may be as follows:

Sulphur Dioxide (SO_2) Effects

SO_2 has long been known to cause injury to plants at elevated levels. Symptoms of phyto-toxicity can occur in plants for concentrations as low as 0.088 mg/m³. Long term SO_2 levels of 0.75 to 1.25 mg/m³ can damage non-coniferous trees.

Nitrogen Oxides (NO_x) Effects

NO_x can directly injure plant tissue with the same appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Concentrations of NO_x at 6.3 - 12.5 mg/m³ injure most indigenous vegetation.

It is expected that the resulting ground concentrations after dispersion of the above pollutants emitted from the new power plant will be significantly lower.

Dust impacts can also be expected during the construction phase.

4.1.4 Air Quality/Dispersion Modelling

It is recommended that the IPP developer refines the predicted impacts through an appropriate Air Quality Model. This computer software will allow the developer to estimate maximum ground level concentrations and are used extensively by regulatory agencies for comparing air quality impacts with air quality standards.

One such model that can be used is the USEPA approved Model ISCST3. This model allows for various input options and can simulate impacts for both simple and complex terrain. Simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stacks under evaluation. Complex terrain is considered to be an area where the terrain features are all higher in elevation than the top of stacks under evaluation.

The model will be particularly helpful to assess the impacts especially where on shore winds are directing the stack emissions inland and to develop appropriate mitigative measures. Expected Ambient Air Quality resulting from the plant operations can also be defined.

4.2 NOISE

The Mauritian Standards for noise were promulgated in 1997. The standards are presented in Appendix B. Industrial noise is limited to an Leq of 60 dBA during daytime hours and 55 dBA during night-time hours. A tonal character adjustment of +5 dBA can be applied to the measured value where the noise has a definite continuous note, such as a whine or a hiss. Neighbourhood noise is limited to an Leq between 50 to 60 dBA.

4.2.1 Fort William

Noise impacts during construction are likely to be negative especially at Fort William where residential communities are present but the decommissioning of the Fort Victoria Power Station with the coming into operation of the new power plant will be beneficial for the region. The new plant will incorporate more efficient noise control measures.

The major sources of operational noise for both alternatives at Fort William are tabulated below.

Table 4.1 – Major Noise Sources at Fort William

Alternative	Major Source of Noise
Combined Cycle	Air inlets of gas turbines
	Gas and steam turbines
	Gas turbine enclosure ventilation
	Gas turbine exhausts
	Discharge from HRSG stacks
	High velocity discharges to atmosphere (of steam)
Diesel	Air inlets of diesel engines
	Diesel engine exhausts

4.2.2 Montagne Jacquot

The major sources of noise for the coal plant at Montagne Jacquot are as follows:

(i) Steam turbines

(ii) Discharge from boiler stacks

(iii) High velocity discharges to atmosphere (steam)

(iv) Coal crushers and mills

4.3 WATER REQUIREMENT

Water for cooling of the plant equipment, fire protection, etc., will be obtained from the sea. Treatment of the already polluted sea water prior to use will be required at Fort William. Fresh water supply (not exceeding 500 ppm of total dissolved solids and negligible turbidity) will be needed for cycle make-up, drinking, washing of heavy fuel oil if required, house keeping, etc. After use, seawater will again be returned to the sea so that there will be little or no net consumption. Fresh water, on the other hand, will be discharged to the wastewater stream. This will be treated as required and then discharged to the sea with storm drainage water.

Typical water requirements for the 300 MW plant (ultimate capacity) will be:

Plant	Seawater	Fresh water
Combined Cycle	25,000 m^3/hr	35 m^3/hr
Diesel plant	17,000 m^3/hr	20 m^3/hr
Coal fired	70,000 m^3/hr	60 m^3/hr

4.4 WASTE WATER GENERATION AND TREATMENT

4.4.1 Fort William

Main sources of wastewater will be water treatment plant (such as de-mineralizer regeneration) wastes, sanitary wastes, boiler blow downs and water contaminated with oil.

Water treatment plant wastes may contain excess mineral acids and alkalis used in the ion-exchange resin regeneration processes. They will be neutralized by addition of required chemicals to bring their pH to 6 - 9 range before disposal.

Sanitary wastes will be treated in a packaged sewage treatment plant to reduce its Biochemical Oxygen Demand (BOD) and then sterilized by chlorination.

Boiler blow downs will contain traces of boiler water treatment chemicals like sodium phosphates, etc. It will be mixed with the sea cooling water discharge for dilution.

Oily wastewater will be de-emulsified and then treated in oil/water separators to reduce free oil content of the effluent to less than 20 ppm. It will then be diluted by mixing with the sea cooling water discharge stream. Separated oil and sludge will be disposed off by on-site incineration.

After necessary treatments, all wastewater from the plant will be discharged to the sea with the cooling water. Seawater will be returned to the sea at a temperature around 6 degrees centigrade higher than the intake.

4.4.2 Montagne Jacquot

Sources of waste water and their treatment in this plant will also be similar to the above, except that the volume of oily waste water will be much less and so may not need any special treatment. But it will be replaced by storm water run-offs from the outdoor storage piles of coal. These pile run-offs may contain coal particles, traces of heavy metals, and may also be slightly acidic. An impervious layer will be provided under the coal storage areas to prevent leaching of the run-offs into the soil. They will be routed into a retention pond to allow the entrained coal dust to settle out, and then neutralized by addition of lime, before being decanted for disposal with rest of the wastewater.

4.5 FUEL STORAGE AND HANDLING SAFETY

The safety measures will fully comply with the recommendations of the National Fire Protection Association (NFPA) of the USA.

4.5.1 Oil

1. Spill Protection: Oil handling areas and particularly the storage tanks will be enclosed by retention dykes.

2. Ventilation: Areas where oil vapors can be released, such as pumps, valves, hose connections, etc. shall be located in well-ventilated spaces. Unloading areas will be kept away from open flames such as boiler burners. Explosion-proof fittings and lighting fixtures will be used in these areas. Electrical installations in these areas will be suitable for their appropriate hazard classification zones.

4.5.2 Coal

1. Protection will be provided against possibility of explosions caused by coal dusts by adequate ventilation and good housekeeping.

2. Fire protection by spraying of water. Sprinklers over conveyor belts. Flooding of coal milling circuit with steam to extinguish mill fires. Temperature alarms in coal bunkers to detect fires due to spontaneous ignition.

3. Air-borne dust impacts from the outdoor coal storage will be minimised through proper management and house keeping.

4.5.3 Electro-Chlorination Plant

1. Ventilation : Areas where hydrogen/chlorine gas will be produced shall be well-ventilated, mechanical means of forced ventilation will also be provided if need be.

2. Protection : The facilities will be equipped with ready to wear mask and air breathing apparatus. Hydrogen/Chlorine detectors and alarms will be provided.

4.6 HEALTH AND SAFETY HAZARDS

Design and operation of the power plant will comply with the applicable local, U.S. and International Codes and Standards. These are issued by various national and international engineering associations, governmental regulatory bodies, etc., including OSHA, NFPA, WHO, WORLD BANK, ADB, etc.

It is proposed that the project compounds be monitored regularly and appropriate personnel protection and engineering controls applied. The major health risks are heat-related illness. Safety concerns which are very serious include electrical hazards, slips, trips and falls, confined space entry, fires and burns, exposure to hazardous chemicals etc. Noise can also be a major concern. All the future employees of the power station will be trained to strictly observe health and safety regulations, policies, codes and standards.

4.7 TRANSMISSION LINE IMPACTS

Transmission lines from the power plant will be by overhead 132 KV transmission lines. Similar lines are already in service in Mauritius, though they are currently at a reduced voltage level of 66 KV. Impact of the new transmission lines will be similar to the existing ones.

The proposed route from Fort William will be westward along the coast to the mouth of the river, and then inland along the gorge of the river. From Montagne Jacquot site, the route will be directly inland over the sugar cane fields.

Some of the significant impacts, like all other overhead transmission lines, will be:

1. using up some land for the base of the transmission towers, which will slightly reduce land available for other uses, such as housing, sugar cane fields, etc;

2. aesthetics of the overhead lines may not be appealing to some people;

3. there may be a perceived health hazard from the small electro-magnetic field present near these lines. It may be noted that there is no sound scientific basis of this so far; and

4. Corona effects which is the localised ionization of air near the conductors which under some conditions, can result in audible noise and radio or television interference.

Routing the lines away from residential areas will minimize the last three concerns.

4.8 SOCIAL AND CULTURAL IMPACTS

4.8.1 Land Use Impact

Fort William

Land use impacts for the proposed project at Fort William are consistent with the current land use nearby with industrial activities, such as the sand plant and Bulk Sugar Terminal.

The setting up of the facilities will not aesthetically disturb the environment.

One beneficial impact is that with the advent of the project, the uncontrolled dumping presently occurring on the site will cease.

Montagne Jacquot

As no site has been properly identified for the setting up of a new power plant, it is believed that some agricultural land under sugar cane cultivation might be taken up.

The height of the buildings, coal piles and stacks will have a negative visual impact as the site is not developed yet. The future Sewerage Treatment Plant might mask to some extent the project facilities.

The proposed construction of a new jetty for coal unloading and the berthing of ships will negatively impact the environment around the site. Strong public protest can be expected for the construction of this structure.

4.8.2 Population Impacts

The infrastructure requirements for both sites will likely increase employment in the area. Personnel will be required to operate and maintain the Power Station. This will require higher levels of technical training for the power plant and pollution control systems.

The implementation of the project will not require the relocation of people as there is presently no residences on both sites.

4.8.3 Cultural Resources

No impacts to cultural patterns, historical and archaeological resources will occur as a result of the project implementation on either site.

4.9 TRAFFIC

The main traffic impact expected will be during the construction phase for transportation of materials and equipment. The additional traffic resulting from the same may significantly add to the existing traffic. However, this traffic will reduce during the operational phase to a point that there will be no major impact on the existing condition. During operation of the coal fired plant at Montagne Jacquot, there will be hauling of boiler ash to the engineered landfill sites which is not significant.

5. MITIGATIVE MEASURES AND ENVIRONMENTAL MONITORING

5.1 MITIGATIVE MEASURES

5.1.1 Air Emissions

The selected plant will be fitted with stacks of such height (2.5 times the height of the nearest tallest structure) that adequate dispersion of the contaminants will occur in the atmosphere before it can reach the ground. Measures, such as steam injection into the gas turbines for the combined cycle alternative will be undertaken to control the NO_x emissions.

It is expected that the decommissioning of the "old" Fort Victoria power station will reduce the air pollution load in the region through the use of higher stacks and new air pollution abatement technologies for the new plant.

The use of separate low sulphur distillate will be made whenever onshore winds cause the ambient SO_2 levels to rise to unacceptable levels. These levels will be determined through regular monitoring. The distillate may be gas-oil, or even Jet A1, which will also be used during start-ups.

In case of Montagne Jacquot, coal of lower sulphur content will be used to attain the air quality standards and to minimise SO_2 emissions. To control the emissions of Particulate Matter and to meet the standards, Electro-Static Precipitators (ESP) will be used.

One of the significant features of the plant at Montagne Jacquot will be to minimise the dust problems associated with use of coal as fuel. Special care in this regard will be taken at all coal transfer points with adequate ventilation and dust collectors. Large falls from the stacking conveyors will be avoided by use of adjustable telescopic chutes. Outdoor conveyors will be housed in enclosed galleries. Electrical installations in areas with coal dust laden atmosphere will be specially designed to avoid possibilities of dust explosions. Water sprays will be used to prevent migration of coal dust. Coal handling areas will be located on the down wind side of the more sensitive sections of the plant as far as possible. Coal piles will be formed in the storage yard in "windrows", i.e. with its longer dimension in the direction of the prevailing wind. Coal piles will have trapezoidal sections with sloped sides to facilitate shedding of rainwater. Similar measures will be taken to control dust for the ash also. Unloading of fly ash on to truck beds will be through pug mills for wetting, telescopic chutes to break the fall, exhaust ventilation, etc. After loading on trucks, ash will be wetted with water and then covered with tarpaulin sheets to minimize dusting during the trip to the disposal areas.

However, if coal dust and leachate constitute a problem, the coal will be stored in closed sheds instead of open-air storage.

5.1.2 Noise

The new power station will represent a new significant source of noise. To meet the Mauritian Standards, the following general measures might be required for all the three alternatives although it is expected that such measures will have to be implemented at Fort William because of the adjacent residential areas:

1. Construction of noise barriers, such as walls

2. Provision of buffer zones, planted with trees between the major noise sources and the residences.

Fort William (Combined Cycle Alternative)

Table 5.1 below gives Mitigative Measures to be provided for Noise Sources at Fort William (Combined Cycle Alternative)

Table 5.1
Mitigative Measures for Noise Sources at Fort William (Combined Cycle Alternative)

Noise Source		Mitigative Measures
1.	Air Inlets of Gas Turbines	Provided with silencer baffles and acoustic lining inside ducts
2.	Gas & Steam Turbines	Enclosure around machine with thermal and acoustic insulations
3.	Gas turbine enclosure ventilation	Silencers at air inlets and outlets
4.	Gas Turbine Exhausts	Heat Recovery Steam Generators located down stream of gas turbines act as silencers. Bypass stacks will be provided with silencing baffles
5.	Discharge from Boiler Stacks	Discharge velocity will be limited to 20 m/sec maximum to keep noise at ground level to low levels
6.	High velocity discharges to atmosphere (of steam)	Silencers (Safety valve discharges, Flash tank and Blow Down tank vents, start up vents, etc.)

General Measures:

All rotating equipment like pumps, fans, motors, etc. will have maximum permissible noise levels of not more than 85 dBA at 1 m from their outside surfaces to permit unprotected exposures of the plant operators for 8 hour shifts as per OSHA requirements. Operators will use ear protectors in the local higher noise areas around the generating units, and access to these areas will be controlled to ensure this.

Large pumps and generating units will be housed inside buildings to reduce propagation of noise from them.

Residential areas to the South and West of the plant near the ground level will also be shielded from the machinery noise by the barrier provided by the line of large oil storage tanks located near the plant boundary. In addition, inside faces of the machine halls for the gas and steam turbines will have acoustic panels in the directions of residential areas (South & West) to lower the noise level outside of the plant boundary to the level required by local regulations.

Fort William (Diesel Alternative)

Silencers will be provided as indicated in Table 5.2 below to minimise the noise impacts for this alternative.

Table 5.2
Mitigative Measures for Noise Sources at Fort William (Diesel Alternative)

Noise Source		Mitigative Measures
1.	Air Inlets of diesel engines	Provided with silencer baffles and acoustic lining inside ducts
2.	Diesel engine exhausts	Silencers (mufflers)

The General Measures for the Combined Circle Alternative described above shall also apply for this alternative.

Montagne Jacquot (Coal Fired)

Table 5.3 below give the Mitigative Measures for the major noise sources for this alternative.

Table 5.3
Mitigative Measures for Noise Sources at Montagne Jacquot

Noise Source		Mitigative Measures
1.	Steam Turbines	Enclosure around machine with thermal and acoustic insulations
2.	Discharge from Boiler Stacks	Discharge velocity will be limited to 20 m/s maximum to keep noise at ground level to low levels.
3.	High velocity discharges to atmosphere (of steam)	Silencers (Safety valve discharges, Flash tank and Blow Down tank vents, start up vents, etc.)
4.	Coal crushers and mills	Located in buildings with noise attenuating walls

General Measures:

All rotating equipment like pumps, fans, motors, etc., will have maximum permissible noise levels of not more than 85 dBA at 1 m from their outside surfaces to permit unprotected exposures of the plant operators for 8 hour shifts as per OSHA requirements. Operators will use ear protectors in the local higher noise areas around the generating units, coal mills, crushers, etc. and access to these areas will be controlled to ensure this. Large pumps, generating units, and other noisy equipment like coal crushers, mills, etc. will be housed inside buildings to reduce propagation of noise from them. Operation of the outdoor coal handling plant will be normally restricted to daylight hours to reduce noise at night.

5.1.3 Water and Wastewater

The IPP developer will have to apply for an Industrial Effluent Discharge Permit from the authorities as per the Environment Protection (Industrial Effluent Discharge Permit) Regulations 1998 (refer to Appendix B). The issue of the permit will allow the authorities concerned to ensure that the effluent standards are met prior to discharge into the sea. Therefore, the project operator will have to ensure that treatment processes are adequate. The proposed wastewater treatment processes are:

- Sewage treatment plant
- API type oil/water separator for oily wastewater streams
- Mixing with seawater cooling effluent for dilution prior to discharge
- Settling pond for coal run off

An impervious layer will be provided at the bottom of the coal storage area to prevent leaching of rainwater run-offs from the piles to the nearby aquifers. An adequate drain collection system will be provided around the coal piles to isolate the run-offs and send it to a treatment system (settling, neutralization & decanting) before discharge.

5.1.4 Solid Waste

Combustible solid wastes such as oily wastes and sludge will be disposed off by on-site incineration. Other major wastes such as coal ash in the case of the Montagne Jacquot alternative can be disposed as follows: -

(i) Recycling by incorporation in the manufacture of concrete, road construction, etc.

(ii) Land disposal after ensuring that the heavy metals contents will not leach from the containment area. A properly engineered landfill can be used for this purpose.

5.2 ENVIRONMENTAL MONITORING PROGRAMMES

Monitoring programmes are essential in order to assess the effectiveness of the mitigation measures. In addition, Environmental monitoring will provide information for assessing the impacts of the Power Plant.

5.2.1 Air

Air monitoring can be performed on a regularly basis and will include both stack sampling and ambient air quality measurements.

Stack sampling will be performed for PM, NO_x and SO_2 since these pollutants are emitted in the greatest amounts in relation to air quality standards. The stacks will have to be fitted with sampling platforms and all the necessary measuring equipment.

Ambient monitoring will be carried in the vicinity of the site and the monitoring methods can be as per the US EPA reference methods for PM, NO_x and SO_2. The ambient monitoring programme will also include routine monitoring at the Bulk Sugar Terminal and of the plant species within the Robert Edward Hart Garden.

5.2.2 Water

Water quality monitoring during operation of the power station will be an important process to check on the efficiency of the various treatment and control systems are functioning as designed. Standard methods of measurements can be used for the following parameters:

- Temperature
- pH
- Chemical Oxygen Demand (COD)
- Biochemical Oxygen Demand (BOD)
- Total Suspended Solids (TSS)
- Total Dissolved Solids (TDS)

All measurements will be recorded for inspection or environmental auditing.

5.2.3 Noise

Post-operation noise monitoring programme will be important to assess the noise levels in relation to the new power station. Additional mitigative measures can be applied if need be.

5.2.4 Fuel Handling and Storage

<u>Fort William</u>

All oil tanks will be within containment walls for protection against accidental spills. The base of the containment area will have an impermeable liner to prevent

contamination of the groundwater. The containment volume will be determined as per NFPA.

Montagne Jacquot

The coal storage and handling facilities will be closely monitored to limit dust emissions and runoff. Shortcomings in the procedures will be assessed and proper mitigation applied.

5.2.5 Occupational Health and Safety

Training, air monitoring, medical surveillance and engineering controls are important factors for the safe operation of the new power station. Training will be conducted by a specialist in occupational health and safety who can also advise on shortcomings and propose remedial measures.

Medical surveillance will be important to set up a baseline for employee health and monitor health status.

6. CONCLUSIONS

The preliminary Environmental Impact Assessment has identified the likely impacts that will arise from a new Power Station at Fort William or Montagne Jacquot. Refinement of the impacts and mitigative measures will be carried out by the IPP developer once the site and plant technology are selected. The full EIA report, which is a legal requirement under the Environmental Protection Act of 1991 for obtaining an EIA Licence, will be prepared by the IPP developer.

The preliminary EIA study has identified the potential for significant impacts on air quality, noise and the marine environment.

Fort William

Air quality at this site is already affected by several factories within the project area namely the port. Stack emissions are the main concern for both options dealt with at the Fort William site location. However, this will not be a major issue for most of the time as the predominant easterly winds will disperse the emissions out to sea. The sensitive receptors, i.e. the residential areas, the Robert Edward Hart Garden and the Bulk Sugar Terminal facilities are located upwind. The main risk will be when onshore winds occurring during the summer months can cause the emissions to disperse towards these potentially sensitive receptors. The impacts resulting will require further investigations by the project developer. Good management will reduce air quality impacts during the construction phase.

Noise impacts are most likely to result during operation of the power station facilities. Mitigative measures such as barrier walls, buffer zones will have to be implemented to protect the most sensitive receptor which are the residential areas adjacent to the site.

No significant impacts are likely to result from the project to the already polluted marine environment. The potentially polluting materials such as fuel oil and diesel will be stored in tanks within to prevent accidental spillage into the sea. Nevertheless, there may be local protests of the local fisherman communities if additional effluent discharges are allowed into the ocean.

Montagne Jacquot

The air quality at Montagne Jacquot will be negatively impacted by the stack emissions and coal storage. The predominant easterly winds will carry the pollutants out to sea but the summer months' onshore winds will disperse the same inland. There are presently no potentially sensitive receptors for such a situation except for sugar cane fields. The impacts of dust for open coal storage and handling will be significant but can be mitigated by proper management and good housekeeping. Also, the use of low sulphur content fuel will reduce the concentration of SO_2 from the stack emissions.

The noise impacts will have to be controlled by suitable means. The marine environment at Montagne Jacquot is likely to be affected by the construction of a new

jetty to allow coal transporting ships to berth. The polluting coal pile runoff and other wastewater will undergo treatment prior to discharge.

The environmental impacts from the project at any of the two sites considered can be mitigated using appropriate techniques to meet the local and World Bank requirements.

Table 6.1 – Summary of Potential Impacts, Applicable Guidelines and Mitigation Measures

PARAMETER	APPLICABLE GUIDELINES	POTENTIAL IMPACTS	POSSIBLE MITIGATION MEASURES	RESIDUAL IMPACT
AIR EMISSIONS **Particulate Matter (PM)**	**Emissions Standards** 200 mg/m³ (local) 50 mg/Nm³ (World Bank) **Ambient Air Quality Standards** PM (TSP) 50 µg/m³ max. - Annual average 150 µg/m³ max. - 24 hr average PM_{10} 100 µg/m³ – 24 hr average			
FORT WILLIAM Combined Cycle Alternative and Diesel Plant Alternative	Same as above	Expected Emissions from Stacks TSP : 10 mg/Nm³ PM_{10} : 3 mg/Nm³ The above figures indicate that the stack concentration for particulate matter will be well below the standards limit.	• Provision of stack of such height that ground concentration will be low enough to meet the ambient air quality standards. • Regular monitoring to be carried out to check the above. Corrective measures to be applied if necessary. • Regular maintenance and good housekeeping practice to be adopted by operator.	Negligible Impact on Air Quality (assuming mitigation measures are effectively applied).
MONTAGNE JACQUOT Coal Fired Plant	Same as above.	Expected Emissions from Stacks TSP : 100 mg/Nm³ PM_{10} : 30 mg/Nm³ Air borne dust emissions from open coal and ash storage and handling.	• Use of Electro-Static Precipitators (ESP) coupled with adequate stack height to minimise ground concentration. • Monitoring exercise and maintenance – same as above. • Coal handling areas to be located downwind. • Coal and ash conveyors to be enclosed in galleries. • Ash carrying lorries to be fitted with covers. • Possibility of coal storage in enclosed sheds to be considered.	Minor impact expected when onshore winds are prevailing, especially, if outdoor coal storage is envisaged.

PARAMETER	APPLICABLE GUIDELINES	POTENTIAL IMPACTS	POSSIBLE MITIGATION MEASURES	RESIDUAL IMPACT
SULPHUR DIOXIDE (SO_2)	**Emissions Standards** ≤ 2000 mg/Nm³ (World Bank) **Ambient Air Quality Standards** Annual average: 50 µg/m³ max. 150 µg/m³ max. (World Bank) 200 µg/m³ max. - 24 hr average 350 µg/m³ max. - 1 hr average			
FORT WILLIAM Combined Cycle Alternative and Diesel Plant Alternative	Same as above.	• Expected Emissions: - 600 mg/Nm³ per % sulphur content of fuel oil - 1250 mg/Nm³ per % sulphur content of fuel oil • Use of lower sulphur fuel for both plants will not cause emission to exceed the World Bank limit of 2000 mg/Nm³. • Prevailing easterly winds will carry pollutants out to sea for most of the time. • Onshore winds during summer months will cause pollutants to disperse inland.	• Use of low sulphur fuel. • Provision of suitable stack height. • Use of Flue Gas Desulphurization technology to be considered if necessary. • Use separate low sulphur distillate whenever onshore winds are prevailing.	Negligible impact expected (assuming mitigation measures are effectively applied).
MONTAGNE JACQUOT Coal Fired Plant	Same as above.	Expected Emissions: 2250 mg/Nm³ per % sulphur content of coal	• Use of low sulphur coal. • Use of Flue Gas Desulphurization technology. • Use of Fluidised Bed Combustion technique to reduce SO_2 emissions. • Appropriate stack height to be provided for acceptable dispersal and reduction in ground concentration.	Same as above.

Table 6.1 - Summary of Potential, Impacts, Applicable Guidelines and Mitigation Measures

PARAMETER	APPLICABLE GUIDELINES	POTENTIAL IMPACTS	POSSIBLE MITIGATION MEASURES	RESIDUAL IMPACT
NITROUS OXIDES (NO_x)	**Emissions Standards** 1000 mg/rn³ for a diesel plant (local) 300 mg/Nm³ for an oil fired CC plant (World Bank) 750 mg/Nm³ for a coal fired plant (World Bank) **Ambient Air Quality Standards** 200 µg/m³ max. - 24 hr average (local) 150 µg/m³ - 24 hr average (World Bank) 100 µg/m³ - Annual average (World Bank)			
FORT WILLIAM Combined Cycle Alternative and Diesel Plant Alternative	Same as above.	• Expected Emissions: - 123 mg/Nm³ for Combined Cycle Alternative - 1670 mg/Nm³ for Diesel Plant Alternative • Local and World Bank emission limits for NO_x will be exceeded for the Diesel Plant Alternative. • Prevailing Easterly winds will carry pollutants out to sea for most of the time. • Summer on shore winds will cause pollution to disperse in land. • High concentration of NO_x from the stacks may raise the ambient level sufficient to cause health problems. Nevertheless, ambient air quality in the project area is bound to improve with the decommissioning of the "old" Fort Victoria Power Plant.	• Emulsification of water in the fuel for the Diesel Plant Alternative. • Provision of suitable stack height. • Ambient air quality monitoring to assess the effects of the power plant.	Negligible impact expected with the decommissioning of the existing Fort Victoria Power Plant (assuming mitigation measures are effectively applied).

PARAMETER	APPLICABLE GUIDELINES	POTENTIAL IMPACTS	POSSIBLE MITIGATION MEASURES	RESIDUAL IMPACT
NOISE	**Local Standards** Industrial Noise: 07.00 – 21.00 hrs : 60 dB(A)Leq 21.00 – 07.00 hrs : 55 dB(A)Leq Neighbourhood Noise: 07.00 – 18.00 hrs : 60 dB(A)Leq 18.00 – 21.00 hrs : 55 dB(A)Leq 21.00 – 07.00 hrs : 50 dB(A)Leq **World Bank Guidelines** Receptor: Max. Allowable, Leq (hourly) in dB(A) Daytime 07.00 – 22.00 / Nightime 22.00 – 07.00 Residential Institutional Educational: 55 / 45 Industrial Commercial: 70 / 70			
FORT WILLIAM and **MONTAGNE JACQUOT.**	Same as above.	• Negative impact to the nearby residential areas of Bain des Dames. • Positive impact after the decommissioning of the considerable noise generating power plant at Fort Victoria.	• Construction of noise barriers. • Provision of buffer zones. • Noisy machinery and equipment equipped with noise abatement devices.	Positive impact over the existing situation (assuming mitigation measures are effectively applied and Fort Victoria Power Station is decommissioned).

PARAMETER	APPLICABLE GUIDELINES	POTENTIAL IMPACTS	POSSIBLE MITIGATION MEASURES	RESIDUAL IMPACT
WATER AND WASTEWATER	**Effluent Quality** pH : 6 – 9 TSS : 50 mg/l No visible oil Temperature : 40°C max. No more than 3°C within mixing zone. COD : 750 mg/l max. BOD : 250 mg/l max. Floatables : 6 mm max. size	Water Usage Plant / Seawater (m^3/hr) / Fresh Water (m^3/hr) Combined Cycle / 25,000 / 35 Diesel Plant / 17,000 / 20 Coal Fired / 70,000 / 60 • Wastewater with acids and alkalis will be produced and may leak into ground. • Oily wastewater also expected. • Pile runoffs for coal storage at Montagne Jacquot may contaminate water bodies. • Sanitary wastewater leaching to groundwater or flowing to sea.	• All wastewater will be intercepted and directed towards appropriate treatment facilities prior to discharge. • Pile runoff from coal storage will not be allowed to flow into stormwater drains. • Septic tanks and leaching fields or connection to existing sewers will be provided to sanitary wastes.	Negligible impact expected in groundwater bodies and on the marine environment (assuming mitigation measures are effectively applied).
FUEL STORAGE AND HANDLING	To follow the recommendations of National Fire Protection Association (NFPA) of the USA.	• Fuel oil spillage can cause land contamination, groundwater pollution and subsequently marine pollution. • Explosives and fire may occur due to improper handling, leakage, etc. • Toxic gases, such as chlorine may lead to fatalities.	• Storage tanks will be enclosed by retention dytes. • Proper ventilation to be provided to minimise risk of explosions. • Ready to wear mask and air breathing apparatus provided to personnel in case of toxic gas leaks. • Outdoor coal storage will be properly managed and good housekeeping practices to be implemented by well trained staff.	Negligible impact expected (assuming mitigation measures are effectively applied).
HEALTH AND SAFETY HAZARDS	Applicable local, U.S. and International Codes and Standards	• Injury, burns and fatalities.	• Project compounds will be monitored regularly and appropriate personnel protection and engineering controls applied. • Employees will be trained to strictly observed health and safety regulations, policies, codes and standards.	Negligible impact expected (assuming mitigation measures are effectively applied).

Table 6.1 - Summary of Potential, Impacts, Applicable Guidelines and Mitigation Measures

PARAMETER	APPLICABLE GUIDELINES	POTENTIAL IMPACTS	POSSIBLE MITIGATION MEASURES	RESIDUAL IMPACT
TRANSMISSION LINE		• Use up of land. • Aesthetically not appealing. • Corona effects cause radio interference.	Routing of line away from residential areas.	Minor impact on land use and aesthetics.
SOCIAL AND CULTURAL IMPACT		Land will be taken up and will not be available for other uses, such as housing, recreation, etc.	• Project at Fort William will be consistent with nearby industrial activities. • Public consultation to be carried out to avoid protests and subsequent delays in Project Implementation.	Negligible impact expected (assuming mitigation measures are effectively applied).
TRAFFIC		Traffic expected to increase during the construction phase of the project.	Plan delivery of materials to site during off peak hours to minimise disruption in the normal traffic.	• Temporary impact during construction phase. • Negligible impact during operational phase.

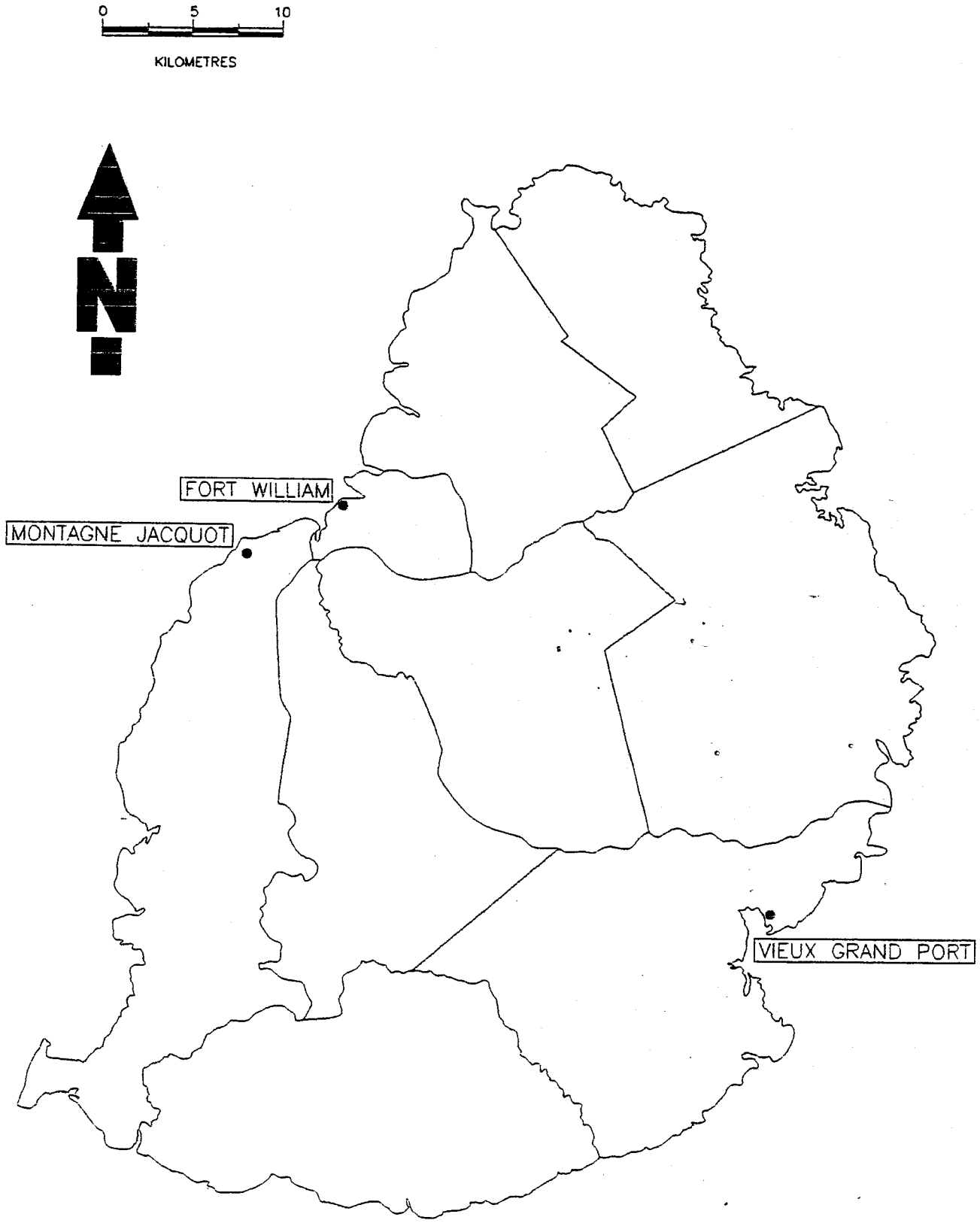


FIGURE 1-1 : LOCATION OF SITES

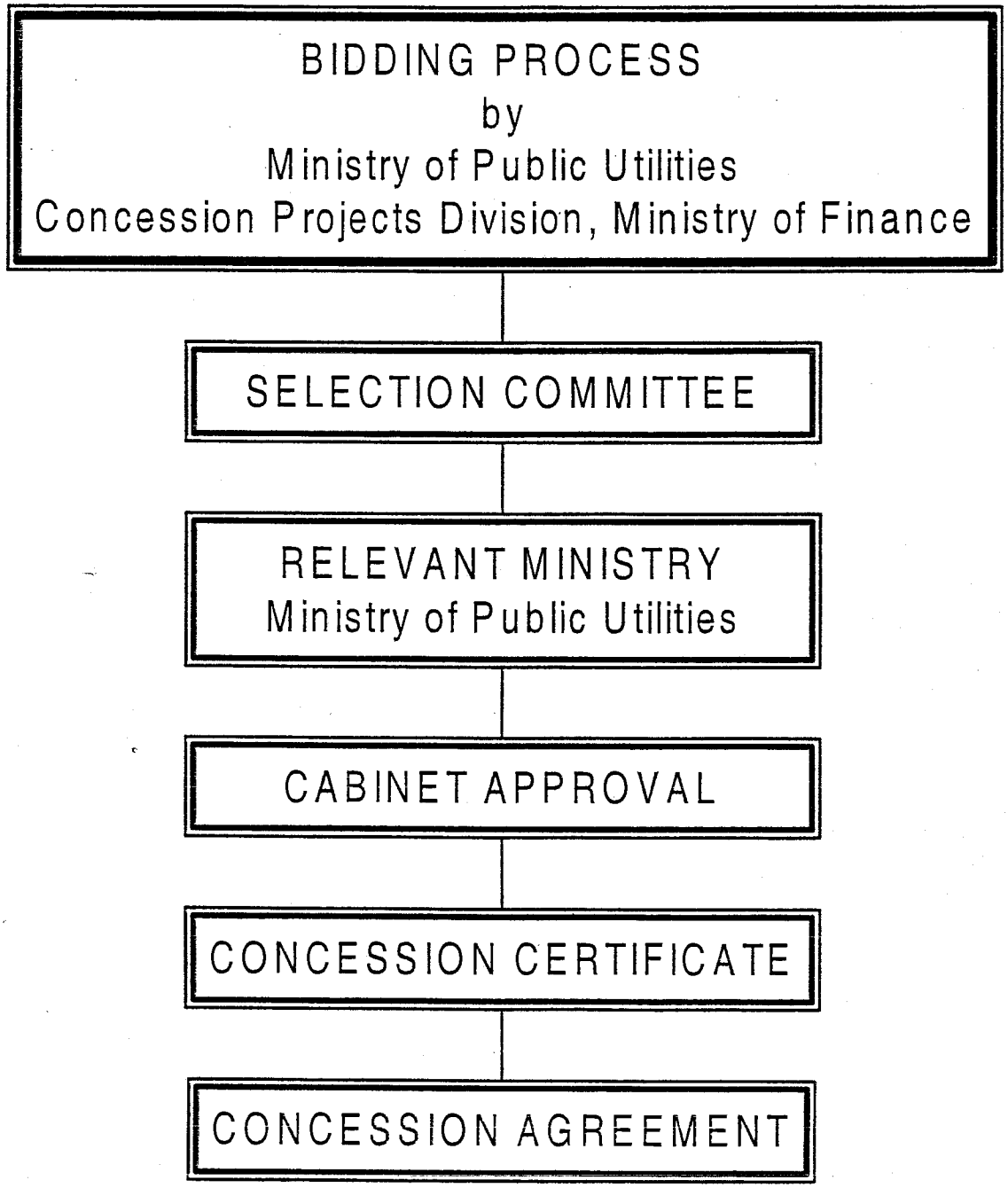
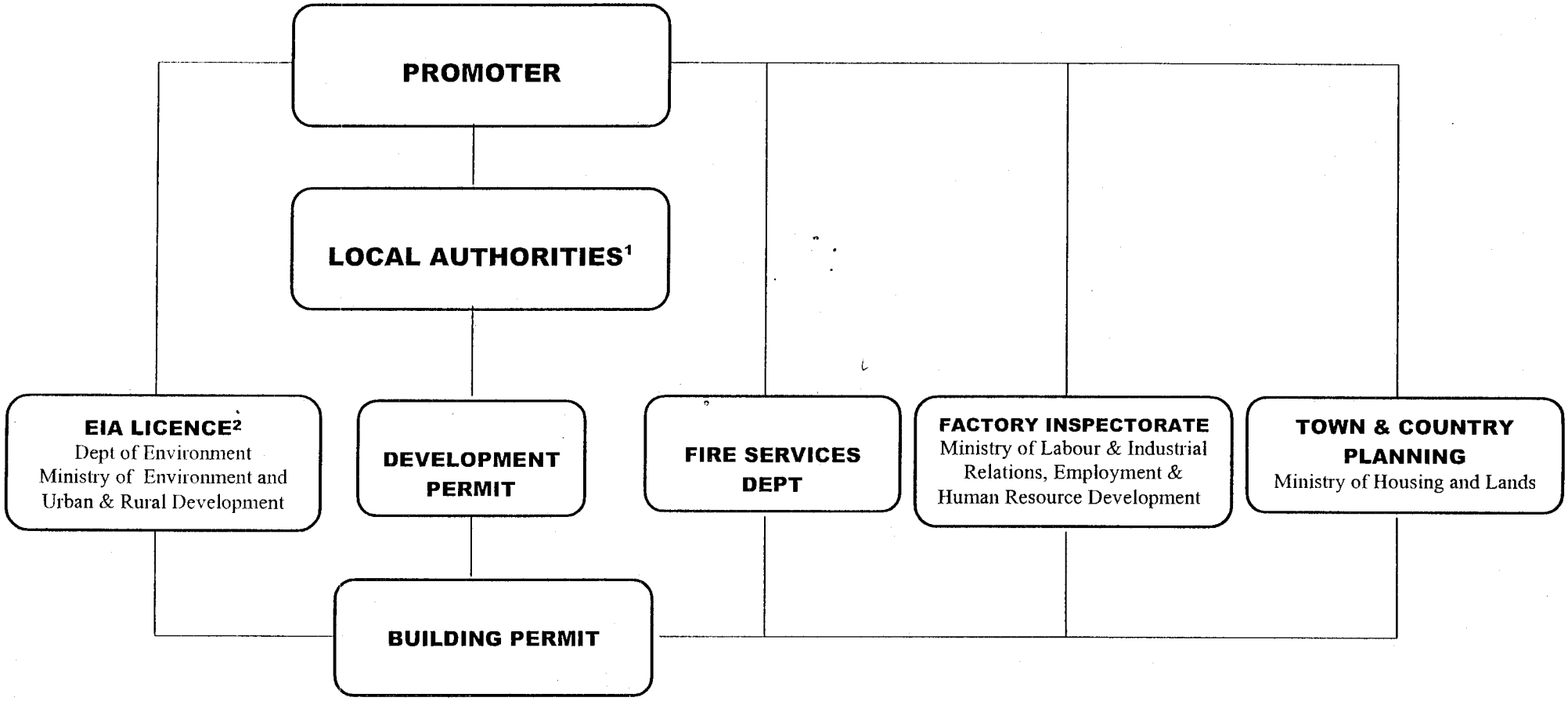


FIGURE 1.2

PROJECT IMPLEMENTATION PROCESS UNDER THE CONCESSION PROJECT ACT (1997)



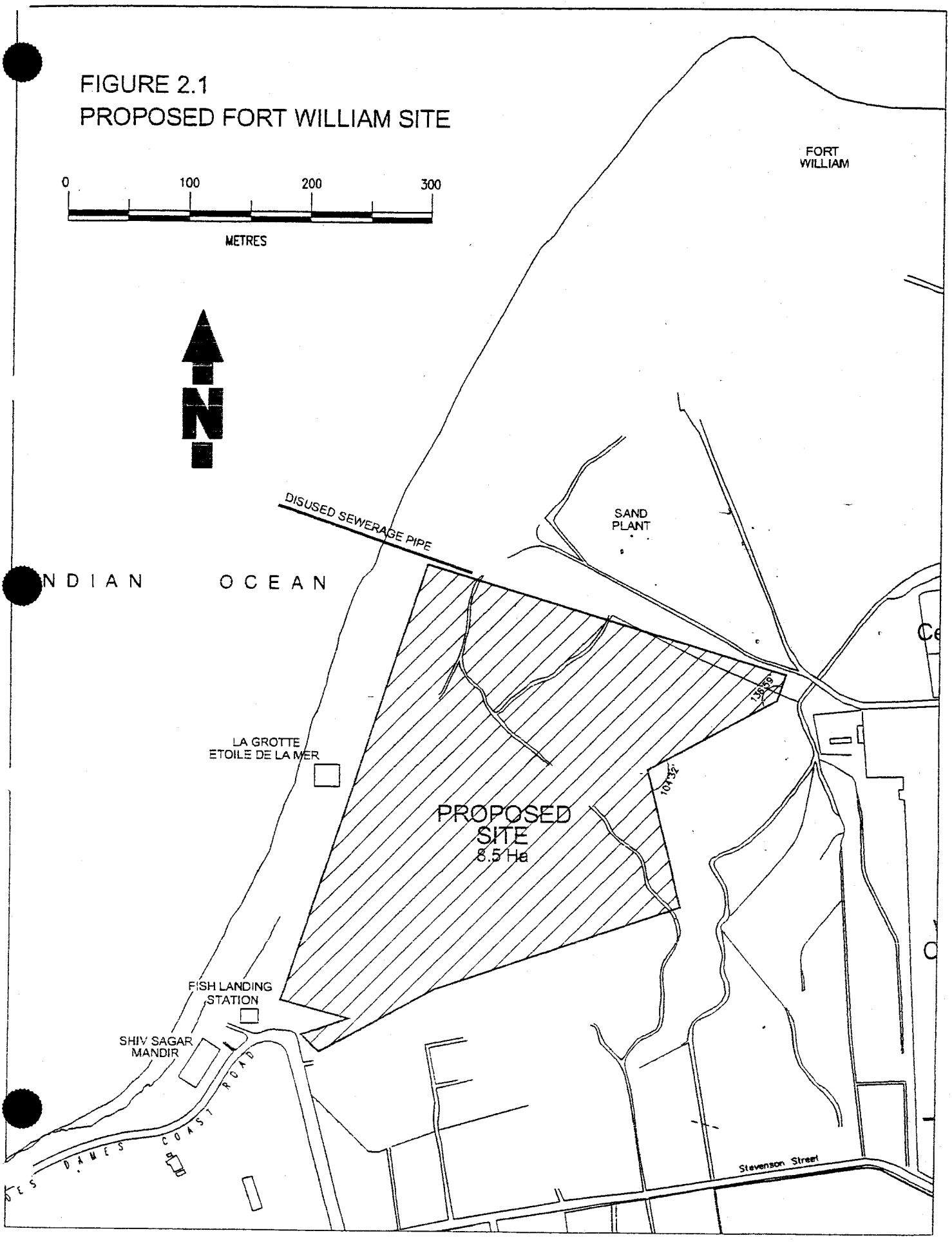
Notes:

1. Relevant Local Authorities for
   Fort William : Municipality of Port Louis
   Montagne Jacquot : Black River District Council
2. Projects Requiring an Environmental Impact Assessment

FIGURE 1.3

PROJECT PERMIT REQUIREMENTS FROM LOCAL AUTHORITIES

FIGURE 2.1
PROPOSED FORT WILLIAM SITE



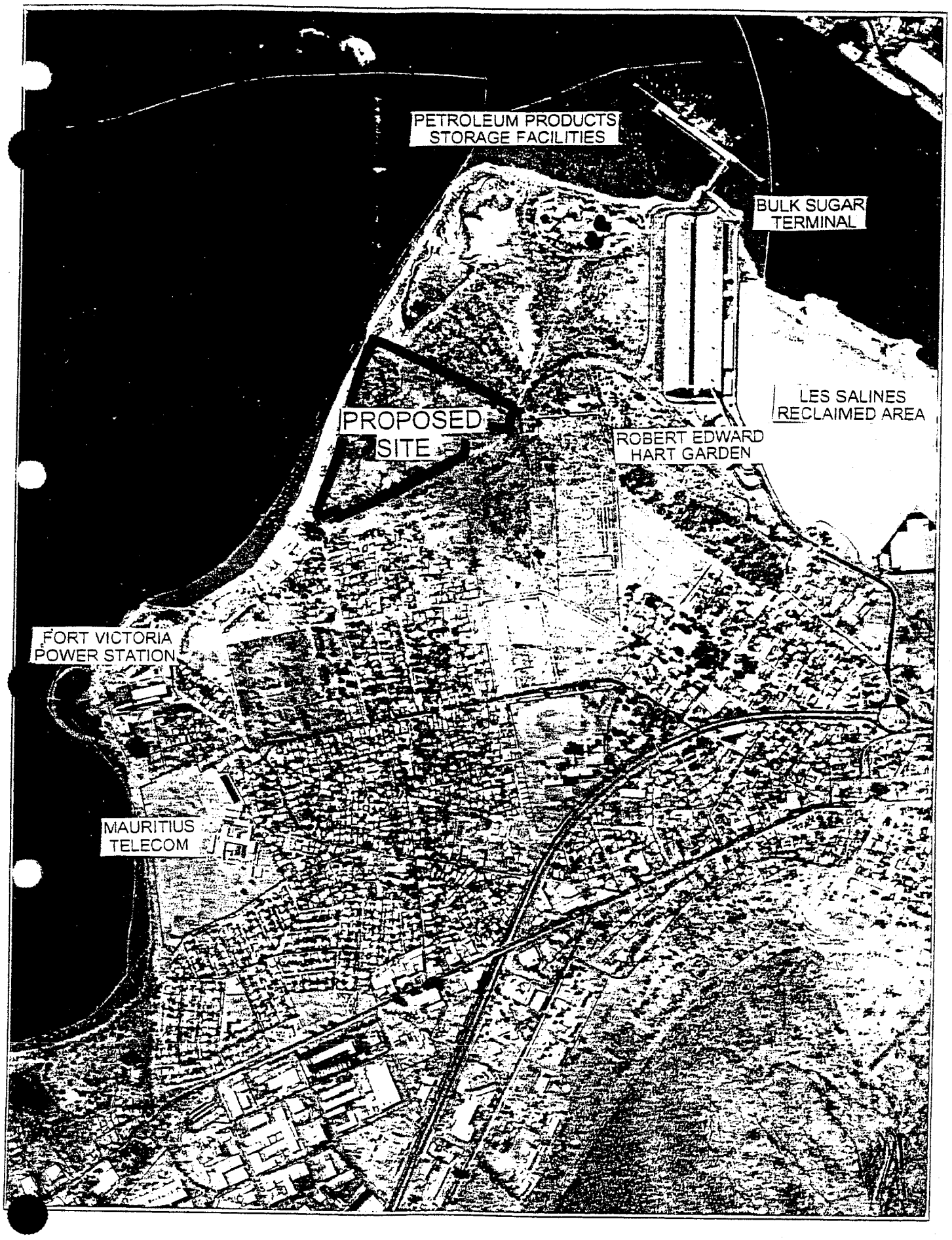


FIGURE 2.2: AERIAL PHOTOGRAPH OF THE PROPOSED FORT WILLIAM SITE AND SURROUNDINGS (1994)

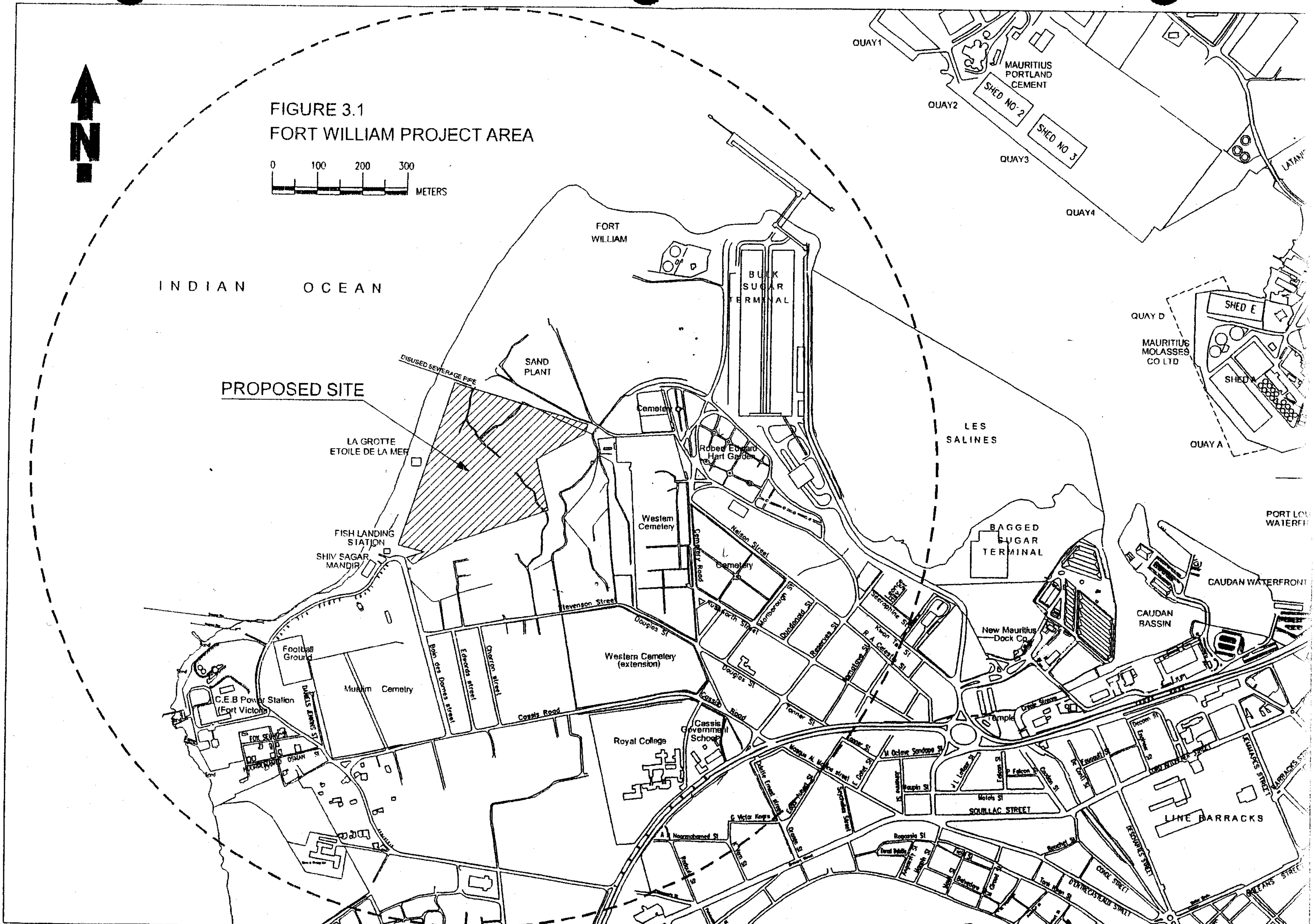


FIGURE 3.1
FORT WILLIAM PROJECT AREA
N
0
100
200
300
METERS
INDIAN OCEAN
PROPOSED SITE
FORT WILLIAM
SAND PLANT
DISUSED SEVERAGE PIPE
LA GROTTE ETOILE DE LA MER
FISH LANDING STATION
SHIV SAGAR MANDIR
BULK SUGAR TERMINAL
LES SALINES
BAGGED SUGAR TERMINAL
QUAY1
QUAY2
QUAY3
QUAY4
MAURITIUS PORTLAND CEMENT
SHED NO 2
SHED NO 3
QUAY D
QUAY A
SHED E
SHED A
MAURITIUS MOLASSES CO LTD
CAUDAN WATERFRONT
CAUDAN BASSIN
New Mauritius Dock Co
Robert Edward Hart Garden
Cemetery
Western Cemetery
Western Cemetery (extension)
Royal College
Cassis Government School
Muslim Cemetry
Football Ground
C.E.B Power Station (Fort Victoria)
LINE BARRACKS
Nelson Street
Cemetery Road
Stevenson Street
Douglas St
Cassis Road
Bain des Dames street
Edwards street
Charron street
Daniels Jenkins St
SOUILLAC STREET
DESCHARTES STREET
CONOL STREET
D'ENTRECASTEAUX STREET
JEMMAPES STREET
Temple

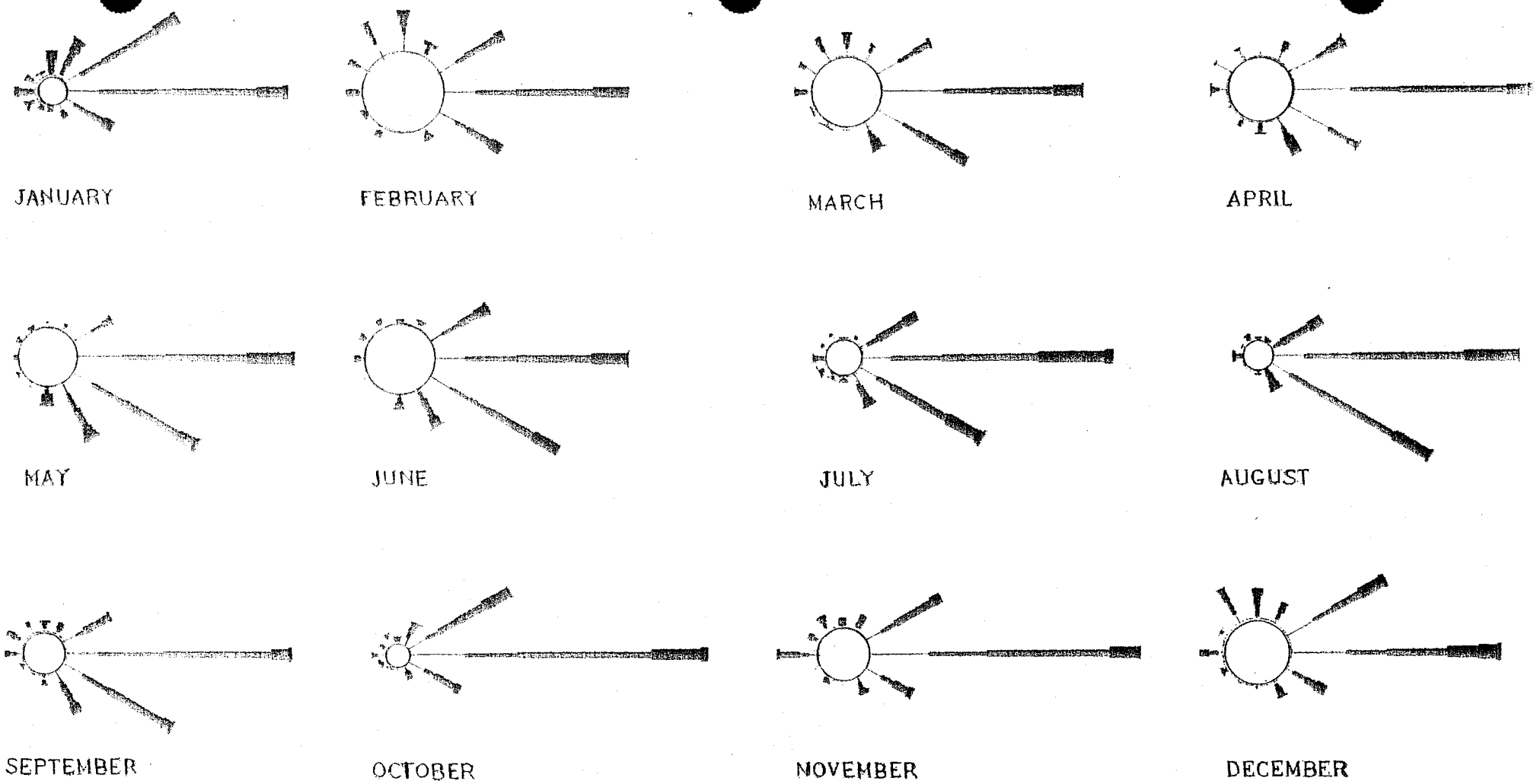
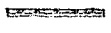


FIGURE 3·2 MONTHLY WIND DISTRIBUTION AT FORT WILLIAM (1987–90)

OCCURRENCE SCALE



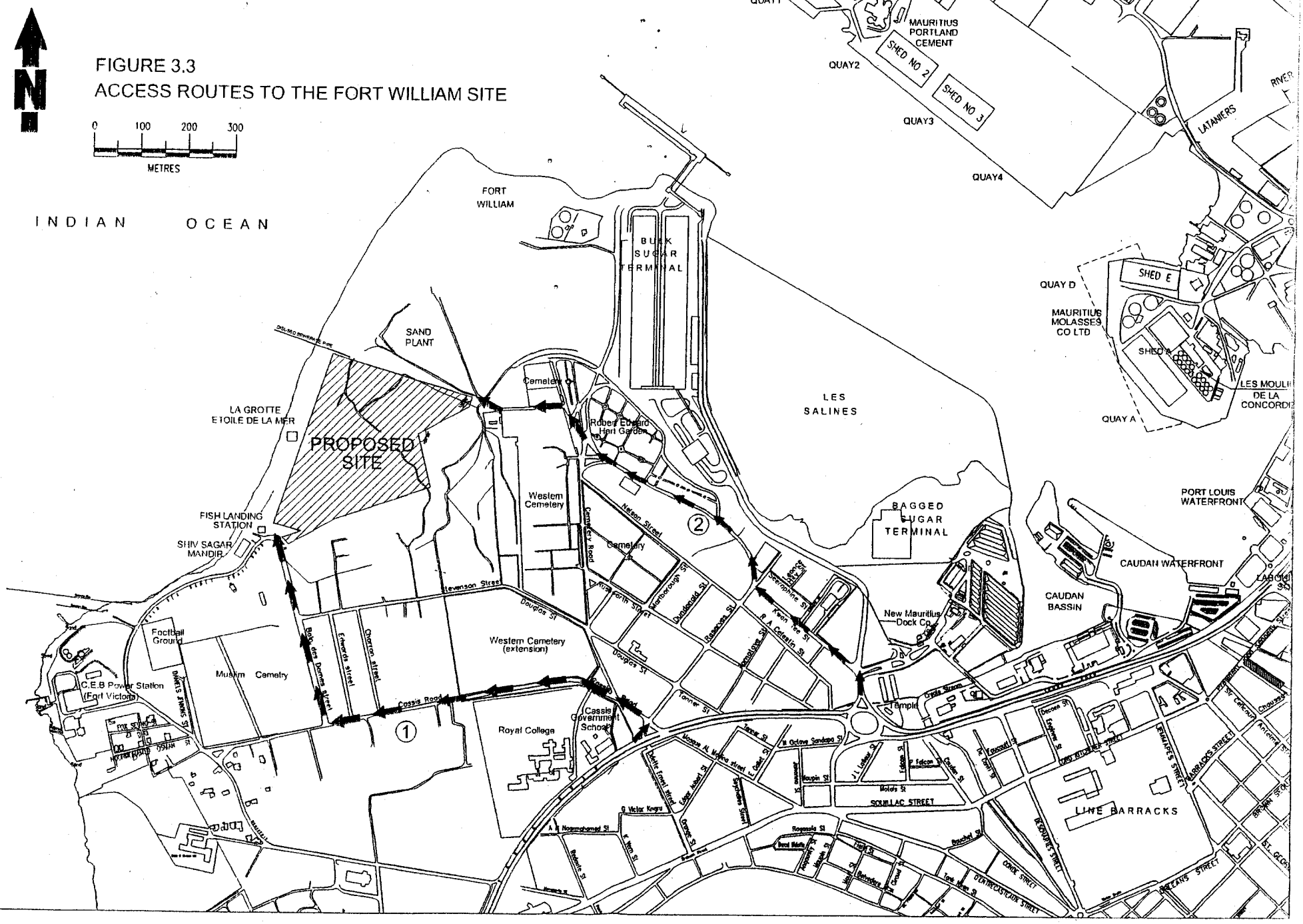
0 5 10 %

WIND VELOCITY	
CLASS	RANGE (m/s)
1	0 – < 2
2	2 – < 3.5
3	3.5 – < 5.5
4	5.5 – < 8
5	8 – < 10.5
6	> 10.5

WIND VELOCITY CLASSES

1 2 3 4 5 0

FIGURE 3.3
ACCESS ROUTES TO THE FORT WILLIAM SITE



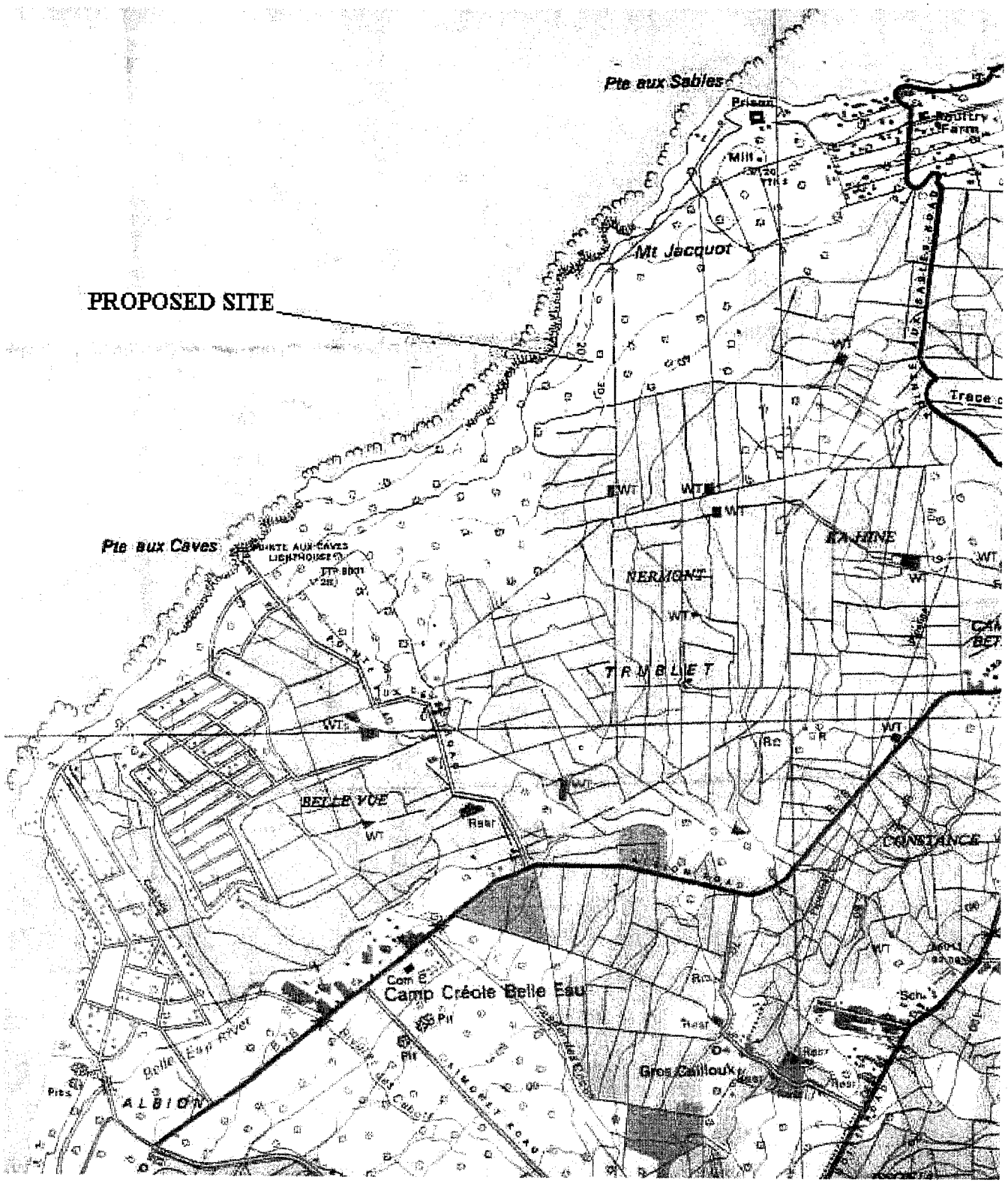


Figure 3.4: Montagne Jacquot Area

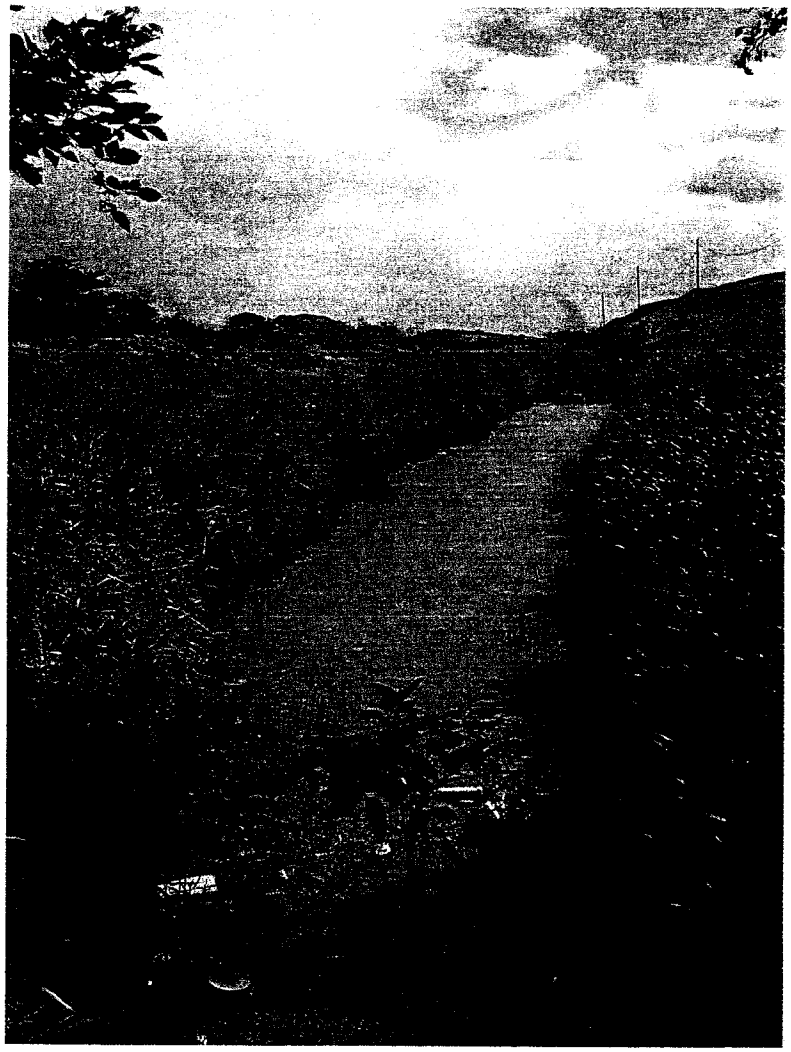


Plate 3.1 - Standing water in channel adjacent to sand plant

Plate 3.2 - Shoreline along Fort Victoria Sewage Treatment Plant

Plate 3.3 - Site seen from the eastern boundary looking to the northwest
(The sand plant can be seen in the background)

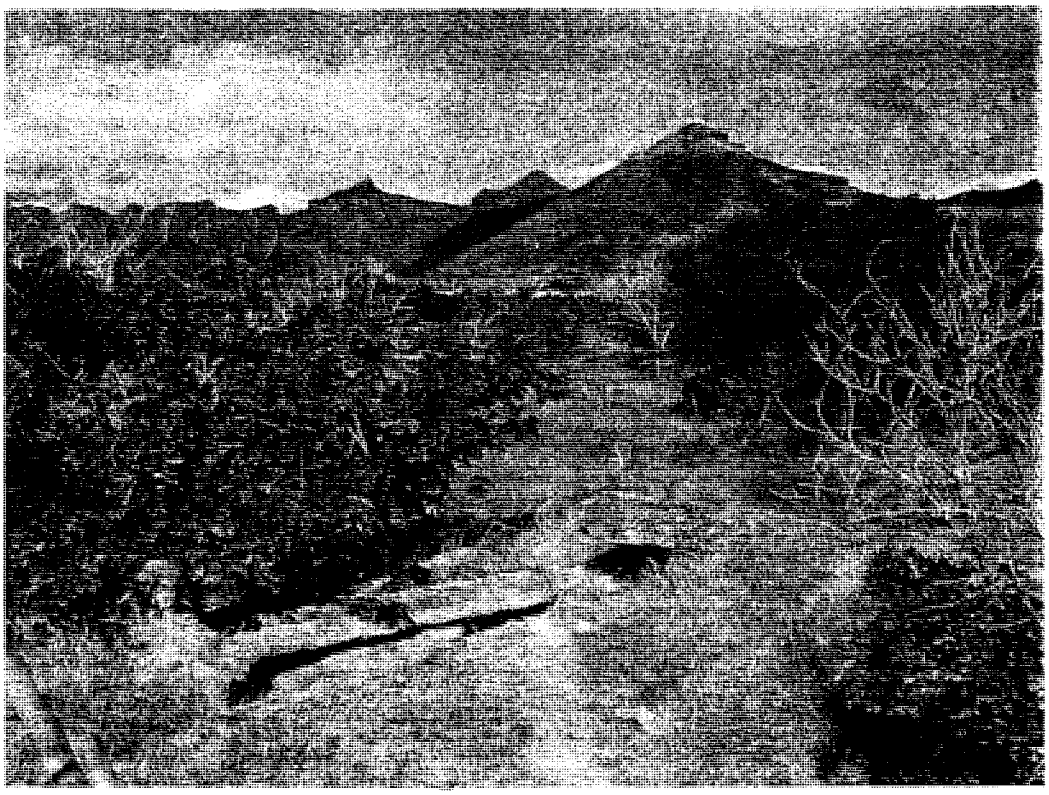


Plate 3.4 - Site as seen from the northwest boundary

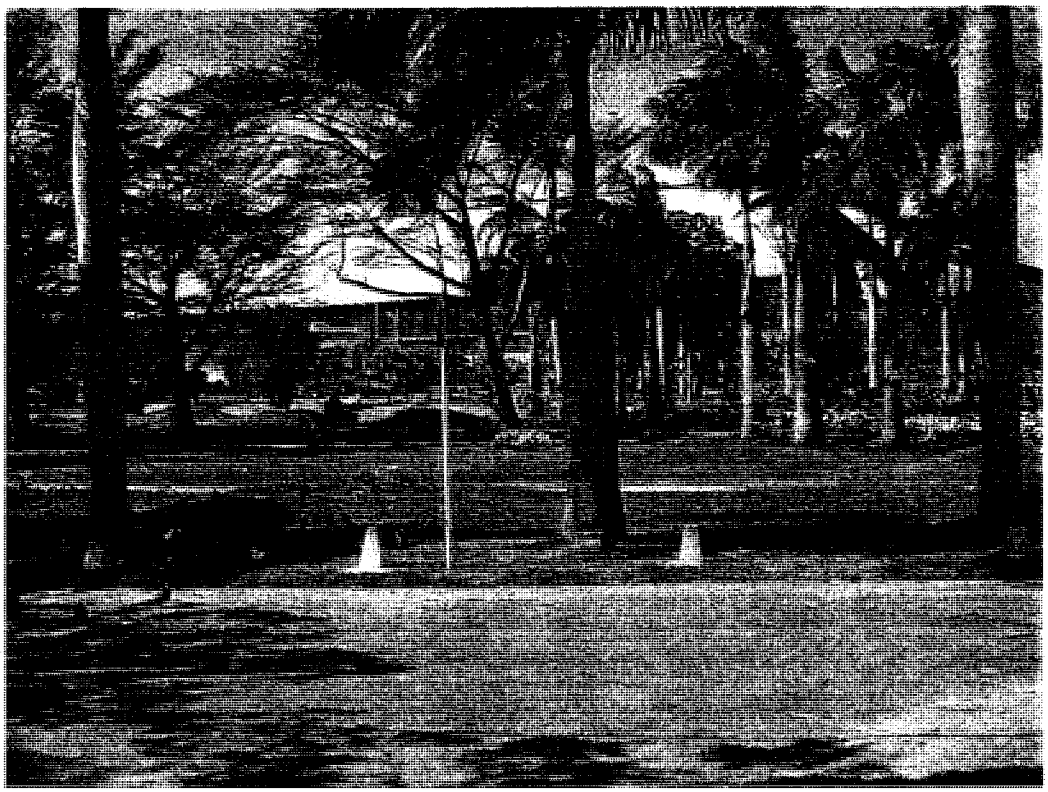


Plate 3.5 - The Robert Edward Hart Garden with
The Bulk Sugar Terminal in the background

Plate 3.6 - The shoreline at the sand plant (note the heavy algal growth in the sea)

Plate 3.7 - The polluted shoreline at Fort William with the Bulk Sugar Terminal facilities in the background

APPENDIX A

ENVIRONMENTAL PROTECTION ACT (1991)

THE ENVIRONMENT PROTECTION ACT 1991

Act No. 34 of 1991

ARRANGEMENT OF SECTIONS

PART I - PRELIMINARY

1. Short title
2. Interpretation
3. Application of Act

PART II - ADMINISTRATION

4. The National Environment Commission
5. Functions and powers of the Commission
6. Powers of the Minister
7. The Department of Environment
8. The Environment Advisory Council
9. Duties of the Council
10. Technical advisory committee

PART III - ENFORCEMENT AGENCIES

11. Enforcing agencies
12. The Environment Coordination Committee

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13. Application for EIA licence
14. Contents of EIA
15. Public comment
16. Review of EIA
17. Public hearing
18. Decision on EIA
19. EIA approval
20. Submission of fresh EIA
21. Transfer of EIA licence
22. Effect of EIA licence
23. Exemption

PART V - SPILL AND ENVIRONMENTAL EMERGENCY

24. Duty to notify Director
25. Measures taken by Director
26. Clean-up and removal operations
27. Liability for spill
28. Recovery of expenses
29. Environmental emergency
30. Powers in case of spill or emergency
31. Regulations under this Part

PART VI - NATIONAL ENVIRONMENTAL STANDARDS

32. Issue of standards
33. Standards for water
34. Effluent limitations
35. Standards for air
36. Standards for noise
37. Standards for hazardous waste
38. Standards for non-hazardous waste
39. Standards for presticide residue
40. Standards for odours
41. Quality control of laboratories

PART VII - COASTAL AND MARITIME ZONE MANAGEMENT

42. Interpretation under this Part
43. Protection of the zone
44. Dumping in the zone

PART VIII - THE ENVIRONMENT APPEAL TRIBUNAL

45. The Environment Appeal Tribunal
46. Jurisdiction of the Tribunal
47. Proceedings of the Tribunal
48. Determination of the Tribunal
49. Appeal to the Supreme Court
50. Regulations by the Tribunal

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51. The National Environment Fund
52. Objects of the Fund
53. The Board

54. Income and disbursement
55. Audit and accounts
56. Regulations in respect of the Fund

PART X - ENFORCEMENT

57. Programme approval
58. Enforcement notice
59. Prohibition notice
60. General provisions on notices
61. Consultation on notices
62. Variation notice
63. Revocation of notices
64. Powers of entry
65. Entry and arrest without warrant
66. Compliance monitoring
67. Offences
68. Powers of Court
69. Jurisdiction

PART XI - MISCELLANEOUS PROVISIONS

70. Restriction of liability
71. Liability of corporate bodies
72. Disclosure of information
73. Code of practice
74. Regulations
75. Consequential amendments
76. Commencement

FIRST SCHEDULE
Undertakings Requiring An Environmental Impact Assessment

SECOND SCHEDULE
National Environment Commission

THIRD SCHEDULE
Environmental Advisory Council

FOURTH SCHEDULE
Enforcing Agencies

AN ACT

To provide for the protection and management of the environmental assets of Mauritius so that their capacity to sustain the society and its development remains unimpaired and to foster harmony between quality of life, environmental protection and sustainable development for the present and future generations; more specifically to provide for the legal framework and mechanism to protect the natural environment, to plan for environmental management and to coordinate the inter-relations of environmental issues and to ensure the proper implementation of governmental policies and enforcement provisions for the protection of human health and the environment of Mauritius.

ENACTED by the Parliament of Mauritius, as follows:

Part I

PRELIMINARY

1. SHORT TITLE

This Act may be cited as the Environment Protection Act 1991.

2. INTERPRETATION

In this Act -

"accredited laboratory" means a public or private laboratory accredited to conduct analyses of environmental samples under section 41 (2);

"air" includes air within a building, a vehicle or within any enclosure or structure;

"authorised officer" means an officer designated under section 7 (5);

"Board" means the Board established under section 53 (1);

"Central Water Authority" means the Central Water Authority established under the Central Water Authority Act;

"Commission" means the National Environment Commission established under section 4;

"Committee" means the Environment Coordination Committee established under section 12;

"Contingency plan" means measures intended to be applied in the event of a spill or an environmental emergency;

"Council" means the Environmental Advisory Council established under section 8;

"Department" means the Department of Environment established under section 7 (1);

"Director" means the Director of Environment appointed under section 7 (2)

"discharge" includes deposit, emission and leakage;

"effluent limitations" means any restriction prescribed under section 34 on quantities, rates and concentrations of chemical, biological or other constituents which are discharged into the waters;

"EIA Committee" means EIA Committee established under Section 17; **(Amended 4/93)**

"EIA" means an environmental impact assessment;

"EIA licence" means a licence issued under section 18 (4);

"enforcement notice" means a notice referred to under section 58;

"enforcing agency" means an enforcing agency declared under section 11;

"environment" includes land, air, water, or any of these media, and all living organisms;

"environmental data" means data obtained form the laboratory analyses of environmental samples;

"environmental impact assessment" means a document containing the information required under section 14;

"environmental laws" means:-

(a) this Act and any regulations made under this Act, and includes any direction, order, notice issued under, or any requirement imposed by this Act;

(b) any other enactment, or part of any other enactment which the Minister may by regulations declare with the approval of the Commission;

"environment liaison officer" means an environment liaison officer designated under section 11 (3);

"exempt undertaking" means an undertaking by a public department in relation to which a declaration is made under section 23;

"Finance Officer" means the Finance Officer posted at the Ministry;

"financial year" has the meaning assigned to it by section 111 of the Constitution;

"Fund" means the National Environment Fund established under section 51;

"hazardous substance" means a substance declared as a hazardous substance under section 37 (1);

"holder" means the holder of an EIA licence;

"local authority" has the meaning assigned to it in the Local Government Act 1989;

"medium" means environmental medium and includes air, land and waters;

"Minister" means the Minister to whom responsibility for the subject of the environment is assigned ;

"Ministry" means the Ministry having responsibility for the subject of the environment;

"monitoring" includes the inspection, measurement sampling or analysis of any discharge of a pollutant or of any environmental medium in any locality, whether periodically or continuously;

"national environmental standards" means standards referred to under Part VI;

"noise" includes vibration;

"non-hazardous waste" means solid waste other than hazardous waste and clinical waste;

"notice" means an enforcement notice, a prohibition notice, and a variation notice;

"owner of a pollutant" means the owner or the person having the charge, management or control of a pollutant which is spilled;

"person responsible" means the owner, or the person having the charge, management or control of an activity, enterprise or undertaking;

"pesticide residue" means any substance resulting from the use of a pesticide or of the derivation of a pesticide;

"pollutant" means a substance which may cause harm, damage or injury to the environment, to plant or animal life, or to human health; and includes any substance from which a pollutant is derived;

"Prime Minister" means the Prime Minister of the Government of Mauritius;

"Programme approval" means a programme approval referred to under section 57 (3)

"programme of measures" includes steps, plans, proposals;

"prohibition notice" means a notice referred to under section 59;

"proponent", subject to sections 13 (5) and 21 (4), means a person who -

(a) is the owner of, or who has the charge, management or control of an undertaking; or

(b) carries out or proposes to carry out an undertaking;

"public comments" means submissions made under section 15 by any person other than a public department on an EIA;

"public department" means a Ministry in the Government of Mauritius, a parastatal body and a public authority established under any enactment and includes an enforcing agency;

"relevant enforcing agency" means the enforcing agency designated in the Fourth Schedule in relation to a specified medium or pollutant;

"spill" means a discharge of a pollutant into the environment from or out of a structure, vehicle, vessel, craft, or other carrier or container, which:

(a) is abnormal having regards to all the circumstances of the discharge; and

(b) poses a serious threat to the environment;

"standards" includes criteria and specifications;

"substance" means any natural or artificial substance, whether in solid or liquid form or in the form of a gas or vapour, and includes mixtures of substances, electricity and heat;

"technical advisory committee" means a committee established under section 10;

"Tribunal" means the Environment Appeal Tribunal established under section 45; **(Amended 4/93)**

"undertaking" means such enterprise or activity or any proposal, plan, or programme in respect of an enterprise or activity by a public department, local authority, or any other person, as is prescribed in the First Schedule, and includes any modification, change, alteration or addition to an undertaking;

"zone" has the meaning assigned to it by section 42.

3. APPLICATION OF ACT

This Act shall

(a) bind the Crown;

(b) apply to

(i) the island of Mauritius;

(ii) the islands under the jurisdiction of the State of Mauritius with such modifications as the Minister may, by regulations, prescribe.

Part II

ADMINISTRATION

4. THE NATIONAL ENVIRONMENT COMMISSION

(1) There is established for the purposes of this Act a National Environment Commission.

(2) The Commission shall consist of -

(a) the Prime Minister, as Chairman,

(b) the Minister, as Vice Chairman,

(c) the Ministers to whom are assigned responsibility for the subjects listed in the Second Schedule, and

(d) such other Ministers as the Prime Minister may designate.

5. FUNCTIONS AND POWERS OF THE COMMISSION

(1) The Commission shall -

(a) set national objectives and goals, and determine policies and priorities for the protection of the environment, having due regard to the recommendations of the Minister;

(b) review progress made by public departments on any aspect of environmental management projects and programmes;

(c) ensure coordination and cooperation between public departments, local authorities and other government organisations engaged in environmental protection programmes;

(d) make such recommendations and issue such directions as it may determine to public departments.

(e) monitor and review the activities of public departments concerned with the protection and management of the environment.

(2) The Director shall act as secretary to the Commission.

6. POWERS OF THE MINISTER

Subject to any direction by the Commission, the Minister shall for the purposes of this Act -

(a) propose and develop policies on all aspects of environmental protection and management pursuant to national objectives and goals set by the Commission from time to time;

(b) coordinate and monitor all activities concerning the protection and management of the environment;

(c) investigate reports of pollution, spills, and other related cases;

(d) establish such standards for the protection of the air, land, water and as may be necessary to safeguard the human health and the environment;

(e) carry out research and commission studies on environmental quality and related matters;

(f) prepare environmental action plans and issue reports on the state of the environment in cooperation with other public departments, the Council, and non-governmental organisations or associations;

(g) initiate and coordinate actions required in a state of environmental emergency or any other situations which may pose a serious threat to the environment;

(h) appoint technical advisory committees or other committees;

(i) publish and disseminate information concerning the protection of the environment;

(j) carry out such other activities as may be necessary or expedient for the administration of this Act.

7. THE DEPARTMENT OF ENVIRONMENT

(1) There is established within the Ministry for the purposes of this Act a Department of Environment.

(2) The Department shall be administered by a Director of Environment who shall

(a) be a public officer,

(b) be appointed by the Public Service Commission,

(c) be responsible for the control, operation and management of the day to day business of the Department,

(d) carry out the duties and functions provided under this Act, and such other duties as the Minister may assign to him,

(e) be responsible to the Minister for the proper discharge of his functions under this Act and for the implementation of such policies as may be determined.

(3) There shall be appointed at the Department such officers as may be necessary for the proper discharge of the functions and duties of the Director under this Act.

(4) The officers of the department shall be public officers and shall be under the direct administrative control of the Director.

(5) The Director may designate any officer of the Department as authorised officer who shall have the duties and powers conferred by this Act.

8. THE ENVIRONMENT ADVISORY COUNCIL

(1) There shall be established an Environmental Advisory Council.

(2) The Council shall consist of one representative from each of the organisations or public departments listed in the Third Schedule and such other persons having competence and knowledge in matters relating to the protection and management of the environment, as may be appointed by the Minister.

(3) The Council may elect one of its members as Chairman.

(4) A member of the Council other than a representative of an organisation or association shall hold office for a period of three years and shall be eligible for reappointment.

(5) One third of the members of the Council shall constitute a quorum.

(6) The Council shall regulate its own meetings and proceedings in such manner as it thinks fit.

(7) The Director shall designate an officer of the Department to act as secretary to the Council.

9. DUTIES OF THE COUNCIL

The Council shall

(a) consider any matter affecting the quality of the environment and report to the Minister;

(b) advise the Minister on the state of environment and make recommendations to him regarding actions and measures for the improvement of the quality of the environment.

10. TECHNICAL ADVISORY COMMITTEE

(1) The Minister may at any time establish such technical advisory committee as he thinks fit to advise him on matters pertaining to the scientific and technical aspects of environmental protection and management.

(2) The technical advisory committee shall

(a) consist of members appointed by the Minister,

(b) provide advice on any matter specified by the Minister,

(c) obtain any assistance from the Director as may reasonably be required to carry out its functions,

(d) be discharged on submission of its opinion on the matter referred to it, unless the Minister -

(i) requests further advice, or

(ii) otherwise directs;

(e) regulate its own meetings and proceedings in such manner as it thinks fit.

(3) Any person having a sound technical knowledge of the matter on which advice is required -

(a) may be appointed on a technical advisory committee on such terms and conditions as may be determined by the Minister;

(b) shall not hold a public office solely by virtue of his appointment on the committee;

(c) shall be under the duty of confidentiality provided under section 72.

Part III

ENFORCEMENT AGENCIES

11. ENFORCING AGENCIES

(1) There shall be such enforcing agencies as are declared in the Fourth Schedule in respect of such environmental medium, or such pollutant as is specified.

(2) The enforcing agencies shall have the functions, duties and powers prescribed in the Fourth Schedule.

(3) Each enforcing agency shall designate an environment liaison officer who shall have such functions, duties and powers as prescribed in the Fourth Schedule.

(4) The Minister may with the approval of the Commission amend the Fourth Schedule.

12. THE ENVIRONMENT COORDINATION COMMITTEE

(1) There shall be for the purposes of this Act an Environment Coordination Committee which shall consist of

(a) the Permanent Secretary of the Ministry, as Chairman;

(b) the enforcing agencies, or their representatives;

(c) the environment liaison officers;

(d) the Director;

(e) the Deputy Director of the Department;

(f) any other public officer designated by the Committee.

(2) The Committee shall

(a) develop such policies and administrative measures as are necessary to ensure prompt and effective consultation on matters relating to environment protection and management;

(b) ensure that information is shared among the enforcing agencies, the Department and other public departments so as to develop a better understanding of environmental issues and of problems relating to enforcement of environmental laws;

(c) advise the Minister and, where requested, the Commission, on matters relating to environmental standards, guidelines, codes of practice and other control measures for the purpose of avoiding duplication of functions among public departments and ensuring proper enforcement of environmental laws; and

(d) generally to ensure the maximum cooperation and coordination among enforcing agencies and other public departments dealing with environment protection.

(3) The Committee may

(a) make recommendations to the Minister on any matter relating to the protection and management of the environment, including national environmental standards, the processing of applications for EIA licence, the review of EIA, spills and environmental emergency, enforcement procedures and policies;

(b) propose to the Minister amendment of the Fourth Schedule;

(c) adopt any memorandum of understanding on the use of facilities under the control of any public department;

(d) provide sound guidelines on sampling, monitoring and laboratory analyses under an environmental law.

(4) The Committee shall

(a) regulate its own meetings and proceedings as it thinks fit;

(b) meet as often as it is necessary at the request of its chairman, but in any case at least once every month.

(5) For the purpose of discharging its functions under this Act, the Committee may -

(a) establish sub-committees;

(b) delegate any of its functions and powers to its Chairman, the Director or any subcommittee.

Part IV

ENVIRONMENTAL IMPACT ASSESSMENT

13. APPLICATION FOR EIA LICENCE

(1) Notwithstanding any licence, permit, or approval granted under any other enactment, any person being a proponent who commences, proceeds with, carries out, executes or conducts, or causes to commence, proceed with, carry out, execute or conduct, an undertaking

(a) without an EIA licence; or

(b) in breach of any condition of the licence,

shall commit an offence.

(2) Notwithstanding subsection (1) a proponent

(a) may for the purpose of an understaking prepare a feasibility study or do any research or any act in furtherance of an application for an EIA licence, or for an approval, permission or licence required under any other enactment in respect of the undertaking;

(b) shall inform the Director of any act done under paragraph (a).

(3) A proponent applying for an EIA licence in relation to this undertaking shall submit to the Director an environment impact assessment.

(4) Where ownership, control or management of an undertaking is transferred before an EIA is approved to any person, the proponent and that person shall jointly notify the Director of the transfer and communicate a copy of the document witnessing the transfer.

(5) On notification under subsection (4), the person to whom the transfer is made shall be deemed to be the proponent in respect of the undertaking transferred as from the date of the notification.

(6) Unless a joint notification of transfer is given to the Director, the person applying for an EIA licence shall be deemed to be the proponent.

(7) Any person who contravenes subsection (4) shall commit an offence.

14. CONTENTS OF EIA

An EIA shall contain a true statement and description of

(a) the location of the undertaking and its surroundings;

(b) the principle, concept and purpose of the undertaking;

(c) the direct or indirect effects that the undertaking is likely to have on the environment;

(d) the social, economic and cultural effects that undertaking is likely to have on people and society;

(e) any actions or measures which may avoid, prevent, change, mitigate or remedy the likely effects of the undertaking on the environment, people and society;

(f) the inevitable adverse environmental effects that the undertaking is likely to have on the environment, people and society, if it is implemented in the manner proposed by the proponent;

(g) the irreversible and irretrievable commitments of resources which will be involved by the undertaking , if implemented in the matter proposed by the proponent;

(h) any alternatives to the proposed undertaking;

(i) such other information as may be necessary to a proper review of the potential environmental impact of the undertaking.

15. PUBLIC COMMENT

(1) An EIA submitted under section 13 (3) shall be open at all reasonable hours for public inspection.

(2) The Director shall give notice to that effect in two issues of the *Gazette* and in two issues of two daily newspapers, there being in each case an interval of at least 7 days between the first and second publications.

(3) A notice published under subsection (2) shall state

(a) a summary description of the undertaking;

(b) the address where the undertaking is to be carried out;

(c) the place where the EIA may be inspected;

(d) the time limit for the submission of public comments in writing.

(4) The Director may on application extend the time limit to afford reasonable opportunity for any person to submit public comments on the EIA.

16. REVIEW OF EIA

(1) The Director shall

(a) review an EIA submitted by a proponent and determine its scope and contents; and

(b) refer the EIA other than the EIA relating to an exempt undertaking with such comments and observations as he thinks appropriate, and with any public comments submitted, to the EIA Committee for examination **(Amended 4/93)**

(2) The Director may for the purpose of the review under subsection (1) (a)

(a) request any public department, an enforcing agency, any non-governmental organisation or any other person to submit their observation in writing on the EIA;

(b) set up a technical advisory committee to advise him on the EIA or on any aspects of the undertaking;

(c) require the proponent to carry out further study or to submit additional information for the purpose of ensuring that the EIA is as accurate and exhaustive as possible.

17. EIA COMMITTEE

(1) There is established for the purposes of this Act an EIA Committee which shall consist of

(a) the Permanent Secretary, Ministry of Environment and Quality of Life, as Chairman;

(b) the Director;

(c) a representative of the Ministry of Health;

(d) a representative of the Ministry of Agriculture, Fisheries & Natural Resources;

(e) a representative of the Ministry of Industry and Industrial Technology;

(f) a representative of the Ministry of Housing, Land & Town & Country Planning; and

(g) a representative of the Ministry of Energy, Water Resources & Postal Services.

(2) The EIA Committee shall examine applications for EIA licence referred to it after review by the Director and shall make such recommendations to the Minister as it thinks fit.

(3) Four members of the EIA Committee shall constitute a quorum.

(4) The EIA Committee may

(a) establish any sub-committee

(b) with the approval of the Minister, co-opt any person as member.

(5) No co-opted member shall

(a) be deemed to hold a public office solely by virtue of his designation as member of the EIA Committee;

(b) have any voting right.

(6) Subject to the other provisions of this section, the EIA Committee shall regulate its meetings and proceedings in such manner as it thinks fit. **(Amended 4/93)**

18. DECISION ON EIA

(1) The Minister shall after taking into account recommendations of the EIA Committee make his findings; **(Amended 4/93)**

(a) refer it back to the Director with a direction to set up a technical advisory committee for further consideration of the EIA;

(b) require the proponent to furnish any additional information as may be needed to determine the environmental impact of the undertaking;

(c) where an EIA provides insufficient information to determine the scope or the impact of the undertaking on the environment, people or society, disapprove the EIA;

(d) subject to section 19, approve the EIA with a direction to issue an EIA licence on such terms and conditions as it considers appropriate.

(2) subject to an appeal under section 49, the findings of the Minister shall be final and binding.

(3) The Director shall comply and give effect to the findings of the Minister under subsection (1).

(4) where an EIA is approved by the Minister, the Director shall issue an EIA licence on the terms and conditions contained in a direction under subsection (1).

19. EIA APPROVAL

(1) In considering approval of an EIA, account shall be taken of

(a) the minimum requirements of an EIA as prescribed in regulations;

(b) the environmental factors considered in the EIA;

(c) the measures proposed to avoid or minimise adverse effects on the environment, people or society;

(d) the alternatives proposed in the EIA;

(e) such other matters that may be relevant in weighing the significance or insignificance of the potential environmental impact of the undertaking.

(2) Where an EIA is approved or a direction is given by the Minister under subsection 3(b) , the EIA and the directions shall be deemed to be conditions of the EIA licence issued under section 18 (4).

(3) The Minister may at any time notwithstanding an approved EIA

(a) revoke an EIA licence, or amend the conditions of an EIA licence;

(b) give the proponent such directions as he considers necessary in relation to

(i) the methods of execution and the phasing of the undertaking;

(ii) works or actions required to prevent, reduce or eliminate the adverse effects of the undertaking on the environment, people and society;

(iii) research, investigation, and monitoring programmes related to the undertaking;

(iv) any other aspect of the undertaking or of the execution of the undertaking which is reasonably expected to have adverse environmental effects;

(c) require the proponent to submit at such interval as he may determine, reports on the impacts of the undertaking on the environment, people and society.

(4) Any person who fails to comply with a requirement under subsection 3(c), shall commit an offence.

20. SUBMISSION OF FRESH EIA

(1) The Director may at any time after the issue of an EIA licence order a holder to submit a fresh EIA in respect of his undertaking within such time as may be specified.

(2) An order under subsection (1) may be issued where in the opinion of the Director

(a) the undertaking is or is likely to be a source of pollution to the environment;

(b) there is a substantial change or modification in the undertaking, or in the manner in which the undertaking is being operated;

(c) the undertaking poses a threat to the environment; or

(d) the circumstances of the undertaking with regard to its surrounding environment so require.

(3) Where a person being a holder fails to comply with an order issued under subsection (1)

(a) he shall commit an offence;

(b) his EIA licence shall be cancelled.

21. TRANSFER OF EIA LICENCE

(1) An EIA licence may be transferred by the holder to a person who purports to own, or to have charge, or management, or control of the undertaking to which the licence relates.

(2) Where an EIA licence is transferred under this section, the person to whom it is transferred and the holder shall jointly notify the Director in writing of the transfer not later than thirty days of the transfer, and communicate the document witnessing the transfer .

(3) Where no joint notification of transfer is given in accordance with subsection (2), the holder shall be deemed for the purposes of this Act to be the owner, or the person having charge, or management or control of the undertaking, as the case may be.

(4) An EIA licence which is transferred to a person under this section shall have effect on the date the Director is notified as if it has been issued to that person and be subject to the same conditions as were attached to it immediately before that date.

(5) Any person who contravenes subsection (2) shall commit an offence.

22. EFFECT OF EIA LICENCE

(1) No civil or criminal liability in respect of an undertaking or consequence resulting from an undertaking shall be incurred by the Government of Mauritius, the Minister, or any public officer by reason of the approval of an EIA or the grant of an EIA licence, or by reason of any conditions attached to an EIA licence.

(2) The fact that an EIA licence is issued in respect of an undertaking shall afford no defence to any civil action or to a prosecution under any enactment other than section 13(1) concerning that undertaking or the manner it is operated or managed.

23. EXEMPTION

(1) The Minister may declare an undertaking by a public department, which in his opinion is urgently needed in the national interest or for the economic development of Mauritius, to be an exempt undertaking.

(2) Sections 13 and 16 *(b)* shall not apply in respect of an exempt undertaking.

(3) The Director shall refer an EIA in respect of an exempt undertaking together with his comments and observations and with any public comments submitted to the Minister for his decision.

(4) The Minister may approve the EIA on such conditions as he thinks fit, having regard to section 19.

(5) On approving an EIA under subsection (4), the Minister shall cause a notice to be published in the *Gazette* stating -

(a) a summary description of the undertaking and its location;

(b) the proponent of the undertaking;

(c) a declaration that the undertaking is an exempt undertaking;

(d) the approval of the EIA and the conditions attached to the approval.

Part V

SPILL AND ENVIRONMENTAL EMERGENCY

24. DUTY TO NOTIFY DIRECTOR

(1) Any office of a public department or of a local authority who is informed of a spill, shall notify the Director.

(2) Any owner of a pollutant which is spilled shall forthwith -

(a) notify the Director,

(b) inform the Director of -

(i) the circumstances of the spill,

(ii) any action taken or proposed to be taken in relation to the spill,

(c) do everything practicable to -

(i) prevent, eliminate and ameliorate the adverse effects of the spill,

(ii) restore the environment.

25. MEASURES TAKEN BY DIRECTOR

(1) Where the owner of a pollutant which is spilled

(a) is reasonably suspected of contravening section 24 (2) (c),

(b) cannot promptly be identified,

(c) requests the assistance of the Director in relation to a spill,

the Director may initiate any action and take any measures necessary in the public interest to prevent, eliminate and ameliorate the adverse effects on and to restore the environment.

(2) In the event of a spill, the Director may order the owner of the pollutant which is spilled, or any other person to do such action within such period of time as he may specify in order to

(a) prevent, eliminate or ameliorate the adverse environmental effects of the spill,

(b) restore the environment,

(c) dispose of or in any way deal with the pollutant or any object reasonably suspected to be affected by the pollutant.

(3) The Director may direct any person conducting an activity which may, in the Director's opinion, cause a spill

(a) to prepare a contingency plan satisfactory to the Director,

(b) to make such modification as he thinks appropriate to an existing contingency plan.

(4) The Minister may make regulations providing for the requirement of contingency plans in respect of such activities or buildings as may be prescribed.

26. CLEAN-UP AND REMOVAL OPERATIONS

The Minister shall prescribe

(a) the procedures for clean-up and removal operations in the event of a spill;

(b) the method of storage and of disposal of any pollutant or of any object, plant, animal, or any part of the environment removed in a clean-up or removal operation or otherwise affected by a pollutant.

27. LIABILITY FOR SPILL

(1) Any person affected in any way by a spill shall have a right to damages from the owner of a pollutant.

(2) Subject to this section, Article 1384 alinea 1 of the Code Napoléon shall apply to an action under subsection (1).

(3) For the purposes of an action for damages under this section

(a) the owner of a pollutant shall be presumed to be liable for any damages caused by a spill;

(b) the owner of a pollutant which is spilled shall always be deemed to be the "gardien" of the pollutant;

(c) a pollutant shall always be deemed to be in the custody of the owner of the pollutant;

(d) the burden of proving that the damage was not caused by the pollutant which was spilled, shall always rest on the owner of the pollutant;

(e) "force majeure", "la faute du tiers", or "la faute exclusive de la victime" shall not be a defence.

(4) Where there are several owners of a pollutant, the action may be directed against all or anyone of them.

(5) Where damage is caused by a spill to the environment, or to any property, object or thing which is not the subject of private ownership, the Attorney-General may claim damages against the owner of the pollutant in accordance with this section.

28. RECOVERY OF EXPENSES

(1) The Director may recover from the owner of a pollutant which is spilled all costs and expenses incurred as a result of

(i) any clean-up or removal operation,

(ii) any measure taken to prevent, eliminate and ameliorate the adverse effects of a spill on the environment;

(iii) any measure taken to dispose of or to deal with the pollutant.

(2) The costs and expenses referred to in subsection (1) shall be deemed to be civil debts owed by the owner of a pollutant to the Government of Mauritius.

29. ENVIRONMENTAL EMERGENCY

(1) Where a major threat to the environment is posed as a result of a spill or otherwise, the Prime Minister may in consultation with the Minister declare an environmental emergency.

(2) Notwithstanding any enactment, where an emergency is declared under subsection (1), the Prime Minister may make such order as he thinks fit to any public department for the purpose of the protection of the environment.

(3) The Commission shall prepare such contingency plan as is appropriate in the event of an emergency situation.

30. POWERS IN CASE OF SPILL OR EMERGENCY

Any person engaged in an action or measure taken by the Director in the case of a spill, or in furtherance of an order by the Prime Minister in the case of an emergency, may

(a) without warrant enter any premises and have access through or over any building, structure, vehicle or by land, water or air,

(b) construct or set up any structure, machinery, materials and equipment on any premises,

(c) remove the pollutant or any object, plant, animal, to any part of the environment which is reasonably suspected to be effected by the pollutant, and

(d) stop, inspect, search and detain any vehicle.

31 REGULATIONS UNDER THIS PART

The Minister may make regulations under this Part

(a) for the purpose of preventing or in any way dealing with a spill,

(b) after consultation with the Commission, for the purpose of environmental emergency.

Part VI

NATIONAL ENVIRONMENTAL STANDARDS

32. ISSUE OF STANDARDS

(1) Without prejudice to the Occupational Safety, Health and Welfare Act, and subject to this section, the Minister shall, for the control of pollution of the environment, have exclusive authority to issue national environmental standards in relation to -

(a) water,

(b) effluent limitations,

(c) air,

(d) noise,

(e) waste,

(f) pesticide residues, and

(g) odour.

(2) A public department, a non-governmental organisation, or any person may make recommendations to the Minister in respect of national environment standards.

(3) Where the Minister proposes to issue national environmental standards or to amend existing standards, he may consult a technical advisory committee and the Committee.

(4) Before issuing any national environmental standards, the Minister shall cause the proposed standards to be published by notice in the *Gazette* and in two daily newspapers and invite submissions in writing on the proposed standards within such period as may be specified.

(5) No standards shall be issued unless the relevant enforcing agency has been consulted.

33. STANDARDS FOR WATER

(1) The Minister shall prescribe standards for water quality to protect the public health, welfare and the environment, and to provide adequate safeguard for the quality of water.

(2) The Minister may establish different standards for water quality having regard to the use and value of water for domestic supplies, propagation of fish, flora, fauna, and wildlife, recreational purpose, agricultural, industrial and other uses.

34. EFFLUENT LIMITATIONS

The Minister shall establish -

(a) effluent limitations for sources of pollution by effluents in accordance with the applicable pollution control technology, having regard to existing and to new sources of pollution,

(b) time schedule for installation and operation of applicable pollution control technology.

35. STANDARDS FOR AIR

(1) The Minister shall prescribe standards to protect the quality of air resources so as to promote the public health and welfare, and the development and the productive capacity of the human, animal, or plant life.

(2) The standards prescribed under subsection (1) shall provide for

(a) minimum essential air quality,

(b) the control of concentration of substances in the air which separately or in combination are likely to result in damage or deterioration of property, of human, animal and plant health,

(c) controls for atmospheric pollution originating from energy and industrial sources, including pollution produced by aircrafts and other self-propelled vehicles, and by factories and power generating station,

(d) standards applicable to emission from mobile sources causing or contributing to air pollution, or endangering public health and welfare.

36. STANDARDS FOR NOISE

The Minister shall prescribe such standards for noise emission as are required to preserve and maintain public health and the environment.

37. STANDARDS FOR HAZARDOUS WASTE

(1) The Minister may by regulations declare any substance to be a hazardous substance.

(2) In determining what substances shall be declared hazardous, the Minister shall have regard to such special circumstances as he considers appropriate, including quantity, location, and climatic conditions relating to discharges.

(3) The Minister shall prescribe standards for hazardous wastes to control pollution of the environment and to promote public health and welfare.

(4) The Minister may make regulations for

(a) the control of the import, export, collection, movement, transportation and disposal of hazardous wastes;

(b) the licensing of waste disposal sites and waste management systems and other facilities relating to the disposal of hazardous wastes in an environmentally sound manner.

38. STANDARDS FOR NON-HAZARDOUS WASTE

The Minister shall prescribe standards for the collection, transportation, storage, processing, disposal and re-cycling of non-hazardous wastes.

39. STANDARDS FOR PESTICIDE RESIDUE

(1) The Minister shall prescribe standards for the concentration of pesticide residues in raw agricultural commodities, food and animal feeds.

(2) For the purpose of subsection (1), raw agricultural commodities

(a) include fresh or frozen fruits and vegetables in their raw state, grains, nuts, eggs, raw milk, meat and other agricultural produce,

(b) but do not include any agricultural produce or food which is processed, fabricated or manufactured by cooking, dehydrating, milling or by any others means.

40. STANDARDS FOR ODOURS

The Minister shall prescribe such standards for odours as are required to preserve and maintain public health and the environment.

41. QUALITY CONTROL OF LABORATORIES

(1) For the purpose of assessing analytical performance and ensuring the validity and comparability of environmental data, the Minister shall, in relation to accredited laboratories

(a) prescribe standards of procedure for quality assurance and quality control;

(b) establish analytical quality control programmes;

(c) prescribe calibration procedures for analytical instruments used in accredited laboratories.

(2) The Minister may on application accredit a public or private laboratory conducting or intending to conduct laboratory analyses of environmental samples or providing environmental data.

(3) An analysis of environmental sample conducted by or environmental data provided by a laboratory other than an accredited laboratory shall not be admissible evidence in any proceeding before a Court of law or before the Tribunal.

Part VII

COASTAL AND MARITIME ZONE MANAGEMENT

42. INTERPRETATION UNDER THIS PART

In this Part -

"baseline" has the meaning assigned to it in the Territorial Sea Act;

"coastal zone"

(a) means

(i) any area of seawater including any low-tide elevation, land, beach, islet, reefs, rocks, lying between the baseline and the highwater mark;

(ii) any land which is situated wholly or partly within 81.21 metres from the highwater mark;

(b) includes any estuary or mouth of a river, stream or canal which lies within 81.21 metres from the outermost point of its bank on the sea at high tide;

"dumping" means

(i) any deliberate disposal of wastes or other matter from vessels, aircraft, platforms or other man-made structures at sea;

(ii) any deliberate disposal of vessels, aircraft, or other man-made structures at sea;

"maritime zone" means the maritime zone under the jurisdiction of the State of Mauritius, and includes the territorial sea, the exclusive economic zone, and the continental shelf, as defined in the Maritime Zones Act;

"zone" means the coastal and maritime zone.

43. PROTECTION OF THE ZONE.

(1) The Minister may make such regulations as he thinks fit to prevent, reduce and control pollution in the zone.

(2) Notwithstanding the generality of subsection (1), the regulations may provide for -

(a) such measures as are necessary to ensure that activities in the zone are so conducted as not to cause damage by pollution to the natural environment;

(b) the control and prevention of pollution from vessels, crafts, and other engines used in the zone;

(c) the control and prevention of pollution from installations and devices used in the exploration or exploitation of the natural resources of the sea-bed and subsoil of the maritime zone;

(d) the control and prevention of pollution of the marine environment from land-based sources, including rivers, estuaries, pipelines, and outfall structures;

(e) the control and prevention of pollution of the marine environment arising from or in connection with seabed activities and from artificial islands, installations and structures in the maritime zone;

(f) such other matters relating to the preservation and conservation of the environment of the zone.

44. DUMPING IN THE ZONE

(1) Subject to subsection (2), no person shall release or cause to release into the zone such toxic, harmful or noxious substances from or through the atmosphere or by dumping.

(2) It shall be a defence to a prosecution under subsection (1) to prove that the release or the dumping was due to or was rendered necessary by "force majeure", or for the protection of human life.

(3) Any person who contravenes subsection (1) shall commit an offence.

Part VIII

THE ENVIRONMENT APPEAL TRIBUNAL

45. THE ENVIRONMENT APPEAL TRIBUNAL

(1) There is established for the purposes of this Act an Environment Appeal Tribunal which shall consist of

(a) a Chairman, who shall be a barrister-at-law of not less than ten years standing, appointed by the Public Service Commission, and

(b) such other members as may be appointed by the Minister.

(2) The Minister may -

(a) appoint such members on an ad hoc basis and for such period as he considers necessary to serve on the Tribunal;

(b) designate such public officers as he thinks fit to assist in conducting the business of the Tribunal;

(c) approve such fees as may be paid to the members of the Tribunal.

46. JURISDICTION OF THE TRIBUNAL

(1) The Tribunal shall hear and determine appeals against

(a) the findings of the Minister on an EIA, or any decisions of the Minister.

(i) on an EIA under Section 18; or

(ii) revoking an EIA licence or amending the conditions of and EIA licence under section 19(3)(a); **(Amended 4/93)**

(b) a direction given under section 19(3)(b);

(c) an order of the Director to submit a fresh EIA under section 20(1);

(d) the revocation of a programme approval under section 57;

(e) the issue of an enforcement notice, a prohibition notice and a variation notice under sections 58, 59 and 62;

(f) a requirement of compliance monitoring under section 66.

(2) Any person may appeal within 30 days of the decision, direction, order, or notice referred to in subsection (1) in such form and manner as may be prescribed by regulations.

47. PROCEEDINGS OF THE TRIBUNAL

(1) The Tribunal shall sit at such place and time as the Chairman of the Tribunal may determine.

(2) Where the Tribunal adjourns any proceedings, it may resume them at such place and time as the Chairman of the Tribunal may determine.

(3) Subject to any regulations made under section 50, all appeals before the Tribunal shall be instituted and conducted

(a) as far as possible in the same manner as proceedings in a civil matter before a District Magistrate;

(b) in accordance with the law of evidence in force in Mauritius;

(c) in public, except with the agreement of all the parties, or where the Tribunal so orders in the public interest.

(4) The Tribunal may

(a) make such orders for requiring the attendance of persons and the production of articles or documents, as it thinks necessary or expedient;

(b) take evidence on oath and may for that purpose administer oaths;

(c) and on its own motion, summon and hear any person as witness.

(5) Any person who

(a) fails to attend the Tribunal after having been required to do so under subsection (4);

(b) refuses to take an oath before the Tribunal or to answer fully and satisfactorily to the best of his knowledge and belief any question lawfully put to him in any proceedings before the Tribunal or to produce any article or document when required to do so by the Tribunal;

(c) knowingly gives false evidence or evidence which he knows to be misleading before the Tribunal;

(d) at any sitting of the Tribunal -

(i) wilfully insults any member thereof;

(ii) wilfully interrupts the proceedings, or commits any contempt of the Tribunal,

shall commit an offence.

48. DETERMINATION OF THE TRIBUNAL

(1) (a) For the purpose of hearing and determining any cause or matter under this Act, the Tribunal shall be constituted by the Chairman and at least any 2 of its members.

(b) A member of the Tribunal who has a direct interest in any cause or matter which is the subject of proceedings before the Tribunal shall not take part in those proceedings.

(2) Where there is a disagreement among the members of the Tribunal, the decision of the majority shall be the determination of the Tribunal.

(3) Subject to section 49, a decision or finding of the Tribunal on any cause or matter before it, shall be final and binding on the parties.

(4) On hearing an appeal, the Tribunal may confirm, amend or cancel any decision, order, direction or notice referred to in section 46.

(5) Where a decision, order, direction or notice is confirmed or amended, the Tribunal shall specify the period within which it shall be complied with.

(6) Any person who fails to comply with a decision, order, direction or notice confirmed or amended by the Tribunal, shall commit an offence.

(7) (a) The Tribunal may make such order as to costs as may be prescribed.

(b) An order made under paragraph (a) shall be enforced in the same manner as an order for costs in proceedings before a Judge.

(c) No order under paragraph (a) shall be made against the Crown, the Minister, the Department or the Director.

(8) Proceedings before the Tribunal shall be exempt from stamp duty and registration dues.

49. APPEAL TO THE SUPREME COURT

(1) Any party who is dissatisfied with the decision or findings of the Tribunal relating to an appeal under section 48, as being erroneous in point of law may appeal to the Supreme court. **(Amended 4/93)**

(2) Any party wishing to appeal to the Supreme Court under subsection (1) shall, within 21 days of the date of the decision of the Tribunal **(Amended 4/93)**

(a) lodge with, or send by registered post to the Chairman of the Tribunal a written application requiring the Tribunal to state and sign a case for the opinion of the Supreme Court on the grounds stated therein;

(b) at the same time or earlier forward a copy of his application by registered post to the other party.

(3) An appeal under this section shall be prosecuted in the manner provided by rules made by the Supreme Court.

50. REGULATIONS BY THE TRIBUNAL

The Tribunal may make regulations for the purpose of instituting and conducting proceedings of appeals **(Amended 4/93)**

Part IX

THE NATIONAL ENVIRONMENT FUND

51. THE NATIONAL ENVIRONMENT FUND

(1) There shall be established a National Environment Fund.

(2) The Fund shall be deemed to be a Special Fund for the purposes of the Finance and Audit Act.

52. OBJECTS OF THE FUND

The objects of the Fund shall be -

(a) to provide for foreign laboratory support for analysis of environment samples;

(b) to carry out programmes to prevent and reduce pollution;

(c) to promote environmental education and research;

(d) to support non-governmental organisations engaged in environment protection;

(e) to encourage local environmental initiatives;

(f) to publish reports on the environment;

(g) to promote, support and encourage activities relating to environment protection and management.

53. THE BOARD

(1) The Fund shall be administered by a Board which shall consist of

(a) The Permanent Secretary, Ministry of Environment, Chairman;

(b) The Accountant-General, or his representative;

(c) The Director, and

(d) any other person designated by the Minister.

(2) The Board shall

(a) comply with such directions of a general character as the Minister may give;

(b) furnish to the Minister such information with respect to the discharge of its functions as the Minister may require;

(c) be convened by the Chairman at such time and place as he thinks fit;

(d) regulate its meetings and proceedings in such manner as it thinks fit.

54. INCOME AND DISBURSEMENT

(1) The Fund shall consist of

(a) any money lawfully accruing to the Fund;

(b) donations;

(c) any funds raised from public activities organised with the approval of he Board.

(2) No disbursement of money shall be made from the Fund except

(a) for the purposes of the Fund;

(b) with the authorisation of the Board.

(3) Article 910 of the Code Napoléon shall not apply to donations made to the Fund.

55. AUDIT AND ACCOUNTS

(1) The Finance Officer shall -

(a) not later than 3 months after each financial year, prepare and submit to the Director of Audit

(i) an annual statement of the receipts and payments of the Fund for that financial year; and

(ii) a balance sheet showing the assets and liabilities of the Fund in respect of that financial year;

(b) furnish to the Minister as soon as practicable after the end of each financial year, a report dealing with the activities and financial position of the Fund during that period; **(Amended 4/93)**

(c) attend the meetings of and advise the Board on the financial standing of the Fund.

(2) The Minister shall at the earliest available opportunity, lay a copy of the annual report and audited annual accounts of the financial year before the Assembly. **(Amended 4/93)**

56. REGULATIONS IN RESPECT OF THE FUND.

The Minister may with the approval of the Board make such regulations as he thinks fit for the purposes of the Fund.

Part X

ENFORCEMENT

57. PROGRAMME APPROVAL

(1) Where he is of opinion that a person is contravening, or is likely to contravene an environmental law, the Director may cause to be served on him a programme notice

(a) stating the opinion of the Director;

(b) specifying the matter constituting the contravention or the matter making it likely that the contravention will arise, as the case may be;

(c) requesting the person to submit for his approval before a specified date a written programme of measures which the person intends to take to remedy the contravention or to eliminate the likelihood of a contravention.

(2) The Director may

(a) hold consultations with the person to determine the appropriate method of remedying the contravention or eliminating the likelihood of a contravention,

(b) consult a technical advisory committee or the Committee,

(c) request the person to submit additional information, proposal or research study.

(3) On approving a programme of measures, the Director shall issue a programme approval stating

(a) the notice issued under subsection (1),

(b) the measures that shall be taken to remedy the contravention or eliminate the likelihood of a contravention, and

(c) the period within which the measures shall be implemented.

(4) the Director may

(a) supervise and issue directions in respect of the implementation of the measures contained in the programme approval;

(b) with the consent of the person, modify the programme approval;

(c) at any time, revoke a programme approval.

(5) No person shall be prosecuted for a contravention in respect of which a programme approval is in force.

(6) Where

(a) a person fails to comply with

(i) a request in a notice under subsection (1);

(ii) a programme approval issued under subsection (3);

(iii) any direction issued under subsection (4); or

(b) a programme approval revoked under subsection (4); the Director may issue an enforcement notice or a prohibition notice.

58. ENFORCEMENT NOTICE

(1) Where he is of the opinion that

(a) a person is contravening, or is likely to contravene an environmental law,

(b) a programme approval will not provide an effectual remedy, or a prohibition notice not appropriate,

the Director may cause to be served on the person an enforcement notice.

(2) An enforcement notice shall

(a) state the opinion of the Director;

(b) specify the matter constituting the contravention or the matter making it likely that the contravention will arise, as the case may be;

(c) specify the measures that shall be taken to remedy the contravention or to remedy or eliminate the matter making it likely that the contravention will arise, as the case may be; and

(d) specify a period within which those measures shall be implemented.

(3) No person shall be prosecuted for a contravention in respect of which an enforcement notice was issued as long as the notice is in force.

(4) Any person who fails to comply with an enforcement notice shall commit an offence.

59. PROHIBITION NOTICE

(1) Where he is of the opinion that an enterprise or activity or the manner in which the enterprise or activity is carried on, involves an imminent risk of serious pollution of the environment, the Director may cause to be served on the person owning, or managing, or in charge of, or in control of the enterprise or activity a prohibition notice.

(2) A prohibition notice may be served whether or not

(a) the enterprise or activity, or the manner in which the enterprise or activity is carried on, constituted a contravention of an environmental law;

(b) there is in force in relation to that enterprise or activity, a licence, permit or approval issued under any environmental law or any other enactment .

(3) A prohibition notice shall

(a) state the Director's opinion;

(b) specify the risk of serious pollution involved as well as the way in which the enterprise, activity or the manner in which the enterprise or activity is carried on, is suspected to give rise to the risk;

(c) specify the measures that shall be taken to remove the risk of pollution and the period within which they shall be implemented;

(d) specify the enterprise or activity, or any aspect of the enterprise or activity that is prohibited, or specify any conditions in which the enterprise or activity may be carried on.

(4) A prohibition notice shall not be a bar to a prosecution for any offence, even if there are consultations with the person served with the notice.

(5) Any person who fails to comply with a prohibition notice, shall commit an offence.

60. GENERAL PROVISIONS ON NOTICES

Sections 61 to 64 shall apply to enforcement notices and to prohibition notices, and in these sections

(a) *"notice"* means an enforcement notice and a prohibition notice, and does not include a variation notice;

(b) *"person affected"* means a person on whom a notice is served or is proposed to be served.

61. CONSULTATION ON NOTICES

(1) Before or at any time after issuing a notice, the Director shall as far as he deems practicable consult

(a) the person affected;

(b) the Committee.

(2) The Director may consult a technical advisory committee or any public department on a notice.

62. VARIATION NOTICE

(1) Any person affected, or any enforcing agency may apply to the Director for an amendment of a notice.

(2) The Director, on his own initiative, or on application, may amend a notice by causing to be served on the person affected a variation notice.

(3) A variation notice shall -

(a) refer to the notice which is amended;

(b) specify the amendment to the notice;

(c) where necessary, vary the date specified in the notice.

(4) A variation notice shall supersede the notice to which it refers to the extent of the amendment.

63. REVOCATION OF NOTICES

(1) Where he is satisfied that

(a) the measures required to be taken in a notice have been implemented;

(b) there exists no further pollution or risk of pollution to the environment caused by the enterprise, activity or the manner in which the enterprise or activity is carried on;

(c) the notice is not or will not be effectual;

the Director may revoke a notice and shall inform the person affected in writing.

(2) The Director may

(a) when revoking any notice, serve a programme approval;

(b) when revoking an enforcement notice, serve a prohibition notice;

(c) when revoking a prohibition notice, serve an enforcement notice.

64. POWERS OF ENTRY

(1) An authorised officer may, at any time, enter any premises other than a private dwelling house for the purposes of

(a) carrying out any lawful order given by the Minister or the Director under this Act;

(b) determining whether any environmental law or any enforcement notice, prohibition notice, direction is being complied with ;

(c) discharging any other functions under an environmental law.

(2) Subject to section 65, except with the consent of the owner, an authorised officer shall not enter a private dwelling unless he has given to the owner not less than 24 hours' notice in writing of his proposed entry.

(3) An authorised officer may on entering any premises

(a) require the owner to produce any records, documents or licences,

(b) examine any such records, documents or licences and take copies or extracts,

(c) makes plans, take photographs and carry out inspections,

(d) make tests, take measurements and samples, inspect plants, machineries, equipments, vehicles,

(e) require the owner of the premises entered upon or any person employed by him, or any other person on the premises to give to the authorised officer all reasonable assistance and to answer all proper questions either orally or in writing.

(4) On entering any premises, the authorised officer may bring with him any person or equipment he may consider necessary for the purposes of his entry.

65. ENTRY AND ARREST WITHOUT WARRANT

(1) Where

(a) there is or has been a contravention of an environmental law,

(b) there is reasonable suspicion that a contravention of an environmental law has been or is likely to be committed,

(c) an environmental emergency is declared,

(d) a spill occurs or is reasonably suspected to have occurred, or is likely to occur,

(e) in his opinion, there is an imminent risk of serious pollution of the environment,

an authorised officer may, at any time, without warrant

(i) enter and search premises;

(ii) secure any article, object, equipment, plant, machinery related to the contravention, or suspected to be a cause of spill or pollution to the environment;

(iii) secure any document, file, or record reasonably required for the investigation or for the prevention of the contravention;

(iv) arrest any person reasonably suspected of the contravention;

(v) exercise any of the powers conferred under section 64 (3).

(2) When exercising any powers conferred by section 64 and this section, an authorised officer shall, if so requested by any person affected, produce to that person a document under the hand of the Director stating that he is authorised to exercise the powers so conferred.

(3) Any person who in relation to the exercise of the powers conferred by section 64 and this section

(a) refuses to allow an authorised officer to enter any premises or to take any person or equipment with him in the exercise of his powers;

(b) obstructs or impedes an authorised officer in the exercise of any of his powers;

(c) fails to provide assistance or information requested by the authorised officer;

(d) gives to an authorised officer any information which is false or misleading;

shall commit an offence.

66. COMPLIANCE MONITORING

(1) The Director may, after consultation with the Committee, in relation to any activity, enterprise, or undertaking, carry out, cause to be carried out, or arrange for such monitoring of

(a) environmental quality, and

(b) the nature, extent and effects of discharges of pollutants, as the Director may consider necessary for ensuring compliance with an environmental law.

(2) The Director may, as he considers necessary, require a person responsible for an activity, enterprise, or undertaking from which there is a discharge of a pollutant into the environment to carry out such monitoring of the nature, extent and effect of the discharge and of the quality of any environmental medium likely to be affected by the discharge, and to keep and to supply to him such records of the monitoring as the Director considers necessary.

(3) Any person who fails to comply with a requirement under subsection (2) shall commit an offence.

67. OFFENCES

(1) Any person who

(a) fails to comply with any requirement, notice, order or direction issued under this Act ;

(b) on being required to submit a report or to provide information under this Act,

(i) fails to do so within the specified date, or

(ii) submits a false report or submits a report misleading in any material particular, or

(iii) provides false or misleading information;

(c) contravenes this Act;

shall commit an offence and unless it is otherwise specifically provided, shall

(i) on a first conviction be liable to a fine not exceeding Rs 5000 and to imprisonment for a tern not exceeding two years;

(ii) on a second or subsequent offence relating to an environmental law, be liable to a fine not exceeding Rs10 000 and to imprisonment for a term of imprisonment not exceeding eight years.

(2) Any person who commits an offence under sections 13 (1), 20 (3) (a), 44 (3), 48 (6), 58 (4) and 59 (5) shall

(a) on a first conviction, be liable to a fine which shall be not less than Rs10,000 and not more than Rs25,000 and to imprisonment for a term not exceeding 6 years;

(b) on a second or subsequent conviction, be liable to a fine which shall be not less than Rs 50,000 and not more than Rs250,000 and to imprisonment for a term which shall be not less than 6 years and not more than 12 years.

(3) Any person who commits an offence under sections 13 (7), 19 (4), 21 (5), and 66 (3), shall

(a) on a first conviction be liable to a fine which shall be not less than Rs6,000 and not more than Rs15,000 and to imprisonment for a term not exceeding 4 years;

(b) on a second or subsequent conviction be liable to a fine which shall not be less than Rs25,000 and not more than Rs150,000 and to imprisonment for a term which shall be not less than 6 years and not more than 8 years.

68. POWERS OF COURT

(I) In addition to any penalty under section 67, the Court may

(a) order the forfeiture of any object, machine, plant, vehicle or any article used in or connected in any way with the commission of an offence;

(b) order or prohibit the doing of any act to stop a continuing contravention.

(2) Where the conviction relates to an enforcement notice, a prohibition notice, an order or direction, the Court shall order compliance with the notice, order or direction within such period as the Court may determine.

(3) Where the conviction relates to section 13 (1), the Court shall make an order that the undertaking be stopped, ceased, closed or pulled down as the case may be.

69. JURISDICTION

(1) Notwithstanding

(a) Section 114 of the Courts Act; and

(b) Section 72 of the District and Intermediate Courts (Criminal Jurisdiction) Act,

a Magistrate shall have jurisdiction to try all offences under an environmental law and may impose any penalty provided under the enactment.

(2) The following enactments shall not apply to a sentence provided under any environmental law

(a) sections 152 and 153 of the Criminal Procedure Act;

(b) the Probation of Offenders Act.

Part XI

MISCELLANEOUS PROVISIONS

70. RESTRICTION OF LIABILITY

(1) No civil or criminal liability shall attach to the Minister, the Director, or to any officer of the Department in respect of any act done in good faith in the execution or purported execution of their duties or their power under this Act.

(2) The Director and the Officers of the Department shall be public officers for the purposes of the Public Officers Protection Act and the Criminal Code.

(3) Subsection (1) shall be in addition to and not in derogation from the Public Officers Protection Act.

71. LIABILITY OF CORPORATE BODIES

Where an offence under an environmental law is committed by a corporate body or by any person acting on behalf of the corporate body or by any person employed by a corporate body, the Court shall impose the maximum penalty prescribed.

72. DISCLOSURE OF INFORMATION

Where the Director or any other officer of the Department, or any person appointed on a committee or any other person discharging any function or duty under this Act discloses otherwise than in the performance of his duty any information relating to any trade secret used in carrying on a particular undertaking and the information has been given to him or obtained by him by virtue of this Act, he shall commit an offence.

73. CODE OF PRACTICE

(1) The Minister may after consultation with the Committee cause to be published in the *Gazette* codes of practice for the purpose of providing practical guidance with respect to appropriate pollution control technology, and generally with respect to the protection of the environment.

(2) The Minister may for the preparation of a code of practice consult a technical advisory committee or any person he thinks fit.

74. REGULATIONS

(1) The Minister may

(a) make regulations for the purposes of this Act;

(b) subject to this Act, by regulations, amend the Schedules.

(2) Regulations made under this section may

(a) make provisions for the issue, amendment and revocation of licences;

(b) provide for the taking of fees and the levy of charges;

(c) make different provisions for different classes of activities or things and for different areas;

(d) make provisions for the purpose of this Act in respect of islands under the jurisdiction of Mauritius other than the Island of Mauritius.

75. CONSEQUENTIAL AMENDMENTS

(1) The Board of Agriculture, Natural Resources and the Environment Act is amended -

(a) in section 1, by deleting the words 'Natural Resources and the Environment Act' and replacing them by the words

"and Natural Resources Act";

(b) in section 2, by deleting the definition of "Board" and replacing it by the following -

"Board" means the Board of Agriculture and Natural Resources established by section 3;

(c) in section 3 (1), by deleting the words "Natural Resources and the Environment" and replacing them by the words "and Natural Resources".

(2) The Central Water Authority Act is amended

(a) in section 2, by deleting the definition of "polluted water";

(b) in section 20(2)(*l*), by inserting before the words "to supervise", the following words -

"unless otherwise provided under any other enactment";

(c) by deleting section 21 (k);

(d) by deleting section 42 and replacing it by the following section

42. *IMMUNITY OF AUTHORITY*

The Authority shall not be responsible for any damage resulting from the irregularity and insufficiency of supply of water for whatever purpose.

(e) by deleting section 46 A.

(3) The Chemical Analyses Act is repealed.

(4) The Criminal Code (Supplementary)Act is amended in section 110 by deleting subsections (2) and (3) and by renumbering the existing subsection (4) as subsection (2).

(5) The Dangerous Substances Act and the Dangerous Substances Regulations 1914 are repealed.

(6) The Fisheries Act is amended in section 9 by deleting

(a) in the marginal note, the words "and the environment".

(b) subsection (3).

(7) The Ground Water Act is amended by deleting subsection (2) of section 4 and by renumbering the existing subsection (3) as subsection (2).

(8) The Local Government Act is amended

(a) in section 2, by inserting in their appropriate places the following definitions

"disposal", in relation to waste, includes the sorting, carriage, transportation, treatment, storage and tipping above or under ground, and the transportation operations necessary for its recovery, re-use or recycling;

"disposal site" means a disposal site designated under section 156A (6);

"Environment Co-ordination Committee" means the environment Coordination Committee established under the Environment Protection Act 1991;

"waste" means solid waste other than hazardous waste, clinical waste and pharmaceutical waste;

(b) in section 51(1), by deleting paragraph (b) and replacing it by the following paragraph

(b) subject to any regulations under section 156A (5), the collection and removal of waste to disposal sites;

(c) by inserting immediately after section 156 the following new part, and renumbering the existing Part X as Part XI.

Part X

156A. *CONTROL OF WASTE*

(1) The Permanent Secretary shall make arrangements for

(a) the collection and disposal of waste;

(b) the operation and management of disposal sites.

(2) In making arrangements under subsection (1), the Permanent Secretary shall

(a) comply with such standards and code of practice issued under the Environment Protection Act 1991;

(b) consult the Environment Coordination Committee.

(3) The Minister may make regulations to give effect to the arrangements made.

(4) The regulations may provide for

(a) the issue, amendment and revocation of licences;

(b) the taking of fees and the levy of charges;

(c) the removal of waste unlawfully deposited and the recovery of expenses incurred for the removal;

(d) any matter relating to enforcement, including the issue of enforcement notices, powers of entry, search and arrest, and the seizure of any vehicle, object or thing used in the commission of an offence under the regulations.

(5) The regulations may

(a) make different provisions for different categories of waste, and for different disposal sites;

(b) provide that a person who contravenes them shall commit an offence, and shall on conviction be liable to a fine not exceeding Rs 25,000, and to a term of imprisonment not exceeding 5 years;

(c) provide that, in addition to the punishment under paragraph (b), the court may order the forfeiture of any vehicle, object or thing used in the commission of the offence.

(6) Subject to any requirements imposed under the Environment Protection Act 1991, the Minister may, by notice in the *Gazette*, designate a disposal site.

(7) Notwithstanding section 114 of the Courts Act, and section 72 of the District and Intermediate Courts (Criminal Jurisdiction) Act, a Magistrate shall have jurisdiction to try all offences under this section and under any regulation made under this section.

(9) The National Coast Guard Act 1988 is amended

(a) in section 2 by inserting at its appropriate place the following definition

"environmental laws" has the meaning assigned to it by section 2 of the Environment Protection Act 1991;

(b) in section 6 (1) by inserting after the word "section" the following words

"and any environmental law,"

(10) The Noise Prevention Act and the following regulations are repealed

(a) The Noise Prevention (Beau Bassin - Rose Hill) Regulations 1939;

(b) The Noise Prevention (Curepipe) Regulations 1939;

(c) The Noise Prevention (Port Louis) Regulations 1939;

(d) The Noise Prevention (Q. Bornes) Regulations 1939;

(e) The Noise Prevention (Rural Districts) Regulations 1942;

(f) The Noise Prevention (Vacoas-Phoenix) Regulations 1939;

(g) The Noise Prevention Victoria Hospital) Regulations 1939;

(11) The Occupational Safety, Health and Welfare Act 1988 is amended in subsection (1) of section 4 by deleting the words "The Minister" and replacing them by the words

"Without prejudice to any standards issued under the Environment Protection Act 1991, the Minister."

(12) The Public Health Act is amended

(a) in section 2, by inserting in its appropriate place the following definition

"environmental law" has the meaning assigned to it in the Environment Protection Act 1991;

(b) in section 18, by deleting the word "nuisance" and inserting before the word "includes" the following

Without prejudice to any environmental law, "nuisance"

(c) by deleting sections 84 to 88 and 150.

(13) The Rivers and Canals Act is amended

(a) in section 26, by deleting subsection (2) and renumbering the subsection (3) as subsection (2);

(b) in section 68, by deleting paragraphs (c), (i) and (j), and renumbering the remaining paragraphs accordingly;

(c) by repealing sections 70, 87, 88 and 91;

(14) The Town and Country Planning Act is amended

(a) in section 2, by inserting in its appropriate place the following definition

"EIA licence" has the meaning assigned to it in the Environment Protection Act;

"undertaking" has the meaning assigned to it in the Environment Protection Act;

(b) in section 7, by inserting the following subsection (4)

"Where an application under subsection (3) relates to an undertaking, the local authority shall not grant a permit unless there is in relation to that undertaking an EIA licence".

(15) The Town and Country Planning Act 1990 is amended

(a) in section 2, by inserting in their appropriate places the following definitions

"EIA licence" has the meaning assigned to it in the Environment Protection Act 1991;

"undertaking" has the meaning assigned to it in the Environment Protection Act 1991;

(b) in section 12 (i), by inserting after paragraph (a) the following paragraph

(i) the provisions of Part IV of the Environment Protection Act and any standards issued under that Act;

(ii) by renumbering the existing paragraphs (b) to (e) as paragraphs (c) to (f) accordingly;

(c) in section 13, by deleting the exertion "A development order" where it first occurs, and replacing it by the following words -

"Subject to section 14 A, a development";

(d) by adding after section 14 the following section -

14 A. PERMIT FOR UNDERTAKING

No permit for development shall be granted in respect of an undertaking, unless there is in relation to it an EIA licence.

(16) The Territorial Sea Act is amended by deleting section 9.

76. Commencement

This Act shall come into force on a date to be fixed by Proclamation and different dates may be fixed in respect of different provisions.

Passed by the Legislative Assembly on the first day of July, one thousand nine hundred and ninety-one.

FIRST SCHEDULE

(section 2)

UNDERTAKINGS REQUIRING AN ENVIRONMENTAL IMPACT ASSESSMENT

A. MANUFACTURING

Sugar industries and refineries

Timber treatment plants

Manufacture of chemical fertilisers

Manufacture of polyurethane foam

Petroleum refineries

Manufacture of rubber products

Bulk storage facilities for petroleum, petro-chemical and hazardous chemical products

Food processing and canning industries

Power stations

Manufacture or packing of cements

Sawmills

Stone crushing plants

Block making plants

Premix concrete plants

Textile industry associated with dyeing, weaving, washing, knitting, bleaching and printing

Tanneries and leather finishing

Manufacture, formulation and packing of pesticides

Installation for cold storages/refrigeration plants and chilling plants

Manufacture and use of asbestos and asbestos-based products

Coral sand crushing and processing

Waste incinerators

Breweries

Refining and processing of edible oil and fats

Asphalt plants including asphalt mix for road construction

Manufacture of matches

Wine industries

Manufacture of batteries

B. COASTAL DEVELOPMENT PROJECTS

Wetlands development

Creation of islands

Removal of sand, coral, beach rock or natural vegetation

Sand crushing, screening and washing

Mining of sand dunes and sea beds

Lagoon dredging and reprofiling of sea beds

Modification existing coastline

Marinas

Construction of jetties

Barachois development

C. PORT AND HARBOUR DEVELOPMENT

Harbour construction and development

Construction of air fields, aviation strips and landing grounds

Harbour dredging operations

Vessel related activities

Fishing ports

Handling and storage of petroleum products, liquid gas, coal and chemicals

D. LAND USE AND DEVELOPMENT

Zoning changes

Dredging, draining and filling of wetlands

Lands clearing in watersheds, nature reserves and natural parks

Land reclamation

Quarrying

Parcelling out land into 10 or more plots **(Amended 4/93)**

E. SEWERAGE AND WATER SUPPLY

Sewage works and outfalls

Sewage treatment plants

F. TRANSPORTATION

Land transport infrastructure

Airports, highways and rapid transit systems

G. MANUFACTURE, HANDLING, STORAGE AND TRANSPORT OF HAZARDOUS MATERIALS AND PESTICIDES

H. WASTE MANAGEMENT

Landfills

Waste disposal installations for incineration or chemical treatment of all types of waste, including hazardous waste, or change of use of lands for the deposit of such waste

I. URBAN DEVELOPMENT PROJECTS

Hospital construction

Major housing projects

Restructuring of land holdings on urban fringes

Industrial estate

Depot for buses and motor vehicles

Traffic centre

New town and satellite town

Hotels and motels

J. AGRICULTURE AND FORESTRY

Deforestation

Commercial/industrial rearing of livestock including poultry, pig, goat and sheep

Rearing of crocodiles, birds, monkeys in nature reserves or elsewhere

SECOND SCHEDULE

(section 4)

NATIONAL ENVIRONMENT COMMISSION

Ministers who are assigned responsibilities for the following subjects

Finance

Economic Planning & Development

Education

Energy, Water Resources

Tourism

Youth & Sports

Agriculture, Fisheries & Natural Resources

Works

Industry & Industrial Technology

Local Government.

Labour & Industrial Relations

Rodrigues

Health

THIRD SCHEDULE

(Section 2)

ENVIRONMENTAL ADVISORY COUNCIL

1. A representative of the following Ministries
   (a) Ministry of Environment & Lands Use
   (b) Ministry responsible for the subject of water resources
   (c) Ministry of Health
   (d) Ministry of Agriculture, Fisheries and Natural Resources
   (e) Ministry of Local Government
   (f) Ministry of Labour & Industrial Relations
   (g) Ministry of Rodrigues
2. A representative of Mauritius Employers' Federation
3. A representative of The Medical Council
4. A representative of Mauritius Sugar Producers' Association
5. A representative of Mauritius Chamber of Commerce & Industry
6. A representative of University of Mauritius
7. A representative of The Institution of Engineers
8 A representative of The Mauritius Bar Council
9. A representative of AHRIM
10. A representative of The Mauritius Association of Architects
11. A representative of Mauritius Export Processing Zone Association
12 A representative of La Société des Historiens de l'Ile Maurice
13. A representative of Non Governmental Organizations
14. A representative of the Mauritius Union of Journalists
15. A representative of Association des Autorités Urbaines
16. A representative of Association of District Councils
17. A representative of Trade Unions approved by Ministry of Labour & Industrial Relations
18. Two persons appointed by the Minister

FOURTH SCHEDULE

(Section 11)

ENFORCING AGENCIES

1. In this Schedule

"Act" means the Environment Protection Act 1991;

"functions" includes duties and powers conferred by the Act;

"inland waters"

(a) includes

(i) any river, watercourse, stream, lake, pond,

(ii) ground waters, water in a well, borehole or any passage or atic constructed in connection with a well or borehole;

(iii) effluents other than those containing hazardous substances;

(b) does not include

(i) waters in the coastal and maritime zone except effluent discharged in the coastal zone;

(ii) water supplied for drinking and domestic purposes;

"relevant enforcing agency" means the enforcing agency designated in respect of a medium, or the aspects of a medium, or a pollutant specified in paragraph 2;

"record" means a record of inspections, compliance monitoring exercises and information and environmental data obtained as result of such monitoring;

"sphere of responsibility" means the functions exercisable by an enforcing agency over the medium, or the aspects of a medium, or the pollutant specified in paragraph 2;

"zone" has the meaning assigned to it by section 2 of the Act;

2. (1) The enforcing agencies shall be

(a) in relation to air, noise, quality control of water supplied for drinking and domestic purposes, and odour, the Permanent Secretary to the Ministry of Health;

(b) in relation to inland waters and effluents, the Permanent Secretary to the Ministry responsible for the subject of water resources;

(c) in relation to solid wastes, the Permanent Secretary to the Ministry of Local Government;

(d) in relation to pesticide residue, the Permanent Secretary to the Ministry of Agriculture, Fisheries and Natural Resources;

(e) in relation to waters in the zone, the Permanent Secretary to the Ministry of Fisheries and Marine Resources (G.N. Nº 16 of 1994)

(f) in relation to national environmental standards, affecting the island of Rodrigues, the Island Secretary for Rodrigues;

(2) Where no enforcing agency is specifically designated in relation to any medium or any pollutant, the Department shall be deemed to have responsibility for exercising the functions of an enforcing agency in relation to that medium or pollutant.

3. An enforcing agency shall in respect of its sphere of responsibility

(a) supervise enforcement of national environmental standards and notices, orders and directives issued under an environmental law;

(b) verify compliance with environmental laws;

(c) conduct such regular monitoring, sampling, test and analyses as to ensure compliance with environmental laws;

(d) provide such assistance as may be required for reviewing an EIA, and in case of a spill or of an environmental emergency;

(e) carry out directions issued by the Minister on the recommendation of the Environment Coordination Committee.

4. (1) An enforcing agency shall have all the powers conferred on the Director by sections 57, 58, 61 (1), 62 and 63 of the Act to issue and to revoke any notice other than a prohibition notice.

(2) For the purpose of sub-paragraph (1), reference to the Director in sections 57, 58, 61 (1), 62 and 63 shall be read as if reference is made to an enforcing agency.

(3) An enforcing agency shall

(a) have all the powers conferred on an authorised officer under sections 64 and 65 of the Act, and may delegate in writing its powers to any officer posted under his authority;

(b) make available to other enforcing agencies and to the Department all facilities required for carrying out laboratory analyses and tests;

(c) keep a record of all inspections and compliance monitoring exercises and information and environmental data obtained as a result of such monitoring;

(d) at his request, provide the Director with a copy of the record.

5. An enforcing agency shall report, as soon as is practicable, to the Director, through its environment liaison officer, any contravention of an environmental law relating to its sphere of responsibility.

6. Where an enforcing agency suspects, or detects any contravention of an environmental law, beyond its sphere of responsibility, it shall forthwith inform the Director and the relevant enforcing agency.

APPENDIX B

RELEVANT NATIONAL ENVIRONMENTAL STANDARDS

Standards for Air

Government Notice No. 105 of 1998

THE ENVIRONMENT PROTECTION ACT 1991

Regulations made by the Minister under Section 35 of the Environment Protection Act 1991

1. These regulations may be cited as the Environment Protection (Standards for Air) Regulations 1998.

2. In these regulations —

"Act" means the Environment Protection Act 1991;

"chimney" means a structure or opening from or through which a product of combustion or an air pollutant is emitted into the atmosphere;

"enforcing agency" means the agency specified in paragraph 2(1)(a) of the Fourth Schedule to the Act;

"existing factories" means factories which entered into operation before the commencement of these regulations;

"factory" has the same meaning as in section 2 of the Labour Act;

"industrial process" means any process operated at a factory which may entail a pollutant being emitted into the atmosphere;

"smoke" includes all particulate matter in smoke.

3. (1) The national environmental standards for the emission of pollutants in the atmosphere shall be those set out in the First Schedule.

(2) Every factory shall comply with the emission standards set out in the First Schedule.

(3) Existing factories shall comply with the emission standards set out in the First Schedule as from 1 February 1999.

4. (1) The enforcing agency may require that a chimney serving an industrial process be fitted with an aperture for the insertion of a probe to measure the composition, characteristics and quantities of emissions.

(2) The aperture shall be in the chimney wall and of such size and within such height as the enforcing agency may require.

(3) The enforcing agency may require that a safe means of access to the aperture be provided for the purpose of monitoring emissions from the chimney.

(4) Notwithstanding the other provisions of these regulations, the enforcing agency may decide that certain parameters in the First Schedule shall not apply to any specific chimney.

5. (1) The national environmental standards for ambient air shall be those set out in the Second Schedule.

(2) In exercising its powers under these regulations, the enforcing agency may take account of the national environmental standards set out in the Second Schedule.

6. (1) The enforcing agency may use measuring instruments for the purpose of assessing the quality of air.

(2) Measuring instruments shall, for the purpose of these regulations include—

(a) any apparatus for separating any air impurity from the gas or liquid medium in which it is carried;

(b) any device to indicate or record air pollution or give warning of excessive air pollution; and

(c) any other device used for the purposes of preventing or limiting air pollution.

Made by the Minister on 24th August, 1998.

FIRST SCHEDULE

(regulation 3)

Emission Standards

The following standards are maximum limits for the corresponding pollutant

	Pollutant	*Applicable to*	*Standard*
(i)	Smoke	All stationary fuel burning source	Ringlemann No. 2 or equivalent opacity (not to exceed more than 5 minutes in any period of one hour)
(ii)	Solid particles	*(a)* Any trade, industry, process, industrial plant or fuel-burning equipment	200 mg/m^3
		(b) Any existing trade, industry process or industrial plant using bagasse as fuel	400 mg/m^3
(iii)	Sulphuric acid mist or sulphur trioxide	*(a)* Any trade, industry or process (other than combustion processes and plants for the manufacture of sulphuric acid)	120 mg/m^3 as sulphur trioxide
		(b) Any trade, industry or process in which sulphuric acid is manufactured	30 000mg/m^3 as sulphur trioxide
(iv)	Fluorine compounds	Any trade, industry or process in the operation of which fluorine, hydrofluoric acid or any inorganic fluorine compounds are emitted	100mg/m^3 as hydrofluoric acid
(v)	Hydrogen Chloride	Any trade, industry or process	200mg/m^3 as hydrogen chloride
(vi)	Chlorine	Any trade, industry or process	100mg/m^3 as chlorine

(vii)	Hydrogen sulphide	Any trade, industry or process	5 ppm as hydrogen sulphide gas
(viii)	Nitric acid or oxides of nitrogen	Any trade, industry or process in which the manufacture of nitric acid is carried out	2 000 mg/m^3 as nitrogen dioxide
(ix)	Nitric acid or oxides of Nitrogen	Any trade, industry or process other than nitric acid plant	1 000 mg/m^3 as nitrogen dioxide
(x)	Carbon monoxide	Any trade, industry or process	1 000 mg/m^3 as carbon monoxide

SECOND SCHEDULE

(regulation 5)

Ambient Air Quality Standards and Measurement Methods

Ambient Pollutant	*Standard (ug/m^3) maximum*	*Averaging Time*	*Measurement Method**
Total suspended particles	150	24-hour	Hi-Volume
	50	Annual average	Sampler
PM 10	100	24-hours	Hi-volume Sampler
Sulpher Dioxide	350	1-hour	Fluorescence SO_2
	200	24-hour	Analyser
	50	Annual average	Colorimetry
Nitrogen Dioxide	200	24-hour	Sodium Arsenite Chemiluminescence
Carbon Monoxide	25,000	1-hour	Nondispersive
	10,000	8-hour	Infrared Photometry
Lead	1.5	3-month average	Hi-volume Sampler with Atomic Absorpsion
Ozone	100	1-hour	Ozone Analyser, Chemiluminescence

* the measurement methods are those indicated or other methods acceptable to the enforcing agency

Standards for Noise

Government Notice No. 17 of 1997

THE ENVIRONMENT PROTECTION ACT 1991

Regulations made by the Minister under sections 36 and 74 of the Environment Protection Act 1991

1. These regulations may be cited as the Environment Protection (Environmental Standards for Noise) Regulations 1997.

2. In these regulations —

"dB(A) L_{eq}" means the equivalent A-weighted sound pressure level measured in decibel;

"factory" has the same meaning as in section 71 of the Occupational Safety, Health and Welfare Act 1988;

"industrial noise" means noise generated by a factory;

"neighbourhood noise" means any noise other than -

(a) industrial noise; or

(b) noise made by an aircraft, an animal or traffic.

3. The environmental noise standards shall be the standards specified in the Schedule.

4. Regulation 3 shall not, for a period of 2 years as from the commencement of these regulations, apply to industrial noise if the activity generating such noise has already started at the commencement of these regulations.

5. (1) Noise measurements shall, as far as practicable, be effected one metre from the nearest opening of any residential building facing the noise source and at 1.5 metres above the ground or floor level.

(2) The measurement methods and equipment used shall be those approved by the enforcing agency.

6. These regulations shall come into operation on 1 March, 1997.

Made by the Minister on 13 February, 1997.

SCHEDULE

(regulation 3)

NOISE EXPOSURE LIMITS

Industrial Noise

07.00 — 21.00 hrs ...	60*dB(A) L_{eq}
21.00 — 07.00 hrs ...	55*dB(A) L_{eq}

Neighbourhood Noise

07.00 — 18.00 hrs ...	60 dB(A) L_{eq}
18.00 — 21.00 hrs ...	55 dB(A) L_{eq}
21.00 — 07.00 hrs ...	50 dB(A) L_{eq}

---

* Apply a tonal character adjustment of +5 dB(A) to the measured value where the noise has a definite continuous note such as a whine or hiss.

Proposed Mauritian Standards for Effluent Discharge into the Ocean

Parameter	Unit	Maximum permissible limits
Temperature	^{0}C	40
pH	-	5 – 9
Floatables	mm	6
Biochemical Oxygen Demand (BOD_5)	mg/l	250
Chemical Oxygen Demand (COD)	mg/l	750
Suspended Solids	mg/l	300
Cadmium	µg/l	20
Chromium (VI)	µg/l	100
Chromium, Total	µg/l	500
Cyanides (as CN)	µg/l	100
Lead	mg/l	2
Nickel	mg/l	2
Zinc	mg/l	2
Mercury	µg/l	10
Arsenic	µg/l	200
Total Pesticides	mg/l	1
Oil & Grease	mg/l	No visible Oil

Source: Department of Environment

WASTE WATER DISCHARGE STANDARDS

LIST	DETERMINANT	UNITS	NATURE OF RECEIVING WATERS					
			W1-W2 WS River Aquifer	W3 Other Rivers	W4 Irrigation	W5 Lagoon	W6 Ocean	W7 Sewers
	EFFLUENT QUALITY CLASS		E4	E3	E2	E5	E1	E6
A	Temperature	C	30	30	30	30	50	40
	pH		5-9	5-9	5-9	5-9	4-10	5-9
	Colour	Haze	20	30	-	20	-	-
	Chemical Oxygen Demand	mg/l	60	90	90	60	750	1000
	BOD	,,	(10)	(20)	(30)		(250)	-
	Suspended Solids	,,	15	30	45	15	100	2000
	Chloride	,,	250	1000	250	-	-	-
	Sulphate	,,	250	500	500	-	-	800
B	Nitrate N	,,	15	-	-	5	-	20
	Ammonia N	,,	5	10	-	5	-	100
	Total dissolved solids	,,	1000	2000	2000	-	-	-
	Phosphate P	,,	5	-	-	1	-	30
	Cadmium	µg/l	20	20	20	20	20	20
	Chromate chromium	µg/l	50	50	50	50	100	100
	Copper	mg/l	0.5	0.5	1	0.1	-	20
C	Lead	mg/l	0.1	0.2	2	0.1	-	10
	Mercury	µg/l	20	20	20	20	20	20
	Nickel	mg/l	0.1	0.2	0.5	0.5	10	10
	Zinc	mg/l	0.5	1.0	5	0.1	-	30
	Oil	mg/l	No visible Oil					50
	Detergents	mg/l	1	5	5	1	-	50
D	Pesticides Carbonate	µg/l	100	100	100	25	-	250
	Chlorinated	µg/l	10	10	10	5	-	50
	Phosphorous	µg/l	100	100	100	25	-	250

Source: Sewerage Master Plan (1993)

Application for an Industrial Effluent Discharge Permit

Government Notice No. of 1998

THE ENVIRONMENT PROTECTION ACT 1991

Regulations made by the Minister under Section 74 of the Environment Protection Act 1991

1. These regulations may be cited as the Environment Protection (Industrial Effluent Discharge Permit) Regulations 1998.

2. In these regulations-

"Act" means the Environment Protection Act 1991;

"permit" means an Industrial Effluent Discharge Permit issued under regulation 4(1);

"industrial effluent" means water sullied or contaminated by any matter, in solution or suspension that may cause harm or damage to the environment, derived from its use in connection with an industrial activity;

"watercourse" means any natural or artificial channel, pipe or conduit carrying or that may carry water and discharging directly or indirectly into waterbody;

"waterbody" includes underground water, stream, river, canal, lake, pond, reservoir, estuary, lagoon and sea;

3. (1) No person shall discharge or cause to be discharged any industrial effluent into a watercourse or waterbody unless he has an Industrial Effluent Discharge Permit from the appropriate enforcing agency.

(2) Notwithstanding paragraph 3(1), no person shall discharge or cause to be discharged any industrial effluent into -

(a) any watercourse through which water used for domestic purposes runs; or

(b) any waterbody in which water used for domestic purposes is kept.

(3) A person who wishes to obtain a permit referred to in paragraph 3(1) shall make an application to the appropriate enforcing agency.

4. (1) An application for a permit shall be made in the form set out in the First Schedule.

(2) In the case of an enterprise already in operation at the time of an application, the person in charge of the management of the enterprise shall submit a certificate showing the result of an analysis of the industrial effluent together with the application for a permit.

(3) Where an analysis of industrial effluent is required under paragraph 4(2), it shall be conducted in such a manner as may be approved by the appropriate enforcing agency.

5. (1) Where the enforcing agency is satisfied that an applicant has complied with the Act and any regulation made under the Act, it may grant a permit to the applicant upon payment of a fee of.....rupees.

(2) A permit issued under paragraph 5(1) shall specify –

(a) the maximum volume of industrial effluent, that may be discharged daily;

(b) the maximum rate at which any industrial effluent may be discharged at any time;

(c) the frequency of sampling and location of sampling points of the industrial effluent; and

(d) the frequency of analysis to be conducted in respect of the industrial effluent.

(3) A permit shall be valid for a period of one year.

6. (1) The person in charge of the management of the enterprise shall cause the result of analysis of an industrial effluent to be sent to the Department of Environment and to the appropriate enforcing agency on a monthly basis, specifying the date, time and location of sampling for each and every sample.

(2) The method of sampling, the sample storage and method of analysis shall be those approved by the enforcing agency.

7. (1) An application for the renewal of a permit shall be made –

(a) in the form set out in the Second Schedule;

(b) at least 3 months before the expiry of the permit.

(2) The enforcing agency may renew a permit if it is satisfied that the applicant has complied with the Act, any regulation made under the Act and upon payment of a fee of.....rupees.

8. (1) Subject to paragraph 8(2), where the holder of a permit fails to comply with these regulations, the enforcing agency may revoke the permit;

(2) The enforcing agency shall not revoke a permit unless it has requested the holder thereof to submit the reasons in writing why his permit should not be revoked.

9. These regulations shall come into force on.....1998.

Made by the Minister on.....

/S.S

FIRST SCHEDULE

(regulation 4(1))

APPLICATION FOR A PERMIT IN RESPECT OF DISCHARGE OF ANY INDUSTRIAL EFFLUENT INTO ANY WATERCOURSE OR WATERBODY

To: .....
(name of enforcing agency)

PARTICULARS

1. Name of industry .....

   Address .....

2. Name of person responsible .....

   Address .....

   Phone No./ Fax No. .....

3. Location of discharge point (location plan to be annexed).....

   .....

4. Nature and composition of the industrial effluents to be discharged (Analysis certificate/s to be attached where appropraite)

   .....

   .....

5. Frequency of industrial effluent discharged daily .....

6. Maximum daily volume of industrial effluent to be discharged .....

7. Maximum rate of discharge per second .....

8. Method of sampling .....

   Frequency .....

   Location .....

9. Method of analysis per parameter *.....

   .....

   .....

   .....

I/We request that I/We may be granted an Industrial Effluent Discharge Permit in accordance with the particulars given above.

I/We undertake to comply with prescribed standards.

I/We also undertake to submit to the Department of Environment and the Enforcing Agency a monthly return of our compliance monitoring data.

Date .....

.....
Name of applicant

.....
Signature of applicant

*A list of approved methods on sampling, sample storage and methods of analysis is available at the relevant enforcing agency.

FOR OFFICE USE ONLY

Permit No. .....

Issued on .....

Reference .....

Date .....

SECOND SCHEDULE

(regulation7 (1))

APPLICATION FOR THE RENEWAL OF AN INDUSTRIAL EFFLUENT DISCHARGE PERMIT

To: .....
(name of enforcing agency)

I/We .....

being licensed to discharge industrial effluent into .....

hereby apply for the renewal of my/our permit No. .....

dated .....

Date .....

.....
.... Name of applicant

.....
.... Signature of applicant

FOR OFFICE USE ONLY

New Permit No. .....

Issued on .....

Reference .....

Date .....

C:/my documents/permit slo1.doc

APPENDIX C

THE CONCESSION PROJECTS BILL (1997)

THE CONCESSION PROJECTS BILL

(No. XII of 1997)

Explanatory Memorandum

The object of this Bill is to provide the legal framework for the execution of projects under appropriate concession agreements.

V.K. Bunwaree
Minister of Finance

20 June, 1997

THE CONCESSION PROJECTS BILL

(No. XII of 1997)

ARRANGEMENT OF CLAUSES

Clause

1. Short title

PART I - GENERAL PROVISIONS

2. Interpretation
3. The Concession Projects Division
4. Functions of the Concession Projects Division
5. One stop shop
6. The concessionaire
7. Confidentiality
8. Cabinet approval
9. Signature of the concession agreement

PART II - CONCESSION PROJECTS

10. Report of concession projects to Cabinet
11. Approval by Cabinet
12. Referral to the Concession Projects Division

PART III - BIDDING PROCEDURE FOR AWARDING CONCESSIONS

13. Selection Committee
14. Disclosure of interest
15. Pre-selection exercise
16. Pre-selection
17. Invitation to bid
18. Selection procedure

PART IV - THE TERMS OF THE CONCESSION

19. The concession agreement
20. The concession period
21. The concessionaire's obligations
22. The concessionaire's rights
23. The Grantor's rights
24. Concession fee
25. Default by a bidder
26. State land
27. Tariff
28. Remittance of profits abroad
29. Foreign exchange
30. The assets of the concession
31. Return of the assets of the concession
32. Local services, goods and labour
33. Taxes and duties
34. Governing law
35. Resolution of disputes
36. Regulations

A BILL

To provide for the legal framework for the execution of projects under appropriate concession agreements.

ENACTED by the Parliament of Mauritius, as follows -

1. Short title

This Act may be cited as the Concession Projects Act 1997.

PART I

GENERAL PROVISIONS

2. Interpretation

In this Act -

"concession agreement" means an agreement between a Grantor and a concessionaire relating to the implementation of a concession project;

"concessionaire" means the party referred to in section 6;

"Concession project" means generally a service or project to build, set up, own, operate, rent, lease, finance, modernise, manage, maintain, develop, or transfer in accordance with a concession agreement which may provide for any variant thereof, including BOT (Build, Operate and Transfer) , BOO (Build, Own and Operate), BOOT (Build, Own, Operate and Transfer), DBFO (Design, Build, Finance and Operate), MOT (Modernise, Own/Operate and Transfer);

"Concession Projects Division" means a division set up in accordance with section 3 of this Act;

"Grantor" means the party who on behalf of the State attributes, signs and monitors the implementation of a concession agreement;

"Minister" means the Minister to whom responsibility for the subject of Finance is assigned;

"public sector institution" means any Ministry, Government Department, Statutory Body or Local Authority;

"pre-selected bidder" means a bidder pre-selected under section 15;

"relevant Minister" means the Minister responsible for the subject-matter of a concession project;

"relevant Ministry" means the Ministry responsible for the subject matter of the concession project;

"Selection Committee" means the committee set up in respect of a concession project under section 13;

3. The Concession Projects Division

There is established for the purposes of this Act a Concession Projects Division, within the Ministry of Finance, to deal with all concession projects including those set out in the Schedule.

4. Functions of the Concession Projects Division

The Concession Projects Division shall be primarily responsible for -

(1) (a) promoting and marketing the development of concession projects;

(b) approving pre-selection procedures and invitations to bid documentation and drawing rules and regulations regarding the bidding procedure for concession projects;

(c) assisting the relevant Ministries and Government agencies in the development, coordination and implementation of concession projects;

(d) advising Government in rationalising and co-ordinating administrative procedures between Ministries, Government agencies and local authorities relating to concession projects;

(e) overseeing and monitoring the progress and assisting in the smooth execution of concession projects and, for this purpose, ensuring coordination and cooperation between the public sector agencies, private corporations and non-governmental organisations concerned directly or indirectly in the implementation of concession projects; and

(f) keeping a register of all concession agreements and concession projects.

(2) The Concession Projects Division shall promptly make accessible to the public copies of any rule or regulation of general application relating to the bidding procedure for concession projects.

5. One-stop shop

(1) Notwithstanding any other enactment, any application for a permit, a licence, an authorisation or approval necessary for the performance and implementation of any concession project shall be made to, and dealt with by, the Concession Projects Division.

(2) The Concession Projects Division shall deal with all applications diligently and in case of a delay exceeding 4 weeks, shall inform the applicants of the reasons for the delay.

(3) Notwithstanding any other enactment, every public sector institution shall attend immediately to any application referred by the Concession Projects Division for the issue of any licence, permit, authorisation or approval.

(4) The public sector institution shall notwithstanding any other enactment, process the application for any licence, permit, authorisation or approval within a period of 3 weeks and shall issue such licence, permit, authorisation or approval through the Concession Projects Division.

6. The concessionaire

(1) Every concession agreement shall be signed by the concessionaire.

(2) The concessionaire shall be a corporate body registered, incorporated or established in Mauritius or a consortium of such corporate bodies.

7. Confidentiality

(1) All documents and information relating to a concession project shall be treated as confidential and secret.

(2) No employee or member of the Concession Projects Division, and no Selection Committee or any other unit handling any document or having any information relating to a concession project, shall disclose any matter relating to the project to any unauthorised person or to any person without authority.

8. Cabinet approval

(1) No concession project shall be awarded or Concession Certificate issued in respect of a concession project unless the concession agreement relating to the concession project has been approved by Cabinet.

(2) A Concession Certificate shall be issued by the relevant Minister, after the concession project has been approved by Cabinet .

9. Signature of the concession agreement

(1) The Grantor and the concessionaire shall sign the concession agreement after the Concession Certificate has been issued under section 8.

(2) Subject to the other provisions of this Act, every concession agreement shall be binding on the parties to the agreement.

PART II

CONCESSION PROJECTS

10. Report of concession projects to Cabinet

(1) Where the relevant Minister is of opinion that any service or project specified in the Schedule or otherwise may be suitable for execution as a concession project, the relevant Minister may submit a report in relation to the project for consideration and approval by Cabinet.

(2) Notwithstanding subsection (1), the Prime Minister may request a relevant Minister to submit a report on any service or project which in his opinion may be suitable for execution as a concession project.

(3) A report submitted to Cabinet pursuant to subsection (1) or (2) shall -

(a) define the nature and scope of the service or project;

(b) specify the terms proposed for a concession agreement;

(c) indicate whether there is any proposal in respect of the implementation of the project.

(4) Where a proposal has been received in respect of the project, the report shall specify its exact nature and scope.

11. Approval by Cabinet

(1) Upon receipt of a report under section 10, Cabinet may approve the report or commission any studies relevant to the project.

(2) Where the report is approved under subsection (1), Cabinet may specify whether the award of the project shall be without bidding or shall be subject to bidding procedure.

(3) A concession project may be approved by Cabinet for award without bidding -

(a) where Cabinet is satisfied that owing to its technological, strategic or security characteristics no bidding is required; or

(b) where it is to be partly or wholly financed from a grant or concessionary loan from a foreign institution or state.

12. Referral to Concession Projects Division

(1) Where Cabinet approves the award of a concession project without bidding, the matter shall be referred to the Concession Projects Division for implementation in accordance with this section.

(2) Upon a referral under subsection (1), the Concession Projects Division shall -

(a) examine the terms of the project in the light of the report;

(b) draw up the final concession agreement in consultation with the Grantor; and

(c) submit its recommendations together with the concession agreement to the relevant Minister who will seek the approval of Cabinet for the award of the concession project.

PART III

BIDDING PROCEDURE FOR AWARDING CONCESSIONS

13. Selection Committee

(1) There shall be a Selection Committee for the award of concession projects which are subject to bidding procedure under this Act.

(2) The Selection Committee shall consist of -

(a) a Chairperson

(b) a Vice Chairperson; and

(c) 3 other members, having wide experience in legal, administrative, economic, financial, engineering, scientific or technical matters.

(3) The Chairperson, Vice-Chairperson and members of the Selection Committee shall be appointed by the President of the Republic, acting in accordance with the advice of the Prime Minister, on such terms and conditions as may be determined by the Prime Minister.

(4) For the purposes of subsection (3), the Prime Minister shall consult the Leader of the Opposition.

(5) (a) The Selection Committee may, for the purpose of obtaining technical expertise and assistance in respect of a concession project, co-opt 2 other members to be appointed from a list of persons approved by the President of the Republic.

(b) A co-opted member shall be entitled to participate in the deliberations of the Selection Committee and shall be entitled to vote;

(6) At any meeting of the Selection Committee -

(a) the Vice-Chairperson shall preside over the meeting in the absence of the Chairperson;

(b) 4 members, including the Chairperson or Vice-Chairperson or both of them, shall constitute a quorum;

(c) each member shall have one vote on the matter in question and, in the event of an equality of votes, the Chairperson of the meeting shall have a casting vote;

(d) shall, subject to this section, regulate its meetings and proceedings in such manner as it deems fit.

(7) The President of the Republic may, on the advice of the Prime Minister, at any time terminate the appointment of a member who has been guilty of -

(a) any misconduct, default or breach of trust in the discharge of his duties;

(b) an offence of such nature as renders it undesirable that his appointment should be continued.

14. Disclosure of interest

(1) Where any member of the Selection Committee or the Chairperson or Vice-Chairperson of the Selection Committee or any officer assisting the Committee has any direct or indirect interest in any matter under consideration at a meeting, he shall, as soon as practicable after the commencement of the meeting, disclose his interest and shall not, unless the Selection Committee directs otherwise, take part in the discussion touching that matter.

(2) A disclosure of interest made under this section shall be recorded in the minutes of the meeting at which it is made.

15. Pre-selection exercise

(1) The Selection Committee shall carry out a pre-selection exercise to select potential bidders of appropriate technical, financial and managerial capacity to carry out a project as a concession project.

(2) The pre-selection documents shall be prepared by the relevant Ministry and shall include a public invitation for applicants to apply for pre-selection.

(3) Every pre-selection document shall be subject to the approval of the Concession Projects Division before issuance and publication.

(4) The Concession Projects Division shall prepare appropriate questionnaires to elicit full information from potential bidders regarding experience in the domain of the specific concession project or concession projects generally, managerial ability, financial status, credit worthiness, specialised personnel, and regarding such other matters as may be considered necessary.

(5) The Concession Projects Division shall require potential bidders to submit full information regarding the structure of the bidding organisation and paid-up capital, the existence of any contract between its shareholders and of any insurance plan or other plan regarding the distribution of risks.

(6) The invitation to apply for pre-selection shall be open to all corporate bodies or consortium of corporate bodies registered, incorporated or established in Mauritius or overseas.

16. Pre-selection

The Selection Committee shall be responsible for examining and evaluating all applications for the pre-selection of pre-selected bidders.

17. Invitation to bid

(1) The relevant Ministry shall prepare the documents relating to the invitation to bid and such documents shall include rules for the submission of bids, a draft concession agreement and the criteria according to which bids shall be evaluated.

(2) The Selection Committee shall issue the invitation to bid to the pre-selected bidders.

(3) Every bid by the pre-selected bidders shall -

(a) be a firm bid to the Selection Committee to enter into the concession agreement on the terms stated therein;

(b) be supported by a form of security specified in the invitation to bid documentation;

(c) give details of the legal capacity and ownership of the entity which will be the concessionaire;

(d) contain an affirmation that the information supplied at the stage of pre-selection continues to apply;

(e) be submitted on or before the deadline specified in the invitation to bid.

(4) Notwithstanding any other enactment, the provisions of the Central Tender Board Act shall not apply to any concession project under this Act.

18. Selection procedure

(1) The Selection Committee shall examine and evaluate all the bids received from pre-selected bidders and shall submit its selection to the relevant Ministry for the award of the concession project.

(2) In the discharge of its functions under this Act, the Selection Committee shall -

(a) act expeditiously and with due diligence;

(b) strive to achieve the highest standard of equity, by ensuring that all bidders are afforded equality of opportunity and are treated fairly.

(3) Upon receipt of the decision of the Selection Committee under subsection (1), the relevant Ministry shall seek the approval of Cabinet under section 8 for the award of the concession project.

(4) Where Cabinet has approved the award of a concession project under section 8, the relevant Ministry shall give public notice of the name of the successful bidder and publish the award in 2 daily newspapers.

(5) Upon signature of the concession agreement the successful bidder shall take the necessary steps to establish the concessionaire in accordance with the terms of its bid.

PART IV

THE TERMS OF THE CONCESSION

19. The concession agreement

A concession agreement concluded pursuant to the present Act shall be in written form, signed by the concessionaire and the Grantor, and shall inter alia include -

(a) the object of the concession;

(b) the concession period;

(c) the rights and obligations of the Grantor and the concessionaire;

(d) the projects to be implemented by the concessionaire, the standards to which the works must conform and the time limits within which such works are to be performed;

(e) the possible allocation of land to the concessionaire for the concession project;

(f) the rights of the concessionaire to use the land and the buildings, structures and other installations he erects thereon;

(g) the fee, if any, to be paid by the concessionaire for the concession as well as the timing and method of payment;

(h) the guarantee to be provided by the concessionaire for the performance of its obligations under the concession agreement;

(i) the services to be provided by the concessionaire;

(j) the regime for the fixing, adjustment, revision, publication and collection of tariff;

(k) the financial organisation and reporting regime applicable to the concessionaire;

(l) provisions relating to the transfer by the concessionaire to the Grantor or the Grantor's designee of the assets linked to the concession at the end of the concession period;

(m) provisions governing the responsibility of the parties;

(n) provisions relating to the possibility for the concessionaire to sub-contract the performance of its obligations under the concession agreement;

(o) provisions on the maintenance, upgrading and transfer of technology;

(p) provisions relating to environmental protection;

(q) the conditions which may entitle either party to terminate the concession agreement prior to its agreed date of termination and the rights and obligations of the parties consequential on such termination;

(r) provisions relating to the insurance of the object of the concession;

(s) provisions regarding the lenders' step-in rights in case of default of the concessionaire;

(t) provisions relating to force majeure;

(u) the procedure for the resolution of disputes between the parties;

(v) provisions specifying the date of entry into effect of the concession agreement.

20. The concession period

(1) The initial period of the concession shall be agreed between the parties to the concession agreement but shall not exceed 50 years.

(2) The concession agreement may provide for the possibility of extending the period of the concession to the concessionaire without the need to prepare a new invitation to bid, provided that the extension of the term of the concession agreement does not exceed one half of the initial concession period.

21. The concessionaire's obligations

(1) The concessionaire shall perform its obligations under the concession agreement, including the management and operation of the services or project, at its own costs and risks in accordance with the terms of the concession agreement.

(2) The concessionaire shall finance or obtain the financing necessary for its activities under the concession agreement at its own costs and risks and without recourse to Grantor credits or guarantees except as expressly stated in the concession agreement.

(3) The concessionaire shall be liable to third parties for its activities under the concession agreement in accordance with all applicable laws and regulations.

(4) The concessionaire shall comply with all applicable laws and regulations.

22. The concessionaire's rights

(1) Subject to subsection (2), the concessionaire shall have and enjoy the rights granted to it under the concession agreement exclusively throughout the concession period in accordance with the terms of the concession agreement.

(2) Where the concessionaire is not granted any exclusive right, he shall be entitled, subject to the concession agreement, to any compensation that is allowed.

(3) Subject to section 27, the concessionaire shall be entitled to charge and collect payment of tariff for the services performed by the concessionaire on such terms and conditions as may be set out in the concession agreement.

(4) The concession agreement may provide that the concessionaire shall be entitled to pledge or create any charge or lien, by way of security to a bank or financial institution providing financing in relation to the Project, on the rights of the concessionaire under the concession agreement.

23. The Grantor's rights

(1) The Grantor shall retain the right to monitor the performance by the concessionaire of its obligations under the concession agreement and, in the event of default by the concessionaire, the Grantor shall have the right in accordance with the terms of the concession agreement to impose sanctions on the concessionaire, rectify the default itself or terminate the concession agreement.

(2) The Grantor may require reports and information from the concessionaire on the performance and financial situation of the concessionaire.

24. Concession fee

The concession agreement may provide that the concessionaire shall pay a fee for the grant of the concession on conditions and terms specified in the concession agreement.

25. Default by a bidder

(1) Where a bidder, having been selected as the successful bidder, fails to establish the concessionaire in accordance with the terms of its bid or where the concessionaire fails to sign the concession agreement, the Grantor may, after obtaining the prior approval of Cabinet through the relevant Ministry, revoke the selection of that bidder.

(2) Where a selected bidder is revoked under subsection (1), the Grantor may, after obtaining the prior approval of Cabinet through the relevant Minister, select the next placed bidder for the award of the concession project .

26. State Land

(1) Land and buildings belonging to the State may be made available to the concessionaire as necessary in accordance with the terms of the concession agreement.

(2) Any expropriation procedure necessary for a project shall be handled and managed in the manner provided for in the Land Acquisition Act.

(3) The property rights in any expropriated immovable assets shall vest with the State.

(4) The concession agreement may provide that either the Grantor or the concessionaire shall be responsible to pay any compensation for the expropriation of any property and the manner in which such compensation shall be paid.

(5) The concession agreement may provide for any necessary facilities which may be given by the State to the concessionaire in respect of right to use roads and other supporting public facilities in carrying out the project.

27. Tariff

(1) Subject to any enactment regulating the tariff and the conditions and quality of services governing them, a concession agreement -

(a) may provide for any tariff to be paid by users, including the State, as the Grantor and the concessionaire may agree;

(b) shall specify the currency in which any tariff may be charged and collected;

(c) may provide for any tariff to be fixed and adjusted in accordance to a defined index, including but not limited to a price index, or the value of the local currency against a foreign currency.

28. Remittance of profits abroad

The concession agreement may set out the terms on which the concessionaire shall be entitled to remit all or part of its income from its activities under the concession agreement outside the Republic of Mauritius.

29. Foreign exchange

(1) The concessionaire shall be entitled to convert its income from its activities under the concession agreement from the local currency into one or more foreign currencies specified in the concession agreement.

(2) The Grantor may, under the concession agreement, undertake to guarantee the availability of sufficient foreign currency to enable such conversion and may further agree to provide or procure the provision of a guarantee from a bank or other financial institution in support of its undertaking.

30 The assets of the concession

(1) Subject to subsection (2), the Grantor shall retain ownership of the assets which are the object of the concession throughout the concession period.

(2) The concession agreement may -

(a) set out the conditions on which the concessionaire may be entitled to dispose of or sell to a third party assets which previously formed part of the property of the Grantor;

(b) provide for the terms on which the concessionaire may retain all or part of the proceeds from such a disposition or sale;

(c) set out the terms on which new assets brought into the concession by the concessionaire may become the property of the Grantor.

31. Return of the assets of the concession

Where a concession agreement provides for the eventual transfer of the assets which are the subject of the concession, the concession agreement shall set out the terms on which, at the end of the concession period, the Concessionaire shall return to the Grantor or its nominee all the assets.

32. Local services, goods and labour

(1) In performing its activities under the concession agreement, the concessionaire shall have recourse to local services and goods whenever they are available and competitive.

(2) In evaluating any tender received following an invitation to tender issued by a concessionaire pursuant to its activities under a concession agreement, due account shall be taken of the extent to which the tenderer proposes, in executing any contract awarded to him, to have recourse to local services and local goods.

(3) With the exception of the concessionaire's permanent work force and the minimum of foreign specialists required if any, the concessionaire shall employ competent local labour for the performance of its activities under the concession agreement.

33. Taxes and Duties

The Minister may, on such terms and conditions as he may decide, remit or refund the whole or part of any duty, levy, charge, fee, rate or tax payable or paid under any enactment in respect of a concession project.

34. Governing law

A concession agreement concluded under this Act shall be governed by and construed in accordance with the laws of the Republic of Mauritius.

35. Resolution of disputes

(1) The concession agreement may provide for disputes between the parties to be settled by the competent judicial authority or by arbitration according to rules defined in the concession agreement.

(2) An award issued by an arbitration tribunal in accordance with an arbitration clause included in a concession agreement concluded under this Act shall be valid and enforceable by and against both the Grantor and the concessionaire according to its terms.

36. Regulations

(1) The Minister may -

(a) make such regulations as he thinks fit for the purposes of this Act;

(b) by regulations, amend the Schedule.

(2) Any regulations made under this section may provide for the levying of fees and charges.

Schedule

(sections 3 and 10)

1. Telecommunication services, system and networks (public telephone service, public mobile radiophone service, nationwide public paging service, nationwide distribution and broadcast of public radio and television programs, and the use of frequency related to broadcasting) not including closed circuit services;

2. Water supply, including production, management, cleaning and distribution, sewerage and drainage;

3. Electric power generation, transmission and distribution;

4. Public roads, highways, expressways, bridges, tunnels and their engineering structures;

5. Airports, terminals and related aviation facilities;

6. Port development including terminals, piers, handling, storage, Freeport infrastructure and other facilities and services;

7. Environmental and solid waste management projects including composting plants, collection facilities, incinerators, landfill and other municipal and rural services;

8. Rail and non-rail based transportation system and facilities;

9. Industrial zones, informatics and other export zones;

10. Leisure parks and theme parks, hotel and tourism related projects;

11. Storage infrastructure of bulk products;

12. Postal services;

13. Health education and scientific research infrastructure projects;

14. Development on State lands allowing the provision of services to support commercial and non-commercial activities;

15. Other infrastructure projects to support development activities.

Appendix G

Estimated Project Costs & Project Schedule Report – Task 7

MAURITIUS POWER STATIONS

ESTIMATED PROJECT COSTS
&
PROJECT SCHEDULE

Prepared for

The Ministry of Public Utilities and The Central Electricity Board of Mauritius

Prepared by:

K&M Engineering and Consulting Corporation
Washington, DC

KULJIAN CORPORATION
ENGINEERS • ARCHITECTS • CONSULTANTS
PHILADELPHIA, PA.,U.S.A.

January 2001

MAURITIUS POWER STATIONS

ESTIMATED PROJECT COSTS
&
PROJECT SCHEDULES

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1.0	**Project Hard Costs**
	– Introduction
	– Methodology and Assumptions for the Cost Estimates
	1. Combined Cycle Estimated Hard Costs Project Milestone Schedule Preliminary Project Bar Chart Schedule
	2. Diesel Estimated Hard Costs Project Milestone Schedule Preliminary Project Bar Chart Schedule
	3. Coal Estimated Hard Costs Project Milestone Schedule Preliminary Project Bar Chart Schedule
2.0	**Project Soft Costs**
	Lender expenses Lender fees Developer expenses Developer fees Project Expenses Other Project Soft Costs
3.0	**Summary Total Project Costs**

INTRODUCTION

The following report has been prepared by K&M Engineering and Consulting Corporation ("K&M") and its subcontractor, The Kuljian Corporation ("Kuljian"), for the Ministry of Public Utilities (MPU) and the Central Electricity Board (CEB) of Mauritius. Its purpose is to provide an *estimate* of the capital costs required for three different power project technologies: an oil-fired combined cycle plant, a diesel power plant and a coal-fired steam plant.

In preparing this report K&M has followed Task 7 of the Feasibility Study Terms of Reference, which outlines the major cost items in a power project. In addition we have prepared a breakdown of the various soft cost items expected in developing an independent power project (IPP) for the three plant configurations. Section 1 of this report provides itemized estimates of project hard costs. There is also a description of the methodology and assumptions used in deriving these hard cost items. Section 2 of this report describes the typical soft costs for developing an IPP of this nature. This Section also provides K&M's soft cost estimate for each of the three configurations. Section 3 of the report provides a summary of total project costs. In addition we have included a bar chart analysis of the hard cost and soft cost items for each configuration.

The cost estimates in this Estimated Project Cost Report are higher than the estimates used in the Technology Selection Report submitted to the MPU in April 2000. The cost estimates in this report include shared facilities for the ultimate build out of a 3x100 MW facility at the Fort William or Montagne Jacquot site. Shared facilities were not included in the Technology Selection Report. In addition, the cost estimates in this report reflect higher market prices for gas turbines, as well as cost escalations reflecting overall price increases since the time of preparing the Technology Selection Report.

The project cost estimates derived in this report will be used in the financial model which K&M is preparing for this project. The financial model will include a calculation of the estimated cost of electricity from an IPP under each of the three project configurations. The financial model and its associated outputs will be part of the Final Report prepared for the Mauritius IPP Feasibility Study.

SECTION 1
PROJECT HARD COSTS

A. INTRODUCTION

The following section describes estimated hard costs for the construction of a 100 MW power project for each of the three technologies proposed: oil-fired combined cycle plant, diesel plant and coal-fired steam plant.

For each of the three technologies, project hard costs are presented as follows:

1. Total EPC contract costs consisting of:
   - detailed erected cost estimates, spare parts, design engineering and project management costs
   - Commercial factors such as contingencies, fees and legal, insurance and bonding costs
2. Other hard costs such as transmission facilities and purchase of land.

K&M is assuming that the 100 MW project is the first phase of a 3x100 MW facility which will ultimately be developed at the site. Certain common infrastructure for the final 300 MW project have been incorporated into this cost estimate for the purpose of achieving cost efficiencies.

B. ERECTED COST ESTIMATES METHODOLOGY

The cost estimates for all three alternative power plant technologies have been compiled in accordance with the standard procedures of Kuljian. These procedures involve the following major steps:

1. Development of the conceptual design and site plan to define the salient technical particulars of the major systems and the main equipment of plant.

2. Defining the main cost elements and then estimating their costs from the in-house Cost Data Base, supplemented by:

   a. Budgetary cost data from vendors for the main equipment, which, depending on the technology, consisted of:

Technology	Item	Vendor
Combined Cycle	Gas Turbine Generator Steam Turbine Generator	General Electric General Electric and Siemens-Westinghouse
Diesel	Diesel engine generator with auxiliary systems	Burmeister and Wain Scandinavian Contractor, USA
Coal	Utility Boiler Steam Turbine Generator	DB Riley, B&W and Foster Wheeler General Electric and Siemens-Westinghouse

b. Cost estimating guidelines provided by standard publications, such as:

   i) "Process Plant Construction Estimating Standards", Richardson Engineering Services Inc., USA.

   ii) Means Cost Data (Building Construction, Mechanical, Electrical), R.S. Means Company Inc., USA.

3. Reconciliation of the total plant costs using known constructed costs of similar projects completed recently as benchmarks. Specific project costs were taken from those in which Kuljian was involved, as well as those reported by various publications of the industries.

   For all three technologies, generic plant cost data were taken from:

   - "Projected Costs of Generating Electricity – Update 1998", International Energy Agency, Organization for Economic Co-operation and Development (OECD), France.
   - Publications of Electric Power Research Institute (EPRI) for cost of utility power plants.

   In addition, combined cycle cost data were obtained in:

   - "Gas Turbine World 1999-2000 Hand book", Pequot Publishing Inc., USA.
   - Cost data generated by the design software GTPRO from Thermoflow with the latest database.

   For the diesel technology, cost data of the complete DG installation was checked against the installed cost data of MPU Fort George installation after adjusting for unit size change as well as escalation.

4. All erection costs are denominated in year 2003 dollars. Cost estimates have been escalated by 3% from base year numbers until year 2001 to account for price increases during these years. Gas turbine costs for the combined cycle plant have been escalated by three percent from 2001-2003 to reflect further cost increases. All other cost estimates for the combined cycle plant, as well as for the diesel and coal plants, have not been escalated for the period 2001-2003. It is not expected that these items will not increase in price during this period.

C. ERECTED COST ESTIMATE ASSUMPTIONS

1) It is assumed that the plant site will ultimately support a 300 MW power plant that is to be constructed in three phases of 100 MW each. The following cost estimates concern the first phase of the project; however, it is presumed that certain infrastructure for the full 300 MW plant will be constructed during this phase.

2) The following cost estimates include all expenses relative to plant erection, i.e. mechanical, electrical, civil engineering, instrumentation and controls costs, cost of spare parts, and design engineering and project management costs.

3) The erected cost estimates do not include the following:

Items not Included	Reason for non-inclusion in erected cost estimate
• Customs duty, excise duty, sales tax, VAT etc. as applicable in Mauritius	It is assumed the project will be approved as a "Pioneer Status Enterprise"
• Allowance for contingency	Considered as a commercial factor added to erected costs to make up the EPC cost (see detailed tables of cost estimates, sections 1 and 3).
• Legal, financial, bonding and insurance fees	Considered as a commercial factor added to erected costs to make up the EPC cost (see detailed tables of cost estimates, sections 1 and 3).
• Cost of land	Considered as "other hard costs" (see detailed tables of cost estimates, sections 1 and 3). It is assumed the MPU or other relevant government agency will lease the land to the IPP at a nominal cost. For the coal plant; however, it is assumed the IPP will purchase land to locate an ash disposal facility.
• Infrastructure facilities outside the plant boundary fencing namely access road, sewerage, telecommunication, power evacuation beyond 132 kV switchyard, city water supply system	Considered as "other hard costs" (see detailed tables of cost estimates, sections 1 and 3).
• Interest during construction	Considered as a soft cost (see sections 2 and 3)
• Permits and licenses	Considered as soft costs (see sections 2 and 3)

1. Combined Cycle Power Plant at Fort William

Costs for the following works have been estimated for the ultimate plant capacity of 300 MW and have been incorporated into the first phase costs:

i) Bathymetric survey, topographic survey and geo-technical investigations

ii) Fuel supply jetty

iii) Marine works for installation of submarine intake pipes, except minor work for later phases

iv) Supply and installation of submarine intake pipes up to pump house

v) Oily combustible incinerator and re-boiler

vi) Electrical DC system, UPS and O/G line take off

vii) Site development and grading work, boundary fencing and in-plant roads, except minor work for later phases. This work includes leveling the site to +3.00 metres AMSL, sea front protection and necessary piling works needed for foundations of Power House, main equipment, etc.

viii) Support and miscellaneous buildings like workshop, administrative, spares and consumable storage, gate house etc.

ix) A significant part of outdoor fire water system and pumping, and compressed air plant will be built in the first phase of the plant.

x) The outgoing feeders (2 Nos.) and bus-coupler bays of the 132 kV GIS are included in the first phase.

CAPITAL COST ESTIMATE
COMBINED CYCLE PLANT AT FORT WILLIAM
PHASED PLANT CONSTRUCTION (Total 300 MW)

Sl No.	Description	Factor (%)	Phase I 100 MW Power Block (US$000)
A	MECHANICAL		
1	Gas turbines, Heat recovery steam generators (HRSG), ductwork, Stack, Steam Turbine-generator, Surface Condenser, Power cycle pumps, Integral Instrumentation.		$32,012
2	Circulating water (CW) and Auxiliary cooling water (ACW) system, including Intake pumps, Aux. Cooling water pumps, Intake submarine CW pipes, Traveling water screen at pumphouse, on shore CW supply and Return CW pipes, Electro-chlorination plant, piping, valves and specialties.		$1,700
3	Liquid dual fuel (Heavy fuel oil and gas oil) system, including Treatment, Storage tanks, Pumps, Oil/water separator, Reboiler and Incinerator		$2,600
4	Plant water and Demineralized water system, including Storage tanks and Pumps		$800
5	HP and LP Piping and Appurtenances		$800
6	Ventilation and Air Conditioning, Fire protection and Plant and Instrument air System, cranes and hoists, maitenance workshop, turbine oil system, chemical feed system, boiler blowdown system, and balance of plant items.		$1,200
7	**FOB price of above Mechanical Plants (items 1 thru' 6)**		**$39,112**
8	Transportation in USA (or foreign country), Marine freight, Handling at Mauritius port, transportation within Mauritius, unloading and Storage at Site, all transit Insurances, as applicable on Item 7	5	$1,956
9	**Landed cost of all Mechanical items at site (items 7 + 8)**		**$41,068**
10	Erection, Testing and Commissioning of Mechanical Plant	15	$6,160
11	**Mechanical Plant, as erected**		**$47,228**

CAPITAL COST ESTIMATE
COMBINED CYCLE PLANT AT FORT WILLIAM
PHASED PLANT CONSTRUCTION (Total 300 MW)

Sl No.	Description	Factor (%)	Phase I 100 MW Power Block (US$000)
B	ELECTRICAL		
1	Power Transformers		$1,200
2	Bus Ducts		$870
3	6.6 KV/415 V Switchgears, MCC and Distribution Boards and DC System		$930
4	Power and Control cables (including 132 KV cables), Lighting system, Grounding system, Cable tray and accessories, Local control stations, UPS system, Plant communication system, Neutral grounding devices, Electrical laboratory, O/G line take off, Miscellaneous items.		$1,130
5	132 KV Gas Insulated Substation (GIS), Indoor		$2,220
6	**FOB price of above Electrical Plants (items 1 thru' 5)**		**$6,350**
7	Transportation in USA (or foreign country), Marine freight, Handling at Mauritius port, transportation within Mauritius, unloading and Storage at Site, all transit Insurances, as applicable on Item 6	5	$318
8	**Landed cost of all Electrical items at site (items 6 + 7)**		**$6,668**
9	Erection, Testing and Commissioning of Electrical Plant	15	$1,000
10	**Electrical Plant, as erected**		**$7,668**
C	SITE INVESTIGATIONS, CIVIL, STRUCTURAL & ARCHITECTURAL WORKS		
1	Bathymetric survey, Topo survey, Off-shore and On-shore Geotechnical Investigations		$150
2	Marine works for laying Submarine intake pipes		$1,000
3	Jetty		$5,000
4	Site grading work		$340
5	Site development work including inplant roads and plant boundary fencing, shore protection, drainage and landscaping		$3,000
6	Civil, Structural and Architectural works, including Intake pumphouse, and discharge outfall,all foundations, piling, inplant buildings and superstructures.		$14,000
7	**Site investigation, civil, struct. & arch. Works**		**$23,490**

CAPITAL COST ESTIMATE
COMBINED CYCLE PLANT AT FORT WILLIAM
PHASED PLANT CONSTRUCTION (Total 300 MW)

Sl No.	Description	Factor (%)	Phase I 100 MW Power Block (US$000)
D	**INSTRUMENTATION AND CONTROL**		
1	DCS system, SCADA system, SWAS, Local instruments, Laboratory instruments, Pollution monitoring instruments, FOB.		$3,000
2	Transportation in USA (or foreign country), Marine freight, Handling at Mauritius port, transportation within Mauritius, unloading and Storage at Site, all transit Insurances, as applicable on Item 1	5	$150
3	**Landed cost of all I & C items at site (items 1 + 2)**		**$3,150**
4	Erection, Testing and Commissioning of I & C System	15	$473
5	**Instrumentation & Control, as erected**		**$3,623**
E	**SPARE PARTS**		
	Spare parts for all Mechanical, Electrical and I & C plants, at Site		$2,000
F	**Design engineering and project management**		$4,500
	Total Erected Cost of Phase I Combined Cycle Plant, Including Spare Parts		**$88,508**
G	**Combined Cycle Total EPC Cost (Excluding spare parts)**		
	Mechanical Plant, as erected		$47,228
	Electrical Plant, as erected		$7,668
	Site investigation, civil, struct. & arch. Works		$23,490
	Instrumentation & Control, as erected		$3,623
	Design engineering and project management		$4,500
	Contingencies and fees	**5%**	**$4,325**
	TOTAL EPC COST		**$90,833**
H	**Combined Cycle Total Hard Costs**		
	EPC Cost		$90,833
	Spare Parts		$2,000
	Transmission facilities		$1,000
	Land		$0
	Total Hard Costs		**$93,833**

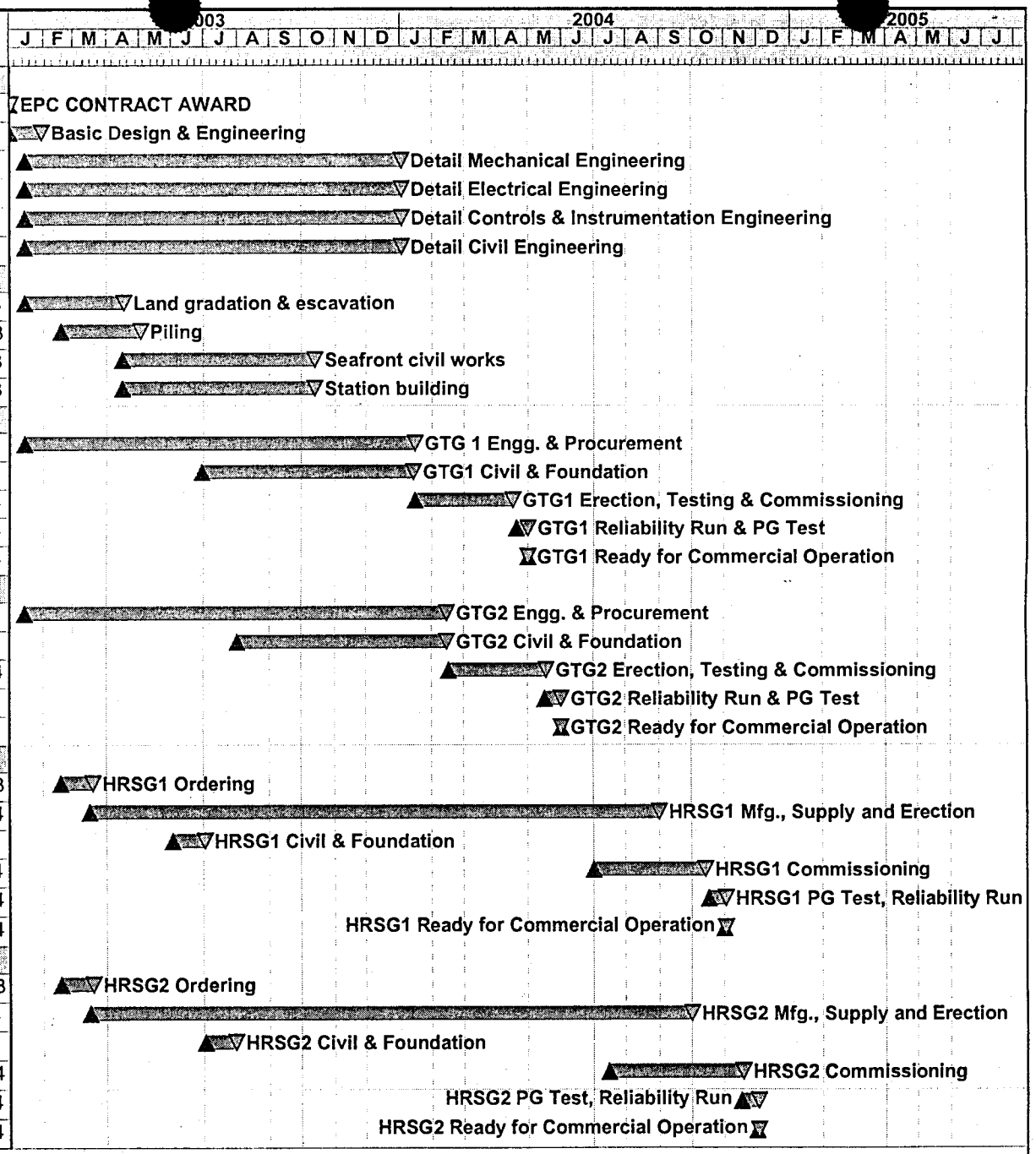
Combined Cycle Power Project at Fort William

Major Project Milestones

For first power block of 100 MW

NO	Milestone Activity	Schedule From date of award of EPC contract
1	Auxiliary Boiler ready for commercial operation	16 months
2	GTG #1 ready for CO	16 months
3	GTG #2 ready for CO	17 months
4	Switchyard (progressively)	14-17 months
5	HRSG#1 ready for CO	22 months
6	HRSG#2 ready for CO	23 months
7	STG ready for CO	24 months

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
GENERAL				
1000	EPC CONTRACT AWARD	1	01JAN03	01JAN03
1020	Basic Design & Engineering	22	01JAN03	30JAN03
1030	Detail Mechanical Engineering	252	15JAN03	01JAN04
1040	Detail Electrical Engineering	252	15JAN03	01JAN04
1050	Detail Controls & Instrumentation	252	15JAN03	01JAN04
1060	Detail Civil Engineering	252	15JAN03	01JAN04
MISC. CIVIL, STRUCTURAL & ARCHITECTURAL				
5010	Land gradation & escavation	67	15JAN03	17APR03
5020	Piling	55	17FEB03	02MAY03
5030	Seafront civil works	130	15APR03	13OCT03
5040	Station building	130	15APR03	13OCT03
GAS TURBINE GENERATOR #1				
1210	GTG 1 Engg. & Procurement	262	15JAN03	15JAN04
1211	GTG1 Civil & Foundation	142	30JUN03	13JAN04
1220	GTG1 Erection, Testing & Commissioning	66	15JAN04	15APR04
1240	GTG1 Reliability Run & PG Test	10	19APR04	30APR04
1250	GTG1 Ready for Commercial Operation	1	30APR04	30APR04
GAS TURBINE GENERATOR #2				
1410	GTG2 Engg. & Procurement	283	15JAN03	13FEB04
1411	GTG2 Civil & Foundation	141	01AUG03	13FEB04
1420	GTG2 Erection, Testing & Commissioning	66	16FEB04	17MAY04
1440	GTG2 Reliability Run & PG Test	12	17MAY04	01JUN04
1450	GTG2 Ready for Commercial Operation	1	01JUN04	01JUN04
HRSG #1				
1610	HRSG1 Ordering	22	17FEB03	18MAR03
1630	HRSG1 Mfg., Supply and Erection	382	17MAR03	31AUG04
1620	HRSG1 Civil & Foundation	22	02JUN03	01JUL03
1640	HRSG1 Commissioning	75	02JUL04	14OCT04
1650	HRSG1 PG Test, Reliability Run	11	18OCT04	01NOV04
1660	HRSG1 Ready for Commercial Operation	1	01NOV04	01NOV04
HRSG#2				
1810	HRSG2 Ordering	22	17FEB03	18MAR03
1830	HRSG2 Mfg., Supply and Erection	404	17MAR03	30SEP04
1820	HRSG2 Civil & Foundation	20	03JUL03	30JUL03
1840	HRSG2 Commissioning	89	16JUL04	17NOV04
1850	HRSG2 PG Test, Reliability Run	12	16NOV04	01DEC04
1860	HRSG2 Ready for Commercial Operation	1	01DEC04	01DEC04



Project Start	01JAN03	Early Bar	
Project Finish		Float Bar	
Data Date	01JAN03	Progress Bar	
Run Date	04DEC00	Critical Activity	

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FOT1

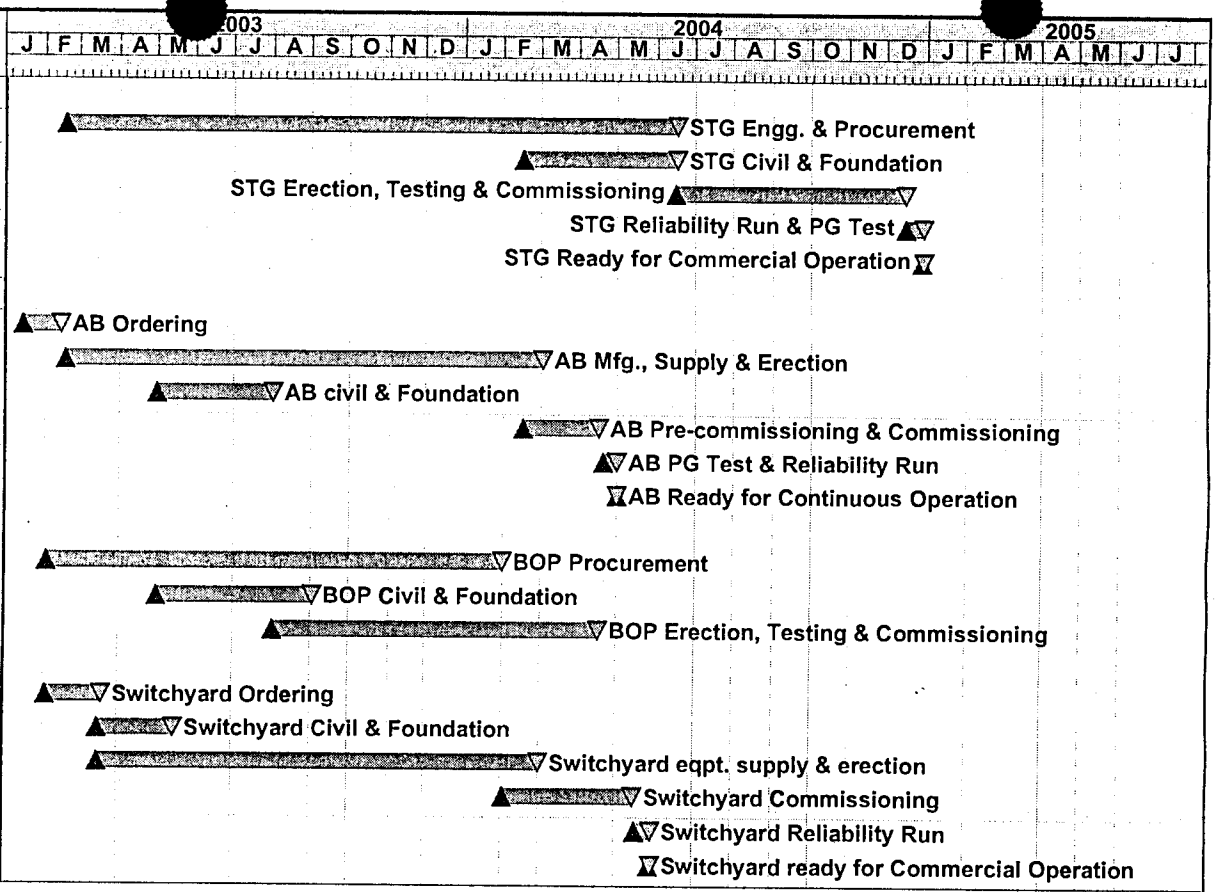
Sheet 1 of 2

THE KULJIAN CORPORATION

FORT WILLIAM, COMBINED CYCLE

Classic Schedule Layout

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
STEAM TURBINE GENERATOR				
2010	STG Engg. & Procurement	349	17FEB03	17JUN04
2020	STG Civil & Foundation	89	16FEB04	17JUN04
2030	STG Erection, Testing & Commissioning	132	15JUN04	15DEC04
2040	STG Reliability Run & PG Test	10	15DEC04	28DEC04
2050	STG Ready for Commercial Operation	1	28DEC04	28DEC04
AUX. BOILER				
2210	AB Ordering	22	15JAN03	13FEB03
2230	AB Mfg., Supply & Erection	272	17FEB03	02MAR04
2220	AB civil & Foundation	65	02MAY03	31JUL03
2240	AB Pre-commissioning & Commissioning	45	16FEB04	16APR04
2250	AB PG Test & Reliability Run	10	19APR04	30APR04
2260	AB Ready for Continuous Operation	1	30APR04	30APR04
BALANCE OF PLANT				
4010	BOP Procurement	260	03FEB03	30JAN04
4020	BOP Civil & Foundation	87	02MAY03	01SEP03
4040	BOP Erection, Testing & Commissioning	185	01AUG03	15APR04
132 KV SWITCHYARD				
3010	Switchyard Ordering	32	03FEB03	18MAR03
3020	Switchyard Civil & Foundation	44	17MAR03	15MAY03
3030	Switchyard eqpt. supply & erection	251	17MAR03	01MAR04
3040	Switchyard Commissioning	75	02FEB04	14MAY04
3050	Switchyard Reliability Run	10	17MAY04	28MAY04
3060	Switchyard ready for Commercial	1	28MAY04	28MAY04



2. Diesel Power Plant at Fort William

Costs for the following works have been estimated for the ultimate plant capacity of 300 MW:

i) Bathymetric survey, topographic survey and geo-technical investigations

ii) Fuel Supply jetty

iii) Site development and grading work. This work includes leveling the site to +3.00 metres AMSL, sea front protection and necessary piling works needed for foundations of Power House, main equipment, etc.

iv) Boundary fencing and inplant roads

The diesel engines will be cooled in closed cycle water - air (fan) cooled Radiators and sea water cooling has not been utilized.

The diesel engine will be burning heavy fuel oil after treatment. The NOx generation will be kept below 2,000 mg/M3 (World Bank Guidelines) by employing valve time retardation and/or water emulsification of fuel oil, but additional Catalytic converters (SCR) to reduce NOx down further have not been considered in the cost estimate.

CAPITAL COST ESTIMATE
DIESEL ENGINE GENERATOR PLANT AT FORT WILLIAM
PHASED PLANT CONSTRUCTION (Total 300 MW)

Sl No.	Description	Factor (%)	Phase I 2 X 50 MW Units (US$000)
A	**MECHANICAL**		
1	Diesel Engine, Exhaust Silencer, Electric Generator, Heat recovery steam generator (HRSG), closed loop Radiator cooling, tall metallic stack.		$61,175
2	Liquid dual fuel (Heavy fuel oil and gas oil) system, including Treatment, Storage tanks, Pumps, Oil/water separator, Reboiler and Incinerator		$2,400
3	Plant water, cooling water and treated water system, including Storage tanks, Pumps and piping		$750
4	Yard and LP Piping system and Appurtenances		$610
5	Ventilation and Air Conditioning, Fire protection and Plant and Instrument air System, cranes and hoists, maitenance workshop, and balance of plant items.		$1,250
6	**FOB price of above Mechanical Plants (items 1 thru' 5)**		**$66,185**
7	Transportation in USA (or foreign country), Marine freight, Handling at Mauritius port, transportation within Mauritius, unloading and Storage at Site, all transit Insurances, as applicable on Item 6	10	$6,619
8	**Landed cost of all Mechanical items at site (items 6 + 7)**		**$72,804**
9	Erection, Testing and Commissioning of Mechanical Plant	20	$14,561
10	**Mechanical Plant, as erected**		**$87,364**

CAPITAL COST ESTIMATE
DIESEL ENGINE GENERATOR PLANT AT FORT WILLIAM
PHASED PLANT CONSTRUCTION (Total 300 MW)

Sl No.	Description	Factor (%)	Phase I 2 X 50 MW Units (US$000)
B	ELECTRICAL		
1	Power Transformers		$1,108
2	Bus Ducts		$630
3	6.6 KV/415 V Switchgears, MCC and Distribution Boards and DC System		$820
4	Power and Control cables (including 132 KV cables), Lighting system, Grounding system, Cable tray and accessories, Local control stations, UPS system, Plant communication system, Neutral grounding devices, Electrical laboratory, O/G line take off, Miscell		$1,024
5	132 KV Gas Insulated Substation (GIS), Indoor		$1,850
6	**FOB price of above Electrical Plants (items 1 thru' 5)**		**$5,432**
7	Transportation in USA (or foreign country), Marine freight, Handling at Mauritius port, transportation within Mauritius, unloading and Storage at Site, all transit Insurances, as applicable on Item 6	5	$272
8	**Landed cost of all Electrical items at site (items 6 + 7)**		**$5,703**
9	Erection, Testing and Commissioning of Electrical Plant	15	$855
10	**Electrical Plant, as erected**		**$6,559**
C	SITE INVESTIGATIONS, CIVIL, STRUCTURAL & ARCHITECTURAL WORKS		
1	Bathymetric survey, Topo survey, Off-shore and On-shore Geotechnical Investigations (For 300 MW Station)		$135
2	Jetty		$5,000
3	Site grading work		$315
4	Site development work including inplant roads and plant boundary fencing, shore protection, drainage and landscaping for 300 MW Plant		$2,850
5	Civil, Structural and Architectural works for 100 MW plant, all foundations, vibration isolation, noise abatement, piling, inplant buildings and superstructures.		$13,500
6	**Site investigations, civil, struct. & arch. Works**		**$21,800**

CAPITAL COST ESTIMATE
DIESEL ENGINE GENERATOR PLANT AT FORT WILLIAM
PHASED PLANT CONSTRUCTION (Total 300 MW)

Sl No.	Description	Factor (%)	Phase I 2 X 50 MW Units (US$000)
D	INSTRUMENTATION AND CONTROL		
1	DCS system, SCADA system, Local instruments, Laboratory instruments, Pollution monitoring instruments, FOB.		$2,250
2	Transportation in USA (or foreign country), Marine freight, Handling at Mauritius port, transportation within Mauritius, unloading and Storage at Site, all transit Insurances, as applicable on Item 1	5	$113
3	Landed cost of all I & C items at site (items 1 + 2)		$2,363
4	Erection, Testing and Commissioning of I & C System	15	$354
5	Instrumentation & Control, as erected		$2,717
E	SPARE PARTS		
	Spare parts for all Mechanical, Electrical and I & C plants, at Site		$3,235
F	Design engineering, project management		$4,275
	Total Erected Cost of Phase I Diesel Engine Generator Plant, including Spare Parts		$125,949
G	Diesel Plant Total EPC Costs (Excluding spare parts)		
	Mechanical Plant, as erected		$87,364
	Electrical Plant, as erected		$6,559
	Site investigations, civil, struct. & arch. Works		$21,800
	Instrumentation & Control, as erected		$2,717
	Design engineering, project management		$4,275
	Contingencies and fees	**5%**	**$6,136**
	TOTAL EPC COST		$128,850
H	Diesel Plant total Hard Costs		
	EPC Cost		$128,850
	Spare Parts		$3,235
	Transmission facilities		$1,000
	Land		$0
	Total Hard Costs		$133,085

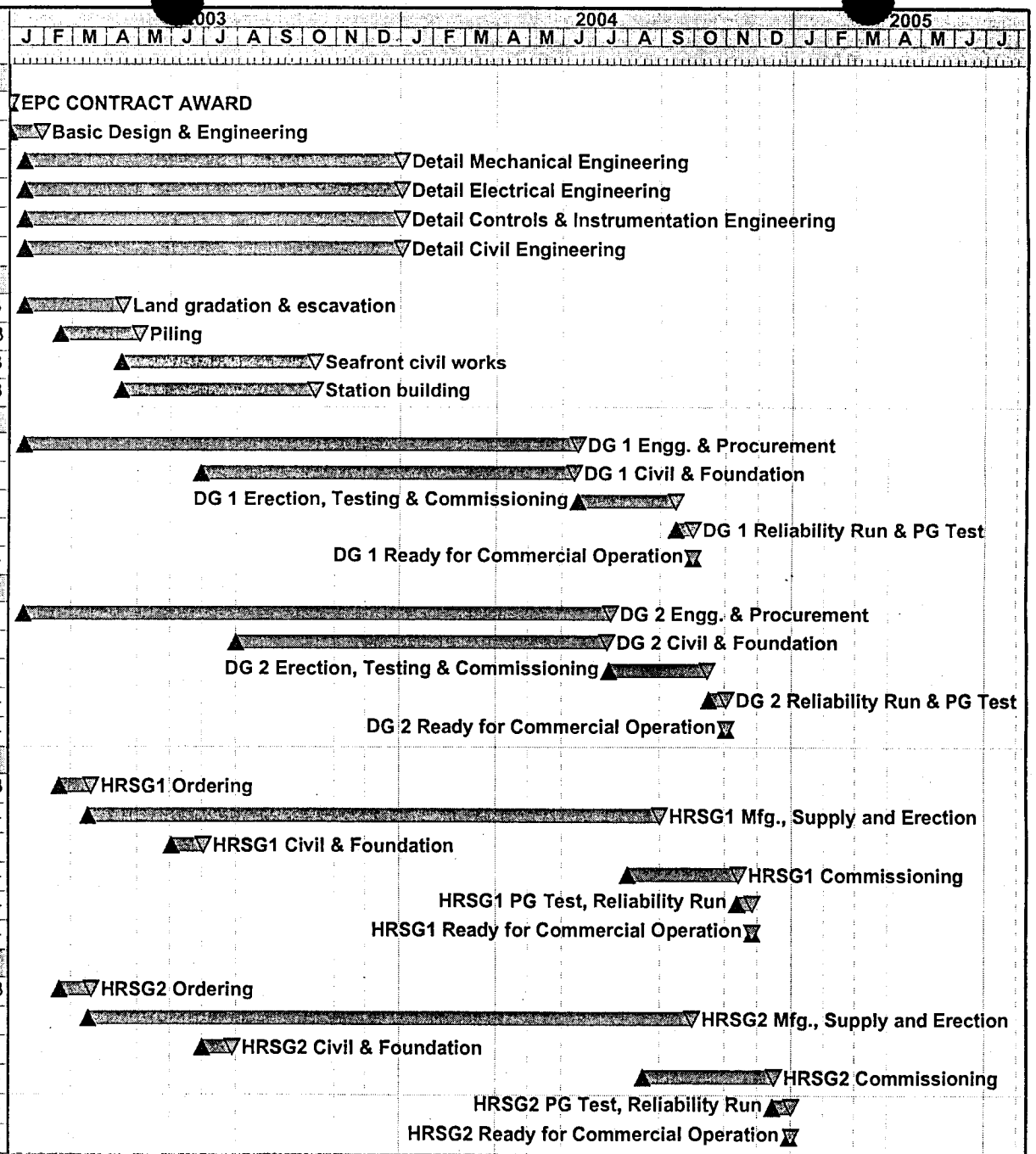
Diesel Power Project at Fort William

Major Project Milestones

For first power block of 2x50MW

NO	Milestone Activity	Schedule From date of award of EPC contract
1	Auxiliary Boiler ready for commercial operation	16 months
2	DG #1 ready for CO	21 months
3	DG #2 ready for CO	22 months
4	Switchyard (progressively)	14-17 months
5	HRSG#1 ready for CO	23 months
6	HRSG#2 ready for CO	24 months

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
GENERAL				
1000	EPC CONTRACT AWARD	1	01JAN03	01JAN03
1020	Basic Design & Engineering	22	01JAN03	30JAN03
1030	Detail Mechanical Engineering	252	15JAN03	01JAN04
1040	Detail Electrical Engineering	252	15JAN03	01JAN04
1050	Detail Controls & Instrumentation	252	15JAN03	01JAN04
1060	Detail Civil Engineering	252	15JAN03	01JAN04
MISC. CIVIL, STRUCTURAL & ARCHITECTURAL				
5010	Land gradation & escavation	67	15JAN03	17APR03
5020	Piling	55	17FEB03	02MAY03
5030	Seafront civil works	130	15APR03	13OCT03
5040	Station building	130	15APR03	13OCT03
DIESEL ENGINE GENERATOR #1				
1210	DG 1 Engg. & Procurement	370	15JAN03	15JUN04
1211	DG 1 Civil & Foundation	250	30JUN03	11JUN04
1220	DG 1 Erection, Testing & Commissioning	67	15JUN04	15SEP04
1240	DG 1 Reliability Run & PG Test	11	16SEP04	30SEP04
1250	DG 1 Ready for Commercial Operation	1	01OCT04	01OCT04
DIESEL ENGINE GENERATOR #2				
1410	DG 2 Engg. & Procurement	393	15JAN03	16JUL04
1411	DG 2 Civil & Foundation	248	01AUG03	13JUL04
1420	DG 2 Erection, Testing & Commissioning	66	16JUL04	15OCT04
1440	DG 2 Reliability Run & PG Test	12	18OCT04	02NOV04
1450	DG 2 Ready for Commercial Operation	1	02NOV04	02NOV04
HRSG #1				
1610	HRSG1 Ordering	22	17FEB03	18MAR03
1630	HRSG1 Mfg., Supply and Erection	382	17MAR03	31AUG04
1620	HRSG1 Civil & Foundation	22	02JUN03	01JUL03
1640	HRSG1 Commissioning	75	02AUG04	12NOV04
1650	HRSG1 PG Test, Reliability Run	11	12NOV04	26NOV04
1660	HRSG1 Ready for Commercial Operation	1	26NOV04	26NOV04
HRSG#2				
1810	HRSG2 Ordering	22	17FEB03	18MAR03
1830	HRSG2 Mfg., Supply and Erection	404	17MAR03	30SEP04
1820	HRSG2 Civil & Foundation	20	01JUL03	28JUL03
1840	HRSG2 Commissioning	89	16AUG04	16DEC04
1850	HRSG2 PG Test, Reliability Run	12	16DEC04	31DEC04
1860	HRSG2 Ready for Commercial Operation	1	31DEC04	31DEC04



Project Start	01JAN03	Early Bar
Project Finish	[illegible]	Float Bar
Data Date	01JAN03	Progress Bar
Run Date	04DEC00	Critical Activity

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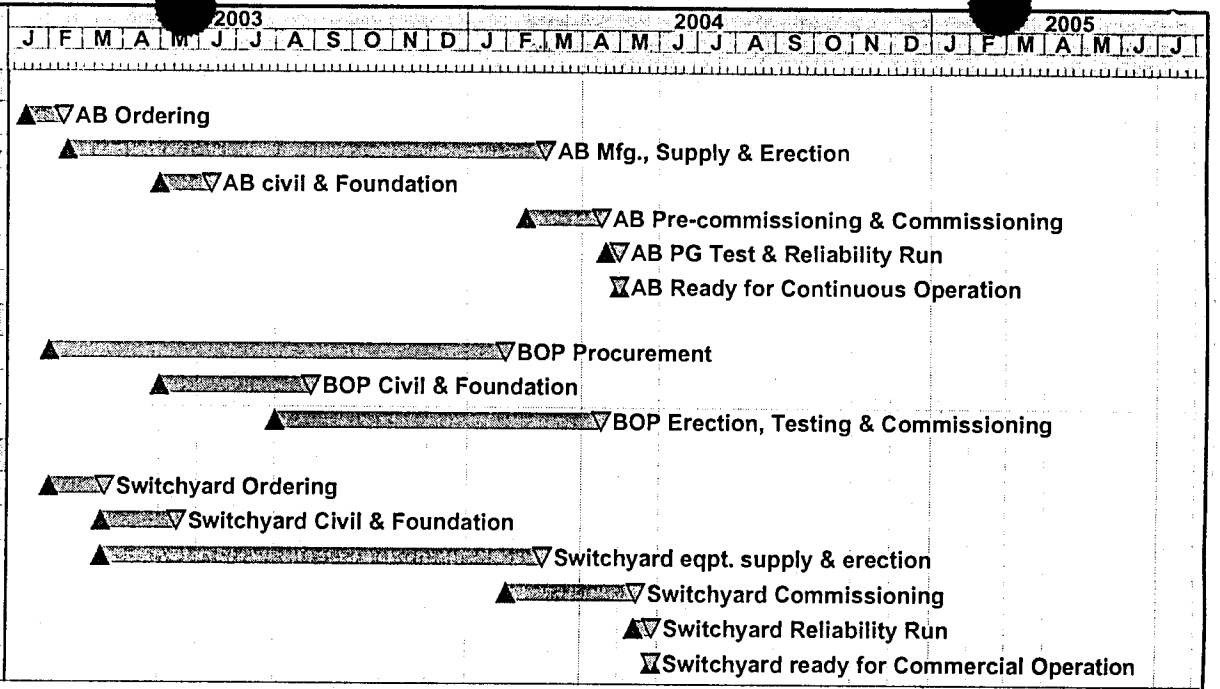
FOT2

Sheet 1 of 2

THE KULJIAN CORPORATION
FORT WILLIAM. DIESEL PLANT
Classic Schedule Layout

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
AUX. BOILER				
2210	AB Ordering	22	15JAN03	13FEB03
2230	AB Mfg., Supply & Erection	272	17FEB03	02MAR04
2220	AB civil & Foundation	30	01MAY03	11JUN03
2240	AB Pre-commissioning & Commissioning	45	16FEB04	16APR04
2250	AB PG Test & Reliability Run	10	19APR04	30APR04
2260	AB Ready for Continuous Operation	1	30APR04	30APR04
BALANCE OF PLANT				
4010	BOP Procurement	260	03FEB03	30JAN04
4020	BOP Civil & Foundation	87	01MAY03	29AUG03
4040	BOP Erection, Testing & Commissioning	185	01AUG03	15APR04
132 KV SWITCHYARD				
3010	Switchyard Ordering	32	03FEB03	18MAR03
3020	Switchyard Civil & Foundation	44	17MAR03	15MAY03
3030	Switchyard eqpt. supply & erection	251	17MAR03	01MAR04
3040	Switchyard Commissioning	75	02FEB04	14MAY04
3050	Switchyard Reliability Run	10	14MAY04	27MAY04
3060	Switchyard ready for Commercial	1	27MAY04	27MAY04



3. Coal-Fired Power Plant at Montagne Jacquot

The following works will be completed for the ultimate plant capacity of 300 MW, although rest of the plant is provided for the first phase of 100 MW only:

i) Bathymetric survey, topographic survey and geo-technical investigations

ii) Fuel supply jetty

iii) Marine works for installation of submarine intake pipes

iv) Supply and installation of submarine intake pipes

v) Site development and grading work. This work includes leveling the site, sea front protection and necessary piling works needed for foundations of Power House, main equipment, etc.

vi) Boundary fencing and inplant roads

CAPITAL COST ESTIMATE
COAL FIRED PLANT AT MONTAGNE JACQUOT
PHASED PLANT CONSTRUCTION (Total 300 MW)

Sl No.	Description	Factor (%)	Phase I 2 X 50 MW Units (US$000)
A	MECHANICAL		
1	Pulverized coal fired boiler pressure parts, steel structures, galleries, staircases, coal mills, air/gas fans, all electric drive motors, air heater/economizer, boiler trims, dust collectors, all ash hoppers, ductwork, expansion joints, dampers, stack br		$23,000
2	Steam turbine generator, including integral gland/seal steam and lubricating/governing oil system, seawater cooled steam surface condenser, air evacuation system, regenerative Hp/Lp heaters, deaerator, power cycle pumps and drives, steam bypass system.		$14,100
3	Circulating water (CW) system including Intake pumps, Intake submarine CW pipes for 300 MW plant, Traveling water screen at pumphouse, on shore CW supply and Return CW pipes for 100 MW plant in each phase, Electro-chlorination plant, piping, valves and sp		$5,400
4	Coal Unloading, storage, handling, reclaim and distribution system, including bulldozers		$3,900
5	Ash handling system (In plant)		$1,300
6	Liquid dual fuel (Heavy fuel oil and gas oil) system, including Storage tanks, Pumps, heaters etc.		$400
7	Plant water, water pretreatment and demineralized water system, potable water, auxiliary cooling water system including heat exchangers, storage tanks and pumps, waste water treatment system, testing laboratory.		$1,400
8	HP, LP and Yard Piping system and Appurtenances		$1,920
9	Ventilation and Air Conditioning, Fire protection and alarm system, Plant and Instrument air System, Auxiliary boiler, Emergency diesel generator, cranes and hoists, maitenance workshop, turbine oil system, chemical feed system, boiler blowdown system, an		$1,500
10	FOB price of above Mechanical Plants (items 1 thru 9)		$52,920
11	Transportation in USA (or foreign country), Marine freight, Handling at Mauritius port, transportation within Mauritius, unloading and Storage at Site, all transit Insurances, as applicable on Item 10	7	$3,704
12	Landed cost of all Mechanical items at site (items 10 + 11)		$56,624
13	Erection, Testing and Commissioning of Mechanical Plant	18	$10,192
14	Mechanical Plant, as erected		$66,817

CAPITAL COST ESTIMATE
COAL FIRED PLANT AT MONTAGNE JACQUOT
PHASED PLANT CONSTRUCTION (Total 300 MW)

Sl No.	Description	Factor (%)	Phase I 2 X 50 MW Units (US$000)
B	ELECTRICAL		
1	Power Transformers		$2,085
2	Bus Ducts		$980
3	6.6 KV/415 V Switchgears, MCC and Distribution Boards and DC System		$1,444
4	Power and Control cables (including 132 KV cables), Lighting system, Grounding system, Cable tray and accessories, Local control stations, UPS system, Plant communication system, Neutral grounding devices, Electrical laboratory, O/G line take off, Miscell		$1,424
5	132 KV Gas Insulated Substation (GIS), Indoor		$2,590
6	FOB price of above Electrical Plants (items 1 thru' 5)		$8,523
7	Transportation in USA (or foreign country), Marine freight, Handling at Mauritius port, transportation within Mauritius, unloading and Storage at Site, all transit Insurances, as applicable on Item 6	5	$426
8	Landed cost of all Electrical Items at site (items 6 + 7)		$8,949
9	Erection, Testing and Commissioning of Electrical Plant	15	$1,342
10	Electrical Plant, as erected		$10,292
C	SITE INVESTIGATIONS, CIVIL, STRUCTURAL & ARCHITECTURAL WORKS		
1	Bathymetric survey, Topo survey, Off-shore and On shore Geotechnical Investigations (For 300 MW Station)		$215
2	Marine works for laying Submarine intake pipes		$1,000
3	Fuel Unloading Jetty		$7,000
4	Site grading work		$510
5	Site development work including inplant roads and plant boundary fencing, shore protection, drainage and landscaping for 300 MW Plant		$4,850
6	Civil, Structural and Architectural works for 100 MW plant, including Common boiler stack, Intake pumphouse, and discharge outfall,all foundations, inplant buildings and superstructures, including raw coal bunkers in Power house, trenches, pipe racks.		$22,900
7	Sitre investigations, civil, struct. & arch. Works		$36,475

CAPITAL COST ESTIMATE
COAL FIRED PLANT AT MONTAGNE JACQUOT
PHASED PLANT CONSTRUCTION (Total 300 MW)

Sl No.	Description	Factor (%)	Phase I 2 X 50 MW Units (US$000)
D	INSTRUMENTATION AND CONTROL		
1	DCS system, SCADA system, SWAS, Local instruments, Laboratory instruments, Pollution monitoring instruments, FOB.		$4,000
2	Transportation in USA (or foreign country), Marine freight, Handling at Mauritius port, transportation within Mauritius, unloading and Storage at Site, all transit Insurances, as applicable on Item 8	5	$200
3	Landed cost of all I & C items at site (items 1 + 2)		$4,200
4	Erection, Testing and Commissioning of I & C System	15	$630
5	Instrumentation & Control, as erected		$4,830
E	SPARE PARTS		
	Spare parts for all Mechanical, Electrical and I & C plants, at Site		$2,093
F	Design engineering, project management		$4,820
G	Purchase of private land for the Power Plant and Ash disposal (Engineered landfill) areas		$1,700
	Total Erected Cost of First Phase (100 MW) Coal Fired Plant, Including Spare Parts and Land purchase		$127,027
H	Coal-fired steam plant total EPC Costs (Excluding spare parts)		
	Mechanical Plant, as erected	0	$66,817
	Electrical Plant, as erected	0	$10,292
	Sitre investigations, civil, struct. & arch. Works	0	$36,475
	Instrumentation & Control, as erected	0	$4,830
	Design engineering, project management	0	$4,820
	Contingencies and fees	**5%**	**$6,162**
	TOTAL EPC COSTS		$129,395
I	Coal-fired plant total hard costs		
	EPC		$129,395
	Spare parts		$2,093
	Transmission Facilities		$1,600
	Land for ash disposal		$1,700
	Total Hard Costs		$134,788

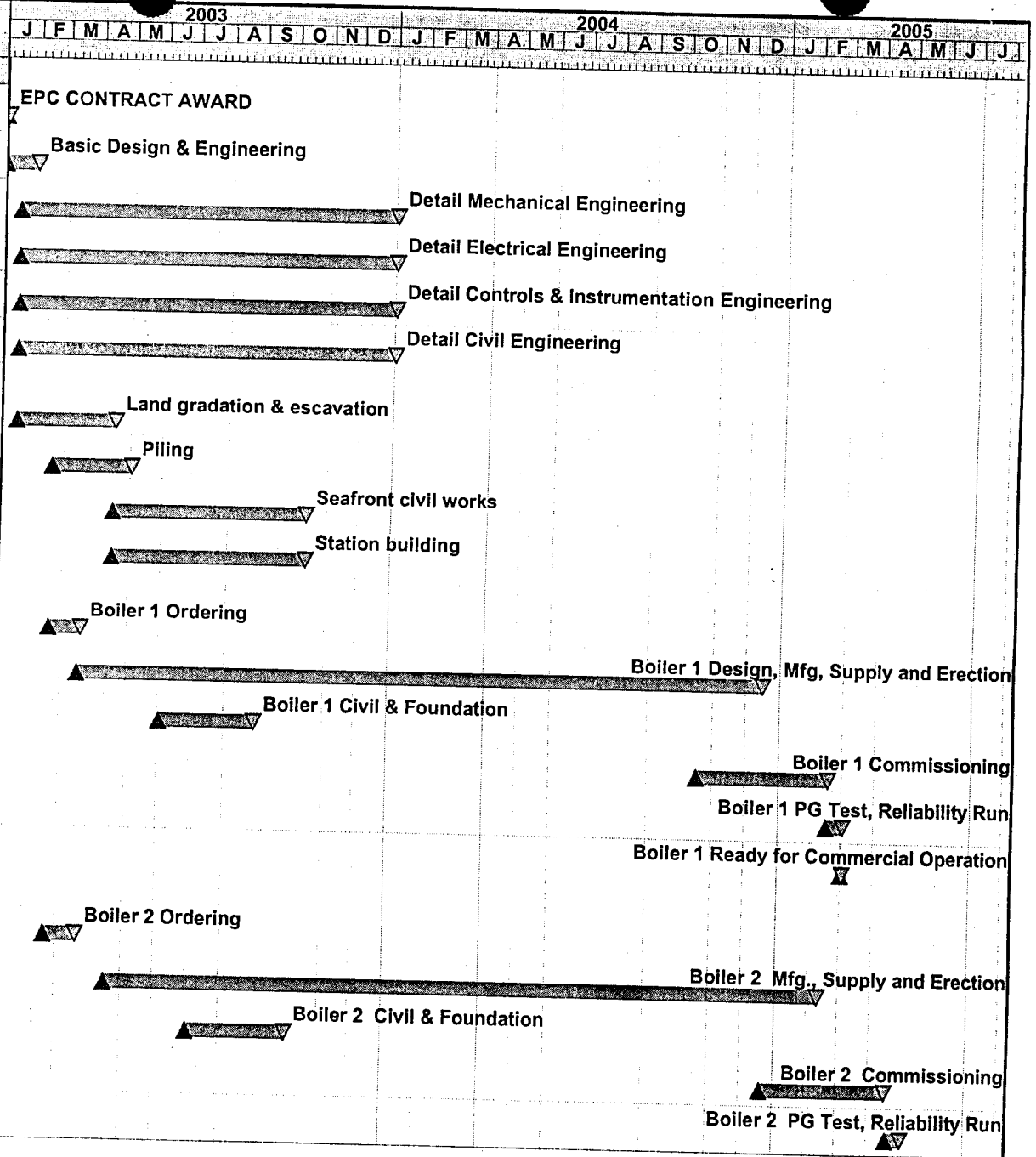
Coal-fired Power Project at Montagne Jacquot

Major Project Milestones

For first power block of 2x50MW

NO	Milestone Activity	Schedule From date of award of EPC contract
1	Auxiliary Boiler ready for commercial operation	25 months
2	Utility Boiler #1 ready for CO	26 months
3	Utility Boiler #2 ready for CO	28 months
4	STG#1 ready for CO	29 months
5	STG#2 ready for CO	30 months
6	Switchyard (progressively)	30 months

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
GENERAL				
1000	EPC CONTRACT AWARD	1	01JAN03	01JAN03
1020	Basic Design & Engineering	22	01JAN03	30JAN03
1030	Detail Mechanical Engineering	252	15JAN03	01JAN04
1040	Detail Electrical Engineering	252	15JAN03	01JAN04
1050	Detail Controls & Instrumentation Engineering	252	15JAN03	01JAN04
1060	Detail Civil Engineering	252	15JAN03	01JAN04
MISC. CIVIL, STRUCTURAL & ARCHITECTURAL				
5010	Land gradation & escavation	67	15JAN03	17APR03
5020	Piling	55	17FEB03	02MAY03
5030	Seafront civil works	130	15APR03	13OCT03
5040	Station building	130	15APR03	13OCT03
UTILITY BOILER #1				
1610	Boiler 1 Ordering	22	17FEB03	18MAR03
1630	Boiler 1 Design, Mfg, Supply and Erection	459	17MAR03	16DEC04
1620	Boiler 1 Civil & Foundation	65	02JUN03	29AUG03
1640	Boiler 1 Commissioning	87	18OCT04	15FEB05
1650	Boiler 1 PG Test, Reliability Run	12	15FEB05	02MAR05
1660	Boiler 1 Ready for Commercial Operation	1	02MAR05	02MAR05
UTILITY BOILER #2				
1810	Boiler 2 Ordering	22	17FEB03	18MAR03
1830	Boiler 2 Mfg., Supply and Erection	478	15APR03	10FEB05
1820	Boiler 2 Civil & Foundation	65	03JUL03	01OCT03
1840	Boiler 2 Commissioning	85	20DEC04	15APR05
1850	Boiler 2 PG Test, Reliability Run	11	18APR05	02MAY05



Project Start 01JAN03
Project Finish
Data Date 01JAN03
Run Date 04DEC00

Early Bar
Float Bar
Progress Bar
Critical Activity

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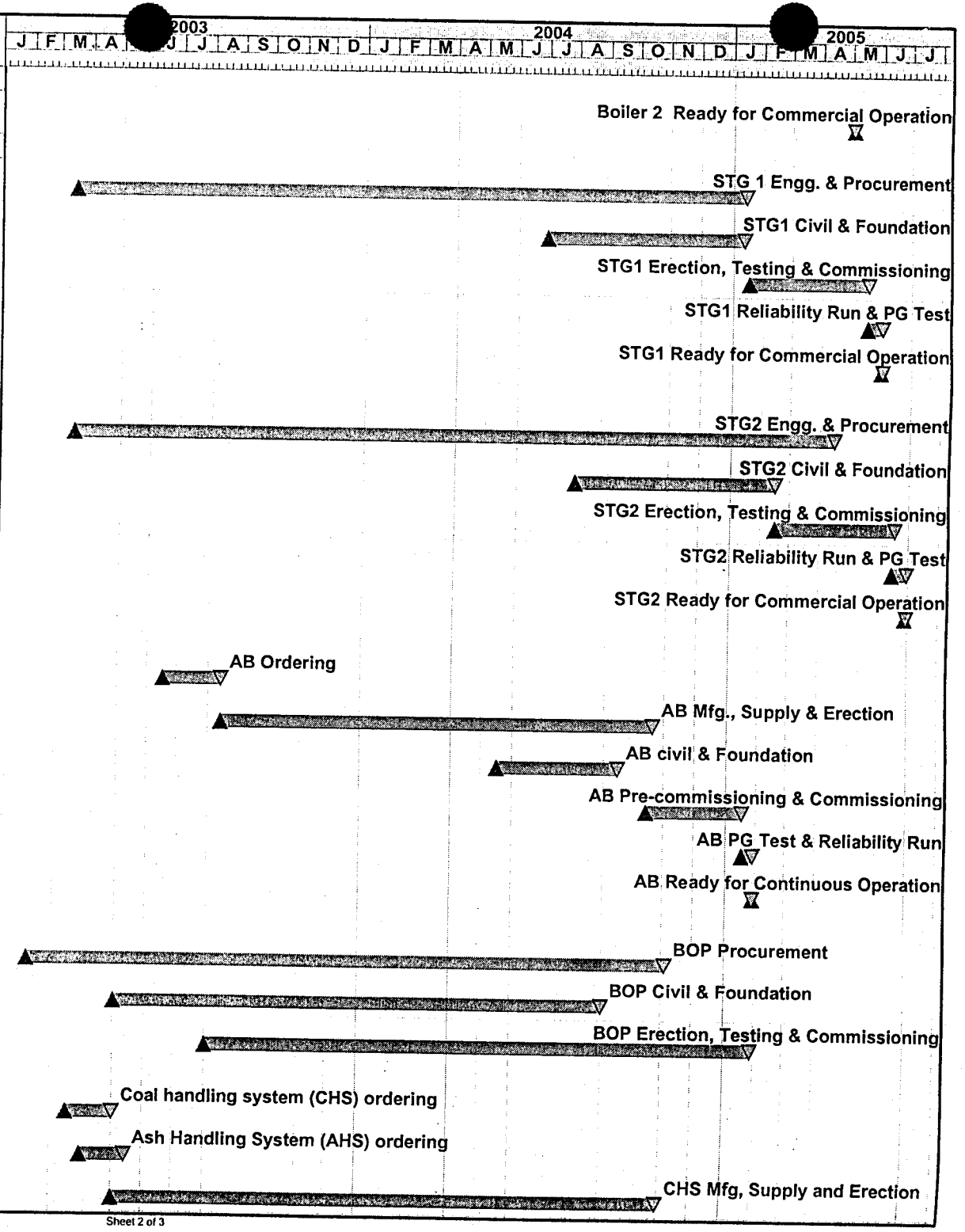
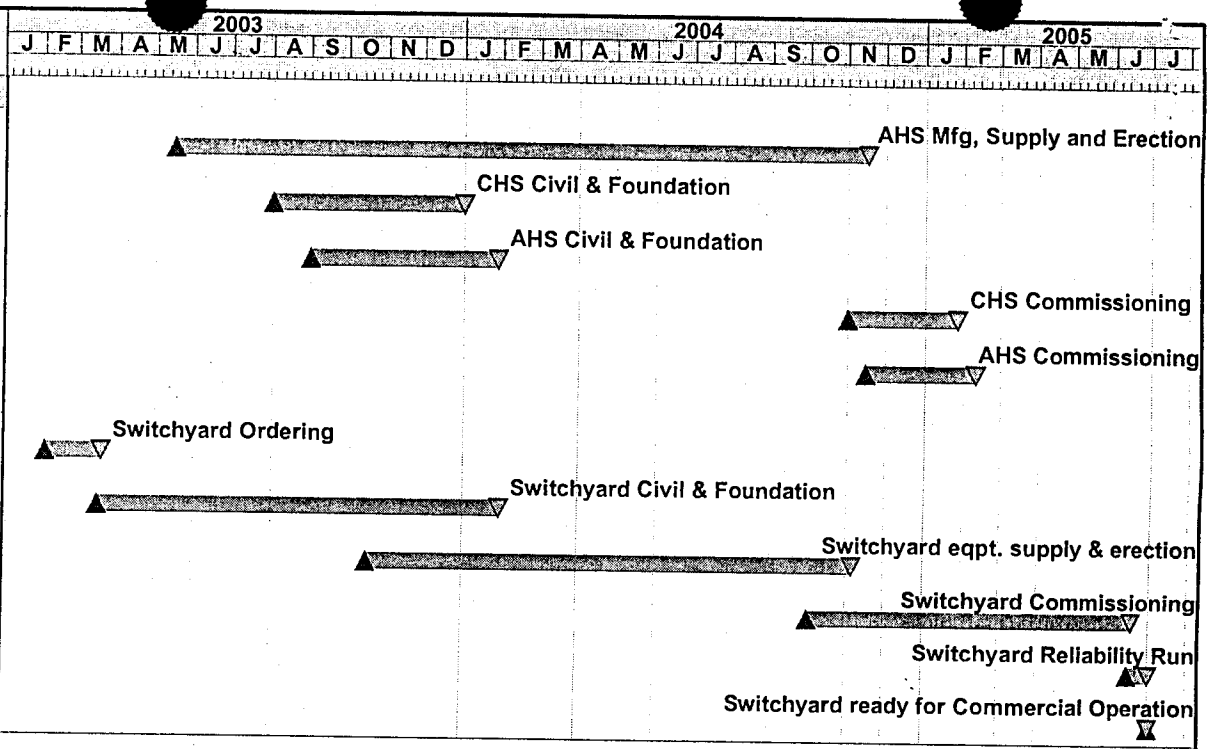
THE KULJIAN CORPORATION
MONTAGNE JACQUOT. COAL PLANT
Classic Schedule Layout

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
UTILITY BOILER #2				
1860	Boiler 2 Ready for Commercial Operation	1	02MAY05	02MAY05
STEAM TURBINE GENERATOR #1				
1210	STG 1 Engg. & Procurement	479	17MAR03	13JAN05
1211	STG1 Civil & Foundation	141	30JUN04	12JAN05
1220	STG1 Erection, Testing & Commissioning	87	17JAN05	17MAY05
1240	STG1 Reliability Run & PG Test	12	16MAY05	31MAY05
1250	STG1 Ready for Commercial Operation	1	31MAY05	31MAY05
STEAM TURBINE GENERATOR #2				
1410	STG2 Engg. & Procurement	544	17MAR03	14APR05
1411	STG2 Civil & Foundation	142	30JUL04	14FEB05
1420	STG2 Erection, Testing & Commissioning	89	15FEB05	17JUN05
1440	STG2 Reliability Run & PG Test	11	15JUN05	29JUN05
1450	STG2 Ready for Commercial Operation	1	29JUN05	29JUN05
AUX. BOILER				
2210	AB Ordering	44	16JUN03	14AUG03
2230	AB Mfg., Supply & Erection	310	14AUG03	20OCT04
2220	AB civil & Foundation	88	17MAY04	15SEP04
2240	AB Pre-commissioning & Commissioning	67	15OCT04	17JAN05
2250	AB PG Test & Reliability Run	10	17JAN05	28JAN05
2260	AB Ready for Continuous Operation	1	28JAN05	28JAN05
BALANCE OF PLANT				
4010	BOP Procurement	458	03FEB03	03NOV04
4020	BOP Civil & Foundation	348	02MAY03	31AUG04
4040	BOP Erection, Testing & Commissioning	390	01AUG03	27JAN05
COAL & ASH HANDLING SYSTEM				
6010	Coal handling system (CHS) ordering	34	17MAR03	01MAY03
6050	Ash Handling System (AHS) ordering	33	31MAR03	14MAY03
6015	CHS Mfg, Supply and Erection	391	02MAY03	29OCT04



Activity ID	Activity Description	Orig Dur	Early Start	Early Finish
COAL & ASH HANDLING SYSTEM				
6055	AHS Mfg, Supply and Erection	393	16MAY03	16NOV04
6020	CHS Civil & Foundation	109	01AUG03	31DEC03
6060	AHS Civil & Foundation	107	01SEP03	27JAN04
6025	CHS Commissioning	63	01NOV04	26JAN05
6065	AHS Commissioning	63	15NOV04	09FEB05
132 KV SWITCHYARD				
3010	Switchyard Ordering	32	03FEB03	18MAR03
3020	Switchyard Civil & Foundation	229	17MAR03	29JAN04
3030	Switchyard eqpt. supply & erection	275	17OCT03	04NOV04
3040	Switchyard Commissioning	185	01OCT04	16JUN05
3050	Switchyard Reliability Run	12	15JUN05	30JUN05
3060	Switchyard ready for Commercial Operation	1	01JUL05	01JUL05



SECTION 2
PROJECT SOFT COSTS

An independent power project's (IPP) soft costs can be divided into the following general categories of expenses:

- The lenders' expenses and fees
- The developers' expenses and fees
- The project expenses
- Other project soft costs

Project soft costs generally range between 25% and 35% of total project costs (including interest during construction). In the case of Mauritius, depending on the technology selected for the IPP, soft costs represent:

- For the Combined Cycle Plant: approximately 30%
- For the Diesel Plant: approximately 27%
- For the Coal Plant: approximately 29%

1. Lender Expenses

Expenses that are incurred by the lenders during the debt structuring process.

In the period preceding financial close, lenders will require the advice of several professionals to analyze the project from an independent perspective (i.e. not influenced by the developer's interests). Such professionals typically include local and international counsel, independent engineers, fuel consultants (if applicable) and insurance consultants. The cost of services of these professionals will depend on how quickly (or not) the project reaches financial close. When projects require lengthy discussion periods, lender expenses can run high, particularly those related to legal advisors. In addition to these costs, lenders will incur miscellaneous expenses that are generally categorized as "out-of-pocket". Expenses for advisor services and other out-of-pocket can range between US$500,000 and US$1 million, depending on the timing to financial close.

K&M estimates that Lender Expenses for the Mauritius IPPs will be approximately US$775,000.

2. Lender Fees

Lenders will charge the developers various fees for advisor services, loan arranging, and other loan-specific costs. These fees are usually calculated as a percentage of the loan, and will therefore increase with higher debt amounts. They include[1]:

- Debt arrangement and advisory fee (1.5%)
- Commitment fee (Percentage of the undrawn loan, 0.75%)
- Mobilization/retainer fee (0.5%)
- Loan facility fee (1.5%)
- Agency fee: this fee is charged periodically throughout the entire construction and debt repayment period. It can range between US$25,000 and US$75,000 a year.

[1] Percentages indicated in parenthesis reflect K&M's estimates for the Mauritius IPPs

For the three project configurations under consideration in Mauritius, K&M estimates lender fees to amount to approximately:

- Combined Cycle: US$3.7 million
- Diesel: US$5.2 million
- Coal: US$ 5.7 million

3. Developer Expenses

Expenses incurred by the developer in the period that precedes financial close.

Developers require the assistance of various advisors in the period preceding financial close. Advisors include legal counsel (local and foreign), and accountants (local and international). Developer expenses for these advisory services can range between US$1 million and US$1.5 million.

In addition, developers will incur additional development costs, which might include project site surveys, bid proposal preparation, project studies, out-of-pocket expenses, etc. Development costs will depend on the complexities of the project (site location, access, etc...). For the Mauritius IPPs, K&M estimates that developer expenses will amount to approximately US$3.5 million.

4. Developer Fees

Developers will include in their project cost estimate a percentage of the total project cost as a success fee. Developer success fees can range between 2% and 4% of total project costs, and K&M has assumed that these fees will be 2% of total project costs for the Mauritius IPPs.

5. Project Expenses

These expenses are incurred over the project construction period and can either be a one-time cost, or a periodical cost (annual, semi-annual, monthly). Expenses that are typically classified under this item include those related to construction management, project independent engineers, environmental consultants, environmental impact reports (EIA study), pre-operation mobilization of the operation and maintenance contractor, contract administration, etc...

Project expenses include such costs as:

<u>5.1 Equity arrangement and advisory fee</u>

This expense may be incurred in several circumstances such as:

- Capital contribution is sought from parties (financial institutions) which are not members of the project consortium or partnership
- Developers resort to an advisor for equity arrangement

5.2 Insurance During Construction

Insurance coverage during construction is both for commercial and political risk.

Commercial risk insurance covers hazard and liability during construction and is calculated as an annual percentage of the total EPC cost. In the case of Mauritius, K&M estimates this percentage at 1% of the EPC cost.

Political risk insurance during construction is calculated as a percentage of total equity and covers items such as war and civil unrest, expropriation, foreign exchange inconvertibility and contract frustration. The cost of undertaking political risk insurance varies according to which political risk items need to be covered. Coverage can be selected to protect debt and equity, and K&M estimates that political risk coverage requirements for the Mauritius IPPs will be low, and will amount to approximately 1% of the equity invested in the project.

5.3 Contingency Reserve

Lenders generally require that the developer include a contingency reserve to cover cost overruns. This amount is usually calculated as a percentage of the EPC cost and can range between 3% and 10%. In the case of Mauritius, K&M estimates the contingency reserve will be 5% of total EPC costs.

6. Other Project Soft Costs

6.1 Interest During Construction (IDC)

This is interest accrued during the construction period on the drawn portion of the loans and is typically included in the total project cost. Total IDC will depend on the amount of the construction loan, the drawdown schedule of the debt (i.e. whether equity is drawn first, last or pari passu with debt), and on the duration of the construction period.

6.2 Initial Working Capital

This will vary for each project and will depend on the project's working capital requirements. Working capital can be funded in the construction loan to provide the project with an immediate source of cash to meet initial working capital needs at the onset of project operation.

6.3 Initial funding of Debt Service Reserve Account (DSRA)

Lenders generally require that the developer hold in escrow an amount to cover at least six months' worth of debt service (principal and interest payments). Rules vary among the lenders, and developers may choose to build the DSRA after the start of project operations. It is sometimes necessary to fund the DSRA through a portion of the construction loan particularly when cash flows from operations in the first several years of the project cannot support the additional impact of a DSRA build-up. In the case of Mauritius projects, K&M has assumed that the DSRA will be built-up at the onset of project operations.

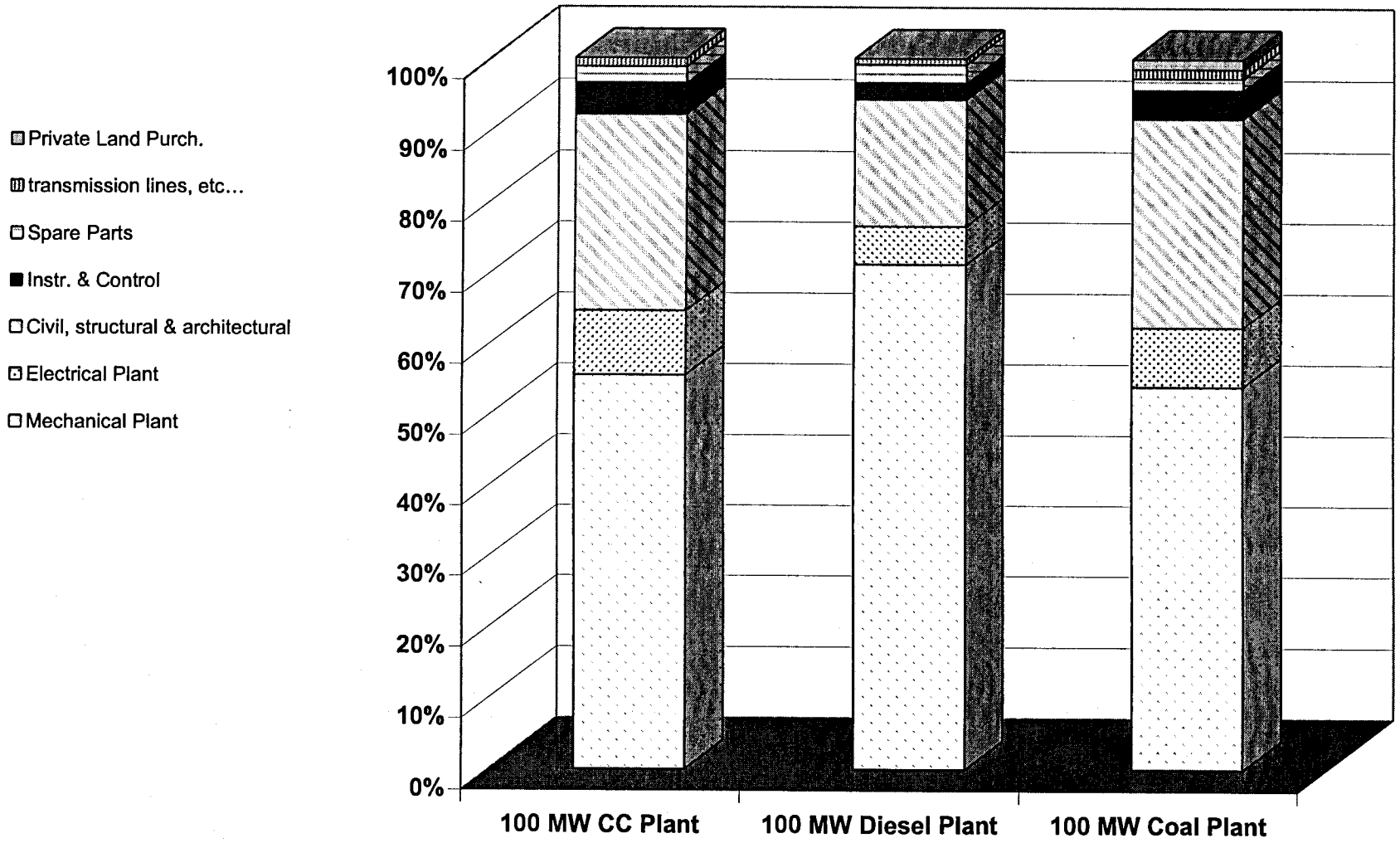
SECTION 3
SUMMARY OF CAPITAL COSTS

The following table summarizes project hard and soft costs for all three technologies for the construction of the first phase of the project.

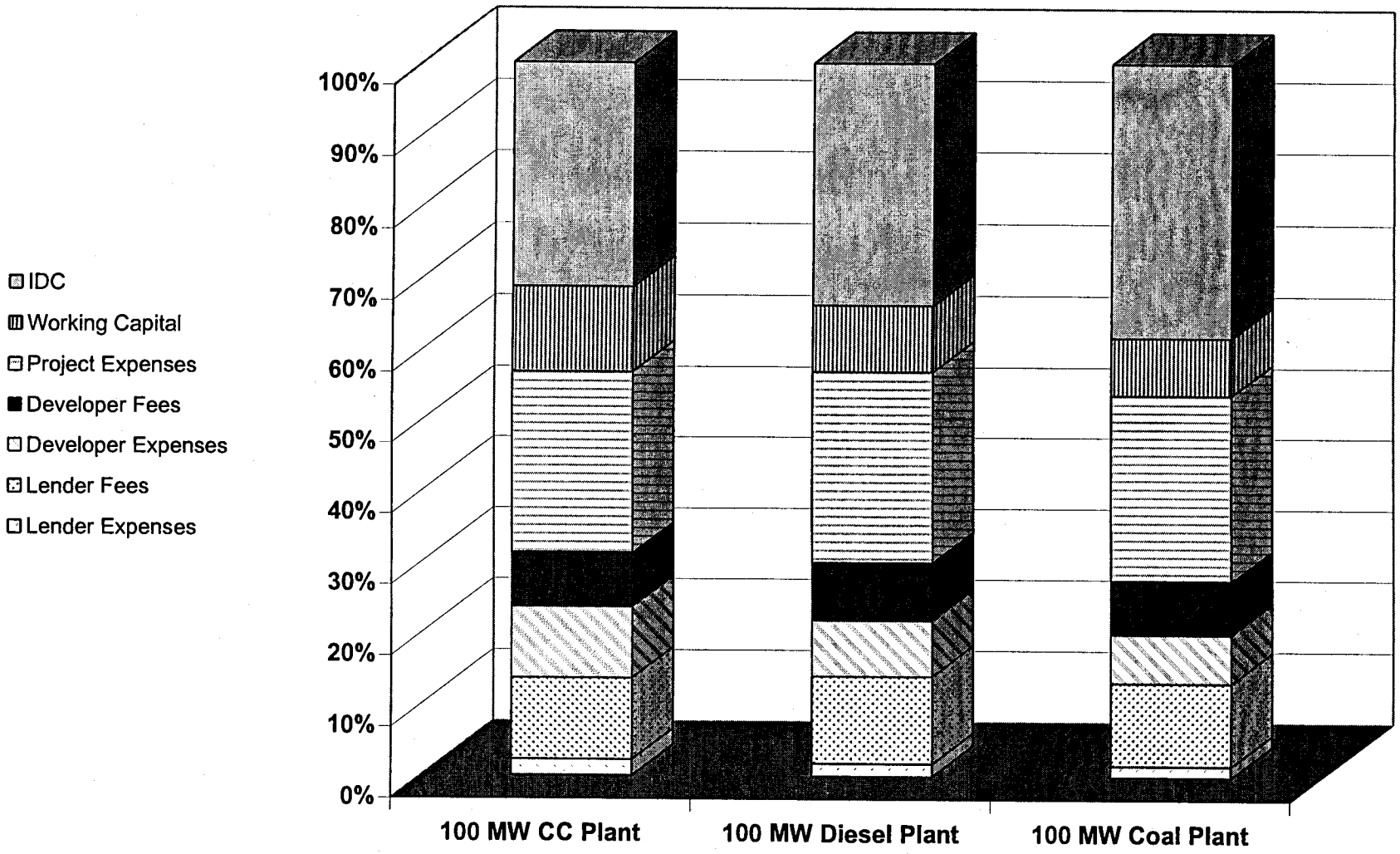
SUMMARY OF ESTIMATED CAPITAL COSTS FOR MAURITIUS POWER PROJECTS

	100 MW Combined Cycle Plant at Fort William (US$000)		2 x 50 MW Diesel Plant at Fort William (US$000)		2 x 50 MW Coal Plant at Montagne Jacquot (US$000)	
HARD COSTS Including contingencies and fees						
		% Hard Cost		% Hard Cost		% Hard Cost
Mechanical Plant as Erected	$47,228	50%	$87,364	66%	$66,817	50%
Electrical Plant as Erected	$7,668	8%	$6,559	5%	$10,292	8%
Site investigations, civil, structural & architectural works	$23,490	25%	$21,800	16%	$36,475	27%
Instrumentation and Control	$3,623	4%	$2,717	2%	$4,830	4%
Design Engineering & Project Management	$4,500	5%	$4,275	5%	$4,820	5%
Contingencies and fees	$4,325	5%	$6,136	7%	$6,162	7%
Total EPC Cost	$90,833		$128,850		$129,395	
Spare Parts	$2,000	2%	$3,235	2%	$2,093	2%
Infrastructure facilities outside plant boundaries (transmission lines, etc...)	$1,000	1%	$1,000	1%	$1,600	1%
Private Land Purchase	$0	0%	$0	0%	$1,700	1%
Land Lease Cost	$0	0%	$0	0%	$0	0%
TOTAL HARD COSTS	$93,833	74%	$133,085	76%	$134,788	73%
SOFT COSTS	24 mos const.		24 mos const.		30 mos const.	
		% Soft Cost		% Soft Cost		% Soft Cost
Lender Expenses	$775	2%	$775	2%	$775	2%
Lender Fees	$3,840	11%	$5,264	12%	$5,729	12%
Developer Expenses	$3,350	10%	$3,350	8%	$3,350	7%
Developer Fees	$2,550	8%	$3,522	8%	$3,683	7%
Project Expenses	$8,648	26%	$11,601	27%	$12,961	26%
Working Capital	$4,000	12%	$4,000	9%	$4,000	8%
Interest During Construction	$10,516	31%	$14,525	34%	$18,844	38%
TOTAL SOFT COSTS	$33,679	26%	$43,037	24%	$49,342	27%
TOTAL PROJECT COSTS	$127,512	100%	$176,122		$184,130	

Hard Cost Items for Mauritius Power Projects



Soft Cost Items for Mauritius Power Projects



Appendix H

Power Purchase Agreement and Concession Agreement Term Sheets – Task 9

Power Purchase Agreement
Terms and Conditions

The Project Company, a company formed under the Laws of Mauritius, will enter into a Power Purchase Agreement ("PPA") with the Central Electricity Board ("CEB") at the end of negotiations and prior to Financial Close for the sale and purchase of Dependable Capacity and Net Energy Output generated by the Facility. A summary of the PPA terms and conditions follows. Numbering corresponds to the numbers of the Articles in the PPA.

1. Definitions and Interpretation.

Article 1 will set forth the definitions to be used in the Power Purchase Agreement. These definitions will be consistent with the definitions in the Concession Agreement. For the purposes of the bid, the definitions in RFP Section A, (1) Definitions, shall be used. These definitions will be modified, as appropriate, for the PPA and CA.

2. Term of Agreement.

Except for earlier terminations due to prolonged Force Majeure or Events of Default (see 16 and 17 below), the term of the Agreement shall commence on the Effective Date and terminate twenty (20) years after the Commercial Operation Date.

3. Conditions Precedent.

Except for the parties obligations under Articles 11(d) and 15(l) and (n), satisfaction of the following shall be conditions precedent to the obligations of each party to perform its obligations under the PPA that must be satisfied prior to Financial Close.

a. With respect to the CEB:
- Receipt of the Development Security pursuant to Article 11(d); and
- Satisfaction of the conditions precedent to the GOM's obligations under the CA.

b. With respect to the Project Company:
- Satisfaction of the conditions precedent to the Project Company's obligations under the CA.

4. Sale and Purchase of Capacity and Energy.

This Article will describe the obligation of the Project Company to sell Dependable Capacity and Net Energy Output and the obligation of the CEB to purchase Dependable Capacity and Net Energy Output of the Facility. Sales to third parties will not be permitted.

5. Covenants, Representations and Warranties.

a. The Project Company will covenant to:

- Design, engineer, finance, construct, complete, own and operate the Facility in accordance with the Functional Specifications and Technical Limits, the World Bank Guidelines, the Laws of Mauritius, the Consents, the O&M Contract, Dispatch Instructions and Prudent Utility Practices;
- Design, construct and complete the Facility in a good and workmanlike manner with new materials and equipment and with a useful life of thirty (30) years;
- At least [TBD] days prior to scheduled testing and commissioning of a unit, or the Facility, as applicable, deliver to CEB detailed programs and protocols for testing and commissioning with an opportunity for the CEB to comment on same;
- At least [TBD] days prior to scheduled testing and commissioning of a Unit or the Facility, intended startup and schedule for same;
- Allow the CEB access to the Site during construction and operation for the purpose of observation.
- After the Commercial Operation Date, operate and maintain the Facilty in accordance with the operating procedures established by the parties, the Technical Limits, the World Bank Guidelines, the Laws of Mauritius and the Consents and Prudent Utility Practices;
- Procure and maintain all Consents in accordance with the Laws of Mauritius;
- Engage only qualified personnel for the construction and operation of the Facility; and
- Provide all facilities necessary for the comfort and safety of its personnel.

b. The Project Company will represent and warrant as to due incorporation; good standing; corporate authority to execute, deliver and perform the PPA; compliance with corporate organizational documents and other contracts and documents; litigation; and enforceability of PPA.

c. The CEB will covenant to:

- Operate and maintain the Interconnection Facilities and the Grid System in accordance with Prudent Grid Practices and/or Prudent Utility Practices; the operating procedures established by the parties and the Laws of Mauritius; and in such a manner as not to have a material adverse effect on the Facility;
- Exercise its right to Dispatch the Facility in accordance with the PPA and to ensure that the Grid System is ready and capable of accepting Net Energy Output;
- Issue to the Project Company by the Commercial Operation Date, the permit required by and in accordance with the requirements of Sections 4 to 6 of the Electricity Act and to make arrangements for the issuance of a

Presidential Proclamation required pursuant to Section 7 of the Electricity Act.

- Obtain and maintain all permits, licenses and approvals required by any Public Sector Entity with jurisdiction over the CEB, the Interconnection Facilities, the Metering System and the Grid System.

d. The CEB will represent and warrant as to due incorporation; good standing; authority to execute, deliver and perform the PPA; compliance with corporate organizational documents and other contracts and documents; litigation; and enforceability of PPA.

6. Interconnection Facilities.

a. The Project Company is responsible for the design, construction, installation and commissioning of the Interconnection Facilities in accordance with the terms of the PPA. The Interconnection Facilities will be transferred to the CEB upon commissioning.

b. The CEB shall obtain and grant to the Project Company all necessary easements and rights of way to design, construct and install the Interconnection Facilities.

c. The parties will cooperate in coordinating the protective devices between the Facility and the Grid System. The parties will cooperate in testing the Interconnection Facilities prior to the [Phase 1 Initial Operation Date][Required Commercial Operation Date].

7. Testing and Capacity Ratings.

a. The details of the Commissioning tests are set forth in Section C of the RFP. These tests will be incorporated into a Schedule to be attached to the PPA. Note that the Initial Dependable Capacity, upon Commissioning, may be set at up to 105% of the Contract Facility Capacity. Thereafter, the Dependable Capacity and the Net Heat Rate will be tested every six months. The CEB will be allowed one test between semi-annual tests if it reasonably believes that the currently set Dependable Capacity is inaccurate. The CEB will provide the Project Company with reasonable and prompt assistance in carrying out all testing and Commissioning. The CEB shall be entitled to be present at all testing and Commissioning and shall receive copies of all test results.

b. The Facility or any Phase thereof, as applicable, may be deemed Commissioned if the CEB delays testing for more than 10 days. In this case for payment purposes Dependable Capacity will be set at Contract Capacity, and heat rate will be set at Guaranteed Heat Rate. The Facility shall be tested within 10 days after CEB declares that it is ready for a test, and Dependable Capacity and heat rate will be reset based on the results of the test. The CEB will be entitled to a refund to the extent that, when the Facility is tested, the Dependable Capacity is below the Contract Capacity and the heat rate is above the Guaranteed Heat Rate; further, the CEB will be entitled to a full refund in the event that the Facility does not test at the Threshold Capacity.

8. Control and Operation of the Facility.

a. The parties will establish a Joint Operating Committee comprised of 6 members, 3 from the CEB and 3 from the Project Company. The first Chairman will be appointed by the CEB; this position rotates between the parties thereafter on an annual basis. The Joint Operating Committee will develop written operating procedures at least [60] days prior to the [Phase I Initial Operation Date][Commercial Operation Date]. The Committee's other duties include coordination of construction and Commissioning, procedures for shutdown or reduction in capacity during Force Majeure, coordination of scheduled maintenance, coordination of forecasts or requirements from the Facility, etc. A 2/3 majority makes decisions.

b. The PPA will set out Dispatch Procedures whereby:

- The CEB will notify the Project Company in advance on a yearly and quarterly basis of its estimated requirements for Net Energy Output:
- The Project Company will notify the CEB in advance of its anticipated availability for each week;
- The Project Company will notify the CEB of its declared availability by a certain time each day for each hour of the following day; and
- The CEB will notify the Project Company of its requirements for Net Energy Output by a certain time each day for each hour of the following day. Thereafter, the CEB may issue instructions to vary Dispatch.

c. Availability—

- The PPA will set forth procedures for scheduling maintenance of the Facility. Scheduled Outages and Major Overhauls must be scheduled between May and October.
- For combined cycle and diesel technologies the total of Scheduled Outages, Maintenance Outages, Major Overhauls and Forced Outages shall not exceed 1314 hours in any year. For coal technology this total shall not exceed 1314 hours for year with no Major Overhauls and 1752 hours for year with Major Overhauls.
- Frequency and duration of Major Overhauls shall be based on recommendations of equipment manufacturers and Prudent Utility Practices.
- The CEB can require the Project Company to reschedule a Scheduled Outage but must give 90 days notice and pay any documented increase in costs. The Project Company must make reasonable efforts to schedule Maintenance Outages during off-peak hours.

d. This Article will also provide for emergency operation plans and maintenance of operating records for at least 60 months.

9. Metering.

The Project Company must procure and install the metering system used to measure Net Energy Output for the purposes of billing pursuant to the CEB's requirements as set forth in the RFP Section C, Subsection 4.3.9. The CEB will own, operate and maintain the system at its own expense. The CEB will be required to test and calibrate the metering system annually. The parties will negotiate the terms of any retesting of meters. The Project Company may purchase and install a back-up metering system but it must be identical to the one procured for the CEB.

10. Billing and Payment.

a. The Tariff, as described in Section B of the RFP, will be detailed in a Schedule to the PPA. The Project Company will invoice the CEB for Dependable Capacity and Net Energy Output on a monthly basis within 10 days after the close of the relevant month. Invoices will be stated in US dollars but paid in Mauritius rupees based on the Paid Exchange Rate. The CEB will pay each invoice within thirty (30) days of receipt. The CEB will pay for Net Energy Output generated during the period of testing and startup.

b. Late payments will be subject to interest at the rate of 3% over the Prime Lending Rate, as announced by the State Bank of Mauritius from time to time. The CEB may withhold disputed Energy and Supplemental Charge payments but such amounts must be paid into escrow subject to resolution of the dispute.

11. Liquidated Damages (LD's) Payable by the Project Company.

a. Delay LD's--Delay LD's are set for the each day beyond the Required Commercial Operation Date, at $[ ] per day up to a maximum of $[ ] (equivalent of 180 days).

b. Capacity LD's--If the Project Company cannot achieve the Contract Dependable Capacity within 3 months after the Commercial Operation Date, the Project Company must pay "buydown" LD's of $ 300 per kW up to 10% of the Contract Dependable Capacity (converted to kW).

c. Availability LD's—Availability LD's are due at the end of each year for deficiencies in Availability below 85%. In concept, the availability LD's are based on the Capacity Payment prevailing for that year and will be calculated using the following formula:

$$LD_a = CP_{annual} \times (1 - A/GA),$$

where LD_a – Availability LD's, Rupees;
CP_{annual} –Total annual capacity payment for this Contract Year, Rupees;
A – actual availabity for this Contract Year, %;
GA – guaranteed availability for this Contract Year, %.

d. The Project Company will provide a Development Security in a form acceptable to the CEB in the amount of $ 3,000,000 upon execution of the Project Agreements. The Development Security will remain valid until the date which is three (3) months after Financial Close. Upon Financial Close the Project Company will provide a Performance Security in a form acceptable to the CEB in the amount of $ 15,000,000. Upon achievement of the Commercial Operation Date, the Project Company shall be entitled to reduce the amount of the Performance Security to $ 5,000,000. The Performance Security shall stay in effect until termination of the PPA.

e. The CEB will have a right of set off for liquidated damages or any other payment due and owing to the CEB against Tariff payments and the Performance Security.

12. Insurance.

a. The Project Company must maintain the following insurance from and after Financial Close:

- During the Construction Period, marine and air cargo, builders' all risk and consequential loss (or business interruption). The consequential loss insurance should cover an amount equal to interest accruing under the financing documents and any other financing costs assuming a delay of 12 months.

- During the Operation Period, all risks, machinery breakdown insurance and consequential loss (or business interruption). The consequential loss insurance should cover an amount equal to estimated Capacity Payments assuming a delay of 12 months.

- During both Periods, general liability, workers compensation and employer's liability and auto insurance.

b. The above insurance shall contain the following endorsements:

- The GOM, MPU and the CEB and their directors, officers and employees and agents ("additional insured parties") named as "additional insureds";

- Insurance is primary with respect to the interests of the additional insured parties;

- Cross liability clause; and

- Waiver of subrogation rights; and

- 30 days' advance notice to the GOM, MPU and the CEB of material change or cancellation.

13. Liability and Indemnification

a. The CEB and the Project Company will indemnify each other for property damage or personal injury resulting from their negligence. Such indemnities are in excess of any insurance carried by the relevant party.

b. This Article shall also contain a waiver of consequential loss damages provision with respect to either party with an exception for liquidated damages and any consequential loss payable to a third party for which indemnification is provided above.

14. Force Majeure.

a. These provisions, which address Non-Government Force Majeure and Government Force Majeure, are designed to coordinate with the Concession Agreement. The principles and definitions applicable to Force Majeure are found primarily in the Concession Agreement.

b. Note that the CEB's payment obligations during the existence of a Force Majeure Event are as follows:

- During the existence of a Non-Government Force Majeure that affects the Project Company's ability to make Dependable Capacity available and deliver Net Energy Output, the CEB will be obligated to pay for that Dependable Capacity available, if any, and Net Energy Output delivered, if any.

- During the existence of a Non-Government Force Majeure that affects the CEB's ability to receive Net Energy Output, the CEB will be obligated to pay for available Dependable Capacity and Net Energy Output delivered, if any.

- During the existence of a Government Force Majeure, the CEB will be required to pay for available Dependable Capacity and Net Energy Output delivered, if any.

15. Default and Termination.

a. The following will be Project Company Events of Default:

- Failure of the Project Company to submit the Performance Security at Financial Close;

- Failure of the Project Company to commence construction within ninety (90) days after Financial Close;

- After commencement of construction, but prior to the Commercial Operation Date, the abandonment of the Facility by the Project Company for a period of thirty (30) consecutive days without the prior written consent of the CEB;

- Failure of the Project Company to achieve the Commercial Operation Date within one hundred eighty (180) Days after the Required Commercial Operation Date;

- Abandonment by the Project Company of the operation of the Facility after the Commercial Operation Date for a period of thirty (30) consecutive Days without the prior written consent of the CEB;

- Failure of the Facility to achieve the Threshold Capacity during Commercial Operation testing and upon annual testing of Dependable Capacity thereafter, including permitted retests;

- The Project Company's failure to operate, maintain, modify, or repair the Facility in accordance with Prudent Utility Practices, such that safety of persons and property, the Facility or the CEB's service to its customers is adversely affected;

- Except as otherwise permitted herein or under the Concession Agreement, the assignment or transfer of the Project Company's rights or obligations in the assets of the Project without obtaining the prior written consent of the CEB;

- Except for the purpose of amalgamation or reconstruction (provided, that such amalgamation or reconstruction does not affect the ability of the amalgamated or reconstructed entity, as the case may be, to perform its obligations under this Agreement), the occurrence of any of the following events: (i) the commencement of voluntary winding up of the Project Company; (ii) the appointment of a liquidator by the Project Company; (iii) submittal of an application to a court of competent jurisdiction for mandatory liquidation of the Project Company which is not dismissed during a period not to exceed [TBD] Days; (iv) the issuance of a final and conclusive order by a competent court of jurisdiction for liquidation of the Project Company; or (v) the transfer, conveyance, loss, or relinquishment of the Project Company's right to own and/or operate the Facility or any material part thereof or to occupy the Site to any person without the prior written consent of the CEB;

- Any statement, representation, or warranty by the Project Company in this Agreement proving to have been incorrect, in any material respect, when made or when deemed to have been made and such failure or incorrect statement, representation, or warranty having a material and adverse effect on the Project Company's ability to perform its obligations under this Agreement;

- Any material breach by the Project Company of the PPA, that is not remedied within thirty (30) Days after notice from the CEB stating that a material breach of such Agreement has occurred that could result in the termination of the Agreement, identifying the material breach in question in reasonable detail and demanding remedy thereof; or

- The occurrence of a Project Company Event of Default under the Concession Agreement that is not cured within the applicable period provided for therein.

b. The following will be CEB Events of Default:

- Abandonment by the Project Company of the operation of the Facility after the Commercial Operation Date for a period of thirty (30) consecutive Days without the prior written consent of the CEB;

- Failure of the Facility to achieve the Threshold Capacity during Commercial Operation testing and upon annual testing of Dependable Capacity thereafter, including permitted retests;

- The Project Company's failure to operate, maintain, modify, or repair the Facility in accordance with Prudent Utility Practices, such that safety of persons and property, the Facility or the CEB's service to its customers is adversely affected;

- Except as otherwise permitted herein or under the Concession Agreement, the assignment or transfer of the Project Company's rights or obligations in the assets of the Project without obtaining the prior written consent of the CEB;

- Except for the purpose of amalgamation or reconstruction (provided, that such amalgamation or reconstruction does not affect the ability of the amalgamated or reconstructed entity, as the case may be, to perform its obligations under this Agreement), the occurrence of any of the following events: (i) the commencement of voluntary winding up of the Project Company; (ii) the appointment of a liquidator by the Project Company; (iii) submittal of an application to a court of competent jurisdiction for mandatory liquidation of the Project Company which is not dismissed during a period not to exceed [TBD] Days; (iv) the issuance of a final and conclusive order by a competent court of jurisdiction for liquidation of the Project Company; or (v) the transfer, conveyance, loss, or relinquishment of the Project Company's right to own and/or operate the Facility or any material part thereof or to occupy the Site to any person without the prior written consent of the CEB;

- Any statement, representation, or warranty by the Project Company in this Agreement proving to have been incorrect, in any material respect, when made or when deemed to have been made and such failure or incorrect statement, representation, or warranty having a material and adverse effect on the Project Company's ability to perform its obligations under this Agreement;

- Any material breach by the Project Company of the PPA, that is not remedied within thirty (30) Days after notice from the CEB stating that a material breach of such Agreement has occurred that could result in the termination of the Agreement, identifying the material breach in question in reasonable detail and demanding remedy thereof; or

- The occurrence of a Project Company Event of Default under the Concession Agreement that is not cured within the applicable period provided for therein.

b. The following will be CEB Events of Default:

- The dissolution, pursuant to law, of the CEB, except for (i) the privatization of the CEB or any of its subsidiaries, or (ii) an amalgamation, reorganization or reconstruction of the CEB, in each case, where the GOM, without interruption, guarantees the payment of the succeeding entity or entities on the same terms and conditions as the Payment Guarantee or such other commercial security is provided for the obligation of the succeeding entity that in the reasonable business judgment of the Project Company provides an adequate alternative to the Payment Guarantee;

- Any default or defaults by the CEB in the making of any payment or payments required to be made by it within thirty (30) Days of the due date therefor and then, upon notice to the GOM, any default or defaults by the GOM in the making of any payment in accordance with the terms of the Guarantee which continues unpaid for an additional (15) Business Days;

- Any material breach by the CEB of this Agreement which is not remedied within thirty (30) Days after notice from the Project Company to the CEB stating that a material breach of the Agreement has occurred that could result in the termination of the Agreement, identifying the material breach in reasonable detail and demanding remedy thereof;

- The occurrence of a MPU Event of Default under the Concession Agreement which is not cured within the applicable period provided for therein;

- Any Change in Law (i) making unenforceable, invalid, or void any material undertaking of the CEB, GOM or MPU under this Agreement or the Concession Agreement or (ii) making it unlawful for the Project Company, its Lenders or the investors to make or receive any payment, to perform any obligation or to enjoy or enforce any material right under this Agreement, or (iii) any such payment, the performance of any such material obligation or the enjoyment or enforcement of any such material right unenforceable, invalid or void as a result of any such Change in Law;

- Any statement, representation, or warranty by the CEB in this Agreement proving to have been incorrect, in any material respect, when made or when deemed to have been made and such failure or incorrect statement, representation, or warranty having a material and adverse effect on the CEB's ability to perform its obligations under this Agreement.

c. The parties will negotiate notices of Events of Default and cure rights in accordance with standard international practice. The Lenders will have cure and step-in rights in the event of a Project Company Event of Default.

d. Subject to permitted notice, cure and step-in rights, the CEB shall be entitled to terminate the PPA upon occurrence of any Project Company Event of Default.

e. Subject to permitted notice and cure rights, the Project Company shall be entitled to terminate the PPA upon the occurrence of any CEB Event of Default.

f. Remedies for termination of the PPA are handled under the CA.

16. Resolution of Disputes.

a. Disputes shall be referred to mediation and, if mediation fails, to international arbitration pursuant to the UNCITRAL Rules. The place of mediation and arbitration shall be Port Louis, Mauritius. In the case of arbitration, the Project Company may elect to conduct arbitration in [London, England or Paris, France or Geneva, Switzerland or Singapore], provided that the Project Company reimburses the CEB for reasonable out-of-pocket fees in excess of the fees the CEB would otherwise incur for arbitration in Port Louis.

b. The governing law for purposes of contract interpretation is the Laws of Mauritius.

c. This Article will contain a waiver of sovereign immunity by the CEB.

17. Miscellaneous Provisions.

This Article will contain a number of miscellaneous provisions, including the following:

a. CEB Disclaimer of Liability for Review
b. CEB Right to Inspect Facility Records
c. Reciprocal Financial Disclosure Obligations (annual audited financials and semi-annual balance sheets with statement of any material adverse impacts on financial status)
d. Notices
e. Amendments
f. Headings
g. Third Party Beneficiaries
h. No Implied Waiver
i. Survival
j. Entirety
k. Language (English)
l. Restrictions on Assignment (subject to permitted assignments to Lenders)
m. Successors and Assigns
n. Confidentiality
o. Counterparts
p. Severability

Concession Agreement
Terms and Conditions

The Project Company, a company formed under the Laws of Mauritius, will enter into a Concession Agreement ("CA") with the Government of Mauritius ("GOM"), as represented by the Ministry of Public Utilities ("MPU"), at the end of negotiations and prior to Financial Close. The CA gives the Project Company certain rights, including the exclusive right to develop the Project. A summary of the CA terms and conditions follows. Numbering corresponds to the numbers of the Articles in the CA.

1. Definitions and Interpretation.

Article 1 will set forth the definitions to be used in the Concession Agreement. These definitions will be consistent with the definitions in the Power Purchase Agreement. For the purposes of the bid, the definitions in RFP Section A, (1) Definitions, shall be used. These definitions will be modified, as appropriate, for the CA and the PPA.

2. Term of Agreement.

The term of the Agreement shall commence on the Effective Date and shall continue in full force and effect until terminating in accordance with the terms of this Agreement.

3. Implementation of the Project.

a. The Project Company shall develop, finance, insure, design, construct, complete, own, operate and maintain the Project in accordance with the CA, the PPA and the Laws of Mauritius.

b. The Project Company shall achieve Financial Close not later than [90]Days after the Effective Date.

c. Except for the parties' obligations under Articles 3 (d) and (e), 5, 6 (a) and (b), and 15 (i) and (k), satisfaction of the following shall be conditions precedent to the obligations of each party to perform its obligations under the CA that must be satisfied prior to or at Financial Close.

- With respect to the GOM:

  The Project Company shall have delivered all documents comprising the Security Package , and the Environmental Impact Statement for the GOM's review and approval;

  The Project Company shall have obtained and delivered copies of those Consents necessary for commencement of construction;

  The Project Company shall have executed those agreements comprising the Security Package in case of debt financing of the project ;

The Project Company shall have delivered the Development Security and the Performance Security to the CEB according to Article 11.d of the PPA;

- With respect to the Project Company:
  The GOM shall have granted the approvals contemplated in Articles 3 (d) and (e).

d. The Project Company shall deliver a copy to the GOM, with a copy to the CEB, and the GOM will have the right to approve, in its sole discretion exercised reasonably, all of the documents in the Security Package and any amendments thereto that materially and adversely affect the rights of the GOMor the CEB. The GOM shall use reasonable efforts to give or withhold its approvals within thirty (30) days after receipt of the subject document.

e. The Project Company shall deliver a copy to the GOM, with a copy to the CEB, and the GOM will have the right to review and approve, in its sole discretion exercised reasonably, the Environmental Impact Statement. The GOM shall use reasonable efforts to give or withhold its approvals within thirty (30) days after receipt of the subject document.

4. Grant of Rights to the Project Company.

a. Pursuant to Clause 22(1) of the Concession Projects Act, the GOM shall grant to the Project Company the exclusive right to develop, finance, insure, design, construct, complete, own, operate and maintain the Facility in accordance with the CA, the PPA and the Laws of Mauritius.

b. Except as provided in the Security Package, the Project Company shall not grant any leases, licenses, rights-of-way, easements or other interests relating to real property constituting the Site to any other entity without the prior written approval of GOM in its reasonable discretion

5. Licenses and Consents.

The Project Company shall be required to obtain and maintain the consents and deliver copies thereof to the GOM, with copies to the CEB. The GOM shall use reasonable efforts to promote and support the Project Company's applications for the Consents to expedite their approval, subject to proper application by the Project Company.

6. Construction, Operation and Maintenance of the Facility.

a. The Project Company may contract with a Construction Contractor to design, construct, install, and commission the Facility and an O&M Contractor to operate and maintain the Facility; however, the appointment of the Construction Contractor and the O&M Contractor shall not relieve the Project Company of any of its obligations.

b. GOM acknowledges the Project Company's appointment of _____ as the Construction Contractor. GOM acknowledges the Project Company's appointment of _____ as the O&M Contractor. The Project Company shall not replace the Construction Contractor

or the O&M Contractor without the prior written consent of GOM, which consent shall not be unreasonably withheld or delayed.

c. To the maximum extent practicable and subject to availability and competitiveness, the Project Company shall use local services and goods in the construction, operation and maintenance of the Project. Except for the Project Company's permanent work force and minimum number of foreign specialists, the Project Company must engage competent local labor for the performance of its obligations hereunder and under the PPA.

d. The Project Company shall obtain all work permits, visas and other immigration permits, if necessary, for individuals involved in the Project in accordance with the Laws of Mauritius. The GOM shall use reasonable efforts to promote and support the Project Company's applications for all such permits to expedite their approval, subject to proper application by the Project Company.

7. Taxes and Duties.

a. GOM will allow the Project Company to import Fuel for the Facility without taxes, duties, and tariffs.

b. GOM will grant the project company status of "pioneer" or "strategic local enterprise" [this status provides some tax, import, and currency exchange incentives] subject to approval of MPU and other relevant governmental agencies.

8. Foreign Currency Exchange and Transfer of Funds.

a. The Project Company may convert its income under the PPA from Rupees to US Dollars.

b. Pursuant to Article 29(2) of the Concession Act, the GOM will guarantee the availability of US dollars to enable conversion.

c. The Project Company shall be entitled to the free transfer of all funds connected with the Project, the PPA or this Agreement outside of Mauritius.

9. Payment Guarantee.

The GOM will guarantee all of the CEB's payment obligations under the PPA, including any amounts due to the Project Company as a result of termination.

10. Restrictions on Acquisition and Transfers of Shares and Assets.

a. The GOM shall not and shall not permit any Public Sector Entity to take any discriminatory action which materially and adversely affects the Project or the performance of the Project Company's obligations under the Security Package, or expropriate or, except as hereinafter provided, acquire the Facility or the Project Company, whether in whole or in part. Nothing in the foregoing shall apply to any actions taken by the GOM or the CEB pursuant to the rights and obligations arising under this Agreement, the PPA and the other documents comprising the Security Package.

b. The GOM shall not and shall not permit any Public Sector Entity to expropriate, compulsorily acquire, nationalize, or otherwise compulsorily procure any shares or assets of the Project Company.

c. No Member of the Bidding Consortium shall transfer any shares owned by it at any time prior to the Commercial Operation Date or for a period of eight (8) Years after the Commercial Operation Date. The Lead Bidder's shares in the Project shall be maintained throughout the term of the PPA. Standard exceptions shall be made for transfers to other Members, parent or sister corporations, transfers pursuant to foreclosure of a security interest as permitted hereunder, etc.

11. Representations and Warranties of the Parties

a. The Project Company will represent and warrant as to due incorporation; good standing; corporate authority to execute, deliver and perform the CA; compliance with corporate organizational documents and other contracts and documents; litigation; and enforceability of CA.

b. The GOM will represent and warrant as to authority to execute, deliver and perform the CA; and enforceability of the CA.

12. Force Majeure.

The definitions and consequences of the occurrence of Force Majeure Events are set forth in Attachment A.

13. Default and Termination.

a. The following will be Project Company Events of Default:

- The failure of the Project Company to achieve Financial Close before _____ _____, 200__;
- The occurrence of a Project Company Event of Default under the PPA;

- Except as otherwise permitted herein or under the PPA, the assignment or transfer of the Project Company's rights or obligations in the assets of the Project, without obtaining the prior written consent of the GOM;
- Except for the purpose of amalgamation or reconstruction (provided, that such amalgamation or reconstruction does not affect the ability of the amalgamated or reconstructed entity, as the case may be, to perform its obligations under this Agreement), the occurrence of any of the following events: (i) the commencement of a voluntary winding up of the Project Company; (ii) the appointment of a liquidator by the Project Company; (iii) submittal of an application to a court of competent jurisdiction for mandatory liquidation of the Project Company which is not dismissed during a period not to exceed [TBD] Days; (iv) the issuance of a final and conclusive order by a competent court of jurisdiction for liquidation of the Project Company; or (v) the transfer, conveyance, loss, or relinquishment of the Project Company's right to own and/or operate the Facility or any material part thereof or to occupy the Site to any person without the prior written consent of the GOM;
- Any statement, representation, or warranty by the Project Company in this Agreement proving to have been incorrect, in any material respect, when made or when deemed to have been made and such failure or incorrect statement, representation, or warranty having a material and adverse effect on the GOM's ability to perform its obligations under this Agreement; or
- Any material breach by the Project Company of this Agreement that is not remedied within thirty (30) Days after notice from GOM, stating that a material breach of such Agreement has occurred that could result in the termination of the Agreement, identifying the material breach in question in reasonable detail, and demanding remedy thereof.

b. The following shall be GOM Events of Default:

- Except as otherwise permitted herein, the expropriation, compulsory acquisition, or nationalization by GOM or any Public Sector Entity of (i) any share capital of the Project Company, or (ii) any material asset or right of the Project Company;
- Except as otherwise permitted herein, any procurement by GOM of (i) any share capital of the Project Company if the result would be for the GOM to acquire ownership or control of [____] percent (__%) or more of the issued share capital, or (ii) any material asset or right of the Project Company;
- The dissolution, pursuant to law, of the CEB, except for (i) the privatization of CEB or any of its subsidiaries, or (ii) an amalgamation, reorganization or reconstruction of the CEB, in each case where GOM without interruption guarantees the payment of the succeeding entity(ies) on the same terms and conditions as set forth in this Agreement or such other commercial security is provided for the obligation of the succeeding entity(ies) that in the reasonable business judgment of the Project Company provides an adequate alternative to such guarantee;

- Any default or defaults by GOM in the making of any payment or payments required to be made by it under Article 9 on the due date for payment that exceed, in the aggregate at any one time, a sum equivalent to [TBD] months of Capacity Payments under the PPA;
- Any material breach by the GOM of the CA that is not remedied within thirty (30) Days after notice from the Project Company to GOM stating that a material breach of the Agreement has occurred that could result in the termination of this Agreement, identifying the material breach in reasonable detail, and demanding remedy thereof;
- The occurrence of a CEB Event of Default under the PPA; or
- Any Change in Law making (i) unenforceable, invalid, or void any material undertaking of GOM or the GOM under this Agreement or the PPA; or (ii) it unlawful for the Project Company, its Lenders or the Members to make or receive any payment, to perform any obligation or to enjoy or enforce any material rights under this Agreement; or (iii) any such payment, the performance of any such material obligation or the enjoyment or enforcement of any such material right unenforceable, invalid or void as a result of any such Change in Law.

c. The parties will negotiate notices of Events of Default and cure rights in accordance with standard international practice. The Lenders will have cure and step-in rights in the event of a Project Company Event of Default.

d. Subject to permitted notice, cure and step-in rights, the GOM shall be entitled to terminate the CA upon occurrence of any Project Company Event of Default. In such case, the GOM will have the right, but not the obligation, to purchase the Facility for the total amount of debt outstanding to the Lenders. With respect to a breach of the Project Company's obligation to reach Financial Close, as set forth in subsection (a) above, the GOM's sole remedy shall be encashment of the Development Security. With respect to any other Project Company Event of Default, the GOM shall be entitled to any other remedy at law or equity.

e. Subject to permitted notice and cure rights, the Project Company shall be entitled to terminate the CA upon the occurrence of any GOM Event of Default. In such case, the Project Company may elect to transfer the Facility to the GOM for [the total amount of debt outstanding to the Lenders, plus the initial equity investment by the members of the Project Company multiplied by a fraction the numerator of which is the number of years remaining in the initial term of the PPA and the denominator of which is the initial term of the PPA plus for a period equal to the lesser of (i) five (5) years and (ii) the remainder of the initial term of the PPA an amount equal to the net cash flow for such period discounted to its present value by a applying a discount rate equal to [[TBD] percent (__%).] The Project Company shall be entitled to any other remedy at law or equity for a GOM Event of Default.

14. Resolution of Disputes.

a. Disputes shall be referred to mediation and, if mediation fails, to international arbitration pursuant to the UNCITRAL Rules. The place of mediation and arbitration shall

be Port Louis, Mauritius. In the case of arbitration, the Project Company may elect to conduct arbitration in [London, England or Paris, France or Geneva, Switzerland or Singapore], provided that the Project Company reimburses the GOM for reasonable out-of-pocket fees in excess of the fees the GOM would otherwise incur for arbitration in Port Louis.

b. The governing law for purposes of contract interpretation is the Laws of Mauritius.

c. This Article will contain a waiver of sovereign immunity by the GOM.

15. Miscellaneous Provisions.

This Article will contain a number of miscellaneous provisions, including the following:

a. Notices
b. Amendments
c. Headings
d. Third Party Beneficiaries
e. No Implied Waiver
f. Survival
g. Entirety
h. Language (English)
i. Restrictions on Assignment (subject to permitted assignments to Lenders)
j. Successors and Assigns
k. Confidentiality
l. Counterparts
m. Severability

ATTACHMENT A

FORCE MAJEURE

1. Definitions

"Force Majeure"

Any event or circumstance or combination of events or circumstances arising on or after the Effective Date that is beyond the reasonable control of a Party and that materially and adversely affects the performance by that Party of its obligations under or pursuant to this Agreement; provided, however, that such material and adverse effect could not have been prevented, overcome, or remedied in whole or in part by the affected Party through the exercise of diligence and reasonable care, it being understood and agreed that reasonable care includes the expenditure of sums of money to protect the Facility from a casualty event, which sums are reasonable in light of the likelihood of such event, the probable effect of such event if it should occur, and the likely efficacy of the protection measures. "Force Majeure" shall include the following events and circumstances, but only to the extent that each satisfies the above requirements:

"Non-Government Force Majeure"

- Typical natural force majeure events, such as lightning, drought, fire, earthquakes, volcanoes, landslides, flood or cyclone or any other analogous event of nature; or

- The occurrence of any of the following outside Mauritius that does not involve Mauritius: acts of war or hostilities (whether declared or undeclared), invasion, armed conflict or act of foreign enemy, blockade, embargo (including unavailability or shortage of fuel or materials), revolution, riot, etc.

"Government Force Majeure"

Any of the following, in each case occurring in Mauritius or involving Mauritius:

- Acts of war or hostilities (whether declared or undeclared), invasion, armed conflict or act of foreign enemy, blockade, embargo (including unavailability or shortage of fuel or materials), revolution, riot, etc.;

- Strikes, lockouts, work-to-rule actions, go-slows, curfew restrictions or other industrial action or labor disputes that are not restricted solely to employees of the PC or any of its contractors and subcontractors;

- Any Change-in-Law (other than a Change-in-Law that does not restrict the Project Company's ability to fulfil its obligations under the [Project Documents]);

- Any Lapse of Consent;
- The unavailability of Fuel due to another Government Force Majeure Event; or
- Unlawful action by any Public Sector Entity directed against the Project.

"Change-in-Law"

(a) The adoption, promulgation, or modification after the Effective Date of any Law of Mauritius, or

(b) The imposition by a Public Sector Entity of any material condition in connection with the issuance, renewal, or modification of any Consent after the Effective Date, that in either case establishes requirements for the operation or maintenance of the Facility that are materially more restrictive than the most restrictive requirements (i) in effect as of the Effective Date, (ii) specified in any applications, or other documents filed in connection with such applications, for any Consent filed by the Project Company on or before the Commercial Operation Date of this Agreement or (iii) agreed to by the Project Company in any agreement in the Security Package.

"Lapse of Consent"

Any Consent (a) ceasing to remain in full force and effect or (b) not being issued or renewed upon application having been properly and timely made and diligently pursued or (c) being made subject, subsequent to its grant, to any terms or conditions that materially and adversely affect the Project Company's ability to perform its obligations under any document included within the Security Package, in each of the above instances through no fault of the Project Company.