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PROJECT EVALUATION FOR ELECTRICITY GENERATION PROJECTS: A COLLECTION OF CASE STUDIES

Prepared by
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Cover photograph from Beautiful Jamaica, by Evan Blake, published by Vista Publications, Jamaica, West Indies, 1970.

Forward

This report represents the second phase of a project to train the staff of the Ministry of Mining and Energy (MME) in the procedures for project review using the techniques of sensitivity and risk analysis. 1 The project began with a series of lectures covering financial evaluation techniques, micro-computer applications, probability analysis and risk assessment. Attendants at the course included both engineers and economists from the MME as well as professional staff from the Petroleum Corporation of Jamaica (PCJ) and the Jamaica Public Service (JPS) electric utility. The principles taught in these lectures were then applied in the preparation of a series of three case studies. These case studies examined projects which had reached the stage where a feasibility study had already been prepared and the projects had been recommended for implementation.

A project review team was formed for each case study and a four step procedure was implemented. The first step was a technical review of the project as presented in the feasibility study. This review was made by the engineering member of the team. The second step was a review of the expected financial costs and benefits of the project which was performed by the team's economist. The third step was a sensitivity analysis of the financial viability of the project which was performed by the team members using the Ministry's computer facilities. The final step was a risk analysis of the project to determine the degree of uncertainty regarding the outcome of the project. This last step was performed by the team under the supervision of the lecturer.

This report contains the reports prepared for each of the case studies as well as an introductory chapter providing background material for these studies. The results of these case studies provide three useful conclusions with regards to the use of the four-step procedure for project review. First, the techniques of sensitivity analysis and probabilistic risk analysis provide useful tools for evaluating project feasibility and for identifying the additional information that is needed prior to approving the implementation of the project. Second, the techniques of sensitivity and risk analysis can be effectively taught to professional staff through a combination of lectures, computer training and on-the-job training application in the form of case studies. The latter is an essential component. Third, a project review procedure similar to that used in the case studies should be applied to all of the major projects being considered not only by MME but by other agencies of the government involved in the implementation of major capital projects.

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1 This report was prepared as part of a larger USAID funded project for providing technical support to the Ministry of Mining and Energy in various phases of energy planning.

INTRODUCTION TO THE CASE STUDIES

John Arnold

I.1 Background

This report examines three energy-related projects which have been presented to the Jamaican government for possible implementation. These projects are:

1. a conversion of two existing electrical generation units at Old Harbour from Bunker "C" to coal
2. a thermal-electic power plant to be fueled by peat obtained from the bogs at Negril
3. a run-of-the-river hydro-electric facility to be constructed on the Y.S. River

Each project has been the subject on one or more evaluations culminating in a feasibility study and each has been recommended as financially and economically feasible. In the summer of 1985, the staff of the Ministry of Mining and Energy reviewed each of the three projects to determine if the technical and cost evaluations were reasonable.1 They introduced changes in the project design and in the cost estimates where they felt these were required. They then analyzed the revised projects using the tools of financial and risk analysis. The results of their analysis indicated that of the three projects, only one appeared to be feasible at the present time. Their findings are presented in the following case studies. The authors of these studies also discuss the information that is needed to provide a more complete evaluation and to reduce the uncertainties associated with each of these projects.

I.2 Escalation Factors

The three projects was originally evaluated by converting local and foreign exchange costs and benefits into U.S. dollars and then computing the various performance measures, e.g. the internal rate of return. The same approach has been used in the case studies. Since the original feasibility studies were prepared at different times, it was necessary to escalate the costs in these reports to a common period, which was selected to be the end of the second quarter of 1985.

Separate factors were developed for escalating the foreign and local costs. Both are shown in table I.1. The escalators for foreign equipment and for other foreign costs were developed using

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1. This effort involved the Ministry's project economists working together with participants from the electric utility, JPS, and foreign consultant's who were working with the Ministry on various phases of energy policy. The participants are listed separately at the beginning of each of the case studies.

Table I.1

COST ESCALATION FACTORS

YEAR	QUARTER	FOREIGN EXCHANGE EQUIPMENT	FOREIGN EXCHANGE OTHER	LOCAL COSTS LABOR	LOCAL COSTS EQUIPMENT	LOCAL COSTS OTHER	EXCHANGE RATE J$ PER US$
1983	1	1.05	1.09	1.3	1.9	1.66	$2.75
	2	1.05	1.08	1.3	1.9	1.6	$2.71
	3	1.05	1.07	1.3	1.75	1.5	$2.96
	4	1.04	1.06	1.3	1.65	1.46	$3.15
1984	1	1.03	1.045	1.15	1.5	1.37	$3.55
	2	1.02	1.03	1.15	1.35	1.22	$3.89
	3	1.01	1.02	1.15	1.23	1.14	$4.30
	4	1.01	1.01	1.15	1.14	1.12	$4.95
1985	1	1.01	1.01	1	1.05	1.06	$5.50
	2	1	1	1	1	1	$5.65

the U.S. Manufacturing and Consumer price indices.2 The local exchange escalators were determined based on a combination of factors. For local equipment, the escalation rate was computed by taking an average of the escalation rates for Jamaica and the U.S after adjusting for changes in the rate of exchange between the two currencies. The average of the two countries escalation rates was used in order to account for the imported materials and components used in locally manufactured equipment. The escalation factor for local labor was based on recent contract negotiations between JPS and PCJ and their employees. These negotiations involve multi-year contracts which include a wage escalation clause. These clauses were used as a basis for computing the

2. During the last two years, the U.S. inflation rates have been relatively low, due in part to a considerable appreciation in the value of the U.S. dollar. In order to determine if these figures were reasonable, a comparison of changes in inflation rates and in foreign exchange rates (against the SDR) for the U.S. and several European countries was made. This comparison indicated that similar escalation rates apply in most of these countries.

escalation factor. For other local costs, the escalation factor was derived from the Jamaican Consumer Price Index.

Since local costs were presented in the feasibility reports in the form of US dollars, it was necessary to convert the original estimates into Jamaican dollars using the exchange rates specified in the reports. These costs were then inflated to 1985 prices using the local cost escalation factors mentioned above and then reconverted to US dollars using the mid-1985 exchange rate of US$1=J$5.65.

I.3 Measurement of Financial Benefits

The three projects included in the case studies all involve electricity generation facilities which will be operated by J.P.S. Different methods were used in each of the feasibilty reports to determine the financial benefits. Two of the three had methodological problems. Only the coal conversion feasibility study contained an analysis of the financial benefits which would accrue to JPS as a result of implementation of the project. Since JPS already operates a number of power plants which provide electricity for the central grid, the financial benefits from a new generation facility would be the cost savings resulting from not having to use alternative methods of electricity generation.

The calculation of benefits for the coal conversion project is relatively simple. There would be no increase in the capacity of the JPS system and the reliability of the system would not change significantly since the conversion would utilize much of the existing generating and distribution equipment. Therefore, the financial benefits would be the savings in the fuel cost which would be realized if these units were converted. Since the units proposed for conversion, Old Harbour units 3 and 4, have recently been rehabilitated, their heat rates are relatively low. With the mid-1985 price for Bunker "C", the marginal fuel cost for these facilties when operating at 80% of their capacity is US$.050 per Kilowatt-hour of net generation. A similar figure had been used in the feasibility report to perform a financial analysis based on the marginal cost of capital to the government.

For the Y.S. River hydroelectric project, the calculation of financial benefits is more difficult. Since the project involves a run-of-the-river hydroelectric facility, the electricity produced will be used as a substitute for electricity generated by baseload units. Because the facility would only operate for part of the year, it would not add to the capacity of the JPS system.3 The JPS currently operates its baseload facilities

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3 The issue of whether the reliability of the supply from the combined system of hydroelectric facilities, given the difference in periods of flow for units located in different parts of the island, is sufficient to justify including part of the hydroelectric capacity as part of the baseload capacity is addressed in an upcoming paper by Robert Miller of JPS.

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using an "economic dispatch" system, therefore, the electricity produced by the hydroelectric facilties would be used in place of electricity generated by the less efficient baseload units such as the larger steam turbines at Hunt's Bay. The Y.S. River facility would produce a small amount of electricity relative to these units, even when operating at its rated capacity. Therefore, the financial benefits from the Y.S River facility are calculated based on the short-run marginal costs of generating for electricity from the Hunt's Bay units 5 and 6. This cost was computed using the mid-1985 price for Bunker "C" and the marginal heat rate for the two units when they are operating at 80% of capacity. The resulting financial benefit of electricity at the busbar is US$.056 per kilowatt-hour for 1985 fuel prices. The feasibility report mistakenly assumed that the hydroelectric facility would be used to substitute for peak generating capacity, and therefore the relatively inefficient heat rate and high fuel costs of the Gas turbines units were used.

The financial analysis of the Negril Peat project is the most complex of the three projects studied. This project would provide a major source of new capacity. In the short-run, the construction of this facility would allow JPS, to either:

1. reduce the fuel use in the less efficient baseload facilities and increase total system reliability or
2. retire one of the older baseload units ahead of schedule

In the long run, the project would allow JPS to either:

1. delay the construction of new capacity or
2. replace one of the less efficient baseload units

It is unlikely that JPS would retire any of its units ahead of schedule given its recent history of power outages and low system reliability. Therefore, in the short run, it is expected that the financial benefit will be derived from a reduction in the fuel used to generate electricity in existing baseload units. Because of its size, the peat-fired plant would allow for a reduction of output in all of the baseload power plants. As a result, a weighted average of the marginal heat rates for all the baseload units was used to determine the marginal costs for generating electricity. The resulting financial benefit is US$.042 per kilowatt-hour at the busbar.

In the long run, JPS would most probably use the Negril facility to provide additional capacity to meet the projected increase in demand. The project would therefore provided the additional financial benefit of delaying construction of additional capacity. The long run marginal cost for expansion of the JPS facility is estimated to be US$.018 per kilowatt hour for the capital costs and US$.037 per kilowatt hour for fuel at mid-1985 prices. In the feasibility report, a fixed amount of US$.09 per kilowatt-hour at the busbar was used to compute the financial benefits. In the case study, the electricity at the busbar was initially valued using the short-run marginal cost of the existing baseload system and in later years was valued at the long-run marginal cost for new capacity. The former was used up until the

year 1996 when it is expected that additional capacity will be required (see sections I.5 and I.6).

I.4 Fuel Prices

In order to estimate the financial benefits for the three case studies, the costs for the fuels used in the existing electricity generation facilities were estimated using mid-1985 prices. Since the analysis was done using constant values, it was not necessary to escalate the fuel costs to account for inflation. However, the costs of coal and petroleum fuels are expected to increase at a rate greater than inflation for much of the project planning period. Therefore it was necessary to estimate the change in fuel prices measured in constant terms over the life of the projects. These estimates were obtained by using the escalation rates from a forecast of fuel prices prepared by the World Bank.4 The baseline prices for Bunker "C" and No. 2 Distillate (45-47 Cetane) were obtained by taking the current Caribbean spot market prices5 and adding a charge of US$4 per barrel for transportation and markerting. The baseline price for coal was estimated by taking the current spot price for steam coal (12,000 Btu/lb., 12% ash content, 1.5% S) at Hampton Roads and adding a US$10/ton transportation cost, a US$1.75/ton allowance for a higher heating value (12,500 BTU/lb.), and a $4/ton differential to allow for contract price over spot price.6 The resulting baseline prices are US$26.20 per barrel for Bunker "C", US$32.60 per barrel for No. 2 Distillate and US$59.75 per metric ton for steam coal. The escalated costs for subsequent years, based on the IBRD factors, are shown in table I.2.

I.5 Forecast of Electricity Demand

The benefits of the projects discussed in the case studies depend on the ability of these projects to produce electricity at a lower cost. For the peat project, the benefits also depend on the ability of the project to provide additional capacity to meet future demand. In order to estimate the requirement for future capacity, projections of future electricity consumption were prepared. These projections are based on a review of the pattern of electricity consumption over the last 23 years. This consumption data is broken down into four rate categories:

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4 IBRD (Economic Analysis and Projections Department) memo, "Half Yearly Revision of Commodity Price Forecasts and Quarterly Review of Commodity Markets for December 1984", Jan 8 1985.

5. ex-refinery as listed in Platt's Oilgram July 1985.

6. These figures are similar to those suggested in the coal conversion report by Bechtel.

Table 1.2
Projected Fuel Prices

	FORECASTED FUEL PRICES(F.O.B.) (US$/BBL)			FORECAST DELIVERED FUEL PRICES (US$/BBL)		
	COAL	BUNKER C	DIESEL	COAL	BUNKER C	DIESEL
1985	$44.00	$22.20	$30.20	$59.75	$26.20	$34.20
1986	$41.36	$20.65	$28.09	$57.11	$24.65	$32.09
1987	$38.72	$19.31	$26.27	$54.47	$23.31	$30.27
1988	$38.72	$19.31	$26.27	$54.47	$23.31	$30.27
1989	$40.04	$20.42	$27.78	$55.79	$24.42	$31.78
1990	$40.48	$21.31	$28.99	$56.23	$25.31	$32.99
1991	$40.92	$22.42	$30.50	$56.67	$26.42	$34.50
1992	$41.58	$23.53	$32.01	$57.33	$27.53	$36.01
1993	$42.02	$24.64	$33.52	$57.77	$28.64	$37.52
1994	$42.68	$25.97	$35.33	$58.43	$29.97	$39.33
1995	$43.12	$27.08	$36.84	$58.87	$31.08	$40.84
1996	$44.22	$27.77	$37.78	$59.97	$31.77	$41.78
1997	$45.32	$28.46	$38.72	$61.07	$32.46	$42.72
1998	$46.42	$29.17	$39.68	$62.17	$33.17	$43.68
1999	$47.61	$29.90	$40.68	$63.36	$33.90	$44.68
2000	$48.80	$30.64	$41.68	$64.55	$34.64	$45.68
2001	$49.98	$31.41	$42.73	$65.73	$35.41	$46.73
2002	$51.26	$32.19	$43.79	$67.01	$36.19	$47.79
2003	$52.54	$32.99	$44.88	$68.29	$36.99	$48.88
2004	$53.86	$33.83	$46.02	$69.61	$37.83	$50.02
2005	$55.18	$34.68	$47.17	$70.93	$38.68	$51.17

1. residential,
2. small commercial and industrial,
3. large commercial and industrial, and
4. public lighting and other users.

For these categories, data is available on the number of hookups and the average use per hookup. The rate of growth in hookups for each of the rate groups is shown in table I.3 while the rate of growth in consumption per hookup is shown in table I.4. Regression analysis was used to determine the correlation between these parameters and:

1. the price of the electricity
2. the level of economic activity in the country.

The following discussion focuses on each of the four categories of users and develops separate models for forecasting the level of use in each category. A summary of the results of the regression analyses and the format of the relationships developed for the forecasts is shown in the appendix C. The principal measures of economic activity that were considered are the Gross Domestic Product as measured for the hotel sector, the manufacturing sector and for all sectors excluding bauxite (see table I.5). The bauxite sector was excluded because it produces primarily for export and because it purchases its own petroleum products and generates its own electricity. The price of electricity was computed in constant value as an average revenue per kilowatt-hour delivered for each category of use (see tableI.6).7

The decade of rapid growth which began in the early 1960's was followed by a period of economic stagnation, the effects of which continue to be felt. Therefore, separate regressions were made for the 23 year period from 1962 to 1984 and for the decade from 1974 to 1984. During the latter period, there were two occassions on which severe power shortages occurred, 1973-74 and 1979-1982. Since the consumption of electricity was restricted during these periods, a variable was introduced into the analysis to account for the effects of these shortages.

Of the four categories of users, the small commercial and industrial users account for more than 2/5 of the total electricity consumed. The residential sector accounts for another 1/3. The remaining consumption is split between the large commercial and industrial users and the public users(Figure I.1 and I.2)

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7. The analysis presented in this report is limited in scope to examining the relationship between demand and those explanatory variables for which projections are available. A previous effort aimed at determining the factors affecting electricity demand was much more detailed in its consideration of explanatory variables. This work was performed by Roddy Ashby of the PCJ and presented at the Energy Symposium held in Kingston,July 1985.

Table I.3
Number of Hookups for Each Rate Category

YEAR	RESIDENTIAL	SMALL C&I	LARGE C&I	OTHERS
1961	0	0	0	0
1962	53150	13259	6	159
1963	56896	14177	8	180
1964	60226	14684	9	201
1965	64948	15254	9	218
1966	70639	15406	9	571
1967	76900	15464	9	1175
1968	83353	16295	10	1244
1969	90530	17123	12	1309
1970	97225	17945	13	1405
1971	104306	18908	15	1534
1972	113775	19941	15	1612
1973	122515	20875	15	1758
1974	131964	21441	15	1847
1975	142075	21999	18	1983
1976	153272	22636	21	2014
1977	163834	23316	21	2094
1978	177745	23651	24	2168
1979	189858	23861	24	2223
1980	199468	23765	23	2229
1981	208390	23876	23	2229
1982	216403	24207	22	2221
1983	220669	24329	22	2208
1984	224547	23951	22	2117

Table I.4
Electricity Consumption Per User For Each Rate Category

YEAR	RESIDENTIAL	SMALL C&I	LARGE C&I	OTHERS
1961	0	0	0	0
1962	1352	11325	7618	105610
1963	1369	11628	7404	102650
1964	1454	12867	8318	108453
1965	1541	14473	9555	108532
1966	1666	15062	8659	81825
1967	1745	16684	9245	46435
1968	1810	17330	9399	49734
1969	2009	18460	8309	58639
1970	2091	18778	9196	53586
1971	2110	20074	8975	58772
1972	2483	21882	8774	60087
1973	2403	20615	9458	58934
1974	2255	20231	9431	63220
1975	2306	21146	7903	65735
1976	2256	21333	7472	66736
1977	2116	20822	7102	73870
1978	1972	20246	6498	69642
1979	1738	18751	5872	63758
1980	1592	18298	5804	61319
1981	1511	18072	5466	65027
1982	1518	19287	6302	65136
1983	1656	21559	6634	61844
1984	1640	21502	6455	62352

9

Table I.5
Parameters Used to Analyze Electricity Demand

YEAR	POPULATION	GDP(CONSTANT J$)	NON-BAUXITE GDP	NET DISP.INCOME/CAPIT.
1961	1199	$0.00	$1,622.00	$0.00
1962	1216	$1,105.00	$1,660.00	$535.99
1963	1257	$1,145.00	$1,697.00	$542.22
1964	1365	$1,245.00	$1,740.00	$561.87
1965	1471	$1,345.00	$1,740.00	$593.50
1966	1528	$1,395.00	$1,765.00	$590.03
1967	1567	$4.04	$1,790.00	$679.09
1968	1662	$1,525.00	$1,815.00	$716.14
1969	1770	$1,670.00	$1,844.00	$636.31
1970	1982	$1,853.00	$1,869.00	$668.62
1971	2042	$1,904.00	$1,901.00	$860.19
1972	2231	$2,082.00	$1,932.00	$889.23
1973	2240	$2,069.00	$1,976.00	$1,022.04
1974	2153	$1,966.00	$2,025.00	$1,002.22
1975	2143	$1,995.00	$2,060.00	$963.46
1976	2011	$1,894.00	$2,072.00	$856.80
1977	1962	$1,822.00	$2,097.00	$819.81
1978	1971	$1,827.00	$2,123.00	$811.29
1979	1941	$1,799.00	$2,149.00	$791.71
1980	1828	$1,669.70	$2,173.00	$735.29
1981	1888	$1,727.60	$2,204.00	$766.35
1982	1889	$1,776.50	$2,242.00	$754.69
1983	1922	$1,809.00	$2,289.00	$773.20
1984	1922	$0.00	$2,324.00	$736.00

Table I.6
Average Price Charged for Electricity by Category
(J$ per kilowatt-hour)

YEAR	RESIDENTIAL	SMALL C&I	LARGE C&I	OTHERS
1961	$0.00	$0.00	$0.00	$0.00
1962	$7.08	$5.24	$2.64	$4.93
1963	$6.75	$4.94	$2.69	$4.87
1964	$6.66	$4.88	$2.63	$4.78
1965	$6.47	$4.65	$2.51	$4.74
1966	$5.69	$4.09	$2.29	$4.23
1967	$5.51	$4.04	$2.38	$4.10
1968	$5.40	$4.00	$2.40	$4.00
1969	$4.40	$3.37	$2.09	$2.72
1970	$4.14	$3.29	$1.98	$3.22
1971	$4.04	$3.08	$1.94	$3.00
1972	$3.99	$3.42	$2.21	$3.48
1973	$4.19	$3.70	$2.30	$3.39
1974	$5.38	$4.81	$3.86	$4.43
1975	$5.50	$4.85	$3.71	$4.57
1976	$6.53	$5.52	$4.13	$5.38
1977	$6.83	$5.68	$4.33	$5.46
1978	$7.13	$5.94	$4.67	$6.00
1979	$8.48	$7.05	$5.75	$7.33
1980	$9.22	$7.79	$6.45	$8.24
1981	$10.34	$8.72	$7.44	$8.97
1982	$10.21	$8.47	$7.15	$8.98
1983	$9.45	$7.73	$6.34	$8.36
1984	$13.75	$11.08	$9.83	$11.94

Figure I.1

DISTRIBUTION OF ELECTRICITY USE

BY TYPE OF USER 1984

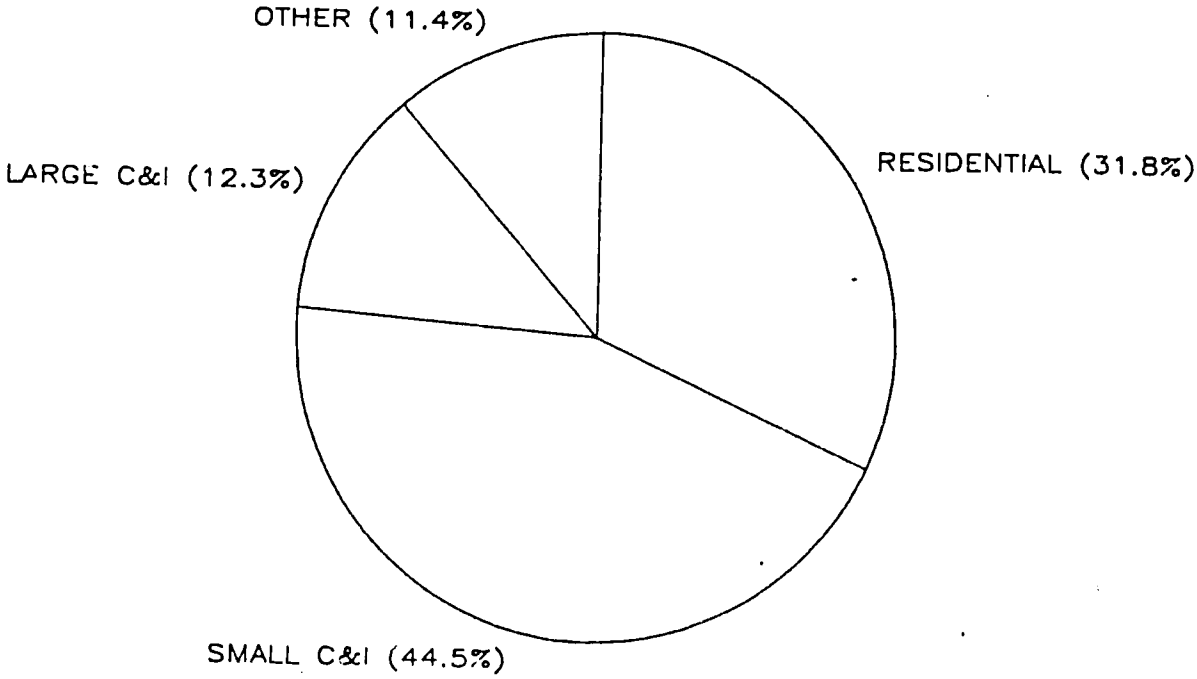
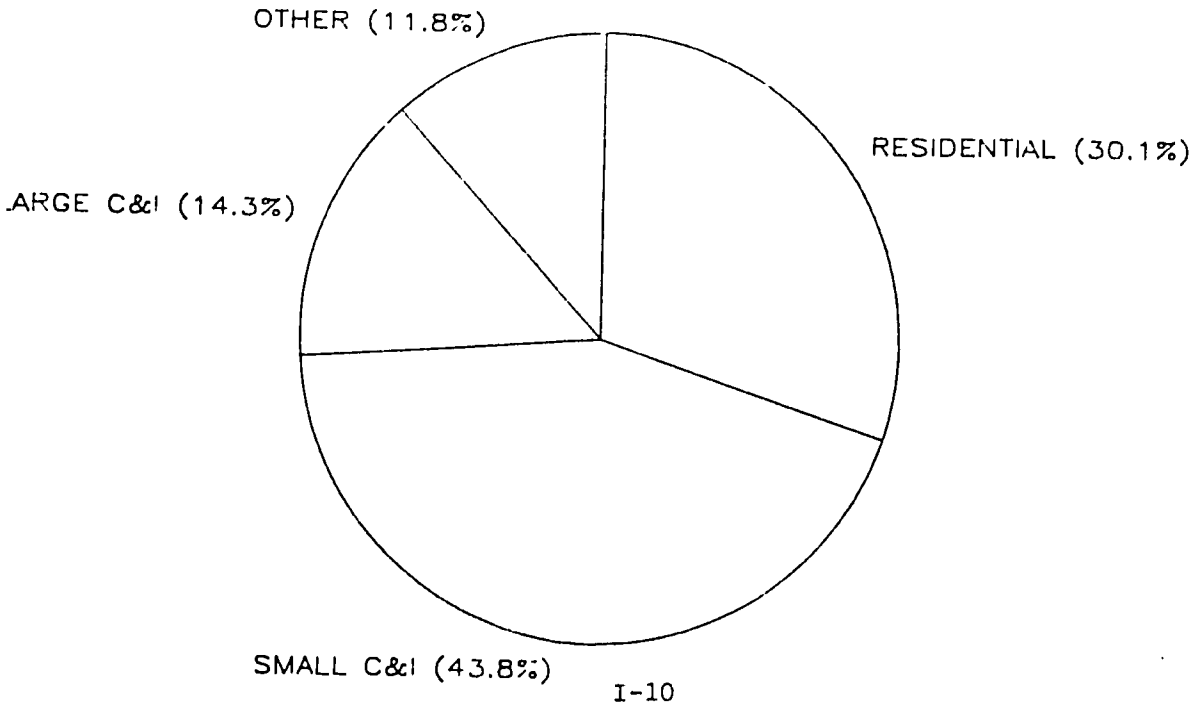


Figure I.2

DISTRIBUTION OF ELECTRICITY USE

BY TYPE OF USER 1974



Small Commercial and Industrial Users

The number of small commercial and industrial users (C&I, small) increased steadily since 1962, but the rate of increase has slowed markedly in the last decade. For the 23 year period, the number of hookups grew at an average rate of 6.3%. In the last ten years the rate of increase in the number of hookups has declined and the total number appears to be approaching an asymptotic value of approximately 24,500. The effect of economic growth as measured by the non-bauxite GDP had little effect on the annual rate of increase. and the elasticity of demand for hookups is estimated to be only .29. The price of electricity also appears to have had little effect on the growth in the number of hookups over this period.

The short run trend of asymptotic growth was used as a basis for the "low" forecast of hookups. The long run trend of steady percentage growth was used as a basis for the "high" forecast. The "expected" forecast was prepared by assuming that the number of hookups will increase with the growth in GDP but with a slightly higher elasticity of demand, .5.

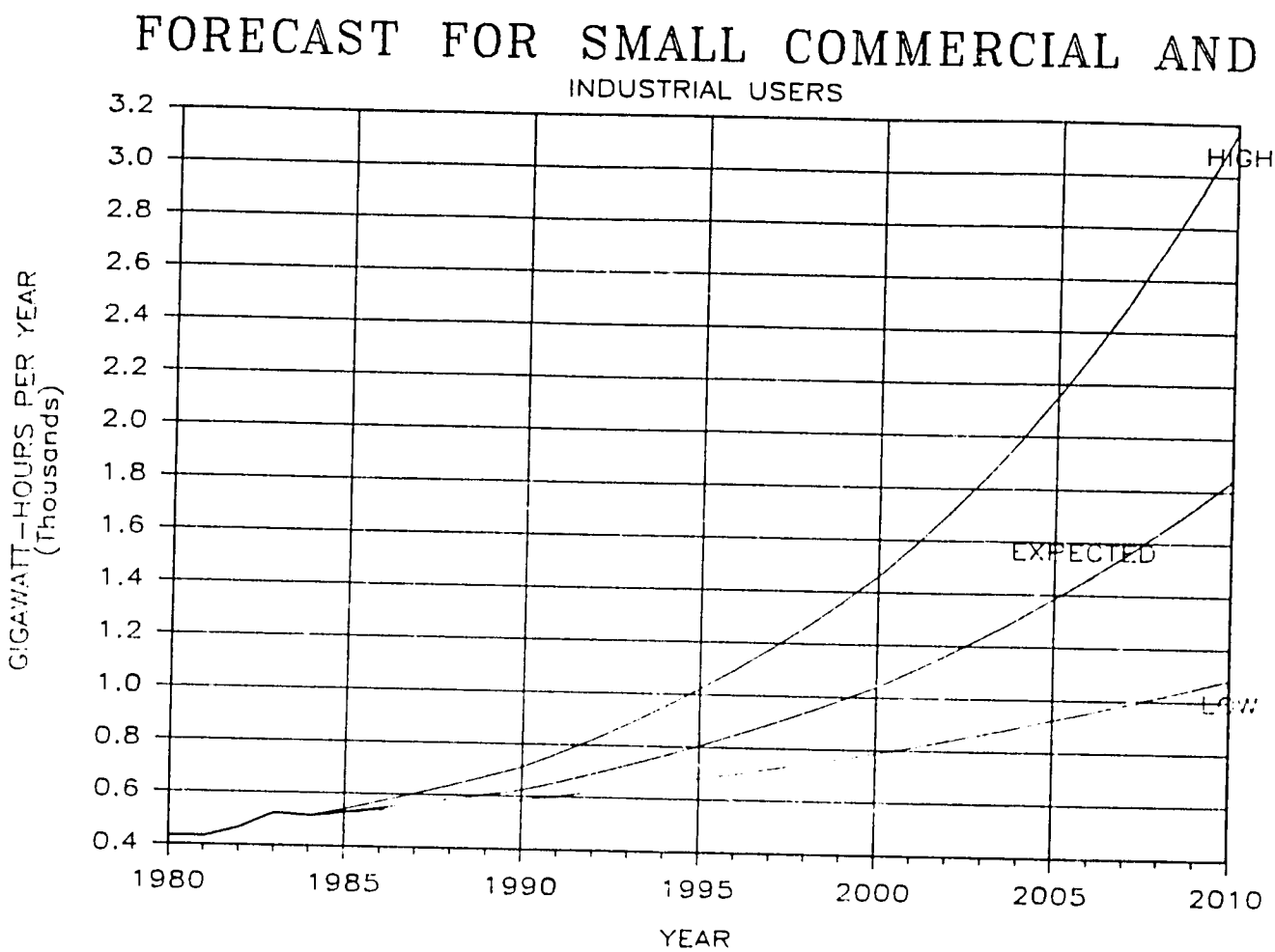
The average electricity consumed per hookup increased by only .8% per annum over the period 1962-1984 after allowing for the effects of power outages and growth in GDP. The elasticity of consumption per hookup with respect to GDP was .88. In the last decade, the correlation between consumption per hookup and these explanatory variables decreased significantly. In addition, the annual growth rate dropped to .7% and the elasticity with respect to GDP declined to .63. It was also during this period that the power outages had a relatively strong impact on consumption. The price of electricity appears to have had some effect on the level of consumption in both the short run and the long run, but the effect was not as great as the effect of GDP.

The "low" forecast for consumption per hookup was prepared using the previous decade's growth rate of .7% and elasticity of demand with respect to GDP of .63. The "high" forecast was prepared using the annual growth rate and the elasticity for the 23 year period. The "expected" forecast was prepared using the average values for the short and long run growth rates and elasticities. The total consumption for the sector was forecast by combining the forecasts for hookups and for consumption to produce a high-high, expected-expected and low-low forecast as shown in Figure I.3.

Residential Users

The electricity consumption in the residential sector grew at a slightly slower rate than in the small C&I sector. However the proportion of total electricity use accounted for by this sector remained relatively constant as shown in Figure I.1 and I.2. The number of hookups grew at an annual rate of about 7% for the 23 year period. In the last decade, this rate has declined significantly as the coverage of the grid has been extended to

Figure I.3


FORECAST FOR SMALL COMMERCIAL AND
INDUSTRIAL USERS
GIGAWATT-HOURS PER YEAR
(Thousands)
3.2
3.0
2.8
2.6
2.4
2.2
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
1980
1985
1990
1995
2000
2005
2010
YEAR
HIGH
EXPECTED
LOW

most parts of the island (see Figure I.4). The increase in hookups is now determined in large part by the pace of the rural electrification program. The annual increase since 1974 has been slightly less than 10,000 hookups per year. In the long run, it is expected that the number of hookups will grow in proportion to household formation.

The "low" forecast for growth in hookups was prepared using a rate of growth equal to the forecasted rate of growth in population. This rate was used to approximate the rate of growth in household formation. The "expected" forecast was developed using the current rate of expansion, _% which is expected to continue for much of the planning period. The "high" forecast was developed assuming that the number of hookups will grow at a rate 2% greater than the growth in popuation.

The amount of electricity consumed per residentual hookup has been affected by two trends. The first trend is the increasing use of electrical appliances and equipment in Jamaican households. The second trend is the declining electricity consumption per new hook-up. The latter trend results from the fact that the new hookups are for households which have a lower income level. The result of these opposing trends has been that while the consumption per household nearly doubled between 1962 to 1973, it declined by 50% from 1953 to 1984. Only in the last two years has there been a slight increase. The average level of consumption is closely correlated with the per capita non-bauxite GDP. Over the 23 year period the elasticity of consumption was 1.35. The elasticity increased to 1.61 in the last ten years as the per capita GDP declined.

The "high", "expected" and "low" projections for consumption per household were prepared using elasticities of consumption with respect to per capita GDP of 1.61, 1.35 and 1.1 respectively. The forecast for total consumption was prepared in a manner similar to that for the small commercial and industrial sector. The results are shown in Figure I.5.

Large Commercial and Industrial Users

The large commercial and industrial users represent a relatively small group, currently numbering 22, which have a hookup capacity in excess of 1000 kva. These account for 22% of the total consumption in the commercial and industrial sector. In forecasting the demand for this sector, it was assumed that new hookups will be created as a result of growth in the demand for users currently in the small commercial and industrial category. Since projections for the latter category have already been prepared, it is only necessary to project the consumption for the current users. The average consumption of the large C&I users has fluctuated considerably over the last two decades as new hookups have been added and old ones have been disconnected. The only factor which appears to be correlated with the average consumption per hookup is the average price of electricity for this category.

Figure I.4

JPS TRANSMISSION AND DISTRIBUTION SYSTEM

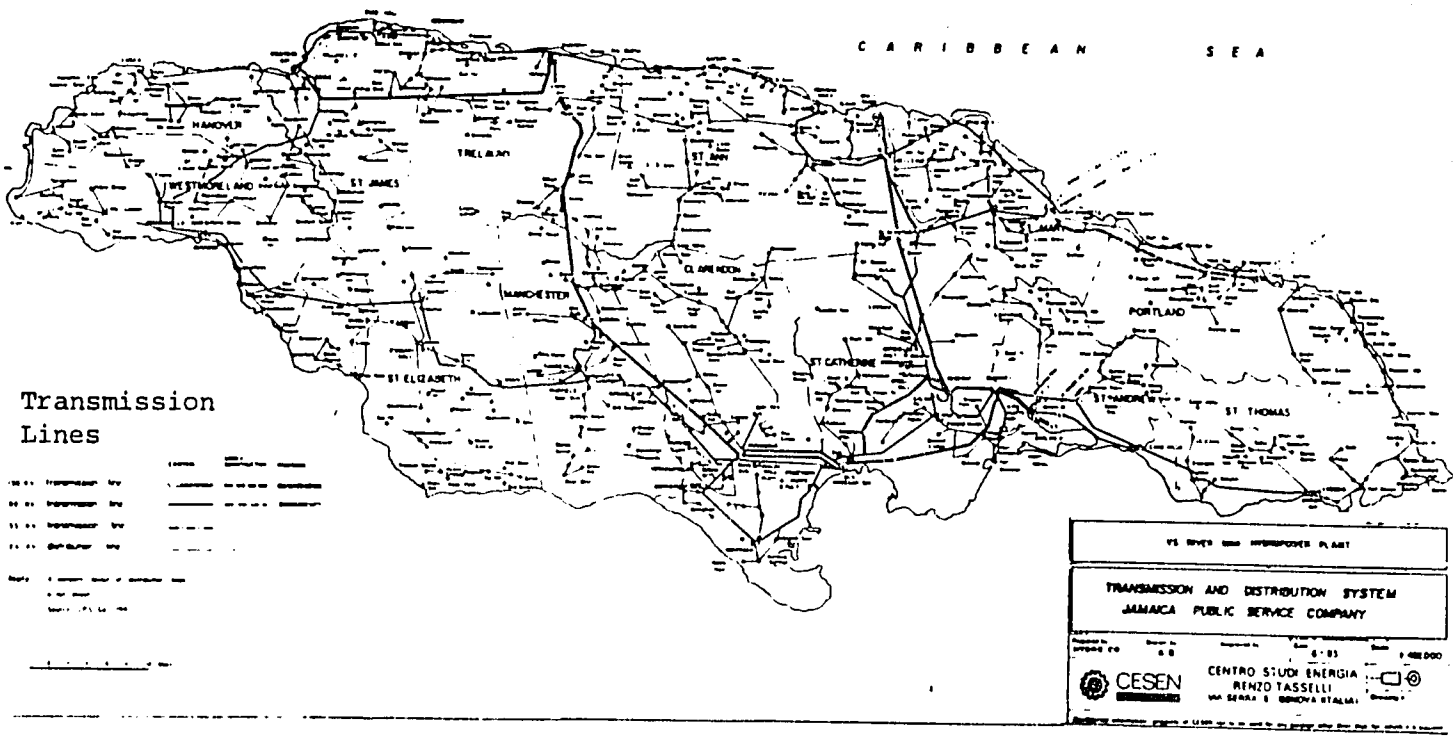
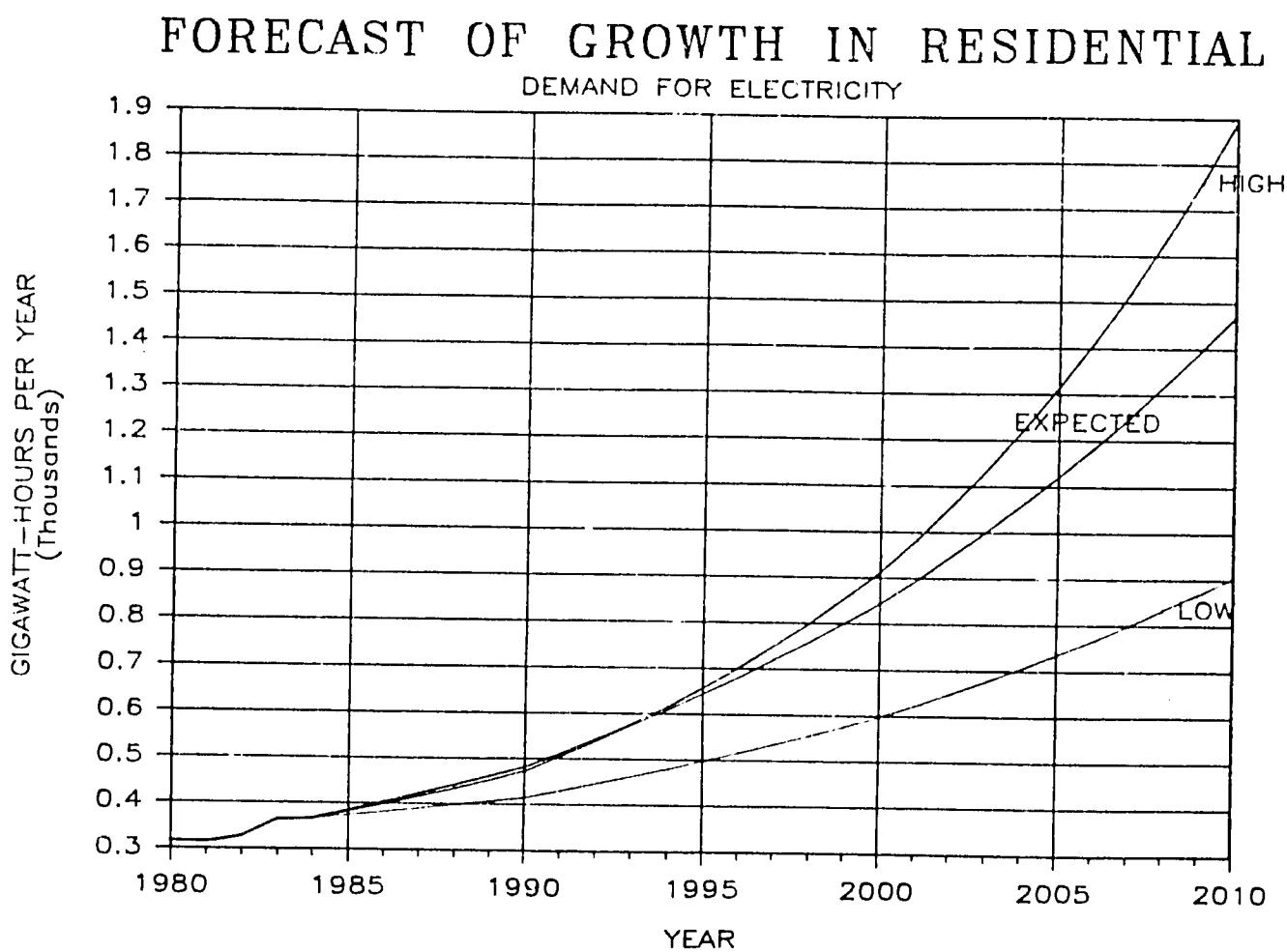


Figure I.5



The elasticity of demand with respect to the price measured in constant J$ is -.36. Since the current rate charged this group is well below the long-run marginal cost for producing the electricity, it is expected that the rate will increase in real terms in the next three years and there will be a downward adjustment in consumption as a result.

For the "low" forecast, it is assumed that adjustment will be -14% and that thereafter the level of consumption will remain constant. For the "expected" forecast, it is assumed that the downward adjustment will be 7% and that demand will increase by .5% per annum thereafter. For the "high" forecast it is assumed that there will be no downward adjustment and that consumption per hookup will increase by 1% per annuum.. The resulting forecasts of consumption for this sector are shown in Figure I.6.

Public Lighting and Other Users

The users included in the rate category "Other" are primarily government facilities and municipal lighting. The number of users in this category increased rapidly from 1963 to 1975, but the increase from 1975 to 1984 totaled only 10% and there was a 4% decline in the final year. The average consumption per user over the last 16 years has fluctuated ±15% about an average of 63 MW-hr per year. The current austerity measures undertaken by the government are expected to continue for several years with a resulting drop in the total consumption in this sector. Thereafter the consumption is expected to increase at a rate proportional to the rate of increase in the GDP.

For the "high", "expected" and "low" forecasts, the initial decrease in consumption per hookup is expected to be 5%, 10%, and 15% respectively up through 1986. Starting in 1987, the rate of consumption per hookup is expected to increase. For the high, expected and low forecasts, this rate of increase is expected to be at rates equal to 90%, 60%, and 30% of the rate of growth in GDP, respectively. The results of these forecasts are shown in Figure I.7.

Total Consumption

When the projections of the growth in the four rate groups are added together, the results are as shown in Figure I.8. The expected forecast is for total consumption to reach 1.5 GW-hr in the year 1992, 2 GW-hr in the year 1998 and 3 GW-hr in the year 2007. These projections are considerably lower than those prepared for MME in 1982 and reflect the continuing moderation of growth in demand.8 The projected demand indicates that the current capacity, as described in the following section, will be sufficient for the next ten years.

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8 reference - MilGann report

Figure I.6

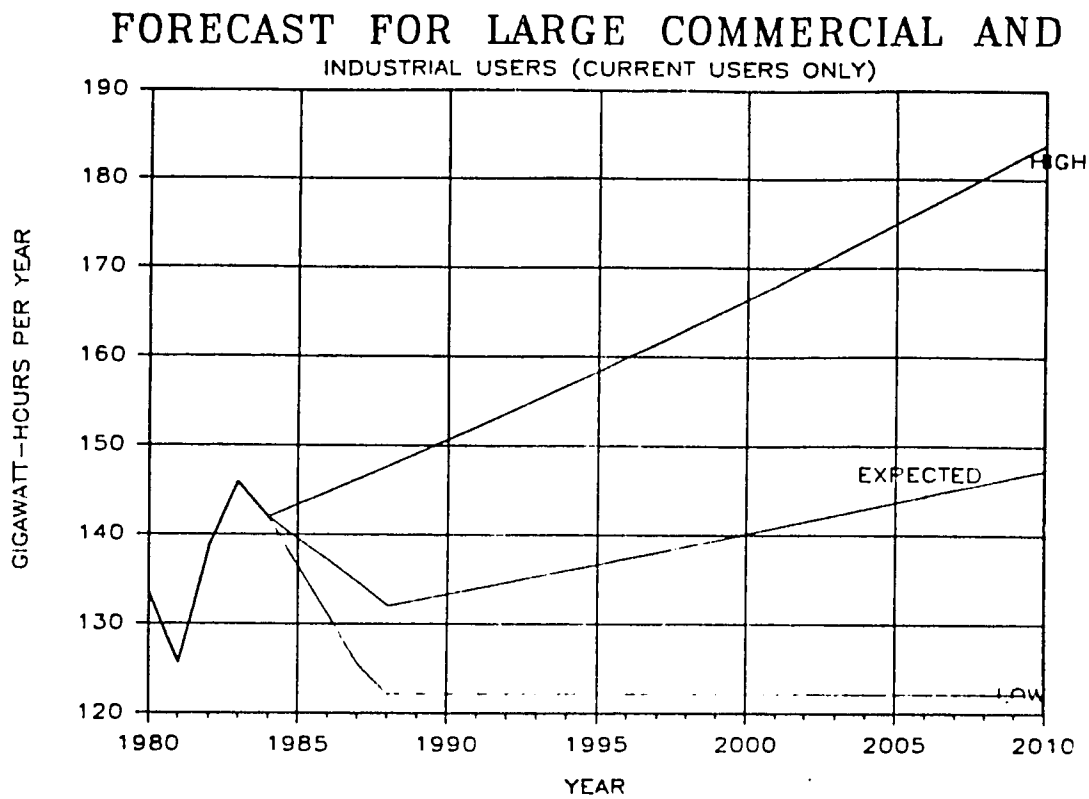


Figure I.7

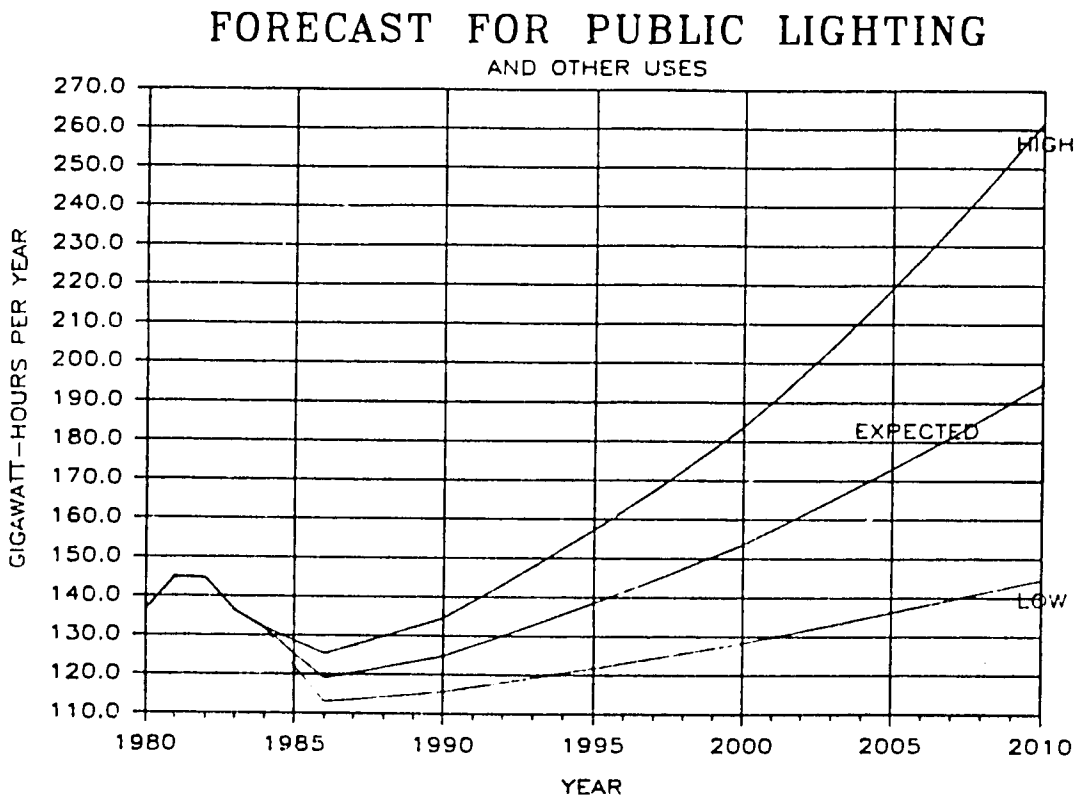
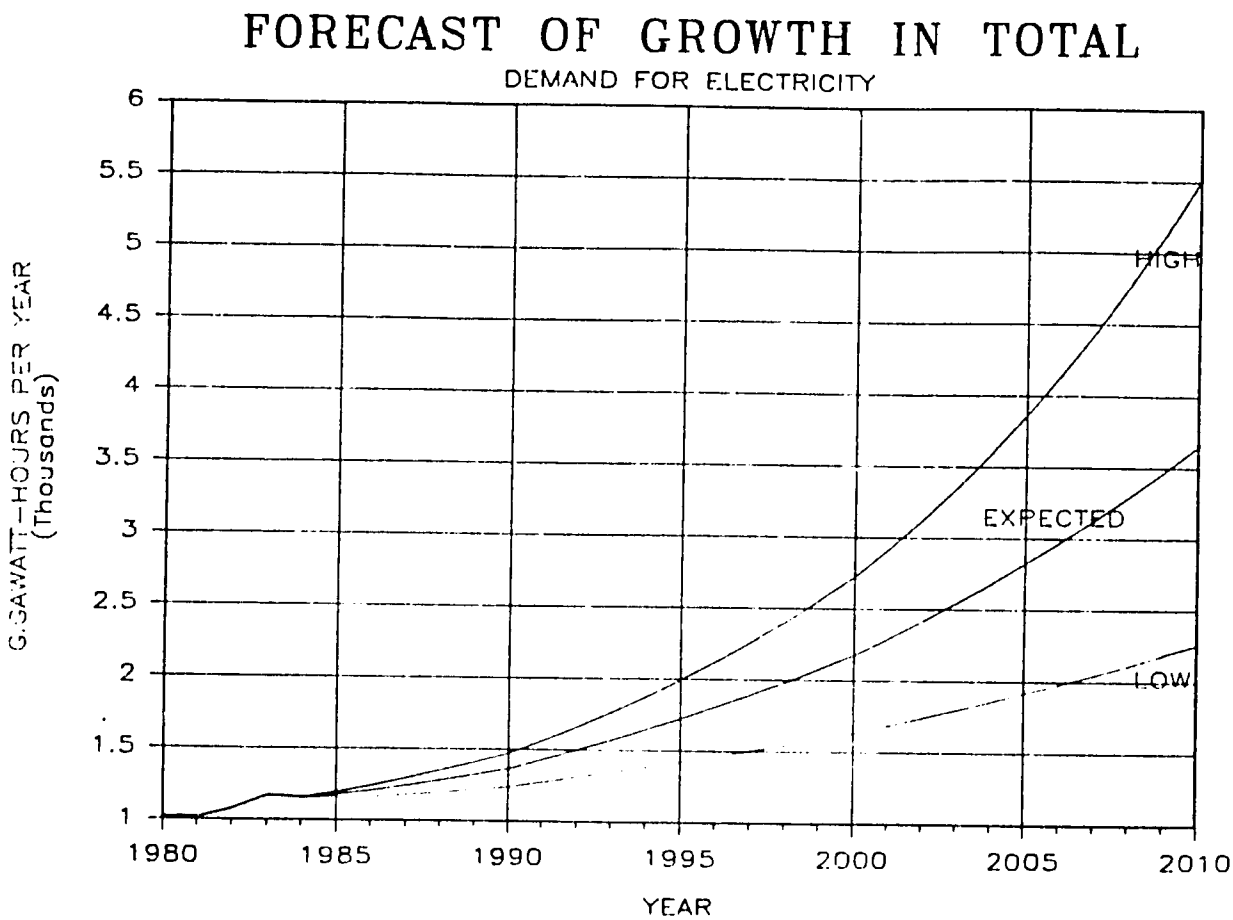


Figure I.8


FORECAST OF GROWTH IN TOTAL
DEMAND FOR ELECTRICITY
GIGAWATT-HOURS PER YEAR
(Thousands)
6
5.5
5
4.5
4
3.5
3
2.5
2
1.5
1
1980
1985
1990
1995
2000
2005
2010
YEAR
HIGH
EXPECTED
LOW

17

I.6 JPS System Capacity

The existing JPS generating capacity includes 10 steam-turbine units fueled with Bunker "C", 5 Gas Turbine units fueled with No. 2 Distillate (45-47 Cetane), 2 Slow-Speed Diesel Units fueled with Bunker "C" and 5 Hydroelectric facilities. A summary of the system including the nominal and actual capacity of the units, their age and their heat rate at 80% capacity is shown in table I.7. The baseload power is generated by the units at Old Harbor, Rockfort and Unit #6 at Hunt's Bay as well as by the hydroelectric facilities. The gas turbines and the smaller units at Hunt's Bay provide peaking and standby power. The level of utilization of these facilities over the last 10 years is shown in table I.8 for each type of generating capacity. These aggregate numbers conceal a considerable variation in the level of use of individual units. For example, the relatively new Unit #6 at Hunt's Bay has a utilization in excess of 80%, while the older units at Hunt's Bay are rarely used.

The effects of the improved system reliability as a result of the recently completed rehabilitation project can be seen in the increase in utilization of the steam turbine units. It is likely that the overall level of utilization for these units could be increased to 60-65%, through a continuing program of preventitive maintenance. The new Rockfort diesel-powered facility is designed for a level of utilization in excess of 80%. As a result, the baseload output, exclusive of hydro-electric power, should be on the order of 1.7 million megawatt-hours.

The utilization of the hydro-electric facilities has declined in recent years due in part to a lack of rainfall. It is expected that the level of utilization will return to a 90% level in the future. In addition to the existing hydroelectric facilities, some 25 megawatts of nominal hydro capacity are expected to be introduced over the next several years. Assuming that the utilization of these systems will be on the order of 80%, then the baseload power available from these systems will be on the order to .28 million megawatt-hours per year.

The utilization of the gas turbines has declined with the improvement of the baseload system. Similarly, the use of the small inefficient steam-turbine units at Hunt's Bay has decreased. In the future these units are expected to operate at a maximum utilization of 15% which would imply an output of .18 million megawatt-hours.

The output of the total system is thus expected to produce a maximum of 2.13 million megawatt-hours.9 If the distribution losses continue to be on the order of 15%, then the demand which can be met is on the order of 1.8 million megawatt-hours. This is the level of demand which is forecast to occur in 1996.

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9. Assuming that the daily and seasonal fluctuations are not altered to a significant extent.

Table I.7

Description of Existing JPS System

UNIT NAME	OLD HARB.1	OLD HARB.2	OLD HARB.3	OLD HARB.4
TYPE	STEAM	STEAM	STEAM	STEAM
FUEL	BUNKER C	BUNKER C	BUNKER C	BUNKER C
CAPACITY - NAMEPLATE	33	60	69	69
CAPACITY - EFFECTIVE (MW)	29	57	52	65
MARGINAL HEAT RATE -80% CAPACITY	2,548	2,513	2,569	2,614
UNIT NAME	HUNTS BAY 1	HUNTS BAY 2	HUNTS BAY 3	HUNTS BAY 4
TYPE	STEAM	STEAM	STEAM	STEAM
FUEL	BUNKER C	BUNKER C	BUNKER C	BUNKER C
CAPACITY - NAMEPLATE	13	13	14	14
CAPACITY - EFFECTIVE (MW)	8	8	10	10
MARGINAL HEAT RATE -80% CAPACITY	4,748	4,748	4,367	4,367
UNIT NAME	HUNTS BAY 5	HUNTS BAY 6	GAS TURB.1	GAS TURB.2
TYPE	STEAM	STEAM	GAS TURBINE	GAS TURBINE
FUEL	BUNKER C	BUNKER C	NO. 2 DISTIL.	NO. 2 DISTIL.
CAPACITY - NAMEPLATE	19	65	17	17
CAPACITY - EFFECTIVE (MW)	19	62	13	13
MARGINAL HEAT RATE -80% CAPACITY	3,105	2,631	5,716	5,716
UNIT NAME	GAS TURB.4	GAS TURB.5	BOGUE G.T.3	ROCKPORT
TYPE	GAS TURBINE	GAS TURBINE	GAS TURBINE	SLOW SP.DSL.
FUEL	NO. 2 DISTIL.	NO. 2 DISTIL.	NO. 2 DISTIL.	BUNKER C
CAPACITY - NAMEPLATE	23	23	23	40
CAPACITY - EFFECTIVE (MW)	20	17	17	40
MARGINAL HEAT RATE -80% CAPACITY	4,243	4,516	4,516	2,150

Table I.8

Utilization of Existing JPS Capacity by Type of Facility

Generating Facility by Source of Energy	System Utilization (percent)				
	1976	1977	1978	1979	
STEAM	37.4%	30.1%	32.6%	29.5%	
HYDRO	84.0%	83.0%	87.3%	82.4%	
DIESEL	12.2%	18.2%	11.8%	20.4%	
TOTAL	33.1%	29.2%	30.0%	29.2%	
	1980	1981	1982	1983	1984
STEAM	31.9%	33.4%	31.3%	40.4%	46.5%
HYDRO	101.7%	101.1%	97.0%	60.9%	62.4%
DIESEL	8.5%	7.0%	27.4%	11.0%	7.4%
TOTAL	29.1%	30.9%	32.7%	35.7%	39.6%

Peak Capacity

The ability of the existing system to meet future demand is determined not so much by the amount of electricity generated per year as by the peak demands placed on the system. The daily peaks for JPS occur during the working hours from 10 am to 4 pm and again in the evening at about 10 pm. The monthly and seasonal peaks are relatively mild given the eveness of the climate. The relationship between peak demand and total electricity generated has changed very little over the last two decades. In the period from 1970 to 1982, the peak ratio varied within a ±5% band. The forecast for electricity consumption indicates that the percentage of electricity consumed by the residential sector will increase only slightly and the percentage consumed by the commercial and industrial sector will stay about the same. As a result there may be some increase in the evening peak. However, the relationship between annual consumption and peak demand is expected to experience very little change over the next 25 years.

Three forecasts of the peak demand were prepared assuming that:

1. for the "low" forecast - the ratio of the peak consumption to the total consumption will not change and the level of consumption will be equal to that in the "low" forecast presented in the previous section
2. for the "expected" forecast - the ratio of peak consumption to total consumption will increase by 5% and the level of total consumption will be equal to that in the "expected" forecast presented in the previous section.
3. for the "high" forecast - the ratio will increase by 10% and the level of consumption will be equal to that in the "high" forecast in the previous section.

The current system capacity, when adjusted for the additional 25 MW of hydro capacity and assuming a 90% availability during peak periods, can produce an output of 465 MW. The expected forecast as shown in Figure I.9 and I.10 indicates that this level will be reached in 1996. For the high forecast, the system will be able to meet the peak demand only through 1992 and for the low forecast through the year 2004.

Figure I.9

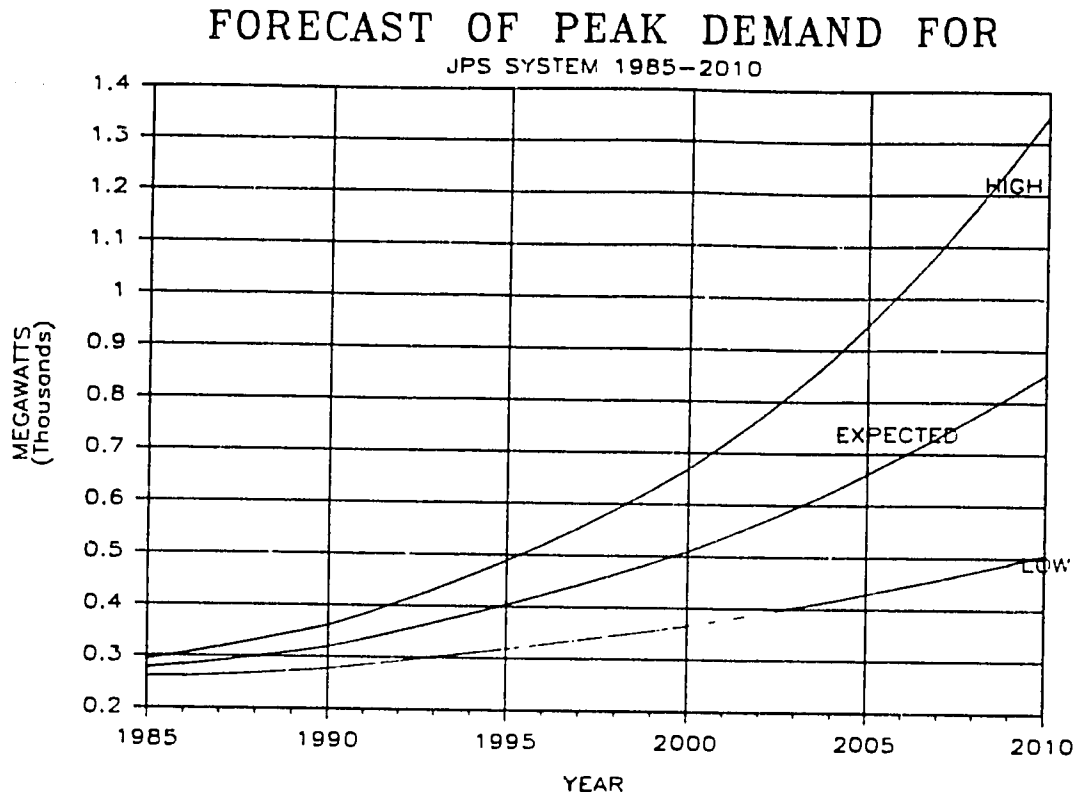
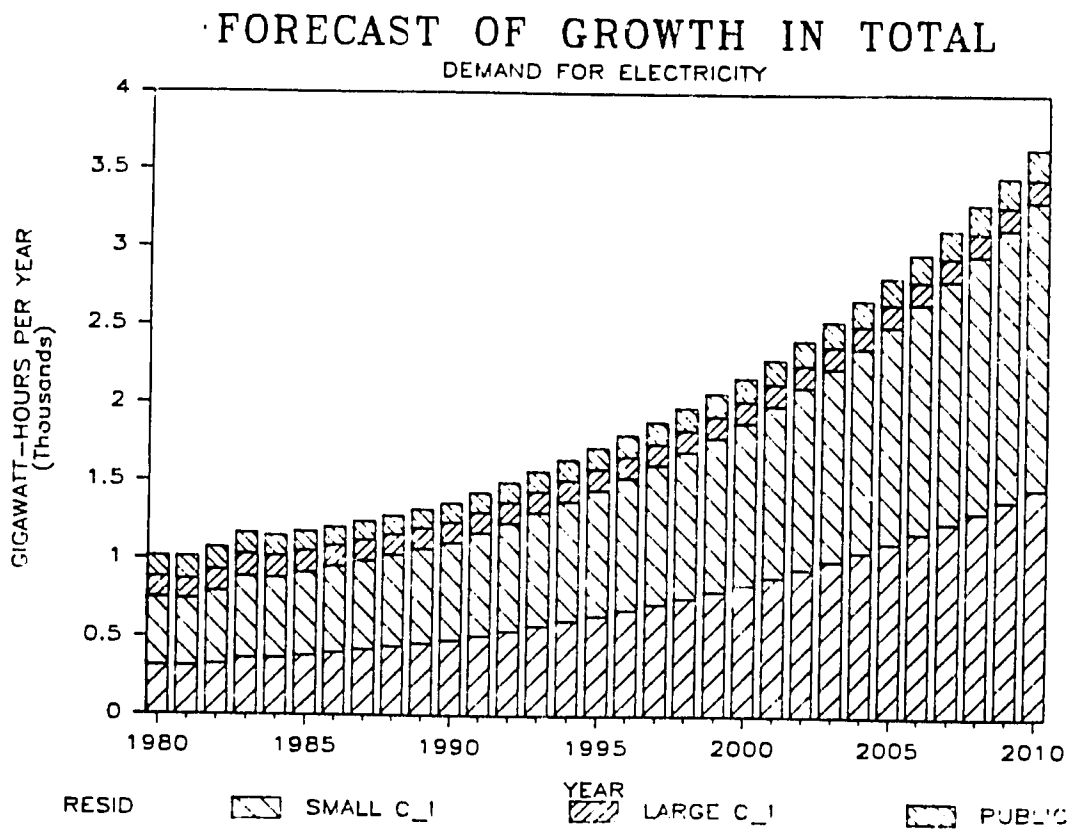


Figure I.10



COAL CONVERSION OF OLD HARBOUR UNITS 3 AND 4

Flora Mosaka-Wright, David Keith, John Arnold 1

II.1 Background

The proposed project concerns the retrofitting of the JPS Old Harbour steam power units 3 and 4 to burn pulverized coal. These are two of the three largest units in the JPS system, rated at 68.5 MWe each. At present, the boilers for these units burn No. 6 fuel oil of relatively high sulphur content, 2.5%-3% S. The project is designed as a fuel substitution, rather than capacity expansion, project with the goal of foreign exchange savings.

The two new boilers, each with a steam generation capacity of 610,000 pounds per hour, are to be installed in parallel with the existing boilers. The existing turbine generators are to be retained. The boilers are to tie in with the existing system by means of new steam and condensate piping. A new stack is to be built to handle the boiler emissions. Complete coal material-handling facilities are required, including port facilities, vessel off-loading equipment, storage facilities, transfer conveyors, mobile equipment, and coal sizing crushers.

The two new boilers would be dedicated to individual turbine units and would produce superheated steam at 1300 psig, 950o F. These boilers could generate full rated capacity on either coal or No. 6 fuel oil. Heat recovery equipment, integral to the boiler (air heater and economizer), together with low excess combustion air design (20% excess air), would result in a low stack temperature (300o F.) and high efficiency (0.88). Coal firing rates at full load would total 56,000 lb/hr. Each boiler would be served by two coal pulverizers of 26,000 lb/hr grinding capacity each.

The proposed air quality control system amounts to particulate emission control only. No flue gas desulphurization is included in the design. Sulphur dioxide emissions would be reduced over the existing case. Electrostatic precipitators are included to achieve a 99.7% recovery of particulate emissions (fly ash). A maximum emissions specification of 0.03 lb/million Btu would be achieved based on the U.S. Environmental Protection Agency air quality standards. This design achieves an increase in air quality over the existing installation, including a 33% reduction in sulphur dioxide and a 40% reduction in total suspended particulate emissions. The design stack height is 450 ft. per U.S. EPA "Good Engineering Practice".

Port facilites would be constructed, including channel dredging, to permit docking by 20,000 dwt coal colliers. Coal unloading and transfer equipment, rated at a nominal 900 ton/hr,

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1. Mrs. Mosaka-Wright is a project economist with the Ministry, David Keith is the energy conservation advisor to the Ministry

would convey the coal to the 25,000 ton active pile and 75,000 ton (60 day) inactive pile. A reclaimer system, rated at 250 ton/hr would deliver coal to the vibrating screen and crusher and into the feed silos, 4 to each boiler.

The ash handling system is designed to collect all ash from the boilers, electrostatic precipitators, economizers, and air preheaters. Bottom ash would be collected in hoppers and discharged by gravity through isolation gates into a submerged drag chain conveyor and delivered to an enclosed pit. Fly ash would be removed from the air preheater and precipitator pneumatically to a silo. Ultimately all ash would be removed by truck to a 50 acre ash disposal site (landfill) made up of six 8-acre cells.

Other equipment included as part of the conversion would be piping, control room, structural work, electrical supply for the pumps, fans, and coal handling equipment and the instrumentation.

II.2 Technical Assessment of Proposed Design

The technical feasibility study is assessed to have been well prepared. The concept is technically feasible and makes use of internationally accepted engineering design codes and practices. The level of detail in the engineering feasibility study is of sufficient degree to consider the document a preliminary design. Although the conversion study had no clearly identifiable technical flaws, there are a number of issues that can be raised. These relate to cost, reliability, efficiency and other matters.

Conversion versus a New Plant

The study is concerned with the conversion of two existing units of the JPS system. These units are two of the most efficient JPS units. In contrast, a number of other units of lower efficiency are also in service. Projections by JPS and others indicate that new capacity will be needed in the latter half of the 1990's. One issue is therefore whether conversion of these efficient units is preferable to a new coal-fired plant. Bechtel addressed this issue by referring to the limited funds available to Jamaica. Their conclusion is that Jamaica would be unlikely to qualify for loans of the magnitude required for a new plant (about US$50 million additional). Discussions between Jamaica and the World Bank over the past year would indicate otherwise. This case study is limited to an examination of the conversion project, but a similar effort should be undertaken for the proposal of a new coal-fired plant as well as for a closer examination of the option for increased utilization of the existing system through improved maintenance and reliability.

Turbine Generator Reliability

Since the installation is a retrofit, fuel-subsititution project, the existing turbine-generators and other equipment will continue

in service. Therefore, the availability of the complete coal-fired power plant will be a function of the reliabiliity of the new coal-handling and boiler system as well as the reliabiliity of the existing turbines, condensers, and other equipment. Historically, the availability of Old Harbour Units 3 and 4 has been poor, about 40% prior to the recent rehabilitation program. Since that program, the reliabiliity has approached 70%. In contrast, a similar unit at Hunts Bay achieved an availability of over 86% prior to rehabilitation and 96% afterwards. The low level availability at Old Harbour has been caused primarily by turbine failures. It is now believed that the cause of some of these problems has been rectified by the recent rehabilitation. However, the relatively low availability following rehabilitation indicates that there are still problems. These units were the first of a series produced by GE and therefore may be expected to have lower reliability over their operating lifetimes. The third such unit, Hunts Bay #6, has achieved a much better availability. This may have been because of design changes or improved installation procedures by the contractor or superior operations and maintenance practices by the staff at Hunts Bay.

Boiler Efficiency

Efficiency considerations appear to be well-addressed in the study. A boiler efficiency of 88%, stack temperature of 300o F., and excess air level of 20% correspond to best achievable values for coal-fired equipment of this size. The choice of a simple Rankine Cycle (no reheat) is appropriate for this size. The low stack temperature is achieved with large heat-recovery heat exchangers (economizer and air heater). The study does not indicate how the excess air level is maintained. An oxygen trim system is assumed to be used. It is disturbing that the electrostatic precipitator is sized to handle a gas load corresponding to 50% excess air. This sizing could be merely as a safety factor, but if it indicates that the actual excess air level could fluctuate to such an extent, then the controls specified should be questioned. The boiler would suffer an efficiency loss of about 3% at 50% excess air as compared with 20% excess air.

Environmental Air Quality Design

Environmental considerations seem to have been adequately taken into account in the feasibilty study. However, one wonders whether the application of US EPA air quality standards, in the absence of existing Jamaica standards, is appropriate. The idea of improved air quality relative to that at the existing plant is an attractice concept for selling the project to donor agencies, but may entail needless additional cost since there are no apparent air quality problems in the Old Harbour area at present. Obvious cost savings in the electrostatic precipitation and the chimney components could be achieved if the requirement were made that present air quality levels be maintained.

Planning and Scheduling

The level of detail in the proposed program implementation plan described by the consultants indicates their extensive experience in such projects. Their qualification to perform such work are recognized throughout the world. However, the proposed "fast-track" schedule of 24 months to complete the first boiler is one which appears to be too short, given local conditions in Jamaica.

II.3 Cost Estimates

The cost estimates for the conversion to coal of units number 3 and 4 at Old Harbour were prepared in mid 1983. The numbers were derived from four sources:

1. fixed bids for the principle pieces of equipment 2
2. actual expenditures on a similar project in the Caribbean 3
3. standard unit costs for construction
4. labor rates provided by JPS

The costs were estimated in mid 1983 prices and were recaclualted to first quarter 1987 prices (the middle of the proposed construction period) using a 6.5% escalation rate.

Capital Costs

The capital costs for the project were divided into twelve components. The costs for three components,

1. the coal receiving and handling equipment, - including the conveyors, stackers, crushers and separators,
2. the boilers including the control systems, and
3. the precipitators,

were estimated from fixed bid quotations. These accounted for about 2/5 of the total capital costs. The costs for seven other components,

1. the smoke stacks,
2. the pneumatic fly ash handling equipment,
3. the mobile equipment for handling the coal and ash,
4. the required structures including a coal elevator,

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2. The results of these bids were not included in the report. The chapter containing this information was not released because of its confidential nature, however, the consultants indicated that the bids were from international suppliers

3 The location and nature of this project was not made clear in the report

5. the additional steam, water and air piping,
6. the electrical distribution and control systems, and
7. the upgrading of the cycle control equipment on the two turbine generators

were estimated using the reference Caribbean project adjusted for local requirements. The remaining two components, the dock facilities, including the ship unloaders, and the site preparation including land acquistion, road construction, pilings and foundation work, were estimated using standard unit costs. The actual costs for obtaining the additional land were assumed to be negligible. The original cost estimates prepared by the consultants are shown in table II.1. Their estimates are broken down into local and foreign components.

The capital costs appear reasonable except for those pertaining to the emissions control equipment and the contingency allowances. The coal conversion project includes the installation of high stacks and precipitators in order to reduce the amount of particulate emissions below there present level. The costs for these two components can be revised downward to correspond to a system which would maintain the current level of emissions.

The contingency allowances included by the consultants reflect their attitude towards the uncertainty of their cost estimates. The contingency allowance for those estimates based on fixed bid quotes was set at 3%. This figure would not be unreasonable if the project were expected to proceed on a fixed timetable commencing relatively soon after the quotes were made. However, given the uncertainties with the scheduled start of construction as well as the fact that the quotes are already more than a year old, a greater uncertainty should be attached to these estimates. For the costs that were based on the Caribbean reference project, a contingency fee of 10% was included whereas for those estimates based on standard unit costs a 20% contingency factor was introduced. These contingencies seem reasonable.

The other problems with respect to capital costs are related to the uncertainties associated of some of the cost estimates. The turbine/generators were recently reconditioned as part of a major rehabilitation project undertaken by JPS. This rehabilitation improved the conversion efficiency of the unit and extended the period until the next renewal. While these units could be maintained in good working order for an indefinite period, there remains some uncertainty as to their economic service life. The same problem applies to the existing support systems such as the air compressors, condensate and feedwater pumps, and water treatment systems which will also be maintained for use in the converted system.

The uncertainties associated with the coal handling equipment and faciliites are even more serious. At present there are no suitable docking facilities and little information was available to the consultants regarding the hydrology or the hydraulics of the proposed site. The costs for the ship unloader were based on a fixed quote which the consultants later invalidated. The estimates for the dock facilities were based on a rough estimate

Table II.1
CAPITAL COSTS FOR THE COAL CONVERSION PROJECT
(in MN $ US)

Description of Item	Total Cost	Local	Foreign
Coal Receiving and and Receiving Equipment	5.0	.4	4.6
Boilers	29.5	1.9	27.6
Precipitators	6.3	-	6.3
Stacks	3.5	-	3.5
Fly Ash Handling Equip.	1.6	-	1.6
Building Superstructures	3.7	2.1	1.6
Piping and Mechanical	9.7	1.5	8.2
Electrical and Instrumentation	6.8	1.1	5.7
Dock Facilities	15.1	3.0	12.1
Site Preparation	7.2	3.8	3.4
Upgrading Turbine/ Generators	.5	-	.5
Mobile Equipment	.6	-	.6
Total	89.5	13.8	75.7

Table II.2
OPERATING COSTS FOR COAL CONVERSION
(in 000's of US$)

Pre-Startup (2nd year only)	Total Cost	Local	Foreign
Training	88		88
Spare Parts Inventory	250		250
Operational (every year)			
salaries (14 additional employees)	190	190	
spare parts			
turbine	50		50
pulverizer	120		120
balance of plant	250		250
maintenance			
ash disposal system	90	90	
coal handling equip.	150		150
dredging	200		200
fuel oil	350		350
consumables, other O&M	280		280
training (first 5 years only)	750		750

of the costs for the civil works. While the resulting estimates are not unreasonable, the actual cost will probably be within a range of ±35%.

Operating Costs

The operating costs for the coal conversion project were computed as the incremental costs for labor and spare parts, the fuel costs for operating the coal handling and ash disposal equipment, the dredging costs for the coal pier and the costs for training both prior to and after startup. A summary of the operating costs estimated by the consultants is shown in table II.2. These costs include both the pre-startup and post-startup costs.

The salaries for the additional personnel required to operate the generating plant and the coal-handling facilities were estimated to be J$338,000 based on the JPS rate scale. The figure shown in table II.2 were obtained by converting this number to US$ using the official exchange rate in force at the time and escalating by 15% per annum. The pre-startup training costs are for training of the plant operators, exclusive of the boiler operators. The training costs for the boiler operators were estimated to be US$212,000 and were included in the capital cost for the boiler. The post-startup training is primarily for technical supervision during the first five years of operation. The cost of the spares inventory shown in table II.2 is exclusive of the US$800,000 in spare parts for the boilers and precipitators which were included in their capital costs. The annual costs for spare parts costs shown in table II.2 were broken down according to those used for the turbine/generator systems, the pulverizer, and the balance of the plant. The spares for the turbines are the additional costs required to maintain the turbine/generators in the new configuration. The annual cost for dredging was approximated by assuming that the coal pier would have maintenance dredging performed once every five years at a cost of US$1 million. Estimates are also included as to the costs for the fuel used in the existing oil-fired generators to provide electricity for operation of the coal-handling and ash removal facilities as well as for auxilliary power.

The operating costs, unlike the capital costs, were determined based on general experience. Several of the estimated costs appear to be unreasonable. The total costs for post-startup training over the five year period, about US$4 million, appears quite high even allowing for the fact that Jamaica does not presently have experience with coal-handling operations. This cost could be decreased either by reducing the scope of the technical assistance or by using less expensive experts (presumably U.S. salaries were used as a basis for these estimates).

The costs for spares and maintenance, on the other hand, appear low. The annual repair and maintenance costs for the plant, exclusive of the pulverizer, mobile equipment, and dredging, is about US$580 thousand or .7% of the plant costs. A more

reasonable figure would be on the order of US$1 million per year or an additional US$.42 mn per year.

Another problem with the estimates of the annual costs concerns the fuel costs. The consultants assumed that the electricity to operate the plant and coal-handling facilities would be obtained from the other oil-fired generation facilities at Old Harbour rather than from the coal-fired facility itself. The cost of this electricity was set equal to the cost of the petroelum fuel used to generate it rather than the value of the electrcity at the busbar. This approach is not only unorthodox but also incorrect. A better way of accounting for the cost of this electricity is to deduct it from the projected output of the converted facility.

The major problem with the estimates of operating costs are that they represent the incremental costs involved with operating a converted plant. Not included in the estimates are the costs for the existing staff or for the maintenance of the existing facilities. The incremental cost approach can be used only if:

1. the income from the conversion (or the savings resulting from the conversion) is also computed on an incremental basis
2. the current operating procedures for the JPS facilities are adequate to maintain the existing facilities at an acceptable level of performance
3. proper allowance is made for renewal of the main components of the plant

The first issue will be dealt with explicitly in the next section. The second issue has caused concern among the donor agencies reviewing the project. However, an increase in expenditure for maintenance would be needed whether or not the project is implemented in order to insure that the facility continues to operate efficiently over the expected planning period. The third issue appears to be a general failure to consider the life cycle costs for the equipment used in this project.4 Proper maintenance of equipment does not eliminate the need for periodic renewal of that equipment. These costs should be introduced into the calculations by allowing for explicit renewals of the mobile equipment, material-handling equipment and turbine/generators at specified periods during the life of the project. Some typical renewal periods are shown in table II.3.

The principal operating cost for this project is the cost of the fuel to generate the electricity. This cost was not included in table II.2. The unit cost for the coal was determined based on quotes from U.S. suppliers for the f.o.b. prices of steam coal with 1.5% sulfur and 12% ash, delivered to Hampton Roads. The overall conversion efficiency of the coal handling and power generating facility was estimated to be 31% or .4 tons of coal

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4. This is also a problem with the other two projects discussed in these case studies

per MW-hr generated. If an allowance is made for internal power consumption, then the conversion efficiency drops to 29.2% and the coal required per MW-hr at the busbar would be .425 tons.

Table II.3
ESTIMATED PERIODS BETWEEN RENEWALS

Item	Years between Renewals
Boilers	10-25
Ship Unloaders	15-20
Turbines	10-15
Generators	20-30
Mobile Equipment	5-10

II.4 Sensitivity Analysis

The project evaluation performed for the feasibility study was repeated using capital, operating and fuel costs escalated to mid-1985 prices. The fuel costs for both coal and petroleum were escalated based on the price forecast shown in table I.2. The mid-1985 price of coal delivered in Jamaica is estimated to be US$59.75/ton or US$2.17/mn Btu, while that for Bunker "C" is estimated to be US$26.20/barrel or US$4.23/mn Btu. A second project evaluation was performed using the revised costs and benefits derived from the findings of the technical and cost reviews. These revisions included reductions in the costs for training, the precipitators and the smoke stacks of 50%, 20% and 50%, respectively, and an increase in the contingency allowance for those capital costs based on fixed bids to 5%. In addition, the utilization of the facility was assumed to be 80% for the first five years (versus 70% used by the consultant's) and then to drop by 1-1/2% a year up to a limit of 60%. This decline in utilization results from the reduction in reliability with age and from the introduction of additional, lower-cost baseload capacity over the life of the facility. Finally, the construction schedule was revised from 2 to 3 years.

The results of the sensitivity tests for both the original and the revised analysis were similar as can be seen in table II.4. The expected IRR for the project is 18.6% using the consultants' assumptions (the original analysis) and 17.3% using the new assumptions (the revised analysis). The benefit/cost ratios are also similar, 1.4 for the original analysis and 1.3 for the revised analysis. However, because both the financial costs and benefits are assumed to be less in the revised analysis, the net present value is only $74 million versus $95 million for the original analysis.

The project evaluation included senstivity analysis for the major planning parameters. Those parameters which have a minimal effect on the project's internal rate of return, net present value

Table II.4

Sensitivity Test Results for the Original Project

Performance Measures	Values
Present Value of	
Total Benefits	$336,972,052.7
Total Costs	$241,993,449.7
Capital Costs	$81,510,594.6
Net Present Value	$94,978,602.9
Net Benefits/Capital	1.17
Benefit/Cost Ratio	1.39
Internal Rate of Return	18.61%

Sensitivity Test Results for the Revised Project

Performance Measures	Values
Present Value of	
Total Benefits	$329,643,673.7
Total Costs	$255,851,696.3
Capital Costs	$84,124,919.3
Net Present Value	$73,791,977.4
Net Benefits/Capital Cost	0.88
Benefits/Cost Ratio	1.29
Internal Rate of Return	17.26%

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and benefit/ cost ratio include the cost of labor and the length of time required for construction of the facility. The cost of labor has little effect because the project involves a relatively small amount of additional labor. Most of the required staff are currently operating the existing units at Old Harbour and are not included in the incremental cost of the project. A change of the labor cost of ±50% has a negligible effect on the project IRR and benefit/cost ratio. The effect of a change in the construction period for the new facility was determined by varying the time from 2 to 4 years. Since the annual net income following construction is relatively constant over the life of the project and because an increase in period of construction was assumed to spread out but not increase the capital cost, the change in construction time from 2 to 4 years produced a variation in IRR of only ±.4%, while the benefit/cost ratio remained unchanged. In the revised analysis, the construction time was varied between 2 and 5 years with the result that the IRR changed by ±1.5%, while the benefit/cost changed negligibly.

The planning parameters which have a significant effect on the feasibility of the project are the discount rate, the capital costs, the utilization of the facility, and the rate of escalation in the real cost of alternative fuels. The effect on the project's net present value of varying the discount factor between 8% and 15% is shown in Figure II.1 for the original analysis and in Figure II.2 for the revised analysis. For the original analysis, the net present value of the project varied from $145 million at 8% down to $25 million at 15%. For the revised analysis the net present value of the project varied from $115 million to $15 million. The importance of the discount factor is attributed to the relatively constant stream of net income over the life of the project. The higher the discount rate, the less important will be the net income during the later years of the project.

The effect of the project's capital costs was determined by varying these costs from -20% to +40% of their expected value. For the original analysis, the variation in capital costs produced a change in the IRR from 14.4% to 21.8% (Figure II.3). The change in net present value was from 2/3 to 7/6 of the expected value. For the revised analysis, there was a similar but more pronounced effect with the IRR varying between 12.3% and 20.5% (Figure II.4) and the net present value changing over a range of 3/5 to 5/4 of the expected value. The sensitivity of the project to change in capital costs is understandable given the small cost of annual operations relative to the capital cost.

The income obtained from the project was determined directly from the level of utilization of the installed generating capacity. The consultants had assumed a constant level of utilization of 70% of capacity whereas in the revised analysis it was assumed that initial utilization would be higher but that it would decline over the life of the project. The effect of the latter scenario is to increase the feasibility of the project by yielding higher returns early on in the project and lower yields later in the

Figure II.1

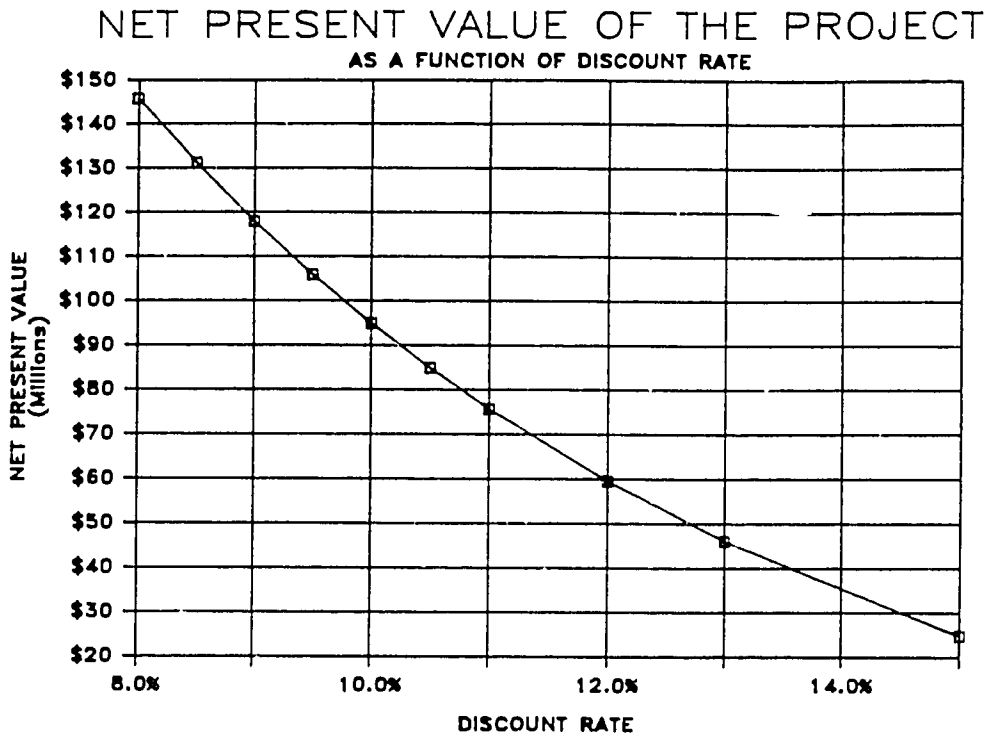

Figure II.2

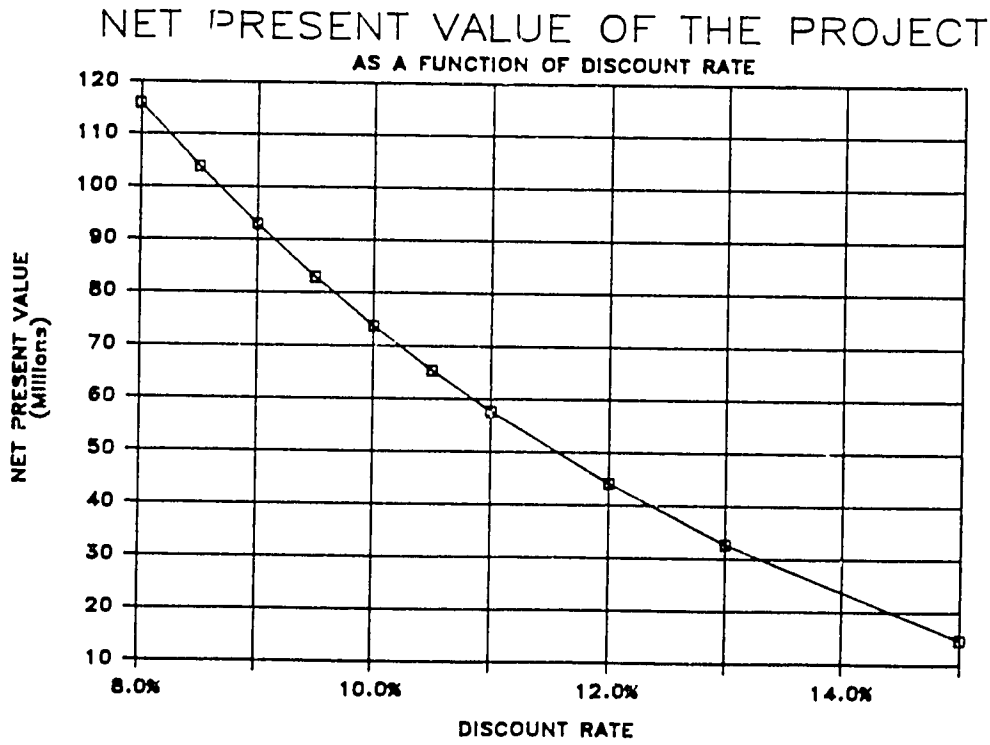

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Figure II.3

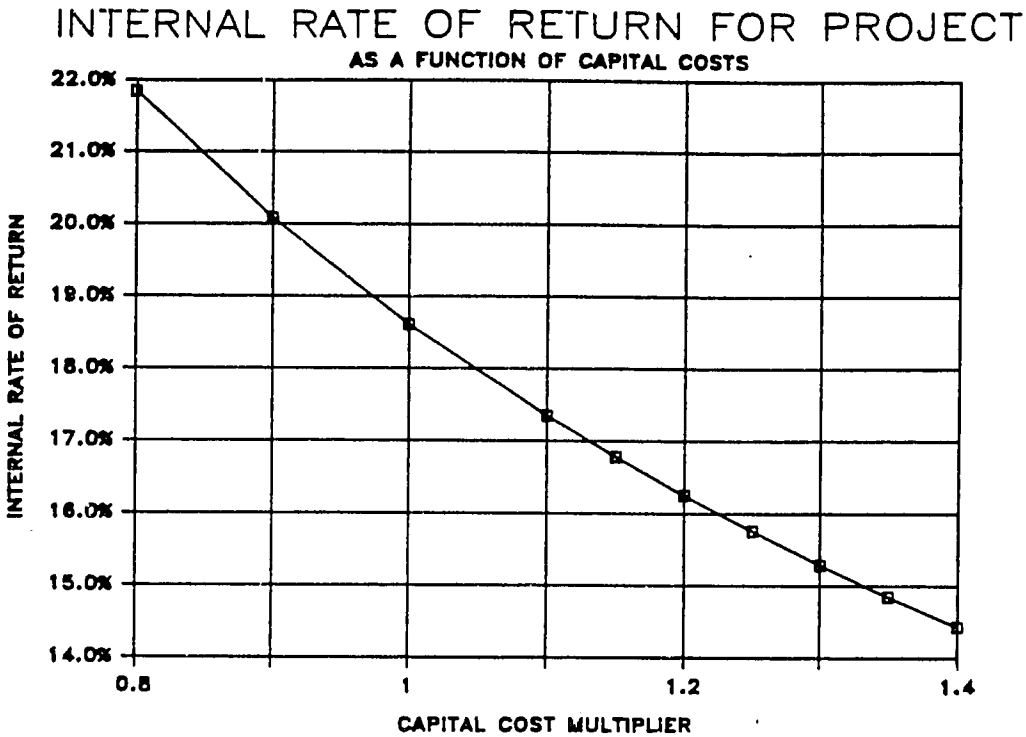
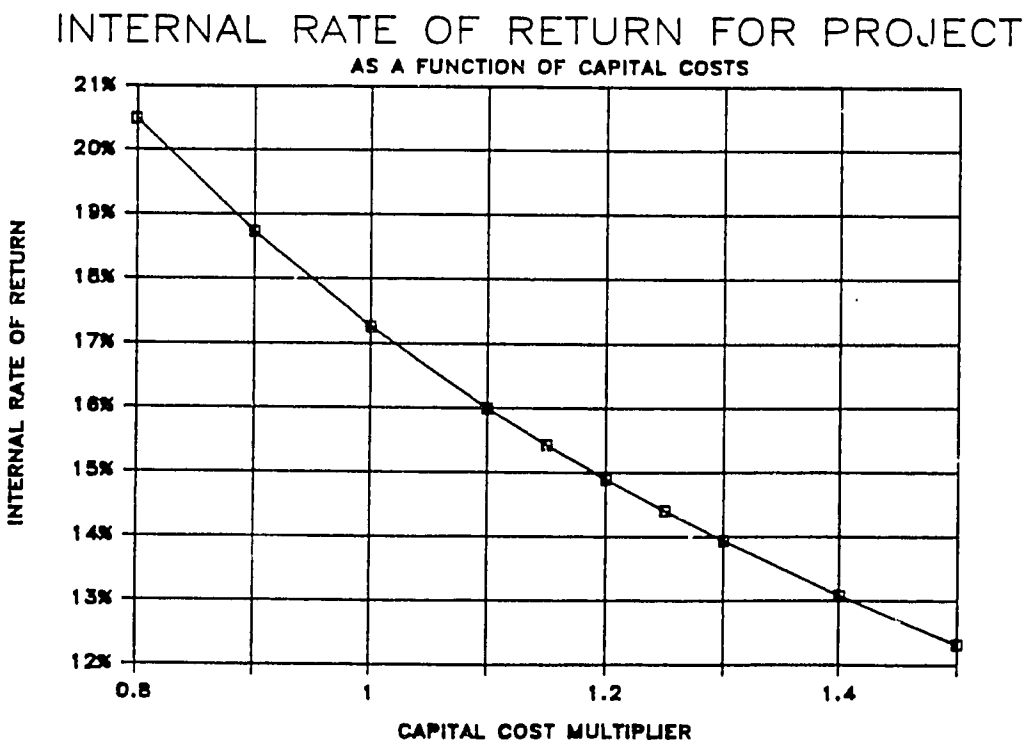


Figure II.4



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project. In both the original and the revised analysis, a change in the maximum level of utilization will have a significant effect on the expected returns from the project. A reduction in the maximum utilization from 80% to 60% in the original analysis produced a drop in the IRR from 20.7% to 16.4% and a reduction in the net present value from $122 million to $68 million. For the revised analysis, the reduction in the overall utilization by 20% reduced the IRR from 17.3% to 11.6% and the net present value from $74 million to $15 million.

The effect of the change in fuel cost was examined by multiplying the price of both the petroleum fuels and the coal by a fixed percentage. Since the coal costs less per kilowatt--hour of electricity generated, a uniform percentage increase in the price of both increases the returns to the project. For the original analysis a 25% increase in the price produced an increase in the IRR by 3.6% while a 20% reduction in the fuel price decreased the IRR by 3.1% (Figure II.5). For the revised project, the change in the IRR was almost the same (Figure II.6). The net present value for the original analysis increased by 50% with a 25% increase in fuel prices and decreased by 40% with a 20% decrease in fuel price. For the revised analysis, the net present value changed by about +50% and -60% with a similar modification in price.

The results of the sensitivity tests for the revised analysis indicate that the project is feasible for all expected ranges of the planning parameters. However, prior to the implementation of the project, a survey of the condition and useful life of the existing machinery and equipment which will be used as part of the conversion should be made. Also the potential cost for construction of a coal-handling berth should be investigated in more detail and a more precise estimate prepared of the required facility. This could be performed by local firms in a 6 month period, but more time and expense would be required to obtain relatively accurate information on the likely cost for capital and maintenance dredging. At the present time, there is significant uncertainty regarding the condition of the existing equipment and the cost of the coal-handling port facility, There is also considerable uncertainty with regards to the future cost for coal and petroleum fuels. While it is assumed that the prices for the two fuels will move together, it is uncertain how their prices will change relative to other costs. Since the financial benefits are directly affected by the change in fuel prices, the variation in price over time will have an effect on project viability. These three factors are all treated as probabilistic variables in the risk analysis described in the next section.

II.5 Risk Analysis

The effect of the uncertainties of major planning paramters on the financial viability of the coal conversion project were tested using probabilistic analysis. The capital cost for the

Figure II.5

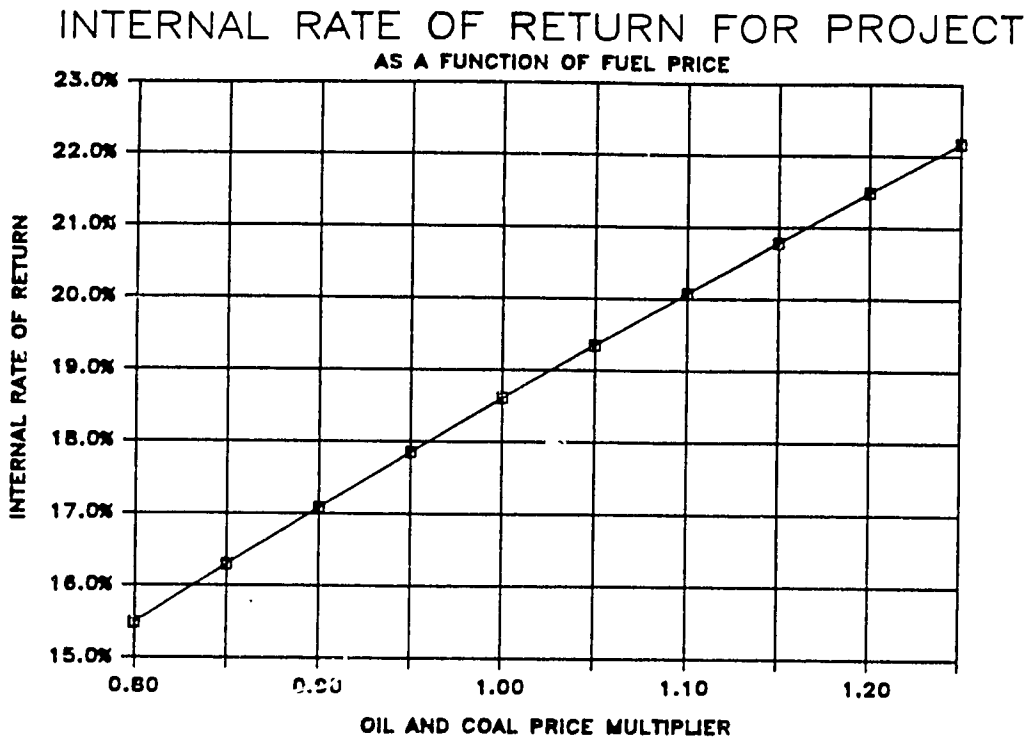
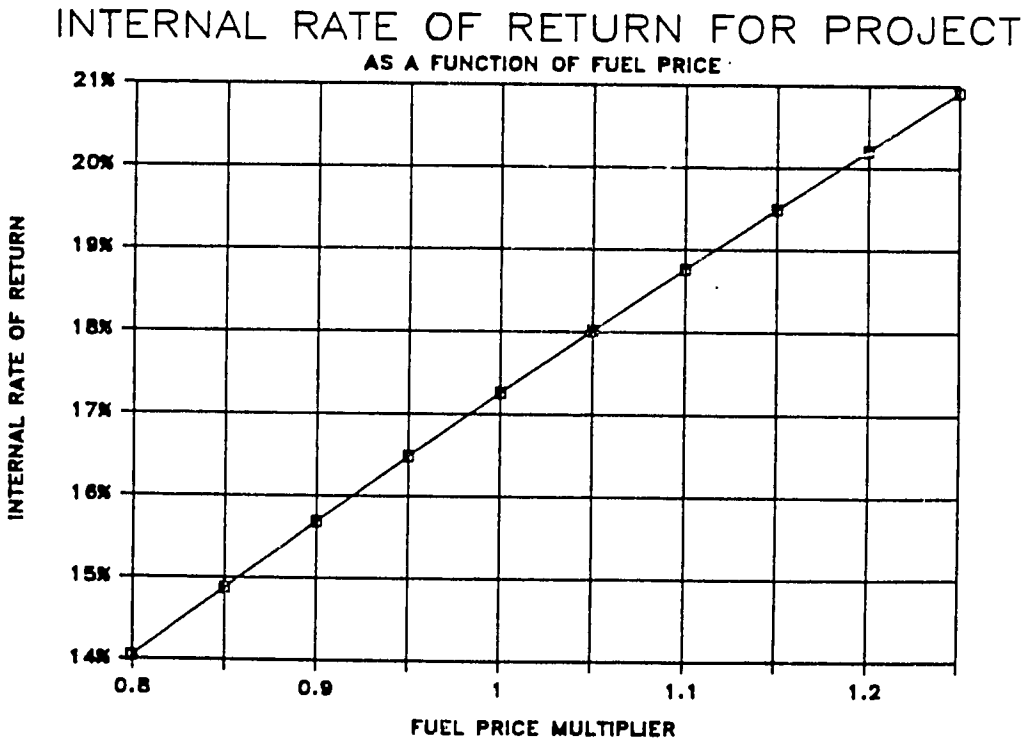


Figure II.6



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project, the level of utilization of the converted units, and the cost ofthe fuels used to generate the electricity were all treated as random variables. The probability function describing the capital cost was assumed to be a second-order Erlang distribution with the most likely value being the revised costs presented in section II.3. The minimum cost was assumed to be 10% below the revised cost. This distribution was chosen to reflect the fact that capital cost overruns are more likely to occur than cost underruns. The probability that the capital costs would exceed the most likely value by more than 20% was assumed to be 20% as shown in figure II.7.

In the revised analysis, the facility was assumed to generate an annual output equivalent to an average utilization of 80% of effective capacity. The level of utilization was then assumed to decline gradually after the first 5 years of operation. In the risk analysis, the output was modelled probabilistically using a reversed second-order Erlang with the expected value of the output equal to the level of utilization used in the revised analysis. The maximum level of output was assumed to be 5% greater than the expected value. This distribution was selected because:

1. the upper level of utilization is constrained by the required downtime for maintenance and
2. the likelihood of a lower than expected level of utilization is greater than the likelihood of a higher than expected level of utilization.

There was assumed to be a 10% chance that the output would be below 90% of the expected value. The probability distribution for this variable is shown in figure II.8. In the analysis, the output for all years was adjusted using the same value of the random variable.

The escalation rate for the real costs of the coal used by the converted facility and for the petroleum fuels used by the existing facilities was determined using the current forecast described in section I.4. This forecast used an average annual rate of increase of 4.2% for the periods 1987 to 1995. A lower growth rate, 2.5% per annum, was assumed for the remainder of the project period. In order to model the uncertainty of these estimates, the projected rates of increase in real prices from 1987 onwards were treated as random variables. The growth rate during the first eight years was modelled as a fourth-order Erlang distribution with the expected value of the distribution set equal to the 4.2% average annual rate of growth used in the original forecast and the maximum possible rate of growth set to 6%. This distribution as shown in Figure II.9 assumes that there is a negligible chance that the growth rate in price will be below 2% and an 80% probability that it will be between 3% and 5.5%. The rate of increase in real fuel prices in the period after 1995 was modelled as a normal distribution to reflect the lack of information on whether the actual rate is more likely to be higher or lower. The forecasted rate of 2.5% was used as the most likely rate and it was assumed that there is a 95% probability that the

Figure II.7

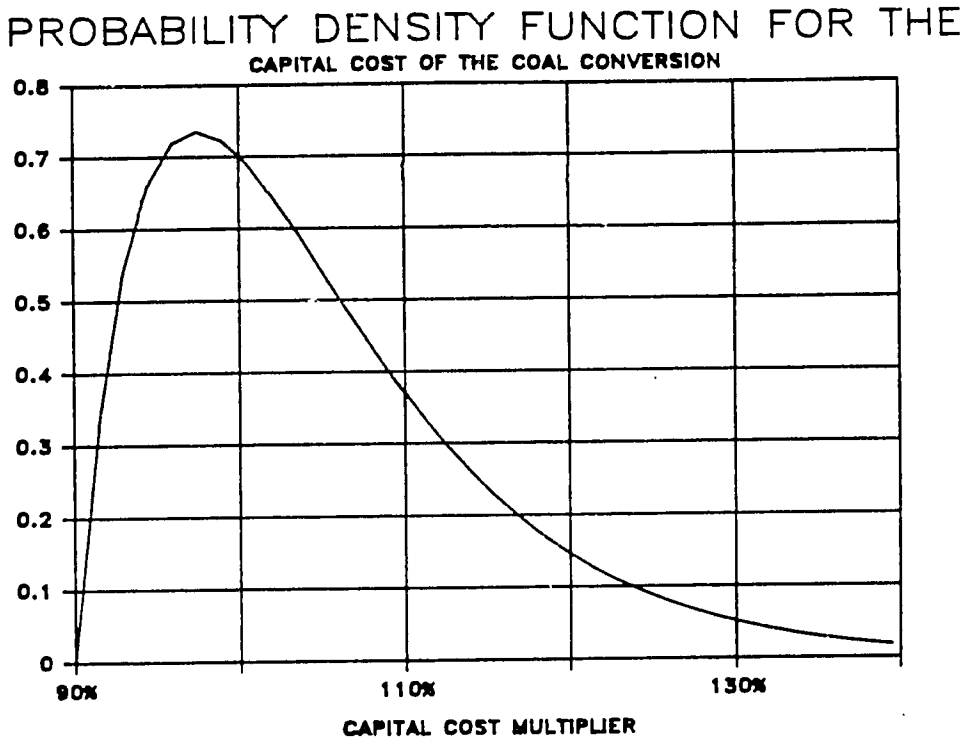

Figure II.8

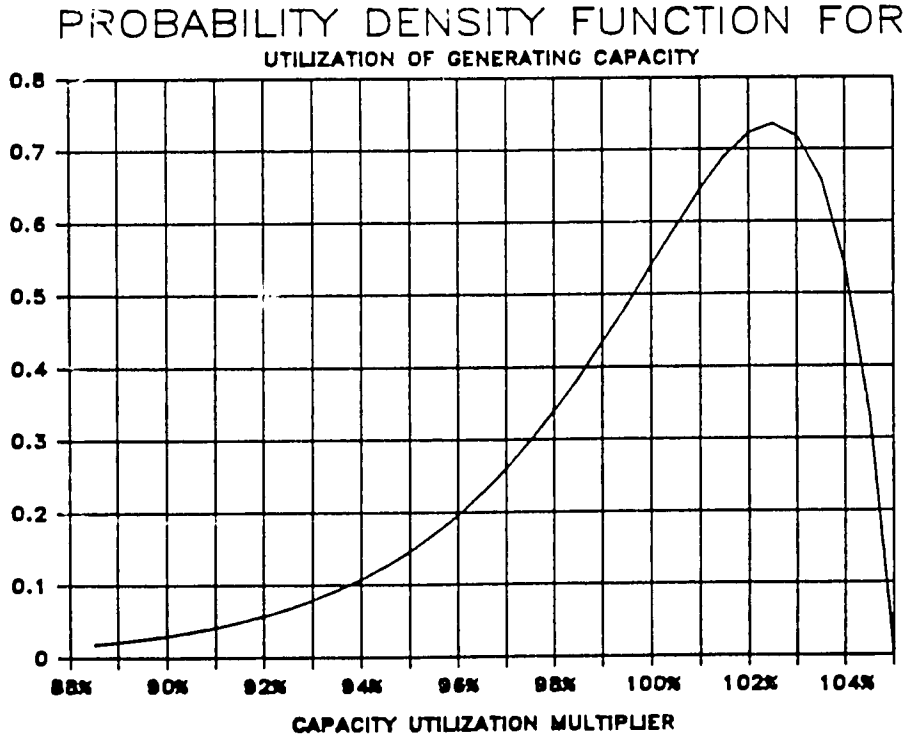

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Figure II.9

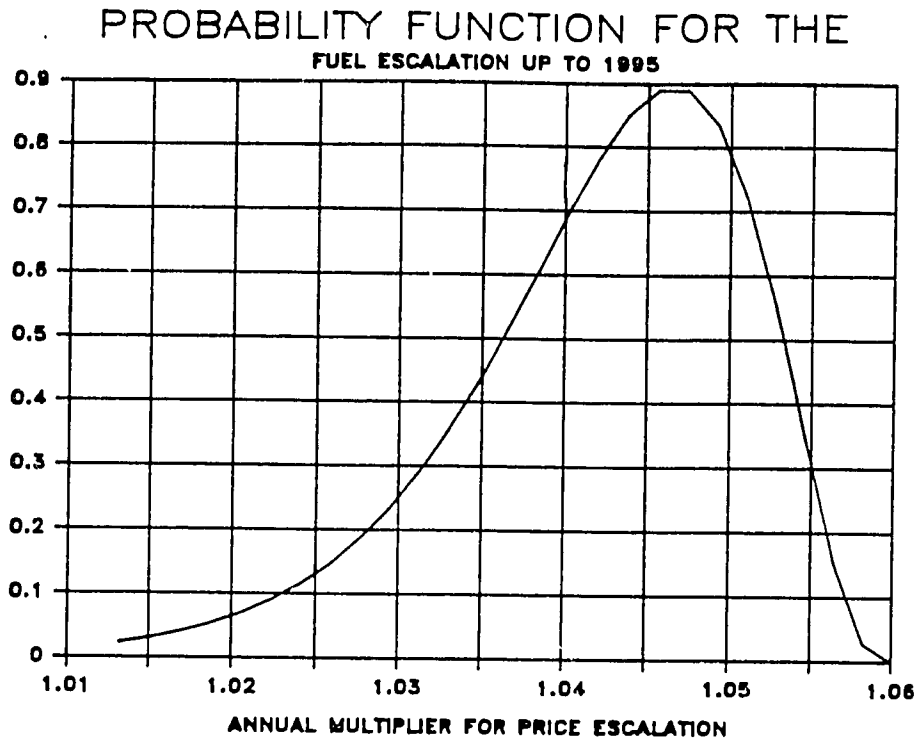
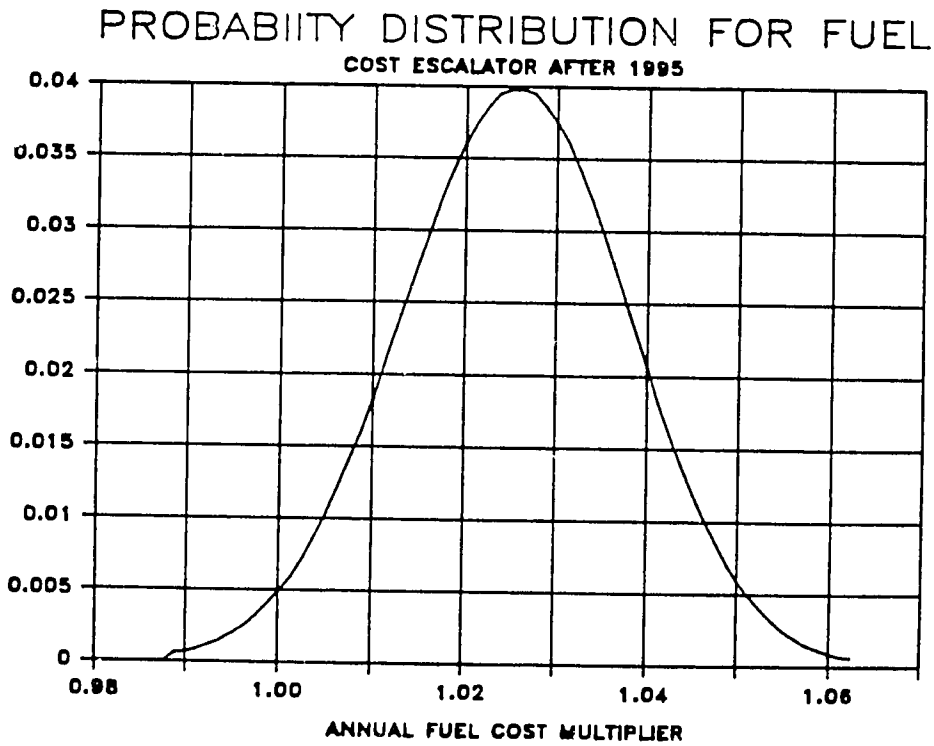


Figure II.10



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average rate of price increase for the period will be between 0% and 5% per annum (see Figure II.10).

These various probability functions were used to generate values for the three planning parameters as part of a Monte Carlo simulation of the financial outcome of the project. The simulation involved 600 iterations from which the statistics in table II.5 were taken. The results of the simulation shown an expected net present value for the project of US$67 million at a discount rate of 10%. There is a 50% probability that the net present value will be greater than this amount and 0% probability that the net present value will be negative. The cumulative probability distribution for the net present value (see Figure II.11) indicates that there is a 75% chance that the net present value for the project will be between US$40 and US$90 million. The expected value of the project's internal rate of return is 16.4% and there is a 50% probability that it will be between 15.3% and 17.6%. The cumulative probability distribution for the IRR shown in Figure II.12 indicates that there is a negligible chance that the rate of return will be below 12% or above 20%.

The conclusions which can be derived from the risk analysis are:

1. The coal conversion project is viable for all foreseeable outcomes of the project.
2. The expected internal rate of return for the project is below the value stated in the feasibility study but is still greater than the discount rate
3. The degree of uncertainty of the project's outcome, as measured by the coefficient of variation for the the internal rate of return and the benefit cost ratio, is smaller than for the other projects considered in this report.
4. The uncertainties concerning the reliability of the existing equipment which will be used in the converted facility have not been dealt with in the risk analysis due to a lack of information on the condition of this equipment following the recent rehabilitation program. This information should be obtained and included in the risk analysis prior to going ahead with the project.
5. The design of the coal-unloading facility remains uncertain. Although a broad range of capital costs were used in the risk analysis without effecting the feasibility, it will be necessary to have better information on the possible design of this facility before implementing the project.
6. The life cycle costs for the generating facility both with and without the conversion have not been determined. Although it is not expected that these incremental costs will affect the viability of the project, nevertheless, they should be determined and analyzed prior to implementation of the project.

Table II.5

Results of Coal Conversion Risk Analysis

BASIC STATISTICS	NPV	RATE OF RETURN	BENEFIT/COST
AVERAGE	$67,378,974	16.4%	1.26
STANDARD DEVARIANCE	$23,133,832	1.9%	0.09
COEFF. OF VARIAT.	0.34	0.11	0.07
MINIMUM	$739,951		1.00
MAXIMUM	$125,970,635		1.49
CONFIDENCE LEVEL	84%	84%	84%
HIGH	$90,784,765	18.4%	1.35
LOW	$24,253,374	12.7%	1.09
CONFIDENCE LEVEL	50%	50%	49%
HIGH	$82,144,704	17.6%	1.32
LOW	$54,428,045	15.3%	1.21

Figure II.11

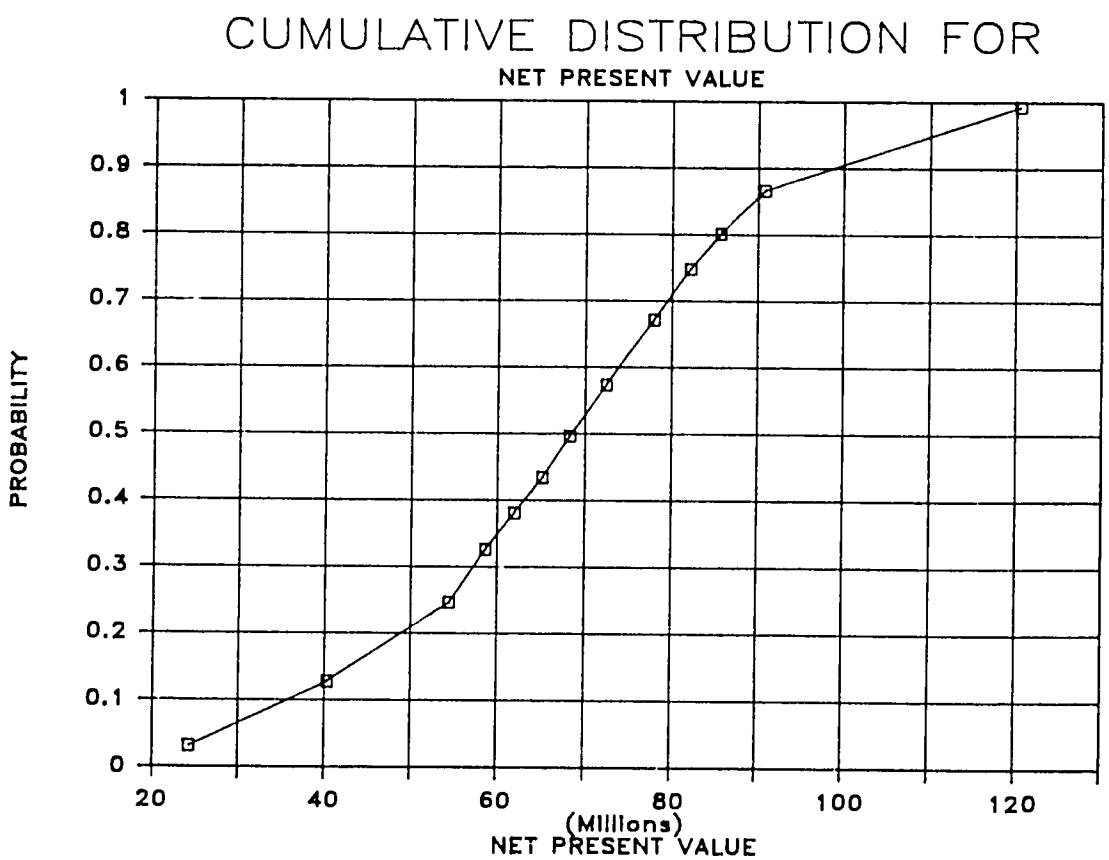
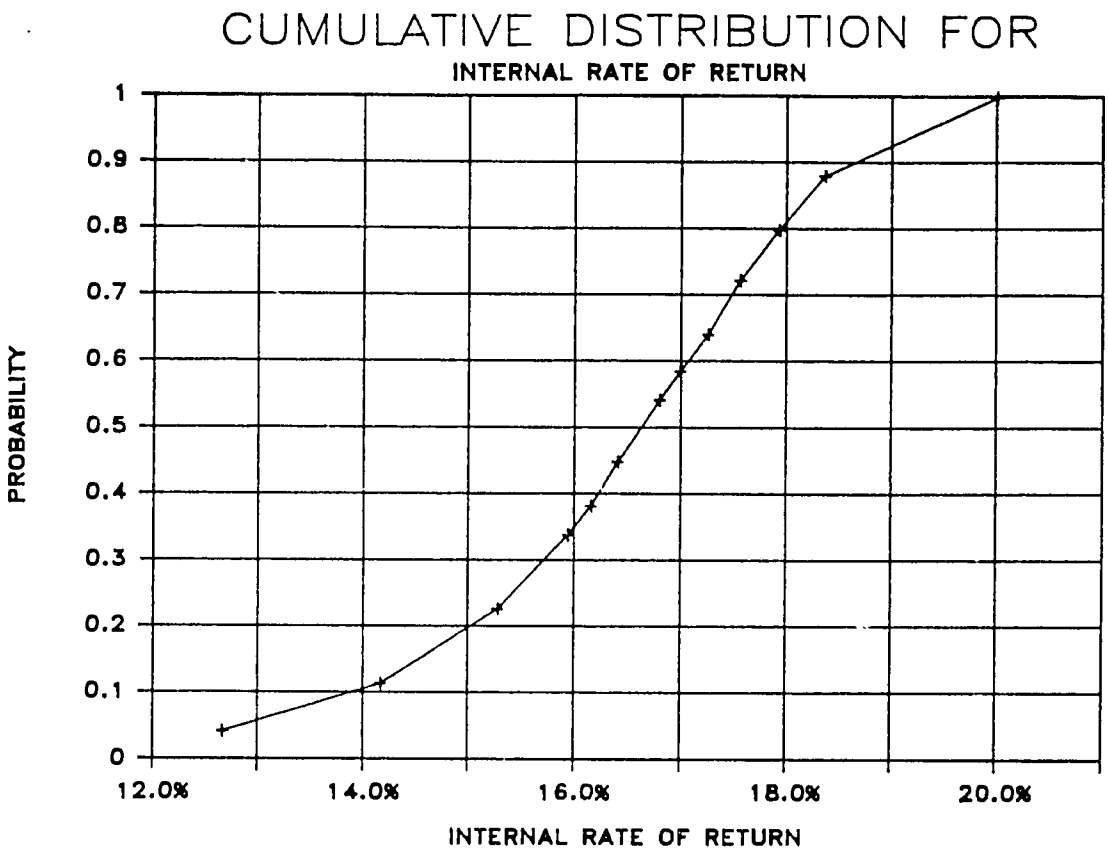


Figure II.12


CUMULATIVE DISTRIBUTION FOR
INTERNAL RATE OF RETURN
PROBABILITY
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
12.0%
14.0%
16.0%
18.0%
20.0%
INTERNAL RATE OF RETURN

Y.S. RIVER HYDRO PROJECT

Robert J. Miller, Glen Ichikawa, John Arnold 1

III.1 Background

The Y.S. River is located in the parish of St. Elizabeth. A previous survey of potential hydroelectric projects prepared by Motor Colombus in 1975 identified the Y.S. River as having hydro potential. In 1978 a feasibility study was carried out and concluded that the project was technically and economically feasible. The only reservation expressed in this report was that the project might not be environmentally sound. The water diverted for the hydroelectric project would normally flow over the falls at Ipswich which were considered a potential tourist attraction despite its relative inaccessibility. In 1983, the Italian engineering firm CESEN was contracted to carry out a study of how to utilize the Y.S. River hydro potential in an environmentally sound and economically feasible way. This study, which was completed in 1984, recommended the construction of a slightly smaller hydroelectric plant than had previously been recommended. The Motor Columbus study had proposed a facility designed to handle a maximum flow of 247 cubic feet per second and generate a maximum of 3.2 MWe whereas the CESEN study proposed a maximum design flow of 194 c.f.s and a generating capacity of 2.6 MWe.

III.2 Technical Review

The analysis of this project, as performed by the consultants, has some significant problems, especially in the areas of hydrologogical and power systems analyses. These problems can be divided into three general categories relating to:

1. the hydrology of the river and related flows,
2. the sizing of the power facility, and
3. the civil and structural design.

The problems related to the hydrology are the most serious. First, the consultants collected only 15 measurements of the flow at the Ipswich site where the diversion to the hydroelectric facility is due to take place. They did not collect downstream flow measurements at the Middle Quarters site on the same days even though most of their analysis is based on a comparison of the flows at Ipswich and Middle Quarters.

Second, the consultants used these 15 measurements to develop a stage/discharge relationship for the range of river depths up to 6 feet, even though the measurements at Ipswich

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only covered depths between 1 and 2.8 feet. They used previously collected data from Middle Quarters to estimate the relationship at Ipswich for the range between 2.8 and 6 feet. It is this latter range which is critical since the design flow for the facility would require a river depth well above 3 feet.

Third, they began collecting river depth data at the Ipswich site in August of 1981 but only collected the data through the end of the year even though the report was not completed until a few years later. The period during which the measurements were made did not include the several months of the dry season when the the river is supplied entirely by groundwater and the total flow is very low. During this period, it is likely that the facility would not be operated due to the very low flow in the river. Also there were no flow measurements taken in the several months during which there are heavy rains and there should be a large run-off component. During this latter period, the facility should be operating at its design capacity. Furthermore, the recommendation of the previous feasibility study to gather data on the rainfall was not heeded. The lack of discharge and rainfall measurements for the months in which the station is expected to operate at full capacity contributes significantly to the uncertainty of the results of this study.

Fourth, the information on the stream flow at Middle Quarters which was used for estimating the flow at Ipswich was collected only through 1981 although more recent data was available during preparation of the report.

Fifth, the consultants used a rather elaborate procedure to convert the 5 months of water level data collected at the Ipswich site to develop an a priori stage/discharge relationship. The consultants then compared these estimates with the downstream flow data recorded at Middle Quarters. The correlation between the flows at the two sites was considered adequate to base their further analysis on the results. However, since the depth/-discharge relationship used at Ipswich had been produced using data from Middle Quarters, the fact that there is a correlation between the actual flows at Middle Quarters and the theoretical flows at Ipswich proves very little. Based on the relatively small sample of flow data, the consultants extrapolated a statistical transform and used 30 years of data from Middle Quarters station to produce a table of simulated daily stream flows at Ipswich for 26 years.

Sixth, there is a seasonal flow that enters the river after the falls which may add a significant component to the flows at Middle Quarters, but not at Ipswich, during the rainy season. The size of this flow is unknown since no simulataneous flow measurements have been made at the intake site at Ipswich and the Middle Quarters. This seasonal flow was identified by the geologist on the consultant team but appears to have been ignored by the team's hydrologist. There is also an irrigation canal located between these two sites which draws water from the Y.S River. This flow was regarded as insignificant since it did not affect the consultants' correlations.

The results of the hydrological analysis leaves considerable uncertainty as to the flow actually available from the Y.S.River. The geology of the area does not provide sufficient insight as to the relationship between the flows at Ipswich and Middle Quarters because of the importance of the run-off component of the flow at both sites. Also the extent of the contributions of the irrigation diversion and the seasonal flow are not known. The previous study performed by Motor Columbus had suggested that a permanent gauge be installed at the intake but this was not done by the consultants or by the Hydrology Department.

The availability of discharge will vary with the time of year. The consultants analysis indicates that the low discharge months include December through April. In these months, the facility would produce little or no electricity. Therefore, it is unclear whether the facility should be operated at all for this period. The high water months are August through October when there should be sufficient flow to operate the facilty at capacity in most years. The variation in flow with time of year would cause the amount of electricity generated during the year to vary from zero to the design capacity. Over a ten year period, the amount of electricity generated would vary by a considerable amount, probably as much as ±50%. This variation could have significant affects on the feasibility of the project. The lack of flow data from the Ipswich site increases the uncertaintly regarding the flow. The uncertainty due to lack of data will be correlated from year to year whereas the effects due to variation in annual rainfall will be random from year to year.

The sizing of the facility was based on the estimates of the annual flow. The uncertainties regarding this flow cast some doubt on the selection of the size of the turbines. In addition, there are some problems with the procedure used to convert the estimates of flow into the most appropriate size for the turbine/-generators. The consultants computed the unit cost of the electricity generated as a function of the size of the turbine/-generator and the distribution of flow during a typical year. They then sized the turbine/generator so as to minimize the cost of electricity generation. There are three problems with this approach. The first is the use of a discount figure and expected life for amortizing the cost of the turbine/generator which was different from that used in their financial analysis. Since these parameters affect the magnitude of the costs but not the resulting choice, this problem can be ignored. The second problem is that the consultants did not use a power duration curve in selecting the sizes of the turbines. This raises the problem of the basis from which they estimated the costs of generation. The third problem is that the sizes of the turbine/generators were selected to minimize the cost of electricity generation for the facility rather than to maximize the savings for the whole system. The latter approach is accomplished by estimating the marginal costs to the system for generating a kilowatt-hour and then sizing the turbine/generator so that the marginal cost of electricity generation as a function of the size of the turbine/generator will

be equal to the marginal cost for the system. Since the consultants' generation cost curve is relatively flat for the turbine/-generator sizes shown in the report (see Figure TAB.2 in the CESN report), it is likely that a larger capacity installation would provide greater net benefits.

The conversion figures used to estimate the amount of electricity generated seem to be reasonable. The transformers have a conversion efficiency of .985 and the generators have a conversion efficiency of .95. Two turbines were used in the design so as to provide power over a range of flows from .74 to 5.57 cubic meters per second. The consultants seem to have sized the two turbines based on a standard ratio between the small and large units. The turbine conversion efficiencies range from .83 to .90 depending on the level of utilization of capacity. Since the consultants did not compute a power duration curve from the estimates of the annual flow, they were not able to include this range in their calculations of the amount of electricity generated. The use of a power duration curve would have allowed for a more careful selection of the size of the appropriate size turbines. The previous feasibility study suggested that the turbines be of equal size to allow for ease of maintenance and to limit the required supply of spare parts. In any case, a load duration curve should have been used to examine the tradeoff in cost and performance for the different sizes of turbines.

The design of the civil works and physical structures for the hydro-electric plant is far from certain since no soil samples were taken. The geology of the site is not sufficiently well known to allow for a reliable estimate of the cost for the constructing the civil works. Also, there is some uncertainty as to the ability of the weir, as designed, to hold water. If the channel cut for the intake has a significant leakage, then it will be necessary to use a grout curtain and/or a lining for the storage area. This could add as much as 100% to the cost of the weir. Finally, geological tests were not made for the proposed tunnel site to determine the ability to construct an unlined tunnel. If the planned alignment includes a significant cavity, then it would be necessary to install a steel water pipe to bridge the cavity. This could add as much as 100% to the cost of the structure.

The environmental issues associated with the construction of a hydro-electric plant near the falls will not be dealt with in this case study. The consultants allowance of a minimum flow of 1/4 cubic meter per second (10 cfs) to meet "ecological-environmental" concerns appears to be low given that the current average flow is about 20 times this amount. Also, the question of the accessibility or attraction of the site to both Jamaican and foreign tourists has not been reviewed.

III.3 Cost Review

The cost estimates for construction of the hydro facility are presented in chapter 5 of the consultants' report. These costs were calculated in reasonable detail given the information available. However there are certain problems with these estimates and with the information used to prepare them. The most serious problem is the separation between foreign and local costs. In general the consultant's over-estimated the foreign exchange component of the capital costs and underestimated the local costs. This appears to have resulted from an arbitrary division of local and foreign costs according to fixed proportions. As a result, foreign exchange costs were assigned to activities such as clearing vegetation and other site preparation activities which would be entirely local costs. In order to update the costs presented in the feasibility study and to reallocate costs according to the foreign and local components, discussions were held with a local representative of the consultants. During these discussions, it was determined that the the costs for the project were currently being revised. It was also determined that the costs and time for construction should be modified to account for construction of the pressure gallery which would require 18 months rather than the originally anticipated 8 months and therefore would represent the project's critical path.

The change in the schedule has an important impact on the labor costs. These costs were recomputed using the revised construction schedule shown in Figure III.1. The new schedule requires 22 months rather than the originally proposed 18 months and would require five construction crews. The allocation of this labor and the monthly costs are shown in table III.1. The cost of the additional labor did not significantly increase the total capital costs for the project. The final estimate of the capital costs for the hydro facility amount to US$3.5 million or more than US$1500 per installed kilowatt versus the original estimate of about US$3 million or US$1300 per installed kilowatt. The cost for site preparation decreased by about 9% from the original estimates and the cost for the power house was reduced by 25%. On the other hand, the cost for the surge tanks increased by 88% and the cost for the pressure gallery rose by 72%. Whereas the original estimates combined the indirect costs and the contingency fee, the revised estimates have identified these as separate costs. This contingency is used to account for the uncertainties of the estimates of the various cost components. Among the principal uncertainties are:

a. the geological structure in the area of the intake, pressure tunnel and surge tank which will determine the type of construction and the resulting costs for the facility.
b. the hydrology of the site which might justify a revision in the size of the facility to be installed and therefore in the cost of the equipment.

Table III.1

LABOUR RATE CALCULATIONS

JOB CLASSIFICATION	SKILLED UNSKILLED	MONTHLY RATE $	YARD CREWS		CREW 1		CREW 2		CREW 3		CREW 4	
			NO.	VAL.	NO.	VAL.	NO.	VAL.	NO.	VAL.	NO.	VAL.
SITE MANAGER		6,000.00	1	6,000.00								
FOREMAN		2,790.00			1	2,790.00	1	2,790.00	1	2,790.00	1	2,790.00
MECHANIC		1,860.00	1	1,860.00								
ELECTRICTIAN		1,953.00	1	1,953.00								
MASON		1,860.00			2	3,720.00	2	3,720.00	2	3,720.00	2	3,720.00
CARPENTERS		1,612.00			2	3.224.00	4	6,448.00	2	3,224.00	2	3,224.00
BLASTER		2,480.00					1	2,480.00				
WATCHMAN	UNSKILLED	1,103.52	12	13,242.20								
STOREKEEPER		1,240.00	2	2,480.00								
LABOURER	UNSKILLED	1,240.00	4	4,960.00	8	9,920.00	20	24,800.00	6	7,440.00	6	7,440.00
GATEMAN	UNSKILLED	1,240.00										
LABOURER (ASPHALT)	UNSKILLED	1,860.00										
ACCOUNTANT		4,000.00	1	4,000.00								
STEEL BENDER		1,730.00			2	3,460.00						
TOTAL SKILLED				16,293.00		13,194.00		15,438.00		9,734.00		9,734.00
TOTAL UNSKILLED				18,202.00		9,920.00		24,800.00		7,440.00		7,440.00
TOTAL LABOUR/MNTH.				34,495.00		23,114.00		40,238.00		17,174.00		17,174.00

Figure III.1

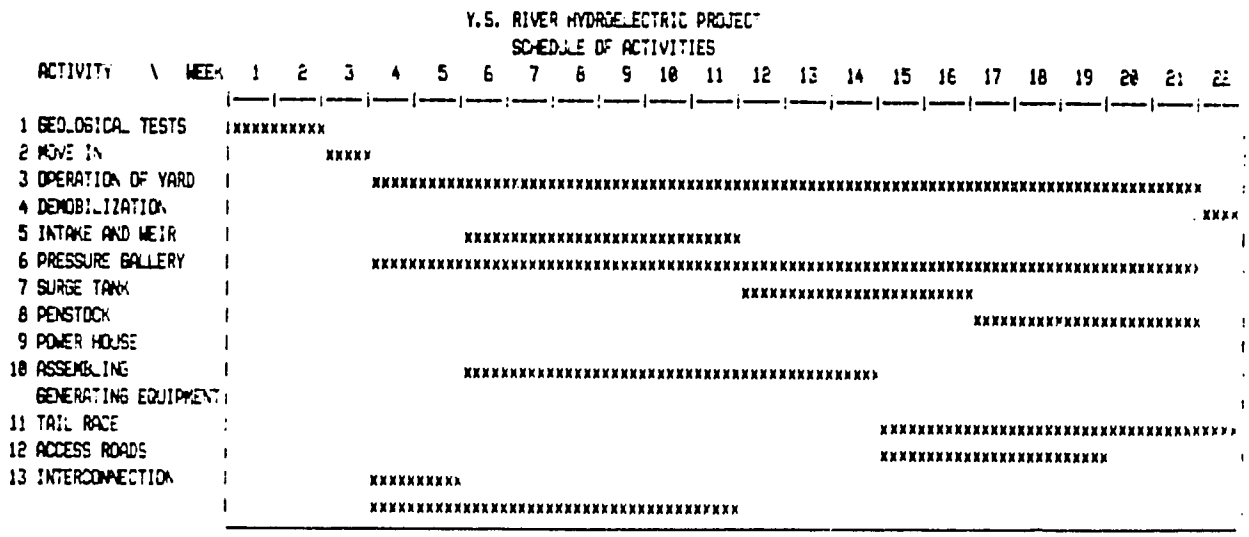

Table III.2

Project Costs for Material and Labor

Item	Local Costs Labor 000's J$	Local Costs Material 000's J$	Foreign Costs Equipment 000's US$
Access Road	355		
Mobilizations & Site Preparation	4642		
Geological Testing		160	
Intake & Weir	139	571	
Pressure Tunnel	724	2,576	
Surge Tank	116	409	
Penstock	116	39	32
Power House	206	434	1,063
Tail Race	86	129	
Land Acquisition		25	
Interconnection (6.4 miles)	351		126
Subtotal	6,735	4,343	1,230
Contingencies	1,010	651	
Engineering & Administration	451		280
Total	8,196	4,994	1,693

49

Table III.3

Construction Costs for Y.S. River Hydro Facility

Item	Expenditure Year 1		Expenditure Year 2	
	local 000's J$	Foreign 000's US$	Local 000's J$	Foreign 000's US$
Access Road	355			
Site Installation (includes the geological tests)	2853		1949	
Intake and Weir	710			
Pressure Gallery	1650		1650	
Surge Tank	105		420	
Penstock			155	32
Power House	498		142	
Electromechnical Equipment		531		531
Tailrace & Outflow			215	
Interconnection	351	126		
Land Acquisition	25			
Contingencies			1662	183
Indirect Costs	232	131	219	149
Total	6779	789	6412	895

The estimates presented in table III.2 and III.3 take these factors into account and should be considered the most likely cost for the facility.

III.4 Sensitivity Analysis

The financial viability of the Y.S. Hydro project was examined using both the original analysis as presented in the consultant's report and the revised analysis prepared as a result of the technical and cost review. The original analysis was updated to reflect mid-1985 prices. The revised analysis contains the updated costs presented in tables III.1 through III.3. These include a larger local capital cost but a smaller foreign exchange cost. The operating and maintenance costs in the revised analysis were about the same for both the local and foreign exchange costs. The amount of electricity generated by the project was the same for both analyses, but the valuation of the electricity differed. The consultants had assumed that the hydro facility would provide a substitute for the peak-load gas-turbine generating sets which have a relatively high heat rate. In the revised analysis, the hydro facility was assumed to provide a substitute for the smaller, less efficient steam-turbine baseload generators.

The results of the feasibility analyses were significantly different as shown in table III.4 primarily because the value of the electricity is estimated at US$.056 per kilowatt-hour for the savings in fuel and maintenance versus a value of US$.09 per kilowatt-hour used by the consultants. As a result, the IRR for the revised analysis is 11% whereas the consultants estimates produce a rate of return in excess of 21%. At a discount rate of 10%, the original analysis indicated a net present value for the project of nearly US$3.4 million whereas the revised analysis indicated an NPV of only US$.2 million. In neither case were the results significantly affected by changes in the operating and maintenance costs. A 50% change in these costs changed the IRR by less than a percentage point.

The factors which had a significant effect on the feasibility of the project were the discount rate, the capital costs, the costs of the fuel for the existing generating capacity, and the level of utilization of the hydro facility. A change in the discount rate from 8% to 15% for the original analysis produced a change in the net present value of +42% to -63%. The same change in the revised analysis changed the NPV from US$1.1 million to -US$1.1 million (see Figure III.2). A change in capital costs has a signficant effect on the outcome of the original analysis but has less of an effect on the revised analysis. In the former, a reduction in the capital cost of 30% increases the project IRR by +8.6% whereas a 50% increase in the capital costs will reduce the IRR by 7.2%. In the revised analysis, a similar change in capital costs caused a change in IRR of just ±4% (Figure III.3).

Table III.4

Results for the Revised Analysis of the
YS River Project

Performance Measures	Values
Present Value of	
Total Benefits	$3,879,840.6
Total Costs	$3,667,590.5
Capital Costs	$3,481,107.7
Net Present Value	$212,250.1
Net Benefits/Capital Costs	0.06
Benefit/Cost Ratio	1.06
Internal Rate of Return	10.59%

Figure III.2

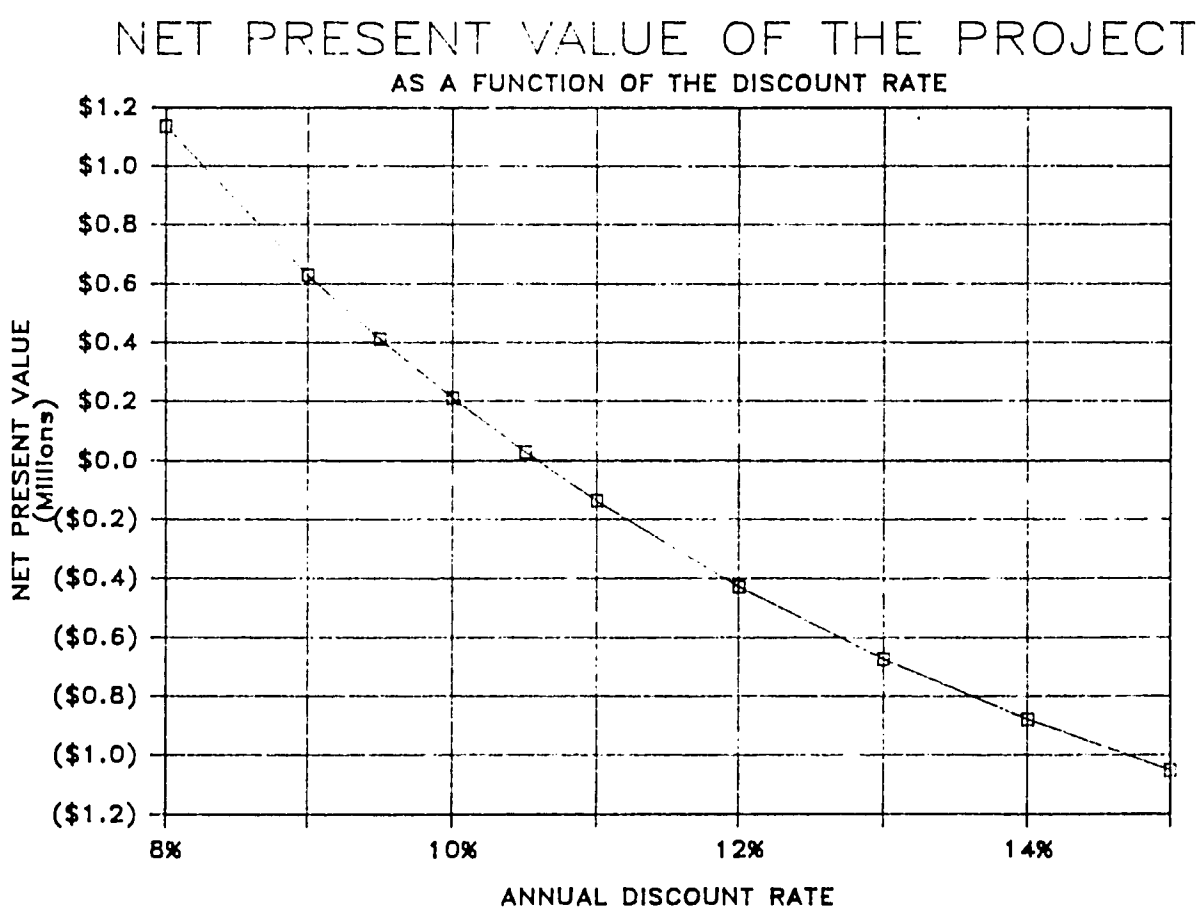

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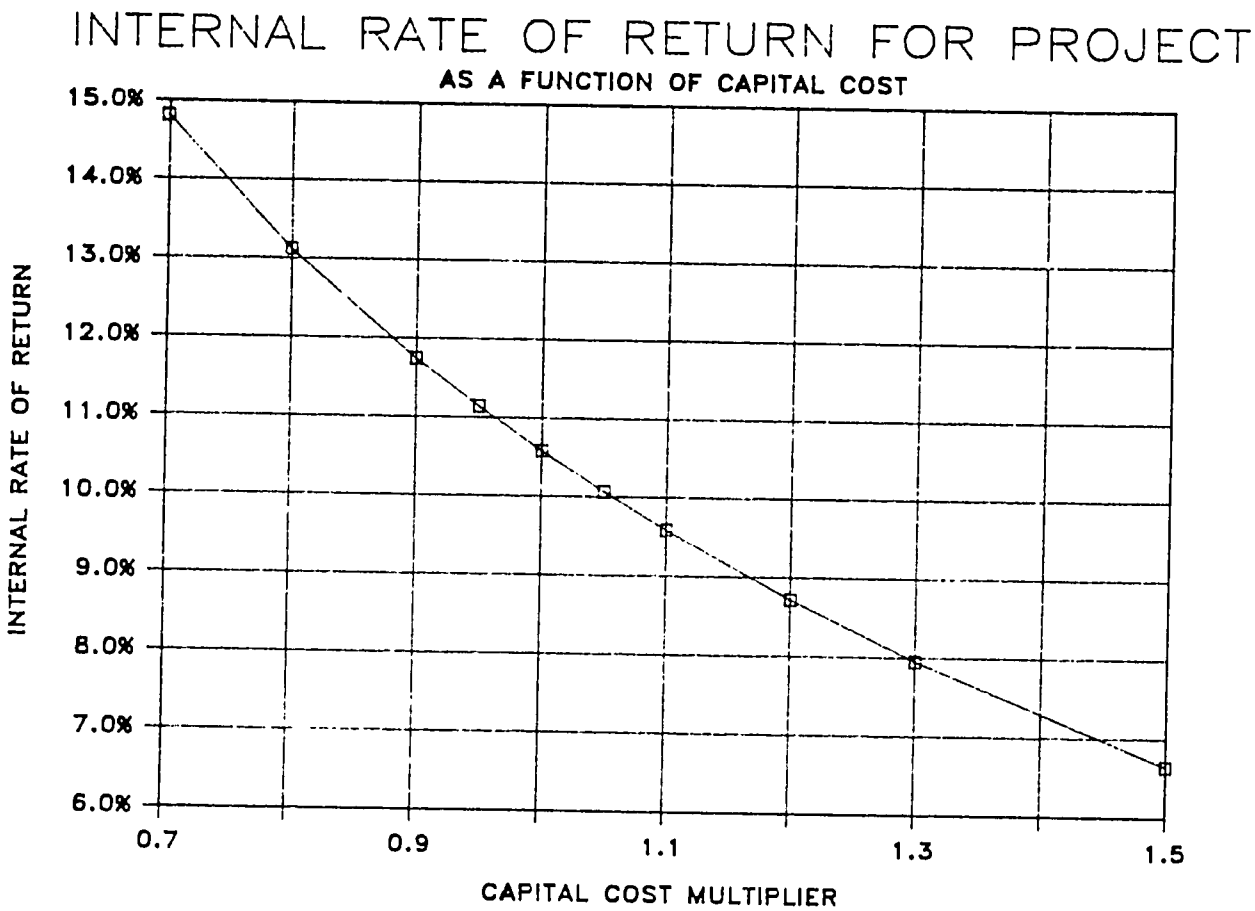
Figure III.3



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The benefits from the Y.S. Hydro project are computed as the savings in the fuel which would be used by alternative generating facilities if the hydro facility is not available. As a result, the benefits are determined by the level of utilization of the facility and the costs of the fuel which would be used. The original analysis suggested that the hydro project would produce an average of 9.5 gigawatt-hours per year. However, the basis for this estimate is a series of assumptions and some circular reasoning which raise serious doubts as to the accuracy of this estimate. If the output is reduced to 7.5 gigawatt hours per year then the project IRR will drop from 21.4% to 15.8% in the original analysis and from 10.6% to 8.2% in the revised analysis (see Figure III.4).

The value of the fuel savings which result from the output of this facility are determined by the fuel prices for medium distillate (diesel) in the original analysis and for fuel oil (Bunker C) in the revised analysis. The prices for these fuels were estimated using the projections presented in table I.2. If the prices were to increase by 25%, then the IRR for the revised analysis would increase to 13.6%. On the other hand, if the price were to decrease by 20% then the IRR would drop to 8.4% (see Figure III.5) For the original analysis, a decrease in the value of electricity from the US$.09 used by the consultants to the US$.055/kw-hr would reduce the IRR from 21.4% to 12.9% (see Figure III.6).

The results of the sensitivity analysis indicate that the project would be feasible for the range of values of each parameter tested. However, the project is less attractive given the revised estimates of the costs of the project and the value of the electricity generated. In order to understand the likelihood of the outcome of the project given the uncertainties involving a number of the planning parameters, a risk analysis was performed using probability functions to represent some of the parameters that appear to have a significant impact on the financial outcome of the project.

III.5 Risk Analysis

The risk associated with constructing a hydroelectric facility was examined by using a probabilistic model to evaluate the uncertainties associated with the capital cost of the facility and the amount of electricity which will be generated each year. The value of the capital cost was assumed to be a random variable distributed in the form of an Erlang-2 distribution. The capital cost for the facility as presented in tables II.2 and III.3 was used as the most likely value for the capital cost. This distribution was selected because of the possibility for higher-than-expected capital costs due to a lack of engineering data concerning the site. The distribution, as shown in Figure III.7, assumes that there is a 60% chance that the actual capital cost will be within ±10% of the most likely value but that there is a 20% chance that the costs will be more than 20% above the

Figure III.4

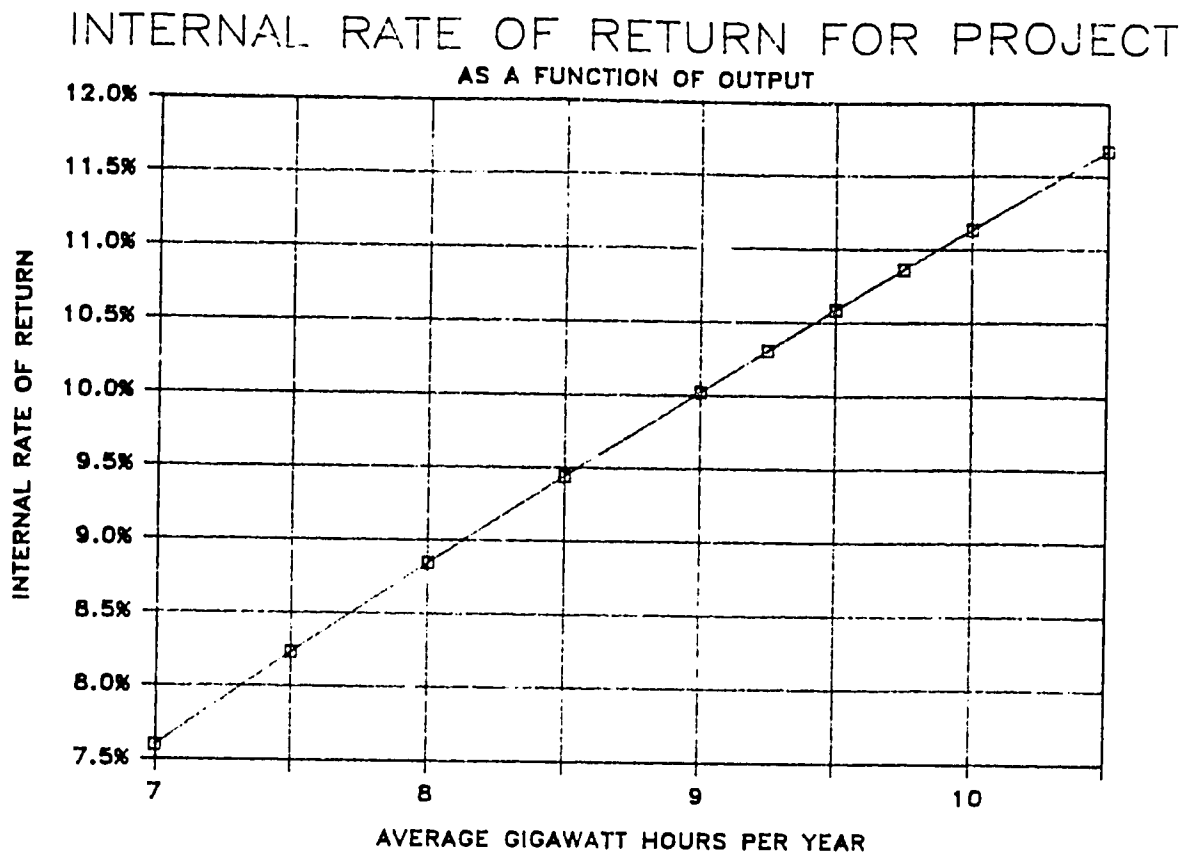


Figure III.5

Figure III.5

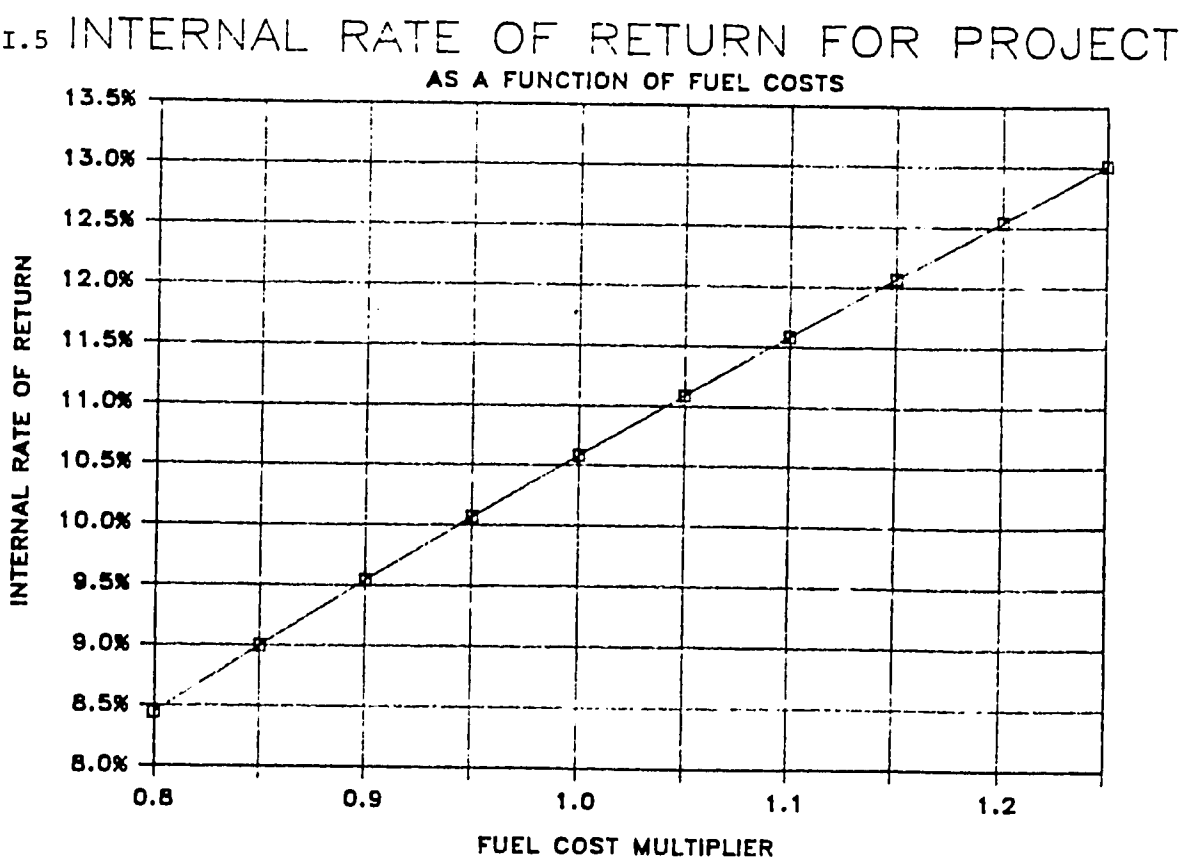


Figure III.6

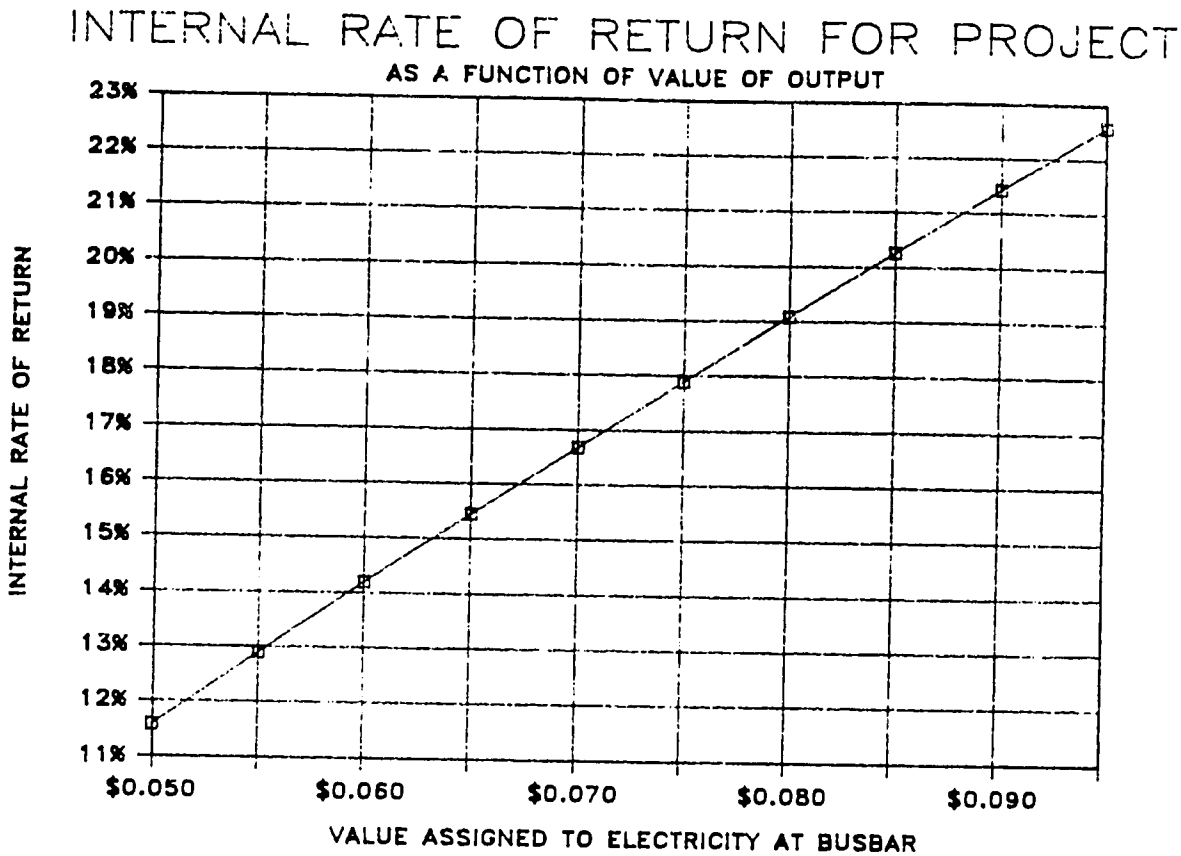
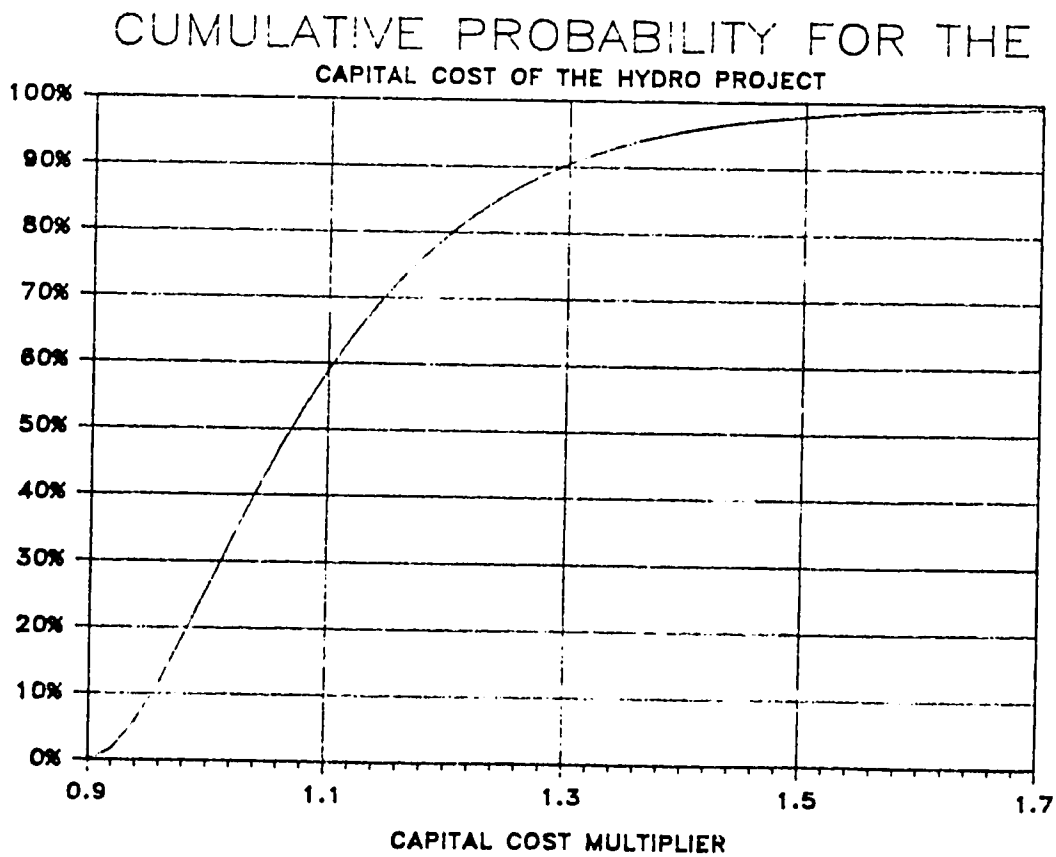


Figure III.7



most likely value.

The amount of electricity generated by the facility is controlled by two factors, the average annual flow in the river and the variation of this flow from year to year. The average annual flow was modelled as a reverse Erlang-2 distribution in which the most likely value was that amount which would yield the design output of 9.5 gigawatt-hours per year. This probability distribution was used because it includes a specific maximum flow and the probability that the flow will be below the expected amount decreases exponentially. The selected distribution assumes that the annual flow would not exceed a value 10% above the most likely value and that there is a 55% chance that the annual flow will be within ±10% of the most likely value. The probability that the facility would generate less than 80% of the design average is only 15%. The year-to-year variation in rainfall and therefore flow through the turbines was modelled by using a normal distribution with the average annual flow as the most likely value and a 95% chance that the annual rainfall will be ±20% of this value (see Figure III.9).

The probability distributions for the capital cost and the annual output were used in a Monte Carlo simulation to determine the variation in the project's performance measures. The results were computed using different values for the capital cost and the output. The values for the output were determined by first selecting an average annual flow using the probability function in Figure III.8 and then determining the flows in individual years using the probability function in Figure III.9. The simulation was run for 800 iterations and the statistics on the results were computed as shown in table III.5. The expected net present value for the project at a discount rate of 10% was -$.6 million. There is only a 25% probability that the net present value would be positive as shown in Figure III.10. The average internal rate of return was 8.5% with a standard deviation of 1.6%. This value is 2% lower than the IRR computed using the most likely values of the planning parameters as shown in table III.4. The lower IRR results from the fact that the probabilities that the capital cost will exceed the most likely value and the output will be less than the most likely value are greater than the probabilities that the opposite will occur.

The results of the risk analysis lead to the following conclusions:

1. There is a 75% chance that the rate of return from the project will be less than the financial discount rate of 10%.
2. The probabilities of a greater than proposed capital cost and less than forecast electricity output result in a 25% chance that the net present value for the project will be a loss in excess of $1 million.
3. The maximum possible internal rate of return is about 12% but there is a 60% chance that the IRR will be between 7% and 10%.

4. The level of uncertainty of the outcome of this project as measured by the coefficients of variation in table III.5, is greater than for the coal conversion project and similar to that for the peat prject even though the latter involves an untried technology. The principal reason for this is the inherent uncertainty associated with the flow of water in the Y.S. River as well as the lack of adequate flow measurements at the site.
5. The project which was considered financially viable using the parameters obtained from the technical and cost review, appears to be not viable because of the probability of a higher-than-expected capital cost and lower-than-forecast design flow.
6. The project which was considered financially viable in the feasibility report appears to be not viable primarily because of the lower value assigned to the electricity at the busbar. This value was not treated as a random variable in the risk analysis even though there is some uncertainty as to the future price of the petroleum fuel which would be saved through the introduction of this project. The results from the other two case studies indicate that the introduction of a probability distribution to describe the future fuel prices would have increased the uncertainty associated with the project but would have not increased the expected returns from the project.

Figure III.8

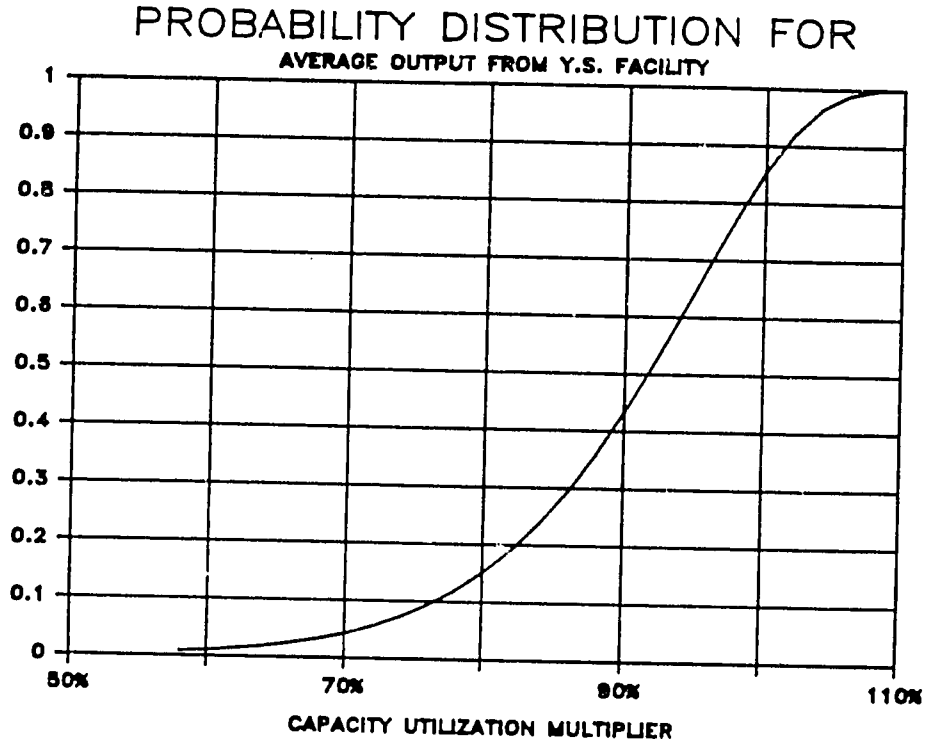


Figure III.9

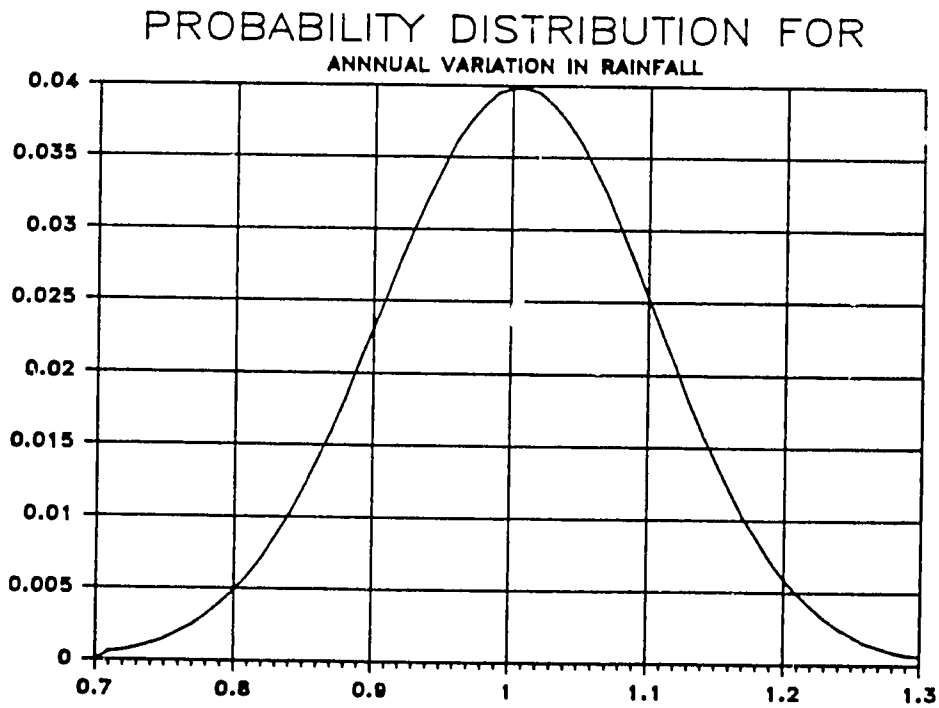


Table III.5

Results of YS River Risk Analysis

	BASIC STATISTICS		
	NPV	RATE OF RETURN	BENEFIT/COST
AVERAGE	($586,868)	8.5%	0.87
STANDARD DEVIAT.	$685,594	1.6%	0.14
COEFF. OF VARIAT.	-1.17	0.19	0.17
MINIMUM	($3,792,022)		0.45
MAXIMUM	$737,728		1.22
CONFIDENCE LEVEL	93%	93%	93%
HIGH	$255,344	10.7%	1.07
LOW	($3,517,627)	2.9%	0.43
CONFIDENCE LEVEL	60%	61%	61%
HIGH	($22,015)	9.9%	0.99
LOW	($1,198,573)	6.9%	0.72

Figure III.10

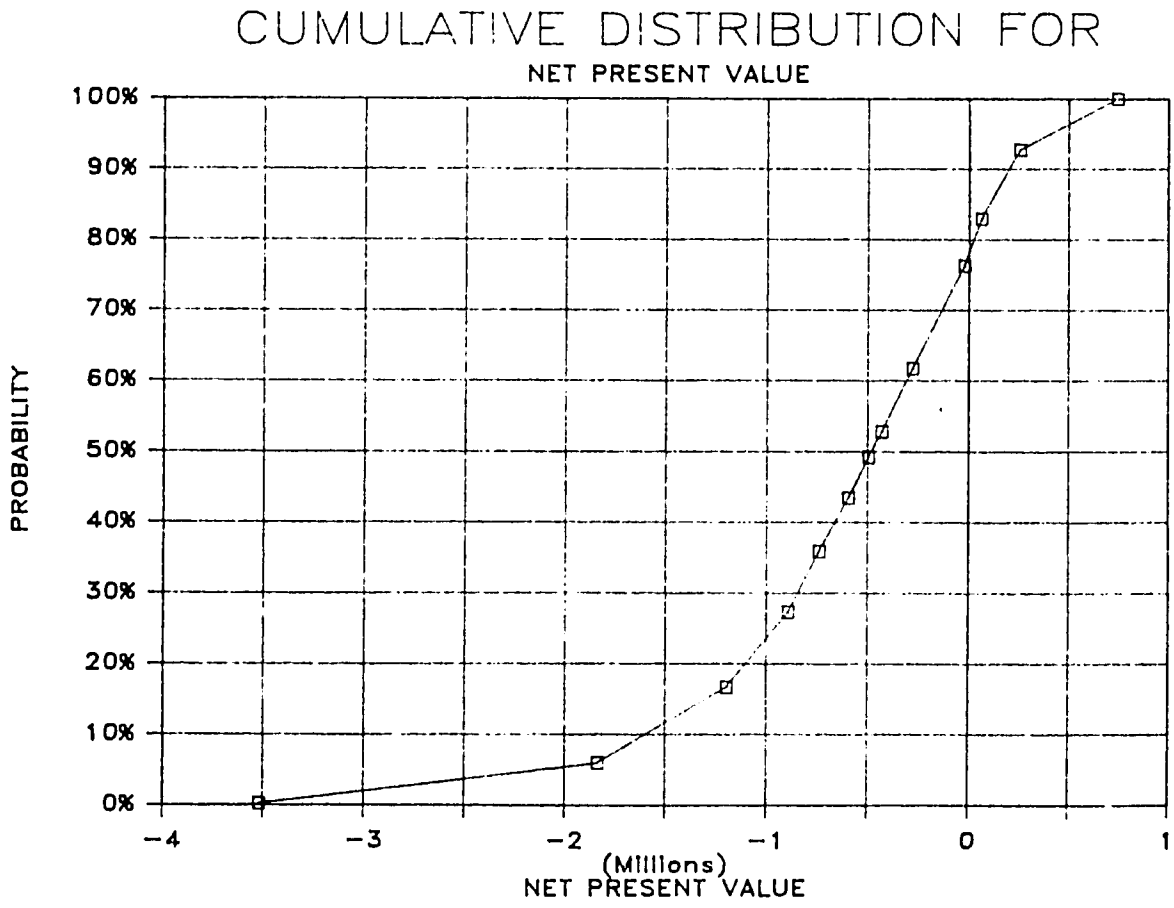


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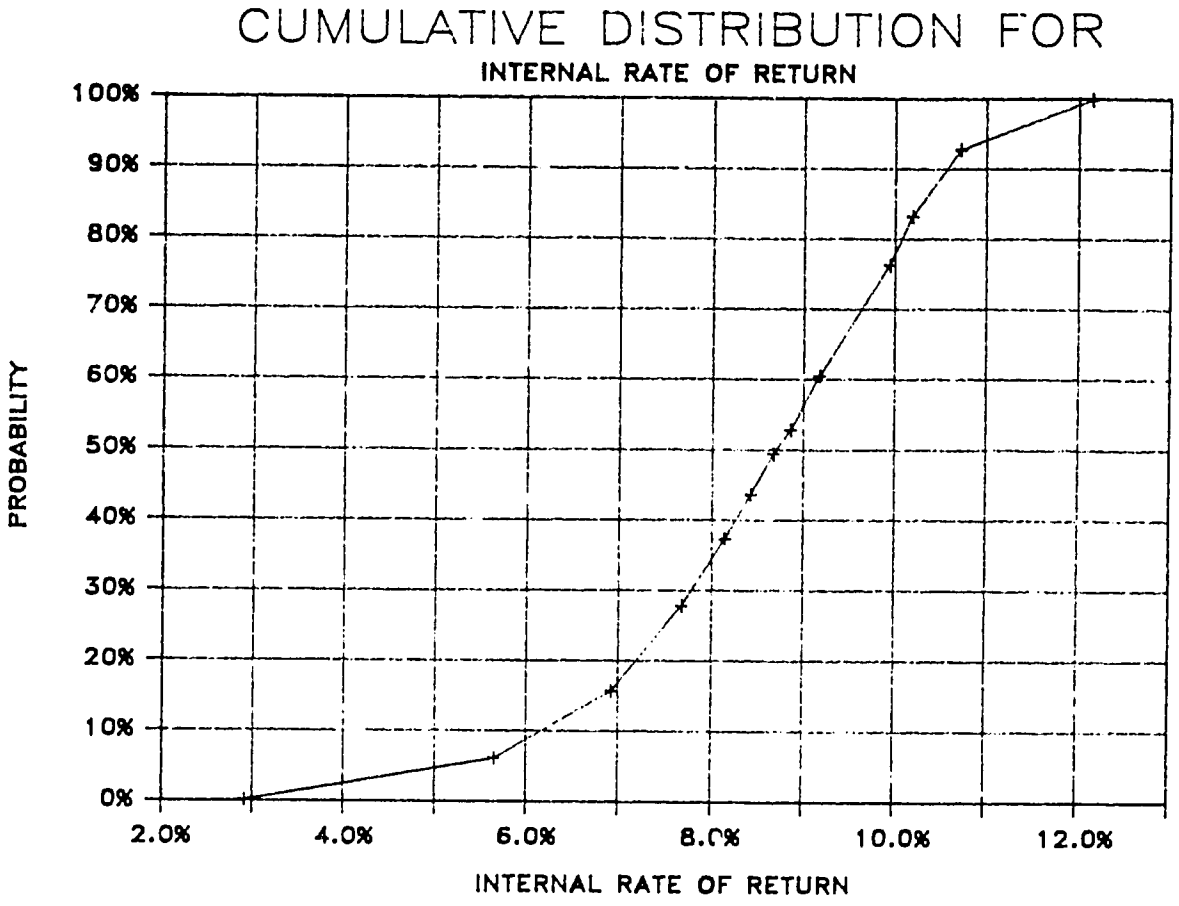
Figure III.11



Negril Peat Project

Solvalyn Eccles, Avril Benjamin, John Arnold [1]

IV.1 Introduction

The peat lands at Negril are located in a swamp behind a barrier beach. The potential of this area to produce peat as a fuel for generating electricity has been under intensive study for nearly a decade. The principal difficulty with using the peat from this area is that the swamp cannot be drained except through constant pumping because most of it is located below sea level. Various strategies have been explored over the years for extracting the wet peat from the swamp and then drying it at another location. The project as currently proposed uses a relatively capital-intensive approach to the extraction and drying of the peat in order to avoid the costs and organizational problems associated with those methods suggested in the previous proposals. Although the present proposal avoids many of the problems of earlier studies, uncertainty as to the success of the project remains because there is no prior operational experience with this system even though the different components of the system have been used in similar environments.

IV.2 Previous Studies

The first major study of the Negril Peat project was a prefeasibility study prepared by Ewbank Engineering of Ireland and submitted to the government in 1979. This study established that the peat could be used to fire a boiler. The report contained an initial project design and estimates as to the cost of the thermal station. The difficulties with drying the peat, which has a 90% moisture content (wet basis) at the time it is excavated, were acknowledged and a separate study on the cost of the land required for patio drying was prepared in 1981 by a local consulting firm, APEC. Another difficulty with the proposed project was the environmental impact of the mining operation, especially as it affected the coral reef located offshore from where the peat lands drain into the ocean. The coral reef protects the barrier beach from erosion and allows for a growing tourist industry in the area. The environmental impact of the project was studied in 1981 by the Traverse Group under contract to the National Research Council of Jamaica and in 1983 by a team from Lund University in Sweden.

The amount of peat reserves were surveyed under the direction of Professor Robinson at UWI in 1982. The results of this survey are discussed in the section IV.3. Finally in 1984, the Finnish consultants JP Energy Oy, working under contract to the

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Petroleum Corporation of Jamaica, prepared a prefeasibility, feasibility and preliminary engineering study of the project. The prefeasibility study considered five alternative methods for transporting, drying and burning the peat for electricity generation. The feasibility study examined the system selected in more detail and determined the capital and operating costs for the project. The preliminary engineering study developed the mass and energy balances for the selected system and prepared performance specifications for the major pieces of equipment in that system. In the prefeasibility study, the two alternative methods considered for transporting the peat from the wetlands to the generation facility were by barge and by pipeline. The four drying procedures considered were:

1. the use of drying patios,
2. extrusion and solar drying in ponds,
3. pressing and thermal drying, and
4. pressing, wet carbonization and thermal drying.

The two alternative methods of combustion were direct combustion for generating steam and gasification for use in a diesel-powered generator. The system selected used barges, dewatering presses, thermal dryers, and direct combustion.

The remainder of this report is concerned with analyzing the results of the feasibility study regarding the proposed system of extraction, transport, drying and combustion as described below.

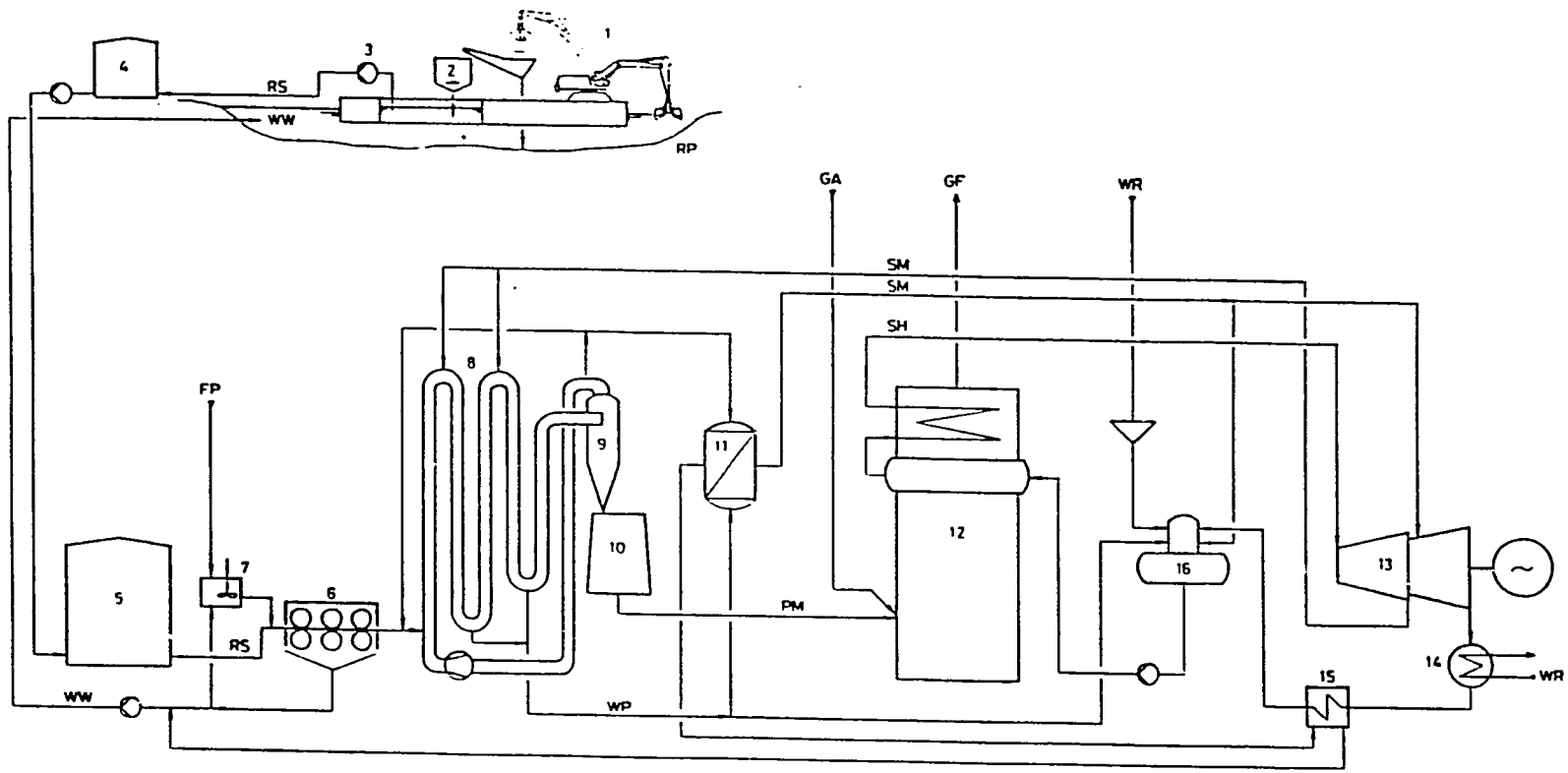
IV.3 Proposed System for Peat Extraction, Drying and Combustion

The selected peat power generation procedure would involve a multi-stage project as shown in Figure IV.1. The peat would be excavated using two barges with clam-shell excavators mounted on the deck. These excavators would dig out the morass so as to remove all except the bottom 1/2 meter of peat. The excavators would then load the wet peat into a hopper where the free water would run-off. A visual inspection of the excavated peat would be made and any pieces of wood would be removed. Each hopper barge would be equipped with two macerators for processing the peat to produce a pumpable slurry with about 90% moisture content. The slurry would be stored in the hold of the barge. The barge would also be equipped with pumps for tranferring the slurry through a floating polythene pipeline to a surge tank located at the barge marshalling area. The peat slurry would then be pumped to slurry storage tanks at the power plant via a buried polythene pipeline. The equipment on the barges would be powered with electricity provided through marine cables from the barge marshalling area. The excavation barges would move using poles located on the stern of the barge. The cables and pipeline would follow the barge and would be supported by rafts. Intermediate slurry pumping stations would be placed on these rafts as the distance between the barge and the marshalling area increased.

At the power generation plant, which is to be located away from the Morass along the coast, the peat would be transferred from the storage tanks to dewatering filter presses. The presses

Figure IV.1

Negril Power Plant Simplified Flow Diagram



LEGEND

1. EXCAVATOR
2. MACERATOR
3. TRANSPORT PUMP
4. HOLDING TANK
5. STORAGE TANK
6. FILTER PRESSES
7. DISSOLVING TANK
8. BP DRYERS
9. CYCLONE
10. FUEL STORAGE
11. STEAM REFORMER
12. STEAM GENERATOR
13. TURBOGENERATOR
14. CONDENSER
15. CONDENSATE PREHEATER
16. FEED WATER TANK

RP RAW PEAT
RS RAW PEAT SLURRY
PM PEAT FUEL
GA AIR
GF FLUE GAS
WP PRIMARY CONDENSATE
WR RAW WATER
WW PROCESS WATER

SM STEAM, HIGH PRESSURE
SM STEAM, MEDIUM PRESSURE
FP FLOCCULENTS

JAAKKO PÖYRY		
	P230-HM-2-00	N1084-02006
PETROLEUM CORPORATION OF JAMAICA		
NEGRIL POWER PLANT		
SIMPLIFIED FLOW DIAGRAM		

would produce filter cake with approximately 75% moisture content. Flocculants would be added to the slurry prior to entering the presses. The solid particles removed from the filtrate and pressate by these flocculants would be collected in a settling chest and returned to the slurry tank. The filter cakes would be moved by conveyor to the cake storage area. From there the cakes would be conveyed to the feeder bins in the power plant and then to the thermal dryers. The back-pressure thermal dryers include three stages: first, a disperger for reducing the peat to suitable size particles, second, a pressurized steam heat exchanger to reduce the moisture content of the peat to 15% and third, a pressurized cyclone to remove the steam.

The dried peat is fired in suspension in a steam-boiler furnace. The electricity is generated by a conventional steam turbine/generator. The ash from the furnace is collected in the grate and tranferred to a silo. The ash in the flue gas is removed by electric percipitators. The components of this system with their design processing rates are shown in table IV.1. The expected mass and energy flows are shown in table IV.2.

IV.4 Peat Resources

The amount of energy available from the peat in the Negril Morass was determined by measuring six parameters:

1. the area covered by the peat,
2. the average depth of the bog,
3. the density of the peat in situ,
4. the moisture content of the peat in situ,
5. the ash content of the bone-dry peat, and
6. the energy content of ash-free, bone-dry peat

The results of Robinson's survey were used to compute the area and average depth of the existing peat reserves. This study included a survey of the 2300 hectares of peat morass using a square grid of 201 meters with a total of 584 sampling points at which the depth of the peat was measured. The average thickness was found to be on the order of 5.5 meters and the total reserves were estimated to be 127.9 million cubic meters. These parameters were used in the consultant's report and are considered to be accurate within ±10%.

The bulk density of the peat from the morass was not determined as part of the Robinson's survey. The data from an earlier Bechtel report (1971) indicated a density of less than 1.0 gm/cm3 but this seemed unreasonable to the consultant's given that the saturated peat should have a density greater than water. Therefore additional tests were conducted at the consultant's laboratory in Finland where the bulk density of the <u>in situ</u> peat was found to be 1.023 grams/cm3. Because only 12 samples from four locations were tested, the average density for the bog would be within ±15% of this estimate. However, the consultant's argument that the density of saturated peat should be greater than 1.0 combined with the fact that 90% of the <u>in situ</u> peat is water (with a density of 1.0) should limit the range of possible values

Table IV.1

System Components and Performance

Activity	Units	Performance	Reserves
excavation	2 barges with clam-shell excavators	360 m3/hr with utilization 82%, 590 m3/hr overall	1 extra barge
maceration to produce slurry	2 macerators per barge		excess capacity for macerators
transport	1 pipeline per barge	580 m3/hr	surge tank with one hour capacity
	2 pipelines on shore to power station	7000m3/day	20% spare capacity holding tank with 7000 m3 capacity
pressing	48 filter presses		
storage	filter cake storage, conveyors and front-end loaders		
drying	2 feed bins: screw conveyor: disc disperger:back pressure thermal dryer, cyclone; fuel silo	100m3 @	
combustion	2 boilers; 2 turbo-generators	80% efficiency; 30 MW output	

Table IV.2

Mass and Energy Balances

Stage	Mass	Energy
raw peat	1 ton (90% m.c.)	.497 MW-hr
peat slurry	.98 ton (90% m.c.)	.486 MW-hr
peat cake	.388 ton (75% m.c.)	.482 MW-hr
peat fuel	.114 ton (15% m.c.)	.479 MW-hr
electricity	.017 ton ash	.124 MW-hr

Electricity Consumption

extraction, maceration, and transport	.0034 MW-hr
mechanical dewatering	.0016 MW-hr
thermal drying	.0100 MW-hr
steam and power generation	.0075 MW-hr

Output to Grid per ton wet peat mined = .1015 MW-hr

for the average density of the morass to ±2.5% of the estimated value.

The measurements of moisture content performed by Robinson were thought to have provided low results because of the loss of water while collecting the samples (even though a Hillier sampler was used). These measurements were performed at two different times. Each group of samples had a wide variance in moisture content. In addition, the first group of samples had an average moisture content of 90.1% whereas the second group had an average of 86.8%. This relatively small difference in average moisture content yields a difference of approximately 33% in the estimate of solid fuel contained in the excavated peat (13.2/9.9). The large variance of the data from the Robinson survey and the unreasonableness of some of the individual results made the consultants question those results. In order to provide a more reliable estimate they measured the moisture content of their 12 samples. These samples were found to have a moisture content ranging from 88% to 93%. The higher values were thought to be due to the fact that the samples were taken from close to the surface of the peat reserves. The small number of samples and the procedure of transporting the samples to Finland before determining the moisture content limited the reliability of these tests.

Perhaps the most serious difficulty with the approach taken by both Robinson and the consultants is a methodological problem. Both performed separate measurements of the density and the mositure content of the in situ peat. However, the desired information for the purpose of estimating reserves is the dry solid content per unit volume of in situ peat. The procedure used by Robinson and by the consultants provides an estimate of the average moisture content of the peat reserves which is 90% with an accuracy of ±3%. The implied accuracy of the amount of solids in the in situ peat is thus ±30%. The dry matter content could have been determined more accurately by measuring directly the amount of dry matter obtained from a given volume of in situ peat. The sample cores could be collected so that they contain a uniform cross-section of the peat from the surface to the bottom of the reserves. This procedures would significantly increase the reliability of the results.

Tests of the ash contents were made for the 12 samples collected by the consultants. The average was found to be 13.25% versus the 16% average reported in Robinson's survey. When the results of both reports were combined with the information on moisture content, it was found that there was a relatively strong correlation between moisture content and ash content which explains some of the variation observed in both studies. If the resulting regression coefficients are used, then the average ash content from Robinson's study, 16%, implies an expected moisture content of 88%. If the consultants's average ash content of 13.25% is used then the expected moisture content would be about 90%.

The heating value of the bone dry peat were measured for 65 samples in Robinson's survey. The results showed a surprisingly

wide variation of 7.6-25.0 MJ/kg, on an ash-free basis, with a mean of 20 Mj/kg and a standard deviation of 4.3. 2 The consultants performed calorimetry tests of their 12 samples and obtained a mean of 23.7 MJ/kg with a standard deviation of .9. These latter results are more reasonable given that the chemical composition of peat in a single deposit should not vary significantly. The consultants' analysis of chemical composition of the peat agreed with the calorimetry analysis when the former was converted to heating value using the Matt/Spenser equation. This equation gave a high heating value of 23.1 MJ/kg after the chemical components had been adjusted to correspond to the higher ash content observed by Robinson. Based on the evidence presented in their report, the consultant's estimate of the average heat value appears reliable despite their small sample size. The accuracy of their average heat value as an estimate of the average for the the morass is probably on the order of ±7.5%.

The estimates of the amount of fuel available in the peat deposits were prepared by the consultants assuming that 75% of the reserves are mineable. The generating units are expected to have a conversion coefficient of 20.5% from extracted peat to generated electricity at the busbar based on the energy balances presented above. This conversion factor allows for the internal use of electricity equal to 18.2% of the total electricity generated.

The expected life of the reserves assuming it is used to fuel a 60 MWe thermal generating plant can be computed using the following equation.

$$N = F * A * \bar{d} * p * (1-w) * \frac{(100-a)}{100} * E * e / (60 * h)$$

where
- N = the life of the reserve in years
- F = the fraction of the reserves which is mineable
- A = the area covered by the peat reserves
- $\bar{d}$ = the average depth of the peatreserves
- p = the bulk density of the peat in situ
- w = moisture content of the peat in situ on a wet basis
- a = the ash content as a percentage of the dried peat (0% moisture)
- E = the energy content (high heating value) of the dried peat
- e = the efficiency of energy conversion from dry peat to electricity at the busbar
- h = the effective hours of operation

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2. Of all the tests disscussed so far, the bombe calorimetry tests are the most sensitive to accurate calibration and careful laboratory procedure. Therefore, they are the most vulnerable to measurement error.

The expected life of the reserves is computed to be 26 years using the above formula. The numbers used are shown in table IV.3 along with the estimated accuracy of these values. The probability distribution for the life of the reserves was estimated by using a normal distrbution for each of the parameters and setting the standard deviations to 1/2 the percentages shown below. The resulting probability distribution is shown in Figure IV.2.

Table IV.3

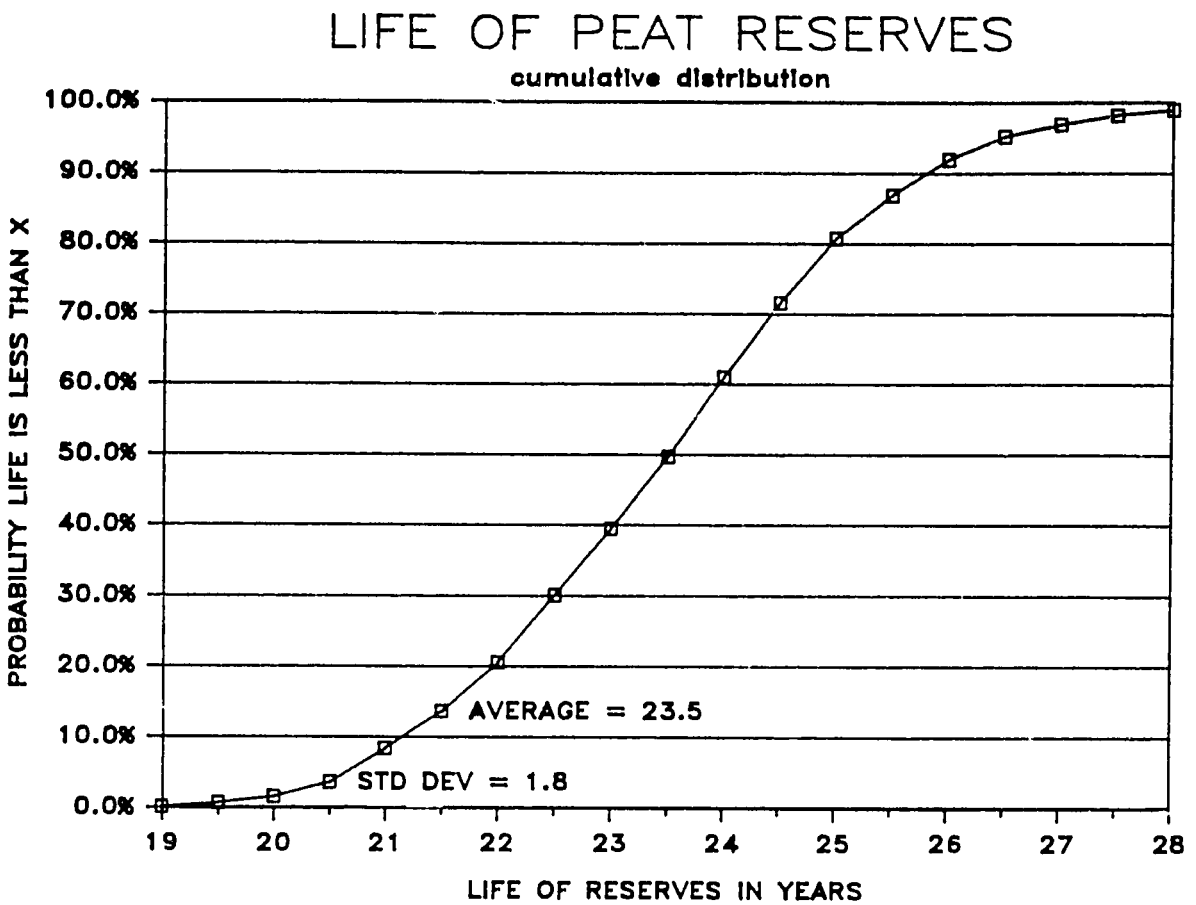
Factors Affecting Life of Peat Resources

mineable reserves	.75		±5%
areas	2300*10000	meter	3±10%
depth	5.56	meters	±10%
density	1023	kg/m3	±2.5%
solid content	(1-.9)		±3%
ash free solids	(1.-.16)		±2
heat value	23.1	MJ/kg	±7.5%
conversion effic.	.205		±5%
output generated	60	MWe	
energy/kw-hr	3590	MJ/kw-hr	
annual utilization	7000	hours	

IV.5 Peat Slurry Pipeline

The requirements for macreators and pipelines and for the energy needed to pump the peat from the Morass to the power plant were determined based on tests made in Finland. There the peat samples were macerated using a pulper located at the Pulp and Paper Research Institute. Using the results of these tests, the consultants estimated the residence time in the pulper and the power requirements for the macerator. Since the Negril peat samples were not of a sufficient bulk to test the pumping requirements, a comparison was made with Swedish peat for which slurry pumping tests had already been conducted. The two types of peat were then tested to determine the relationship between viscosity and shear rate for each sample. Since the Negil peat had a consistently lower viscosity, it was assumed that the results from the Swedish pumping test could be used as a basis for the cost estimates. The question of how the pumping requirements would change with the length of the pipeline between the harvesting site and the barge marshalling area was not tested but an assumption was made about the change in pressure over distance and the required pumping capacity was estimated. However, it does not appear that an allowance was made for the additional energy costs for this pumping during the life of the facility. With regards to the pumping of the peat, the study concluded that: "If a more accurate design were needed, large-scale pumping trials would have

Figure IV.2



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to be carried out." Since the estimates of the costs for the pipeline and for the energy required for pumping the peat are based on very little experimental data, they must be treated as relatively uncertain parameters.

IV.6 Dewatering the Peat

The consultants tried two methods of dewatering. The first used hydraulic water suction but produced filter cake with too high a moisture content. The second used mechanical filter presses. Several varieties of mechanical presses were tested using equal quantities of sedge and mangrove. The best results were obtained with a Hynnat press which produced filter cake with a 71.2% moisture content after the slurry had been treated with flocculants. In the project design, the consultants assumed that the presses would reduce the moisture content to only 75%. Based on the measurements of the throughput of these presses, it was determined that 48 units would be required to dewater the peat slurry at a rate commensurate with the fuel requirements of the power generation facility when 100% utilized. Because of the number of tests performed, the results of this dewatering analysis are considered reliable.

IV.7 Peat Drying

One of the principal difficulties with using the peat from the Negril swamp is the drying of the peat prior to combustion. The consultants reviewed the earlier work on drying and conducted extensive tests. They found that simple patio drying would reduce the moisture content from 90% on a wet basis to 83% in 7-10 days but that additional drying time had little effect. The moisture content seemed to reach an equilibrium of 80% moisture content after several weeks. Although the moisture content could be further reduced by milling the peat after it was removed from the bog, this procedure was found to be very costly.

Due to the rainfall in this area, patio-drying can be performed only six months in the year. For a 40 MWe generator, the maximum inventory of peat which would have to be stored at one time is 525 thousand cubic meters. Because the depth at which the sod can be stored is limited, the land required for drying would amount to 330 hectares. This method of drying also requires a considerable amount of equipment for moving the peat to the patio, converting it to sod, piling it, turning it, and loading it onto trucks for transport to the power generation facility.

The estimates of the resources required for this drying activity indicated a sufficiently large cost of operation to justify adopting the alternative scheme of using thermal dryers. Since the thermal drying is a relatively energy-intensive process, tests were performed to determine both the amount of moisture which could be removed and the amount of energy required. The tests were performed using a dryer which was equipped with a heat recovery system. These tests showed that at the slowest feed

rate, the dryers were capable of reducing the moisture content of the peat cakes to 9%. These tests results were also used to estimate the equipment requirements.

IV.8 The Costs for Peat Extraction, Drying and Conversion to Electricity

The consultant's estimates for the capital costs were based primarily on two sources:

1. tender prices for the major equipment and
2. standard unit costs for construction and for smaller equipment

The split between foreign and local costs was based on "discussions with PCJ and Jamaican contractors". For the capital equipment costs, price quotes for the major pieces of machinery were obtained as shown below:

1. Dewatering Filter Presses - Hynnat Oy, Finland
2. Thermal Dryers - MoDo Chemetics Ab, Sweden
3. Steam Generator and Auxilliaries - A. Ahlstrom Osaakeyhtio, Finland
4. Turbines, generators, and feedewater systems - AEG Kanis Turbinenfadrik, West Germany
5. High Voltage Transmission equipment - JPS

These account for a little over half of the equipment costs for the project. The non-equipment capital costs are primarily indirect costs including the costs for temporary facilities and services, project engineering, construction mangement, and pre-operational expenses.

The prices used for the feasibility study were for the first quarter of 1984 when the exchange rate was US$1 = J$3.3. The inflation indexes used to update the foreign and local costs to mid-1985 prices were:

1. local wages = +15% (-33% in foreign exchange)
2. local construction and civil works = +37% (-20% foreign exchange)
3. imported machinery priced in US$ = +3%
4. local equipment = +50% (-12.4% foreign exchange)

The operating costs for peat extraction and drying and for power generation include the costs for labor, fuel, chemicals, spare parts and additional pipeline and pumps. The costs for labor were treated as a fixed cost. The consultants estimated the manpower requirements for the project and used the wage scales from PCJ to estimate the annual costs (see table IV.4). The labor is expected to operate the plant continuously and to extract and process the peat for 20 hours per day, seven days per week. The cost for the spare parts was also treated as a fixed annual cost, but no allowance was made for this expense during the first 3 years of operation. The allowance for additional piping and pumps was estimated to be $.5 mn. every three years. The consultants indicated that their estimates for these costs were based on standard unit costs but no breakdown was provided. Other fixed operating costs included the costs for insurance, training and

miscellaneous items.

The operating costs for fuels and chemicals were treated as variable costs. The fuels used include fuel oil for starting up the boilers and diesel fuel for operating the trucks and other land-based equipment. The equipment on the barge and the pumps are all assumed to be powered by electricity produced by the power plant. The fuel costs were estimated from PCJ prices quotes and from estimates of the fuel consumption of the equipment. The principal chemicals used are the flocculants which are introduced into the slurry before it enters the presses. The costs of the flocculants were determined based on a quote from a single supplier.

The principal elements of the cost estimate prepared by the consultants are shown in table IV.4. These figures were revised based on the technnical and cost reviews and were also updated to mid-1985 prices. The revisions are as follows. The original estimate of the inventory of spare parts was only $420,000 or about 1/2 percent of the total machinery costs. In the revised estimates, the spare parts inventory for the dryers and boilers was set equal to 1% of the equipment costs, while that for the moving machinery was set equal to 10% of the equipment costs. The original estimates contained no allowance for spare parts during the first three years but this was revised to begin with the first year of full operation. The estimates for spare parts also included no local costs although about 1/5 of the machinery costs are listed as being locally purchased. The split of foreign and local costs has therefore been corrected as shown in table IV.4.

The contingency factor was also revised. The consultants had used a 6% contingency factor. This is extremely low given that there is no comparable system on which to base the engineering estimates much less the cost estimates. The contingency factor was therefore increased to 15%.

The principal problem with the cost estimates is the amount of equipment allocated for excavating, slurrying, pressing and drying. The system design allows for some reserve capacity in each stage of the processing of the peat, however, these processes are sequential and very little buffer storage has been provided. As a result, the breakdown of any part of the process would have serious implications on the performance of the power plant. Since the plant is supposed to operate at about 85% of its rated capacity, there is very little allowance for a reduction in the peat excavation and processing activities except during the scheduled maintenance period of 28 days per year. In the revised cost estimates, the problem of reliability of peat supplies has been accounted for in two ways. First, the costs estimates for machinery and processing equipment has been increased by 25% and the allowance for spare parts has been increased by 20% in order to allow for increased peat extraction, processing and storage capacity. Second, the utilization of the facility has been assumed to decline over the life of the project from 85%, which is to be maintained over the first five years of operation, to 60% which is the JPS system norm.

Table IV.4

Revised Cost Estimates
(000's US$)

Description of Item Cost		Original Cost	Revised Cost	Escalated
CAPITAL COSTS				
Civil Works	FE	140	140	146
	LC	11300	1130	9040
Machinery	FE	51800	64750	66700
	LC	14200	17750	15550
Piping	FE	1900	2375	2446
	LC	200	250	219
Electrical	FE	8200	8200	8440
Equipment	LC	2600	3250	2850
Process	FE	500	625	644
Equipment	LC	200	250	219
Spare Parts	FE	400	720	740
Inventory	LC	-	240	192
Indirect	FE	9700	9700	10137
Costs	LC	5000	6500	5200
Working	FE	900	900	940
Capital	LC	6100	6100	4880
Contingency	FE	5100		
	LC	1500		
OPERATING COSTS				
Personnel	LC	990	1139	766
Replacement	FE	600	720	773
Parts	LC	200	240	219
Other Costs	LC	600	750	657

IV.9 Sensitivity Analysis

The feasibility analysis of the Negril Peat project was performed in two stages. First, the consultant's estimates of financial costs and benefits were updated from 1st quarter 1984 prices to mid-1985 prices and sensitivity tests were performed to determine the effects of changes in major project parameters on the internal rate of return, net present value and benefit--cost ratio. The parameters tested included the following:

1. the discount factor - 5% to 15%
2. the utilization of the facility - initally 60% to 85%
3. the life of the peat resources - 18 to 27 years
4. the capital costs of the facility - -20% and +25%
5. the amount of electricity generated which is required for internal use - 15% to 33%

The net present value of the project was US$105 million for a discount rate of 10% but this varied significantly as a function of the discount rate is shown in Figure IV.3. For all other tests, the project IRR remained above 17% and the benefit/cost ratio was above 1.5 (assuming a discount rate of 10%). As an example, the effect of the variation in capital costs changed the IRR by only ±4% as shown in Figure IV.4. The principal factor which affects the project's viability is the value given to the electricity generated. This value was not computed explicitly in the first stage of the analysis. Instead a fixed value of US$.09 was assigned to a kilowatt hour at the busbar based on discussions with PCJ. The sensitivity of the project feasibility to this assumption is shown in Figure IV.5. In the second stage of the analysis, an explicit calculation of the value of the electricity was made.

The second stage of the analysis took into account the various cost revisions as discussed in the previous section. In addition, the time for construction was extended to 4 years to allow for the fact that no such facility has yet been built although each of the proposed system components has been used in similar applications. The expenditure for spare parts was incurred beginning in the fifth year, the first year of operation. The level of utilization of the Negril facility was lowered to 80% for the first five years of operation and then reduced by 1-1/2% per year to take into account the reduction in efficiency of the Negril facility and the eventual introduction of newer more efficient generating capacity which will lower the position of the Negril facility on the JPS "economic dispatch" curve.

Since the Negril peat facility will provide electricity which would otherwise be generated by existing JPS capacity for its first several years of operation, the output of the facility was initially valued at the cost of the fuel which would be saved if the project were implemented. The savings would be realized by reducing the level of utilization of the less-efficient baseload units. In the future, when JPS has to expand its capacity to meet

Figure IV.3

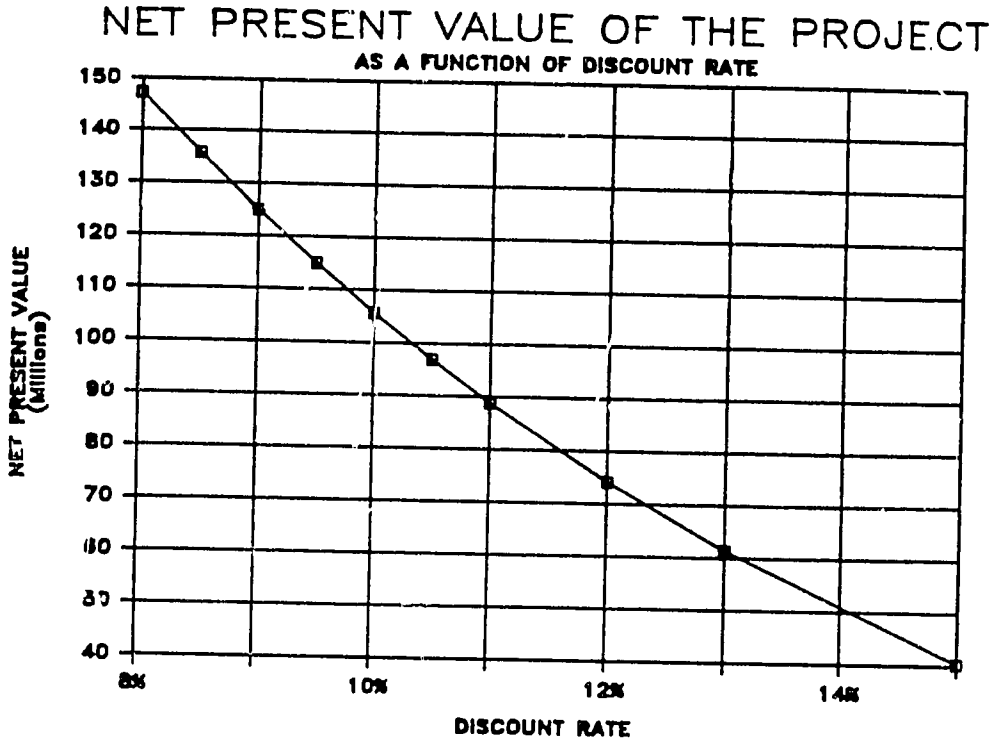

Figure IV.4

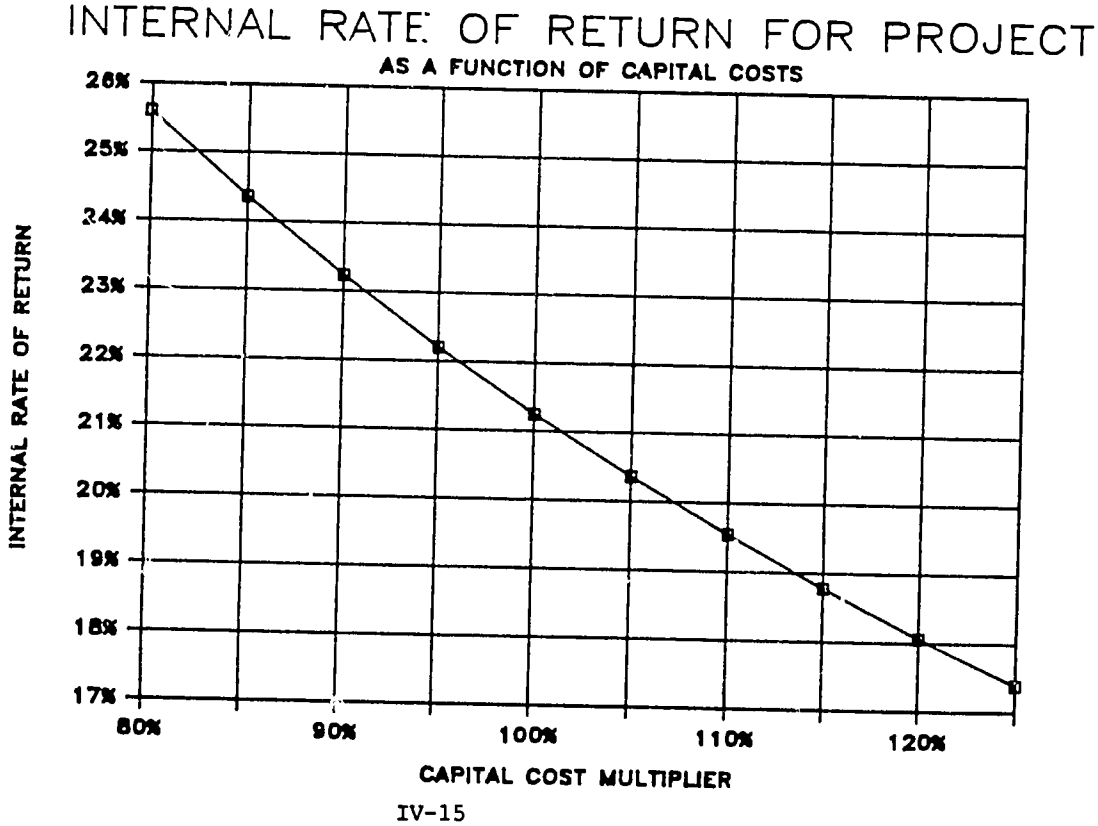

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Figure IV.5

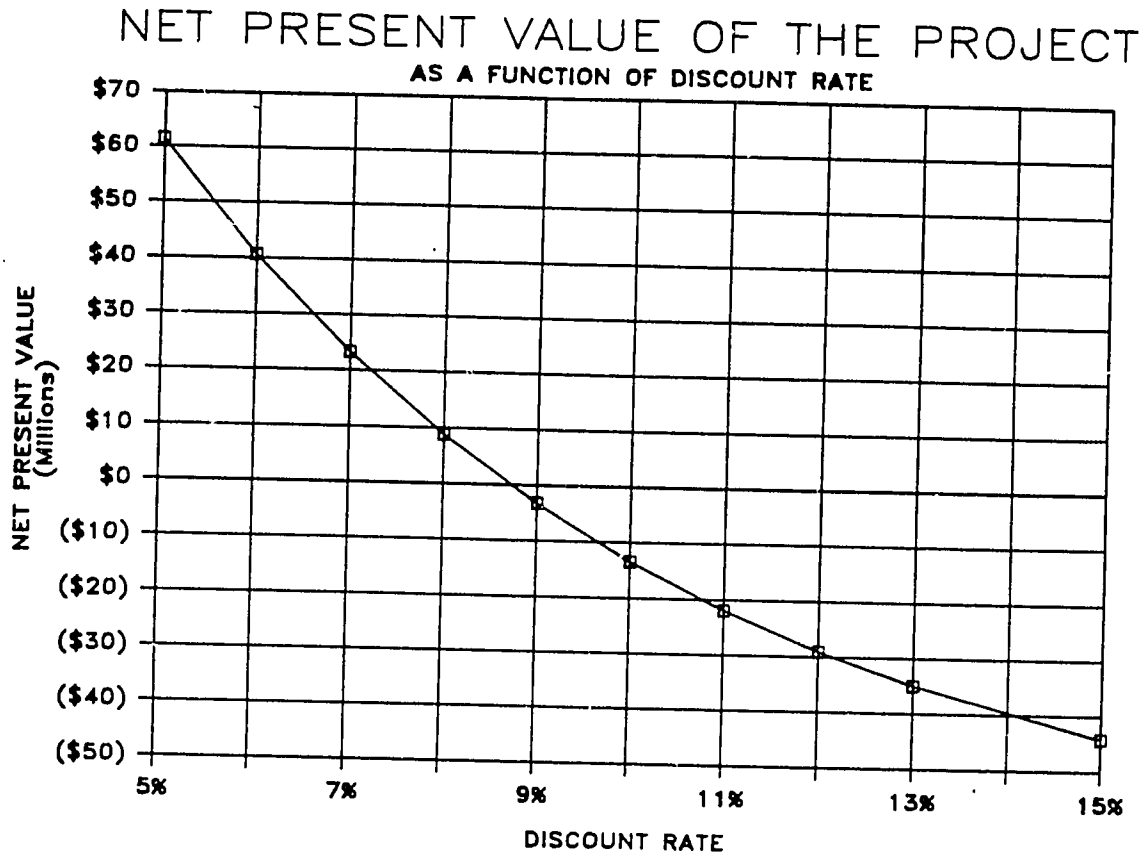


Table IV.5

Results for the Revised Analysis of the Negril Peat Project

PERFORMANCE MEASURES

	---VALUES---
PRESENT VALUE OF	
TOTAL BENEFITS	$130,828,147.1
TOTAL COSTS	$144,214,316.8
CAPITAL COSTS	$114,925,738.5
NET PRESENT VALUE	($13,386,169.7)
NET BENEFITS/CAPITAL COST	-0.12
BENEFIT/COST RATIO	0.91
INTERNAL RATE OF RETURN	8.72%

growing demand, then the Negril facility would be used for the first 40 MWe of additional capacity. Several forecasts, including the one presented earlier in this report, indicate that new capacity will be required in the second half of the 1990's. At this time, the electricity generated at the Negril unit would be valued at the cost of new generating capacity. The long term expansion plan prepared by MONENCO was used to estimate the long-run marginal costs for generating capacity. This cost was amortized and combined with the expected heat rate and petroleum prices to derive a long-run marginal cost of electricity. This cost ranges from S$.055 per kilowatt-hour in 1986 to US$.090 in 2010 as a result of the projected change in fuel costs. These costs were used to value the electricity produced at the busbar for the years after an expansion in capacity would be required.

The increase in costs and reduction in the value of the output for the second stage of sensitivity tests resulted in an expected internal rate of return of 8.7% and a net present value of -$13.4 million assuming a 10% discount factor (see table IV.5) The variations in the major parameters used in the sensitivity tests were similar to those used in the first stage except that certain parameters were added to the list. These include:

1. the costs of the petroleum fuels used in alternative units - -20% and +25%
2. the year in which the growth in demand requires an expansion in the JPS system - 1990 to 1999
3. the labor cost - -50% to +50%

For these tests the internal rate of return remained in the range of 6% to 11% and the benefit-cost ratio between .63 and 1.34 at a discount factor of 10%. The greatest variation was caused by a change in the expected year of system expansion. This is the first year in which the electricity is valued at the long-run rather than the short run marginal cost. The effects of this parameter on the project IRR are shown in Figure IV.6. Changes in the costs for fuel and the capital costs for the facilility had the next most important effect on the project's viability. The effects of these parameters on the project IRR are shown in Figures IV.7 and 8. The utilization of the facility, the life of the peat resources and the percentage of internal use of electricity all had similar effects on the project's IRR, NPV and B/C ratio for the range of values indicated above. The former had the greatest impact and the latter the least (see Figures IV.9-11) The labor costs had relatively insignficant effects on the project outcome.

The results of the sensitivty analysis indicate that the Negril peat project has a rate of return which is below the assumed discount rate for most of the possible values of the planning parameters. This finding disagrees with the analysis based on the consultants' estimates primarily because of the different values assigned to the electricity generated. The value used by the consultants appears to be unreasonably high. Another reason for the discrepancy is the difference in expected capital

Figure IV.6

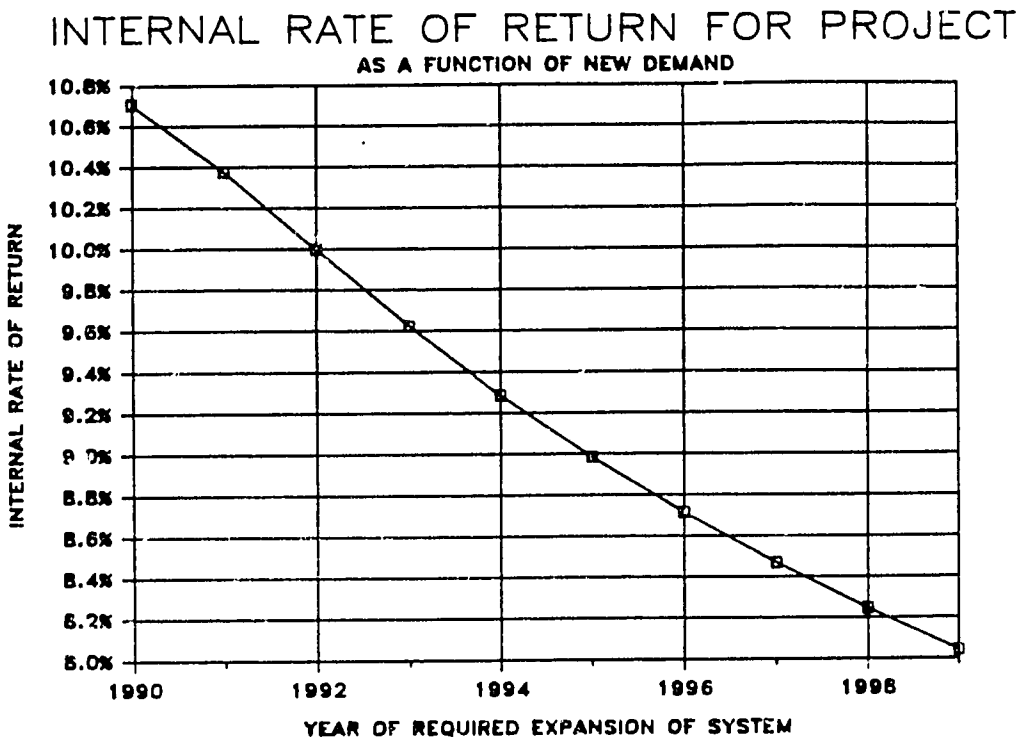


Figure IV.7

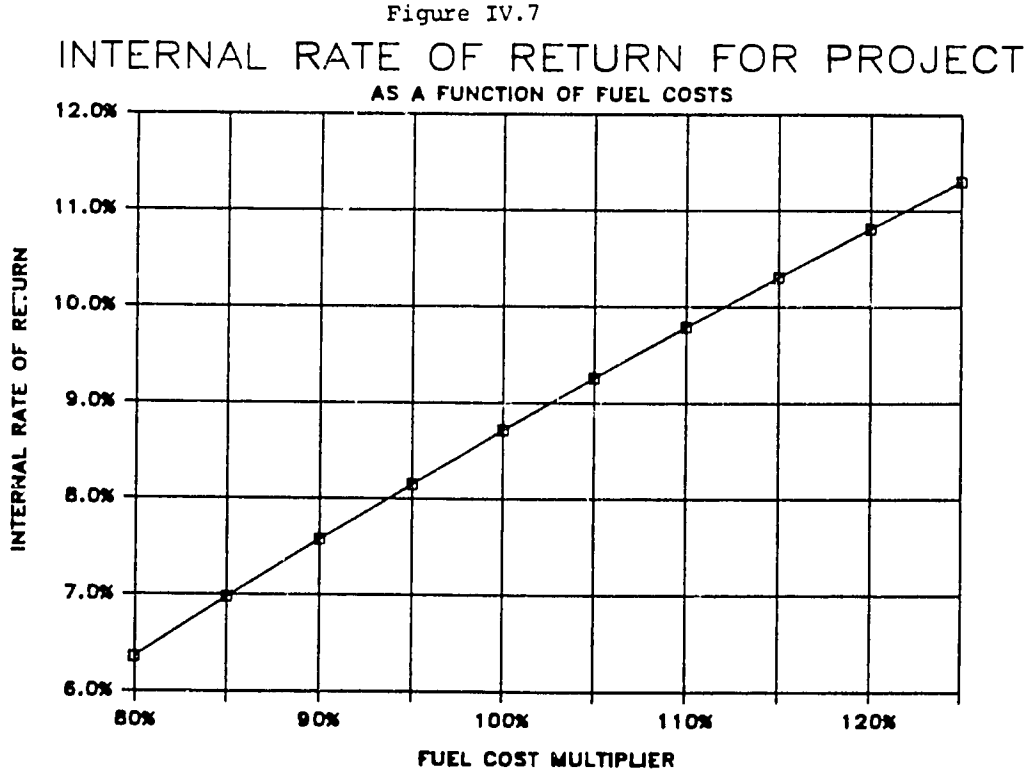


Figure IV.8

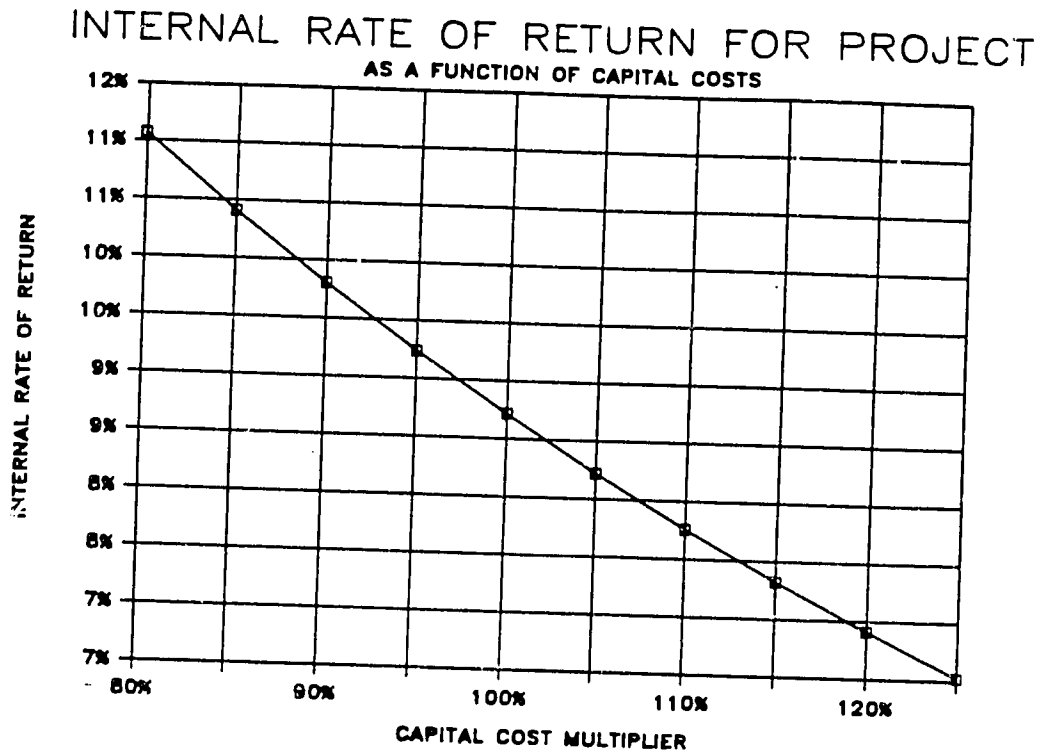


Figure IV.9

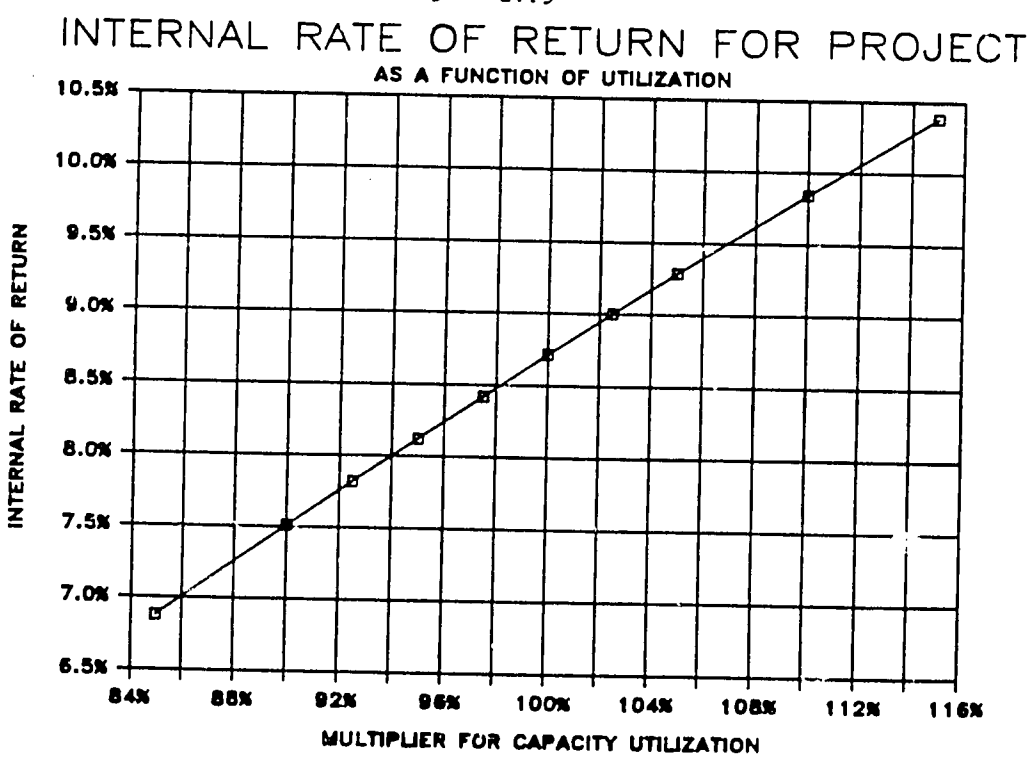


Figure IV.10

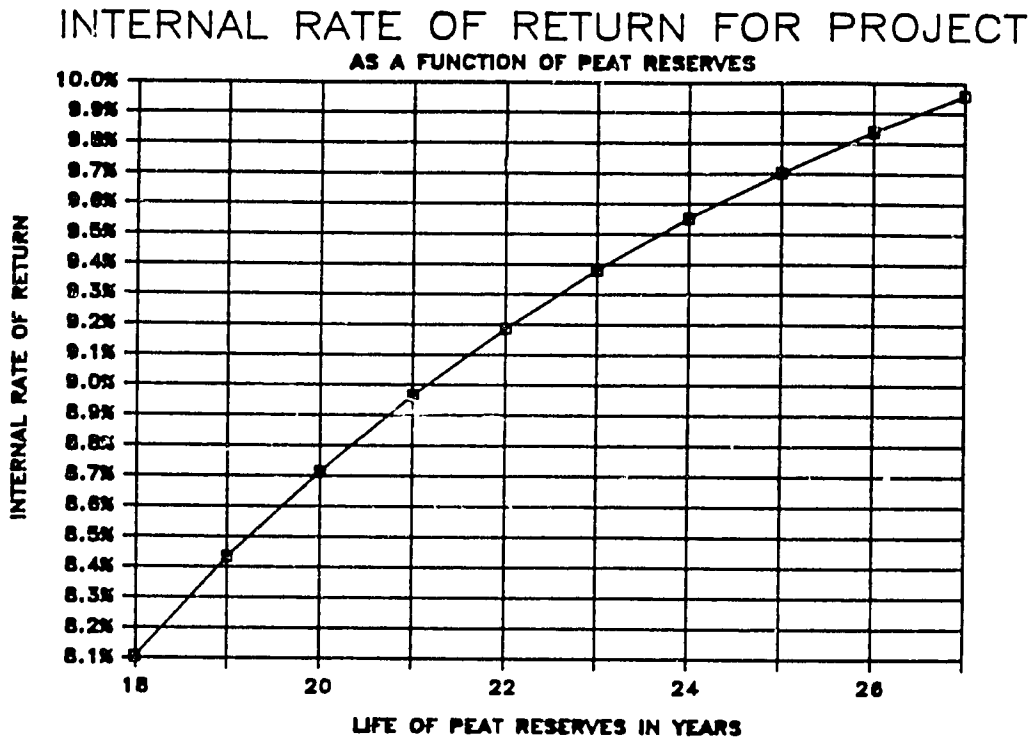
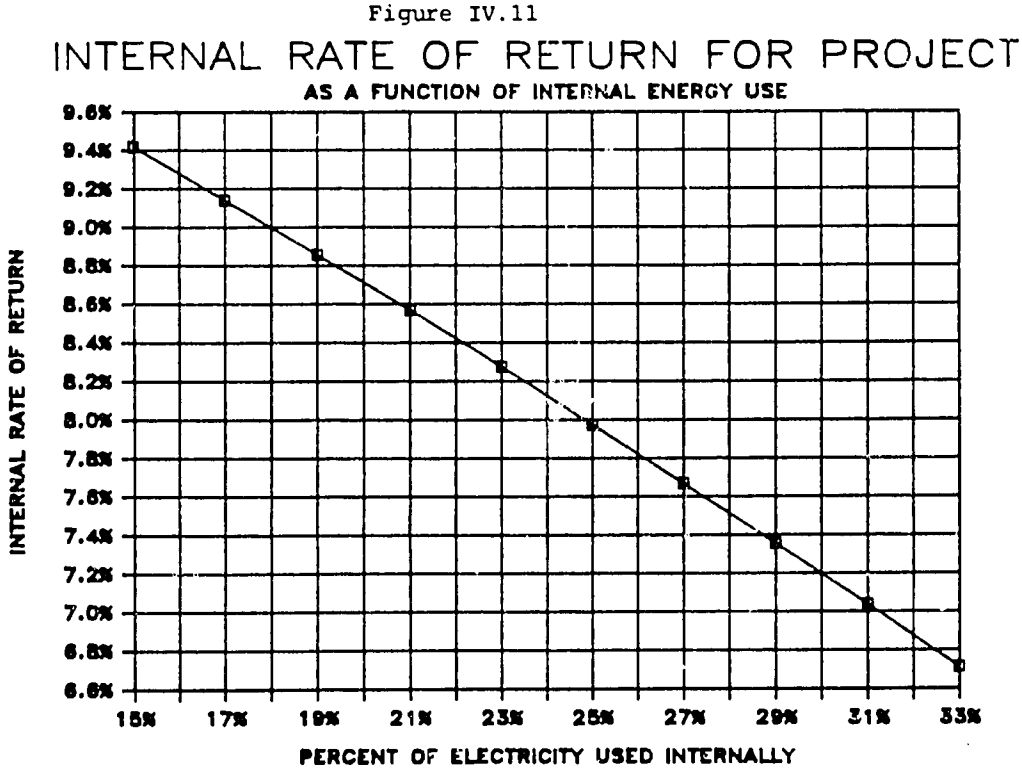


Figure IV.11



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costs. The revised capital costs are higher not because the estimates of the consultants are thought to be wrong but rather because it was felt that the system did not have sufficient spare capacity to provide the level of reliability required for the proposed level of utilization of the facility.

The results of the sensitivity analysis point out the need for a closer review of the system design with special attention being given to system reliability and for a review of the method used to value the output or the generating facility. These two efforts should precede any decisions on whether to undertake the project. In addition, there are considerable uncertainties associated with this project since it represents a new application of existing technology. Of the parameters considered, the greatest uncertainties are associated with the capital and maintenance costs for the facility, the value of the fuels for which the Negril peat will substitute, the life of the peat resources and the year in which an expansion of capacity would be required if the Negril facility were not constructed. These values are included as probability functions in the risk analysis discussed in the next section.

IV.10 Risk Analysis

The risk associated with undertaking the construction and operation of a peat-fired thermal plant was examined using probabilistic analysis. Random variables were used to define:

1. the year in which the JPS system as currently configured (including the planned expansion in hydro-electric facilities) would be expanded,
2. the useful life of the peat resource,
3. the capital cost for the plant, and
4. the rate of escalation in the price of alternative fuels.

The capital cost of the facility was modelled using an second--order Erlang distribution with the most likely value set equal to the capital costs as computed in the revised cost analysis and the minimum value set equal to 90% of the most likely value. This distribution is similar to that used for capital costs in the other case studies. The exact form of the distribution is shown in Figure IV.12.

The year in which the JPS system will be expanded if the Peat project is not implemented was modelled as a discrete probability function with the most likely value being 1996 and a symmetrical distribution around this value (see Figure IV.13). The earliest the expansion will be required is 1992 and the latest is 2000 based on the expansion requirements for the high and low forecasts of growth in electricity demand. There is a 75% probability that the expansion will occur between 1994 and 1998.

The rate of escalation in the price of the petroleum fuels which will otherwise be used to generate electricity was modelled using the same two probability functions as discussed in the Old Harbour Coal Conversion case study in chapter II. The probability

Figure IV.12

PROBABILITY DENSITY FUNCTION FOR THE CAPITAL COST OF THE NEGRIL PROJECT

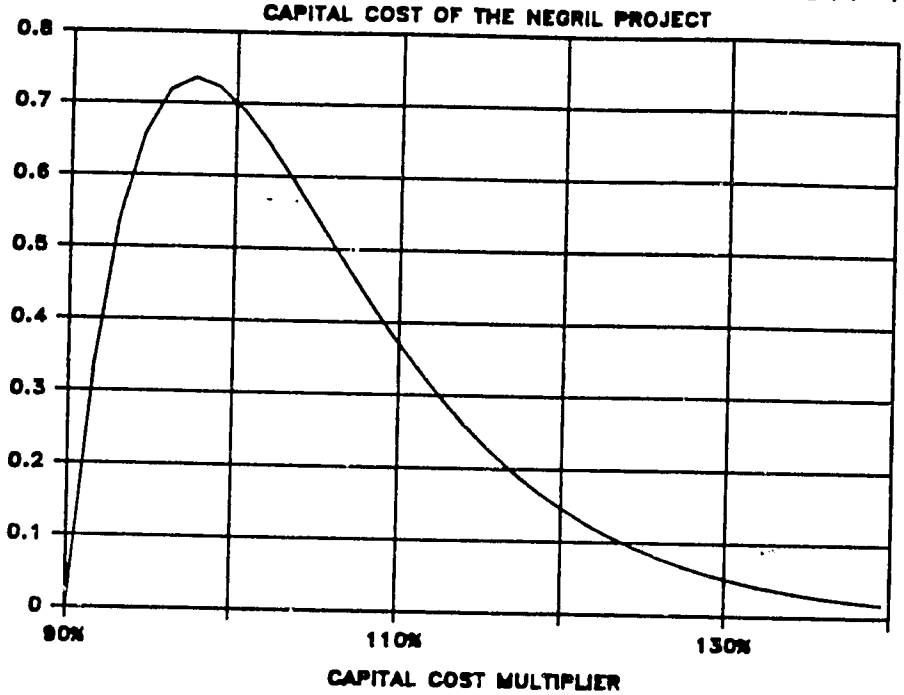


Figure IV.13

DISCRETE PROBABILITY FUNCTION FOR YEAR OF FUTURE JPS EXPANSION

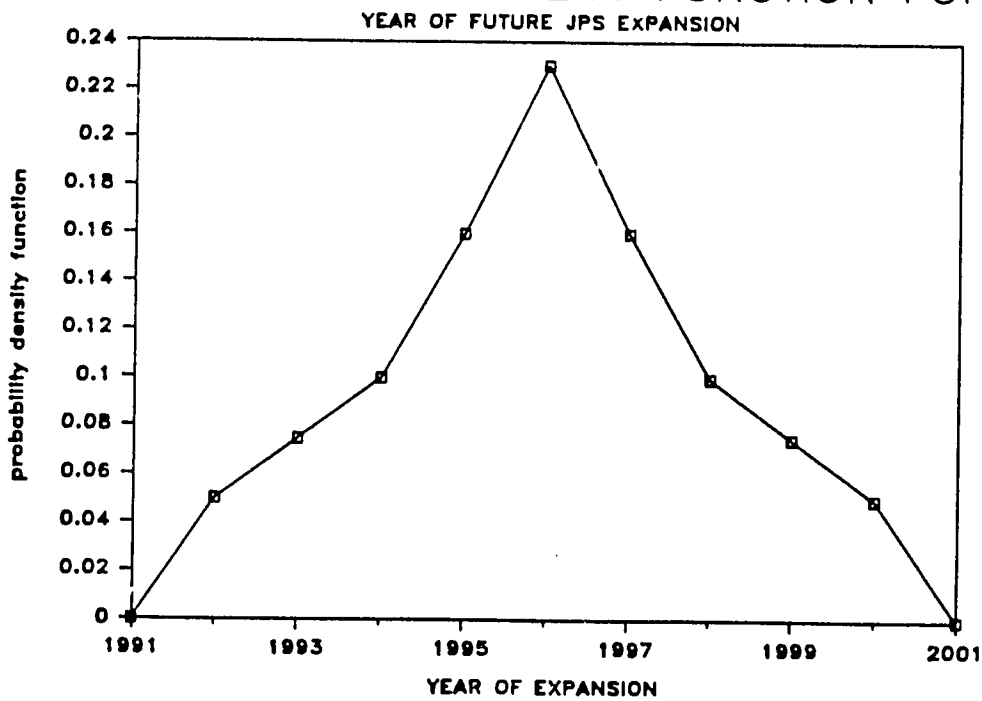
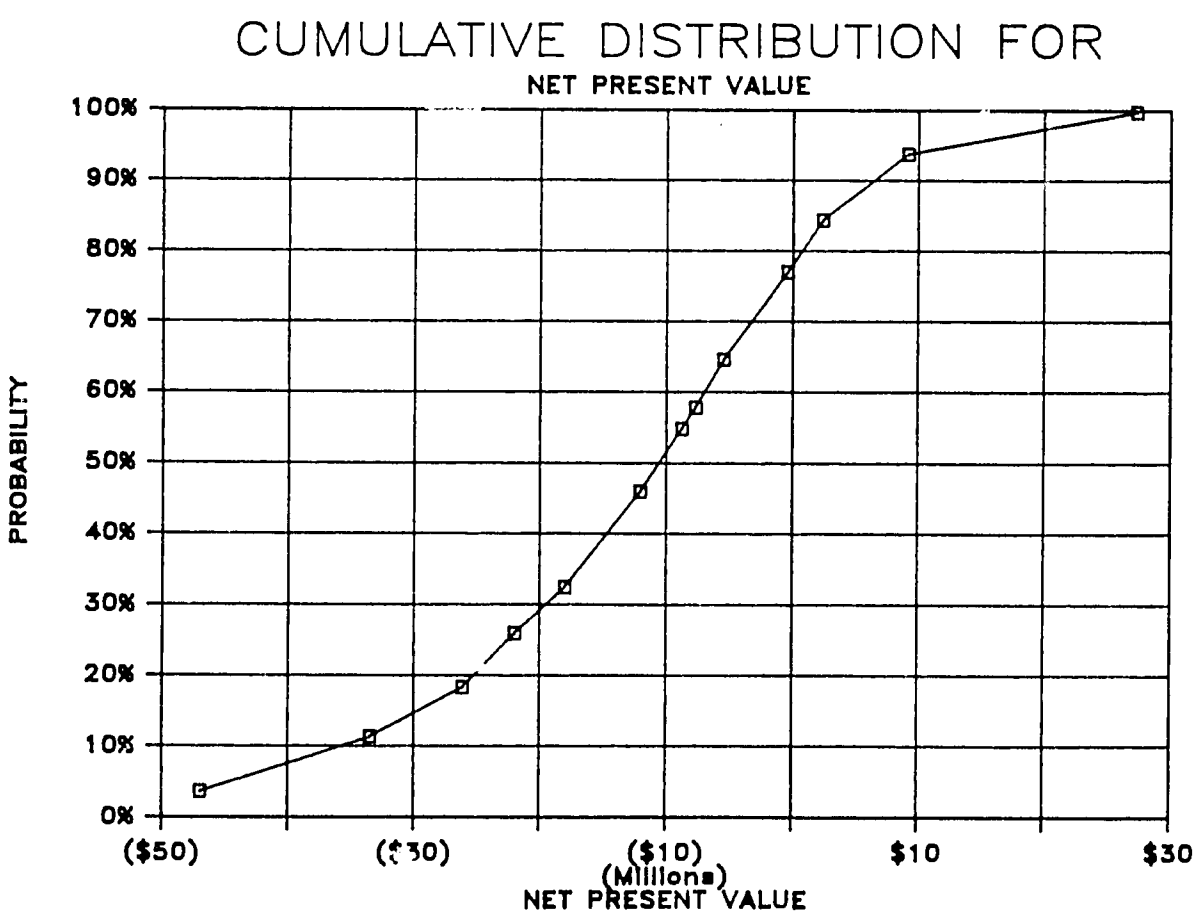


Table IV.6

Results of the Negril Peat Project
Risk Analysis

BASIC STATISTICS	NPV	RATE OF RETURN	BENEFIT/COST
AVERAGE	($13,040,606)	8.9%	0.92
STANDARD DEVIAT.	$17,036,483	1.4%	0.11
COEFF. OF VARIAT.	-1.31	0.16	0.12
MINIMUM	($78,112,434)		0.54
MAXIMUM	$32,096,033		1.23
CONFIDENCE LEVEL	90%	89%	89%
HIGH	$9,191,552	10.8%	1.07
LOW	($46,931,478)	6.4%	0.74
CONFIDENCE LEVEL	59%	59%	58%
HIGH	($424,239)	10.0%	1.00
LOW	($26,088,446)	7.7%	0.83

Figure IV.14



distribution for the life of the peat reserves was modelled by converting the probability distribution shown in Figure IV.2 to a discrete distribution.

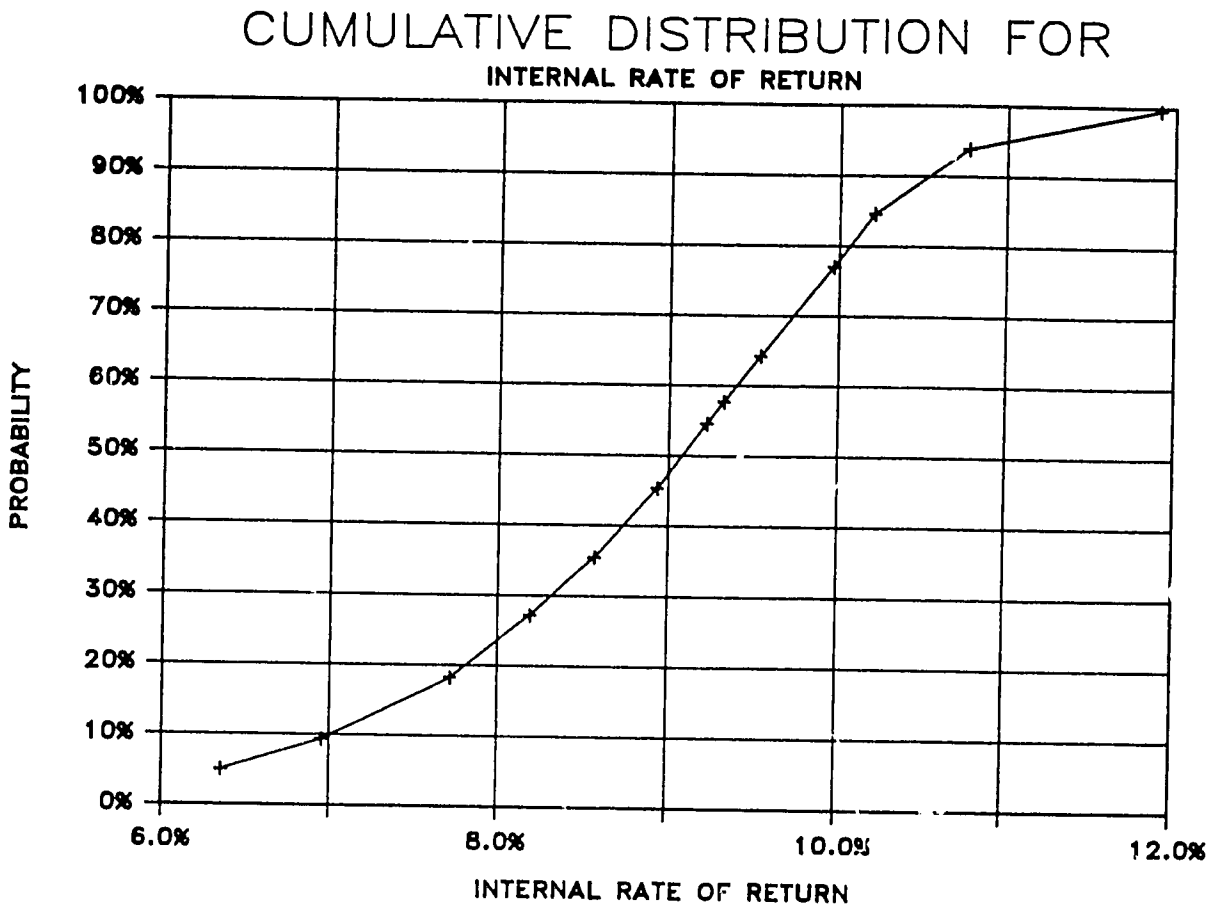
The change in the project's financial viablility with a change in the four planning parameters was examined using a 600 iteration Monte Carlo simulation. The statistics collected from this simulation are shown in table IV.6. These shown that the expected net present value from the project using a discount rate of 10% would amount to a loss of US$13 million. There is only a 22% chance that the net present value would be positive and a 15% chance that the loss would exceed US$30 million in terms of net present value (see Figure IV.14).

The expected internal rate of return from the project is 8.9% and there is a 55% chance that the rate of return will be between 8% and 10%. According to the simulation results, the maximum possible rate of return is just under 12% and the lowest possible rate of return about 6%. The cumulative probability distribution for the internal rate of return is shown in Figure IV.15.

The conclusions which can be derived from the risk analysis are as follows:

1. The project is not considered viable in financial terms assuming a discount rate of 10%.
2. The additional cost for the plant and the reduced value for the electricity generated have altered the project from one that appeared to have an acceptable financial rate of return to one that does not.
3. The uncertainty with regards to the financial performance of the project is slightly less than for the Y.S. River project, but greater than for the Coal Conversion project.
4. The uncertainty with regards to the outcome might have been greater if the level of utilization of the plant had been treated as a probabilistic function, however, the capacity of the peat excavation and processing is assumed to have been increased to a sufficient level to permit the plant to operate at the planned level of utilization without difficulty
5. The three factors which have changed since the original conception of the project is that a capital-intensive approach has been adopted because of perceived operational problems, the costs of the fuels for which the peat was meant to substitute have dropped in real terms, and the JPS system has been expanded and rehabilitated so that the short-run cost of generating electricity has been greatly reduced while the requirement for added capacity has been pushed further into the future. Further consideration of the project should probably be delayed until one or more of these

Figure IV.15


CUMULATIVE DISTRIBUTION FOR
INTERNAL RATE OF RETURN
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
PROBABILITY
6.0%
8.0%
10.0%
12.0%
INTERNAL RATE OF RETURN

factors changes in such a way as to make the project appear more feasible.

6. Any additional study which is done on the peat project should focus on the design of the system components so as to provide a reliable supply of fuel to the facility and should include a determination of the life cycle costs for the facility.

CONCLUSIONS

V.1 The Approach

The case studies presented in chapters 2 through 4 concern projects which had already been subjected to a feasibility studies and were considered both financially and economically viable. The results of the feasibility studies were analyzed using a standardized procedure which began with a technical review of the project to determine the level of detail and precision in the engineering analysis and the reasonableness of the resulting technical design. This was followed by a financial review of the estimates of the project's cost and benefits. Any revisions in the technical design or in the estimation of the costs and benefits which were suggested by this analysis were incorporated into an evaluatin of the project's viability using first sensitivity analysis and then risk analysis. The sensitivity analysis identified those planning parameters which have an important effect on the viability of the project. The risk analysis was used to analyze the uncertainty associated with the value of these parameters and thereby the uncertainty associated with the outcome of the project.

V.2 Results of the Analysis

The technical review was successful in identifying some major problems with the projects included in the case study. Among the issues identified were:

1. the lack of reserve capacity and buffer storage for the sequential activities involved in excavating and processing the peat fuel at Negril
2. the lack of basic flow data for the Y.S. River hydroelectric facility and the failure to develop a load duration curve for sizing the turbine generators
3. the potential overdesign of the pollution control equipment in the coal conversion proposal

The cost review was successful not only in identifiying specific problems with the costs in each project but also in pointing out the more general problems of:

1. failing to account for the full life-cycle costs of the project including the cost of equipment renewal
2. using incorrect assumptions in determining the value of the electricity generated by these projects
3. making insufficient allowances for contingencies

The sensitivity analysis was performed using a software package which permitted a quick evaluation of the assumptions and parameters used in the project design. This analysis identifed several parameters that had an important effect on project

viability. Two of the most important parameters in all of the case studies were the capital costs for the facility and the value of the electricity generated. On the other hand, project timing (in the near term) and operating costs (including labor costs) had very little effect on the project's viabilty.

The risk analysis incorporated the uncertainties regarding the capital costs and value of electricity for each project in the project evaluation. In one project, the risk analysis indicated that the expected outcome of the project made it not viable even though in the most likely situation the project would be viable. This analysis also pointed out the need for additional planning data to reduce the uncertainty of the outcome for each project. A summary of the results of the risk analyses is shown in Table V.1. The coal conversion project has the highest value for the expected rate of return and the least uncertainty with regards to that outcome. The hydro project has the lowest expected internal rate of return and the greatest uncertainty with regards to its outcome. The coal conversion project not only has a higher expected value for its IRR than the other projects, it is also "stochastically dominant". The probability distribution for its IRR ranges from a return of 12% to 20% whereas the distributions for the IRR's of the other two projects range from 6% to 12%.

Table V.1
Results of the Risk Analysis

Project	Old Harbour Coal	Y.S. River Hydro	Negril Peat
most likely			
IRR (%)	17.3	10.6	8.7
NPV (US$ mn)	84.1	.2	-13.4
expected			
IRR (%)	16.4	8.5	8.9
NPV (US$ mn)	67.4	-.6	-13.0
measure of risk			
IRR	.11	.19	.16
NPV	.34	1.17	1.31

V.3 Conclusions for the Coal Conversion Project

The coal conversion project was found to be feasible although the expected rate of return was less than estimated in the feasibility report. A decision on whether to proceed with the project should be made after performing additional studies to reduce the uncertainties regarding:

1. the condition of the existing generators and other equipment which would be used in the project
2. the design and costs of the coal-handling port

project with two other proposals, the construction of a complete coal-fired thermal plant and the improvement in maintenance of the existing JPS system so as to provide a more reliable supply.

V.4 Conclusions for the Y.S. River Project

The Y.S. River project was found to be infeasible at this time. Although the most likely outcome of the project would provide an internal rate of return slightly greater than the discount rate, the expected outcome is for a much lower rate of return because of the uncertainties regarding the flow in the river. This project has already been studied in detail twice. Any future consideration of this project should be delayed until adequate stream data has been collected and a load duration curve prepared for the planned facility. If this curve indicates that the output of the facility could be increased at a reasonable cost, then a more detailed survey of the site should be made to prepare a final estimate of the construction costs. This effort should not be undertaken at this time, if more promising hydro--electric sites have been identified.

The evaluation for this facility assumed that the supply of electricity from the Y.S. River generator would not be sufficiently regular to attribute to this project an increase in system capacity. The project might be viable if, as part of the overall evaluation of the portfolio of hydroelectric projects, it is found that the reliability of the system of hydroelectric facilities is sufficient to justify attributing a "capacity credit" to a portion of the nominal capacity of each individual facility, then the project might be viable. However, no attempt is currently underway to perform a portfolio evaluation of the hydroelectric projects.

V.5 Conclusions for the Negril Peat Project

The peat project does not appear to be feasible at this time. The relatively large foreign exchange costs for the facility balance any savings in foreign exchange through fuel substitution. It is also but unlikely that this project is economically feasible since the project design is capital-intensive and the foreign exchange expenditure for the plant is considerable. This project will become more attractive in the future when the increase in demand for electricity requires an expansion of the JPS generating capacity. If additional baseload capacity is required, then this project should be reconsidered. The current technical approach appears reasonable given the operational problems inherent in earlier designs. However, any further evaluations of this project should be proceeded by a careful operations analysis of the proposed design to determine the ability of the peat excavation, processing and transport system to provide a reliable supply of fuel to the generating facility.

V.6 Future Efforts

These case studies have demonstrated the capabilities of the Ministry to perform a systematic analysis of the financial viability of projects involving the production of electricity and other forms of energy. This skill should be developed through a continuing program of project review under the leadership of the economic section of the Project Implementation Unit. A working strategy should be developed in which the Ministry's economists can call on the services of engineers within and outside of the Ministry who can assist in the technical review of different projects. This strategy should also allow for consultation with the project consultants to clarify the basis for the techncial and cost assumptions used in the feasibility studies and to determine the degree of uncertainty associated with the more important planning parameters.

The software which was used in these case studies has been revised to more closely meet the needs of the Ministry's staff and one of the technical advisors who participated in these case studies will be available for providing additional guidance during the remainder of 1985. It is strongly recommended that the momentum developed during these case studies be maintained and that the Ministry staff continue to develop their analytical skills through further evaluations of projects currently being considered by the Ministry.

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APPENDICES

Figure A.1

TOTAL ELECTRICITY CONSUMPTION 1962–1984

BY TYPE OF USER

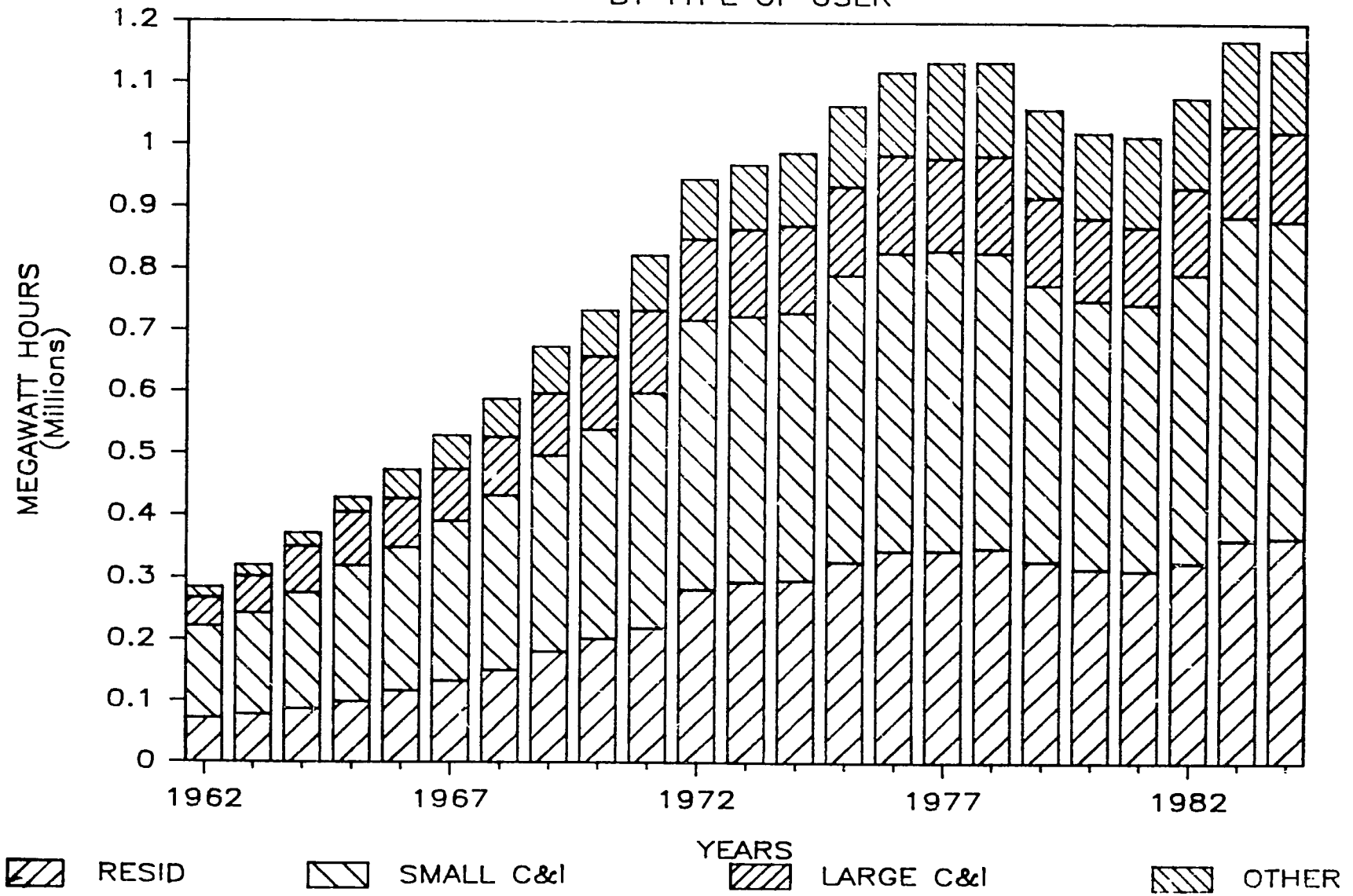

Figure A.2

NUMBER OF JPS CUSTOMERS 1962–1984

BY TYPE OF USER

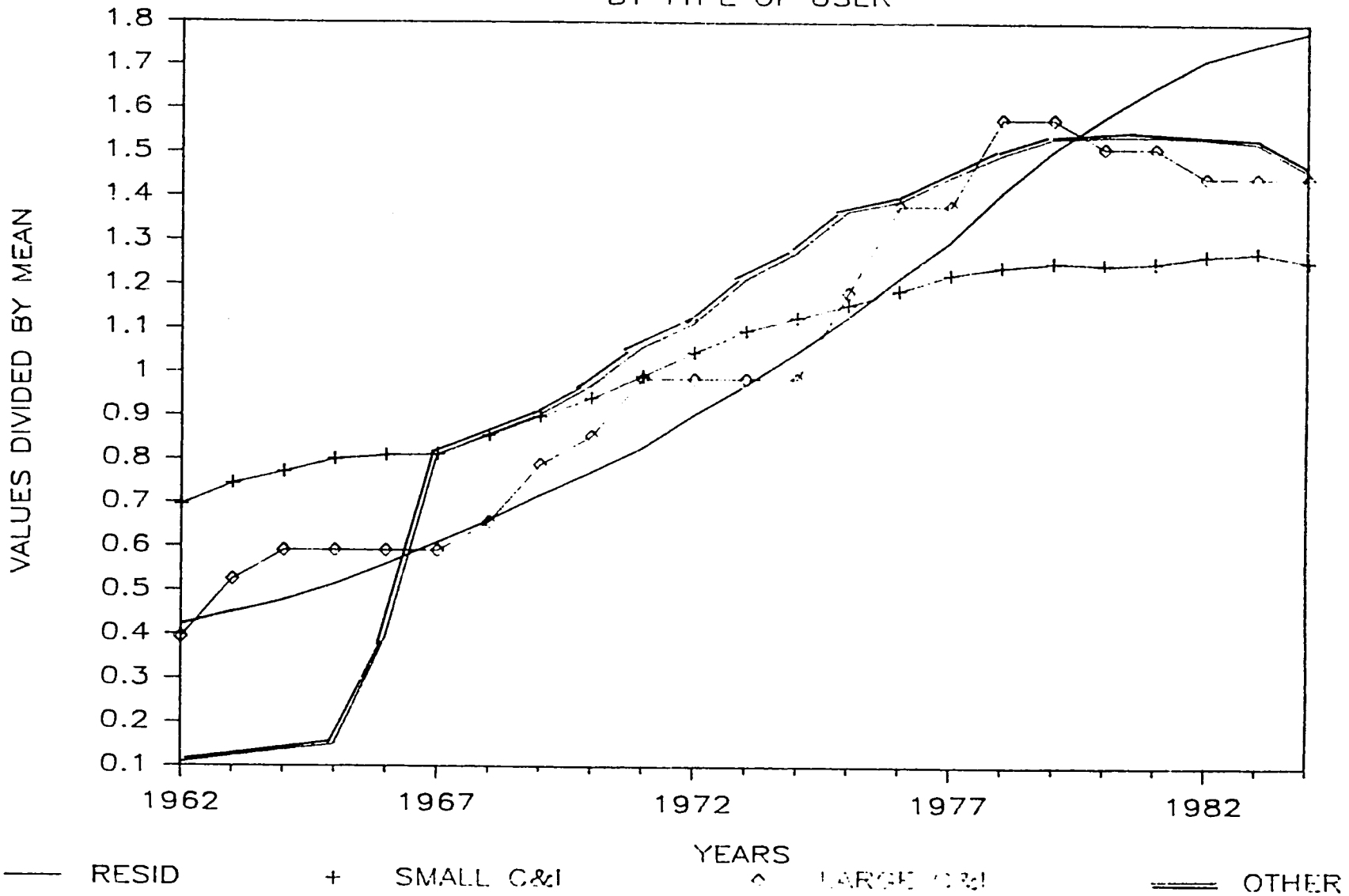

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Figure A.3

AVERAGE ELECTRICITY CONSUMPTION PER USER

BY TYPE OF USER 1962–1984

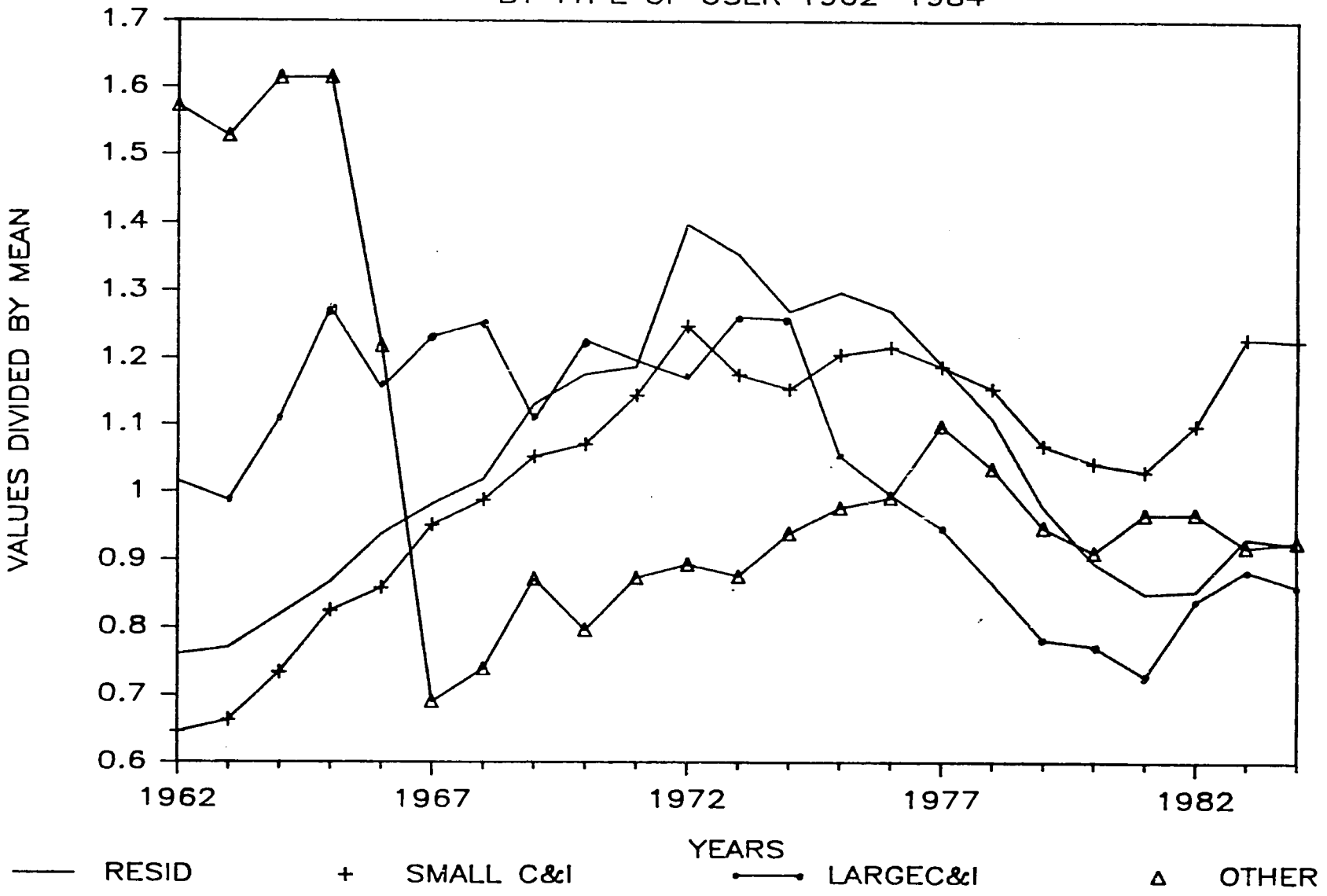

Table A.1

FORECAST OF ELECTRICITY DEMAND

SMALL COMMERCIAL AND INDUSTRIAL

YEAR	HOOKUPS HIGH	HOOKUPS EXPECTED	HOOKUPS LOW	CONSUMPTION/HOOKUP HIGH	CONSUMPTION/HOOKUP EXPECTED	CONSUMPTION/HOOKUP LOW	CONSUMPTION (GW-HR) HIGH	CONSUMPTION (GW-HR) EXPECTED	CONSUMPTION (GW-HR) LOW
1980	23765	23765	23765	18298	18298	18298	435	435	435
1981	23876	23876	23876	18072	18072	18072	431	431	431
1982	24207	24207	24207	19287	19287	19287	467	467	467
1983	24329	24329	24329	21559	21559	21559	525	525	525
1984	23954	23954	23954	21502	21502	21502	515	515	515
1985	24667	24194	24044	22051	21991	21930	544	532	527
1986	25401	24435	24114	22613	22492	22367	574	550	539
1987	26157	24680	24169	23190	23003	22813	607	568	551
1988	26935	24927	24212	23782	23527	23267	641	586	563
1989	27737	25176	24245	24389	24062	23731	676	606	575
1990	28562	25428	24271	25011	24610	24204	714	626	587
1991	29536	25873	24292	25984	25451	24916	767	658	605
1992	30542	26325	24308	26994	26321	25649	824	693	623
1993	31583	26786	24320	28043	27220	26404	886	729	642
1994	32660	27255	24329	29133	28151	27180	951	767	661
1995	33773	27732	24337	30266	29113	27980	1022	807	681
1996	34924	28217	24343	31443	30108	28804	1098	850	701
1997	36114	28711	24347	32665	31137	29651	1180	894	722
1998	37345	29213	24351	33935	32201	30524	1267	941	743
1999	38617	29725	24354	35255	33302	31422	1361	990	765
2000	39933	30245	24356	36625	34440	32346	1463	1042	788
2001	41352	30850	24358	38212	35748	33401	1580	1103	814
2002	42821	31467	24359	39868	37106	34489	1707	1168	840
2003	44342	32096	24360	41596	38516	35613	1844	1236	868
2004	45917	32738	24361	43398	39979	36774	1993	1309	896
2005	47548	33393	24361	45279	41498	37972	2153	1386	925
2006	49236	34061	24362	47241	43074	39210	2326	1467	955
2007	50985	34742	24362	49288	44710	40488	2513	1553	986
2008	52796	35437	24363	51423	46409	41808	2715	1645	1019
2009	54672	36145	24363	53652	48172	43170	2933	1741	1052
2010	56614	36868	24363	55977	50002	44577	3169	1843	1086
2011	58624	37606	24363	58402	51901	46030	3424	1952	1121
2012	60707	38358	24363	60933	53873	47530	3699	2066	1158
2013	62863	39125	24363	63573	55919	49079	3996	2188	1196
2014	65096	39907	24363	66328	58043	50679	4318	2316	1235
2015	67408	40705	24363	69202	60248	52331	4665	2452	1275
2016	69803	41520	24363	72201	62537	54036	5040	2597	1317

Table A.2

FORECAST OF ELECTRICITY DEMAND

YEAR	HOOKUPS HIGH	HOOKUPS EXPECTED	HOOKUPS LOW	RESIDENTIAL CONSUMPTION/HOOKUP HIGH	RESIDENTIAL CONSUMPTION/HOOKUP EXPECTED	RESIDENTIAL CONSUMPTION/HOOKUP LOW	CONSUMPTION HIGH	CONSUMPTION EXPECTED	CONSUMPTION LOW
1980	199468	199468	199468	1592	1592	1592	318	318	318
1981	208390	208390	208390	1511	1511	1511	315	315	315
1982	216403	216403	216403	1518	1518	1518	328	328	328
1983	220669	220669	220669	1656	1656	1656	365	365	365
1984	224547	224547	224547	1640	1640	1640	368	368	368
1985	232406	234297	227915	1653	1651	1649	384	387	376
1986	240540	244047	231334	1666	1662	1658	401	406	384
1987	248959	253797	234804	1679	1673	1667	418	425	391
1988	257673	263547	238326	1692	1684	1676	436	444	399
1989	266691	273297	241901	1706	1695	1685	455	463	408
1990	276026	283047	245529	1719	1707	1694	475	483	416
1991	285686	292797	249212	1773	1752	1731	507	513	431
1992	295686	302547	252951	1829	1799	1768	541	544	447
1993	306035	312297	256745	1887	1846	1807	577	577	464
1994	316746	322047	260596	1946	1895	1846	617	610	481
1995	327832	331797	264505	2008	1946	1886	658	646	499
1996	339306	341547	268472	2071	1998	1927	703	682	517
1997	351182	351297	272500	2136	2051	1968	750	720	536
1998	363473	361047	276587	2204	2105	2011	801	760	556
1999	376195	370797	280736	2273	2161	2055	855	801	577
2000	389361	380547	284947	2345	2219	2099	913	844	598
2001	402989	390297	289221	2437	2293	2156	982	895	624
2002	417094	400047	293559	2533	2369	2214	1057	948	650
2003	431692	409797	297963	2633	2448	2274	1137	1003	678
2004	446801	419547	302432	2737	2529	2336	1223	1061	707
2005	462439	429297	306969	2845	2613	2399	1316	1122	737
2006	478625	439047	311573	2957	2700	2464	1415	1185	768
2007	495376	448797	316247	3073	2790	2531	1522	1252	800
2008	512715	458547	320991	3194	2883	2600	1638	1322	834
2009	530660	468297	325805	3320	2978	2670	1762	1395	870
2010	549233	478047	330693	3451	3077	2743	1896	1471	907
2011	568456	487797	335653	3587	3180	2817	2039	1551	945
2012	588352	497547	340688	3729	3286	2893	2194	1635	986
2013	608944	507297	345798	3876	3395	2972	2360	1722	1028
2014	630257	517047	350985	4028	3508	3052	2539	1814	1071
2015	652316	526797	356250	4187	3624	3135	2731	1909	1117
2016	675147	536547	361593	4352	3745	3220	2938	2009	1164
2017	698777	546297	367017	4524	3869	3307	3161	2114	1214

Table A.3

LARGE COMMERCIAL AND INDUSTRIAL

YEAR	HOOKUPS EXPECTED	CONSUMPTION/HOOKUP (GW-HR) HIGH	EXPECTED	LOW	CONSUMPTION HIGH	EXPECTED	LOW
1980	23	5804	5804	5804	133	133	133
1981	23	5466	5466	5466	126	126	126
1982	22	6302	6302	6302	139	139	139
1983	22	6634	6634	6634	146	146	146
1984	22	6455	6455	6455	142	142	142
1985	22	6520	6345	6205	143	140	137
1986	22	6585	6235	5955	145	137	131
1987	22	6651	6125	5705	146	135	126
1988	22	6717	6003	5551	148	132	122
1989	22	6784	6033	5551	149	133	122
1990	22	6852	6063	5551	151	133	122
1991	22	6921	6094	5551	152	134	122
1992	22	6990	6124	5551	154	135	122
1993	22	7060	6155	5551	155	135	122
1994	22	7130	6186	5551	157	136	122
1995	22	7202	6216	5551	158	137	122
1996	22	7274	6248	5551	160	137	122
1997	22	7346	6279	5551	162	138	122
1998	22	7420	6310	5551	163	139	122
1999	22	7494	6342	5551	165	140	122
2000	22	7569	6373	5551	167	140	122
2001	22	7645	6405	5551	168	141	122
2002	22	7721	6437	5551	170	142	122
2003	22	7798	6469	5551	172	142	122
2004	22	7876	6502	5551	173	143	122
2005	22	7955	6534	5551	175	144	122
2006	22	8035	6567	5551	177	144	122
2007	22	8115	6600	5551	179	145	122
2008	22	8196	6633	5551	180	146	122
2009	22	8278	6666	5551	182	147	122
2010	22	8361	6699	5551	184	147	122
2011	22	8444	6733	5551	186	148	122
2012	22	8529	6767	5551	188	149	122
2013	22	8614	6800	5551	190	150	122
2014	22	8700	6834	5551	191	150	122
2015	22	8787	6869	5551	193	151	122
2016	22	8875	6903	5551	195	152	122

Table A.4

YEAR	PUBLIC AND OTHER USERS CONSUMPTION HIGH	EXPECTED	LOW
1980	137	137	137
1981	145	145	145
1982	145	145	145
1983	137	137	137
1984	132	132	132
1985	129	125	122
1986	125	119	113
1987	128	121	114
1988	130	122	114
1989	132	123	115
1990	135	125	116
1991	139	128	117
1992	143	130	118
1993	148	133	119
1994	153	136	121
1995	157	139	122
1996	162	142	123
1997	167	145	124
1998	173	148	126
1999	178	151	127
2000	184	154	128
2001	190	158	130
2002	197	161	132
2003	204	165	133
2004	212	169	135
2005	219	173	136
2006	227	177	138
2007	235	182	140
2008	244	186	141
2009	253	190	143
2010	262	195	145
2011	271	200	146
2012	281	204	148
2013	291	209	150
2014	302	214	152
2015	312	220	154
2016	324	225	155
2017	335	230	157

PROJECT TITLE PROJECT TITLE BECHTEL COAL CONVERSION STUDY

DATA ITEMS \ YEAR	DATA ITEMS \ YEAR	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
CAPITAL COSTS TOTAL	CAPITAL COSTS TOTAL											
Dock Facilities FE	Dock Facilities FE	4315667	4315667	4315667	0	0	0					
Dock LC	Dock LC	834867	834867	834867	0	0	0					
Site Preparation FE	Site Preparation FE	1212667	1212667	1212667	0	0	0					
Site LC	Site LC	1071150	1071150	1071150	0	0	0					
Coal Rec'ving & Handling FE	Coal Rec'ving & Handling FE	1610000	1610000	1610000	0	0	0					
Coal Rec'g LC	Coal Rec'g LC	128850	128850	128850	0	0	0					
Building Superstructures FE	Building Superstructures FE	570667	570667	570667	0	0	0					
Bldg LC	Bldg LC	582832	582832	582832	0	0	0					
Boilers FE	Boilers FE	9660000	9660000	9660000	0	0	0					
Boilers LC	Boilers LC	481062	481062	481062	0	0	0					
Precipitators	Precipitators	2205000	2205000	2205000	0	0	0					
Stacks	Stacks	1225000	1225000	1225000	0	0	0					
Fly ash handling	Fly ash handling	560000	560000	560000	0	0	0					
Piping & mech FE	Piping & mech FE	2870000	2870000	2870000	0	0	0					
Piping LC	Piping LC	470584	470584	470584	0	0	0					
Electrical & Instrument'n FE	Electrical & Instrument'n FE	1995000	1995000	1995000	0	0	0					
Electrical LC	Electrical LC	349735	349735	349735	0	0	0					
Contingency	Contingency	0	0	7999938	0	0	0					
Land LC	Land LC	23628	0	0	0	0	0					
TOTAL FE PROJECT COST	TOTAL FE PROJECT COST	24224000	24224000	38223938	0	0	0					
TOTAL LC PROJECT COST	TOTAL LC PROJECT COST	4150708	4127000	4127000	0	0	0					
TOTAL PROJECT COST	TOTAL PROJECT COST	30374707	30351079	30351017	0	0	0					
TOTAL CAPITAL COST	TOTAL CAPITAL COST	30374708	30351000	30351017	0	0	0					
SUM TOTAL CAPITAL COST	SUM TOTAL CAPITAL COST	99076004										
PRE-OPERATION COSTS, all FE	PRE-OPERATION COSTS, all FE											
Initial fuel supply	Initial fuel supply	0	0	0	0	0	0	0				
Operator Training	Operator Training	0	0	94160	0	0	0	0				
Spare Parts	Spare Parts	0	0	262500	0	0	0	0				
Mobile Equipment	Mobile Equipment	0	0	630000	0	0	0	0				
Upgrade Turbine/Generators	Upgrade Turbine/Generators	0	0	525000	0	0	0	0				
TOTAL INCREMENTAL COST	TOTAL INCREMENTAL COST	0	0	1511660	0	0	0	0				
OPERATIONS AND MAINTENANCE	OPERATIONS AND MAINTENANCE											
FUEL	FUEL											
Coal Price (US$/ton, CIF)	Coal Price (US$/ton, CIF)	57 11	54 47	54 47	55 79	56 23	56.67	57.33	57.77	58.43	58 87	59.97
Coal supplies FE	Coal supplies FE	0	0	0	18704804	18852323	18999843	19221122	19368641	19589921	19737440	20106239
SALARIES	SALARIES											
Foreman LC	Foreman LC	0	0	0	14310	14310	14310	14310	14310	14310	14310	14310
Asst Foreman LC	Asst Foreman LC	0	0	0	11448	11448	11448	11448	11448	11448	11448	11448
Vehicle Operators (3) LC	Vehicle Operators (3) LC	0	0	0	24531	24531	24531	24531	24531	24531	24531	24531
Ash truck drivers (2) LC	Ash truck drivers (2) LC	0	0	0	16354	16354	16354	16354	16354	16354	16354	16354
Coal boiler operators (4) LC	Coal boiler operators (4) LC	0	0	0	40885	40885	40885	40885	40885	40885	40885	40885
Maintenance positions (3) LC	Maintenance positions (3) LC	0	0	0	30664	30664	30664	30664	30664	30664	30664	30664
MAINTENANCE, all FE	MAINTENANCE, all FE											
Ash disposal	Ash disposal	0	0	0	94500	94500	94500	94500	94500	94500	94500	94500
Coal handling	Coal handling	0	0	0	367500	367500	367500	367500	367500	367500	367500	367500
Spares mill & balanceofplant	Spares mill & balanceofplant	0	0	0	441000	441000	441000	441000	441000	441000	441000	441000

Figure E.1
COAL CONVERSION ORIGINAL ANALYSIS

Figure B.1 (cont.)

PROJECT TITLE											
Old Harbour Units 3&4											
DATA ITEMS \ YEAR	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
CAPITAL COSTS TOTAL											
Dock Facilities FE											
Dock LC											
Site Preparation FE											
Site LC											
Coal Rec'ving & Handling FE											
Coal Rec'g LC											
Building Superstructures FE											
Bldg LC											
Boilers FE											
Boilers LC											
Precipitators											
Stacks											
Fly ash handling											
Piping & mech FE											
Piping LC											
Electrical & Instrument'n FE											
Electrical LC											
Contingency											
Land LC											
TOTAL FE PROJECT COST											
TOTAL LC PROJECT COST											
TOTAL PROJECT COST											
Capital cost multiplier											
TOTAL CAPITAL COST											
SUM TOTAL CAPITAL COST											
PRE-OPERATION COSTS, all FE											
Initial fuel supply											
Operator Training											
Spare Parts											
Mobile Equipment											
Upgrade Turbine/Generators											
TOTAL INCREMENTAL COST											
OPERATIONS AND MAINTENANCE											
FUEL											
Coal Price (US$/ton, CIF)	62.17	63.36	64.55	65.73	67.01	68.29	69.61	70.93	72.70	74.52	76.38
Coal supplies FE	22034913	22001402	21950951	21879993	21824650	21750914	21671239	21572597	21509506	21415474	21950861
SALARIES											
Foreman LC	14310	14310	14310	14310	14310	14310	14310	14310	14310	14310	14310
Asst Foreman LC	11440	11440	11440	11440	11440	11440	11440	11440	11440	11440	11440
Vehicle Operators (3) LC	24531	24531	24531	24531	24531	24531	24531	24531	24531	24531	24531
Ash truck drivers (2) LC	16354	16354	16354	16354	16354	16354	16354	16354	16354	16354	16354
Coal boiler operators (4) LC	40885	40885	40885	40885	40885	40885	40885	40885	40885	40885	40885
Maintenance positions (3) LC	30664	30664	30664	30664	30664	30664	30664	30664	30664	30664	30664
MAINTENANCE, all FE											
Ash disposal	94500	94500	94500	94500	94500	94500	94500	94500	94500	94500	94500
Coal handling	367500	367500	367500	367500	367500	367500	367500	367500	367500	367500	367500
Spares, mill & balanceofplant	882000	882000	882000	882000	882000	882000	882000	882000	882000	882000	882000

PROJECT TITLE
Old Harbour Units 3&4

DATA ITEMS \ YEAR	2009	2010	2011	2012	2013	2014	2015	2016
CAPITAL COSTS TOTAL								
Dock Facilities FE								
Dock LC								
Site Preparation FE								
Site LC								
Coal Rec'ving & Handling FE								
Coal Rec'g LC								
Building Superstructures FE								
Bldg LC								
Boilers FE								
Boilers LC								
Precipitators								
Stacks								
Fly ash handling								
Piping & mech FE								
Piping LC								
Electrical & Instrument'n FE								
Electrical LC								
Contingency								
Land LC								
TOTAL FE PROJECT COST								
TOTAL LC PROJECT COST								
TOTAL PROJECT COST								
Capital cost multiplier								
TOTAL CAPITAL COST								
SUM TOTAL CAPITAL COST								
PRE-OPERATION COSTS, all FE								
Initial fuel supply								
Operator Training								
Spare Parts								
Mobile Equipment								
Upgrade Turbine/Generators								
TOTAL INCREMENTAL COST								
OPERATIONS AND MAINTENANCE								
FUEL								
Coal Price (US$/ton, CIF)	78 29	80 25	82 26	84 31	86 42	88.58	90 80	93.07
Coal supplies FE	22499632	23062123	23638676	24229643	24835384	25456269	26092676	26744993
SALARIES								
Foreman LC	14310	14310	14310	14310	14310	14310	14310	0
Asst Foreman LC	11440	11440	11440	11440	11440	11440	11440	0
Vehicle Operators (3) LC	24531	24531	24531	24531	24531	24531	24531	0
Ash truck drivers (1) LC	16354	16354	16354	16354	16354	16354	16354	0
Coal boiler operators (4) LC	40885	40885	40885	40885	40885	40885	40885	0
Maintenance positions (3) LC	30664	30664	30664	30664	30664	30664	30664	0
MAINTENANCE, all FE								
Ash disposal	94500	94500	94500	94500	94500	94500	94500	0
Coal handling	367500	367500	367500	367500	367500	367500	367500	0
Spares mill & balanceofplant	882000	882000	882000	882000	882000	882000	882000	0

Figure B.1(cont)

PROJECT TITLE BECHTEL COAL CONVERSION PROJECT

Old Harbour Units 3&4 MMET. 8/85; Revision of Bechtel 1983

DATA ITEMS \ YEAR	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Auxiliary power	0	0	0	0	0	0	0	0	0	0	0	0
Miscellaneous items FE	0	0	0	294000	294000	294000	294000	294000	294000	294000	294000	294000
Miscellaneous items LC	0	0	0	201600	201600	201600	201600	201600	201600	201600	201600	201600
TECHNICAL ASSIST & TRAINING FE	0	0	0	401250	401250	401250	401250	401250	0	0	0	0
ANNUAL FE O&M	0	0	0	23617760	23786362	23954956	24207846	24376440	24228081	23973729	23956463	23938623
ANNUAL LC O&M	0	0	0	339791	339791	339791	339791	339791	339791	339791	339791	339791
TOTAL ANNUAL O&M	0	0	0	23957560	24126153	24294747	24547638	24716231	24567872	24313521	24296254	24278414
FE COSTS	26680983	26680983	37192438	23617760	23786362	23954956	24207846	24376440	24228081	23973729	23956463	23938623
LC COSTS	4442912	4419283	4419283	339791	339791	339791	339791	339791	339791	339791	339791	339791
TOTAL COSTS	31123895	31100267	41611722	23957560	24126153	24294747	24547638	24716231	24567872	24313521	24296254	24278414
BENEFITS												
Plant Utilization	0	0	0	0.8	0.8	0.8	0.8	0.8	0.8	0.785	0.77	0.755
Fuel oil price (US$/bbl, CIF)	24.65	23.31	23.31	24.42	25.31	26.42	27.53	28.64	29.97	31.08	31.86	32.65
Petroleum savings,(US$/yr)	0	0	0	39101117	40526179	42303502	44080826	45858149	47987735	48831964	49096341	49343416
Electric power sales (MW-hr)	0	0	0	902,490	902,490	902,490	902,490	902,490	902,490	885,569	868,647	851,725
TOTAL BENEFITS, FE SAVINGS	0	0	0	39101117	40526179	42303502	44080826	45858149	47987735	48831964	49096341	49343416
ANNUAL NET BENEFITS	(31,123,895)	(31,100,267)	(41,611,722)	15,143,558	16,400,025	18,008,755	19,533,188	21,141,918	23,419,863	24,518,443	24,800,087	25,073,002

Figure B.1 (cont.)

PROJECT TITLE

Old Harbour Units 3&4

DATA ITEMS \ YEAR	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Auxiliary power	0	0	0	0	0	0	0	0	0	0	0
Miscellaneous items FE	294000	294000	294000	294000	294000	294000	294000	294000	294000	294000	294000
Miscellaneous items LC	201600	201600	201600	201600	201600	201600	201600	201600	201600	201600	201600
TECHNICAL ASSIST & TRAINING FE	0	0	0	0	0	0	0	0	0	0	0
ANNUAL FE O&M	23874513	23841082	23798551	23719593	23664250	23590514	23510839	23412197	23429184	23255874	23798461
ANNUAL LC O&M	339791	339791	339791	339791	339791	339791	339791	339791	339791	339791	339791
TOTAL ANNUAL O&M	24214304	24180873	24138342	24059385	24004041	23930305	23850630	23751988	23768975	23594665	24138252
FE COSTS	23874513	23841082	23798551	23719593	23664250	23590514	23510839	23412197	23429184	23255874	23798461
LC COSTS	339791	339791	339791	339791	339791	339791	339791	339791	339791	339791	339791
TOTAL COSTS	24214304	24180873	24138342	24059385	24004041	23930305	23850630	23751988	23768975	23594665	24138252
BENEFITS											
Plant Utilisation	0.74	0.725	0.71	0.695	0.68	0.665	0.65	0.635	0.62	0.6	0.6
Fuel oil price (US$/bbl, CIF)	33.47	34.31	35.16	36.04	36.94	37.87	38.81	39.79	40.78	41.80	42.84
Petroleum savings,(US$/yr)	49572161	49781503	49970329	50137403	50281764	50401922	50496663	50564639	50604454	50196353	51451262
Electric power sales (MW-hr)	834,803	817,882	800,960	784,038	767,117	750,195	733,273	716,352	699,430	676,868	676,868
TOTAL BENEFITS, FE SAVINGS	49572161	49781503	49970329	50137403	50281764	50401922	50496663	50564639	50604454	50196353	51451262
ANNUAL NET BENEFITS	25,357,857	25,600,630	25,839,986	26,078,099	26,277,723	26,471,617	26,646,033	26,812,651	26,835,479	26,601,688	27,321,010

Figure B.1 (cont.)

PROJECT TITLE

Old Harbour Units 3&4

DATA ITEMS \ YEAR	2009	2010	2011	2012	2013	2014	2015	2016
Auxiliary power	0	0	0	0	0	0	0	0
Miscellaneous items FE	294000	294000	294000	294000	294000	294000	294000	294000
Miscellaneous items LC	201600	201600	201600	201600	201600	201600	201600	201600
TECHNICAL ASSIST & TRAINING FE	0	0	0	0	0	0	0	0
ANNUAL FE O&M	24339232	24981723	25478276	26069243	26674984	27295869	27932276	27240593
ANNUAL LC O&M	339791	339791	339791	339791	339791	339791	339791	201600
TOTAL ANNUAL O&M	24679024	25241514	25818067	26408034	27014775	27635660	28272067	27442193
FE COSTS	24339232	24981723	25478276	26069243	26674984	27295869	27932276	27240593
LC COSTS	339791	339791	339791	339791	339791	339791	339791	201600
TOTAL COSTS	24679024	25241514	25818067	26408034	27014775	27635660	28272067	27442193
BENEFITS								
Plant Utilisation	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Fuel oil price (US$/bbl, CIF)	43.92	45.01	46.14	47.29	48.47	49.69	50.93	52.20
Petroleum savings,(US$/yr)	52737544	54055982	55407382	56792566	58212381	59667690	61159382	62688367
Electric power sales (MW-hr)	676,868	676,868	676,868	676,868	676,868	676,868	676,868	676,868
TOTAL BENEFITS, FE SAVINGS	52737544	54055982	55407382	56792566	58212381	59667690	61159382	62688367
ANNUAL NET BENEFITS	28,058,520	28,814,468	29,589,314	30,383,532	31,197,605	32,032,030	32,887,316	35,246,175

Figure B.1 (cont)

Figure B.2

COAL CONVERSION REVISED ANALYSIS

PROJECT TITLE BECHTEL COAL CONVERSION PROJECT

Old Harbour Units 3&4 MMET, 9/85; Revision of Bechtel 1983

DATA ITEMS \ YEAR	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
CAPITAL COSTS TOTAL												
Dock Facilities FE	5826150	5826150	5826150	0	0	0						
Dock LC	1127071	1127071	1127071	0	0	0						
Site Preparation FE	1212667	1212667	1212667	0	0	0						
Site LC	1071150	1071150	1071150	0	0	0						
Coal Rec'ving & Handling FE	1610000	1610000	1610000	0	0	0						
Coal Rec'g LC	128850	128850	128850	0	0	0						
Building Superstructures FE	570667	570667	570667	0	0	0						
Bldg LC	502832	502832	502832	0	0	0						
Boilers FE	9660000	9660000	9660000	0	0	0						
Boilers LC	681862	681862	681862	0	0	0						
Precipitators	1764000	1764000	1764000	0	0	0						
Stacks	612500	612500	612500	0	0	0						
Fly ash handling	560000	560000	560000	0	0	0						
Piping & mech FE	2870000	2870000	2870000	0	0	0						
Piping LC	470584	470584	470584	0	0	0						
Electrical & Instrument'n FE	1995000	1995000	1995000	0	0	0						
Electrical LC	349735	349735	349735	0	0	0						
Con'' ency	0	0	8999795	0	0	0						
Land LC	23620	0	0	0	0	0						
TOTAL FE PROJECT COST	26680983	26680983	35680778	0	0	0						
TOTAL LC PROJECT COST	4442912	4419283	4419283	0	0	0						
TOTAL PROJECT COST	31123895	31100267	40100062	0	0	0						
Capital cost multiplier	1	1	1	1	1	1						
TOTAL CAPITAL COST	31123895	31100267	40100062	0	0	0						
SUM TOTAL CAPITAL COST	102324223 00											
PRE-OPERATION COSTS, all FE												
Initial fuel supply	0	0	0	0	0	0	0					
Operator Training	0	0	94160	0	0	0	0					
Spare Parts	0	5	262500	0	0	0	0					
Mobile Equipment	0	0	630000	0	0	0	0					
Upgrade Turbine/Generators	0	0	525000	0	0	0	0					
TOTAL INCREMENTAL COST	0	0	1511660	0	0	0	0					
OPERATIONS AND MAINTENANCE												
FUEL												
Coal Price (US$/ton, CIF)	57 11	54 47	54 47	55 79	56 23	56 67	57 33	57.77	58.43	58.87	59.97	61.09
Coal supplies FE	0	0	0	21374910	21545512	21714106	21966996	22135590	22308401	22134129	22116863	22091023
SALARIES												
Foreman LC	0	0	0	14310	14310	14310	14310	14310	14310	14310	14310	14310
Asst Foreman LC	0	0	0	11440	11440	11440	11440	11440	11440	11440	11440	11440
Vehicle Operators (3) LC	0	0	0	24531	24531	24531	24531	24531	24531	24531	24531	24531
Ash truck drivers (2) LC	0	0	0	16354	16354	16354	16354	16354	16354	16354	16354	16354
Coal boiler operators (4) LC	0	0	0	40885	40885	40885	40885	40885	40885	40885	40885	40885
Maintenance positions (3) LC	0	0	0	30664	30664	30664	30664	30664	30664	30664	30664	30664
MAINTENANCE, all FE												
Ash disposal	0	0	0	94500	94500	94500	94500	94500	94500	94500	94500	94505
Coal handling	0	0	0	367500	367500	367500	367500	367500	367500	367500	367500	367500
Spares mill & balanceofplant	0	0	0	882000	882000	882000	882000	882000	882000	882000	882000	882000

PROJECT TITLE

DATA ITEMS \ YEAR	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
CAPITAL COSTS TOTAL														
Dock Facilities FE														
Dock LC														
Site Preparation FE														
Site LC														
Coal Rec'ving & Handling FE														
Coal Rec'g LC														
Building Superstructures FE														
Bldg LC														
Boilers FE														
Boilers LC														
Precipitators														
Stacks														
Fly ash handling														
Piping & mech FE														
Piping LC														
Electrical & Instrument'n FE														
Electrical LC														
Contingency														
Land LC														
TOTAL FE PROJECT COST														
TOTAL LC PROJECT COST														
TOTAL PROJECT COST														
TOTAL CAPITAL COST														
SUM TOTAL CAPITAL COST														
PRE-OPERATION COSTS, all FE														
Initial fuel supply														
Operator Training														
Spare Parts														
Mobile Equipment														
Upgrade Turbine/Generators														
TOTAL INCREMENTAL COST														
OPERATIONS AND MAINTENANCE														
FUEL														
Coal Price (US$/ton, CIF)	61.09	62.17	63.36	64.55	65.73	67.01	68.29	69.61	70.93	72.70	74.52	76.38	78.27	80.25
Coal supplies FE	23481743	23843837	21242818	21441783	22037484	22466551	22895699	23338257	23780816	24375336	24984720	25609338	26249571	26705050
SALARIES														
Foreman LC	14310	14310	14310	14310	14310	14310	14310	14310	14310	14310	14310	14310	14310	14310
Asst Foreman LC	11448	11448	11448	11448	11448	11448	11448	11448	11448	11448	11448	11448	11448	11448
Vehicle Operators (3) LC	24531	24531	24531	24531	24531	24531	24531	24531	24531	24531	24531	24531	24531	24531
Ash truck drivers (2) LC	16354	16354	16354	16354	16354	16354	16354	16354	16354	16354	16354	16354	16354	16354
Coal boiler operators (4) LC	40885	40885	40885	40885	40885	40885	40885	40885	40885	40885	40885	40885	40885	40885
Maintenance positions (3) LC	30664	30664	30664	30664	30664	30664	30664	30664	30664	30664	30664	30664	30664	30664
MAINTENANCE, all FE														
Ash disposal	94500	94500	94500	94500	94500	94500	94500	94500	94500	94500	94500	94500	94500	94500
Coal handling	367500	367500	367500	367500	367500	367500	367500	367500	367500	367500	367500	367500	367500	367500
Spares mill & balanceofplant	441000	441000	441000	441000	441000	441000	441000	441000	441000	441000	441000	441000	441000	441000

Figure B.2 (cont)

PROJECT TITLE PROJECT TITLE BECHTEL COAL CONVERSION STUDY

DATA ITEMS \ YEAR	DATA ITEMS \ YEAR	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Auxiliary power	Auxiliary power	0	0	0	367500	367500	367500	367500	367500	367500	367500	367500
Miscellaneous items	Miscellaneous items	0	0	0	0	0	0	0	0	0	0	0
TECHNICAL ASSIST & TRAINING FE	TECHNICAL ASSIST & TRAINING FE	0	0	0	802500	802500	802500	802500	802500	0	0	0
ANNUAL FE O&M	ANNUAL FE O&M	0	0	0	20777804	20925323	21072843	21294122	21441641	20860421	21007940	21376739
ANNUAL LC O&M	ANNUAL LC O&M	0	0	0	138191	138191	138191	138191	138191	138191	138191	138191
TOTAL ANNUAL O&M	TOTAL ANNUAL O&M	0	0	0	20915995	21063514	21211034	21432313	21579833	20998612	21146131	21514930
FE COSTS	FE COSTS	26224000	26224000	35735598	20777804	20925323	21072843	21294122	21441641	20860421	21007940	21376739
LC COSTS	LC COSTS	4150708	4127000	4127000	138191	138191	138191	138191	138191	138191	138191	138191
TOTAL COSTS	TOTAL COSTS	30374708	30351000	39862677	20915995	21063514	21211034	21432313	21579833	20998612	21146131	21514930
BENEFITS	BENEFITS											
Fuel oil price (US$/bbl, CIF)	Fuel oil price (US$/bbl, CIF)	24 43	23 31	23 31	24 42	25 31	26 42	27 53	28 64	29 97	31.08	31.86
Petroleum savings,(US$/yr)	Petroleum savings,(US$/yr)	0	0	0	27297908	28292877	29533695	30774513	32015330	33502076	34742893	35611666
Electric power sales (MW-HR)	Electric power sales (MW-HR)	0	0	0	840004	840004	840004	840004	840004	840004	840004	840004
TOTAL BENEFITS, FE SAVINGS	TOTAL BENEFITS, FE SAVINGS	0	0	0	27297908	28292877	29533695	30774513	32015330	33502076	34742893	35611666
ANNUAL NET BENEFITS	ANNUAL NET BENEFITS	-30374787	-30351079	-39862677	6381992 8132	7229363 1	8322661 2	9342199 5	10435497 6	12503463 827	13596761	14096535.4

Figure B.2 (cont.)

PROJECT TITLE

DATA ITEMS \ YEAR	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Auxiliary power	367500	367500	367500	367500	367500	367500	367500	367500	367500	367500	367500	367500	367500	367500
Miscellaneous items	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TECHNICAL ASSIST & TRAINING FE	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL FE O&M	21752243	22114337	22513310	22912283	23307904	23737051	24166199	24608757	25051316	25445834	26255220	26879838	27520071	28176310
ANNUAL LC O&M	138191	138191	138191	138191	138191	138191	138191	138191	138191	138191	138191	138191	138191	138191
TOTAL ANNUAL O&M	21890434	22252528	22651501	23050474	23446095	23875242	24304390	24746949	25189507	25584027	26393411	27018029	27658262	28314502
FE COSTS	21752243	22114337	22513310	22912283	23307904	23737051	24166199	24608757	25051316	25445834	26255220	26879838	27520071	28176310
LC COSTS	138191	138191	138191	138191	138191	138191	138191	138191	138191	138191	138191	138191	138191	138191
TOTAL COSTS	21890434	22252528	22651501	23050474	23446095	23875242	24304390	24746949	25189507	25584027	26393411	27018029	27658262	28314502
BENEFITS														
Fuel oil price (US$/bbl, CIF)	32 65	33 47	34 31	35 16	36 04	36 94	37 87	38 81	39 79	40 78	41 80	42 84	43 92	45.01
Petroleum savings,(US$/yr)	36501752	37414296	38349653	39308395	40291105	41298382	42330842	43389113	44473841	45585687	46725329	47893462	49090799	50318069
Electric power sales (MW-HR)	840884	840884	840884	840884	840884	840884	840884	840884	840884	840884	840884	840884	840884	840884
TOTAL BENEFITS, FE SAVINGS	36501752	37414296	38349653	39308395	40291105	41298382	42330842	43389113	44473841	45585687	46725329	47893462	49090799	50318069
ANNUAL NET BENEFITS	14611317 9119	15161768 37	15698152	16257928	16845010	17423139	18026451 845	18642164	19284333	19901659	20331918	20875433	21432534.	22003567.

Figure B.2 (cont.)

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PROJECT NAME HYDROELECTRIC PLANT ON Y S RIVER

DATA ITEMS	YEAR	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
SITE INSTALLATION	LOC	159,683	159,683												
	FOR	489,834	0												
INTAKE AND WEAR	LOC	94,142	0												
	FOR	33,318	0												
PRESSURE GALLERY	LOC	108,982	51,681												
	FOR	0	99,667												
SURGE TANK	LOC	26,887	11,112												
	FOR	12,376	0												
PENSTOCK	LOC	12,484	0												
	FOR	18,928	21,857												
POWER HOUSE	LOC	31,975	47,962												
	FOR	28,878	43,317												
ELECTROMECHANICAL	LOC	0	58,487												
	FOR	0	1,125,398												
TAILRACE AND OUTFLOW	LOC	0	15,579												
	FOR	0	4,702												
INTERCONNECTION	LOC	0	105,133												
	FOR	0	59,866												
INDIRECT	LOC	141,258	141,258												
	FOR	138,385	138,385												
SUBTOTAL CAPITAL	LOC	654,362	598,747												
	FOR	825,719	1,455,381												
TOTAL CAPITAL COSTS		1,480,081	2,046,048												
OP & MAINT COST	LOC			22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567
	FOR			5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642
CASH FLOW OF COSTS	LOC	654,362	598,747	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567
	FOR	825,719	1,455,381	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642
TOTAL COSTS		1,480,081	2,046,048	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209
Calculation of benefits (reduction in operating costs) using a thermal alternative															
ENERGY GENERATED	GWH	0	0	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
INCOME FROM ELECTRICITY				855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000
NET INCOME		-1480000.5	-2046048.1	826790.970	826790.97049	826790.970	826790.970	826790.970	826790.970	826790.97049	826790.9	826790.970	826790.97049	826790.97049	826790.97

Y.S. RIVER HYRDROELECTRIC PROJECT - ORIGINAL ANALYSIS

Figure B.3

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Figure B.3 (cont.)

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567
5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642
22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567	22,567
5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642	5,642
28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209	28,209
9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000	855,000
826790.970	826790.970	826790.9	826790.97049	826790.970	826790.970	826790.970	826790.970	826790.970	826790.970	826790.970	826790.970	826790.970	826790.970	826790.970	826790.970	826790.97

Y.S. RIVER HYDROELECTRIC PROJECT - REVISED ANALYSIS

Figure B.4

PROJECT NAME HYDROELECTRIC PLANT ON Y S RIVER

DATA ITEMS	YEAR	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
ACCESS ROAD	LOC	42,032													
	FOR														
SITE INSTALLATION	LOC	504,950	344,950												
	FOR	0	0												
INTAKE AND WEIR	LOC	125,664	0												
	FOR	0	0												
PRESSURE GALLERY	LOC	292,035	292,035												
	FOR	0	0												
SURGE TANK	LOC	18,584	74,336												
	FOR	0	0												
PENSTOCK	LOC	0	27,434												
	FOR	0	31,523												
POWER HOUSE	LOC	88,182	25,172												
	FOR	0	0												
ELECTROMECHANICAL	LOC	0	0												
	FOR	531,398	531,398												
TAILRACE AND OUTFLOW	LOC	0	38,053												
	FOR	0	0												
INTERCONNECTION	LOC	62,091	0												
	FOR	125,688	0												
LAND ACQUISITION	LOC	4,425													
	FOR														
CONTINGENCIES	LOC		294,188												
	FOR		183,881												
INDIRECT	LOC	41,815	38,799												
	FOR	131,417	149,184												
SUBTOTAL CAPITAL	LOC	1,195,274	840,788												
	FOR	788,503	712,185												
TOTAL CAPITAL COSTS		1,983,777	1,552,885												
OP & MAINT COST	LOC			16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976
	FOR			4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244
CASH FLOW OF COSTS	LOC	1,195,274	840,788	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976
	FOR	788,503	712,185	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244
TOTAL COSTS		1,983,777	1,552,885	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220
Calculation of benefits (reduction in operating costs) using a thermal alternative															
ENERGY GENERATED	GWH	0	0	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
HEAT RATE DISPLACED	BTU/KWH	12000	12000	12000	12000	12000	12000	12000	12000	12000	12000	12000	12000	12000	12000
HEAT CONTENT	MBTU/BBL	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
FUEL PRICE	US$/BBL	22.2	20.65	19.31	19.31	20.42	21.31	22.42	23.53	24.64	25.97	27.08	27.77	28.46	29.18
VARIABLE O & M	LOC	0	0	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000

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FUEL	FOR														
	LOC														
	FOR	0	0	355,055	355,055	375,465	391,829	412,239	432,648	453,058	477,513	497,923	518,610	523,375	536,459
FLOW OF BENEFITS	LOC	0	0	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000
	FOR	0	0	355055	355055	375465	391829	412239	432648	453058	477513	497923	518610	523375	536459
TOTAL BENEFITS		0	0	374055	374055	394465	410829	431239	451648	472058	496513	516923	537610	542375	555459
NET CASH FLOW	LOC	-1195274	-840788	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024
	FOR	-788503	-712105	350811	350811	371221	387585	407995	428404	448814	473269	493679	506344	519131	532215
TOTAL NET		-1983777	-1552885	352835	352835	373245	389609	410019	430428	450838	475293	495703	508398	521155	534239

Figure B.4 (cont.)

Figure B.4 (cont.)

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976
4,244	4,244	4,244	4,244	4,245	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244
16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976	16,976
4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244	4,244
21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220	21,220
9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
12000	12000	12000	12000	12000	12000	12000	12000	12000	12000	12000	12000	12000	12000	12000	12000	12000
6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2

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29.91	30.65	31.42	32.20	33.01	33.84	34.68	35.55	36.44	37.35	38.28	39.24	40.22	41.22	42.26	43.31	44.39
19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000
547,871	563,618	577,708	592,151	606,954	622,128	637,682	653,624	669,964	686,713	703,881	721,478	739,515	758,003	776,953	796,377	816,286
19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000	19000
549871	563618	577708	592151	606954	622128	637682	653624	669964	686713	703881	721478	739515	758003	776953	796377	816286
568871	582618	596708	611151	625954	641128	656682	672624	688964	705713	722881	740478	758515	777003	795953	815377	835286
2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024
545627	559374	573464	587907	602710	617884	633438	649380	665720	682469	699637	717234	735271	753759	772709	792133	812042
547651	561398	575488	589931	604734	619908	635462	651404	667744	684493	701661	719258	737295	755783	774733	794157	814066

Figure B.4 (cont.)

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Figure B.5

NEGRIL PEAT PROJECT - ORIGINAL ANALYSIS

PROJECT TITLE PROJECT TITLE NEGRIL PEAT PROJECT

DATA ITEMS \ YEAR	DATA ITEMS \ YEAR	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
CAPITAL COST **********	CAPITAL COST **********										
CIVIL WORKS FE	CIVIL WORKS FE	487,667	487,667	487,667	0	0					
CIVIL WORKS LC	CIVIL WORKS LC	3,013,333	3,013,333	3,013,333	0	0					
MACHINERY FE	MACHINERY FE	17,784,667	17,784,667	17,784,667	0	0					
MACHINERY LC	MACHINERY LC	4,146,400	4,146,400	4,146,400	0	0					
PIPING FE	PIPING FE	652,333	652,333	652,333	0	0					
PIPING LC	PIPING LC	58,400	58,400	58,400	0	0					
ELECTRICAL EQUIP FE	ELECTRICAL EQUIP FE	2,815,333	2,815,333	2,815,333	0	0					
ELECTRICAL EQUIP LC	ELECTRICAL EQUIP LC	759,200	759,200	759,200	0	0					
PROCESS EQUIP FE	PROCESS EQUIP FE	171,667	171,667	171,667	0	0					
PROCESS EQUIP LC	PROCESS EQUIP LC	58,400	58,400	58,400	0	0					
SPARE PARTS INVENTORY FE	SPARE PARTS INVENTORY FE	137,333	137,333	137,333	0	0					
INDIRECT COST FE	INDIRECT COST FE	3,378,833	3,378,833	3,378,833	0	0					
INDIRECT COST LC	INDIRECT COST LC	1,333,333	1,333,333	1,333,333	0	0					
WORKING CAP FE	WORKING CAP FE	313,500	313,500	313,500	0	0					
WORKING CAP LC	WORKING CAP LC	1,626,667	1,626,667	1,626,667	0	0					
CONTINGENCY FE	CONTINGENCY FE	0	0	5,100,000	0	0					
CONTINGENCY LC	CONTINGENCY LC	0	0	1,500,000	0	0					
TOTAL CAPIT COST FE	TOTAL CAPIT COST FE	25,741,333	25,741,333	30,841,333	0	0	0				
TOTAL CAPIT COST LC	TOTAL CAPIT COST LC	10,995,733	10,995,733	12,495,733	0	0	0				
TOTAL CAPITAL COSTS	TOTAL CAPITAL COSTS	36,737,067	36,737,067	43,337,067	0	0	0	0	0	0	0
OPERATING & MAITENANCE COSTS	OPERATING & MAITENANCE COSTS **********										
PERSONNEL (W&S) LC	PERSONNEL (W&S) LC	0	0	0	665280	665280	665280	665280	665280	665280	665280
MAINTENANCE MATERIAL FE	MAINTENANCE MATERIAL FE	0	0	0	0	0	0	610000	610000	610000	610000
MAINTENANCE MATERIAL LC	MAINTENANCE MATERIAL LC	0	0	0	0	0	0	160000	160000	160000	160000
OTHER COSTS LC	OTHER COSTS LC	0	0	0	480000	480000	480000	480000	480000	480000	480000
CONSUMABLES	CONSUMABLES **********										
FUEL OIL FE	FUEL OIL FE	0	0	0	39188	52474	61341	64378	67415	71054	74891
DIESEL OIL FE	DIESEL OIL FE	0	0	0	61183	81970	95742	100713	105464	111159	115910
CHEMICALS FE	CHEMICALS FE	0	0	0	1893019	2433882	2784313	2784313	2784313	2784313	2784313
CHEMICALS LC	CHEMICALS LC	0	0	0	40383	77636	86262	86262	86262	86262	86262
RENEWALS	RENEWALS **********										
SLURRY PIPE EXTENSIONS FE	SLURRY PIPE EXTENSIONS FE	0	0	0	0	0	0	0	466075	0	0
SLURRY PIPE EXTENSIONS LC	SLURRY PIPE EXTENSIONS LC	0	0	0	0	0	0	0	38800	0	0
TOTAL OPERATING AND MAINTENANC	TOTAL OPERATING AND MAINTENANCE COSTS **********										
TOTAL O&M FE	TOTAL O&M FE	0	0	0	1993311	2548446	2861617	3487665	3961248	3584526	3512314
TOTAL O&M LC	TOTAL O&M LC	0	0	0	1205663	1232916	1231542	1391542	1427542	1391542	1391542
TOTAL O&M	TOTAL O&M	0	0	0	3198974	3791362	4093159	4878947	5390810	4896068	4903856
AMOUNT OF ELECTRICITY GENERATE	AMOUNT OF ELECTRICITY GENERATED **********										
TOTAL MEGAWATT HOURS GENERATED	TOTAL MEGAWATT HOURS GENERATED	0	0	0	367728	473848	525600	525600	525600	525600	525600
MEGAWATT HOURS AT BUSBAR	MEGAWATT HOURS AT BUSBAR	0	0	0	293968	377959	419954	419954	419954	419954	419954
MEGAWATTS FOR SALES	MEGAWATTS FOR SALES	0	0	0	246933	317486	352762	352762	352762	352762	352762
TOTAL COSTS	TOTAL COSTS	36737067	36737067	43337067	3198974	3791362	4093159	4878947	5390810	4896068	4903856
TOTAL INCOME	TOTAL INCOME	0	0	0	24457127	34016306	37795896	37795896	37795896	37795896	37795896
NET INCOME	NET INCOME	-36737067	-36737067	-43337067	23258153	30224945	33702737	32916949	32405086	32899828	32892040

PROJECT TITLE

DATA ITEMS \ YEAR	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
CAPITAL COST **********												
CIVIL WORKS FE												
CIVIL WORKS LC												
MACHINERY FE												
MACHINERY LC												
PIPING FE												
PIPING LC												
ELECTRICAL EQUIP FE												
ELECTRICAL EQUIP LC												
PROCESS EQUIP FE												
PROCESS EQUIP LC												
SPARE PARTS INVENTORY FE												
INDIRECT COST FE												
INDIRECT COST LC												
WORKING CAP FE												
WORKING CAP LC												
CONTINGENCY FE												
CONTINGENCY LC												
TOTAL CAPIT COST FE												
TOTAL CAPIT COST LC												
TOTAL CAPITAL COSTS	0	0	0	0	0	0	0	0	0	0	0	0
OPERATING & MAITENANCE COSTS **********												
PERSONNEL (W&S) LC	665280	665280	665280	665280	665280	665280	665280	665280	665280	665280	665280	665280
MAINTENANCE MATERIAL FE	610000	610000	610000	610000	610000	610000	610000	610000	610000	610000	610000	610000
MAINTENANCE MATERIAL LC	160000	160000	160000	160000	160000	160000	160000	160000	160000	160000	160000	160000
OTHER COSTS LC	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000	400000
CONSUMABLES **********												
FUEL OIL FE	75979	77867	79809	81806	83831	85938	88072	90261	92559	94885	97257	99688
DIESEL OIL FE	118867	121825	124845	127991	131138	134441	137776	141206	144793	148411	152121	155924
CHEMICALS FE	2704313	2704313	2704313	2704313	2704313	2704313	2704313	2704313	2704313	2704313	2704313	2704313
CHEMICALS LC	86262	86262	86262	86262	86262	86262	86262	86262	86262	86262	86262	86262
RENEWALS **********												
SLURRY PIPE EXTENSIONS FE	0	0	466875	0	0	0	0	466875	0	0	0	0
SLURRY PIPE EXTENSIONS LC	0	0	30000	0	0	0	0	30000	0	0	0	0
TOTAL OPERATING AND MAINTENANCE COSTS **********												
TOTAL O&M FE	3517159	3522805	3993843	3532111	3537282	3542693	3548162	4019855	3559665	3565609	3571691	3577926
TOTAL O&M LC	1391542	1391542	1429542	1391542	1391542	1391542	1391542	1429542	1391542	1391542	1391542	1391542
TOTAL O&M	4908701	4913547	5422585	4923653	4928824	4934235	4939704	5449397	4951207	4957151	4963233	4969468
AMOUNT OF ELECTRICITY GENERATED **********												
TOTAL MEGAWATT HOURS GENERATED	525600	525600	525600	525600	525600	525600	525600	525600	525600	525600	525600	525600
MEGAWATT HOURS AT BUSBAR	419954	419954	419954	419954	419954	419954	419954	419954	419954	419954	419954	419954
MEGAWATTS FOR SALES	352762	352762	352762	352762	352762	352762	352762	352762	352762	352762	352762	352762
TOTAL COSTS	4908701	4913547	5422585	4923653	4928824	4934235	4939704	5449397	4951207	4957151	4963233	4969468
TOTAL INCOME	37795896	37795896	37795896	37795896	37795896	37795896	37795896	37795896	37795896	37795896	37795896	37795896
NET INCOME	32887195	32882349	32373311	32872243	32867072	32861661	32856192	32346499	32844689	32838745	32832663	32826428

Figure B.5 (cont.)

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PROJECT TITLE

DATA ITEMS \ YEAR	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAPITAL COST **********									
CIVIL WORKS FE									
CIVIL WORKS LC									
MACHINERY FE									
MACHINERY LC									
PIPING FE									
PIPING LC									
ELECTRICAL EQUIP FE									
ELECTRICAL EQUIP LC									
PROCESS EQUIP FE									
PROCESS EQUIP LC									
SPARE PARTS INVENTORY FE									
INDIRECT COST FE									
INDIRECT COST LC									
WORKING CAP FE									
WORKING CAP LC									
CONTINGENCY FE									
CONTINGENCY LC									
TOTAL CAPIT COST FE									
TOTAL CAPIT COST LC									
TOTAL CAPITAL COSTS	0	0	0	0	0	0	0	0	0
OPERATING & MAITENANCE COSTS **********									
PERSONNEL (W&S) LC	665200	665200	665200	665200	665200	665200	665200	665200	665200
MAINTENANCE MATERIAL FE	618000	618000	618000	618000	618000	618000	618000	618000	618000
MAINTENANCE MATERIAL LC	160000	160000	160000	160000	160000	160000	160000	160000	160000
OTHER COSTS LC	480000	480000	480000	480000	480000	480000	480000	480000	480000
CONSUMABLES **********									
FUEL OIL FE	102180	104735	107353	110037	112788	115608	118498	121460	124497
DIESEL OIL FE	159822	163818	167913	172111	176414	180824	185345	189978	194728
CHEMICALS FE	2704313	2704313	2704313	2704313	2704313	2704313	2704313	2704313	2704313
CHEMICALS LC	86262	86262	86262	86262	86262	86262	86262	86262	86262
RENEWALS **********									
SLURRY PIPE EXTENSIONS FE	466075	0	0	0	0	466075	0	0	0
SLURRY PIPE EXTENSIONS LC	38000	0	0	0	0	38000	0	0	0
TOTAL OPERATING AND MAINTENANCE COSTS **********									
TOTAL O&M FE	4050391	3598846	3597588	3604462	3611515	4034828	3626156	3633752	3641538
TOTAL O&M LC	1429542	1391542	1391542	1391542	1391542	1429542	1391542	1391542	1391542
TOTAL O&M	5479933	4982408	4989122	4996004	5003057	5514342	5017698	5025294	5033080
AMOUNT OF ELECTRICITY GENERATED **********									
TOTAL MEGAWATT HOURS GENERATED	525600	525600	525600	525600	525600	525600	525600	525600	525600
MEGAWATT HOURS AT BUSBAR	419954	419954	419954	419954	419954	419954	419954	419954	419954
MEGAWATTS FOR SALES	352762	352762	352762	352762	352762	352762	352762	352762	352762
TOTAL COSTS	5479933	0	0	0	0	0	0	0	0
TOTAL INCOME	37795896	0	0	0	0	0	0	0	0
NET INCOME	32315963	0	0	0	0	0	0	0	0

Figure B.5 (cont.)

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PROJECT TITLE PROJECT TITLE NEGRIL PEAT PROJECT

DATA ITEMS \ YEAR	DATA ITEMS \ YEAR	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
FUEL PRICE, DIESEL (US$/BBL)	FUEL PRICE, DIESEL (US$/BBL)	28 89	26 27	26 27	27 78	28 99	30 5	32 81	33 51	35.33	36.84
FUEL PRICE, BUNKER C (US$/BBL)	FUEL PRICE, BUNKER C (US$/BBL)	20 65	19 31	19.31	20 42	21 31	22 42	23 53	24.64	25.97	27.08

Figure B.5 (cont.)

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PROJECT TITLE

DATA ITEMS \ YEAR	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
FUEL PRICE, DIESEL (US$/BBL)	37.78	38.72	39.68	40.68	41.68	42.73	43.79	44.88	46.02	47.17	48.35	49.56
FUEL PRICE, BUNKER C (US$/BBL)	27.77	28.46	29.17	29.9	30.64	31.41	32.19	33.99	33.03	34.46	35.55	36.44

Figure B.5 (cont.)

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PROJECT TITLE

DATA ITEMS \ YEAR	2008	2009	2010	2011	2012	2013	2014	2015	2016
FUEL PRICE, DIESEL (US$/BBL)	50 80	52 07	53 37	54 70	56 07	57 47	58 91	60.38	61.89
FUEL PRICE, BUNKER C (US$/BBL)	37 35	38 28	39 24	40 22	41 22	42 25	43 31	44 39	45 50

Figure B.5 (cont.)

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Figure B.6

NEGRIL PEAT PROJECT - REVISED ANALYSIS

PROJECT TITLE NEGRIL PEAT PROJECT

DATA ITEMS \ YEAR	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
CAPITAL COST **********												
CIVIL WORKS FE	1,463,000											
CIVIL WORKS LC	9,040,000											
MACHINERY FE	66,692,500											
MACHINERY LC	15,549,000											
PIPING FE	2,446,250											
PIPING LC	219,000											
ELECTRICAL EQUIP FE	8,446,000											
ELECTRICAL EQUIP LC	2,277,600											
PROCESS EQUIP FE	643,750											
PROCESS EQUIP LC	219,000											
SPARE PARTS INVENTORY FE	741,600											
SPARE PARTS INVENTORY LC	192,000											
INDIRECT COST FE	10,136,500											
INDIRECT COST LC	5,200,000											
WORKING CAP FE	940,500											
WORKING CAP LC	4,000,000											
CONTINGENCY FE	0	0	0	13,585,440	0							
CONTINGENCY LC	0	0	0	4,904,490	0							
TOTAL CAPIT COST FE	91,510,100	0	0	13,585,440	0							
TOTAL CAPIT COST LC	37,574,600	0	0	4,904,490	0							
TOTAL CAPITAL COSTS	32,271,675	32,271,675	32,271,675	50,761,605	0							
OPERATING & MAITENANCE COSTS **********												
PERSONNEL (W&S) LC	0	0	0	0	765400	765400	765400	765400	765400	765400	765400	765400
MAINTENANCE MATERIAL FE	0	0	0	0	741600	741600	741600	741600	741600	741600	741600	741600
MAINTENANCE MATERIAL LC	0	0	0	0	210240	210240	210240	210240	210240	210240	210240	210240
OTHER COSTS LC	0	0	0	0	600000	600000	600000	600000	600000	600000	600000	600000
CONSUMABLES **********												
FUEL OIL FE	0	0	0	0	48785	55034	64176	67353	69361	71404	71795	72117
DIESEL OIL FE	0	0	0	0	63807	86098	100400	105370	108512	111707	112269	112790
CHEMICALS FE	0	0	0	0	1895389	2436926	2707698	2707698	2656929	2606159	2555390	2504621
CHEMICALS LC	0	0	0	0	68459	[illegible]	86370	86370	84751	83131	81512	79892
RENEWALS **********												
SLURRY PIPE EXTENSIONS FE	0	0	0	0	0	0	0	0	466875	0	0	0
SLURRY PIPE EXTENSIONS LC	0	0	0	0	0	0	0	0	38000	0	0	0
TOTAL OPERATING AND MAINTENANCE COSTS **********												
TOTAL O&M FE	0	0	0	0	2741581	3319660	3613874	3622820	4042477	3530875	3481054	3431127
TOTAL O&M LC	0	0	0	0	1636107	1653381	1662018	1662018	1690399	1638779	1657160	1655540
TOTAL O&M	0	0	0	0	4377688	4973041	5275892	5284838	5740875	5189649	5138214	5086668
AMOUNT OF ELECTRICITY GENERATED **********												
TOTAL MEGAWATT HOURS GENERATED	0	0	0	0	367920	473840	525690	525688	515745	505898	496035	486188
PLANT UTILIZATION			00 0%	00 0%	00 0%	00 0%	00 0%	00 0%	78 5%	77 0%	75 5%	74 0%
MEGAWATT HOURS AT BUSBAR	0	0	0	0	294336	378432	420488	420488	412596	404712	396828	388944
MEGAWATTS FOR SALES	0	0	0	0	241355	310314	344794	344794	338329	331864	325399	318934
TOTAL COSTS	32271675	32271675	32271675	50761605	4377688	4973041	5275892	5284838	5740875	5189649	5138214	5086668
TOTAL INCOME	0	0	0	0	11961885	16116600	18766885	19667696	20235275	20791867	20838602	27993557
NET INCOME	-32271675	-32271675	-32271675	-50761605	7583317	11143559	13490993	14383657	14494400	15601418	22900388	22906889

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FUEL PRICE, DIESEL (US$/BBL)	$28.1	$26.3	$26.3	$27.6	$28.9	$30.4	$31.9	$33.4	$35.1	$36.8	$37.8	$38.7
FUEL PRICE, BUNKER C (US$/BBL)	$20.7	$19.3	$19.3	$20.3	$21.3	$22.3	$23.4	$24.6	$25.8	$27.1	$27.8	$28.5
ELECT VALUE(FUEL SAVINGS)$/KW-HR	$0.040	$0.037	$0.037	$0.039	$0.041	$0.043	$0.045	$0.047	$0.049	$0.051	$0.053	$0.054
LONG RUN MARGINAL COST $/KW-HR	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.010	$0.010

Figure B.6 (cont.)

Figure B.6 (cont.)

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
765400	765400	765400	765400	765400	765400	765400	765400	765400	765400	765400	765400	765400	765400	765400
741600	741600	741600	741600	741600	741600	741600	741600	741600	741600	741600	741600	741600	741600	741600
210240	210240	210240	210240	210240	210240	210240	210240	210240	210240	210240	210240	210240	210240	210240
600000	600000	600000	600000	600000	600000	600000	600000	600000	600000	600000	600000	600000	600000	600000
72410	72694	72919	73139	73301	73429	73561	73620	73642	74060	76731	78649	80616	82631	84697
113266	113676	114076	114484	114678	114893	115048	115139	115162	117065	119992	122992	126066	129218	132449
2453851	2403082	2352313	2301543	2250774	2200005	2149235	2098466	2047697	2038774	2038774	2038774	2038774	2038774	2038774
78273	74653	75034	73414	71795	70176	68556	66937	65317	64777	64777	64777	64777	64777	64777
0	466875	0	0	0	0	466875	0	0	0	0	466875	0	0	0
0	38000	0	0	0	0	38000	0	0	0	0	38000	0	0	0
3381135	3797147	3280908	3230686	3180353	3129927	3545519	3020832	2970181	2964298	2969097	3440898	2979056	2998223	2989519
1653921	1698381	1650682	1649862	1647443	1645024	1682204	1642585	1640965	1640925	1640925	1678425	1640925	1640925	1640925
5035056	5487448	4931590	4879749	4827796	4775750	5227723	4671417	4619866	4604724	4609522	5118515	4619981	4624468	4629946
476325	466478	456615	446760	436905	427050	417195	407340	397485	394200	394200	394200	394200	394200	394200
72.5%	71.0%	69.5%	68.0%	66.5%	65.0%	63.5%	62.0%	60.5%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
381060	373176	365292	357408	349524	341640	333756	325872	317988	315360	315360	315360	315360	315360	315360
312469	306094	299539	293075	286610	280145	273680	267215	260750	258595	258595	258595	258595	258595	258595
5035056	5487448	4931590	4879749	4827796	4775750	5227723	4671417	4619866	4604724	4609522	5118515	0	0	0
27948296	27878347	27807221	27726488	********	27533589	27428463	27295411	27157820	27464797	28009505	28567831	0	0	0
22905240	22390899	22875631	22846659	********	22757838	22192740	22623995	22538754	22860074	23399983	23449316	0	0	0

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Figure B.6 (cont.)

$39.7	$40.7	$41.7	$42.7	$43.8	$44.9	$46.0	$47.2	$48.3	$49.5	$50.8	$52.1	$53.4	$54.7	$56.1
$29.2	$29.9	$30.6	$31.4	$32.2	$33.0	$33.8	$34.7	$35.5	$36.4	$37.3	$38.3	$39.2	$40.2	$41.2
$0.055	$0.057	$0.058	$0.060	$0.061	$0.063	$0.064	$0.066	$0.067	$0.069	$0.071	$0.073	$0.074	$0.076	$0.078
$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

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Annex C
Results of Regression Analysis

Table C.1
Number of Hookups for Small Commercial and Industrial Users
Natual Logarithm of Number of Hookups 1963-1984

	COEFFICIENT	STANDARD ERROR	T-STATISTIC
CONST	-39.53127	2.991912	-13.21271
YEAR	2.395985E-02	1.663235E-03	14.40557
LNGDPNBX	.2877775	6.550241E-02	4.393389

R-squared	.9652116	Mean of depend var	9.893303
Adjusted R-squared	.9615496	Std dev depend var	.1930466
Std err of regress	3.785404E-02	Residual sum	-1.376312E-08
Durbin Watson stat	.2683683	Sum squared resid	2.722563E-02
F statistic	263.5795 F		

Number of Hookups 1974-1984

	COEFFICIENT	STANDARD ERROR	T-STATISTIC
CONST[-1]	5360.564	1333.737	4.019207
CUSTOMRS[-1]	.7799217	.0577022	13.51633

R-squared	.9530495	Mean of depend var	23366.55
Adjusted R-squared	.9478328	Std dev depend var	939.7945
Std err of regress	214.6505	Residual sum	-1.985527E-05
Durbin Watson stat	1.284988	Sum squared resid	414673.6
F statistic	182.6911 F		

Table C.2
Consumption per Hookup for Small Commercial and Industrial Users
Natural Logarithm of Consumption 1962-1984

	COEFFICIENT	STANDARD ERROR	T-STATISTIC
CONST	-11.90256	3.189237	-3.732102
YEAR	7.685291E-03	1.758812E-03	4.369591
OUTAGES	-8.598008E-02	2.257526E-02	-3.808598
LNGDPNBX	.8837274	.0596259	14.8212

R-squared	.9697968	Mean of depend var	9.796436
Adjusted R-squared	.9650279	Std dev depend var	.1965521
Std err of regress	3.675686E-02	Residual sum	-2.365181E-09
Durbin Watson stat	1.266895	Sum squared resid	2.567026E-02
F statistic	203.3579 F		

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Table C.2 (cont.)
Natural Logarithm of Consumption 1974-1984

	COEFFICIENT	STANDARD ERROR	T-STATISTIC
CONST	-9.124474	8.954026	-1.019036
YEAR	7.247222E-03	3.685677E-03	1.966321
OUTAGES	-.1002981	2.424395E-02	-4.137036
LNGDPNBX	.6293486	.2859918	2.200583

R-squared	.8879535	Mean of depend var	9.907178
Adjusted R-squared	.8399336	Std dev depend var	6.599877E-02
Std err of regress	2.640499E-02	Residual sum	3.917774E-10
Durbin Watson stat	2.341108	Sum squared resid	4.880564E-03
F statistic	18.49135 F		

Table C.3
Number of Hookups for Residential Users
Natural Logarithm of Hookups 1962-1984

	COEFFICIENT	STANDARD ERROR	T-STATISTIC
CONST	-127.0635	2.982903	-42.59728
YEAR	7.032186E-02	1.511853E-03	46.51369

R-squared	.9903869	Mean of depend var	11.6815
Adjusted R-squared	.9899291	Std dev depend var	.4792552
Std err of regress	4.809499E-02	Residual sum	-6.478835E-10
Durbin Watson stat	.1963466	Sum squared resid	.0485757
F statistic	2163.523 F		

Table C.4
Average Consumption per Hookup for Residential Users
Natural Logarithm of Consumption 1962-1984

	COEFFICIENT	STANDARD ERROR	T-STATISTIC
CONST	7.745748	1.892356E-02	409.3178
OUTAGES	-5.832323E-02	2.823096E-02	-2.065932
LNGDPPC	1.34471	8.338576E-02	16.12637

R-squared	.9291397	Mean of depend var	7.507269
Adjusted R-squared	.9220536	Std dev depend var	.1866848
Std err of regress	5.212031E-02	Residual sum	-7.990801E-09
Durbin Watson stat	.789085	Sum squared resid	5.433053E-02
F statistic	131.1227 F		

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Table C.4 (cont.)
Natural Logarithm of Consumption 1974-1984

	COEFFICIENT	STANDARD ERROR	T-STATISTIC
CONST	7.825698	2.851345E-02	274.4564
OUTAGES	-9.678849E-02	.032498	-2.978291
LNGDPPC	1.606215	.1685316	9.530644

R-squared	.9502676	Mean of depend var	7.520342
Adjusted R-squared	.9378345	Std dev depend var	.1680714
Std err of regress	4.190524E-02	Residual sum	-6.851779E-09
Durbin Watson stat	1.957135	Sum squared resid	1.404839E-02
F statistic	76.43051 F		

Table C.5
Total Consumption for Other Users 1963-1984

	COEFFICIENT	STANDARD ERROR	T-STATISTIC
CONST	-1.75807E+07	1146030	-15.34053
YEAR	8982.604	584.1501	15.37722
CONPRICE	-8420.203	1574.008	-5.349532

R-squared	.9482028	Mean of depend var	99705.72
Adjusted R-squared	.9427504	Std dev depend var	45592.96
Std err of regress	10908.97	Residual sum	-1.903132E-03
Durbin Watson stat	.7463008	Sum squared resid	2.261108E+09
F statistic	173.9075		

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