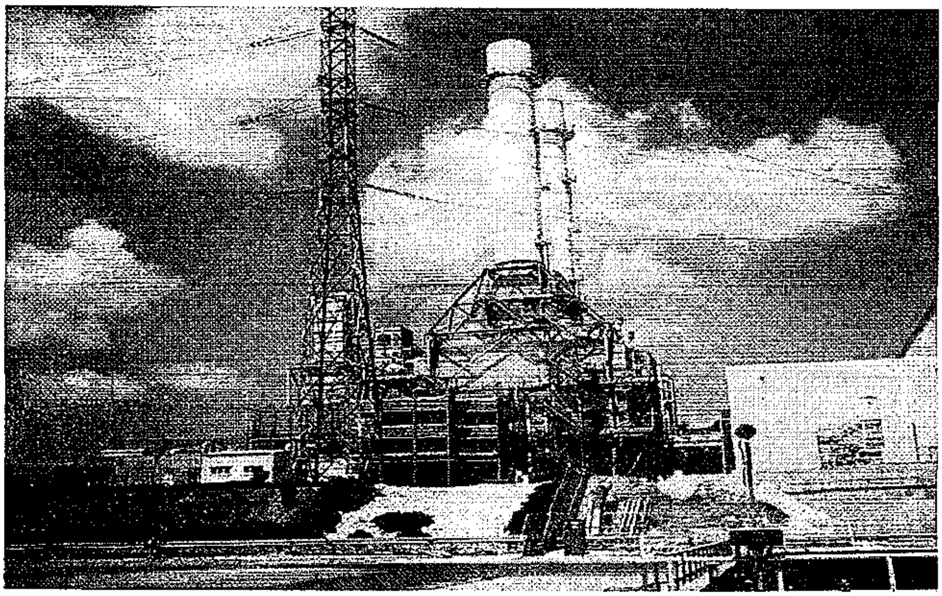
Office of Utilities Regulation

Electricity Generation Least Cost Expansion Plan for Jamaica



OUR

OFFICE OF UTILITIES REGULATION

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EXECUTIVE SUMMARY

The Office of Utilities Regulation (OUR) commissioned a review of the generation least cost expansion plan (LCEP) submitted by JPS, in accordance with the terms of its license, in order to determine the extent to which the proposed plan satisfies the requirement of ensuring that a reliable supply of electricity is provided to consumers at the least possible cost. Review of the JPS plan lead to the conclusion that a full update was required for the following primary reasons:

- The forecasted demand growth of 3.5% per year used by JPS was unjustifiably low;
- World oil prices had changed dramatically since the JPS plan was prepared and the medium term outlook for fuel prices is significantly higher;
- The Government of Jamaica has negotiated an arrangement with the Government of the Republic of Trinidad and Tobago for the provision of limited quantities of natural gas at a price substantially below what JPS had assumed;

Revised least cost planning analyses were performed based on the following:

- Peak demand growth averaging 4.57% per annum based on an updated demand forecast;
- Revised fuel prices taking into account the most recent international forecasts and subsequent developments, including the proposed arrangement with Trinidad;
- Other adjustments to the inputs used by JPS to ensure consistency in the data used.

The immediate results of the analyses are as follows;

- Approximately 230 MW of additional net generating capacity is required over the next three years in order to avert excessive power outages.
- The first block of 76 MW is required in 2005, the second block of 38 MW in 2006 and the remainder by 2007/08.
- Ideally, the additional capacity should be in the form of 2 combined cycle plants burning natural gas at the price agreed with Trinidad. This could be achieved by the following route:
    - 2 x 38 MW of gas turbine capacity burning No. 2 Distillate in 2005;
    - 1 x 38 MW of gas turbine capacity burning No. 2 Distillate in 2006;
    - By 2007/08, combine these three gas turbines with an additional gas turbine and two heat recovery steam generators to create 2 x 115 MW combined cycle plants which would utilize LNG from Trinidad at the agreed price.
- Preparations should be made for an additional baseload plant of 115 MW to be installed in 2010. This plant would likely be another combined cycle plant, if LNG prices similar to those being offered by Trinidad are available. For significantly higher LNG prices, coal fired steam plants would be the preferred option.
- The next block of capacity required after this would be required between 2013 and 2015 but by this time the least cost plan should be updated to determine the optimal plant type.

1 INTRODUCTION

As the regulator of the electricity sector, the Office of Utilities Regulation (OUR) has a duty to ensure that electricity is provided to consumers at an acceptable level of reliability and in the most cost effective manner. As the sole commercial provider of electricity, Jamaica Public Service Company Limited (JPS) has traditionally been responsible for preparing and implementing the necessary plans to achieve these objectives. However, as of April 2004, the regulations will allow for competition in the provision of additional generating capacity.

JPS has recently submitted their generation Least Cost Expansion Plan (LCEP) dated February 2004 to the OUR. This document sets out what JPS determined to be the optimal capacity requirements to reliably meet projected electricity demands for the medium term. It also describes the bases on which these requirements were determined.

Having reviewed the proposed JPS LCEP, it was determined that a full update of the plan was needed for the following main reasons:

- JPS used a low demand scenario for the forecast primarily on the assumption of decreasing system losses and marginal economic growth. Losses have in fact been increasing and the Jamaican economy has been growing at over 2.5% per annum with expectations that this growth rate will continue over the medium term.
- As a result of negotiations with the Government of Trinidad and Tobago, LNG is now expected to be available in limited quantities at a price that is significantly lower than originally assumed by JPS.
- Oil prices have changed dramatically over the last few months and the outlook is now for higher prices.

These factors are the primary determinants of the size, timing and characteristics of generating capacity requirements.

This report first presents the updated generation system least cost expansion plan and then discusses the methodology, assumptions and inputs used to derive the plan. It is structured as follows:

Chapter 1: Introduction

Chapter 2: Recommended Generation Expansion Plan

Chapter 3: Demand Forecast

Chapter 4: Fuel Prices Used

Chapter 5: General Planning Guidelines and Constraints

Chapter 6: Expected Performance of Existing Generating Plants

Chapter 7: Analysis and Preliminary Screening of System Expansion Options

Chapter 8: Optimization Methodology and Results

Appendices

2 RECOMMENDED GENERATION EXPANSION PLAN

2.1 *GENERAL*

This section describes the recommended generation system least cost expansion plan (LCEP) for the Jamaica Electricity Sector. Also included in this section are some of the major sensitivity analyses done on the Plan.

Detailed descriptions of the inputs and methodology used are given in the subsequent sections. These include the demand forecasts, fuel price forecasts, analysis of existing facilities and analysis of development options.

2.2 *DEMAND / SUPPLY BALANCE WITH NO NEW PLANT*

In order to put the recommended plan into perspective, it is necessary to have an appreciation of the demand / supply balance if no new capacity is added to the system. This scenario is demonstrated in Exhibit 2.1 and is characterized by the following:

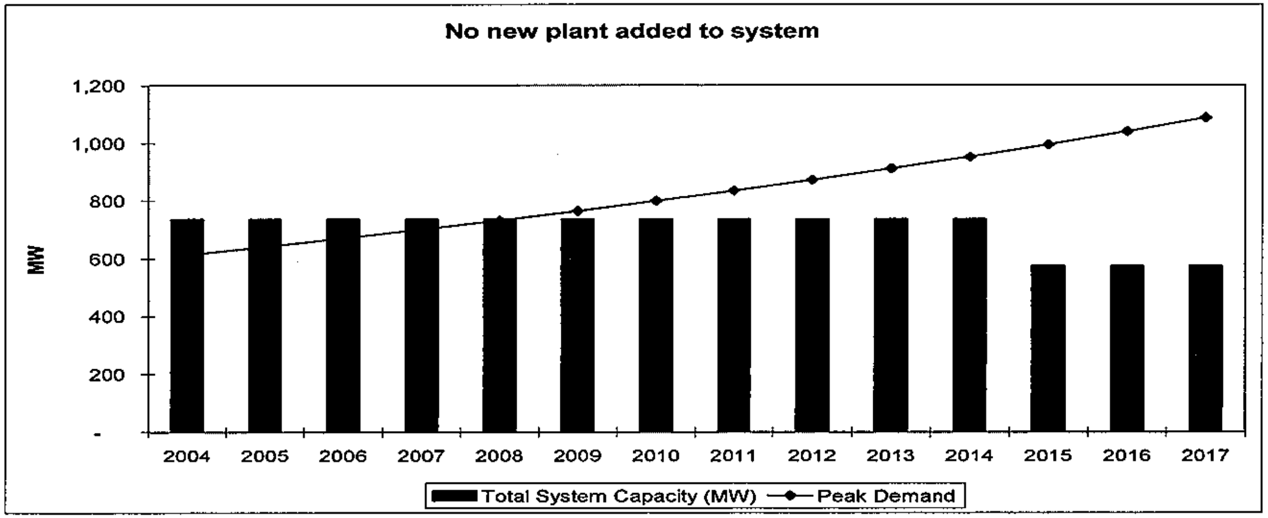
- Based on expectations of a peak demand of 614 MW in 2004 and available useful capacity of 737 MW, the reserve margin in 2004 is 123 MW or 20% of peak demand. This situation is already contributing to power cuts with the loss of load probability (LOLP) of 1.126% exceeding the benchmark safe level of 0.55%. (LOLP indicates the chance of load shedding due to generation shortfalls on a given day and is benchmarked for Jamaica at 0.55%. Developed countries use benchmark LOLPs of less than half of this figure).
- In 2005, with the peak demand expected to grow at over 4.5%, the reserve capacity would rapidly reduce to 95 MW or 14.8%, and by 2006 the reserve capacity would be 66 MW and the reserve margin 9.9%. At this point, the LOLP would be close to 5% and power cuts worse than those experienced in 2001 would be likely. From then on the situation would dramatically worsen.
- With a significant number of the existing large steam plants at or approaching their normal useful lives and with tighter reserve margins and fewer opportunities to comfortably schedule maintenance, equipment failures would worsen.

The critical point to be made is that the ideal time for adding generating capacity to the system has passed. Further delays will not only result in greater supply outages, but will also lead to solutions that are economically sub optimal.

Exhibit 2.1 Supply / Demand Balance if no new plant is added

NO NEW PLANT ADDED

Year	Plant Retired	Plant Added	Fuel Type	Unit Net Output (MW)	No. of Units	Capacity Added (MW)	Capacity Retired (MW)	Total System Capacity (MW)	Peak Demand	Reserve Capacity (MW)	Reserve Margin (%)	Loss of Load Probability (%)	Loss of Load Probability (hours/year)
2004								737	614	123	20.0%	1.126%	98.6
2005						-		737	642	95	14.8%	2.341%	205.1
2006						-		737	671	66	9.9%	4.611%	403.9
2007						-		737	701	36	5.2%		-
2008						-		737	732	5	0.7%		-
2009						-		737	765	(28)	-3.6%		-
2010						-		737	799	(62)	-7.7%		-
2011						-		737	835	(97)	-11.7%		-
2012						-		737	872	(135)	-15.5%		-
2013						-		737	911	(174)	-19.1%		-
2014						-		737	952	(215)	-22.6%		-
2015	JPPC, JEP, OH1					-	162	575	995	(420)	-42.2%		-
2016						-		575	1,041	(465)	-44.7%		-
2017						-		575	1,088	(513)	-47.1%		-
TOTAL					-	-	162						



2.3 THE KEY ASSUMPTIONS OF THE BASE PLAN

The Recommended Plan is based on the following assumptions:

- Planning objective of having a loss of load probability of no more than 0.55% (or 48 hours per year). This is a measure of system reliability and indicates the chance of having a power cut.
- Average growth in demand of 4.57% per year in accordance with the revised demand forecast.
- LNG fuel available from Trinidad at a price within the assumed range of $3.20 to $3.80 / mbtu (Million British Thermal Units) at the power plant site in sufficient quantities to support two combined cycle plants of 115 MW each.
- LNG from Trinidad can be made available in 2007.
- Additional LNG obtainable at an average market price of $4.3 / mbtu.
- Coal available at plant at an average price of $1.5/mbtu.
- The only plants retired during the planning horizon are JPPC, JEP and Old Harbour No. 1, all in 2015, based on the JPS retirement schedule.
- Medium speed diesels and gas turbines can be made available in 2005 and 2006. The gas turbines made available in these years can be converted to combined cycle plants in 2007 which can be run on the expected natural gas from Trinidad.
- Average discount rate of 12% for calculating present value of costs. This is based on the OUR's estimate of the weighted average cost of capital (WACC) of JPS used in the 2004 tariff review.

2.4 THE BASE CASE PLAN

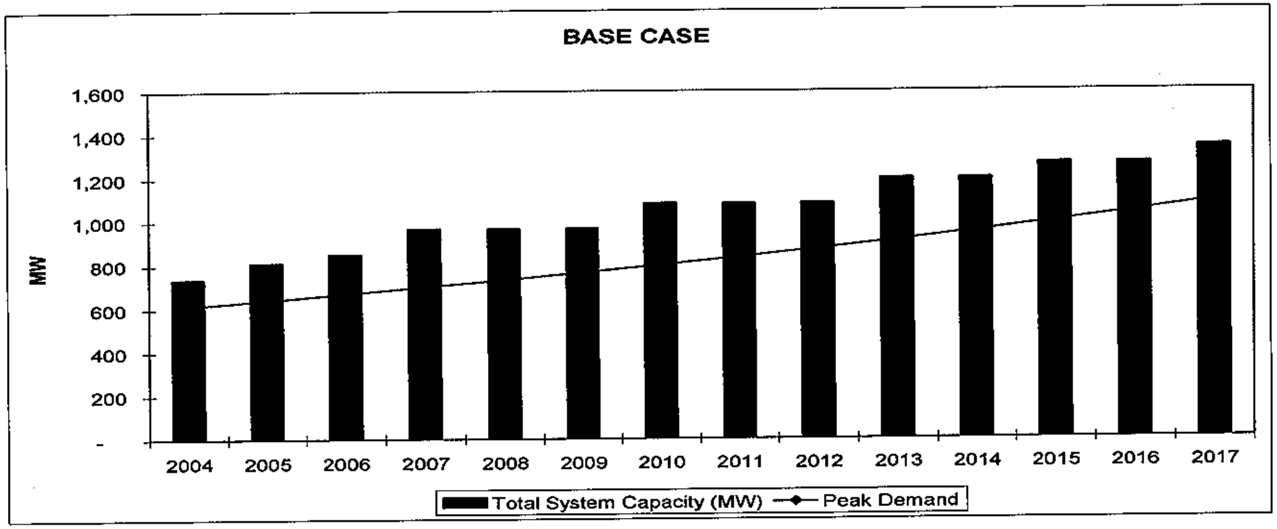
The Recommended Plan for the period up to 2017 is summarized in Exhibit 2.2. The plan calls for:

- Three gas turbines of 38 MW net output each by 2006 to deal with the immediate shortfall in capacity and demand growth;
- Conversion of these three gas turbines into two 115 MW combined cycle plants by adding an additional 38 MW gas turbine and two heat recovery systems. These combined cycle plants would be fired with natural gas from Trinidad;
- Three coal fired plants, each with net output of 115 MW, in 2010, 2013 and 2015 respectively to handle expected growth in demand;
- An additional 115 MW combined cycle plant and a 115 MW coal fired steam plant in 2015 which would replace 162 MW of capacity being retired as well as support demand growth;
- Two 38 MW gas turbines in 2017 to address demand growth.

Exhibit 2.2 Recommended Base Case Generation Least Cost Expansion Plan

BASE CASE

Year	Plant Retired/ Converted	Plant Added	Fuel Type	Unit Net Output (MW)	No. of Units	Capacity Added (MW)	Capacity Retired/ Converted (MW)	Total System Capacity (MW)	Peak Demand	Reserve Capacity (MW)	Reserve Margin (%)	Loss of Load Probability (%)	Loss of Load Probability (hours/year)
2004								737	614	123	20.0%	1.126%	98.6
2005		2 Gas Turbines	No. 2 Distillate	38	2	76		813	642	171	26.7%	0.318%	27.9
2006		1 Gas Turbine	No. 2 Distillate	38	1	38		851	671	180	26.9%	0.258%	22.6
2007	3 GTs converted	2 Combined Cycle	NG from T&T	115	2	230	114	967	701	266	38.0%	0.044%	3.9
2008						-		967	732	235	32.1%	0.108%	9.5
2009						-		967	765	202	26.5%	0.266%	23.3
2010		1 Coal Fired Steam	Coal	115	1	115		1,082	799	283	35.5%	0.056%	4.9
2011						-		1,082	835	248	29.7%	0.142%	12.4
2012						-		1,082	872	210	24.1%	0.356%	31.2
2013		1 Coal Fired Steam	Coal	115	1	115		1,197	911	286	31.4%	0.089%	7.8
2014						-		1,197	952	245	25.7%	0.234%	20.5
2015	JPPC, JEP, OH1	1 Coal, 1 NGCC	Coal / NG	115	2	230	162	1,265	995	270	27.1%	0.206%	18.0
2016						-		1,265	1,041	225	21.6%	0.513%	44.9
2017		2 Gas Turbines	No. 2 Distillate	38	2	76		1,341	1,088	253	23.2%	0.304%	26.6
TOTAL					11	880	276						



Parameter	US$ M
Plan cost from WASP	1,403.24
Adjustment for early GTs	3.61
Total Cost	**1,406.85**

KEY

NGCC
Natural gas combined cycle.

JPPC
Jamaica Private Power IPP (60 MW)

JEP
Jamaica Energy Partners IPP (72 MW)

OH1
Old Harbour No.1 oil fired steam plant

NG
Natural Gas

2.5 COMMENTS ON THE RECOMMENDED BASE CASE PLAN

At the prices assumed for coal and natural gas (other than the gas to be provided at the reduced price from Trinidad) the difference in cost between using coal fired plants in 2010, 2013 and 2015 compared to using combined cycle plants burning natural gas is small. Coal is preferred because of the reduced price volatility of this fuel on the world market. However, if additional natural gas can be made available for new plants at the reduced price, the gas fired combined cycle would be the preferred choice for these baseload plants.

If gas turbines could have been made available in 2005 or if the medium speed diesels cannot be brought in well before the start of 2006, gas turbines would be preferred to the medium speed diesels at regular prices. However, if there are added benefits that JPS can obtain such as a significant reduction in the cost of the existing JEP capacity and lower costs relating to the additional units because of the already existing infrastructure, then medium speed diesels obtained by this means could be more attractive. In the absence of specific details on the JPS / JEP negotiations, this determination cannot be made.

2.6 THE "IDEAL" PLAN

It should be noted that if the quantity of natural gas from Trinidad was not limited, at a price within the range of \$3.2 to \$3.8 / mbtu, the "ideal" plan would have been for all additional generating capacity to be combined cycle plants fired with this fuel, except for one gas turbine in 2017. If possible, a combined cycle plant would have been optimal for 2005, 2007, 2010 and 2013 and two such plants for 2015.

This plan is not possible given the constraints regarding the availability of the fuel from Trinidad and the construction time for the plants. However, it is useful to note that the proposed base case ensures that the plants that would be put in 2005 and 2006 can be converted to combined cycle plants in 2007 so that there are no "stop gap" plants left in the system after 2007 that are inconsistent with what would be considered the ideal plan.

If additional natural gas beyond what is expected from Trinidad can be made available at costs significantly below the assumed open market price of \$4.3 / mbtu, natural gas fired combined cycle plants would be more attractive than coal fired plants. Every effort should therefore be made to secure as much natural gas as possible within or below the aforementioned price range for the power sector and to ensure that prices do not escalate unduly over the long term by negotiating appropriate indexation terms.

2.7 COAL BASED PLAN

With natural gas (other than that from Trinidad) priced at or above \$4.3/mbtu, the Base Case plan would be largely coal based. Thus three of the four major baseload plants required between 2010 and 2015 would be coal fired steam units. If no natural gas fired plant, other than the first two fired with gas from Trinidad, is to be included, the plan would be as shown in Exhibit 2.3.

This plan would be characterized as follows:

- The cost of the plan would be almost the same as for the base case, exceeding the latter by a mere \$0.32M or 0.02%.
- The only changes relative to the base case is from 2015 onwards. In 2015, two coal fired units would be added, instead of one coal plant and one combined cycle plant. Instead of having two gas turbines in 2017, one of these would now be brought forward to 2016.

2.8 GAS BASED PLAN

If all new baseload plants were to be combined cycle plants fired with natural gas the plan would be as shown in Exhibit 2.4. Again the assumption is that only the first two plants would be fired with gas from Trinidad at a price within the range of \$3.2 to \$3.8 /mbtu and the others fired with gas at \$4.3/mbtu. This plan would be as follows:

- The additional cost compared to the Base Case would be \$6.3 Million or 0.45%. The additional cost compared to the coal based plan would be \$6.0 Million.
- Again up to 2007, the plan would remain unchanged. Following this there would be a combined cycle plant in 2010, one in 2013 and two in 2015, followed by two gas turbines in 2017.

2.9 PETCOKE AS AN OPTION

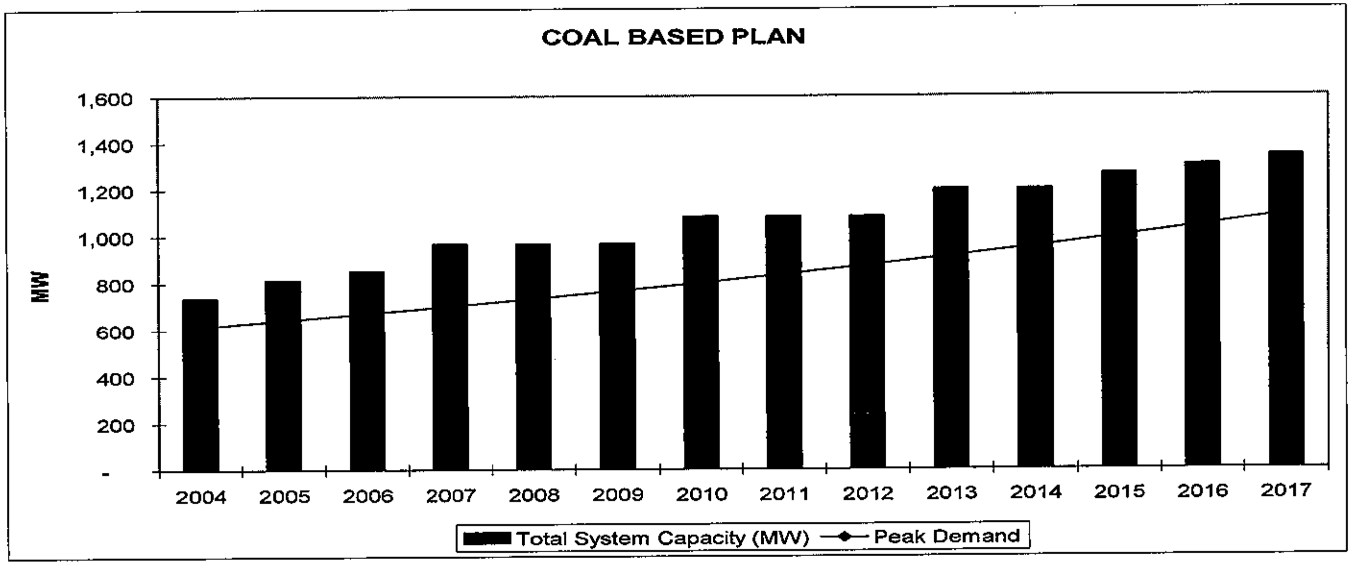
Petcoke can be obtained at fairly low prices. JPS / Mirant are of the view that this fuel could be obtained at \$0.57/mbtu. The price used in this study was \$0.75/mbtu for fuel delivered at the plant. Even though the price of petcoke is low, plants burning this fuel are very capital intensive. In addition there are major concerns regarding environmental impact of using this fuel.

Petcoke fired plants are less attractive than combined cycle plants burning natural gas from Trinidad but can compete with plants fired with coal and natural gas at \$4.3/mbtu. The use of this fuel does warrant some further investigations to determine the additional costs of meeting environmental standards and if the fuel could be a viable option with these costs. Issues relating to fuel security would also have to be investigated.

Exhibit 2.3 Coal Based Plan

COAL BASED PLAN (EXCEPT FOR FIRST NGCC)
ESTIMATED ADDITIONAL COST COMPARED TO BASE CASE (US$ M) 0.32

Year	Plant Retired/ Converted	Plant Added	Fuel Type	Unit Net Output (MW)	No. of Units	Capacity Added (MW)	Capacity Retired/ Converted (MW)	Total System Capacity (MW)	Peak Demand	Reserve Capacity (MW)	Reserve Margin (%)	Loss of Load Probability (%)	Loss of Load Probability (hours/year)
2004								737	614	123	20.0%	1.126%	98.6
2005		Gas Turbine	No. 2	38	2	76		813	642	171	26.7%	0.318%	27.9
2006		Gas Turbine	No. 2	38	1	38		851	671	180	26.9%	0.258%	22.6
2007	3 GTs converted	Combined Cycle	NG from T&T	115	2	230	114	967	701	266	38.0%	0.044%	3.9
2008						-		967	732	235	32.1%	0.108%	9.5
2009						-		967	765	202	26.5%	0.266%	23.3
2010		Coal Fired Steam	Coal	115	1	115		1,082	799	283	35.5%	0.056%	4.9
2011						-		1,082	835	248	29.7%	0.142%	12.4
2012						-		1,082	872	210	24.1%	0.356%	31.2
2013		Coal Fired Steam	Coal	115	1	115		1,197	911	286	31.4%	0.089%	7.8
2014						-		1,197	952	245	25.7%	0.234%	20.5
2015	JPPC, JEP, OH1	Coal Fired Steam	Coal	115	2	230	162	1,265	995	270	27.1%	0.236%	20.7
2016		Gas Turbine	No. 2	38	1	38		1,303	1,041	263	25.2%	0.280%	24.5
2017		Gas Turbine	No. 2	38	1	38		1,341	1,088	253	23.2%	0.344%	30.1
TOTAL					11	880	276						



Parameter	US$ M
Plan cost from WASP	1,403.56
Adjustment for GTs	3.61
Total Cost	1,407.17
Base Case Cost	1,406.85
Cost over Base Case	**0.32**
% Over Base Case	0.02%

2.10 PRELIMINARY EVALUATION OF JEP PROPOSAL

An attempt was made to simulate the JEP proposal that JPS has reported that it is considering. The information available on this proposal is as follows:

- JEP would provide an additional 48MW of medium speed diesel capacity under similar terms to the existing agreement;
- There would be a 20% discount on the fixed price (currently at $23/kW/mth) for the total capacity being provided;
- The contract term would be extended by ten years.

Simulation of this proposal gave the results shown in Exhibit 2.5.

The following comments relate to the proposal as simulated:

- The additional cost of the proposal would be $54 Million or 3.8% compared to the Base Case Plan.
- The additional 48MW alone would not ensure that the system reliability requirement is met in 2005. The reserve margin in 2005 would still be only 143MW or 22% and the LOLP would be 0.72%, above the target of 0.55%.
- Two new gas turbines would still be required by 2006.
- Only one combined cycle plant using the T&T gas would be required in 2007, raising issues regarding the take-up of the this gas and a possible increase in the average cost.
- The assumption in the analysis was that the second combined cycle plant in 2010 could use the T&T gas. If this is not possible, the cost of accepting the JEP proposal would further increase.
- The JEP plant would effectively substitute for one of the five major baseload plants required after 2007. However, the substitution is not simple as the entire plant mix is re-optimized. There is therefore no single proxy plant that can be accurately used to evaluate the avoided cost benchmark.
- JPS would again be stuck with a "stop gap" plant for the long term and therefore could not get back on track to the least cost option possible. The original JEP plant started out as a 40MW "stop gap" plant but ended up as a 72 MW long term plant following the explosion at Old Harbour. It has proven to be very costly as it was not originally part of the least cost plan at the time, as is the case now.

The advantage would be that, if no other option is available, the plant would significantly reduce the incidents of power cut in 2005. However, this would only be the case if the plant can be commissioned by the middle of the year. If it is later, it ought to be possible to put in gas turbines within the same time frame. In fact, JPS has in the past been able to competitively put in a 42 MW BOOT gas turbine plant within a six month period.

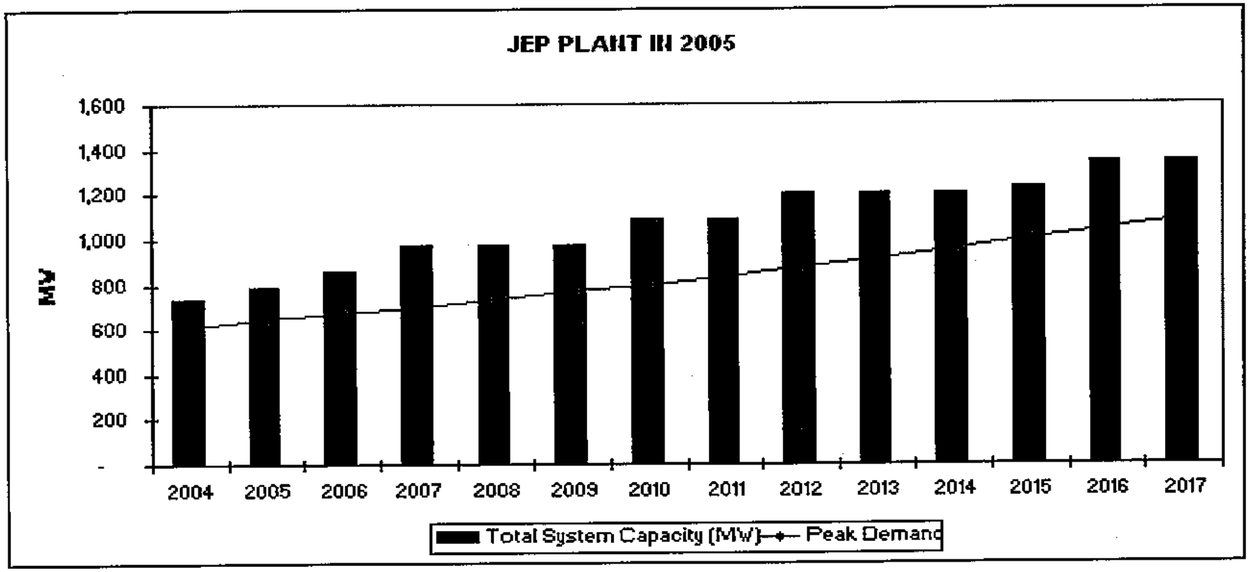
Based on this preliminary analysis, the JEP proposal would only be attractive if further reductions in cost can be negotiated.

Exhibit 2.5 Preliminary Assessment of the JEP Proposal

JEP capacity increased by 48 MW 2005, 20% discount on fixed cost and plant life extended by ten years.

ESTIMATED ADDITIONAL COST COMPARED TO BASE CA: 53.66

Year	Plant Retired	Plant Added	Fuel Type	Unit Net Output (MW)	No. of Units	Capacity Added (MW)	Capacity Retired/ Converted (MW)	Total System Capacity (MW)	Peak Demand	Reserve Capacity (MW)	Reserve Margin (%)	Loss of Load Probability (%)	Loss of Load Probability (hours/year)
2004								737	614	123	20.0%	1.126%	98.6
2005		JEP	No. 6	48	1	48		785	642	143	22.3%	**0.719%**	63.0
2006		Gas Turbine	No. 2	38	2	76		861	671	190	28.4%	0.183%	16.0
2007		Combined Cycle	NG from T&T	115	1	115		976	701	275	39.3%	0.022%	1.9
2008						-		976	732	244	33.3%	0.060%	5.3
2009						-		976	765	211	27.6%	0.162%	14.2
2010		Combined Cycle	NG from T&T	115	1	115		1,091	799	292	36.6%	0.025%	2.2
2011						-		1,091	835	257	30.7%	0.071%	6.2
2012		Coal Fired Stean	Coal	115	1	115		1,206	872	334	38.3%	0.016%	1.4
2013						-		1,206	911	295	32.4%	0.048%	4.2
2014						-		1,206	952	254	26.7%	0.140%	12.3
2015	JPPC, OH1	Coal Fired Stean	Coal	115	1	115	90	1,231	995	236	23.7%	0.283%	24.8
2016		Coal Fired Stean	Coal	115	1	115		1,346	1,041	306	29.4%	0.089%	7.8
2017						-		1,346	1,088	258	23.7%	0.257%	22.5
TOTAL					**8**	**699**	**90**						



Parameter	US$ M
Plan Cost from WASP	1,460.51
Adjustment	-
Total Cost	1,460.51
Base Case Cost	1,406.85
Cost over Base Ca	**53.66**
% Over Base Case	3.81%

NOTE:
LOLP criterion still not met in 2005.

3 DEMAND FORECAST

3.1 THE FORECAST

A graph showing the historical and forecasted peak demands is shown in Exhibit 3.1. Exhibit 3.2 is a table giving the energy and peak demand values. As shown, the expected average growth rate over the next twenty years for energy and system peak are 4.63% and 4.57% respectively.

The energy use projection was prepared using regression models developed based on historical relationships between the electricity use for each rate class and various economic variables. The latest available load research data was used to determine the load and coincidence factors which were then used to derive expected peak demands. A schematic outlining the forecast methodology is shown in Exhibit 3.3 and the structure of the spreadsheet model used is shown in Exhibit 3.4.

The forecast is based on the following assumptions for the population and macroeconomic variables:

- GDP Growth of 2.5% per annum;
- Mean population growth rate of 0.6%;
- Average household size decreasing gradually from 3.3 to 3.0 by 2017;
- Average inflation decreasing smoothly over time to just over 5% by 2017;
- Real per capita disposable income increasing by 11% per annum;
- Average net interest rates decreasing from 19.32% to 16.6% by 2017.

The regression models were built using Eviews 5, which is a specialized modeling software, and Microsoft Excel. The models were tested against historical data to check for accuracy. An example of one of the tests is shown in Exhibit 3.5. The graph compares actual number of residential customers to what would have been forecasted.

More details on the development of the demand forecast are presented in a separate document.

Exhibit 3.1 Peak Demand

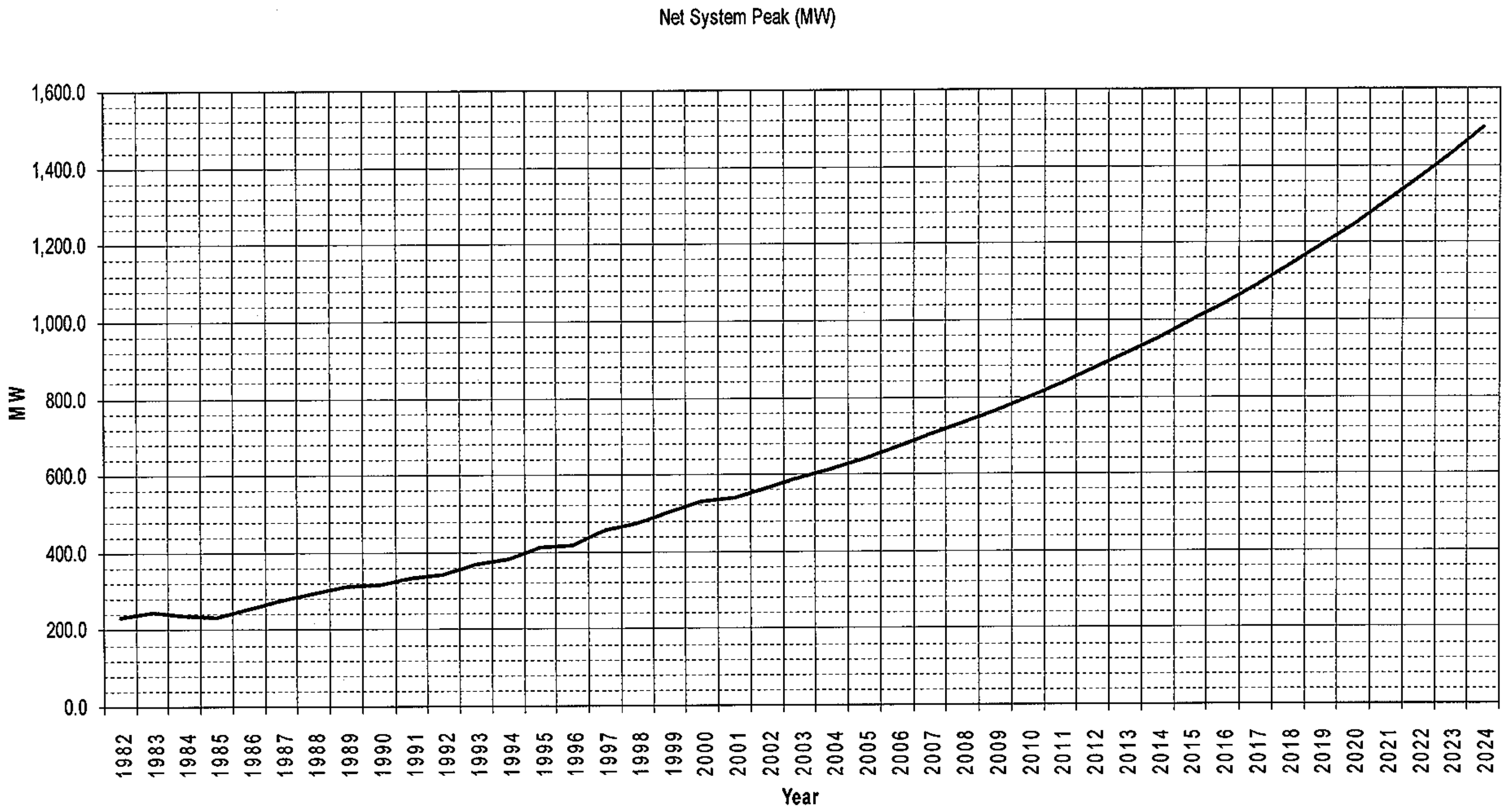


Exhibit 3.2 Energy and Peak Demand Projections

Year	Sales after Extraordinary Sales (MWh)	Sales After Reduction in Unbilled Supply (MWh)	Total Energy Delivered (Sales & Unbilled) (MWh)	Total Losses (MWh)	Losses as % of Net Generation	Net Generation (MWh)	Net Generation Growth Rate	Load Factor	Net System Peak (MW)	Peak Demand Growth Rate
1991	1,670,336	1,670,336	1,869,074	382,475	18.63%	2,052,811	2.22%	70.29%	333.4	5.04%
1992	1,692,485	1,692,485	1,966,568	460,256	21.38%	2,152,741	4.87%	71.57%	343.4	3.00%
1993	1,793,037	1,793,037	2,035,896	440,093	19.71%	2,233,130	3.73%	69.11%	368.9	7.43%
1994	1,869,114	1,869,114	2,118,713	455,202	19.58%	2,324,316	4.08%	69.82%	380.0	3.02%
1995	1,998,031	1,998,031	2,197,303	419,055	17.34%	2,417,086	3.99%	67.06%	411.5	8.27%
1996	2,146,848	2,146,848	2,320,680	409,985	16.03%	2,556,833	5.78%	69.77%	418.4	1.67%
1997	2,281,130	2,281,130	2,517,464	487,258	17.60%	2,768,388	8.27%	69.63%	453.9	8.49%
1998	2,446,189	2,446,189	2,669,455	492,347	16.75%	2,938,536	6.15%	70.72%	474.3	4.51%
1999	2,576,155	2,576,155	2,805,236	512,458	16.59%	3,088,613	5.11%	69.78%	505.3	6.52%
2000	2,738,995	2,738,995	2,998,896	561,190	17.00%	3,300,185	6.85%	71.04%	530.3	4.95%
2001	2,793,375	2,793,375	3,053,470	567,366	16.88%	3,360,741	1.83%	71.29%	538.2	1.48%
2002	2,896,547	2,896,547	3,206,285	628,358	17.83%	3,524,905	4.88%	71.36%	563.9	4.78%
2003	2,998,344	2,998,344	3,366,187	697,661	18.88%	3,696,005	4.85%	71.51%	590.0	4.64%
2004	**3,135,817**	**3,154,447**	**3,470,351**	**725,370**	**18.85%**	**3,848,273**	**4.12%**	**71.54%**	**614.0**	**4.07%**
2005	3,284,465	3,305,798	3,631,367	751,781	18.69%	4,022,868	4.54%	71.55%	641.9	4.53%
2006	3,439,462	3,463,688	3,799,009	778,988	18.53%	4,204,489	4.51%	71.56%	670.8	4.50%
2007	3,601,377	3,628,699	3,973,873	807,082	18.37%	4,393,774	4.50%	71.57%	700.8	4.48%
2008	3,770,790	3,801,424	4,156,558	836,153	18.21%	4,591,371	4.50%	71.59%	732.1	4.47%
2009	3,948,297	3,982,475	4,347,678	866,289	18.06%	4,797,936	4.50%	71.62%	764.7	4.46%
2010	4,134,516	4,172,483	4,547,864	897,576	17.90%	5,014,144	4.51%	71.65%	798.9	4.46%
2011	4,330,087	4,372,109	4,757,770	930,103	17.75%	5,240,692	4.52%	71.69%	834.5	4.47%
2012	4,535,685	4,582,044	4,978,075	963,960	17.60%	5,478,307	4.53%	71.72%	871.9	4.48%
2013	4,752,016	4,803,016	5,209,494	999,239	17.45%	5,727,745	4.55%	71.77%	911.1	4.49%
2014	4,979,829	5,035,794	5,452,773	1,036,035	17.30%	5,989,801	4.58%	71.81%	952.1	4.51%
2015	5,219,917	5,281,195	5,708,703	1,074,446	17.15%	6,265,315	4.60%	71.86%	995.3	4.53%
2016	5,473,121	5,540,086	5,978,117	1,114,575	17.00%	6,555,169	4.63%	71.92%	1040.5	4.55%
2017	5,740,337	5,813,391	6,261,900	1,156,529	16.86%	6,860,300	4.65%	71.97%	1088.1	4.57%
2018	6,022,521	6,102,094	6,560,987	1,200,422	16.72%	7,181,699	4.68%	72.03%	1138.2	4.60%
2019	6,320,695	6,407,249	6,876,374	1,246,371	16.57%	7,520,418	4.72%	72.09%	1190.8	4.63%
2020	6,635,947	6,729,981	7,209,119	1,294,502	16.43%	7,877,576	4.75%	72.16%	1246.3	4.66%
2021	6,969,447	7,071,494	7,560,347	1,344,947	16.29%	8,254,361	4.78%	72.22%	1304.7	4.69%
2022	7,322,443	7,433,078	7,931,256	1,397,844	16.16%	8,652,037	4.82%	72.29%	1366.2	4.72%
2023	7,696,275	7,816,116	8,323,120	1,453,342	16.02%	9,071,949	4.85%	72.37%	1431.1	4.75%
2024	8,092,376	8,222,089	8,737,297	1,511,596	15.89%	9,515,528	4.89%	72.44%	1499.4	4.78%
1982-2003	4.99%	4.99%	4.95%	4.82%	-0.13%	4.96%		0.38%	4.55%	
2004-2024	4.85%	4.91%	4.72%	3.74%	-0.85%	4.63%		0.06%	4.57%	

Exhibit 3.3 Demand Forecast Methodology

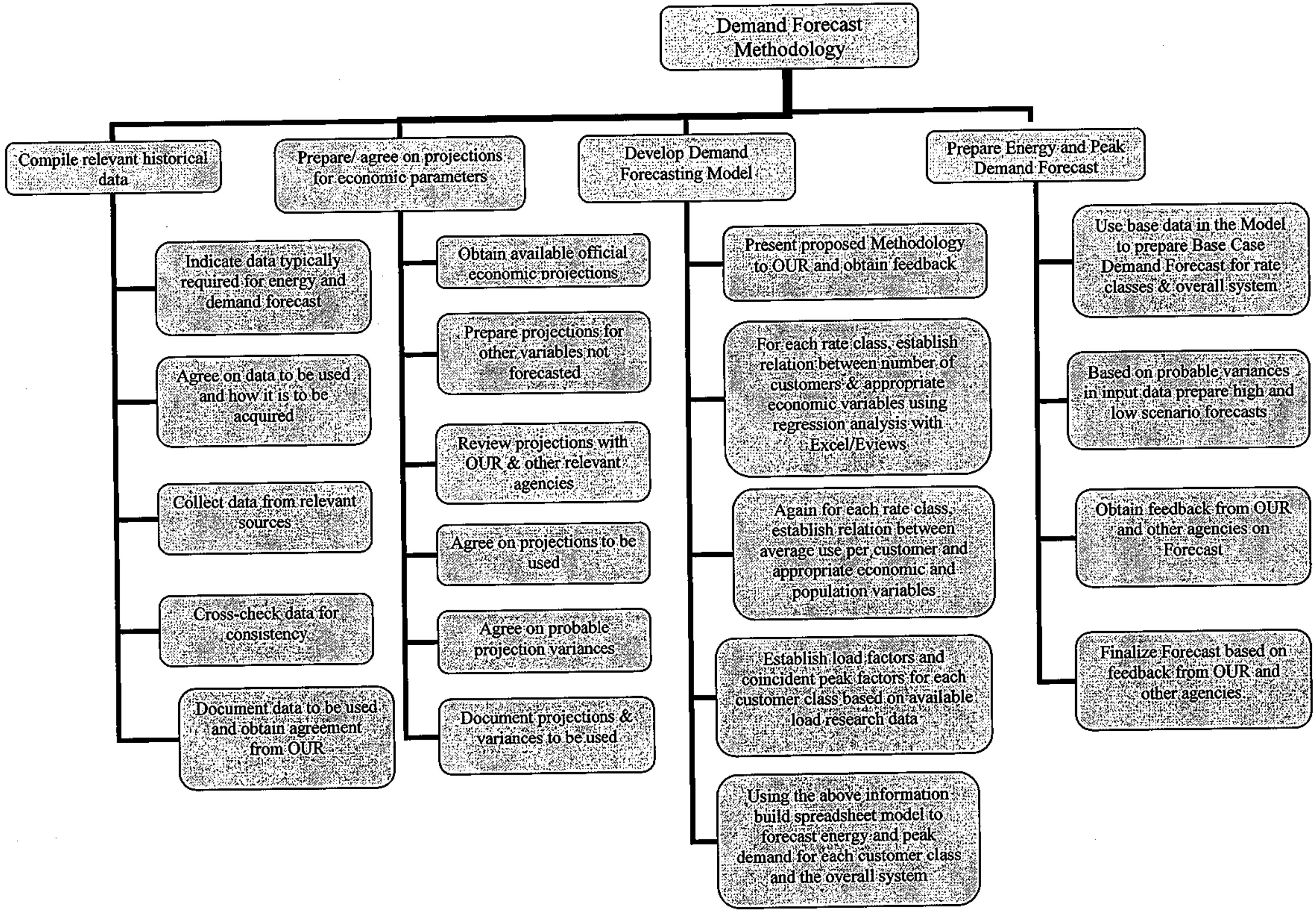


Exhibit 3.4 Demand Forecast Spreadsheet Model Structure

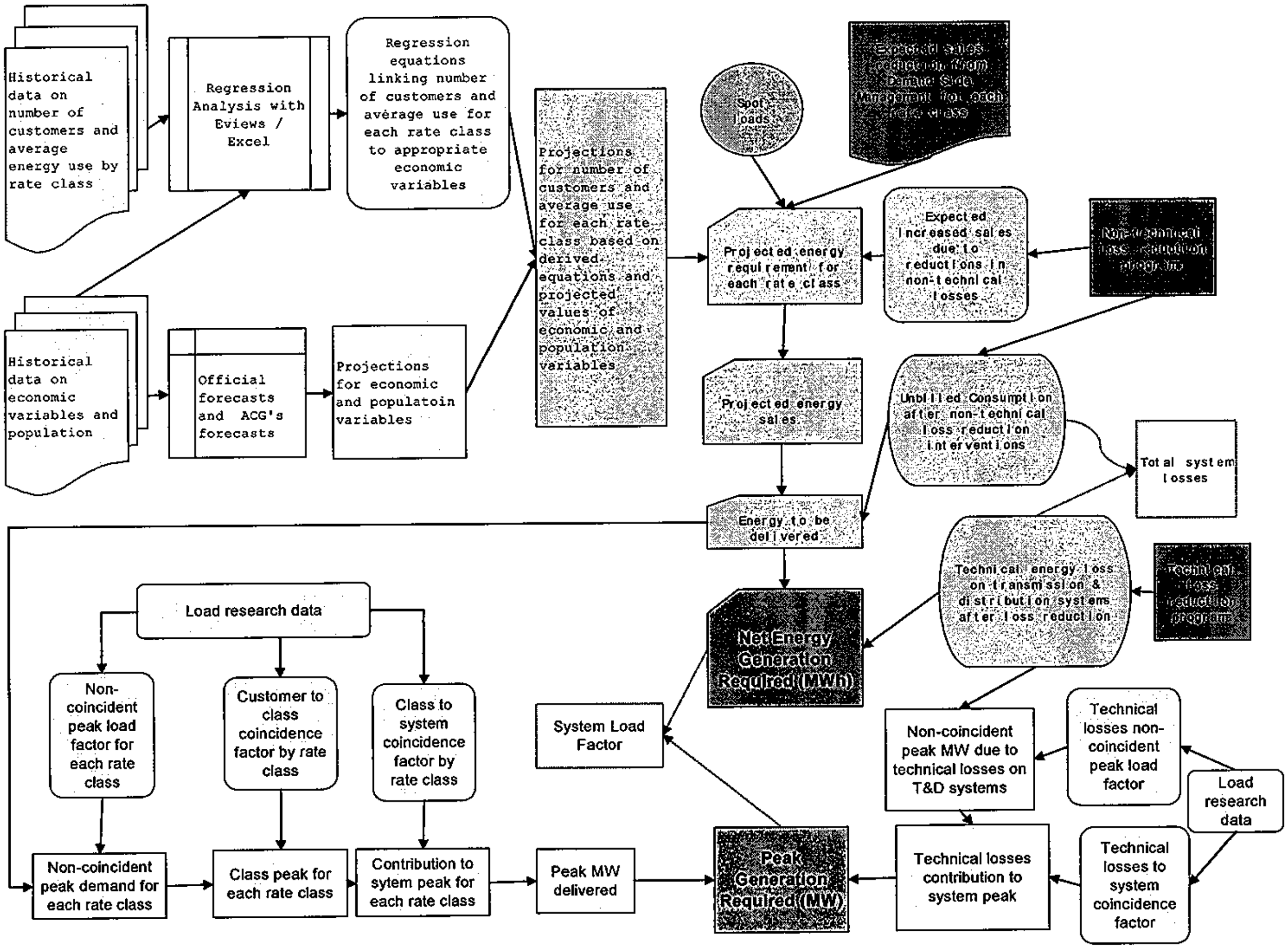
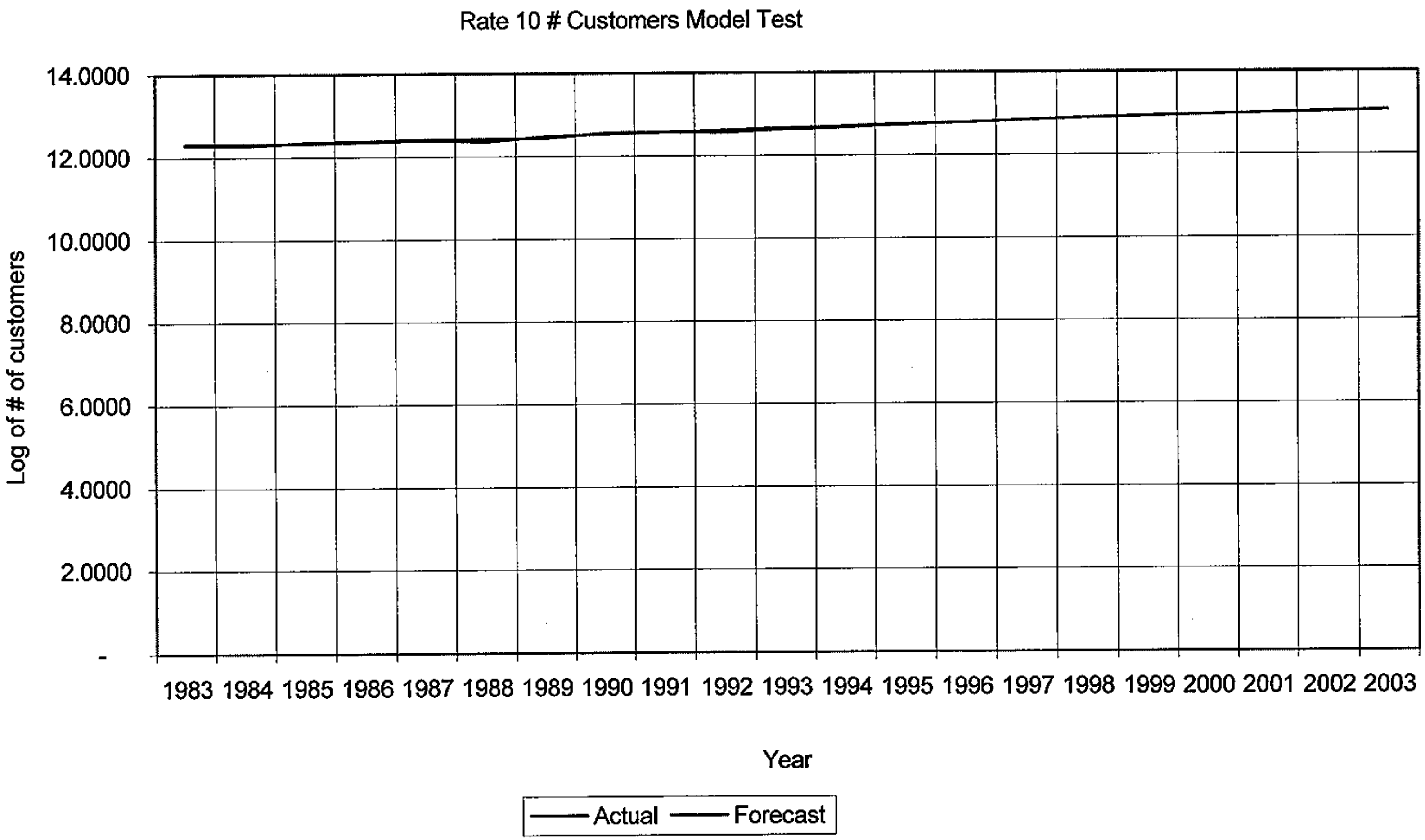


Exhibit 3.5: Model Predictions versus Historical Data for Number of Rate 10 Customers. (Similar checks were done for all rate categories for both number of customers and average energy consumption).

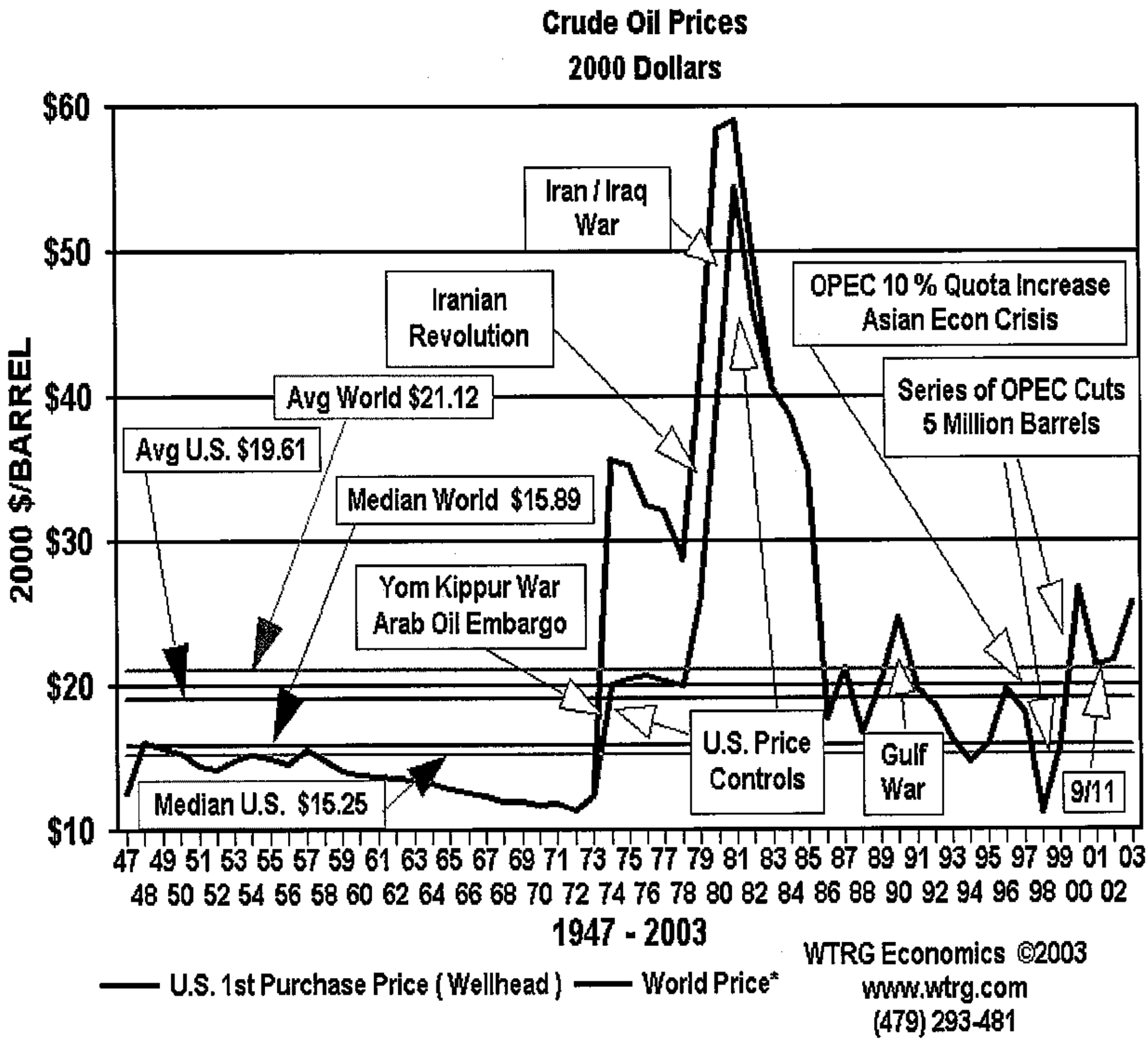


4 FUEL PRICES

4.1 DIFFICULTIES IN FORECASTING FUEL PRICES

Fuel prices, especially for petroleum based fuels, are extremely hard to predict as they are not only influenced by demand and supply conditions but also by political events and perceptions. Exhibit 4.1 indicates the movements in oil prices since 1947 and the primary factors driving them.

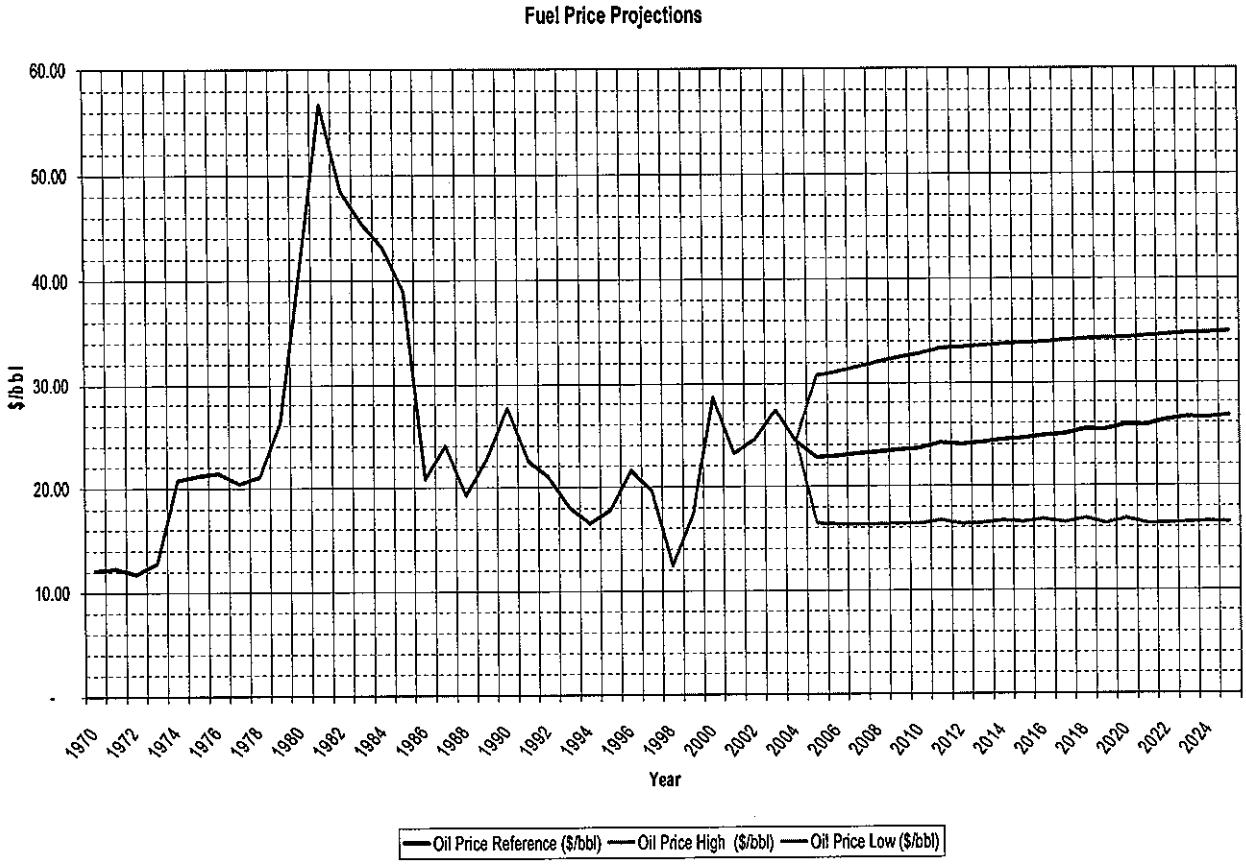
Exhibit 4.1 Crude Oil Price Volatility



4.2 RECENT FUEL FORECASTS

Forecasts for oil prices at the beginning of 2004 have been proven wrong within a few months. International Energy Outlook 2004 prepared by the Energy Information Administration, Office of Integrated Analysis and Forecasting of the US Department of Energy and dated April 2004, is one of the most recent and comprehensive forecasts of energy consumption and prices. Even this forecast has already been defied by recent oil prices. Exhibit 4.2 shows their forecast for world oil prices.

Exhibit 4.2 US DOE Forecast for Oil Prices



Oil prices have risen to over US$ 55 per barrel in 2004, well above the forecast of US$24 per barrel. Further, the general opinion is that there has been a structural shift and prices below $30/barrel are not likely in the medium term.

4.3 FUEL PRICES USED IN BASE CASE PLAN

The base fuel prices used in the plan are shown in Exhibit 4.3. Prices used by JPS are also included for comparison.

As is the recommended practice in WASP simulations, these prices were kept fixed in real terms for the Base Case. Sensitivity analyses were then done by applying different price escalation factors based on the latest forecasts and current price performance.

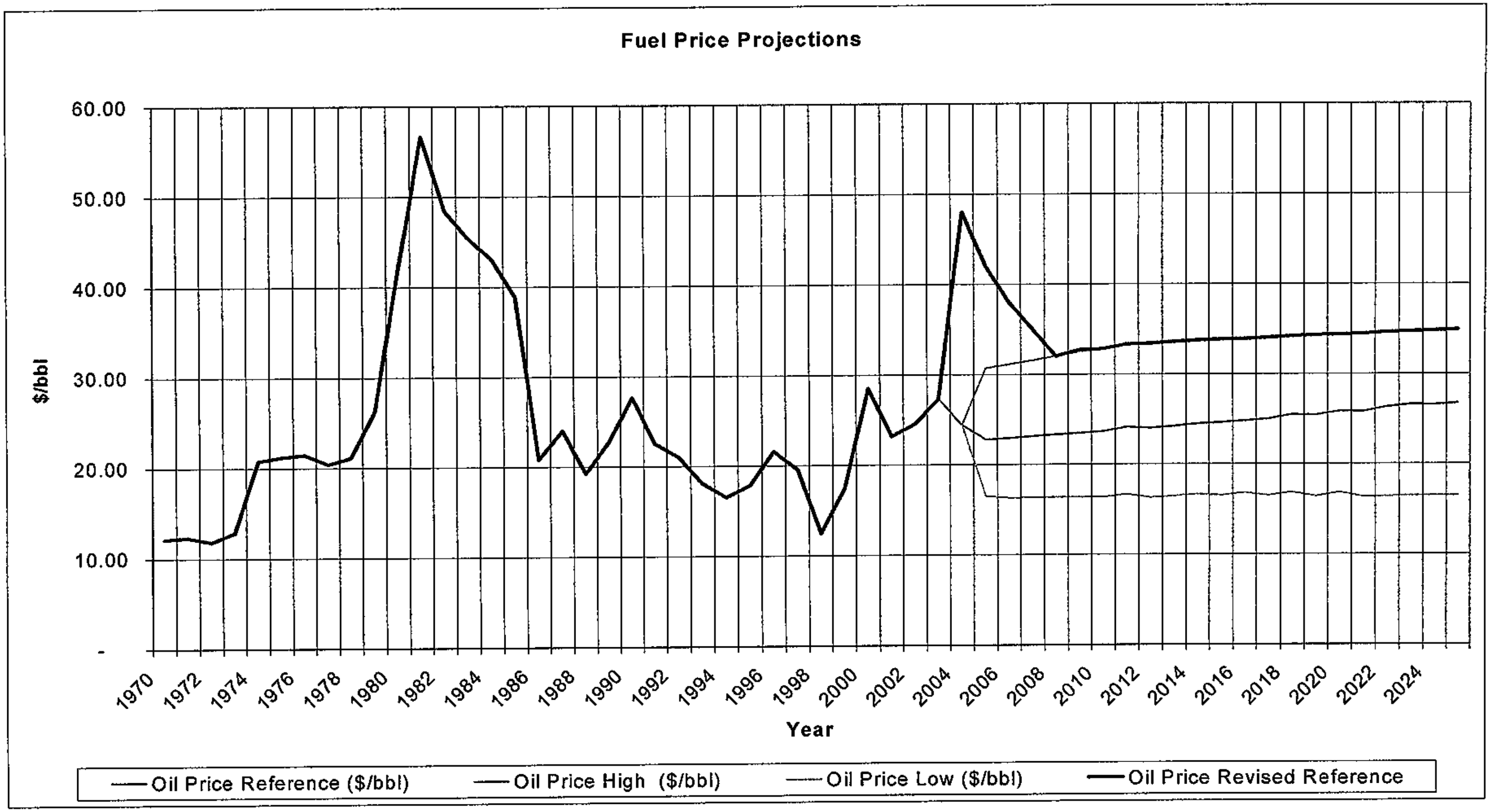
Exhibit 4.3 Base Fuel Prices Used in Plan

Fuel Type	Delivered Price ($/Mbtu)	Price Used by JPS ($/Mbtu)	Comments
LNG from Trinidad government	< 3.90	3.90	LNG from Trinidad is assumed available in limited quantities at a price within the range $3.2 to $3.8 /Mbtu
LNG on world market	4.30	3.90	Price used is based on information from latest international forecasts and recent prices.
Coal	1.50	1.28	Includes component for fuel handling
HFO	4.13 to 4.38	3.54	Varies by plant site. Based on adjustments to DOE forecast and Petrojam pricing formula.
ADO	6.83 to 6.95	6.55	Varies by plant site. Based on adjustments to DOE forecast and Petrojam pricing formula.
Petcoke	0.75	0.57	There are uncertainties regarding price, supply security and additional costs to meet environmental standards.
Orimulsion	1.82	1.55	There are uncertainties regarding price, supply security and additional costs to meet environmental standards.

The detailed derivations of the base prices are included in a separate report but the following key points may be noted.

- The modification to the DOE forecast for world oil prices is shown in Exhibit 4.4. The basic assumption made was that the DOE high scenario price would be sustained over the medium to long term and that the current spike in prices will decline to the high forecast by 2009. Note that even though the peak oil price is over $55/barrel, it is expected that the average for the year 2004 will be about $48/barrel.

Exhibit 4.4 Revised Forecasts for Average World Oil Prices

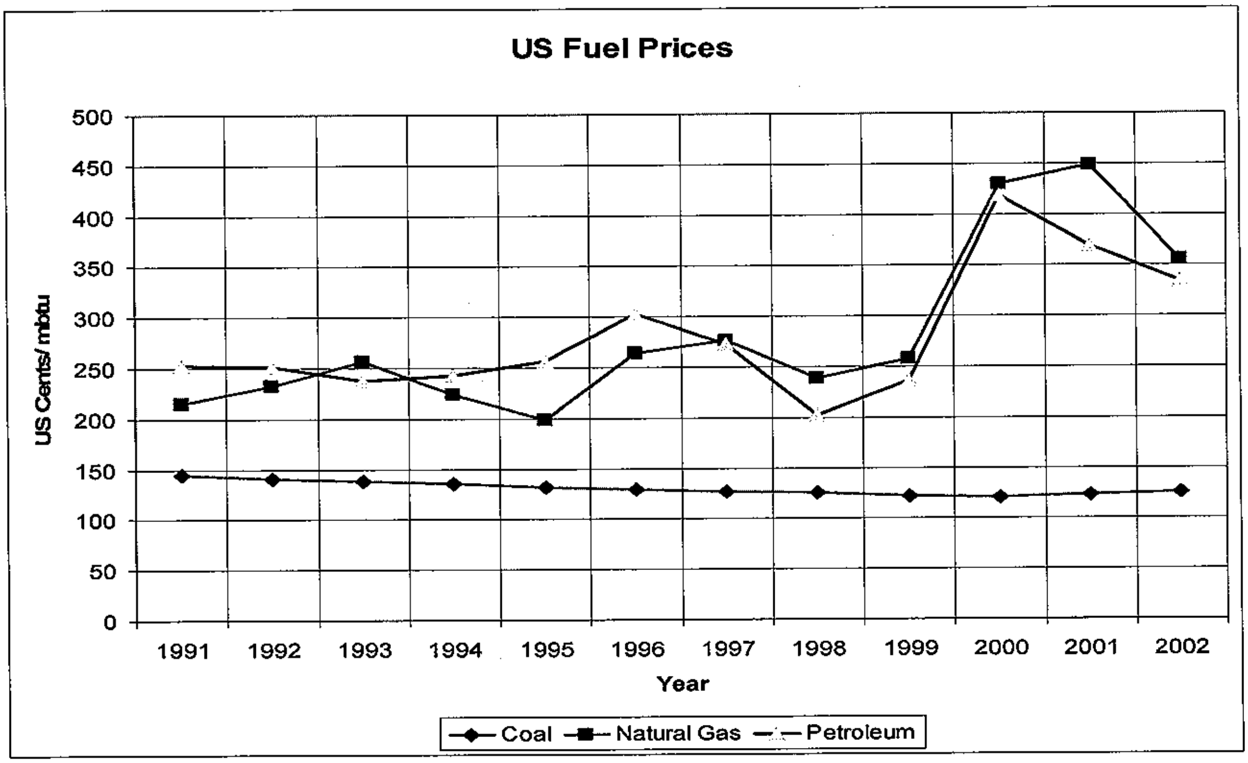


- Projected market LNG prices were derived from forecasted prices for delivery of LNG to the US.
- HFO and ADO prices were derived from the world oil price projections and adjusted based on the Petrojam pricing formulae for delivery of fuel to the various generating sites.
- Petcoke and Orimulsion prices were based on adjustments to the prices JPS said they could get these fuels at, taking into account the general upward trend in the prices of all fuels.
- Projected coal prices were derived based on projected prices to the US Gulf Coast with some adjustments for delivery to Jamaica.

Based on historical trends, coal prices are expected to remain fairly stable over the medium to long term compared to the other fuels. In fact, some forecasts have coal prices decreasing marginally over the next twenty five years. Some movement, however, is included in the forecast as other fuel prices move up.

LNG prices on the world market are expected to track oil prices, unless appropriate long term contracts can be negotiated which do not index prices to world market prices. The prices of LNG, coal and HFO in the US market shown in Exhibit 4.5 bear out this conclusion.

Exhibit 4.5 US Fuel Price Movements over Last Decade



5 PLANNINNG CONSTRAINTS AND ASSUMPTIONS

The following were used.

- Loss of Load Probability (LOLP) limit of 0.55% which is equivalent to 48 hours per year. This figure is ten to twenty times as high as that used in some developed countries. It represents the likelihood of having power cuts on a given day.
- Estimated cost of energy not served (ENS)[1] was increased to $2.08 / kWh to take into account expected escalation since the original figure of $1.5/kWh was derived in 1991. The basis of the adjustments was the US inflation rate, since the figure is quoted in US Dollars. The calculations are shown in Exhibit 5.1.

Exhibit 5.1 Recalculation of the cost of energy not served

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- The average discount rate used to bring costs to a present value was 12%, the weighted cost of capital (WACC) derived for JPS by the OUR and used in the 2004 tariff review. JPS had used a discount rate of 15% in their plan. The discount rate has a significant effect on the plan with higher rates favoring plants with lower capital costs and higher operating costs. Thus moving from 15% to 12% increased the attractiveness of coal fired plants versus natural gas fired plants as baseload units.
- The planning horizon generally used for electric utilities is twenty years or more. JPS terminated its analysis at 2017 for a horizon of thirteen years. The horizon was not changed in the review in order to maintain comparability with the JPS Plan. However, for the next update, a longer term horizon should be used in order to put the medium term projects into a broader perspective. This will be particularly important for JPS as a number of larger oil fired steam plants may need to be retired shortly after 2017.

6 ANALYSIS OF EXISTING FACILITIES

6.1 GENERAL PLANT DATA

The JPS data on the performance of the existing facilities seem reasonable and was not modified. Data on the existing plants as reported in the JPS report is summarized in Exhibit 6.1. The only major concern related to the extended useful lives of some of the older plants. This needs further investigation to determine if the expected performance levels can be sustained over the extended lives of the facilities.

[1] Cost of ENS represents the estimated economic / social cost of power outages.

Exhibit 6.1 Existing Dispatchable Power Plants in the JPS System

Plants	Name Plate Capacity (MW)	Net Output Rating (MW)	Technology	In Service Date	Forced Outage Rate (%)	Availability (%)
A) Steam						
OH1	33.0	30.0	Oil-fired Steam	1968	8.0	85
OH2	60.0	60.0	Oil-fired Steam	1970	8.0	85
OH3	68.5	65.0	Oil-fired Steam	1972	8.0	85
OH4	68.5	68.5	Oil-fired Steam	1973	8.0	85
B6	68.5	68.5	Oil-fired Steam	1976	8.0	85
B) Diesels						
RF1	20.0	18.0	Slow speed diesel	1985	5.0	85
RF2	20.0	18.0	Slow speed diesel	1985	5.0	85
C) CC Plants						
GT 12	40.0	38.0	Combined Cycle Plant	2002	3.0	90
GT 13	40.0	38.0		2002		
ST 14	40.0	38.0		2003		
D) GTs						
GT 3	22.8	21.5	Combustion Turbine	1973	5.0	85
GT 4	22.8	21.5	Combustion Turbine	1974	5.0	85
GT 5	22.5	21.5	Combustion Turbine	1974	5.0	85
GT 6	18.5	14.0	Combustion Turbine	1990	5.0	90
GT 7	18.5	14.0	Combustion Turbine	1990	5.0	90
GT 8	16.5	14.0	Combustion Turbine	1992	5.0	90
GT 9	20.5	20.0	Combustion Turbine	1992	5.0	90
GT 10	33.0	32.5	Combustion Turbine	1993	5.0	85
GT 11	20.0	20.0	Combustion Turbine	2001	5.0	90
E) Hydro						
JPS Hydro plants	23.0	21.5	Hydro			
F) IPPs						
IPPs (4 contracts)	158.6	145.2	Diesel/Steam		5.0	90

In addition to the plants listed above, there is a 20 MW wind turbine plant with expected average output of 7 MW. The capacity provided by this facility is not considered firm.

6.2 EXPECTED PLANT NET OUTPUT

The expected net output (see Exhibit 6.2) is less than the system rating. It is 100MW less than the nameplate ratings and 60 MW less than the maximum continuous rating (MCR).

MCR represents the gross output of the plants as opposed to the design output which is represented by the nameplate rating. The net capacity is the MCR less parasitic loads. The expected maximum output further takes into account expected deratings and retirements.

Jamaica Broilers IPP and Gas Turbine No. 4 have been taken out of the system and the JAMALCO IPP is expected to provide less than half of the contracted capacity.

It should be further noted that a significant number of the JPS owned plants are at or near their normally expected economic useful lives. Even though JPS plans to do extensive work on these plants to keep them in shape, it is likely that performances will deteriorate.

Exhibit 6.2 Expected Output from JPS Facilities in 2005

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The modeling of the costs associated with the existing independent power producers was incorrectly done by JPS. The fuel costs are included in the variable O&M costs and thus would not move with changes in fuel prices and plant dispatch. These costs are significant and should be modeled based on heat rates and expected fuel prices at these facilities. For the new Base Case, fuel prices were kept constant in real terms but allowed to escalate for fuel sensitivity analyses. Thus the modeling of the IPP's would not pose a problem for the Base Case scenario. The fixed and variable charges, however, were changed based on recent data obtained. Exhibit 6.3 shows the calculations of fixed and variable charges for the dispatchable IPPs in the system.

Exhibit 6.3 Calculation of IPP Fixed and Variable Payments

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Exhibit 6.4 Operating Parameters Used for Existing Plants in Analyses

NAME	Number of Sets	Min Load (MW)	Capacity (MW)	Base Heat Rate (kCal/kWh)	Incremental Heat Rate (kCal/kWh)	Domestic Fuel Cost (Cents/ Million kCal)	Foreign Fuel Cost (Cents/ Million kCal)	Forced Outage Rate (%)	Scheduled Maintenance Days	Maintenance Class (MW)	Fixed O&M ($/kW/ Mth)	Variable O&M ($/MWh)
OH2	1	30	57	3,659	3,334	-	1,640	8	26	60	0.38	6.70
RF1	1	9	17	2,511	2,063	-	1,739	5	37	20	0.93	8.00
OH4	1	30	65	3,195	2,901	-	1,640	8	25	60	0.33	6.70
GT4	1	5	21	6,514	2,357	-	2,710	5	37	20	0.39	5.00
GT5	1	5	21	7,104	2,698	-	2,710	5	37	20	0.39	5.00
GT10	1	8	32	5,048	2,523	-	2,710	5	37	30	0.26	5.00
RF2	1	9	17	2,511	2,063	-	1,739	5	37	20	0.93	8.00
JPPC	2	10	30	-	-	-	-	7	11	30	41.69	51.58
GT6	1	5	14	5,244	3,450	-	2,757	5	18	20	0.60	5.00
GT7	1	5	14	5,390	3,129	-	2,757	5	18	20	0.60	5.00
GT3	1	5	21	6,702	2,451	-	2,757	5	37	20	0.39	5.00
GT8	1	5	14	5,944	2,908	-	2,757	5	18	20	0.60	5.00
GT9	1	8	20	7,694	622	-	2,757	5	18	20	0.42	5.00
JEP	8	3	9	-	-	-	-	6	15	20	22.95	60.06
JAML	1	10	11	-	-	-	-	5	18	20	15.00	39.76
BRLS	1	10	12	-	-	-	-	5	18	20	15.00	28.00
HBB6	1	30	65	3,436	2,715	-	1,694	8	26	60	0.33	6.70
OH1	1	14	28	3,906	3,512	-	1,640	8	26	30	0.75	6.70
OH3	1	30	62	3,578	2,546	-	1,640	8	26	60	0.35	6.70
BOGT	1	8	20	6,300	885	-	2,757	5	18	25	0.42	5.00
CCGT	0	8	38	6,300	2,146	-	2,710	5	18	40	0.25	5.00
ALCO	0	4	5	-	-	-	-	5	18	20	14.00	37.00
GT05	0	8	38	6,300	2,146	-	2,710	5	18	40	0.25	5.00

7 SYSTEM DEVELOPMENT OPTIONS

The performance parameters used by JPS for the expansion options were kept for the revised base case. Sensitivity analyses done included variations in these costs based on existing uncertainties associated with the respective technologies and expected environmental constraints. Details of the figures used are shown in Exhibit 7.1.

All of the short-listed technologies used by JPS were used in the analyses. The screening exercise was therefore not repeated.

Exhibit 7.1 Cost and Operating Parameters Used for Expansion Options

NAME	GTRB	CC#2	NGCC	CCFB	ORFS	MSDO	PFSM	NGC2
DESCRIPTION	Gas Turbine	Combined Cycle	Natural Gas Fired Combined Cycle	Coal Fired Steam	Orimulsion Fired Steam	Medium Speed Diesel	Petcoke Fired Steam	Natual Gas Fired CC (gas from T&T)
Number of Sets	0	0	0	0	0	0	0	0
Min Load (MW)	10	20	20	40	40	5	40	20
Capacity (MW)	38	115	115	115	115	38	115	115
Base Heat Rate (kCal/kWh)	4,133	2,268	2,268	3,150	3,150	2,117	3,150	2,268
Incremental Heat Rate (kCal/kWh)	2,098	1,839	1,839	2,311	2,272	2,146	2,389	1,839
Domestic Fuel Cost (Cents/ Million kCal)	-	-	-	-	-	-	-	-
Foreign Fuel Cost (Cents/ Million kCal)	2,710	2,710	1,705	595	721	1,694	300	1,389
Fuel Type	No. 2	No. 2	LNG at $4.3/ mbtu	Coal	Orimulsion	No. 6	Petcoke	LNG at $3.5/ mbtu
Fast Spinning Reserve (%)	0	0	0	10	10	10	10	0
Forced Outage Rate (%)	3	3	3	5	5	6	5	3
Scheduled Maintenance Days	18	26	26	26	26	33	26	26
Maintenance Class (MW)	40	115	115	115	115	40	115	115
Fixed O&M ($/kW/Mth)	0.37	0.99	0.99	2.48	2.87	1.80	4.61	0.99
Variable O&M ($/MWh)	1.50	6.00	6.00	7.00	7.00	15.00	7.50	6.00
Heat Rate (Btu/kWh)	10,350	7,500	7,500	10,200	10,200	8,400	10,200	7,500
Capital Cost ($/kW)	638.8	964.3	898.5	1,512.3	1,633.2	1,588.3	1,693.7	898.5
Life (Years)	25	25	25	30	30	25	30	25
Interest During Construction (%)	5.16	10.63	10.63	16.45	16.45	10.63	16.45	10.63
Construction time (Years)	0.5	2.0	2.0	3.0	3.0	2.0	3.0	2.0

8 SIMULATION AND OPTIMIZATION

The basic tool used in the optimization process to derive the least cost plan was the Wien Automatic System Planning Package (WASP). This is a widely used generation planning software package which is designed to find the economically optimal expansion policy for an electric utility within user-specified constraints. It utilizes:

- Probabilistic estimation to simulate generation system performance including production costs, energy not served and system reliability;
- Linear programming to determine optimal plant dispatch; and
- Dynamic programming for comparing costs of alternative expansion sequences.

The program has a modular structure which allows for monitoring of intermediate results of an expansion planning exercise. It comprises seven distinct modules which have to be executed in a required sequence in order to achieve an optimal generation plan. The modules are as follows:

LOADSY (Load System Description) which processes information describing period peak loads and load duration curves for the power system over the study period.

FIXSYS (Fixed System Description) which processes information describing the existing generation system and any pre-determined additions or retirements, as well as information on any constraints imposed by the user.

VARSYS (Variable System Description) which processes information describing the various generating plants which are to be considered as candidates for expanding the generation system.

CONGEN (Configuration Generator) which calculates all possible year-to-year combinations of expansion candidate additions which satisfy certain input constraints and which in combination with the fixed system can satisfy the loads.

MERSIN (Merge and Simulate) which considers all configurations put forward by CONGEN and uses probabilistic simulation of system operations to calculate the associated production costs, energy not served and system reliability for each configuration.

DYNPRO (Dynamic Programming Optimization) which determines the optimum expansion plan based on previously derived operating costs along with input information on capital costs, energy not served cost, other economic parameters and the specified reliability criteria.

REPROBAT (Report Writer of WASP in Batched Environment) which writes a report summarizing the total or partial results for the optimum or near optimum power system expansion plan for fixed expansion schedules.

9 APPENDIX I: WASP REPORT FOR THE BASE CASE

YEAR------ PRESENT WORTH COST OF THE YEAR (K$)------						OBJ.FUN.	LOLP	GTRB		NGCC		ORFS		PFSM	
	CONCST	SALVAL	OPCOST	ENSCST	TOTAL	(CUMM.)	%		CC#2		CCFB		MSDO		NGC2
2017	7815	6699	41546	334	42997	2331721	0.304	2	1-	1	3	0	0	0	2
2016	0	0	43975	656	44631	2288724	0.513	0	1-	1	3	0	0	0	2
2015	56729	36040	46698	264	67651	2244093	0.206	0	1-	1	3	0	0	0	2
2014	0	0	66164	312	66476	2176442	0.234	0	1-	0	2	0	0	0	2
2013	44640	21108	70986	119	94636	2109966	0.089	0	1-	0	2	0	0	0	2
2012	0	0	81481	586	82066	2015330	0.356	0	1-	0	1	0	0	0	2
2011	0	0	87420	240	87661	1933263	0.142	0	1-	0	1	0	0	0	2
2010	62715	18575	94012	95	138247	1845603	0.056	0	1-	0	1	0	0	0	2
2009	0	0	109222	551	109773	1707356	0.266	0	1-	0	0	0	0	0	2
2008	0	0	117336	232	117568	1597583	0.108	0	1-	0	0	0	0	0	2
2007	104698	16855	126343	94	214280	1480015	0.044	0	1	0	0	0	0	0	2
2006	0	0	162511	651	163162	1265735	0.258	0	1	0	0	0	0	0	0
2005	0	0	173190	901	174091	1102573	0.318	0	1	0	0	0	0	0	0
2004	0	0	185169	4031	189200	928482	1.126	0	1	0	0	0	0	0	0
2003	88404	6460	198780	1192	281916	739282	0.342	0	1	0	0	0	0	0	0
2002	0	0	219740	438	220178	457366	0.146	0	0	0	0	0	0	0	0
2001	0	0	234278	2910	237188	237188	0.750	0	0	0	0	0	0	0	0

SUMMARY REPORT
ON A GENERATION EXPANSION PLAN FOR
ONLY 2 NGC2 AND NO PETCOKE
PROCESSED BY THE WASP-IV COMPUTER PROGRAM PACKAGE
OF THE IAEA

STUDY PERIOD

2001 - 2017

PLANNING PERIOD

2001 - 2017

CONSTRUCTION COSTS
IN MILLION $
ARE REPORTED ONLY FOR
PLANTS COMMISSIONED
DURING THE PLANNING PERIOD.
ALL OTHER INFORMATION IS GIVEN
FOR THE WHOLE STUDY PERIOD.

DATE OF REPORT : 10/27/2004
STUDY CARRIED OUT BY : ALBERT GORDON
NO PETCOKE OPTION

INFORMATION SUPPLIED BY USER :

ONLY 2 COMBINED CYCLE AVAILABLE WITH T&T GAS
NO PETCOKE ALLOWED

THIS IS A LIST OF THE DIFFERENT TYPES OF ELECTRIC POWER PLANTS
USED IN THE STUDY.
THE NUMERIC CODES ARE USED BY THE COMPUTER PROGRAMS

0	HFO	Bunker'C (NO6)
1	COAL	Coal
2	DISL	Diesel (NO2)
3	NATG	NATURAL GAS
4	PETC	PETCOKE
5	ORIM	ORIMULSION
6	LNGT	LNG FROM T&T
7	****	NOT APPLICABLE
8	****	NOT APPLICABLE
9	****	NOT APPLICABLE

SYSTEM WITHOUT PUMPED STORAGE PROJECTS:

HROR	RUN-OF-RIVER PLANT
HSTO	SHORT TERM STORAGE

ANNUAL LOAD DESCRIPTION
PERIOD(S) PER YEAR : 4

YEAR	PEAKLOAD MW	GR.RATE %	MIN.LOAD MW	GR.RATE %	ENERGY GWH	GR.RATE %	LOADFACTOR %
2001	538.2	-	234.1	-	3361.1	-	71.29
2002	563.9	4.8	246.1	5.1	3525.3	4.9	71.37
2003	590.0	4.6	259.2	5.3	3696.1	4.8	71.51
2004	614.0	4.1	270.2	4.2	3848.3	4.1	71.55
2005	641.9	4.5	282.4	4.5	4023.1	4.5	71.55
2006	670.8	4.5	295.3	4.6	4205.0	4.5	71.56
2007	700.8	4.5	308.7	4.5	4393.9	4.5	71.57
2008	732.1	4.5	322.8	4.6	4591.6	4.5	71.60
2009	764.8	4.5	337.7	4.6	4798.6	4.5	71.63
2010	798.9	4.5	353.1	4.6	5014.5	4.5	71.65
2011	834.6	4.5	369.6	4.6	5241.3	4.5	71.69
2012	871.9	4.5	386.7	4.7	5478.6	4.5	71.73
2013	911.1	4.5	404.8	4.7	5728.1	4.6	71.77
2014	952.1	4.5	424.0	4.7	5989.9	4.6	71.82
2015	995.3	4.5	444.0	4.7	6265.6	4.6	71.86
2016	1040.5	4.5	465.3	4.8	6555.0	4.6	71.92
2017	1088.1	4.6	487.8	4.8	6860.3	4.7	71.97

FIXED SYSTEM

SUMMARY DESCRIPTION OF THERMAL PLANTS IN YEAR 2001

NO.	NAME	NO. OF SETS	MIN. LOAD MW	CAPA CITY MW	HEAT RATES KCAL/KWH BASE LOAD	AVGE INCR	FUEL COSTS CENTS/ MILLION KCAL DMSTC	FORGN	FUEL TYPE	FAST SPIN RES %	FOR %	DAYS SCHL MAIN	MAIN CLAS MW	O&M (FIX) $/KWM	O&M (VAR) $/MWH
3	OH2	1	30.	57.	3659.	3334.	0.0	1640.0	0	10	8.0	26	60.	0.38	6.70
4	RF1	1	9.	17.	2511.	2063.	0.0	1739.0	0	10	5.0	37	20.	0.93	8.00
5	OH4	1	30.	65.	3195.	2901.	0.0	1640.0	0	10	8.0	25	60.	0.33	6.70
6	GT4	1	5.	21.	6514.	2357.	0.0	2710.0	2	0	5.0	37	20.	0.39	5.00
7	GT5	1	5.	21.	7104.	2698.	0.0	2710.0	2	0	5.0	37	20.	0.39	5.00
8	GT10	1	8.	32.	5048.	2523.	0.0	2710.0	2	0	5.0	37	30.	0.26	5.00
9	RF2	1	9.	17.	2511.	2063.	0.0	1739.0	0	10	5.0	37	20.	0.93	8.00
10	JPPC	2	10.	30.	0.	0.	0.0	0.0	0	10	7.0	11	30.	41.69	51.58
11	GT6	1	5.	14.	5244.	3450.	0.0	2757.0	2	0	5.0	18	20.	0.60	5.00
12	GT7	1	5.	14.	5390.	3129.	0.0	2757.0	2	0	5.0	18	20.	0.60	5.00
13	GT3	1	5.	21.	6702.	2451.	0.0	2757.0	2	0	5.0	37	20.	0.39	5.00
14	GT8	1	5.	14.	5944.	2908.	0.0	2757.0	2	0	5.0	18	20.	0.60	5.00
15	GT9	1	8.	20.	7694.	622.	0.0	2757.0	2	0	5.0	18	20.	0.42	5.00
16	JEP	8	3.	9.	0.	0.	0.0	0.0	0	0	6.0	15	20.	22.95	60.06
17	JAML	1	10.	11.	0.	0.	0.0	0.0	0	0	5.0	18	20.	15.00	39.76
18	BRLS	1	10.	12.	0.	0.	0.0	0.0	0	0	5.0	18	20.	15.00	28.00
19	HBB6	1	30.	65.	3436.	2715.	0.0	1694.0	0	10	8.0	26	60.	0.33	6.70
20	OH1	1	14.	28.	3906.	3512.	0.0	1640.0	0	10	8.0	26	30.	0.75	6.70
21	OH3	1	30.	62.	3578.	2546.	0.0	1640.0	0	10	8.0	26	60.	0.35	6.70
22	BOGT	1	8.	20.	6300.	885.	0.0	2757.0	2	0	5.0	18	25.	0.42	5.00
23	CCGT	0	8.	38.	6300.	2146.	0.0	2710.0	2	0	5.0	18	40.	0.25	5.00
24	ALCO	0	4.	5.	0.	0.	0.0	0.0	0	0	5.0	18	20.	14.00	37.00
25	GT05	0	8.	38.	6300.	2146.	0.0	2710.0	2	0	5.0	18	40.	0.25	5.00

FIXED SYSTEM
SUMMARY DESCRIPTION OF COMPOSITE HYDROELECTRIC PLANT TYPE HROR
*** CAPACITY IN MW * ENERGY IN GWH ***
FIXED O&M COSTS : 2.000 $/KW-MONTH

YEAR	PROJ	PER	HYDROCONDITION 1 PROB.: 1.00 CAPACITY BASE	PEAK	ENERGY
2001	7	1	7.	0.	14.
		2	11.	0.	25.
		3	11.	0.	23.
		4	12.	0.	25.
		INST.CAP.		17.	
		TOTAL ENERGY			88.

FIXED SYSTEM
THERMAL ADDITIONS AND RETIREMENTS
NUMBER OF SETS ADDED AND RETIRED(-)
2001 TO 2017

YEAR: 19.. (200./20..)

NO.	NAME	2	3	4	5	6	7	8	9	10	11	12	13	14	15
6	GT4		-1												
10	JPPC														-2
16	JEP														-8
17	JAML			-1											
18	BRLS			-1											
20	OH1														-1
23	CCGT	2	-2		2	1	-3								
24	ALCO			1											

FIXED SYSTEM
SUMMARY OF INSTALLED CAPACITIES
(NOMINAL CAPACITIES (MW))

	HYDROELECTRIC				THERMAL											TOTAL
	HROR		HSTO		FUEL TYPE											
					0	1	2	3	4	5	6	7	8	9		
YEAR	PR.	CAP	PR.	CAP	HFO	COAL	DISL	NATG	PETC	ORIM	LNGT	****	****	****		
2001	7	17.	0	0.	467.	0.	177.	0.	0.	0.	0.	0.	0.	0.		662.
2002	7	17.	0	0.	467.	0.	252.	0.	0.	0.	0.	0.	0.	0.		736.
2003	7	17.	0	0.	467.	0.	156.	0.	0.	0.	0.	0.	0.	0.		640.
2004	7	17.	0	0.	449.	0.	156.	0.	0.	0.	0.	0.	0.	0.		622.
2005	7	17.	0	0.	449.	0.	231.	0.	0.	0.	0.	0.	0.	0.		697.
2006	7	17.	0	0.	449.	0.	268.	0.	0.	0.	0.	0.	0.	0.		734.
2007	7	17.	0	0.	449.	0.	156.	0.	0.	0.	0.	0.	0.	0.		622.
2008	7	17.	0	0.	449.	0.	156.	0.	0.	0.	0.	0.	0.	0.		622.
2009	7	17.	0	0.	449.	0.	156.	0.	0.	0.	0.	0.	0.	0.		622.
2010	7	17.	0	0.	449.	0.	156.	0.	0.	0.	0.	0.	0.	0.		622.
2011	7	17.	0	0.	449.	0.	156.	0.	0.	0.	0.	0.	0.	0.		622.
2012	7	17.	0	0.	449.	0.	156.	0.	0.	0.	0.	0.	0.	0.		622.
2013	7	17.	0	0.	449.	0.	156.	0.	0.	0.	0.	0.	0.	0.		622.
2014	7	17.	0	0.	449.	0.	156.	0.	0.	0.	0.	0.	0.	0.		622.
2015	7	17.	0	0.	289.	0.	156.	0.	0.	0.	0.	0.	0.	0.		461.
2016	7	17.	0	0.	289.	0.	156.	0.	0.	0.	0.	0.	0.	0.		461.
2017	7	17.	0	0.	289.	0.	156.	0.	0.	0.	0.	0.	0.	0.		461.

VARIABLE SYSTEM
SUMMARY DESCRIPTION OF THERMAL PLANTS

NO.	NAME	NO. OF SETS	MIN. LOAD MW	CAPA CITY MW	HEAT RATES KCAL/KWH BASE LOAD	AVGE INCR	FUEL COSTS CENTS/ MILLION KCAL DMSTC	FORGN	FUEL TYPE	FAST SPIN RES %	FOR %	DAYS SCHL MAIN	MAIN CLAS MW	O&M (FIX) $/KWM	O&M (VAR) $/MWH
1	GTRB	0	10.	38.	4133.	2098.	0.0	2710.0	2	0	3.0	18	40.	0.37	1.50
2	CC#2	0	20.	115.	2268.	1839.	0.0	2710.0	2	0	3.0	26	115.	0.99	6.00
3	NGCC	0	20.	115.	2268.	1839.	0.0	1705.0	3	0	3.0	26	115.	0.99	6.00
4	CCFB	0	40.	115.	3150.	2311.	0.0	595.2	1	10	5.0	26	115.	2.48	7.00
5	ORFS	0	40.	115.	3150.	2272.	0.0	720.8	5	10	5.0	26	115.	2.87	7.00
6	MSDO	0	5.	38.	2117.	2146.	0.0	1694.0	0	10	6.0	33	40.	1.80	15.00
7	PFSM	0	40.	115.	3150.	2389.	0.0	300.0	4	10	5.0	26	115.	4.61	7.50
8	NGC2	0	20.	115.	2268.	1839.	0.0	1389.0	6	0	3.0	26	115.	0.99	6.00

C O N G E N
CONSTRAINTS ON CONFIGURATIONS GENERATED
CON: NUMBER OF CONFIGURATIONS
MIMIMUM
MAXIMUM

		RES.	PERMITTED EXTREME CONFIGURATIONS OF ALTERNATIVES									
YEAR	CON	MAR- GIN	GTRB	CC#2	NGCC	CCFB	ORFS	MSDO	PFSM	NGC2	HROR	HSTO
2001	1	0	0	0	0	0	0	0	0	0		
		40	0	0	0	0	0	0	0	0		
2002	1	0	0	0	0	0	0	0	0	0		
		40	0	0	0	0	0	0	0	0		
2003	1	0	0	1	0	0	0	0	0	0		
		40	0	1	0	0	0	0	0	0		
2004	1	0	0	1	0	0	0	0	0	0		
		40	0	1	0	0	0	0	0	0		
2005	1	0	0	1	0	0	0	0	0	0		
		40	0	1	0	0	0	0	0	0		
2006	1	0	0	1	0	0	0	0	0	0		
		40	0	1	0	0	0	0	0	0		
2007	1	0	0	1	0	0	0	0	0	2		
		40	1	1	0	0	0	0	0	2		
2008	2	0	0	1	0	0	0	0	0	2		
		40	1	2	1	2	0	0	0	2		
2009	2	0	0	1	0	0	0	0	0	2		
		40	1	2	1	2	0	0	0	2		
2010	8	0	0	1	0	0	0	0	0	2		
		40	1	2	2	2	0	0	0	2		
2011	8	0	0	1	0	0	0	0	0	2		
		40	1	2	2	2	0	0	0	2		
2012	13	0	0	1	0	0	0	0	0	2		
		40	1	2	2	2	0	0	0	2		
2013	8	0	0	1	0	1	0	0	0	2		
		40	1	2	2	3	0	0	0	2		
2014	13	0	0	1	0	1	0	0	0	2		

		40	1	2	2	3	0	0	0	2
2015	36	0	0	1	0	2	0	0	0	2
		40	1	2	2	4	1	0	0	2
2016	45	0	0	1	0	2	0	0	0	2
		40	1	2	2	4	1	0	0	2
2017	98	0	0	1	0	2	0	0	0	2
		40	3	2	2	4	1	0	0	2
	240	TOTAL NUMBER OF CONFIGURATIONS GENERATED								

OPTIMUM SOLUTION

ANNUAL ADDITIONS: CAPACITY(MW) AND NUMBER OF UNITS OR PROJECTS

FOR DETAILS OF INDIVIDUAL UNITS OR PROJECTS SEE VARIABLE SYSTEM REPORT

SEE ALSO FIXED SYSTEM REPORT FOR OTHER ADDITIONS OR RETIREMENTS

NAME :			GTRB	CC#2	NGCC	CCFB	ORFS	MSDO	PFSM	NGC2	HROR	HSTO
SIZE (MW):			38.	115.	115.	115.	115.	38.	115.	115.	0.	0.
YEAR	%LOLP	CAP										
2001	0.750	0.										
2002	0.146	0.										
2003	0.342	115.		1								
2004	1.126	0.										
2005	0.318	0.										
2006	0.258	0.										
2007	0.044	230.								2		
2008	0.108	0.										
2009	0.266	0.										
2010	0.056	115.				1						
2011	0.142	0.										
2012	0.356	0.										
2013	0.089	115.				1						
2014	0.234	0.										
2015	0.206	230.			1	1						
2016	0.513	0.										
2017	0.304	75.	2									
TOTALS		880.	2	1	1	3	0	0	0	2	0	0

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
(NOMINAL CAPACITY (MW))
THERMAL FUEL TYPE
CAPACITIES

YEAR	0 HFO	1 COAL	2 DISL	3 NATG	4 PETC	5 ORIM	6 LNGT	7 ****	8 ****	9 ****	TOTAL CAP
2001	467	0	177	0	0	0	0	0	0	0	645
2002	467	0	252	0	0	0	0	0	0	0	720
2003	467	0	271	0	0	0	0	0	0	0	738
2004	449	0	271	0	0	0	0	0	0	0	720
2005	449	0	346	0	0	0	0	0	0	0	795
2006	449	0	384	0	0	0	0	0	0	0	833
2007	449	0	271	0	0	0	230	0	0	0	950
2008	449	0	271	0	0	0	230	0	0	0	950
2009	449	0	271	0	0	0	230	0	0	0	950
2010	449	115	271	0	0	0	230	0	0	0	1065
2011	449	115	271	0	0	0	230	0	0	0	1065
2012	449	115	271	0	0	0	230	0	0	0	1065
2013	449	230	271	0	0	0	230	0	0	0	1180
2014	449	230	271	0	0	0	230	0	0	0	1180
2015	289	345	271	115	0	0	230	0	0	0	1250
2016	289	345	271	115	0	0	230	0	0	0	1250
2017	289	345	346	115	0	0	230	0	0	0	1325

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
(NOMINAL CAPACITY IN MW, ENERGY IN GWH)

YEAR	PUMPED STORAGE PUMP PR.	PUMPED STORAGE PUMP CAP	HYDRO ELECTRIC HYDR PR.	HYDRO ELECTRIC HYDR CAP	TOTAL THERMAL CAPACITY	TOTAL CAP	SYSTEM RES. %	SYSTEM LOLP. %	ENERGY NOT SERVED HYDROCONDITION 1
2001	0	0	7	17	645	662	22.9	0.750	1.5
2002	0	0	7	17	720	737	30.6	0.146	0.2
2003	0	0	7	17	738	755	28.0	0.342	0.8
2004	0	0	7	17	720	737	20.0	1.126	2.9
2005	0	0	7	17	795	812	26.5	0.318	0.7
2006	0	0	7	17	833	850	26.6	0.258	0.6
2007	0	0	7	17	950	967	38.0	0.044	0.1
2008	0	0	7	17	950	967	32.1	0.108	0.3
2009	0	0	7	17	950	967	26.4	0.266	0.7
2010	0	0	7	17	1065	1082	35.4	0.056	0.1
2011	0	0	7	17	1065	1082	29.6	0.142	0.4
2012	0	0	7	17	1065	1082	24.1	0.356	1.0
2013	0	0	7	17	1180	1197	31.4	0.089	0.2
2014	0	0	7	17	1180	1197	25.7	0.234	0.7
2015	0	0	7	17	1250	1267	27.2	0.206	0.7
2016	0	0	7	17	1250	1267	21.7	0.513	1.8
2017	0	0	7	17	1325	1342	23.3	0.304	1.0

10 APPENDIX2: BASE CASE PLANT OUTPUT / CAPACITY FACTORS

*** SUMMARY OF YEAR 2005 **

CONFIGURATION SIMULATED 0 1 0 0 0 0 0 0

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	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO. OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FUEL CONSUMPTION FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	62.55	312.32	0.00	0.00	20626.604
4	RF1	0	0.0	1	85.26	129.21	0.00	0.00	6385.826
5	OH4	0	0.0	1	85.62	488.25	0.00	0.00	27844.355
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	1.08	2.02	0.00	0.00	327.134
8	GT10	2	0.0	1	5.18	14.40	0.00	0.00	1474.438
9	RF2	0	0.0	1	85.26	129.21	0.00	0.00	6385.826
10	JPPC	0	0.0	2	90.22	474.19	0.00	0.00	54475.289
11	GT6	2	0.0	1	0.33	0.40	0.00	0.00	148.217
12	GT7	2	0.0	1	0.72	0.88	0.00	0.00	202.087
13	GT3	2	0.0	1	2.97	5.56	0.00	0.00	686.843
14	GT8	2	0.0	1	0.50	0.61	0.00	0.00	172.236
15	GT9	2	0.0	1	1.91	3.33	0.00	0.00	477.495
16	JEP	0	0.0	8	62.11	391.72	0.00	0.00	43355.309
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	68.21	388.96	0.00	0.00	23496.148
20	OH1	0	0.0	1	58.77	146.73	0.00	0.00	10368.538
21	OH3	0	0.0	1	84.62	458.11	0.00	0.00	26258.631
22	BOGT	2	0.0	1	9.39	16.37	0.00	0.00	1694.435
23	CCGT	2	0.0	2	21.03	138.17	0.00	0.00	13756.312
24	ALCO	0	0.0	1	90.26	39.53	0.00	0.00	2302.771
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	0	0.00	0.00	0.00	0.00	0.000
27	CC#2	2	0.0	1	78.87	794.49	0.00	0.00	47562.039
28	NGCC	3	0.0	0	0.00	0.00	0.00	0.00	0.000
29	CCFB	1	0.0	0	0.00	0.00	0.00	0.00	0.000
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000

31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	0	0.00	0.00	0.00	0.00	0.000
TOTALS						4022.36			288406.156

*********************************** THERMAL PLANTS AGGREGATED BY PLANT TYPE ***********************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL DOMESTIC (TON)	CONSUMPTION FOREIGN (TON)	GENERATION COSTS (K$)
0	447	75.55	2958.23	0.00	0.00	221499.28
1	0	0.00	0.00	0.00	0.00	0.00
2	340	32.78	976.22	0.00	0.00	66501.24
3	0	0.00	0.00	0.00	0.00	0.00
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	0	0.00	0.00	0.00	0.00	0.00
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2005

SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 0 1 0 0 0 0 0 0

	CAPACITY (MW)	TOTAL COSTS	O&M COSTS	TOTAL	DOMESTIC	FOREIGN
		***** EXPECTED GENERATION COSTS (K$) *****		**** F U E L C O S T S ****		
THERMAL PLANTS						
TYPE 0	449.1	221499.3	115900.7	105598.6	0.0	105598.6
TYPE 1	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 2	346.0	66501.2	8066.8	58434.4	0.0	58434.4
TYPE 3	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	795.1	288000.5	123967.5	164033.0	0.0	164033.0
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	812.0	288406.1	124373.1	164033.0	0.0	164033.0

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	0.7
LOSS-OF-LOAD PROBABILITY (%)	0.3176
EXPECTED LOLP (WEIGHED) (%)	0.3176

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2005

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	65.3	83.7	83.4	79.9	312.3
RF1	36.0	30.8	31.6	30.8	129.2
OH4	100.5	130.7	131.1	125.9	488.2
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.5	0.5	0.6	0.4	2.0
GT10	4.3	4.2	2.4	3.5	14.4
RF2	36.0	30.8	31.6	30.8	129.2
JPPC	122.2	122.2	107.6	122.2	474.2
GT6	0.1	0.1	0.1	0.1	0.4
GT7	0.2	0.2	0.3	0.2	0.9
GT3	1.5	1.4	1.6	1.1	5.6
GT8	0.1	0.1	0.2	0.1	0.6
GT9	0.8	0.8	1.0	0.7	3.3
JEP	105.4	95.9	95.9	94.6	391.7
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	81.3	104.9	103.7	99.0	389.0
OH1	40.8	39.0	28.1	38.8	146.7
OH3	93.9	122.4	123.5	118.3	458.1
BOGT	4.9	4.8	3.8	2.9	16.4
CCGT	43.2	28.7	34.2	32.1	138.2
ALCO	10.4	9.7	9.8	9.7	39.5
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	0.0	0.0	0.0	0.0	0.0
CC#2	222.4	149.1	212.4	210.5	794.5
NGCC	0.0	0.0	0.0	0.0	0.0
CCFB	0.0	0.0	0.0	0.0	0.0
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	0.0	0.0	0.0	0.0	0.0

`********************************************** SUMMARY OF YEAR 2006 ************************************************`

CONFIGURATION SIMULATED 0 1 0 0 0 0 0 0

`**********************************************************************************************************************`

	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO.OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FUEL CONSUMPTION FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	64.82	323.68	0.00	0.00	21323.518
4	RF1	0	0.0	1	85.26	129.21	0.00	0.00	6385.826
5	OH4	0	0.0	1	85.71	488.77	0.00	0.00	27872.461
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	0.87	1.63	0.00	0.00	283.891
8	GT10	2	0.0	1	4.29	11.92	0.00	0.00	1237.352
9	RF2	0	0.0	1	85.26	129.21	0.00	0.00	6385.827
10	JPPC	0	0.0	2	90.22	474.19	0.00	0.00	54475.293
11	GT6	2	0.0	1	0.26	0.32	0.00	0.00	138.692
12	GT7	2	0.0	1	0.59	0.71	0.00	0.00	183.114
13	GT3	2	0.0	1	2.41	4.52	0.00	0.00	578.576
14	GT8	2	0.0	1	0.40	0.49	0.00	0.00	158.626
15	GT9	2	0.0	1	1.55	2.70	0.00	0.00	405.822
16	JEP	0	0.0	8	65.38	412.35	0.00	0.00	44594.285
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	70.91	404.41	0.00	0.00	24310.342
20	OH1	0	0.0	1	61.65	153.92	0.00	0.00	10830.450
21	OH3	0	0.0	1	85.08	460.58	0.00	0.00	26378.217
22	BOGT	2	0.0	1	7.67	13.38	0.00	0.00	1403.244
23	CCGT	2	0.0	3	23.72	233.77	0.00	0.00	23832.330
24	ALCO	0	0.0	1	90.26	39.53	0.00	0.00	2302.769
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	0	0.00	0.00	0.00	0.00	0.000
27	CC#2	2	0.0	1	82.51	831.19	0.00	0.00	49611.090
28	NGCC	3	0.0	0	0.00	0.00	0.00	0.00	0.000
29	CCFB	1	0.0	0	0.00	0.00	0.00	0.00	0.000
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000
31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	0	0.00	0.00	0.00	0.00	0.000
TOTALS						4204.38			303097.312

************************************ THERMAL PLANTS AGGREGATED BY PLANT TYPE ************************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL DOMESTIC (TON)	CONSUMPTION FOREIGN (TON)	GENERATION COSTS (K$)
0	447	77.02	3015.83	0.00	0.00	224858.98
1	0	0.00	0.00	0.00	0.00	0.00
2	377	33.33	1100.64	0.00	0.00	77832.73
3	0	0.00	0.00	0.00	0.00	0.00
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	0	0.00	0.00	0.00	0.00	0.00
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2006
SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 0 1 0 0 0 0 0 0

		***** EXPECTED GENERATION COSTS (K$) *****				
	CAPACITY	TOTAL	O&M	**** F U E L	C O S T S ****	
	(MW)	COSTS	COSTS	TOTAL	DOMESTIC	FOREIGN
THERMAL PLANTS						
TYPE 0	449.1	224859.0	117387.4	107471.5	0.0	107471.5
TYPE 1	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 2	383.5	77832.7	8838.1	68994.6	0.0	68994.6
TYPE 3	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	832.6	302691.8	126225.6	176466.2	0.0	176466.2
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	849.5	303097.3	126631.1	176466.2	0.0	176466.2

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	0.6
LOSS-OF-LOAD PROBABILITY (%)	0.2579
EXPECTED LOLP (WEIGHED) (%)	0.2579

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2006

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	67.4	84.5	86.6	85.3	323.7
RF1	36.0	30.8	31.6	30.8	129.2
OH4	100.5	126.0	131.2	131.1	488.8
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.4	0.3	0.5	0.4	1.6
GT10	3.4	3.2	2.0	3.4	11.9
RF2	36.0	30.8	31.6	30.8	129.2
JPPC	122.2	122.2	107.6	122.2	474.2
GT6	0.1	0.1	0.1	0.1	0.3
GT7	0.1	0.1	0.2	0.2	0.7
GT3	1.2	1.0	1.3	1.1	4.5
GT8	0.1	0.1	0.2	0.1	0.5
GT9	0.6	0.6	0.8	0.7	2.7
JEP	110.8	103.2	100.9	97.6	412.3
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	84.7	106.4	107.7	105.6	404.4
OH1	42.5	41.8	29.5	40.2	153.9
OH3	94.2	118.6	124.1	123.7	460.6
BOGT	3.8	2.7	3.1	3.7	13.4
CCGT	69.3	61.9	58.0	44.6	233.8
ALCO	10.4	9.7	9.8	9.7	39.5
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	0.0	0.0	0.0	0.0	0.0
CC#2	230.8	160.8	222.8	216.9	831.2
NGCC	0.0	0.0	0.0	0.0	0.0
CCFB	0.0	0.0	0.0	0.0	0.0
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	0.0	0.0	0.0	0.0	0.0

** SUMMARY OF YEAR 2007 **

CONFIGURATION SIMULATED 0 1 0 0 0 0 0 2

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	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO.OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	46.34	231.38	0.00	0.00	15658.513
4	RF1	0	0.0	1	75.94	115.09	0.00	0.00	5766.230
5	OH4	0	0.0	1	65.28	372.27	0.00	0.00	21549.615
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	0.15	0.29	0.00	0.00	132.541
8	GT10	2	0.0	1	0.84	2.33	0.00	0.00	323.118
9	RF2	0	0.0	1	74.39	112.74	0.00	0.00	5663.285
10	JPPC	0	0.0	2	69.06	363.01	0.00	0.00	48740.617
11	GT6	2	0.0	1	0.05	0.06	0.00	0.00	106.868
12	GT7	2	0.0	1	0.10	0.12	0.00	0.00	114.011
13	GT3	2	0.0	1	0.44	0.82	0.00	0.00	187.452
14	GT8	2	0.0	1	0.07	0.08	0.00	0.00	109.820
15	GT9	2	0.0	1	0.28	0.48	0.00	0.00	154.952
16	JEP	0	0.0	8	34.64	218.50	0.00	0.00	32951.977
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	45.75	260.88	0.00	0.00	16747.326
20	OH1	0	0.0	1	36.84	91.97	0.00	0.00	6747.177
21	OH3	0	0.0	1	63.01	341.11	0.00	0.00	20589.215
22	BOGT	2	0.0	1	1.60	2.80	0.00	0.00	374.461
23	CCGT	2	0.0	0	0.00	0.00	0.00	0.00	0.000
24	ALCO	0	0.0	1	86.74	37.99	0.00	0.00	2245.706
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	0	0.00	0.00	0.00	0.00	0.000
27	CC#2	2	0.0	1	39.19	394.84	0.00	0.00	25247.021
28	NGCC	3	0.0	0	0.00	0.00	0.00	0.00	0.000
29	CCFB	1	0.0	0	0.00	0.00	0.00	0.00	0.000
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000
31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	2	87.31	1759.14	0.00	0.00	60102.082
TOTALS						4393.80			263917.594

************************************ THERMAL PLANTS AGGREGATED BY PLANT TYPE ************************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL DOMESTIC (TON)	CONSUMPTION FOREIGN (TON)	GENERATION COSTS (K$)
0	447	54.78	2144.93	0.00	0.00	176659.67
1	0	0.00	0.00	0.00	0.00	0.00
2	265	17.31	401.82	0.00	0.00	26750.24
3	0	0.00	0.00	0.00	0.00	0.00
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	230	87.31	1759.14	0.00	0.00	60102.08
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2007

SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 0 1 0 0 0 0 0 2

	CAPACITY (MW)	***** EXPECTED GENERATION COSTS (K$) ***** TOTAL COSTS	O&M COSTS	**** F U E L C O S T S **** TOTAL	DOMESTIC	FOREIGN
THERMAL PLANTS						
TYPE 0	449.1	176659.7	96132.6	80527.1	0.0	80527.1
TYPE 1	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 2	271.0	26750.2	4570.2	22180.1	0.0	22180.1
TYPE 3	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	230.0	60102.1	13287.2	46814.9	0.0	46814.9
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	950.1	263512.0	113990.0	149522.0	0.0	149522.0
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	967.0	263917.6	114395.6	149522.0	0.0	149522.0

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	0.1
LOSS-OF-LOAD PROBABILITY (%)	0.0440
EXPECTED LOLP (WEIGHED) (%)	0.0440

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2007

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	47.0	63.6	59.1	61.6	231.4
RF1	26.8	34.9	26.4	27.0	115.1
OH4	76.0	104.3	93.8	98.2	372.3
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.1	0.1	0.0	0.1	0.3
GT10	0.6	1.0	0.4	0.3	2.3
RF2	26.4	33.6	26.0	26.7	112.7
JPPC	91.5	101.8	90.0	79.7	363.0
GT6	0.0	0.0	0.0	0.0	0.1
GT7	0.0	0.0	0.0	0.0	0.1
GT3	0.2	0.3	0.1	0.2	0.8
GT8	0.0	0.0	0.0	0.0	0.1
GT9	0.1	0.2	0.1	0.1	0.5
JEP	52.7	63.2	51.0	51.6	218.5
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	52.1	77.8	64.0	67.0	260.9
OH1	28.9	26.8	21.2	15.1	92.0
OH3	69.7	95.1	86.1	90.2	341.1
BOGT	0.7	1.2	0.4	0.5	2.8
CCGT	0.0	0.0	0.0	0.0	0.0
ALCO	9.2	10.3	9.2	9.3	38.0
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	0.0	0.0	0.0	0.0	0.0
CC#2	107.3	91.6	97.3	98.6	394.8
NGCC	0.0	0.0	0.0	0.0	0.0
CCFB	0.0	0.0	0.0	0.0	0.0
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	471.2	345.2	472.3	470.4	1759.1

*** SUMMARY OF YEAR 2008 **

CONFIGURATION SIMULATED 0 1 0 0 0 0 0 2

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	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO.OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	47.52	237.29	0.00	0.00	16021.562
4	RF1	0	0.0	1	78.63	119.16	0.00	0.00	5945.140
5	OH4	0	0.0	1	67.67	385.92	0.00	0.00	22290.242
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	0.35	0.66	0.00	0.00	173.780
8	GT10	2	0.0	1	1.72	4.77	0.00	0.00	553.566
9	RF2	0	0.0	1	77.34	117.21	0.00	0.00	5859.354
10	JPPC	0	0.0	2	73.04	383.87	0.00	0.00	49816.977
11	GT6	2	0.0	1	0.11	0.14	0.00	0.00	116.427
12	GT7	2	0.0	1	0.24	0.29	0.00	0.00	133.522
13	GT3	2	0.0	1	0.95	1.79	0.00	0.00	289.349
14	GT8	2	0.0	1	0.16	0.20	0.00	0.00	123.840
15	GT9	2	0.0	1	0.61	1.06	0.00	0.00	219.994
16	JEP	0	0.0	8	37.61	237.20	0.00	0.00	34074.863
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	49.14	280.26	0.00	0.00	17768.738
20	OH1	0	0.0	1	39.89	99.58	0.00	0.00	7270.268
21	OH3	0	0.0	1	65.32	353.60	0.00	0.00	21194.666
22	BOGT	2	0.0	1	3.01	5.25	0.00	0.00	611.807
23	CCGT	2	0.0	0	0.00	0.00	0.00	0.00	0.000
24	ALCO	0	0.0	1	88.06	38.57	0.00	0.00	2267.118
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	0	0.00	0.00	0.00	0.00	0.000
27	CC#2	2	0.0	1	45.00	453.37	0.00	0.00	28515.186
28	NGCC	3	0.0	0	0.00	0.00	0.00	0.00	0.000
29	CCFB	1	0.0	0	0.00	0.00	0.00	0.00	0.000
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000
31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	2	88.51	1783.23	0.00	0.00	60862.211
TOTALS						4591.33			274514.219

*********************************** THERMAL PLANTS AGGREGATED BY PLANT TYPE ***********************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
0	447	57.53	2252.67	0.00	0.00	182508.91
1	0	0.00	0.00	0.00	0.00	0.00
2	265	20.14	467.52	0.00	0.00	30737.47
3	0	0.00	0.00	0.00	0.00	0.00
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	230	88.51	1783.23	0.00	0.00	60862.21
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2008
SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 0 1 0 0 0 0 0 2

	CAPACITY (MW)	***** EXPECTED GENERATION COSTS (K$) ***** TOTAL COSTS	O&M COSTS	**** F U E L C O S T S **** TOTAL	DOMESTIC	FOREIGN
THERMAL PLANTS						
TYPE 0	449.1	182508.9	98817.2	83691.7	0.0	83691.7
TYPE 1	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 2	271.0	30737.5	4957.2	25780.3	0.0	25780.3
TYPE 3	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	230.0	60862.2	13431.8	47430.4	0.0	47430.4
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	950.1	274108.6	117206.2	156902.4	0.0	156902.4
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	967.0	274514.2	117611.8	156902.4	0.0	156902.4

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	0.3
LOSS-OF-LOAD PROBABILITY (%)	0.1084
EXPECTED LOLP (WEIGHED) (%)	0.1084

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2008

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	48.1	66.5	60.1	62.6	237.3
RF1	28.2	35.3	27.5	28.2	119.2
OH4	78.6	108.6	97.1	101.6	385.9
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.2	0.2	0.1	0.2	0.7
GT10	1.2	2.1	0.9	0.6	4.8
RF2	27.7	34.7	27.1	27.8	117.2
JPPC	96.7	108.4	94.8	84.0	383.9
GT6	0.0	0.0	0.0	0.0	0.1
GT7	0.1	0.1	0.1	0.1	0.3
GT3	0.4	0.7	0.3	0.4	1.8
GT8	0.1	0.1	0.0	0.1	0.2
GT9	0.2	0.4	0.2	0.2	1.1
JEP	57.2	70.4	54.5	55.1	237.2
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	56.0	85.0	68.1	71.2	280.3
OH1	29.4	28.9	24.1	17.2	99.6
OH3	72.1	98.5	89.4	93.6	353.6
BOGT	1.3	2.3	0.7	0.9	5.3
CCGT	0.0	0.0	0.0	0.0	0.0
ALCO	9.4	10.3	9.4	9.5	38.6
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	0.0	0.0	0.0	0.0	0.0
CC#2	123.5	100.1	114.3	115.6	453.4
NGCC	0.0	0.0	0.0	0.0	0.0
CCFB	0.0	0.0	0.0	0.0	0.0
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	478.7	346.8	479.4	478.3	1783.2

** SUMMARY OF YEAR 2009 **

CONFIGURATION SIMULATED 0 1 0 0 0 0 0 2

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	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO.OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	49.33	246.30	0.00	0.00	16574.678
4	RF1	0	0.0	1	81.45	123.43	0.00	0.00	6132.370
5	OH4	0	0.0	1	70.36	401.24	0.00	0.00	23121.920
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	0.79	1.47	0.00	0.00	265.194
8	GT10	2	0.0	1	3.31	9.19	0.00	0.00	973.598
9	RF2	0	0.0	1	80.34	121.76	0.00	0.00	6058.901
10	JPPC	0	0.0	2	77.53	407.49	0.00	0.00	51035.203
11	GT6	2	0.0	1	0.27	0.33	0.00	0.00	139.689
12	GT7	2	0.0	1	0.54	0.66	0.00	0.00	176.803
13	GT3	2	0.0	1	1.97	3.69	0.00	0.00	486.792
14	GT8	2	0.0	1	0.39	0.47	0.00	0.00	155.982
15	GT9	2	0.0	1	1.33	2.32	0.00	0.00	360.218
16	JEP	0	0.0	8	41.88	264.12	0.00	0.00	35691.684
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	53.14	303.02	0.00	0.00	18968.121
20	OH1	0	0.0	1	43.33	108.19	0.00	0.00	7853.188
21	OH3	0	0.0	1	67.61	366.00	0.00	0.00	21795.486
22	BOGT	2	0.0	1	5.68	9.91	0.00	0.00	1058.066
23	CCGT	2	0.0	0	0.00	0.00	0.00	0.00	0.000
24	ALCO	0	0.0	1	89.08	39.02	0.00	0.00	2283.568
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	0	0.00	0.00	0.00	0.00	0.000
27	CC#2	2	0.0	1	50.07	504.38	0.00	0.00	31363.018
28	NGCC	3	0.0	0	0.00	0.00	0.00	0.00	0.000
29	CCFB	1	0.0	0	0.00	0.00	0.00	0.00	0.000
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000
31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	2	89.19	1797.02	0.00	0.00	61297.027
TOTALS						4797.92			286197.062

*********************************** THERMAL PLANTS AGGREGATED BY PLANT TYPE ***********************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
0	447	60.80	2380.57	0.00	0.00	189515.11
1	0	0.00	0.00	0.00	0.00	0.00
2	265	22.94	532.42	0.00	0.00	34979.36
3	0	0.00	0.00	0.00	0.00	0.00
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	230	89.19	1797.02	0.00	0.00	61297.03
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2009
SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 0 1 0 0 0 0 0 2

	CAPACITY (MW)	***** EXPECTED TOTAL COSTS	GENERATION O&M COSTS	COSTS (K$) ***** **** F U E L TOTAL	C O S T S **** DOMESTIC	FOREIGN
THERMAL PLANTS						
TYPE 0	449.1	189515.1	102195.6	87319.6	0.0	87319.6
TYPE 1	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 2	271.0	34979.4	5332.7	29646.7	0.0	29646.7
TYPE 3	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	230.0	61297.0	13514.5	47782.5	0.0	47782.5
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	950.1	285791.5	121042.8	164748.7	0.0	164748.7
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	967.0	286197.1	121448.4	164748.7	0.0	164748.7

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	0.7
LOSS-OF-LOAD PROBABILITY (%)	0.2660
EXPECTED LOLP (WEIGHED) (%)	0.2660

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2009

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	49.9	70.1	61.8	64.4	246.3
RF1	29.4	35.6	28.9	29.6	123.4
OH4	81.5	113.8	100.6	105.3	401.2
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.3	0.6	0.2	0.3	1.5
GT10	2.3	4.1	1.7	1.2	9.2
RF2	29.0	35.2	28.4	29.1	121.8
JPPC	103.3	114.1	100.8	89.3	407.5
GT6	0.1	0.1	0.1	0.1	0.3
GT7	0.2	0.2	0.1	0.2	0.7
GT3	0.8	1.6	0.6	0.8	3.7
GT8	0.1	0.1	0.1	0.1	0.5
GT9	0.5	0.9	0.4	0.5	2.3
JEP	63.8	79.8	59.9	60.6	264.1
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	61.7	90.2	73.8	77.3	303.0
OH1	30.5	31.3	27.1	19.4	108.2
OH3	74.5	102.1	92.5	96.8	366.0
BOGT	2.4	4.3	1.4	1.8	9.9
CCGT	0.0	0.0	0.0	0.0	0.0
ALCO	9.5	10.4	9.5	9.6	39.0
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	0.0	0.0	0.0	0.0	0.0
CC#2	136.7	107.8	129.4	130.5	504.4
NGCC	0.0	0.0	0.0	0.0	0.0
CCFB	0.0	0.0	0.0	0.0	0.0
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	483.0	347.7	483.4	482.8	1797.0

** SUMMARY OF YEAR 2010 **

CONFIGURATION SIMULATED 0 1 0 1 0 0 0 2

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	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO.OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	46.18	230.57	0.00	0.00	15609.036
4	RF1	0	0.0	1	71.01	107.61	0.00	0.00	5438.283
5	OH4	0	0.0	1	62.01	353.63	0.00	0.00	20537.549
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	0.17	0.32	0.00	0.00	135.839
8	GT10	2	0.0	1	0.80	2.23	0.00	0.00	312.186
9	RF2	0	0.0	1	69.73	105.67	0.00	0.00	5353.204
10	JPPC	0	0.0	2	63.70	334.80	0.00	0.00	47285.691
11	GT6	2	0.0	1	0.06	0.07	0.00	0.00	108.331
12	GT7	2	0.0	1	0.11	0.14	0.00	0.00	116.154
13	GT3	2	0.0	1	0.45	0.84	0.00	0.00	189.112
14	GT8	2	0.0	1	0.08	0.10	0.00	0.00	111.436
15	GT9	2	0.0	1	0.29	0.50	0.00	0.00	156.383
16	JEP	0	0.0	8	33.90	213.84	0.00	0.00	32671.861
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	44.48	253.65	0.00	0.00	16366.472
20	OH1	0	0.0	1	36.92	92.17	0.00	0.00	6762.828
21	OH3	0	0.0	1	60.07	325.21	0.00	0.00	19818.865
22	BOGT	2	0.0	1	1.47	2.56	0.00	0.00	350.443
23	CCGT	2	0.0	0	0.00	0.00	0.00	0.00	0.000
24	ALCO	0	0.0	1	84.21	36.88	0.00	0.00	2204.649
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	0	0.00	0.00	0.00	0.00	0.000
27	CC#2	2	0.0	1	34.26	345.13	0.00	0.00	22472.430
28	NGCC	3	0.0	0	0.00	0.00	0.00	0.00	0.000
29	CCFB	1	0.0	1	88.24	888.89	0.00	0.00	23415.297
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000
31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	2	80.98	1631.60	0.00	0.00	56080.242
TOTALS						5014.31			275901.875

************************************ THERMAL PLANTS AGGREGATED BY PLANT TYPE ************************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
0	447	52.46	2054.03	0.00	0.00	172048.41
1	115	88.24	888.89	0.00	0.00	23415.30
2	265	15.16	351.88	0.00	0.00	23952.31
3	0	0.00	0.00	0.00	0.00	0.00
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	230	80.98	1631.60	0.00	0.00	56080.24
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2010
SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 0 1 0 1 0 0 0 2

***** EXPECTED GENERATION COSTS (K$) *****

	CAPACITY (MW)	TOTAL COSTS	O&M COSTS	**** F U E L TOTAL	C O S T S DOMESTIC	**** FOREIGN
THERMAL PLANTS						
TYPE 0	449.1	172048.4	93956.2	78092.2	0.0	78092.2
TYPE 1	115.0	23415.3	9644.6	13770.7	0.0	13770.7
TYPE 2	271.0	23952.3	4270.8	19681.5	0.0	19681.5
TYPE 3	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	230.0	56080.2	12522.0	43558.2	0.0	43558.2
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1065.1	275496.3	120393.6	155102.7	0.0	155102.7
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	1082.0	275901.9	120799.2	155102.7	0.0	155102.7

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	0.1
LOSS-OF-LOAD PROBABILITY (%)	0.0556
EXPECTED LOLP (WEIGHED) (%)	0.0556

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2010

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	46.8	63.3	59.1	61.4	230.6
RF1	29.2	32.3	21.3	24.7	107.6
OH4	71.9	99.7	89.3	92.8	353.6
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.1	0.1	0.1	0.1	0.3
GT10	0.5	1.0	0.4	0.3	2.2
RF2	29.0	31.0	21.1	24.5	105.7
JPPC	84.5	92.9	83.9	73.5	334.8
GT6	0.0	0.0	0.0	0.0	0.1
GT7	0.0	0.0	0.0	0.0	0.1
GT3	0.2	0.4	0.1	0.2	0.8
GT8	0.0	0.0	0.0	0.0	0.1
GT9	0.1	0.2	0.1	0.1	0.5
JEP	54.7	61.2	47.8	50.2	213.8
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	50.8	74.5	63.0	65.4	253.6
OH1	28.8	22.2	28.6	12.5	92.2
OH3	66.0	91.8	82.1	85.3	325.2
BOGT	0.6	1.2	0.4	0.4	2.6
CCGT	0.0	0.0	0.0	0.0	0.0
ALCO	9.6	10.0	8.3	8.9	36.9
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	0.0	0.0	0.0	0.0	0.0
CC#2	88.8	88.5	84.5	83.3	345.1
NGCC	0.0	0.0	0.0	0.0	0.0
CCFB	230.9	179.4	239.3	239.3	888.9
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	419.8	353.1	426.5	432.2	1631.6

** SUMMARY OF YEAR 2011 **

CONFIGURATION SIMULATED 0 1 0 1 0 0 0 2

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	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO.OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	47.29	236.13	0.00	0.00	15950.343
4	RF1	0	0.0	1	73.51	111.40	0.00	0.00	5604.437
5	OH4	0	0.0	1	64.52	367.91	0.00	0.00	21313.016
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	0.40	0.75	0.00	0.00	183.854
8	GT10	2	0.0	1	1.72	4.77	0.00	0.00	551.947
9	RF2	0	0.0	1	72.05	109.18	0.00	0.00	5507.296
10	JPPC	0	0.0	2	66.98	352.04	0.00	0.00	48175.039
11	GT6	2	0.0	1	0.14	0.17	0.00	0.00	120.797
12	GT7	2	0.0	1	0.28	0.34	0.00	0.00	139.580
13	GT3	2	0.0	1	1.00	1.87	0.00	0.00	297.737
14	GT8	2	0.0	1	0.20	0.24	0.00	0.00	128.760
15	GT9	2	0.0	1	0.66	1.15	0.00	0.00	228.275
16	JEP	0	0.0	8	36.60	230.82	0.00	0.00	33691.742
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	47.54	271.11	0.00	0.00	17286.607
20	OH1	0	0.0	1	39.21	97.90	0.00	0.00	7153.736
21	OH3	0	0.0	1	62.65	339.16	0.00	0.00	20494.889
22	BOGT	2	0.0	1	2.88	5.01	0.00	0.00	585.147
23	CCGT	2	0.0	0	0.00	0.00	0.00	0.00	0.000
24	ALCO	0	0.0	1	85.32	37.37	0.00	0.00	2222.685
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	0	0.00	0.00	0.00	0.00	0.000
27	CC#2	2	0.0	1	40.58	408.82	0.00	0.00	26028.598
28	NGCC	3	0.0	0	0.00	0.00	0.00	0.00	0.000
29	CCFB	1	0.0	1	88.24	888.89	0.00	0.00	23415.414
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000
31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	2	83.78	1687.97	0.00	0.00	57858.281
TOTALS						5240.93			287343.812

************************************ THERMAL PLANTS AGGREGATED BY PLANT TYPE ************************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL DOMESTIC (TON)	CONSUMPTION FOREIGN (TON)	GENERATION COSTS (K$)
0	447	54.98	2153.03	0.00	0.00	177399.80
1	115	88.24	888.89	0.00	0.00	23415.41
2	265	18.23	423.13	0.00	0.00	28264.70
3	0	0.00	0.00	0.00	0.00	0.00
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	230	83.78	1687.97	0.00	0.00	57858.28
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2011
SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 0 1 0 1 0 0 0 2

	CAPACITY (MW)	***** EXPECTED GENERATION COSTS (K$) ***** TOTAL COSTS	O&M COSTS	**** F U E L C O S T S **** TOTAL	DOMESTIC	FOREIGN
THERMAL PLANTS						
TYPE 0	449.1	177399.8	96323.7	81076.1	0.0	81076.1
TYPE 1	115.0	23415.4	9644.7	13770.8	0.0	13770.8
TYPE 2	271.0	28264.7	4690.7	23574.0	0.0	23574.0
TYPE 3	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	230.0	57858.3	12860.2	44998.1	0.0	44998.1
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1065.1	286938.2	123519.3	163418.9	0.0	163418.9
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	1082.0	287343.8	123924.9	163418.9	0.0	163418.9

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	0.4
LOSS-OF-LOAD PROBABILITY (%)	0.1422
EXPECTED LOLP (WEIGHED) (%)	0.1422

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2011

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	47.7	66.0	60.0	62.3	236.1
RF1	30.1	33.9	21.9	25.5	111.4
OH4	74.8	103.5	93.0	96.6	367.9
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.2	0.3	0.1	0.2	0.8
GT10	1.1	2.2	0.9	0.6	4.8
RF2	29.8	32.4	21.7	25.2	109.2
JPPC	88.6	98.1	88.1	77.2	352.0
GT6	0.0	0.1	0.0	0.0	0.2
GT7	0.1	0.1	0.1	0.1	0.3
GT3	0.4	0.8	0.3	0.4	1.9
GT8	0.0	0.1	0.1	0.1	0.2
GT9	0.2	0.5	0.2	0.2	1.1
JEP	58.8	68.0	50.8	53.1	230.8
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	54.0	81.6	66.5	69.0	271.1
OH1	29.3	25.7	29.1	13.9	97.9
OH3	68.8	95.1	85.9	89.3	339.2
BOGT	1.1	2.3	0.8	0.9	5.0
CCGT	0.0	0.0	0.0	0.0	0.0
ALCO	9.7	10.2	8.4	9.0	37.4
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	0.0	0.0	0.0	0.0	0.0
CC#2	106.2	99.0	102.4	101.1	408.8
NGCC	0.0	0.0	0.0	0.0	0.0
CCFB	230.9	179.4	239.3	239.3	888.9
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	435.7	359.1	444.1	449.0	1688.0

** SUMMARY OF YEAR 2012 **

CONFIGURATION SIMULATED 0 1 0 1 0 0 0 2

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	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO.OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FUEL CONSUMPTION FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	49.08	245.07	0.00	0.00	16498.740
4	RF1	0	0.0	1	75.96	115.11	0.00	0.00	5767.350
5	OH4	0	0.0	1	67.02	382.19	0.00	0.00	22087.959
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	0.93	1.74	0.00	0.00	293.582
8	GT10	2	0.0	1	3.41	9.46	0.00	0.00	994.565
9	RF2	0	0.0	1	74.77	113.32	0.00	0.00	5688.600
10	JPPC	0	0.0	2	70.50	370.57	0.00	0.00	49130.977
11	GT6	2	0.0	1	0.35	0.43	0.00	0.00	151.597
12	GT7	2	0.0	1	0.66	0.80	0.00	0.00	193.169
13	GT3	2	0.0	1	2.11	3.96	0.00	0.00	514.255
14	GT8	2	0.0	1	0.48	0.59	0.00	0.00	169.530
15	GT9	2	0.0	1	1.49	2.60	0.00	0.00	387.859
16	JEP	0	0.0	8	40.54	255.69	0.00	0.00	35185.840
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	51.23	292.14	0.00	0.00	18394.668
20	OH1	0	0.0	1	42.21	105.37	0.00	0.00	7656.241
21	OH3	0	0.0	1	65.04	352.09	0.00	0.00	21121.455
22	BOGT	2	0.0	1	5.52	9.62	0.00	0.00	1023.815
23	CCGT	2	0.0	0	0.00	0.00	0.00	0.00	0.000
24	ALCO	0	0.0	1	86.41	37.85	0.00	0.00	2240.403
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	0	0.00	0.00	0.00	0.00	0.000
27	CC#2	2	0.0	1	46.41	467.58	0.00	0.00	29309.371
28	NGCC	3	0.0	0	0.00	0.00	0.00	0.00	0.000
29	CCFB	1	0.0	1	88.24	888.89	0.00	0.00	23415.414
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000
31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	2	86.09	1734.55	0.00	0.00	59327.562
TOTALS						5477.53			299958.531

************************************ THERMAL PLANTS AGGREGATED BY PLANT TYPE ************************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL DOMESTIC (TON)	CONSUMPTION FOREIGN (TON)	GENERATION COSTS (K$)
0	447	57.96	2269.41	0.00	0.00	183772.20
1	115	88.24	888.89	0.00	0.00	23415.41
2	265	21.40	496.77	0.00	0.00	33037.74
3	0	0.00	0.00	0.00	0.00	0.00
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	230	86.09	1734.55	0.00	0.00	59327.56
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2012
SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 0 1 0 1 0 0 0 2

***** EXPECTED GENERATION COSTS (K$) *****

	CAPACITY (MW)	TOTAL COSTS	O&M COSTS	**** F U E L C O S T S **** TOTAL	DOMESTIC	FOREIGN
THERMAL PLANTS						
TYPE 0	449.1	183772.2	99287.3	84484.9	0.0	84484.9
TYPE 1	115.0	23415.4	9644.7	13770.8	0.0	13770.8
TYPE 2	271.0	33037.7	5117.7	27920.0	0.0	27920.0
TYPE 3	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	230.0	59327.6	13139.7	46187.9	0.0	46187.9
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1065.1	299552.9	127189.4	172363.6	0.0	172363.6
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	1082.0	299958.5	127595.0	172363.6	0.0	172363.6

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	1.0
LOSS-OF-LOAD PROBABILITY (%)	0.3555
EXPECTED LOLP (WEIGHED) (%)	0.3555

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2012

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	49.5	69.7	61.8	64.0	245.1
RF1	31.3	34.8	22.7	26.3	115.1
OH4	77.6	107.6	96.6	100.4	382.2
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.4	0.7	0.3	0.4	1.7
GT10	2.1	4.3	1.9	1.1	9.5
RF2	30.8	33.9	22.5	26.1	113.3
JPPC	92.8	104.6	92.3	80.9	370.6
GT6	0.1	0.1	0.1	0.1	0.4
GT7	0.1	0.3	0.2	0.2	0.8
GT3	0.9	1.7	0.6	0.8	4.0
GT8	0.1	0.2	0.1	0.1	0.6
GT9	0.5	1.1	0.5	0.5	2.6
JEP	65.0	77.0	55.6	58.0	255.7
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	58.9	88.0	71.4	73.9	292.1
OH1	30.3	29.7	29.8	15.6	105.4
OH3	71.4	98.7	89.2	92.8	352.1
BOGT	2.2	4.3	1.4	1.7	9.6
CCGT	0.0	0.0	0.0	0.0	0.0
ALCO	9.9	10.3	8.5	9.2	37.8
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	0.0	0.0	0.0	0.0	0.0
CC#2	121.7	107.5	119.8	118.6	467.6
NGCC	0.0	0.0	0.0	0.0	0.0
CCFB	230.9	179.4	239.3	239.3	888.9
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	449.3	362.3	459.5	463.5	1734.5

*** SUMMARY OF YEAR 2013 **

CONFIGURATION SIMULATED 0 1 0 2 0 0 0 2

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	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO.OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	46.25	230.93	0.00	0.00	15631.013
4	RF1	0	0.0	1	68.40	103.65	0.00	0.00	5264.554
5	OH4	0	0.0	1	60.27	343.73	0.00	0.00	20000.139
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	0.24	0.45	0.00	0.00	149.984
8	GT10	2	0.0	1	0.96	2.65	0.00	0.00	351.579
9	RF2	0	0.0	1	67.45	102.21	0.00	0.00	5201.415
10	JPPC	0	0.0	2	60.72	319.14	0.00	0.00	46478.188
11	GT6	2	0.0	1	0.09	0.11	0.00	0.00	113.625
12	GT7	2	0.0	1	0.16	0.20	0.00	0.00	122.991
13	GT3	2	0.0	1	0.57	1.06	0.00	0.00	211.845
14	GT8	2	0.0	1	0.12	0.15	0.00	0.00	117.377
15	GT9	2	0.0	1	0.39	0.68	0.00	0.00	175.614
16	JEP	0	0.0	8	33.86	213.56	0.00	0.00	32655.395
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	44.30	252.62	0.00	0.00	16312.258
20	OH1	0	0.0	1	35.68	89.07	0.00	0.00	6542.088
21	OH3	0	0.0	1	58.58	317.14	0.00	0.00	19427.809
22	BOGT	2	0.0	1	1.65	2.88	0.00	0.00	378.840
23	CCGT	2	0.0	0	0.00	0.00	0.00	0.00	0.000
24	ALCO	0	0.0	1	83.03	36.37	0.00	0.00	2185.640
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	0	0.00	0.00	0.00	0.00	0.000
27	CC#2	2	0.0	1	32.91	331.58	0.00	0.00	21715.557
28	NGCC	3	0.0	0	0.00	0.00	0.00	0.00	0.000
29	CCFB	1	0.0	2	88.03	1773.70	0.00	0.00	46745.582
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000
31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	2	75.34	1518.01	0.00	0.00	52496.836
TOTALS						5727.80			292683.938

************************************ THERMAL PLANTS AGGREGATED BY PLANT TYPE ************************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL DOMESTIC (TON)	CONSUMPTION FOREIGN (TON)	GENERATION COSTS (K$)
0	447	51.29	2008.43	0.00	0.00	169698.50
1	230	88.03	1773.70	0.00	0.00	46745.58
2	265	14.64	339.76	0.00	0.00	23337.41
3	0	0.00	0.00	0.00	0.00	0.00
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	230	75.34	1518.01	0.00	0.00	52496.84
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2013
SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 0 1 0 2 0 0 0 2

***** EXPECTED GENERATION COSTS (K$) *****

	CAPACITY (MW)	TOTAL COSTS	O&M COSTS	**** FUEL COSTS **** TOTAL	DOMESTIC	FOREIGN
THERMAL PLANTS						
TYPE 0	449.1	169698.5	92908.2	76790.3	0.0	76790.3
TYPE 1	230.0	46745.6	19260.7	27484.9	0.0	27484.9
TYPE 2	271.0	23337.4	4196.6	19140.8	0.0	19140.8
TYPE 3	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	230.0	52496.8	11840.4	40656.4	0.0	40656.4
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1180.1	292278.3	128206.0	164072.4	0.0	164072.4
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	1197.0	292683.9	128611.5	164072.4	0.0	164072.4

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	0.2
LOSS-OF-LOAD PROBABILITY (%)	0.0888
EXPECTED LOLP (WEIGHED) (%)	0.0888

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2013

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	61.8	63.0	47.1	59.1	230.9
RF1	24.4	30.3	28.5	20.5	103.7
OH4	91.6	95.8	70.2	86.1	343.7
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.1	0.1	0.1	0.1	0.4
GT10	0.4	1.0	0.8	0.5	2.7
RF2	24.2	29.5	28.2	20.4	102.2
JPPC	71.8	87.0	81.0	79.4	319.1
GT6	0.0	0.0	0.0	0.0	0.1
GT7	0.0	0.1	0.1	0.0	0.2
GT3	0.2	0.4	0.3	0.2	1.1
GT8	0.0	0.0	0.0	0.0	0.1
GT9	0.2	0.2	0.2	0.1	0.7
JEP	51.0	59.1	55.7	47.7	213.6
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	66.6	72.0	51.3	62.7	252.6
OH1	12.1	19.3	29.0	28.7	89.1
OH3	84.4	88.8	64.9	79.0	317.1
BOGT	0.6	1.1	0.8	0.4	2.9
CCGT	0.0	0.0	0.0	0.0	0.0
ALCO	8.9	9.7	9.5	8.2	36.4
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	0.0	0.0	0.0	0.0	0.0
CC#2	77.7	85.4	90.0	78.5	331.6
NGCC	0.0	0.0	0.0	0.0	0.0
CCFB	436.9	382.6	477.6	476.6	1773.7
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	374.0	352.2	402.8	389.0	1518.0

** SUMMARY OF YEAR 2014 ***

CONFIGURATION SIMULATED 0 1 0 2 0 0 0 2

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	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO.OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	47.47	237.05	0.00	0.00	16006.363
4	RF1	0	0.0	1	70.72	107.18	0.00	0.00	5419.398
5	OH4	0	0.0	1	62.86	358.46	0.00	0.00	20799.680
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	0.57	1.07	0.00	0.00	219.470
8	GT10	2	0.0	1	2.08	5.77	0.00	0.00	643.916
9	RF2	0	0.0	1	69.75	105.71	0.00	0.00	5354.909
10	JPPC	0	0.0	2	64.12	337.01	0.00	0.00	47399.895
11	GT6	2	0.0	1	0.23	0.29	0.00	0.00	134.364
12	GT7	2	0.0	1	0.42	0.51	0.00	0.00	158.933
13	GT3	2	0.0	1	1.31	2.45	0.00	0.00	356.401
14	GT8	2	0.0	1	0.32	0.39	0.00	0.00	145.596
15	GT9	2	0.0	1	0.92	1.60	0.00	0.00	277.506
16	JEP	0	0.0	8	36.85	232.44	0.00	0.00	33789.211
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	47.36	270.08	0.00	0.00	17232.191
20	OH1	0	0.0	1	37.81	94.40	0.00	0.00	6902.355
21	OH3	0	0.0	1	61.43	332.56	0.00	0.00	20175.162
22	BOGT	2	0.0	1	3.36	5.86	0.00	0.00	662.432
23	CCGT	2	0.0	0	0.00	0.00	0.00	0.00	0.000
24	ALCO	0	0.0	1	84.05	36.82	0.00	0.00	2202.180
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	0	0.00	0.00	0.00	0.00	0.000
27	CC#2	2	0.0	1	39.63	399.27	0.00	0.00	25494.971
28	NGCC	3	0.0	0	0.00	0.00	0.00	0.00	0.000
29	CCFB	1	0.0	2	88.17	1776.35	0.00	0.00	46800.637
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000
31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	2	79.21	1595.98	0.00	0.00	54956.586
TOTALS						5989.15			305537.750

*********************************** THERMAL PLANTS AGGREGATED BY PLANT TYPE ***********************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
0	447	53.93	2111.70	0.00	0.00	175281.36
1	230	88.17	1776.35	0.00	0.00	46800.63
2	265	17.97	417.20	0.00	0.00	28093.58
3	0	0.00	0.00	0.00	0.00	0.00
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	230	79.21	1595.98	0.00	0.00	54956.59
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2014

SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 0 1 0 2 0 0 0 2

***** EXPECTED GENERATION COSTS (K$) *****

	CAPACITY (MW)	TOTAL COSTS	O&M COSTS	**** F U E L C O S T S **** TOTAL	DOMESTIC	FOREIGN
THERMAL PLANTS						
TYPE 0	449.1	175281.4	95432.2	79849.2	0.0	79849.2
TYPE 1	230.0	46800.6	19279.2	27521.4	0.0	27521.4
TYPE 2	271.0	28093.6	4651.5	23442.1	0.0	23442.1
TYPE 3	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	230.0	54956.6	12308.3	42648.3	0.0	42648.3
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1180.1	305132.2	131671.2	173460.9	0.0	173460.9
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	1197.0	305537.8	132076.8	173460.9	0.0	173460.9

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	0.7
LOSS-OF-LOAD PROBABILITY (%)	0.2342
EXPECTED LOLP (WEIGHED) (%)	0.2342

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2014

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	63.0	65.5	48.5	60.2	237.0
RF1	25.2	31.4	29.4	21.2	107.2
OH4	95.5	99.6	73.2	90.1	358.5
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.2	0.4	0.3	0.2	1.1
GT10	0.8	2.2	1.7	1.1	5.8
RF2	25.0	30.5	29.1	21.1	105.7
JPPC	75.8	91.7	85.6	83.9	337.0
GT6	0.1	0.1	0.1	0.1	0.3
GT7	0.1	0.2	0.1	0.1	0.5
GT3	0.5	0.9	0.7	0.4	2.5
GT8	0.1	0.1	0.1	0.1	0.4
GT9	0.4	0.5	0.4	0.3	1.6
JEP	55.1	65.8	60.6	50.9	232.4
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	70.8	78.2	54.7	66.3	270.1
OH1	13.6	22.0	29.7	29.2	94.4
OH3	88.7	92.4	67.8	83.7	332.6
BOGT	1.2	2.2	1.6	0.9	5.9
CCGT	0.0	0.0	0.0	0.0	0.0
ALCO	9.0	9.9	9.6	8.3	36.8
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	0.0	0.0	0.0	0.0	0.0
CC#2	94.8	98.9	108.9	96.6	399.3
NGCC	0.0	0.0	0.0	0.0	0.0
CCFB	437.5	382.8	478.3	477.8	1776.4
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	393.4	366.7	424.2	411.7	1596.0

*** SUMMARY OF YEAR 2015 **

CONFIGURATION SIMULATED 0 1 1 3 0 0 0 2

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	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO.OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	46.48	232.10	0.00	0.00	15702.483
4	RF1	0	0.0	1	61.02	92.47	0.00	0.00	4773.887
5	OH4	0	0.0	1	54.97	313.49	0.00	0.00	18359.223
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	0.46	0.86	0.00	0.00	194.702
8	GT10	2	0.0	1	1.63	4.54	0.00	0.00	529.281
9	RF2	0	0.0	1	60.38	91.51	0.00	0.00	4731.637
10	JPPC	0	0.0	0	0.00	0.00	0.00	0.00	0.000
11	GT6	2	0.0	1	0.19	0.23	0.00	0.00	128.230
12	GT7	2	0.0	1	0.36	0.44	0.00	0.00	151.024
13	GT3	2	0.0	1	1.01	1.89	0.00	0.00	296.972
14	GT8	2	0.0	1	0.28	0.34	0.00	0.00	139.899
15	GT9	2	0.0	1	0.71	1.24	0.00	0.00	237.704
16	JEP	0	0.0	0	0.00	0.00	0.00	0.00	0.000
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	42.02	239.66	0.00	0.00	15629.196
20	OH1	0	0.0	0	0.00	0.00	0.00	0.00	0.000
21	OH3	0	0.0	1	52.74	285.50	0.00	0.00	17894.781
22	BOGT	2	0.0	1	2.64	4.61	0.00	0.00	540.015
23	CCGT	2	0.0	0	0.00	0.00	0.00	0.00	0.000
24	ALCO	0	0.0	1	82.44	36.11	0.00	0.00	2176.094
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	0	0.00	0.00	0.00	0.00	0.000
27	CC#2	2	0.0	1	25.83	260.20	0.00	0.00	17729.393
28	NGCC	3	0.0	1	51.43	518.14	0.00	0.00	21875.393
29	CCFB	1	0.0	3	87.76	2652.16	0.00	0.00	69943.625
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000
31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	2	71.55	1441.53	0.00	0.00	50084.340
TOTALS						6264.90			241523.469

************************************ THERMAL PLANTS AGGREGATED BY PLANT TYPE ************************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL DOMESTIC (TON)	CONSUMPTION FOREIGN (TON)	GENERATION COSTS (K$)
0	287	51.34	1290.83	0.00	0.00	79267.30
1	345	87.76	2652.16	0.00	0.00	69943.62
2	265	11.82	274.34	0.00	0.00	19947.22
3	115	51.43	518.14	0.00	0.00	21875.39
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	230	71.55	1441.53	0.00	0.00	50084.34
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2015

SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 0 1 1 3 0 0 0 2

	CAPACITY (MW)	***** EXPECTED GENERATION COSTS (K$) ***** TOTAL COSTS	O&M COSTS	**** F U E L C O S T S **** TOTAL	DOMESTIC	FOREIGN
THERMAL PLANTS						
TYPE 0	288.6	79267.3	12243.1	67024.2	0.0	67024.2
TYPE 1	345.0	69943.6	28832.3	41111.3	0.0	41111.3
TYPE 2	271.0	19947.2	3798.1	16149.1	0.0	16149.1
TYPE 3	115.0	21875.4	4475.0	17400.4	0.0	17400.4
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	230.0	50084.3	11381.6	38702.7	0.0	38702.7
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1249.6	241117.9	60730.1	180387.7	0.0	180387.7
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	1266.5	241523.5	61135.7	180387.7	0.0	180387.7

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	0.7
LOSS-OF-LOAD PROBABILITY (%)	0.2059
EXPECTED LOLP (WEIGHED) (%)	0.2059

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2015

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	63.0	62.8	47.2	59.1	232.1
RF1	26.5	26.4	24.0	15.6	92.5
OH4	88.2	87.6	62.5	75.2	313.5
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.3	0.2	0.2	0.1	0.9
GT10	1.5	1.4	1.2	0.5	4.5
RF2	26.3	26.1	23.7	15.4	91.5
JPPC	0.0	0.0	0.0	0.0	0.0
GT6	0.1	0.1	0.1	0.1	0.2
GT7	0.1	0.1	0.1	0.1	0.4
GT3	0.6	0.6	0.5	0.2	1.9
GT8	0.1	0.1	0.1	0.1	0.3
GT9	0.4	0.3	0.3	0.2	1.2
JEP	0.0	0.0	0.0	0.0	0.0
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	65.8	65.4	48.3	60.2	239.7
OH1	0.0	0.0	0.0	0.0	0.0
OH3	80.4	79.6	56.7	68.9	285.5
BOGT	1.5	1.4	1.1	0.5	4.6
CCGT	0.0	0.0	0.0	0.0	0.0
ALCO	9.6	9.6	9.2	7.7	36.1
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	0.0	0.0	0.0	0.0	0.0
CC#2	66.7	65.3	67.2	60.9	260.2
NGCC	127.3	126.0	135.4	129.5	518.1
CCFB	613.1	612.8	714.2	712.1	2652.2
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	347.0	343.6	383.0	367.9	1441.5

*** SUMMARY OF YEAR 2016 **

CONFIGURATION SIMULATED 0 1 1 3 0 0 0 2

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	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO.OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	47.92	239.26	0.00	0.00	16142.481
4	RF1	0	0.0	1	63.59	96.37	0.00	0.00	4945.145
5	OH4	0	0.0	1	58.76	335.07	0.00	0.00	19530.357
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	1.08	2.03	0.00	0.00	324.225
8	GT10	2	0.0	1	3.35	9.29	0.00	0.00	970.340
9	RF2	0	0.0	1	63.10	95.63	0.00	0.00	4912.772
10	JPPC	0	0.0	0	0.00	0.00	0.00	0.00	0.000
11	GT6	2	0.0	1	0.48	0.59	0.00	0.00	170.219
12	GT7	2	0.0	1	0.84	1.02	0.00	0.00	218.540
13	GT3	2	0.0	1	2.25	4.22	0.00	0.00	538.375
14	GT8	2	0.0	1	0.64	0.78	0.00	0.00	192.237
15	GT9	2	0.0	1	1.64	2.87	0.00	0.00	414.574
16	JEP	0	0.0	0	0.00	0.00	0.00	0.00	0.000
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	44.39	253.12	0.00	0.00	16338.610
20	OH1	0	0.0	0	0.00	0.00	0.00	0.00	0.000
21	OH3	0	0.0	1	57.08	309.04	0.00	0.00	19035.391
22	BOGT	2	0.0	1	5.02	8.75	0.00	0.00	932.366
23	CCGT	2	0.0	0	0.00	0.00	0.00	0.00	0.000
24	ALCO	0	0.0	1	83.51	36.58	0.00	0.00	2193.307
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	0	0.00	0.00	0.00	0.00	0.000
27	CC#2	2	0.0	1	31.57	318.04	0.00	0.00	20959.293
28	NGCC	3	0.0	1	55.70	561.17	0.00	0.00	23482.900
29	CCFB	1	0.0	3	88.00	2659.61	0.00	0.00	70098.406
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000
31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	2	76.02	1531.74	0.00	0.00	52929.953
TOTALS						6553.10			254735.094

************************************ THERMAL PLANTS AGGREGATED BY PLANT TYPE ************************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
0	287	54.30	1365.07	0.00	0.00	83098.05
1	345	88.00	2659.61	0.00	0.00	70098.40
2	265	14.97	347.58	0.00	0.00	24720.17
3	115	55.70	561.17	0.00	0.00	23482.90
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	230	76.02	1531.74	0.00	0.00	52929.95
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2016
SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 0 1 1 3 0 0 0 2

***** EXPECTED GENERATION COSTS (K$) *****

	CAPACITY (MW)	TOTAL COSTS	O&M COSTS	**** FUEL COSTS **** TOTAL	DOMESTIC	FOREIGN
THERMAL PLANTS						
TYPE 0	288.6	83098.1	12765.1	70333.0	0.0	70333.0
TYPE 1	345.0	70098.4	28884.5	41213.9	0.0	41213.9
TYPE 2	271.0	24720.2	4222.2	20498.0	0.0	20498.0
TYPE 3	115.0	23482.9	4733.2	18749.7	0.0	18749.7
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	230.0	52930.0	11922.9	41007.1	0.0	41007.1
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1249.6	254329.5	62527.8	191801.7	0.0	191801.7
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	1266.5	254735.1	62933.4	191801.7	0.0	191801.7

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	1.8
LOSS-OF-LOAD PROBABILITY (%)	0.5132
EXPECTED LOLP (WEIGHED) (%)	0.5132

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2016

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	65.4	65.1	48.6	60.2	239.3
RF1	27.5	27.4	25.1	16.4	96.4
OH4	92.6	92.1	67.6	82.7	335.1
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.6	0.6	0.5	0.3	2.0
GT10	3.1	2.9	2.4	1.0	9.3
RF2	27.2	27.1	24.9	16.4	95.6
JPPC	0.0	0.0	0.0	0.0	0.0
GT6	0.2	0.1	0.1	0.1	0.6
GT7	0.3	0.3	0.3	0.2	1.0
GT3	1.4	1.3	1.0	0.6	4.2
GT8	0.2	0.2	0.2	0.2	0.8
GT9	0.9	0.8	0.7	0.5	2.9
JEP	0.0	0.0	0.0	0.0	0.0
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	70.2	69.8	50.9	62.2	253.1
OH1	0.0	0.0	0.0	0.0	0.0
OH3	86.1	85.6	62.3	75.1	309.0
BOGT	2.8	2.6	2.2	1.1	8.7
CCGT	0.0	0.0	0.0	0.0	0.0
ALCO	9.7	9.7	9.4	7.8	36.6
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	0.0	0.0	0.0	0.0	0.0
CC#2	82.3	80.6	82.0	73.2	318.0
NGCC	137.0	135.7	147.0	141.5	561.2
CCFB	614.4	614.2	716.2	714.9	2659.6
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	366.9	364.0	407.3	393.6	1531.7

*** SUMMARY OF YEAR 2017 ***

CONFIGURATION SIMULATED 2 1 1 3 0 0 0 2

****

	PLANT NAME	PLANT TYPE	UNIT CAPACITY (MW)	NO.OF UNITS	CAPACITY FACTOR (%)	ENERGY (GWH)	FUEL CONSUMPTION DOMESTIC (TON)	FOREIGN (TON)	GENERATION COSTS (K$)
1	HROR	10	0.0	1	59.38	87.91	0.00	0.00	405.600
2	HSTO	11	0.0	1	0.00	0.00	0.00	0.00	0.000
3	OH2	0	0.0	1	50.34	251.35	0.00	0.00	16884.422
4	RF1	0	0.0	1	65.85	99.79	0.00	0.00	5095.247
5	OH4	0	0.0	1	61.55	350.99	0.00	0.00	20394.277
6	GT4	2	0.0	0	0.00	0.00	0.00	0.00	0.000
7	GT5	2	0.0	1	0.65	1.21	0.00	0.00	234.262
8	GT10	2	0.0	1	2.11	5.86	0.00	0.00	651.131
9	RF2	0	0.0	1	65.37	99.07	0.00	0.00	5063.438
10	JPPC	0	0.0	0	0.00	0.00	0.00	0.00	0.000
11	GT6	2	0.0	1	0.29	0.35	0.00	0.00	141.891
12	GT7	2	0.0	1	0.49	0.60	0.00	0.00	169.148
13	GT3	2	0.0	1	1.33	2.49	0.00	0.00	359.499
14	GT8	2	0.0	1	0.37	0.45	0.00	0.00	153.280
15	GT9	2	0.0	1	0.98	1.71	0.00	0.00	287.511
16	JEP	0	0.0	0	0.00	0.00	0.00	0.00	0.000
17	JAML	0	0.0	0	0.00	0.00	0.00	0.00	0.000
18	BRLS	0	0.0	0	0.00	0.00	0.00	0.00	0.000
19	HBB6	0	0.0	1	47.47	270.69	0.00	0.00	17264.127
20	OH1	0	0.0	0	0.00	0.00	0.00	0.00	0.000
21	OH3	0	0.0	1	60.40	326.98	0.00	0.00	19904.736
22	BOGT	2	0.0	1	3.25	5.67	0.00	0.00	639.153
23	CCGT	2	0.0	0	0.00	0.00	0.00	0.00	0.000
24	ALCO	0	0.0	1	84.55	37.03	0.00	0.00	2210.294
25	GT05	2	0.0	0	0.00	0.00	0.00	0.00	0.000
26	GTRB	2	0.0	2	6.97	45.78	0.00	0.00	3965.796
27	CC#2	2	0.0	1	38.56	388.42	0.00	0.00	24889.197
28	NGCC	3	0.0	1	60.03	604.70	0.00	0.00	25108.941
29	CCFB	1	0.0	3	88.14	2663.77	0.00	0.00	70184.578
30	ORFS	5	0.0	0	0.00	0.00	0.00	0.00	0.000
31	MSDO	0	0.0	0	0.00	0.00	0.00	0.00	0.000
32	PFSM	4	0.0	0	0.00	0.00	0.00	0.00	0.000
33	NGC2	6	0.0	2	80.13	1614.40	0.00	0.00	55537.234
TOTALS						6859.23			269543.812

************************************ THERMAL PLANTS AGGREGATED BY PLANT TYPE ************************************

PLANT TYPE	TOTAL CAPACITY (MW)	CAPACITY FACTOR (%)	TOTAL ENERGY (GWH)	TOTAL FUEL DOMESTIC (TON)	CONSUMPTION FOREIGN (TON)	GENERATION COSTS (K$)
0	287	57.11	1435.90	0.00	0.00	86816.54
1	345	88.14	2663.77	0.00	0.00	70184.58
2	340	15.19	452.55	0.00	0.00	31490.87
3	115	60.03	604.70	0.00	0.00	25108.94
4	0	0.00	0.00	0.00	0.00	0.00
5	0	0.00	0.00	0.00	0.00	0.00
6	230	80.13	1614.40	0.00	0.00	55537.24
7	0	0.00	0.00	0.00	0.00	0.00
8	0	0.00	0.00	0.00	0.00	0.00
9	0	0.00	0.00	0.00	0.00	0.00

YEAR 2017

SUMMARY OF RESULTS FOR CONFIGURATION SIMULATED 2 1 1 3 0 0 0 2

	CAPACITY (MW)	***** EXPECTED TOTAL COSTS	GENERATION O&M COSTS	COSTS (K$) ***** **** F U E L TOTAL	C O S T S **** DOMESTIC	FOREIGN
THERMAL PLANTS						
TYPE 0	288.6	86816.5	13262.4	73554.1	0.0	73554.1
TYPE 1	345.0	70184.6	28913.6	41271.0	0.0	41271.0
TYPE 2	346.0	31490.9	4990.2	26500.7	0.0	26500.7
TYPE 3	115.0	25108.9	4994.4	20114.5	0.0	20114.5
TYPE 4	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 5	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 6	230.0	55537.2	12418.8	43118.4	0.0	43118.4
TYPE 7	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 8	0.0	0.0	0.0	0.0	0.0	0.0
TYPE 9	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL THERMAL	1324.6	269138.2	64579.4	204558.8	0.0	204558.8
HYDRO PLANTS						
TYPE HROR	16.9		405.6			
TYPE HSTO	0.0		0.0			
TOTAL HYDRO	16.9		405.6			
TOTAL SYSTEM	1341.5	269543.8	64985.0	204558.8	0.0	204558.8

HYDROCONDITION	1
PROBABILITY (%)	100.0
UNSERVED ENERGY (GWH)	1.0
LOSS-OF-LOAD PROBABILITY (%)	0.3036
EXPECTED LOLP (WEIGHED) (%)	0.3036

ENERGY OUTPUT (GWH) BY PLANT FOR YEAR 2017

PLANT	PERIODS: 1	2	3	4	TOTAL
HROR	14.2	25.1	23.1	25.5	87.9
HSTO	0.0	0.0	0.0	0.0	0.0
OH2	69.3	68.9	51.2	62.0	251.4
RF1	28.4	28.3	22.4	20.7	99.8
OH4	96.5	96.1	71.5	87.0	351.0
GT4	0.0	0.0	0.0	0.0	0.0
GT5	0.3	0.3	0.3	0.3	1.2
GT10	1.8	1.7	1.6	0.7	5.9
RF2	28.2	28.1	22.3	20.6	99.1
JPPC	0.0	0.0	0.0	0.0	0.0
GT6	0.1	0.1	0.1	0.1	0.4
GT7	0.2	0.1	0.2	0.1	0.6
GT3	0.7	0.7	0.6	0.5	2.5
GT8	0.1	0.1	0.1	0.1	0.5
GT9	0.5	0.4	0.5	0.4	1.7
JEP	0.0	0.0	0.0	0.0	0.0
JAML	0.0	0.0	0.0	0.0	0.0
BRLS	0.0	0.0	0.0	0.0	0.0
HBB6	75.6	75.0	54.5	65.6	270.7
OH1	0.0	0.0	0.0	0.0	0.0
OH3	90.1	89.6	66.4	80.9	327.0
BOGT	1.7	1.6	1.5	0.8	5.7
CCGT	0.0	0.0	0.0	0.0	0.0
ALCO	9.8	9.8	8.8	8.6	37.0
GT05	0.0	0.0	0.0	0.0	0.0
GTRB	14.3	13.5	12.3	5.7	45.8
CC#2	99.0	97.5	103.8	88.1	388.4
NGCC	147.3	145.9	159.4	152.1	604.7
CCFB	615.0	615.0	717.3	716.4	2663.8
ORFS	0.0	0.0	0.0	0.0	0.0
MSDO	0.0	0.0	0.0	0.0	0.0
PFSM	0.0	0.0	0.0	0.0	0.0
NGC2	384.8	382.3	431.6	415.6	1614.4

11 APPENDIX 3: REVIEW OF JPS PROPOSED LCEP

11.1 DOCUMENT REVIEWED

The document reviewed was titled "JPSCo Least Cost Generation Expansion Plan (2004-2012)" dated February 13, 2004. This report referred to supporting "detailed engineering and planning analyses that are subject to separate documents". The only related separate document obtained was the demand forecast report dated January 2003 and entitled "JPSCo Demand Forecast 2003".

11.2 GENERAL COMMENT

The general approach used by JPS in the preparation of the least cost expansion plan (LCEP) was correct. However, the report submitted lacked sufficient details in many instances and there are inconsistencies in some key areas. The result is that some of the key inputs, and by extension, the final recommendations are questionable.

JPS utilized a low demand forecast on the basis of expected reduced losses and negligible economic growth. Both these assumptions appear incorrect and hence the forecast used for the base case was not adequately justified.

A number of critical developments took place subsequent to the completion of the JPS report. These include significant increases in fuel prices on the world market and an agreement between the Government of Jamaica and the Government of the Republic of Trinidad and Tobago for the supply of liquefied natural gas (LNG) to Jamaica at a price well below the world market price.

Given the above, the JPS proposed plan was considered to be in need of a full update.

In the following sections, comments are made on the specific aspects of the proposed JPS LCEP. To the extent that some of these comments question the approach used by JPS, it is hoped that they will be considered as constructive criticisms to be taken into consideration in the preparation of future least cost expansion plans.

11.3 PLANNING METHODOLOGY

JPS used the WASP III generation planning software as the primary tool for preparation of the LCEP. This software is among the best programs available for this exercise and JPS has a tradition of obtaining reliable projections for capacity requirements and system performance using it. It should be noted, however, that the WASP program results should always be considered in the context of practical constraints relating to factors that cannot be easily simulated. The WASP output should therefore be considered as only the first stage in defining least cost, practical and viable generation system development projects.

11.4 DEMAND FORECAST

GENERAL

As noted by JPS, the demand forecast is a most important determinant of generation expansion requirements. It is therefore important that reasonable care is taken in its preparation. Further, it should be noted that demand for electricity is not necessarily entirely reflected in supply as there tends to be shortfalls in supply from time to time. Net generation output can be used to calculate demand by subtracting system losses from it. However, when the system peak is not being met due to load shedding, net generation less losses ceases to reflect actual demand and appropriate adjustments are required to prevent distortion of projected values.

The dangers of grossly under- or over-estimating future energy and capacity requirements are well known in the power industry. Underestimation of demand can lead to under investment in additional capacity resulting in unreliable supply with the associated adverse economic and social effects. On the other hand, overestimation of demand can result in excessive investments in new capacity which, among other things, will result in higher tariffs being required if the utility is to stay viable.

PEAK DEMAND AND ENERGY FORECAST

JPS indicated in the LCEP report that they were "presenting" a forecast of 3.3% but in fact used a forecast of 3.5% for growth in energy and peak demand. This was against the background that, as noted by JPS:

- Over the last decade, energy and peak output have been growing at approximately 5.0% per annum except for 2001 when reliability and other problems affected supply.
- JPS' most recent demand forecast report (of 2003) suggested continued growth in demand at 4.5% per annum.

The reasons given by JPS for using 3.5% were:

- Less than expected economic growth; and
- Dampening in demand due to success in loss reduction.

In fact, the JPS Low Demand forecast of 3.3% in the 2003 report was based on 0% GDP growth, whereas the base forecast of 4.5% growth in demand assumed GDP growth of 3.0%. GDP has been growing at over 2.5% and economic projections are for this trend to continue. This would make the argument for a forecast closer to the base figure of 4.5% rather than to the low value of 3.3%.

The second reason given by JPS that losses are being reduced is also questionable as the latest reports indicate the opposite trend. Energy losses for the years 2001, 2002 and 2003 were reported to be 16.88%, 17.83% and 18.88% respectively. This indicates fairly significant increases in losses over a three year period.

Given the above, use of the JPS low forecast for their base case plan is inappropriate. Further, having developed what was considered by JPS to be a reasonably good demand forecasting model based on several years of historical data, JPS should have gone back to this model and updated it with the presumed new outlook for the input variables in order to come up with a revised forecast.

SYSTEM LOAD FACTOR

JPS assumed a step change in system load factor going forward. The argument being made is that a structural change in the demand pattern has occurred. In the JPS report, the load factor for 2004 to 2012 based on the energy and peak demands was 73.85%.

It is possible that the structure of the demand is changing and this could affect the load factor. However, the load factor would also appear to be increasing if load shedding occurs during system peak demand hours.

DEMAND FIGURES USED IN WASP SIMULATIONS

Based on the WASP printout included in the JPS report, the actual load factor used was 73.97%. This is inconsistent with the implied figure of 73.85% based on the peak and energy forecast figures given on page 4 of the report. There is therefore an inconsistency between the forecast given in the document and that used in the WASP simulations.

There are other questions relating to the load factor used by JPS. Load factors in the report were as follows:

Period	Load Factor Reported/ Used by JPS
2001 to 2002	71.29%
2003 to 2017	73.97%

No explanation was given for this sudden change in load factor and expected constant value from 2003 to 2017.

The high generation load factor in 2003 may have been due to the fact that JPS was shedding load during peak demand periods. JPS has indeed confirmed that some load shedding had occurred and that a peak in excess of the reported net value of 571.3MW may have occurred.

The growth rates in minimum demand reported in the WASP output in the JPS report also warrant some explanation. The minimum, peak demand and energy growth rates in the JPS report were as follows:

Period	Growth in Minimum Load Reported/Used by JPS	Growth in Peak Load Reported/Used by JPS	Growth in Energy Requirement Reported/Used by JPS
2002	4.8%	4.8%	4.8%
2003	**14.0%**	**1.3%**	**5.1%**
2004-2017	3.5%	3.5%	3.5%

No data was obtained to support the reported sudden jump in minimum load in 2003 and the expected fall back to a constant growth rate of 3.5% for the subsequent years. Further, it appears unusual that while the minimum load was growing at 14% in 2003, the peak load was growing at a mere 1.3% even though both reportedly grew by the same rate of 4.8% in 2002.

ENERGY VALUES USED IN WASP SIMULATIONS

The energy figures forecasted by JPS differed appreciably from those actually used in the WASP simulations. The comparisons are shown below.

Year	Energy Forecast (GWh)	Energy Used in Simulation (GWh)	Difference (GWh)
2004	3825.4	3831.3	5.9
2005	3959.2	3965.5	6.3
2006	4097.8	4104.1	6.3
2007	4241.2	4248.0	6.8
2008	4389.7	4397.0	7.3
2009	4543.3	4550.6	7.3
2010	4702.3	4710.0	7.7
2011	4866.9	4874.6	7.7
2012	5037.3	5045.6	8.3

The differences are not large enough to significantly affect the expansion plan but may indicate a difficulty in simulating the demand curve. If such a difficulty exists, it could lead to the demand forecast being oversimplified in order to facilitate easy simulations in the WASP. This could potentially compromise the integrity of the demand forecasting exercise[2].

[2] A spreadsheet model prepared for the review can be made available to assist JPS with load duration curve simulations in WASP.

11.5 FUEL PRICES

The JPS base fuel prices are reported to be based on "JPS/Mirant market research information". It is therefore reasonable to expect that JPS/Mirant can obtain fuel at the prices indicated, except for LNG for which the information was said to be inadequate.

The base prices used by JPS were as follows:

FUEL TYPE	$/MBTU
LNG	3.9
Coal	1.28
Petcoke	0.57
Orimulsion	1.55
HFO	3.54
ADO	6.55

These figures were assumed to be in effect as at 2002. The assumed price escalation factors were not given in the JPS report but, based on the WASP input file received from JPS these ranged from 1.02 in 2003 to 1.25 in 2017. Identical escalation factors were used for all fuels.

The recommended practice in using WASP is to carefully choose the base prices, initially keep escalation factors at 1.0 and vary these factors afterwards to perform sensitivities on fuel prices. The alternative approach is to forecast real changes in fuel prices and represent these using the escalation factors. The latter approach seemed to have been used by JPS but no basis was given for the price escalation factors used.

The following are issues regarding the fuel prices used by JPS:

- Not enough information was presented to support the base prices and escalation factors used;
- Prices apparently did not take into consideration storage, handling and inland distribution costs that may be applicable to the different fuels.
- Prices for petcoke (and orimulsion to a lesser extent) were low and it was not clear if the requisite costs to mitigate adverse environmental impacts of burning these fuels had been taken into account anywhere in the analyses.
- There were no comments on issues relating to expected security and price volatility associated with each fuel type.
- Recent fuel prices have turned out to be significantly different from the forecasts and the international price outlook has changed significantly.
- Recent developments regarding the availability of LNG at a price significantly lower than that originally assumed by JPS.

Given the critical value of fuel prices in determination of the least cost solution, further analyses of the fuel prices was deemed to be necessary. In addition, due to the recent developments which have significantly changed the outlook for fuel prices, there is an overwhelming argument for the revision of the proposed plan.

11.6 GENERATION EXPANSION PLANNING OPTIONS

Capital costs used by JPS were as follows:

PLANT TYPE	Capital Cost Stated to be Used in JPS Report ($/kW)	Capital Cost Actually Used by JPS ($/kW)
Combined cycle	900	792
Gas Turbine	600	600
Coal fired Steam	1550	1250
Medium Speed Diesel	1000	1400
Low Speed Diesel	1400	Not Considered
Petcoke Fired Steam	Not Given	1693.7
Orimulsion Fired Steam	Not Given	1633.2

Thus there were inconsistencies between the figures presented and those actually used by JPS.

The capital costs used apparently did not take into consideration environmental requirements especially for the coal, orimulsion and petcoke fired plants.

Other plant parameters including heat rates and O&M costs appeared reasonable.

It should be noted that site specific costs were not taken into account by JPS and that these can vary significantly. In particular, if new sites are to be developed users of them would be at a disadvantage compared to users of existing sites. This may have adverse implications for entities other than JPS or the existing independent power producers providing new capacity.

11.7 PRELIMINARY SCREENING

The screening curves prepared by JPS raises a few fundamental questions. Based on the curves presented, natural gas combined cycle would be the cheapest option at all capacity factors below 70%. This is unusual since at low capacity factors one would normally expect low capital cost options such as the simple cycle gas turbine to be least cost.

The petcoke fired plant appears as the least cost option at all capacity factors above 70% and this would imply that petcoke fired plants would be strong competitors for baseload duty. This is not surprising due to the low price of $ 0.57 / mbtu used for this fuel. It is surprising, however, that this technology at the reported prices does not factor in the reported least cost plan and that JPS has not commented explicitly on this.

11.8 THE JPS RECOMMENDED LEAST COST PLAN

JPS recommended natural gas fired combined cycle plants as the least cost option even at the stated price of $3.9 /mbtu. The recommended plant additions were as follows:

- 40 MW stop gap in 2005
- 120 MW NGCC phased over 2006/07 (one GT in 2006 followed by other GT and heat recovery section in 2007)
- 120 MW NGCC similarly phased over 2010/2011

The second best option was coal with an additional cost over the planning period of US$30 Million. This plan comprises:

- 40 MW stop gap in 2005
- 40 MW stop gap in 2006
- 120 MW coal fired steam in 2008
- 120 MW coal fired steam in 2011

Concerns regarding the reported plan are as follows:

- No simulation was presented to demonstrate the NGCC least cost solution as proposed.
- The differences in the overall costs for the two plans as taken from the WASP output provided in the JPS report was US$14.671 M. Phasing the NGCC would add to this difference but it is not likely to result in the difference reaching the US$30 M reported by JPS.
- LOLP limit for 2007 was violated. This is due to the fact that JPS relaxed the LOLP constraint for that year. Enforcement of the LOLP requirement would have resulted in additional capacity being required in 2007.

11.9 RESIMULATION OF THE JPS BASE CASE

Not all the details required to resimulate the JPS analyses were presented in the JPS report. A request was made for the input files and one set was received. The resimulation exercise lead to some concerns regarding how JPS went about producing an optimal plan. The major ones are as follows:

- The LOLP criterion of 2 days per year was not strictly adhered as a standard for all future years. By relaxing it in a critical year, JPS prevented the selection of additional capacity.
- Not all technologies were allowed to be freely selected. This appears to have been the case with Petcoke and may have been a deliberate move by JPS due to uncertainties regarding this fuel. Given that the plants were presented as feasible options, however, they should have been allowed as a choice and then eliminated if there are reasons outside reported costs that justify this.
- The fuel escalation factors can be critical to the least cost option. Justification of escalation factors used should have been presented. It is also not clear if the factors obtained in the WASP data file obtained from JPS were the ones actually used in the determination of the their base case plan.

- The forecasted demand was not accurately modeled due to the apparent difficulties in modeling the load duration curve to obtain the exact load factors. The difference between the JPS desired load factor and what they eventually modeled was, however, not considered significant enough to change the plan.
- Installed capacities of existing hydroelectric plants were understated.

11.10 SENSITIVITIES ON THE JPS RECOMMENDED PLAN

Various sensitivity analyses were performed on the JPS plan starting with the base data used by JPS. The one of major concern was that, with the appropriate LOLP criterion enforced in 2007, an additional 40 MW plant was required. This means that, based on the JPS input data and consistent enforcement of the LOLP criterion, 240 MW of additional capacity would be required by 2008.

It was not clear why JPS relaxed the LOLP constraint in 2007.

11.11 NEED FOR DEVELOPMENT OF NEW PLAN

Based on the review, it was determined that a revised plan was required primarily for the following reasons:

- Planning assumptions and constraints needed to be revised:
    - LOLP criterion should be kept consistent
    - Cost of energy not served used by JPS of $1.5/kwh was determined in 1991 and needed to be updated
- The demand forecast used for the base case appears to be too low and not adequately supported by rigorous analysis.
- Load factor used for the forecast period assumes structural shift in demand and is not supported by any analysis. Load factor actually used in WASP is different from that stated in forecast.
- Fuel price outlook has changed significantly.
    - LNG is now expected to be available in limited quantities at an attractive price.
    - Oil prices have changed dramatically over the last few months and the outlook is now for higher prices.
- Characteristics of some of the technology options need to be investigated further. In particular, Petcoke prices seem attractive but other factors may militate against use of this fuel.
- The constraints applied to the optimization process may have precluded some options that would have been otherwise selected.

12 APPENDIX 4: RESPONSE TO QUESTIONS ON THE LCEP

12.1 QUESTIONS / COMMENTS BY JPS

QUESTIONS / COMMENTS

JPS made the following comments with respect to the LCEP prepared by the OUR:

- *The peak demand used by the OUR for year 2003 is 15 MW higher than the actual for the period, distorting the demand projections and the true capacity requirement. Additionally, the 2004 forecast of 614 MW (Net) as compared to 587 MW (Net) peak to date further magnifies the over forecast.*
- *JPS disagrees with the Office's demand growth forecast of 4.5%. It is believed that this is an overly aggressive forecast given actual rates over the last three years and the year-to-date and the continued dampening effect on demand of high fuel prices over the short to medium term. JPS maintain that a growth rate of 3.5% adequately reflects historical trends and future upside potential.*

JPS believe that the combined effect of these factors could lead the Office to recommend a capacity expansion plan that is excessive, and could result in significant overbuilding which ultimately would not represent the least cost solution for customers.

However, JPS is cognizant of the concern regarding the potential for higher demand growth rates based on projected expansion in the economy. JPS believe that this contingency should be dealt with in the 2005 LCEP by adding an additional 40 MW of capacity in 2008 or even 2007 since the construction period for all feasible technologies for economical capacity of this size will be less than two years. This will allow a decision to be made when more actual information is available regarding JPS' demand growth rate, thereby mitigating the risk of prematurely committing ratepayers to capacity that may not be necessary.

RESPONSE

The JPS comments focus on the demand forecast which they believe is high. Their view is that the base figure for peak demand in 2003 should be 15 MW lower and that the peak demand growth rate should be 3.5% rather than 4.5%. However, they recognize that, based on economic projections, there is a potential for higher growth and propose to address this by "adding an additional 40 MW in 2008 or even 2007".

The demand growth rate suggested by JPS is not supported by thorough analysis. The analysis in section 11.4 should be noted. Further, JPS continues to equate the maximum generation with maximum demand. These can be different when there is load shedding as was the case in 2003.

In addressing the issue of the demand figure used for 2003, it should be noted that the energy consumption used in the report is identical to that reported by JPS for the year. The energy consumption for 2003 used in the report was 3696.0 GWh which is identical to what was reported by JPS. However, the energy demand used by JPS for 2003 was higher at 3701.8 GWh (even though 3696 GWh is quoted on page 4 of their report).

The difference between the peak demands for 2003 resulted because:

- JPS assumed that actual peak generation was the peak demand (despite loadshedding) and that the reason for the high energy demand and relatively low peak was a step change in load factor from 71.29% to 73.97% due to a 14% growth in the minimum load and a 1.3% growth in the peak load during the same year. No explanation was given for these unusual figures.
- In the plan prepared by the Office, the more reasonable assumption is made that the peak demand grew at a similar rate to the energy demand (consistent with historical trends), there was no major change in the load factor and that the reason for the low peak generation was load shedding resulting in actual peak demand not being met. As a result, the deemed peak demand used for 2003 was higher than that reported by JPS.

It should be noted that even at a peak demand growth rate of 3.5%, approximately 200MW of additional plant capacity will still be required between 2005 and 2008 in order to prevent excessive power cuts (which are already occurring in 2004). There is therefore no disagreement over the fact that urgent measures need to be taken to address the short / medium term capacity requirements.

12.2 QUESTIONS / COMMENTS BY OTHER PARTIES

QUESTION / COMMENT ON LNG

The report assumes that LNG will be available from Trinidad in 2007 and delivered to the point of usage at a price within the range US$3.2 to $3.8 /Mbtu. It has been indicated that Jamaica will have to fund 40% of the costs of the receiving terminal and re-gassing facilities. How will this investment be amortized if not from the price of fuel? If from the price of fuel, is that cost reflected in the indicated price of gas to the power stations?

Reportedly Jamaica will be supplied with one million tons of gas per annum. The only significant users identified are JPS and Jamalco. Rough calculations indicate that if all JPS steam units and gas turbines at Hunts Bay were to be converted to burn gas then the JPS demand for gas would be about 600 thousand short tons (2,000 pounds each) per annum. Since the report is based on gas priced within the raneg $3.20 to $3.80 /Mbtu, then it ought properly to evaluate the economic feasibility of retiring all steam plant and replacing them with combined cycle plant (CCGT) located in the vicinity of Old Harbour as soon as can be realistically achieved. The greater efficiency of the CCGT would allow about twice as much electricity to be generated with the tonnage of gas allocated to JPS and would obviate the need for a gas pipeline from Port Esquivel to Hunts Bay.

An important statement is made in Section 2.10 of the document, seventh bullet point from the beginning of the section. There is stated:

"Only one combined cycle plant using T&T gas would be required in 2007, raising issues regarding the take-up of this gas and a possible increase in the average costs".

This is a fundamental issue in the development of the plan and needs to be addressed more fully than, has been done.

The report assumes LNG will be available in Jamaica in 2007. This seems very optimistic.

What data source provides the basis for the estimate that LNG from non-Trinidadian sources will cost US$4.3/ Mbtu? That figure is well below the estimates seen from sources such as the IEA and the US Department of Energy.

RESPONSE

The price assumed for LNG includes all costs involved in delivering the fuel to the plant site, including amortization of investments in the proposed receiving terminal and re-gasification facilities.

The base plan calls for installation of two combined cycle plants (constructed in stages) using LNG by 2007/08. A review of the retirement schedule for the existing older units is to be undertaken in more detail over the next few months.

LNG is expected to be available by 2007/08. However, if LNG is not available as planned then the combined cycle plants would be run on No.2 distillate until LNG is made available.

The GOJ negotiating team is of the view that prices for LNG similar to those expected from Trinidad are possible from other sources but with added transportation costs. The figure used represents a fairly conservative estimate based on these assumptions and projections for prices of LNG expected to be imported into the US.

QUESTION / COMMENT ON JEP EXPANSION IN 2005

The report states that the additional 48 MW of diesel generation being planned for 2005 will not ensure that agreed supply reliability criteria would be maintained. Shouldn't the OUR then require a larger block of generation to be acquired? It is to be remembered that a multi-unit diesel plant operating below its rated aggregated capacity does not provide the same degree of spinning reserve as would be available from a single-unit generator of the same rating.

The proposed extension of the existing JEP contract for a further 10 years at a 20% reduction in the available capacity does not, on superficial examination, appear to be attractive. In 2005 the existing plant will have completed half its contract period. Extending the service for a further ten years using the same equipment would appear to merit a more significant price reduction than is currently being proposed, even allowing for additional capacity to be installed. Will the contract period for the new capacity be ten years? What also needs to be addressed is the non-fuel variable charge imposed by JEP for energy supplies. The current contract was negotiated at a time when JPS was in an extremely weak negotiating position. My recollection is that the JEP non-fuel variable operating charge is currently about 2.0 US cents per kilowatt-hour. In the late 1990s Wartsila signed similar contracts (e.g. Tsavo in Kenya) in which that parameter was priced at less than 1 USc per kWh. The last sentence of Section 2.10 to the effect that further cost reductions in the prices being proposed by JEP ought to be negotiated is strongly supported.

RESPONSE

The comments are reasonable and consistent with the recommendations of this report.

QUESTION / COMMENT ON JAMALCO AND PETCOKE

It is known that the government is pursuing discussions with Jamalco for that alumina refinery to become an important generation source for the JPS system. Discussions are also being conducted with interested parties for upgrading the Petrojam refinery. The proposed upgrade involves a generating plant using petcoke as fuel and supplying power to the grid. Shouldn't the report include these possible generation sources in its evaluation of generation alternatives?

RESPONSE

At the time of preparation of the report sufficient information was not available on the options mentioned for meaningful analyses. However, the base case plan sets the benchmark capacity size and duty requirements and so any facility meeting the criteria at least cost should be selected.

QUESTION / COMMENT ON EFFECT OF LOSS REDUCTION

It is possible that the effect of loss reduction on the system demand is being over-estimated. The most likely area of loss reduction will be the non-technical. Non-technical losses represent energy that is being consumed but not being paid for. If the extent of losses is reduced, there will be some reduction in consumption, but that amount will be less than the total reduction experienced. Even technical loss reduction will not reduce system demand to the full extent. Reducing technical losses will have the effect of increasing voltage at the consumer supply points and therefore result in some increase in consumption at the same level of use of appliances and other consuming devices. The net effect of successful loss reduction will therefore be reflected more in increased revenues than in reduction in system demand.

RESPONSE

The point is well taken with respect to non-technical losses and in fact in the demand forecast, an assumption was made that 50% of the non-technical loss reduction would be converted to additional sales. Regarding technical losses, however, it was assumed that any reduction in this area results in a direct reduction in generation requirements. The assumption is that efforts will be made to maintain supply voltage levels regardless of the level of technical losses. Conservative loss reduction expectations were included in the demand forecast as follows:

- Total losses as % of net generation would gradually reduce from 18.85% in 2004 to 16.86% in 2017 due to the fact that:
  - Unbilled sales as a % of Sales would reduce from 11.08% in 2004 to 9.72% in 2017.
  - Technical losses as % of energy delivered would reduce from 10.89% in 2004 to 9.56% in 2017.

QUESTION / COMMENT ON SYSTEM LOAD FACTOR

The plan is based on an increasing average system load factor (Section 3.1). Although the annual statistical data may appear to support this position the report itself comments that the annual data may distort the true picture since load shedding will have the effect of making the load factor appear to be higher than it is in reality. In my opinion, if one were to look at daily system demand curves developed for a typical day on which there was no load shedding, the curves would appear to be getting increasingly peaky, that is, demand is growing faster than energy consumption. This fact is also supported, I believe, *by the statistics that show that residential consumption is growing faster than the other major tariff categories.*

RESPONSE

The projected system load factor is based on a rigorous demand analysis based on latest available load research data and regression models. More current load research data would improve the confidence in the projected load factors. Further, the projected increases in load factor are in line with historical trends and the figures are significantly below the values assumed by JPS.

JPS should be encouraged to make every effort to resuscitate the load research program in order to reduce the subjectivity used by them in determining load factors.

QUESTION / COMMENT ON DISCOUNT RATE

The discount rate used for investment planning ought to be higher than the target rate of return on capital invested.

RESPONSE

Using a higher discount rate would distort the plan in favour of less capital intensive plants.

QUESTION / COMMENT ON CAPITAL COST OF MEDIUM SPEED DIESEL

The estimate of $1,588 per kW for investment costs in a medium speed diesel (Exhibit 7.1) needs to be revisited.

RESPONSE

The capital costs used in the simulations done by JPS were not changed for the base case as JPS had indicated that these costs were based on market research by themselves and Mirant. The cost also includes interest during construction. If the implicit interest during construction is removed, the base capital cost assumed by JPS works out to be $1,400/kW. This is 3.6% higher than the reported $1,351/kW ($100M for 74 MW) paid for the existing JEP medium speed diesel plant in 1995.

13 APPENDIX 5: RE-EVALUATION OF THE JEP PROPOSAL

Subsequent to the initial preliminary evaluation of the JEP proposal, more detailed information pertaining to the proposal has been received. WASP simulation of the JEP proposal with the additional information has been conducted and the results have indicated that the additional cost of the proposal has moved from the US $54 Million, as reported in section 2.10, to US$19 Million.

It should be pointed out that the main difference in the preliminary assessment and the later is that, for the later there is a 28.54% discount on the fixed price (currently at $23/kW/mth) for the total capacity being provided, where as, for the preliminary assessment a 20% discount was used.