Generation Expansion Plan

2010

OFFICE OF UTILITIES REGULATION

Prepared by: OUR
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EXECUTIVE SUMMARY

Amidst the recent down turn in the global economy to which Jamaica, a small developing economy, was not immune, indications are that electricity demand in the country is increasing, despite energy savings measures that have been implemented and efficiency improvement programs that are being promoted.

At the same time, the electricity generation infrastructure is aging resulting in a number of power plants becoming candidates for displacement by more efficient and economic ones while others have already exceeded their useful economic life. Unless new generation capacity is introduced to cover the emerging gap between electricity demand and supply, the Jamaican electricity sector will be under severe pressure in the coming years, with unfavourable consequences for the overall economy.

Planning for new power generation facilities has traditionally been carried out largely on the basis of economic criteria, with primary focus on the minimization of both the capital investment and operational costs. However, the choice of technologies for these new facilities not only influences the required capital investment, but also significantly impacts the energy policy objectives of the country namely, maintaining a secure energy supply, encouraging competition in the sector and protection of the environment.

It should be emphasized that the expansion of the electricity generation system not only provides a basis for reducing generation cost, but also provides an opportunity for improving efficiency and reducing emission of green house gases (GHG) in the power sector. In this regard, a careful and comprehensive strategy for the expansion of the system is required, since choices for the future technology and fuel mix will impact the sector in the long term, thereby impacting the objectives of achieving a modern, secure and sustainable energy system in the country.

Regarding the future fuel mix, most energy outlooks have indicated that the penetration of Renewables will increase, however, they are not likely to dominate the electricity generation sector before 2030.

This study attempts to assess the present status of Jamaica's electricity generation system, evaluate available alternatives and identify the new generation capacity requirements of the system up to 2029.

Through the application of the least cost expansion planning approaches, the technology and fuel mix of power plants emerging from the various expansion scenarios were carefully analysed and presented.

Objective

The generation expansion plan is largely influenced by the need for new and more efficient generating capacity to reliably meet system demand at least economic cost. The plan is also an integral part of an overall strategy to reduce energy cost and Jamaica's dependence on imported liquid based fossil fuels. As such the plan aims to support the implementation of the National Energy Policy 2009 - 2030, focusing on: (1) increasing the contribution of renewable energy (wind, solar, hydro and biomass) in electricity generation; (2) effecting fuel diversification through the development of the natural gas industry. According to the policy, it is expected that by 2030 Jamaica will achieve:

A modern, efficient, diversified and environmentally sustainable energy sector providing affordable and accessible energy supplies with long-term energy security and supported by informed public behaviour on energy issues and an appropriate policy, regulatory and institutional framework.

Sector Regulation

The Office of Utilities Regulation is a multi-sector regulatory agency which was established in 1995 by the Office of Utilities Regulation Act (as amended in 2000) from which it derives its mandate.

Section 4 (1) of the OUR Act sets out the functions of the Office; Section 4 (3) provides for the Office, in the performance of its functions under the Act to

"Undertake such measures as it considers necessary or desirable to:

(a) encourage competition in the provision of prescribed utility services;
(b) protect the interests of consumers in relation to the supply of a prescribed utility service;
(c) encourage the development and use of indigenous resources;
(d) promote and encourage the development of modern and efficient utility services; and
(e) enquire into the nature and extent of the prescribed utility services provided by a licensee or specified organization".

Schedule 1 of the Act defines Prescribed Utility Services (and therefore the services over which the OUR has regulatory responsibility) as:

1. The provision of telecommunications services;
2. The provision of public passenger transportation by road, rail or ferry;
3. The provision of sewerage services;

4. The generation, transmission, distribution and supply of electricity; and
5. The supply or distribution of water.

Sector specific legislation such as the All-Island Electric Licence 2001 granted to Jamaica Public Service Company Limited (JPS) sets out specific provisions, consistent with the principles elaborated in the OUR Act, as to the Office's functions in the particular sector and/or its relationship to the service provider. The management and administration of the procurement process for new generating plant capacity as well as the preparation of the Least Cost Expansion Plan (LCEP) was transferred to the OUR by means of an agreement in 2007 between the Government of Jamaica (GOJ) and Marubeni Corporation acting through its affiliate Marubeni Caribbean Power Holding Inc. (Marubeni), consequent on the sale of Mirant Corporations' shares in JPS to Marubeni.

Regulatory Policy for the Electricity Sector entitled "**Guidelines for the Addition of Generating Capacity to the Public Electricity Supply System"** was established by the OUR in 2006. The policy outlines the procedures for the addition of new generating capacity to the electric power grid.

Electricity Sector

Pursuant to Condition 2, of the All-Island Electric Licence, 2001, JPS has the exclusive rights to transmit, distribute and supply electricity for public and private purposes in all parts of the island. At the end of 2009, JPS had a customer base of 584,623 including residential, commercial and industrial consumers. The gross peak demand to date is 644 MW and the average system load factor is approximately 74%. There is a number of self-producers of electricity in the country, with the largest being the bauxite alumina companies and the sugar refineries.

JPS was privatised by the GOJ in 2001 at which time 80% of the common equity was sold to Mirant JPSCo (Barbados) SKL (Mirant), an energy company having its principal office in Georgia, United States of America. The GOJ retained a 20% shareholding in JPS. On August 9, 2007 Marubeni Caribbean Power Holdings, Inc., a wholly owned subsidiary of Marubeni Corporation of Japan, purchased Mirant's majority shares in JPS. On March 4, 2009 Marubeni transferred 50% of its shares in Marubeni Caribbean Power Holdings Inc. to Abu Dhabi National Energy Company (TAQA) of the United Arab Emirates.

JPS presently owns and operates eighteen (18) thermal power generating units located at four (4) Sites (Rockfort, Hunts Bay, Bogue and Old Harbour) and seven (7) hydro plants independently sited across the island. These JPS plants accounts for a total installed capacity of approximately 616.5 MW. Independent Power Producers (IPPs) presently supply approximately 190 MW of firm capacity to grid under long-term contracts with JPS. A wind power facility (IPP) with an installed capacity of 20.7 MW also supplies electrical energy to the grid under contract (energy-only).

On an operational basis, the total available generating capacity supplying the JPS grid is approximately 767 MW (the amount does not include Old Harbour unit 1 (30MW), Bogue GT6 (18MW) – which are presently out of service due to major equipment failure since 2008).

The existing oil-fired steam plants have aged considerably. Over the years a number of turbines and boilers have been refurbished. However, the average age of the steam plants is 37 years. At Old Harbour the four steam units are over 35 years old, despite their rehabilitation over the years, their operating parameters at present indicate that all these units have surpassed their useful economic life.

JPS has an extensive transmission and distribution system which covers the length and breadth of Jamaica. The transmission system includes approximately 400 km of 138 kV lines and nearly 800 km of 69 kV lines. The system consists of twelve (12) 138/69 kV inter-bus transformers with a total capacity of 798 MVA and fifty three (53) 69 kV transformers (total capacity of 1026 MVA) which supplies the primary distribution system at 24 kV, 13.8 kV and 12 kV.

The coverage of the overall electricity infrastructure results in over 95% electrification of the country.

Total system losses inclusive of technical and non-technical in 2009 averaged 23%.

Demand Forecast

Under the base demand forecast, peak demand, which is the main driver for new generating capacity, is projected to grow at an average rate of 3.8% per annum over the twenty year (20) year planning horizon (2010 to 2029). Net peak demand expected for 2010 is 625.8 MW with the peak occurring during the summer period.

A gross system peak of 627.5 MW has been achieved year-to-date.

Net generation for 2010 is forecasted at 4,253.8 GWh. According to the forecast this is projected to grow at an average rate of 4.0 % per annum over the period 2010 to 2029.

It should also be noted that based on the expected growth in system demand (MW), forced outage rates and maintenance schedule of the existing generating units, there may be critical periods between 2010 and 2013 where the system's reliability is compromised.

Planning Parameters and Procedure

New generating capacity required for the Electricity generation system is generally determined on the basis of an LCEP. This plan essentially seeks to identify the resource requirements and the approximate timing of these requirements to assure a defined level of reliability of power supply to the consumer at the lowest economic cost. Due to the high capital cost and long lead time required for generation expansions, the plan must be prepared years ahead of the implementation deadline. Normally, expansion plans encompass periods of twenty (20) years or more, of which the investments for the first five (5) to seven (7) years are firm and projects identified for later periods will be subject to regular reviews to reflect the effects of changing relevant conditions.

Wien Automatic System Planning Package (WASP) was the primary simulation tool used for evaluating the alternatives.

Implementation of the generation expansion plan requires rigorous analysis of the transmission system in order to determine how the system can be modified or expanded and optimised to accommodate the addition of new generating capacity as dictated by demand growth requirements, and importantly, to determine the appropriate location on the network for siting the new generating plants.

A maximum Loss of Load Probability (LOLP) of two (2) days per year (0.55%), which equates to 48 hours per annum, was used as the reliability constraint. This condition provides the grid operator with the allowance to take out a single large unit (68 MW) for planned maintenance and have a fault outage on another and still maintain adequate supply to customers.

The cost of Unserved Energy used in the study was US$2.32/kWh. This reflects the average cost to the economy for energy not delivered.

In summary, this report documents the investigations carried out by the OUR in determining the optimal generation expansion solution which identifies the schedule of capacity additions required to satisfy the projected electricity demand with a certain margin of reserve while respecting the reliability criteria (LOLP) over the planning period.

Comparison of various scenarios and sensitivity analysis were also conducted.

Constraints

Combined generation/transmission system analysis is important in understanding the technical constraints that will impact the planning, design and operation of the system. The system analysis requires the execution of several interrelated studies covering generating capacity requirement, load flows, fault analysis, system stability, etc., in order to determine the siting of new generating capacity, transmission line requirements, voltage levels, circuit breaker ratings and protection system settings.

Load flow analysis based on system data will identify the expansion required in the transmission system, duly taking into account the load location and the siting of new generating stations. Load flows must be determined for several operating conditions, including power plant outages.

Short-circuit analysis will determine whether higher voltage levels are required at certain points in the system. In addition to steady state studies, analysis of the transient stability of the system is also necessary. The system must be examined for all possible sources of electrical disturbance to ensure that synchronization is maintained with large plants connected to it. In particular, the system must be stable in the event of loss of the largest plant or unit when operating at full power, with due regard to system configuration and characteristics of the components.

A major constraining factor associated with these analyses is the level of coordination required to ensure that the system is properly optimised.

Although operating characteristics play an important role in the planning process, equally important are factors not related to plant/system operating characteristics, for example, siting constraints, environmental constraints, public safety, social impact, financial constraints and licensing considerations, industrial capability and manpower requirements which cannot be ignored.

Technology and Fuel Options

There are several generation technology options available that were considered for the expansion of the electricity generation system. These options include:

- Gas turbines: open-cycle and combined-cycle variants running on Natural Gas or Automotive Diesel Oil (ADO).

- Diesel engines: medium-speed and low-speed units running on Heavy Fuel Oil or Natural Gas

- Conventional steam units: powered by coal with electrostatic precipitators, Flue Gas Desulphurization and Selective Catalytic Recovery Controls.

Table 1: Generation Technology and Fuel options for System Expansion

Technology	Fuel			
	NG	ADO	HFO	COAL
Combined Cycle	y	y		
Combustion Turbine	y	y		
Medium Speed Diesel	y		y	
Slow Speed Diesel	y		y	
Steam				y

Trajectory of Jamaica's Electricity System

Three main expansion strategies were contemplated in defining the trajectory of Jamaica's electricity system over the 20 years planning horizon. These are as follows:

- Natural Gas strategy
- Coal/ Natural Gas strategy
- Business-as-usual strategy

Note: a number of sensitivities was developed based on these cases.

Natural Gas-based strategy

Under this strategy, the trajectory of the electric generating system was established by developing the optimum generation expansion plan respecting certain technical and economic constraints. The optimum expansion plan for the system, identified using the WASP model, is shown in Table 2.

Table 2: Optimum Generation Expansion Plan under the Natural Gas-only Strategy

Year	Plant Type to be added to the System	No. of units x Capacity (MW)
2014	Natural Gas-fired Combined Cycle Gas Turbine unit	3 x 120
2016	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120
2017	Natural Gas-fired Simple Cycle Gas Turbine unit	1 x 40
2018	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120
2019	Natural Gas-fired Simple Cycle Gas Turbine unit	1 x 40
2020	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120
2022	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120
2024	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120
2025	Natural Gas-fired Simple Cycle Gas Turbine unit	1 x 40
2026	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120
2028	Natural Gas-fired Simple Cycle Gas Turbine unit	1 x 40
2029	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120

As shown in Table 2, Combined Cycle Gas Turbine technology accounts for the majority of the capacity requirements over the period 2014 – 2029.

Overall, the total capacity that will be required by 2029 to both meet the increasing demand for electricity and displace aged existing plants is estimated at 1360 MW with a total cost of approximately US$ 5.77 Billion.

Natural Gas/Coal Strategy

Under the hybrid (Natural Gas/Coal) strategy, the trajectory of the electric generating system was established by developing the optimum generation expansion plan respecting certain technical and economic constraints. The optimum expansion plan for the system, identified using the WASP model, is shown in Table 3.

Table 3: Optimum Generation Expansion Plan under a Natural Gas/Coal Strategy

Year	Plant Type to be added to the System	No. of units x Capacity (MW)
2014	Natural Gas-fired Combined Cycle unit	3 x 120
2016	Coal unit	1 x 120
2017	Natural Gas-fired Simple Cycle Gas Turbine unit	1 x 40
2018	Coal unit	1 x 120
2020	Coal unit	1 x 120
2021	Coal unit	1 x 120
2023	Coal unit	1 x 120
2025	Coal unit	1 x 120
2026	Coal unit	1 x 120
2028	Coal unit	1 x 120

As shown in Table 3, Pulverized Coal technology accounts for the majority of the capacity requirements over the period 2014 – 2029.

Overall, the total capacity that will be required by 2029 to both meet the increasing demand for electricity and displace aged existing plants is estimated at 1360 MW (gross), with a total cost of approximately US$5.85 Billion.

Business-as- usual Case

Under this strategy, the trajectory of the electric generating system was established by developing the optimum generation expansion plan respecting certain technical and economic constraints. The optimum expansion plan for the system, identified using the WASP model, is shown in Table 4.

Table 3: Optimum Generation Expansion Plan (Business-as-usual Case– HFO & ADO)

Year	Plant Type to be added to the System	No. of units x Capacity (MW)
2014	Slow Speed Diesel (SSD) plant	5 x 60
2015	Slow Speed Diesel plant	1 x 60
2016	Slow Speed Diesel plant	1 x 60
2018	Slow Speed Diesel plant	2 x 60
2019	Slow Speed Diesel plant	1 x 60
2020	Slow Speed Diesel plant	1 x 60
2021	Slow Speed Diesel plant	1 x 60
2022	Oil-fired Combustion Turbine	1 x 40
2023	Slow Speed Diesel plant	1 x 60
2024	Slow Speed Diesel plant	1 x 60
2025	Oil-fired Combustion Turbine unit	1 x 40
2026	One Oil-fired Combined Cycle unit; one SSD	1 x 120; 1 x 60
2027	Slow Speed Diesel plant	1 x 60
2028	Slow Speed Diesel plant	1 x 60
2029	Slow Speed Diesel plant	1 x 60

Overall, the total capacity that will be required by 2029 to both meet the increasing demand for electricity and displace aged existing plants is estimated at 1280 MW with a total cost of approximately US$ 8.18 Billion.

Conclusion

- New baseload capacity is urgently required in the system, but given the expected constraints regarding construction time and/or fuel availability, it is unlikely that such capacity can be in place before 2014.

- This study recommends the commissioning 360 MW (3x120MW) of Natural Gas-fired combined cycle capacity in 2014. Of this amount, 292 MW will be for displacement of aged, inefficient capacity and the remainder for demand growth requirements.

- Over the next 20 years, approximately 1400 MW of new fossil fuel power plant capacity will have to be constructed in Jamaica, to meet the projected demand for electricity and to displace aged power plants, depending on the penetration of Renewables and possibly nuclear power. Approximately 800 MW of this new capacity needs to be constructed in the coming decade, highlighting the urgency of the issue. The capital requirements for the new power plant fleet are in the range of US$ 6.0 to 8 billion depending on the mix of technologies that will be deployed.

- The most critical variable in determining the type of plants to be installed in the short to medium term relates to the availability of natural gas in terms of: price, quantity; and timing.

- The business-as-usual strategy demonstrates that the continued proliferation of petroleum based fuels is not sustainable and unresponsive to the national energy policy objectives.

- The fuel diversification objective was not sufficiently achieved under the Natural Gas (only) expansion strategy.

- The penetration of Renewable energy-based generation has not been significant on the basis that these resources currently cannot significantly substitute for baseload generation from fossil fuels. Nonetheless the energy contribution from the existing and proposed projects has been incorporated in the expansion and is reflected in the overall future annual generation of the system.

These conclusions do not in any way prejudice the country's commitment to the utilization of any one fuel type for the expansion of the electricity generation system and by extension the energy sector. Strictly, from a planning perspective, the conclusions rather reflect the results of the various expansion alternatives that were investigated subject to the assumptions made.

It is worth noting that new generation capacity is an important component of meeting increasing energy demand, but it is not the only option. Incremental electricity needs can also be met through a mix of sources including new generation units, improved energy efficiency in end-use as well as in generation and transmission. Investments in transmission systems and better control and management of demand are thus important alternatives to new generation resources. All alternatives need to be evaluated to ensure the best options are pursued.

While the LCEP analyses are useful in establishing the trajectory of the electricity generation system and energy policy objectives, they need to be complemented by other forms of analysis to ensure that the energy system is appropriately optimised.

In summary, this report focuses on the capacity requirements, generation costs, sensitivity analyses around the optimal generation expansion strategy, and the security and sustainability of Jamaica's electricity system over the medium to long term. Importantly, the results are essential for new generation capacity investment decisions and thus, provide useful information to the market place. However, given the uncertainties and risks that may be involved, investment decisions related to new power plant projects must be carefully evaluated and analysed.

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LIST OF ACRONYMNS AND ABBREVIATIONS

ADO	Automotive Diesel Oil
AEO	Annual Energy Outlook (United States, Department of Energy, EIA)
BTU	British Thermal Unit
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat & Power
CNG	Compressed Natural Gas
COUE	Cost of Energy not Served
EIA	Energy Information Administration (United States)
EFOR	Equivalent Forced Outage Rate
EUE	Expected Unserved Energy
FGD	Flue Gas Desulphurization
FOB	Free On Board
FOR	Forced Outage Rate
GWh	Gigawatt-hour
GOJ	Government of Jamaica
GT	Gas Turbine
HAWT	Horizontal Axis Wind Turbine
HB	Hunts Bay
HFO	Heavy Fuel Oil
IAEA	International Atomic Energy Agency
IDC	Interests During Construction
IPP	Independent Power Producer
JEP	Jamaica Energy Partners
JPPC	Jamaica Private Power Company
JPS	Jamaica Public Service Company Limited
LCEP	Least Cost Expansion Plan
LDC	Load Duration Curve
LNG	Liquid Natural Gas
LOLP	Loss of Load Probability
LU	Large Unit
MMBtu	Million British Thermal Unit
MCR	Maximum Continuous Rating
MSD	Medium Speed Diesel
MT	Metric Ton
MWh	Megawatt-hour
NEPA	National Environmental and Planning Agency
NG	Natural Gas
NGCC	Natural Gas-fired Combined Cycle
OEM	Original Equipment Manufacturer
OFCC	Oil Fired Combined Cycle

OH	Old Harbour
OUR	Office of Utility Regulation
PetroJam	PetroJam Refinery
PPA	Purchase Power Agreement
RET	Renewable Energy Technology
RF	Rockfort
RM	Reserve Margin
SCR	Selective Catalytic Recovery
SSD	Slow Speed Diesel
WASP	Wien Automatic System Planning Package
WWFL	Wigton Wind Farm Limited

1 INTRODCTION

1.1 Background

The purpose of a power generation system is to satisfy electricity demand with an adequate and acceptable level of service at best cost. Electricity is mainly generated from a mix of thermal and hydro power plants and other facilities such as wind farms and photovoltaic systems. New electricity generation capacity has to be constructed when a gap between supply and demand is anticipated, caused by the retirement of old plants and/or by the increasing electricity demand beyond the level that can be met by the existing operational capacity.

In Jamaica, the planning for new electricity generation infrastructure has traditionally been performed on the basis of economics that is the minimization of the lifetime cost of the plant comprising the capital investment cost and operating costs. However, the choice of technologies to fill the gap between the existing and required electricity generation capacity not only affects the magnitude of the required capital investment, but greatly impacts, among other things on:

- the generating cost of electricity, which in turn impacts on the quality of life of the Jamaican citizen and on the competitiveness of the Jamaican economy at large;

- the consumption of primary energy resources, with an accompanying effect on the security of energy supply; and

- the emission of greenhouse gases (GHG) from the power sector.

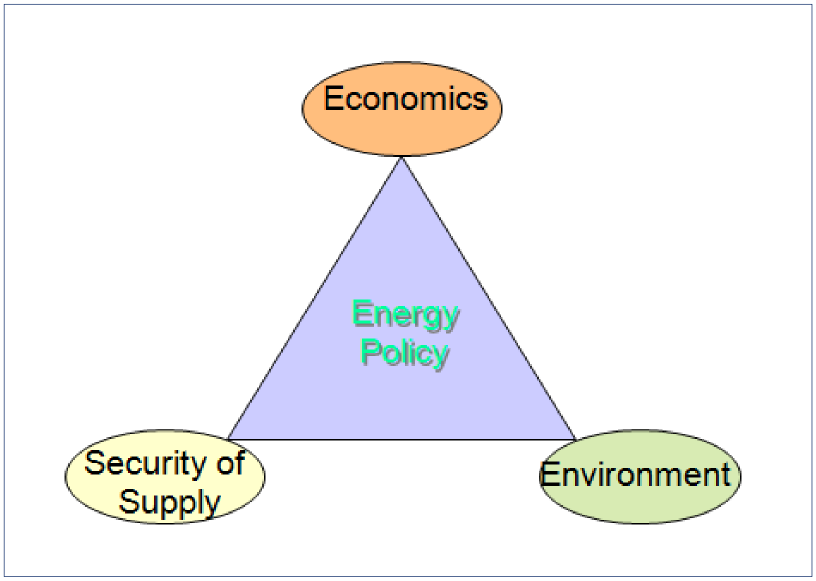
In steering Jamaica along a more sustainable path, these three issues will have to be the main drivers of the National Energy Policy, which will in turn influence the long-term generation expansion planning process.

In this regard, the planning for the expansion of the electricity generation capacity should not be considered as an isolated issue that only concerns the electricity sector but should rather be treated as a key component in the formulation of an overall sustainable energy strategy for the country.

The dimensions of a sustainable energy system are illustrated in Figure 1.1-1. All three pillars are integral to the energy sector and should therefore influence any power generation expansion strategy.

In this context, it can be deduced that the continuous utilization of liquid-based fossil fuel for electricity generation in Jamaica is deemed unsustainable.

Figure 1.1-1: The Energy Policy Triangle



1.2 Break-out of Jamaica's Electricity Generation

Table 1.2-1 shows the current mix of generating plants in the system, while Figure 1.2-1 illustrates the proportion of electricity generation from the various energy sources up to the end of 2009. As shown, fossil fuel (liquid) based plants accounts for a significant portion (approximately 95%) of the installed generating capacity. This composition is commensurate with electricity production, where petroleum based fuels in the form of HFO and ADO also account for approximately 95% of the total system annual average energy generation. This demonstrates the country's heavy dependence on petroleum based fuels for electricity generation.

Table 1.2-1: Current Mix of Generation Technologies

Technology	Plant Type	No. of Plants	Fuel Type	Total Capacity (MW)	% of Total
Fossil Fuel Plants	Steam (Power only)	5	HFO	292.0	**95%**
	Steam (CHP)	6	HFO	1.0	
	Diesel	1	HFO	224.4	
	Combined Cycle	1	ADO	114.0	
	Combustion Turbine	8	ADO	165.5	
Total Fossil				**796.9**	
RET	Hydro	7		22.3	**5%**
	Wind	1		20.7	
Total RET				**43.0**	
TOTAL				**839.9**	**100%**

In an attempt to address this crucial situation, the Government of Jamaica (GOJ) through the National Energy Policy (2009 – 2030) has promulgated several long term strategies; chief among them is energy diversification.

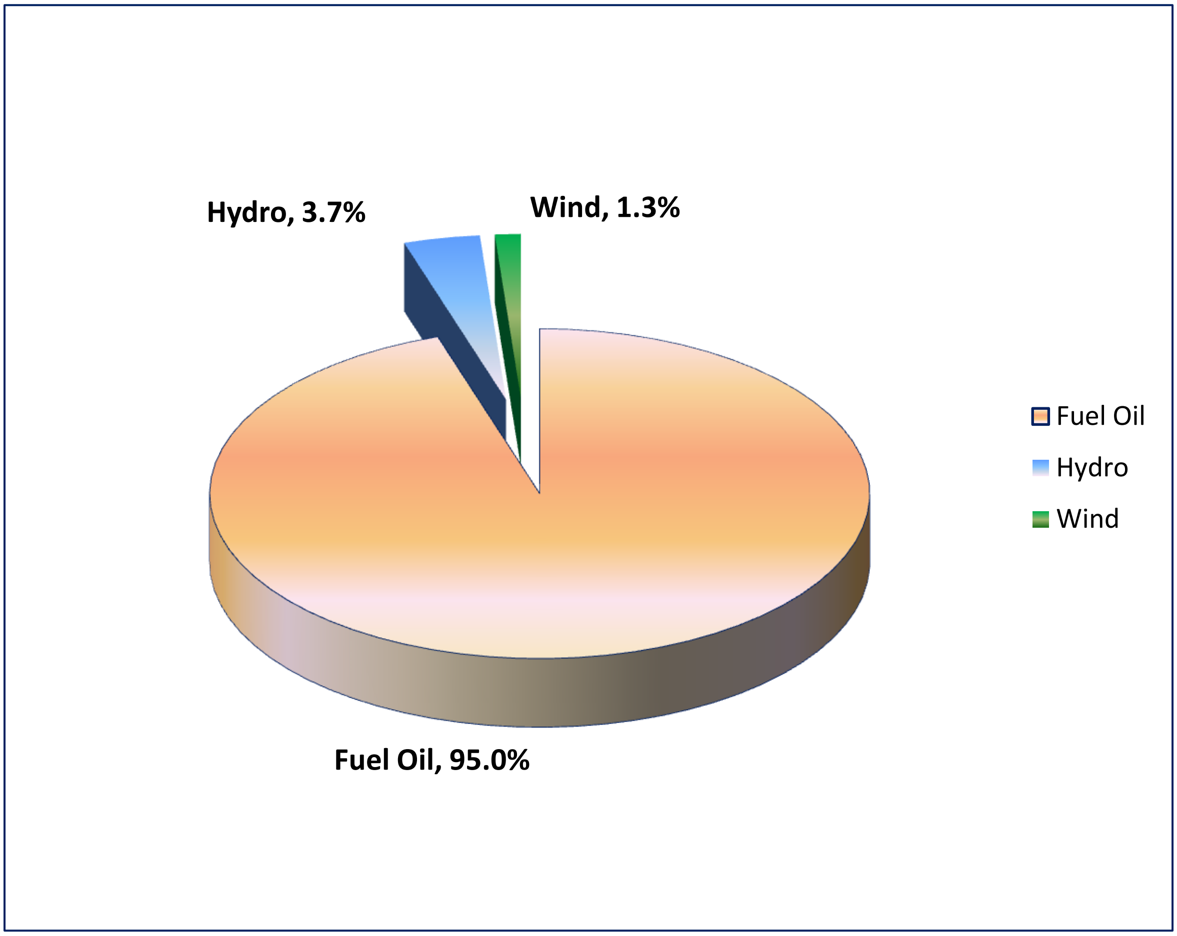
The policy defines energy diversification as follows:

"*Energy diversification will involve moving from an almost total dependence on petroleum to other sources, including natural gas, coal, petcoke, nuclear, and renewable energy such as solar, wind, and bio-fuels. In the short to medium term, natural gas would be the fuel of choice for generation of electricity and the production of alumina*".

The fundamental objective of these interventions is to diversify the country's fuel mix so as to reduce the exposure and heavy dependence associated with any one fuel source for energy production while simultaneously improving the security of the country's energy supply.

In this regard, steps have been taken to put in place infrastructure and facilities for the reception, and re-gasification of Liquefied Natural Gas (LNG); storage and distribution of natural gas for utilization in the electricity and bauxite sector in the coming years.

Figure 1.2-1: **Jamaica's Electricity Generation by Fuel Type**



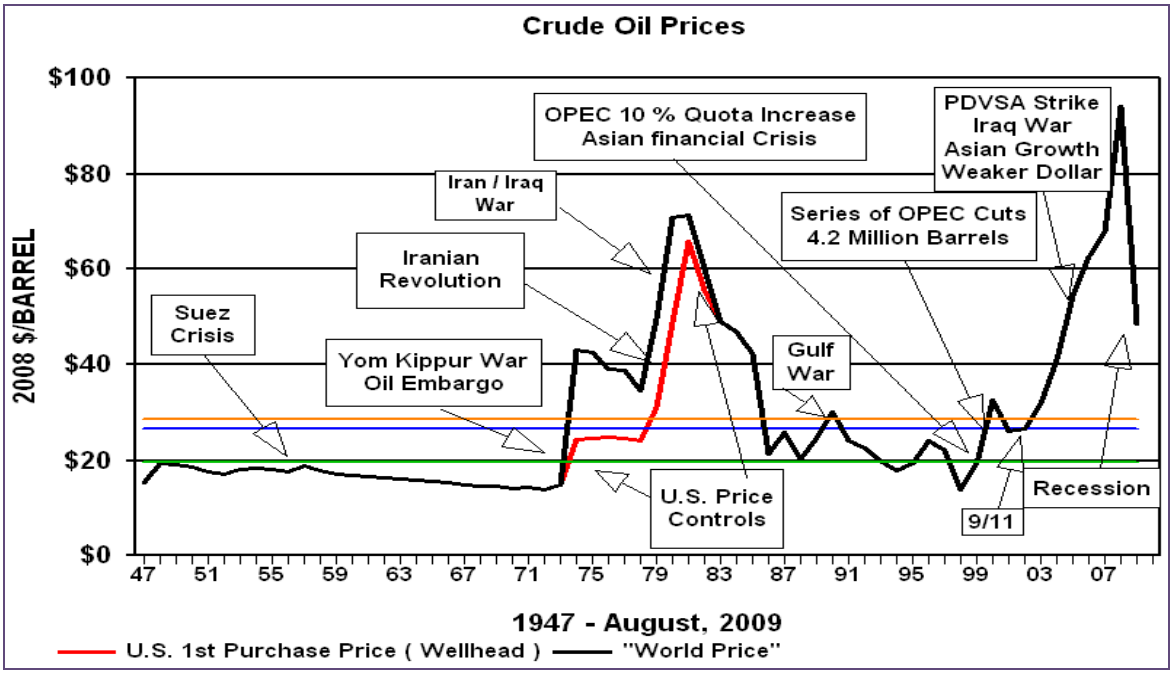
Source: JPS data (2005 – 2009)

In context, Jamaica does not naturally possess crude oil; therefore all its crude oil requirements have to be imported. However, world oil price is extremely volatile as it is not only influenced by global demand and supply dynamics but also by geopolitical events, perceptions and speculations.

Figure 1.2-2, for example, shows the movements in crude oil prices over the period 1947 to August 2009, and their primary driving factors. It is therefore apparent that Jamaica's security of electricity supply and consequently its socio-economic well being is presently hostage to international politics and affairs.

Against this background, having cognisance to the National Energy Policy initiatives, it is imperative that the system is planned and developed so as to ensure the achievement of a secure and sustainable energy supply for the country.

Figure 1.2-2: Crude Oil Price 1947 – August, 2009



Source: WTRG Economics (www.wtrg.com)

1.3 Generation Expansion

The least cost expansion plan is developed to determine the size and timing of new generating capacity required to maintain an adequate and reliable electricity demand-supply balance for the public electricity system over the medium to long term, at least economic cost.

In developing the plan, there are several and sometimes conflicting factors that must be evaluated. These include, among other things, the expected annual growth in electricity demand, the projected performance of the existing generating system, the future cost of inputs, the types of technologies available for utilization in the electricity generation process, and government policy directions.

Given the long lead time required for the development of new generation facilities, it is prudent to make decisions on capacity additions many years ahead of the time when they are required.

The Jamaican electricity sector at this stage is being impacted by a number of critical issues, which if not urgently addressed could have implications for its medium to long-term sustainability and a profound impact on the future economy. These include:

- The significant dependence on liquid fossil fuels for power generation

- The cost of power driven by the existing fuel mix,
- An aged fleet of existing generating plants
- Inefficiencies in the production and delivery of electric power
- Reliability and stability of the power supply

With respect to these issues, a number of strategies have been formulated with the aim of providing workable solutions in the medium to long-term. The expectation is that the proper implementation of these strategies should ultimately result in the achievement of a secure, sustainable and economical energy supply in the country. Among the strategies are:

- Energy diversification
- Energy efficiency
- Conservation
- Participation of Renewables

As discussed above, the issue of heavy dependence on imported oil together with the exposure to world oil prices volatility can be addressed by an effective fuel diversification strategy. This may offer tremendous benefits to the sector by effectively reducing the exposure associated with any one fuel type while at the same time improving energy security.

While there are obvious benefits that can be achieved from fuel diversification, it must be recognized that if the process is not properly pursued it could possibly result in a mere fuel switching scenario.

From a practical stand point, the expansion of Jamaica's electricity generation system mainly depends on Natural Gas and/or Coal for realising the objectives discussed above.

As part of the overall strategy for improving energy efficiency, reducing energy cost and achieving long-term energy sustainability and security, the GOJ has been encouraging the development of renewable projects aimed at supplying electrical energy to the grid. The objectives and expected penetration of Renewables are also outlined in the National Energy Policy.

The proposed targets for the contribution of Renewables in the energy mix are 11% by 2012, 12.5% by 2015 and 20% by 2030. Increased percentage of Renewables in the energy mix is expected to yield the benefit of reduced dependence on imported oil. Increased use of Renewables should also result in lower levels of air pollution, a smaller carbon footprint for Jamaica and better compliance with international conventions on climate change.

While there are tangible benefits from increased participation of Renewables in the system, based on the characteristics of the resource it usually does not provide firm capacity, except for biomass and hence cannot solely be depended on for the reliable expansion of the power system. They however, cannot be ignored in the campaign to diversify the country's energy mix especially in light of technological advancements which could result in lower cost and improved performance of RETs making them more competitive on a comparative basis with conventional counter parts.

In 2006, the OUR introduced a regulatory policy guideline for the addition of new capacity to the public utility grid. These guidelines have sought among other things to more clearly define the process by which small capacity additions (less than 15MW) of renewable and co-generation type projects will be accommodated in the LCEP framework. These new policies will have some direct influence on the development and analyses of the results of the LCEP process.

The responsibility for the development of the LCEP as well as the management and administration of the procurement process for new generating plant capacity was transferred to the OUR by means of an agreement in 2007 between the Government of Jamaica (GOJ) and Marubeni Corporation acting through its affiliate Marubeni Caribbean Power Holding Inc. (Marubeni), consequent on the sale of Mirant Corporations' shares in JPS to Marubeni..

Since assuming this responsibility, the OUR has successfully procured 65.5MW of new generating capacity which is scheduled to be commissioned by the end of 2011. The capacity is to be provided by JEP using MSD engines running on HFO (1.8% Sulphur). A Power Purchase Agreement (PPA) was negotiated by JEP and JPS which was concluded in April 2010.

Recent capacity additions have considerably improved fuel conversion efficiency (heat-rate) under normal operating conditions. The additions of new generating capacity from more efficient technologies will require significant capital investments; however, the overall benefit and cost reduction expected from the introduction of new capacity will be thoroughly evaluated.

Generation technology choices and timing of new generating capacity are only a component of the many decisions to be made in the LCEP process. The choice of suitable sites for the construction of these generating plants, the associated reinforcement/modification of the transmission system to interconnect these plants and convey the power to loads and the environmental implications of any infrastructure development complementing the expansion are issues that must be considered and assessed. These issues will be addressed in more details in Chapter 2.

1.4 Objective and Scope of Study

The broad objective of this study is to establish an optimised development program for the public electricity generation sector designed to secure a reliable supply of electricity over the long term at least cost. The rationale in support of this emerged out of the pressing need to tackle the issues and minimize the risks associated with input energy and electricity generation in Jamaica and the need to direct the country along a more sustainable path.

The specific objectives of this study are:

- to evaluate various fuel supply options in order to determine the appropriate fuel/generation mix for the future taking into consideration the need for diversification and reduced dependence on fuel oil.
- to identify and evaluate alternative generation options based on known projects and technologies available in the market.
- to estimate the capacity requirements for the electricity generation system over the period 2010 to 2029 under different assumptions to inform the generation procurement process;
- to determine the present value cost associated with different generation development sequences under different assumptions and constraints and assessed variations in this cost when the estimated outcomes for key variables are changed.
- to provide results and recommendations to facilitate the materialization of the National Energy Policy objective of developing a diversified, secure and sustainable energy system for the country in the future.

1.5 Report Overview

Following this introduction, this report is composed of thirteen chapters. The outline of the remaining chapters in the report is as follows:

Chapter 2

This provides a detailed description of the generation expansion planning process, the constraints to the process and the legal and regulatory framework under which the planning is executed.

Chapter 3

Chapter 3 provides a description of the load characteristics of the system including, energy and peak demand projections, load curves and load duration curves (LDC).

Chapter 4

The price assumptions and the basis of the price projections for the various fuel types used in the study are reported in this chapter.

Chapter 5

The planning parameters used in the study are defined in this chapter.

Chapter 6

Chapter 6 describes Jamaica's existing electric generation system and provides details of the existing plant data that was used in the modelling the system.

Chapter 7

This chapter gives details of the committed projects that were included in the expansion plan.

Chapter 8

This chapter describes the candidate technologies that were considered for expansion electric generating system options. It also gives details of the data set that was used to model the candidate plants.

Chapter 9

In chapter 9, the expansion strategies are analysed and results presented.

Chapter 10

In this chapter, sensitivity analyses built –up around various scenarios are analysed and discussed.

Chapter 11

In this chapter, the results and associated issues are discussed.

Chapter 12

This chapter summarises the findings of the study and recommendations made.

Chapter 13

Appendices

2 THE EXPANSION PLANNING PROCESS

2.1 General

Planning for the expansion of an electricity generation system is an integrated process that involves analysing the anticipated demand for electricity and making an objective choice for the optimal mix of new power plants that should be installed to ensure an adequate and economic supply of electricity to users.

In this respect, the decision for the technology mix of the new power plants is based on a full consideration of financial and fuel resources, environmental and policy constraints, the technical/economic performance of different types of power plants and the evolution of these factors.

Capacity planning is generally carried out over a long-term horizon, in view of the long technical lifetimes of power plants and their long-term impact on the energy system.

Essentially, the aim of generation expansion planning is to identify the magnitude of capacity needed, recommend the mix of power plant types that will have to be constructed and determine where they should be built as well as the timing of their construction and when they become operational.

The implications of not getting this right are obvious, for example:

a) Insufficient investment in capacity will result in poor system reliability

b) Over-investment will lead to unnecessary high cost of electricity

c) Inappropriate choice of technologies will result in higher overall system costs and subsequently higher electricity prices

d) Bad timing of capacity additions could lead to both poor system reliability and higher cost of supply

2.2 Planning Procedures and Methodology

The policies and procedures that influences the least cost expansion planning process have been formulated by the OUR, with due consideration to the Government's broad and strategic objectives as promulgated in the National Energy Policy 2009 -2030. These procedures were established as gauge for ensuring an acceptable level of electricity service and the best use of available resources in the country.

Some of the general procedures that are observed in developing the LCEP are as follows:

Demand Forecast Methodology:

The forecast demand for electricity is based primarily on the Government's official projection for the country's economic growth. The economic indicators are mainly provided by the Planning Institute of Jamaica (PIOJ).

Determination of Reliability Criteria:

The threshold operating reliability for the system is a Loss of Load Probability (LOLP) of an equivalent two (2) outage days per year (0.55%). This is a measure of the equivalent number of days that the system load is likely to exceed the available generation.

Determination of the Cost of Energy-not-Served:

The cost of energy not served (ENS) to the economy is estimated at US$2.32/kWh. This is based on an independent evaluation done in 1991 that determined the value of ENS at the time to be US$1.51/kWh. However, this value was adjusted using US CPI for use in the study. The cost of ENS attempts to quantify the overall average impact of not providing energy for production and other economic and social activities.

Evaluation of Energy Resources and Power Generation Technologies:

- Fuel presently being used and potential fuel to be used in the future
- Energy diversification
- Cogeneration
- Characterisation of power plant technologies

Participation of Renewables:

Renewable Resources that are suitable for power generation carry an additional benefit of up to 15% of its economic cost. This 15% is a premium for external benefits, sometimes intangible, having to do with fuel supply diversity and environmental advantages of these applications over their conventional counterparts. The policy guidelines developed by the OUR provides details on the treatment of these technologies.

2.3 Capacity Planning Methodology

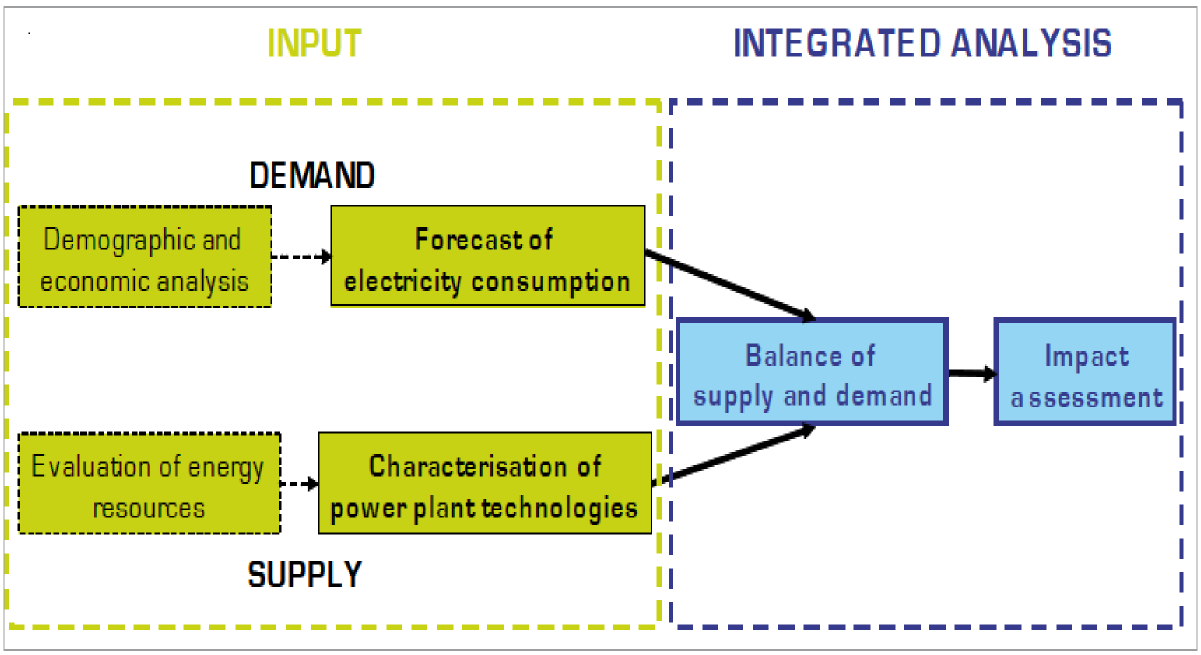
The planning for new generating capacity is generally carried out in three stages:

1) Forecasting of the electricity demand of the electrical system throughout the time span of the project

2) Conducting a technical/economic assessment of all proven power generation technologies considered for deployment during the planning horizon. This step is normally complemented by an analysis of the availability of energy resources which may impose constraints to the planning by recommending or restricting use of specific types of energy resources. For example, promoting the use of Natural Gas or discouraging the use of Coal.

3) Balancing electricity demand and supply within the temporal boundaries of the planning, and estimating the capacity needed and the electricity generation technology mix.

Figure 2.3-1: Stages in Electricity Generation Capacity Planning



Source: JRC Reference Report (EU)

Due to the high capital cost of power plants together with the long lead time for commissioning, it is imperative that plans for new generation capacity are initiated many years ahead of the forecasted time of need.

2.3.1 Demand Forecasting Methodology

The energy and peak demand forecast is the first step in the planning process and is the foundation on which the developed plans are based.

The forecast is therefore developed through a comprehensive approach in order to predict future behaviour.

Forecasting electricity demand is a very complex exercise due to uncertainties over the time span of the planning. In the short term, hours or days, the profile and magnitude of the electricity demands depends mainly on the time of day and weather conditions. The relationship between demand and average daily temperature is stochastic impeding the accurate prediction of electricity demand a few days in advance even when reliable information pertaining to anticipated weather conditions is available. In the medium to long-term the demand for electricity depends on other factors that are difficult to predict, these are among other things:

- Economic development within the country: the demand for electricity is linked to economic activity and hence the gross domestic product;
- Changes in consumption behaviour due to, for example, improvements in living conditions;
- Demographic and population changes;
- The overall situation in the energy sector and the electricity market, for example changes in electricity and fuel prices; and
- The implementation of polices such as energy conservation, emission constraints, etc.

The methodology applied in developing the forecast model attempts to establish relationships between economic trends, local community trends, sectorial characteristics (e.g. housing, pricing, conservation) and the demand for electricity. These are derived from historical data. The starting point of the forecast is projecting energy sales from which net generation and the peak demand are determined.

The theoretical basis of OUR forecasting is to establish these relationships and assess the impact of key economic activities on the demand for electricity. This is done with the aid of an econometric model and utilizes explanatory variables such as:

- Real Disposable Income
- Gross Domestic Product
- Electricity Pricing

- Population
- Exchange Rate

Regression analyses are used to quantify the relationship between these variables and the demand for electricity. Known loads from specific projects are also incorporated into the model. Based on projections of these variables, the resultant sales projections can be derived.

Historical data as well as projections of system losses and load factor enable the corresponding net generation and peak demand to be derived from the forecast sales figures.

As indicated earlier, there is always going to be some degree of uncertainty in the electricity demand forecast. In recognition of this, the OUR has sought to develop not only a most likely or base forecast, but also a high and a low demand forecast scenario to reasonably capture possible uncertainties. The high and low forecasts are based on optimistic and pessimistic projections for economic out turn respectively. The plans are presented on the basis of the base forecast. However, scenario analyses are done using the high and low demand forecast to test the robustness of the plan.

The forecast is revised and updated as required to reflect changing economic conditions and to ensure that the plans developed represent the most economic expansion solution for the electricity generation system.

The OUR considered the possible impact of demand side management initiatives during the process of developing the forecast subject to the availability of plausible information on sustainable projects of material value.

2.3.2 Supply Side Planning

The supply side planning analyses are of two dimensions as it incorporates a reliability evaluation as well as an economic optimisation process.

The supply side planning process selects a suitable combination of units from a pool of technically feasible power generation technologies that can operate in different modes to maintain an operating reliability equal or superior to the threshold reliability. The most economic option among the alternatives is pursued.

The large set of technology options is reduced through a preliminary screening process, which eliminates some technologies on the basis of technical incompatibility with the Jamaican power system and/ or obvious uncompetitive economic life cycle costs.

Suitable projects are selected from the remaining options (candidate plants) based on their relative cost characteristics in different modes of operation to fill the supply gap created by the projected increase in electricity demand and the state of the existing system. Two main parameters drive the need for additional capacity; the Loss of Load Probability (LOLP), which is a measure of the reliability with which the system can meet the demand for electricity, and the extent of unserved energy which is a function of the system capability to supply its total energy requirement.

2.4 Evaluation

A base expansion plan is developed to fit all the pre-defined standards, requirements and constraints. The plan basically represents a solution, which reflects the system requirements based on the OUR's best estimate of forecast variables and conditions. This plan is then subjected to several scenarios and sensitivity analyses. These analyses test the robustness of the plan to certain fundamental changes in assumptions and variables, e.g., system demand, fuel price, existing system parameters etc.

The economic optimisation process is a detailed evaluation that isolates from a combination of resource options, a plan with the lowest overall system production cost, while the reliability criteria and economic considerations determine the schedule of resource requirements. This evaluation is typically done over a 20 to 30 year period to appreciate the full life-cycle cost implication of immediate decisions.

The costs used in this evaluation are net of local taxation. The plan that is therefore derived from the LCEP process is one for which the country will incur minimum expenditure to realize the mandated objectives.

2.5 Description of Wien Automatic System Planning Software

The OUR utilizes the Wien Automatic System Planning Package (WASP-IV) developed by the International Atomic Energy Agency (IAEA), to assist in the planning process.

WASP-IV is designed to:

- find the optimal expansion plan over a period of up to 30 years within constraints given by the planner
- utilise *probabilistic estimation* of system production costs, unserved energy cost and reliability
- use *linear programming technique* for determining optimal dispatch policy satisfying exogenous constraints on environmental emissions, fuel availability and electricity generation by some plants

- use *dynamic method of optimisation* for comparing the costs of alternative system expansion policies.

The Optimum Expansion Plan is evaluated in terms of minimum discounted total costs.

Each possible sequence of generating units added to the system and meeting the constraints is evaluated by means of a cost function (objective function) which is composed of capital investment costs, salvage value of investment costs, fuel costs, non-fuel operation and maintenance costs and unserved energy costs.

The cost function to be evaluated by WASP can be represented by the expression shown below.

$$B_j = \sum_t (I_{jt} - S_{jt} + F_{jt} + M_{jt} + U_{jt})$$

where:

t = time, t=1,...,T

I = Capital costs

S = Salvage value

F = Fuel costs

M = O&M costs

U = Unserved energy costs

Source: WASP manual

Note: All costs are discounted net present values

2.5.1 WASP Inputs

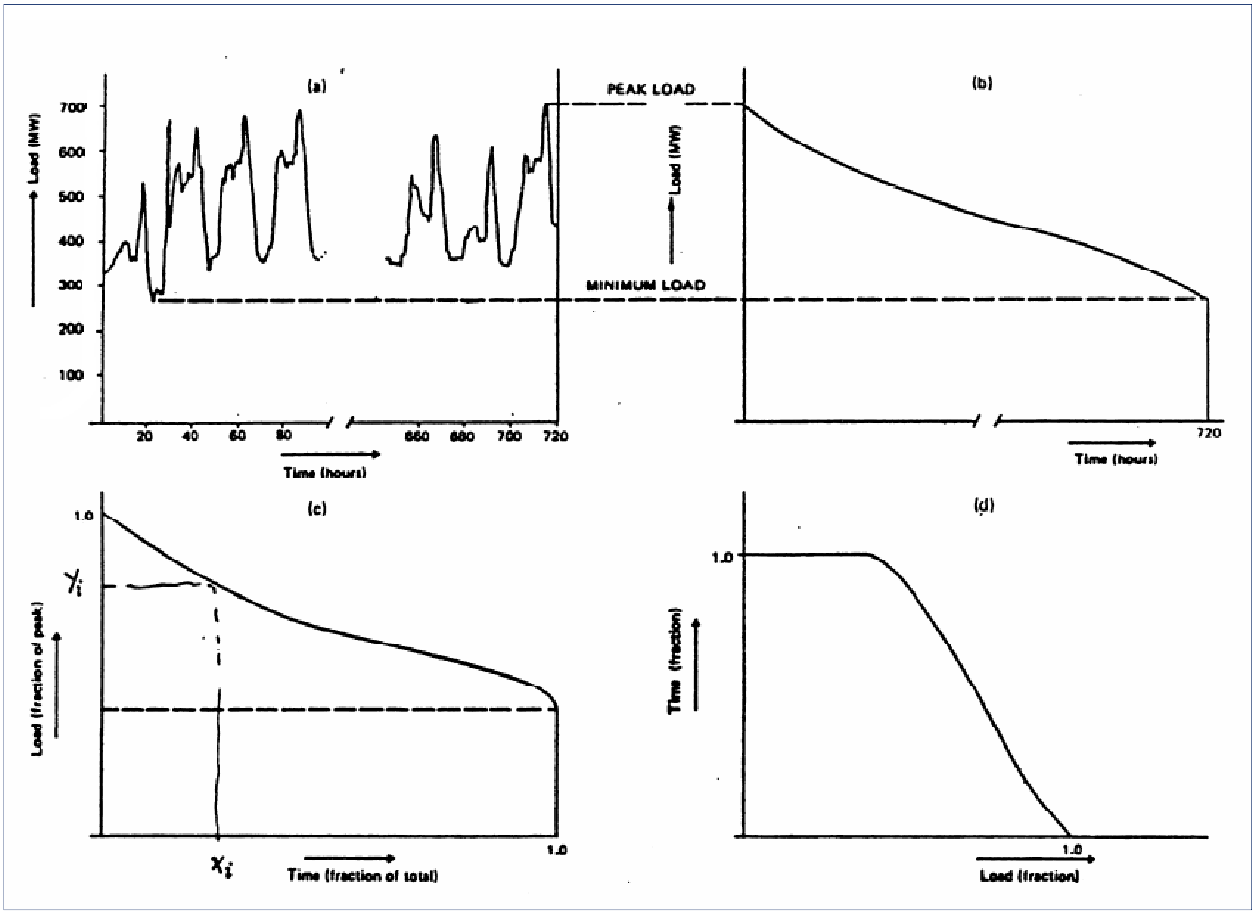
Some of the key inputs to WASP are:

- Demand and load duration data (seasonal)
- Hydrological variations (seasonal)
- Unit size, forced outage rate, scheduled maintenance of candidate units, pollutant emissions
- Existing system and commitments
- Economic parameters
- Reliability constraints

2.5.2 Representation of the System Load in WASP

The load imposed on an electric power system changes at every moment during the day, from day to day, from month to month, and from year to year. In WASP, the changing nature of the load from one year to another is taken into account by specifying the peak demand forecasted for each year in study. If seasonal changes of the load characteristics or of the hydroelectric power stations are to be considered, the year is sub-divided into a number of equal periods. In this model, the characteristics of the load in each period must be specified and the period becomes the basic unit for simulation of system operation.

Figure 2.5.2-1 Representation of the Load of a Power System: (a) Chronological Hourly Loads; (b) Load Duration Curve; (c) Normalized Load Duration Curve; (d) Inverted (normalized) Load Duration Curve



Source IAEA

Let us assume that for a given power system, the year must be subdivided into periods of one month each, and that Figure 2.5.2-1 (a) represents the chronological hourly load curve for one of these monthly periods. Curves such as the one in this figure, together with the relevant plant information, are very useful for determining the schedule of maintenance and energy production of each unit in the system and when the period of interest covers a week, a few months, or 1 to years. For long-range planning studies, such as the ones carried out by the use of WASP, it is convenient to transform this chronological load curve into a load duration curve (LDC) to represent the characteristics of the load as illustrated in Figure 2.5.2-1 (b). Similar to the chronological hourly load curve, the area under the LDC measures the total energy requirements of the system; however, the chronological sequence of loads has been lost. In the load duration curve the abscissa represents the number of hours during which the system load equals or exceeds the associated amount of power on the ordinate. The LDC can also be represented by normalizing the load and time variables with respect to the peak load and total number of hours of the period, respectively, as shown in Figure 2.5.2-1(c). With this representation, any point on the abscissa (Xi) becomes the fraction of time for which the load equals or exceeds the fraction of load represented by the associated point in the ordinate (Yi). The so-defined normalized LDC of each of the time periods specified in the year are the ones used to prepare the input data to be given in the Load Description Module of the WASP Program.

For convenience of the calculations of system reliability and plant generation performed using probabilistic simulation, the axes of the load duration curve must be reversed as shown in Figure 2.5.2-1(d).

2.5.3 Output from WASP

Key outputs from WASP include:

- Optimum expansion plan over study period
- Expected generation from all units for all periods
- Reliability performance
  - LOLP
  - unserved energy
  - reserve margins
- Foreign and domestic expenditures
- Cash flow over time
- Pollutant emissions
- Sensitivity to key parameters

2.6 Site Evaluation and Selection

An important aspect of justifying the technical viability of power generation technologies is to ensure that the country can accommodate the siting requirements. The specific choice of sites is the subject of a separate evaluation exercise.

The selection of a site for a power plant is influenced by a number of factors. These factors are either directly related to the operating requirements, design and layout of the plant or the requirements of the electric system which it serves.

In the process of site selection a location can only be a site possibility if it satisfies certain minimum requirement for housing a power station. Economics then determines the selection of the best site from a set of possible locations. The site with the lowest evaluated cost is typically the one selected.

However, in a situation where the options for power plant sites are limited, the choice of technology or generating units is constrained by the sites available for power plant application.

The following is a list of considerations that influence the choice of an appropriate site for a power station development:

- Proximity to the point of consumption (load centre);

- A relatively level area of land adequate to accommodate the plant facilities including allowances for possible future expansion. Critical to this is identifying suitable geology and topography to accommodate the civil works necessary to erect the facility;

- Proximity and access to a source of adequate quantities of water (requirement vary with technology);

- Interconnection and transmission expansion/reinforcements requirements to reliably deliver power to point of demand;

- Environmental considerations, areas of concern to environmental authorities include noise level, gas emissions, discharge of effluence etc.;

- Infrastructure items such as roads, domestic water, telephone, sewage etc. form a very important part of the site selection process; and

- Accessibility to fuel supply. This is measured in terms of proximity to port facilities, existing pipelines or existing fuel handling facilities. For projects involving the introduction of new fuels to a site without the appropriate infrastructure, the required infrastructure cost would be included in the evaluation.

In addition, permits and licenses are often required from governmental and other agencies to utilize a site for that particular application. In some situations the considerations for siting are done in tandem with evaluating the technology preference.

2.7 Transmission Planning

The transmission system development plan is influenced by the requirements of the generation Least Cost Expansion Plan and Distribution Plan. Following the review and update of the Least Cost Generation Expansion plan a study or an assessment of the transmission system must be conducted to ascertain the adequacy of the transmission facilities to reliably evacuate the expected power generation from new generation facilities to serve the forecasted load.

The transmission plans are developed to meet predetermined reliability standards and benchmark in a similar way to the generation expansion plan. Applicable technical standards for the design and expansion of the JPS transmission system include:

Bus Voltages

Under normal operating conditions, voltages on all 69 kV and 138 kV bus bars should be within ±5% of nominal voltage levels.

Under emergency condition, all 69 kV and 138 kV bus voltages can vary within +5% and -10% of nominal voltages in the event of a single outage contingency.

Line Outage Contingency

The system of transmission lines out of a generating station should be designed to withstand a double outage contingency (one large unit and a line out) situation. In other cases the transmission system should be able to adequately supply all substation demands with the outage of any single transmission line section, 69 kV or 138 kV.

Equipment Loading

Under emergency outage conditions, temporary overloading up to 110% of continuous MVA ratings is allowed for transmission lines and up to 110% for transformers.

Environmental

All transmission lines must be designed (aerial, underground, etc) to meet the applicable environmental regulations and standards.

Electricity Sector Transmission and Distribution (T&D) Code

The implementation of the electricity sector T&D code is also expected to outline the relevant procedures for the planning, design and operation of the transmission system.

2.8 Environmental Regulations

The National Environment and Planning Agency (NEPA) is the agency given the authority for ensuring protection of the environment and orderly development in Jamaica.

Currently there are Laws & Regulations and Policies & Standards that provide for the management, conservation and protection of the environment and natural resources of the country. There are also various codes, guidelines and international conventions that are relevant to new infrastructure developments. These include but are not limited to:

- The Natural Resources Conservation Authority Act of 1991

- The Permits & Licensing Regulations

    - ✓ Draft air quality regulations (new rules published 2006)
    - ✓ Draft Trade Effluent and Industrial Sludge Regulations
    - ✓ Noise Guidelines
    - ✓ World Bank Guidelines

Environmental impact of new power projects will be assessed by NEPA before permits or approvals are granted.

2.9 Constraints to the Planning and Design Process

The expansion and design configuration of an electric generating system is impacted by various constraints. These arise out of the need for the provision of a safe, secure, reliable and cost effective supply of electricity to customers.

These constraints include the following:

- maximum permissible unit size
- availability of capital
- construction lead time of equipment
- man-power resource and requirements
- siting requirements

The issue of unit size and the associated operating cost, investment, and engineering trade-offs to assure the best overall cost for electricity was given careful consideration in this plan. The economic and technical merits of a 120 MW capacity block as opposed to 80 MW as previously contemplated was carefully examined.

The rationale for this was that moving to blocks of 120 MW or slightly greater provides an opportunity for Jamaica to benefit from an improvement in efficiency and cost of production.

Presently, there are currently two generating facilities operating on the system rated at 114 & 124 MW and have not posed any stability related problems.

2.10 Legal and Regulatory Framework

The following laws & regulations and policies and standards are used to guide the development of the electricity sector.

- The All-island Electric Licence, 2001
- The Office of Utilities Regulation Act (as amended 2000)
- The Electric Lighting Act
- Regulatory Policy for the addition of New Generating Capacity to the Public Utility Grid
- The National Energy Policy (2009 – 2030)

3 LOAD CHARACTERISTICS

3.1 Demand Forecast

Forecasts for electricity demand are usually produced with the assistance of macroeconomic and sectoral economic analyses based on pre-described scenarios and using econometric models that postulate casual relationships between electricity demand and economic activity, population technology trends, etc. The forecasts are further treated to deliver the types of information required in generation expansion planning, namely, peak load and the profile of the electricity demand that are typically featured in a load duration curve (LDC).

3.2 Base Forecast

Table 3.2-1 and Figure 3.2-1 show the base demand projections for the electricity system over a twenty (20) year period from 2010 to 2029. The electricity sector long-term forecasting methodology for generation and peak demand adopted the use of economic modelling techniques which defined electricity consumption as a function of the growth in the number of customers and the growth in the level of usage per customer.

Essentially, the econometric approach to electricity consumption forecasting seeks to explain the underlying determinants of electricity consumption through the application of economic theory using statistical and mathematical measurement techniques.

The model seeks to determine economic and other factors that influence the demand for electricity, such factors include price, income, basic economic and demographic growth indicators.

3.2.1 Key drivers

There is a wide range of potential drivers of long term electricity demand, ranging from demand for Jamaica produced goods, population growth and long-term growth in employment. The drivers can be split into four (4) broad areas; economic activity (measured by GDP), demographics, electricity prices (and demand responsiveness) and energy intensities (determined by the type of electricity end use and technology). The availability of reliable series of historical and forecast data largely determines the drivers that can be utilized for long term forecasting. The key drivers and contributing factors are outlined in this document.

The models assessed in this analysis are focused at producing forecasts that reflect changes in historical demand and its drivers. Underlying historical improvements in energy efficiency for example are already reflected in the demand numbers. Possible step changes in demand may occur as a result of policy changes. It is outside the scope of this analysis to consider the impact of future policy changes and if, and how, they should be wound into the demand forecasts.

3.2.2 Modelling uncertainty

Various econometric models for each rate classes was postulated and assessed. On assessment, models were selected based on how they fitted the historical data well while minimizing forecast uncertainty. The OUR is of the view that model accuracy needs to be balanced against the requirement that the model be intuitive, cost effective and fairly easy to explain.

Additionally, scenario assumptions about economic and demographic growth projections are made to account for the risk or uncertainty of the forecast being too high or too low. Hence, in addition to a base forecast, a high and low scenario was developed to account for the risk in planning for the system expansion. Table 3.3-1 and 3.4-1 shows the low and high demand forecast respectively.

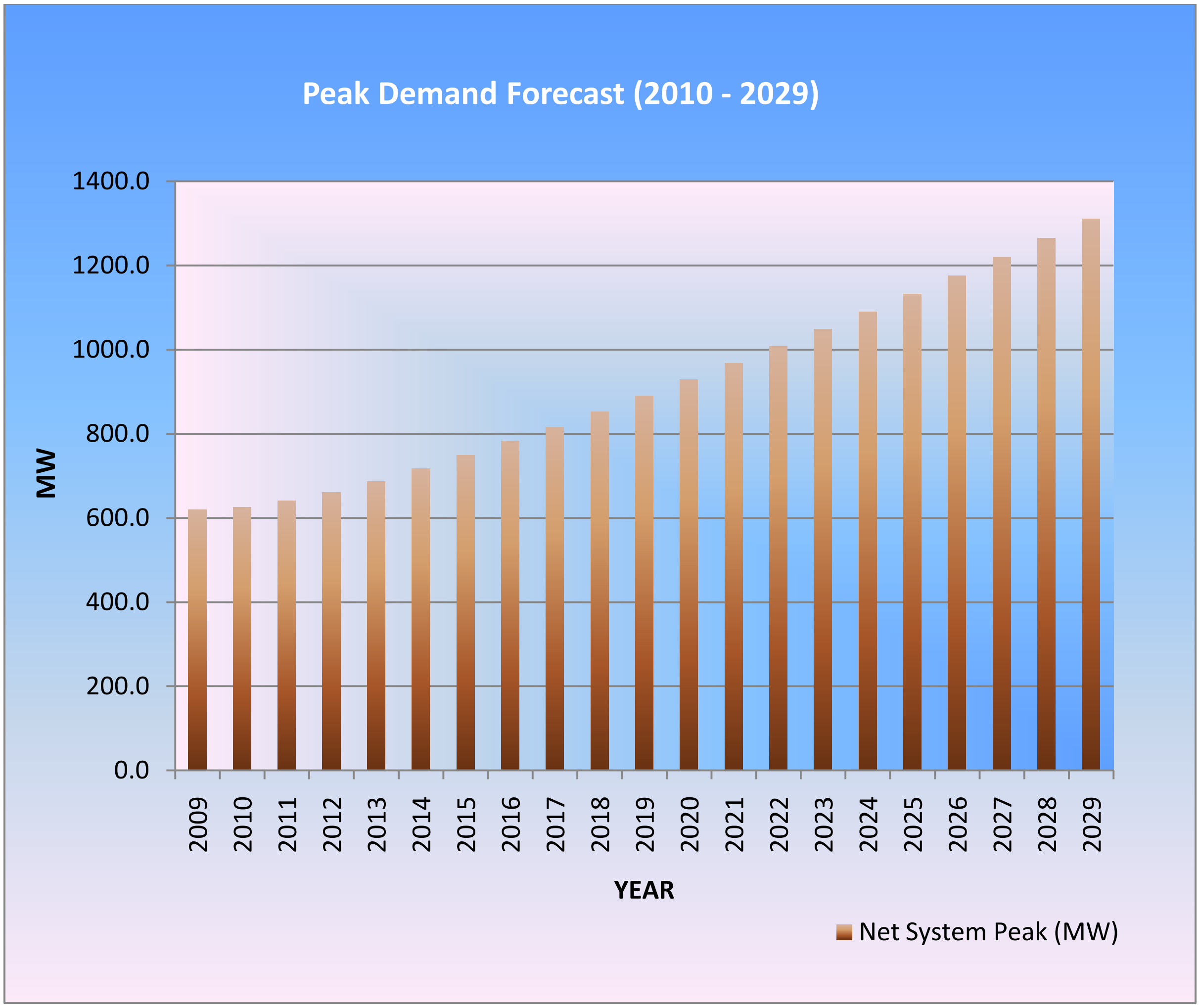
Table 3.2-1: Base Forecast – Net Generation and Net System Peak (2010 – 2029)

Year	Net Gen (MWh)	Net Gen Growth Rate (%)	Load Factor (%)	Net System Peak (MW)	Peak Growth Rate (%)
2009	4,213,981	-	77.6	619.9	-
2010	4,253,796	0.94%	77.6	625.8	0.95%
2011	4,373,845	2.82%	77.96	640.5	2.35%
2012	4,531,735	3.61%	78.28	660.8	3.17%
2013	4,725,330	4.27%	78.57	686.5	3.89%
2014	4,951,437	4.78%	78.84	717.0	4.44%
2015	5,190,379	4.83%	79.07	749.3	4.50%
2016	5,434,953	4.71%	79.28	782.6	4.44%
2017	5,681,720	4.54%	79.47	816.1	4.28%
2018	5,949,989	4.72%	79.64	852.8	4.50%
2019	6,223,245	4.59%	79.8	890.3	4.40%
2020	6,502,098	4.48%	79.93	928.6	4.30%
2021	6,786,213	4.37%	80.06	967.7	4.21%
2022	7,075,842	4.27%	80.17	1007.6	4.12%
2023	7,370,946	4.17%	80.27	1,048.3	4.04%
2024	7,671,693	4.08%	80.35	1,089.9	3.97%
2025	7,978,175	3.99%	80.43	1,132.3	3.89%
2026	8,290,569	3.92%	80.51	1,175.6	3.82%
2027	8,609,043	3.84%	80.57	1,219.8	3.76%
2028	8,933,808	3.77%	80.63	1,264.9	3.70%
2029	9,265,086	3.71%	80.68	1,310.9	3.64%

For the base demand forecast, peak demand is projected to grow at an average rate of 3.8% per annum over the twenty year (20) year planning horizon (2010 to 2029). Net peak demand expected for 2010 is 625.8 MW with the peak occurring during the summer period.

Net generation for 2010 is forecasted at 4,253.8 GWh. It is also projected to grow at an average rate of 4.0 % per annum over the period 2010 to 2029.

Figure 3.2-1: Base Forecast – Net Peak Demand (2010 – 2029)



3.3 Low Forecast

Table 3.3-1: Low Forecast – Net Generation and Net Peak Forecast (2010 – 2029)

Year	Net Generation (MWh)	Net Gen Growth Rate (%)	Load Factor (%)	Net Peak (MW)	Peak Growth Rate (%)
2009	4,213,983	-	78%	619.9	-
2010	4,200,306	-0.32%	78%	617.9	-0.32%
2011	4,280,216	1.90%	78%	626.7	1.43%
2012	4,394,610	2.67%	78%	640.8	2.25%
2013	4,515,761	2.76%	79%	656.1	2.38%
2014	4,674,215	3.51%	79%	676.8	3.17%
2015	4,838,504	3.51%	79%	698.5	3.21%
2016	5,001,740	3.37%	79%	720.2	3.10%
2017	5,160,705	3.18%	79%	741.3	2.93%
2018	5,316,970	3.03%	80%	762.1	2.81%
2019	5,469,455	2.87%	80%	782.5	2.67%
2020	5,618,650	2.73%	80%	802.4	2.55%
2021	5,764,213	2.59%	80%	821.9	2.43%
2022	5,906,330	2.47%	80%	841.0	2.32%
2023	6,044,935	2.35%	80%	859.7	2.22%
2024	6,180,146	2.24%	80%	878.0	2.12%
2025	6,312,015	2.13%	80%	895.8	2.03%
2026	6,440,659	2.04%	81%	913.3	1.95%
2027	6,566,187	1.95%	81%	930.3	1.87%
2028	6,688,730	1.87%	81%	947.0	1.79%
2029	6,808,424	1.79%	81%	963.3	1.72%

Under the low demand forecast, peak demand is projected to grow at an average rate of 2.2 % per annum over the twenty year (20) year planning horizon (2010 to 2029). Net peak demand expected for 2010 is 618 MW with the peak occurring during the summer period.

Net generation for 2010 is forecasted at 4,200.3 GWh. It is also projected to grow at an average rate of 2.43 % per annum over the period 2010 to 2029.

3.4 High Forecast

Table 3.4-1: High Forecast – Net Generation and Net Peak Forecast (2010 – 2029)

Year	Net Generation (MWh)	Net Gen Growth Rate (%)	Load Factor (%)	Net Peak (MW)	Peak Growth Rate (%)
2009	4,213,983	2.2%	78%	619.9	2.7%
2010	4,321,214	2.5%	78%	635.7	2.5%
2011	4,503,073	4.2%	78%	659.4	3.7%
2012	4,728,639	5.0%	78%	689.5	4.6%
2013	4,971,610	5.1%	79%	722.3	4.7%
2014	5,254,511	5.7%	79%	760.9	5.3%
2015	5,606,396	6.7%	79%	809.4	6.4%
2016	5,979,749	6.7%	79%	861.0	6.4%
2017	6,372,128	6.6%	79%	915.3	6.3%
2018	6,786,523	6.5%	80%	972.7	6.3%
2019	7,222,889	6.4%	80%	1,033.3	6.2%
2020	7,683,046	6.4%	80%	1,097.2	6.2%
2021	8,167,861	6.3%	80%	1,164.7	6.1%
2022	8,678,883	6.3%	80%	1,235.8	6.1%
2023	9,217,413	6.2%	80%	1,310.9	6.1%
2024	9,785,047	6.2%	80%	1,390.1	6.0%
2025	10,383,376	6.1%	80%	1,473.6	6.0%
2026	11,014,170	6.1%	81%	1,561.8	6.0%
2027	11,679,284	6.0%	81%	1,654.8	6.0%
2028	12,380,722	6.0%	81%	1,752.9	5.9%
2029	13,120,615	6.0%	81%	1,856.5	5.9%

Under the high demand forecast, peak demand is projected to grow at an average rate of 5.6 % per annum over the twenty year (20) year planning horizon (2010 to 2029). Net peak demand expected for 2010 is 636 MW with the peak occurring during the summer period.

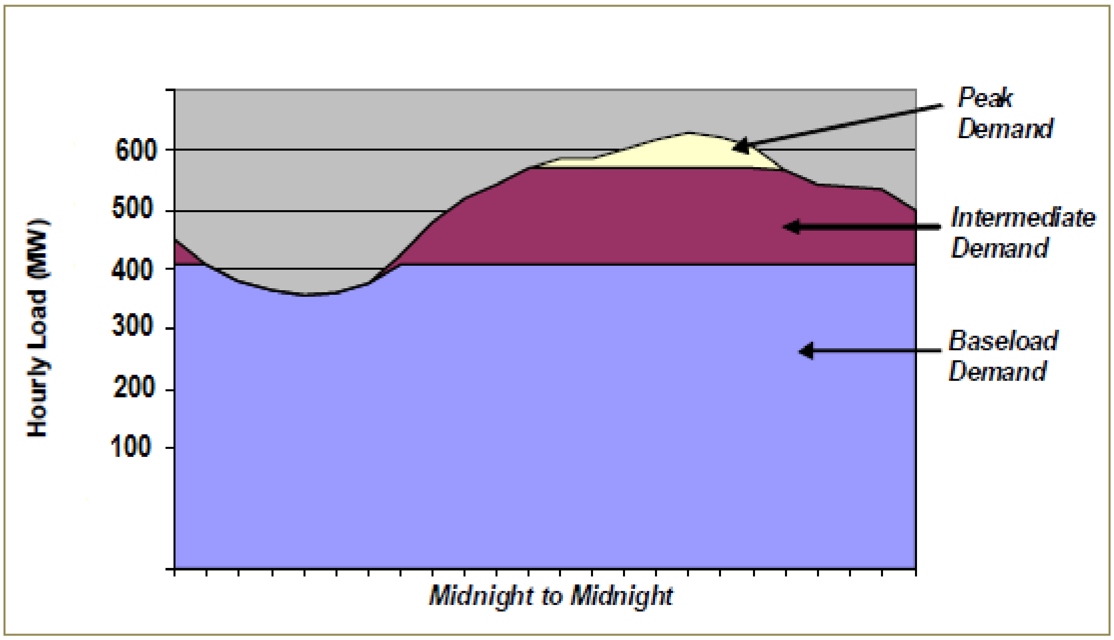
Net generation for 2010 is forecasted at 4,321.2 GWh. It is also projected to grow at an average rate of 5.8 % per annum over the period 2010 to 2029.

3.5 System Load Profile

The demand for electricity ("load") faced by an electric power system varies moment to moment with changes in commercial and residential activities and the weather. Load begins growing in the morning as people start waking up, peaks in the early afternoon, and bottoms-out in the late evening and early morning. The variation in load is typically shown using load curves. Basically, these curves are plots of temporal average loads (hourly, half-hourly, etc) ranked by time of occurrence.

Figure 3.5-1 represents an illustrative daily load curve, which demonstrates the variation in system load over a daily 24 hour cycle.

Figure 3.5-1: Illustrative Load Curve



The shape of the daily load curve dictates how electric power systems are operated. As shown in Figure 3.5-1, there is a minimum demand for electricity that occurs throughout the day. This base level of demand is met with "baseload" generating units which have low variable operating costs[1]. Baseload units can also meet some of the demand above the base, and can reduce output when demand is unusually low. The units do this by "ramping" generation up and down to meet fluctuations in demand.

[1] Variable costs are costs that vary directly with changes in output. For fossil fuel units the most important variable cost is fuel. Solar and wind plants have minimal or no variable costs.

The greater part of the daily up and down swings in demand is met with "intermediate" units (also referred to as load-following or cycling units). These units can quickly change their output to match the change in demand. Load-following plants can also serve as "spinning reserve" units that are running but not putting power on the grid, and are immediately available to meet unanticipated increases in load or to back up other units that go off-line due to breakdowns.

The highest daily loads are met with peaking units. These units are typically the most expensive to operate, but can quickly start-up and shutdown to meet brief peaks in demand. Peaking units also serve as spinning reserve and as "quick start" units able to go from shutdown to full load in minutes. A peaking unit typically operates for only a few hundred hours a year (low capacity factor).

The mode of power plant operation and cost characteristics will be discussed in greater details in Chapter 8.

In Jamaica, the power system has a fairly consistent daily load pattern on weekdays and weekends; these are shown in Figures 3.5-2 and 3.5-3 respectively.

Figure 3.5-2: Typical Weekday Load profile for Jamaica's power system

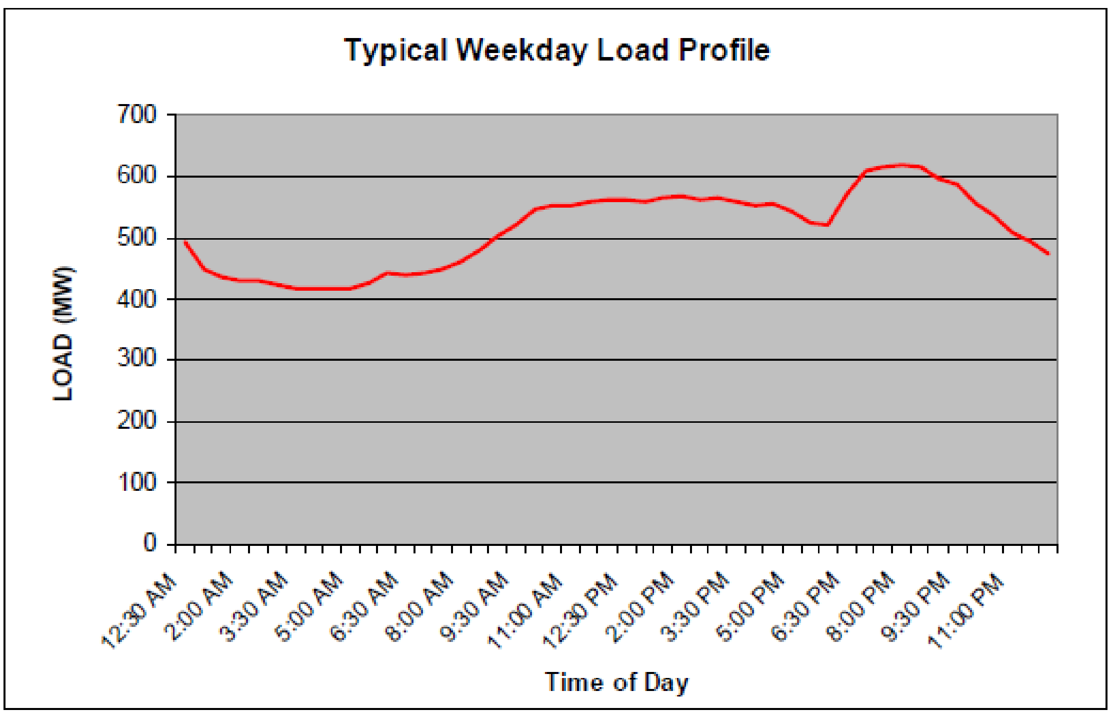
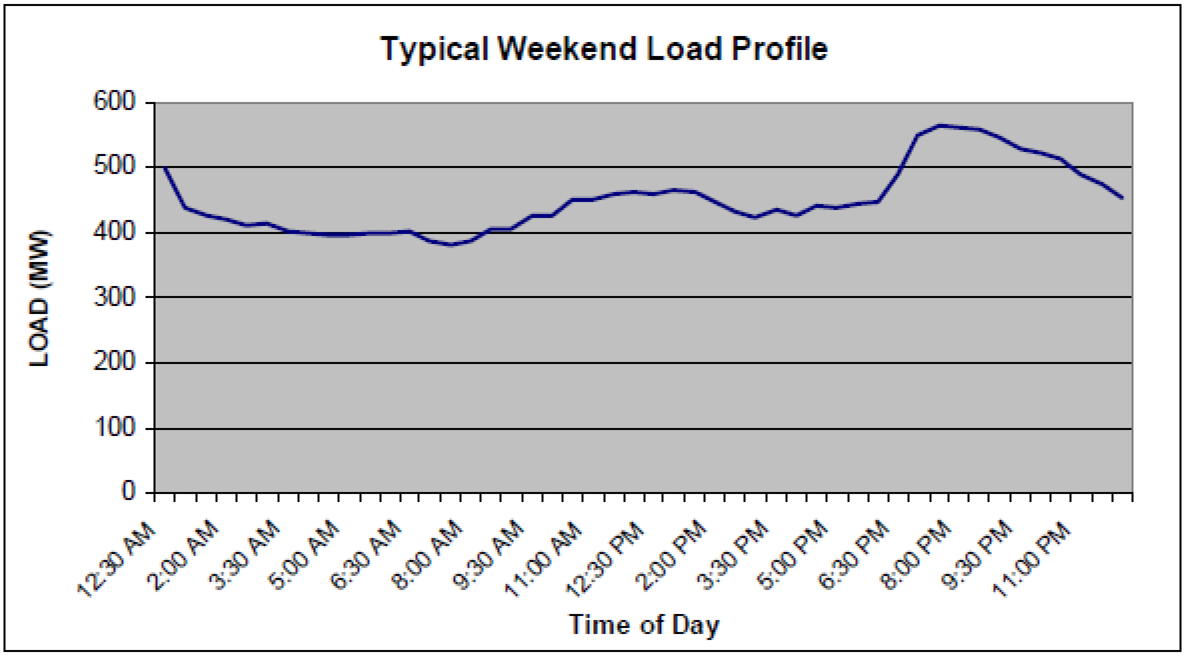


Figure 3.5-3: Typical Weekend Load profile for Jamaica's power system

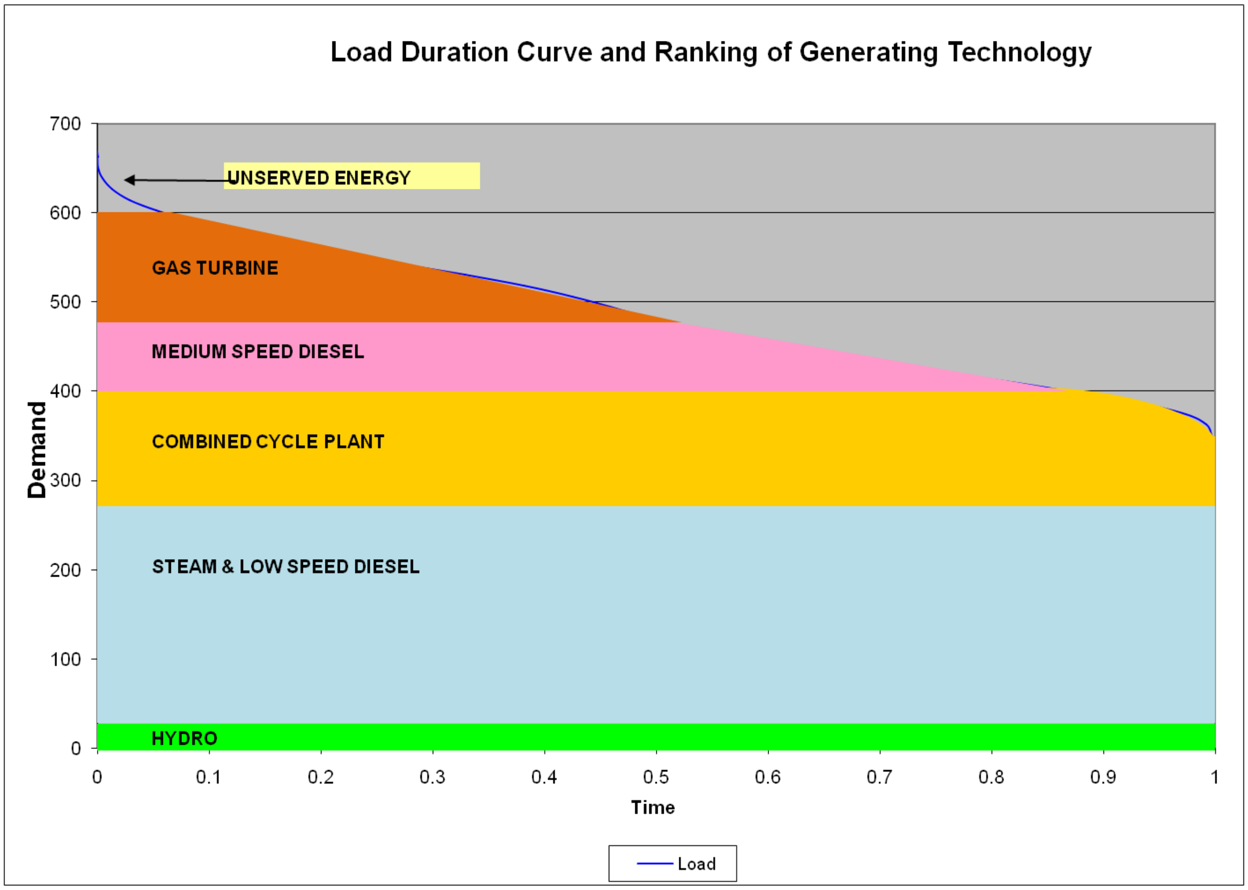


3.6 Load Duration Curve

While peak load dictates the magnitude of the installed capacity, it does not provide any information on the use of electricity, that is, how many hours of a given period loads will have a certain value. This information is essential for identifying the power generation technology mix and the operation of the installed capacity.

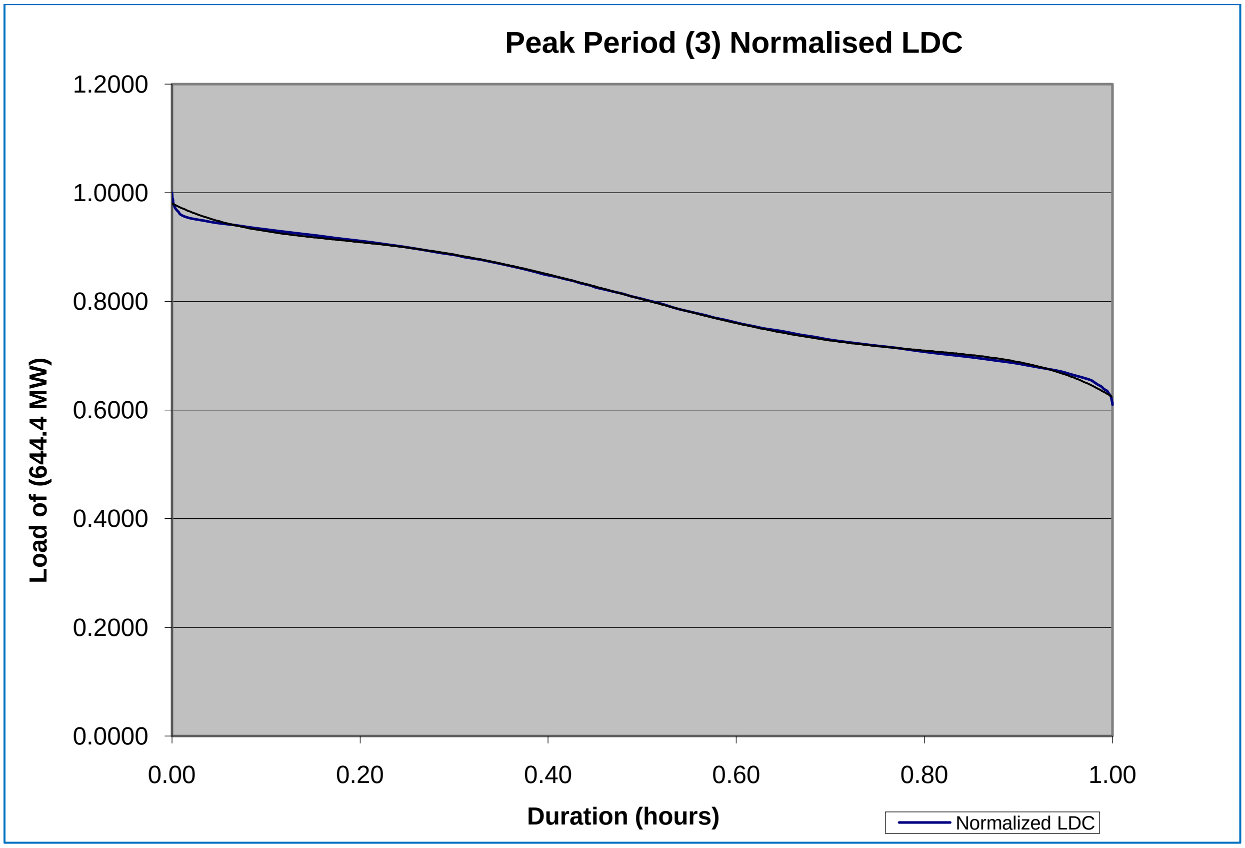
This type of information is extracted from a load duration curve. The LDC is a graphic representation of all the loads in the electricity system; in other words the rearrangement of loads within a time period from the highest to the lowest. Figure 3.6-1 shows the LDC for the daily load curves for Jamaica's electricity system for the period July-September 2009. The ranking of the various power generation technologies supplying the capacity to meet the demand is also illustrated.

Figure 3.6-1: Load Duration Curve of Jamaica's Electricity System in Peak Period



Projecting the LDCs in the future can pose a significant challenge. However, the approach adopted was to normalize the present LDCs and combine them with the projected peak for each corresponding period. The normalized LDC for period 3 (summer period) used in the study is shown in Figure 3.6-2.

Figure 3.6-2: Normalized LDC for period 3 (July – September 2009)



4 FUEL PRICE

Fuel price is one of the most critical determinants of the cost of power generation and consequently is a major factor in selecting the optimal generation system development path.

4.1 Price Projections

Fuel price forecasts are important but can be difficult to develop as fuel prices are not only influenced by the economics of supply and demand in the market but also by geo-political events, market perceptions and speculation.

The four (4) main fuels considered for the expansion are Automotive Diesel Oil (ADO), Heavy Fuel Oil (HFO), Coal and Natural Gas (NG). The prices of HFO and ADO are probably the most difficult to predict due to the feature of high volatility in world market prices as shown in Figure 1.2-2.

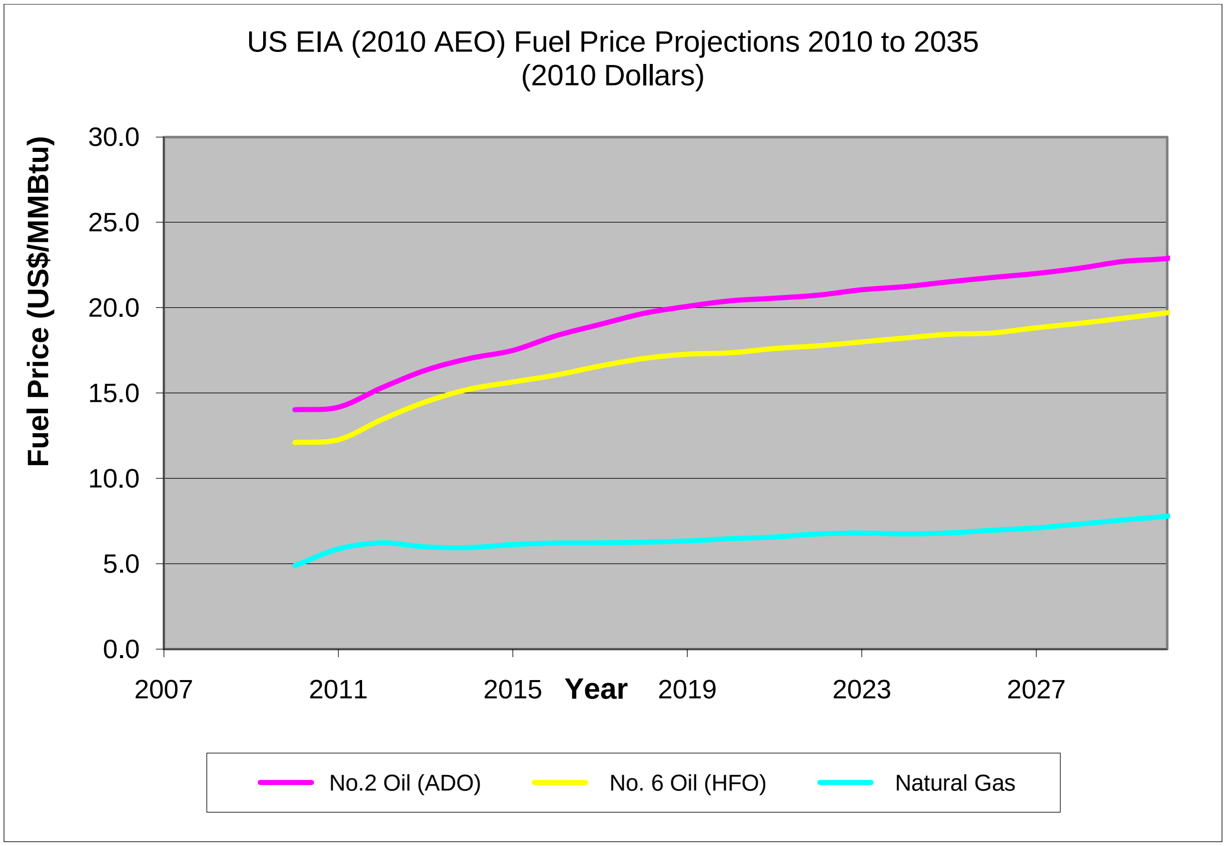
Natural Gas is currently being sourced by the GOJ through competitive procurement arrangements, however, the details of these arrangements including the pricing mechanism are not fully known at this time.

Average import price assumptions for Natural Gas, HFO and ADO were developed from the US Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2010 reference case fuel forecast. The average calorific values connected to these prices were also obtained from EIA data.

The prices used are expressed in terms of both energy content and quantity.

The EIA AEO 2010 price projections of Natural Gas (NG), No. 2 Oil (ADO) and No. 6 Oil (HFO) for 2010 to 2035 are shown in Figure 4.1-1 below.

Figure 4.1-1: US EIA AEO 2010 Reference Case Fuel Price Projections



The price projections for ADO, HFO and Natural Gas used in the study are shown in Table 4.1-1.

Table 4.1-1: Table Fuel Price Projections used in the Study

Fuel Price Projections - US$/MMBtu (2010 Dollars)			
Year	No. 2 Oil (ADO)	No. 6 Oil (HFO)	Natural Gas
2010	14.02	12.10	4.88
2011	14.17	12.27	5.87
2012	15.32	13.45	6.22
2013	16.34	14.48	5.99
2014	17.03	15.23	5.95
2015	17.50	15.65	6.13
2016	18.37	16.06	6.21
2017	19.03	16.58	6.22
2018	19.67	17.02	6.27
2019	20.08	17.27	6.33
2020	20.41	17.36	6.47
2021	20.56	17.61	6.57
2022	20.74	17.77	6.75
2023	21.05	18.00	6.80
2024	21.24	18.23	6.75
2025	21.52	18.44	6.81
2026	21.77	18.52	6.96
2027	22.01	18.82	7.10
2028	22.32	19.09	7.33
2029	22.72	19.39	7.57

The average prices for ADO, HFO and Natural Gas over the period are shown in Table 4.1-2

Table 4.1-2: Average Fuel Prices over the planning period

Fuel	Price ($/MMBtu)
ADO	19.29
HFO	16.67
NG	6.46

The projected prices shown in Table 4.1-1 were further adjusted to account for freight and other expected local expenses in order to establish the base prices used in the study. The adjustments are as follows:

HFO and ADO:

The projected prices for HFO and ADO were adjusted using Petrojam's pricing formulae for fuel delivery to the various power plants.

Natural Gas:

The projected prices for Natural Gas were adjusted by US$2.50/MMBtu to cover freight charges, LNG infrastructure and gas pipe line costs. This adjustment factor was provided by the LNG Project Team.

Coal

Approximate coal prices ranging between US$70 - US$75 per tonne based on Colombian coal market price indications were used in the study. These prices were further adjusted to include approximate freight rates and handling charges ranging between US$15 - US$20 per tonne. These charges were developed based on International Freight rates and handling charges.

Sources include the following among others:

- International Energy agency (IEA)/Nuclear Energy Agency (NEA) – projected cost of Geenarting Electricty 2010 edition
- IEA Energy Statitcs – Coal Publication
- GlobalCoal Information

Delivered price of coal used in the study is estimated at US$90/tonne.

4.2 Fuel Prices at Plant Site

Fuel prices delivered power plants are given in Table 4.2-1.

Table 4.2-1: Plant Gate Fuel Prices

Fuel Type	Delivered Fuel Prices (US$/MMBtu)	Delivered Fuel Prices
No. 2 Oil (ADO)	17.60	US$102/barrel
No. 6 Oil (HFO)	13.76	US$86/barrel
NATURAL GAS	8.50	
COAL	3.78	US$90/tonne

PETCOKE:

The price of Petcoke is generally lower than coal and provides an attractive alternative; however, no price forecast was developed for this fuel option as it is linked to the expansion and upgrade of the Petrojam Refinery.

5 PLANNING PARAMETERS

5.1 Planning Horizon

The large lead times associated with the commissioning of new generating plants make it necessary to carry out generation expansion planning over an extended time frame.

The study is based on a planning horizon of twenty (20) years, which is in accordance with normal industry practice of 20 to 30 years. Increasing the planning horizon may improve the optimisation of the net benefit of electricity over the long run; however, this may be nullified by the corresponding increases in uncertainty of the various projections that are required.

The reference year for the study is 2010.

5.2 Economic Data

This section presents a brief overview of the planning parameters to be used in the study.
The parameters address the economic/financial criteria and technical constraints that will dictate the conditions of the study.

5.2.1 Currency

All costs are expressed in US dollars.

5.2.2 Insurance

The costs for insurance are included in the fixed operation and maintenance cost component.

5.2.3 Cost of Expected Unserved Energy

The cost of expected unserved energy (COUE) to be utilized in the study is US$2.32/kWh.

5.2.4 Taxes

Taxes are not included in this study.

5.2.5 Cost Escalation

The analysis will be carried out in constant dollar terms based on January 1, 2010 price levels.
Price escalations due to inflation are not considered over the planning horizon.

5.2.6 Discount Rate

The discount rate used in the study is 11.95%, this represents the weighted average cost of capital (WACC) determined by the OUR for Jamaica's electricity sector in 2009.

5.3 Reliability Constraints

5.3.1 Loss of Load Probability

LOLP is a reliability index that indicates the probability that some portion of the load will not be satisfied by the available generating capacity. More specifically, it is defined as the proportion of days per year or hours per year when sufficient generating capacity may be inadequate to satisfy the system demands is likely to be experienced. (Refer to Figure 5.3-1)

LOLP is usually expressed as a ratio of times; for example, 1 day per year equals a probability of 0.00274 (i.e. 1/365).

LOLP actually represents the aggregate duration of all expected outages rather than the probability of an outage occurring.

The LOLP reliability criterion used in the study is two days (48 hours) per year (or 0.55%).
This value represents the likelihood that the demand will outstrip the available capacity for a total of 48 hours in any year given planned maintenance, force outage rates and system demand.

5.3.2 Expected Unserved Energy

EUE measures the expected energy demand which will not be satisfied in any given year as a result of generating capacity deficiencies and/or shortages in basic energy supplies. Mathematically, EUE is the sum of the probability-weighted energy curtailments caused by capacity deficiencies throughout the year.

EUE is expressed either in MWh or as a percentage in which case it is equal to the expected unsupplied energy divided by the annual energy demand and multiplied by 100.

The target value of EUE to be used in the study is not to exceed 1% in each calendar year.

5.3.3 Reserve Margin

Reserve margin is a measure of the generating capacity available over and above the amount required to meet the system load requirements. It is defined as the difference between the total available generating system capacity and the annual peak system load, divided by the peak system load, in other words, it is the excess of installed generating capacity over annual peak load expressed as a fraction (or in percentage) of annual peak load. While this deterministic reliability index does not directly reflect system parameters such as generation mix, unit size and forced outage rates, it does provide a reasonable relative estimate of reliability performance when parameters other than reserve margin remain essentially constant.

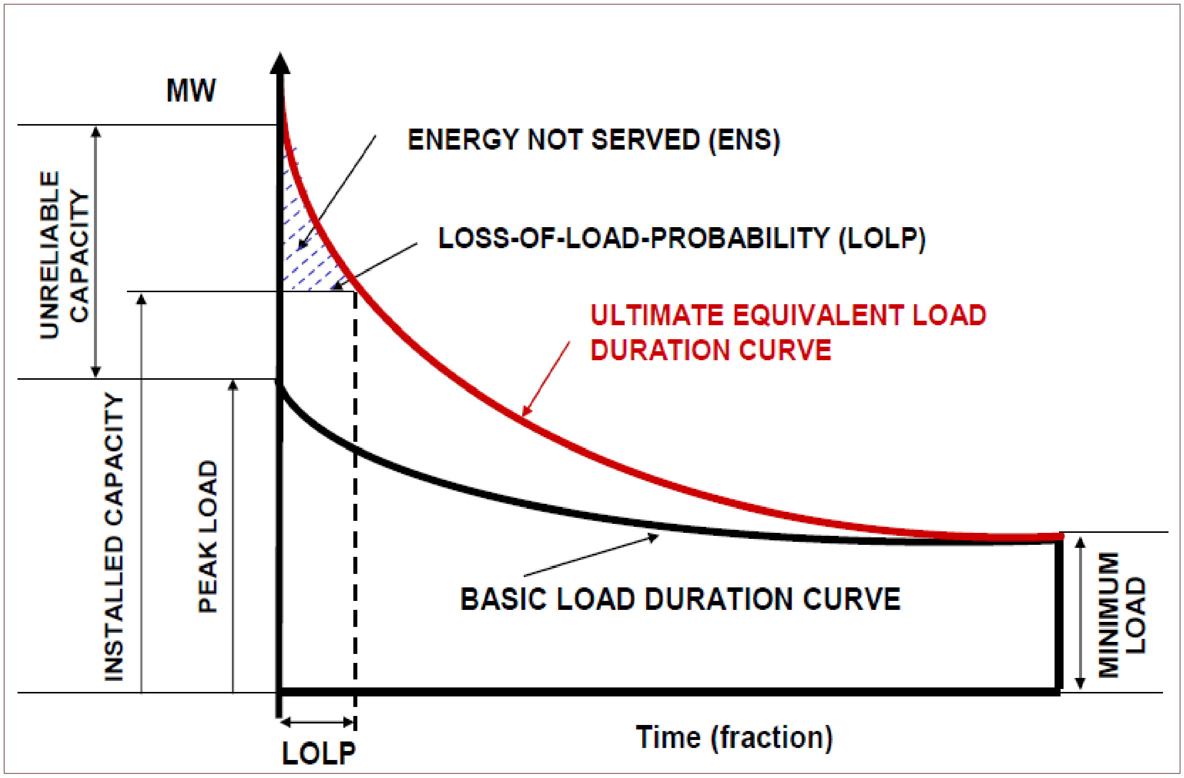
The loss of the single largest generating unit is a reliability measure that reflects the effect of unit size on the reserve requirements. The large unit approach compares the total installed generating capacity less the annual peak system load (i.e. the reserve margin) with the largest installed units on the system. In contrast to reserve margin, this approach begins to recognize explicitly the impact of a single outage; loss of largest generating unit.

Based on the system profile in terms of unit sizes, overall system generating maximum continuous rating (MCR) and peak demand, the minimum reserve margin should be at a level to permit the removal of one of the single largest generating units (currently 68.5MW) for planned maintenance and still be able to maintain adequate supply to customers in the event of an instantaneous trip of another unit`. It is important to note, that the reserve margin is not static, and as the system grows, if no new generating capacity is introduced, the minimum required reserve (%) will dwindle.

The minimum reserve margin used in the study is estimated at 25%.

As for the spinning reserve, JPS has adopted a strategy of maintaining a 30MW capacity level for spinning reserve commitments. This has been modelled as such.

Figure 5.3-1: Illustrating LOLP and Energy-not-Served



Source: Argonne National Laboratory (US DOE)

5.4 Environmental Considerations

One of the major considerations in the expansion an electric generation system is the environmental impact each of the plant types in the list of expansion candidates will have in the process of supplying the increasing load. One of the main environmental considerations for the thermal plants is level of emission gases that are likely to be discharged into the atmosphere.

Environmental effects associated with the expansion of the electricity generation system will be assessed by the appropriate regulatory authority.

It should be noted that this particular study does not address environmental constraints.

6 EXISTING GENERATING SYSTEM

6.1 Background

Although the generation expansion planning process is primarily driven by demand growth projections, it is also significantly influenced by the present characteristics and projected performance of the existing system.

Evaluation of the existing system involves the assessment of the historic performance of the generating units, Original Equipment Manufacturers' (OEM) specifications and recommendations, scheduled maintenance programs and technical operating limitations. The objective of this exercise is to reasonably predict the future performance of the existing system by developing projections of plant parameters including schedule maintenance days, forced outage rates, operations & maintenance cost, efficiency, availability and retirement schedule.

6.2 System Historical Performance

In 2009 total net generation to the grid was approximately 4213.98 GWh of which 3,203.88 GWh resulted in sales to approximately 584,218 customers; with 23.7 % recorded as system losses (refer to Table 6.2-1). Approximately 95% of the production came from fuel oil with the remainder provided by renewable energy technologies comprising of wind and hydro (refer to Figure 1.2-1). Although the renewable capacities of wind and hydro are 20.7 MW and 21.5 MW respectively, hydro contributed approximately 70.5 % of the total production for this group.

Table 6.2-1: 2009 Generation Summary

Net Generation (GWh)	Sales (GWh)	System losses (%)	Average System Heat Rate (kJ/kWh)
4,213.98	3,203.88	23.7	10,154

Data source: JPS

Purchased energy from IPPs accounted for approximately 32 % of the total energy supplied to the grid during the year.

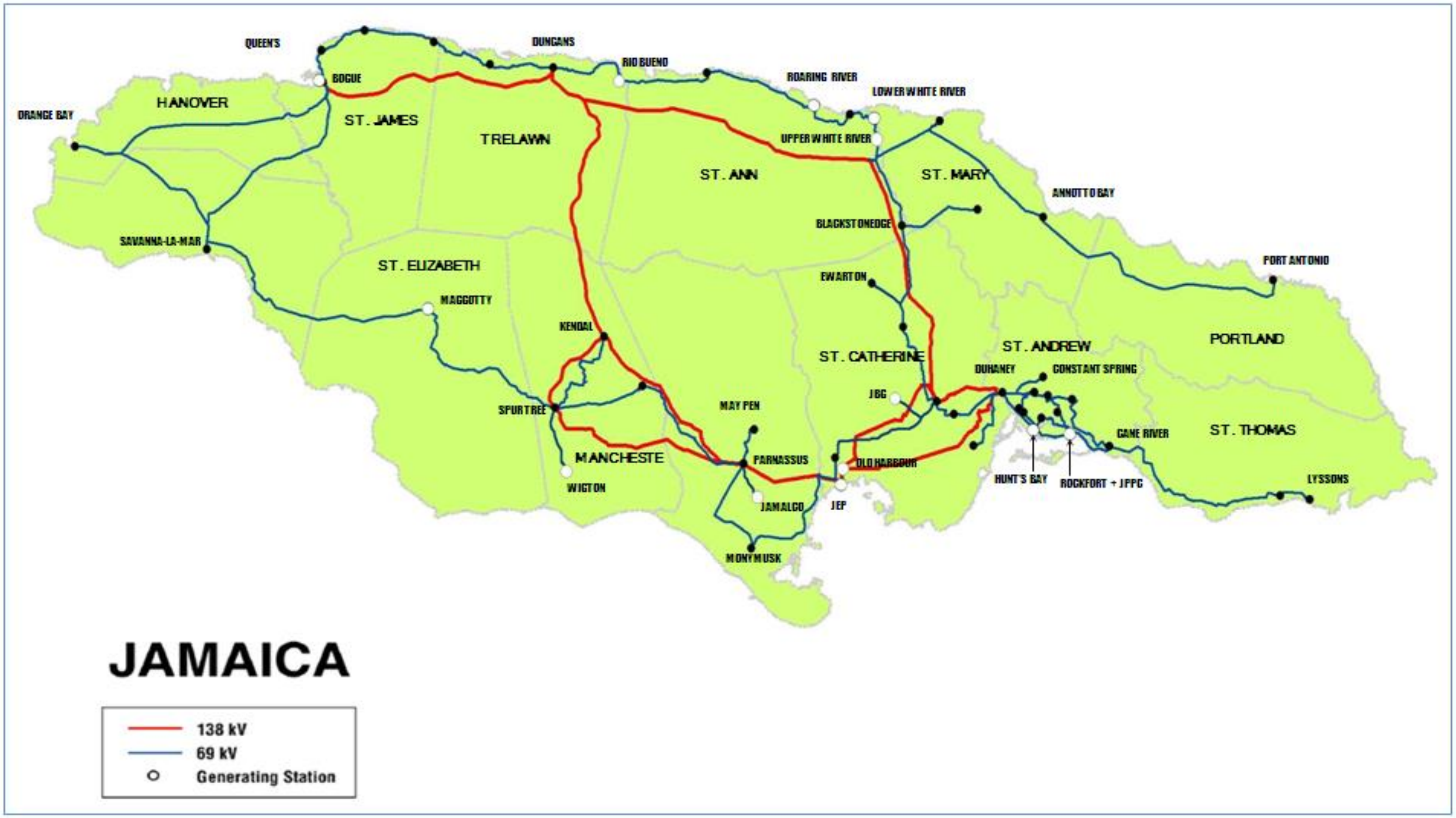
6.3 Existing Generation Sites

There are four (4) major sites that are presently used for power generation. These sites are strategically located based on geography, electrical connectivity and load proximity. This provides them with different attributes and levels of importance especially as it relates to operational flexibility.

Petrojam, the state owned oil refinery, presently supplies all the fuel requirements of JPS and IPPs under long-term Fuel Supply Agreements (FSA).

Figure 6.3-1 shows the general layout of JPS transmission system and the location of existing generating stations and their point of connection to the transmission network. A description of the existing generating sites is provided in Section 6.3.1.

Figure 6.3-1: Layout of the Existing Generation and Transmission System



Source: Electricity Sector Generation Code (edited)

6.3.1 Description of Plant Sites

Old Harbour

The Old Harbour Power Station is located in the Parish of St. Catherine to the south of Old Harbour town. The station is comprised of two generation facilities, a steam plant owned and operated by JPS and medium speed diesel plant privately owned by JEP.
JPS Plant:

The plant consists of four (4) Oil-Fired Steam units powered by HFO (3% sulphur) with a total capacity of 223.5 MW. Fuel is supplied to the plants via a mooring facility owned by JEP. ADO or propane gas is used for initial light–off in the start up of the boilers.

As reported by JPS, OH unit1 (30MW) has been out of operation since August 9, 2008. The unit was forced out of service because of major damage to its turbine rotor and associated auxiliary equipment.

JEP complex:

This facility consists of two (2) barges privately owned and operated by JEP. The barges utilize MSD engines running on HFO (3%) for power generation and have a combined capacity of 124.36 MW. Fuel is supplied to the units via JEP's mooring facility.

Barge#1: consists of eight units with a total capacity of 74.16 MW (8 x 12.06MW)

Barge#2: consists of 3 units with a total capacity of 51.24 (3 x 17.08MW)

Interconnection of the complex (JEP) to the grid is accommodated through a single line to the Old Harbour 138kV switch yard.

Hunts Bay

Hunts Bay Power Station is located in Kingston on the waterfront of the Kingston Harbour.
It consists of a 68.5 MW Steam Turbine-Generator set and two (2) operational Combustion Turbines totalling 54MW. Both No. 6 (HFO - 3% S) and No. 2 (ADO) fuel are used at this station and are supplied directly via pipelines from the adjacent Petrojam Refinery.

Rockfort

The Rockfort Power Station, located adjacent to the Kingston Harbour, consists of a barge containing two (2) SSD units (RF1 – 20MW and RF2 – 20MW). This station is in close proximity to another SSD plant owned by JPPC with a net of capacity of 61MW (2x30MW units). HFO (2.2% S) is supplied to the stations via ship and tanker trucks.

Bogue

Bogue is to the North West of the island in St. James just outside the major tourist area of Montego Bay. It is located 3 kilometers inland and up to 2003 consisted of mainly peaking units. Presently, six (6) Combustion Turbines with a total capacity of 115.5 MW are located at this site. The units are supplied with No. 2 fuel from the Petrojam facility at the Montego Bay Freeport via a pipeline over a three-mile distance. In 2003, a Combined Cycle Gas Turbine unit rated at 114MW operating No. 2 fuel (ADO) was commissioned at the site making the station the second largest on the island on the basis of installed capacity.

Wigton

Wigton Wind Farm is located in the parish of Manchester. It is the first large scale wind production facility on the island and represents the single largest renewable project on one site at 20MW installed capacity. The facility was commissioned in 2004.

Halse Hall

A co-generation facility owned by Jamalco (an alumina production plant) is located in Halse Hall, Clarendon. The generation technology is Oil-Fired Steam. The facility was originally contracted to export 11 MW to the grid subject to process requirements. However, due to activities related to the expansion of alumina refining process, only approximately 5 MW is supplied on average to grid. Fuel is supplied via rail from Jamalco's Rocky Point port.

Spring Village

Jamaica Broilers co-generation facility is located at Spring Village, St. Catherine in the central part of the Island. The complex is comprised of 4 medium speed diesel units. Presently JPS has a 'take as available' arrangement in place with Jamaica Broilers.

Hydro Plant Sites

JPS owns six (7) operational hydro plants at 4 locations across the island. The total capacity is 22.29 MW with the largest unit being 6MW (refer to Table 6.8.2-1).

It should be noted that a hydropower plant with an installed capacity of 0.4 MW is located at Rams Horn in the parish of St. Andrew. This plant has been out of operation for an extended period of time due to significant damages to the civil infrastructure.

According to JPS, the status of the facility is being reviewed with the aim of returning it to service by 2012.

6.4 Capacity Status

Presently, the power system has approximately 816 MW of firm installed generating capacity of this total, 190 MW or 23% is in the form of Power Purchase Agreements (PPAs) between JPS and IPPs. The IPPs contracted for firm capacity are namely, Jamaica Private Power Company (JPPC), Jamaica Energy Partners (JEP) and Jamalco. The Table 6.4-1, details the installed functional capacity of the system.

Table 6.4-1: Installed Capacity

Owner	Technology	Old Harbour	Hunts Bay	Bogue	Rockfort	Other	Total (MW)
JPS	Hydro					22.29	**22.29**
	Steam	223.5	68.5				**292.0**
	Diesel				40.0		**40.0**
	Comb Turbine		54.0	103.5			**157.5**
	Combined Cycle			114.0			**114.0**
IPPs	Steam					5.0	**5.0**
	MSD	124.36					**124.36**
	SSD				61.0		**61.0**
Total							**816.15**

The respective capacities from the following power generation facilities were not included as part of the overall functional capacity because they are not contracted for firm dependable capacity.

- Wigton Wind Farm (20.7 MW) energy only contract
- Jamaica Broilers as available energy contract

6.5 Existing Technology and Fuels

The Jamaican electricity sector over the years has acquired substantial operational and maintenance experience with many different power generation technologies, plant arrangements and configurations, namely:

- Oil-Fired Steam (Conventional - Power only)
- Combustion Turbines (Aero-derivative and Industrial)
- Slow Speed Diesel
- Medium Speed Diesel (Power only)
- Oil-Fired Steam (Co-generation)
- Combined Cycle Gas Turbine (Oil-fired)
- Medium Speed Diesel (Co-generation)
- Run of River Hydro
- Wind Turbine (HAWT)
- Solar (Photovoltaic)

The participation of wind power technology in the Jamaica's electricity system has added another dimension to the monitoring and control strategy of the power system due to the variability in production during normal operations occasioned by the intermittent nature of the resource.

In spite of the challenges imposed by these technologies, the system based on its design, configuration and control strategy has been robust enough to cope with this variable energy production characteristic. It is due to this variability in production that energy supplied to grid from these facilities is transacted under energy only contracts.

It is worth noting that while the average energy contribution from this particular RET is important to the system, the Grid Operator in preparing its daily unit commitment schedule has to commit additional capacity to maintain reliable power supply during periods of large fluctuations in wind power output. This additional capacity allowance imposes an additional cost to the system.

All the fossil fuels used in the electricity sector are petroleum based and are supplied by a single supplier, the state owned Oil Refinery, Petrojam based on long-term Fuel Supply Agreements.

6.6 Treatment of Aged Generation Plants

Table 6.7-1 indicates that many of the existing plants operating in the power system are close to their economic lifespan, while some have surpassed it.

According to standard industrial project assessment practices, the technical lifetime for steam plant is 35 - 40 years. Plant that uses gas turbines including combined cycle is 25 years and diesel plant 25 years.

Power purchase contracts for two of the IPP terminate 20 years after initial commercial operations date; these plants were retired accordingly in the study.

6.6.1 JPS Plants

Preliminary simulation results revealed that the JPS' oil-fired steam units should all be displaced by 2014 for economic reasons. That is because, the addition of more economic new plants to the system caused significant reductions in the utilizations (capacity factors) of the steam units to levels that are not technically feasible for them to operate.

JPS slow speed diesel units (RF1 and RF2) located at Rockfort have been in service from 1985 and are now up for retirement, however, due to level rehabilitation that has been done on these units, displacement has been deferred to 2020.

The peaking units (simple cycle gas turbine) were assessed differently due to the reserve standby role that they play in load dispatch. The last of such unit to be added to the JPS grid was done mainly on the basis of quickly improving the reserve margin and system reliability. In consideration of this functionality, no peaking plant was scheduled for retirement over the time span of the plan.

6.6.2 IPP Owned Plants

Power Purchase Agreements (PPAs) for the existing IPPs operating in the Jamaican power system expires 20 years after the initial commercial operations date. This indicates the timetable for the retirement of these plants.

In the study, IPP owned generation plants are retired at the end of their existing contracts:

Accordingly:

- JPPC is scheduled for retirement in 2017, and
- JEP in 2025

It should be noted that the current IPP contracts provide for possible extension of the agreement for an additional period on terms mutually agreeable between the IPP and JPS. This however, has to be approved by the OUR.

6.7 Characteristics of the Existing Thermal Generating Plants

Table 6.7-1 summarizes the capabilities and performance characteristics of the existing thermal generating units operating in the system.

Table 6.7-1: Capabilities and Performance Characteristics of the Existing Thermal Generating Units

Unit	Description	Fuel	Gross Capacity (MW)	Station Service (%)	Net Capacity (MW)	Min operating level (MW)	Planned Outage Days	Forced Outage Rate (%)	Approx. Availability (%)	Net Heat Rate at Min Capacity (kJ/kWh)	Net Heat Rate at Max. Capacity (kJ/kWh)	Fixed O&M Cost (US$/kW-Month)	Variable O&M Cost (US$/ MWh)	C.O.D	Age (Yrs)
							JPS plants								
OH1	Oil Fired Steam	HFO	30.0	5.0%	28.5		O/S				-			1968	42
OH2	Oil Fired Steam	HFO	60.0	5.0%	57.0	30.0	26	10.0%	83%	13,641	12,854	0.38	6.70	1970	40
OH3	Oil Fired Steam	HFO	65.0	5.0%	61.8	30.0	24	10.0%	83%	13,236	12,452	0.35	6.70	1972	38
OH4	Oil Fired Steam	HFO	68.5	5.0%	65.1	30.0	24	10.0%	83%	13,612	12,407	0.33	6.70	1973	37
HB6	Oil Fired Steam	HFO	68.5	5.0%	65.1	30.0	24	10.0%	83%	13,810	12,272	0.33	6.70	1976	34
RF1	Slow Speed Diesel	HFO	20.0	4.0%	19.2	9.0	11	8.0%	89%	10,538	9,403	0.93	8.00	1985	25
RF2	Slow Speed Diesel	HFO	20.0	4.0%	19.2	9.0	11	8.0%	89%	10,342	9,258	0.93	8.00	1985	25
GT5	Combustion Turbine	ADO	21.5	0.5%	21.4	5.0	18	7.0%	88%	30,951	14,908	0.26	5.00	1974	36
GT10	Combustion Turbine	ADO	32.5	1.3%	32.1	8.0	18	7.0%	88%	24,299	13,563	0.42	5.00	1993	17
GT3	Combustion Turbine	ADO	21.5	0.5%	21.4	5.0	18	7.0%	88%	30,567	14,243	0.39	5.00	1973	37
GT6	Combustion Turbine	ADO	18.0	0.5%	17.9	5.0	7	5.0%	93%	23,919	14,130	0.39	5.00	1990	20
GT7	Combustion Turbine	ADO	18.0	0.5%	17.9	5.0	7	5.0%	93%	28,856	15,772	0.6	5.00	1990	20
GT8	Combustion Turbine	ADO	18.0	0.5%	17.9	5.0	7	5.0%	93%	23,919	14,130	0.6	5.00	1992	18
GT9	Combustion Turbine	ADO	20.0	0.5%	19.9	8.0	7	5.0%	93%	21,137	14,565	0.6	5.00	1992	18
GT11	Combustion Turbine	ADO	20.0	0.5%	19.9	8.0	44	5.0%	83%	15,354	11,807	0.42	5.00	2001	9
BOCC	Combined Cycle	ADO	114.0	2.6%	111.0	80.0	26	3.0%	90%	9,654	9,133	0.99	6.00	2003	7
							Independent Power Providers (IPPs)								
JPPC	Slow Speed Diesel	HFO	60.0		60		26	3.0%	90%		8,144	28.63	9.50	1996	14
JEP	Medium Speed Diesel	HFO												1995	15
JEP	Medium Speed Diesel	HFO	124.36		124.3		23	4.0%	90%		8,206	18.46	20.17	2006	4
ALCO	Oil Fired Steam (CHP)	HFO			0.4		19	5.0%	90%		–	15.00	12.07	–	–

Data source: JPS

6.8 Existing Renewable Technologies

Currently, there are only two (2) Renewable Energy Technologies (RETs) operating in the power system, these are namely, wind and hydro.

Based on performance up to the end of 2009, as shown in Table 6.8-1, approximately 5% of total annual system generation (net) comes from renewable sources (approximately 4% from hydro and 1% from wind).

Table 6.8-1: Renewable Energy contribution to total Net Generation

Year	Renewable (GWh)	Total Net Gen (GWh)	RE % of Net System Generation
2005	201.22	3,877.99	5.2%
2006	225.04	4,046.43	5.6%
2007	211.75	4,075.48	5.2%
2008	207.41	4,123.29	5.0%
2009	198.64	4,213.98	4.7%
Average			**5.1%**

6.8.1 Wind

Wigton Wind farm located in the parish of Manchester was commissioned in 2004 with an installed capacity of 20.7MW. The facility was designed to operate at a capacity factor of approximately 35% (representing an average annual capacity of 7MW); however the plant has since failed to meet expectation. The plant currently produces energy at a capacity factor of less than 30%, a consequence of lower than expected wind distribution and maintenance related problems. In 2009, the wind farm supplied approximately 58.6 GWh of energy to the grid.

Munro wind

Munro College runs a single wind turbine with installed capacity of 225 kW which supplies energy to the grid base on availability.

6.8.2 Hydro

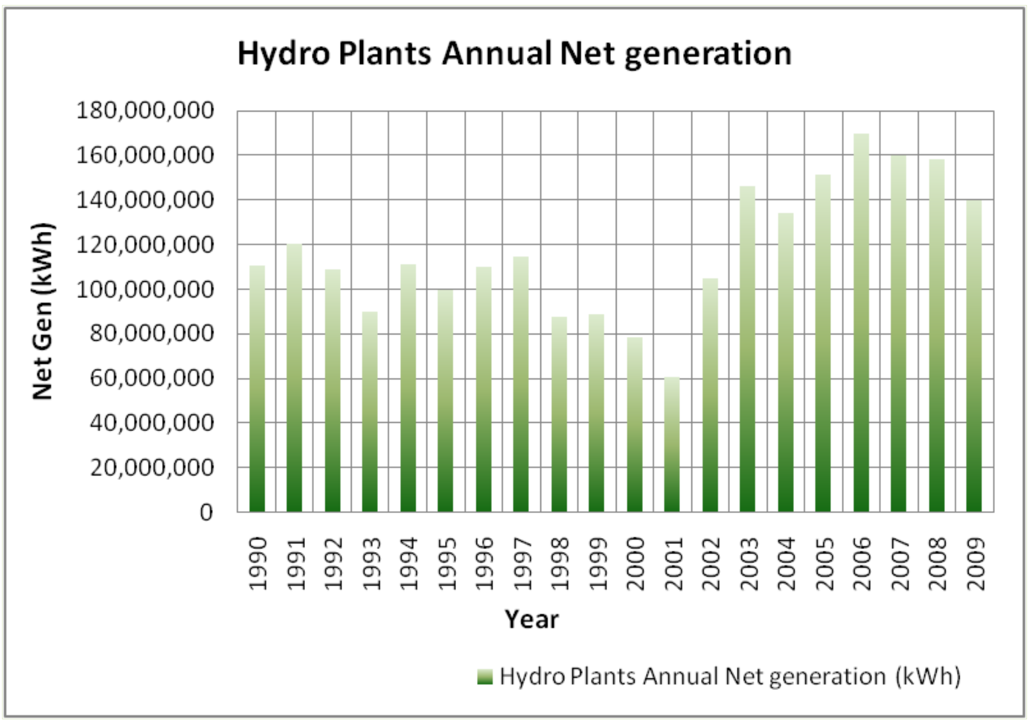
The system consists of seven (7) small hydro plants located at different sites over the country with an aggregated installed capacity of 22.29 MW (refer to Table 6.8.2-1). These facilities are run-of-river (R.O.R) with only a small amount energy produced in the critical period of low river flow rates.

Table 6.8.2-1: Installed Capacity of Existing Hydro Plants

Hydro Plant	Installed Capacity (MW)
Roaring River	4.05
Upper White River	3.19
Lower White River	4.75
Rio Bueno - A	2.50
Rio Bueno - B	1.10
Maggotty	6.00
Constant Spring	0.70
Total	**22.29**

The annual energy generation from the available hydro plants combined averaged 117 GWh over the period 1990 to 2009. This energy was supplied at an average annual capacity factor of approximately 60% (refer to Figure 6.8.2-1)

Figure 6.8.2-1: Hydro Plants Net Generation over the Period 1990 to 2009



6.9 Expected Energy from Existing Renewable Technologies

Table 6.9-1 shows the expected energy generation from existing Renewable Energy Technologies modelled in the study.

Table 6.9-1: Expected Generation from Existing RET

Renewable Energy Technology	Installed Capacity (MW)	Expected Annual Energy Contribution (GWh)
Hydro	**22.3**	**155.0**
Wind	**20.7**	**54.4**

6.10 Jamaica's Renewable Potential

In order to realize Jamaica's renewable potential, further development of indigenous renewable energy resources such as solar, hydro, wind and biomass will have to be explored with the goal of increasing the percentage of Renewables in the energy mix. Development of this potential will benefit the country by reducing its dependence on imported oil. Increased use of Renewables will also result in lowering the level of air pollution, a smaller carbon footprint for Jamaica and better enable compliance with international conventions on climate change.

The goal of realizing Jamaica's energy resource potential through the development of renewable energy sources as outlined in the National Energy Policy (2009 – 2030) is dependent on the following among other things:

- Increasing the percentage of Renewables in the energy mix by meeting the proposed targets of 11% by 2012, 12.5% by 2015 and 20% by 2030
- Reducing dependence on imported energy supplies through continued exploration for and development of indigenous energy resources where economically viable and technically feasible
- Prioritisation of renewable energy sources by economic feasibility criteria, environmental considerations including carbon abatement
- Enhancing the development of efficient and low cost renewable plants with a size of 15 MW or more on a competitive basis through a level playing field
- Introducing strategy that ensures that less than 15MW of renewable energy plants will be built on no-objection basis using base opportunity cost and negotiable premium cap and 15MW or more to be obtained on a competitive basis through the OUR process

6.10.1 Renewable Potential for Electric Power generation

The potential for grid connected renewable projects is summarized in Table 6.10-1

Table 6.10 -1: Renewable Potential for Electricity Generation

Renewable Potential in Jamaica			
Hydro	**Wind**	**Biomass**	**Solar**
> 80 MW	**> 60 MW**	**>100 MW**	**-**

Source: ECLAC 2005, OUR assessment

7 COMMITTED PROJECTS

7.1 Thermal Plants

In this study, one thermal generating plant has been modelled as a committed project. The plant is a medium speed diesel fuelled by HFO (1.8% Sulphur) to be located at Hunts Bay in the parish of Kingston and is expected to provide interim capacity of 65.5 MW to the grid by the end of 2011.

The facility will supply electric power using six (6) diesel generators operating at 11 kV at the generator terminals. Each generator will have an active power rating of 11,349 kW and will have an automatic speed governor and an automatic voltage regulator (AVR) to facilitate operation in parallel with existing generating sets on the power grid.

Table 7.1-1: gives the capabilities and operating cost characteristics of the committed generating plants.

Table 7.1-1: Performance and Operating Cost Characteristics of the Committed Thermal Generating Plant

Plant Type	Fuel Type	Net Export to Grid (MW)	Planned Outage Days	Forced Outage Rate (%)	Net Heat Rate at Maximum Capacity (kJ/kWh)	Fixed O&M Cost (US$/kW-Month)	Variable O&M Cost (US$/MWh)
MSD	HFO	65.5	15	4.0	8,569	6.054	13.60

7.2 Petcoke Cogeneration Project

A 100 MW Petcoke-fired Cogeneration plant (a joint venture between JPS and Petrojam) which would be developed as a result of the expansion of Petrojam's refinery was proposed as a far back as 2007. This project, if implemented, is expected to provide 82MW of net capacity to the grid by 2013. However, no data for modelling the plant was submitted and as such this project was not included in the expansion plan.

7.3 Renewable Projects

7.3.1 Expansion of Wigton Wind Farm

Based on a proposal submitted to the OUR by Wigton Wind Farm Ltd. for the addition of new generation to the grid, the company has indicated its commitment to expanding its existing generating facility of 20.7 MW by an additional 14 MW. This 14.0 MW addition will be comprised of (7x2 MW), Vestas V80 wind turbines interconnected with the power grid.

The expected average annual energy production from this additional capacity that will be exported to the grid is 37.0 GWh at an average capacity factor of 30%.

The energy contribution from this additional capacity has been modelled in the study.

In addition to the committed thermal plant mentioned above, two small renewable energy plants are also considered. These are described in Table 7.3-1.

Table 7.3-1: JPS Proposed Renewable Projects

Project	Capacity (MW)	Output	Completion Date
Munro Wind Farm	3.0	10.5 GWh/yr @ 40% CF	Dec-10
Maggotty Hydro	6.4	26.0 GWh/yr @ 45% CF	Dec-12

8 EXPANSION OPTIONS

8.1 Power Plant Technology Assessment

Various power plant types are available for the expansion of the electricity generation system, such as combined and simple cycle gas turbines, internal combustion reciprocating engines, pulverized coal plants, nuclear plants, hydropower plants, wind turbines and photovoltaic. The selection of the most suitable types of power plant for the power generation mix is based to a large extent on their specific operational performance and cost characteristics.

Power plants have traditionally been grouped according to their mode of operation into base load, peak load and intermediate load (load-following).

Base load plants are relatively large plants designed to operate continuously for at least 60% of the year, generating electricity at a constant rate irrespective of electricity demand, except in the case of repairs or maintenance. They usually have low operating costs and high thermal efficiencies, but in general they cost more to construct have long start-up times.

Load following plants operate for approximately 20% to 40% of the year reducing their output even shutting down during periods of low demand, for example during the night or weekends.

Peak load plants operate only when there is a high demand for electricity, from as much as few hours per to a few days per year -no more than 10% of the total hours in the year. They are usually less efficient than base load plants, hence they have higher operating costs, but they are cheaper to build and have very short start-up times.

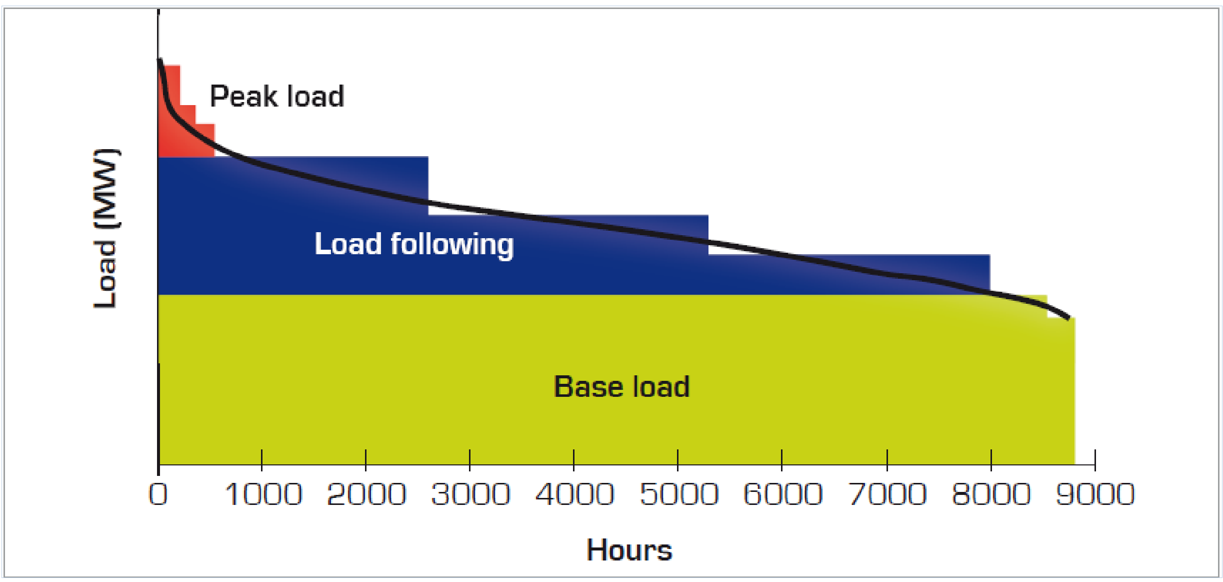
Table 8.1-1: Cost characteristics of groups of power plants

Power Plant Group	Annual Fixed Cost (FC)	Variable Cost per unit of Electrical Energy Generated (VC)
Base load	High	Low
Intermediate load	Medium	Medium
Peak load	Low	High

The grouping of power plants as indicated above changes over time. Key criteria are the economics of electricity generation and the technical ability of the plant to adapt to rapid changes in plant output in response to changes in demand.

The proportion of these groups of power plant in the electricity generation system depends on the requirement for peak and base load, which is reflected in the shape of the LDC. This is schematically illustrated in Figure 8.1-1. The participation of base load plants is high when the LDC is flattened. In contrast, a prominent peak will necessitate a large peak plant capacity. However, the shape of the LDC is not the sole determinant of the technology mix. This is influenced by the shape of the LDC together with cost attributes of the different power plant type.

Figure 8.1-1: **Schematic representation of the contribution of base load, load following and peak load plants in the generation capacity of an electricity system as a result of the shape of the load duration curve. The coloured steps in the graph represent the capacity of the individual power plants; and the height of each coloured segment is an indication of the capacity of the plants in the corresponding mode of operation.**



Each power plant type has its own fixed and variable cost characteristics and hence is represented by its own characteristic cost curve. The general cost characteristics for different groups of power plants are summarized in Table 8.1-1.

8.2 Technology Options

Generation costs are important factors in the choice of technology to meet increasing demand and to dispalce ageing plants. The accuracy and usefulness of these costs significantly depends on the assessments made in estimating the input cost components such as, investment, fuel and O&M costs.

Gas Turbines

Gas turbines (open and combined cycle) are standardised to a great extent, with many similar plants in operation. These plants have relatively short construction times and can be built within 6 to 24 months. Combine Cycle Gas Turbibes (CCGT) can be built as quickly as 18 months in ideal circumstances, but can also take up to 36 months. These technologies can be built in relatively small sizes without significantly increasing cost per kW of installed capacity. CCGTs can thus be built in stages, commissioning the gas turbine before the entire plant, and in modules, increasing the capacity in steps.

Coal Plants

Coal plants are adapted to specific local conditions, making standardisation more difficult. However, investment costs are relatively stable and predictable. The construction times for these plants are 4 to 5 years.

In addition to construction cost issues, a power plant project also needs planning and development, licensing and approvals, all varying with project, location and technology.

8.3 Thermal Candidate Plants

Tables 8.3-1 summarizes the performance and cost characteristics of the candidate generation plants that were considered for expansion of the country's power generation system.

Table 8.3-1: Performance and Cost Characteristics of Candidate Technologies

Plant Type	Fuel Type	Plant Capacity (MW)	Planned Outage Days	Forced Outage Rate (%)	Net Heat Rate at Maximum Capacity (kJ/kWh)	Fixed O&M Cost (US$/kW-Month)	Variable O&M Cost (US$/MWh)
Combined Cycle	NG	120	26	3.0	7,654	1.07	2.53
Combined Cycle	ADO	120	26	3.0	7,654	1.07	2.53
Combustion Turbine	NG	40	18	3.0	10,600	1.04	3.70
Combustion Turbine	ADO	40	18	3.0	10,600	1.04	3.70
Medium Speed Diesel	HFO	60	18	4.0	8,569	6.05	13.60
Slow Speed Diesel	HFO	60	18	4.0	7,596	7.00	8.50
Coal Fired Steam	COAL	120	26	5.0	9,729	2.40	5.00

These data were derived from several sources including:

- Assumption to the EIA Annual Energy Outlook, 2010
- Gas Turbine World 2010 GTW Handbook
- CRS - Power Plants Characteristics and Costs Report to US Congress 2008.

Taking into consideration data from Jamaica's recently concluded Generation Capacity Procurement.

Note: New generation capacity from nuclear sources was not considered in this study.

8.4 Capital Investment Costs of Candidate Plants

Investment costs are probably the most important parameter in any investment decision. They vary greatly from technology to technology, over time and from country to country. They are sensitive to a number of input factors such as manufacturing costs, labour and other construction-related costs. Plant and equipment costs are also subject to manufacturing capacity constraints. High demand for some equipment worldwide may cause equipment prices to escalate (example, gas and wind turbines).

The capital investment costs for the various candidate generation plants that were considered for expansion of the generation system are shown in Table 8.3-2 below. The costs given are inclusive of the interests during construction (IDC) related expenses.

Table 8.4-1: Capital Investment Costs for the Candidate Generating Plants

Plant Type	Total Capital Cost - IDC included (US$/kW)	Construction Period (Years)	Economic Life (Years)	Emission Control unit included in cost
Coal Plant (PV)	3019	4	35	ESP, FGD, SCR[2]
Combined Cycle (NG/ADO)	1317	2	25	SCR
Combustion Turbine NG/ADO)	870	1	25	SCR
Medium Speed Diesel	1690	1	25	
Slow Speed Diesel	2397	2	25	

8.5 Capital Cost Components

The total investment cost of a power generation plants considered in this study includes the overnight construction cost and IDC, but excludes refurbishing and decommissioning costs.

The overnight construction cost includes owner's cost, EPC (engineering, procurement and construction) and contingency costs.

- EPC cost: this is the cost of the primary contract for building the plant. It includes the cost of designing the facility, buying the equipment and materials, and construction
- Owner's cost: these are any construction costs that the owner handles outside the EPC contract.

[2] ESP – Electro Static Precipitator; FGD – Flue Gas Desulphurization ; SCR – Selective Catalytic Recovery

Capitalized financing charges: a plant developer incurs financing charges while a power plant is being built. This includes interest on debt and an imputed cost of equity capital. Until the plant is operating these costs are capitalized; that is, become part of the investment cost of the project for tax, regulatory and financial analysis purposes.

9 EXPANSION STRATEGIES

9.1 Natural Gas Case

The GOJ fuel diversification strategy includes landing Natural Gas on the island for consumption in the industrial and electricity sectors together with increasing the penetration of renewable energy base resources in the portfolio mix.

The latest available information on LNG indicates that it may become available in 2013

The specific terms of a LNG deal have not been finalized and therefore the information is not available. However, for the purpose of this study the OUR has based its price projections on the EIA, 2010 AEO Natural Gas price and adjusted to reflect plant gate price based on a mark-up of US$2.50/MMBtu provided to the OUR by the LNG project development team.

In developing this case, the following were assumed:

- Natural gas is assumed available by the end of 2013
- Existing generating units were not converted to consume Natural Gas
- Natural Gas is assumed available at a price of US$ 8.50/MMBtu

9.2 Natural Gas/Coal Case

Due to the relatively long time associated with the construction of coal plants, and having cognisance to the GOJ's gas infrastructure development schedule of landing gas on the island by 2013, coal as a fuel option and by extension coal technologies could not be considered as a competing option during the initial phase of the expansion, that is, at the beginning of the year 2014. From a practical standpoint, 2016 is a more likely date for evaluating a coal option.

In this case, Natural Gas would be used as a bridge fuel offering a short term solution until coal becomes available.

As in the case with natural gas, the price of coal used in the study is based on EIA, 2010 Annual Energy Outlook fuel prices forecast.

In developing the case, the following were assumed:

- Natural gas is assumed available by the end of 2013
- Existing generating units were not converted to consume Natural Gas

- Coal is assumed available at a price of US$ 90/tonne (US$3.78/MMBtu)
- Coal is assumed available in 2016.

9.3 Business-as-usual case

In developing this case, the following were assumed:

- Natural gas is assumed unavailable throughout the study.
- Coal is assumed unavailable throughout the study.
- The expansion is based on HFO and ADO.

9.4 Simulation Results

The results of the WASP simulations to determine the size and timing of the capacity requirements for each expansion case are as follows:

9.4.1 Natural Gas Case

The recommended Generation Expansion Plan for the Natural Gas expansion strategy is summarized in Table 9.4.1-1 and Figure 9.4.1-1. The expansion schedule is as follows:

2014:

- Commissioning of 351 MW (360 MW gross – 3 X 120MW) of Natural Gas-fired Combined Cycle capacity
- Displacement of Old Harbour units 2, 3, 4 and Hunts Bay B6 - (249 MW of oil-fired steam capacity)

2016: Commissioning of 117 MW (120 MW gross) Natural Gas-fired Combined Cycle unit
2017: Commissioning of 39 MW (40 MW gross) Simple Cycle Gas Turbine unit
2018:

- Commissioning of 117 MW Natural Gas-fired Combined Cycle unit
- Retirement of JPPC (60MW) – expiration of PPA

2019: Commissioning of 39 MW Simple Cycle Gas Turbine unit
2020: Commissioning of 117 MW Natural Gas-fired Combined Cycle unit
2022: Commissioning of 117 MW Natural Gas-fired Combined Cycle unit
2024: Commissioning of 117 MW Natural Gas-fired Combined Cycle unit
2025: Commissioning of 39 MW Gas Turbine
2026:

- Commissioning of 117 MW Natural Gas-fired Combined Cycle unit
- Retirement of JEP Barges located at Old Harbour (124.2MW) – expiration of PPA

2028: Commissioning of 39 MW Simple Cycle Gas Turbine unit
2029: Commissioning of 117 MW Natural Gas-fired Combined Cycle unit

The generation capacity required at the beginning of 2014 is projected at 360 MW (3x120 MW) representing a net capacity to the system of approximately 351 MW.

As derived from the WASP optimisation, the indicative cost of the plan (2010 – 2029) is **US$5.77 Billion** (2010 constant dollars). (Refer to Appendix 1)

Table 9.4.1-1: Demand/Capacity Projections for 2010 to 2029 for the Natural Gas Strategy

Year	Net Capacity Retired (MW)	Net Capacity Addition (MW)	Plant Added/Retired	Total Net Capacity (MW)	Net System Peak (MW)	Reserve Capacity (MW)	Reserve Capacity (%)	Loss of load Probability (%)	Loss of load Probability (days)
2010				773.1	625.8	147.3	23.5%	2.971	10.8
2011				773.1	640.5	132.6	20.7%	2.433	8.9
2012		65.5	JEP (West Kgn) MSD plant	838.6	660.8	177.8	26.9%	0.556	2.0
2013				838.6	686.5	152.1	22.2%	0.974	3.6
2014	249	351	Install 3 NGCC units; Retire OH2,OH3,OH4, B6	940.6	717.0	223.6	31.2%	0.139	0.5
2015				940.6	749.3	191.3	25.5%	0.317	1.2
2016		117	Install NGCC	1057.6	782.6	275.0	35.1%	0.051	0.2
2017		39	Install GT unit	1096.6	816.1	280.5	34.4%	0.045	0.2
2018	60	117	Install NGCC unit; Retire JPPC	1153.6	852.8	300.8	35.3%	0.039	0.1
2019		39	Install GT unit	1192.6	890.3	302.3	34.0%	0.038	0.1
2020	38.4	117	Install NGCC unit	1271.2	928.6	342.6	36.9%	0.019	0.1
2021				1271.2	967.7	303.5	31.4%	0.049	0.2
2022		117	Install NGCC unit	1388.2	1007.6	380.6	37.8%	0.010	0.0
2023				1388.2	1048.3	339.9	32.4%	0.028	0.1
2024		117	Install NGCC unit	1505.2	1089.9	415.3	38.1%	0.005	0.0
2025		39	Install GT unit	1544.2	1132.3	411.9	36.4%	0.006	0.0
2026	124.3	117	Install NGCC unit; Retire JEP (OH)	1536.9	1175.6	361.3	30.7%	0.022	0.1
2027				1536.9	1219.8	317.1	26.0%	0.059	0.2
2028		39	Install GT unit	1575.9	1264.9	311.0	24.6%	0.069	0.3
2029		117	Install NGCC unit	1692.9	1310.9	382.0	29.1%	0.017	0.1

Figure 9.4.1-1: Supply versus Demand Projections (2010 – 2029) – Natural Gas Case

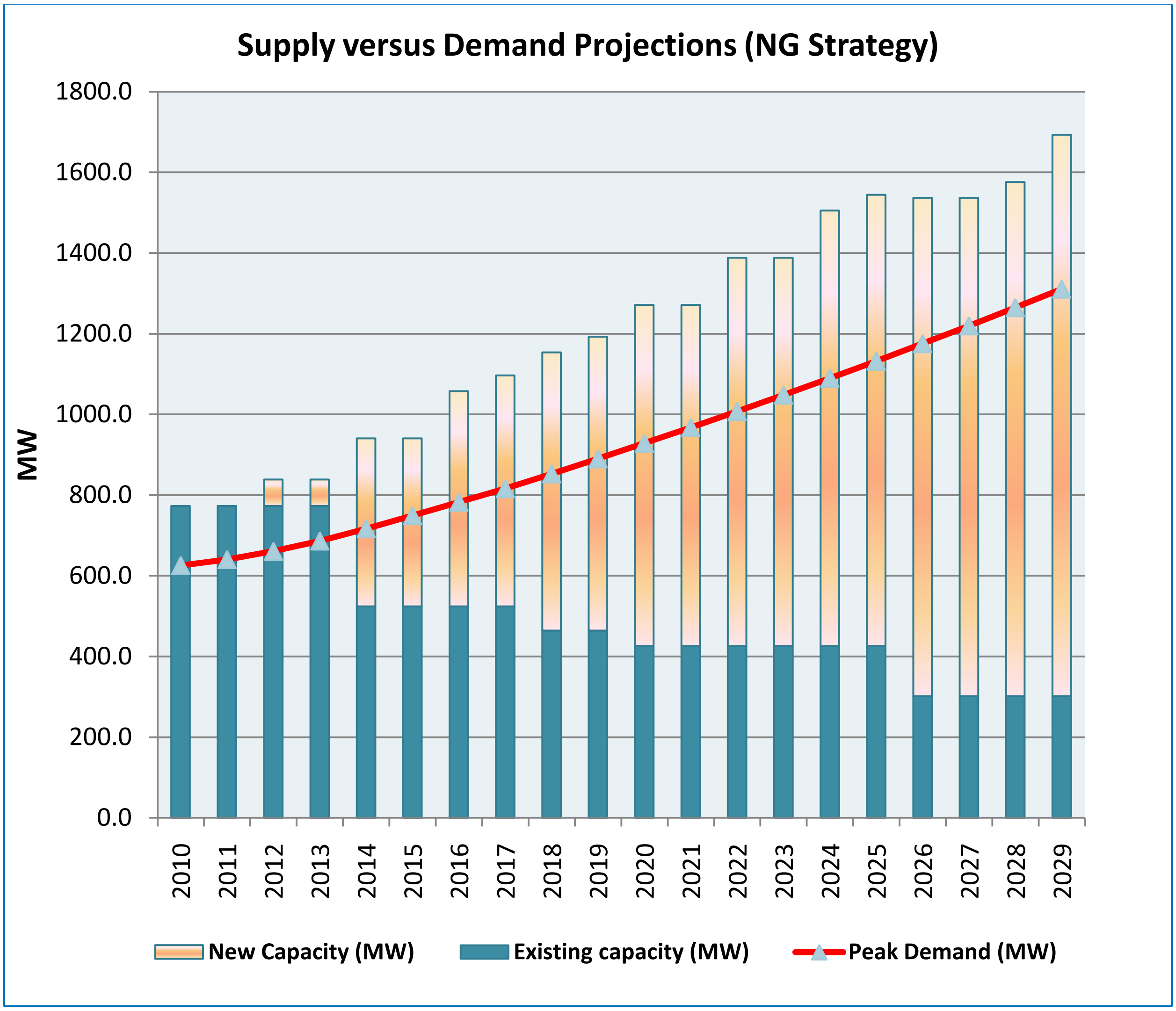
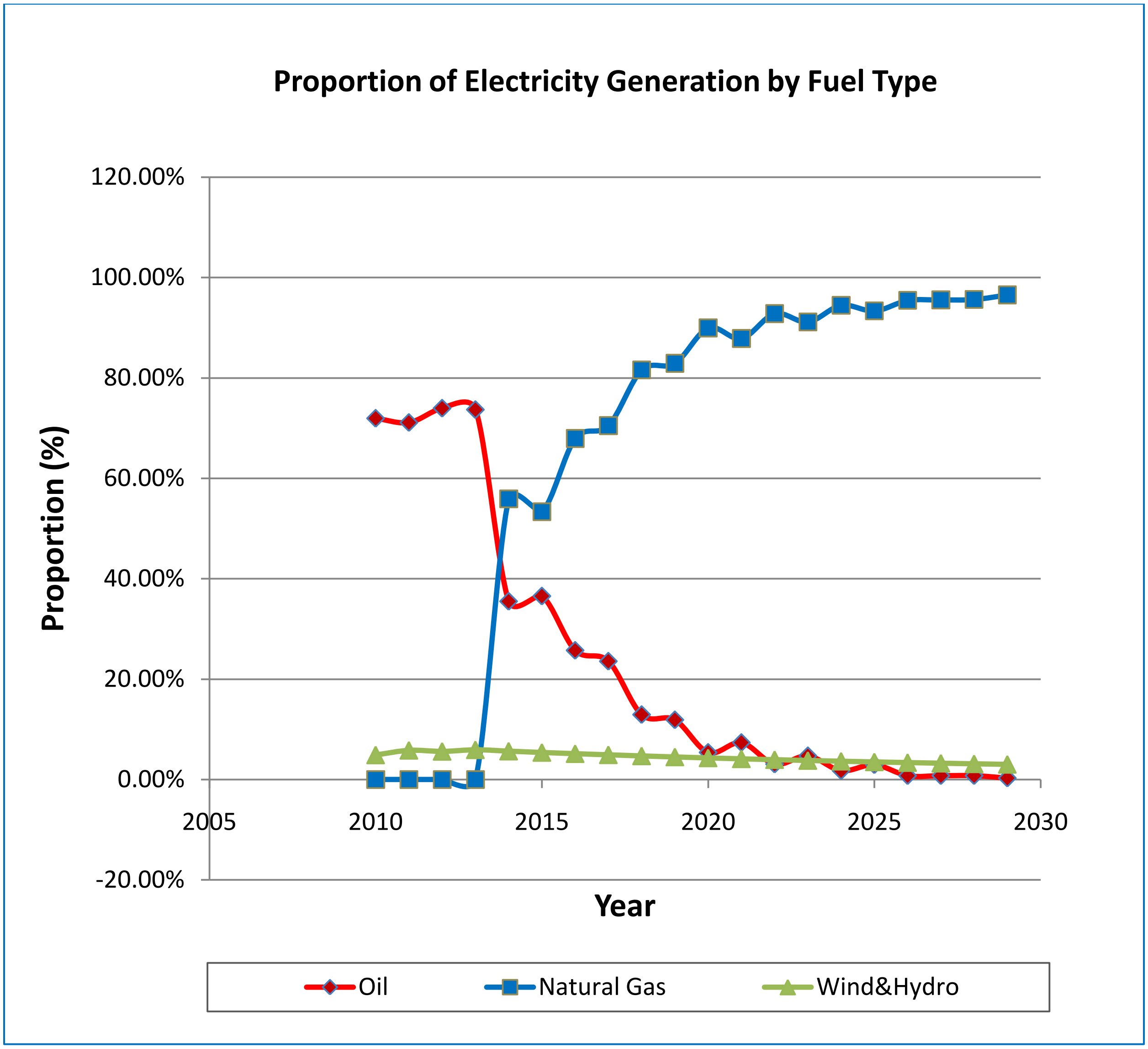


Figure 9.4.1-2: Proportion Electricity Generation Fuel Type (NG strategy)



The composition of electricity generation from the various energy resources under the Natural Gas expansion is shown in Figure 9.4.1-2. The relative proportions indicate that the fuel diversification objective was not necessarily realised under this expansion strategy. The result rather reflects the substitution of one energy source for another.

9.4.2 Natural Gas/Coal Case

The recommended Generation Least Cost Expansion Plan for the case in which Natural Gas and Coal are available for fuel diversification is summarized in Table 9.4.2-1 and Figure 9.4.2-1. The expansion schedule is as follows:

2014:

- Commissioning of 351 MW (360 MW gross – 3X120 MW) Natural Gas Combined Cycle capacity.
- Displacement of Old Harbour units 2, 3, 4 and Hunts Bay B6 - (oil-fired steam)

2016: Commissioning of 114 MW (120 MW gross) Coal unit
2017: Commissioning of 39 MW Simple Cycle Gas Turbine capacity
2018:

- Commissioning of 114MW Coal unit
- Retirement of JPPC (60 MW) – expiration of PPA

2020: Commissioning of 114 MW Coal unit
2021: Commissioning of 114 MW Coal unit
2023: Commissioning of 114 MW Coal unit
2025: Commissioning of 114 MW Coal unit
2026:

- Commissioning of 114 MW Coal unit
- Retirement of JEP (Old Harbour) MSD plant (124.36MW) – expiration of PPA

2028: Commissioning of 114MW Coal unit

The Total net capacity requirement for the system 2014 is projected at 351 MW (360 MW - gross)

As derived from the WASP optimisation, the plan (2010 – 2029) has a total cost of US**$5.84 Billion** (indicative). (See Appendix 2)

Table 9.4.2-1: Demand/Capacity Requirements for 2010 to 2029 (Natural Gas/Coal Plan)

Year	Net Capacity Retired (MW)	Net Capacity Addition (MW)	Plant Added/Retired	Total Net Capacity (MW)	Net Peak (MW)	Reserve Capacity (MW)	Reserve capacity (%)	Loss of load Probability (%)	Loss of load Probability (days)
2010				773.1	625.8	147.3	23.5%	2.982	10.9
2011				773.1	640.5	132.6	20.7%	2.441	8.9
2012		65.5	JEP (West Kgn) MSD plant	838.6	660.8	177.8	26.9%	0.557	2.0
2013				838.6	686.5	152.1	22.2%	0.977	3.6
2014	249	351	Install 3 NGCC units; Retire OH2,OH3,OH4, B6	940.6	717.0	223.6	31.2%	0.138	0.5
2015				940.6	749.3	191.3	25.5%	0.317	1.2
2016		114	Install Coal unit	1054.6	782.6	272.0	34.8%	0.066	0.2
2017		39	Install GT unit	1093.6	816.1	277.5	34.0%	0.058	0.2
2018	60	114	Install Coal unit; Retire JPPC	1147.6	852.8	294.8	34.6%	0.066	0.2
2019				1147.6	890.3	257.3	28.9%	0.164	0.6
2020	38.4	114	Install Coal unit	1223.2	928.6	294.6	31.7%	0.096	0.4
2021		114	Install Coal unit	1337.2	967.7	369.5	38.2%	0.025	0.1
2022				1337.2	1007.6	329.6	32.7%	0.065	0.2
2023		114	Install Coal unit	1451.2	1048.3	402.9	38.4%	0.017	0.1
2024				1451.2	1089.9	361.3	33.1%	0.046	0.2
2025		114	Install Coal unit	1565.2	1132.3	432.9	38.2%	0.014	0.1
2026	124.3	114	Install Coal unit; Retire JEP (OH)	1554.9	1175.6	379.3	32.3%	0.049	0.2
2027			Install Coal unit	1554.9	1219.8	335.1	27.5%	0.123	0.4
2028		114		1668.9	1264.9	404.0	31.9%	0.041	0.1
2029			Install Coal unit	1668.9	1310.9	358.0	27.3%	0.104	0.4

Figure 9.4.2-1: Supply versus Demand Projections (2010 – 2029) – NG/Coal Case

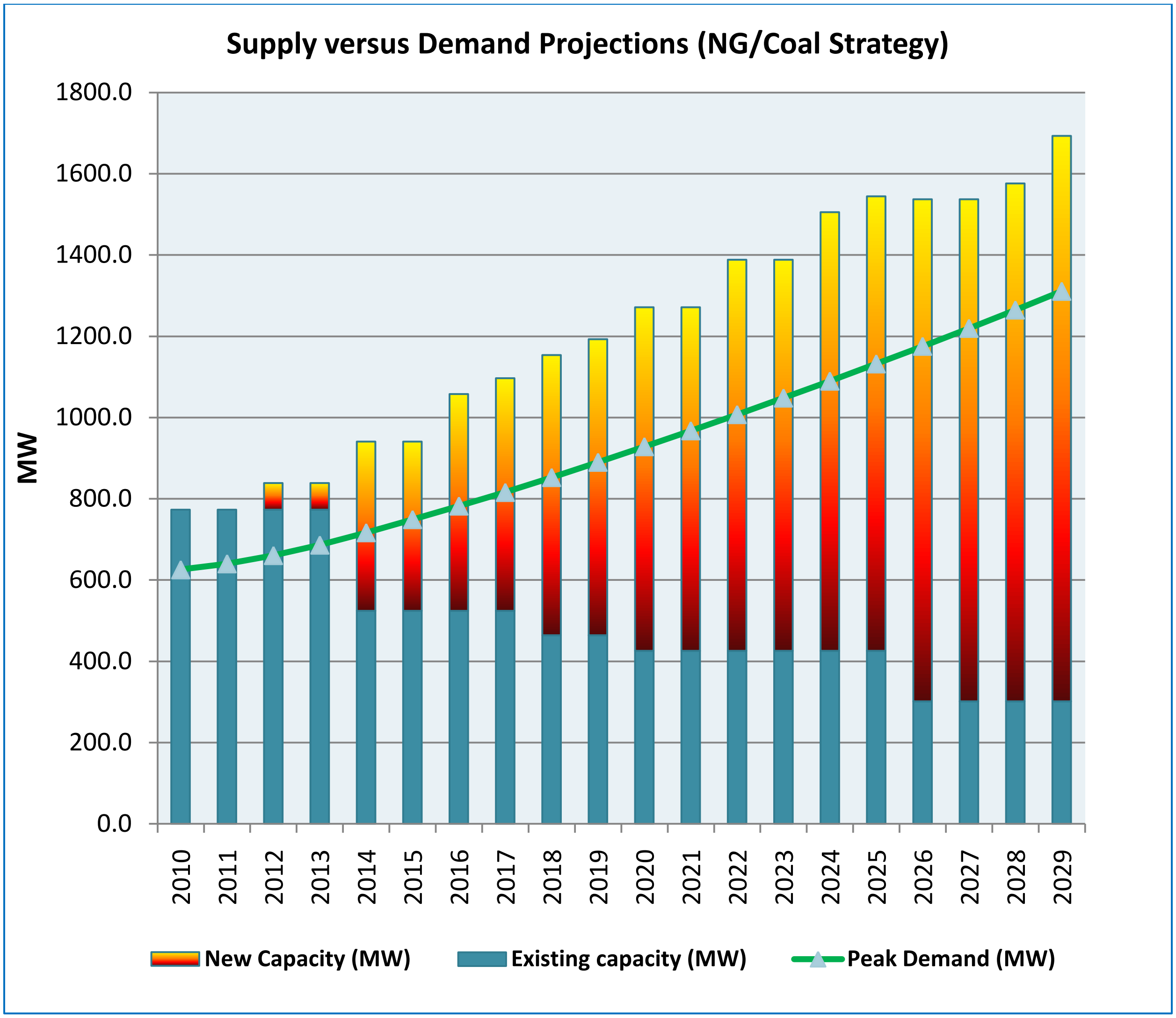
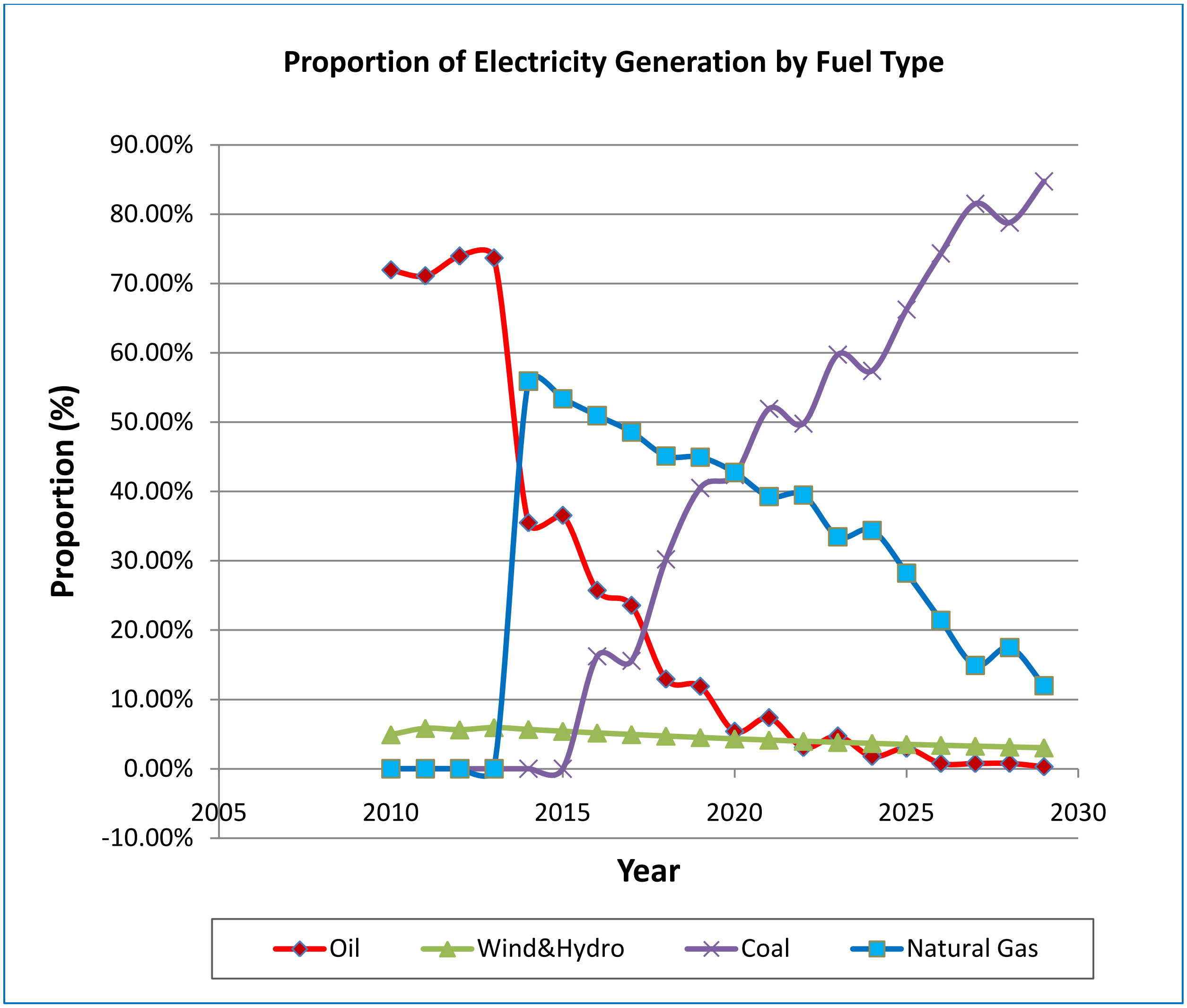


Figure 9.4.2-2: Proportion Electricity Generation Fuel Type (NG/Coal Strategy)



The composition of electricity generation from the various energy resources under the Natural Gas / coal expansion is shown in Figure 9.4.1-2. This scenario reflects a more diversified portfolio.

9.4.3 Business- as-usual Case (HFO & ADO)

The Generation Least Cost Expansion Plan in which the use of petroleum based fuels (HFO and ADO) is continued is summarized in Table 9.4.3-1 and Figure 9.4.3-1. The expansion schedule is as follows:

2011: Commissioning of JEP New 65.5 MW (net) MSD plant.
2014:

- Commissioning of 360 MW (6X60 MW) Slow Speed Diesel capacity for displacement of aged, inefficient baseload capacity and to peak demand growth requirement.
- Retirement of Old Harbour units 2, 3, 4 and Hunts Bay B6 - (oil-fired steam)

2016: Commissioning of 60 MW SSD capacity
2018:

- Commissioning of 120 MW (2X60 MW) SSD capacity
- Retirement of JPPC (60 MW) – expiration of PPA

2019: Commissioning of 60 MW SSD capacity
2020: Commissioning of 60 MW SSD capacity
2021: Commissioning of 60 MW SSD capacity
2022: Commissioning of 39 MW Oil-fired Combustion Turbine capacity
2024: Commissioning of 60 MW SSD capacity
2025: Commissioning of 39 MW Oil-fired Combustion Turbine capacity
2026:

- Commissioning of 60 MW SSD capacity
- Commissioning of 117 MW Oil-fired Combined Cycle capacity
- Retirement of JEP MSD plant located at Old Harbour (124.36MW) – expiration of PPA

2027: Commissioning of 60 MW SSD capacity
2028: Commissioning of 60 MW SSD capacity
2029: Commissioning of 60 MW SSD capacity

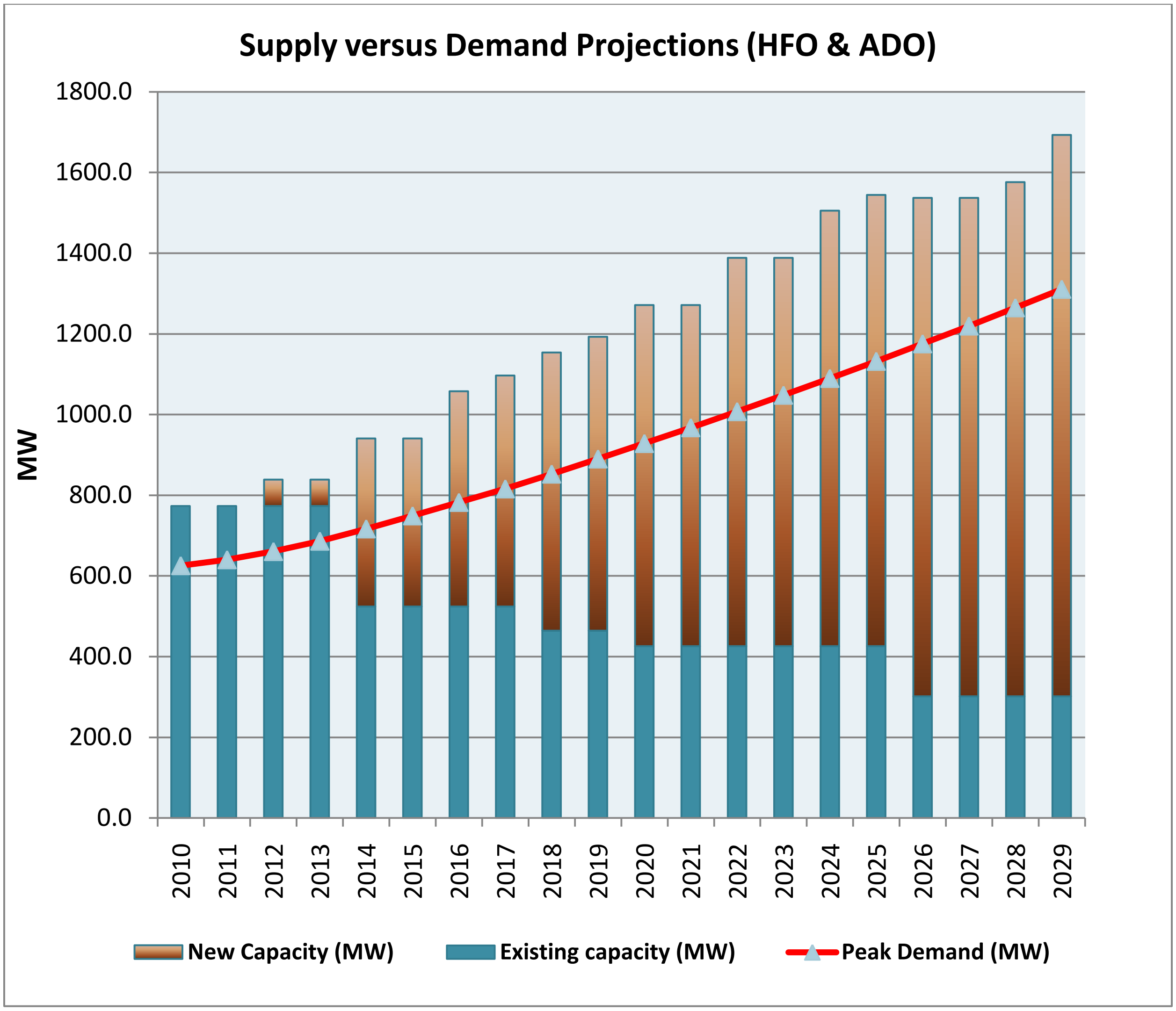
The Total net capacity requirement for the system 2014 is projected at 360 MW.

As derived from the WASP optimisation, the plan (2010 – 2029) has a total cost of US**$ 8.17 Billion** (2010 constant dollars). (See Appendix 3)

Figure: Table 9.4.3-1: Demand/Capacity Requirements for 2010 to 2029 (Business-as-usual case – HFO & ADO)

Year	Net Capacity Retired (MW)	Net Capacity Addition (MW)	Plant Added/Retired	Total Net Capacity (MW)	Net System Peak (MW)	Reserve Capacity (MW)	Reserve capacity (%)	Loss of load Probability (%)	Loss of load Probability (days)
2010				773.1	625.8	147.3	23.5%	2.982	10.9
2011				773.1	640.5	132.6	20.7%	2.441	8.9
2012		65.5	JEP (West Kgn) MSD plant	838.6	660.8	177.8	26.9%	0.557	2.0
2013				838.6	686.5	152.1	22.2%	0.977	3.6
2014	249	300	Install 5 SSD plants; Retire OH2,OH3,OH4, B6	889.6	717.0	172.6	24.1%	0.036	0.1
2015		60	Install SSD plant	949.6	749.3	200.3	26.7%	0.100	0.4
2016		60	Install SSD plant	1009.6	782.6	227.0	29.0%	0.050	0.2
2017				1009.6	816.1	193.5	23.7%	0.136	0.5
2018	60	120	Install 2 SSD plants; Retire JPPC	1069.6	852.8	216.8	25.4%	0.068	0.2
2019		60	Install SSD plant	1129.6	890.3	239.3	26.9%	0.040	0.1
2020	38.4	60	Install SSD plant	1151.2	928.6	222.6	24.0%	0.068	0.2
2021		60	Install SSD plant	1211.2	967.7	243.5	25.2%	0.037	0.1
2022		39	Install OFCTunit	1250.2	1007.6	242.6	24.1%	0.041	0.1
2023		60	Install SSD plant	1310.2	1048.3	261.9	25.0%	0.023	0.1
2024		60	Install SSD plant	1370.2	1089.9	280.3	25.7%	0.014	0.1
2025		39	Install OFCT unit	1409.2	1132.3	276.9	24.5%	0.017	0.1
2026	124.3	177	Install OFCC unit; SSD plant; Retire JEP (OH)	1461.9	1175.6	286.3	24.4%	0.012	0.0
2027		60	Install SSD plant	1521.9	1219.8	302.1	24.8%	0.008	0.0
2028		60	Install SSD plant	1581.9	1264.9	317.0	25.1%	0.005	0.0
2029		60	Install SSD plant	1641.9	1310.9	331.0	25.2%	0.003	0.0

Figure 9.4.3-1: Supply versus Demand Projections (2010 – 2029) – Business-as-usual case



10 SENSITIVITY ANALYSIS

The purpose of conducting sensitivity analyses in generation expansion studies is to investigate the variation of the optimal solution to the most important parameters for which the planner(s) and sometimes the decision-makers accord the highest degree of uncertainty. Some of the sensitivity analyses most frequently considered are:

- demand forecast,
- fuel cost,
- investment cost of new power plants,
- discount rate,
- year in which certain plants can be added to the system,
- special considerations related to plant site,
- quality of supply (reserve margin, LOLP limit, cost of unserved energy),
- environmental issues/constraints.

A general rule for conducting sensitivity analyses is to consider all type of information for which large uncertainties are recognised at the outset of the optimisation study, either because of lack of knowledge on their statistical or current value (for example, acceptable LOLP for the system, equivalent forced outage rates and O&M cost of existing units etc.) or because their future evolution is difficult to predict (fuel costs, load forecast etc.).

Sensitivities considered in this study are outlined below:

10.1 Demand Sensitivity

Two demand sensitivities were conducted during the study. These were based on a high forecast and a low forecast. The results reflected adjustments in the timing and the magnitude the of capacity requirement, however, the technology selection as obtained in the base demand (Natural Gas) case did not change.

10.1-1 Cost and Capacity Comparison for Base, Low and High Foreccast cases

Scenario	Capacity Required (MW)	Cost of Plant US$ (billion)
Base forecast case	1360	5.77
Low forecast case	960	5.39
High forecast case	2000	6.45

10.1.1 Demand Sensitivity - Low Demand Case

This case differs from the Base Case as follows:

- No violation in reliability criteria in 2013 due to the lower demand projection and committed project.
- Two Combined Cycle units and one Simple Cycle Gas Turbine required in 2014.
- Three less Combined Cycle unit required over the planning horizon compared with the base forecast case.

The capacity schedule for the low demand case is shown in Table 10.1.1-1.

Table 10.1.2-1: Demand Sensitivity - Low Forecast

Year	Net Capacity Retired/ Displaced (MW)	Net Capacity Addition (MW)	Plant Added/Retired	Net Capacity (MW)	Net System Peak (MW)	Reserve Capacity (MW)	Reserve capacity (%)	Loss of load Probability (%)	Loss of load Probability (days)
2010				773.1	617.9	155.2	25.1%	2.507	9.2
2011				773.1	626.7	146.4	23.4%	1.792	6.5
2012		65.5	JEP (West Kgn) MSD plant	838.6	640.8	197.8	30.9%	0.329	1.2
2013				838.6	656.1	182.5	27.8%	0.455	1.7
2014	249	273	2 NGCC units; 1 GT unit; displace OH2,OH3,OH4, B6	862.6	676.8	185.8	27.5%	0.277	1.0
2015				862.6	698.5	164.1	23.5%	0.464	1.7
2016		117	Install NGCC unit	979.6	720.2	259.4	36.0%	0.052	0.2
2017				979.6	741.3	238.3	32.1%	0.099	0.4
2018	60	117	NGCC unit; Retire JPPC	1036.6	762.1	274.5	36.0%	0.048	0.2
2019				1036.6	782.5	254.1	32.5%	0.084	0.3
2020	38.4		Displacement of RF1 and RF2	998.2	802.4	195.8	24.4%	0.383	1.4
2021		117	Install NGCC unit	1115.2	821.9	293.3	35.7%	0.048	0.2
2022		39	Install GT unit	1154.2	841.0	313.2	37.2%	0.028	0.1
2023				1154.2	859.7	294.5	34.3%	0.046	0.2
2024		39	Install GT unit	1193.2	878.0	315.2	35.9%	0.027	0.1
2025				1193.2	895.8	297.4	33.2%	0.043	0.2
2026	124.3	117	Install NGCC unit; Retire JEP (OH)	1185.9	913.3	272.6	29.8%	0.072	0.3
2027				1185.9	930.3	255.6	27.5%	0.113	0.4
2028		117	Install NGCC unit	1302.9	947.0	355.9	37.6%	0.011	0.0
2029				1302.9	963.3	339.6	35.3%	0.018	0.1

10.1.2 Demand Sensitivity – High Forecast

The capacity schedule for the High demand case is shown in Table 10.1.2-1.

This case differs from the Base Case as follows:

- Violation of reliability criteria extended to the end of 2013 due to increased demand and lead time to install a new unit
- Three (3) Natural Gas-fired Combined Cycle (NGCC) units and one Simple Cycle Gas Turbine required in 2014. The fourth NGCC unit is push forward to 2015.
- Four (4) more Combined Cycle units required over the planning horizon compared with the base demand forecast case

Note

Cost comparison for the base, high and low forecast cases is shown in table 10.1-1 above.

Table 10.1.2-2: Demand Sensitivity – High Forecast

Year	Net Capacity Retired/ Displaced (MW)	Net Capacity Addition (MW)	Plant Added/Retired	Total Net Capacity (MW)	Net Peak (MW)	Reserve Capacity (MW)	Reserve capacity (%)	Loss of load Probability (%)	Loss of load Probability (days)
2010				773.1	635.7	137.4	21.6%	3.660	13.4
2011				773.1	659.4	113.7	17.2%	3.637	13.3
2012		65.5	JEP (West Kgn) MSD plant	838.6	689.5	149.1	21.6%	1.125	4.1
2013				838.6	722.3	116.3	16.1%	2.205	8.0
2014	249	390	3 NGCC units; 1 GT unit; displace OH2,OH3,OH4, B6	979.6	760.9	218.7	28.7%	0.159	0.6
2015		117	Install NGCC unit	1,096.6	809.4	287.2	35.5%	0.035	0.1
2016		39	Install GT unit	1,135.6	861.0	274.6	31.9%	0.052	0.2
2017		117	Install NGCC unit	1,252.6	915.3	337.3	36.9%	0.016	0.1
2018	60	117	Install NGCC unit; Retire JPPC	1,309.6	972.7	336.9	34.6%	0.021	0.1
2019		117	Install NGCC unit	1,426.6	1,033.3	393.3	38.1%	0.007	0.0
2020	38.4	117	Install NGCC unit; displace RF1 and RF2	1,505.2	1,097.2	408.0	37.2%	0.006	0.0
2021		39	Install GT unit	1,544.2	1,164.7	379.5	32.6%	0.014	0.1
2022		117	Install NGCC unit	1,661.2	1,235.8	425.4	34.4%	0.006	0.0
2023				1,661.2	1,310.9	350.3	26.7%	0.039	0.1
2024		117	Install NGCC unit	1,778.2	1,390.1	388.1	27.9%	0.021	0.1
2025		117	Install NGCC unit	1,895.2	1,473.6	421.6	28.6%	0.012	0.0
2026	124.3	195	NGCC unit; 2 GT units; Retire JEP (OH)	1,965.9	1,561.8	404.1	25.9%	0.022	0.1
2027		117	Install NGCC unit	2,082.9	1,654.8	428.1	25.9%	0.018	0.1
2028		117	Install 3 GT units	2,199.9	1,752.9	447.0	25.5%	0.013	0.0
2029		117	Install NGCC unit	2,316.9	1,856.5	460.4	24.8%	0.013	0.0

10.2 Fuel Price Sensitivity

10.2.1 Coal Price

Based on issues regarding the price of coal delivered to Jamaica, two scenarios based on delivered coal prices of US$100/tonne and US$110/tonne, keeping all other were conducted, keeping all other parameters constant. The capacity schedule and technology mix are shown in results are shown in Table 10.2.1-1 and Table 10.2.1-2 respectively.

At a Coal price of US$ 100/tonne, the WASP optimisation indicates a shift in the timing for the addition of coal plant capacity to 2020 compared with the base case where coal is priced at US$90/tonne). This represents a partial substitution of Coal technology by Natural Gas combined cycle technology influenced by the cost characteristics of the technology in the earlier period of the expansion.

At a Coal price of US$ 110/tonne, the WASP optimaization indicates a total displacement of coal technology by Natural Gas-fired plants.

Table 10.2.1-1: Coal Price Sensitivity –US$100/tonne

Year	Net Capacity Retired (MW)	Net Capacity Addition (MW)	Plant Added/Retired	Total Net Capacity (MW)	Net Peak (MW)	Reserve Capacity (MW)	Reserve capacity (%)	Loss of load Probability (%)	Loss of load Probability (days)
2010				773.1	625.8	147.3	23.5%	2.982	10.9
2011				773.1	640.5	132.6	20.7%	2.441	8.9
2012		65.5	JEP (West Kgn) MSD plant	838.6	660.8	177.8	26.9%	0.557	2.0
2013				838.6	686.5	152.1	22.2%	0.977	3.6
2014	249	351	Install 3 NGCC units; Displace OH2,OH3,OH4, B6	940.6	717.0	223.6	31.2%	0.138	0.5
2015				940.6	749.3	191.3	25.5%	0.317	1.2
2016		117	Install NGCC unit	1057.6	782.6	275.0	35.1%	0.066	0.2
2017		39	Install GT unit	1096.6	816.1	280.5	34.4%	0.058	0.2
2018	60	117	Install NGCC unit; Retire JPPC	1153.6	852.8	300.8	35.3%	0.066	0.2
2019		39	Install GT unit	1192.6	890.3	302.3	34.0%	0.164	0.6
2020	38.4	114	Install Coal unit; Displace RF1 and RF2	1268.2	928.6	339.6	36.6%	0.096	0.4
2021				1268.2	967.7	300.5	31.1%	0.025	0.1
2022		114	Install Coal unit	1382.2	1007.6	374.6	37.2%	0.065	0.2
2023				1382.2	1048.3	333.9	31.9%	0.017	0.1
2024		114	Install Coal unit	1496.2	1089.9	406.3	37.3%	0.046	0.2
2025				1496.2	1132.3	363.9	32.1%	0.014	0.1
2026	124.3	114	Install Coal unit; Retire JEP (OH)	1485.9	1175.6	310.3	26.4%	0.049	0.2
2027		114	Install Coal unit	1599.9	1219.8	380.1	31.2%	0.123	0.4
2028				1599.9	1264.9	335.0	26.5%	0.041	0.1
2029		114	Install Coal unit	1713.9	1310.9	403.0	30.7%	0.104	0.4

Table 10.2.1-2: Coal Price Sensitivity –US$110/tonne

Year	Plant Type to be added to the System	No. of units x Capacity (MW)
2014	Natural Gas-fired Combined Cycle Gas Turbine unit	3 x 120
2016	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120
2017	Natural Gas-fired Simple Cycle Gas Turbine unit	1 x 40
2018	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120
2019	Natural Gas-fired Simple Cycle Gas Turbine unit	1 x 40
2020	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120
2022	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120
2024	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120
2025	Natural Gas-fired Simple Cycle Gas Turbine unit	1 x 40
2026	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120
2028	Natural Gas-fired Simple Cycle Gas Turbine unit	1 x 40
2029	Natural Gas-fired Combined Cycle Gas Turbine unit	1 x 120

11 DISCUSSION

The specific power plant technologies to be installed in 2014 and beyond are largely dependent on the fuel type available for system expansion. This means that the expansion strategy which encourages fuel diversification to be adopted in the short to medium term is hugely dependent on the outcome of the Natural Gas project proposed for Jamaica. Despite the relatively low and predictable prices of Coal, a Coal expansion strategy could not be initiated in 2014 for practical reasons related to lead time among other things.

The results of the study under the base demand forecast indicate that in 2013 the reliability criterion is violated. This means that the specified number of days or hours during the year that electricity generation cannot meet demand has been exceeded with the consequence of power outages to customers. This reliability concern can be addressed by the following approaches:

- Introduce temporary capacity in the range of 40 – 60 MW for at least a one year period until the new power plants are commissioned.

- Fast tracking of new projects to come on line by the end of the first half of 2013. Every effort should be made to achieve this option as to embark on another interim capacity at this time would be impractical.

11.1 Natural Gas Plan

The Natural Gas plan identifies the need for 360 MW (3x120 MW) of new baseload capacity in the form of combined cycle gas turbines (CCGT) in 2014 followed by an additional 120 MW CCGT in 2016.

Following the completion of the tender process, the CCGT plant is expected to require 24 months for completion from award of contract, so it should be available by January 2014. Any delays in this extremely tight program will make it difficult to achieve the target completion date.

While the issue of system reliability in the interim cannot be ignored, the focus should be concentrated on the expansion of baseload capacity for obvious reasons. Given the push towards fuel diversification which is to be realised by the utilization of Natural Gas in the short to medium term and other fuels over the longer term, possible consideration for interim capacity for operation over an extended period may serve to derail the fuel diversification outcome. Therefore, any decision supporting the provision of interim capacity must be implemented on a short-term basis to maintain reliability until the baseload capacity is commissioned.

Based on the simulation results, once the first block of baseload capacity is commissioned, JPS' oil-fired steam units will all displaced for economic reasons. This is because; the addition of more economic new plants to the system will result in significant reductions in the utilizations (capacity factors) of the steam units to levels that are not technically feasible for them to operate.

11.2 Natural Gas - Coal Plan

This plan seeks to establish the optimal generation expansion solution based on a Natural Gas/Coal strategy which attempts to advance the country's fuel diversification initiative.

The plan identifies the need for 360 MW (3x120 MW) of new baseload capacity in the form combined cycle gas turbines (CCGT) in 2014 followed by a 120 MW Coal plant in 2016.

The OUR in accordance with its mandate supports the fuel diversification initiative; however it is quite aware of the impact that indecision or uncertainties associated with the LNG project or any other fuel strategy can have on the optimal expansion of electricity generation system.

11.3 Business-as-usual Plan

The business-as-usual scenario establishes the optimal generation expansion plan based on an HFO/ADO fuel strategy.

Similar to the other expansion scenarios discussed, this plan also identifies the need for 360 MW of new capacity in 2014 but to be provided by diesel engines.

The plan essentially highlights the cost of the continued proliferation of liquid fossil fuels for expansion of the electricity generation system.

Preliminary estimates indicates that the cost of not changing strategy translates to approximately 0.5 million US dollars per day. This imposes an additional burden on the users of electricity service in Jamaica.

11.4 Conversion of Existing Generation Plants to use Natural Gas

The conversion of some of the existing plants may be necessary to remain attractive in the merit order for dispatch.

In the event that natural gas becomes available in 2014, the addition of new generation capacity supplied by Natural Gas – fired combined cycle units will adversely affect the utilization of the Bogue combine cycle unit reducing the capacity factor to significantly low levels which are not economically feasible for the unit to operate. This indicates that if Natural Gas is not supplied to Bogue, the continued operation of the unit in combined cycle mode may become an issue of concern.

Not withstanding the above, the unit is strategically located in the power system and satisfies an important network function of enhancing voltage profile and stability of the transmission system. While this support role is essential for system operation, it implies a must run status of the unit with the possible result of sub-optimal operation of the power system.

Channelling gas to Bogue and modifying the unit to consume gas represents a useful solution with associated benefits, however, this proposition will have to be evaluated on the basis of economics where the assumed benefits justifies the cost of construction, operation and maintenance of a gas pipeline or alternative method of supply such as compressed gas round island movement.

In the case of IPP owned plants, JEP in particular, the issue of low utilization when gas plants are introduced is also a matter for attention. Although not as severe as the case with Bogue combined cycle unit due to operation with a cheaper fuel and at higher conversion efficiencies, the plants are nonetheless affected. In this regard, it would be necessary for these plants to be converted to use Natural Gas to ensure a reasonable dispatch especially when more gas plants are added to the system further in the planning period.

11.5 Renewables

The gravitation towards renewable projects for electricity generation in Jamaica has not been aggressive, which could be attributed to the high capital cost of the conversion technologies, legal issues, lack of information on the availability of potential resources, environmental and intrusion issues among other things. This deduction is based on the observation that currently only 5% of net system generation is supplied by renewable sources with conservative expectations advancing into the future as there are only three (3) small scale projects committed for commissioning in the early phase of the study. The expected energy contributions from these projects when aggregated with the existing renewable energy production is not likely to meet the Energy Policy short term target of 11% penetration by 2012.

In relation to the above, provided that obstacles are cleared and the costs of RETs are reduced in the future, interest in Renewables may improve possibly leading to greater participation.

In supplying renewable power to the grid, firm dependable capacity may not be guaranteed depending on the technology, which means that the supply arrangement may take the form of energy-only contracts where energy is supplied on an as-available basis due to variability of the resource.

11.5.1 Variability Issues

Variable renewable energy technologies exploit natural resources which are not constant and thus not fully predictable. These technologies include wind, solar photovoltaic, solar thermal, tidal energy, wave energy and run-of-river hydro, etc.

Not all renewables are variable. Biomass and storage-based hydro are categorised as dispatchable renewable energy technologies, as such, they can be contracted to supply firm capacity to grid.

Variability is not a new phenomenon in power systems. Demand fluctuates continually, as does supply. However, a greater share of variable renewable energy will increase the aggregate variability and uncertainty seen by a power system. As penetration increases and results in variability of similar amplitude to demand, measures will need to be taken to ensure continued reliable operation.

In the case of wind power where large fluctuations in output are possible, accurate prediction of wind power output is crucial to reduce the allocation of reserves in advance, particularly on a timescale of several hours to days ahead of dispatch. Improved output forecasting and intra - hour revised dispatch may facilitate more efficient scheduling of flexible reserves.

Even with more reliable forecasts, power systems will still require some enhancement of flexibility to absorb large shares of fluctuating variable renewable energy output in a reliable manner.

11.5.2 Costs Issues

Although renewable energy resources are recognized as an important component of the energy diversification strategy, they do not adequately support the objective of providing reliable and economical power. Even with the prevailing high oil prices, Renewables in the main are still challenged to meet the threshold avoided cost benchmarks established by conventional fossil fuelled technologies even with subsidies of up to 15% of avoided cost.

While all generation technologies incur certain grid integration costs, the integration of variable Renewable-based electricity production such as wind and solar is expected to be more costly than non variable resources due to the need to increase flexibility in the system. Wind power can only be generated when wind speeds are within an operational range. Thus, back-up resources are generally required to maintain reliable supply in periods when wind speeds are outside of that range. This has implications for operating and balancing the system in real-time, as well as for total system costs and the long-term development of the generation portfolio and electric power network.

In Jamaica, energy supplied by renewable sources will undoubtedly displace some quantity of fossil fuel with the benefit of reducing the fuel bill to the country; however, this benefit has to be evaluated against the cost of importing the Renewable Energy Conversion Technologies. In addition, there is a cost of having standby capacity to cover for shortfalls when the renewable resource is unavailable, which cannot be neglected.

11.6 Treatment of Cogeneration

Co-generation is the combined (simultaneous) generation of electric (or mechanical) and thermal energy from the same initial energy source.
Nowadays, this process is considered as one of the most effective techniques for achieving a more efficient usage of fuels, natural and financial resources savings and environmental protection.

Despite these important attributes, the procurement of new generating capacity from these facilities in Jamaica will have to be guided by the Regulatory Policy for the Electricity Sector entitled “Guidelines for the Addition of New Generating Capacity to the Public Electricity Supply System” and the All-island Electric Licence, 2001.

With regard to the expansion of the electricity generation system and the alumina production sector with the proposed use of Natural Gas, indications from the industry is that cogeneration by bauxite companies is being contemplated as an option for satisfying a proportion of the capacity requirement for the electricity sector. However, in addition to the guidelines mentioned above, it should be noted that the capacity requirement of 360 MW required for 2014 is not separate from any capacity intended to be supplied by cogeneration facilities. If cogeneration is being considered, power providers need to acknowledge that it is in response to the initial block of baseload capacity required in 2014.

Evaluation of the capacity contribution from possible cogeneration projects indicates that the capacity to be supplied by power-only projects would be substantially reduced.

11.7 Unit Size and Reserve Margin

The proposed unit size of 120 MW for the coal plant would be the single largest unit on the grid if implemented. The largest existing unit operating in the system is 120 MW which is modular while the largest single unit is 68.5 MW. The potential efficiency and production costs benefits to be gained for this size plant are based on the technology and will be assessed further.

Presently, JPS operates the grid with a 30 MW reserve margin to protect against the loss of the small to medium sized units. For the larger 60 MW steam units JPS has adopted a shed and restore strategy to minimize the impact of the loss.

11.8 Re-powering

This technique involves the conversion of conventional steam plant into a Combined Cycle Gas Turbine (CCGT) unit by substituting the steam boiler with a combination of gas turbines and Heat Recovery Steam Generators and feeding steam to the original steam unit.

This technique results in a generating unit that is possibly cheaper than procuring a new CCGT unit. However, it is to be noted that capital cost and efficiency figures are very site-specific since they vary with the condition and the amount of modifications required to the original plant.

Therefore, the economic advantage of having this option needs to be studied more deeply before embarking on such a project. It could be evaluated as an alternative bid and if proposed to be successful would attract specific performance targets with attendant penalties. This option is therefore not discussed any further in the report.

11.9 Dual Fuel Functionality

In accordance with its mandate, the OUR is responsible for ensuring that a reliable and adequate electricity supply is available to customers at all times.

Therefore, whether or not Natural Gas is available on the island by 2014, based on demand projections, the capacity will still be required to prevent power shortages.

Given the uncertainties that are associated with landing Natural Gas in Jamaica, an appropriate mitigation strategy is to specify that plants should be equipped with dual fired capability (NG/HFO or NG/ADO) when procuring the new generation capacity. Technically, this can be seen as a reasonable proposition however, the additional cost for this added feature may not be economical.

11.10 Transmission Requirements and Siting

The availability of suitable sites and the capability of the transmission network to reliably and effectively link production to demand will certainly influence the final expansion plan.

Based on the current arrangement of the network, if plants are going to be sited outside of the corporate area, additional transmission capacity may be required. This needs to be evaluated by means of a network study.

Presently, there are limited expansion opportunities available at most of the existing power plant sites. Therefore, based on the recommended technologies for expansion and the proposed implementation timelines, potential sites will have to be identified and evaluated, ahead of schedule for their suitability to locate the new power generation plants.

11.11 Energy Diversification

Diversification has always been considered an essential element for ensuring long term electricity security. A diversified generation mix coupled with a geographical diversification of fuel sources and supply routes and vectors would mitigate the long term risks of supply disruption. Such diversification strategy is equally applicable at the electric utility, or national level.

Fuel diversification is a contributing factor to the security of fuel supply for the electricity generation sector. A major objective of the National Energy Policy is to limit Jamaica's external vulnerability to imported liquid-based fossil fuels. This purpose is served by a decrease in petroleum based fuels in power generation, which implies an increase in the utilization of Natural Gas and/or Coal.

It should be noted however that while there are tremendous benefits to be gained from a carefully planned energy diversification strategy, if the program is not properly pursued, there is a risk of just merely switching dependency on one single fuel type to another.

11.12 Energy Security and Environmental Sustainability Issues

Separate from the economics of electricity supply, the Jamaican power sector and by extension the global power sector is confronted with the challenges of energy security and climate change.

Electricity security depends importantly on reliable and secure supply of the fuels used in power generation.

Fuel supplies can be subject to interruptions for a variety of reasons. Supply interruption can be caused by weather (for example, natural disaters) or related to infrastructure failure, especially if there is only one supply link. Risks of this nature tend to be more acute in countries that are heavily dependent on imported natural gas. As with other generation sources, gas supply risks can be mitigated through stocks/storage, but these are relatively expensive to maintain and can also be subject to infrastructure risks. Other measures, notably fuel switching and interruptible long term supply contracts can also be employed.

Given the variable nature of renewable-based generation such as wind, solar and hydro, they cannot provide reliable baseload electricity without proper back up resources. This therefore implies that these alternatives cannot favourably contribute to the security of the electricity supply.

Generally, gas is considered a flexible, low capital cost, low-risk generation option, efficient way to meet peak and reliability needs, and an ideal complement for intermittent renewable generation. In this regard, many countries are likely to become increasingly dependent on gas imports over the coming decades, with the consequence of cost escalation and availability issues.

Gas supply interruptions could impact power supply security, thus requiring a closer monitoring and coordination between the gas and power industries from a security of supply perspective.

With regards to the environment, each generation technology has its own unique impact.

Renewables are considered part of the **low-carbon** technologies, while coal-fired power plants generally emit significantly higher quantities of CO2 compared to gas-fired power plants.

The above mentioned issues related to energy security and environment sustainability were not evaluated in the WASP optimization model but have been taken into account in the generation expansion process.

11.13 Uncertainties and Risks

Although the LCEP approach provides analyses on the mix of generation technologies and the commensurate costs of expansion, the real market place is much more complex and characterised by multiple risks and uncertainties that are outside of the scope of the LCEP methodology.

Some of the main uncertainties and risks that can potentially impact investments in power generation include, among other things, the following:

- Regulatory risk - this includes both the regulation of electricity sector, environmental regulations concerning air emmissions and safety regulations;
- Political risk at the national and the local level pertaining to the acceptability of new power generation investments;
- Technological risks for new technologies such as certain renewable energies or coal technologies;

- Changes in fiscal policy, with respect to income taxes, which affect, in particular, technologies with a high proportion of capital expenditures;
- High amounts of capital-at-risk and high ratios of fixed or sunk costs to total costs ratios that limit flexibility in case that market conditions change;
- Changes in input prices, which will particularly affect technologies relying on fossil fuels;
- Safety and human health risks (air-borne pollution, site contamination, major accidents);
- Availability of adequate human resources, skills and knowledge (especially for advanced technologies);
- Security of supply risks for the availability of certain inputs, for example, natural gas that is sourced from certain regions of the world.

(Source: IEA 2010 Publication, projected cost of Generating Electricity)

Key uncertainties and risks investors face are summarised in Table 11.13-1

Table 11.13-1: Main Risk Factors for Investers in Power Generation

Plant Risk	Market Risk	Regulatory Risk	Political Risk
Construction cost	Fuel cost	Market design	Environmental standards
Lead time	Demand	Regulation of competition	CO2 contraints
Operational cost	Competition	Regulation of transmission	Support for specific technologies/fuel
Availability/ performance	Electricity price	Licensing and approval	Energy efficiency

Source IEA 2010

Although some risks are common to all technologies (example, demand and policy uncertainties) the nature and degree of risks differ significantly from project to project and from technology to technology. For example, the regulatory risk may be the most important risk facing coal power plant projects, due to social and local acceptance issues as well as complexity and uncertainty of siting and permitting. Furthermore, coal fired power projects face the risks of stringent environmental regulation and climate polices.

The regulatory risk of investments in natural gas-fired generation may be low, however, in countries where all the natural gas requirements are imported, there may be relatively high risks associated with gas supply and price increases which can significantly impact overall generation costs.

Renewable projects may be less subject to environmental scrutiny; nevertheless they are still exposed to the risks associated with transmission, including access, interconnection, and integration, all of which do have an impact on costs, although there is the benefit of low and stable operating costs.

12 CONCLUSIONS

From the analysis carried out and described in the previous sections, the following conclusions have been reached:

- New ~~baseload~~base load capacity is urgently required in the system, but given the expected constraints regarding construction time and/or fuel availability, it is unlikely that such capacity can be commissioned before 2014.
- This study recommends the commissioning 360 MW (3x120MW) of Natural Gas-fired combined cycle capacity in 2014. Of this amount, 292 MW will be for displacement of aged, inefficient capacity and the remainder for demand growth requirements.
- Over the next 20 years, approximately 1400 MW of new fossil fuel power plant capacity will have to be constructed in Jamaica, to meet the projected demand for electricity and to displace aged power plants, depending on the penetration of Renewables and possibly nuclear power. Approximately 800 MW of this new capacity needs to be constructed in the coming decade, highlighting the urgency of the issue. The capital requirements for the new power plant fleet are in the range of US$ 6 to 8 billion depending on the mix of technologies that will be deployed.
- The most critical variable in determining the type of plants to be installed in the short to medium involves the availability of Natural Gas in terms of: price, quantity; and timing.
- The continued utilization of liquid fossil fuels is unsustainable for the Jamaican electricity sector.
- The cost to the country of not changing strategy could be approximately 0.5 million US dollars per day
- The fuel diversification objective was not sufficiently achieved under the Natural Gas (only) expansion strategy.
- The penetration of renewable energy-based generation has not been significant on the basis that these resources currently cannot significantly substitute for baseload generation using fossil fuels. Nonetheless the energy contribution from the existing and proposed plants has been incorporated in the expansion and is reflected in the overall future annual generation of the system.

The optimal technology mix for the power generation sector of the future is the one that simultaneously reduces CO_2 emission, fossil fuel consumption and the production cost of electricity. It is therefore apparent from this analysis that specific market and technology development conditions need to be met for these objectives to be accomplished at the same time. As a consequence, the policy maker or regulator must develop and implement the relevant strategies to influence the factors that define the evolution of power generation capacity, ultimately steering the electricity sector and by extension the country along a sustainable path that is compatible with the goals of the energy and environmental policies.

It is worth noting that new generation capacity is an important component of meeting increasing energy demand, but it is not the only option. Incremental electricity needs can also be met through a mix of sources including new generation units, improved energy efficiency in end-use as well as in generation and transmission. Investments in transmission systems and better control and management of demand are thus important alternatives to new generation resources. All alternatives need to be evaluated to ensure the best options are pursued.

While the LCEP analyses are useful in establishing the trajectory of the electricity generation system and energy policy objectives, they need to be complemented by other forms of analysis to ensure that the energy system is appropriately optimised.

In summary, this report focuses on the capacity requirements, generation costs, sensitivity analyses around the optimal generation expansion strategy, and the security and sustainability of Jamaica's electricity system over the medium to long term. Importantly, the results are essential to new generation capacity investment decisions and thus, provide useful information to the market place. However, given the uncertainties and risks that may be involved, investment decisions related to new power plant projects must be carefully evaluated and analysed.

13 APPENDICES

APPENDIX 1: DYNPRO Output from WASP - Natural Gas Case

YEAR	PRESENT WORTH COST OF THE YEAR (K$) CONCST	SALVAL	OPCOST	ENSCST	TOTAL	OBJ.FUN. (CUMM.)	LOLP %	NGCC	GT	MSD	MSG	SSD	PvCO	OFCT	OFCC
2035	0	0	45773	4	45777	6150112	0.054	10	4	0	0	0	0	0	0
2034	0	0	51242	5	51247	6104336	0.054	10	4	0	0	0	0	0	0
2033	0	0	57366	5	57371	6053089	0.054	10	4	0	0	0	0	0	0
2032	0	0	64221	6	64227	5995718	0.054	10	4	0	0	0	0	0	0
2031	0	0	71895	6	71902	5931491	0.054	10	4	0	0	0	0	0	0
2030	0	0	80487	7	80494	5859589	0.054	10	4	0	0	0	0	0	0
2029	18043	5895	86780	5	98933	5779095	0.017	10	4	0	0	0	0	0	0
2028	4448	1226	92778	26	96026	5680162	0.069	9	4	0	0	0	0	0	0
2027	4979	1154	97914	57	101797	5584136	0.059	9	3	0	0	0	0	0	0
2026	25315	4912	104599	35	125037	5482340	0.051	9	2	0	0	0	0	0	0
2025	0	0	116749	12	116761	5357303	0.017	8	2	0	0	0	0	0	0
2024	31727	4258	123613	0	151083	5240542	0.005	8	2	0	0	0	0	0	0
2023	0	0	137332	7	137339	5089459	0.028	7	2	0	0	0	0	0	0
2022	39763	3602	144041	0	180202	4952120	0.010	7	2	0	0	0	0	0	0
2021	0	0	161489	43	161532	4771918	0.049	6	2	0	0	0	0	0	0
2020	49835	2947	167607	6	214501	4610387	0.019	6	2	0	0	0	0	0	0
2019	12285	577	193254	33	204995	4395886	0.038	5	2	0	0	0	0	0	0
2018	62457	2293	204980	58	265202	4190891	0.039	5	1	0	0	0	0	0	0
2017	15396	433	251712	62	266737	3925689	0.045	4	1	0	0	0	0	0	0
2016	78276	1638	269283	102	346023	3658952	0.051	4	0	0	0	0	0	0	0
2015	0	0	326081	1024	327105	3312929	0.317	3	0	0	0	0	0	0	0
2014	294304	2947	334444	433	626234	2985824	0.139	3	0	0	0	0	0	0	0
2013	0	0	554320	4245	558566	2359590	0.974	0	0	0	0	0	0	0	0
2012	0	0	563273	2561	565834	1801024	0.556	0	0	0	0	0	0	0	0
2011	0	0	575456	14655	590111	1235191	2.433	0	0	0	0	0	0	0	0
2010	0	0	624556	20525	645080	645080	2.971	0	0	0	0	0	0	0	0

APPENDIX 2: DYNPRO Output from WASP - Natural Gas/Coal Case

YEAR------	PRESENT WORTH COST OF THE YEAR (K$)------				OBJ.FUN.	LOLP	NGCC		MSD		SSD		OFCT	
	CONCST	SALVAL	OPCOST	ENSCST	TOTAL	(CUMM.)	%	GT		MSG		PvCO		OFCC
2035	0	0	28540	3	28543	6099706	0.036	3	1	0	0	0	9	0	0
2034	0	0	31950	3	31954	6071164	0.036	3	1	0	0	0	9	0	0
2033	0	0	35768	4	35772	6039210	0.036	3	1	0	0	0	9	0	0
2032	0	0	40043	4	40047	6003438	0.036	3	1	0	0	0	9	0	0
2031	0	0	44828	4	44832	5963392	0.036	3	1	0	0	0	9	0	0
2030	35999	15152	50185	5	71036	5918560	0.036	3	1	0	0	0	9	0	0
2029	0	0	57408	72	57481	5847524	0.104	3	1	0	0	0	8	0	0
2028	45116	14107	60031	4	91044	5790043	0.041	3	1	0	0	0	8	0	0
2027	0	0	68548	130	68678	5698999	0.123	3	1	0	0	0	7	0	0
2026	56543	13062	71759	30	115270	5630322	0.049	3	1	0	0	0	7	0	0
2025	63300	12540	86310	2	137073	5515052	0.014	3	1	0	0	0	6	0	0
2024	0	0	100525	40	100566	5377979	0.046	3	1	0	0	0	5	0	0
2023	79333	11495	104907	0	172746	5277414	0.017	3	1	0	0	0	5	0	0
2022	0	0	123564	83	123647	5104668	0.065	3	1	0	0	0	4	0	0
2021	99427	10450	127251	0	216228	4981021	0.025	3	1	0	0	0	4	0	0
2020	111308	9927	152488	151	254021	4764793	0.096	3	1	0	0	0	3	0	0
2019	0	0	187565	351	187916	4510773	0.164	3	1	0	0	0	2	0	0
2018	139500	8882	191156	100	321874	4322857	0.066	3	1	0	0	0	2	0	0
2017	15396	433	244412	99	259474	4000983	0.058	3	1	0	0	0	1	0	0
2016	174833	7837	261047	151	428193	3741509	0.066	3	0	0	0	0	1	0	0
2015	0	0	326083	1022	327105	3313315	0.317	3	0	0	0	0	0	0	0
2014	294304	2948	334450	432	626239	2986211	0.138	3	0	0	0	0	0	0	0
2013	0	0	554379	4254	558634	2359972	0.977	0	0	0	0	0	0	0	0
2012	0	0	563335	2565	565900	1801339	0.557	0	0	0	0	0	0	0	0
2011	0	0	575527	14697	590224	1235439	2.441	0	0	0	0	0	0	0	0
2010	0	0	624627	20587	645215	645215	2.982	0	0	0	0	0	0	0	0

APPENDIX 4: DYNPRO Output from WASP: Business-as-usual Case

YEAR------	PRESENT WORTH COST OF THE YEAR (K$)------					OBJ.FUN.	LOLP	NGCC		MSD		SSD		OFCT	
	CONCST	SALVAL	OPCOST	ENSCST	TOTAL	(CUMM.)	%		GT		MSG		PvCO		OFCC
2035	0	0	90223	0	90223	8919183	0.002	0	0	0	0	19	0	2	1
2034	0	0	101005	0	101005	8828960	0.002	0	0	0	0	19	0	2	1
2033	0	0	113075	0	113075	8727955	0.002	0	0	0	0	19	0	2	1
2032	0	0	126587	0	126587	8614880	0.002	0	0	0	0	19	0	2	1
2031	0	0	141714	0	141714	8488293	0.002	0	0	0	0	19	0	2	1
2030	15043	5808	158649	0	167885	8346579	0.002	0	0	0	0	19	0	2	1
2029	16841	5502	171546	5	182890	8178695	0.003	0	0	0	0	18	0	2	1
2028	18853	5196	183759	5	197421	7995805	0.005	0	0	0	0	17	0	2	1
2027	21106	4891	196871	1	213088	7798385	0.008	0	0	0	0	16	0	2	1
2026	48944	9498	210865	10	250322	7585297	0.012	0	0	0	0	15	0	2	1
2025	6241	1009	230773	0	236005	7334975	0.017	0	0	0	0	14	0	2	0
2024	29613	3974	245073	26	270739	7098971	0.014	0	0	0	0	14	0	1	0
2023	33152	3668	262179	12	291675	6828232	0.023	0	0	0	0	13	0	1	0
2022	8756	793	280598	38	288599	6536558	0.041	0	0	0	0	12	0	1	0
2021	41548	3057	297180	53	335725	6247959	0.037	0	0	0	0	12	0	0	0
2020	46513	2751	317499	94	361356	5912234	0.068	0	0	0	0	11	0	0	0
2019	52072	2445	341286	35	390948	5550878	0.040	0	0	0	0	10	0	0	0
2018	116589	4279	364517	116	476942	5159930	0.068	0	0	0	0	9	0	0	0
2017	0	0	397104	260	397365	4682988	0.136	0	0	0	0	7	0	0	0
2016	73059	1528	413096	50	484677	4285624	0.050	0	0	0	0	7	0	0	0
2015	81790	1223	438952	220	519739	3800947	0.100	0	0	0	0	6	0	0	0
2014	457818	4585	467373	630	921236	3281208	0.207	0	0	0	0	5	0	0	0
2013	0	0	554379	4254	558634	2359972	0.977	0	0	0	0	0	0	0	0
2012	0	0	563335	2565	565900	1801339	0.557	0	0	0	0	0	0	0	0
2011	0	0	575527	14697	590224	1235439	2.441	0	0	0	0	0	0	0	0
2010	0	0	624627	20587	645215	645215	2.982	0	0	0	0	0	0	0	0

APPENDIX 5: DYNPRO Output from WASP: Sensitivity – Low Demand Forecast

YEAR------	PRESENT WORTH	COST OF THE	YEAR (K$)------			OBJ.FUN.	LOLP	NGCC		MSD		SSD		OFCT	
	CONCST	SALVAL	OPCOST	ENSCST	TOTAL	(CUMM.)	%		GT		MSG		PvCO		OFCC
2035	0	0	33298	3	33301	5664365	0.028	7	3	0	0	0	0	0	0
2034	0	0	37277	4	37280	5631065	0.028	7	3	0	0	0	0	0	0
2033	0	0	41731	4	41735	5593785	0.028	7	3	0	0	0	0	0	0
2032	0	0	46718	4	46723	5552050	0.028	7	3	0	0	0	0	0	0
2031	0	0	52301	5	52306	5505327	0.028	7	3	0	0	0	0	0	0
2030	0	0	58551	6	58557	5453022	0.028	7	3	0	0	0	0	0	0
2029	0	0	64327	6	64332	5394465	0.018	7	3	0	0	0	0	0	0
2028	20199	5567	69420	6	84058	5330133	0.011	7	3	0	0	0	0	0	0
2027	0	0	78265	90	78356	5246075	0.113	6	3	0	0	0	0	0	0
2026	25315	4912	84365	53	104822	5167720	0.072	6	3	0	0	0	0	0	0
2025	0	0	103253	30	103283	5062898	0.043	5	3	0	0	0	0	0	0
2024	6986	938	110709	15	116772	4959615	0.027	5	3	0	0	0	0	0	0
2023	0	0	122191	31	122222	4842843	0.046	5	2	0	0	0	0	0	0
2022	8756	793	130483	22	138468	4720621	0.028	5	2	0	0	0	0	0	0
2021	44515	3275	142408	48	183696	4582153	0.048	5	1	0	0	0	0	0	0
2020	0	0	178477	750	179227	4398457	0.383	4	1	0	0	0	0	0	0
2019	0	0	186997	140	187137	4219231	0.084	4	1	0	0	0	0	0	0
2018	62457	2293	197356	51	257571	4032094	0.048	4	1	0	0	0	0	0	0
2017	0	0	254261	202	254464	3774523	0.099	3	1	0	0	0	0	0	0
2016	78276	1637	267714	92	344444	3520060	0.052	3	1	0	0	0	0	0	0
2015	0	0	333549	1578	335127	3175616	0.464	2	1	0	0	0	0	0	0
2014	217805	2181	349777	939	566339	2840489	0.277	2	1	0	0	0	0	0	0
2013	0	0	524736	1813	526550	2274150	0.455	0	0	0	0	0	0	0	0
2012	0	0	543191	1433	544625	1747600	0.329	0	0	0	0	0	0	0	0
2011	0	0	560415	10399	570814	1202975	1.792	0	0	0	0	0	0	0	0
2010	0	0	615194	16968	632162	632162	2.507	0	0	0	0	0	0	0	0

APPENDIX 6: DYNPRO Output from WASP: Sensitivity – High Demand Forecast

YEAR------	PRESENT WORTH COST OF THE YEAR (K$)------					OBJ.FUN.	LOLP	NGCC		MSD		SSD		OFCT	
	CONCST	SALVAL	OPCOST	ENSCST	TOTAL	(CUMM.)	%		GT		MSG		PvCO		OFCC
2035	0	0	66306	6	66313	6996918	0.006	15	9	0	0	0	0	0	0
2034	0	0	74230	7	74237	6930605	0.006	15	9	0	0	0	0	0	0
2033	0	0	83100	8	83108	6856369	0.006	15	9	0	0	0	0	0	0
2032	0	0	93031	9	93040	6773261	0.006	15	9	0	0	0	0	0	0
2031	0	0	104148	10	104158	6680221	0.006	15	9	0	0	0	0	0	0
2030	19666	7593	116594	11	128678	6576064	0.006	15	9	0	0	0	0	0	0
2029	18043	5895	123058	0	135207	6447386	0.013	14	8	0	0	0	0	0	0
2028	13344	3678	127899	5	137570	6312179	0.013	13	8	0	0	0	0	0	0
2027	22613	5240	131988	22	149384	6174610	0.018	13	5	0	0	0	0	0	0
2026	36464	7076	138170	4	167562	6025226	0.022	12	5	0	0	0	0	0	0
2025	28341	4585	147838	24	171618	5857664	0.012	11	3	0	0	0	0	0	0
2024	31727	4257	156088	37	183595	5686047	0.021	10	3	0	0	0	0	0	0
2023	0	0	167367	45	167412	5502452	0.039	9	3	0	0	0	0	0	0
2022	39763	3603	172454	15	208631	5335040	0.006	9	3	0	0	0	0	0	0
2021	9802	721	181535	17	190633	5126410	0.014	8	3	0	0	0	0	0	0
2020	49835	2947	188352	0	235240	4935777	0.006	8	2	0	0	0	0	0	0
2019	55790	2620	200149	0	253320	4700538	0.007	7	2	0	0	0	0	0	0
2018	62457	2293	219904	28	280096	4447218	0.021	6	2	0	0	0	0	0	0
2017	69920	1965	255466	0	323422	4167122	0.016	5	2	0	0	0	0	0	0
2016	17236	361	292591	106	309573	3843700	0.052	4	2	0	0	0	0	0	0
2015	87630	1310	302036	25	388381	3534128	0.035	4	1	0	0	0	0	0	0
2014	315906	3164	351687	502	664931	3145747	0.159	3	1	0	0	0	0	0	0
2013	0	0	590302	10621	600924	2480817	2.205	0	0	0	0	0	0	0	0
2012	0	0	592838	5600	598438	1879893	1.125	0	0	0	0	0	0	0	0
2011	0	0	596244	22993	619238	1281455	3.637	0	0	0	0	0	0	0	0
2010	0	0	636322	25896	662218	662218	3.660	0	0	0	0	0	0	0	0

APPENDIX 7: DYNPRO Output from WASP: Coal Price Sensitivity – US$100/tonne

YEAR	PRESENT WORTH COST OF THE YEAR (K$) CONCST	SALVAL	OPCOST	ENSCST	TOTAL	OBJ.FUN. (CUMM.)	LOLP %	NGCC	GT	MSD	MSG	SSD	PvCO	OFCT	OFCC
2035	0	0	36097	17	36115	6144573	0.089	5	2	0	0	0	6	0	0
2034	0	0	40411	19	40430	6108459	0.089	5	2	0	0	0	6	0	0
2033	0	0	45240	22	45262	6068029	0.089	5	2	0	0	0	6	0	0
2032	0	0	50646	24	50671	6022767	0.089	5	2	0	0	0	6	0	0
2031	0	0	56698	27	56726	5972097	0.089	5	2	0	0	0	6	0	0
2030	0	0	63474	30	63504	5915371	0.089	5	2	0	0	0	6	0	0
2029	40300	14629	67735	5	93412	5851867	0.032	5	2	0	0	0	6	0	0
2028	0	0	75670	72	75742	5758456	0.099	5	2	0	0	0	5	0	0
2027	50508	13584	79799	15	116737	5682714	0.038	5	2	0	0	0	5	0	0
2026	56543	13062	89653	118	133253	5565977	0.115	5	2	0	0	0	4	0	0
2025	0	0	105557	15	105573	5432725	0.033	5	2	0	0	0	3	0	0
2024	70865	12017	111002	3	169853	5327152	0.012	5	2	0	0	0	3	0	0
2023	0	0	128609	16	128626	5157300	0.044	5	2	0	0	0	2	0	0
2022	88814	10972	134183	1	212025	5028674	0.016	5	2	0	0	0	2	0	0
2021	0	0	156681	62	156743	4816649	0.062	5	2	0	0	0	1	0	0
2020	111308	9927	162218	13	263612	4659906	0.024	5	2	0	0	0	1	0	0
2019	12285	577	193259	33	205000	4396295	0.038	5	2	0	0	0	0	0	0
2018	62457	2292	204985	58	265208	4191295	0.039	5	1	0	0	0	0	0	0
2017	15396	433	251717	62	266743	3926087	0.045	4	1	0	0	0	0	0	0
2016	78276	1637	269289	101	346029	3659345	0.050	4	0	0	0	0	0	0	0
2015	0	0	326083	1022	327105	3313315	0.317	3	0	0	0	0	0	0	0
2014	294304	2948	334450	432	626239	2986211	0.138	3	0	0	0	0	0	0	0
2013	0	0	554379	4254	558634	2359972	0.977	0	0	0	0	0	0	0	0
2012	0	0	563335	2565	565900	1801339	0.557	0	0	0	0	0	0	0	0
2011	0	0	575527	14697	590224	1235439	2.441	0	0	0	0	0	0	0	0
2010	0	0	624627	20587	645215	645215	2.982	0	0	0	0	0	0	0	0

Key:

NGCC – Natural Gas Combined Cycle
GT – Gas Turbine
OFCT- Oil-Fired Combustion Turbine
MSD – Medium Speed Diesel
MSG – Medium Speed Gas
OFCC Oil-Fired Combined Cycle
SSD- Slow Speed Diesel
PvCO – Pulverised Coal
CONCST – Construction Cost
SALVAL – Salvage Value
OPCST – Operational Cost
ENSCST – Energy Not Served Cost
LOLP – Loss-of-Load-Probability

APPENDIX 5: REPROBAT REPORT

SUMMARY REPORT
ON A GENERATION EXPANSION PLAN FOR
base case_NG
PROCESSED BY THE WASP-IV COMPUTER PROGRAM PACKAGE
OF THE IAEA

STUDY PERIOD

2010 - 2035

PLANNING PERIOD

2010 - 2029

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 : 8/22/2010
STUDY CARRIED OUT BY :

INFORMATION SUPPLIED BY USER :

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  Residual Fuel (No.6)
1  DISL  Automotive Diesel Oi
2  NATG  Natural Gas (LNG)
3  COAL  Steam Coal
4  PETC  Petcoke
5   CNG  Compressed NG
6
7
8  ****  NOT APPLICABLE
9  ****  NOT APPLICABLE
```

SYSTEM WITHOUT PUMPED STORAGE PROJECTS:

```
HYD1  RUN-OF-RIVER PLANT
HYD2  WIND-AS- HYD- PLANT
```

ANNUAL LOAD DESCRIPTION
PERIOD(S) PER YEAR : 4

YEAR	PEAKLOAD MW	GR.RATE %	MIN.LOAD MW	GR.RATE %	ENERGY GWH	GR.RATE %	LOADFACTOR %
2010	625.8	-	357.4	-	4253.8	-	77.60
2011	640.5	2.3	368.2	3.0	4373.8	2.8	77.95
2012	660.8	3.2	391.5	6.3	4531.7	3.6	78.29
2013	686.5	3.9	411.8	5.2	4725.3	4.3	78.58
2014	717.0	4.4	430.1	4.4	4951.4	4.8	78.83
2015	749.3	4.5	450.8	4.8	5190.4	4.8	79.07
2016	782.6	4.4	470.6	4.4	5435.0	4.7	79.28
2017	816.1	4.3	491.7	4.5	5681.6	4.5	79.47
2018	852.8	4.5	515.4	4.8	5950.0	4.7	79.65
2019	890.3	4.4	542.8	5.3	6223.0	4.6	79.79
2020	928.6	4.3	569.0	4.8	6501.9	4.5	79.93
2021	967.7	4.2	598.4	5.2	6786.0	4.4	80.05
2022	1007.6	4.1	625.6	4.5	7075.7	4.3	80.16
2023	1048.3	4.0	656.8	5.0	7370.7	4.2	80.26
2024	1089.9	4.0	687.3	4.7	7671.5	4.1	80.35
2025	1132.3	3.9	721.6	5.0	7977.9	4.0	80.43
2026	1175.6	3.8	752.3	4.3	8290.3	3.9	80.50
2027	1219.8	3.8	776.9	3.3	8608.6	3.8	80.56
2028	1264.9	3.7	808.2	4.0	8933.8	3.8	80.63
2029	1310.9	3.6	841.6	4.1	9265.1	3.7	80.68
2030	1358.0	3.6	876.0	4.1	9603.1	3.6	80.73
2031	1358.0	0.0	876.0	0.0	9603.1	0.0	80.73
2032	1358.0	0.0	876.0	0.0	9603.1	0.0	80.73
2033	1358.0	0.0	876.0	0.0	9603.1	0.0	80.73
2034	1358.0	0.0	876.0	0.0	9603.1	0.0	80.73
2035	1358.0	0.0	876.0	0.0	9603.1	0.0	80.73

FIXED SYSTEM
SUMMARY DESCRIPTION OF THERMAL PLANTS IN YEAR 2010

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	OH1	0	14.	28.	3906.	3512.	0.0	0.0	0	0	8.0	28	30.	0.75	6.70
4	OH2	1	30.	57.	3258.	2882.	0.0	5460.0	0	0	10.0	26	65.	0.38	6.70
5	OH3	1	30.	62.	3161.	2814.	0.0	5460.0	0	0	10.0	24	65.	0.35	6.70
6	OH4	1	30.	65.	3251.	2739.	0.0	5460.0	0	0	10.0	24	65.	0.33	6.70
7	HB6	1	30.	65.	3298.	2645.	0.0	5512.0	0	0	10.0	24	65.	0.33	6.70
8	RF1	1	9.	19.	2517.	2024.	0.0	5557.0	0	0	8.0	11	20.	0.93	8.00
9	RF2	1	9.	19.	2470.	1999.	0.0	5557.0	0	0	8.0	11	20.	0.93	8.00
10	GT5	1	5.	21.	7393.	2400.	0.0	6959.0	1	0	7.0	18	20.	0.39	5.00
11	GT10	1	8.	32.	5804.	2402.	0.0	6959.0	1	0	7.0	18	30.	0.26	5.00
12	GT3	1	5.	21.	7301.	2220.	0.0	7008.0	1	0	7.0	18	20.	0.39	5.00
13	GT6	0	5.	18.	5713.	2476.	0.0	7008.0	1	0	5.0	7	20.	0.60	5.00
14	GT7	1	5.	18.	6892.	2565.	0.0	7008.0	1	0	5.0	7	20.	0.60	5.00
15	GT8	1	5.	18.	5713.	2476.	0.0	7008.0	1	0	5.0	7	20.	0.60	5.00
16	GT9	0	8.	20.	5048.	2432.	0.0	7008.0	1	0	5.0	7	20.	0.42	5.00
17	GT11	1	8.	20.	3667.	2251.	0.0	7008.0	1	0	5.0	44	20.	0.42	5.00
18	BOCC	1	80.	111.	2306.	1889.	0.0	6456.0	1	0	5.0	28	120.	0.99	6.00
19	JPPC	1	9.	60.	1927.	1927.	0.0	5571.0	0	0	4.0	30	30.	35.33	9.11
20	JEP2	1	3.	124.	2058.	2058.	0.0	5449.0	0	0	3.0	31	120.	17.73	20.70
21	ALCO	1	0.	0.	2269.	2269.	0.0	5460.0	0	0	5.0	19	20.	15.00	11.90
22	PETC	0	20.	82.	2950.	2160.	0.0	0.0	4	0	5.0	26	80.	2.48	7.00
23	ngt3	0	5.	21.	7301.	2220.	0.0	3621.0	3	0	5.0	38	20.	0.39	5.00
24	ngt6	0	5.	18.	5713.	2476.	0.0	3621.0	3	0	5.0	19	20.	0.60	5.00
25	ngt7	0	5.	14.	6892.	2565.	0.0	3621.0	3	0	5.0	19	20.	0.60	5.00
26	ngt8	0	5.	18.	5713.	2476.	0.0	3621.0	3	0	5.0	19	20.	0.60	5.00
27	ngt9	0	8.	20.	5048.	2432.	0.0	3621.0	3	0	5.0	19	20.	0.60	5.00
28	ng11	0	8.	20.	3667.	2251.	0.0	3621.0	3	0	5.0	19	20.	0.42	5.00
29	JEPK	0	8.	66.	2047.	2047.	0.0	5512.0	0	0	4.0	26	65.	27.38	13.60
30	nBCC	0	80.	111.	2306.	1889.	0.0	3621.0	3	0	0.3	26	120.	0.99	6.00
31	nJEO	0	3.	124.	2058.	2058.	0.0	3621.0	3	0	4.0	23	120.	17.79	19.79
32	nJEK	0	8.	66.	2047.	2047.	0.0	3621.0	3	0	4.0	26	65.	28.38	13.60

FIXED SYSTEM
SUMMARY DESCRIPTION OF COMPOSITE HYDROELECTRIC PLANT TYPE HYD1
*** CAPACITY IN MW * ENERGY IN GWH ***
FIXED O&M COSTS : 2.500 $/KW-MONTH

YEAR	PROJ	PER	HYDROCONDITION 1 PROB.: 1.00 CAPACITY BASE	PEAK	ENERGY
2010	6	1	17.	0.	37.
		2	17.	0.	37.
		3	19.	0.	42.
		4	18.	0.	39.
		INST.CAP.		22.	
		TOTAL ENERGY			156.
2013	7	1	20.	0.	43.
		2	20.	0.	44.
		3	23.	0.	50.
		4	21.	0.	46.
		INST.CAP.		28.	
		TOTAL ENERGY			182.

```
                    FIXED SYSTEM
     SUMMARY DESCRIPTION OF COMPOSITE HYDROELECTRIC PLANT TYPE HYD2
          *** CAPACITY IN MW * ENERGY IN GWH ***
            FIXED O&M COSTS : 2.500 $/KW-MONTH
      P      HYDROCONDITION 1
      R  P      PROB.: 1.00
      O  E   CAPACITY  ENERGY
YEAR  J  R  BASE  PEAK

2010  1  1     6.    0.   13.
         2     7.    0.   15.
         3     6.    0.   14.
         4     5.    0.   12.
        INST.CAP.   21.
        TOTAL ENERGY      53.

2011  3  1    11.    0.   24.
         2    13.    0.   28.
         3    12.    0.   26.
         4    10.    0.   22.
        INST.CAP.   38.
        TOTAL ENERGY      99.
```

FIXED SYSTEM
THERMAL ADDITIONS AND RETIREMENTS
NUMBER OF SETS ADDED AND RETIRED(-)
2010 TO 2035

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

NO.	NAME	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
4	OH2				-1												
5	OH3				-1												
6	OH4				-1												
7	HB6				-1												
8	RF1										-1						
9	RF2										-1						
13	GT6	1															
16	GT9		1														
19	JPPC								-1								
20	JEP2																-1
29	JEPK		1														

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

	HYDROELECTRIC				THERMAL										TOTAL
	HYD1		HYD2		F U E L T Y P E										
					0	1	2	3	4	5	6	7	8	9	
YEAR	PR.	CAP	PR.	CAP	HFO	DISL	NATG	COAL	PETC	CNG			****	****	
2010	6	22.	1	21.	472.	242.	0.	0.	0.	0.	0.	0.	0.	0.	756.
2011	6	22.	3	38.	472.	260.	0.	0.	0.	0.	0.	0.	0.	0.	791.
2012	6	22.	3	38.	538.	279.	0.	0.	0.	0.	0.	0.	0.	0.	876.
2013	7	28.	3	38.	538.	279.	0.	0.	0.	0.	0.	0.	0.	0.	883.
2014	7	28.	3	38.	289.	279.	0.	0.	0.	0.	0.	0.	0.	0.	634.
2015	7	28.	3	38.	289.	279.	0.	0.	0.	0.	0.	0.	0.	0.	634.
2016	7	28.	3	38.	289.	279.	0.	0.	0.	0.	0.	0.	0.	0.	634.
2017	7	28.	3	38.	289.	279.	0.	0.	0.	0.	0.	0.	0.	0.	634.
2018	7	28.	3	38.	229.	279.	0.	0.	0.	0.	0.	0.	0.	0.	574.
2019	7	28.	3	38.	229.	279.	0.	0.	0.	0.	0.	0.	0.	0.	574.
2020	7	28.	3	38.	190.	279.	0.	0.	0.	0.	0.	0.	0.	0.	535.
2021	7	28.	3	38.	190.	279.	0.	0.	0.	0.	0.	0.	0.	0.	535.
2022	7	28.	3	38.	190.	279.	0.	0.	0.	0.	0.	0.	0.	0.	535.
2023	7	28.	3	38.	190.	279.	0.	0.	0.	0.	0.	0.	0.	0.	535.
2024	7	28.	3	38.	190.	279.	0.	0.	0.	0.	0.	0.	0.	0.	535.
2025	7	28.	3	38.	190.	279.	0.	0.	0.	0.	0.	0.	0.	0.	535.
2026	7	28.	3	38.	66.	279.	0.	0.	0.	0.	0.	0.	0.	0.	411.
2027	7	28.	3	38.	66.	279.	0.	0.	0.	0.	0.	0.	0.	0.	411.
2028	7	28.	3	38.	66.	279.	0.	0.	0.	0.	0.	0.	0.	0.	411.
2029	7	28.	3	38.	66.	279.	0.	0.	0.	0.	0.	0.	0.	0.	411.
2030	7	28.	3	38.	66.	279.	0.	0.	0.	0.	0.	0.	0.	0.	411.
2031	7	28.	3	38.	66.	279.	0.	0.	0.	0.	0.	0.	0.	0.	411.
2032	7	28.	3	38.	66.	279.	0.	0.	0.	0.	0.	0.	0.	0.	411.
2033	7	28.	3	38.	66.	279.	0.	0.	0.	0.	0.	0.	0.	0.	411.
2034	7	28.	3	38.	66.	279.	0.	0.	0.	0.	0.	0.	0.	0.	411.
2035	7	28.	3	38.	66.	279.	0.	0.	0.	0.	0.	0.	0.	0.	411.

VARIABLE SYSTEM

SUMMARY DESCRIPTION OF THERMAL PLANTS

NO.	NAME	NO. OF SETS	MIN. LOAD MW	CAPA CITY MW	HEAT RATES KCAL/KWH BASE LOAD	HEAT RATES KCAL/KWH AVGE INCR	FUEL COSTS CENTS/ MILLION KCAL DMSTC	FUEL COSTS CENTS/ MILLION KCAL FORGN	FUEL TYPE	FAST SPIN RES %	FOR %	DAYS SCHL MAIN	MAIN CLAS MW	O&M (FIX) $/KWM	O&M (VAR) $/MWH
1	NGCC	0	80.	117.	2306.	873.	0.0	3352.0	2	0	3.0	26	120.	1.07	2.53
2	GT	0	8.	39.	6100.	1827.	0.0	3352.0	2	0	3.0	18	40.	1.05	3.70
3	MSD	0	8.	60.	2047.	2047.	0.0	5512.0	0	10	4.0	18	60.	6.05	13.60
4	MSG	0	8.	60.	2047.	2047.	0.0	3352.0	2	10	4.0	18	60.	6.05	13.60
5	SSD	0	9.	60.	1814.	1814.	0.0	5571.0	0	10	3.0	18	60.	7.00	8.50
6	PvCO	0	30.	114.	3030.	2097.	0.0	1500.0	3	10	5.0	26	120.	2.34	5.00
7	OFCT	0	8.	39.	6100.	1827.	0.0	6959.0	1	0	3.0	18	40.	1.05	3.70
8	OFCC	0	80.	117.	2306.	873.	0.0	7008.0	1	0	3.0	26	120.	1.07	2.53

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

YEAR	CON	RES. MAR- GIN	NGCC	GT	MSD	MSG	SSD	PvCO	OFCT	OFCC
			PERMITTED EXTREME CONFIGURATIONS OF ALTERNATIVES							
2010	1	0	0	0	0	0	0	0	0	0
		40	0	0	0	0	0	0	0	0
2011	1	0	0	0	0	0	0	0	0	0
		40	0	0	0	0	0	0	0	0
2012	1	0	0	0	0	0	0	0	0	0
		40	0	0	0	0	0	0	0	0
2013	1	0	0	0	0	0	0	0	0	0
		40	0	0	0	0	0	0	0	0
2014	5	25	2	0	0	0	0	0	0	0
		40	8	6	0	0	0	0	0	0
2015	6	25	2	0	0	0	0	0	0	0
		40	8	6	0	0	0	0	0	0
2016	4	25	3	0	0	0	0	0	0	0
		40	9	6	0	0	0	0	0	0
2017	5	25	3	0	0	0	0	0	0	0
		40	9	6	0	0	0	0	0	0
2018	5	25	4	0	0	0	0	0	0	0
		40	10	6	0	0	0	0	0	0
2019	7	25	4	1	0	0	0	0	0	0
		40	10	7	0	0	0	0	0	0
2020	6	25	5	1	0	0	0	0	0	0
		40	11	7	0	0	0	0	0	0
2021	6	25	5	1	0	0	0	0	0	0
		40	11	7	0	0	0	0	0	0
2022	6	25	6	1	0	0	0	0	0	0
		40	12	7	0	0	0	0	0	0
2023	7	25	6	1	0	0	0	0	0	0
		40	12	7	0	0	0	0	0	0
2024	6	25	7	1	0	0	0	0	0	0

		40	13	7	0	0	0	0	0	0
2025	7	25	7	1	0	0	0	0	0	0
		40	13	7	0	0	0	0	0	0
2026	11	25	8	1	0	0	0	0	0	0
		40	14	7	0	0	0	0	0	0
2027	11	25	8	2	0	0	0	0	0	0
		40	14	8	0	0	0	0	0	0
2028	11	25	8	3	0	0	0	0	0	0
		40	14	9	0	0	0	0	0	0
2029	11	25	9	3	0	0	0	0	0	0
		40	15	9	0	0	0	0	0	0

C O N G E N (CONTD.)
CONSTRAINTS ON CONFIGURATIONS GENERATED
CON: NUMBER OF CONFIGURATIONS
MIMIMUM
MAXIMUM

YEAR	CON	RES. MAR- GIN	NGCC	GT	MSD	MSG	SSD	PvCO	OFCT	OFCC
			PERMITTED EXTREME CONFIGURATIONS OF ALTERNATIVES							
2030	14	25	9	3	0	0	0	0	0	0
		40	15	9	0	0	0	0	0	0
2031	14	25	9	3	0	0	0	0	0	0
		40	15	9	0	0	0	0	0	0
2032	14	25	9	3	0	0	0	0	0	0
		40	15	9	0	0	0	0	0	0
2033	14	25	9	3	0	0	0	0	0	0
		40	15	9	0	0	0	0	0	0
2034	14	25	9	3	0	0	0	0	0	0
		40	15	9	0	0	0	0	0	0
2035	14	25	9	3	0	0	0	0	0	0
		40	15	9	0	0	0	0	0	0

202 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 :	NGCC	GT	MSD	MSG	SSD	PvCO	OFCT	OFCC
SIZE (MW):	117.	39.	60.	60.	60.	114.	39.	117.

YEAR	%LOLP	CAP								
2010	2.971	0.								
2011	2.433	0.								
2012	0.556	0.								
2013	0.974	0.								
2014	0.139	351.	3							
2015	0.317	0.								
2016	0.051	117.	1							
2017	0.045	39.		1						
2018	0.039	117.	1							
2019	0.038	39.		1						
2020	0.019	117.	1							
2021	0.049	0.								
2022	0.010	117.	1							
2023	0.028	0.								
2024	0.005	117.	1							
2025	0.017	0.								
2026	0.051	117.	1							
2027	0.059	39.		1						
2028	0.069	39.		1						
2029	0.017	117.	1							
2030	0.054	0.								
2031	0.054	0.								
2032	0.054	0.								
2033	0.054	0.								
2034	0.054	0.								
2035	0.054	0.								
TOTALS		1326.	10	4	0	0	0	0	0	0

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
(NOMINAL CAPACITY (MW))

YEAR	0 HFO	1 DISL	2 NATG	3 COAL	4 PETC	5 CNG	6	7	8 ****	9 ****	TOTAL CAP
	THERMAL FUEL TYPE CAPACITIES										
2010	472	242	0	0	0	0	0	0	0	0	714
2011	472	260	0	0	0	0	0	0	0	0	732
2012	538	279	0	0	0	0	0	0	0	0	817
2013	538	279	0	0	0	0	0	0	0	0	817
2014	289	279	351	0	0	0	0	0	0	0	919
2015	289	279	351	0	0	0	0	0	0	0	919
2016	289	279	468	0	0	0	0	0	0	0	1036
2017	289	279	507	0	0	0	0	0	0	0	1075
2018	229	279	624	0	0	0	0	0	0	0	1132
2019	229	279	663	0	0	0	0	0	0	0	1171
2020	190	279	780	0	0	0	0	0	0	0	1250
2021	190	279	780	0	0	0	0	0	0	0	1250
2022	190	279	897	0	0	0	0	0	0	0	1367
2023	190	279	897	0	0	0	0	0	0	0	1367
2024	190	279	1014	0	0	0	0	0	0	0	1484
2025	190	279	1014	0	0	0	0	0	0	0	1484
2026	66	279	1131	0	0	0	0	0	0	0	1476
2027	66	279	1170	0	0	0	0	0	0	0	1515
2028	66	279	1209	0	0	0	0	0	0	0	1554
2029	66	279	1326	0	0	0	0	0	0	0	1671
2030	66	279	1326	0	0	0	0	0	0	0	1671
2031	66	279	1326	0	0	0	0	0	0	0	1671
2032	66	279	1326	0	0	0	0	0	0	0	1671
2033	66	279	1326	0	0	0	0	0	0	0	1671
2034	66	279	1326	0	0	0	0	0	0	0	1671
2035	66	279	1326	0	0	0	0	0	0	0	1671

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
2010	0	0	7	42	714	756	20.8	2.971	9.4
2011	0	0	9	59	732	791	23.5	2.433	7.5
2012	0	0	9	59	817	876	32.6	0.556	1.5
2013	0	0	10	66	817	883	28.6	0.974	2.7
2014	0	0	10	66	919	985	37.3	0.139	0.3
2015	0	0	10	66	919	985	31.4	0.317	0.8
2016	0	0	10	66	1036	1102	40.8	0.051	0.1
2017	0	0	10	66	1075	1141	39.8	0.045	0.1
2018	0	0	10	66	1132	1198	40.4	0.039	0.1
2019	0	0	10	66	1171	1237	38.9	0.038	0.0
2020	0	0	10	66	1250	1315	41.6	0.019	0.0
2021	0	0	10	66	1250	1315	35.9	0.049	0.1
2022	0	0	10	66	1367	1432	42.1	0.010	0.0
2023	0	0	10	66	1367	1432	36.6	0.028	0.0
2024	0	0	10	66	1484	1549	42.1	0.005	0.0
2025	0	0	10	66	1484	1549	36.8	0.017	0.0
2026	0	0	10	66	1476	1542	31.2	0.051	0.1
2027	0	0	10	66	1515	1581	29.6	0.059	0.2
2028	0	0	10	66	1554	1620	28.1	0.069	0.1
2029	0	0	10	66	1671	1737	32.5	0.017	0.0
2030	0	0	10	66	1671	1737	27.9	0.054	0.0
2031	0	0	10	66	1671	1737	27.9	0.054	0.0
2032	0	0	10	66	1671	1737	27.9	0.054	0.0
2033	0	0	10	66	1671	1737	27.9	0.054	0.0
2034	0	0	10	66	1671	1737	27.9	0.054	0.0
2035	0	0	10	66	1671	1737	27.9	0.054	0.0

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
FUEL STOCK OF THERMAL PLANTS BY FUEL TYPE (KTON)
THERMAL FUEL TYPES

	0		1		2		3		4	
YEAR	HFO		DISL		NATG		COAL		PETC	
	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
FUEL STOCK OF THERMAL PLANTS BY FUEL TYPE (KTON)
THERMAL FUEL TYPES

YEAR	5 CNG DOM.	5 CNG FOR	6 DOM.	6 FOR	7 DOM.	7 FOR	8 **** DOM.	8 **** FOR	9 **** DOM.	9 **** FOR
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
EXPECTED GENERATION BY PLANT TYPE (GWH)

	HYDROELECTRIC			THERMAL FUEL TYPES											
				0	1	2	3	4	5	6	7	8	9		GR.
YEAR	HYD1	HYD2	TOTAL	HFO	DISL	NATG	COAL	PETC	CNG			****	****	TOTAL	TOTAL
2010	156	53	209	3054	981	0	0	0	0	0	0	0	0	4035	4244
2011	156	99	255	3105	1005	0	0	0	0	0	0	0	0	4110	4365
2012	156	99	255	3351	924	0	0	0	0	0	0	0	0	4275	4530
2013	182	99	281	3480	961	0	0	0	0	0	0	0	0	4441	4722
2014	182	99	281	1757	143	2769	0	0	0	0	0	0	0	4669	4950
2015	182	99	281	1896	243	2769	0	0	0	0	0	0	0	4908	5189
2016	182	99	281	1398	63	3692	0	0	0	0	0	0	0	5153	5434
2017	182	99	281	1338	56	4006	0	0	0	0	0	0	0	5400	5681
2018	182	99	281	769	45	4855	0	0	0	0	0	0	0	5669	5950
2019	182	99	281	739	43	5160	0	0	0	0	0	0	0	5942	6223
2020	182	99	281	350	21	5850	0	0	0	0	0	0	0	6221	6502
2021	182	99	281	499	43	5962	0	0	0	0	0	0	0	6504	6785
2022	182	99	281	216	11	6567	0	0	0	0	0	0	0	6794	7075
2023	182	99	281	347	23	6719	0	0	0	0	0	0	0	7089	7370
2024	182	99	281	135	6	7248	0	0	0	0	0	0	0	7389	7670
2025	182	99	281	234	14	7448	0	0	0	0	0	0	0	7696	7977
2026	182	99	281	63	34	7913	0	0	0	0	0	0	0	8010	8291
2027	182	99	281	65	36	8226	0	0	0	0	0	0	0	8327	8608
2028	182	99	281	68	40	8545	0	0	0	0	0	0	0	8653	8934
2029	182	99	281	26	13	8945	0	0	0	0	0	0	0	8984	9265
2030	182	99	281	51	29	9241	0	0	0	0	0	0	0	9321	9602
2031	182	99	281	51	29	9241	0	0	0	0	0	0	0	9321	9602
2032	182	99	281	51	29	9241	0	0	0	0	0	0	0	9321	9602
2033	182	99	281	51	29	9241	0	0	0	0	0	0	0	9321	9602
2034	182	99	281	51	29	9241	0	0	0	0	0	0	0	9321	9602
2035	182	99	281	51	29	9241	0	0	0	0	0	0	0	9321	9602

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
EXPECTED FUEL CONSUMPTION OF THERMAL PLANTS BY FUEL TYPE (KTON)

	THERMAL FUEL TYPES									
	0		1		2		3		4	
YEAR	HFO		DISL		NATG		COAL		PETC	
	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

SUMMARY OF
FIXED SYSTEM PLUS OPTIMUM SOLUTION
EXPECTED FUEL CONSUMPTION OF THERMAL PLANTS BY FUEL TYPE (KTON)

THERMAL FUEL TYPES

	5		6		7		8		9	
YEAR	CNG						****		****	
	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR	DOM.	FOR
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

D Y N P R O

SUMMARY OF CAPITAL COSTS OF ALTERNATIVES IN $/KW

PLANT	CAPITAL COSTS (DEPRECIABLE PART) DOMESTIC	FOREIGN	INCLUSIVE IDC %	CONSTR. TIME (YEARS)	PLANT LIFE (YEARS)	CAPITAL COSTS (NON-DEPREC. PART) DOMESTIC	FOREIGN
THERMAL PLANT CAPITAL COSTS							
NGCC	0.0	1317.0	9.61	2.00	25.	0.0	0.0
GT	0.0	870.0	4.90	1.00	25.	0.0	0.0
MSD	0.0	1690.0	4.90	1.00	25.	0.0	0.0
MSG	0.0	1690.0	4.90	1.00	25.	0.0	0.0
SSD	0.0	2397.0	9.61	2.00	25.	0.0	0.0
PvCO	0.0	3019.0	18.46	4.00	35.	0.0	0.0
OFCT	0.0	870.0	4.90	1.00	25.	0.0	0.0
OFCC	0.0	1317.0	9.61	2.00	25.	0.0	0.0

```
                              D Y N P R O
                        ECONOMIC PARAMETERS AND CONSTRAINTS
                   ALL COSTS WILL BE DISCOUNTED TO YEAR    :   2010
                   BASE YEAR FOR ESCALATION CALCULATION IS :   2010
DISCOUNT RATE APPLIED TO ALL DOMESTIC COSTS - %/YR    11.9
DISCOUNT RATE APPLIED TO ALL FOREIGN  COSTS - %/YR    11.9
    2010 INITIAL VALUES :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         **************
         NAME OF ALTERNATIVES :
         NGCC  GT    MSD   MSG   SSD   PvCO  OFCT  OFCC
ESCALATION RATIOS FOR CAPITAL COSTS ( 0)
-----------------------------------
DOMESTIC 1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
```

```
                                D Y N P R O  (CONTD.)
                          ECONOMIC PARAMETERS AND CONSTRAINTS
    2010 INITIAL VALUES :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         **************
FUEL TYPE:                   T  H  E  R  M  A  L                     HYDRO    ENERGY
           HFO  DISL  NATG  COAL  PETC   CNG              ****  ****  HYD1  HYD2  NOT
                                                                                  SERVED
ESCALATION RATIOS FOR OPERATING COSTS ( 0)
-------------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          5.0000
DEPRECIATION OPTION (16)  :  0 = LINEAR
```

```
                                        D Y N P R O
                        LISTING OF MODIFIED CONSTRAINTS DURING STUDY PERIOD
    2011 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         ********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)         1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)         5.0000
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.01  1.01  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2012 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         ********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)         1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)         5.0000
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.08  1.06  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2013 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         ********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)         1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)         2.0000
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
```

```
FOREIGN   1.07  1.05  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2014 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.05  1.03  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2015 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.02  1.02  1.02  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2016 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.02  1.04  1.01  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2017 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000
```

```
COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.03  1.03  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2018 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         ********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.02  1.03  1.01  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2019 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         ********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.01  1.02  1.01  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2020 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         ********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
```

```
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.00  1.01  1.02  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2021 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.01  1.01  1.01  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2022 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.01  1.01  1.02  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2023 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
```

```
FOREIGN   1.01  1.01  1.01  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2024 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.01  1.01  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2025 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.01  1.01  1.01  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2026 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.00  1.01  1.02  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2027 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000
```

```
COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                         ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.01  1.01  1.01  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2028 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                         ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.01  1.01  1.02  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2029 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                         ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.01  1.02  1.02  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2030 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                         ($/KWH)       2.3200    0.0000    0.0000
```

```
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2031 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2032 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2033 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
```

```
FOREIGN   1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2034 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
    2035 YEAR WHEN NEW VALUES ARE IN FORCE :  (XX) = INDEX NUMBER; ( 0) = NO INDEX READ
         *********************************
PENALTY FACTOR ON FOREIGN EXPENDITURE   ( 3)          1.0000

COEFFICIENTS OF ENERGY NOT SERVED COST FUNCTION (11)   CF1       CF2       CF3
-----------------------------------------------
                                        ($/KWH)       2.3200    0.0000    0.0000
CRITICAL LOSS OF LOAD PROBABILITY IN %  (12)          0.5500
ESCALATION RATIOS FOR FUEL COSTS (17)
--------------------------------
DOMESTIC  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
FOREIGN   1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00  1.00
```

EXPECTED COST OF OPERATION
FUEL COST
DOMESTIC

TYPE OF PLANT:		HFO	DISL	NATG	COAL	PETC	CNG			****	****
YEAR	TOTAL	COST BY FUEL TYPE (MILLION $)									
2010	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2014	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2016	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		0.0		0.0		0.0		0.0		0.0	
TOTALS	0.0		0.0		0.0		0.0		0.0		0.0

EXPECTED COST OF OPERATION
FUEL COST
FOREIGN

TYPE OF PLANT:		HFO	DISL	NATG	COAL	PETC	CNG			****	****
YEAR	TOTAL	COST BY FUEL TYPE (MILLION $)									
2010	562.9	412.6	150.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	582.6	425.1	157.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	621.5	474.7	146.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2013	696.2	532.5	163.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2014	440.4	242.1	26.4	172.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	488.2	266.8	46.0	175.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2016	447.9	199.5	12.2	236.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	473.3	196.5	11.2	265.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	449.6	117.5	9.4	322.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2019	478.1	114.1	9.0	355.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	465.0	53.3	4.4	407.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	505.0	76.7	9.4	418.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	506.3	33.6	2.3	470.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	543.4	54.4	5.1	483.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	549.2	21.4	1.4	526.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	583.3	37.5	3.2	542.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	612.1	10.1	7.6	594.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	642.9	10.5	8.3	624.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	684.2	11.1	9.2	663.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2029	718.0	4.3	3.1	710.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	746.7	8.5	7.0	731.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	746.7	8.5	7.0	731.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	746.7	8.5	7.0	731.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2033	746.7	8.5	7.0	731.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	746.7	8.5	7.0	731.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	746.7	8.5	7.0	731.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTALS	15530.1	3345.2	828.5	11356.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0

EXPECTED COST OF OPERATION
OPERATION & MAINTENANCE AND ENERGY NOT SERVED (ENS)
DOMESTIC

COST BY FUEL TYPE (MILLION $)

TYPE OF PLANT: YEAR	TOTAL	HFO	DISL	NATG	COAL	PETC	CNG			****	****	HYD1	HYD2	ENS
2010	119.7	88.9	7.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	21.7
2011	116.4	89.3	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.1	17.4
2012	128.8	116.0	7.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.1	3.4
2013	133.0	116.8	7.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	6.3
2014	116.1	98.9	3.0	11.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.7
2015	120.4	101.3	3.6	11.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	1.9
2016	113.2	93.1	2.6	15.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.2
2017	113.8	92.2	2.5	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2018	85.7	60.5	2.5	20.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.2
2019	86.7	60.0	2.5	22.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2020	83.3	53.7	2.3	25.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.0
2021	86.6	56.4	2.5	25.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.2
2022	84.3	51.5	2.3	28.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.0
2023	87.0	53.7	2.3	28.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.0
2024	86.1	50.2	2.2	31.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.0
2025	88.4	51.8	2.3	32.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2026	61.8	22.4	2.4	34.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.2
2027	63.5	22.5	2.4	36.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.4
2028	64.8	22.5	2.4	37.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.2
2029	66.2	21.9	2.3	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.0
2030	67.6	22.3	2.4	40.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2031	67.6	22.3	2.4	40.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2032	67.6	22.3	2.4	40.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2033	67.6	22.3	2.4	40.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2034	67.6	22.3	2.4	40.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2035	67.6	22.3	2.4	40.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
TOTALS	2311.1	1457.5	85.7	664.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.3	28.9	53.6

EXPECTED COST OF OPERATION
TOTAL COST
DOMESTIC AND FOREIGN

COST BY FUEL TYPE (MILLION $)

TYPE OF PLANT: YEAR	TOTAL	HFO	DISL	NATG	COAL	PETC	CNG			****	****	HYD1	HYD2	ENS
2010	682.5	501.5	158.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.6	21.7
2011	699.0	514.3	165.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.1	17.4
2012	750.3	590.7	154.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.1	3.4
2013	829.2	649.3	171.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	6.3
2014	556.5	341.0	29.4	183.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.7
2015	608.6	368.2	49.6	186.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	1.9
2016	561.1	292.6	14.8	251.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.2
2017	587.1	288.7	13.8	282.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2018	535.2	178.0	11.8	343.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.2
2019	564.8	174.1	11.5	377.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2020	548.4	107.1	6.7	432.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.0
2021	591.6	133.1	11.8	444.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.2
2022	590.6	85.1	4.6	498.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.0
2023	630.4	108.1	7.5	512.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.0
2024	635.2	71.6	3.7	557.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.0
2025	671.7	89.3	5.5	574.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2026	673.9	32.5	10.0	629.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.2
2027	706.3	33.0	10.7	660.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.4
2028	749.1	33.7	11.6	701.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.2
2029	784.2	26.2	5.4	750.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.0
2030	814.3	30.8	9.4	772.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2031	814.3	30.8	9.4	772.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2032	814.3	30.8	9.4	772.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2033	814.3	30.8	9.4	772.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2034	814.3	30.8	9.4	772.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
2035	814.3	30.8	9.4	772.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.1	0.1
TOTALS	17841.2	4802.6	914.2	12020.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.3	28.9	53.6

FOREIGN CONSTRUCTION COSTS (MILLION $)

YEAR	#	PLANT	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	SUM
2014	3	NGCC	131.2	286.7											417.8
2016	1	NGCC			43.7	95.6									139.3
2017	1	GT					32.3								32.3
2018	1	NGCC					43.7	95.6							139.3
2019	1	GT							32.3						32.3
2020	1	NGCC							43.7	95.6					139.3
2022	1	NGCC									43.7	95.6			139.3
2024	1	NGCC											43.7	95.6	139.3
END TOTAL			131.2		43.7		76.0		76.0		43.7		43.7		
				286.7		95.6		95.6		95.6		95.6		95.6	

FOREIGN CONSTRUCTION COSTS (MILLION $) (CONTD.)

YEAR	#	PLANT	2024	2025	2026	2027	2028	SUM
2026	1	NGCC	43.7	95.6				139.3
2027	1	GT			32.3			32.3
2028	1	GT				32.3		32.3
2029	1	NGCC				43.7	95.6	139.3
END TOTAL			43.7	95.6	32.3	76.0	95.6	1521.9

FOREIGN INT. DURING CONSTR. (MILLION $)

YEAR	#	PLANT	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	SUM
2014	3	NGCC	7.7	33.4											41.1
2016	1	NGCC			2.6	11.1									13.7
2017	1	GT					1.9								1.9
2018	1	NGCC					2.6	11.1							13.7
2019	1	GT							1.9						1.9
2020	1	NGCC							2.6	11.1					13.7
2022	1	NGCC									2.6	11.1			13.7
2024	1	NGCC											2.6	11.1	13.7
END TOTAL			7.7		2.6		4.5		4.5		2.6		2.6		
				33.4		11.1		11.1		11.1		11.1		11.1	

FOREIGN INT. DURING CONSTR. (MILLION $) (CONTD.)

YEAR	#	PLANT	2024	2025	2026	2027	2028	SUM
2026	1	NGCC	2.6	11.1				13.7
2027	1	GT			1.9			1.9
2028	1	GT				1.9		1.9
2029	1	NGCC				2.6	11.1	13.7
END TOTAL			2.6	11.1	1.9	4.5	11.1	144.5

FOREIGN CONSTRUCTION & IDC (MILLION $)

YEAR	#	PLANT	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	SUM
2014	3	NGCC	138.9	320.0											458.9
2016	1	NGCC			46.3	106.7									153.0
2017	1	GT					34.2								34.2
2018	1	NGCC					46.3	106.7							153.0
2019	1	GT							34.2						34.2
2020	1	NGCC							46.3	106.7					153.0
2022	1	NGCC									46.3	106.7			153.0
2024	1	NGCC											46.3	106.7	153.0
END TOTAL			138.9		46.3		80.4		80.4		46.3		46.3		
				320.0		106.7		106.7		106.7		106.7		106.7	

FOREIGN CONSTRUCTION & IDC (MILLION $) (CONTD.)

YEAR	#	PLANT	2024	2025	2026	2027	2028	SUM
2026	1	NGCC	46.3	106.7				153.0
2027	1	GT			34.2			34.2
2028	1	GT				34.2		34.2
2029	1	NGCC				46.3	106.7	153.0
END TOTAL			46.3	106.7	34.2	80.4	106.7	1666.4

CAPITAL CASH FLOW SUMMARY OF CANDIDATES (MILLION $)

	NON-DEPRECIABLE			DEPRECIABLE			IDC			
YEAR	DOM.	FOR.	TOTAL	DOM.	FOR.	TOTAL	DOM.	FOR.	TOTAL	GR. TOT.
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	131.19	131.19	0.00	7.69	7.69	138.87
2013	0.00	0.00	0.00	0.00	286.66	286.66	0.00	33.39	33.39	320.05
2014	0.00	0.00	0.00	0.00	43.73	43.73	0.00	2.56	2.56	46.29
2015	0.00	0.00	0.00	0.00	95.55	95.55	0.00	11.13	11.13	106.68
2016	0.00	0.00	0.00	0.00	76.00	76.00	0.00	4.45	4.45	80.45
2017	0.00	0.00	0.00	0.00	95.55	95.55	0.00	11.13	11.13	106.68
2018	0.00	0.00	0.00	0.00	76.00	76.00	0.00	4.45	4.45	80.45
2019	0.00	0.00	0.00	0.00	95.55	95.55	0.00	11.13	11.13	106.68
2020	0.00	0.00	0.00	0.00	43.73	43.73	0.00	2.56	2.56	46.29
2021	0.00	0.00	0.00	0.00	95.55	95.55	0.00	11.13	11.13	106.68
2022	0.00	0.00	0.00	0.00	43.73	43.73	0.00	2.56	2.56	46.29
2023	0.00	0.00	0.00	0.00	95.55	95.55	0.00	11.13	11.13	106.68
2024	0.00	0.00	0.00	0.00	43.73	43.73	0.00	2.56	2.56	46.29
2025	0.00	0.00	0.00	0.00	95.55	95.55	0.00	11.13	11.13	106.68
2026	0.00	0.00	0.00	0.00	32.27	32.27	0.00	1.89	1.89	34.16
2027	0.00	0.00	0.00	0.00	76.00	76.00	0.00	4.45	4.45	80.45
2028	0.00	0.00	0.00	0.00	95.55	95.55	0.00	11.13	11.13	106.68
DOM.	0.00			0.00			0.00			
FOREIGN		0.00			1521.88			144.49		
TOTAL			0.00			1521.88			144.49	1666.37

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